# DEMAND MANAGEMENT ACTIVITIES APPLICABLE TO ELECTRICITY NETWORKS

***Prepared for the***
***Demand Management and Planning Project***
***undertaken jointly by***
***NSW Department of Infrastructure, Planning and Natural Resources,***
***EnergyAustralia and TransGrid***

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Energy Futures Australia Pty Ltd
11 Binya Close
Hornsby Heights NSW 2077
Australia
Phone: + 61 2 9477 7885
Mobile: + 61 411 467 982
Fax: + 61 2 9477 7503
Email: efa@efa.com.au
Website: http://www.efa.com.au

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# EXECUTIVE SUMMARY

The Demand Management and Planning Project is concerned with demand management activities to achieve a specific purpose – deferring or avoiding expansion of the electricity supply network in the inner Sydney region. This is 'network-driven' demand management, which is concerned with reducing demand on the electricity network in specific ways which maintain system reliability in the immediate term and over the longer term defer the need for network augmentation.

While network-driven demand management activities can also lead to lower prices in the wholesale electricity market, increased energy efficiency and/or reduced greenhouse gas emissions, these are not the major objectives of network-driven demand management. The prime objective is to relieve constraints on distribution and/or transmission networks at lower costs than building 'poles and wires' solutions. Therefore, this report focuses on the effectiveness of demand management activities in relieving network constraints and it does not examine other possible outcomes from implementing demand management projects.

The majority of the report comprises a survey which reviews and summarises a sample of relevant demand management activities undertaken in Australia and internationally over about the last 20 years. The survey focuses on activities which may provide ideas for demand management programs which could be undertaken to relieve constraints in the inner Sydney region electricity network, and more generally in localities throughout New South Wales where there are local network constraints.

The demand management activities included in the survey are classified as follows:
- distributed generation, including standby generation and cogeneration;
- energy efficiency;
- fuel substitution;
- integrated demand management projects;
- load management, including interruptible loads, direct load control and demand response;
- power factor correction;
- policy and planning.

The survey of demand management activities which forms the basis of this report showed that demand management options can effectively achieve load reductions on electricity networks. These load reductions can be targeted to occur:
- across the whole of the electrical load curve, or only at the time of the network system peak; and
- generally across the network in a particular geographical area, or restricted to one or more specific network elements such as certain lines or substations.

If the load reductions achieved through demand management are sufficiently large and appropriately targeted they may relieve network constraints and consequently may be able to defer requirements to build network augmentations.

All types of demand management activities can be used to relieve network constraints. However, whether a particular demand management activity is appropriate and/or cost effective in a particular situation will depend on the specific nature of the network problem being addressed and the availability and relative costs of demand-side resources in that situation.

# 1. INTRODUCTION

## 1.1 Engagement

In 2002, the Metrogrid electricity network project, which involved expansion of the infrastructure supplying electricity to the Sydney Central Business District, received land use planning approval. The Conditions of Consent for this approval required the establishment of a program of activities to offset the environmental and social impacts of providing additional electricity supplies to the inner Sydney region, by investigating the potential for reducing the demand for electricity by all classes of consumers.

Accordingly, the Department of Infrastructure, Planning and Natural Resources (DIPNR), EnergyAustralia and TransGrid have formed a partnership to undertake a Demand Management and Planning Project (DM&P Project) to identify and investigate the potential for reducing the demand for electricity in the inner Sydney region. Opportunities exist to reduce the level of use of electricity by existing and proposed end users. Through realising these opportunities, it may be possible to offset the natural growth in electricity usage and so defer or avoid the need for further expansion of the network infrastructure.

In connection with the DM&P Project, DIPNR has engaged Dr David Crossley of the consultancy company Energy Futures Australia Pty Ltd to carry out a survey of demand management activities. This consultancy project is to prepare a report on local and international activities in demand management that relate to the options identified in the Conditions of Consent for the Metrogrid project, or to the more general objective of demand reduction. The report should include a review of both local and international activities in electricity demand management, including past activities where appropriate.

## 1.2. Types of Demand Management

In the electricity industry, the term 'demand management' is used to refer to actions which change the electrical demand on the system. The term has been used to refer to a wide range of activities, including:

- actions taken on the customer side of the electricity meter (the 'demand side'), such as energy efficiency measures and power factor correction;
- arrangements for reducing loads on request, such as interruptibility contracts and direct load control;
- fuel switching, such as changing from electricity to gas for water heating; and
- distributed generation, such as stand by generators in office buildings or photovoltaic modules on rooftops.

The DM&P Project is concerned with demand management activities to achieve a specific purpose – deferring or avoiding expansion of the electricity supply network in the inner Sydney region. Consequently, the definition of demand management used by the DM&P Project is as follows:

> *In the context of this project, Demand Management is any action which intentionally leads to a reduction in the electrical demand on the supply network at times when the load is near capacity such that the need for expansion of the*

> *supply infrastructure is deferred or avoided and the environmental impacts of additional network assets are reduced.*[1]

Therefore, the DM&P Project is focussed on a particular set of demand management activities which a recent IPART report has termed ‘network-driven’ demand management:

> *These [activities] focus on solving network capacity constraints in ways that are more cost-effective (and often have lower environmental impacts) than network augmentation.*[2]

The IPART report actually identified three main types of electricity demand management[3]:

- **environmentally-driven** – concerned with reducing energy use through increased energy efficiency and/or reducing greenhouse gas emissions through demand side abatement;
- **network-driven** – concerned with reducing demand on the electricity network in specific ways which maintain system reliability in the immediate term and over the longer term defer the need for network augmentation;
- **market-driven** – concerned with short-term responses to energy market conditions (‘demand response’), particularly reacting to high market prices caused by reduced generation or network capacity.

Figure 1 (page 3) illustrates the relationships between these three types of demand management. While network-driven demand management is, by definition, focussed on dealing with network problems, both the other two types of demand management can also deliver benefits to electricity networks. Short-term load reductions can be bid into the National Electricity Market in response to high market prices caused by congestion in the electricity network, thereby relieving network constraints. Environmentally-driven energy efficiency and demand side abatement projects can relieve network constraints if they are undertaken in geographical locations where the network is congested and/or if they deliver demand reductions at peak times on the network.

While network-driven demand management activities can also lead to lower prices in the wholesale electricity market, increased energy efficiency and/or reduced greenhouse gas emissions, these are not the major objectives of network-driven demand management. The prime objective is to relieve constraints on distribution and/or transmission networks at lower costs than building ‘poles and wires’ solutions. Therefore, this report focuses on the effectiveness of demand management activities in relieving network constraints and it does not examine other possible outcomes from implementing demand management projects.

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1 Department of Infrastructure, Planning and Natural Resources, EnergyAustralia and TransGrid (2003). *Demand Management and Planning Project Fact Sheet.* Sydney, DIPNR, p 1.

2 Independent Pricing and Regulatory Tribunal of NSW (2002). *Inquiry into the Role of Demand Management and Other Options in the Provision of Energy Services. Final Report.* Sydney, The Tribunal, p 3.

3 These are the types of demand management identified in the IPART report but with revised definitions.

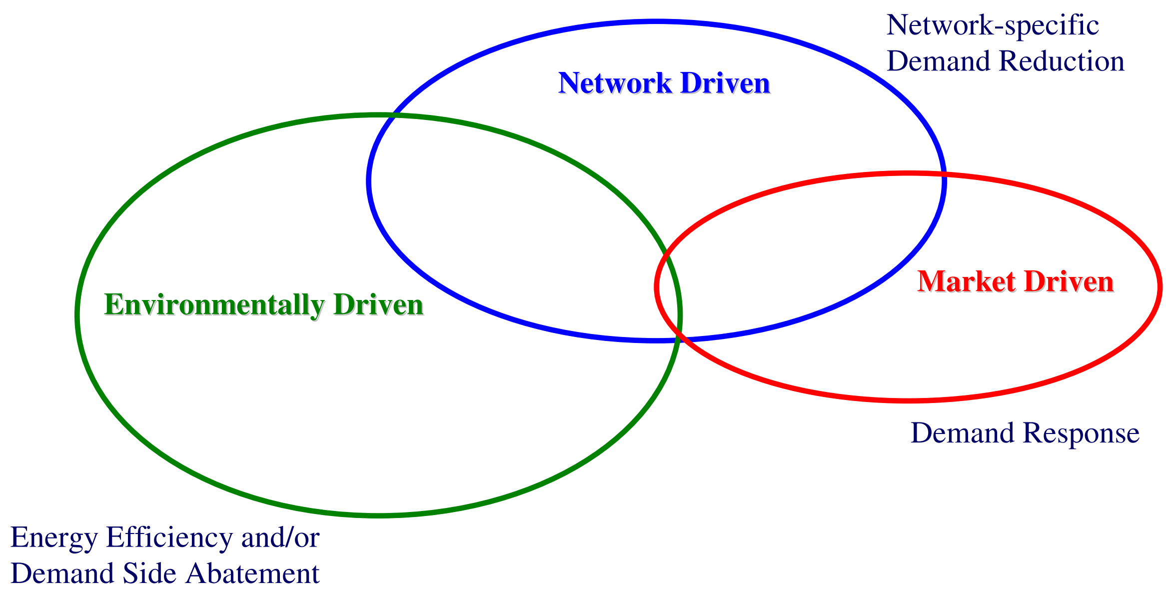


**Figure 1. Interactions Between the Three Types of Demand Management**

**Source: Modified from Gordon (2003)**[4]

## 1.3 Characteristics of Network Constraints

To be effective in relieving network constraints, demand management activities must be capable of addressing the particular characteristics of these constraints. Network constraints have both timing and spatial dimensions.

In relation to timing, network constraints may be:

- **narrow peak related** – occurring strongly at the time of the system peak and lasting seconds, minutes or a couple of hours; or
- **broad peak related** – less strongly related to the absolute system peak, occurring generally across the electrical load curve and lasting several hours, days, months, years or indefinitely (eg where the network is close to capacity).

In relation to the spatial dimension, network constraints can:

- occur generally across the network in a particular geographical area; or
- be associated with one or more specific network elements such as certain lines or substations.

Therefore, these characteristics were taken into account when identifying specific demand management projects for inclusion in this report.

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[4] Gordon, N. (2003). *Demand Management.* PowerPoint presentation. Sydney, EnergyAustralia Network.

# 2. SURVEY OF DEMAND MANAGEMENT ACTIVITIES

## 2.1 Composition of the Survey

The survey which forms the basis of this report is intended to review relevant demand management activities undertaken in Australia and internationally over the last 20 years or so. The survey focuses on activities which may provide ideas for demand management programs which could be undertaken to relieve constraints in the inner Sydney region electricity network, and more generally in localities throughout New South Wales where there are local network constraints.

There have been a large number of demand management activities undertaken worldwide over the last 20 years which could be applicable to electricity networks. In the time available for this consultancy project, it was simply not practical to review all (or even a significant portion) of these activities. Therefore, it was necessary to select a sample of demand management activities which demonstrate relevant program methodologies and techniques particularly well.

Several of the demand management activities included in the survey were not implemented specifically to deal with network problems. Some environmentally- or market-driven demand management activities demonstrate methodologies and techniques which could be used effectively to relieve network constraints. Examples of these types of demand management were therefore included in the survey.

The survey does attempt to include all important network-driven demand management activities which have been undertaken in the last five years or so in the greater Sydney area by the electricity distribution businesses EnergyAustralia and Integral Energy. Summaries of the demand management planning processes used by these two businesses were also included in the survey.

## 2.2 Classification of Demand Management Activities

A broad range of demand management activities were included in the survey. These activities are listed in Table 1 (page 5) and the detailed summaries of each activity are included in the Appendix (page 17).

The demand management activities included in the survey were classified as follows:

- distributed generation, including standby generation and cogeneration;
- energy efficiency;
- fuel substitution;
- integrated demand management projects;
- load management, including interruptible loads, direct load control and demand response;
- power factor correction;
- policy and planning.

| **Table 1. Demand Management Activities Included in the Survey** | |
|---|---|
| **Distributed Generation** | |
| DG01 | Kerman Photovoltaic Grid-Support Project, California |
| DG02 | Chicago Energy Reliability and Capacity Account |
| DG03 | Bairnsdale Power Station, Victoria |
| DG04 | Somerton Power Plant, Victoria |
| **Energy Efficiency** | |
| EE01 | Espanola Power Savers Project, Ontario |
| EE02 | Poland Efficient Lighting Project DSM Pilot |
| EE03 | Katoomba Demand Management Project, New South Wales |
| EE04 | Standard Offer Program for Residential and Commercial Energy Efficiency, Texas |
| EE05 | Air Conditioning Distributor Market Transformation Program, Texas |
| **Fuel Substitution** | |
| FS01 | Tahmoor Fuel Substitution Project, New South Wales |
| **Integrated Demand Management Projects** | |
| IP01 | Brookvale/Dee Why Demand Management Initiatives, Sydney |
| IP02 | Parramatta CBD Demand Management Project, Sydney |
| IP03 | Castle Hill Demand Management Project, Sydney |
| **Load Management** | |
| LM01 | Sacramento Residential Peak Corps, California |
| LM02 | Thermal Cool Storage Program, Texas |
| LM03 | California Energy Cooperatives |
| LM04 | Mad River Valley Project, Vermont |
| LM05 | Ethos Project Trial of Multimedia Energy Management Systems, Wales |
| LM06 | Baulkham Hills Substation Deferral, Sydney |
| LM07 | New England Demand Response Programs, USA |
| LM08 | Western Sydney Interruptible Air Conditioning Rebate Trial |
| LM09 | Sydney CBD Demand Curtailment Project |
| **Power Factor Correction** | |
| PF01 | Marayong Power Factor Correction Program, Sydney |
| PF02 | Brookvale/Dee Why Power Factor Correction Project, Sydney |
| **Policy and Planning** | |
| PL01 | Review of Demand Management Provisions of the Australian National Electricity Code |
| PL02 | Integral Energy Demand Management Planning Process |
| PL03 | EnergyAustralia Demand Management Planning Process |

## 2.3 Distributed Generation

Distributed generators are small and modular and are usually connected directly to the local distribution network, rather than to the transmission network. Distributed generation can inject energy into the electricity network close to the load it serves and in this situation reduces demand on the portion of the network which would otherwise supply the load. Distributed generation can also reduce network losses, improve utilisation (load factor) of existing transmission and generation assets and provide voltage support on long rural lines.

Many distributed generation projects have been implemented in NSW, including:

- large scale facilities such as the Tower-Appin facility fuelled with coal seam methane and the Smithfield cogeneration plant fuelled with natural gas;
- smaller facilities such as standby generators at industrial sites and in office buildings, industrial cogeneration facilities, wind farms and centralised grid-connected photovoltaic arrays; and
- very small facilities such as rooftop grid-connected photovoltaic systems.

However, none of these facilities have been installed specifically to provide support for the electricity network. Indeed, dedicated network augmentation projects have had to be undertaken to enable connection of some larger distributed generation facilities in NSW to the network.

### *2.3.1 Network Application*

Some types of distributed generation which operate continuously can be used to reduce overall demand across the whole electrical load curve. Other types which operate intermittently, such as standby generators, can be used to reduce demand at the time of the system peak. Distributed generation facilities installed to provide network support can be deployed strategically in geographical areas where network constraints occur or can be installed in particular localities to reduce demand on a specific network element.

### *2.3.2 Survey Examples*

The Appendix (page 17) contains detailed summaries of four distributed generation projects which were implemented specifically to provide network support:

DG01 Kerman Photovoltaic Grid-Support Project, California
DG02 Chicago Energy Reliability and Capacity Account
DG03 Bairnsdale Power Station, Victoria
DG04 Somerton Power Plant, Victoria

The Kerman Photovoltaic Grid-Support Project was designed and built specifically to measure the benefits for network support of distributed generation using photovoltaics. A single-axis tracker design was used to enhance the capture of the afternoon solar resources for peaking power. The Kerman plant was connected to a semi-rural distribution feeder downstream of the Kerman substation. A transformer bank located in the substation maintained feeder voltage and supplied current to customers. The transformer loading was nearing its rating and that load growth was sufficiently small to enable the transformer replacement to be significantly deferred with a moderate PV investment.

The Chicago Energy Reliability and Capacity Account project makes extensive use of distributed generation, including standby generators and photovoltaics. A number of natural-gas fired standby generators located in public buildings were identified. There were many more diesel generators, but the City decided not to use these because of air pollution problems. To make the gas-fired units available as a network of distributed generators, the City developed a SCADA system to link them to a central operating facility. This will provide a dispersed network of reliable distributed generators for use in system emergencies. The City also expects to dispatch the standby generators, to the degree permitted by air quality permits, at periods of high system prices. Income from power generation at peak periods will help to pay for the costs of the program. The City also negotiated an arrangement with a photovoltaics manufacturer to locate a manufacturing plant in Chicago and has installed photovoltaic arrays at schools and museums throughout the City.

The two natural gas-fired power stations in Victoria were built in locations where electricity demand was growing and could not be supported by the existing electricity network. The Bairnsdale power station was an attractive lower cost alternative to building a transmission line from the Latrobe Valley. The Somerton power plant is located within AGL's electricity distribution system and has avoided the construction of an additional terminal station.

## 2.4 Energy Efficiency

### *2.4.1 Network Application*

Most energy efficiency projects reduce overall demand across the whole electrical load curve and can be used to combat the effect of general load growth on the network. It may also be possible to use energy efficiency to reduce demand at the time of the system peak if loads which contribute to that peak can be identified and energy efficiency measures applied specifically to those loads. Energy efficiency projects can be deployed strategically in geographical areas where network constraints occur or can be implemented in particular localities to reduce demand on a specific network element.

### *2.4.2 Survey Examples*

The Appendix (page 17) contains detailed summaries of five energy efficiency projects:

EE01 Espanola Power Savers Project, Ontario
EE02 Poland Efficient Lighting Project DSM Pilot
EE03 Katoomba Demand Management Project, New South Wales
EE04 Standard Offer Program for Residential and Commercial Energy Efficiency, Texas
EE05 Air Conditioning Distributor Market Transformation Program, Texas

The Espanola Power Savers Project was a community-based energy efficiency project which mounted a full-scale effort to extract the maximum possible reduction in electricity consumption from a geographically concentrated area – a small township with a population of 6000. The project implemented concentrated marketing in both the residential and commercial sectors, carrying out comprehensive energy audits and inspections, and providing incentives for the installation of energy efficiency measures.

The Poland Efficient Lighting Project (PELP) was developed to reduce greenhouse gas emissions by accelerating the introduction of compact fluorescent lamps (CFLs) in Poland. The DSM pilot, a component of PELP, was designed to use CFLs to help introduce demand management to Polish electric utilities, in particular, to introduce the concept of using demand management to defer distribution and transmission investments in the Polish electricity system. Specifically, the pilot aimed to reduce peak power loads in geographic areas where the existing electricity network capacity was inadequate to meet existing loads or soon would be inadequate to meet future load growth.

The Katoomba Demand Management Project focussed on energy efficiency in the residential sector and was implemented by Integral Energy to attempt to defer further augmentation of the local distribution network. The program used one full-time advocate of energy efficiency measures to provide advice to homebuilders and developers. The program used publicity on radio, educational programs and the creation of a register of energy efficiency service providers who could install or sell items such as insulation, double glazed windows, alternative fuel appliances, high efficiency light fittings and heat pumps. Integral Energy paid for the provision of information about energy efficiency to householder but did not subsidise the cost of energy efficiency devices.

The Standard Offer Program for Residential and Commercial Energy Efficiency in Texas is a performance-based program which offers incentive payments for the installation of a wide range of measures that reduce energy use and peak demand. The program was developed to provide an incentive to suppliers of energy services to implement electric energy-efficiency projects at the facilities of residential and small commercial customers. Each year, the local network utility establishes a budget for the program and then purchases peak demand reductions and energy savings from energy efficiency service providers who market and install energy efficiency measures until the budget is exhausted. The primary objective of the program is to achieve cost effective reduction in peak summer demand in the utility's service territory.

Through the Air Conditioning Distributor Market Transformation Program in Texas the local network utility pays incentives to distributors for installations of high efficiency air conditioners until the program budget is exhausted. The program is designed to increase the installation of high efficiency air conditioners in the new and replacement residential and small commercial market in order to reduce summer peak demand for electricity in the utility's service territory.

## 2.5 Fuel Substitution

As a demand management activity, fuel substitution from electricity to other fuels operates in a similar way to energy efficiency. However, fuel substitution leads to end uses being lost to electricity, probably permanently, whereas with energy efficiency the end uses continue to be served by electricity but at a reduced load level.

### *2.5.1 Network Application*

Most fuel substitution projects reduce overall demand across the whole electrical load curve and can be used to combat the effect of general load growth on the network. It may also be possible to use fuel substitution to reduce demand at the time of the system peak if loads which contribute to that peak can be identified and fuel substitution applied specifically to those loads. Fuel substitution projects can be deployed strategically in geographical areas where network constraints occur or can be implemented in particular localities to reduce demand on a specific network element.

### 2.5.2 Survey Example

The Appendix (page 17) contains a detailed summary of one fuel substitution project:

FS01 Tahmoor Fuel Substitution Project, New South Wales

The purpose of the Tahmoor Fuel Substitution Project was to defer augmentation of the distribution network by controlling growth in the winter evening peak demand and combating a low load factor. Through the project, Integral Energy promoted the use of bottled gas by residential customers for cooking and space heating. Integral arranged the installation of bottled gas and appliances and provided subsidies for the installation of bottled gas and for each bottled gas appliance.

## 2.6 Integrated Demand Management Projects

Integrated demand management projects employ a range of demand management activities appropriate to the objectives they are aiming to achieve.

### 2.6.1 Network Application

Integrated demand management projects are used both to reduce overall demand across the whole electrical load curve and to reduce demand at the time of the system peak. Typically such projects are deployed strategically in geographical areas where network constraints occur but can also be implemented in particular localities to reduce demand on a specific network element.

### 2.6.2 Survey Examples

The Appendix (page 17) contains detailed summaries of three integrated demand management projects:

IP01 Brookvale/Dee Why Demand Management Initiatives, Sydney
IP02 Parramatta CBD Demand Management Project, Sydney
IP03 Castle Hill Demand Management Project, Sydney

With the Brookvale/Dee Why Demand Management Initiatives, EnergyAustralia is aiming to defer capital investment in the local sub-transmission infrastructure. The initiatives will target the commercial and industrial sectors and will comprise: installation (or repair) of low voltage power factor correction equipment at target customers' premises; the use of a privately-owned standby generator to export energy to the network during peak periods; and a Standard Offer for demand reductions achieved by customers or third party aggregators through energy efficiency measures undertaken at target customers' premises.

Through the Parramatta CBD Demand Management Project, Integral Energy is aiming to defer two zone substations using demand management initiatives targeted at both existing commercial and high-density residential load and new developments. The demand management activities being considered for the commercial sector include the installation of power factor correction equipment and the use of existing back-up generators to allow interruption of mains electricity without loss of amenity to specific customers in time of system stress.

In the Castle Hill Demand Management Project, Integral Energy is aiming to defer the installation of additional network infrastructure despite high levels of load growth. The program will target the commercial sector and will include interruptible loads, the use of existing standby generators, the installation of high efficiency air conditioning (and the upgrading of existing air conditioning systems), and the installation of efficient lighting and power factor correction equipment in new and replacement applications.

## 2.7 Load Management

There are several different types of load management measures, including:

- load shifting technologies;
- direct load control;
- interruptibility arrangements;
- market-driven demand response.

### *2.7.1 Network Application*

Load management projects typically only reduce demand at the time of the system peak. Load management projects can be deployed strategically in geographical areas where network constraints occur at the system peak or can be implemented in particular localities to reduce peak demand on a specific network element.

### *2.7.2 Survey Examples*

The Appendix (page 17) contains detailed summaries of nine load management projects:

LM01 Sacramento Residential Peak Corps, California
LM02 Thermal Cool Storage Program, Texas
LM03 California Energy Cooperatives
LM04 Mad River Valley Project, Vermont
LM05 Ethos Project Trial of Multimedia Energy Management Systems, Wales
LM06 Baulkham Hills Substation Deferral, Sydney
LM07 New England Demand Response Programs, USA
LM08 Western Sydney Interruptible Air Conditioning Rebate Trial
LM09 Sydney CBD Demand Curtailment Project

The Sacramento Residential Peace Corps program was initiated in 1979 to address needle peaks in the load on Sacramento's electricity network. The program has now been operating for 24 years. The Peak Corps involved direct load control cycling of central air conditioners during selected summer afternoons. Residential customers apply to become Peak Corps members and allow the utility to install a cycling device and send a radio signal to cycle their central air conditioners by switching them off and on at times determined by the utility.

The Thermal Cool Storage Program in Texas shifted electrical load to off-peak hours, reducing peak demand, and provided space and/or process cooling during on-peak periods. The program offered financial incentives for the installation of systems which provide space and/or process cooling for commercial or industrial facilities by running chillers at night and in the early morning to produce and store chilled water or ice, which is then used to provide cooling during the hottest part of the day.

Members of California Energy Cooperatives are large commercial and industrial electricity customers who work together to provide load management services to electricity utilities. Members of an energy cooperative shed loads at critical peak times when called upon by their serving utilities and each member is paid to do so. By coordinating their efforts, these users can respond collectively with a high degree of individual flexibility and reliability to calls by the utility to shed load.

The Mad River Valley Project was implemented to eliminate the need for a major upgrade of a distribution line. A major electricity customer and the local utility entered into a customer-managed interruptible contract, under which the customer committed to ensure that the total load on the distribution line as measured at the closest substation (including the loads of other customers) would not exceed the safe level. The customer installed a real-time meter at its operations base, and telemetry to monitor total local load at the substation. The customer committed to manage its operations so as to keep total local load at all times below the safe level.

The Ethos Project Trial of Multimedia Energy Management Systems was designed to test whether it was possible to achieve peak load reductions on an electricity distribution network by using multi-media energy management systems in the residential sector. The systems optimised the charging period of domestic storage appliances, including space heaters and water heaters, in response to cost information broadcast by the local electricity utility. The combination of a dynamic tariff/cost structure and the energy management systems enabled the utility to influence when energy was used to charge storage appliances and also had the ability to prevent charging completely in any specified period.

The Baulkham Hills Substation Deferral project was undertaken to defer the construction of a zone substation, which had become necessary as a result of the growth in afternoon summer peaks. The project comprises an agreement with one major industrial customer who uses large furnaces and puts a substantial peak demand on the network. Under the agreement, the customer is given 24 hours notice to shed load during the peak period on the following day. The customer is able to achieve this shift by speeding up production prior to the event and then slowing it down from its average rate during the peak.

Under the Demand Response Programs established by the New England Independent System Operator (ISO-NE) in the USA, commercial and industrial electricity users can receive incentive payments if they reduce their electricity consumption or operate their own electricity generation facilities in response to high real-time prices in the wholesale electricity market or when the reliability of the region’s electricity network is stressed. ISO-NE informs customers when a demand response is required. An advanced electricity meter capable of recording energy consumption every 5 to 15 minutes is required to participate in most of the ISO-NE demand response programs. A range of demand response programs is available to customers, including programs where the customers load is under direct load control by ISO-NE and programs where the customer is free to choose whether or not to react to a call for a demand response.

In the Western Sydney Interruptible Air Conditioning Rebate Trial, Integral Energy sponsored a trial of air-conditioning cycling to reduce the system peak by definite agreed amounts. The trial investigated the efficacy of an air conditioner cycling program for network issues (ie deferring capital expenditure) and for retail issues (ie reducing exposure to high pool prices). Residential customers were offered incentives if they were selected to participate in the trial.

In the Sydney CBD Demand Curtailment Project, EnergyAustralia intends to deliver the capability to dispatch peak load curtailment in the Sydney CBD through remote control of air conditioning plant and other major plant in a portfolio of CBD buildings. The project will establish links between a central load control point and the various building management systems. These links will enable direct load control of the building management systems to reduce electricity demand in the CBD on an at-call basis for short periods (up to 5 hours). It is expected to be able to rotate demand reductions across a portfolio of several buildings during the call period, with each building contributing to delivering the total required demand reduction.

## 2.8 Power Factor Correction

### *2.8.1 Network Application*

Most power factor correction projects reduce overall demand across the whole electrical load curve. It may also be possible to use power factor correction to reduce demand at the time of the system peak if loads which contribute to that peak can be identified and power factor correction applied specifically to those loads. Power factor correction can be deployed strategically in geographical areas where network constraints occur or can be implemented in particular localities to reduce demand on a specific network element.

### *2.8.2 Survey Example*

The Appendix (page 17) contains a detailed summary of two power factor correction projects:

PF01 Marayong Power Factor Correction Program, Sydney
PF02 Brookvale/Dee Why Power Factor Correction Project, Sydney

The purpose of the Marayong Power Factor Correction Project was to reduce the load on particular zone substation and thereby defer the capital expenditure required to strengthen a specific feeder. Integral Energy identified low power factor loads in the area served by the substation and proceeded to install power factor correction equipment in the low voltage network outside customers' premises (not on the customer side of the meter). Integral paid for the equipment and the installation. This program was implemented without the involvement of customers.

The Brookvale/Dee Why Power Factor Correction Project forms part of a larger demand management project designed to defer the construction of two new sub-transmission underground feeders. EnergyAustralia will draw customers' attention to the requirement in the NSW Service and Installation Rules that customers maintain a minimum power factor of 0.9. The objective will be to combine a notification of a customer's need to comply with the Rules with an individual proposal for EnergyAustralia to implement low voltage power factor correction, based on a financial contribution by the customer to the cost of supplying and installing (or repairing) power factor correction equipment.

## 2.9 Policy and Planning

### *2.9.1 Network Application*

Demand management policy and planning activities investigate or determine how electricity network businesses incorporate demand management into their network planning.

### *2.9.2 Survey Examples*

The Appendix (page 17) contains a detailed summary of three demand management policy and planning activities:

PL01 Review of Demand Management Provisions of the Australian National Electricity Code
PL02 Integral Energy Demand Management Planning Process
PL03 EnergyAustralia Demand Management Planning Process

In the Review of Demand Management Provisions of the Australian National Electricity Code, the Total Environment Centre is undertaking a study to investigate the current status of, and efforts towards, demand management in the Australian National Electricity Market (NEM). The purpose of this project is to advocate for increased incentives for demand management in the interests of consumers of electricity in the NEM. The project will undertake two case studies. One study will investigate the decision making process underlying the current transmission network augmentation being undertaken by TransGrid and EnergyAustralia in Sydney's CBD. A second study will focus on the claimed failure of tendering processes to be undertaken and to attract significant interest from the demand management provider sector in Victoria, particularly in relation to VenCorp's recent call for tenders on demand management for the South Eastern substation upgrade.

The two main processes within Integral Energy's Demand Management Planning Process, are the use of the Reasonableness Test to identify promising demand management opportunities, and the Request for Proposals (RFP) process, which is used to solicit the involvement of third parties in the active pursuit and implementation of demand management initiatives. The Reasonableness Test requires that the following conditions be met for demand management to warrant further consideration:

- the expected overloading is sufficient to require investment in system support to meet Integral's relevant reliability requirements;
- the constraint is caused by load growth rather than aging equipment, greenfield development or large spot loads; and
- the estimated annualised cost of the required supply-side system support exceeds $200,000 for at least one year.

Once it has been determined that a public demand management investigation is reasonable according to the above criteria, an RFP is generally issued. This document fully explains the constraint; the timing, nature and cost of the likely supply-side network solution(s); any potential demand management solutions, any available statistics on the nature of the customer base within the affected area; the nature and rate of the load growth that is causing the need for system augmentation; and the magnitude and timing of load reduction that the demand-side initiatives will need to provide in order to achieve the desired network asset deferral.

The first step in the EnergyAustralia Demand Management Planning Process is the screening test. This consists of an analysis of the drivers behind the emerging network constraint, determination of the extent to which demand is driving investment, and the demand management requirement to relieve the constraint. The screening test report provides the basis for a decision whether or not to proceed with a further investigation. The first stage of the investigation process is usually a Demand Management Scoping Investigation. Based on the demand management requirements identified in the screening test, this investigation identifies the possible demand management options that might exist in the study area, and determines the approximate amount available and likely cost (to EnergyAustralia) of each of the identified options. The Scoping Investigation includes a significant element of public consultation as a means of identifying the widest possible range of potential demand management options for consideration. The final stage of the investigation process is the Detailed Demand Management Investigation. This is more narrowly focussed on the specific opportunities identified as suitable in the Scoping Investigation, and is intended to provide quality information on the practicality, size and likely cost of demand management options that can be used to prepare the necessary business cases and implementation strategy. The implementation strategy may include a range of implementation options, including RFP's, standard offers, marketing programs and direct customer negotiations depending on the demand management options being sought. At this stage EnergyAustralia aims to be in a position to go to the market with a firm budget and commitment to proceed and a clear specification of what is required.

# 3. ISSUES RAISED BY THE SURVEY

## 3.1 Effectiveness of Demand Management Options

Table 2 summarises the relative effectiveness of demand management options in relieving network constraints, based on the characteristics of these constraints as identified in section 1.3 (page 3). The table shows that all options can be effective in relieving constraints, with some variations in degrees of effectiveness. However, whether a demand management option is appropriate and/or cost effective in a particular situation will depend on the specific nature of the network problem being addressed and the availability and relative costs of demand-side resources in that situation.

**Table 2. Relative Effectiveness of Demand Management Options in Relieving Network Constraints**

| Demand Management Option | Overall Load Reduction | Peak Load Reduction | Geographical Area | Specific Network Element |
|---|---|---|---|---|
| Distributed generation | ++ | ++ | ++ | ++ |
| Energy efficiency | ++ | + | ++ | + |
| Fuel substitution | ++ | + | ++ | + |
| Integrated demand management projects | ++ | ++ | ++ | + |
| Load management | | ++ | ++ | ++ |
| Power factor correction | ++ | + | ++ | ++ |

## 3.2 Relative Costs of Demand Management Options

One of the possible outcomes from the survey of demand management activities was a comparison of the relative costs of applying different demand management options to relieve network constraints.

Much detailed work has been carried out, particularly in the United States in the 1990s, on the costs of demand management options. However, this information is now not easily accessible. The information on demand management costs which is currently available is sparse and of questionable comparability. Frequently, it is unclear exactly what costs the information includes and excludes. In addition, costs are available in a number of different currencies and in currency values at a range of different dates.

Given sufficient time and resources to carry out detailed research, it may be possible to produce useful information on the relative costs of different demand management options to relieve network constraints, though given the difficulty in obtaining comparable cost information, this could be difficult. It was simply not possible to carry out such an analysis in the time available for this consultancy project.

## 3.3 Persistence of Demand Management Outcomes

The persistence of demand management outcomes has been the subject of some debate. Some studies have suggested that, particularly where customer behaviour change is involved, load reductions achieved through demand management projects are not maintained over time.

Since some of the demand management projects included in the survey were implemented many years ago, an attempt was made to locate reports of load monitoring carried out over extended time periods after projects were implemented. Some projects, particularly the Espanola Power Savers Project (page 26), were specifically set up to enable extensive load monitoring to be carried out. However, no reports of monitoring over extended time periods could be found.

The persistence of demand management outcomes over time may be less important in a network-driven demand management context than in a situation where demand management is being implemented to achieve environmental objectives, such as abatement of greenhouse gas emissions. Network-driven demand management is usually implemented to achieve deferral of a specific network augmentation project for a defined period. In most circumstances, demand management is usually not able to completely avoid a network augmentation because load growth still continues, though at a lower rate, after a demand management project has been implemented. Therefore, a load reduction achieved through demand management is usually only required until the load on the network element reaches its design rating and the network augmentation has to be built.

# 4. CONCLUSION

The survey of demand management activities which forms the basis of this report showed that demand management options can effectively achieve load reductions on electricity networks. These load reductions can be targeted to occur:

- across the whole of the electrical load curve, or only at the time of the network system peak; and
- generally across the network in a particular geographical area, or restricted to one or more specific network elements such as certain lines or substations.

If the load reductions achieved through demand management are sufficiently large and appropriately targeted they may relieve network constraints and consequently may be able to defer requirements to build network augmentations.

All types of demand management activities can be used to relieve network constraints. However, whether a particular demand management activity is appropriate and/or cost effective in a particular situation will depend on the specific nature of the network problem being addressed and the availability and relative costs of demand-side resources in that situation.

The survey also showed that there is a relative lack of published performance data or post implementation analysis for network-driven demand management projects. There is generally little quality information available on actual project costs and not much reliable information on post-implementation project performance. This is a cause for concern. The lack of credible and robust information makes it difficult for electricity network businesses to benchmark their own demand management activities against the experience of others and may form a significant barrier to the implementation of cost effective network-driven demand management.

The range of demand management activities identified in the survey are similar to those listed for investigation in the Conditions of Consent for the Demand Management and Planning Project. This suggests that the investigation and reporting activities required under the Conditions of Consent are appropriate.

# APPENDIX
# SUMMARIES OF DEMAND MANAGEMENT ACTIVITIES

| Demand Management Activities Included in the Survey | |
|---|---|
| **Distributed Generation** | |
| DG01 | Kerman Photovoltaic Grid-Support Project, California |
| DG02 | Chicago Energy Reliability and Capacity Account |
| DG03 | Bairnsdale Power Station, Victoria |
| DG04 | Somerton Power Plant, Victoria |
| **Energy Efficiency** | |
| EE01 | Espanola Power Savers Project, Ontario |
| EE02 | Poland Efficient Lighting Project DSM Pilot |
| EE03 | Katoomba Demand Management Project, New South Wales |
| EE04 | Standard Offer Program for Residential and Commercial Energy Efficiency, Texas |
| EE05 | Air Conditioning Distributor Market Transformation Program, Texas |
| **Fuel Substitution** | |
| FS01 | Tahmoor Fuel Substitution Project, New South Wales |
| **Integrated Demand Management Projects** | |
| IP01 | Brookvale/Dee Why Demand Management Initiatives, Sydney |
| IP02 | Parramatta CBD Demand Management Project, Sydney |
| IP03 | Castle Hill Demand Management Project, Sydney |
| **Load Management** | |
| LM01 | Sacramento Residential Peak Corps, California |
| LM02 | Thermal Cool Storage Program, Texas |
| LM03 | California Energy Cooperatives |
| LM04 | Mad River Valley Project, Vermont |
| LM05 | Ethos Project Trial of Multimedia Energy Management Systems, Wales |
| LM06 | Baulkham Hills Substation Deferral, Sydney |
| LM07 | New England Demand Response Programs, USA |
| LM08 | Western Sydney Interruptible Air Conditioning Rebate Trial |
| LM09 | Sydney CBD Demand Curtailment Project |
| **Power Factor Correction** | |
| PF01 | Marayong Power Factor Correction Program, Sydney |
| PF02 | Brookvale/Dee Why Power Factor Correction Project, Sydney |
| **Policy and Planning** | |
| PL01 | Review of Demand Management Provisions of the Australian National Electricity Code |
| PL02 | Integral Energy Demand Management Planning Process |
| PL03 | EnergyAustralia Demand Management Planning Process |

## DG01 Kerman Photovoltaic Grid-Support Project, California

| | |
|---|---|
| **Location** | Kerman (near Fresno), California, USA |
| **Project Proponent** | Pacific Gas and Electric Company |
| **Date Project Implemented** | 1993 |
| **Type of Project** | ☐ Standby generation<br>☐ Cogeneration<br>☑ Other distributed generation<br>☐ Interruptible loads<br>☐ Direct load control<br>☐ Other short-term demand response<br>☐ Energy efficiency<br>☐ Fuel substitution<br>☐ Power factor correction<br>☐ Policy and/or planning |
| **Technology** | 500 kW single axis tracker photovoltaic array |

**Drivers for Project**

The Kerman PV power plant is reported to be the first plant designed and built to measure the benefits of grid-support PV. The following benefits were identified:

- enhancement of system reliability through increased capacity;
- displacement of energy generation leading to avoided fuel costs.
- reduction in the emissions resulting from fossil fuel combustion;
- increased voltage support in the local network leading to deferral of capital expenditure;
- reduction in losses of energy and reactive power;
- deferral of replacement of transformer and maintenance of tap changer;
- deferral of transmission capacity augmentation;
- savings in power plant dispatch from reduced need to keep load-following units on-line.

| | |
|---|---|
| **Market Segments Addressed** | ☐ Residential customers<br>☐ Commercial and small industrial customers<br>☐ Large industrial customers<br>☑ Additional generation |
| **No Participants** | Not applicable |

**Description of Project**

The Kerman PV power plant began commercial operation in June 1993. The plant was purchased by competitive bid, with part of the selection criteria allocated to the projected economic value the system would provide to the electricity utility. Siemens Solar Industries was selected to provide a single-axis tracker design to enhance the capture of the afternoon solar resources for peaking power.

The Kerman plant was located several miles outside the city of Kerman which is about 15 miles west of Fresno in California's Central Valley. The plant was rated at a nominal 500 kWac and was connected to a semi-rural 12 kV distribution feeder about eight circuit miles downstream of the Kerman substation. A 10 MVA transformer bank located in the Kerman substation maintained feeder voltage and supplied current to customers.

The Kerman feeder was selected after screening a total of 600 distribution feeders and 175 substation transformers in the San Joaquin Valley area. The screening process was conducted primarily on the basis of the match between the solar resource and transformer and feeder loads during peak hours. Secondary criteria were that the transformer loading was nearing its rating and that load growth was sufficiently small to enable the transformer replacement to be significantly deferred with a moderate PV investment.

A data acquisition system archived over 100 different parameters on a real time basis, covering the Kerman solar resource, PV plant performance, and electricity distribution system operation. The benefits of the Kerman plant were calculated based on data recorded over a one-year period from 1 July 1993 to 30 June 1994 and on data collected during a series of special tests.

**Results**

| | |
|---|---|
| Enhancement of system reliability | Generation system capacity increased by 385kW |
| Displacement of energy generation | Plant achieved about 25% capacity factor, highly correlated to PG&E loads |
| Reduction in emissions | Pollution reduced by 155 tonnes of $CO_2$ and 0.5 tonne of $NO_x$ each year |
| Increased voltage support | Voltage support was predictable; 3 volts provided on a 120V base |
| Reduction in losses of energy and reactive power | Energy losses reduced by 58,500 kWh/yr. Reactive power losses reduced by 350kVAR. |
| Deferral of transformer replacement and maintenance of tap changer | Transformer cooled by more than 4°C and capacity increased by 410Kw on peak day. Tap changer maintenance interval increased by more than 10 years. |
| Deferral of transmission capacity augmentation | Transmission system capacity increased by 450kW on peak |
| Savings in power plant dispatch | PV plant delivered 90% capacity coincident with peak load-following dispatch |

In 1996, the Kerman project was terminated by PG&E, according to news reports because the maintenance costs of about USD20,000 per annum were too high. However, PG&E may also have had problems selling the facility's output at market prices because California's electricity market rules at that time largely excluded franchise utilities from the generation market. With the prices achieved in the California electricity market in the early 2000s, the value of the Kerman facility's energy output alone would greatly exceed the project's maintenance costs, without accounting for the reliability benefits, or for the benefits that load reduction brings to wholesale market by lowering the overall market clearing price.

**Project Cost**

**Relevance to Network Demand Management in NSW**

May be opportunities to install large scale PV power plants on long rural feeders.

**Contacts**

**Sources**

Wenger, H J, Hoff, T E and Farmer B K (1994). Measuring the value of distributed photovoltaic generation: Final results of the Kerman grid-support project. *1st World Conference on Photovoltaic Energy Conversion, 5-9 December, Waikoloa, Hawaii.*

## DG02 Chicago Energy Reliability and Capacity Account

| | |
|---|---|
| **Location** | Chicago, Illinois, USA |
| **Project Proponent** | City of Chicago/Commonwealth Edison |
| **Date Project Implemented** | Progressively from May 1999 |
| **Type of Project** | ☑ Standby generation<br>☐ Cogeneration<br>☑ Other distributed generation<br>☐ Interruptible loads<br>☐ Direct load control<br>☐ Other short-term demand response<br>☑ Energy efficiency<br>☐ Fuel substitution<br>☐ Power factor correction<br>☐ Policy and/or planning |
| **Technology** | Standby generators, photovoltaics, energy efficiency technology |

**Drivers for Project**

Commonwealth Edison (ComEd), as a vertically integrated utility has a franchise to supply electricity in the City of Chicago. When the franchise came up for renewal in 1992, problems with aging distribution infrastructure were known to be serious. Part of the 29-year franchise renewal was a commitment by the utility to spend USD1 billion on transmission and distribution upgrades over the following 10 years.

When it appeared that ComEd was not on schedule with these upgrades, the City of Chicago sued, and obtained a settlement that included, among other things, a commitment by ComEd to spend $1.25 billion in transmission and distribution infrastructure by the year 2004. ComEd also made payments totalling $100 million to the City of Chicago to establish a Chicago Energy Reliability and Capacity Account to fund reliability-enhancing projects within the City.

Additional impetus for action by both ComEd and the City came from a series of outages across Chicago neighbourhoods, including the downtown Loop, in July and August of 1999. Aging distribution plant, overloaded in the midst of a heat wave, repeatedly failed or was taken out of service to prevent failure. The resulting public outcry led to an intense focus both on upgrading distribution facilities and on lowering growth in peak demand in stressed distribution areas.

| | |
|---|---|
| **Market Segments Addressed** | ☐ Residential customers<br>☑ Commercial and small industrial customers<br>☑ Large industrial customers<br>☑ Additional generation |

**No Participants**

**Description of Project**

The $100 million Energy Reliability and Capacity Account is administered by the Energy Division of the City of Chicago's Department of Environment. The program has several major elements, enhancing reliability both through efficiency investments, and through investments in distributed generation:

The "Rebuild Chicago" program assists commercial and industrial firms to upgrade the efficiency of their facilities. As of early 2001, one million square feet of commercial and industrial space had been upgraded under this program, with 25 million square feet enrolled and being treated. In addition 15 million square feet of public facilities is targeted for efficiency-related upgrades.

There is also a distributed generation program. In preparing to deal with electrical outages, the City constructed a list of all of the "critical facilities" that would need attention, and discovered over 8,000 sites on the list. About 6,000 of these involved traffic lights at key intersections, but there are also

| | |
|---|---|
| 2,000 critical buildings: schools, high rises, police stations, hospitals, and so on. An inventory of these facilities revealed a large number of on-site standby generators. Although most of these generators are diesels that the City does not want to deploy regularly, there are also a total of 13 MW of natural-gas fired standby generators in public buildings (12 MW in units over 400kw each). To make these units available as a network of distributed generators, the City developed a SCADA system to link them to a central operating facility. This will provide a dispersed network of reliable distributed generators for use in system emergencies. The City also expects to dispatch the standby generators, to the degree permitted by air quality permits, at periods of high system prices. Income from power generation at peak periods will help to pay for the costs of the program.<br><br>Finally, the Energy Reliability and Capacity Account is supporting development of distributed renewable resources within the City. The leading initiative here is in photovoltaics. The Energy Division negotiated an arrangement with a PV manufacturer to locate a manufacturing plant in Chicago and has purchased 250 kW in PV arrays at six schools (10 kW each) and several prominent museums (approximately 50 kW each) throughout the City. ComEd also committed to a purchase of $12 million in PV arrays for deployment in Chicago. The Energy Division has also constructed a "Renewable Energy Farm" on a brownfield site, which hosts a wind turbine, an advanced fuel cell, and a large PV array – at 2.5 MW, said to be the world's largest PV installation. | |
| **Results** | |
| **Project Cost** | $100 million (contribution by ComEd) |
| **Relevance to Network Demand Management in NSW**<br>A similar integrated approach to support constrained network infrastructure could be adopted in appropriate areas of NSW, such as the Sydney CBD. | |
| **Contacts** | Antonia Ornelas<br>Energy Division<br>Department of Environment<br>City of Chicago<br>Tel: + 1 312 744 7203<br>Fax: + 1 312 744 6451<br>Email: aornelas@cityofchicago.org |
| **Sources**<br><br>Cowart, R (2001). *Distributed Resources and Electric System Reliability.* Gardiner, Maine, The Regulatory Assistance Project. (Website: www.raponline.org) | |

## DG03 Bairnsdale Power Station, Victoria

| | |
|---|---|
| **Location** | Bairnsdale, Victoria, Australia |
| **Project Proponent** | Duke Energy International |
| **Date Project Implemented** | Unit 1 – June 2001<br>Unit 2 – January 2002 |
| **Type of Project** | ☐ Standby generation<br>☐ Cogeneration<br>☑ Other distributed generation<br>☐ Interruptible loads<br>☐ Direct load control<br>☐ Other short-term demand response<br>☐ Energy efficiency<br>☐ Fuel substitution<br>☐ Power factor correction<br>☐ Policy and/or planning |
| **Technology** | 2 x 43 MW aero-derivative gas turbines fuelled by natural gas |

**Drivers for Project**

The Bairnsdale power station was developed to meet higher local electricity demand. It was an attractive lower cost alternative to building a 150 km, 220 kV transmission line from the Latrobe Valley to Bairnsdale. The second unit was committed in response to increased electricity demand and the subsequent higher peak power prices in Victoria.

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| **Market Segments Addressed** | ☐ Residential customers<br>☐ Commercial and small industrial customers<br>☐ Large industrial customers<br>☑ Additional generation |
| **No Participants** | Not applicable |

**Description of Project**

The Bairnsdale power station is located five kilometres west of the East Gippsland town of Bairnsdale in eastern Victoria. It operates as a peaking plant and also provides network support to the local distribution network operated by TXU. Natural gas is supplied to the power station by Duke Energy's Eastern Gas Pipeline. The 795 km Longford-to-Sydney pipeline supplies gas from the Bass Strait gas fields off the Victorian coast.

Power is generated at 11,000 volts and stepped up to 66,000 volts for connection to TXU's local distribution network. A network support agreement is in place with TXU that underpins the operation of the power station during periods when the local network is under pressure. A Static Var Compensator is also part of the project. This improves reliability for local business and community. The power station is registered under the National Electricity Market as a scheduled market generator, and electricity is dispatched and settled through the electricity pool.

Natural gas has lower emissions intensity than coal and is more efficient in conversion. In addition, the plant produces no sulphur emissions and it utilizes low-NOx turbine technology.

**Results**

| | |
|---|---|
| **Project Cost** | $75 million |

| | |
|---|---|
| **Relevance to Network Demand Management in NSW** | |
| Gas turbine power stations could be located in NSW in locations where network reinforcement is required and a gas supply is available. | |
| **Contacts** | Michelle Barry<br>Duke Energy International<br>Tel: 07 3334 5864 |
| **Sources** | |
| *EcoGeneration* magazine, June/July 2001 | |

## DG04 Somerton Power Plant, Victoria

| | |
|---|---|
| **Location** | Somerton, Victoria, Australia |
| **Project Proponent** | AGL |
| **Date Project Implemented** | Progressively from January 2002 |
| **Type of Project** | ☐ Standby generation<br>☐ Cogeneration<br>☑ Other distributed generation<br>☐ Interruptible loads<br>☐ Direct load control<br>☐ Other short-term demand response<br>☐ Energy efficiency<br>☐ Fuel substitution<br>☐ Power factor correction<br>☐ Policy and/or planning |
| **Technology** | 4 x Frame 6 gas turbines |

**Drivers for Project**

The Somerton Power Plant site is located within AGL's electricity distribution system and has avoided the construction of an additional terminal station. The Regulator has approved the recovery of avoided costs through regulated tariffs.

The plant was built very quickly to meet the perceived demand for more power in the summer of 2001/02. AGL announced in May 2001 that it would build the plant. Construction commenced in July 2001 and commissioning was undertaken progressively from January 2002.

| | |
|---|---|
| **Market Segments Addressed** | ☐ Residential customers<br>☐ Commercial and small industrial customers<br>☐ Large industrial customers<br>☑ Additional generation |
| **No Participants** | Not applicable |

**Description of Project**

The Somerton Power Plant is located in Somerton on the Hume Highway 20 kilometres north of Melbourne. The plant is connected to AGL's 66,000 volt distribution network. The plant operates at times of peak demand (usually high temperature days in summer) for approximately 400 hours a year (approximately five per cent of the year). One full-time operator is based at the plant, and additional staff remotely control the plant from AGL's control centre in Melbourne.

The Somerton Power Plant is powered by four General Electric Frame 6 open-cycle gas turbines, each with an output of 35–40 MW, giving a total capacity of 150 MW. Three units were sourced from Holland and one from Germany and weigh up to 300 tonnes each. The units were specifically selected because of their suitability for connection with AGL's distribution network. The units have been fitted with demineralised water injection, which improves the NOx emission level of the plant.

All power generated is sold into the National Electricity Market (NEM). The power plant is a scheduled market generator and will be dispatched into the market to meet customer requirements.

In generating electricity, the plant produces at least 30 per cent less greenhouse gas than the Australian NEM pool average.

**Results**

| | |
|---|---|
| **Project Cost** | |
| **Relevance to Network Demand Management in NSW**<br>Gas turbine power stations could be located in NSW in locations where network reinforcement is required and a gas supply is available. | |
| **Contacts** | Geoff Donohue<br>Manager, Public Affairs<br>AGL Gas Companies<br>Tel: 02 9922 8590<br>Fax: 02 9922 8772<br>Email: gdonohue@agl.com.au |
| **Sources**<br>*EcoGeneration* magazine, April/May 2002 | |

| EE01 Espanola Power Savers Project, Ontario | |
|---|---|
| **Location** | Espanola, Ontario, Canada |
| **Project Proponent** | Ontario Hydro/Espanola Hydro Electric Commission |
| **Date Project Implemented** | June 1991 to March 1993 |
| **Type of Project** | ☐ Standby generation<br>☐ Cogeneration<br>☐ Other distributed generation<br>☐ Interruptible loads<br>☐ Direct load control<br>☐ Other short-term demand response<br>☑ Energy efficiency<br>☐ Fuel substitution<br>☐ Power factor correction<br>☐ Policy and/or planning |
| **Technology** | A range of energy efficiency measures |

**Drivers for Project**

The Espanola Power Savers Project was a community-based energy efficiency project which mounted a full-scale effort to extract the maximum possible reduction in electricity consumption from a geographically concentrated area. The project was designed to research the potential for this type of DSM approach in Ontario.

The Project's four main objectives were:

- to assess the community-based delivery concept as an additional, aggressive approach to demand management marketing;
- to determine the maximum attainable load reductions through the installation of cost effective retrofit and replacement measures, in the shortest period of time;
- to assess the "transferability" of the community-based delivery concept to the Ontario province;
- to collect and evaluate data to augment existing residential and commercial databases.

| | |
|---|---|
| **Market Segments Addressed** | ☑ Residential customers<br>☑ Commercial and small industrial customers<br>☐ Large industrial customers<br>☐ Additional generation |
| **No Participants** | |

**Description of Project**

The township of Espanola has a population of about 6,000 and is a pulp and paper community situated on the Spanish River in north eastern Ontario approximately 500 km north of Toronto. Espanola was chosen for the project because it is geographically delimited, had a stable economy and the proportion of electric heating was representative of a northern Canadian community. Also it was evident from the outset that the town officials and the citizens demonstrated civic pride and would be receptive to a community-based conservation program. Representatives from Ontario Hydro, the local distribution utility (Espanola Hydro), and the Town of Espanola took part in a signing ceremony which formalised the responsibilities of these three principal parties.

The Espanola Power Savers Project was carried out in both the residential and commercial sectors through implementing concentrated marketing, carrying out comprehensive energy audits and inspections, and providing incentives for the installation of energy efficiency measures.

The project had five key features:

- it was targeted to a specific geographic area;
- it used the community network to champion the energy efficiency effort;
- the electricity utility acted as the project manager and catalyst;

- incentive levels were high; and
- customers' decision making was facilitated.

*Approach*

The Espanola Power Savers Project used a two pronged approach. First an extensive, cost effective list of energy conservation measures and installation specifications was established to maximise energy savings. Second, the project used a market saturation approach to elicit attitudinal and behavioural change that optimised energy savings and then maintained the energy efficiency built into the community.

This second aspect is one of the important elements of the Espanola Project – its "legacy". To avoid attrition and "take-back" effects after the project was completed, the project design included methods for maintaining the energy efficiency built into the community by the project over the short term. The aim was to achieve a long-term "culture shift" by saturating a specific geographic area, attracting high levels of interest and participation, encouraging community leaders to champion the project, and leaving the knowledge and skills within the community to promote sustained efficient energy use. The challenge was to motivate all residents in the town to change attitudes and make energy-saving behaviour a habit.

Unfortunately, there do not seem to have been any long-term follow-up evaluation studies to determine whether a persistent culture shift in energy using behaviour was achieved by the Espanola Project.

*Project Measures*

Selecting energy efficiency measures and calculating incentives were important tasks of the project design phase. All existing and new technology products were screened using the DSStrategist computerised cost-benefit model, initially without project costs. The cost effective measures were re-analysed and incentive levels established at the lesser of the incremental installed cost of the measure or its full system avoided cost.

In total over 100 energy efficiency measures were approved. A few measures, when considered on their own, did not pass the test. However when bundled with other measure(s) that were being installed at the same time, they became cost effective. The measures ranged from energy efficient lighting to varying degrees of insulation for the entire building envelope, as well as energy efficient windows, doors, plus water and space heating options.

The range of measures offered was determined by the customer's classification. Customers were grouped as either all-electric or non-electric. The all-electric customers were offered more measures, as they had greater potential energy savings. Commercial customers received more extensive lighting measures.

*Marketing*

The operational phase of the project began on 1 June, 1991, with the opening of a field office in Espanola. A community picnic was held which was partially sponsored by various conservation industry suppliers and associations. It was announced that householders and businesses in the community had until 31 May, 1992 to sign up for the project.

The sign-up process started early when interested citizens flooded an ad hoc information booth set up at the local shopping mall days after the project was announced. They requested more information and many were ready to participate. The project team quickly responded by having these "early adopters" sign a log and advising them that they would be re-contacted as soon as the project got underway. Later the residents were able to sign-up at the Sportsmen's Show, at the Espanola Hydro office and at the project store front. By the time the project began, almost 50% of the homes and businesses were signed up.

A community assessment was carried out in the spring of 1991 to obtain a comprehensive understanding of the environment in which the program was to be launched. Besides collecting and analysing traditional demographic data, the assessment attempted to discover the formal and informal networks/power structure within the community.

A detailed marketing/communication plan was developed and implemented. It emphasised cultivation of community interest and support to achieve a maximum participation rate and uptake of recommended energy efficiency measures and to achieve a community "culture shift" to wise electricity use over the long term.

A cornerstone of the plan involved the formation of a Community Advisory Committee at the outset of the project which consisted of over 30 representatives from organisations within the town. The committee had two primary functions:

- to provide advice and guidance to the project on ways to promote the wise use of electricity; and
- to provide direct community feedback to the project on existing and potential project-related issues.

The Committee included representatives from a cross section of groups and organisations within the town including the Student Council, Chamber of Commerce, Senior Citizens, and the Lions Club. Membership included club chairpersons, local business owners, teachers, news and media people, as well as representatives from the town council and the utility. The Committee was organised prior to the formal launch of the project and provided direct community feedback to the project team in the field. Feedback on such issues as scheduling, inspections, and contractor performance all resulted in direct improvements to project delivery. The Committee was also instrumental in tasks ranging from increasing the comfort levels of seniors participating in the project, to scheduling presentations to various community groups and clubs. The Committee also helped to organize an energy saving tip contest, assisted in producing a newsletter, and helped to establish a recycling/reuse depot for project materials.

Additional community involvement/communication mechanisms included: project newsletters, open house/information nights, presentations to community organisations, an energy conservation week, radio/newspaper advertising, municipal council presentations, a curriculum based energy conservation educational package, a spring writing contest, high school presentations, Energy Conservation Comer in the Public Library, logo/slogan contest, opening ceremonies, picnics and displays, energy saving tips contest, electricity bill inserts, direct mail, and cable TV community service announcements.

*Project Delivery*

For Espanola home or business owners, the Espanola Power Savers Project involved five main steps:

I. making contact with the project office to request an energy audit;
2. a visit by a qualified energy auditor/contractor team to recommend energy efficiency measures to be installed;
3. approval of work by the home/business owner by signing an agreement with the general contractor;
4. installation of energy efficient measures by qualified contractors; and
5. inspection of all major work to ensure energy savings and customer satisfaction.

*The Energy Audit*

The energy audit was designed to identify the most complete set of energy efficiency measures that would result in the greatest reduction in electricity demand and energy efficiency savings. The audits were conducted by a two-person team made up of a qualified energy auditor and a representative of the general contractor. The auditor introduced the Espanola Power Savers goals and its potential benefits to the owner.

The type of audit conducted depended on the service classification of the customer. The four main classifications were; residential all electric (which had electric space heating and water heating); residential non electric (which had space heating other than electric and optional electric water heater); commercial all electric (same as residential all electric) and commercial non electric (the same as the residential non electric). Each classification bad its own audit form.

The all-electric audit was based on the "whole-house approach," which included a full inspection of the building shell inside and out. Particular attention was paid to check for proper ventilation and for moisture problems. Working together, the auditor and contractor's representative measured all windows, doors and areas to be insulated.

At the completion of the audit, the auditor presented a set of recommendations to the customer. At this point the contractor's representative took over the meeting and explained the costs of the recommended measures and the incentives available from Ontario Hydro. The customer was also made aware of Ontario Hydro's financing plan that allowed the customer to participate with no upfront costs. The customers usually took at least two weeks or longer to make their decision. When ready to proceed, the home or business owner signed a project application form and contract with the general contractor's representative.

*Installation of Measures*

The general contractor responsible for handling all the project's installations was selected by Ontario Hydro through a competitive bidding process which delineated the unit costs of specific retrofit and replacement measures. The general contractor in turn subcontracted to local and regional contractors for the installations. The general contractor's tasks included scheduling and coordinating sub-trades and ensuring installations met project specifications.

The installation of energy-efficient measures was conducted by qualified tradespeople. All trades persons who worked on installations were certified by Ontario Hydro and a trade association to assure proper workmanship. Further on the job training was carried out daily to ensure quality work was being done. All work was covered by a warranty program.

*Inspection of Work*

Originally all major work was to have had one final inspection after the completion of the installation. Early in the project it was evident that this was not adequate. An interim inspection process was designed to allow up to seven progress inspections. The final inspection continued to be carried out. The inspector checked that each measure had been installed to specifications and reconciled the installed measures to the work order. The inspector also ensured that the owner was satisfied with the contractor's work. The customer then signed a release form that allowed Ontario Hydro to pay the utility's incentive money directly to the general contractor.

**Results**

The Espanola Power Savers Project achieved an overall very high 86% participation rate, defined as the number of energy audits completed compared to the total eligible sites. An eligible site was any building that was deemed suitable for possible participation in the project. The criteria used to determine eligibility included: the individual customer electricity consumption, the type of heating, size of building and type of end use.

Of the customers who underwent an energy audit, an overall 91% accepted at least one measure from the list of measures recommended by the auditor. The accepted measures represented 71% of the total estimated energy savings from all the recommended measures.

| Type of Site | Average Customer Contribution per Site (1992 Canadian dollars) | Average Ontario Hydro Incentive per Site (1992 Canadian dollars) | Average KW Reduction per Site | Average Annual kWh Saving per Site |
|---|---|---|---|---|
| Residential all electric | 2,684 | 4,200 | 1.87 | 6,832 |
| Residential non electric | 17 | 194 | 0.12 | 1,071 |
| Commercial all electric | 3,323 | 8,411 | 6.99 | 24,904 |
| Commercial non electric | 552 | 4,346 | 2.21 | 11,911 |
| Average for all sites | 1,237 | 2,454 | 1.20 | 4,873 |

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| **Project Cost** | USD 9.4 million (1992 dollars) |
| **Relevance to Network Demand Management in NSW**<br>A similar intensive community-based promotion of energy efficiency could be implemented in geographically delimited localities in NSW where the distribution network is constrained. | |
| **Contacts** | |
| **Sources**<br>Sharp, V.J., D,Angelo, P. and Ruhnke, W (1993). Espanola community-based energy conservation: results to date. *Proceedings of the Summer Study of the European Council for an Energy Efficient Economy*. Published at: http://www.eceee.org/library_links/proceedings/1993/pdf93/932013.PDF<br>The Results Center (1992). *Ontario Hydro Espanola Power Savers Project: Profile # 16*. Available at: http://sol.crest.org/efficiency/irt/16.pdf | |

# EE02 Poland Efficient Lighting Project DSM Pilot

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|---|---|
| **Location** | Cities of Chelmno, Elk and Zywiec, Poland |
| **Project Proponent** | Municipal governments and distribution utilities in the three cities |
| **Date Project Implemented** | 1996 |
| **Type of Project** | ☐ Standby generation<br>☐ Cogeneration<br>☐ Other distributed generation<br>☐ Interruptible loads<br>☐ Direct load control<br>☐ Other short-term demand response<br>☑ Energy efficiency<br>☐ Fuel substitution<br>☐ Power factor correction<br>☐ Policy and/or planning |
| **Technology** | Compact fluorescent lamps |

**Drivers for Project**

The Poland Efficient Lighting Project (PELP) was developed by the International Finance Corporation (IFC), the private sector affiliate of the World Bank Group, and funded with USD5 million from the Global Environment Facility (GEF) to reduce greenhouse gas emissions by accelerating the introduction of compact fluorescent lamps (CFLs) in Poland. The DSM pilot was a component of PELP.

The DSM pilot was designed to use CFLs to help introduce DSM to Polish electric utilities, in particular, to introduce the concept of using DSM to defer distribution and transmission investments in the Polish electricity system.

The idea of using DSM to defer investments in distribution and transmission systems can be placed in the larger context of a utility planning concept known as distributed utilities (DU). The DU concept seeks to identify small-scale "distributed" electric resources both supply- and demand-side that can be alternatives to traditional electricity network and central power station investments. Both these resources are small relative to traditional central generation resources; and they are distributed throughout the electric system, located near the loads they serve. Locating resources near load centres allows electricity utilities to avoid or defer expensive transmission and distribution systems upgrades that would otherwise be needed.

The DSM pilot was intended to demonstrate to the Polish electricity industry, in real field conditions, the potential benefits of a demand-side program implemented in a DU analytical framework. Specifically, the pilot aimed to reduce peak power loads in geographic areas where the existing electricity network capacity was inadequate to meet existing loads or soon would be inadequate to meet future load growth.

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| **Market Segments Addressed** | ☑ Residential customers<br>☐ Commercial and small industrial customers<br>☐ Large industrial customers<br>☐ Additional generation |
| **No Participants** | |

**Description of Project**

The DSM pilot was initially designed to be led and implemented by selected electricity distribution companies in Poland, but their reluctance to engage in such a role forced the pilot to be redesigned. (Among other things, their reluctance was based on the belief that a project that would result in reduced electricity sales couldn't possibly be good for their business.) The new pilot design depended on the majority involvement and leadership of municipal governments, with electricity distribution companies providing a supporting role.

Municipal governments were thought to be good candidates for majority involvement in the DSM pilot:

- they had a strong political interest in reducing the energy costs of their citizens;
- they had a public mandate to engage in activities that improved the environment.;
- they had a legal responsibility to plan for and make investments in the electric distribution network within their jurisdictions, making them very interested in programs designed to defer such investments.

Three cities and their regional electricity utilities were selected to participate in the DSM pilot: Chelmno (a city of about 22,000 inhabitants in north-central Poland), Elk (a city of about 54,000 inhabitants in north-east Poland), and Zywiec (a city of about 35,000 inhabitants in south-central Poland). The cities were selected because they were willing and able to participate and they had areas with electricity network capacity problems. While the entire areas of all three cities participated in the DSM pilot, several target areas within the cities were established for intensive CFL promotion and electric load analysis. Engineers from the electric power distribution companies in Elk and Chelmno (Torun ZE and Bialystok ZE, respectively) identified the primary trouble spots in residential areas of their distribution systems. These areas had network components (cables or transformers) whose use was nearing their rated capacities. These neighbourhoods were selected as the target areas for the DSM pilot.

The backbone of the DSM pilot was a CFL subsidy/coupon system, which was designed to persuade large numbers of people in selected areas to purchase and install CFLs. The cost of CFLs sold through the pilot was subsidised with USD100,000 of PELP funding. The subsidies were directed at participating CFL manufacturers in exchange for their agreement to certain negotiated wholesale prices and delivery arrangements.

The subsidised lamps were made available to the residents of the three cities using discount coupons. There were three types of coupons, labelled A, B, and C. The A and B coupons, which offered the highest price discounts (cc 55% and 45% respectively), were delivered only to those residents living in the target areas. The C coupons (ca 35% discount) were delivered to the remaining residents of the participating cities. (A small number of C coupons were also delivered to residents in the target areas.) In all three cities, the A and B coupons were valid only for the first two weeks of the pilot's operation. This timeframe was established to encourage residents in the target areas to make their CFL purchases quickly so that it would be easier to measure the effect of a massive CFL installation on the electricity networks in the target areas (where measurements of electricity use were focused). The C coupons were valid for six weeks, after which the pilot CFL sales ceased.

To achieve a high level of sales at the retail stores, a large-scale public education and promotion campaign was implemented. The campaign included numerous promotional events at local schools, public places, and included installing CFLs in the church of a popular parish priest, after which CFL sales surged.

The points on the electricity network serving the target areas in Chelmno and Elk were the focus of the load measurements and analysis completed as part of this pilot program. Load measurements were taken using meters that measured both real and reactive power at each of the measurement points. The meters recorded average power over every 15-minute interval. Short-term measurements were also taken of the current harmonic distortion, before and after CFL installation, on the low voltage (0.4-kV) lines. Measurements were taken continuously for a period of over 100 days, from mid-January to early June, in most cases.

**Results**

A high level of CFL sales was achieved in the three cities: more than 33,000 CFLs were sold in six weeks. A large number of CFLs were sold per household, which is especially notable given the low average incomes of the areas involved. There were larger numbers of CFL sold per household in the target areas, with the number varying from 9.66 per household in the Zywiec target area to 1.10 per household in all of Elk. Sales per household outside the target areas were achieved with strict limits on the availability of CFLs that could be purchased with coupons. Sales of CFLs per day to

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| these areas continued to grow strongly until the supply limitation was encountered.<br><br>Estimates of the per-CFL peak lighting load reductions were produced using modelled lighting load shapes, data on the number and wattage of CFLs sold for each of the measured areas in Elk and Chelmno, and a procedure for allocating purchased lamps among the most used lighting points according to their pre-CFL installation installed wattage. Peak savings per CFL were highest in areas where lower CFL penetrations were achieved because most CFLs in these locations were installed in high-use fixtures, such as the kitchen and the largest room. Residents in locations with higher CFL penetrations installed the additional lamps in lower-use fixtures, such as bathrooms and halls, driving down the per-CFL peak savings.<br><br>Modelling results show that during the local peak hour of 20:00 on the peak day of the year (1 January), the end-use savings correspond to a 15% reduction in total electric peak demand for target area P4, a 16% reduction for P5, and a 15% reduction for P6.<br><br>Measurements were also made to assess the power quality impact of the CFL installations in the areas of Chelmno and Zywiec that achieved the highest level of CFL penetration. Measurement in both cities did not reveal any influence on voltage distortion from installing CFLs. Measurements of current distortion in Chelmno revealed a small increase after CFL installation, while measurements of current distortion in Zywiec made conclusions difficult to draw. Measured increases of current on the neutral lines in Chelmno were small, and total current on the neutral lines were still well within safety standards after the CFLs were installed.<br><br>Further modelling studies showed that if Torun ZE had paid all costs of promoting and distributing the CFLs in the P4 area, this program have been a cost-effective investment for Torun ZE. | |
| **Project Cost** | USD100,000 of PELP funding |
| **Relevance to Network Demand Management in NSW**<br>A similar mass promotion of CFLs to reduce load on constrained distribution network infrastructure could be adopted in appropriate areas of NSW. | |
| **Contacts** | Dana Younger<br>GEF Projects Coordinator<br>IFC Environmental Projects Unit<br>2121 Pennsylvania Avenue, NW<br>Room F-9K-148<br>Washington DC, 20433<br>USA<br>Tel: (202) 473-4779<br>Fax: (202) 974-4349<br>E-mail: dyounger@ifc.org<br>Web site: http://www.ifc.org |
| **Sources**<br><br>Gula, A., Hanzelka, Z., Ledbetter, M., Pratt, R. and Rudzki, P (1999). Results and possible dissemination of the Polish efficient lighting project - the DSM pilot. *Proceedings of the Summer Study of the European Council for an Energy Efficient Economy.* Published at: http://www.eceee.org/library_links/proceedings/1999/pdf99/Panel2/2-05.pdf<br><br>Ledbetter, M., Pratt, R., Gula, A., Rudzki, P., Hanzelka, Z., Filipowicz, M., Rudek, R., Stana, P. and Puza, A. (1998). *IFC/GEF Poland Efficient Lighting Project: Demand-Side Management Pilot – Final Report,* Batelle Memorial Institute. Available at: http://www.efficientlighting.net/docs/docum/backg/pelp-dsm-report.pdf | |

| EE03 Katoomba Demand Management Project, New South Wales | |
|---|---|
| **Location** | Katoomba, NSW, Australia |
| **Project Proponent** | Integral Energy |
| **Date Project Implemented** | 1998 to 2003 |
| **Type of Project** | ☐ Standby generation<br>☐ Cogeneration<br>☐ Other distributed generation<br>☐ Interruptible loads<br>☐ Direct load control<br>☐ Other short-term demand response<br>☑ Energy efficiency<br>☐ Fuel substitution<br>☐ Power factor correction<br>☐ Policy and/or planning |
| **Technology** | Various energy efficiency measures |
| **Drivers for Project**<br>In late 1990s, the electricity network infrastructure in the Katoomba area of the Blue Mountains west of Sydney had limited capacity and, due to load growth, required a new transmission substation at Katoomba North which was constructed in 1996/97. In 1998, Integral Energy launched a demand management program, focussing on energy efficiency in the residential sector, to attempt to defer further augmentation of the network. | |
| **Market Segments Addressed** | ☑ Residential customers<br>☐ Commercial and small industrial customers<br>☐ Large industrial customers<br>☐ Additional generation |
| **No Participants** | Energy efficiency advice was given to thousands of customers over a five to six year period |
| **Description of Project**<br>The program used one full-time advocate of energy efficiency measures to provide advice to homebuilders and developers. The program used publicity on radio, educational programs and the creation of a register of energy efficiency service providers that could install or sell items such as insulation, double glazed windows, alternative fuel appliances, high efficiency light fittings and heat pumps.<br>The program's primary incentive (and therefore the prime motivation for customers) was the bill savings that would result from the use of more efficient end-use devices. A secondary benefit was that Integral was able to arrange a register of energy efficiency equipment vendors and installers. This was provided to customers thereby giving them additional confidence regarding energy savings. Integral also ensured that the registered vendors offered their products and services at reasonable prices. However, Integral did not arrange for the installation of energy efficiency measures or provide subsidies for the installation cost. | |
| **Results**<br>The program ran from 1998 for about five years. It was successful in achieving reductions in winter peak period loads, particularly space heating loads. However, the summer load continued to grow.<br>The program successfully deferred additional capital works in the area – including the construction of a second feeder and second transformer – until 2006/07. | |
| **Project Cost** | $70,000 per annum (administrative cost) |

| **Relevance to Network Demand Management in NSW** | |
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| A similar community-based promotion of energy efficiency could be implemented in geographically delimited localities in NSW where the distribution network is constrained. | |
| **Contacts** | Frank Bucca<br>Demand Management & Utilisation Manager<br>System Development Department<br>Integral Energy<br>PO Box 6366<br>Blacktown NSW 2148<br>Tel: 02 9853 6566<br>Fax: 02 9853 6099<br>E-mail: bucca@integral.com.au |
| **Sources** | |
| Charles River Associates (2003). *DM Programs for Integral Energy.* Melbourne, CRA. | |
| Personal communication, Frank Bucca, Integral Energy, November 2003. | |

## EE04 Standard Offer Program for Residential and Commercial Energy Efficiency, Texas

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| **Location** | Texas, USA |
| **Project Proponent** | Oncor Electric Delivery Company (a subsidiary of TXU Corp responsible for electricity transmission and distribution) |
| **Date Project Implemented** | 2002 and continuing |
| **Type of Project** | ☐ Standby generation<br>☐ Cogeneration<br>☐ Other distributed generation<br>☐ Interruptible loads<br>☐ Direct load control<br>☐ Other short-term demand response<br>☑ Energy efficiency<br>☐ Fuel substitution<br>☐ Power factor correction<br>☐ Policy and/or planning |
| **Technology** | Various energy efficiency measures |

**Drivers for Project**

The Texas Legislature passed Senate Bill 7 (SB7) in 1999, which restructured the state's electric utility industry. Specifically, the law calls for each investor-owned utility to meet 10% reduction in its annual growth in system demand each year through savings achieved by energy efficiency programs. Consequently, Oncor is required to achieve a 10 percent reduction in annual system demand growth by January 1, 2004 and each year thereafter. The Residential and Small Commercial Standard Offer Program (R&SC SOP) represents a step toward achieving this requirement.

The R&SC SOP complies with the Residential and Small Commercial Standard Offer Program promulgated by the Public Utility Commission of Texas in PUCT Substantive Rule 25.184.

The R&SC SOP is a performance-based program which offers incentive payments for the installation of a wide range of measures that reduce energy use and peak demand. The program was developed by Oncor to provide an incentive to suppliers of energy services to implement electric energy-efficiency projects at the facilities of Oncor's residential and small commercial customers.

The primary objective of the R&SC SOP is to achieve cost effective reduction in peak summer demand in the Oncor's service territory.

Additional objectives of the program are to:

- make energy efficiency incentive programs available to all customer classes;
- maximize customer energy and bill savings;
- stimulate investment in efficient technologies most likely to reduce Oncor's peak capacity requirements during summer;
- acquire cost-effective energy efficiency resources;
- minimize the burden of measurements and verification requirements associated with standard offer programs by offering deemed or simple savings calculations for many measures.

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| **Market Segments Addressed** | ☑ Residential customers<br>☑ Commercial and small industrial customers<br>☐ Large industrial customers<br>☐ Additional generation |
| **No Participants** | |

**Description of Project**

Each year, Oncor establishes a budget for the R&SC SOP and then purchases peak demand reductions and energy savings from energy efficiency service providers who market and install energy efficiency measures until the budget is exhausted. Oncor relies upon the marketing capabilities of energy efficiency service providers to sell energy efficiency measures to Oncor's residential and small commercial customers. Oncor is not directly involved in the marketing, sales, or delivery of energy efficiency services to its customers.

*Program Participants*

The R&SC SOP involves three types of participants: the program administrator (Oncor), energy efficiency service providers ("Project Sponsors"), and energy efficiency customers ("Host Customers").

Oncor's responsibilities include:

- conducting workshops for potential Project Sponsors;
- reviewing and approving or rejecting all project applications;
- performing certain inspection activities; and
- authorising and issuing incentive payments.

A Project Sponsor's responsibilities include:

- conducting marketing activities to potential Host Customers;
- completing the installation of approved projects by required deadlines and in accordance with any mandatory progress milestones;
- developing and submitting project documentation;
- providing customer service to Host Customers, including the satisfactory resolution of any customer complaints.

A Host Customer's responsibilities include:

- committing to an energy efficiency project;
- entering into a Host Customer Agreement with the selected Project Sponsor; and
- providing Oncor, and any statewide measurement and verification contractor, access to the project site both before and after project completion for installation inspection.

*Eligible Project Sponsors*

Project Sponsors may include Energy Service Companies, Retail Electric Providers, HVAC Contractors, Lighting Companies and other energy conservation firms or commercial customers. Any entity meeting the application requirements that installs eligible residential energy efficiency measures at a customer site with residential electricity distribution service from Oncor is eligible to participate in the R&SC SOP as a Project Sponsor.

In addition, any third-party entity meeting the application requirements that installs eligible energy efficiency measures at a non-residential customer site with a minimum project size of 20 kW and a maximum demand that does not exceed 100 kW (250 KW in 2004) is eligible to participate in the program as a Project Sponsor. Larger projects and projects on multiple sites owned by the same commercial customer in Oncor's distribution service area may be eligible under Oncor's separate Commercial and Industrial Standard Offer Program.

*Program Options*

The R&SC SOP offers multiple project options. This creates a greater opportunity for a variety of Project Sponsors to participate.

There are three project options to choose from in the 2004 R&SC SOP:

- the Small Single Family & Small Commercial Project Option;
- the Large Single Family & Small Commercial Project Option; or
- the Large Multifamily Project Option.

While a Project Sponsor may concurrently participate in the large project options, it may not participate in any of the large project options and the small project option at the same time. By choosing a project option, the Project Sponsor indicates the size of the project to be implemented. With the exception of projects in the Small Single Family & Small Commercial Project Option, all R&SC SOP Project Applications must propose a minimum project size of 20 kW of peak demand savings.

Each project option has a separate budget as well as specific and unique program requirements. Applications from potential Project Sponsors are reviewed on a first-come, first served basis in each project option until all budget funds have been allocated. So that multiple Project Sponsors will have a chance to participate, no one Project Sponsor or its affiliate(s) may receive more than the budgeted amount for each project option or twenty percent (20%) of all available R&SC SOP funds in any one year.

*Eligible Savings Measures*

Energy efficiency measures in residential, multifamily and small commercial applications that reduce electric energy consumption and system peak demand at the customer site(s) are eligible for the R&SC SOP. Eligible measures do not include repair or maintenance activities or behavioural changes.

Energy-efficient measures in all end uses (e.g. lighting, cooling, and heating) are eligible for the R&SC SOP. However, a maximum of 65% of a project's kW and kWh incentive payments may come from energy-efficient lighting equipment and/or lighting controls when installed with lighting efficiency upgrade (except daylighting).

All measures eligible for R&SC SOP incentive funds must exceed applicable current United States Federal Government minimum efficiency standards. In cases where standards do not exist, demand and energy savings credits are based on efficiency improvements relative to typical efficiencies in like circumstances.

To minimise the burden of measurement and verification requirements, Oncor offers deemed or simple savings calculations for many energy efficiency measures, including energy efficient air conditioners, heat pump space heaters, ceiling and wall insulation, energy efficient windows, high efficiency appliances and replacement of water heaters (electric to high efficiency electric or high efficiency gas or solar). In addition, the Public Utilities Commission of Texas has approved deemed savings for particular energy efficiency measures.

*Incentive Levels*

The R&SC SOP pays incentives for energy savings and demand reductions, based on dollars per kilowatt and dollars per kilowatt-hour incentive rates based on 50% of avoided cost benefit. Demand (kW) payment is based on peak demand savings.

The incentive levels offered for the R&SC SOP during 2003 and 2004 are as follows:
**kW:** USD 270.00
**kWh:** USD 0.0925

**Results**

Since the R&SC SOP commenced only in late 2002 for savings in 2003, results from the program are not yet available.

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| **Project Cost** | Available funds for incentive payments:<br>2003: USD 4,775,469<br>2004: USD 6,333,346 |

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| **Relevance to Network Demand Management in NSW**<br>A similar Standard Offer program could be implemented in geographically delimited localities in NSW where the distribution network is constrained. | |
| **Contacts** | Garrey Prcin<br>Oncor Electric Delivery Company<br>500 N Akard, Suite 09-164<br>Dallas TX 75201<br>USA<br>Tel: + 1 214 486 5808<br>E-mail: garrey.prcin@oncorgroup.com |
| **Sources**<br>Oncor Electric Delivery Company (2002). *2003 Oncor Residential & Small Commercial Standard Offer Program Manual.* Dallas, Texas, Oncor. Available at: http://www.oncorgroup.com/electricity/teem/res/Residential_and_Small_Commercial_SOP_Manual_2003.pdf<br>Oncor Electric Delivery Company (2003). *2004 Oncor Residential & Small Commercial Standard Offer Program Manual.* Dallas, Texas, Oncor. Available at: http://www.oncorgroup.com/electricity/teem/res/Residential_and_Small_Commercial_SOP_Manual_2004.pdf<br>Oncor Electric Delivery Company (2003). *2004 Deemed Saver Helper.* Dallas, Texas, Oncor. Available at: http://www.oncorgroup.com/electricity/teem/res/helperapp_ressop_nov2003_.xls<br>Oncor's website at: http://www.oncorgroup.com/electricity/teem/res/default.asp | |

## EE05 Air Conditioning Distributor Market Transformation Program, Texas

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| **Location** | Texas, USA |
| **Project Proponent** | Oncor Electric Delivery Company (a subsidiary of TXU Corp responsible for electricity transmission and distribution) |
| **Date Project Implemented** | 2003 and continuing |
| **Type of Project** | ☐ Standby generation<br>☐ Cogeneration<br>☐ Other distributed generation<br>☐ Interruptible loads<br>☐ Direct load control<br>☐ Other short-term demand response<br>☑ Energy efficiency<br>☐ Fuel substitution<br>☐ Power factor correction<br>☐ Policy and/or planning |
| **Technology** | Various energy efficiency measures |

**Drivers for Project**

The Texas Legislature passed Senate Bill 7 (SB7) in 1999, which restructured the state's electric utility industry. Specifically, the law calls for each investor-owned utility to meet 10% reduction in its annual growth in system demand each year through savings achieved by energy efficiency programs. Consequently, Oncor is required to achieve a 10 percent reduction in annual system demand growth by January 1, 2004 and each year thereafter. The Air Conditioning Distributor Market Transformation Program (A/C Distributor MTP) represents a step toward achieving this requirement.

The A/C Distributor MTP pays incentives to distributors for installations of high efficiency air conditioners. The program is designed to increase the installation of high efficiency air conditioners in the new and replacement residential and small commercial market in order to reduce summer peak demand for electricity in the Oncor service territory.

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| **Market Segments Addressed** | ☑ Residential customers<br>☑ Commercial and small industrial customers<br>☐ Large industrial customers<br>☐ Additional generation |
| **No Participants** | |

**Description of Project**

The A/C Distributor MTP is available to distributors only and incentives are paid to participating distributors until the annual budget for the program is exhausted. A distributor is defined as any entity that sells or sources equipment to dealers, such as manufacturer's representatives, wholesalers, or "supply houses". Distributors utilise their dealers to make and document installations. . Dealers and customers are not eligible to receive direct payment from Oncor.

To be eligible for incentive payments, an installation location must receive electric distribution service by Oncor. A customer's actual electric bill may come from TXU Energy, Reliant Energy or a number of other retail electric providers. Customers served by electric cooperatives or municipal systems are not eligible for this program. End use customers must be informed of the program and be aware that an onsite inspection of the installation may occur.

Incentive amounts vary by the efficiency and size range of the installed air conditioner. A qualified load calculation is required for each installation. No incentives are paid for installations that fail inspections. Equipment installed under any other Oncor or TXU Energy Program where an incentive is paid, is not eligible for this program. Incentives are paid under only one program.

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| **Results**<br>Since the A/C Distributor MTP commenced only in late 2002 for savings in 2003, results from the program are not yet available. | |
| **Project Cost** | Incentive budget of USD 4,000,000 for the 2004 program |
| **Relevance to Network Demand Management in NSW**<br>A similar air conditioner market transformation program could be implemented to reduce peak system demand in geographically delimited localities in NSW where the distribution network is constrained. | |
| **Contacts** | Jerry Adams<br>Oncor Electric Delivery Company<br>500 N Akard, Suite 09-164<br>Dallas TX 75201<br>USA<br>Tel: + 1 800 273 8741<br>E-mail: jerryadams@oncorgroup.com |
| **Sources**<br>Oncor's website at: http://www.oncorgroup.com/electricity/teem/mtp/acdistributors.asp | |

## FS01 Tahmoor Fuel Substitution Project, New South Wales

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| **Location** | Tahmoor, NSW, Australia |
| **Project Proponent** | Integral Energy |
| **Date Project Implemented** | 1998 to 2001 |
| **Type of Project** | ☐ Standby generation<br>☐ Cogeneration<br>☐ Other distributed generation<br>☐ Interruptible loads<br>☐ Direct load control<br>☐ Other short-term demand response<br>☐ Energy efficiency<br>☑ Fuel substitution<br>☐ Power factor correction<br>☐ Policy and/or planning |
| **Technology** | Bottled gas cooking and space heating technology |

**Drivers for Project**

The Tahmoor fuel substitution program was undertaken in the Southern Highlands region south west of Sydney. The purpose of the program was to defer augmentation of the distribution network by controlling growth in the winter evening peak demand and combating a low load factor.

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| **Market Segments Addressed** | ☑ Residential customers<br>☐ Commercial and small industrial customers<br>☐ Large industrial customers<br>☐ Additional generation |
| **No Participants** | About 100 |

**Description of Project**

The program promoted the use of bottled gas by residential customers for cooking and space heating. Customers were contacted via a letterbox drop with a personalised letter providing details of subsidies available from Integral and the costs of bottled gas appliances. Integral arranged the installation of bottled gas and appliances and provided subsidies of $150 for the installation of bottled gas plus $150 per appliance.

**Results**

The program succeeded in flattening load growth to a degree, but take-up was less than had been hoped. One reason may have been that at the time the program was underway, the state's primary gas distributor made public overtures about extending reticulated natural gas to the area. These plans never materialised, but the possibility of using mains gas may have delayed and ultimately prevented customers from making decisions in favour of Integral's bottled gas alternative.

As a result, the program deferred the supply-side system augmentation for a shorter period than had originally been forecast. The augmentation is now scheduled for 2003/04.

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| **Project Cost** | $40,000 subsidies paid to customers plus $18,000 administrative costs |

**Relevance to Network Demand Management in NSW**

A similar promotion of fuel substitution could be implemented in geographically delimited localities in NSW where the distribution network is constrained.

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| **Contacts** | Frank Bucca<br>Demand Management & Utilisation Manager<br>System Development Department<br>Integral Energy<br>PO Box 6366<br>Blacktown NSW 2148<br>Tel: 02 9853 6566<br>Fax: 02 9853 6099<br>E-mail: bucca@integral.com.au |

**Sources**

Charles River Associates (2003). *DM Programs for Integral Energy.* Melbourne, CRA.

Personal communication, Frank Bucca, Integral Energy, November 2003.

| **IP01 Brookvale/Dee Why Demand Management Initiatives, Sydney** | |
|---|---|
| **Location** | Brookvale/Dee Why area, Sydney, Australia |
| **Project Proponent** | EnergyAustralia |
| **Date Project Implemented** | Project commenced in October 2003 |
| **Type of Project** | ☑ Standby generation<br>☐ Cogeneration<br>☐ Other distributed generation<br>☐ Interruptible loads<br>☐ Direct load control<br>☐ Other short-term demand response<br>☑ Energy efficiency<br>☐ Fuel substitution<br>☑ Power factor correction<br>☐ Policy and/or planning |
| **Technology** | Various |

**Drivers for Project**

The Warringah sub-transmission network is forecast to exceed firm rating over the summer of 2004/05. System augmentation to prevent this would involve installing and commissioning two new sub-transmission underground feeders by summer 2004/05 at a cost to EnergyAustralia Network of $5 million. Demand management initiatives could potentially defer this need for capital investment. A reduction in demand of 3MVA could defer capital works for one year, which represents an NPV benefit to EnergyAustralia Network of $420,000.

The peak load in Warringah in summer occurs between 8:00 am and 9:30 pm and is largely attributed to commercial air conditioning, lighting systems, office equipment and some industrial processing. The daily load profile indicates that large commercial / industrial customers in the target areas dominate the electrical demand. Air conditioning and industrial processing equipment contribute most to the peak demand between 8:30 am and 5:30 pm during the summer.

From a public consultation process in December 2002, and field visits by EnergyAustralia officers, a number of potential demand management options were identified. These options were assessed to be sufficiently large and potentially cost effective to provide a means of economically deferring the proposed supply side investment for one year.

In particular, the following three initiatives targeted at the commercial and industrial sectors were identified as potentially viable demand management options that could provide up to 3.8 MVA summer demand reduction:

- installation (or repair) of low voltage power factor correction (LV PFC) equipment at target customers' premises;
- the use of a privately-owned standby generator to export energy to the network during peak periods on the network;
- a Standard Offer for demand reductions achieved by customers or third party aggregators through energy efficiency measures undertaken at target customers' premises.

A recommendation was made to proceed to develop all three initiatives in parallel to confirm the demand management potential.

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| **Market Segments Addressed** | ☐ Residential customers<br>☑ Commercial and small industrial customers<br>☐ Large industrial customers<br>☐ Additional generation |
| **No Participants** | |

**Description of Project**

An integrated project was developed into three work streams consisting of the three identified demand management initiatives.

*Power Factor Correction Project*

A detailed description of this project is included as program summary PF02 on page 78.

*Stand-By Generator Initiative*

The existing 1MVA stand-by generator at Manly Warringah Rugby League Club was identified as one of the potential demand management options to achieve the required 3MVA load reduction. EnergyAustralia sought and received "in principle" agreement from Manly Warringah Rugby Leagues Club to proceed with the project and investigated the feasibility on that basis.

The scope of work is to carry out upgrades to MWRLC generation control systems and main switchboard and upgrades to the EnergyAustralia network, including protection systems, to allow the generator to be connected in parallel to the network and to run at times of system peak.

EnergyAustralia recently completed a "learn by doing" project in which the stand-by generator at North Ryde RSL Club was converted to a SCTT system, which allowed it to supply the customer load in peak demand periods. This has provided valuable information regarding the feasibility of employing existing stand-by generators as dispatchable network support options. However, under this system the North Ryde RSL generator does not export power to the grid. This means that the value of this type of system to EnergyAustralia in terms of load reduction is only equal to the load drawn by the club during the time in which the generator runs.

Running a generator in parallel with the network is the next logical step in the "learn by doing" context as it allows the generator to export power to the grid, allowing EnergyAustralia to take advantage of the full capacity of the generator and maximise the load reduction value.

*Energy Efficiency Standard Offer Initiative*

The Energy Efficiency Standard Offer Initiative seeks to realise the required demand reduction through the implementation of energy efficiency initiatives at target customer sites within the study area.

A respondent to the public consultation that formed part of the DM investigations for Brookvale / Dee Why identified a potential to secure 1.2MVA of demand reduction from commercial and industrial efficiency initiatives in the target area. Consequently, EnergyAustralia will invite submissions from interested organisations (as third party aggregators) or individual customers who can offer projects to secure the required demand reduction from commercial and industrial energy efficiency initiatives.

Experience in the identification and implementation of commercial and industrial energy efficiency projects again suggests that some form of stimulus additional to the potential economic benefits will be beneficial to ensuring the appropriate decision-makers are committed to proceeding with energy efficiency measures. Hence, EnergyAustralia will make a Standard Offer of $200 per kVA of demand reduction achieved. The objective will be to place the Standard Offer in the market as an incentive to draw out sufficient commitment to the implementation of energy efficiency projects to meet a minimum project subscription level (to be set – approximately 0.8MVA), and up to the required 1.2MVA.

**Results**

Since the project has commenced only recently, as at November 2003 no results are available.

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| **Project Cost** | Not finalised |

**Relevance to Network Demand Management in NSW**

A similar integrated project comprising several complementary demand management initiatives implemented within a geographically delimited target area may be an effective way to acquire the demand reduction required to enable the deferral of network augmentations in NSW locations where the network is constrained.

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|---|---|
| **Contacts** | Pat Dunn<br>Project Manager<br>Demand Management<br>EnergyAustralia<br>L14, 570 George St, Sydney<br>Tel: (02) 9269 7369 Fax: (02) 9269 7372<br>E-mail: pdunn@energy.com.au<br>http://www.energy.com.au |
| **Sources**<br><br>Personal communication, Pat Dunn, EnergyAustralia, November 2003. | |

## IP02 Parramatta CBD Demand Management Project, Sydney

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|---|---|
| **Location** | Parramatta, Sydney, Australia |
| **Project Proponent** | Integral Energy |
| **Date Project Implemented** | 2003 |
| **Type of Project** | ☑ Standby generation<br>☐ Cogeneration<br>☐ Other distributed generation<br>☐ Interruptible loads<br>☐ Direct load control<br>☐ Other short-term demand response<br>☑ Energy efficiency<br>☐ Fuel substitution<br>☑ Power factor correction<br>☐ Policy and/or planning |
| **Technology** | Various |

**Drivers for Project**

In 2002, the local council relaxed the guidelines specifying the limits on building heights in the central business district area of Parramatta in western Sydney. This has the potential to result in rapid demand growth that could quickly exceed network capabilities, through extension of existing buildings (several examples of this are already in the planning stages) and/or the construction of buildings that significantly exceed historic floor-space specification and load sizes.

Based on these considerations, by 2013 peak loads in the area could be in the order of 236MVA, which could require the construction of another two zone substations within the CBD. Demand-side initiatives targeted at both existing commercial and high-density residential load and new developments could potentially defer these investments.

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| **Market Segments Addressed** | ☑ Residential customers<br>☑ Commercial and small industrial customers<br>☐ Large industrial customers<br>☐ Additional generation |

**No Participants**

**Description of Project**

Integral Energy is cooperating with the NSW Sustainable Energy Development Authority to develop a Commercial Building Greenhouse Gas Rating Scheme for the area. As part of this study, Integral has funded and conducted a major survey to identify and establish the opportunities for demand management (DM) in the Parramatta CBD. Integral personnel accompany SEDA's consultants to identify other opportunities for DM in office buildings in the Parramatta CBD. Study results indicate that sufficient DM opportunities exist to possibly defer the need for supply-side augmentation.

Integral has begun making offers to building owners/managers for the implementation of appropriate DM initiatives. The DM options being considered include the installation of power factor correction equipment and the use of existing back-up generators to allow interruption of mains electricity without loss of amenity to specific customers in time of system stress.

In late 2003, Integral will issue a Request for Proposals to identify other DM initiatives and extend the DM program with the aim of deferring any network augmentation in the area until June 2006. This would constitute a two-year deferral of the supply-side asset.

**Results**

Implementation of the DM program has only just commenced in late 2003, so no results are available yet.

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| **Project Cost** | $400,000 (Integral's budget for this program) |
| **Relevance to Network Demand Management in NSW**<br>A similar integrated project comprising several complementary demand management initiatives implemented within a geographically delimited target area may be an effective way to acquire the demand reduction required to enable the deferral of network augmentations in NSW locations where the network is constrained. | |
| **Contacts** | Frank Bucca<br>Demand Management & Utilisation Manager<br>System Development Department<br>Integral Energy<br>PO Box 6366<br>Blacktown NSW 2148<br>Tel: 02 9853 6566<br>Fax: 02 9853 6099<br>E-mail: bucca@integral.com.au |
| **Sources**<br>Charles River Associates (2003). *DM Programs for Integral Energy.* Melbourne, CRA.<br>Personal communication, Frank Bucca, Integral Energy, November 2003. | |

| **IP03 Castle Hill Demand Management Project, Sydney** | |
|---|---|
| **Location** | Castle Hill, Sydney, Australia |
| **Project Proponent** | Integral Energy |
| **Date Project Implemented** | 2003 to 2006 |
| **Type of Project** | ☑ Standby generation<br>☐ Cogeneration<br>☐ Other distributed generation<br>☑ Interruptible loads<br>☐ Direct load control<br>☐ Other short-term demand response<br>☑ Energy efficiency<br>☐ Fuel substitution<br>☑ Power factor correction<br>☐ Policy and/or planning |
| **Technology** | Various |
| **Drivers for Project**<br>Increasing penetration and use of air conditioners in the Castle Hill commercial centre and surrounding residential areas in western Sydney will result in summer peak loads exceeding system capability. Despite the high levels of load growth, initial assessments indicated that sufficient demand could be curtailed to defer the installation of additional network infrastructure.<br>Reductions in summer peak demand of 1 MVA initially, and further reductions of 0.5 MVA per annum will be required to defer the supply-side augmentations that are now anticipated to be required. A notional three-year deferral would provide a DM budget of sufficient value to warrant proceeding with a DM option. | |
| **Market Segments Addressed** | ☑ Residential customers<br>☑ Commercial and small industrial customers<br>☐ Large industrial customers<br>☐ Additional generation |
| **No Participants** | |
| **Description of Project**<br>Integral Energy determined that an RFP for DM strategies was warranted. However, this has been supplanted by an offer from the NSW Sustainable Energy Development Authority (SEDA) to conduct a DM program focussed on the commercial sector.<br>SEDA is contacting commercial sector customers via face to face meetings to identify DM opportunities. The program will target interruptible loads, the use of existing standby generators, the installation of high efficiency air conditioning (and the upgrading of existing air conditioning systems), and the installation of efficient lighting and power factor correction equipment in new and replacement applications.<br>Integral has provided funding to SEDA for the program. Once the program has established itself with larger commercial customers, thought will be given to extending it downward to smaller commercial customers and onwards to the residential sector.<br>The program will run for three years and is expected to defer supply-side system augmentation until November 2009. | |
| **Results**<br>Implementation of the DM program has only just commenced in late 2003, so no results are available yet. | |

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| **Project Cost** | \$300,000 (Integral's budget for the program) |
| **Relevance to Network Demand Management in NSW**<br>A similar integrated project comprising several complementary demand management initiatives implemented within a geographically delimited target area may be an effective way to acquire the demand reduction required to enable the deferral of network augmentations in NSW locations where the network is constrained. | |
| **Contacts** | Frank Bucca<br>Demand Management & Utilisation Manager<br>System Development Department<br>Integral Energy<br>PO Box 6366<br>Blacktown NSW 2148<br>Tel: 02 9853 6566<br>Fax: 02 9853 6099<br>E-mail: bucca@integral.com.au |
| **Sources**<br>Charles River Associates (2003). *DM Programs for Integral Energy.* Melbourne, CRA.<br>Personal communication, Frank Bucca, Integral Energy, November 2003. | |

## LM01 Sacramento Residential Peak Corps, California

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|---|---|
| **Location** | Sacramento, California, USA |
| **Project Proponent** | SMUD (Sacramento Municipal Electricity District) |
| **Date Project Implemented** | 1979 to present |
| **Type of Project** | ☐ Standby generation<br>☐ Cogeneration<br>☐ Other distributed generation<br>☐ Interruptible loads<br>☑ Direct load control<br>☐ Other short-term demand response<br>☐ Energy efficiency<br>☐ Fuel substitution<br>☐ Power factor correction<br>☐ Policy and/or planning |
| **Technology** | Cycling of residential air conditioners |

**Drivers for Project**

This project was initiated in 1979 to address needle peaks in the load on Sacramento's electricity network which occur on summer days when temperatures climb above 100°F (38°C). The program has now been operating for 24 years.

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| **Market Segments Addressed** | ☑ Residential customers<br>☐ Commercial and small industrial customers<br>☐ Large industrial customers<br>☐ Additional generation |
| **No Participants** | 100,000 (as at November 2003) |

**Description of Project**

The Peak Corps program provides peak clipping and load shifting through the remote cycling of central air conditioners during selected summer afternoons. Residential customers apply to become Peak Corps members and allow SMUD to install a cycling device and send a radio signal to cycle their central air conditioners by switching them off and on at times determined by SMUD. The cycling device is installed and maintained by SMUD at no cost to the customer.

The program is available to SMUD residents whose home has central air conditioning or a heat pump. Renters must gain the approval of their property manager. Window or wall air conditioners and evaporative coolers are not eligible. Customers operating child or convalescent care business in their homes are not eligible for this program.

Temperatures during the summer in Sacramento can often exceed 100°F (38°C), and on these days SMUD's system approaches or reaches peak demand. In order to reduce this demand SMUD typically cycles participating central air conditioners 10 to 16 days between 1 June and 30 September. Heat waves often last for a few days so cycling may occur several days in a row.

In addition, when there is an energy shortage, the California Independent System Operator (CA-ISO) may call upon SMUD to reduce load. Before going to rotating power outages, SMUD may cycle Peak Corps air conditioners.

Cycling can occur periodically during the day or on weekends. On a "typical" cycling day, cycling occurs for between 2 1/2 and 4 hours. When an air conditioner is being cycled, this is indicated by a flashing green light on the cycling device. To cater for special household occasions, customers can elect to be taken off the Peak Corps program for one day only during the summer without losing their savings. Customers must provide two days notice to SMUD if they want to utilise this option.

The program currently (November 2003) offers three cycling options with the program participants receiving discounts on their June through September electric bills. In addition to the monthly discount, Peak Corps members receive additional savings (up to $3) each day their air conditioner is cycled.

*Option 1*

- Save $2.50 a month ($10 per season)
- Additional $1 savings for each day of cycling
- 0 to 27 minutes of cycling time per hour

*Option 2*

- Save $3.75 a month ($15 per season)
- Additional $2 savings for each day of cycling
- 0 to 39 minutes of cycling time per hour

*Option 3*

- Save $5 a month ($20 per season)
- Additional $3 savings for each day of cycling
- 0 to 60 minutes of cycling time per hour

**Results**

Results for the Peak Corps program from 1979, when the program started, to 1993 were published in a report by the Results Center (see Sources below). During this period, the air conditioner load under direct load control increased from 0.5 MW in the first year of the program to 100.4 MW in 1993.

At the 1992 summer peak, it was estimated that the Peak Corps program contributed a load reduction of 88 MW. The peak load on SMUD's system in 1993 was 2,146 MW and occurred in August.

Following a large increase in participation in the Peak Corps program and the addition of new cycling options, a new monitoring sample of participants was assembled in 1991. Monitoring results from this new sample showed that the average load reduction per participant was much smaller than had previously been estimated. The average AC load of the 1991 group was considerably smaller than the average load of the participants in earlier monitoring samples, indicating better insulated houses, and more efficient and properly-sized air conditioners, and therefore a lower cooling load. Customers who signed up for the new, more rigorous cycling options operated their air conditioners less intensively on the hottest days when cycling occurred and therefore tended to use less energy than other SMUD customers.

**Project Cost**

In 1993, the total annual cost of the Peak Corps program was USD 3.0 million. In that year an additional 12.1 MW of controlled load was recruited by the program

In a 1992 study, SMUD found all Peak Corps cycling options offered at that time to be cost effective when compared to the avoided cost of a natural gas power plant.

**Relevance to Network Demand Management in NSW**

Direct load control cycling of air conditioners, in both the residential and commercial sector, could be cost-effective for reducing peak loads on constrained elements of the NSW electricity network.

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|---|---|
| **Contacts** | Sacramento Municipal Electricity District<br>P.O. Box 15830<br>Sacramento CA 95852-1830<br>USA<br>Telephone: 0011 1 888 742 7683 and press 32<br>Web site:<br>http://www.smud.org/residential/saving/peak.html |
| **Sources**<br><br>Sacramento Municipal Utility District web site at: http://www.smud.org/residential/saving/peak.html<br><br>The Results Center (1994). *Sacramento Municipal District Residential Peak Corps: Profile # 83.* Available at: http://sol.crest.org/efficiency/irt/83.pdf | |

## LM02 Thermal Cool Storage Program, Texas

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|---|---|
| **Location** | Dallas-Fort Worth and part of Texas, USA |
| **Project Proponent** | TU Electric (now split into TXU Energy, an electricity retailer and generator and Oncor, responsible for electricity transmission and distribution; both are subsidiaries of TXU Corp) |
| **Date Project Implemented** | Commenced in 1982 |
| **Type of Project** | ☐ Standby generation<br>☐ Cogeneration<br>☐ Other distributed generation<br>☐ Interruptible loads<br>☐ Direct load control<br>☑ Other short-term demand response<br>☐ Energy efficiency<br>☐ Fuel substitution<br>☐ Power factor correction<br>☐ Policy and/or planning |
| **Technology** | Thermal cool storage using off-peak production of chilled water or ice |

**Drivers for Project**

During the late 1970s TU recognised the need to address the increasing air conditioning load of commercial buildings. Thermal cool storage was seen as a promising means of flattening commercial air conditioning load shapes. In 1981, TU realised that offering financial incentives would eliminate many barriers to installation of thermal cool storage systems. These barriers included a high initial system cost, a long payback period and the large physical size of a thermal cool storage system compared to a standard system.

TU's Thermal Cool Storage program shifted electrical load to off-peak hours, reducing peak demand, and provided space and/or process cooling during TU's on-peak periods (noon to 8 pm, weekdays, June through September).

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| **Market Segments Addressed** | ☐ Residential customers<br>☑ Commercial and small industrial customers<br>☐ Large industrial customers<br>☐ Additional generation |
| **No Participants** | 205 (as at 1992) |

**Description of Project**

A thermal cool storage system provides space and/or process cooling for commercial or industrial installations by running chillers at night and in the early morning to produce and store chilled water or ice, which is then used to provide cooling during the hottest part of the day.

The Thermal Cool Storage program was the first non-residential DSM program offered by TU Electric, beginning full-scale in 1982. The program provided cash incentives to customers who installed thermal storage systems. The incentives were based on the load shifted from on-peak to off-peak hours.

In 1993, TU offered incentives of USD 250/kW for the first 1,000 kW of load shifted plus USD 125/kW for all remaining load shifted. Incentive payments were limited to either the above schedule or to the customer's capital investment minus one year's estimated electric bill savings, whichever was lower. Qualifying customers had to have a payback for the thermal cool storage system exceeding one year. In addition to cash incentives, thermal storage customers could achieve additional savings by taking advantage of the Time-of-Day tariff option. This option was available to customers who shifted electricity use from on-peak to off-peak hours.

Both new and retrofitted buildings qualified for the Thermal Cool Storage program. Partial storage systems that were expanded to take additional load off-peak received incentives based on the additional load shifted. Where a thermal storage system was intentionally oversized to allow for future expansion, the customer was eligible for the full cash incentives only upon completion of the expansion. While the majority of systems installed through the program provided all of the building's cooling needs, customers using systems that provide only partial cooling were also eligible.

TU did not physically control the loads of customers participating in the Thermal Cool Storage program. Each customer was responsible for ensuring that their thermal cool storage system was switched off during TU's peak demand period. The types of system controls used by thermal cool storage customers ranged from simple timers to complex computer systems. Achieving significant savings on the electric bill through reducing peak demand, especially in conjunction with the Time-of-Day rate option provided a very strong incentive for TU thermal storage customers to carefully monitor the operating hours of their thermal cool storage system.

TU focused on marketing the concept and benefits of thermal cool storage and did not sell any thermal cool storage equipment. For customers who were interested in thermal cool storage, equipment manufacturers presented formal proposals that included costs and equipment options. The final decision on choice of equipment was up to the customer.

TU's marketing efforts for the Thermal Cool Storage program were geared toward the three predominant parties in the decision making process: the developers/owners, engineers, and architects. TU field representatives marketed the program to customers and to trade allies (architects, engineers, equipment manufacturers and distributors) by explaining the benefits of thermal cool storage and the customer incentives that TU offered. TU also provided customer building audits which included an analysis of various HVAC system types and system estimated operating costs.

When the Thermal Cool Storage program began in the early 1980s, large office buildings were the most receptive to the program. Developers constructing buildings less than 500,000 square feet were generally not interested in the concept. Before 1986 a typical installation was in an office building exceeding 500,000 square feet.

By 1986 the construction boom in Dallas was slowing and the number of large construction projects dropped drastically. During 1987 and 1988 almost twice as many customers installed thermal storage systems as in the previous five years, but the load reductions added by the program in these two years were approximately half those achieved during the previous five years, which indicates a sharp drop in the size of the typical building participating in the program.

Space and process cooling thermal storage systems were installed in a wide variety of building types throughout the TU service area including hospitals, hotels, government facilities, churches, schools, food processing plants, and industrial manufacturing facilities. Many of the systems installed used chilled water rather than ice as the storage medium, which was different from most other areas of the United States.

**Results**

Results for the Thermal Cool Storage program from 1982, when the program started, to 1992 were published in a report by the Results Center (see Sources below). During this period, the total load shifted from on-peak to off-peak increased from 3.8 MW in the first year of the program to 70.5 MW in 1992.

Peak load reductions per program participant fluctuated greatly over the lifetime of the program. In 1982, reductions were at their highest level with 1.9 MW of peak load reduction per participant joining the program that year, although only two participants were involved. Peak load reductions per participant were lowest in 1986 at 119 kW per participant joining that year. In 1992, peak load reductions per participant joining that year were 204 kW.

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| **Project Cost**<br>In 1992, the total annual cost of the Thermal Cool Storage program was USD 2.7 million. In that year, an additional 5.1 MW of peak load reduction was recruited by the program.<br>The Results Center calculated that TU spent USD 278/kW shifted in 1991 and USD 527/kW shifted in 1992. The average for this two year period was USD 351/kW. These figures compared favourably with USD 664/kW which would have been TU's 1992 capital cost (plus O&M costs) to build an off-the-shelf combined cycle combustion turbine including an 18% simple cycle reserve margin. |
| **Relevance to Network Demand Management in NSW**<br>Promoting thermal cool storage in commercial office buildings, could be cost-effective for reducing peak loads on constrained elements of the NSW electricity network located in the Sydney CBD and other business centres in NSW. |
| **Contacts** |
| **Sources**<br>The Results Center (1993). TU Electric Thermal Cool Storage: Profile # 52. Available at: http://sol.crest.org/efficiency/irt/52.pdf |

## LM03 California Energy Cooperatives

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|---|---|
| **Location** | California, Long Island, New York City, Boston, and Sweden |
| **Project Proponent** | The Energy Coalition |
| **Date Project Implemented** | The Energy Coalition was formed in 1981 and is still continuing |
| **Type of Project** | ☐ Standby generation<br>☐ Cogeneration<br>☐ Other distributed generation<br>☑ Interruptible loads<br>☐ Direct load control<br>☐ Other short-term demand response<br>☐ Energy efficiency<br>☐ Fuel substitution<br>☐ Power factor correction<br>☐ Policy and/or planning |
| **Technology** | Co-ordination of load shedding |

**Drivers for Project**

The Energy Coalition is a unique organisation that was established by a third party to coordinate the energy use of large commercial and industrial customers and to broker this service to Southern California Edison and other utilities. The Coalition was created by and for large commercial and industrial energy users who want to act responsibly to shed load at times of utility capacity constraints through sophisticated management of their facilities. By coordinating their efforts, these users can respond collectively with a high degree of individual flexibility and reliability to calls by the utility to shed load. The Coalition has created a process whereby large users can fulfil the dual goals of enhancing their own bottom line through wise energy management while serving as responsible corporate citizens.

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| **Market Segments Addressed** | ☐ Residential customers<br>☑ Commercial and small industrial customers<br>☑ Large industrial customers<br>☐ Additional generation |

**No Participants**

**Description of Project**

The Energy Coalition is a non-profit organisation that was formed to pool together major end-users into ‘energy cooperatives’. Members of these cooperatives work together to provide load management services to electricity utilities.

The first energy cooperative, built under the auspices of John Phillips’ Engineering Supervision Company, was developed in 1975 for the Los Angeles Department of Water and Power and was supported by the federal Energy and Research Development Agency. The California Energy Coalition – as The Energy Coalition is formally registered – was developed in 1981 when Southern California Edison sought John Phillips’ expertise to develop energy cooperatives in Orange County. The Energy Coalition has become the facilitator of the energy cooperatives process and works with large users to develop load-shedding strategies that are sensitive to times of day, times of year, and special processes. The Energy Coalition has also built energy cooperatives for Pacific Gas & Electric, Long Island Lighting Company, Boston Edison, Commonwealth Edison, and in Sweden.

As members of an energy cooperative, large commercial and industrial customers work together to shed loads at critical peak times when called upon by their serving utilities. Each member is paid to do so at a cost far less than the utility would have to pay to buy electricity generation peaking capacity. By bringing together end-users and by pooling customers with highly diverse load profiles, energy cooperatives use ‘smart’ load management strategies with the least impact on participants.

This allows for customer control and flexibility in load curtailment. For example a cooperative member who undertakes critical energy-using processes that would otherwise prohibit them from participating in load curtailment programs can participate in an energy cooperative because, when necessary, their contribution can be provided by another member.

Energy cooperatives are based on computer networks which continuously monitor the individual and collective energy use and load reductions of large users and provides a system for dispatching load reduction capacity. A central computer located at the cooperative's headquarters links each member of the cooperative to the utility control centre. When the utility requests a load curtailment, the central system evaluates the proportionate load reduction required from each cooperative member to fulfil the utility's requirement. The load reduction 'game plan' (or strategy) is then defined, and each member is advised of their respective targets. The central system monitors each member's load reduction path to assure compliance. If a particular member cannot meet their target, the system automatically reallocates that load reduction to other members based on pre-existing priority agreements. In this way, the energy cooperative meets its load reduction obligations expediently and with minimal impact on its members.

During a load curtailment, the utility has no idea about which cooperative members are providing what levels of load reductions. It is the responsibility of the cooperative to get members to 'ramp down' their power consumption to firm service levels, and to organise compensating load reductions by other members for members who cannot achieve their targets.

In the original energy cooperative set up in 1982, The Energy Coalition established a contractual 15-year agreement with Southern California Edison (SCE) for load management capabilities. The Coalition was paid an incentive for every kilowatt of peak demand that the Coalition could reliably reduce to the firm (or minimum) service level. Of that fee, the Coalition retained 15% for its management and 5% to enhance its capabilities. The Coalition then wrote cheques to its members based on their agreed prorated share of the overall capability. On average, members agreed to achieve a load reduction of 10% up to fifteen times a year for periods of up to six hours. If, by compensating for another member, a member exceeded their agreed level of load reduction, they received a prorated share of the resulting incentives. The Orange County Sanitation District, for example, could reduce load far below the 10% level by using backup generators and deferring some processes if necessary to compensate for fellow members.

The original agreement with SCE did not limit the size of the first cooperative. However, by 1986 when the Coalition wanted to add two additional cooperatives, the capacity situation in Southern California had changed from a shortage to an excess. Consequently, SCE was far more cautious about the energy cooperative approach and limited the size of the additional cooperatives as well as their geographic distribution. Each of the two new cooperatives were limited to a maximum of 10 MW of curtailable capacity. In addition, each member had to be located within a ten-mile radius of a central point mutually established by SCE and the Coalition.

Over time, The Energy Coalition management has targeted and marketed their services only to key customers whom they feel will add benefit to the Coalition. If an end-user is interested in joining an energy cooperative, meetings are scheduled to educate them about the requirements of membership and the benefits of joining. A walk-through survey is usually conducted on the spot, and a knowledgeable Coalition staffer inquires about key energy use data as well as the level of energy management operating expertise in house.

After the initial visit, if a potential member is still interested, the Coalition prepares an analysis which includes information on the cost of joining an energy cooperative (analysis, equipment installation, and training), the commitment that the cooperative will require of the prospective member, and the approximate benefit that the member will accrue on an annual basis. Once the 'game plan' for load curtailments has been identified, the equipment installed and facility management trained, a new member is up and running. Members then attend cooperative meetings held every other month to share experiences and discuss opportunities for higher levels of energy management.

The results of energy cooperatives are measurable to the utility and end-user alike and energy cooperatives reduce demand as needed by the utility they serve. For utilities, the capacity savings delivered by the cooperative's members can be reliable and cost effective. For members, energy cooperatives provide revenues from energy savings while maintaining required energy services.

**Results**

Results for the energy cooperatives established by The Energy Coalition for Southern California Edison (SCE) from 1982, when the first cooperative was formed, to 1991 were published in a report by the Results Center (see Sources below).

Each summer month the Coalition set a coincident peak level for each energy cooperative. This peak level was measured during SCE's on-peak tariff period, which in 1991 was noon to 6pm every Monday through Friday. (This period was subject to change.) Whether there was a load curtailment or not, SCE paid the margin between each energy cooperative's monthly coincident peak demand, measured every five minutes, and the firm service level for load reductions established for each cooperative on 1 May, prior to the summer, each year.

Between 1982 and 1991, the energy cooperatives were able to provide SCE with between 3.9 MW and 18.2 MW of peak load reduction capacity. In 1991, an unusually cool summer, the cooperatives were able to provide 14.0 MW. However, because SCE was in a situation of excess capacity, it did not call a load curtailment by the energy cooperatives between 1983 and 1991.

**Project Cost**

There are two types of cost for energy cooperatives. First, are the startup costs which are not included in the Results Center report. Second, are the utility payments to the energy cooperatives which are detailed below.

In 1991, SCE paid The Energy Coalition USD 6.90/kW per month for the amount of dispatchable load reduction the Coalition had available for the four months of summer. Whether there was a curtailment or not, the utility paid the Coalition USD 27.60/kW/year (USD 6.90 x 4 months) for the ability to curtail power to firm service levels. In 1991, SCE paid the Coalition a total of USD 364,899. for this service. From 1982 to 1991, SCE paid a total of USD 4,095,301 (1990$).

Prior to 1988, the formula for payments was slightly different and SCE paid for peaking load reduction capacity for the winter as well. The Coalition's members were paid USD 2.08/kW/month for the eight winter months, plus USD 4.16/kW/month for the four summer months. This gave a grand total of USD 33.28/kW/year.

If an energy cooperative could not meet its aggregate firm service level it was penalised four times the payment charge, a penalty of USD 27.60/kW in 1991. Whichever member failed to meet its firm service level was responsible for the shortfall. Other members had the opportunity to make up the shortfall and avoid the penalty.

Between 1982 and 1991, SCE paid the Coalition a total of USD 275/kW for dispatchable load reduction. This compares with costs at that time of USD 300 to 700/kW for electricity generation peaking plant (usually gas turbines).

**Relevance to Network Demand Management in NSW**

The Energy Coalition has shown that cooperative provision of load reductions by a number of end-users can be managed successfully by a third party. The Energy Coalition provided dispatchable peak load reduction capacity direct to a utility, primarily to meet shortfalls in generation capacity. While this model is not directly applicable to the National Electricity Market or to relieving congestion in NSW electricity networks, the model could be adapted to function in local conditions. For example, third party aggregators could manage load reductions offered by end-users and bid these into the National Electricity Market in ways which relieved localised network constraints.

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| **Contacts** | The Energy Coalition<br>1540 South Coast Highway, Suite204<br>Laguna Beach, California 92651<br>USA<br>Tel:  0011 1 949 497 5110<br>Fax: 0011 1 949 497 6406<br>Web site:  http://www.energycoalition.org |
| **Sources**<br>The Energy Coalition web site at: http://www.energycoalition.org<br>The Results Center (1992).  *California Energy Coalition Energy Cooperatives: Profile # 9.*  Available at: http://sol.crest.org/efficiency/irt/9.pdf | |

## LM04 Mad River Valley Project, Vermont

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|---|---|
| **Location** | Warren, Vermont, USA |
| **Project Proponent** | Green Mountain Power/Sugarbush Resort |
| **Date Project Implemented** | 1989, 1995/96 |
| **Type of Project** | ☐ Standby generation<br>☐ Cogeneration<br>☐ Other distributed generation<br>☑ Interruptible loads<br>☐ Direct load control<br>☐ Other short-term demand response<br>☑ Energy efficiency<br>☑ Fuel substitution<br>☐ Power factor correction<br>☐ Policy and/or planning |
| **Technology** | Conversion of electric hot water heaters and electric space heating in buildings to alternative fuels plus other technologies |

**Drivers for Project**

The Mad River Valley is a mountain/valley region in central Vermont which is home to growing resort developments associated with three ski areas, two operated by the Sugarbush Resort. The Valley is served by Green Mountain Power (GMP) by way of a 34.5kV distribution line extending in a long “U” down one valley, across a ridge and back along the highway on the other side of the ridge. Sugarbush Resort, the largest load on the line, is located at the base of the “U”, its weakest point.

In 1989, the ski area was engaged in a major expansion project, and informed GMP that it was planning to increase its load by up to 15 MW to accommodate a new hotel and conference centre and significant new snowmaking equipment.

The reliable capacity of the 34.5 kv line was 30 MW, and a 15 MW increase in load at that location would impair reliability of the line or require an upgrade. Studies by GMP concluded that the appropriate upgrade would be a parallel 34.5kv line down the Valley, at a cost of at least $5 million.

The initial request by the customer, Sugarbush Resort, was for an upgrade by GMP, at GMP’s expense. However, under Vermont’s line extension rules, it was likely that a major portion of the cost of the upgrade would be charged to the customer. Neither the customer nor GMP wanted to pay for the line.

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| **Market Segments Addressed** | ☑ Residential customers<br>☑ Commercial and small industrial customers<br>☐ Large industrial customers<br>☐ Additional generation |

**No Participants**

**Description of Project**

The details of the project were negotiated among GMP, Sugarbush Resort, the Public Advocate, and later approved by state regulators.

The project had two major elements:

- a customer load management commitment;
- a targeted utility efficiency program in the Mad River Valley.

Under the customer load management commitment, Sugarbush Resort and GMP entered into a customer-managed interruptible contract, under which Sugarbush committed to ensure that load on the distribution line, as measured at the closest substation, would not exceed the safe 30 MW level. Sugarbush installed a real-time meter at its operations base, and telemetry to monitor total local load at the substation. Sugarbush committed to manage its resort and snowmaking operations so as to keep total local load at all times below 30 MW. In general, Sugarbush managed load to move snowmaking operations off the Valley's winter peak hours, which are coincident with GMP's and the state's peak load hours. Unlike the other interruptible contracts for snowmaking in effect at most of Vermont's ski areas, this contract required the customer to manage its own load while taking the load of all other customers on the substation into account. In addition to avoiding the cost of the power line upgrade, Sugarbush received a discount for the electricity it purchased.

The targeted utility efficiency program was a concentrated effort by GMP to improve energy efficiency and lower peak demand in the community. At the urging of the Public Advocate, GMP focused some of its DSM programs on the Mad River Valley. In 1995, GMP and Sugarbush Resort funded the Mad River Valley Energy Project, a pilot project which conducted free evaluations of customers' energy consumption. Commercial and industrial users were targeted, although residential users were encouraged to participate. Over a period of 18 to 24 months, GMP delivered a variety of DSM measures across all customer classes. The largest savings came from numerous conversions of electric hot water heaters and electric space heating in buildings to alternative fuels, but many other measures were installed. The pilot project was completed in 1996.

**Results**

Figures from GMP show that electrical demand in the Mad River Valley rose from 3.4 MVA in 1966 to 22.0 MVA in 1989 (an average annual increase of 24%). Since 1989, demand has stabilised at approximately 22 MVA. This compares with a Vermont state-wide growth rate in demand of 2.1% per year.

One criticism of the Mad River Valley Energy Project is that GMP largely abandoned the follow-on DSM work once the network problem was resolved, and may have missed additional cost-effective efficiency opportunities. Consequently, a singular focus on network-driven DSM may lead to lost opportunities for other energy efficiency savings, if not combined with a broad program design for energy efficiency generally.

The cost-effective solution to this network problem came about only when it was clear that much of the cost of the network upgrade would be charged to the customer driving the need for it. If the cost of this upgrade had been smeared across GMP's tariffs, it is much less likely that GMP would, on its own, have negotiated the unique load management contract with the customer, regardless of its cost-effectiveness.

**Project Cost**

**Relevance to Network Demand Management in NSW**

While the situation presented here seems unique, its principal elements could be applied in many other circumstances. First, a combination of load management and energy efficiency avoided an expensive network upgrade and maintained reliable service in an area with rapidly-growing electricity demand. Second, the load management efforts reduced peak loads on the electricity network. The basic principles of this project could be applied to similar situations in NSW, with the load management component being undertaken by either the customer or the electricity network business.

**Contacts**

**Sources**

Cowart, R (2001). Distributed Resources and Electric System Reliability. Gardiner, Maine, The Regulatory Assistance Project. (Website: http://www.raponline.org)

Warren Town Plan at http://www.madrivervalley.com/images/news/chapt5.pdf

## LM05 Ethos Project Trial of Multimedia Energy Management Systems, Wales

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|---|---|
| **Location** | South Wales, United Kingdom |
| **Project Proponent** | SWALEC (South Wales Electricity Company) |
| **Date Project Implemented** | 1996 to 1998 |
| **Type of Project** | ☐ Standby generation<br>☐ Cogeneration<br>☐ Other distributed generation<br>☐ Interruptible loads<br>☑ Direct load control<br>☐ Other short-term demand response<br>☐ Energy efficiency<br>☐ Fuel substitution<br>☐ Power factor correction<br>☐ Policy and/or planning |
| **Technology** | Storage space heaters, storage water heaters |

**Drivers for Project**

The ETHOS project was part of the European Commission Esprit programme. The project consortium consisted of a number of European electricity utilities, manufacturers and research organisations. The project began in October 1995 and continued until the end of 1998.

The ETHOS project aimed to test customer acceptance of a wide range of multimedia value added services including domestic energy management, home security and appliance and heating control. The services were developed using the EHS (European Home Systems) standard for in-home communications and aimed to demonstrate the value to electricity utilities of developing two way communications links with customers for value-added services and energy management.

Under the ETHOS project, the then UK electricity supplier SWALEC (currently part of the Scottish and Southern Energy Group) undertook a trial to test whether multimedia energy management systems could be used to achieve demand management outcomes.

Parts of SWALEC's rural distribution network were peaking during the night period because of storage space and water heating loads, with the daytime peak being considerably lower. The trial was therefore designed to test whether it was possible to achieve peak load reductions on SWALEC's electricity distribution network by using multi-media energy management systems. The systems optimised the charging period of storage appliances in response to cost information broadcast by SWALEC. The combination of a dynamic tariff/cost structure and the energy management systems enabled SWALEC to influence when energy was used to charge storage appliances and also had the ability to prevent charging completely in any specified period.

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| **Market Segments Addressed** | ☑ Residential customers<br>☐ Commercial and small industrial customers<br>☐ Large industrial customers<br>☐ Additional generation |
| **No Participants** | 100 (approx) |

**Description of Project**

Each 11 kV feeder in the SWALEC distribution network has its own load profile depending on the type and number of customers it supplies. Using broadcast radio signals to communicate the tariff/cost messages to the energy management systems only enabled SWALEC to split customers into a very limited number of groups. Therefore, the trial also utilised public switched telephone network (PTSN) communications to supplement SWALEC's existing broadcast radio system. This allowed tariff/cost messages to be sent that accurately reflected the requirements of specific parts of the SWALEC distribution network. The PTSN link also allowed two-way communication between

SWAKEC and its customers, therefore providing an opportunity for SWALEC to provide other multimedia services in the future.

Two versions of the CELECT multimedia energy management system were trialled: Low Cost CELECT and Credanet. These systems both employed the EHS communications standard and were used to control storage space heaters and, in the case of LC-CELECT, some direct acting heaters. L-C CELECT had central intelligence and utilised 48 half-hourly cost-reflective messages whereas Credanet had distributed intelligence and used simpler tariff messages. Both systems had user interfaces which allowed customers to specify their requirements in relation to space heating comfort levels.

The trial installed 23 LC-CELECT systems in dwellings located in the rural areas of SWALEC's distribution network. The systems controlled all the space heaters in the dwellings, utilising customer settings, room temperature and electricity cost information to meet the required temperature "set point" at minimum cost. In each dwelling, an Intacom electricity meter was used to collect half-hourly consumption data for the separately metered space and water heating. This enabled comparison of how LC-CELECT managed the customer's use of energy with the user interface settings selected by the customer, the cost reflective messages sent by the utility, and temperatures both indoors and outside. SWALEC also monitored the demand on the section of the distribution network supplying the dwellings in the trial.

The trial also installed 76 Credanet systems in rural dwellings. This system used the EHS communications standard with distributed intelligence and therefore utilised more EHS nodes than LC-CELECT. Credanet also used dedicated heaters with integral transceivers. Whilst L-C CELECT operated as just a single zone with only one comfort temperature, Credanet had three zones and allowed different temperatures to be set for each of three comfort periods in each zone. Credanet did not have the diagnostic or data logging facilities of L-C CELECT and so individual temperature recorders were use to collect room temperature information.

In addition, two prototype DICE water heater controllers were used in the trial to control the immersion heaters in hot water cylinders to meet the customer's requirements for hot water at the minimum energy cost. The DICE controller achieved this by monitoring the contents of the cylinder, assessing the customer's programmed requirements for quantity, availability and temperature of the hot water, and then utilising the cost reflective messages sent by SWALEC to optimise energy use for providing hot water.

It was also intended to trial direct load control of dishwashers and clothes washers/dryers, but the models of these appliances which could be controlled were not available at the time the report of the trial was written.

**Results**

The results of the trial showed that by sending cost reflective messages to LC-CELECT systems, SWALEC was able to achieve a 25% reduction in the peak demand on the relevant section of the distribution network. There was also a significant benefit to SWALEC in reducing the wholesale purchase costs of electricity from the pool which was then part of the England and Wales electricity market.

L-C CELECT improved comfort for customers and also saved energy. Results ranged from a reduction of 32% to an increase of 17% in the energy used for space heating in the trial dwellings. The overall result was a reduction of 8% in electricity consumption. Where there was an increase in consumption it could generally be attributed to the fact that the dwellings were initially under-heated, with the storage heaters having insufficient capacity to meet the required heating demand.

Software and hardware problems with the Credanet systems enabled SWALEC to make only one attempt to modify the shape of the distribution network demand profile. This attempt was successful in reducing the night time peak and also in reducing SWALEC's wholesale purchase costs of electricity from the pool. The Credanet system was also successful in providing improved comfort for customers and reducing the energy used for space heating.

The two prototype DICE water heater controllers were generally successful in using low priced energy to heat the water in the cylinders and avoiding using energy in periods of high energy prices.

| **Project Cost** |
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| **Relevance to Network Demand Management in NSW**<br>The use of multimedia energy management systems to optimise energy use by storage water heaters could be useful in constrained areas of the distribution network in NSW. It might also be worthwhile to investigate the use of such systems to control cycling of residential air conditioners during peak periods on the NSW distribution network. |
| **Contacts** |
| **Sources**<br>David, A (1998). *Overall Project Report*. Ethos Project, Esprit European Funding Programme. Cardiff, SWALEC. |

## LM06 Baulkham Hills Substation Deferral, Sydney

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|---|---|
| **Location** | Baulkham Hills, Sydney, Australia |
| **Project Proponent** | Integral Energy |
| **Date Project Implemented** | 1998 to 2005 |
| **Type of Project** | ☐ Standby generation<br>☐ Cogeneration<br>☐ Other distributed generation<br>☑ Interruptible loads<br>☐ Direct load control<br>☐ Other short-term demand response<br>☐ Energy efficiency<br>☐ Fuel substitution<br>☐ Power factor correction<br>☐ Policy and/or planning |
| **Technology** | Large furnaces |

**Drivers for Project**

This program was undertaken to defer a $1.7 million network augmentation project to construct the Baulkham Hills zone substation, which had become necessary as a result of the growth in the afternoon summer peaks.

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| **Market Segments Addressed** | ☐ Residential customers<br>☐ Commercial and small industrial customers<br>☑ Large industrial customers<br>☐ Additional generation |
| **No Participants** | 1 |

**Description of Project**

This DM program began in 1998 and is essentially an agreement with one major industrial customer who uses large furnaces and puts a substantial peak demand of 12 MVA on the network. Under the agreement, the customer is given 24 hours notice to shed load between 1pm and 5pm the following day. The customer is able to achieve this shift by speeding up production prior to the event and then slowing it down from its average rate during the peak.

**Results**

The agreement with this one customer has achieved peak load reductions of between 3.5 and 4.5 MVA. The majority of the cost of the program has been the payments made to the participating customer which total %50,000. Another approximately $10,000 was incurred in setting up and initiating the program.

The agreement with the customer was originally scheduled to operate from 1998 to 2003. The agreement has since been extended by two years to 2005.

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| **Project Cost** | $50,000 payment to the customer plus $10,000 administrative cost |

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| **Relevance to Network Demand Management in NSW**<br>While this is a unique situation, similar interruptibility agreements with customers who have very large loads may be able to defer the need for network augmentation in geographical locations where the network is constrained. | |
| **Contacts** | Frank Bucca<br>Demand Management & Utilisation Manager<br>System Development Department<br>Integral Energy<br>PO Box 6366<br>Blacktown NSW 2148<br>Tel: 02 9853 6566<br>Fax: 02 9853 6099<br>E-mail: bucca@integral.com.au |
| **Sources**<br>Charles River Associates (2003). *DM Programs for Integral Energy.* Melbourne, CRA.<br>Personal communication, Frank Bucca, Integral Energy, November 2003. | |

## LM07 New England Demand Response Programs, USA

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|---|---|
| **Location** | New England region, USA |
| **Project Proponent** | Independent System Operator New England |
| **Date Project Implemented** | 2001 to present |
| **Type of Project** | ☑ Standby generation<br>☐ Cogeneration<br>☑ Other distributed generation<br>☑ Interruptible loads<br>☑ Direct load control<br>☑ Other short-term demand response<br>☐ Energy efficiency<br>☐ Fuel substitution<br>☐ Power factor correction<br>☐ Policy and/or planning |
| **Technology** | Various |

**Drivers for Project**

Commercial and industrial electricity users in New England can receive incentive payments if they reduce their electricity consumption or operate their own electricity generation facilities:

- in response to high real-time prices in the wholesale electricity market; or
- when the reliability of the region's electricity network is stressed.

Demand response participants provide an important resource for New England. They help ensure the reliability of the electricity network, reduce wholesale price volatility that drives up retail electricity prices, and reduce air pollution by enabling older, less efficient power plants to run less often.

In addition to the immediate financial rewards, customers who participate in demand response programs can achieve long-term benefits. Customers who understand their hourly energy profile and can manage their consumption in response to wholesale prices or reliability events can become more attractive and valued customers to competitive electricity suppliers and may be able to negotiate a lower retail electricity price. In addition, the hourly usage information and software systems available to participating customers can be used to help manage energy consumption, helping to improve the customer's energy efficiency.

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| **Market Segments Addressed** | ☐ Residential customers<br>☑ Commercial and small industrial customers<br>☑ Large industrial customers<br>☐ Additional generation |
| **No Participants** | 200 |

**Description of Project**

Electricity customers who participate in ISO New England demand response programs can contribute demand reduction in a variety of ways:

- by turning off non-essential lights and office equipment;
- by adjusting HVAC, refrigeration and water heater temperatures;
- by delaying or reducing manufacturing processes;
- by operating on-site generators;
- by using an energy management system (EMS).

Customers who wish to participate in a demand response program can do so through an Enrolling Participant. Enrolling Participants can be NEPOOL members (such as local utilities and energy suppliers) or Demand Response Providers. Demand Response Providers are companies that provide technology and services to help customers participate in the demand response programs.

Enrolling Participants are responsible for helping customers identify the demand response program that is most suitable for their operation and enrolling them with ISO New England. ISO New England makes incentive payments to Enrolling Participants who then share the incentives with their customers. Enrolling Participants may also offer other incentives and services.

ISO New England offers four different demand response programs, giving customers the flexibility to choose the program that best fits their individual needs:

- real time demand response;
- real time profiled response;
- real time price response;
- day ahead demand response.

*Real Time Demand Response*

The Real Time Demand Response Program is designed for customers who can make a commitment to reduce electricity demand within either a 30-minutes or a 2-hour advance notice. Customers receive a guaranteed minimum payment of USD 0.50 per kWh in the 30-minute program and USD 0.35 per kWh in the 2-hour program. Payments may be higher (up to a maximum of USD 1.00 per kWh) based on the actual hourly wholesale electricity prices in NEPOOL. In addition, customers may receive additional credit for installed capacity and reserve margin.

*Real Time Profiled Response*

The Real Time Profiled Response program is designed for groups of customers whose loads are under direct load control by an Enrolling Participant and who can reduce their loads within 30-minutes notice from ISO New England. This program is intended for:

- businesses with similar facilities in multiple locations such as retail stores, office buildings, etc;
- companies installing direct load control technologies in residential homes or commercial buildings (eg controlled thermostat programs, water heater and pool pump controls, etc.);
- distributed generation installed in multiple locations.

An Enrolling Participant aggregating a minimum of 1 MW of load reduction for this program is required to provide a statistical response factor for the group of customers. For example, an aggregated 10 MW demand resource having a 50 percent response rate would be credited for 5 MW of response.

*Real Time Price Response*

The Real Time Price Response Program is designed for customers who can reduce electricity demand when wholesale prices are projected to be greater than USD 0.10 per kWh. This is a voluntary program. Customers are not required, but can choose, to reduce demand on a case-by-case basis. These customers are paid the actual hourly wholesale prices (up to a maximum of USD 1.00 per kWh) with a guaranteed minimum price of USD 0.10 per kWh. Customers in this program do not qualify for installed capacity credit.

Most customers pay about USD 0.05 per kWh for retail electricity supply. However, wholesale electricity prices in NEPOOL can reach as high as USD 1.00 per kWh during peak demand periods. For example, in the summer of 2002 wholesale electricity prices exceeded USD 0.10 per kWh for over 40 hours on 12 different days.

*Day Ahead Demand Response*

The Day Ahead Demand Response Program is designed for customers who can offer (bid) load reductions into the day-ahead wholesale market. This program is intended for customers who understand the day-ahead market and are able to competitively price their load reduction to be selected and scheduled a day in advance. The customer's load reduction offer is accepted when the day-ahead market price is equal to or higher than the price offered by the customer. If the customer's offer is accepted, they are paid the day-ahead market clearing price.

If the customer fails to deliver the promised level of load reduction, they will need to make up the difference by purchasing energy at the spot market price for the load that was not reduced. The spot market price may be higher or lower than the day-ahead market clearing price.

The advantage of this program is that it provides the customer greater control over their load reduction. The customer will know a day in advance when their load reduction will be scheduled and for how long. Importantly, the customer sets the price at which they are willing to reduce load.

The disadvantage is that a customer's load may not be selected in the day-ahead market if their bid price is too high. In this case the customer can participate in the Real Time Price Response Program if prices are projected to be higher than USD 0.10/kWh.

*Hourly Metering and Data Reporting*

With the exception of the Real Time Profiled Response Program, an advanced electricity meter capable of recording energy consumption every 5 to 15 minutes is required to participate in the ISO New England demand response programs. Customers who do not already have an interval meter can obtain one from their local utility or energy supplier. Some customers may qualify for financial incentives to pay for the installation of advanced metering and communication technologies.

Interval meter data must be reported to ISO New England to determine the customer's load reductions. Three data reporting options are offered:

- **Internet Based Communication System:** Interval meter data is reported to ISO New England via an internet-based reporting system in near real time. This system also allows ISO New England to notify the customer of price or demand response events. In addition, customers can use the software to analyse their meter data to help identify other cost savings opportunities. This system requires either a telephone or LAN connection.
- **Low Tech Option:** Interval meter data is reported to ISO New England within 36 hours after each operating day. This option is not available for the Real Time Demand Response Program.
- **Super Low Tech Option:** Interval meter data is reported to ISO New England within 3 months after an event day. This option is also not available for the Real Time Demand Response Program.

In the low and super low tech options customers are notified of price or demand response events by email, pager, telephone or fax.

**Results**

To date, approximately 200 electricity customers throughout New England have participated in ISO New England's demand response programs, contributing over 200 MW of load reduction. In 2002, participating customers received in excess of USD 3.3 million in incentive payments and other services.

Participating customers include steel foundries, chemical plants, manufacturing facilities, cement factories, paper mills, food processing facilities (including dairy and beverage), scientific laboratories, supermarkets, apartment buildings and office complexes.

The majority of participating customers reported no adverse impacts on their business (eg decrease in revenues) as a result of participating in the program.

**Project Cost**

**Relevance to Network Demand Management in NSW**

A similar suite of demand response programs could be offered in the Australian National Electricity Market by the market operator, National Electricity Market Management Company (NEMMCO) or by local distribution and/or transmission system operators. Such programs would provide a mechanisms for relieving short term constraints on electricity networks, eg those lasting up to a couple of hours

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| **Contacts** | ISO New England Inc.<br>Holyoke, Massachusetts<br>USA<br>Tel: + 1 413 535 4000<br>Fax: + 1 413 535 4379<br>Email: info@iso-ne.com |

**Sources**

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Townsley, M.W., Waite, S..P. and Mattson, C.C. (2003). *ISO New England 2002 Demand Response Program Evaluation Final Report*. Old Saybrook, Connecticut, Townsley Consulting Group. Available at: http://www.iso-ne.com/Load_Response/Evaluation_And_Review_Of_2002_Load_Response_Program/ISO-NE_DRPE_2002_Final_Rpt.pdf

## LM08 Western Sydney Interruptible Air Conditioning Rebate Trial

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|---|---|
| **Location** | Kings Langley/Glenwood area, Sydney, Australia |
| **Project Proponent** | Integral Energy |
| **Date Project Implemented** | 2001 |
| **Type of Project** | ☐ Standby generation<br>☐ Cogeneration<br>☐ Other distributed generation<br>☐ Interruptible loads<br>☑ Direct load control<br>☐ Other short-term demand response<br>☐ Energy efficiency<br>☐ Fuel substitution<br>☐ Power factor correction<br>☐ Policy and/or planning |
| **Technology** | Air-conditioning |

**Drivers for Project**

Air conditioners create substantial peak loads and hence are candidates for direct load control to reduce system peaks. There are a number of different operational parameters (weather dependence, continuity of use, storage practicality, etc) that mean that direct load control of air conditioning control should be treated carefully.

Integral sponsored a trial of air-conditioning cycling to reduce the system peak by definite agreed amounts. The trial investigated the efficacy of an air conditioner cycling program for network issues (ie deferring capital expenditure) and for retail issues (ie reducing exposure to high pool prices).

The trial investigated the technical and commercial feasibility of using direct control methods to cycle residential air conditioners in order to reduce system peak demands. The main objectives of the trial were to test:

- the reliability and response time of the cycling equipment;
- the impact of air conditioner cycling on the load profile; and
- customer experience with and likely market acceptance of, interrupting air conditioners on hot days.

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| **Market Segments Addressed** | ☑ Residential customers<br>☐ Commercial and small industrial customers<br>☐ Large industrial customers<br>☐ Additional generation |
| **No Participants** | 90 |

**Description of Project**

The trial was located in the Kings Langley/ Glenwood area of western Sydney. Two control technologies, pager and ripple control, were used. The trial comprised six load shedding events of approximately 30 minutes each.

Residential customers were contacted via a letter offering an incentive payment of $150 and the installation of an energy smart kit if they were selected to participate in the trial. Customers completed an initial questionnaire and their responses determined whether they were selected.

Ninety residential customers were selected to participate in the trial. The study used a proportion of the participants as a control sample, with no actual cycling of their air conditioners. At the conclusion of the trial, customers received the $150 incentive payment on receipt of their responses to a final questionnaire about their experiences during the trial.

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| **Results**<br>Both relay technologies operated correctly with the exception of two occurrences where the pager did not reactivate the air conditioner system automatically. When the relay switches were activated, there was an immediate drop in load of 200kVA, which was the amount expected from the sample group.<br>There were some problems in billing, which related to complications posed by the rebates and the need to estimate bills during an unusually hot summer.<br>Customers were found to prefer shorter, but more frequent, off cycles rather than prolonged interruptions.<br>The trial was found to have a high level of administration cost due to customer inquiries and information gathering. The required electronic metering also cost more than expected. | |
| **Project Cost** | \$13,500 incentive payments to customers plus<br>\$15,000 administration cost |
| **Relevance to Network Demand Management in NSW**<br>Cycling of residential air conditioners within a geographically limited area should be effective in reducing peak demands on distribution network elements. This may be able to defer the need for network augmentation in geographical locations where the network is constrained. | |
| **Contacts** | Frank Bucca<br>Demand Management & Utilisation Manager<br>System Development Department<br>Integral Energy<br>PO Box 6366<br>Blacktown NSW 2148<br>Tel: 02 9853 6566<br>Fax: 02 9853 6099<br>E-mail: bucca@integral.com.au |
| **Sources**<br>Charles River Associates (2003). *DM Programs for Integral Energy.* Melbourne, CRA.<br>Personal communication, Frank Bucca, Integral Energy, November 2003. | |

## LM09 Sydney CBD Demand Curtailment Project

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|---|---|
| **Location** | Sydney Central Business District, Australia |
| **Project Proponent** | EnergyAustralia |
| **Date Project Implemented** | Trial to be conducted between December 2003 and February 2004 |
| **Type of Project** | ☐ Standby generation<br>☐ Cogeneration<br>☐ Other distributed generation<br>☐ Interruptible loads<br>☑ Direct load control<br>☐ Other short-term demand response<br>☐ Energy efficiency<br>☐ Fuel substitution<br>☐ Power factor correction<br>☐ Policy and/or planning |
| **Technology** | Mainly air-conditioning / building management systems |

**Drivers for Project**

The CBD Demand Curtailment Project is a demand management demonstration project, with the objective to deliver the capability to dispatch peak load curtailment in the Sydney CBD through remote control of air conditioning plant and other major plant in a portfolio of CBD buildings.

The project will establish links between a central load control point and the various building management systems. These links will enable direct load control of the building management systems to reduce electricity demand in the CBD on an at-call basis for short periods (up to 5 hours). It is expected to be able to rotate demand reductions across a portfolio of several buildings during the call period, with each building contributing to delivering the total required demand reduction.

The key benefits of the project will be to test the validity of this portfolio approach as a means to provide the capability to reduce CBD demand effectively in response to central commands.

| | |
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| **Market Segments Addressed** | ☐ Residential customers<br>☑ Commercial and small industrial customers<br>☐ Large industrial customers<br>☐ Additional generation |

**No Participants**

**Description of Project**

Two EnergyAustralia buildings, Head Office (HOB) and Roden Cutler House (RCH), and two Government Sector buildings, Goodsell House and Town Hall House were selected for a proof of concept trial. Further rollout of the project is intended to include further Sydney CBD buildings.

HOB currently has a building management system. With an upgrade of software, expansion of the condition monitoring on each floor and the addition of the necessary interface modules, the existing BMCS will enable proof of concept testing to be performed. RCH does not currently have a BMCS, or any condition monitoring that would allow for the trial to be performed properly. These elements will be installed to allow RCH to be included in the project.

Following discussions with NSW Department of Commerce, the Goodsell Building was selected as the most suitable building in the Crown portfolio. The Goodsell Building required an upgrade to the BMS system software and a few additional control points. EnergyAustralia agreed to pay for the required upgrade works in exchange for Goodsell's inclusion in the trial.

Town Hall House was identified as needing similar works to the Goodsell building to enable it to participate in the trial and EnergyAustralia agreed to carry out the necessary upgrades in exchange for the City of Sydney agreeing to participate in the trial.

Each of the participant buildings will benefit from the ongoing energy savings achieved through the attention given to optimising the normal operating regimes of their building management systems.

Having established a portfolio of buildings for trial, the project will include the design of programming to call up the buildings across the portfolio to produce demand reductions. A suitable test plan is being developed and will run during summer 2003/2004 when demand on the network peaks. The test plan will evaluate the technical, cost and demand reduction impacts, and the acceptability of this approach to tenants and building owners.

Several portfolio curtailment test strategies are being developed to determine the best approach. These include:

- imposing equipment control programs to reduce demand to a set level and monitoring building conditions to determine impact on comfort;
- adjusting operating setpoints (temperature/humidity) and determining the resulting impact on demand;
- deep, short term demand reductions with little overlap time between buildings;
- longer, shallower demand reductions with greater overlap between buildings.

Curtailment modes have been designed for each building and will be pre-programmed into the BMCS of each building, to be called and cycled when needed by the central control system. Building owners retain right of veto and may disconnect from the trial at any time.

The test program will assess the individual and combined portfolio demand responses, the thermal response of the buildings under various scenarios, and the extent of "bounce back" following curtailment events.

**Results**

The trial is to be run over the summer period 2003/2004, and hence no results are available. However, preliminary modelling of the available curtailment at HOB suggests that 0.5 MVA of demand reduction may be achievable over a period of one hour at that building alone.

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|---|---|
| **Project Cost** | Not finalised |

**Relevance to Network Demand Management in NSW**

Centralised direct load control of air conditioning and other services in major office buildings through their building management systems should be effective in reducing peak demands on distribution and transmission networks. This may be able to defer the need for network augmentation in geographical locations where the network is constrained.

| | |
|---|---|
| **Contacts** | Pat Dunn<br>Project Manager<br>Demand Management<br>EnergyAustralia<br>L14, 570 George St, Sydney<br>Tel: (02) 9269 7369 Fax: (02) 9269 7372<br>E-mail: pdunn@energy.com.au<br>http://www.energy.com.au |

**Sources**

Personal communication, Pat Dunn, EnergyAustralia, November 2003.

| **PF01 Marayong Power Factor Correction Program, Sydney** | |
|---|---|
| **Location** | Marayong, Sydney, Australia |
| **Project Proponent** | Integral Energy |
| **Date Project Implemented** | 2000 |
| **Type of Project** | ☐ Standby generation<br>☐ Cogeneration<br>☐ Other distributed generation<br>☐ Interruptible loads<br>☐ Direct load control<br>☐ Other short-term demand response<br>☐ Energy efficiency<br>☐ Fuel substitution<br>☑ Power factor correction<br>☐ Policy and/or planning |
| **Technology** | Industrial technology |
| **Drivers for Project**<br>The Blacktown feeder, in western Sydney, was not able, on its own, to carry the Marayong zone substation on peak summer days. The supply-side solution would be to transfer this feeder to the Baulkham Hills transmission substation, which would allow all three Baulkham Hills feeders to service the Marayong busbar in the event of a first level contingency at either the Seven Hills or Kellyville zone substation.<br>The purpose of the Marayong Power Factor Correction Project was to reduce the load on the Marayong zone substation and thereby defer the capital expenditure on the Blacktown feeder. | |
| **Market Segments Addressed** | ☐ Residential customers<br>☐ Commercial and small industrial customers<br>☑ Large industrial customers<br>☐ Additional generation |
| **No Participants** | |
| **Description of Project**<br>Investigations were carried out by Integral to identify possible demand-side alternatives to the network augmentation. The investigations included public solicitation through the advertising of an Expression of Interest and consultations with major customers in the Blacktown industrial area. The investigations determined that power factor correction represented the only cost-effective DM opportunity in this area.<br>Integral then proceeded to install power factor correction equipment in the low voltage network outside customers' premises (not on the customer side of the meter). Integral paid for the equipment and the installation.<br>This program was implemented without the involvement of customers. In other localities, Integral is offering incentives to customers for the installation of power factor correction equipment on customer premises but is finding that the response is poor. | |
| **Results**<br>The power factor correction program achieved its goals and deferred a portion of the supply-side project (which would have constructed a third feeder) from 2000 until 2006. | |
| **Project Cost** | Not known |

| **Relevance to Network Demand Management in NSW** | |
|---|---|
| A similar promotion of power factor correction could be implemented in geographically delimited localities in NSW where the distribution network is constrained, particularly where there is a significant industrial load. However, preliminary studies would be required to determine whether payment of a customer incentive would be effective in achieving installation of power factor correction equipment on customer premises. | |
| **Contacts** | Frank Bucca<br>Demand Management & Utilisation Manager<br>System Development Department<br>Integral Energy<br>PO Box 6366<br>Blacktown NSW 2148<br>Tel: 02 9853 6566<br>Fax: 02 9853 6099<br>E-mail: bucca@integral.com.au |
| **Sources** | |
| Charles River Associates (2003). *DM Programs for Integral Energy.* Melbourne, CRA.<br>Personal communication, Frank Bucca, Integral Energy, November 2003. | |

# PF02 Brookvale/Dee Why Power Factor Correction Project, Sydney

| | |
|---|---|
| **Location** | Brookvale/Dee Why area, Sydney, Australia |
| **Project Proponent** | EnergyAustralia |
| **Date Project Implemented** | 2003 |
| **Type of Project** | ☐ Standby generation<br>☐ Cogeneration<br>☐ Other distributed generation<br>☐ Interruptible loads<br>☐ Direct load control<br>☐ Other short-term demand response<br>☐ Energy efficiency<br>☐ Fuel substitution<br>☑ Power factor correction<br>☐ Policy and/or planning |
| **Technology** | Various |

**Drivers for Project**

The Warringah sub-transmission network is forecast to exceed firm rating over the summer of 2004/05. System augmentation to prevent this would involve installing and commissioning two new sub-transmission underground feeders by summer 2004/05 at a cost to EnergyAustralia Network of $5 million. Demand management initiatives could potentially defer this need for capital investment. A reduction in demand of 3MVA could defer capital works for one year, which represents an NPV benefit to EnergyAustralia Network of $420,000.

The peak load in Warringah in summer occurs between 8:00 am and 9:30 pm and is largely attributed to commercial air conditioning, lighting systems, office equipment and some industrial processing. The daily load profile indicates that large commercial / industrial customers in the target areas dominate the electrical demand.

From a public consultation process in December 2002, and field visits by EnergyAustralia officers, a number of potential demand management options were identified, including power factor correction. For further details about the other demand management options see program summary IP01, page 44.

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| **Market Segments Addressed** | ☐ Residential customers<br>☑ Commercial and small industrial customers<br>☑ Large industrial customers<br>☐ Additional generation |
| **No Participants** | About 10 (potential) |

**Description of Project**

Based on actual electrical demand data for the year 2001/2002, the estimated potential demand reduction in the target area through low voltage power factor correction (LV PFC) installation is about 2.0MVA. An assessment of the practically achievable levels of LV PFC within the scoping study conducted as part of initial investigations suggested that the likely realised amount of peak demand reduction through PFC is 1.5MVA.

Experience in the sale of LV PFC suggested that some form of stimulus additional to the potential economic benefits will be required to ensure that the appropriate decision-makers are attentive to a proposal to install PFC at their premises. Hence, the Power Factor Correction Project will draw customers' attention to the requirement in the NSW Service and Installation Rules that customers maintain a minimum power factor of 0.9. The objective will be to combine a notification of a customer's need to comply with the Rules with an individual proposal for EnergyAustralia to assist in implementing LV PFC, based on a financial contribution by the customer to the cost of supplying and installing (or repairing) power factor correction equipment.

Analysis of existing power factor over the period June 2002 to May 2003 for all network customers within the target area with electricity consumption exceeding 750 MWh per annum, identified 17 customers with 24 supplies having a power factor less than 0.9 that could be corrected. These formed the target list of customers to be approached under the Power Factor Correction Initiative.

Customers were sent a letter outlining the constraints on the local network, and the current power factor of the supply or supplies to their premises, with reference to the fact that this power factor does not comply with the NSW Service and Installation Rules. The letter included an offer to assist the customer to maintain compliance with the Rules, reduce their transaction costs in time and effort and receive the economic benefit arising from power factor correction, by allowing EnergyAustralia to facilitate the installation or repair of PFC equipment.

Each customer who agrees to participate will be offered a proposal setting out their financial contribution to the undertaking, and the longer-term benefits. Costs are based on EnergyAustralia's ability to buy PFC equipment at tender in large quantities and reflect a substantial discount to the purchase costs customers would face buying one at a time. The offer will have a reasonable but specific time limit for acceptance to further motivate acceptance. The offer also includes a discount in recognition of the value to EnergyAustralia of the assignment of the right to create NSW Greenhouse Abatement Certificates in respect of the installations. This represents an integration of greenhouse and network deferral value.

Letters have been sent to the target customers and the majority of the nominated sites have been visited. Based on these inspections and the comments from customer contacts, a high level of implementation is expected. Recipients of the letter will be followed up, and negotiations held to ensure a maximum response. Emphasis will be placed on EnergyAustralia's intended role to facilitate the installation or repair process, and the attractiveness of the economics.

**Results**

Since the project has commenced only recently, as at November 2003 no results are available.

**Project Cost**

**Relevance to Network Demand Management in NSW**

A similar promotion of power factor correction could be implemented in geographically delimited localities in NSW where the distribution network is constrained.

**Contacts**

Pat Dunn
Project Manager
Demand Management
EnergyAustralia
L14, 570 George St, Sydney
Tel: (02) 9269 7369 Fax: (02) 9269 7372
E-mail: pdunn@energy.com.au
http://www.energy.com.au

**Sources**

Personal communication, Pat Dunn, EnergyAustralia, November 2003.

## PL01 Review of Demand Management Provisions of the Australian National Electricity Code

| | |
|---|---|
| **Location** | National Electricity Market, Australia |
| **Project Proponent** | Total Environment Centre funded by the Advocacy Panel for the National Electricity Market |
| **Date Project Implemented** | 2003 |
| **Type of Project** | ☐ Standby generation<br>☐ Cogeneration<br>☐ Other distributed generation<br>☐ Interruptible loads<br>☐ Direct load control<br>☐ Other short-term demand response<br>☐ Energy efficiency<br>☐ Fuel substitution<br>☐ Power factor correction<br>☑ Policy and/or planning |
| **Technology** | |

**Drivers for Project**

The ability of the Australian National Electricity Code to encourage substantial development of demand side management (DSM) within the National Electricity Market (NEM) is an issue that directly impacts on consumers and end users of electricity.

The benefits of DSM for consumers as an alternative to more generation and network expansion include lower energy bills, better energy services, the improved utilisation of resources and fewer environmental costs. The Total Environment Centre claims that the failure of the market to deliver these benefits indicates that the interests of consumers are in need of advocacy on DSM.

There are claims that DSM lacks equity and incentives under the National Electricity Code and within the National Electricity Market Management Company (NEMMCO). However, to date no study has systematically evaluated DSM performance in the NEM or in relation to the Code. It is claimed that studies remain piecemeal, geographically isolated, and lack compatible terms of reference and that there remains a distinct lack of understanding of, and advocacy for, DSM.

Therefore, the Total Environment Centre applied for and obtained a grant from the Advocacy Panel for the National Electricity Market to undertake a study on behalf of consumers and end-users of electricity in NSW, Victoria, Queensland and South Australia, to investigate the current status of, and efforts towards, DSM in the NEM.

The purpose of this project is to advocate for increased incentives for DSM in the interests of consumers of electricity in the NEM. In the process, it is claimed that the project will break open an area of the electricity market that has been marginalised in the rush to accommodate demand by traditional means. The project will assist emerging DSM advocates from a range of sectors (environment, social sector, industry, DSM providers etc) to enter the debate by making the issues more visible and understandable. The project will benefit consumers by bringing economically, socially and environmentally sustainable solutions to the table, and by invigorating the debate towards improved efficiency of the market.

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| **Market Segments Addressed** | ☑ Residential customers<br>☑ Commercial and small industrial customers<br>☑ Large industrial customers<br>☐ Additional generation |
| **No Participants** | |

**Description of Project**

The project will comprise the following key elements:

- analysis of the relationship between, and contribution of DSM to efficiency in, the NEM;
- general assessment of the degree to which demand-side solutions have been adopted within the NEM and the extent of demand-side potential currently available;
- two in-depth case studies across two States of substantial, cost-effective DSM opportunities which have been passed over in favour of capacity augmentation, and the costs of those lost opportunities to the consumer;
- review of the economic, social and environmental impact of current and projected under-utilisation of demand-side potential in the NEM on consumers and end users;
- proposal of solutions to improve equity between demand-side and supply-side options, and the potential impacts which the implementation of those solutions may have on electricity consumers.

Within the framework of these key elements, the project will assess whether consumers are paying for unnecessary capacity augmentation due to rules in the National Electricity Code and/or an electricity market that favours supply side responses. The project will ask whether electricity consumers should be given the choice of lower electricity bills and less environmental damage in place of network augmentation, and whether the Code and NEMMCO as currently constituted offer consumers this choice.

The project will undertake two substantial case studies.

One study will investigate the decision making process underlying the current transmission network augmentation being undertaken by TransGrid and EnergyAustralia in Sydney's CBD. The Total Environment Centre claims that TransGrid's augmentation, approved in late 2001, is an example of a major cost-effective, technically feasible and reliable DSM option being passed over in favour of a more expensive network augmentation choice. Despite the NERA report, commissioned by the proponents, finding that the alternatives of DSM and cogeneration were practical and just as reliable as cable augmentation, 'business as usual' decisions were the result.

A second study will be undertaken in Victoria. This study will focus on the claimed failure of tendering processes to be undertaken and to attract significant interest from the DSM provider sector, particularly in relation to VenCorp's recent call for tenders on DSM for the South Eastern substation upgrade.

The common point of reference for these case studies will be the National Electricity Code, its interpretation and whether it contains the appropriate measures to encourage investment in DSM.

**Results**

The project has not yet been completed so no results are currently available.

It is intended that the project will produce analysis and information which will be distributed widely to electricity consumers and their advocates. The report and further advice on DSM policy development by state and national agencies and what community groups can do to encourage improved DSM policy, will be placed on the Total Environment Centre's website, with regular updates.

| **Project Cost** | AUD 41,800 (grant from The Advocacy Panel) |
|---|---|

**Relevance to Network Demand Management in NSW**

Any proposals made by the project to change the ways in which the National Electricity Code deals with demand management, if implemented, may affect opportunities to undertake demand management projects to relieve network constraints in NSW.

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| **Contacts** | Robin Roy<br>Next Energy Pty Ltd<br>Level 12<br>220 George Street<br>Sydney NSW 2000<br>Tel: 02 9251 4072<br>Mobile: 0412 365 422<br>E-mail: rroy@nextenergy.com.au |
| **Sources**<br>Total Environment Centre (2003). *Demand Supply Management: Can the NEC Deliver?* Request for support from The Advocacy Panel. | |

## PL02 Integral Energy Demand Management Planning Process

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|---|---|
| **Location** | Integral Energy distribution area, NSW, Australia |
| **Project Proponent** | Integral Energy |
| **Date Project Implemented** | Current |
| **Type of Project** | ☐ Standby generation<br>☐ Cogeneration<br>☐ Other distributed generation<br>☐ Interruptible loads<br>☐ Direct load control<br>☐ Other short-term demand response<br>☐ Energy efficiency<br>☐ Fuel substitution<br>☐ Power factor correction<br>☑ Policy and/or planning |
| **Technology** | |

**Drivers for Project**

In 1995, electricity distributors in NSW became subject to a license requirement under the *Electricity Supply Act* that obliged them to investigate demand management (DM) as an alternative to network augmentation. This raised the need for a method for conducting those investigations to enable performance against the obligation to be documented, and to ensure that the results of the investigations are robust and prudent.

In 1998, an Working Group comprising representatives from the NSW electricity industry and others was formed to develop the *NSW Code of Practice on Demand Management for Electricity Distributors* in conjunction with the (then) NSW Department of Energy. The purpose of the *Code* was to provide processes and procedures for assessing the applicability and feasibility of DM for network augmentation deferral, and for enlisting the involvement of the private sector and wider community in the development of initiatives to capitalise on the identified demand-side potential. The first edition of the *Demand Management Code* was recognised by the Department of Energy in 1999. The *Code* was subsequently revised and a second edition was recognised by the Ministry of Energy and Utilities in 2001. The *Code* is currently undergoing a further revision during 2003/04.

Integral Energy has developed its own internal DM planning process in conformity with the provisions of the *Demand Management Code*.

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| **Market Segments Addressed** | ☑ Residential customers<br>☑ Commercial and small industrial customers<br>☑ Large industrial customers<br>☐ Additional generation |
| **No Participants** | |

**Description of Project**

Integral's annual network system planning process comprises the following steps.

- On-going load investigations reveal current and forecast system constraints.
- In September or October, the *Transmission Network Planning Review* is released. This provides a snapshot of Integral's electricity network, including a tabular summary of the major projects required within the forecast period and their relative costs. The document also details the status of each transmission substation and zone substation within the Integral area including:
  - load forecasts;
  - investigations of system weaknesses; and
  - possible network solutions.

- In May, the *Strategic Asset Management Plan* is released. This internal document, which as part of the annual budget cycle, details each required project in the forecast period, and its associated expenditure, size, and timetable.
- In June, DM opportunities are investigated using the Reasonableness Test.
- In July, a new *Network Demand Management Plan* is released describing the DM investigations to be undertaken using the public process detailed in the *Demand Management Code*, and those that will be undertaken by Integral staff, as well as the timetable for each investigation.

The last two steps represent a robust process that Integral has established for:

- investigating and assessing demand-side alternatives to system augmentation by issuing Requests for Proposals (RFPs) for individual DM initiatives;
- publishing the results of these studies;
- selecting for implementation those DM initiatives that have been shown to be cost effective; and
- supporting the implementation of the selected demand-side initiatives.

The two main processes within Integral's DM planning process, are the use of the Reasonableness Test to identify promising DM opportunities, and the RFP process, which is used to solicit the involvement of third parties in the active pursuit and implementation of DM initiatives.

*Reasonableness Test*

Where the supply-side planning process has identified that there is likely to be constraint in an element of the distribution system (ie a transmission or zone substation, feeder or transformer) within the next five years, Integral applies the Reasonableness Test to determine whether it is appropriate to invite submissions from the public for non-network options that may be able to alleviate the constraint at lower cost than the supply-side solution, and thereby reduce overall system costs.

Integral developed the Reasonableness Test as part of its internal procedures for implementing the *Demand Management Code of Practice*. The test requires that the following conditions be met for DM to warrant further consideration:

- the expected overloading is sufficient to require investment in system support to meet Integral's relevant reliability requirements;
- the constraint is caused by load growth rather than aging equipment, greenfield development or large spot loads; and
- the estimated annualised cost of the required supply-side system support exceeds $200,000 for at least one year.

The figure of $200,000 comes from the *Demand Management Code* and is based on deferring an investment of approximately $2 million. It is considered that any project less than this size will not provide sufficient resources for program implementation, including the payments for DM that are generally required to motivate end-use customers to undertake demand-side actions.

*RFP Process*

Once it has been determined that a public DM investigation is reasonable according to the above criteria, an RFP is generally issued. The process can have two stages depending on the types, numbers and details of the proposals submitted.

The first stage is the publication of an RFP (also referred to as an expression of interest). This document fully explains the constraint; the timing, nature and cost of the likely supply-side network solution(s); any potential DM solutions, any available statistics on the nature of the customer base within the affected area; the nature and rate of the load growth that is causing the need for system augmentation (including any other aspects of the supply side situation that are relevant); and the magnitude and timing of load reduction that the demand-side initiatives will need to provide in order to achieve the desired network asset deferral.

The second stage is the issue of a tender and is only used if (a) there are many similar proposals or (b) the relative costs and benefits of each proposal are difficult to discern. The tender can be selectively issued to those who submitted cost effective proposals, or can take the form of direct negotiation with customers for load reduction. The responses to this tendering stage must be firm and must include details of how the load reduction is to be provided, the amount of reduction to be provided, and the cost to Integral for providing the reduction.

*Changes in the Demand Management Planning Process*

Integral has implemented changes in its DM planning process based on responses to a survey of organisations that expressed interest in one or more of the DM opportunities, but subsequently did not submit a proposal.

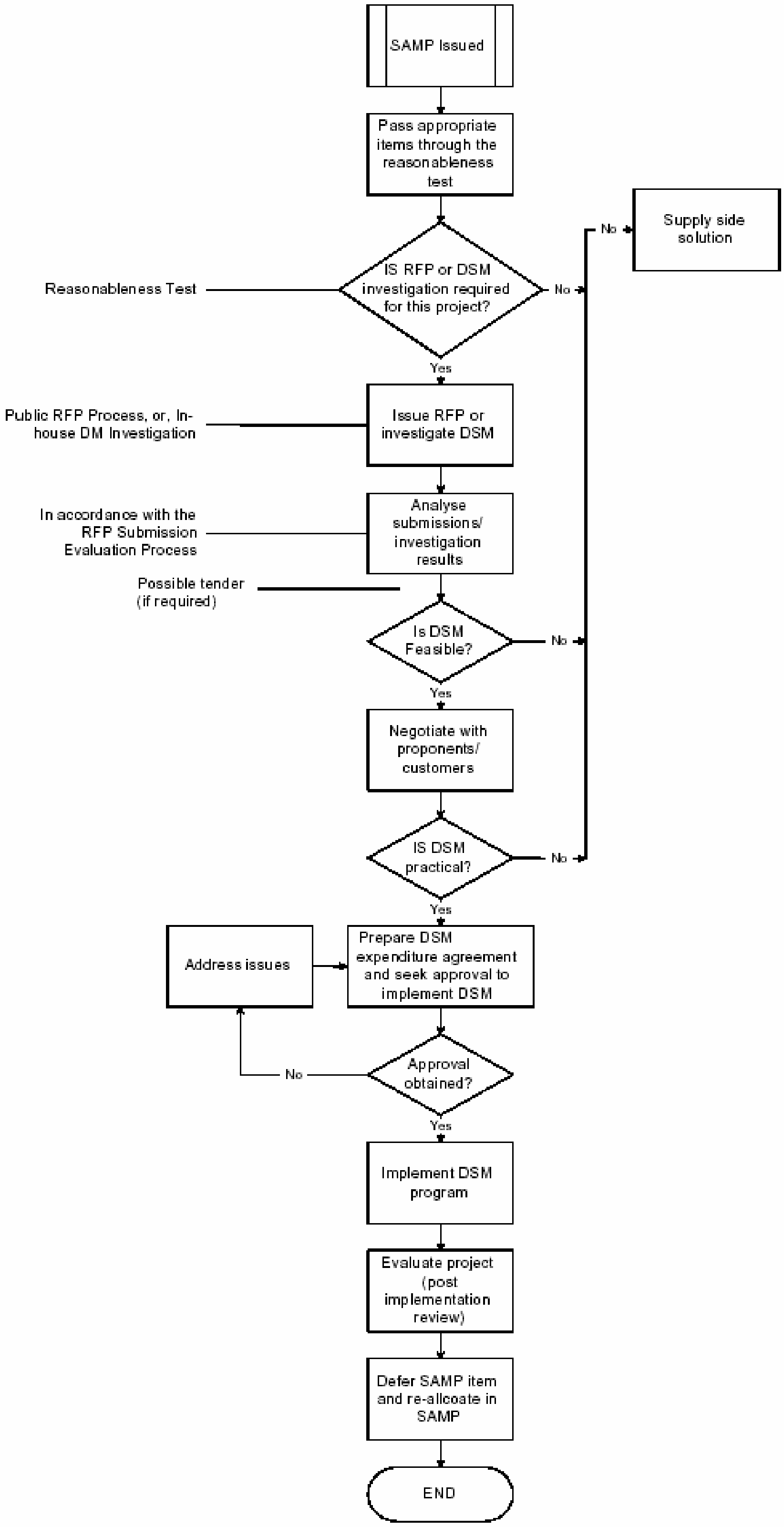
Up until 2002 the analysis of opportunities for DM occurred at the stage in the process where network investment options were assessed. Experience in prior years had indicated that starting the search for DM alternatives at that point was often too late: it did not leave enough time for the prospecting and marketing that is generally required to implement demand management. To correct this problem, in 2002 the analysis of DM opportunities was advanced to commence immediately after the release of the annual *Strategic Asset Management Plan*. Conducting the analysis at this earlier stage allows every possible opportunity to devise and implement effective DM programs.

Initially, Integral required demand management proposals to include detailed descriptions of the DM measures to be undertaken, the schedule on which they would be implemented, their cost, and an assurance that a specified level of load reduction would be achieved. Feedback to Integral showed that potential DM proposers felt unable to provide the level of detail required and felt that the risk of resourcing the required level of investigation was too great. In response, Integral reduced the level of detail required in the RFP process, and will now entertain any level of input provided by customers or third parties regarding DM opportunities. Upon receipt, Integral evaluates the ideas, and for those with merit, undertakes a cooperative process with the proposers to determine whether each proposal has sufficient merit to be carried out by one or the other of the parties.

Customers and potential DM providers have also expressed concern that the preparation of DM proposals requires substantial time and expense, which is invested at significant risk, because the proposal may not be taken up by Integral. The DM services provider is unsure whether a market for the 'product' actually exists until a detailed investigation is undertaken. Once the opportunity is identified, the DM service provider still needs to convince targeted customers to adopt the initiative(s) being proposed. These risks exist on top of the proposal risk, and in combination, are felt by many DM service providers to present too much risk to make responding to a DM RFP attractive. For its part, Integral has noticed that the number of proposals it receives in response to its DM RFPs has been decreasing. To counter this trend, Integral is considering discussing with the Independent Pricing and Regulatory Tribunal (IPART) the merits of allowing Integral to provide a standard payment as partial compensation to DM proposers. IPART would have to accept these preparation costs as part of the DM planning process and therefore authorise their payment by Integral and their recovery as a legitimate DM planning and public consultation expense.

Figure 1 provides an overview of Integral's DM planning process and its integration with the supply-side process.

**Figure 1: Integral's DM Assessment Process**



| | |
|---|---|
| **Results**<br>In April 2002 Integral published its first *Network Demand Management Plan*, and in October 2002 produced the second, which identified those projects contained within the company's 2002 to 2012 *Strategic Asset Management Plan* (SAMP) that could potentially be deferred by demand-side initiatives. Of the 28 network augmentation projects listed in the SAMP, Integral identified 12 as deserving further investigation for demand-side potential, either through the public consultation process, or by Integral staff.<br>The third *Network Demand Management Plan* – based on the system requirements documented in the 2003 to 2013 SAMP – was released in July 2003. Of the 36 projects listed in this document as requiring constraint alleviation, half were considered appropriate for further investigation via the public consultation process. | |
| **Project Cost** | |
| **Relevance to Network Demand Management in NSW**<br>The Integral demand management planning process is one way in which the demand management obligations imposed on electricity distributors in NSW by the *Electricity Supply Act* have been met. The process provides a practical mechanism whereby DM alternatives to network augmentation can be taken into account in the network planning process. | |
| **Contacts** | Frank Bucca<br>Demand Management & Utilisation Manager<br>System Development Department<br>Integral Energy<br>PO Box 6366<br>Blacktown NSW 2148<br>Tel: 02 9853 6566<br>Fax: 02 9853 6099<br>E-mail: bucca@integral.com.au |
| **Sources**<br>Charles River Associates (2003). *DM Programs for Integral Energy.* Melbourne, CRA. | |

## PL03 EnergyAustralia Demand Management Planning Process

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|---|---|
| **Location** | EnergyAustralia distribution area, NSW, Australia |
| **Project Proponent** | EnergyAustralia |
| **Date Project Implemented** | Current |
| **Type of Project** | ☐ Standby generation<br>☐ Cogeneration<br>☐ Other distributed generation<br>☐ Interruptible loads<br>☐ Direct load control<br>☐ Other short-term demand response<br>☐ Energy efficiency<br>☐ Fuel substitution<br>☐ Power factor correction<br>☑ Policy and/or planning |
| **Technology** | |

**Drivers for Project**

EnergyAustralia's very large projected network capital expenditure program is being driven by the growth and increasing peakiness of its network load, its ageing asset base and the increasing complexity associated with project planning approval processes. This has lead to a greater need to ensure all investments are capital efficient.

Under the NSW *Electricity Supply Act*, electricity distributors have licence conditions that oblige them to carry out demand management (DM) investigations before expanding their distribution systems where it would be reasonable to expect that it would be cost effective to avoid or postpone the expansion by implementing DM strategies. Some similar requirements are also embodied in the Australian *National Electricity Code*.

In the last few years these regulatory requirements in relation to network DM have become better defined. IPART and ACCC view network DM as a competitor to supply side investments and hence a check on the prudency of network capex, through both the transparency that DM option evaluation brings to the capital governance processes and the adoption of cost effective DM options.

EnergyAustralia views an effective network demand management approach as a key tool in optimisation of its capital investment portfolio through reduction in demand growth, while ensuring regulatory compliance through demonstrable prudence of investments;

EnergyAustralia has progressively developed and implemented internal DM processes to improve the effectiveness and efficiency of their DM investigations.

| | |
|---|---|
| **Market Segments Addressed** | ☑ Residential customers<br>☑ Commercial and small industrial customers<br>☑ Large industrial customers<br>☐ Additional generation |
| **No Participants** | |

**Description of Project**

Emerging constraints on the supply system are identified through the planning process, and published in the *Annual Electricity System Development Review* (ASDR). Each material constraint is then assessed to determine whether it is reasonable to expect that DM might be cost effective in relieving the constraint. Any constraint where the supply solution cost is likely to exceed $1m is considered material.

This screening test is the first step in the demand management investigation process. This consists of an analysis of the drivers behind the emerging constraint, determination of the extent to which demand is driving investment, and the DM requirement to relieve the constraint. The DM requirement is described as the approximate size, cost per kVA and nature (time of day, seasonality etc) of the DM options that would be required to defer the proposed investment for at least one year. The screening test report provides the basis for a decision whether or not to proceed with a further investigation.

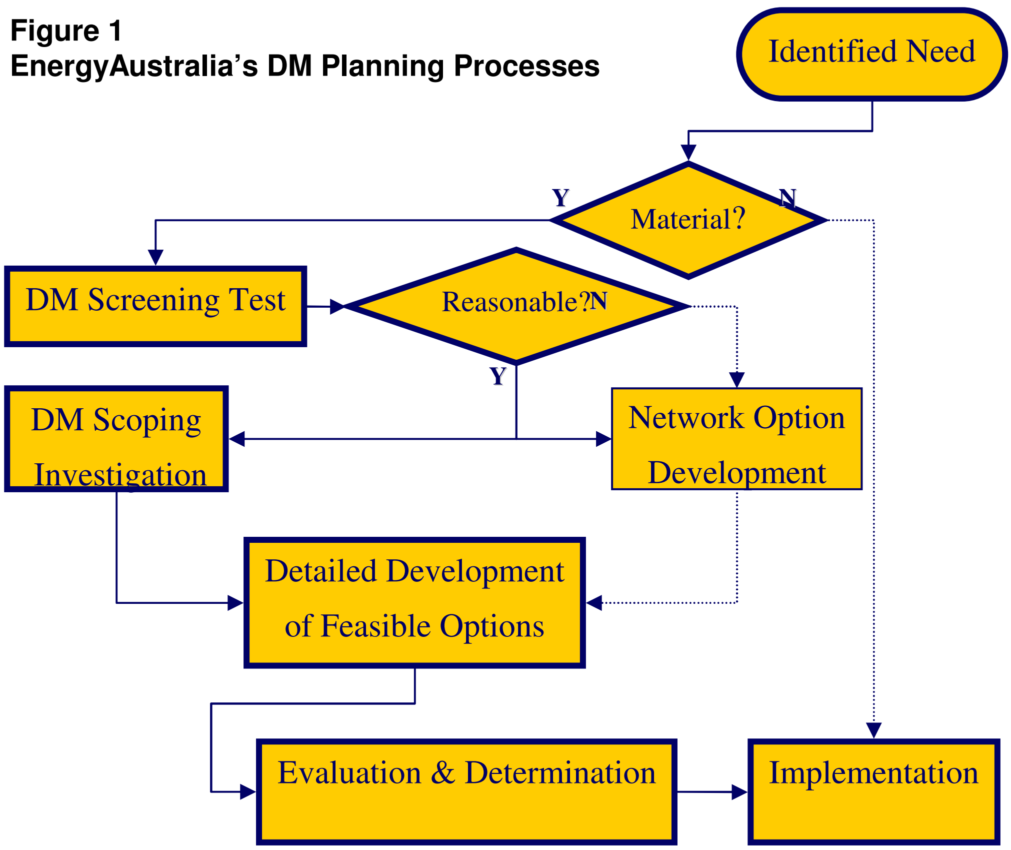
The first investigation phase is a "DM Scoping Investigation". Based on the DM requirements identified in the screening test, this investigation identifies the range of possible DM options that might exist in the study area, and determines the approximate amount available and likely cost (to EnergyAustralia) of each of the identified options. Options are identified through a public consultation and from existing knowledge, field visits and discussions with specific customers. The public consultation at this stage is focussed on identifying potential options and uncovering information that is already known (by another party or parties) but otherwise unavailable to EnergyAustralia. The information is analysed using a standard approach similar to the screening test that compares the net present value of costs for the DM alternative to the net present value of the deferral of the network expansion option. The DM Scoping Investigation provides a more rigorous basis for further refinement of specific options or a recommendation not to proceed further with DM options.

The final stage of the investigation process is the Detailed DM Investigation. This is more narrowly focussed on the specific opportunities identified in the DM Scoping Investigation, and is intended to provide quality information on the practicality, size and likely cost of DM options that can be used to prepare business cases and a DM implementation strategy. A formal RFP may be part of this process where appropriate.

The implementation strategy may include a range of implementation options, including RFP's, standard offers, marketing programs and direct customer negotiations depending on the DM options being sought. At this stage EnergyAustralia aims to be in a position to go to the market with a firm budget and commitment to proceed and a clear specification of what is required.

Figure 1 provides an overview of EnergyAustralia's DM processes.

**Figure 1**
**EnergyAustralia's DM Planning Processes**



| | |
|---|---|
| **Results** | |
| **Project Cost** | |
| **Relevance to Network Demand Management in NSW**<br>The EnergyAustralia demand management planning process is one way in which the demand management obligations imposed on electricity distributors in NSW by the *Electricity Supply Act* have been met. The process provides a practical mechanism whereby DM alternatives to network augmentation can be taken into account in the network planning process. | |
| **Contacts** | Neil Gordon<br>Manager Sustainable Energy<br>EnergyAustralia Network<br>GPO Box 4009<br>Sydney NSW 2001<br>Tel: 02 9269 7371<br>Fax: 02 9269 7372<br>E-mail: ngordon@energy.com.au |
| **Sources**<br>Gordon, N. (2003). *Demand Management at Energy Australia.* Sydney, EnergyAustralia.<br>Gordon, N. (2003). *Demand Management*. PowerPoint presentation. Sydney, EnergyAustralia Network. | |