

# **THE NATIONAL ENERGY MARKET ENVIRONMENTAL AND SOCIAL ISSUES**

**NGO POSITION PAPER  
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# DOES THE NATIONAL ELECTRICITY MARKET WORK?

Total Environment Centre

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## OVERVIEW

Australia's energy supply and demand system is in crisis. Its capacity to meet fundamental economic, social and environmental objectives now and into the future is being questioned.

Depending on who you believe, spiralling energy consumption is either set to trigger \$30 billion of infrastructure investment or cause severe capacity shortfalls due to lack of investment. Either way, if demand is not managed more wisely, it is likely that Australia's famously low energy costs will soon begin to skyrocket.

Parallel to escalating demand is the problem of greenhouse emissions. Without effective leadership at the Federal level, Australia is heading unprepared and unprotected into a carbon constrained future in which emissions will be a debilitating environmental and economic burden. The failure of the Federal Government to commit to a national emissions trading scheme is set to handicap the economy by allowing other countries to impose costs on our carbon, while providing no equivalent internal incentives for domestic emitters to abate. Outside the Kyoto tent, which will direct international carbon regulatory structures, Australia faces economic damage.

Underlying these dilemmas is the mammoth energy reform project that has taken two decades to materialise and still faces enormous, unresolved problems. The years 2004 to 2006 have been slated as a key period of reform in which the Ministerial Council on Energy (MCE) must resolve difficult supply-demand balance issues. Of critical importance are the social and environmental choices that will define the boundaries between the drive for short-term market efficiency and the delivery of social and environmental outcomes. A key will be the evolution of a market that adopts and improves the best of these from each state system, rather than a lowest common denominator model.

One cogent political reality shaping the move towards a market-based electricity system is that electricity supply is seen as an essential service, which governments cannot allow to fail. The other issue is the community's rejection of privatisation, which is seen by market reformers as essential to a functional market. On both issues, governments are vulnerable to their electorates. With the distortions of price dampening measures such as the NSW Electricity Tariff Equalisation Fund (ETEF) being introduced to protect consumers and tax-payer owned corporations, a strategic reappraisal of the National Electricity Market (NEM) architecture may be necessary.

The failure of policy makers to adequately consult before launching into such massive reform in the 1990s resulted in a lack of NGO commitment to the NEM and an incapacity to deliver the triple bottom line. Evidence has mounted to support the view that the market cannot deliver fundamental social objectives. In response, environment and consumer advocates are increasingly finding common ground in the call for regulatory and policy intervention, both of the NEM and externally.

The position papers here, largely produced by a grant to Total Environment Centre from the National Electricity Code Advocacy Panel, are part of an ongoing process being undertaken by consumer and environment groups to advocate the social and environmental bottom lines of reform. TEC's Green Capital program is also part of the avenue for debate.

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<sup>1</sup> Gavan McDonnell, 'NSW Government Ownership and Risk Management in a Mandatory Pool: 'Neither Fish nor Fowl nor ...' in *Power Progress : An Audit Of Australia's Electricity Reform Experiment*, Graeme Hodge, Valarie Sands, David Hayward, David Scott (eds.), Australian Scholarly Publishing, Monash University, 2004.

## **NATIONAL ELECTRICITY MARKET REFORM - BACKGROUND AND ISSUES**

### **A Brief History**

The international drive to transfer the ownership of the electricity sector from governments to the private sector has been in progress for over two decades. In Australia, as in other countries embarking on market reform, the move was advocated by corporate interests and conservative think-tanks, which vigorously argued that government owned electricity utilities had failed to deliver efficiency.<sup>2</sup> Part of the package was the disaggregation of the system into its component parts and the establishment of a market in which different suppliers competed. A series of inquiries and reports culminated in the Industry Commission report (1991) and the Independent Committee of Inquiry into National Competition Policy for Australia (1993) which recommended that Australia disaggregate and privatise its electricity utilities.

The first steps towards privatisation and disaggregation were taken by the Kennett Government in Victoria in 1993, which based the Victorian system on the now-defunct UK model. Despite a huge advertising campaign to gain public support for privatisation, most of the public opposed plans for privatisation.<sup>3</sup> In 1995, at a cost of \$16 billion incentive payments, the Keating Government garnered state agreement to participate in the privatisation and disaggregation of Australia's electricity system, and to establish the National Electricity Market using the Victorian market as a model.

One of the key problems with the 1995 decision was that it lacked a thorough research and consultation period. As a result, it failed to establish adequate political and community consensus. For such a huge restructuring project, a debate and consultation exercise of perhaps a decade may have been expected to take place. Instead, the reform agreement was rushed through, largely behind closed doors, before a series of problems with the proposed system were able to be addressed and key social choices made.

In 1998, the NEM began operating with NSW, Victoria and South Australia participating. By 2001, the national grid had been created, connecting Queensland, New South Wales, Victoria, ACT and South Australia. Tasmania is expected to finalise connection via Basslink in 2005/6.

Today it is a loosely connected set of state power grids moving towards a state of integration and full competition, with a mix of private and public ownership. In the 'mandated pool' generators compete to sell electricity to retailers, who sell to consumers via regulated transmission and distribution networks.

For supporters of market reform, the long term goal has been the creation of a competitive, efficient and national market in which all energy users can access the supplier of their choice. For opponents, the reform project is largely seen as an extension of neo-liberal economic agendas that allow the private sector to acquire assets which have the potential to deliver huge returns. With few success stories and several serious problems outstanding, there remains little consensus on the potential of the reform process to deliver on its promises and meet modern social and environmental needs.

### **Prices**

The key argument used by proponents of deregulation and privatisation has been that by harnessing the market forces to increase competition and efficiency, energy prices will drop. It has been this promise of lower prices that has produced valuable industry allies for free market advocates. Since the birth of the NEM, however, lower prices for many consumers have failed to materialise.

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<sup>2</sup> Sharon Beder, *Power Play: the fight for the world's electricity*, Scribe, 2003, p. 228.

<sup>3</sup> Beder, p. 233.

Apart from some initial price drops for the large, energy intensive industries, electricity generation prices have risen astronomically in states where full privatisation has taken place. In South Australia, prices for business and residential consumers rose 30%.<sup>4</sup> While consumers have borne some of this burden, governments have sought to avoid community backlash by placing caps on retailer charges to customers. In some cases, governments have subsidised retailers for shortfalls.<sup>5</sup> But to date, governments have been unable to completely bridge the gap between generator and retail prices for consumers. For example, after winning election in 2002 on promises of a tougher line on the private generators, South Australian Premier, Mike Rann concluded that there was little the government could do about rising prices because allowing retailers to fully pass on generator prices would bankrupt the state's one retailer, AGL.<sup>6</sup>

## The Market

To date, generator gaming, price caps and industry subsidies have caused prices to fluctuate wildly in the NEM, delivering different outcomes for different sectors. Prices can now move from \$12 per MWh to \$4,000 per MWh in minutes.<sup>7</sup>

Volatility is primarily caused by manipulation to the benefit of suppliers of the 5 minute bid system of the pool, generally regarded as hugely flawed.<sup>8</sup> In this system, the cheapest bids by generators for the provision of electricity are accepted by retailers first, and more expensive ones next, until demand is met. For each 5 minute period, the highest bid accepted becomes the price paid for all electricity.<sup>9,10</sup> In practice it allows generators to artificially push up prices.

Generation companies that own multiple plant, for example, manipulate higher prices by strategically withdrawing capacity from the pool, thereby raising bids. On hot days, when demand is high, generators can make millions by withholding capacity until the price peaks, only to rebid new capacity at inflated prices.<sup>11</sup> As a result, the NEM now operates somewhat like a highly speculative stockmarket.<sup>12</sup> While hedge contracts have been designed to protect retailers from the volatility, the inflated pool prices ensure that contract prices are also driven up.

The big winner in pricing so far has been the aluminium sector which uses 14% of Australia's electricity and produces 16% of greenhouse emissions from the electricity sector, yet which is exempted from high pool prices. Able to lock in low prices for decades in secretive contracts, the sector pays a low \$15 - \$25 per MWh.<sup>13</sup> Along with direct subsidies for electricity, tax-payer funded support amounts to \$410 million annually.<sup>14</sup> An Australia Institute report revealed that subsidies for the aluminium industry were so great that if the sector went off-shore, it would deliver an overall net benefit to the Australian economy.<sup>15</sup>

## The Realpolitik of Privatisation

The political fact is that these markets cannot be allowed to fail. This has not been explicitly accepted by the jurisdictions: the political responsibilities of the individual states are at odds with the market and regulatory design which they themselves accepted during the Keating era.<sup>16</sup>

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<sup>4</sup> John Spoehr, 'Power in Private Hands: The Privatisation of the South Australian Electricity Industry' in Graeme Hodge et al (eds.), p. 74.

<sup>5</sup> Beder, p. 138.

<sup>6</sup> Beder, p. 254.

<sup>7</sup> 'Let there be Light', *Australian Financial Review*, 1 June 2001, p. 80 in Beder, p. 138.

<sup>8</sup> Warwick Parer for COAG, *Towards a Truly National and Efficient Energy Market*, 2002, pp. 17-18

<sup>9</sup> Beder, p. 242.

<sup>10</sup> Alan Pears, 'Energy Reform and the Environment', in Graeme Hodge et al (eds.), p. 176.

<sup>11</sup> Beder, p. 242

<sup>12</sup> John Spoehr, *Power Politics: The electricity crisis and you*, Wakefield Press, accessed on 25.4.04 at

<http://evatt.labor.net.au/publications/papers/83.html>

<sup>13</sup> Clive Hamilton and Hal Turton, *Subsidies to the Aluminum Industry and Climate Change*, The Australia Institute, November 1999, p. 13.

<sup>14</sup> Hamilton and Turton, p.17.

<sup>15</sup> Hamilton and Turton, p. 17.

<sup>16</sup> Gavan McDonnell, draft of 'NSW Government Ownership and Risk Management in a Mandatory Pool: 'Neither Fish nor Fowl nor ...' in Hodge et al, p. 17

Advocates of reform claim that rather than being an intrinsic feature of the NEM and privatisation, market failure in the electricity sector has been caused by the asymmetrical mixture of private and public ownership among the states. NSW and Queensland, having disaggregated generation, retail and networks, are routinely attacked for not completing the reform process and selling up.

There are several reasons for the failure of some states to fully privatise, the most obvious of which has been the community's resounding rejection of the divestment of publicly owned essential services. If profits are to be made, why not send them back to the community in areas such as health, education and public transport? Making a quick shortfall at the expense of an infinite income stream, reliability and control just doesn't make immediate sense to many. And the price shocks and reliability failures experienced by South Australian and Victorian consumers have only served to cement privatisation's bad name. With such opposition, the NSW and Queensland governments can ill-afford to implement their commitment to privatise.

From an environmental perspective, it is arguable whether it is easier for Governments to introduce environmental costs into a public or privately owned generation base. Critics of publicly owned generation argue that state governments are unwilling to take any action that puts the revenue from generation at risk. Critics of privately owned generation argue that it's harder to regulate privately owned generation than public.

Stuck with public ownership for the time being and responsible for the survival of tax-payer owned corporations in a cut-throat market, Queensland and NSW have developed schemes which ensure that their electricity interests are not fully subjected to the NEM pool. The NSW Electricity Tariff Equalisation Fund and the Benchmark Pricing Agreement in Queensland act as insurance against the failure of state owned corporations. Critics argue that this prevents new players from entering the market, pushing up the NEM pool price. In NSW, state owned retailers have failed to provide competitive *GreenPower* to residential consumers. Retailers from other states wanting to sell *GreenPower* in NSW argue that ETEF is slowing their sales of *GreenPower*. But these moves make sense to government, at least in the short term, as strategies to protect publicly owned assets, essential services and political survival.

To date, the NSW government continues its attempt to fully join the NEM. To do so, it needs to negotiate the private/public ownership stalemate. One proposal (that emerged two years ago, but has now disappeared from view), involved farming out risk to the private sector, turning risk into a commodity.<sup>17</sup> Several questions remain with this proposal: what are the extra costs of this kind of risk abatement; and what could be the unintended effects of the transfer of economic power to yet another market?<sup>18</sup>

## **Navigating Regulation**

With the evolution of such increasingly complex mechanisms, it is not surprising that the regulatory landscape that holds those mechanisms in place is also complicated. In essence, the regulatory framework reflects the gradual transfer of jurisdictional responsibility from the state to the national level.

The National Electricity Code currently regulates the market, regional boundaries and the transmission networks, while state regulators oversee regulation of pricing and access for distribution networks and some parts of the retail sectors. In November 2004 the National Electricity Code will move from the National Electricity Code Administrator (NECA) to the new Australian Energy Regulator (AER), after which the states will be under pressure to gradually divest their responsibilities for networks and retailers. The National Electricity Market Management Company (NEMMCO) will also be replaced by the new Australian Energy Market Commission.

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<sup>17</sup> Gavan McDonell, 'NSW Government Ownership and Risk Management in a Mandatory Pool: 'Neither Fish nor Fowl nor ...' in *Power Progress: An Audit Of Australia's Electricity Reform Experiment*, Graeme Hodge, Valarie Sands, David Hayward, David Scott (eds.), Australian Scholarly Publishing, Monash University, 2004, p. 86.

<sup>18</sup> *Ibid.*, p.87.

It is in this process that environmental and community standards are at risk of further erosion, or alternatively could be strengthened in the evolving market structure.

In the negotiation between commercial, environmental and social goals - reliability, safety-nets, efficiency obligations, emissions reductions, cross-subsidies, pricing and access to the grid for embedded (small) generators are just some of the issues that must be addressed. It is critical that community opinions are heard along with those of the well-resourced industry lobbies and corporate funded think-tanks. The characterisation of regulation as a 'narcotic' by think-tanks like the Institute for Public Affairs, with the corresponding implication that the public/government are 'addicts' does little to reassure the community that responsible debate is occurring.<sup>19</sup>

### **The Consumer**

For the consumer, the road to the NEM has been rocky, particularly in states where privatisation has occurred. Along with price rises, consumers have seen a decline in reliability, the erosion of safety nets, the loss of tax-payer owned assets and warnings of supply deficits. The promise of choice has also remained unfulfilled, with the level of customers choosing to swap retailers or 'churn' languishing below 10% by April 2003 in NSW and Victoria.<sup>20</sup> Whether or not these are just teething problems is yet to be established, and leave open the opportunity for policy makers and regulators to prove that privatisation and disaggregation have been for the better.

### **The Environment**

There is little argument that the move to the NEM has to date produced far worse outcomes for the environment. And the ongoing reform process is not looking much better, with the overriding incentive of the market to sell more greenhouse emitting electricity. Currently, inefficiency on the consumer side of the fence is a plus for electricity companies. This explains why most retailers still actively sell and market air-conditioners despite their role in driving expensive, peak demand. The Electricity Supply Association has admitted that there has been a 31 per cent increase in greenhouse emissions as a result of deregulation.<sup>21</sup>

It is clear that without a package of regulations and incentives for energy efficiency and renewables, and in the absence of a national emissions trading scheme, there will be no effective action in the electricity sector on climate change. In the circumstances, it seems ludicrous that the Australian Greenhouse Office (AGO) should claim that "[t]he accelerating energy market reform measure aims to lower the rate of growth of emissions by improving the economic efficiency of energy supply...Energy market reform is a key element of Australia's greenhouse response."<sup>22</sup>

The electricity market does not include any long-run environmental costs such as mining, land use, thermal pollution and climate change. In addition, the market does not provide adequate, long term price signals to foster research, development and commercialisation of renewable energy, energy efficiency or demand management. Policy instruments such as emissions trading, that aim to introduce environmental externalities, and industry development policies like MRET and consumer response initiatives such as a demand management fund, will always be required to correct the structural flaws in the energy market that serve to entrench the status quo.

Nevertheless, it is debateable whether the old state-run systems would be delivering any better results for the environment. Thus new regulatory arrangements such as Queensland's 13% Gas Scheme and NSW's Greenhouse Benchmarks Scheme and the Demand Management Fund have had to be devised.

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<sup>19</sup> Alan Moran, 'Submission to IPART's Review of Regulated Retail Tariffs', Energy Issues Paper No. 22, March 2002, p. 4.

<sup>20</sup> Tony Wood, 'Full Retail Competition - will we go the distance?', p. 6, accessed 29.4.04 at: <http://www.d2003.net/program/pages/papers/Wood,268%20FRC.PDF>

<sup>21</sup> Beder, p. 335.

<sup>22</sup> Australian Greenhouse Office website accessed 25.0404 at: <http://www.greenhouse.gov.au/markets/reform/>

## Consultation

A key cause of the problems with the NEM today arise from the failure of decision makers to fully consult with the community and ensure full discussion and debate before launching the reform juggernaut.<sup>23</sup> By rushing into the NEM, inadequate time for capacity and consensus building has led to limited community support and the lock-in of problematic architectural defects.

The bad habit remains. To date, selective recommendations from the Parer Report<sup>24</sup> have been taken up by the Ministerial Council for Energy (MCE) and are being progressed by six working groups run by state bureaucrats.<sup>25</sup> The scope of social choices available for public comment is limited, and a coherent response to greenhouse is completely lacking.

The standard of consultation in this process is far from adequate. Accessibility, outreach, information, resources and timelines all rank low. Information on consultation processes themselves are buried deep in government websites and require sophisticated technical and economic knowledge to engage. The process is hampered by restrictively short deadlines and under-resourced community and environment sectors. This poor standard of consultation on critical questions cannot be justified when the ramifications of such decisions are so great. In the headlong drive towards the NEM, key environmental and community concerns are once again likely to be being sidelined.

## Representation

The market reform process has been limited by a chronic pattern of good intentions followed by inaction.<sup>26</sup>

This pattern has several causes, not least of which has been the inability of policy makers and bureaucrats from different sectors to integrate their goals, with narrow economic concerns dominating. Most debilitating, however, has been the exclusion of community and environment stakeholders on critical decision making bodies and committees. Key decisions at various levels are routinely black-boxed by technocrats and the electricity industry clique – most are narrowly focused on 'making the market work'.

Likewise, the regulation and management of the NEM has inadequate representation. Without effective representation from all sectors of the community on the critical bodies and committees inside the market process, it can be expected that social and environmental objectives will continue to remain unmet.

## A Better Way for Consultation and Representation

The consultative and representative processes should be greatly improved, including:

- allowing longer lead-times for consultation;
- providing easy to understand briefing papers on each issue that present a range of views;
- better resourcing of the community and environment sectors on par with the advocacy budgets of private and state owned corporations.
- seeking a greater range of independent advice and making the reports public; and;
- developing improved processes for communication between environment, community and energy departments and ministries.

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<sup>23</sup> Thanks to Hugh Outhread for this perspective.

<sup>24</sup> Warwick Parer for COAG, *Towards a Truly National and Efficient Energy Market*, 2002.

<sup>25</sup> See Appendix 2 for an overview of the working groups and associated timelines for reform.

<sup>26</sup> Alan Pears, p. 170-3.

Community and environment stakeholders must be represented in all processes, including:

- oversight of the appointment of NEC/AER Commissioners;
- oversight over the appointment of AEMC Directors;
- NEMMCO's Participant Advisory Committee;
- relevant NEMMCO working groups;
- the Gas Advisory and Code Change Committee;
- the NEC Code Change Committees;

## **Conclusions**

The NEM's future is under debate. What is not in question is the failure, so far, to deliver critical social and environmental objectives.

Choices must be made and acted on before the market itself decides through inaction or perverted signals and we are chained to a disastrous 'race to the bottom'. If the electricity market is to deliver consumer protection and a reduction of greenhouse emissions it will be at the hands of effective NGO engagement and tougher strategic regulation, not a 'light-handed' approach.

Total Environment Centre and its NGO partners will advocate the positions in this paper through a range of actions, including:

- Provision of the paper to relevant decision making bodies and a request for specific answers;
- Briefings of key officials engaged in market reform;
- Supply of the paper to all relevant NGOs at national, state and regional levels;
- Strategic issues notices to the media.

# DEMAND MANAGEMENT AND ENERGY EFFICIENCY

Total Environment Centre

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## OVERVIEW

Demand management (DM) and energy efficiency constitute an essential element of any electricity system. DM can include both the management of peak loads and energy efficiency as a way of reducing base load. The efficient use of infrastructure and the elimination of wastage are key to economic efficiency and the reduction of greenhouse emissions. DM includes a diverse array of customer activities that meet customer energy needs, including cogeneration, standby generation, fuel switching, energy efficiency, interruptible customer contracts, and other load shifting.

Australian policy makers identified the huge potential for DM a decade ago.<sup>27</sup> Since then, a succession of reports have confirmed this potential, and offered a raft of policy and regulatory strategies to harness it.<sup>28</sup> DM projects carried out in NSW have had an exceptional benefit to cost ratio.<sup>29</sup> In the US, where DM Funds have been in existence for many years, the benefits outweigh the costs by up to 6:1.<sup>30</sup> These superior pay-back rates do not include the economic advantages of reducing greenhouse emissions. Despite the benefits, however, demand management and energy efficiency have become trapped in a gulf between policy and practice. As the NEM has evolved, focus has been almost entirely on supply at the expense of end-user efficiency.

In 2002, the Parer Report recognised the importance of DM and recommended several measures to improve demand-side participation, including the establishment of a demand-side bidding pool, the roll-out of interval meters, the removal of retail price caps and improving access for embedded generators to the grid. However, underlying these recommendations was the assumption that the market would naturally lead to a demand-side market able to compete with the supply-side. What Parer and others have failed to recognise is that the market that they are attempting to develop is a market to *sell* electricity. This is in sharp contrast to a market that aims to *save* electricity.

Several working groups under the direction of the Ministerial Council on Energy (MCE) are currently progressing some of the recommendations from the Parer Report. However, many are in conflict with other reforms, and as a package, they fall well short of a strategic response.

Delivering demand management to the customer side of the market has no silver bullets. Instead, it will rely on the vigorous implementation of regulatory controls and incentive mechanisms at all levels of the market - generation, networks, retail, heavy industry and demand management service providers. The following discussion explores what measures could be used to address each of these areas.

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<sup>27</sup> National Grid Management Council, *Demand Management Opportunities in the Competitive Electricity Market*, Vol. 1, Discussion Paper, 1994.

<sup>28</sup> For example, Charles River Associates and Gallagher & Associates "Electricity Demand Side Management Study" prepared for VENCORP, 7 September 2001; Independent Pricing and Regulatory Tribunal, *Inquiry into the Role of Demand Management and Other Options in the Provision of Energy Services*, Oct 2002; Deni Greene and Alan Pears, "Policy Options for Energy Efficiency in Australia" Australian CRC for Renewable Energy Policy Group, January 2003; Charles River Associates and Gallagher & Associates "Electricity Demand Side Management Study" prepared for VENCORP, 7 September 2001

<sup>29</sup> For example, Department of Energy, Utilities and Sustainability, *Electricity Network Performance Report 2000-01*, p. 23-30.

<sup>30</sup> NextEnergy and Total Environment Centre, *Demand Management and the NEM*, 2004, p. 28.

## GENERATION

The Parer Report recommended the development of a demand-side bidding process, designed to compete equally with generator bids in the pool.<sup>31</sup> Under the direction of the MCE, the User Participation Working Group is progressing this proposal. Currently, forward contracts exist between retailers /distributors and large consumers where the consumer agrees to temporarily reduce the use of electricity in response to pre-agreed conditions, such as the pool price, in exchange for a fee.<sup>32</sup> In South Australia, for example, around 239MW is available for load reductions at peak times in response to high pool prices.<sup>33</sup> Further enabling consumers to sell a demand-side response in this way has, the potential to vastly increase DM.

### A Demand-side Aggregation Facility

An off-market, demand-side aggregation facility that manages a range of demand-side responses from large customers has been proposed as an alternative to the 'pay as bid' approach recommended by the Parer Report. The off-market approach has the benefit of being able to mix, match and substitute individual parts of plant curtailment.<sup>34</sup> As such, it provides a form of insurance against failure by individual consumers to carry out committed load reductions. It also insures against the failure of retailers being able to match bid prices. The Energy Users Association of Australia (EUAA), an association which represents large industrial energy users, did a paper trial for an aggregation facility based on real market conditions and found estimated benefits of \$2 billion per year, representing a saving of around \$10 per MWh.<sup>35</sup>

One difficulty that needs to be addressed in any demand-side bidding model is the disparity between the flexibility of generator and demand-side bids. The NEM allows rebidding up to 5 minutes before generator dispatch while most consumers with demand-side bids, particularly those with relatively large quantities of energy, cannot match that level of generator flexibility. This creates inequity for DM providers if the price erodes on a bid after the load reduction has occurred. This lack of parity needs to be resolved before a workable DM aggregation facility is established.

The EUAA has identified a further barrier to the operation of an effective demand-side aggregation facility involving perverse incentives embedded in the National Electricity Code (the Code).<sup>36</sup> While all generators are paid the highest bid price in the spot market, DM bids have the effect of reducing that price, eroding the value of DM. In effect, by bidding DM into the market, DM aggregators are prevented from capturing the real value of their bids. For the development of a workable aggregation facility, the Code should consider an appropriate compensation facility to redress this inequity.

While a functional demand-side aggregation facility has the ability to capture more DM, its focus on large industrials means that it can capture only a small portion of the market. While the roll-out of interval meters has the potential to extend the demand-side aggregation facility to smaller end users, its dependence on high prices makes it relevant in peak periods only, leaving the huge potential of energy efficiency in the base-load untapped. This pattern has already emerged in relation to load curtailment contracts, and demonstrates the way in which cheaper prices can often lead away from, rather than towards, efficiency.<sup>37</sup>

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<sup>31</sup> Warwick Parer for COAG, *Towards a Truly National and Efficient Energy Market*, 2002.p. 178-179.

<sup>32</sup> Electricity Supply Industry Planning Council (SA), *Annual Planning Report*, June 2003, p. 50.

<sup>33</sup> *ibid.*,

<sup>34</sup> Pareto Associates, *A Demand Side Response Facility for the National Electricity Market*, April 2004, p. vii.

<sup>35</sup> *Ibid.*, p. ix.

<sup>36</sup> *Ibid.*, p. xiii.

<sup>37</sup> For example, the Electricity Supply Industry Planning Council of SA points out that lower demand forecasts for 03-04 "...do not allow for a potential demand side response to high pool prices which have been estimated at 239MW for the combined SA region.", Executive Summary, p.3.

## NETWORKS

Networks are the 'poles and wires' part of the electricity system that deliver electricity to consumers. They are natural monopolies and therefore subject to price regulation. Transmission networks, which deliver high-voltage electricity from generators to sub-stations, are regulated by the ACCC under the National Electricity Code. Distribution networks, which deliver electricity from substations to consumers, are regulated by state regulators, with some guidance from the Code.

Network congestion can be used as a driver to defer augmentation investments. Network driven DM also has the potential to mitigate the market power of concentrated supply-side generators.<sup>38</sup> However, huge problems remain in the capture of DM potential by networks. In NSW, for example, less than 2 per cent of capital expenditure is planned for DM in the next five years despite untapped potential of over 30 per cent.<sup>39</sup>

Two central barriers emerge from the form of revenue regulation imposed by the National Electricity Code and the state regulators. The first is the price cap form of regulation that rewards distribution networks for more electricity sales, and does not impose limitations on distribution network augmentations even when more cost-effective alternatives are available. The second barrier is that both transmission and distribution network revenues are determined in relation to networks' Regulated Asset Base. While, in principle, this should not be a barrier to demand management, the lack of an effective procedure for rolling demand management investments into networks' asset bases creates an incentive for networks to build rather than defer their augmentations.

Many aspects of pricing and incentives fall well within the purview of the NEM and the Code. However, the Code does not provide direction or details as to how pricing and incentives should be developed to facilitate effective DM.<sup>40</sup> The NEM should provide a useful forum for addressing the challenges to better pricing, and promote the adoption of clearer pricing and incentives that would facilitate viable DM.<sup>41</sup> The National Electricity Code should address these barriers in the move to the new Australian Energy Regulator, which has the potential to remove jurisdictional discrepancies and adopt mechanisms that promote efficiency across the NEM.

### Network Pricing and Regulation

The Parer Report's recommendation to move from a revenue cap to a price cap for distribution networks has removed incentives for greater efficiency in jurisdictions acting on this advice, such as NSW. The Independent Pricing and Regulatory Tribunal (IPART) draft determination for NSW networks has attempted to compensate for this perverse incentive.<sup>42</sup> In effect, IPART has proposed that networks be able to recoup revenue for both the cost of carrying out DM and for the lost revenue of sales that would have been made had an augmentation gone ahead. This 'D-factor' is integrated into the Weighted Average Price Cap and is passed onto consumers in their final electricity bill. While well intended, this system introduces significant uncertainty in the measurement of 'lost revenue'. Under the system, DM still remains an optional choice for networks, that are still able to choose to augment the network, a likely scenario considering the 'build' culture within these businesses.

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<sup>38</sup> R. Cowart, *Efficient Reliability – The critical role of demand side resource power systems and markets*, prepared for the National Association of Regulatory Utility Commissioners, June 2001, p.2

<sup>39</sup> For example, the National Framework for Energy Efficiency has recently found that cost-effective energy efficiency of 30-70% is available across the sectors.

<sup>40</sup> National Electricity Code, Chapter 6.

<sup>41</sup> NextEnergy and Total Environment Centre, *Demand Management and the NEM*, 2004.

<sup>42</sup> IPART, *Treatment of Demand Management in the Regulatory Framework for Electricity Distribution Pricing 2004/05 to 2008/09 Draft Decision*, February 2004.

Another key barrier to the uptake of DM by networks, also fuelled by the form of revenue regulation currently in place, is 'strategic behaviour' or manipulation of the revenue setting process to increase revenue. Allowable revenue is determined on the basis of a network's Regulated Asset Base (RAB). As regulators do not effectively require the networks to invest in DM when it is cost-effective, networks focus purely on new infrastructure as an answer to increasing demand. This means more poles and wires, and more incentives to sell more electricity. Moves to artificially increase revenue include overstatement of the RAB, over-blown demand projections and capital costs, and stone-walling of embedded generation projects.<sup>43</sup>

The situation is not helped by the obfuscation of revenue review processes in which regulators are increasingly delegating reviews of highly complex technical and economic documents to consultants. The limited scope of these reviews consistently fails to expose network gaming or call networks to account for their failure to undertake DM. The Review of Capital and Operating Expenditure of the NSW distribution networks undertaken by Meritec Limited in NSW, for example, offered no detailed or credible analysis of DM and network options to support its assertion that DM could not have deferred any network capital expenditure during 1999-2003 and was "not likely to have a material impact on the capex" during 2004.<sup>44</sup>

Such opaque assessments cannot be justified in independent regulatory reviews that have enormous impacts on consumers and the environment. If regulators expect networks to take DM seriously, they need to undertake meaningful and substantiated assessments of past network investment and disallow recovery of imprudent investment that should have been deferred. Prudency reviews by regulators need to be more transparent and should include failure to undertake DM when cost-effective as a reason to disallow capital expenditure.

Under-resourced consumer and environmental groups also have little hope of being able to conduct alternative analyses of network planning documents, demand projections and DM projects (or lack of them). To allow meaningful participation by these groups, funding should be made available for regulatory determinations equal to the funding that networks spend on their own advocacy in these processes.

Several networks have rightly noted that there is a lack of clarity regarding the recovery of DM spending by regulators. While IPART has attempted to address this issue in its Draft Determination for 2004-2009,<sup>45</sup> the ACCC has not provided explicit guidance on the treatment of DM spending by transmission networks, and the topic is not addressed in its Draft Statement of Principles for the Regulation of Transmission Revenue.<sup>46</sup> Notably, the Code specifically lists the costs of network augmentation and generation options, but not DM costs, as factors to be included in setting network revenue requirements, and does not require regulators to specify regulatory treatment.<sup>47</sup> While the Code has a broad principle specifying that the transmission regulatory regime must "have regard to the need to...create an environment in which demand side options are given due and reasonable consideration",<sup>48</sup> there are no provisions detailing how that might be achieved.<sup>49</sup>

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 be gradually reduced as the potential for DM is utilised. This would directly implement the policy objectives yet unfulfilled.

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<sup>43</sup> Energy Users Association of Australia and Energy Action Group, *Submission to the Transend Revenue Application*, July 2003.

<sup>44</sup> Meritec Limited, *Review of Capital and Operating Expenditure of the NSW Electricity DNSPs- Final Report*, Sept 2003

<sup>45</sup> IPART, 2004.

<sup>46</sup> ACCC, *Statement of Principles for the Regulation of Transmission Revenues*, Draft, May 1999.

<sup>47</sup> NEC 6.2.4 ©

<sup>48</sup> NEC 6.2.3 (d) (2)

<sup>49</sup> NextEnergy and Total Environment Centre, *Demand Management and the NEM*, 2004, p. 12-13.

More cost-reflective locational pricing is also necessary. Network costs can be very high at specific locations where growing peak demands approach capacity. However, distribution network tariffs typically are flat or averaged across both location and time. As a result they do not provide customers with price signals about congestion costs.

There are a number of challenges in developing and implementing tariffs that reflect congestion costs, including equity considerations.<sup>50,51,52</sup> Advocates for low-income consumers point out that these consumers may be adversely affected by congestion tariffs. However, with the exception of some special groups, it is quite possible to have cost reflective time-of-use and locational tariffs without raising average tariffs. This is done by raising tariffs at times of high congestion and lowering them at other times, with average bills remaining the constant.

## Network Planning

Planning by networks has been traditionally geared towards the reliable supply of electricity, with efficiency concerns limited to the technical, network side of the fence. As such, it has tended to be black-boxed and engineer-driven, with little attention paid to reducing end-user demand. Annual planning reports usually even fail to mention that demand management is an alternative to network expansion, despite its huge potential to defer expensive augmentations.<sup>53</sup> While it might be expected that independent planning bodies would provide oversight on excessive building investments, South Australia's experience with the Electricity Industry Supply Planning Council, dominated by industry representatives, does little to ensure efficient development. In this context, network planning processes need a thorough overhaul if the economic and environmental benefits of demand management are to be captured.

One of the major problems for DM proponents is the absence of an obligation on the part of networks to fully explore and solicit proposals for DM before expanding their networks. While DM proponents are free to come forward in the current NEC planning approach, their proposals need not be specifically sought, and it is unclear how such proposals would be treated. This is inappropriate regulation for monopoly networks with an incentive to build under the price cap. It results in significant inefficiency, with peak demand driven network augmentations only being used for a small amount of the time. In a competitive market, the failure of monopoly networks to treat non-network and generation options equally goes against the spirit and intentions of the Code.<sup>54</sup>

The NSW *Electricity Supply Act*, attempts to address this problem. However, it falls short by only requiring networks to 'investigate and report on' cost-effective demand management solutions to constraints.<sup>55</sup> To ensure that networks operate efficiently, therefore, the National Electricity Code should require networks to solicit proposals for alternative non-network solutions before they undertake major network augmentations and adopt these alternative proposals where they are more cost-effective. This would involve clear protocols for information disclosure, specification of constraints, requests for proposals, and evaluation of proposals.<sup>56</sup>

In addition, the NEC should specify protocols for valuing avoided distribution costs. At present, networks are able to internally deem DM 'not cost-effective' before thorough investigation has been carried out. This process not only results in discrepancies between the networks as to how they value deferrals, but creates an aura of secrecy around the consideration of DM and excludes the DM service provider market and other stakeholders from valuable information.

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<sup>50</sup> NextEnergy and Total Environment Centre, *Demand Management and the NEM*, 2004, p. 13.

<sup>51</sup> See, e.g., Public Interest Advisory Centre "Submission to the Independent Pricing and Regulatory Tribunal Review of Electricity Pricing Distribution" July 2003, p. 4.

<sup>52</sup> Australian Consumers' Association "Submission to the Independent Pricing and Regulatory Tribunal of New South Wales Review of Electricity Networks Pricing for 2004".

<sup>53</sup> For example, VENCORP Annual Report 2002-03; ElectraNet Annual Report 2003.

<sup>54</sup> National Electricity Code, 5.6.2

<sup>55</sup> While this has resulted in little actual DM, it has contributed to the improvement of information disclosure through the networks' Annual Electricity System Distribution Reports (AESDR).

<sup>56</sup> NextEnergy and Total Environment Centre, *Demand Management and the NEM*, 2004, p. 31-32.

## **Network Standard Offers**

DM service providers face similar barriers to those faced by distributed generators attempting to connect to the grid. Negotiation of DM provision, if at all, is often carried out through a request for proposals (RFP) process, in which both transaction costs and risks for DM service providers can be high. 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. As such, they are a critical tool for achieving demand management, providing users and DM service providers with a strong incentive to reduce demand in a transparent, accessible and reliable way.

Standard offers 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.

The NEC should consider requiring networks to develop standard offers for demand reduction where constraints are forecast to arise.

## **RETAIL**

The two impediments to cost-reflective retail pricing across the NEM are the state schemes that protect government owned electricity businesses from price volatility in the market<sup>57</sup> and retail price caps designed to protect consumers from price. While it is appropriate to protect default tariff customers from excessive, monopoly prices as a social objective, the use of these schemes need not restrict the application of DM.

The lack of consumers seeking out competitive retailers has resulted in the majority of consumers remaining on default tariffs which are capped by governments and regulators. Default tariffs are set according to two basic parameters: they are set low enough to protect consumers from high prices; and they are set higher than the lowest non-default tariff in order to allow retailers to recover their costs. In some cases, however, this margin is seen as a necessary component to competition as it creates the incentive for customers to switch retailers.

There are two significant problems with these arrangements. One is the lack of incentive for customers on default tariffs to reduce demand. The other problem is that retailers are automatically reaping profits from the headroom without having to improve efficiency. This inhibits the development of real competition and provides windfall gains for retailers who can raise prices up to the cap set by state governments.

## **Subsidies for the Aluminium Industry**

For a sector that uses such a huge proportion of Australia's electricity, it is inappropriate for the aluminium industry to be sheltered from the market. Along with direct subsidies for electricity, tax-payer funded support amounts to \$410 million annually.<sup>58</sup> Governments should make subsidies to this sector transparent and justify these. The industry should also be subjected to a mandatory energy efficiency benchmark program.

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<sup>57</sup> Such as the Electricity Tariff Equalisation Fund in NSW and the Benchmark Pricing Agreement in Queensland.

<sup>58</sup> Hamilton and Turton, p.17.

## THE DEMAND MANAGEMENT MARKET<sup>59</sup>

Despite the magnitude of the reforms outlined above, without significant funding for capacity building for the supply of DM the market will continue to be dominated by the supply-side and DM will remain undeveloped. Market reforms such as improved network planning protocols, the roll-out of interval meters and a demand-side aggregation facility merely prepare the market for the entry of DM.<sup>60</sup> On their own, they do not enable a DM services market to develop and compete with the approximately \$75<sup>61</sup> billion energy supply industry that was established over a century with massive government assistance. Many jurisdictions in the US have concluded that a parallel market mechanism is needed to specifically target demand management services.

### Demand Management Funds

In order to facilitate this much needed capacity building for both small and large end-users, one or more dedicated demand management funds should be established and mandated to purchase demand management from all players in the market. Without a specific funding mechanism that establishes a demand management market, there will continue to be a lack of dedicated, well-resourced DM competing with traditional supply options within the NEM.

The IPART Inquiry into Demand Management recommended the establishment of DM Funds as an essential step in the development of a DM market.<sup>62</sup> Acting on this recommendation, Premier Carr announced the establishment of a DM Taskforce to investigate this option in November 2003 and the NSW Government is currently progressing this project.<sup>63</sup> For the whole NEM to benefit from the delivery of DM, however, this model needs to be adopted by the new Australian Energy Regulator and applied across all jurisdictions.

The NextEnergy and Total Environment Centre report, 'Demand Management and the National Electricity Market', has developed six critical principles that should guide the establishment of DM Funds.<sup>64</sup> These are outlined below:

#### **Dedicate \$0.001 per kWh for a minimum of 5 years**

Given the current level of maturity of the DM services market, the level of funding should be small relative to the anticipated total opportunity (and to total network and overall electricity spending), yet be sufficient in scale and predictability to attract serious attention from a diverse array of potential suppliers of demand management services. A sum equivalent to \$0.001 per kWh would be a reasonable starting point, consistent with international experience and domestic opportunities. This would be about \$65 million in NSW, and \$40 million in Victoria, or about 1% of electricity revenues. Importantly, this funding should reduce consumers' electricity costs by redirecting funds that would otherwise go to more costly but avoidable network and generation augmentation.

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<sup>59</sup> This section builds on the NextEnergy and Total Environment Centre report, *Demand Management and the National Electricity Market*, February 2004.

<sup>60</sup> The EUAA Report confirms that commercial incentives are preferable over cost-reflective pricing to stimulate DM in Pareto Associates, *A Demand Side Response Facility for the National Electricity Market*, April 2004, p. x.

<sup>61</sup> Based on total assets.

<sup>62</sup> IPART, *Inquiry into the Role of Demand Management and Other Options in the Provision of Energy Services*, 2002, p. iii.

<sup>63</sup> Premier of NSW "News Release Premier Announces Further Measures to Tackle Greenhouse Emissions and Global Warming" 20 November 2003.

<sup>64</sup> NextEnergy and Total Environment Centre, p 30-32.

### **Encourage and Harness Competitive Markets**

A DM Fund should harness the innovation and dynamism of competitive markets. This could be done by making regular Standard Offers and Requests for Proposals that specify the overall goal of facilitating large scale deployment of a broad array of demand management measures on a timely basis and enable respondents the greatest latitude in suggesting projects accordingly. The suggested level of funding should achieve a high level of commercial interest and innovation from existing and prospective demand management providers. To encourage a wide range of non-network solutions, some consideration should also be given to local generation.

### **Establish Funds as Special Purpose Independent Entities in each State**

Under sections 5.6.2, 6.2 and 6.13, or a new section of the Code, NECA should facilitate the development of DM Funds in each jurisdiction to ensure that demand management resources are integrated across the NEM. The Code should specify that DM Funds are to be administered by an independent government-established body, and not by existing electricity companies. This would help ensure appropriate institutional priorities and incentives, and give prospective service providers confidence that their offerings would be appropriately considered. It would also avoid a significant number of potential conflicts of interest. It seems appropriate to establish a separate fund in each state. This approach would be more expedient, and would enable the fund to focus on particular issues and opportunities unique to the each region.

### **Focus Activities on Specific Areas with Identified Upcoming Network Constraints and Establish Performance Targets**

In prioritising Fund activity, it would be appropriate to identify areas where intensive DM activity would be most likely to be able to demonstrate an ability to defer network spending. Performance targets should be established consistent with the level of DM required to defer augmentation and the level of energy efficiency potential available across the NEM.

### **Adopt a Timely and Iterative Approach**

Given the long term lack of progress in achieving significant DM take-up, a DM Fund should accept the timeliness/perfection trade-off in favour of timeliness. That is, it would be preferable to conduct a 'good' Request for Proposal (RFP) in the near term rather than a RFP 'perfect' in the indefinite future. Furthermore, it is inevitable that revisions to future RFP rounds would be made based on the experiences gained in the previous rounds. For example, the delay in progressing the NSW EnergyAustralia/ TransGrid/ Department of Infrastructure, Planning, and Natural Resources DM Fund has sent a poor signal to the market regarding the priority placed on demand management, and contributes to the continuing predominance of traditional supply infrastructure in meeting electricity needs.

### **Support Broader Participation in NEM Planning Processes**

The great majority of Funds should be dedicated to implementation of DM projects. However, some funding should be made available to support broader participation by DM advocates in NEM planning processes, including both the annual planning reviews performed by NSPs and network individual augmentation cases. Currently, few parties beyond current NEM participants regularly comment in NEM planning processes. However, a variety of non-government organisations, industry and consumer associations, and individual DM service providers have differing insights and perspectives that could beneficially test the networks' conclusions and propose alternative approaches.

## THE NATIONAL FRAMEWORK FOR ENERGY EFFICIENCY

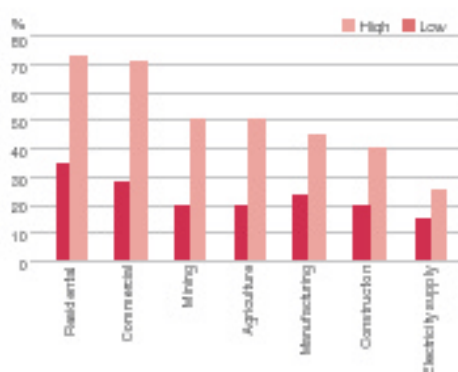
The National Framework for Energy Efficiency (NFEE) is a parallel MCE process that is progressing without explicit reference to the NEM reforms. Despite this disconnect, the potential impact of the NFEE on the NEM is significant. In particular, the NFEE can provide consumers with the means to reduce their demand, driving a parallel market in energy efficiency and demand management. An effectively implemented NFEE has the potential to challenge unhindered supply-side power, reduce pool prices and reduce greenhouse emissions in the most cost-effective manner.

### Modeling

The NFEE process is currently being lead by the Sustainable Energy Authority Victoria (SEAV), using Monash University, Allens Consulting and McLennan Magasanik Associates to model outcomes. Current modeling differentiates between the technical potential and the cost-effective potential of energy efficiency. The term 'cost-effective' does not simply imply that energy efficiency will save on electricity bills. Rather, it imposes particular payback periods in which investments must be returned. In doing so, the modeling excludes the long term savings to be gained from energy efficiency. In confining payback to 8 year, 4 year and 2 year periods, the NFEE's modeling does not attempt comparable equity with pay-back periods for electricity generation plants, which generally use a 20 year pay-back period.

The 'low' Phase One outcomes, shown in the table below, indicates massive GDP savings along with employment benefits and deep greenhouse emissions cuts.

Phase 1 Modeling: Percentage cost-effective energy consumption reduction potential across different sectors



#### Phase 1: Low Scenario Modeling

4 year pay-back rate  
50% penetration  
12 year period  
Commercially available technologies

#### Phase 1: Low Scenario Outcomes

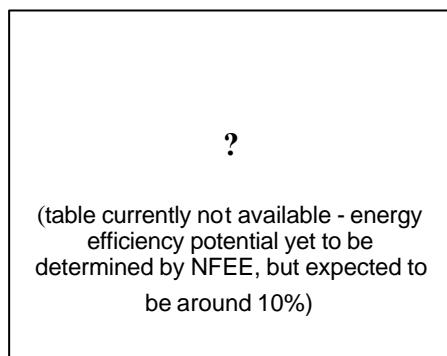
Real GDP \$1.8 billion higher  
Employment increase by 9200  
9% reduction in stationary final energy consumption  
-32 MT CO<sub>2</sub> greenhouse emissions

Source: National Framework for Energy Efficiency<sup>65</sup>

<sup>65</sup> Towards a National Framework for Energy Efficiency- Issues and Challenges, Discussion Paper, Energy Efficiency and Greenhouse Working Group, November 2003, pp. 5-6.

Phase Two outcomes flagged by the NFEE, but yet to be illustrated in the format of the above graph, use far more conservative modeling parameters, shown below.<sup>66</sup>

Phase 2 Modeling: Percentage cost-effective energy consumption reduction potential across different sectors



Phase 2: Low Scenario Modeling  
2.3 year pay-back rate (up to 4 years)  
50% penetration  
12 year period  
Commercially available technologies

Phase 2: Low Scenario Outcomes  
Real GDP \$0.97 billion higher  
Employment increase by 2600  
2.8% reduction in stationary final energy consumption  
-10 MT CO<sub>2</sub> greenhouse emissions

Source: National Framework for Energy Efficiency<sup>67</sup>

A drop of around 20% in energy efficiency potential is forecast in the latest round of modeling. This will result in the exclusion of cogeneration from potential energy efficiency estimates because its pay-back period exceeds the 2.3 year period allowed by Phase 2 modeling.

It has been noted by several commentators that the Phase 2 modeling is overly conservative.<sup>68</sup> Confirming these views, a range of local and international energy efficiency projections contain much higher figures.<sup>69</sup> Practical local experience also confirms that Phase 2 estimates are conservative. Results from the NSW Sustainable Energy Development Authority's (SEDA) Energy Smart Business Program, for example, show that those companies that have completed the Program have achieved energy and greenhouse savings in the order of 20%. In this context, it is critical that all models are presented in the Draft NFEE document and are open to independent evaluation by the provision of modeling parameters and data.

### The Way Forward for Energy Efficiency

Based on its modelling, the NFEE working group has flagged a national 1% target for energy efficiency beyond business as usual (BAU). While this is an achievable and valuable overall objective, particularly if applied on an annual, cumulative basis, its implementation should be specific and targeted. The 1% target should be applied through a combination of improved benchmarks for regulatory bottom-lines, targets for particular sectors and incentive programs to reward industry leaders and encourage excellence.

<sup>66</sup> NFEE modelling workshop, April 22, 2004.

<sup>67</sup> Ibid.

<sup>68</sup> Pointed out by many stakeholders at the recent NFEE modelling workshop, April 22, 2004.

<sup>69</sup> For example, US Electric Power Research Institute has calculated total savings in the range 24% to 44% projected energy use (Barakat and Chamberlin 1990); a report prepared for ETSA with funding from the ESAA, ERDC and SENRAC "Energy Consumption in Small Households" indicated savings in the range 40% to 70% (M. Oliphant, June 1999); Intergovernmental Panel on Climate Change (2001) suggests 30% as a typical average figure across all sectors (business and residential) and nations.

At the regulatory end, the NFEE should co-ordinate a national review and harmonisation of efficiency standards for buildings and equipment, using the best from each state or Commonwealth initiative to ensure under-performers reach minimum standards. Targeted programs should include, but not be limited to, the Mandatory Efficiency Performance Standards (MEPS) for equipment, the Building Code of Australia (BCA) standards, the Victorian 5 Star building regulations and the NSW Building Sustainability Index (BASIX). Subsequent to this review, the NFEE should set stretch targets for each program, developing benchmarks that deliver phased-in efficiency gains linked to milestones. Alternative regulations should also be explored based on the Victorian State Environment Protection Policy which makes energy efficiency targets part of the licence conditions of businesses which already have an EPA licence.

To encourage best practice, incentives for superior performance are also required. These would be achieved most efficiently through the establishment of Demand Management Funds in each state, as outlined above.

In place of these measures, the flagging of a National Energy Efficiency Trading (NEET) certificate scheme should be approached with extreme caution and should not come at the expense of other schemes such as minimum energy efficiency standards and DM funding mechanisms. Requiring such a small increment (1%) to be established and traded through a certificate trading scheme would be an invitation for industry manipulation and excessive administrative costs. Additionally, difficulties in determining baselines and administration costs are significant barriers to the measuring and verification of energy efficiency improvements.<sup>70</sup>

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<sup>70</sup> Additionally, which refers to actions taken beyond what would have been business as usual, is difficult to determine, particularly when attempting to measure an absence, such as energy efficiency.

# INTERVAL METERING

## Moreland Energy Foundation Limited

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### OVERVIEW

The NEM's move to a market in which a 'mandated pool' allows generators to exercise enormous market power by manipulating supply has created extreme price volatility. But while prices can vary from around \$12 to \$4,000 per MWh for retailers, consumers do not notice this volatility as their bills present averaged or 'smeared' costs over months.

Interval meters have the ability to make bills more cost reflective as they record electricity use in half hourly segments, as opposed to the traditional form of metering which simply accumulates consumption, providing a single figure at the end of the period. As this data is collected on particular time periods, time-of-use tariffs can be applied, where consumers pay different amounts for electricity depending upon the time they consume it rather than a smeared price. Therefore, interval metering in conjunction with time-of-use tariffs could remove cross subsidies which tend to promote high energy consumption and high use of peak electricity, passing on benefits to low consuming customers and providing high consuming customers with price signals to indicate the benefits from managing demand. Interval metering technology includes a wide range of metering options, including meters which can be read remotely.

In 2002, the Parer Report recommended that a mandatory roll-out of interval meters to all customers would be necessary to achieve the full benefits of market reform.<sup>71</sup> Currently decisions about whether to install interval metering are the responsibility of the states, although the Ministerial Council for Energy is currently considering a role for the Commonwealth. Victoria is most in favour of a universal mandated roll-out of interval meters, with a draft decision recommending a staged roll out over 5 years. New South Wales, South Australia and Queensland are not in favour of mandatory roll-outs at this time. Most jurisdictions have interval meters for large customers and acknowledge the benefits which have been returned to these customers through access to the technology. There is general concern about the benefits for small customers and whether it outweighs the costs of installing new meters.

### Interval Meters and the National Electricity Market

This position paper supports mandated, large scale roll-out of interval meters. Such roll-outs will progress demand management, particularly of peak demand, reducing the need for increasing system capacity and ultimately reducing greenhouse gas emissions from the energy sector. With this in mind, interval meters need to be introduced within a policy framework of emission reduction and demand management, as well as meeting social policy objectives, such as alleviation of fuel poverty and the removal of socially regressive cross subsidies. It is also acknowledged that meters alone will not be enough. A complete package of demand management initiatives is required, including time of use tariffs, remote control technology and a raft of other measures.

As outlined by the Victorian Essential Services Commission<sup>72</sup>, the benefits of interval metering are:

- The potential to increase the efficiency of the combined wholesale and retail electricity markets, through providing price signals to customers which result in decreased demand during peak times. This avoids the costs of increasing capacity to respond to higher peaks.
- The potential to provide customers with the capacity and incentive to manage their electricity demand more efficiently.
- Increasing price efficiency and product innovation, if retailers use the increased capacity of the new technology.

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<sup>71</sup> Warwick Parer, "Towards a Truly National and Efficient Energy Market", Commonwealth of Australia, 2002 p 180

<sup>72</sup> Essential Services Commission, "Installing Interval Meters for Electricity Customers – Costs and Benefits – Position Paper", November 2002

- Bringing operational network management improvements, if remote meter reading is utilised instead of manual meter reading.
- Increasing the accuracy of settlement by providing accurate data for billing and ensuring equity between customers by removing cross subsidies.

This range of benefits of interval metering is supported, with acknowledgement that some jurisdictions will rank the importance of particular benefits differently. However, all jurisdictions will benefit from the increased capacity to manage their networks better.

As the list of benefits is extensive, it is important that jurisdictions set clear policy objectives which outline what they are trying to achieve with a roll-out. These policy objectives will shape the roll-out approach, in terms of whether to have a targeted or universal roll-out and what sort of technology should be applied.

Support for interval metering is primarily related to the role that interval metering has in facilitating a demand management response. Interval meters can assist in shifting demand away from peaks and in reducing demand overall. For example, their use in Puget Sound Energy's area in Washington State USA led to 43% of residential customers shifting their energy use patterns and 41% reducing their demand overall.<sup>73</sup> They can be used to provide both an incentive and mechanism for demand management, depending on the tariff structure which is linked, and the complementary use of remote control technology. This is particularly relevant for big commercial energy users, which can direct the energy consumption from particular functions to cheap, non peak times to reduce costs and use the meters as part of a more active energy management regime to reduce demand overall.

Interval meters could potentially be used to provide "on the spot" feedback to consumers on their household energy consumption, and they also have the potential to provide an instantaneous price signal for that consumption that more accurately reflects the volatility of the market. Currently the practice of electricity retailers is to bill households three monthly. Providing small customers with price signals up to three months after their actual consumption will not help to change household energy use. With the introduction of interval metering technology, retailers must ensure that consumers receive meaningful and timely feedback on their energy consumption so as to encourage consumers to better manage their energy demand.

It is also noted that the lack of convenient load-management technology in households means small customers are relatively price inelastic, so sending price signals alone will not result in all small customers reducing or shifting demand. This is due to a number of reasons:

- Some customers will pay the higher bills, while other customers will respond to incentives to manage their energy more efficiently. As an example, some householders manage their long distance calls to ensure that they occur only during cheap rate times, others use the phone at any time and pay the bill later. Some elements of energy consumption are easier to shift to cheaper times than others. For instance, pool pumps and dishwashers can easily be timed to switch on when the rate is cheapest; however the time for showering or watching television may be shaped by other factors.
- With air conditioners, householders may be less inclined to manage their use over long, hot periods.

Price inelasticity for small customers should not be used as an excuse to avoid implementing interval metering. Currently South Australia and Victoria are suffering the consequences of unmanaged summer peak demand, due to the combination of a volatile market and the lack of control of air conditioning use in the market place. New South Wales and Queensland have also moved to a summer peak pattern. Not only has air conditioning become installed in more homes (around 50% growth in 5 years<sup>74</sup>), but higher

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<sup>73</sup> Institute for Sustainable Futures, "Submission on Interim Report of the IPART Inquiry into Demand Management", June 2002

<sup>74</sup> Dr Jeff Washusen, "Smart Meters for Smart Competition? Handing Back Power to Consumers", presentation to the Victorian Essential Services Commission, March 2003

capacity, high cost refrigerative air conditioning is becoming more prevalent. Regardless, the current situation sends no price signals to consumers who are investing in long term infrastructure for their homes, despite the fact that a time-of-use tariff would require high air conditioning users to pay an additional \$200 - \$800 on their summer bills<sup>75</sup>. Meanwhile, expensive “peak” capacity is increasingly required to feed the demand for electricity that comes from high air conditioning use, with the cost of increased network capacity, generator and retailer profits passed onto all consumers.

Interval meters and time-of-use tariffs should be installed to provide the basis for, but not the whole approach, to encouraging demand management. Remote control technology and other demand management programs will be essential to driving sustainable demand management. They may also serve to alert the public to the opportunities and dangers of the ongoing market reform process.

## **Rollouts**

Universal roll outs are supported over targeted roll outs as they ensure the cost of the roll-out is minimized and that cross subsidies are able to be eliminated. Given that big energy consumers and high users of peak electricity are currently subsidized by other energy users, it would be difficult to conceive that those currently benefiting from cross subsidies will voluntarily adopt interval metering and time of use tariffs, effectively opting to pay more for their electricity. For instance, in the Puget Sound example quoted above, the time-of-use tariff was abandoned due to complaints from customers about price increases and revenue decreases.<sup>76</sup> This demonstrates that it is not possible to implement time-of-use tariffs and return savings to all customers; invariably some customers will see price increases, while others will save money.

Therefore mandated universal roll-outs should occur in the context of a package of regulatory and program measures designed to protect vulnerable customers and support the right actions being taken by big energy users, prior to them receiving inflated bills. Given the lack of information on household energy use available in the public domain, research is necessary to ensure the impacts of interval meters and time-of-use tariffs on different customer classes are understood and plans are in place to reduce undesirable outcomes.

Roll-outs must be mandated, rather than left to the market. The Victorian Essential Services Commission has stated:

“Market forces alone would fail to deliver a timely interval meter rollout on a scale sufficient to provide economies in meter manufacture, installation and reading,....so regulatory intervention would be required to achieve the economic benefits that would result from a more timely and larger scale rollout, based on its cost–benefit analysis, a net economic benefit would arise from a timely, mandatory rollout of interval meters.”

All jurisdictions should undertake an assessment of interval metering roll-outs, with standard terms of reference for the assessments to be provided by the Ministerial Council on Energy. This should include the requirement to identify which socially vulnerable members of the community may be disadvantaged by a mandated roll-out of interval meters, and how to prevent this disadvantage. Where there are groups identified which will experience a significant increase in their bills, investigation should be undertaken into how to maximize a demand management response.

## **Time of Use Tariffs**

Regulation needs to be made to ensure that time-of-use tariffs are implemented along with interval meters. This is to ensure that retailers do not simply read the new meters as accumulation meters, thereby losing all the benefits of the new technology.

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<sup>75</sup> Dr Jeff Washusen, *ibid*

<sup>76</sup> Gullekson, PJ, AMR, “Price Signals and Demand Response”, California Energy Commission 2002

Both distribution and retail charges need to be based on time-of-use data, and load profiling in the wholesale electricity market needs to be phased out through the mass introduction of interval meters.

Interval metering with time-of-use tariffs needs to be part of a mixed bag of policy responses aimed at demand management. This includes remote control technology, which has been proven overseas to be a very effective way of reducing demand at peak times. For instance, in Texas, Southern California Edison found that they reduced demand by nearly 10 megawatts during the summer of 2003 through a program involving remote control of air conditioners and programmable thermostats.<sup>77</sup>

While the implementation of interval metering and time-of-use tariffs across the board implies the removal of cross subsidies, it is important that subsidies and other positive programs are supported when they are directed to increasing social equity. This includes directly subsidising energy consumption for households experiencing disadvantage; providing direct support to households where air conditioning is necessary for health purposes (such as where a member of the householder suffers from multiple sclerosis). Further, programs should be in place which support a reduction of demand; for instance retrofit programs aimed at low income households, provision of shading to households which require air conditioning etc.

Given that the poor quality of the existing housing and building stock means that existing homes / buildings are subject to wide variations in ambient temperature and therefore comfort levels, it is crucial that all jurisdictions mandate energy ratings for new homes and commercial buildings. This would preferably be achieved through national standards.

The high growth area of air conditioning should be a high priority for regulatory intervention. Given the number of air conditioners in place and being installed, efforts should be made to discourage high wattage installations and encourage high efficiency installations where they occur. Each jurisdiction or the new Australian Energy Regulator should mandate that consumers installing high energy consuming air conditioners over a set wattage level install interval metering and be placed on a time-of-use tariff.

## **Targeting**

While there are clear benefits of this technology for distributors, and potentially customers, some retailers have concerns about rolling-out interval meters to small customers. This is influenced by a number of factors, including the vast increase in technological capacity required to record and analyse time-of-use data and concern about how to charge tariffs where price caps exist. This gives rise to arguments such as retaining load profiling but utilizing seasonal tariffs. The concern with this approach would be that cross subsidies would still occur, albeit at different degrees according to the season. Importantly, it is difficult to conceive of this form of tariff structure having the level of impact on air conditioning, which is required.

Another option is to target households with energy consumption higher than the average with interval meters and time-of-use tariffs. While a universal approach is preferred, this approach would be better than the current situation. However, it would only be equitable if the cost increases for high consuming customers were passed onto lower consuming customers, who would remain on a load profiling system.

Implementation of interval metering requires additional regulation to ensure social equity is maintained and improved. In the Victorian instance, St Vincent de Paul Society argues that the integrity of the retail, distribution and other codes should be maintained and a specific interval meter retail code be developed. This would be necessary to resolve nuts and bolts issues such as billing, collection, information on the bill, tariffs etc.<sup>78</sup>

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<sup>77</sup> MeterSmart media release, "Southern California Edison Measures Summer Peak Savings with MeterSmart; One of Nations Largest Utilities Exceeds Demand Response Goals", April 13 2004

<sup>78</sup> Gavin Duffy, Submission by the St Vincent de Paul Society Victoria to the Essential Services Commission, February 2003

# NETWORK ACCESS FOR DISTRIBUTED GENERATORS IN THE NATIONAL ELECTRICITY MARKET

Australian Conservation Foundation

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## OVERVIEW

Although development of the NEM sought to improve security of electricity supply in participating jurisdictions, its reliance on a few large generation areas and transmission lines, coupled with the lack of required investment in new interconnectors has meant that increased security of supply has remained an elusive goal.

Embedded, or 'distributed' generation<sup>79</sup> (DG) has the potential to move the National Electricity Market (NEM) away from the current reliance on centralised generators and large interconnectors to a decentralised system capable of delivering positive economic and environmental outcomes.

Moving towards a decentralised energy system through increased DG would enable Australia to achieve several critical goals:

- Reduced greenhouse gas emissions. Greater reliance on DG within the NEM will reduce transmission losses and increase utilisation of less GHG intensive energy sources and renewable energy sources;
- Avoided network augmentation costs. This could result in lower network tariffs as DG can avoid network upgrades;
- Improved reliability. A larger number of DGs could lower the dependence on a few large generation areas and critical transmission lines;
- Reduced need for additional large power stations and concentrated generation sources;
- Provide reactive power closer to customers improving power quality, reducing losses and maximising the use of network components.
- Improved employment opportunities. Small-scale renewable projects have been demonstrated to provide more jobs per MWhr of electricity produced than conventional energy sources.
- Greater individual and community control over energy sources.

The difficulty in accessing distribution networks has been an ongoing issue with respect to distributed energy generators. This paper reviews the concerns regarding DG access to distribution networks within the NEM and ongoing processes that seek to address these concerns, both within the National Electricity Code ('the Code') and jurisdictional codes and guidelines. Although progress is being made in a positive direction, many previously identified barriers remain unresolved. Reform is slow and inconsistent across jurisdictions, and has not been able to deliver the full range of benefits that DG can achieve in the NEM. ACF conclude with specific proposals to continue to improve access to distribution networks within the NEM for DG.

This paper limits its discussion to the capacity of DG access to distribution networks to be facilitated through the Code and jurisdictional regulatory frameworks. It is beyond the scope of this document to investigate other issues affecting DG feasibility and competitiveness, such as fuel and retail prices, and the fact that greenhouse gas emissions are not reflected in generation costs.

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<sup>79</sup> Distributed generation (DG) typically refers to small scale generation systems (less than a kilowatt to 30MW) that supply power directly into the distribution system. Typically these systems are close to the electricity load. Examples of DG include natural gas or diesel generators, wind turbines, photovoltaic arrays, biomass and micro-hydro generators and fuel cells.

## The NEM, the National Electricity Code and Distributed Generation

The objectives of the NEM include the provision of non-discriminatory access to transmission and distribution networks and the removal of barriers to entry into the generation and retail markets. Despite these objectives, barriers to new market entrants to the distribution networks remain.

The National Electricity Code sets out “the arrangements and procedures through which electricity generators can access the transmission and distribution networks, as well as the basis for determining the charges for this access, and procedures for network planning and augmentation.”<sup>80</sup> The Code also contains provisions regarding information disclosure that require distribution network service providers (DNSPs) to provide DGs with the necessary information as is reasonably requested for the generator to fully assess the commercial significance of the access arrangements sought by the generator and offered by the distributor.<sup>81</sup>

When it comes to regulating the network access for DGs however, the Code takes a ‘light-handed’ approach. It requires DNSPs to negotiate ‘in good faith,’ but does not provide guidance on how such negotiations should be undertaken. Similarly, it requires that the terms and conditions of an offer to connect must be ‘fair and reasonable,’ but provides no guidance on how the distributor might determine what is fair and reasonable.<sup>82</sup>

The Code is the only Third Party Access Code approved under the Trade Practices Act. While all DNSPs have given an undertaking to the Australian Competition and Consumer Commission (ACCC) that the Code will apply to their operations, in practice the lack of clarity and transparency within the Code continues to allow DNSPs to restrict access to DGs seeking to connect to the distribution system.

The Code provides for separate jurisdictional regulators to undertake a number of roles, including regulation of pricing and access for distribution networks. In instances where small-scale, unregistered generators fall outside the scope of the Code’s application, or generators of modest size are not in a position to pursue access under the Code, the jurisdictional access codes and any associated guidelines are used by the proponents and DNSPs to negotiate access arrangements. In some cases, the Code derogates responsibility for regulating a generator’s access and connection to a distributor’s network, and the provision of use of system services, to the jurisdictional regulator. The jurisdictional regulator’s regulatory arrangements, if different to the Code, thus take preference over the Code. This complexity, coupled with inconsistencies in the existing jurisdictional codes, regulations and guidelines are creating difficulty for proponents to effectively establish advocacy networks or learn from one another’s experiences.

### Why the NEM fails Distributed Generation

Advocates for DGs have identified several ways in which the NEM fails to adequately deal with DG issues.

A critical barrier is the ‘light handed’ regulatory framework. In attempting to be ‘flexible’ and ‘incentive driven,’ light-handed regulation accepts the dubious assertion that economically efficient outcomes are derived by negotiation between parties. The Code’s expectation that monopoly DNSPs will negotiate in ‘good faith’ with DGs for network connection agreements does not acknowledge that the economic regulatory framework provides a disincentive for the DNSPs to facilitate access. DG reduces the need for transmission and/or distribution network services as well as large-scale generation. This can threaten the revenue base of both the transmission/distribution businesses as it reduces the size of the regulated asset base and so future revenue returns.<sup>83</sup> The problems of DG in the NEM that have been ignored or

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<sup>80</sup> IPART Discussion Paper 52. *Distributed Generation*, March 2002, page 7.

<sup>81</sup> Essential Services Commission, *Guideline for Embedded Generation, Draft Decision*, April 2004, page 5.

<sup>82</sup> Essential Services Commission, *Guideline for Embedded Generation, Draft Decision*, page 5.

<sup>83</sup> Hugh Outhred, Associate Professor, School of Electrical Engineering and Telecommunications, University of NSW *Achieving Equal Consideration of Distributed Resources in resolving local or Regional supply Demand constraints* – Combined AP37/38 Colloquium, Adelaide, 17 – 18 September 2001.

overlooked are not likely to be adequately addressed if the regulators continue to insist on a 'light-handed' regulatory approach.<sup>84</sup>

In 2002 the Australian Ecogeneration Association identified the following additional requirements to facilitate DG access to distribution networks:

- Ensuring disclosure of planning information by distribution network businesses so project proponents can negotiate connection costs and receive the value of avoiding distribution network augmentation;
- Introducing a code of practice for distribution network augmentation that gives due consideration to local generation and demand side options where network augmentation is proposed;
- Establishing a negotiation framework in which effective and efficient negotiation of connection agreements can occur;
- Establishing equitable and efficient connection costs for embedded generators so local generators do not have to bear higher costs than similar transmission connected generators;
- Removing distortive demand charges, including minimum chargeable demand, which penalise customers that self-generate and demand side responses;
- Developing network pricing structures which signal the cost to the network of meeting system peak electricity requirements and a customers contribution to that peak; and
- Fully recognising and rewarding the embedded generator for avoided transmission charges caused by its operation. A local generator's customers should not be forced to pay for distant transmission assets, when the power they consume is generated locally.<sup>85</sup>

Consultants to the COAG Energy Market Review (the 'Parer Review') in 2002, Charles River Associates, examined the complaints made by DG proponents and advocates regarding the treatment of DG in the NEM and concluded that, "generally, complaints were found to be valid."<sup>86</sup>

### **Has Any Progress Been Made In Addressing Distributed Generation Concerns?**

Alterations to the Code since its inception have sought to address DG concerns, but have failed to deliver the necessary outcomes.

In December 2001, the National Electricity Code Administrator (NECA) gazetted changes to the Code so that DG's would be reimbursed for the costs of avoided Transmission Use of System Charges (TUOS) from DNSPs (the 'with/without' test). This system relies on appropriate fixed and variable costings in transmission tariffs. It has been the experience of DGs in some jurisdictions however, that DNSPs have been able to structure their tariffs to minimise the payment required, through making the variable usage components (on which the avoided TUOS rebate is based) a relatively small proportion of the total transmission charge.

In March 2002, The Network and Distributed Resources Set of Code Changes were gazetted (contained within Chapter 5). While these changes created prescriptive process requirements of Transmission Network Service Providers (TNSPs), they failed to mandate the same processes for DNSPs. Certain elements of Chapter 5.6, *Planning and Development of a Network*, if applied to DNSPs would greatly enhance DGs opportunities for access. Chapter 5.6.6C required a review of Chapter 5.6 to be completed by March 2003, which may have resulted in an extension of the Code's requirements of DNSPs and improved the treatment of these costs in the pricing and recovery arrangements. This Review has been delayed due to the current reform process.

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<sup>84</sup> Sally Moxham, *Barriers to distributed generation (small-scale renewable) in the NEM: a Victorian perspective*, Masters Dissertation, 2003. (unpublished)

<sup>85</sup> Australian Ecogeneration Association submission to the COAG Energy Review Issues Paper, 2002, Page 6.

<sup>86</sup> Charles River and Associates, *Distribution Network Barriers to Embedded Generation*, submitted to The COAG Energy Market Review, October 2002, page 9.

## The Reform Process

The National Electricity Market Reform should address the issue of a nationally consistent approach to charges to generators for connection, but will only be reviewing transmission in the wholesale electricity market and gas arrangements. Although it will investigate the extent to which jurisdictional regulatory arrangements for distributors should be brought under the jurisdiction of the AER, there is no certainty this will occur and some industry experts expect that distribution access arrangements will, in fact, not be entirely brought under the jurisdiction of the national regulator.<sup>87</sup>

Network access regimes are currently being reviewed by several jurisdictional regulators within the NEM. To date, the most substantial progress has been made by Victoria's Essential Services Commission (ESC) and NSW's Independent Pricing And Regulatory Tribunal (IPART)<sup>88</sup>.

While the ESC's *Guideline for Embedded Generation, Draft Decision* makes some recommendations that address the concerns of DG proponents, such as recommending standard connection fees and standard contracts, and that only shallow costs should apply to DG, some aspects fall short of what would be required to facilitate optimal access. Of particular concern is its failure to recommend further information disclosure provisions for DNSPs. IPART's *Inquiry into the Role of Demand Management and Other Options in the Provision of Energy Services Final Report* differs from the ESC Draft Guideline in its treatment of avoided TUOS and of deep versus shallow costs to the DG, although it also recommends standard connection agreements for small DG projects. It would be useful, though beyond the scope of this paper, to undertake a thorough comparison of each jurisdiction's positions, compared with the conditions required for optimal DG network access.

No attempt has been made to coordinate either the review processes for the jurisdictions undertaking reviews, or to ensure consistency of outcomes. The only nationally coordinated aspects of DG access to distribution networks are the Australian Greenhouse Office's standard connection agreement discussion paper, which was distributed to retailers and DNSPs during October 2003 (the resulting report is yet to be released) and the adoption of Australian Standards for equipment associated with DG.

## Recommendations

Previous reports and submissions to jurisdictional and national inquiries have provided extensive proposed mechanisms to deliver network access to DG within the NEM. Rather than restating previous proposals, this paper identifies priority outstanding issues that will not be adequately addressed within the current framework of the Code review, MCE processes or jurisdictional reviews.

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<sup>87</sup> Pers comm., confidential

<sup>88</sup> The ESC released its *Guideline for Embedded Generation, Draft Decision* and *Electricity Industry Guideline No. 15 Connection Of Embedded Generation, Issue 1* in April 2004 and IPART released its *Inquiry into the Role of Demand Management and Other Options in the Provision of Energy Services Final Report* in October 2002 and its *Treatment of Demand Management in the Regulatory Framework for Electricity Distribution Pricing 2004/05-2008/09 Draft Decision* in February 2004. IPART's DG recommendations were based on the outcomes of Discussion Paper 52, *Distributed Generation*, which was released in March 2002. The Essential Services Commission of South Australia (ESCOSA) released its *Embedded Generation Issues Paper* in November 2003 and intends to have changes to its Distribution Code and accompanying Guidelines completed by the end of 2004. DG is addressed in Chapter 8 of the Tasmanian Electricity Code, *Distribution Operation*, and is similarly up for review at the present time. The revised Draft Code is due to be released for public comment in June 2004, with changes to be completed in time for Tasmania's entry into the NEM in May 2005. Neither the Queensland Office of Energy nor the Queensland Competition Authority, both of whom have regulatory responsibilities, are undertaking reviews of conditions for DG in their jurisdiction.

In order to facilitate a more rapid transition to an ecologically sustainable NEM, the following recommendations must be implemented:

### **1) Jurisdictional Consistency – AER to regulate DNSPs**

The MCE electricity reform process must include a mechanism to ensure consistency across jurisdictional regulators vis a vis access codes and guidelines. Currently the ESC, IPART, ESCOSA and the Office of the Tasmanian Energy Regulator are at different stages of reviewing jurisdictional distribution network access arrangements. In the case of the environment movement, insufficient resources and capacity limits the ability to provide adequate input across all NEM jurisdictions. Coordination of these reviews would enable environment groups and other stakeholders to effectively participate. In addition, consistency of outcomes is required to enable stakeholders to form advocacy coalitions, across jurisdictions that can utilise the work and experience of other DG advocates.

The benefits of greater consistency could be achieved through the Australian Energy Regulator (AER) taking on the regulation of DNSPs. The Parer Review recommended that a 'National Energy Regulator (NER) should be established to be the independent regulator in all jurisdictions, interconnected or otherwise...'<sup>89</sup> Despite the MCE agreement to establish an Australian Energy Regulator (AER) and to the objective of an agreed national regulatory framework for distribution and retailing (other than retail pricing), the actual role that the AER will have in regulating distribution remains unclear. The Retail and Distribution Working Group of the MCE reform process will consider the extent of transfers of the distribution regulatory function and should recommend full transfer of regulation of DNSPs to the AER.

In addition, the newly formed Australian Energy commission should undertake the review required under Provision 5.6.6C of the Code as a matter of priority, with a view to extending the information disclosure requirements to DNSPs.

### **2) Adequate Access to Network Planning Information**

DG proponents and advocates have previously identified the importance of adequate access to network planning information. However, to date it has been insufficiently rectified. Lack of access to information from DNSPs can result in reduced ability for DG proponents to negotiate fair connection agreements. More importantly, it prevents potential investors in DG planning generation installation in areas that will result in returns on investment. Inadequate information is a market imperfection that must be urgently addressed in order to achieve the intended benefits of electricity market reform.

To alleviate information constraints that impede the efficient functioning of the market, more effective mechanisms for information disbursement must be implemented. All jurisdictional DNSPs, irrespective of whether they are publicly or privately owned must be required to prepare and release an Annual Planning Review of Network. The prescriptive provisions within the Code in Chapter 5.6 related to TNSPs must be also applied prescriptively to DNSPs.

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<sup>89</sup> Commonwealth of Australia, *Towards a Truly National and Efficient Energy Market*, Council of Australian Government's Energy Market Review, November 2002, page 27.

### 3) Full recognition of benefits

To date, access arrangements for DG proponents to distribution networks still fail to enable DG proponents to realise the full value their plant delivers. DG may be able to provide:

- Energy – sold to local or other retailers in the wholesale spot market via NEMMCO or through physical or financial contracts;
- Network augmentation deferral - realised in network rebates;
- Network support for one or more technical characteristics - realised in contracts with NSPs;
- Reductions in network losses - reflected in loss factors although full recognition in many cases would require additional rebates;
- Market ancillary services - sold on the spot market via NEMMCO;
- Non-market ancillary services - sold to NEMMCO under contract;
- Reserve trader - contracted to NEMMCO; and
- Renewable Energy Certificates (RECs).<sup>90</sup>

As Charles River and Associates noted, while large and more experienced generators are expected to comprehend and negotiate arrangements across the range of parties, it is daunting for new players and involves significant transaction costs for matters such as information searches and negotiation time.<sup>91</sup>

DG proponents must have simple access to all the information required to both understand and obtain the entire value of their asset. An industry guide should be developed and DG proponents should have free access to experts in governments (within the department or agency with responsibility for sustainable energy development) to enable them to facilitate their access arrangements. DNSPs must have a legal obligation within the Code requiring that they inform DG proponents of the guideline and assistance available.

### 4) Appropriate Economic Regulatory Regime

An economic regulatory regime is required that provides appropriate pressure and incentives to DNSPs to provide network access to DGs across all jurisdictions.

An example is IPART's *Treatment of Demand Management in the Regulatory Framework for Electricity Distribution Pricing 2004/05 to 2008/09 Draft Decision* that allows DNSPs to recover foregone revenue as a result of demand management projects (including DG).

### 5) Policy Drivers

In order for DG to achieve network access to the extent that will deliver the greenhouse and other potential benefits of DG, a supportive policy framework is required. Policies required at the national level include:

- The inclusion of environmental sustainability in the objectives of the NEM;
- Ratification of the Kyoto Protocol, or a legislated national greenhouse gas reduction target;
- A Mandatory Renewable Energy Target of 10 per cent by 2010;
- Energy load growth limits and associated Demand Side Management (DSM) policies.

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<sup>90</sup> Adapted from Charles River and Associates, *Distribution Network Barriers to Embedded Generation*, submitted to The COAG Energy Market Review, October 2002, page 9.

<sup>91</sup> Charles River and Associates, page 9.

## 6) Additional Capacity for NGOs

Advocates for DG are hindered in their ability to engage with reform processes by lack of adequate resources, knowledge and experience. Accessing or developing appropriate knowledge and skills requires sufficient funding for research, consultation and workshops et cetera, as well as staff to undertake stakeholder engagement. The imbalance of resources available to DNSPs compared with DG advocates results in outcomes skewed towards the interests of the more financially endowed stakeholders.

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The following organisations were contacted in the research for this paper:

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Independent Pricing And Review Tribunal (IPART)  
Office of the Tasmanian Energy Regulator  
Essential Services Commission of South Australia (ESCOSA)  
Queensland Office of Energy  
Queensland Competition Authority

# **SUPPRESSION OF PRICE SIGNALS, CONSUMERS AND LOW-INCOME GROUPS**

**NSW Council Of Social Services**

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## **OVERVIEW**

The restructuring of the electricity industry in Australia through the establishment of a National Electricity Market, aspired to enhance economic efficiency, environmental sustainability and social accountability. This task is still to be completed.

The provision of reliable and affordable energy for all citizens is an essential service in any community, and nation. The protection and improvement as opposed to the degradation of the physical and social environment is also a core element of well being. It sits inextricably alongside positive economic development and the fair distribution of its benefits.

The adoption of “full blown” market mechanisms to drive the generation, distribution, sale and consumption of electricity, cannot, of itself, achieve the above mentioned aspirations. The inevitability of uncontrolled market variables and market failure compound the dynamic tension inherent in balancing economic, environmental and social goals. There must be the adoption of appropriate and effective regulatory mechanisms in the public interest, to ensure the benefits of the marketisation are delivered to all consumers and to protect consumers from market failures.

Low income residential consumers (in NSW, this represents approximately 1 million people and approximately 2.5 million people, nationally) rely upon a sound regulatory system to protect them from unaffordable retail price increases and an acceptable quality and reliability of supply.

The following discussion of price signals, demand management and equity of outcomes is pursued against the above framework, with low income residential consumers as the focus.

## **Market Operation and Regulation**

The sovereignty of consumer choice and sufficient contestable products or services are generally regarded as the key attributes of an effective market. Consumers are assumed to have adequate purchasing power and to be appropriately skilled to make informed choices, whilst providers are deemed to compete on price and quality, act ethically and to operate from the same “starting point” in terms of the market structure.

In most markets, the practical application of all of these principles is never universal. Many of these principles are not, and cannot be fully represented in the NEM, for the generation, distribution and provision of electricity,

In NSW, key regulatory mechanisms have been established.

The Electricity Tariff Equalisation Fund (EETF) was created by the NSW Government to “allow the Government to offer regulatory price protection to retail customers in a way that does not undermine competition in the market and does not expose retailers or Government to unacceptable financial risk.”

EETF is a fund into which standard retail suppliers (initially the Government owned electricity retailers) are required to pay money when pool prices are lower than the energy cost component they recover from regulated customers (i.e. most consumers). When pool prices are higher than the energy cost component in the regulated tariff, the EETF will make payments to standard retailers to enable them to purchase wholesale electricity for regulated customers and still earn a regulated margin.

At times, if there are shortfalls in the ETEF, NSW Government owned generators will make payments to cover the shortfall, thus ensuring that the Fund is always in balance.<sup>92</sup> ETEF works to level out the peaks in price and remove a key component of market operation, which arguably would encourage demand management.

A second principal regulatory mechanism in NSW is the oversight of pricing in the energy industry by the Independent Pricing and Regulatory Tribunal (IPART). In recent years, IPART has conducted an annual public review process of applications by the standard retailers to seek price increases and changes, as well as a 2003-04 review of regulated tariffs.

PIAC states, "The fixing of regulated tariffs for low volume users of energy is the flipside of the creation of a framework for full retail competition in this sector. Without competition and its outcome of winners and losers there would be no need for the safe haven of standard tariffs."<sup>93</sup>

From an end user perspective, as IPART itself notes, the best price outcomes for electricity consumers in NSW over the decade 1992/3 – 2001/02, have been achieved under price regulation and not open competition.

The NSW Government appears committed to retaining regulated retail tariffs in electricity and gas, indicating that, "while retail competition has delivered benefits for those participating in the market, the majority of residential and some small business customers have chosen to remain on standard form customer contracts which include regulated retail tariffs and charges."<sup>94</sup>

IPART has recently expressed the view that as retail competition becomes more effective the regulation of prices should become more light handed. In NSW, several retailers have noted these comments and are urging the Tribunal to implement such an approach to price setting for the period up to June 2007.

Some commentators describe the standard tariff for electricity as a safety net. However, others believe that it is not valid to see regulated energy tariffs for low volume consumers as a last resort which should only be available to the most marginal of retail customers. All consumers must benefit if a competitive retail energy market is to be judged as successful, "Until that can be achieved, it is important that there be retained to option for individual small consumers to remain outside the competitive market."<sup>95</sup>

The question of whether price is the only or key determinant in consumers switching energy retailers is also an interesting one. A 2003 United Kingdom study of residential electricity users<sup>96</sup> indicated that price is not the key factor in the consumer decision to switch retailers. The behaviour of energy retailers in NSW that bundle together other services, incentives and rewards with energy in their offers might also confirm this observation. PIAC notes<sup>97</sup> that, "it also contradicts the assertion that the level of regulated tariff in NSW has been limiting the extent of retail competition."

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<sup>92</sup> "Electricity Tariff Equalisation Fund: Information Paper", NSW Treasury, December 2000

<sup>93</sup> "Submission to the IPART Review of Regulated Energy Tariffs", Public Interest Advocacy Centre, February 2004

<sup>94</sup> Terms of reference in "Review of gas and electricity regulated retail tariffs –Issues paper", IPART, October 2003

<sup>95</sup> PIAC 2004 *ibid*

<sup>96</sup> "Strategic change in the market for domestic electricity in the UK"; Brigham, B and Waterson, M (2003),

<sup>97</sup> PIAC 2004 *ibid*

## Market issues

Critics<sup>98</sup> of the operation of ETEF make the following claims:

- State owned electricity generators see a reduced incentive to offer below the long range marginal cost, therefore prices in the National Electricity Market may rise;
- State owned generators are less likely to offer hedges for contestable consumers, therefore transferring risk to these customers and their retail prices; and
- State owned standard retailers are fully hedged for ex-post regulated tariff volume, which is likely to encourage weather-sensitive load and increase per capita consumption and climate change emissions.

It is asserted that the above factors could lead to an upward regulated price spiral, which would be allied with the promotion of high cost loads in the system. This would be subsidised by regulated tariffs, general rises in charges and emissions and a subsidy being paid by low income households to high income household through the rise in the regulated tariff.

Outhred<sup>99</sup> proposes an alternate approach to Full Retail Contestability, which would feature:

- Empowering consumers with significant skills development and resources which might better allow consumers to make informed decisions between meaningful options;
- Using interval metering and retail Contracts for Difference with price and volume profiles negotiated under IPART which might protect low income households, reward appropriate behaviour changes and support transition; and
- Improve network pricing and regulation, which would see price determined according to marginal losses and the likelihood of local constraints, resulting in all investment options being considered equally.
- However, key social and human services sector bodies, such as the NSW Utilities Consumers Advocacy Program (UCAP)<sup>100</sup>, express support for the retention of ETEF. UCAP indicates that:
- The abolition of ETEF would lead to significant price rises for many consumers, especially lower income groups;
- As the NEM does not place requirements on retailers about where to source supply, it is the market and its lack of prescription and not ETEF which leads to retailers using lower priced, more environmentally damaging sources;
- There is no significant evidence that price signals will directly lead to substantial improvements in demand management; and
- The lack of interest by retailers (evidenced in the marketplace), for providing attractive market based retail contracts to certain groups of small volume users.<sup>101</sup>

UCAP believes that demand management outcomes are more likely to be achieved, in an equitable manner, through a mixture of incentives and specific regulation on retailers, combined with direct assistance to enable lower income households to participate in mainstream energy conservation activities, such as household retrofitting, direct assistance to purchase quality energy saving appliances and targeting public education.

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<sup>98</sup> "Prudent expenditure on Network and Non-Network Alternatives"; Hugh Outhred, University of NSW at IPART Forum, April 2001

<sup>99</sup> Outhred *ibid*

<sup>100</sup> The Utilities Consumers Advocacy Program is operated by PIAC and is advised by a Reference Group comprising the Council of Social Service of NSW (NCOSS), the NSW Council on the Ageing (COTA), the Combined Pensioners and Superannuants Association of NSW (CPSA), the Australian Consumers Association (ACA), the Park and Village Services based at CPSA and the Institute of Sustainable Futures, University of Technology.

<sup>101</sup> "Special Investigation: Review of the Effectiveness of Full Retail Competition for Electricity-Final Report", Essential Services Commission, Victoria, September 2002, pg 46

Despite the varied views on ETEF there are other key issues that need to overcome to enable lower income households to become major contributors to prudent energy use. These include:

Lower income people who live in private tenancies where the landlord must make the decision on significant household fitting improvements. The landlord may also attempt to fully pass on, through rent increases, the costs of effective retrofitting. Public tenants in NSW have the advantage of the Department of Housing recognising the benefits of retrofitting and its improvement program of energy and water conservation capacities of premises, for some estates;

The capacity of lower income people to pay for 5 star energy appliances, which may generally cost 60% to 100% extra than the base line model. Some energy retailers in NSW, as part of their community service obligations policy and practice, are providing funding assistance to locally based No Interest Loans Schemes (NILS). These historically have provided small loans to low income applicants to purchase whitegoods and other household essentials. However, because discounted prices by retailers on energy and water efficient appliances still place them well out of reach of households living on Centrelink payments or single source low wages, low income households cannot acquire them.

### **Conclusion**

The ability of the 1 million low income citizens in NSW to fully participate in, and contribute to, energy conservation on the one hand, and sustainable growth strategies for a city like Greater Sydney, on the other - will require a much higher degree of focus and debate by Government, industry, the environment and social movement stakeholders than has been in evidence to date.

# NATIONAL ELECTRICITY MARKET, CONSUMERS AND LOAD GROWTH

## Energy Action Group

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It is important to understand the nature of the electricity market and the technology in order to assess the risks and costs of the National Electricity Market (NEM) to consumers.

### The NEM

The NEM is in the final steps of melding together one of the largest and most complex engineering accomplishments in Australia. The interconnected transmission system provides electricity to consumers from Cooktown in Queensland through to Port Augusta in South Australia, and with the completion of the undersea cable Bass Link will add Tasmania to this system. The NEM can be seen as a series of separate sources of generation (supply) and consumption (load or demand) connected by the transmission system. The transmission system is a relic of the old state owned utilities and consists of a series of different standard transmission voltages in each jurisdiction. The interconnectors were initially designed for system security and reliability and the exchange of small amounts of energy between jurisdictions, with the one exception of the Snowy Mountains Hydroelectric Scheme.

Electricity infrastructure is capital intensive and the industry is particularly risk adverse. The industry will only make a new investment if there are adequate rewards or a regulator authorises the expenditure. This is particularly true for the owners of privatised assets and state treasuries who see the industry as a cash cow!

The NEM is governed by the National Electricity Code, a 1000 page document that sets out how the market operates, operating parameters for generators, the framework for connection agreements between participants, the powers of National Market and Management Company NEMMCo, the ISO, and participant responsibilities. The market consists of market participant generators, retailers, and transmission and distribution companies.

The National Electricity Code is a mix of competing engineering, economic and legal objectives. The majority of market participants will fulfill their obligations under the Code. However if an obligation is not funded under any Code provision then it is unlikely to be actioned unless it is in the strong self interest of the participant. The Code ensures that the financial rewards associated with load growth and load volatility are sufficient to encourage new investment.

The jurisdictions are remarkably sensitive to blackouts as they add to political risk and places further pressure on the industry to perform.

### System Control

NEMMCo, a jurisdictionally owned Independent System Operator, has responsibility for system security, running the market including dispatching generation to the supply demand balance, setting the price for energy and settling the market for market participants. Market participants consist of generators, retailers, financiers, transmission and distribution companies and two large consumers who buy through the NEM pool.

NEMMCo has responsibility for helping the market to plan for future load growth. They also have the power to intervene in the market and direct participants to operate to ensure that the NEM operates securely and to minimise inconvenience for consumers.

## **The Technology**

Electricity is a unique product where supply must equal demand and large quantities are very difficult to store. The frequency of Alternating Current is used as the basis of system control. The Independent System and market Operator (ISO) NEMMCo is required by the National Electricity Code to keep the frequency of the NEM within a tolerance of 50 plus or minus 0.2 Cycles per second.

When load is added or lost, the supply energy must rapidly respond to ensure that the system remains stable. The addition of a significant load over a short space of time or the loss of a generation plant ensures that the frequency of the system will drop below 50 cycles per second. The greater the loss of generation or addition of load, the greater the frequency will drop.

The reverse happens when significant load is lost the frequency will rise above 50 cycles per second and generation has to be reduced to compensate. The addition or loss of a large generator or load makes the system unstable and has to be compensated for rapidly.

The major focus of NEMMCo as the system operator is to run a secure and reliable system with their major emphasis on system security. An electricity system running in an unsecured manner can lead to large scale blackouts and in the worst case scenario a total system black, which then has to be energised and restarted rather carefully to minimise social and economic dislocation.

A secure system needs to have spinning reserve ready to operate instantly, the equivalent of the largest single unit connected at the time. This arrangement is to cover the outage of the largest single unit at any time. It is worth noting that the provision of spinning reserve is not paid for in the NEM. Participant generators are only paid for the energy and services they actually provide to the NEM so the plant providing spinning reserve only gets paid when it gets dispatched to the market and another generator provides the reserve. The market design is based on the premise that when most of the available generation is dispatched the price will rise towards the market cap of \$ 10,000/MWh. This high capped price provided for under the Code is designed to act as an incentive to encourage more generation to enter the market.

## **The Pool**

The NEM is described as a merit order, gross pool with an ex post price adjustment market. Translated, a merit order market is one where the cheapest generation is dispatched first. As the load increases the next most expensive generation is dispatched and as the load continues to increase more and more expensive generators are dispatched. In the NEM the generators can bid the price of energy from minus \$1000/MWh up to \$ 10,000/MWh. The Code requires that every generator over 30 MW connected to the system must bid into the NEM if they wish to be dispatched and paid by NEMMCo. Each generator is allowed to make 10 bids over a range from the minimum generation to maximum generation of the plant. The price of the bids can vary up to the VoLL price. Currently between 25% and 30% of the generation capacity in the NEM is parked with bids over \$ 9000/MWh. The gross pool refers to the requirement that all income received from the sale of electricity dispatched in the NEM is paid and settled by the Independent System Operator. Retailers are required to have prudential requirements in place to cover the costs of their obligations to the market so that the generators do not lose money if a retailer can't meet their obligations and fails. Ex post price adjustment allows NEMMCo to adjust the price after an event, a mistake in dispatch, or a security direction occurs to rectify any pricing mistake or error.

The market is based on 5 minute dispatch periods and prices. The generators, retailers and the two consumers reconcile payments on the 30 minute average of the 5 minute pool prices. All energy sold into the market by generators is paid the dispatch price of the pool for the 30 minute trading period. The price of all energy traded through the pool is transparent; generators who don't get dispatched don't get paid from the pool. However only 10% of all the energy sold through the pool is sold at the pool price. The rest of the energy sold is covered by contracts between various parties.

Around 90 % of the energy sold through the pool is subject to almost totally opaque contract volume and price arrangements between various parties participating in the market. Generators can have either short or long term contracts with a retailer to supply a volume of energy at an agreed price. Generators can contract with each other to supply each other energy in case they have plant failure, a planned outage or they want to speculate on high prices. There are a large number of financial instruments and contracts between parties that underpin energy trading in the NEM. A secondary contract market also exists where energy can be bought and sold between any parties who want to trade.

The NECA web site currently provides a snapshot of the power flows and prices plus some analysis of what has happened in the market at <http://www.neca.com.au/Marketsnapshot/>

The market is designed to deliver price signals but very few if any other than the 2 market participants customers see those signals. All the jurisdictions protect the most volatile load with price caps.

### **The Price**

Price discovery is based on using the services of a number of financial service operators. The most popular service is the Australian Financial Markets Association (AFDMA) forward price curve for flat load or peak load energy prices. Many daily papers publish the Australian Futures Exchange forward prices for 500 MWh blocks of flat and peak load energy. The energy only market constitutes around 99% of NEM revenue while Ancillary Service Payments currently constitute around 1% of the market revenue, but are vital to keep the system in a stable secure operating condition.

NEMMCo adds a levy of \$ 0.35 to \$ 0.37 /MWh to the pool price to run the market and the Code Administrator. This raises around \$ 70 m/a. A new levy arrangement to fund the industry regulation is under consideration by the Ministerial Council on Energy. This arrangement will add a further \$ 40 m/a to consumers bills.

There are price four other costs that influence the market price of energy that consumer pay for. There is the cost to consumers of the mechanism to settle inter regional price differentials, the costs of out of order generation used to bypass transmission constraints within a region Mandated Renewable Energy Targets (MRETS) and any emissions trading scheme like the NSW Greenhouse Benchmarks Scheme.

The market to date has delivered lower energy prices to large consumers and new generation has been built and the system reliability has never been better. However the market and pricing regime has failed to address the massive increase in peak summer loads across the NEM. In both Victoria and South Australia the residential small business summer ramp is the same as the industrial load. Translated, on the hottest day in Victorian the demand moves from 5000 MW at 2 am to 8500 MW at 4.00 pm in the hottest part of the afternoon. The 3500 MW change over the 14 hour period is the same as the state's industrial load.

There needs to be sufficient generation capacity to meet the demand and the transmission and distribution system has to be sized to carry the peak load. The short operating times required for peak load generation suit open cycle gas turbines as the cheapest technology to meet the demand. Turbines are cheap to install, but expensive to run and if actually used to meet peak load they come at a considerable expense to consumers because they are usually at the top price of the dispatch bidding stack.

### **System Reliability**

The merit order dispatch energy only market would collapse without a set of reliability payments called Ancillary Service Payments (ASP). There are 3 separate markets for raising frequency (adding generation) and a parallel set of 3 markets for lowering frequency (losing generation or load). These 6 markets are known as the FCAS markets. There is another set of payments built around Network Constraint Ancillary Services (NCAS) and the last Ancillary Service Payment relates to a set of payments to generators for system restart known as Black Start Ancillary Service Payments (BSASP).

Ancillary Service Payments are allocated on a “causer pay” basis. If a consumer is connected to the system when some event incurs an ASP, and if the consumers helped cause the ASP, then the costs are allocated against consumers who are seen to have contributed to the problem. The best known event occurred at the start of the 6 Frequency Control Ancillary Service Payment markets in November 2002. TransGrid notified the market that they were taking several northern NSW transmission lines out of service over the period of a month to install communications equipment. This decision caused significant frequency control problems between NSW and QLD. The outage cost \$ 160 m in ASPs. NSW generators paid QLD some \$ 80 m to lower frequency and NSW consumers had to pay NSW generators some \$ 80 m to increase frequency.

NEMMCo has the power to direct a market participant to operate plant and equipment if system security parameters are likely to be breached. The directed party can claim operations and maintenance expenses for the time of the direction. There have been several instances in Victoria where the Loy Yang A power station has been directed. In one notorious case Loy Yang was paid \$ 20 m for a day and the energy produced was sent to NSW and South Australia because the expected Victorian load failed to reach the forecast for the day as consumers had reduced their load.

The tighter and lower the system security and reliability operating standards are, the lower the costs of NEMMCo directions because they are not invoked later as often, because the system is given a smaller window to operate with.

The reliability standards for the NEM are currently set by the NECA (National Electricity Code Administrator) Reliability Panel in conjunction with NEMMCo.

The reliability standards are based on a combination of two methods of calculation. The first is called N-1 standard which relates to a standard based on having enough margin to cover the failure of the largest operating unit across a region. The second is to meet a 0.002% Unserved Server Energy standard for the market delivered to the reference nodes.

The NEM is more than an energy only market, Ancillary Service payments can blow out dramatically if the system loses reliability and consumers have little or no control when these costs increase. Large scale demand management, embedded generation and renewable energy have the potential to influence system performance as well as the market participants and consumers behaviour.

## **Price Signals**

The economic basis of the NEM is the use of prices to signal to consumers that they need to change their behaviour. The half hour energy price is designed to reflect the scarcity value of electrical energy at any point in time. High prices should indicate to a consumer that to increase their consumption more will further raise the price until it reaches the cap price known as Value of Lost Load (VoLL) of \$10,000/MWh. Currently the price exceeds \$ 300/MWh for around 5% of the year. This means that 25% of the total revenue passing through the market is derived from 5% of the time.

The NEM has worked to date but there are a number of issues that still need to be addressed. Most of the pricing signals are not seen by the consumers who cause most of the pricing pressures. There are heavy intra tariff cross subsidies where small consumers subsidise larger consumers.

All jurisdictions have ensured that the source of the most volatile load, residential and small business consumers have capped prices. One of the most significant failures of the NEM is the substantial increase in summer peak load growth mainly associated with the use of air-conditioning and cooling appliances.

The available generation capacity, the transmission and distribution systems, all need to have sufficient available capacity to meet the system maximum summer demand. The instantaneous Maximum Demand of a region is measured in Mega Watts (MW). A number of parties, particularly generators and transmission companies, have to solve the problem of sizing the system. This problem is compounded by the various businesses having to work out what the highest temperature and humidity will be and size their systems accordingly. (Generators are not paid if their plant doesn't operate over the summer period unless they have a contract to supply energy with another party.) High temperatures (over 40 C) also affect electrical system efficiency as generators produce less energy and transmission systems lines sag as they heat up and insulation breaks down.

Victoria and South Australia have adopted an approach where they smear the high summer prices over 12 months. The energy price paid by Victorian and South Australian consumers is based on the sum of the amount of energy defined as flat load, peak load and an amount of energy is purchased where the price is capped at \$ 300/MWh. The retailer pays around \$13.50/MWh for the cap. If the cap is not used then the retailer pay \$13.50 for the amount of energy they have under contract. However if a proportion or all of the energy under contract is consumed due to high demand and price is over \$ 300/MWh, then the retailer pays the \$13.50 plus the \$300/MWh for the amount consumed at this price. The use of price caps limits a retailer's exposure to high market prices. The cost of the caps is smeared over South Australian and Victorian consumer's bill for a 12 months period.

Victorian residential consumers are currently paying around \$ 67/MWh and South Australians are paying around \$ 72 /MWh reflecting the peakier South Australian load.

**Table 1 - AFMA and industry forward prices for flat loads in \$/MWh**

State	Calender year 2005	Calender year 2008
New South Wales	35. 82	37. 47
Victoria	32. 37	35. 95
Queensland	32. 36	37. 28
South Australia	36. 11	41. 96

Table 1 shows that the flat load forward energy prices across the market is forecast to change by less than \$ 6/MWh over a 3 year period and that a retailer can currently purchase a forward contract within this range of prices.

The corresponding peak load price is outlined in table 2

**Table 2 - AFMA and Industry forward prices for peak loads in \$/MWh**

State	Calender year 2005	Calender year 2008
New South Wales	52. 08	55. 00
Victoria	47. 45	54. 42
Queensland	46. 83	54. 70
South Australia	56. 80	62. 00

Table 2 shows that the peak load prices are up to \$ 20/MWh higher than the flat load price. Again the 3 year forward price only rises by up to \$7/MWh across the jurisdictions to meet the peak load demand.

These prices are substantially lower than the smeared prices paid for by Victorian and South Australian consumers.

It is clear that small flat load consumers in Victoria and South Australia heavily subsidise peak load consumers and will continue to do so over the 3 years of the AFMA forward curve unless the issue of summer peak load and intra-tariff cross is addressed. There is little evidence to support the theory that energy prices are high enough to encourage consumers to manage their load over periods of high demand and high prices.

New South Wales and Queensland are currently paying an energy price much closer to the flat load price, reflecting jurisdictional policies to control prices. New South Wales uses an Electricity Tariff Equalisation Fund (ETEF) where the price is currently set at around \$ 43 /MWh. The ETEF figure is around \$ 6/MWh more than the current NSW flat rate price and lower than the peak load price.

If the Victorian and South Australian consumers are reluctant to use price as a basis of load management then it is even less likely that NSW and QLD consumers will be inclined to indulge in load management.

AGL, Origin and TXU have found that load volatility and pricing anomalies in Victoria and South Australia are highly profitable and their profit margin are being further protected by the low level of customer churn.

### **Transmission Investment**

There are increasing power flows across the national transmission network as electricity consumption grows by 2% per annum and the summer peak loads grow by more than 3%. The transmission networks were not specifically designed for trading energy across regions there are historic intra regional constraints and the infrastructure is aging. The combination of these 3 factors, load growth, constraints and age, all add to the investment requirements of the transmission owners to meet their licence obligations of 99.8% reliability.

The ACCC has made regulatory determinations allocating \$ 400 million to be spent over the next 5 years to both South Australia's ElectraNet and Tasmania's TransEnd. ACCC is currently in the process of evaluating a request from the NSW transmission owner TransGrid to spend \$1. 4 b over the next 5 years designed to augment and replace network assets to meet future demand and load growth for the state.

Over \$ 2 b of investment has already been allocated across the NEM to provide sufficient transmission capacity to meet load growth and peak summer demand. ACCC will be addressing QLD transmission investment in a year's time. PowerLink, the QLD transmission company saw an 8% maximum demand growth in the previous summer and 13% this last summer, with only 25% air conditioning market penetration in the state. Given the high humidity in the QLD centres of population, one could expect further summer peak load growth in the state until the air conditioning market reaches saturation.

### **Distribution Investment**

There is a major cost impact of increasing summer peak loads on the distribution system, best reflected in the draft determination by the NSW regulator IPART to allocate \$ 5 billion to the 4 distribution businesses to be spent over the next 5 years. The Tasmanian regulator OTTER allocated \$ 400 m while the Victorian, South Australian and Queensland regulators are in the process of setting up the parameters for their determinations due next year. All three systems have experienced substantial summer load growth.

The combination of aging systems and summer peak load growth appears to be driving around \$ 8 b worth of network investment across the NEM.

Summer peak load growth is the key price driver in the NEM. Around \$5b will be spent in the next 5 years on network investment to meet increasingly peaky loads. Each network has to be sized to meet the forecast summer Maximum Demand (MW). In a number of networks this is one or two days per year. The majority of this investment has to be paid for by energy charges measured in \$/MWh.

Integral Energy provides the best example of the problem. They claim that they need to invest \$ 1 b to meet load for 2 days per year. Network utilities solve the allocation of peak load investment by a massive cost smearing exercise between all customers and over the year.

Continuing load growth coupled with even higher summer peak demand growth is costing \$ 5 b worth of network augmentation investment over the next 5 years across the NEM. If this trend continues, the level of investment will need to increase at a faster rate than the load growth increase all this investment has to do is to make sure that the Distribution Businesses meet a load lasting several days so they are able to comply with their relevant Licence conditions and Distribution Code performance requirements.

The NEM and the jurisdictions have failed to address any issues around load growth and summer peak demand. Peak load growth is costing consumers a bundle. There has to be a better way!

# MANDATORY RENEWABLE ENERGY TARGET (MRET)

Greenpeace

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## OVERVIEW

The National Electricity Market has required supplementation from other programs to encourage the development of renewable energy sources. MRET began in 2001 to support new industry and essentially allocates a share of power demand to renewables. However, its future is now under review as well as a number of other barriers to integration of renewables into the market.

In 2003, Greenpeace Australia Pacific published the “Power Shift: *putting renewables on target*” report, which we had commissioned from NEXT Energy.

It was the first study to show that a 10% MRET would:

- Avoid an increase in Australia’s greenhouse gas emissions of 26.5 million tonnes;
- Create 14,000 direct high-quality jobs, mostly in regional Australia;
- Provide a solid foundation for a sustainable energy industry;
- Place Australia on the necessary trajectory for significant greenhouse emissions reductions to avoid the worst impacts of climate change.

## Why do we want a 10% MRET?

Because deep cuts are needed in Australia’s greenhouse gas emissions.

The CSIRO has stated that globally we must reduce greenhouse gas emissions by 60-85% if we are to stabilise atmospheric carbon dioxide at pre-industrial levels. Federal Environment Minister, Dr David Kemp, has also acknowledged the need for ‘deep cuts’, stating that *“the world needs to achieve a 60 percent reduction [in greenhouse gas emissions] by the end of the century”*.

Despite this, Australia is currently heading in the opposite direction. According to the Electricity Supply Association of Australia, emissions from electricity generation, which account for one third of Australia’s greenhouse gas emissions, are expected to increase by 60% from 1990 to 2010.

Also, because there are significant business advantages in a 10% MRET.

According to the World Watch Institute, the renewable energy industry is one of the fastest growing new global industries— growing faster than IT, tourism and manufacturing. Countries that show leadership by supporting new renewable energy industries will benefit by diversifying their economies and creating new employment and manufacturing opportunities. Countries such as Germany and Spain have seized the opportunities presented by renewable energy markets.

For example, in 1993 just 52 megawatts (MW) of wind energy capacity was operating in Spain. By 2002, over 3,550 MW of wind energy had been installed, placing Spain as a world leader in wind power development. The economic advantages from supporting renewable energy in Australia could include:

- trade benefits from exporting clean technologies to Asia and the Pacific region;
- stability and security of energy supply;
- thousands of new jobs in manufacturing, construction and maintenance, mostly in regional Australia.

## **The Mandatory Renewable Energy Target — past, present and future**

A Mandatory Renewable Energy Target was first proposed by the Howard Government in the *Safeguarding the Future* package of 1997, in the lead up to the Kyoto Protocol negotiations. The *Renewable Energy (Electricity) Act*, which established the MRET, was brought before Parliament at the end of 2000 and came into force in April 2001. It aims to increase the amount of renewable energy in Australia's energy mix by requiring all electricity retailers and large industrial consumers to source an additional 9,500 GWh (Gigawatt-hours) of their electricity from renewable sources by 2010. This is policed through the use of Renewable Energy Certificates (RECs) which track the generation and purchase of renewable energy.

### **The Good**

The MRET was designed to create additional renewable energy capacity, reduce greenhouse gas emissions and stimulate the development of economies of scale and scope in renewable energy industries. As a policy measure, it was a world first and has the capacity to lead the way for a massive increase in renewables in Australia.

### **The Bad**

However, a 2% MRET is extremely low compared to many overseas targets. For example, India has a renewables target of 10% by 2012. Germany is among the world leaders with a 12% renewables target by 2010. The UK's target is 10% by 2010 and 20% by 2020. Many US states also have significantly higher targets than Australia's.

During the legislation's development, it was decided that the 2% increase should become a fixed 9,500 GWh target of renewable energy generation. However, this figure was calculated using a projected increase in energy consumption by 2010 which was well below current growth figures. According to the Australian Business Council for Sustainable Energy, this means that the target will be closer to a 0.5% increase than the mandated 2%.

By setting the MRET at 9,500 GWh, Australia risks missing out on the rapidly developing global market. In order to compete with a mature, sustainable renewable energy industry, the target must be increased to match other markets around the world – 10% new renewables by 2010.

### **The Ugly**

Under the regulations to the Act, renewable energy was given a very broad definition, encompassing a number of technologies that are far from sustainable:

- The inclusion of power generated from the combustion of native forest wood waste has been extremely contentious and should be removed. While biomass can be a carbon-neutral, sustainable form of electricity generation, the inclusion of native forest wood waste in the MRET would increase the rate of timber extraction from Australia's native forests.
- The inclusion of incineration as a renewable energy source serves to perpetuate current unsustainable waste production. Incineration is an inferior energy production process compared to genuine renewable technologies. It recovers less of the energy involved in the manufacture of the products and materials in the waste stream than reuse and recycling. Furthermore, municipal waste incineration produces hundreds of chemicals, including highly toxic dioxins, which will be illegal with entry into force of the Stockholm Convention.
- Controversy has also risen over the inclusion of production increases from old hydro-electric generation and the setting of production baselines. It is vital that the system for assessing these baselines and production increases is transparent, to ensure that all energy counted towards the target is above and beyond business as usual increases. Otherwise there may be a windfall to pre-existing generation capacity that could deny support for additional, new renewable energy capacity such as wind and sustainable biomass.

## **The Case for a 10% Mandatory Renewable Energy Target**

*Putting Renewables on Target* found that not only is a 10% MRET achievable by 2010, but it would help develop a strong renewable energy industry in Australia by creating economies of scale and scope. Current growth estimates in electricity consumption (between 2.2% and 3.5% annually to 2010) mean that a 10% MRET would be equivalent to an increase in renewable energy generation of 30,100 – 36,500 GWh per year in 2010.

After analysis of the renewable energy technologies currently available, three technologies warrant particular attention in meeting a 10% MRET— wind energy, solar water heating and sustainable biomass energy from new multiple-benefit revegetation projects.

It is important to recognise that the strong growth needed for these technologies would require the coordinated support and commitment of federal, state and local governments. This would involve, for example, streamlining of planning processes for large renewable energy developments, levelling the playing field for network connection and supporting solar water heating through energy efficiency standards, building code changes and modifications to local government planning regulations.

### **Environmental benefits**

There would be significant environmental benefits from meeting a 10% MRET. Some 26.5 million tonnes of greenhouse gas emissions would be avoided, the equivalent of taking 6 million cars off Australian roads.

### **Economic benefits**

There would be significant economic benefits from meeting a 10% MRET, including attracting manufacturing facilities to Australia and opening regional trade opportunities. Perhaps most significant for the economy would be the direct creation of 14,000 new permanent jobs. It is likely that many more indirect jobs would be created. Many of these jobs, and billions of dollars in investment, would be in rural and regional areas of Australia.

### **Economically neutral**

*Putting Renewables on Target* shows that a 10% MRET by 2010 is achievable at no or very low net cost. Greenpeace notes that this is consistent with a recent study, prepared by consultants McLennan Magasanik Associates for Origin Energy, which confirmed that introducing a 10% MRET (with no new coal plants) would have a minimal impact on the cost competitiveness of Australian industries.

The cost of supplying RECs – the form of currency used to demonstrate compliance with the Act – depends largely on three factors:

- The cost and potential volume of renewable energy generation;
- The cost of other electricity supplies that renewable generation displaces; and
- The cost difference between the two.

### **A carbon cost?**

One critical factor influencing the future cost of electricity is the cost of complying with Australia's international greenhouse commitments. With the increasing likelihood of the Kyoto Protocol coming into force in 2003, and the Australian Government's commitment to meeting the target, whether or not it has ratified the Protocol, there is likely to be some direct or indirect value on carbon emissions by 2010. This should be viewed as an additional cost for non-renewable sources of electricity.

Based on international carbon futures trading and a range suggested by the Australian Greenhouse Office, *Putting Renewables on Target* assumes a cost of \$20 per tonne of carbon dioxide emissions in 2010. This cost, derived from Kyoto Protocol related trading, is likely to arise even if Australia does not ratify the treaty. Greenpeace notes, for example, that it is possible that Australian exports would be subject to tariffs on entering Kyoto compliant trading areas such as the EU and Japan. If that were the case, Australian goods would be indirectly taxed and a cost of carbon would be effectively created for Australian domestic production.

Using \$20 per tonne and an estimate of the 2010 price of electricity by the National Electricity Market Management Company, the study calculates that there is a strong case that the REC sources discussed below would have no or very low incremental cost relative to the non-renewable sources they displace.

### **A level playing field?**

Established industries often argue that renewable energy should be made to compete and should not be given extra support. This argument would be valid if there were a level playing field on which to compete. According to research undertaken by the Institute for Sustainable Futures at the University of Technology, Sydney, the Australian fossil fuel electricity industry is still subsidised by over \$900 million a year. These subsidies reduce the effectiveness of policies to support renewable energy.

In addition, the current structure of the energy market is biased in favour of large, centralised generators due to the structuring of transmission and network connection costs. Shifting the subsidies from fossil fuels to renewable energy and removing the energy market's internal biases would promote a rapid transition towards sustainable energy production.

### **The Most Promising Sources Of Renewable Energy**

Greenpeace's report, "PowerShift: *Putting Renewables on Target*" identifies wind energy, solar water heating and sustainable biomass energy as the sources most likely to make up a 10% MRET energy mix with wind providing 15,000 GWh; sustainable bioenergy 10,000 GWh; and solar water heating 13,000 GWh.

#### **Wind energy**

Over the past decade, wind energy technology has consistently delivered both performance and cost improvements to the extent that it is almost cost-competitive with fossil fuel energy. Continued technological improvements, as well as the economies of scale that would be achieved in reaching a 10% MRET, could close the gap and make wind power as cheap as coal power by 2010. Wind power has the potential to supply at least 15,000 GWh of electricity per year by 2010. This level of production growth would directly create around 3,300 new permanent jobs, mostly in regional Australia.

Two important issues would need to be addressed if wind power is to be appropriately expanded. Currently, new wind farms are required to pay the costs of connection to the electricity grid, while the costs of connecting new fossil fuel plants and major interstate connectors are borne by all consumers. This situation must be corrected if wind is to compete with fossil fuels.

Additionally, the question of community concerns about siting of wind farms will have to be addressed. Local communities should be involved from the beginning of the planning and development process. At the same time, a balance must be found between the local impacts of projects and the need for clean power.

#### **Solar water heating**

Solar water heating is already comparable in cost, over its full life cycle, to most fossil-fuel water heating options. It is a mature technology and has the potential to be on the vast majority of roofs in Australia. Due to the energy intensity of water heating, it can achieve significant greenhouse emission reductions. Solar water heating has the potential to supply the equivalent of at least 13,000 GWh of electricity per year by 2010. This would directly create around 6,000 new permanent jobs.

The challenge for solar water heating lies in achieving large-scale deployment which would be likely to deliver far lower costs, making it a potentially major source of RECs at no net cost.

Achieving the full economic potential of solar water heating will require significant institutional and policy changes, including energy efficiency standards for hot water heaters, building code changes and modifications to local government planning regulations.

### **Sustainable bioenergy**

Multiple-benefit sustainable bioenergy crops, such as Eucalyptus oil mallees, could supply large amounts of renewable energy while also contributing to other environmental needs, such as salinity management. With a cost of carbon and revenue streams from energy, salinity benefits and any other cropping benefits, sustainable bioenergy could soon be cost competitive with fossil fuel energy.

Multiple-benefit sustainable bioenergy has the potential to supply at least 10,000 GWh of electricity per year by 2010, directly creating around 5,000 new permanent jobs, mostly in regional Australia. In weighing the benefits of biomass energy crops, issues of concern include the use of wood from native forests, use of genetically modified organisms, intensive fertiliser and pesticide use, loss of top soil and emissions of toxic compounds.

An increasing number of major political and industry bodies have indicated their support for an increased MRET. These include: Origin Energy, BP Australia, Pacific Hydro, the Australian Business Council for Sustainable Energy, the Australian Wind Energy Association, the Australian Labor Party, the Greens, the Democrats and the South Australian Government.

### **Greenpeace recommends**

- That the 2% mandatory renewable energy target be increased to 10% which, combined with current renewable generation, would equate to renewable energy meeting 20.5% of Australia's electricity generation in 2010. To meet this target, it will be necessary to: coordinate policies at federal, state and local government levels; and address the application of transmission charges and other internal energy market biases against small-scale, decentralised generation;
- That the MRET be increased beyond 2010, with renewable energy meeting at least 30% of electricity generation by 2020 and with targets set as far ahead as 2050 to encourage a continual transition from fossil fuels based generation to renewables. This is vital to create a climate of certainty for investors in projects with such large capital costs and long time-frames;
- That the definition of renewable energy under *the Renewable Energy (Electricity) Act* be altered to exclude the use of unsustainable sources such as native forest wood waste, municipal waste incineration and new large-scale hydro electric schemes;
- That the setting and assessing of baselines and production increases for existing renewable energy generation be transparent, to ensure that all energy counted towards the target is above and beyond business as usual.

For a full copy of

*Putting Renewables on Target: A 10% Mandatory Renewable Energy Target*

Go to [www.greenpeace.org.au/climate/solutions/powershift.html](http://www.greenpeace.org.au/climate/solutions/powershift.html)

Or contact:

Greenpeace Australia Pacific  
Level 4 – 39 Liverpool St  
Sydney 2000 NSW  
02-9261-4666  
[www.greenpeace.org.au](http://www.greenpeace.org.au)

# THE MULTI-STATE EMISSIONS TRADING SCHEME

## Total Environment Centre

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While the National Electricity Market aims to achieve efficiency and competition, it does not seek to internalise the environmental impacts of coal-fired electricity generation. For this reason, emissions trading schemes are required to allocate a carbon price signal as a mechanism to reduce emissions to a target.

The Federal Government has signalled its intention not to ratify the Kyoto Protocol. It has also rejected further exploration of a national emissions trading scheme. In doing so, the Government has isolated itself from both Kyoto ratifying countries and those independently developing emissions trading schemes. The economic implications of these moves are great.

In November 2003, Premier Carr announced his intention to develop a multi-state emissions trading scheme. Currently, discussions between all states, but in particular NSW, Victoria and South Australia are progressing towards the framework for such a scheme.

In a parallel process, NGOs and businesses are developing agreed principles under which such a scheme would gain their support. Consultation between NGOs and business groups is underway and will lead to the development of a report of issues and recommendations.

Key issues facing the development of a multi-state emissions trading scheme include:

- absolute or relative targets;
- level of targets, including long term, deep cuts;
- a uniform 'multi-state' scheme or different schemes in different states;
- emissions, sources or sectors liable under the scheme;
- compatibility with other non-Kyoto schemes;
- future compatibility with Kyoto;
- transitioning from the NSW Greenhouse Benchmarks Scheme;
- inter-state equity and 'burden sharing' between states;
- non-participating states;
- eligibility of bio-sequestration and geo-sequestration;
- the upcoming Federal election;
- the status of other programs such as MRET, MEPS, BASIX etc;
- allocation of certificates by auctioning or by grandfathering; and
- administrative frameworks.

A Final Report on the outcomes of these negotiations will be available in late 2004 on Total Environment Centre's website: [www.tec.org.au](http://www.tec.org.au).

## RECOMMENDATIONS

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### Consultation and Representation in the National Electricity Market

- MCE Reform Program consultation processes should allow longer lead-times.
- MCE Reform Program should provide easy to understand briefing papers on each issue that present a range of views.
- MCE reform program should seek a greater range of independent advice and make reports public.
- Community and environment sectors should be resourced to a level on par with the advocacy budgets of private and state owned corporations.
- MCE should develop improved processes for communication between environment, community and energy departments and ministries to facilitate a more strategic approach to reform.
- Community and environment stakeholders must be represented in all processes, including:
  - oversight of the appointment of NEC/AER Commissioners;
  - oversight over the appointment of AEMC Directors;
  - NEMMCO's Participant Advisory Committee;
  - relevant NEMMCO working groups;
  - the Gas Advisory and Code Change Committee;
  - the NEC Code Change Committee.

### Demand Management

- Create parity between DM and generation in a demand-side response aggregation facility before progressing to the establishment of such a facility.
- Develop an appropriate compensation process to address the problem of DM bids reducing the pool price and eroding the value of DM in an aggregation facility.
- Develop the capability of a demand-side aggregation facility to access the residential market through the use of interval metering.
- The National Electricity Code (NEC) should direct jurisdictional regulators to maintain or return to a revenue cap form of regulation for distribution networks.
- The NEC should develop clearer pricing and incentives for networks to undertake DM, and should consider the following mechanisms:
  - mandating the earmarking of a percentage of network capital expenditure for DM; and/or
  - allowing networks to keep both the cost of DM projects and the foregone revenue on sales lost because of the DM project; and/or
  - allowing networks to add DM projects to their Regulated Asset Base on which future revenue is determined.
- The NEC should mandate that jurisdictional regulators carry out transparent reviews of network investments and disallow capital expenditure when networks have failed to undertake DM when cost-effective.
- Meaningful participation by consumer and environment groups in network determinations should be supported by resourcing on par with networks' advocacy budgets.
- Jurisdictional regulators or the Australian Energy Regulator should facilitate congestion pricing for network charges to send price signals for reducing peak demand in constrained areas.

- The NEC should require networks to solicit proposals for alternative non-network solutions and carry out cost-effective proposals before they undertake planning for major network augmentations.
- The NEC should specify protocols for the valuation of avoided distribution costs for network deferrals.
- The NEC should consider requiring networks to develop standard offers for demand reduction in constrained areas.
- Governments should make subsidies to the aluminium industry transparent and justify these.
- The aluminium industry should be subjected to a mandatory energy efficiency benchmark program, implemented by the National Framework for Energy Efficiency.
- Each jurisdiction should develop Demand Management Funds based on the following principles:
  - funding based on a charge of \$0.001 per kWh or 1% of electricity revenues for a minimum of 5 years;
  - Standard Offers and Requests for Proposals that specify the large scale deployment of a broad array of demand management measures;
  - administration by an independent, government-established body, and not by existing electricity companies;
  - prioritising areas where identified network constraints are arising;
  - establish performance targets;
  - adopt a timely and iterative approach in order to develop experience in the near term;
  - support broader participation in the NEM planning process through the allocation of a portion of funding to DM advocates.
- All National Framework for Energy Efficiency (NREE) models for energy efficiency potential should be reported by the NREE.
- The NREE should release all background parameters and data for modelling to allow for independent evaluation of all models.
- The NREE should have as an annual, cumulative objective at least 1% energy efficiency savings.
- The NREE should adopt a combination of regulatory and incentive approaches to achieving the energy efficiency target.
- An approach based on tradeable certificates should be treated with caution due to issues of additionality.

### **Interval Metering**

- The MCE should support the mandated, universal roll out of interval meters in all jurisdictions.
- All jurisdictions should undertake an assessment of interval metering roll-outs, with standard terms of reference for the assessments to be provided by the Ministerial Council on Energy.
- Each jurisdiction or the Australian Energy Regulator must ensure that time-of-use tariffs are implemented along with interval meters.
- Interval meters should be accompanied by measures that allow consumers to respond to price signals such as remote load control facilities, demand management and energy efficiency appliances.

- Universal roll-outs should occur in the context of a package of regulatory and program measures designed to protect vulnerable customers.
- The integrity of the retail, distribution and other codes should be maintained and a specific interval meter retail code should be developed to resolve issues such as billing, collection, bill information, tariffs etc.
- Both distribution and retail charges need to be based on time-of-use data, and load profiling in the wholesale electricity market needs to be phased out through the mass introduction of interval meters.
- Each jurisdiction or the new Australian Energy Regulator should mandate that consumers installing high energy consuming air conditioners over a set wattage level install interval metering and be placed on a time of use tariff.

### **Network Access for Distributed Generators**

- The MCE electricity reform process must include a mechanism to ensure consistency across jurisdictional regulators vis a vis access codes and guidelines. Greater consistency could be achieved through the Australian Energy Regulator (AER) taking on the regulation of DNSPs.
- The newly formed Australian Energy commission should undertake the review required under Provision 5.6.6C of the Code as a matter of priority, with a view to extending the information disclosure requirements to DNSPs.
- All jurisdictional DNSPs, irrespective of whether they are publicly or privately owned must be required to prepare and release an Annual Planning Review of Network. The prescriptive provisions within the Code in Chapter 5.6 related to TNSPs must be also applied prescriptively to DNSPs.
- DG proponents must have access to all the information required to both understand and obtain the entire value of their asset.
- An industry guide should be developed and DG proponents should have free access to experts in governments (within the department or agency with responsibility for sustainable energy development) to enable them to facilitate their access arrangements. DNSPs must have a legal obligation within the Code requiring that they inform DG proponents of the guideline and assistance available.
- An economic regulatory regime is required that provides appropriate pressure and incentives to DNSPs to provide network access to DGs across all jurisdictions.
- The following policies to support DG are required at the national level, and include:
  - the inclusion of environmental sustainability in the objectives of the NEM;
  - ratification of the Kyoto Protocol, or a legislated national greenhouse gas reduction target;
  - a Mandatory Renewable Energy Target of 10 per cent by 2010; and
  - energy load growth limits and associated Demand Side Management (DSM) policies.
- Advocates for DG should be appropriately resourced to access and develop appropriate knowledge and skills for research, and in order to participate in consultation processes and workshops as stakeholders.

### **Electricity Tariff Equalisation Fund**

- Governments should provide direct assistance to enable lower income households to participate in mainstream energy conservation activities such as retrofitting and purchasing quality energy and water saving appliances.

- State and Territory Departments of Housing should expand their retrofitting programs for energy and water conservation capacities of premises to include all public housing properties and estates.
- Jurisdictional regulators or the AER should mandate the expansion of retailer funding assistance to locally based No Interest Loans Schemes (NILS) for energy and water efficiency appliances. This should be a regulated requirement.
- The Electricity Tariff Equalisation Fund should be kept under review.

### **National Electricity Market, Consumers and Load Growth**

- No jurisdiction has any information base on appliances, appliance purchases, consumption patterns, income, the quality and size of housing stock and ownership. This deficiency must be remedied as a matter of urgency.
- Jurisdictions need to address the issue of rampant growth of summer peak load growth.
- The merit order dispatch of generation coupled with the National Electricity Code rebidding rules delivers poor greenhouse outcomes, and should be reformed.
- A complex electricity market design relying on the goodwill of participants all of whom have a vested interest in the rewards of load growth will ignore any alternative option that will impact on their revenue stream. A rebalancing of interests is required.

### **Mandatory Renewable Energy Target**

- The 2% mandatory renewable energy target should be increased to 10% which, combined with current renewable generation, would equate to renewable energy meeting 20.5% of Australia's electricity generation in 2010. To meet this target, it will be necessary to: coordinate policies at federal, state and local government levels; and address the application of transmission charges and other internal energy market biases against small-scale, decentralised generation.
- The MRET should be increased beyond 2010, with renewable energy meeting at least 30% of electricity generation by 2020 and with targets set as far ahead as 2050 to encourage a continual transition from fossil fuels based generation to renewables. This is vital to create a climate of certainty for investors in projects with such large capital costs and long time-frames.
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- The setting and assessing of baselines and production increases for existing renewable energy generation be transparent, to ensure that all energy counted towards the target is above and beyond business as usual.

# APPENDIX 1 – MINISTERIAL COUNCIL ON ENERGY MARKET REFORM PROGRAM

## Ministerial Council on Energy Energy Market Reform : Program Summary

Denotes stakeholder consultation

MCE denotes MCE decision point

Projects	Qtr 4 / 2003	Qtr 1 / 2004	Qtr 2 / 2004	Qtr 3 / 2004	Qtr 4 / 2004	2005	2006
<b>1. Governance &amp; Institutions [SA]</b>							
<i>Inter-Governmental Agreement</i>	MCE note framework	SCO draft IGA	MCE approve IGA	CoAG endorse IGA			
<i>National Legislation</i>	MCE consider legislative models	MCE finalise legislative framework. SCO develop draft bills	MCE approve bills. Bills introduced in parliaments	Legislation enacted			
<i>Establish AEMC &amp; AER</i>	SCO draft structure & operations paper	MCE endorse structure & operations paper	Commissioners selected	Operations commence		Transfer gas transmission*	
<i>MOU between ACCC-AEMC-AER</i>	SCO draft framework	SCO develop MOU	MCE finalise negotiation & approve MOU	MOU implemented			
<i>NECA &amp; NGPAC Transition</i>	SCO draft transition paper	SCO endorse transition plan		NECA dissolved		NGPAC dissolved (subject to PC gas review)	
<i>Subsume NEMMF into MCE</i>	SCO review NEMMF work program	NEMMF work program continues under SCO/MCE		NEMMF dissolved			
<b>2. Economic Regulation [Vic]</b>							
<i>Energy Access</i>		SCO draft issues paper on national approach	MCE endorse preferred approach	SCO develop national approach (subject to MCE decision and consideration of PC gas review)		MCE agree national structure	
<i>Distribution &amp; Retail</i>	MCE agree policy & timing	SCO develop framework paper	MCE endorse framework paper	SCO develop detailed national structure		MCE agree national structure	Responsibility transferred to AER

\*Note: except WA (with scope for transfer at a later date).

19 December 2003

Projects	Q4/03	Q1/04	Q2/04	Q3/04	Q4/04	2005	2006
<b>3. Electricity Transmission [Qld]</b>							
<i>Transmission Regulatory Reform</i>	MCE endorse policy framework	Commission study on regional boundaries. Commence agreed code changes	MCE consider boundary report. Remove market biases	Implement new regulatory test and transmission availability incentives	Implement new transmission pricing		
<i>National Transmission Planning</i>	NEMMCO commence scoping ANTS.	MCE finalise new planning process	First ANTS produced	Implement last resort power			
<b>4. User Participation [Tas]</b>							
<ul style="list-style-type: none"> <li>o Demand side response</li> <li>o Interval metering</li> <li>o Full Retail Comestability</li> </ul>	SCO develop issues paper	SCO prepare draft report	MCE approve user policy	Implementation commences			
<b>5. Gas Market Development [NT]</b>							
<i>MCMPR Upstream Issues</i>	Advice requested from MCMPR	MCMPR review unproduced areas for 3 <sup>rd</sup> party access		MCE respond to MCMPR review			
<i>PC Gas Access Review</i>	PC issue draft report		PC issue final report	SCO draft response to report	MCE respond to PC review		
<b>6. Program Coordination [C'with]</b>							
<i>Market Consultation</i>	MCE endorse consultation plan	Market consultation (as above)	Consultation continues, as appropriate				