Inquiry into the Role of Demand Management and Other Options in the Provision of Energy Services

Issues Paper

INDEPENDENT PRICING AND REGULATORY TRIBUNAL
OF NEW SOUTH WALES

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Issues Paper

Discussion Paper DP47

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TABLE OF CONTENTS

1 INTRODUCTION

In recent years, concerns about the environmental impact of electricity generation, together with high and volatile prices and generation capacity constraints, have sparked renewed interest in strategies designed to modify the timing and level of consumer demand for electricity, known as demand management. The Premier has asked the Independent Pricing and Regulatory Tribunal (the Tribunal) to undertake an inquiry into what role demand management should play in providing the state's energy services[1]. The terms of reference for the inquiry ask the Tribunal to:

- explore the technical and economic potential of a wide range of demand management, options (including load management and distributed generation options)
- assess whether greater use of these options is warranted
- assess procedures and identify barriers to demand management in the development of electricity networks and the pricing of network services
- advise on other issues that may impede efficient application of demand management.

1.1 Inquiry process and timetable

The Tribunal advertised the draft terms of reference for the inquiry in March 2001 and sought comments from interested parties on the nature of those terms. It received the final terms of reference from the Premier on 28 June 2001 (see Attachment 1).

As part of its inquiry, the Tribunal invites submissions from all interested parties on any issues they believe it should consider. It will also undertake public consultations to obtain stakeholder views, and anticipates releasing one or more discussion papers. Following the release of these papers, the Tribunal will host a roundtable discussion with interested parties.

The indicative timetable for the inquiry is provided below.

Action	Indicative Timetable
Release issues paper	July 2001
Receive submissions from interested parties	August 2001
Hold public consultations	September 2001
Release discussion papers	September – November 2001
Hold roundtable discussion with interested parties	November 2001
Release interim report	January 2002
Receive submissions on interim report	March 2002
Present final report to Premier	June 2002

1 Under Section 12A of the *Independent Pricing and Regulatory Tribunal Act, 1992.*

1.2 Key issues

To assist stakeholders in making their submissions, the Tribunal has identified five key issues on which it particularly seeks comment. These issues are:

- **What is the status of demand management in NSW?** Is there a need for greater clarification of the varying definitions and interpretations of energy demand management? How much demand management is currently being undertaken? Is this an efficient level? If not, has this resulted in inappropriate network capital expenditure, higher consumer energy costs and sub-optimal environmental outcomes?
- **Can demand management improve reliability and security of energy supply?** Reliable supply requires ensuring that generation and network capacity exceeds load requirements. What is the potential impact of greater use of demand management on the reliability of energy services and investment requirements in NSW? Is distributed generation sufficiently reliable?
- **Can demand management reduce the cost of energy services?** What role can demand management play in reducing customers' energy bills? Is demand management economically viable, or would it increase the costs of energy services? Can it reduce the level and volatility of wholesale electricity prices?
- **Can demand management improve environmental performance?** In many cases, demand management can meet our energy needs with reduced associated environmental impacts, such as greenhouse gas emissions. What is the role of demand management in reducing the environmental impacts of electricity supply? To what extent are these impacts factored into decision making?
- **What are the institutional and administrative barriers to demand management?** Do current arrangements in the energy market offer fair and efficient access for suppliers and consumers of demand management? If not, what can be done to address these barriers? Do current regulatory structures offer appropriate incentives? Is a more market-based approach to demand management likely to deliver more efficient outcomes?

This paper provides background information about demand management and the inquiry, and then discusses each of these issues.

While the focus of this inquiry is on the electricity industry, and in particular electricity networks, many of the issues surrounding energy demand management are also relevant to the natural gas industry. Implications for the supply and use of gas will need to be considered in the context of this inquiry.

1.3 How to make a submission

The Tribunal encourages interested parties to comment on the issues raised in this paper, the terms of reference and on the reports specifically referenced. The Tribunal is also interested in receiving comments on any other matter that may be relevant to this inquiry.

All submissions must be made in writing. If your submission is more than 15 pages long, it must be provided on a computer disk in word processor, PDF or spreadsheet format.

All confidential parts of submissions must be clearly marked. However, please note that confidentiality cannot be guaranteed as the *Freedom of Information Act, 1989* and Section 22A of the *Independent Pricing and Regulatory Tribunal Act, 1992* apply to all documents the Tribunal receives.

Submissions must be received by 31 August 2001, and should be sent to:

Inquiry into the Role of Demand Management and other Options
in the Provision of Energy Services (Matter No 01/257)
Independent Pricing and Regulatory Tribunal
PO Box Q290
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2 BACKGROUND

The introduction of competition in energy markets in recent years has often been accompanied by reduced attention to demand management options. However, high and volatile prices and generation capacity constraints in places such as South Australia, Victoria, New Zealand and California have prompted renewed interest in demand management (DM). Although New South Wales is somewhat insulated from these pressures due to its longstanding surplus of generating capacity, there are concerns about the possible environmental and economic consequences if DM and distributed generation options are neglected, particularly in the context of new network investment. These concerns, together with recent DM related reviews in NSW and the structure and regulatory arrangements of the NSW electricity supply industry, form the background to this inquiry.

2.1 Cost and capacity concerns

In Australia, recent history has seen peak electricity demand growing, reserve margins falling toward or below acceptable limits, and generation prices rising. In some cases, prices have come close to the maximum allowable price set in the National Electricity Market (NEM) of $5,000/MWh.[2] In February 2001, for example, prices in Victoria averaged around $95/MWh compared to around $33/MWh the previous year. In South Australia, during the same month, prices averaged more than $130/MWh.[3] Capacity constraints in South Australia have forced retailers to pursue DM options in the form of 'interruptible load' contracts and to encourage customers to conserve electricity during periods of peak summer demand.

Overseas, particularly in response to escalating wholesale electricity prices and serious electricity shortages in California, increasing attention is being paid to the balance between new investment in generation and transmission on the one hand, and DM on the other. In this context, there has been increasing debate about whether demand management, energy efficiency and distributed generation can be cheaper than conventional 'centralised' supply side options, such as large coal-fired power stations and high-voltage transmission lines.

2.2 Environmental concerns

Concerns about global warming and climate change due to the growing concentration of greenhouse gases in the atmosphere is another key issue driving the debate on energy use and DM. The generation of electricity (by burning fossil fuels such as coal, oil and gas) is one of the main producers of greenhouse gases. Australia is expected to become hotter and drier in the coming decades as a consequence of global warming. The CSIRO predicts that by 2030, temperatures over most of the continent will be 0.4°C to 2°C greater than in 1990.[4]

In response to these concerns, the Australian government has joined over 150 other countries in signing the United Nations Framework Convention on Climate Change in 1992. The 1997 Kyoto Protocol builds on this Convention by setting specific emission reduction targets for each developed country. Australia has agreed to limit its emission growth to 8 per cent

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2 According to the National Electricity Market Management Co (NEMMCo) the maximum price is scheduled to increase to $10,000/MWh in April 2002.

3 National Electricity Market Management Co, Market Data from NEMMCo website, average monthly prices.

4 EcoGeneration, *CSIRO forecasts Australia's changing climate*, June/July 2001, p 14.

above 1990 levels by 2008-2012. Estimates suggest that meeting this target will require Australia to reduce emissions by around 30 per cent relative to 'business as usual' projections.

At the 10th Council of Australian Governments meeting, held in June 2001, it was agreed that a National Electricity Market policy Forum of Ministers be established. This forum will give urgent attention to a number of NEM issues, including the effectiveness of regulatory arrangements in promoting efficient market outcomes, regional boundaries and demand-side participation.

As evidence of global warming and climate change grows, future legally binding reduction targets are likely. This suggests that it is economically prudent, as well as environmentally responsible, to prepare for any future abatement obligations by taking advantage of low cost emission reduction strategies available today.

2.3 Recent NSW reviews

In November 2000, the NSW Minister for Energy established an inter-agency working group (convened by the Ministry of Energy and Utilities) to review how effective existing electricity network planning arrangements are in encouraging network developers to consider all options for ensuring a reliable electricity supply, including DM. At the same time, an industry working group reviewed the existing Demand Management Code of Practice for Electricity Distributors with a view to making it more market-based. The reports of both working groups have recently been submitted to the Minister for Energy.

The inter-agency working group report primarily dealt with network constraints, and identifies many positive developments that it suggests will assist the future growth of DM activities. It also identified several impediments in the market which they believe need to be addressed.

The revised Demand Management Code of Practice provides a market-based approach to undertaking demand management, and proposes that DNSPs publish an annual *Electricity System Development Review*. This document would include information to help suppliers of energy services anticipate and plan to meet future demand for their services through approaches that include demand management. The revised DM Code is discussed in more detail in Attachment 2.

Both these reviews provide useful background information and make recommendations on a number of key issues that will be considered in this inquiry. However, both reviews had a much narrower focus than the Tribunal’s inquiry. For example, both focussed primarily on the ability of electricity networks to deliver non-network solutions, and did not look closely at environmental issues and policies and the linkages to pricing and competitive energy markets.

2.4 Industry structure and regulatory arrangements

The NSW electricity supply industry essentially comprises four components:

1. A large-scale centralised generation sector, dominated by coal-fired power stations (grouped into three state-owned corporations) and the Snowy Mountains Hydro-electric Scheme. These generators compete in a wholesale energy market with each other and with generators in connected states.
2. A state-owned high-voltage transmission network, TransGrid, which links population centres to these power stations and to other states.
3. A lower voltage distribution network which delivers power to customers, and four state-owned distributors, including EnergyAustralia, Integral Energy, Country Energy[5] and Australian Inland Energy and Water.
4. Electricity retailers that purchase energy from the generation sector and sell it to customers and provide other related services.

The *Electricity Supply Act 1995* empowers the Minister to issue licences to companies that distribute or retail electricity in NSW. The Tribunal administers the licensing of both distributors (DNSPs) and retailers (including 'standard retailers' and other, non-franchise retailers) in NSW. Both types of licences contain conditions that set out requirements to investigate demand management opportunities, and are discussed in more detail in Attachment 2.

The Tribunal is also the 'Jurisdictional Regulator' for distribution network service pricing in NSW. In regulating network revenues and charges, it has undertaken the following steps relating to DM:

- capped total revenue rather than average prices, in part to avoid a bias against DM
- signalled that the roll-in of capital expenditure may be subject to prudency tests, including the consideration of DM and other options
- provided for the benefits of avoided network costs to be offset against expenditure on DM and embedded (distributed) generation
- made DNSPs responsible for the structure of network charges subject to limits on price increases for residential customers.

The National Electricity Code (the 'Code') provides a framework for the national wholesale electricity market (NEM). Chapters 5 and 6 of the Code establish an access regime within the NEM for distribution and transmission networks. This is discussed in more detail in Attachment 2.

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5 Advance Energy, Great Southern Energy and North Power merged to form Country Energy on 1 July 2001.

3 WHAT IS THE STATUS OF DEMAND MANAGEMENT IN NSW?

3.1 Defining Demand Management

Demand management is one of a number of ways in which suppliers of a resource can meet their customers' energy needs. Hence, the objectives of electricity DM are essentially the same those for the electricity supply industry in general; that is, to meet customers' needs for energy services in a manner that is *reliable*, *efficient*, *inexpensive*, *environmentally sensitive* and *safe*.[6]

Demand management can cover a range of activities aimed at increasing the economic efficiency of energy service delivery. The Tribunal's terms of reference for this inquiry ask it to consider "demand management, load management and distributed generation". For simplicity, throughout this paper and the inquiry, we will use the term *demand management* to refer collectively to its various forms, including:

- **Energy efficiency**, which includes activities that reduce the amount of energy consumed in meeting end-users needs such as lighting, heating/cooling and power. Examples of such activities include introducing higher efficiency equipment or appliances, improving the management of a process or facility, and reducing waste through products such as insulation.
- **Load management**, which involves activities designed to reduce peak load on the electricity system as a whole or in particular parts of the system. In this paper, we distinguish between two 'types' of load management:
  - **Network load management,** including activities that reduce the peak demand on the network, thereby deferring or avoiding the need to augment the network
  - **Generation load management**, including activities that reduce the peak demand in the generation market, thereby avoiding the need to call on the most expensive generators and deferring the need to build new power stations.

  Both network and generation load management achieve a benefit by reducing loads on the system directly or by shifting peak loads into off-peak periods.
- **Distributed generation**, refers to electricity generation that is connected within a DNSP's network rather than within the transmission network (also known as embedded generation). Embedded generators are usually located close to electricity loads and may be linked to industrial processes (for example, cogeneration). Distributed generation can also refer to generation that is not permanently synchronised within a DNSP's system, and so can include stand-alone systems that are separate to the network.

These main forms of demand management are discussed in more detail in Attachment 3.

6 The Tribunal has taken the view that demand management must also provide energy services that meet the criteria of reliability, safety, efficiency, affordability and environmental performance.

3.2 Role of demand management in competitive energy markets

The concept of DM evolved in the 1980s in the context of highly integrated and regulated electricity supply industry structures. Where consumers did not have any choice over their energy supplier, regulators and/or governments in some jurisdictions considered it appropriate that energy suppliers be given incentives, and sometimes directions, to offer consumers the option of DM. This was particularly so where demand management was perceived to be the most cost-effective alternative or where it was seen as delivering other benefits such as improved environmental outcomes.

Over the past decade or so, energy markets worldwide have undergone a transition towards deregulation and increased competition with the aim of achieving improved efficiency and customer service. In Australia, a National Electricity Market was introduced in the early 1990s, with one of the objectives being:

> …encouraging the most efficient, economical and environmentally sound development of the electricity industry consistent with key National and State policies and objectives.[7]

As competition gives consumers a choice of suppliers and services, these developments have weakened the rationale for regulatory or government intervention to encourage DM. Governments and regulators expected that if customers wanted demand management, or if it was the cheapest option available, suppliers would provide it or risk losing customers or profits.

In principle, prices set through competitive markets should provide appropriate incentives for end-users, retailers and other market participants to undertake appropriate DM. In practice, however, the networks remain regulated monopolies and are not subject to competition. This means price signals may be distorted, and may exclude relevant costs such as environmental costs.

It is therefore important that DM be considered within its appropriate market context. An approach to demand management that works in one market structure will be inappropriate in another. Some of the policy and regulatory options for facilitating demand management under different circumstances include:

- **Industry-wide Integrated Resource Planning (IRP).** This approach, which is sometimes called Least Cost Planning (LCP), was common in the United States prior to the introduction of competition reform. DM was undertaken by 'vertically integrated' utilities that spanned generation, transmission, distribution and retailing. Because the industries were integrated monopolies, the regulatory agencies could mandate the utilities to undertake a least cost approach to meeting customers' energy needs. The IRP methodology attempted to compare both supply-side options (eg building new generation) with demand-side options (eg promoting energy efficiency) on an equal basis to determine least cost.
- **IRP for distributors.** Where the industry has been disaggregated and competition introduced, it is still possible to require the residual monopoly components (the networks) to undertake a form of IRP. This is essentially the current approach in NSW, where licence conditions require the state-owned DNSPs to conduct investigations on the cost-effectiveness of implementing demand management

7 National Grid Management Council, *National Grid Protocol First Issue*, December 1992.

strategies before expanding the network. Similar conditions apply to participants under the NEC (these are discussed in more detail in Attachment 2). This approach requires the DNSPs to assess the economic impact of differing options on various stakeholders. Its effectiveness depends on the accuracy of DNSP assessments, the effectiveness of the compliance regime and the financial incentives DNSPs face.

- **Market-based approach**. This approach extends a form of competition into the monopoly distribution network sector by requiring monopoly industry components to test the market for DM at the same time and in the same manner as they test the market before making network investments. The revised DM Code of Practice supports this approach. Its success depends on detailed information disclosure by the DNSPs, a transparent process for identifying, developing and implementing DM options, and a well-developed DM market to offer feasible DM options in response to identified system constraints. Its effectiveness also depends on the compliance regime and on the financial incentives the DNSPs face.
- **Obligations on retailer licence conditions.** While retailers in competitive electricity markets generally have incentives to reduce demand during periods of high demand and high energy prices[8], they have little incentive to reduce demand at other times, through initiatives such as broadly focused energy efficiency programs. Regulators in some jurisdictions have sought to address this by requiring retailers to undertake a prescribed level of energy efficiency activity or to spend a prescribed budget. Others have imposed licence conditions requiring competitive industry elements to undertake prescribed DM. In NSW, licensing conditions require electricity retailers to include DM as part of their greenhouse gas abatement strategies and to report on their progress in implementing these strategies.
- **Establishing a fund to support DM.** In some markets DM is facilitated through the use of government funding, either from general budget funds or raised by a dedicated levy. Such funds can either be:
  - directed to DM via a specific organisation (such as the UK Energy Saving Trust)
  - directed to utilities to deliver prescribed DM services
  - offered to the market for competitive tendering for provision of DM.
- **Regulatory alternatives to DM.** In some countries, particularly in Western Europe and Japan, DM has been encouraged through non-DM means; that is, without relying on the electricity supply industry to deliver it. In particular, energy efficiency has been enforced through minimum energy performance standards for buildings, appliances and equipment. This approach has also been adopted in North America and to lesser extent in Australia. While it can be very effective in promoting energy efficiency, it is unlikely to be effective in promoting load management.

8 The incentive to reduce demand in peak periods will reside with whichever party is exposed to the high pool price. This could be the customer, the retailer, the generator or some other intermediary.

3.3 Is sufficient demand management being undertaken?

Information supplied to the Tribunal for its 1999 Determination indicated that NSW distribution networks intended to spend around $1.45 billion on capital expenditure between 2001 to 2004.[9] In addition, TransGrid forecast capital expenditure of around $946m[10] in that period. Since that time, however, strong growth in demand has led Australia's largest DNSP, Energy Australia, to increase its projected capital expenditure over the five years to 2004 by over 60 per cent to greater than $1 billion.

According to the Electricity Network Management Report produced by the Ministry of Energy and Utilities, DNSPs spent less than $5m on DM in 1999-2000, and thereby achieved savings of $48m through deferred capital investment and over $14m in reduced operating expenditure. Although this DM expenditure is an increase over that reported the previous year, it is still far below the level of investment in network developments.

Several DNSPs have made recent decisions to invest in network augmentation after considering the merits of DM. Examples include:

- EnergyAustralia decided to construct a new $10m, 50MVA zone substation in the Epping / Ryde area.
- TransGrid and EnergyAustralia decided to construct a $200m 330kV transmission cable from Picnic Point to Sydney's Central Business District.
- Australian Inland Energy decided to build a new substation and 22kV line at Balranald at a cost of around $10m.

The two largest types of demand management programs currently being undertaken by NSW DNSPs are residential off-peak hot water programs and large-scale interruptible load contracts. While off-peak hot water programs are effective in shifting peak loads, they are not designed to reduce demand and may have adverse environmental impacts. In some instances, a better outcome, both in terms of load management and environmental impact, might be achieved by encouraging consumers to use other fuels, such as gas, for water heating. Offsetting electrical usage reduces the total electrical demand on the system. At the moment, retailers may not have sufficient incentives to encourage this type of fuel switching response.

How much demand management is currently being undertaken? Is this an efficient level? If not, has this resulted in inappropriate network capital expenditure, higher consumer energy costs and sub-optimal environmental outcomes? To what extent should the principles of DM be applied to the gas industry? The Tribunal particularly seeks information on the level and nature of demand management programs, options and technologies, their potential scale and costs and importantly, suggestions about what criteria should be used to determine whether or not a demand management project proceeds.

9 IPART, *Pricing for Electricity Networks and Retail Supply*, June 1999, Vol 1, p 86.
10 *Ibid*, p 158.

4 CAN DEMAND MANAGEMENT IMPROVE RELIABILITY OF SUPPLY?

Reliability of electricity supply depends on how the system is built and how it is operated and maintained. Historically, utilities have tended to ensure security of supply when confronting a capacity constraint by increasing electricity supply capacity so it is greater than demand—that is, through 'supply side management'. In principle, DM can have a comparable role in maintaining the security of supply by reducing demand, shifting it to other time periods or to other energy sources. How practical this strategy is depends on the comparative cost of implementing DM and its own reliability. Some people argue that demand reduction through DM is not as reliable as new network or generation capacity. On the other hand, not all electrical loads require the same level of reliability. A half-hour interruption to supply to a domestic water heater may have no noticeable effect, but could be catastrophic for a hospital operating theatre or a bank's IT systems if countermeasures fail or are not in place.

4.1 Addressing network capacity constraints

Improving the reliability of supply to consumers is an important factor influencing decisions to invest in increasing network capacity. Scale economies mean that the average cost of network capacity is lower for large 'lumps' of additional capacity than for smaller increments. Network operators, therefore, often decide it is more cost effective to make occasional investments in large increments of capacity rather than frequent smaller investments.

In contrast, investing in DM is usually much less 'lumpy'. This means that DM may be able to lower the investment risk for network operators, by enabling them avoid the need to invest in capacity that may be under utilised for an extended period and by increasing their flexibility to respond to changing circumstances. In principle, these benefits of DM should be factored into network decision-making, but whether this occurs depends on how networks are regulated, the risk they bear and how they manage risk.

When assessing reliability of supply, generation is considered inherently less reliable than transmission. For example, typical availability of a gas turbine is 98 to 99 per cent whereas transformer reliability is up to 99.9 per cent. However, when addressing a network capacity constraint, other issues such as environmental impacts of costs may be relevant. The extent to which they are considered is likely to depend of the regulatory environment.

4.2 Addressing generation capacity constraints

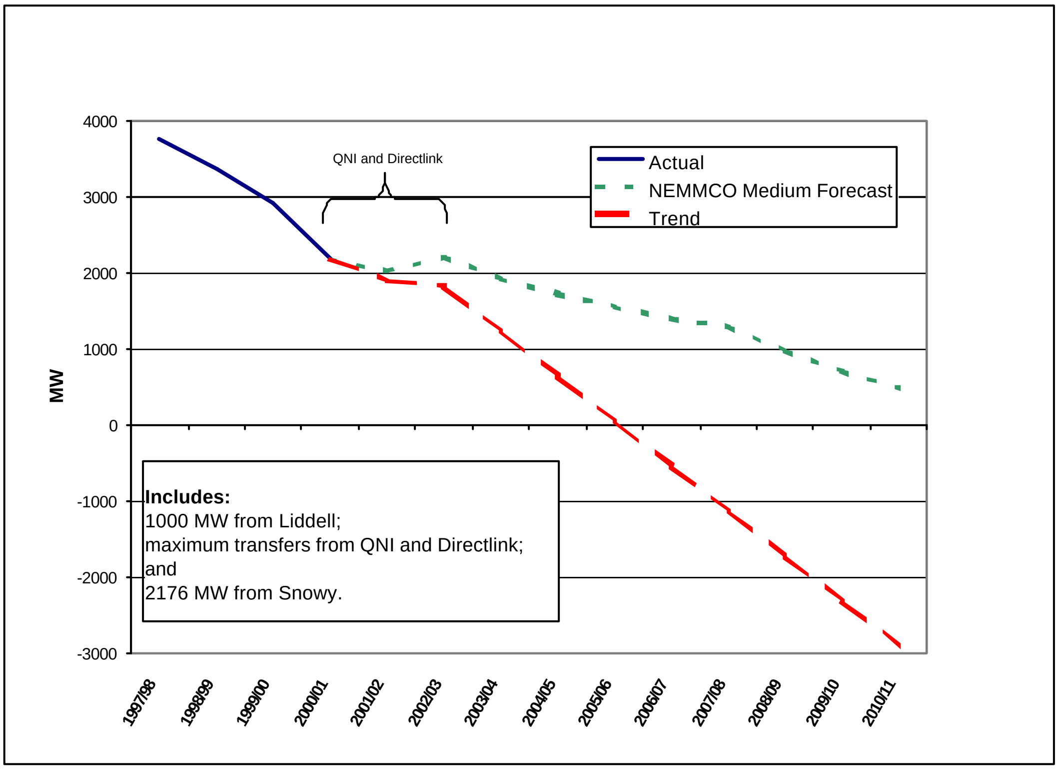
For many years, there has been an oversupply of generating capacity in NSW. However, rising demand and increasing interconnection with other States may mean that generation capacity re-emerges as an issue for reliability of supply in NSW.[11]

The National Electricity Market Management Company (NEMMCO) is currently responsible for forecasting electricity supply and demand in NSW. According to NEMMCO's most recent forecasts, NSW has sufficient generation capacity to meet demand for at least a

11 The NSW Ministry of Energy and Utilities, in conjunction with the NSW Treasury, is currently undertaking work to provide a better understanding of the demand and supply balance in the electricity sector into the future.

decade. Even under its high growth scenario, there is sufficient capacity until 2009/10. On the other hand, the recent growth in electricity peak demand has exceeded NEMMCO's forecasts for the next few years. As Figure 4.1 shows, NSW could face a generation capacity constraint by 2005/06 if recent trends in energy demand growth continue.

Figure 4.1 Forecast generation capacity reserves in NSW



Whereas sufficient network capacity depends on the ability of the electricity network businesses in NSW to predict and plan to cover expected peak demand, sufficient generation capacity depends on the operation of the forces of supply and demand in the competitive electricity market. If demand for energy approached the level of available supply, prices are expected to increase. It is currently up to entrepreneurial organisations to respond by investing in additional capacity to take advantage of these higher prices. This capacity could either be new central electricity generating capacity or DM.

To the extent that consumers are subject to these higher prices, they can modify their demand accordingly. In practice, however, consumers' ability to respond is limited because they are often insulated from the pool energy prices by retail tariffs based on simple flat structures, and have limited knowledge of how to respond to high prices other than by switching off energy-using appliances and equipment. In addition, consumers' individual demand patterns are created over a long time, through their building and equipment purchases and established behaviour patterns, and it is difficult to change quickly and substantially these patterns in response to price shifts.

What is the potential impact of demand management on the reliability of energy services and investment requirements? Is distributed generation sufficiently reliable? Do appropriate planning and market-based processes currently exist to ensure timely, effective and efficient delivery of DM where demand exceeds secure generating supply capacity? Do electricity distribution and transmission networks employ an appropriate methodology for signalling network constraints through network charges?

5 CAN DEMAND MANAGEMENT REDUCE ENERGY SERVICE COSTS?

Consumers purchase energy for the service it provides—for example, to light a room, operate a motor or refrigerate food. Their primary concerns are that these 'energy services' are delivered at an acceptable quality and cost, and when they want them; they don't necessarily care about the volume and timing of energy delivered, the source fuel of the energy and the scale and type of infrastructure used to deliver it. If DM can deliver the same or superior quality of energy services while reducing the volume of energy consumed and/or delay or avoid investments in additional infrastructure to supply it, it has the potential to lower the cost of energy services for consumers.

In principle, consumers already have a direct interest in minimising their cost of energy services, and price signals provide some incentives for them to do so. However, this type of economically rational behaviour rarely occurs, often because of lack of information. Where information is available, and the savings are sufficient to outweigh all the direct and indirect costs and other considerations, consumers can choose the measures that will deliver the lowest cost of energy services. For example, they might invest in more efficient equipment, insulate their homes, switch from electricity to gas, or install building management systems to manage demand.

Beyond measures of this kind, additional DM strategies may have the potential to lower the cost of energy services where:

- DM is not currently competitive because existing price signals do not accurately reflect costs
- Consumers, retailers or other intermediaries face other barriers to achieving efficient outcomes that utilities can cost effectively overcome through DM.

5.1 Competitiveness of Demand Management?

The Tribunal's terms of reference ask it to assess whether a number of technical options for DM have the potential to enhance electricity network capacity and reliability and to meet customer energy service requirements, and if so, whether realising this potential is economically feasible.

There are many factors that could influence whether users and investors take up DM options. One of these factors is the relative cost of DM compared to other options. Other factors may include whether the DM options offer a comparable level of service, including reliability (compared to centralised electricity supply). The ability of retailers to offer appropriate services also is a factor in whether DM is accepted or not.

In considering relative costs, we need to consider both the financial and economic competitiveness of DM. The economic perspective considers the competitiveness for the economy as a whole.

In principle, an *economic* evaluation of demand management, should consider:

- avoided transmission and distribution losses
- deferred transmission and distribution augmentation investment

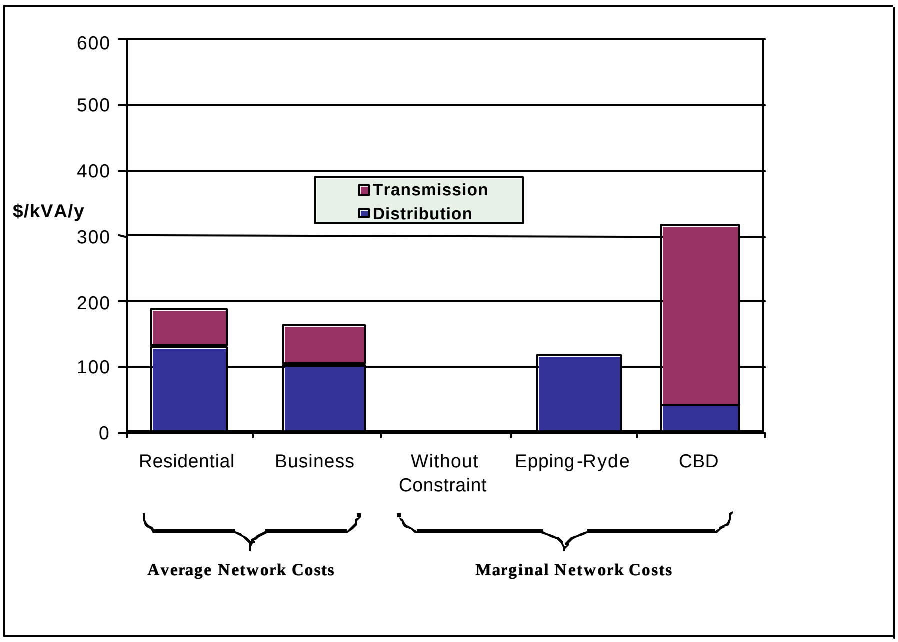
- avoided energy generation cost and
- environmental costs, including greenhouse gas emission reductions (although valuing these costs is often highly contentious).

A *financial* evaluation involves comparing the direct costs and benefits incurred from the perspective of a specific stakeholder, such as the network business or a customer. For example, from the customer's perspective, the net costs of the DM option need to be compared with the sum of the avoided costs of energy generation, network costs and retail costs. These financial costs vary between customers, but at present average around 10 cents per kilowatt hour of energy consumed (kWh). Network costs comprise about half of this.

Resolving the tension between economic and financial costs can difficult. Economic costs matter in assessing community benefit, but the financial costs determine the impact on the network's profitability.

As network costs are driven primarily by peak demand on the system, the key measure of cost from a network perspective is not cents/kWh but dollars per kilowatt of peak demand capacity provided ($/kW). On average this is about $150 to $200 per kW per year as illustrated Figure 5.1.

Figure 5.1 Range of indicative transmission and distribution costs



Notes:

1. Without constraint – where there is spare capacity, the marginal cost of meeting additional demand is close to zero.
2. Epping Ryde – Based on a network augmentation cost of $10m, financing cost of 7.5 per cent per annum, depreciation of 2.5 per cent, two year deferral and firm capacity shortfall of 6 MVA in the first year and 12 MVA in second year (*Epping/North Ryde DSM Scoping Study*, 10 April 2000, p 6).
3. CBD – Based on a network augmentation cost of $190m, financing cost of 7.5 per cent per annum, depreciation of 2.5 per cent per annum, two year deferral and peak demand exceeding firm capacity and growing at 60 MVA per annum (*Supply to Sydney CBD and Inner Suburbs Cost Effectiveness Analysis – Vol 1*, NERA, December 1988, pp 29-30).

Economic costs diverge from financial costs for consumers for several reasons, such as:

1. **Environmental 'externality costs' are not included in the price**. Where electricity supply and use create environmental impacts that are not captured in the consumer price, the financial costs will not reflect the full economic costs. (This issue is discussed in section 6.3 below.)
2. **Transmission and distribution costs tend to be 'highly averaged'**. These costs do not reflect the large differences in the *marginal* cost of a network between areas and times of plentiful capacity where the marginal cost is close to zero, and on the other hand, particular areas and times of capacity shortage where the cost of providing new capacity to meet demand may be many times the average network cost.
3. **Economic regulation may create perverse incentives**. Regulation is intended to achieve efficient outcomes and a range of other criteria. Imperfect information and the sheer complexity of the task may mean that attempts to address one criterion may inadvertently (or intentionally) undermine satisfying another criterion. The result is that what is in the financial interest of the network may not be in wider economic interest.

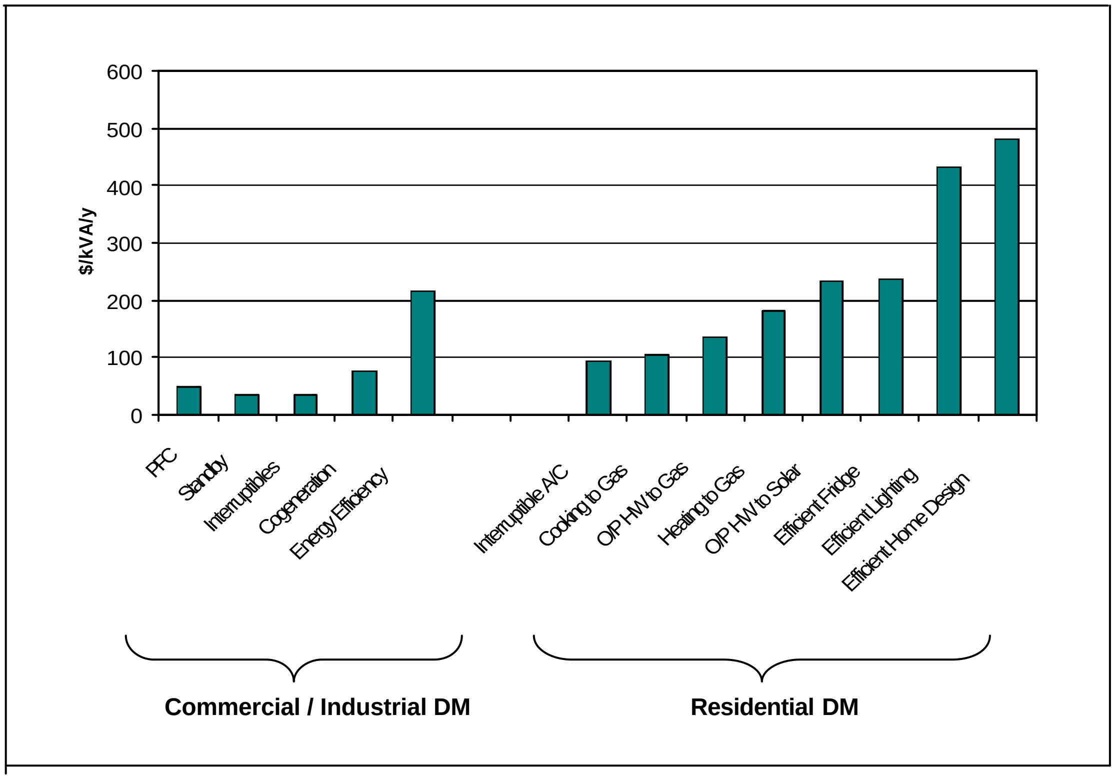
For these reasons, and because the networks are the most likely agents to undertake DM, the financial perspective of the network businesses is the key perspective in practice for assessing DM options. However, any such financial assessment must be tempered by an economic assessment to ensure that all relevant costs and benefits are captured.

The NEC does this through the ACCC Regulatory Test. This test assesses each option proposed by a network service provider to relieve a projected network constraint. It includes an assessment of the market benefit (total net benefits of the proposed augmentation) to all those who produce, distribute and consume electricity in the NEM. It also requires that environmental or other costs (externalities) should be included in the evaluation wherever these reflect "an existing or anticipated regulatory obligation" of the DNSP.

The revised DM Code of Practice does this by assuming that generators, retailers and customers will take account of the value of avoided energy generation and deferred generation investment, and regulators will set efficient limits on environmental impacts so that the net financial cost to the network of undertaking DM will reflect the net economic cost.

Figure 5.2 below provides an estimate of what the net financial cost to the network business may be of undertaking various DM options. For example, assume a distribution system is capacity constrained in an area where a number of electric hot water systems contribute on average 2 KVA to peak demand. Next, assume that it requires an incentive payment from the network of $500 to persuade consumers to switch from electric to gas water heating. In this case, the cost of supporting network services through this means while deferring new network investment for two years is equal to $500 divided by (2KVA times 2 years) or $125 per KVA of load reduction per year. (Note that the net cost to the network will be lower if value can be realised for associated benefits such as overcoming generation capacity constraint or reducing greenhouse gas emissions.)

Figure 5.2 Indicative net financial cost to networks of some DM options



Note: for more information on DM options, see Attachment 3.

5.1.1 The role of cost reflective pricing

To the extent that transmission and distribution prices diverge from costs there is the potential for DM to provide economically superior outcomes. Networks are in a good position to accurately estimate the cost of providing their services even if they do not or cannot reflect these costs in prices. Furthermore, as networks are regulated monopolies, they are not subject to competitive market discipline to reflect costs in prices.

The inter-agency working group report recommended that regulators encourage more cost reflective (or 'constraint reflective') pricing to indicate more clearly to customers the costs of using the network at times of peak demand or when capacity is constrained.

In principle, prices that reflect network 'congestion' would provide better signals for users to respond to and manage their own demand for electricity (without requiring utilities to implement other DM strategies). In practice, however, it would require prices to vary from place to place and from hour to hour. Pricing that full reflects congestion may not be practical, as most customers (residential and small commercial) have limited capacity to be informed of or to respond to real-time pricing. Furthermore, there are significant administrative and equity barriers to sophisticated pricing that reflects network congestion. However, such an approach may be feasible for large contestable customers that have half-hourly metering, as these customers should be in a position to respond to this kind of pricing information.

5.2 Managing energy price risks

Managing energy price risks arising from electricity demand constraints is a key challenge for retailers and consumers in a competitive electricity market. While network costs are predictable, generation prices in the NEM average around $40/MWh and can vary from close to zero to up to $5,000/MWh (current regulated cap).

DM may be able to reduce peak prices by reducing peak demand and the need to call upon the most expensive generators. The extent of this will depend on the strength of the demand response and how it is factored into the setting of prices in the NEM.

In principle if customers receive appropriate price signals, they can respond directly. In practice such signals are at best filtered through to end users. Customers on default tariffs are largely insulated from the level and volatility of wholesale prices. Typically contestable customers will see an average price which masks the volatility in prices but may reflect trends in levels. Retailers may have an incentive to work with customers to provide DM to manage loads. However, retailers do not appear to have been very active in providing such services to date.

What role can demand management play in reducing customers' energy bills? How can the role of consumers in being able to choose DM or other options be made more effective? Is DM economically viable or would it increase the costs of energy services? Can it reduce the level and volatility of wholesale prices? How can synergies be generated between the benefits associated with using DM to manage pool price risk and other potential benefits of DM?

6 CAN DEMAND MANAGEMENT IMPROVE ENVIRONMENTAL OUTCOMES?

The production and use of energy has a range of effects on the environment. Some are created by power stations, while others result from the operation of electricity distribution networks. Some are closely related to peak load, while others relate to the volume of energy consumed, regardless of when it is used. By reducing peak load or total energy consumption, DM can reduce some of these impacts. However, not all demand management options deliver environmental benefits, and at least some have the potential to create adverse environmental impacts in their own right.

6.1 Greenhouse gas emissions

The key environmental issue associated with electricity supply in NSW is the production of greenhouse gas emissions by burning fossil fuels, especially coal, to generate electricity. Around 95 per cent of the electricity supply in this state is generated by coal-burning power stations. DM has the potential to reduce these emissions by lowering energy consumption or by displacing large-scale, centralised (coal) energy generation with distributed generation that produces lower emissions (eg gas-fired generation). On the other hand, not all DM options encourage energy efficiency. For example, off-peak water heating and ice storage for air conditioning encourage increased energy consumption and so can lead to increased greenhouse gas emissions.

Electricity generation is responsible for 37.5 per cent of Australia's total greenhouse gas emissions and these emissions increased by 33 per cent from 1990 to 1999.[12] This pattern of growth is expected to continue until 2010. As discussed in Section 2.2, Australia is committed under the Kyoto Protocol to limit the growth of its greenhouse gas emissions to 8 per cent above 1990 levels over this same period.

Although the binding nature of this commitment is uncertain since the US Government has announced its intention to withdraw from the Kyoto Protocol, it is very likely that the reduction in greenhouse gas emissions will continue to be a policy priority for Australia and the rest of the world. Given this, there is good reason to explore the scope of DM as a cost-effective or low-cost means of facilitating greenhouse gas abatement.

6.2 Local environmental impacts

There are also a range of other, more local environmental issues associated with centralised generation of electricity, and its transmission and distribution to consumers.

The environmental impacts of centralised generation include those on:

- **vegetation and land use,** associated with the power stations themselves, with coal mines and gas pipe lines that supply the fuel used in the power stations, and with the management of associated waste (such as mine tailings and combustion ash)
- **water quality,** associated with accessing and managing water used for cooling in power stations and in coal mining

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[12] The Australian Greenhouse Office, *National Greenhouse Gas Inventory*, 1999.

- **local and regional air quality,** associated with combustions gases (such a oxides of sulphur (SOx) which contribute to acid rain and oxides of nitrogen (NOx) which contribute to photochemical smog
- **river systems,** associated with the building of dams for large hydroelectricity generators.

The environmental impacts of transmission and (to a lesser extent) the distribution lines include:

- possible adverse impacts of electromagnetic fields (EMF)
- impacts on vegetation and biodiversity associated with establishing and maintaining safe corridors for transmissions lines
- visual impact of overhead lines
- impacts on trees and vegetation for fire management.

DM in the form of load management has the potential to defer or avoid investment in additional centralised generation plant and transmission lines and thereby avoid adding to these environmental impacts. Other DM options, however, such as distributed generation and fuel switching could result in other adverse impacts on the environment.

Local impacts of distributed generation are as diverse as the options for distributed generation itself. They include the visual impact of wind turbines, the potential odour problems associated with some methane bio-energy projects, the noise issues associated with gas chilling, and the potential for sooty particulate emissions from using poorly tuned standby diesel generators.

The most significant environmental impact related to DM is probably the production of nitrous oxide emissions from burning diesel, natural gas and some biomass in distributed generation, particularly as most distributed generation is likely to occur in, or close to, population centres that already have significant air pollution problems associated with road transport and industry.

6.3 Valuing environmental costs/benefits

In principle, an economically efficient market could be achieved by ensuring that the economic value of these environmental impacts is incorporated into prices either through an environmental tax or levy, or by setting binding limits on these impacts at a level that reflects an appropriate trade-off between protecting the environment and the cost of doing so (for example, subjecting large power stations to a range of binding licence conditions relating to emissions, water use, waste management).

However, valuing environmental impacts has always been difficult. The adoption of a standard methodology may enable some of the benefits outlined above to be factored into the decision-making process early on. The ability to trade greenhouse abatement credits to a third party improves the financial attractiveness of demand management programs, but is only beginning to have an impact in the assessment of DM options.

The Regulatory Test proposed by the ACCC for network investment requires the network service provider to assess the market benefit (or total net benefits) of all proposed augmentations. It also requires them to consider any environmental costs where these are regulated or likely to be regulated. To date, the Tribunal has not factored environmental values into its prudency reviews of DNSP's capital expenditure.

What role should demand management play in reducing the environmental impacts of electricity supply? To what extent are these impacts factored into decision making? Should environmental values be taken into account? If so, how should they be valued? What is the role for the regulator in setting such values and what would be the impact of this? How should the environmental benefits of reducing or deferring centralised generation and transmission be assessed and balanced against the environmental impacts of DM and, in particular, distributed generation and fuel switching?

7 POTENTIAL INSTITUTIONAL BARRIERS TO DEMAND MANAGEMENT

The Tribunal's terms of reference ask it to recommend institutional and administrative arrangements and procedures to facilitate greater use of demand management. The indicative estimates of the costs quoted in section 3.2 suggests that DM options should be much more widely used in NSW than they currently are. If these cost comparisons are accurate, it is reasonable to ask whether the slow uptake of demand management is the result of factors such as inadequate customer information and/or education, market immaturity, or institutional failure. The policy responses proposed by stakeholders are likely to reflect their views on the relevance of these factors.

7.1 Economic regulation

7.1.1 Form of regulation

To date, the Tribunal has sought to ensure that regulation is not biased against DM, but it has not sought to actively promote it. In the past, the Tribunal has argued that a revenue cap avoids a bias against DM by cutting the link between resources and volumes. However, the current arrangements have resulted in compliance difficulties. Consequently, the Tribunal is interested in the design of price regulation which may overcome the perceived biases of price caps.

Clause 6.10.3(d) of the NEC requires the Tribunal to give prior notice of the price control mechanism to apply during the next regulatory period by July 2002. Clause 6.10.5(b) of the Code requires the Tribunal to adopt one of three price control mechanisms:

- a revenue cap
- a weighted average price cap
- or a combination of the above.[13]

The Tribunal's decision on the form of economic regulation will have important consequences for demand management.

7.1.2 Recovery of demand management expenditure by DNSPs

A key issue identified in the inter-agency working group report is the perceived uncertainty among DNSPs about how the Tribunal will assess their demand management expenditure. This is often cited as a primary reason why DNSPs do not undertake more DM.

As part of the 1999 review, the Tribunal commissioned a capital expenditure review[14] which evaluated the prudency and efficiency of capital expenditure decisions, however the authors noted that there was insufficient information available to properly assess the prudency of investment in demand management. The Tribunal has indicated that it would be likely to adopt a similar approach in future reviews.

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13 IPART will be releasing a separate Issues Paper on this topic in the near future.

14 Worley, *Report to IPART on Capital Expenditure Review in NSW Electricity Distribution, Final Report*, October 1998.

While the Tribunal is not able to endorse the prudency of any particular investment in advance, the Tribunal's position on this issue should be clear. It stated in its December 1999 Determination that:

> Before rolling into the initial capital asset base actual capital expenditure for the period 1 July 1999 to 30 June 2003, the Tribunal will have a prudency review conducted. Prudent investment in demand management may be recovered and rolled forward on the same basis as prudent investment in capital expenditure or operations and maintenance expenditure.[15]

However, DNSPs have expressed concern that regulatory treatment of network investment in DM is not clear, and that this has deterred them from undertaking more DM.

Current regulatory treatment of avoided transmission and distribution losses is particularly relevant to embedded generators. The Tribunal has determined that:

> …as a matter of principle, it is appropriate for avoided TUOS payments paid to an embedded generator to be recovered in the Annual Aggregate Revenue Requirement (AARR), to the extent that these payments reflect the actual TUOS charges avoided by the DNSP as a consequence of the embedded generator.[16]

In the case of Integral Energy's 160 MW embedded generator at Smithfield, the Tribunal decided that for the purposes of 'avoided TUOS' payments, Integral's payments to Smithfield should be recovered in Integral's revenue requirement (to the extent these payments reflect the actual avoided TUOS payments.[17])

Network Pricing Principles

For network businesses, the Tribunal has recently released its report on *Pricing Principles and Methodologies for Prescribed Electricity Distribution Services.*[18] This report sets out pricing principles and rules consistent with the objectives of the NEC and establishes a framework for translating these principles into guidelines the DNSPs can follow in setting prices for prescribed services.

In terms of congestion pricing, the report[19] states that ideally, prices should signal economic costs by having regard to the level of available service capacity, and the impact of additional usage on future investments.

While congestion signalling is difficult to implement and administer, signals may be provided through price levels or price structure. DNSPs are responsible for setting their own network prices under the overall caps set by the Tribunal, and are accountable for these decisions through public disclosure of their costs and pricing strategies.

The Tribunal will be developing Schedules to the Pricing Principles Methodology for both demand management and embedded generation. This process will be integrated with this inquiry.

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15 IPART, *Regulation of NSW Electricity Distribution Networks, December 1999,* p 55.
16 *Ibid,* p 95.
17 *Ibid,* p 99.
18 IPART, 2001, *Pricing Principles and Methodologies for Prescribed Electricity Distribution Services,* March 2001.
19 *Ibid,* p 5.

DNSPs have expressed strong concerns about the certainty of the treatment of expenditures on network investment and demand management or embedded generation alternatives. This inquiry provides an opportunity to consider these issue further in the lead up to the next network price determination. The key issue is how much certainty can and should be provided on the treatment of future expenditure. Resolution of this will need to consider:

- the effect of uncertainty / certainty on investment decisions
- the risk faced by the utilities and the capacity to manage these risks.

The above issues relate to the regulation of networks and distribution in particular. Specific aspects of the management and regulation of the national electricity market are also likely to have significant impacts on the viability of DM options. The roles and responsibilities of participants and regulators in the national electricity market in relation to DM has been a matter of ongoing debate in the evolution of the NEC, and the Tribunal will also be specifically focusing on this issue as part of this inquiry.

7.2 Organisational issues

While market and regulatory incentives are important factors, the extent of DM will also reflect customer perceptions and organisational 'cultures'; that is, the conventions, training, skills, philosophy and 'rules of thumb' that are applied within the utilities. To date, most utilities have focussed on supply-side solutions to meet forecast capacity constraints. The full effects of changing the regulatory or economic incentives to remove barriers to DM will probably take time to flow though the system as individuals learn and adapt to new circumstances. This lag in response may itself be a barrier to the efficient take-up of DM options. In these circumstances, there may be merit in taking specific steps to facilitate a more rapid response. Alternatively, what challenges would this pose for the existing utilities?

A related issue is whether the DM market is sufficiently 'mature'. Given that there has been limited application of DM options to date, can utilities rely on energy service providers or other non-network alternatives to respond in a timely manner to calls for tenders or expressions of interest in measures for meeting a constraint in the electricity system? The revised DM Code of Practice takes a market-based approach to identifying opportunities for DM through the publication of the *Electricity System Development Reviews* (see Attachment 2). A key question is how effective such an approach will be in practice.

According to Charles River Associates experience in New Zealand supports the principle that activating markets to participate in DM can be an effective driver. In the mid 1990s, one of New Zealand's network and retail utilities had developed some DM programs (off-peak hot water, storage heating), but had received a low response. Its Board was reported to be uncommitted to DM. However, through a mix of learning (by training the planning group) and integrating the DM methodology (including a financial model) into the utilities planning, it was able to secure Board support. Before pricing could be relied on to drive DM, a certain level of market transformation (education) needed to occur. It achieved this by initially setting up 'standard offers' for DM. After time, it was able to leave to the now more mature market to create the demand for the DM services being offered.

Do current arrangements in the energy market offer fair and efficient access for suppliers and consumers of demand management? If not, what can be done to address these barriers? Should regulation be neutral between DM and supply-side options? Do current regulatory structures offer appropriate incentives? Are recent moves towards a more market-based approach to demand management likely to deliver more efficient outcomes? How has the establishment and administration of the national electricity market affected the take-up of demand management? How could it be improve in this regard? What role do organisational cultural issues play in obstructing or facilitating demand management? How can these issues best be addressed?

ATTACHMENT 1 TERMS OF REFERENCE

1. Identify energy services options including demand management, load management and distributed generation options and assess their potential, where economically feasible, to enhance electricity network capacity and reliability and meet customer energy service requirements. This assessment should include consideration of:

   a) Synchronisation to the main electricity grid of existing standby generation capacity

   b) Use of gas chilling for air conditioning

   c) Use of large scale and small scale co-generation

   d) Use of other fuels (including natural gas) which can economically substitute for the range of applications for which electricity can be used

   e) Use of solar energy systems

   f) Improved lighting efficiency

   g) Other relevant demand management, load management and distributed generation options and

   h) Take account of different requirements of electricity transmission and distribution networks and the impact of these options on such networks.

2. Assess the extent to which greater use should be made of such options taking into account all relevant economic and environmental benefits and costs and the quality and reliability of energy services, particularly in relation to:

   a) Deferring the need to invest in new electricity transmission and/or distribution network capacity

   b) Reducing the demand for new generation capacity

   c) Enhancing electricity transmission and/or distribution network system reliability and meeting other emerging customer needs

   d) Increasing demand for energy efficiency services and products and

   e) Reducing greenhouse gas emissions and the associated risks and costs for consumers, energy service providers, and the New South Wales economy of Australia complying with the Kyoto Protocol target and possible further international greenhouse emission reduction agreements for the period beyond 2012.

3. Assess existing and proposed procedures for managing and augmenting network services and identify any barriers to the development of cost-effective demand management, load management and distributed generation options. This assessment should include consideration of whether the pricing of network services appropriately reflects the costs of providing those services, including environmental costs.

4. Recommend institutional and administrative arrangements and procedures to facilitate demand management, load management and distributed generation that are likely to lead to the most economically efficient and environmentally sound provision of electricity transmission and/or distribution network services. These arrangements should take account of the roles and responsibilities of the national

electricity market entities and regulatory bodies and their impact on demand management. Matters to be addressed should include:

a) Appropriate arrangements for ensuring competitive neutrality in the provision of network services including any practical means to combine different network, energy and other benefits and costs of demand management projects and other options

b) The practicality and desirability of applying cost-reflective pricing in the operations of network service providers;

c) Appropriate financial arrangements between network service providers and owners and operators of distributed generation;

d) Any need for new arrangements or contracts to facilitate the wider participation and financing of demand management and other options; and

e) Appropriate arrangements and procedures for planning to meet future network service requirements and maintain system reliability.

In considering the above, demand management is meant to include but not be limited to demand management, load management and distributed generation.

The Tribunal is to investigate and report by June 2002.

ATTACHMENT 2 CURRENT INSTITUTIONAL AND ADMINISTRATIVE ARRANGEMENTS

NSW Licensing Regime

The *Electricity Supply Act 1995* establishes the statutory basis for licensing electricity distributors and retail suppliers in NSW. The Act establishes licence conditions. Separate licences are required to conduct electricity distribution and retail supply businesses. Further conditions have been added by the *Electricity Supply (General) Regulation 1996* and by the Minister for Energy.

The objects of the *Electricity Supply Act 1995* (Clause 3) are:

(a) to establish a competitive retail market in electricity so as to promote efficient and environmentally responsible production and use of electricity and to deliver a safe and reliable supply of electricity, and

(b) to confer on network operators such powers as are necessary to enable them to construct, operate, repair and maintain their electricity works, and

(c) to regulate network operations and electricity supply in the retail market in a manner that ensures open access to electricity distribution systems, promotes customer choice and creates customer rights in relation to electricity connections and electricity supply.

The Minister also issues a series of Ministerial Guidelines, which require compliance with several licence conditions. These Guidelines address the licence conditions in detail by covering:

- the requirement to lodge licence plans addressing such issues as customer service, safety and compliance management and performance targets
- key performance indicators
- strategies to achieve greenhouse gas reductions targets (retailers)
- annual reporting requirements to demonstrate compliance with licence conditions
- independent appraisal of annual compliance reports.

Tribunal's Role

The Tribunal has recently taken over responsibility for administering the licensing of NSW electricity distribution and retail businesses and reporting on compliance with licence conditions from the Ministry of Energy and Utilities (MEU). The MEU will continue to provide policy advice to the Minister and to regulate network management.

Specifically, the Tribunal's responsibilities are to:

- monitor and report on compliance
- recommend that the Minister: grant, vary, transfer or cancel licences; impose vary or cancel licence conditions; impose sanctions or require remedial action for any breach
- impose small sanctions or require remedial action.

The Minister for Energy has recently asked the Tribunal to review the licensing regimes for electricity and gas and provide a final report by May 2002.[20] The Terms of Reference are listed on the Tribunal's website.

NSW Retail Sector

One of the objectives of the reform of the electricity industry has been to improve environmental outcomes through:

(a) Reduced levels of principal greenhouse gas emissions, and

(b) Increased utilisation of environmentally superior generating technologies and energy efficiency in consumption.

Retail licensing arrangements in NSW require retailers to develop strategies that will reduce the emission intensity of the energy they source. The *Electricity Supply Act 1995*, Schedule 1 requires the Minister to impose the following condition:

> *c) a condition requiring the holder of the licence to develop 1,3 and 5 year plans for:*
>
> *i. energy efficiency and demand management strategies, and*
>
> *ii. strategies for purchasing energy from sustainable sources, including consideration of cogeneration, purchasing of renewable energy, buy-back schemes form grid-connected solar cells on buildings and remote area power systems.*

Under Licence Condition 3.1, a retail supplier is required to report annually on the implementation of its demand management strategies, the level of greenhouse gas emissions arising from the production of electricity supplied by it, the sources and proportion of electricity supplied by it and its performance in meeting the minimum standards of services required under its standard form customer supply contracts. These outcomes are reported to the Ministry for Energy and Utilities. The Ministry then reports against compliance of the electricity retailers' performance against the benchmark levels of greenhouse gas emissions. The most recent report was attached to the Tribunal's 1999/2000 electricity licence compliance report.[21]

Retailers must have the effectiveness of their greenhouse gas reduction strategies audited by the Environment Protection Authority at three yearly intervals. Currently the Government is reviewing the benchmarks for setting emission reduction levels.

NSW Distribution Sector

The *Electricity Supply Act* 1995 requires any electricity distributor operating in New South Wales to hold a licence. The licences are subject to conditions imposed by the Act and by the Minister for Energy.

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20 The Minister for Energy has made this request under section 9(1)(b) of the IPART Act 1992.

21 IPART, *Electricity distribution and retail licences: compliance report for 1999/2000*, December 2000.

The Act requires that the Minister for Energy impose a condition on each licensed electricity distributor[22] to conduct investigations on the cost effectiveness of implementing demand management strategies that may permit distribution network augmentation work to be deferred or avoided.

Specifically, Schedule 2(6)(5) of the Act states:

> *(5) Without limitation, the Minister must impose the following conditions on each electricity distributor's licence:*
>
> *(a) a condition requiring the holder of the licence, before expanding its distribution system or the capacity of its distribution system, to carry out investigations (being investigations to ascertain whether it would be cost-effective to avoid or postpone the expansion by implementing demand management strategies) in circumstances in which it would be reasonable to expect that it would be cost-effective to avoid or postpone the expansion by implementing such strategies,*
>
> *(b) a condition requiring the holder of the licence to prepare and publish annual reports in relation to the investigations carried out by it as referred to in paragraph (a).*

In accordance with the Act, the Minister has imposed Licence Condition 3.1 in all electricity distributors' licences. This condition substantially repeats the wording from the Act.

NSW Demand Management Code (DM Code)

Currently DNSPs are not required to publish planning statements, but in the new DM Code of Practice, it is recommended that DNSPs publish an annual *Electricity System Development Review* (ESDR) which specifies zones of forecast constraint within a DNSP's area.

The DM Code provides guidance to electricity DNSPs in implementing the demand management requirements in the *NSW Electricity Supply Act 1995.* Compliance with the DM Code is not mandatory. It is recognised by the Director-General of the Ministry of Energy and Utilities and assists DNSPs in fulfilling their licence obligations.

The revised DM Code proposes a market-based approach to demand management options. It attempts to codify the principle that demand management can and should be evaluated at the same time and in the same manner as network augmentation.

Within the DM Code, three Protocols (Disclosure, Specification and Evaluation) have been developed to provide information by the DNSPs to the market. The process will be backed up by the annual system reports published by the DNSPs. This report is to include historical and forecast peak load and capacity information for all zone substations and where appropriate, supply areas. Included in the ESDR will be the Disclosure Protocol which provides information on where constraints are, both in the foreseeable future and where a constraint is forecast within 5 years. This information will allow customers and third parties to consider whether they may be able to assist in addressing the constraint.

[22] Electricity Distributors' licence condition 3.1.

The Specification Protocol ensures that individual system constraints are fully and accurately specified so that proponents of network and non-network options are able to offer relevant proposals. It defines a 'reasonableness test' which the DNSPs should apply in deciding whether to issue a formal 'request for proposals' (RFP) in relation to each constraint.

The Evaluation Protocol is designed to allow the equitable assessment of differing network enhancement and other system support options. Its purpose is to ensure that all network options and proposals are given fair consideration and requires DNSPs to publicly announce the recommended options resulting from the evaluation *and* the total annualised cost to the DNSP of the recommended option(s).

National Electricity Market

The National Electricity Code (the Code) provides a framework for the national wholesale electricity market. Chapters 5 and 6 of the Code establish an access regime within the national electricity market for distribution and transmission networks.

The National Electricity Market Management Company (NEMMCO) considers energy demand forecasts and notifies the market when new capacity is required. TransGrid conducts its own planning and development through its Statement of Opportunities which identifies areas where new capacity may be required in the high voltage transmission system.

The National Electricity Code

Annual Planning Review

The National Electricity Code (the Code) sets out an annual planning review that must be undertaken with the DNSPs by the transmission network service provider (NSP). A Code participant can dispute the network service provider's recommendations if the proposed augmentation is likely to change its use of system charges by more than 2 per cent at the date of the next price review (clause 5.6.2(i)).

Clause 6.10.3 of the Code refers to the need that the regulatory regime must have regard to the need to "create an environment which generation, energy storage, demand side options and network augmentation options are given due and reasonable consideration".

Clause 5.6.2 of the NEC requires that network service providers must consult with interested parties on possible options, "including but not limited to demand management and generation options" to address limitations of the relevant network systems. The Code also makes reference to network service providers carrying out cost-effectiveness analysis of possible options to identify options that "maximise the net benefit to customers".

Regulatory Test

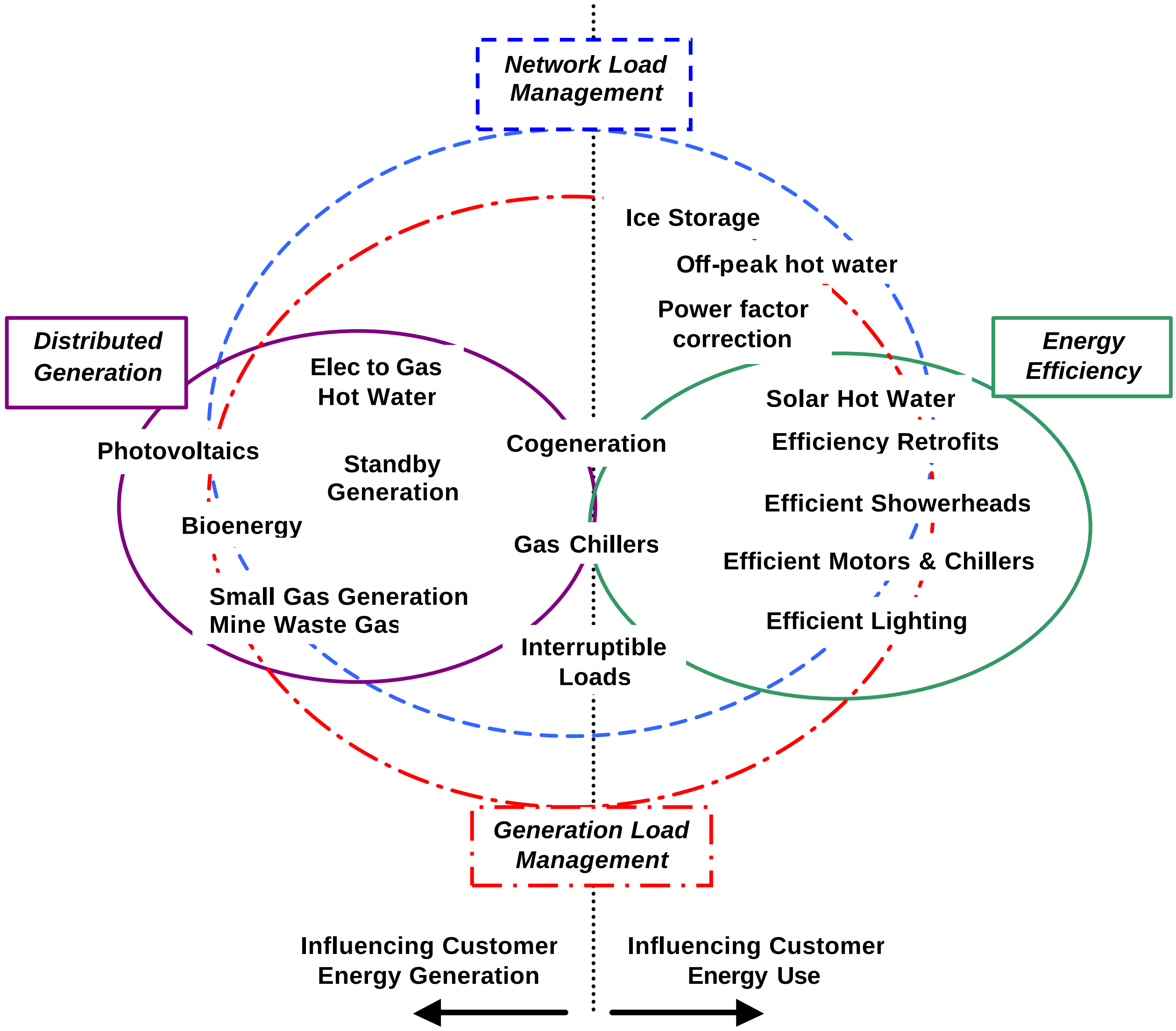
The Code provides for a Regulatory Test which assesses each option proposed by a network service provider to relieve a projected network constraint. The Regulatory Test was proclaimed by the ACCC and includes an assessment of the market benefit (total net benefits of the proposed augmentation) to all those who produce, distribute and consume electricity in the National Electricity Market (NEM). The ACCC, in its role as economic regulator, may write down the value of a particular part of the network if it is considered unnecessary or over-built.

In its submission to the DM Working Group during the development of the new DM Code, TransGrid noted that it considers there is an inconsistency between the revised DM Code and the ACCC's Regulatory Test. The Regulatory Test requires the assessment of market benefit whereas the DM Code asks the DNSPs to assess DM options against their net annualised costs of providing system support. It is argued that the new DM Code delivers greater transparency and certainty to the market than applying the Regulatory Test because it allows energy service providers to bid options to the DNSPs and then have these evaluated on the basis of the DNSP's total net annualised costs.

ATTACHMENT 3 TYPES OF DEMAND MANAGEMENT OPTIONS

The diagram below illustrates how technologies used for demand management overlap and can be used for various applications. Within each circle are a number of technologies which are primarily used to achieve the type of DM illustrated in the boxes adjacent to the circles.

Figure A3.1. Technologies used to achieve Demand Management



In the case of load management, a DNSP could elect to do power factor correction (PFC) which also has a positive impact on generation load management. Or it could decide to increase the use of standby generation, which together with generation load management is also a type of distributed, or embedded, generation.

The diagram also shows that one group of DM options (energy efficiency programs) can influence customer behaviour, while another can influence the groups that supply energy. Both these areas of DM programs involve an investment decision, either directly by the customer or indirectly through the purchases by the supplier of energy (this can be a distributed generator).

This paper has not tried to differentiate between summer versus winter peak demands. The cause of these peaks differs, as does the nature of the response. However, in general, one of the types of DM programs or technologies shown in Figure A3.1 can be used to address either a summer or winter peak.

Load management

As the above diagram illustrates, the types of programs used to deliver network or generation load management are often the same, however the need driving these programs is different.

Network load management refers to activities designed to reduce the peak demand on the network. These types of activities are carried out by DNSPs as they see the benefit of deferring costly investment in augmenting the network and reducing their operating costs. Opportunities for network load management can be constrained by time and location, and if the programs are unsuccessful, reliability of supply may be affected.

Generation load management involves participants altering their demand in response to changes in the market, typically in response to changes in price and to some request by the network service provider. Examples include interruptible or curtailable load contracts, load shedding, peak lopping and load reduction through the substitution of local standby generation.

The SEDA report[23] references several types of load shedding activities, such as interruptible and/or standby generator load programs (where customers reduce their load in response to a request), direct load control programs (where load reductions are remotely activated), and voluntary load control programs (where customers alter their consumption in response to a request). These types of programs provide short-term relief in response to a supply constraint; however, they do not provide long-term reductions in demand for electricity. In every case, the price paid to an end-use customer is primarily determines access to a sheddable load.

The Tribunal's Terms of Reference ask it to consider some particular types of load management: synchronisation to the main electricity grid of existing standby generation, and the use of gas chilling for air conditioning.

Fuel substitution, such as using gas chilling for air conditioning to offset electricity demand, is useful in reducing longer term demands on the system. A study by Energetics[24] evaluated the total technical potential of gas engine chilling in the Epping/Ryde area by 2003/4 and found that 13.5 MVA could be available based on retrofits to existing chillers and new building installations.

In the case of interruptible loads and standby generation, both processes are currently used in the market. Standby generation delivers supply for short periods of peak demand. The incentive to offer these types of program are financial and achieve the objectives of emergency load management or economic dispatch of resources. The difficulty with using standby generation is that this equipment is often less reliable, has environmental

23 SEDA, *Demand Side Management: Evaluating Market Potential in NSW*, July 2001.

24 Energetics, *Epping/North Ryde Demand Side Management Scoping Study*, April 2000.

drawbacks, is not designed to operate for longer than short periods and is often less efficient than other supply options.

However, fuel substitution does not provide the kind of relief that load shedding provides when a system experiences peak loads. Consultants to SEDA have estimated that in Victoria, the sheddable load response from medium-to-large industrial and commercial customers is around 516 MW (technical) and around 220 MW of market potential. This report classifies Tier 1 and Tier 2 type standby generators. Approximately 10 per cent of the standby load response is considered Tier 1—in other words, the transfer from mains power to standby power is seamless.

The Tribunal's Terms of Reference ask it to consider "synchronisation to the main electricity grid of existing standby generation" (ie type Tier 1) in the NSW context. Tier 2 type generators require a momentary power break.

Cogeneration, both large and small scale, can be considered another form of fuel substitution, but it is more often considered a key type of embedded generation. SEDA's estimate of the potential for small scale cogeneration (<10 MW capacity) in NSW is around 200 MW[25]. Biomass is often used as a fuel source for cogeneration or distributed generation, especially in regional areas where the plant can be located close to the fuel source.

Energy efficiency

Energy efficiency can be undertaken by the residential, commercial, or industrial sectors.

In NSW, energy efficiency in the industrial sector consists mainly of:

- high efficiency motors and variable speed drive systems
- improved process heating controls
- energy efficient lamps and ballasts.

Most industrial energy consumption in NSW (60-70 per cent) is dominated by efficient motors and drive systems[26]. Consequently, this is the area where the greatest gains can be achieved through improved energy efficiency.

In the commercial sector, the main load arises from the use of heating, ventilation and air conditioning (HVAC) systems. During warmer summer months this load can be substantial, especially during periods of prolonged hot weather. HVAC loads contribute to summer afternoon peaks on the transmission and distribution network systems. Types of energy efficiency programs that can reduce these loads include control upgrades, motor variable speed drives, and high efficiency motors and fans. In addition, lighting upgrades and upgrades of office equipment also provide opportunities for efficiency improvements and reduce the load on networks.

25 SEDA, *Demand Side Management: Evaluating Market Potential in NSW*, July 2001.

26 *Ibid.*

Energy efficiency in the residential sector includes a range of technical options such as replacement of conventional fluorescent lamps with compact fluorescent lamps, replacement of less energy efficient appliances with more efficient models, promotion of microwave cooking over conventional electric ovens, retrofitting efficient showerheads and taps, improvements to building envelopes (insulation, glazing) and passive measures such as building siting and orientation.

At the residential level, energy efficiency DM programs can include things like water heater wrap programs, weatherisation (ie insulation and draft exclusion) programs, the use of efficient showerheads and more efficient lighting such as compact fluorescent globes. The means to encourage these types of programs are usually rebates, favourable rates or technical assistance.

Despite the benefits of reduced energy costs as a result of investing in energy efficient technologies, few residential energy efficiency programs succeed. Among the possible reasons are a lack of information, learning costs, limited funds for capital expenditure and high implied customer discount rates which reduce the value of further benefits relative to ‘up front’ costs.

Distributed generation

Distributed or embedded generation generally refers to electricity generation that is connected within a DNSP’s network rather than connected to the high voltage transmission network. Distributed generators are usually located close to electricity loads and may be linked to industrial processes (for example cogeneration).

Distributed or embedded generation can range in size from as low as several kWs (eg photovoltaic systems), to several MWs for renewable generators (eg wind generation) up to several hundreds of MW for large-scale industrial projects (eg natural gas-fired cogeneration).

Cogeneration involves the production of combined heat and power. Heat is a normal by-product of energy production and is normally wasted. In cogeneration, the waste heat is captured and used to provide a complementary product, for example steam production. Cogeneration is typically two to three times more efficient than conventional, predominantly coal-fired plant.

When compared to augmenting the transmission or distribution network, embedded generation may offer marginally less reliability. This is because of the way an embedded generator operates and its availability to the system. For the most part, an embedded generator, such as a gas-fired turbine, will operate at times of peak demand and higher prices. However, customers may benefit because the net result is a deferral of network augmentation (and consequent cost savings) and other environmental benefits such as lower greenhouse gas emissions.

In the absence of augmenting the network, an embedded generator provides the benefit of increased network reliability to customers. Embedded generators perform the same functional service that standby distribution and transmission network elements perform.