TOTAL ENVIRONMENT CENTRE

NEXT ENERGY

Demand Management
and the National Electricity Market

Total Environment Centre
Level 2, 362 Kent Street, Sydney, 2000
Ph: 02 9299 5599 Fax: 02 9299 4411
www.tec.org.au

February 2003

About Next Energy

Next Energy is a Sydney-based consulting company with an exclusive focus on utilities issues. Its work includes advice on public policy and regulation; commercial and economic feasibility; development of business plans and models; strategic positioning; and government liaison. The company's clients include a variety of public, private and NGOs. The authors of this report were:

Dr Robin Roy – Robin has over two decades of experience in the energy sector in the U.S. and Australia. Over the last eight years, he has undertaken a wide variety of public and private sector consulting assignments in the Australian energy sector. He is a director of Sydney-based consultancy, Next Energy. Robin was formerly Project Director & Fellow at the United States Congress Office of Technology Assessment where he advised the Congress on competition in the electricity market, energy efficiency initiatives and nuclear industry issues. Prior to that, he worked with Pacific Gas and Electric Company in their strategic planning group. Dr Roy gained a Ph.D., MS and BS from Stanford University.

David Nemtzow – David recently concluded a 10 year term as President and CEO of the US Alliance to Save Energy, a high-powered coalition of business, government, environmental, and consumer leaders promoting the efficient and clean use of energy. He is widely recognised as one of the leading US experts of energy efficiency and has been regularly called upon to testify before US Congressional committees, advise White House officials and brief US corporations on energy policy. David has a BA from Brown University, an MPP from Harvard University's Kennedy School of Government and works as a consultant with Next Energy on a variety of projects.

Graham Mawer – Graham has spent the past seven years working on consulting projects in the Australian energy industry. He is a director of Sydney-based consultancy Next Energy where he has led a variety of energy efficiency, energy purchasing, energy generation and energy technology projects. Before coming to Australia, he worked for a UK technology consulting firm running their northern England office, serving clients in the energy, petrochemical and product manufacturing sectors. He previously worked as an engineering consultant on commercial building projects in Canada. Graham has a B.A.Sc. from the University of Toronto and an MBA from McGill University.

Next Energy
Level 12 – 220 George Street, Sydney NSW 2000
T 02 9251 4072

Table of Contents

Executive Summary

Can demand management opportunities be harnessed to meet changing Australian electricity needs in a more efficient manner than an exclusive reliance on new generation and network augmentation? This report, commissioned by Total Environment Centre with funding from the National Electricity Code Administrator's Advisory Panel, suggests the answer is emphatically, yes.

The potential for demand management is well established and sizeable. The experience of a number of jurisdictions in the US suggests that at least 2800MW of demand management opportunities could realistically be harnessed across the NEM over the next decade with concerted effort. This is equivalent to about $5 billion worth of generation and network assets. A more intensive effort could deliver outcomes well in excess of this level.

> ***"there is significant untapped potential for efficient demand management"***
>
> IPART DM Inquiry 2002

> ***"significant energy efficiency improvement potential available to be exploited across all sectors of the economy"***
>
> COAG Discussion Paper on Energy Efficiency Nov 03

While a number of barriers to demand management exist, other jurisdictions have demonstrated that these can be successfully overcome. Harnessing the potential of demand management in Australia to defer spending on new supplies, lower electricity bills and reduce environmental impacts requires four key steps:

1. Establish DM Funding Mechanism

International experience suggest that, while essential to have appropriate rules to enable demand management, it is insufficient to rely solely on competitive electricity markets to secure substantial demand management outcomes. Indeed, many jurisdictions in the US have concluded that a parallel market mechanism is needed to specifically target demand management services.

US experience suggests that 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 proponents capable of effectively representing DM opportunities within the NEM and competing with traditional supply options.

> **What is Demand Management?**
>
> Demand management includes a diverse array of customer site activities that meet customer energy needs as effectively but more efficiently than the current situation. These include cogeneration, standby generation, fuel switching, energy efficiency, interruptible customer contracts, and other load shifting.

The on-going funding mechanism must be of sufficient magnitude to foster a concerted market response (eg a figure equivalent to at least $0.001 per kWh. This would total about $65 million per year in NSW and $40 million in Victoria, or around 1% of annual retail 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. These funds could be administered by one or more dedicated demand management funds that would purchase demand management services from all players in the market.

As the network planning approach specified under the National Electricity Code relies heavily on consultation with interested parties such as DM service providers, there is no reason to expect that DM would be adequately represented and developed until such time as there are dedicated, well-resourced proponents. Therefore, NECA should actively support and help facilitate the creation of such a funding mechanism in each state to ensure that demand management resources are integrated into the electricity system. Without such effort, the NEC's network planning approach will continue to overlook DM opportunities in favour of traditional supply options.

An alternative approach to more adequately incorporate DM in the network planning process would be for the NEC to specify the DM evaluation activities that must be undertaken by network service providers. Given the lack of detailed information and experience with broad-scale DM deployment in Australia, this would also require earmarking funding by network service providers to ensure that adequate experience is gained to properly assess DM opportunities. While this approach might be effective, it would seem less effective than developing a DM services market and allowing it to compete.

2. Test the Market for Demand Management Prior to Adopting Network Augmentation Decisions

Before network service providers undertake major network augmentations, they should solicit proposals for alternative non-network solutions. This would involve clear protocols for information disclosure, specification of constraints, requests for proposals, and evaluation of proposals. There should also be standing offers for small demand management services. Currently, the National Electricity Code does not have requirements for network service providers to test the market, nor does it provide for standing offers. NECA should promote a comprehensive approach through mandatory DM Codes of Practice for network service providers.

3. Adopt NEM Changes to Facilitate Specific Demand Management Opportunities

A variety of developments are needed to extend existing National Electricity Code provisions to effectively facilitate DM. These include such areas as:

- clearer standard network connection provisions to facilitate small generators;
- development of a market platform for real time DM;
- improved price signals, including trials of localised congestion pricing;
- ongoing assistance to governments in reviewing the roll-out of interval meters and associated pricing issues;
- clarifying the treatment of avoided TUOS and DUOS; and
- clarify the regulatory treatment and recovery of spending by NSPs on DM.

NECA should directly address these areas and undertake changes to the National Electricity Code as appropriate.

4. Implement an Intensive National Framework for Energy Efficiency

Beyond the NEM, a number of actions are required to capture energy efficiency opportunities more broadly. For example, these include strengthening of mandatory energy performance standards for buildings and appliances, and energy efficiency programs for existing buildings and industry. The Ministerial Council on Energy has recently undertaken to develop a NFEE, a step that should be expedited and strengthened to the maximum extent. More details of these suggested steps, and possible amendments to the National Electricity Code that may facilitate them, are given in Table 6.1.

The unfortunate truth is that in practice, no substantial demand management market has evolved in the first five years of the NEM and it is highly unlikely to do so without the types of changes recommended in this document. The two case studies reviewed in this paper (Sydney CBD Transmission Augmentation and the Latrobe Valley to Melbourne Augmentation) clearly demonstrate this point. Unless prompt and decisive action is taken, economic demand management opportunities will continue to be lost.

When established, the NEM generally was expected to both facilitate demand management and to be a primary market-based forum in which demand response would interact with supply operating and investment decisions. However, the core business, the expertise and the priority of the NEM lies in supplying electricity. With this in mind, it appears unrealistic to expect the NEM to be the primary driver of demand management. However, the NEM has a vital demand management facilitation role and needs to make some important changes to deliver in this role.

Similarly, network service providers (NSPs) are charged with both facilitating demand management and being the principal decision-makers concerning whether, when and where specific demand management options are pursued instead of network augmentation. However, the core business of NSPs is and will remain in building, maintaining and operating reliable and economic networks, and rightly so. Consequently, demand management is neither their priority nor a principal area of their expertise. Furthermore, demand management involves assets NSPs do not control, and they have limited relationships with consumers, which is where demand management opportunities lie. In addition, there are presently some regulatory and commercial disincentives for NSPs to aggressively pursue all but the narrowest subset of demand management opportunities. Accordingly, it appears most unrealistic to expect NSPs to be the primary drivers of demand management. Indeed, it may well be unhelpful to put more onus on them other than an active and increasingly effective facilitation role.

Who then are the appropriate parties to be the primary drivers and providers of demand management? Electricity retailers are better placed than NSPs to develop demand management because of their more direct relationship with customers. Additionally, many parties entirely outside the NEM also have major development roles to play in delivering on the full potential for cost-effective demand management. These include appliance vendors, property developers and owners, specialist demand management service providers, some large consumers, and perhaps others if given the right signals and incentives. The four key recommendations outlined above would facilitate these parties' aggressive pursuit of a demand management market.

In short, Australia has an abundant supply of the cheapest, cleanest and smartest energy resource: demand management. To date, this supply is largely untapped which, while unfortunate, does present an excellent and relatively easy opportunity to pursue as a critical component of a reliable and affordable electricity system.

1 Introduction

As a vehicle to identify potential enhancements to demand management in the NEM, this paper examines two cases where DM options were passed over in favour of expenditure on traditional network augmentation. These cases are the Transgrid/EnergyAustralia transmission augmentation to the Sydney CBD and Vencorp's augmentation of the Latrobe Valley to Melbourne transmission network.

The case studies:

1) Explore whether DM was utilised to its full economic potential;
2) Review the economic, social and environmental impact of under-utilisation on consumers;
3) Explore why DM measures were not utilised to their full potential; and
4) Propose solutions to enhance the efficient development and use of DM in the NEM.

Many, but not all of the reasons why DM measures were not utilised to their full potential, and possible solutions, like well within the purview of the NEM's regulators and administrators. This report also identifies some barriers and solutions that lie outside the purview of the NECA, NEMMCO, and the NEM regulators. While beyond the specified scope for the report, they are included for completeness.[1]

The two case studies involved augmentation of transmission networks, rather than distribution. There are significant distinctions between the code requirements and regulatory approaches to transmission and distribution. Nonetheless, much of the broader discussion of DM in this report should be relevant to distribution network DM opportunities as well.

2 Context

2.1 Outlook for Large Increases in Electricity Supply Spending

Australia is entering a period of intensive electricity infrastructure renewal and expansion. Aging electricity assets, a growing economy, changing population distribution and changing consumption patterns are all driving the need for upgraded infrastructure. The investment and operating choices made will have significant implications for consumers, investors (including States owning major electricity companies), the environment, and the economy as a whole.

In the coming decade, government and private parties are expected to invest about $30 billion in new electricity infrastructure to meet the growing needs of Australia's vibrant economy.[2] In NSW alone, the Ministry of Energy & Utilities suggests the possible need for 1500-3000 MW of new generation capacity over the coming decade[3], costing up to $3 billion. In addition, the NSW network companies have identified capital budgets of about $1 billion annually. Notably, while much of these projected costs could be avoided by demand management, there is little indication of anticipated DM investment.

[1] Note: The project grant did not require investigation of barriers and solutions outside the purview of the NECA, NEMMCO and NEM regulators, but NextEnergy agreed with Total Environment Centre to undertake the additional work pro bono to provide a larger picture of the situation, to inform policy makers.
[2] See, e.g., "New ESAA Chair calls for decisive Government leadership on energy policy" 14 November 2003.
[3] Ministry of Energy and Utilities, NSW Statement of System Opportunities, June 2002.

2.2 Large Untapped DM Potential

Major advances in efficient electricity use have been made in Australia and internationally over the past two decades, with commensurate benefits to consumers, as well as broader economic and environmental benefits. These gains have come as the result of a variety of government policies, market forces, and consumer behaviours.[4]

That said, it is generally recognised that much electricity use remains highly inefficient both economically and technically, and that demand management can and should play a far greater role in meeting future needs. Domestically and internationally over the past decades, there has been extensive analysis and development of demand management technology, economics, and policy, which generally find scope for vastly increased uptake of DM.

Diverse DM opportunities, ranging from improved lighting in commercial office buildings to the replacement of electric chillers with gas chillers to the installation of cogeneration plants have long been recognised as having great untapped potential to meet energy needs reliably and cost-effectively, with minimal environmental impacts relative to traditional generation and network solutions.

This opportunity has been recognized in Australia for many years, as shown in a decade-old statement from the NSW Government Pricing Tribunal:[5]

> "It is widely accepted that there is considerable potential to improve the efficiency with which we use electricity and other forms of energy. This potential offers the possibility of reducing both environmental impacts and, up to a point, customers' electricity bills.....The Tribunal wishes to ensure that the regulation of prices helps the community tap the potential gains form demand management more effectively. To this end it wishes to, firstly, improve the price signals to which demand management responds and secondly, remove as far as possible regulatory biases against demand management..."

The opportunity remains today, as the Tribunal concluded last year following an extensive inquiry into DM[6]:

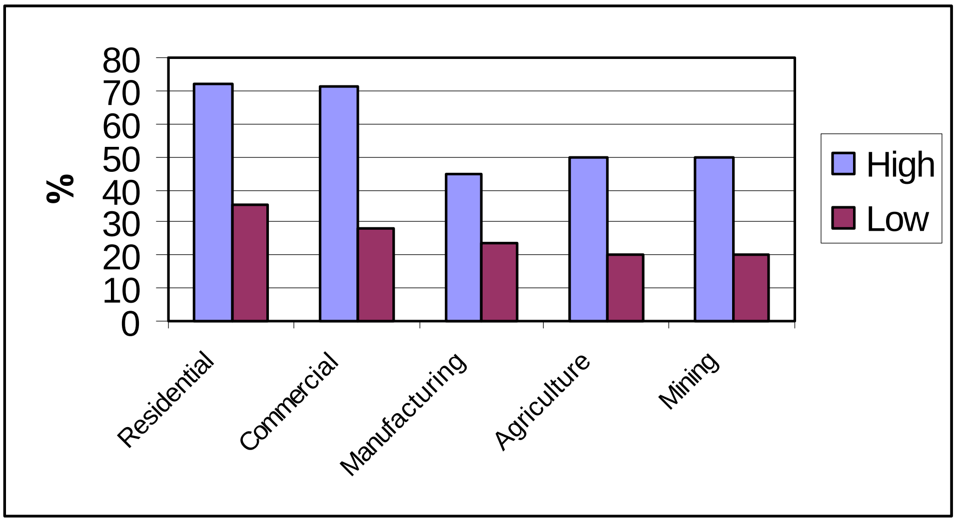
> "The importance of the role demand management can play … stands in stark contrast to the low level of activity in demand management to date. It is the Tribunal's strong view that there is significant unta pped potential for efficient demand management."

The COAG Ministerial Council on Energy has come to the same view with respect to energy efficiency. In its November 2003 Discussion Paper, the MCE notes that energy efficiency efforts to date "have captured only a small proportion of the cost-effective energy efficient potential."[7] Their analysis to date has "indicated significant energy efficiency improvement potential available to be exploited across all sectors of the economy," with cost-effective potential savings of 35% in residential, 28% in commercial, and 25% in manufacturing, with an average four year payback using technologies that are currently commercially available (see Figure 2.1). A higher efficiency scenario involving an average eight-year payback using existing or potentially available technologies indicated opportunities would be more than double that amount.

---

[4] For a broad review of historical energy efficiency programs in Australia, as well as recommended policies, see, Deni Greene and Alan Pears, "Policy Options for Energy Efficiency in Australia" Australian CRC for Renewable Energy Policy Group, January 2003.
[5] Government Pricing Tribunal of NSW, Foreword, Price Regulation and Demand Management, Sept 1994,
[6] IPART Foreword, Inquiry into the Role of Demand Management and Other Options in the Provision of Energy Services, Oct 2002.
[7] COAG Ministerial Council on Energy, Energy Efficiency and Greenhouse Working Group, "Towards a National Framework for Energy Efficiency – Issues and challenges" November 2003.

Figure 2.1: Cost-effective energy consumption reduction potential



Source: COAG Ministerial Council on Energy, Energy Efficiency and Greenhouse Working Group, "Towards a National Framework for Energy Efficiency – Issues and challenges" November 2003. Results of preliminary assessment. Low scenario assumes an average four-year payback using current commercially available technologies. High scenario assumes an average eight-year payback period and existing or developing technologies.

While vast DM opportunity is widely acknowledged, it is also generally recognised that the current suite of government policies and market drivers will fail to deliver on the full potential of DM. Again, looking to the IPART DM inquiry, it is notable that fully thirteen broad initiatives were recommended.[8] **Without intensive support for such initiatives, it should come as no surprise that the vast potential for DM will remain untapped, and that the projected $30 billion in networks and generation spending will be made, to the disbenefit of consumers, the environment and broader society.**

The challenge facing policy makers and governments lies not in assessing whether more DM should be pursued, but rather, in committing to act decisively and effectively on DM initiatives such as those recommended by IPART.

Box 1: What is Demand Management?

For the purposes of this report, demand management includes a diverse array of opportunities at a consumer's site[9] to meet their energy needs as or more effectively, such as:

- **Cogeneration**
  - Use of **standby generation** at customers' sites
  - **Fuel switching** (e.g., using natural gas-fuelled chillers; solar water heating)

- **Energy efficiency** (advanced controls for air conditioning and lighting; better appliances and equipment and buildings)

- **Load shifting** (e.g., deferring non-essential or lower-value loads during extreme peak periods)

[8] IPART Inquiry, pp. 32 – 97.

[9] While there may also be attractive energy efficiency opportunities within an NSPs facilities themselves, e.g., through application of power factor correction at a substation, they fall outside the definition used in this report. Such opportunities are well within the control of NSPs to implement directly, and do not face the same challenges identified in this report.

Box 2: Who Might Supply Demand Management Services?

A wide variety of parties could potentially provide DM services, such as:

- Electricity retailers; (through a range of programs, like specialist DM providers)
- Specialist DM service providers – e.g., engineering consulting firms
- Property developers (by going beyond minimum appliance and building mandatory energy performance standards)
- Appliance and equipment vendors (by marketing higher 'star-rating' devices)
- Standby generator vendors and service providers;
- Metering companies (by enabling more cost-reflective pricing);
- Consumers (by managing their demand);
- Local governments; (by promoting residential energy performance improvements)
- Gas retailers (through fuel substitution).

2.3 Widely Recognized Barriers to DM

With all the promising potential for DM, why has so little DM been taken up to date? The question of impediments to DM has drawn considerable attention for many years, and is increasingly well understood.[10]

This section reviews some key impediments to DM, and comments on the extent to which these are caused by, or could be mitigated more effectively, through the NEM.

Barrier 1: Chicken and Egg: Lack of a Mainstream DM Services Industry

The first and foremost challenge for DM is the chicken and egg problem of the absence of a strong DM services industry with adequate resources to demonstrate and promote demand management effectively. In contrast to the $25 billion energy supply industry, the demand management industry is very small and immature, and has no major dedicated corporate players. Furthermore, DM opportunities are individually small relative to traditional supply options, dispersed across a large number of consumers and sporadic (eg Naps seek DM offerings infrequently and have not regularly taken up the offerings made).

As a result, there are few well-resourced, dedicated advocates to promote effective DM policies, argue for appropriate pricing and incentives, and overcome barriers. For example, whereas all the major NSW network service providers regularly participate in the NSW Ministry of Energy's working group revising the NSW DM Code of Practice, there is little participation by either current or prospective DM service providers.

Notably, the NEM and the NEC do not make provision for the current lack of well-resourced, dedicated DM proponents. This can be a significant barrier to adequate and effective consideration of DM opportunities in the NEM planning and network development. In particular, the NEC planning provisions rely on interested parties, including DM providers, to participate in a

10 For recent relevant reports including discussions of barriers to DM, see, e.g., IPART Inquiry into the Role of Demand Management and Other Options in the Provision of Energy Services Final Report, October 2002; Charles River Associates and Gallaugher & Associates "Electricity Demand Side Management Study" prepared for VENCorp, 7 September 2001; and COAG Ministerial Council on Energy, Energy Efficiency and Greenhouse Working Group, "Towards a National Framework for Energy Efficiency – Issues and challenges" November 2003.

consultation process conducted by the NSP to ensure that DM options are properly identified[11] and assessed[12], and to dispute the plans of network service providers as needed.[13] While this consultation-oriented planning process may be appropriate once there are effective DM proponents, there is no reason to assume that it would obtain adequate participation under the current circumstances.

Barrier 2: DM not a priority for most consumers

By definition, DM opportunities generally lie originally with consumers. However, every household or business has a variety of opportunities that compete for scarce time and capital resources. Energy use in general, and development of DM opportunities in particular, have low or no priority with the great majority of consumers. This is not unreasonable, as for most industries and households, energy is a small proportion of total expenditure. DM opportunities also tend to be relatively unexciting, and lie far from core expertise, and interests.

Consistent with the low priority placed on energy and DM, many consumers have a preference for simplicity and convenience, as opposed to gaining additional information about opportunities. For example, recognising that some customers prefer simplicity in budgeting to feedback in energy costs, some retailers offer 'bill smoothing'[14] or a 'budget plan'[15] that allows paying equal installments throughout the year. While that plan doesn't necessarily reduce information provided regarding energy use, it does insulate the consumer from the more regular financial feedback of quarterly bills based on actual consumption.

With respect to capital resources, the result is that a very high effective discount rate is applied to DM opportunities for both households and industrial customers, when capital is available at all. For example, AMCOR, which is widely recognised as a national leader in identifying and implementing energy efficiency opportunities, has a capital budgeting policy to pursue projects with a payback of under 2 years.[16] This is a high discount rate of about 50%, far greater than the 8% to 12% discount rate currently used in assessing network augmentations. In effect, DM opportunities developed by consumers typically must meet far more demanding requirements for financial performance than do network augmentations.

Similarly, company Boards of Directors, management, and staff all have a variety of activities that typically require more than the available time resources. The result is that non-core activities such as DM typically do not receive the attention they would need for implementation.

As discussed above, the NEM and the NEC do not make provision for the current lack of well-resourced, dedicated DM proponents. This can be a significant barrier to adequate and effective consideration of DM opportunities in NEM planning and network development, given the reliance on DM proponents and other interested parties to represent DM opportunities.[17]

[11] NEC 5.6.6(b) (1) (iii) and 5.6.2 (f)
[12] NEC 5.6.6 (b) (5) and 5.6.2 (g)
[13] NEC 5.6.6 (h)
[14] AGL Energy Sales & Marketing "Submission on the Regulatory Arrangements for the NSW Distribution Network Service Providers from 1 July 2004 – Issues Paper" p. 5.
[15] http://www.txu.com.au/residential/youraccount/budgetsolutions.asp
[16] AMCOR energy efficiency policy statement.
[17] NEC 5.6.6 and 5.6.2

Barrier 3: DM not a priority, and maybe a competitor, for electricity companies

Without a well-established, large DM industry, and without high priority among consumers, many expect that responsibility for DM must lie with electricity companies. In particular, electricity network service providers and electricity retailers are viewed as prospective proponents of DM.

However, while NEMMCO and NSPs have a vital DM role to play, these parties have core business obligations and expertise outside DM that necessarily compete for scarce resources, just as is the case for consumers. NSPs will always have a core competency and business interest in operating, maintaining, and as needed, augmenting highly reliable, economically efficient wires services to meet demand. The commercial interest for NSPs is clearly specified in the NEC, for example, with a regulatory objective for transmission pricing to provide for a revenue stream which includes a fair and reasonable rate of return on efficient investment.[18]

Similarly, NEMMCO must have a core competency and interest in achieving the lowest cost of supply to satisfy demand. The nature of DM opportunities is inherently different from network solutions and supply market operation in several ways. DM requires large numbers of small decisions by consumers, and at this immature stage in its development, involves implementation of novel programs and approaches, in strong contrast with the deployment of large-scale engineering solutions in networks.

Electricity retailers can play an important role, particularly if they view DM as providing an attractive offering to retain customers or secure new ones. However, retailers have a number of potential sales and marketing strategies beyond offering DM, which many may find as or more attractive to pursue.

In the course of its inquiry into DM, IPART came to the following view regarding the role of electricity companies:

> "To a large extent, one of the major obstacles continues to be a culture which favours traditional 'build' engineering solutions and which pays little more than lip service to alternative options."[19]

Notably, VENCorp, in its most recent annual report, does not mention DM.[20] TransGrid pays significantly greater attention to DM in its annual report, noting the potential benefits, and describing a variety of assessments undertaken and steps to facilitate the emergence of DM service providers.[21] Similarly, EnergyAustralia devotes significant attention to DM in its annual report, and undertakes a variety of activities to investigate and develop it. However, these efforts are naturally very small relative to their main network business. For example, EnergyAustralia plans to make $10 million in capital expenditure on DM during the 5 year period 2004/05 to 2008/09, or slightly more than one half of one percent, of the total planned capital expenditure of $1,746 million.[22]

Furthermore, some regulatory practices create disincentives to DM activities by NSPs. For example, several NSPs have noted that there is a lack of clarity regarding whether the transmission and jurisdictional distribution regulators would allow them to recover DM spending, and under what conditions. In particular, the ACCC has not provided explicit guidance on the

[18] NEC 6.2.2
[19] IPART Foreword, Inquiry into the Role of Demand Management and Other Options in the Provision of Energy Services, Oct 2002.
[20] VENCorp Annual Report 2002-03.
[21] TransGrid annual Report 2002.
[22] "EnergyAustralia's Submission on the 2004 Distribution Determination to the Independent Pricing and Regulatory Tribunal" 10 April 2003, p. xi.

treatment of DM spending by transmission NSPs, and the topic is not addressed in its Draft Statement of Principles for the Regulation of Transmission Revenue.[23] 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.[24] While the NEC 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",[25] there are no provisions detailing how that might be achieved. As another example, the use of a regulatory approach involving price caps rather than revenue caps can create an incentive for NSPs to promote additional consumption where networks are unconstrained, as that increases their revenues and earnings. Notably, IPART has adopted a price cap as the form of regulation for the 2004 to 2009 Determination.[26]

Overall, while there are opportunities within the NEM to raise the level of effort by NSPs in promoting and facilitating DM, there should be no question that the NSPs primary role will be in facilitation and assessment, rather than in driving DM programs through to implementation.

Barrier 4: Weak Price Signals and Incentives

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.

Under the NEC, transmission network prices are now set for each connection point rather than averaged across each distributor.[27] However, they do not signal transmission congestion.

In the case of smaller customers, implementing stronger price signals is further impeded by the lack of interval, or time-of-use, meters.

Furthermore, the effectiveness of those price signals that do exist can be greatly weakened where the price of electricity service is paid by a tenant rather than an owner.

There are a variety of efforts to improve network price signals within the NEM. For example, EnergyAustralia has proposed a variety of pricing structures that promote DM, including demand and capacity charges for larger customers, interruptible, seasonal, and reverse block tariffs, and the roll-out of interval metering in conjunction with time of use pricing.[28]

There are, however, a number of challenges in developing and implementing tariffs that reflect congestion costs, including equity considerations[29],[30] a lack of cost-benefit assessment by some jurisdictional regulators regarding the broader roll-out of interval metering,[31] and practical issues

[23] ACCC, Statement of Principles for the Regulation of Transmission Revenues, Draft, May 1999.
[24] NEC 6.2.4 ©
[25] NEC 6.2.3 (d) (2)
[26] IPART "Notice Under Clause 6.10.3 of the National Electricity Code – Economic Regulatory Arrangements, June 2002.
[27] NEC Chapter 6
[28] EnergyAustralia's Submission on the 2004 Distribution Determination to the Independent Pricing and Regulatory Tribunal" 10 April 2003, p. 38.
[29] See, e.g., Public Interest Advisory Centre "Submission to the Independent Pricing and Regulatory Tribunal Review of Electricity Pricing Distribution" July 2003, p. 4.
[30] Australian Consumers' Association "Submission to the Independent Pricing and Regulatory Tribunal of New South Wales Review of Electricity Networks Pricing for 2004".
[31] Joint Jurisdictional Review of the Metrology Procedures, Draft, December 2003.

in coordinating with retailers' billing systems and offerings[32]. And, as noted in Barrier 2, some consumers have a preference for simplicity over strong price signals.

As an alternative to strong price signals, it may be possible to develop strong 'standard offers' that provide incentives to customers that implement DM opportunities. While standard offers have been mooted for NSW distribution companies, and are eventually intended to be included in the DM Code of Practice, they have yet to eventuate.

Many aspects of pricing and incentives fall well within the purview of the NEM and the NEC. However, the NEC does not provide direction or details as to how pricing and incentives should be developed to facilitate effective DM.[33] With respect to interval metering, the jurisdictional regulators are required under the NEC to conduct a joint review of metrology.[34] However, there are no provisions directing the jurisdictions to conduct the benefit – cost analyses upon which sound regulatory decisions should be based. That said, the NEM should provide a useful forum for addressing the challenges to better pricing, and promoting the adoption of clearer pricing and incentives that would facilitate economic DM. There are a number of steps within the NEM that could be taken to improve the development of clearer price signals and incentives. For example, in response to the Parer Report's recommendation that the dispatch process be modified to facilitate demand side response, NEMMCO is planning to investigate the design and development of a suitable process, and associated changes to the National Electricity Code and to IT systems.[35] As another example, jurisdictions could accelerate and enhance their efforts to assess costs and benefits of interval metering and pricing.

Barrier 5: Environmental Costs Not included in Prices

Through the NSW Greenhouse Abatement Certificate legislation, NSW has taken an important step to including a cost of greenhouse emissions within electricity prices.[36] However, other NEM jurisdictions have not yet taken a similar step. Furthermore, it is unclear whether current NGAC prices accurately reflect the environmental costs that will eventuate over time as emissions trading or other greenhouse abatement measures are adopted across Australia.

Accordingly, current prices faced by consumers are lower than they would be if these external costs were internalised. While worth noting, this is likely to be a relatively less important barrier than the proceeding ones, for two reasons. First, many analysts estimate that the cost of greenhouse abatement is likely to be a small fraction of total price. Second, as discussed in Barrier 4, more accurate congestion-related price signals are likely to be more significant, and in any case, many customers would still place low priority on economic DM measures.

Barrier 6: Poor Negotiating Leverage

Prospective DM service providers can be highly dependent on effective negotiations with NSPs. For example, standby generators must negotiate connection agreements, connection costs. DM service providers in general must also negotiate the avoided costs for which the NSP would pay them, including savings of transmission use of system charges, and savings from avoided or deferred network augmentation.

[32] AGL Energy Sales & Marketing "Submission on the Regulatory Arrangements for the NSW Distribution Network Service Providers from 1 July 2004 – Issues Paper" p. 4.
[33] NEC, Chapter 6.
[34] NEC 7.13 (f).
[35] NEMMCO "Statement of Corporate Intent and Budget 2003-04" May 2003 p. 7.
[36] See www.greenhousegas.nsw.gov.au for details of the scheme.

Clearly, however, DM service providers have substantially less information regarding the nature and costs associated with the networks than do the NSPs. Furthermore, they have few practical alternatives should negotiations not proceed in a timely and effective manner.

The NEC requires NSPs to use reasonable endeavours to provide access arrangements, and to negotiate in good faith in establishing connection and service charges.[37] However, given the small number of such cases, it is unclear whether these NEC provisions are effective. Standing offers and connection arrangements would greatly simplify, speed-up and clarify this issue for all parties.

Barrier 7: Another Chicken and Egg: Lack of Australian Experience with Mainstream DM Implementation

Finally, given the lack of effort and limited experience to date with large-scale rollout in Australia of DM opportunities, there are uncertainties about the magnitude, cost and timing of the potential contribution of any specific implementation program. While there is excellent evidence that extensive economic DM opportunities exist, the absence of direct experience creates a reluctance to undertake mainstream implementation efforts.

As discussed above, the NEM and the NEC do not make provision for the current lack of well-resourced, dedicated DM proponents. Similarly, they do not make provision for the lack of experience in large-scale roll-out, not require dedicated efforts by NSPs or other parties to achieve experience to adequately assess DM. This can be a significant barrier to adequate and effective consideration of DM opportunities in NEM planning and network development.[38]

3. Case I: Sydney CBD Augmentation

3.1 Augmentation Plans Driven by Reliability Concerns

In 1998, EnergyAustralia (EA) and TransGrid (TG) identified three concerns with the level of reliability for the supply of electricity to the Sydney CBD and inner suburbs.[39]

First, they came to the view that a high profile area such as the Sydney CBD required a higher reliability criteria than had previously been applied. Second, they noted that peak demands had been growing rapidly, and appeared set to continue on that path. They determined that with continuing rapid peak demand growth, the existing "n-1" criteria would not be met as of 2003. Third, they recognised that much of the existing transmission infrastructure serving the area, particularly some of the 26 132kV lines being relied upon, was old and increasingly at risk of failure.

Accordingly, and as required by Section 5.6.2 of the National Electricity Code, TG and EA undertook an evaluation of network and non-network options.[40] The entire planning process undertaken is summarized in Figure 3.1, and afforded extensive opportunity for input from interested parties.

[37] NEC Section 5.5 (e) and (f).
[38] NEC 5.6.6 and 5.6.2.
[39] Transgrid NSW Annual Planning Statement 1999, pp 11, 24.
[40] The entire process is described in Transgrid and Energy Australia Electricity Supply to Sydney's CBD and Inner Suburbs: Final Report, February 2000

Figure 3.1: Supply to Sydney's CBD and inner suburbs – network planning process

TransGrid/EnergyAustralia joint planning
V
Identified network limitations
V
Preliminary Cost Effectiveness Analysis (NERA), Consultation Paper
V
Affected Code Participants and interested parties notified
V
Advertised in major press and invited submissions invited
V
Published Cost Effectiveness Analysis (by NERA) and Consultation Paper
V
Public Forum - 5th February 1999
V
Submissions published
V
TransGrid/EnergyAustralia joint planning
V
Options reassessed
V
Revised Cost Effectiveness Analysis prepared by NERA
V
Final Report prepared by TransGrid and EnergyAustralia
V
Affected Code Participants and interested parties notified
V
Advertised in major press
V
Cost Effectiveness Analysis and Final Report published
V
40 business day dispute lodgement period

The planning process, including the consultation, was a substantial and extensive undertaking, and drew written comments from fourteen interested parties, four of which directly addressed DM. Fourteen options were examined, including four involving cogeneration, and four involving a diverse array of other DM activities. The estimated net present value of costs for the fourteen options varied significantly, from a low of $124 million to $345 million, as shown in Figure 3.1, under the 'base case' scenario.

Three other scenarios were also considered, involving alternate assumptions regarding whether market forces would result in cogeneration facilities being developed at either Botany, Kurnell or both. These two cogeneration sites had been under active development for some time and had development approvals, but there was question as to whether they would eventuate.

Table 3.1 – Options for the Sydney CBD & Inner Suburbs

Scenario 1 - Base Case		
Option	**Description**	**NPV ($m)**
1	132kV to CBD	238
2	Zetland 330kV	176
3	Sydney South-Haymarket330 kV	167
3A	330kV via Kurnell	178
4	Beaconsfield	169
5	95MW cogen plus 255MW at Botany	231
6	250MW GT at Haymarket	173
7	420MW cogen at Kurnell	345
8	420MW cogen at Kurnell +DSM	310
9	95MW cogen +255MW GT at Botany + DSM	196
10	Sydney South – Haymarket + DSM	134
11A	250MW DSM, with TG & EA cost estimates	124
12	330kV CBD cable and Botany 350MW	140
13	330kV CBD cable and Kurnell 420 MW	180

The 250 MW DM option (11A) was estimated to have the lowest cost in the base case scenario, and among the lowest costs across most other scenarios. However, TG and EA viewed the prospects of achieving 250 MW of DM as highly uncertain.

Ultimately, TransGrid and EnergyAustralia concluded that the "most cost-effective and achievable"[41] solution was to augment the network with a 330kV underground cable between Sydney South and the CBD (Haymarket), and carry out associated works on the 330kV and 132kV systems (option 3). The total capital cost was estimated at about $340 million over the period to 2015.

TransGrid and EA sought and received approval from the Minister for Planning to proceed with the chosen option. Approval was granted to EnergyAustralia for its portion of the works in December 2001, and to TransGrid in February 2002.[42]

Among the conditions of consent to the development, the Minister required the establishment of a DM fund run by the Department of Planning, EnergyAustralia, and TransGrid. EnergyAustralia and TransGrid are to provide $1 million annually for five years. To date, the fund manager has yet to call for an EOI for DM projects or conduct other major development activities. However, the fund manager notes that some calls for EOIs for DM should start to emerge in the next several weeks.[43]

While progress in applying the DM fund has been slow, the network construction work is proceeding well, and is anticipated for completion in time for the summer of 2003/04.[44]

[41] Transgrid and Energy Australia Electricity Supply to Sydney's CBD and Inner Suburbs: Final Report, February 2000, p 9.
[42] Minister for Planning, December 2001; and February 2002.
[43] Personal communication, November 2003.
[44] www.metrogrid.com.au/about.html November 2003.

3.2 Conflicting Views on Cost and Performance of DM

During the course of the planning process, there were substantially differing views as to the cost and availability of DM that could be implemented quickly enough to meet Sydney's reliability needs. In particular, SEDA proposed that over 250MW costing less than $500 per kVA should be achievable from a variety of potential sources. Some of these sources are shown in Table 2.

SEDA based its estimates on both its broad experience across a range of projects and on a brief survey of opportunities identified by AGL, Trane and Energetics specifically in the CBD.

SEDA also put forward the view that a call for expressions of interest, based on a clear definition of the forecast constraints and required network support, would provide substantially better information on DM opportunities, and further suggested that EA and TransGrid provide cost-reflective incentives.

Transgrid and EA did not accept SEDA's assessment that at least 250 MW of peak reduction costing under $500 per kW was reasonably achievable within 3 to 4 years. Rather, they concluded that SEDA's estimate "is extremely optimistic, and is not achievable within the next 3 to 4 years," noting that their consultants held the same view.[45] In their economic modeling, TG and EA assumed that 250 MW of DM would cost $1100 per kW, or more than twice as much as estimated by SEDA.

TransGrid and EA did not pursue SEDA's recommendation to call for EOIs.

Table 3.2 – Opportunities for DM in the Sydney CBD Identified by SEDA[46]

	Demand Reduction	Net cost for DM
Small cogeneration	35 MW	$450 to $600 per kW
Replacing electric chillers with gas chillers	315 MW	$200 to $300 per kW
Standby generation	300 MW	Very low cost
HVAC, Building management system and ice storage systems improvements	~250 MW	$3 to $10 per kW for HVAC and BMS; under $800 per kW for ice storage
Total	**>>250 MW**	**<<$500 per kW**

Even with the benefit of hindsight, it is difficult to draw conclusions as to the whether EA's or SEDA's DM estimates were closer to the mark due to the continuing lack of large-scale roll-out efforts. There have been a number of further successful DM projects in Sydney's CBD, particularly in the area of energy efficiency.[47] However, despite a growing number of successful projects, these remain the rare exception rather than the rule, and the scale of deployment remains very small.

Subsequent to its initial work assessing DM relevant to the Sydney CBD and inner metropolitan suburbs, SEDA has gone on to publish more comprehensive assessments, including one

[45] Final Report, p 67.
[46] SEDA, Supplementary response to the consultation paper "Supply to Sydney's CBD and inner suburbs" 8 April 1999.
[47] See, e.g., Energetics "State Records of NSW: New Lighting Accounts for Savings at Archives" October 2002; and www.abgr.com.au, which discusses the increasing take-up of the Australian Building Greenhouse Rating Scheme by building owners and tenants committing to achieve high levels of cost-effective energy efficiency in their buildings; and www.ecsaustralia.com , which provides a number of case studies of energy efficiency projects.

commissioned by IPART.[48] The findings of that further work indicate a potential for DM at least as favourable as suggested in the original estimates of DM available for the Sydney CBD and inner metropolitan suburbs.

On the other hand, EA has gone on to issue a number of RFPs for DM proposals to defer network augmentation on its distribution network.[49] However, no projects have eventuated from those efforts.[50] Some DM proponents note that while the RFPs were a welcome step, apparent changes in deferral objectives and a lack of transparency have hampered meaningful commercial responses.

On a related front, the Energy Users Association of Australia conducted a paper trial of demand side response in the NEM during 2002. This effort included large consumers with some degree of shiftable loads, electricity retailers, and distribution network service providers. The paper trial indicated both real promise and real barriers, and suggested a series of additional steps that need to be taken.[51]

3.3 Sydney CBD DM Not Developed to its Economic Potential

DM has almost certainly not been developed to its economic potential in the case of the Sydney CBD.

As discussed in Section 2.2, both DM generally, and EE in particular are vastly under-utilised across the Australian economy. As the current suite of government and private sector policies and programs have delivered "only a small proportion of the cost-effective energy efficient potential," there should be no question that this condition is true for the Sydney CBD and inner metropolitan region. Notably, the energy efficiency potential identified by COAG in the National Framework for Energy Efficiency identifies residential and commercial buildings as having the greatest amount of waste[52] – the two main sectors in the Sydney CBD and inner metropolitan region. Much of the energy efficiency potential is likely to be in peak periods, such as improvements in air conditioning, lighting, and controls.

The full extent of economic DM that could be developed in the Sydney CBD and inner suburbs, while likely to be large, remains speculative.

While TransGrid and EA did not accept the validity of SEDA's cost estimate, they did examine what such a cost would produce in terms of NPV. The results of that analysis indicated that, if the SEDA cost and availability estimates were accurate, the DSM option would be far less costly than the other 13 options considered. Specifically, the NPV would have been less than $23 million, or a savings of over $140million relative to the network augmentation option ultimately adopted by TransGrid and EA.

3.3 Why Did the NEM Planning Process Not Take up DM?

As discussed in Section 2.3, there is a long list of reasons that DM has generally not been adopted to its full economic potential.

[48] SEDA "Distributed Energy Solutions Cost & Capacity Estimates for Decentralised Options for Meeting Electricity Demand in NSW" February 2002.
[49] EA RFPs.
[50] EnergyAustralia's Submission on the 2004 Distribution Determination to the Independent Pricing and Regulatory Tribunal" 10 April 2003, p. 38.
[51] Pareto Associates "EUAA's DSR Trial Report of the Independent Consultant" 12 February 2003
[52] NFEE Discussion Paper, section 3.

Specific to the Sydney CBD augmentation case, all of those reasons contributed to the lack of take-up of DM. However, there are several good reasons for the NEM planning process to have adopted a network solution, even while economic DM opportunities remained untapped.

Most importantly, faced with an urgent reliability need, EnergyAustralia and TransGrid necessarily turned to the only solution that was proven, within their means to implement, within their areas of expertise, and consistent with their commercial incentives.

In contrast, while DM measures were highly promising, given the lack of effort and limited experience to date with large-scale rollout, there were significant uncertainties about the magnitude, cost and timing of the potential contribution that any DM program might achieve. Accordingly, to rely on DM would have been an ambitious and risky undertaking.

Furthermore, economic DM did not eventuate on its own (that is, without specific development by EA/TG), and should not have been expected to, due to the lack of an established DM industry, a lack of clear commercial incentives reflecting network and wholesale market cost savings from the NEM, and competing consumer interests and priorities.

Notably, while there are some areas in which the NEM could better facilitate DM (e.g,. in establishing better price signals, and in clarifying connection requirements for small generators) the reasons that DM was not taken up are only partially to do with the NEM. Rather, without significant targeted DM programs sufficient to rapidly develop a substantial DM services industry, it is difficult to envision that DM will ever be deployed to near its full economic potential within the NEM.

4. Case II: Latrobe Valley to Melbourne Augmentation

4.1 Augmentation Plans Driven by Economic Benefits

Unlike the Sydney CBD case, which was driven by a concern over inadequate reliability, the Latrobe Valley to Melbourne augmentation was driven by economic opportunity.

Since 1995, VENCorp's planning processes have identified a transmission constraint between the Latrobe Valley, the location of Victoria's brown coal generation facilities, and Melbourne.[53] By easing the constraint, the following economic benefits could be delivered to customers:

- reduced losses on the network;
- reduced dispatch costs; and
- increased supply reliability beyond the minimum requirement, thereby lowering the cost of unserved energy.

About VENCorp

VENCorp is the monopoly provider of electricity shared transmission network services in Victoria.

VENCorp is responsible for planning and directing the augmentation of the Victorian electricity transmission network. Most transmission assets in Victoria are owned by SPI Powernet, which provides transmission services to VENCorp.

[53] VENCorp, Consultation Paper – Optimising the Latrobe Valley to Melbourne Electricity Transmission Capacity, February 2002.

Also, unlike the Sydney CBD case, augmentation of the Latrobe Melbourne link could be achieved relatively simply and at low cost. In particular, transmission capacity was provided by three lines operating at 500 kV; and a fourth 500 kV line operating at only 220 kV. While greatly reducing the line's capacity, the lower voltage operation was adequate for systems needs at the time of the construction in the 1980s, and allowed the deferral of the purchase and installation of new 500 kV transformers. In proposing the augmentation, VENCorp's planning process had essentially determined that the time for installing the 500 kV transformers had arrived.

VENCorp's economic assessment was published for consultation in February 2002. Five options were considered:

1. No transmission augmentations;
2. Building an all new 500 kV line;
3. Minor upgrades to the other 3 existing 500 kV lines;
4. 4th line upgrade to 500 kV with new transformer at Rowville substation; and
5. 4th line upgrade to 500 kV with new transformer at Cranbourne substation.

Table 4.1 shows the results of the economic analysis. Note that the capital cost of the two options to upgrade the 4th line to 500 kV were about one tenth that of the Sydney CBD project.

Table 4.1 – Estimated Capital Cost and Net Benefits of Transmission Upgrades Options[54]

Option	Capital Cost ($ million)	Net Present Value* ($ million)
1. No Augmentation	0	0
2. New 500 kV line	71	-20.1
3. Minor upgrades	2.6	4.6
4. 4th line upgrade – Rowville	23.8	7.5
5. 4th line upgrade – Cranbourne	35.9	2.9

* Net Present Value under base case modelling, with 8% discount rate.

Five parties made submissions to VENCorp. These included two distribution network service providers, the owner and operator of the Victorian transmission network, a major Latrobe Valley generator, and Snowy Hydro.

No submissions were received from consumers, retailers, or proponents of DM.

VENCorp published its response to submissions received in April 2002[55], and indicated it would proceed with the Rowville option with operation expected for the summer of 2003/04.

In April 2003, VENCorp announced that it would be pursuing the Cranbourne option instead, based on information gained in the initial tendering and development process. A revised economic evaluation indicates that the capital cost estimates for each of the augmentation options increased significantly, as shown in Table 4.2. As a result of the revised evaluation, the Cranbourne option has now been selected. The 4th line upgrade is now expected to be operational by December 2004.[56]

[54] VENCorp, "Economic Evaluation Optimising the Latrobe Valley to Melbourne Electricity Transmission Capacity" February 2002, p. 30, and p. 22,
[55] VENCorp "Response to Submissions" April 2002.
[56] VENCorp "Update on the Economics of Optimising the Latrobe Valley to Melbourne Electricity Transmission Capacity, April 2003.

Table 4.2 – Revised Capital Cost Estimates for Augmentation Options

Option	Feb 2002 Estimate ($ million)	April 2003 Estimate ($ million)
New 500 kV line	71	85
Minor upgrades	2.6	5
4th line upgrade – Rowville	23.8	38
4th line 500 kV upgrade – Cranbourne	35.9	42

4.2 Limited Consideration of DM

VENCorp considered only a narrow subset of DM activities in its initial analysis and did not examine any DM options in the evaluation stage. DM options were excluded based on the view that "…there are no economic competitors for the network solution…," including both DM and additional generation.[57]

VENCorp's negative conclusion on DM appears to have been made prematurely in the process and was overly broad for the following reasons:

1) No Consideration Given to Energy Efficiency: The array of DM opportunities considered was inappropriately narrow and, in particular, did not include energy efficiency. Rather, it appears that only DM opportunities targeted to extreme peak periods were considered. There is no reasonable basis for the exclusion of other DM options.

Properly including energy efficiency opportunities could significantly increase the assessed value of DM. For example, one of the reasons given for excluding DM options from the economic analysis is that "As DSM is…available for brief periods at high price, it will not have any impact on the transmission losses."[58] However, there is a wide array of energy efficiency opportunities that would provide benefits across a large number of hours, such as accelerating the take-up of high efficiency refrigerators and other appliances. Such energy efficiency efforts may not be readily accessible by VenCorp but this is an insufficient basis to exclude them from the evaluation process.

An earlier report for VENCorp on DM opportunities also excluded energy efficiency opportunities from consideration as it focused on enhancing the role of dispatchable load targeted at 'needle peaks'.[59] However, as the Latrobe Valley to Melbourne augmentation is not driven by needle peak considerations, it is entirely inappropriate to exclude energy efficiency.

2) No DM Cost and Performance Assumptions: There does not appear to be any definition of DM, or the outlook for costs, performance, or availability of DM in the Consultation Paper, the Economic Evaluation, or the Technical Report.

3) No Other Parties Highlighted the DM Opportunity: While VENCorp's conclusion on DM was overly broad and in our view probably incorrect, it must be noted that no other parties stepped forward to propose additional or different consideration of DM.[60]

[57] VENCorp "Technical Report", "Economic Evaluation" and "Consultation Paper" p. 14. February 2002.
[58] VENCorp "Economic Evaluation" p. 21.
[59] Charles River Associates and Gallaugher & Associates, "Electricity Demand Side Management Study" 7 September 2001.
[60] VENCorp "Response to Submissions" April 2002.

4.3 Melbourne DM Not Developed to its Economic Potential

Demand management has almost certainly not been developed to its economic potential in the case of the Latrobe Valley to Melbourne augmentation.

As discussed in Section 2, both demand management generally, and energy efficiency in particular are vastly under utilized across the Australian economy. As the current suite of government and private sector policies and programs have delivered "only a small proportion of the cost-effective energy efficient potential,"[61] there should be little question that this condition is true for the Melbourne area.

The energy efficiency potential identified by COAG in the National Framework for Energy Efficiency identifies residential and commercial buildings as having the greatest amount of energy waste[62] – the two main energy consuming sectors in the Melbourne area. However, the full extent of economic DM that could be developed in the Melbourne area, while certain to be large, remains speculative.

4.4 Why Did the NEM Planning Process Not Take up DM?

While the nature of the Melbourne augmentation need is considerably different from the Sydney CBD case, the reasons for not taking up DM are much the same.

As discussed in Section 2.3, there is a long list of reasons that DM has not been adopted to its full economic potential. Specific to the Latrobe Valley to Melbourne augmentation, all of those reasons contributed to the lack of take-up of DM. However, there are several good reasons for the planning process to have adopted a network solution, even while economic DM opportunities remained untapped.

Most importantly, VENCorp was able to clearly identify and assess a relatively low cost network solution that would provide significant economic benefits. The augmentation was well within VENCorp's means to implement, within their area of expertise, and consistent with their commercial incentives.

In contrast, while demand management measures are highly promising, given Australia's generally limited experience to date with large-scale rollout, and the lack of DM proponents participating in the network planning process, there was no good basis for VENCorp to define and assess a different demand management option package. Furthermore, there were no proponents of demand management positioned to come forward and address the specific context of the proposed transmission upgrade. Accordingly, it is hard to imagine how VENCorp could have taken the view that a demand management solution had merit.

Furthermore, economic DM did not eventuate on its own, and should not be expected to due to the lack of an established, mature DM industry, a lack of clear commercial incentives reflecting network and wholesale market cost savings from the NEM, and competing consumer interests and priorities.

Again, as with the Sydney CBD case, while there are some areas in which the NEM could better facilitate DM far more effectively (e.g,. in establishing better price signals, and in clarifying

[61] NFEE Discussion Paper, section 2.
[62] NFEE Discussion Paper, section 3.

connection requirements for small generators) the reasons that DM was not taken up are only partially to do with the NEM. Rather, without significant targeted DM programs sufficient to rapidly develop a substantial DM services industry, it is difficult to envision that DM will ever be deployed to near its full economic potential within the NEM.

5. DM Funds in Competitive US Electricity Markets

5.1 Overview

Electric utilities and regulators in the US have pursued energy efficiency and other demand management since the early 1980s. These activities have taken many different forms across the US over this period – including providing information; offering preferential financing; market transformation; and alternative electric rate design. They have entailed significant expenditures – DM spending in the US peaked in 1993 at US$1.6 billion annually; it is currently at over US$1 billion annually and rising with renewed interest in such programs following the introduction of competitive electricity markets[63] (see Figure 5.1). More importantly, DM has generated substantial energy savings and peak load avoidance – currently estimated at approximately 60,000 gigawatthours[64] and 25,000 megawatts[65] respectively.

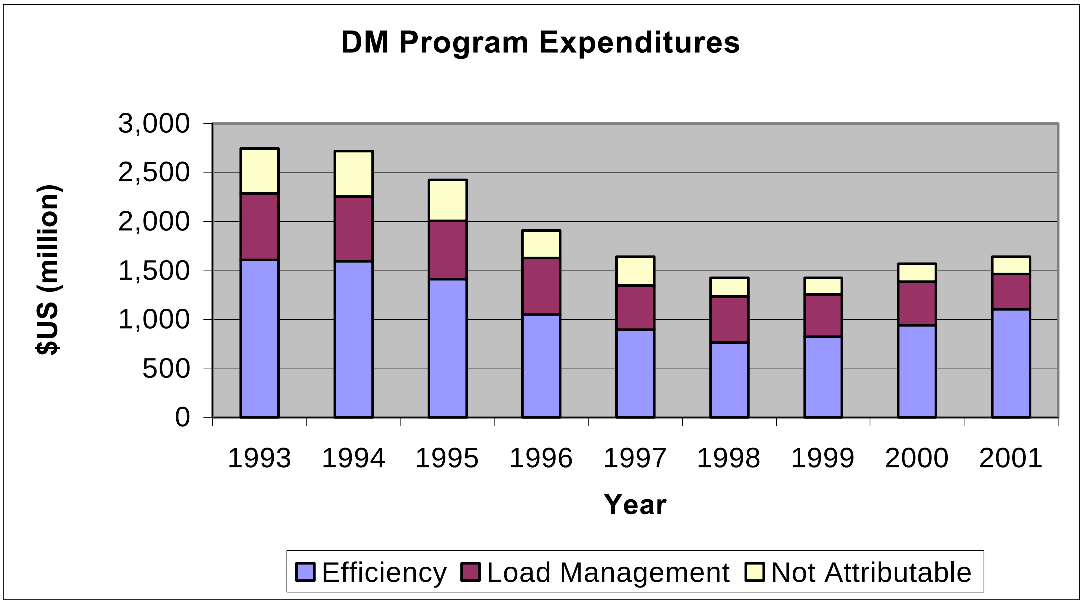


Figure 5.1. Figure 5.1 DSM Program Expenditures[66]

The introduction of retail competition into the electricity market in the US in the mid-1990s in several states has greatly changed DM policies and programs, including their magnitude, design, administration and support among stakeholders. Most importantly, in response to competitive pressures (current and anticipated; real and perceived) numerous states have established "public benefit funds" – state-wide DM and related activities funded by small, mandatory fees on electricity sales. PBFs for energy efficiency and other policy goals (including support for renewable energy, research and development and low-income bill assistance) came into existence

---

[63] York and Kushler, ACEEE, "State Scorecard on Utility & Public Benefits Energy Efficiency Programs: An Update" Dec 2002
[64] York and Kushler, ACEEE, "State Scorecard on Utility & Public Benefits Energy Efficiency Programs: An Update" Dec 2002
[65] U.S. Energy Information Administration, Form EIA-861, "Annual Electric Power Industry Report" as reported in U.S. EIA *Electricity Power Annual 2001*.
[66] U.S. Energy Information Administration, Form EIA-861, "Annual Electric Power Industry Report" as reported in U.S. EIA *Electricity Power Annual 2001*

in the mid-1990s and are now in place in some form in twenty states, investing over US$1 billion annually.

Since the onset of the US's energy crises of the 1970s (notably the OPEC oil embargo and the Three Mile Island nuclear accident) there has been a vigorous debate about whether energy efficiency products and services should be actively promoted by government (through regulations, rate design, taxation, programs and other means) or be left principally to the marketplace. The changing face of electricity DM has both reflected and shaped that debate.

In the past, the primary objective of most DM programs was to provide cost-effective energy and capacity resources to help defer the need for new sources of power, including generating facilities, power purchases, and transmission and distribution capacity additions. However, due to changes occurring within the industry, electric utilities are also using DM to enhance customer service.

Accordingly, DSM programs generally fall into two main categories[67]:

- **Energy efficiency and conservation -** programs to reduce energy use by improving the efficiency of equipment (lighting and motors, for example), buildings, and industrial processes.

- **Load management** – programs to redistribute energy demand to lessen peak demand and hence reduce peak load on generation and transmission facilities and, sometimes to fill in troughs (to strategically increase energy use during periods of low electricity demand.). Examples include load shifting programs (reducing air conditioning loads during periods of peak demand and shifting these loads to less critical periods), time-of-use rates (charging more for electricity during periods of peak demand), and interruptible rates (providing rate discounts in exchange for the right to reduce customers' electricity allocation during the few hours each year with the highest electricity demand).

5.2 Types of US DM Activities

DM efforts in the US have taken many different forms. It is worth keeping in mind the diversified and balkanised nature of the US electricity industry. There are some two hundred investor-owned utilities (providing approximately three-fourths of total US power); literally thousands of state, municipally and rural cooperatively owned utilities; and federally owned providers. Utility regulation is no less balkanised – the utilities are variously regulated by the fifty state utility commissions and/or state governments, and/or the Federal Energy Regulatory Commission and federal government. Demand-side activities are primarily regulated by the States.

Depending on which definition one uses DM may include any or all of the following overlapping but distinct components: energy efficiency, demand-side management, load management, peak load shifting, demand response, and distributed power generation (such as cogeneration and renewable energy sources). DM is used and useful for all consuming sectors: residential (including special efforts for low-income or hard-to-reach populations), commercial and institutional, governmental, and industrial.

DM activities, in turn, may be categorised as follows.[68] Any of these activities may be used to promote any of the DM areas and any of the consuming sectors listed in the previous paragraph;

[67] Thanks to: IRP and DSM for China paper
[68] IRP & DSM for China paper

however, to maximize effectiveness and cost-effectiveness it is necessary to design and implement specific activities to desired areas and sectors.

1. General information to inform customers about generic energy efficiency options.
2. Site -specific information to provide information about specific DM measures appropriate for a particular enterprise or home.
3. Financing to assist customers with paying for DM measures, including loan, rebate, and shared-savings programs.
4. Direct installation to provide complete services to design, finance, and install a package of efficiency measures.
5. Market transformation to seek to change the market for a particular technology or service so that the efficient technology is in widespread use without continued utility intervention.
6. Alternative rate design including time-of-use rates, interruptible rates, and load shifting rates. These programs may or may not save energy, but they can be effective ways to shift loads to off-peak periods.
7. Bid ding schemes in which a utility solicits bids from customers and energy service companies to promote energy savings in the utility's service area.

The first five activities listed above are programmatic in nature and require an expenditure of funds to implement; the latter two are regulatory in nature and do not require a significant implementation budget. Accordingly, Public Benefit Funds may be used for any or all of the five program areas, but are not directly appropriate for the two regulatory issues (beyond providing funds for design, analysis, etc.).

5.3 U.S. Experience with Demand Management

DM activity in the U.S. has been successful by all metrics, including energy saved, load and peak load avoided, generation and transmission investments deferred or avoided, and emissions avoided. With the widespread introduction of contestable energy markets, recent years have seen enormous shifts in program structures and approaches. This appears to have resulted in slight declines in overall outcomes from the peak year of 1996 but, as new DSM programs and public benefits funds have been introduced, the overall benefits are again growing.

Total peak-load reductions from DM were 24,955 megawatts in 2001, according to the U.S. Energy Information Administration (EIA).[69] This level of peak reductions is up 9 percent from the previous year – but down 17 percent from 1996, the year of greatest peak reductions from DM (See Figure 5.2). Energy savings due to DM for the year 2000 were 56,808 gigawatthours, according to analysis conducted by the American Council for an Energy Efficient Economy (ACEEE) using the EIA and other data[70] (See Figure 5.3).

[69] U.S. EIA Electricity Power Annual 2001. Data on demand-side management activities by utilities and public benefit funds are self-reported to the EIA (and not independently verified) according to EIA guidance and definitions.
[70] York and Kushler, ACEEE, "State Scorecard on Utility & Public Benefits Energy Efficiency Programs: An Update" December 2002

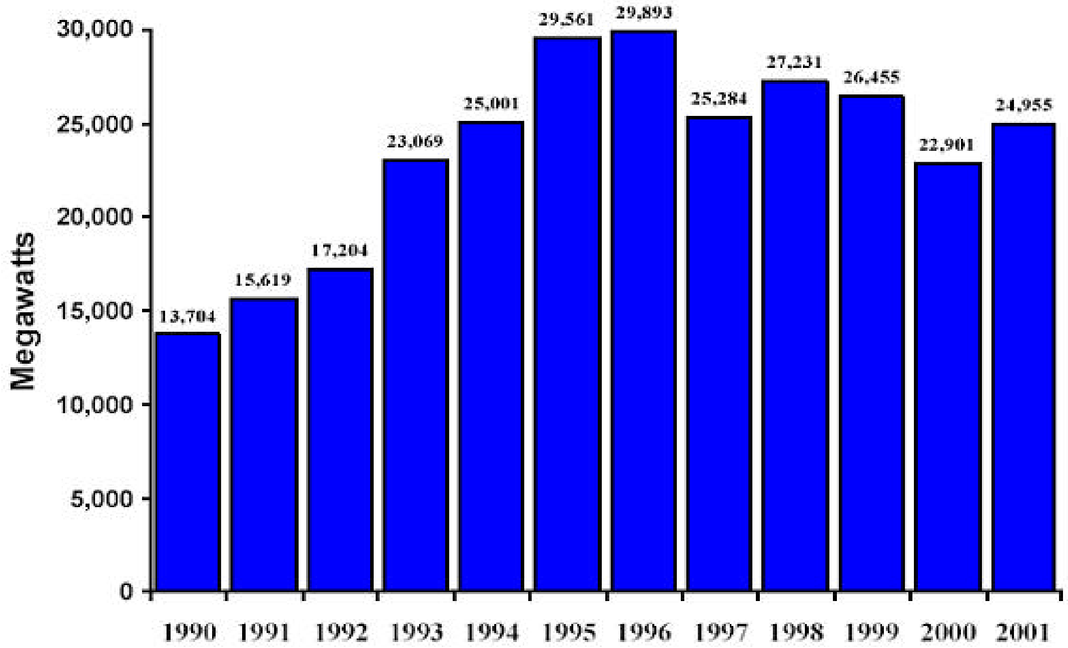


Figure 5.2 - Demand-side management peak load reductions in US, 1990-2001[71]

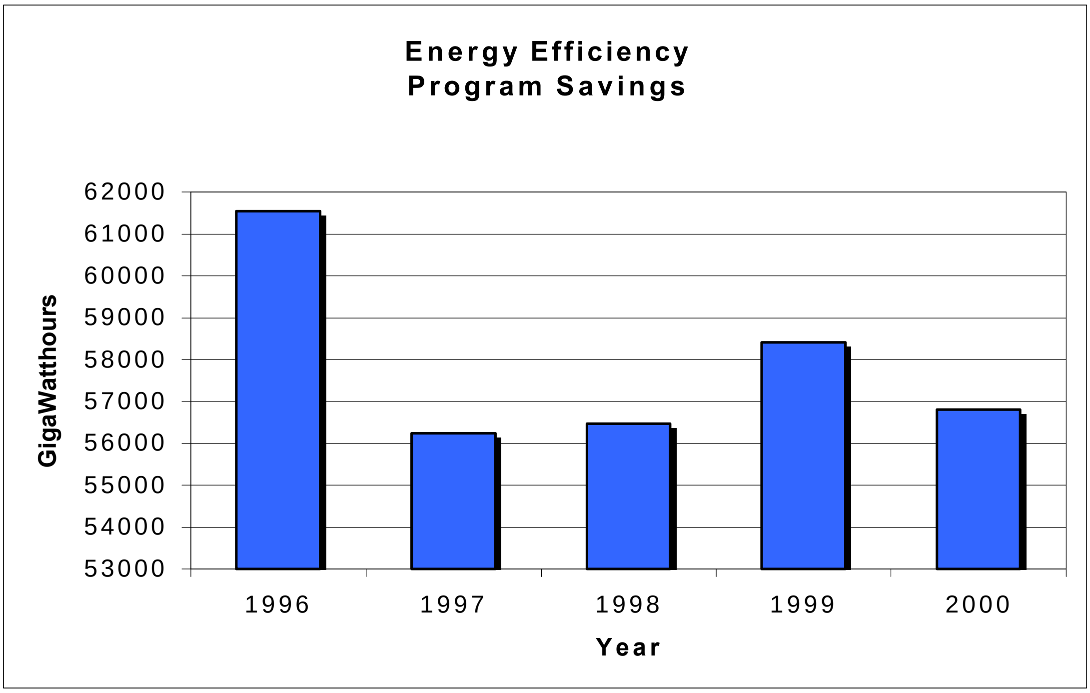


Figure 5.3. Energy Efficiency Program Savings[72]

[71] U.S. Energy Information Administration, Form EIA-861, "Annual Electric Power Industry Report" as reported in U.S. EIA *Electricity Power Annual 2001*
[72] Kushler "Scorecard", page 24, Appendix C "Time Series Data for Selected Variables

5.4 Public Benefit Funds

Twenty states in the U.S. have established demand management trusts or similar entities, supported by a small charge (typically around 1 tenth of a cent/kWh) on distribution service.

California

A Rand Corporation study of California's energy efficiency efforts between 1977 and 1995 determined that they had paid back into that State's economy roughly US$1000 per capita for the US$125 per capita invested. Further, they had avoided the need for new power plant construction in that time period and avoided a 40 percent increase in stationary source air pollution. California's recent power crisis would likely have occurred many years earlier and been far more serious without concerted energy efficiency measures.

New York

In New York, the State's fund has secured commitments in the last 3 years that will reduce electricity demand by more than 140 MW while saving consumers tens of millions of dollars annually. Consumer savings are providing a 1.4 -year payback on funds invested. Further, for each US$1 spent out of the fund, customers, energy service companies and others are investing US$3, providing good leveraging of fund expenditures. These programs are also reducing emissions from power plants and helping economic development in the state.

OTHER STATES/EXAMPLES

- **Connecticut** – Energy Conservation and Management Board oversees US$87m/yr in programs. The programs are estimated to have yielded benefits of 1.7 times costs for residential initiatives and 2.4 times costs for commercial and industrial initiatives.
- **Vermont** – Efficiency Vermont oversees US$11m/yr in programs. The estimated benefits are 1.55 times the costs.
- **Massachusetts** – Massachusetts Electric Co. undertakes US$50m/yr in state mandated programs under close regulatory supervision of the Massachusetts Department of Telecommunications and Energy. The estimated economic benefits are 2.5 times the overall cost of the measures implemented.[73]
- **Minnesota** – Xcel Energy undertakes US$38.5m/yr in state mandated programs. The estimated economic benefits are over the lifetime of the measures installed in that year are estimated to be $233 million, or over six times the program spending.[74]

Demand-side management activities in the U.S. generally cost less than US$0.03 per kWh saved and, in general, average between US$0.02-0.03 per kWh over the last two decades for a wide variety of programs. In addition, the reductions delivered by these programs are highly coincident with peak demand (on average, peak load reductions are three times greater than would be expected from energy efficiency measures targeting flat loads). This has yielded consumer energy bill savings of about US$4 billion annually.

[73] Massachusetts Division of Energy Resources "2001 Energy Efficiency Activities"; and Southwest Energy Efficiency Project "America's Leading Demand-Side Management Programs: A Sampling" November 2003.
[74] "Minnesota Energy Planning Report 2001" January 2002.

6. NEM Steps to Effective DM Utilization

Based on the general understanding to date, on the two case studies, and on the US DM experience, we believe there are four critical steps to achieving effective DM utilisation in the NEM.

These are:

1) **Establishing an Adequate DM Funding Mechanism**
2) **Test the Market for DM Prior to Adopting Network Augmentation Decisions**
3) **Adopt NEM Changes to Facilitate Specific Demand Management Opportunities**
4) **Implement an Intensive National Framework for Energy Efficiency**

Perhaps the most effective way to ensure that the proposed changes are adequately implemented would be through NEC amendments, as laid out in Table 6.1.

Table 6.1 Recommended Steps to Ensure Adequate Utilisation of DM in the NEM

Recommendation	Relevant Code provision, if amendment is required	Principle Body for Implementation
Establish DM Funding Mechanism	5.6.2; 6.2; 6.13	Each NSP regulator to assess and implement as appropriate the establishment of a DM funding mechanism sufficient to provide adequate information to perform DN analyses under 5.6.2(f) and 5.6.2(g)
Test the Market for Demand Management Prior to Adopting Network Augmentation	5.6.2 (c)	Each NSP regulator to establish appropriate requirement
Develop Market Platform for Real Time DM	3.8	NEMMCO to establish DM market platform
Clarify Treatment of DM Expenditure by Both Transmission and Distribution NSPs	6.2.3; 6.2.4(c); 6.10.5(7)(iii)	Each regulator to adopt regulatory principles specifically addressing treatment of DM expenditures in setting NSP revenue requirements
Clarify Standard Network Connection Provisions for Small Generators	5.3; 5.5	Each jurisdictional DNSP regulator to establish provisions, perhaps within DM Codes of Practice
Establish DM Code of Practice for both Transmission and Distribution NSPs	5.6.2(c); 5.6.2(f); 5.6.2(g)	Each NSP regulator to establish an appropriate DM Code of Practice
Establish Congestion Pricing Signals to Facilitate Informed Consumer Choice	6.13; 6.14	Each jurisdictional DNSP regulator to assess and implement as appropriate the establishment of a congestion pricing trials
Support Roll-Out of Interval Meters	7.13	Each jurisdictional DNSP regulator to assess costs and benefits of interval metering roll-out, and to implement as appropriate
Improve Reporting of Potentially Constrained Areas in Network Planning Documents	5.6.2 (b)	Each NSP regulator to specify steps in detail, perhaps within DM Codes of Practice
Specify/Strengthen Requirements for DM Analysis and Consultation Prior to Network Augmentation	5.6.2 (f)	Each NSP regulator to specify steps in detail, perhaps within DM Codes of Practice

6.1 Establish Large Scale Dedicated DM Funds

By far the single most important step to achieving an effective take-up of demand management is the establishment of dedicated DM Funds with adequate funding. Simply put, without a large scale Demand Management Fund deployed with concerted effort, prospective service providers will not come forward, a market in DM services will not evolve, and the benefits that are offered by DM will remain largely untapped.

This urgent step is in accord with Recommendation 1 of the 2002 IPART DM Inquiry[75] and the announcement on 20 November 2003 by the Premier of NSW that a demand management fund is to be established in NSW.[76]

We would suggest six critical principles in guiding the establishment of DM Funds:

- **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.

- **Encourage and Harness Competitive Markets** - A DM Fund should harness the innovation and dynamism of competitive markets. This could be done by making regular 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 that is not necessarily DM (e.g., stand-alone peaking generation in the distribution network.)

- **Establish Fund As Special Purpose Independent Entity in Each State** - A DM Fund should 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.

---

[75] IPART, *Inquiry into the Role of Demand Management and Other Options in the Provision of Energy Services*, 2002, p. iii.
[76] Premier of NSW "News Release Premier Announces Further Measures to Tackle Greenhouse Emissions and Global Warming" 20 November 2003.

- **Adopt a Timely & 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' RFP in the near term rather than a 'perfect' RFP 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 NSPs' conclusions and propose alternative approaches.

NECA should actively support and help facilitate the creation of such a funding mechanism in each state to ensure that demand management resources are integrated into the electricity system.

6.2 Test the Market for Demand Management Prior to Adopting Network Augmentation Decisions

Before network service providers undertake major network augmentations, they should be required to solicit proposals for alternative non-network solutions. This would involve clear protocols for information disclosure, specification of constraints, requests for proposals, and evaluation of proposals. NECA should promote a comprehensive approach through mandatory DM Codes of Practice for network service providers, clarifying and extending the provisions of Section 5.6.2 in the National Electricity Code. This would be a key step in facilitating a DM services market. Furthermore, recognising that transaction costs of participating in a request for proposal process would be very high for many small DM opportunities, NECA should also promote standing offers for small DM services.

NSW has begun adopting such an approach for distribution network service providers, which is detailed through a DM Code of Practice (See figure 6.1).[77] A central feature of the Code of Practice is that it requires NSPs to provide planning information and solicit Requests for Proposal from DM service providers and providers of other non-network options.

A DM Code of Practice requiring testing of the market prior to adopting network augmentation decisions, such as the one evolving in NSW, would have two primary benefits. First, it would lay out in some detail key steps for distributors to take in investigating the opportunity to avoid or defer network augmentation. This goes well beyond the general guidance provided in the NEC, which requires only that NSPs identify and examine DM and other non-network options. As the COP has been recognised by the NSW government, following it should give distributors added

[77] Letter from Director General, Ministry of Energy and Utilities, to Convenor, Demand Management Working Group, 1 August 2001. http://www.doe.nsw.gov.au/industry_performance/index.htm

confidence both that they are performing adequate investigations, and that they are complying with the relevant provisions of their license conditions and of the National Electricity Code.[78]

Second, such a COP should ultimately encourage proponents of DM services to come forward. In particular, a COP increases the transparency of the network evaluation process by requiring distributors to provide access to the information. It also should increase proponents' confidence that their proposals will be appropriately evaluated. In contrast, 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.

[78] Under the NSW Electricity Supply Act, the Minister for Energy imposes license conditions electricity distributor to investigate demand management strategies. However, the Act and the license conditions give little guidance on how those investigations are to be performed, or what would be considered adequate.

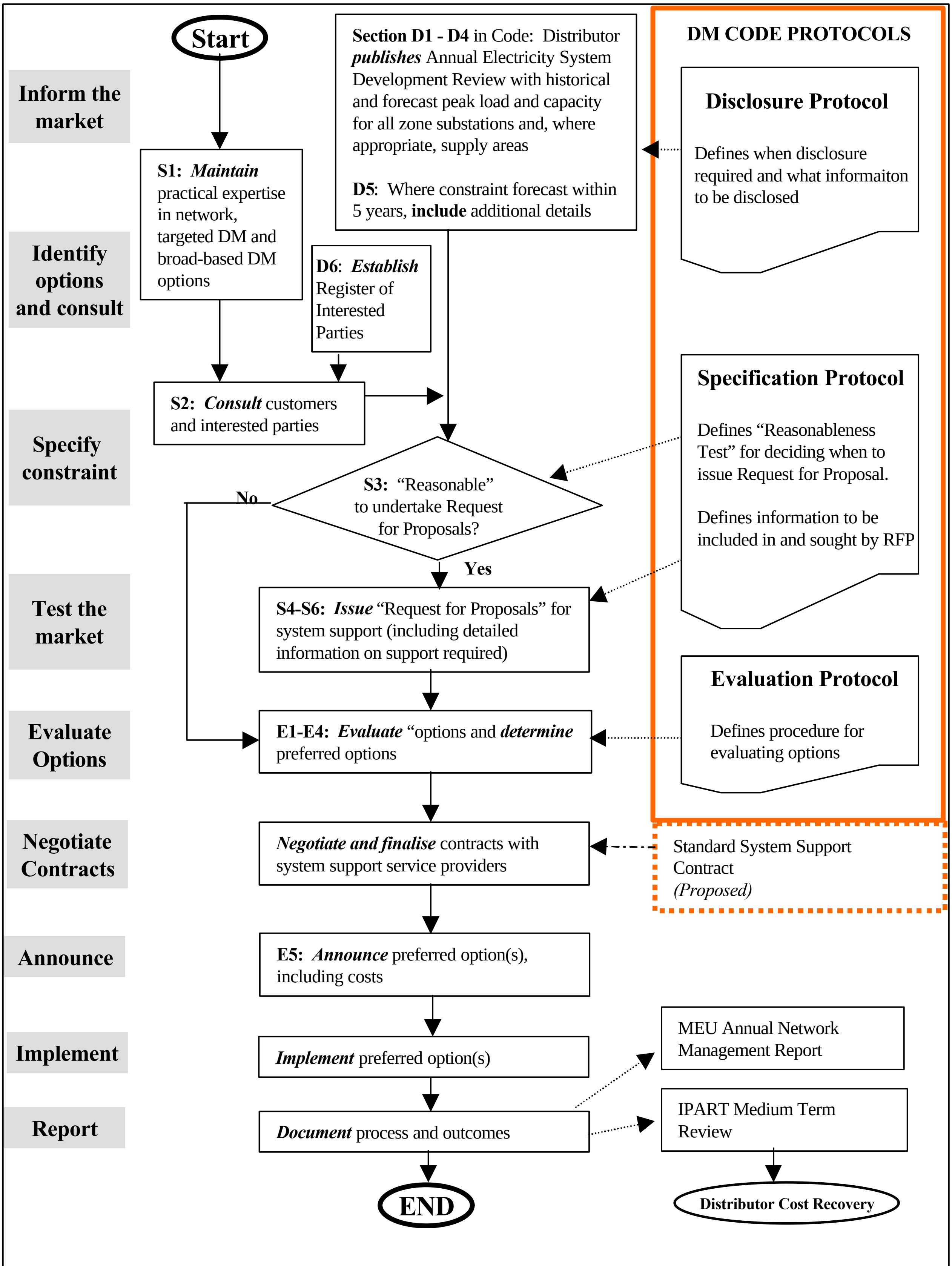


Figure 6.1. Overview of NSW Demand Management Code of Practice

6.3 Adopt NEM Changes to Facilitate Specific Demand Management Opportunities

A variety of developments in the NEM have been suggested to more effectively facilitate demand management. These include such areas as standing offers to facilitate small demand management activities, clearer standard network connection provisions to facilitate small generators, development of a market platform to facilitate interruptible contracts and distributed generation, and improved price signalling and metering to facilitate informed consumer choices. NECA should directly address these areas and undertake changes to the National Electricity Code as appropriate.

IPART, in its 2002 Inquiry into the Role of Demand Management, developed a set of recommendations to improve the utilisation of DM. IPART's recommendations, together with the existing Code of Practice, appear fairly comprehensive and broadly consistent with proposals made by the Victorian Essential Services Commission, and the COAG Energy Market Review, as well as a number of DM proponents.

While these are not 'silver bullet' policies that are sufficient to deliver on the DM potential, they are necessary changes to underpin a DM market and will play an important facilitating role. It should be noted that ongoing revision of DM policies and programs will undoubtedly be necessary as greater experience is gained.

Building on the effort and experience gained to date, NECA should, as a first step, directly address the specific policies recommended by IPART and others in recent years and undertake changes to the National Electricity Code as appropriate. Specifically, NECA should consider the following:

1) **Facilitate small distributed generators by:**

   i) requiring establishment of standard negotiation guidelines and connection agreements[79]
   ii) requiring establishment of a market framework for real time dispatch[80]

2) **Improve prices and price signalling by:**

   i) requiring DNSPs to undertake trials of localised congestion pricing[81]
   ii) requiring regulators to formally set out treatment of avoided TUOS and DUOS[82]
   iii) assisting governments in reviewing the roll-out of interval meters, including directing regulators to enhance and accelerate their performing cost-benefit analyses of interval metering and associated pricing issues[83]

[79] See, e.g., IPART recommendation 8, COAG Energy Market Review; Victorian Essential Services Commission , "Guideline for Embedded Generation: Issues Paper" July 2003; and Australian Ecogeneration Association "COAG Energy Market Review Issues Paper" April 2002.
[80] See, e.g., IPART recommendations 11 and 12, EUAA DSR Trial & COAG Energy Market Review, and Pareto Associates "EUAA D[emand] S[ide] R[esponse] Trial Report of the Independent Consultant" February 2003, which recommends further work toward a DSR facility.
[81] See, e.g., IPART recommendation 6; and Australian Ecogeneration Association "COAG Energy Market Review Issues Paper" April 2002.
[82] See, e.g., IPART recommendation 7; and Australian Ecogeneration Association "COAG Energy Market Review Issues Paper" April 2002,.
[83] See, e.g., IPART recommendation 10, COAG Energy Market Review.

3) **Facilitate real time demand response by requiring the establishment of a demand response trading platform**[84]

4) **Generally encourage NSPs to undertake DM by requiring regulators to clarify the recovery of spending on DM**[85]

6.4 Implement an Intensive National Framework for Energy Efficiency National Framework for Energy Efficiency

Beyond the NEM, a number of actions are required to capture energy efficiency opportunities much more broadly across the economy. This is urgently needed for energy opportunities that are difficult for electricity consumers to control, such as strengthening of mandatory energy performance standards for buildings and appliances. Some major steps forward have been taken recently, such as the adoption of strong mandatory energy performance standards for new housing in Victoria and New South Wales, and the development of Australian Building Greenhouse Rating Scheme for existing and new commercial buildings. There are also opportunities to assist and motivate the energy efficiency efforts of industrial and other customers, by providing technical and institutional support, as in the Energy Efficiency Best Practice Program, the Greenhouse Challenge, and state programs implemented by SEDA and SEAVic. However, far more remains to be done across all sectors, and many energy efficiency programs could be greatly strengthened and accelerated.

The Ministerial Council on Energy has recently undertaken to develop a National Framework for Energy Efficiency, a step that should be expedited to the maximum extent possible. An example of intensive policies that could be implemented under the National Framework for Energy Efficiency can be found in a discussion paper produced by the Australian Business Council for Sustainable Energy.[86] The broad ranging policy options indicate the types of effort that might constitute an intensive NFEE. Rapid implementation of the suggested "Ten First Steps to an Energy Efficient Future" would go a long way to achieving high levels of DM.

[84] See, e.g., IPART recommendations 11; Pareto Associates ""EUAA DSR Trial Report" and COAG Energy Market Review.
[85] See, e.g., IPART recommendation 5.
[86] Australian Business Council for Sustainable Energy "Driving Energy Efficiency – cutting greenhouse emissions – growing the economy – boosting jobs" November 2003.