# Worldwide Survey of Network-driven Demand-side Management Projects

**Research Report No 1**
**Task XV of the International Energy Agency Demand Side Management Programme**

**Second Edition**
**Revised**
**10 October 2008**

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*New Zealand (Energy Efficiency and Conservation Authority, Electricity Networks Association, Electricity Commission and Transpower)*
*South Africa (ESKOM)*
*Spain (Red Electrica de España)*
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## DISCLAIMER



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# THE IEA DEMAND SIDE MANAGEMENT PROGRAMME

The International Energy Agency (IEA) was established in 1974 as an autonomous agency within the framework of the Economic Cooperation and Development (OECD) to carry out a comprehensive program of energy cooperation among its 25 Member countries and the Commission of the European Communities.

An important part of the Agency's program involves collaboration in the research, development and demonstration of new energy technologies to reduce excessive reliance on imported oil, increase long-term energy security and reduce greenhouse gas emissions. The IEA's R&D activities are headed by the Committee on Energy Research and Technology (CERT) and supported by a small Secretariat staff, headquartered in Paris. In addition, three Working Parties are charged with monitoring the various collaborative energy agreements, identifying new areas for cooperation and advising the CERT on policy matters.

Collaborative programs in the various energy technology areas are conducted under Implementing Agreements, which are signed by contracting parties (government agencies or entities designated by them). There are currently over 40 Implementing Agreements, including the IEA Demand-Side Management. Since 1993, the following 20 member countries and the European Commission have been working to clarify and promote opportunities for DSM.

| | | |
|---|---|---|
| Australia | France | New Zealand |
| Austria | Greece | Norway |
| Belgium | Italy | South Africa |
| Canada | India | Spain |
| Denmark | Japan | Sweden |
| European Commission | Korea | United Kingdom |
| Finland | Netherlands | United States |

A total of 20 Tasks (multi-national collaborative research projects) have been initiated by the IEA DSM Programme, 13 of which have been completed. Each Task is managed by an Operating Agent (Project Director) from one of the participating countries. The Operating Agent is responsible for overall project management including project deliverables, milestones, schedule, budget and communications. Overall control of the program rests with an Executive Committee comprised of one representative from each contracting party to the Implementing Agreement. In addition, a number of special ad hoc activities–conferences and workshops–have been organized.

The actual research work for a Task is carried out by a combination of the Operating Agent and a group of Country Experts, depending on the nature of the work to be carried out. Each country which is participating in a Task nominates one or more persons as its Country Expert. Each Expert is responsible for carrying out any research work within his/her country which is required for the Task All the Experts meet regularly to review and assess the progress of the work completed by the Operating Agent and by the group of Experts. Experts meetings are usually held between two and four times a year.

The IEA DSM Programme has undertaken the following Tasks to date:

| | |
|---|---|
| Task I | International Database on Demand-Side Management |
| Task II* | Communications Technologies for Demand-Side Management |
| Task III* | Cooperative Procurement of Innovative Technologies for Demand-Side Management |
| Task IV* | Development of Improved Methods for Integrating Demand-Side Management |
| Task V* | Investigation of Techniques for Implementation of Demand-Side Management Technology in the Marketplace |
| Task VI* | Mechanisms for Promoting DSM and Energy Efficiency in Changing Electricity Businesses |
| Task VII* | International Collaboration on Market Transformation |
| Task VIII* | Demand Side Bidding in a Competitive Electricity Market |
| Task IX* | The Role of Municipalities in a Liberalized System |
| Task X* | Performance Contracting |
| Task XI* | Time of Use Pricing and Energy Use for Demand Management Delivery |
| Task XII | Cooperation on Energy Standards (not proceeded with) |
| Task XIII* | Demand Response Resources |
| Task XIV* | Market Mechanisms for White Certificates Trading |
| Task XV | Network-Driven Demand Side Management |
| Task XVI | Competitive Energy Services |
| Task XVII | Integration of Demand Side Management, Energy Efficiency, Distributed Generation and Renewable Energy Sources |
| Task XVIII | Demand Side Management and Climate Change |
| Task XIX | Micro Demand Response and Energy Saving |
| Task XX | Branding of Energy Efficiency |

* Completed Task

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# FOREWORD

This report is a result of work which was completed within Task XV of the International Energy Agency Demand-Side Management Programme. The title of Task XV is "Network-Driven Demand Side Management." Task XV is a multinational collaborative research project which is investigating demand-side management (DSM) measures which may provide viable alternatives to augmentation of electricity networks and also provide network operational services.

Task XV is organised into five subtasks as follows:

- **Subtask 1:** Worldwide Survey of Network-Driven DSM Projects.
- **Subtask 2:** Assessment and Development of Network-Driven DSM Measures.
- **Subtask 3:** Incorporation of DSM Measures into Network Planning.
- **Subtask 4:** Evaluation and Acquisition of Network-Driven DSM Resources.
- **Subtask 5:** Communication of Information About Network-Driven DSM.

This report summarises the results from Subtask 1.

The Operating Agent (Project Director)for Task XV is Energy Futures Australia Pty Ltd, based in Sydney, Australia.

The work of Task XV is supported (through cost and task sharing) by the seven participating countries: Australia, France, India, New Zealand, South Africa, Spain and the United States. Participants provided one or more Country Experts who were responsible for contributing to the work of the Task and for reviewing work as it was completed. Some countries also nominated representatives who also contributed to the work of Task XV.

Information for this report was collected, and the document was reviewed by, Country Experts and representatives from the organisations listed in the Table on page vii.

The Principal Investigator for, and main author of, this report is Dr David Crossley of Energy Futures Australia Pty Ltd. Any errors and omissions are the sole responsibility of the Principal Investigator.

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|---|---|---|
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| *John Kueck | Oak Ridge National Laboratory | USA |
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# EXECUTIVE SUMMARY

'Network-driven' demand-side management (DSM) 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 DSM 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 this type of DSM. The two prime objectives for network-driven DSM are:

- to relieve constraints on distribution and/or transmission networks at lower costs than building 'poles and wires' solutions; and/or
- to provide services for electricity network system operators, achieving peak load reductions with various response times for network operational support.

Therefore, this report focuses on the role of network-driven DSM in achieving these two objectives and it does not examine other possible outcomes from implementing network-driven DSM projects.

The majority of the report reviews and summarises the results of a sample survey of 64 network-driven DSM projects undertaken worldwide over about the last 15 years. The survey focuses on projects carried out in the seven countries participating in Task XV, but it also includes some projects from other countries.

The network-driven DSM projects included in the survey are classified by the major DSM measure implemented, as follows:

- direct load control;
- distributed generation, including standby generation and cogeneration;
- demand response;
- energy efficiency;
- fuel substitution;
- interruptible loads;
- integrated DSM projects;
- load shifting;
- power factor correction;
- pricing initiatives, including time of use and demand-based tariffs; and
- smart metering.

The survey showed that network-driven DSM options can effectively:

- achieve load reductions on electricity networks that can be targeted to relieve specific network constraints; and
- provide a range of network operational services.

The survey also showed that all types of demand DSM measures can be used to relieve network constraints and/or provide network operational services. However, whether a particular DSM measures 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.

# PART 1:
# REPORT

# 1. INTRODUCTION

## 1.1 Types of DSM

In the electricity industry, the term 'demand-side management' (DSM) 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, direct load control and demand response;
- fuel switching, such as changing from electricity to gas for water heating;
- distributed generation, such as stand by generators in office buildings or photovoltaic modules on rooftops; and
- pricing initiatives, including time of use and demand-based tariffs.

A recent report has identified a particular type of DSM, termed 'network-driven' DSM which the report defined as measures that:

> *…focus on solving network capacity constraints in ways that are more cost-effective (and often have lower environmental impacts) than network augmentation.*[1]

In addition to relieving network constraints, DSM can also provide services for electricity network system operators, achieving peak load reductions with various response times for network operational support. Therefore, Task XV of the IEA DSM Programme has expanded the definition of network-driven DSM to include activities which provide network operational services.

Following is the definition used in Task XV:

> *Network-driven demand-side management 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.*

Under this expanded definition, network-driven DSM measures comprise:

- direct load control;
- distributed generation, including standby generation and cogeneration;
- demand response;
- energy efficiency;
- fuel substitution;
- interruptible loads;
- integrated DSM projects;

[1] Independent Pricing and Regulatory Tribunal of New South Wales (2002). *Inquiry into the Role of Demand Management and Other Options in the Provision of Energy Services. Final Report.* Sydney, The Tribunal, p 3.

- load shifting;
- power factor correction;
- pricing initiatives, including time of use and demand-based tariffs; and
- smart metering.

## 1.2 Focus of this Report

This is the first report from Task XV and it is intended to achieve the objective of Subtask 1 which is "to identify a wide range of DSM measures which can be used to relieve electricity network constraints and/or provide network operational services."[2]

The purpose of the report is to list and summarise network-driven DSM projects implemented around the world and to identify the DSM measures which have been employed in the projects. Therefore, this report is not intended to draw any conclusions about the factors determining the relative effectiveness of the identified network-driven DSM projects. This aspect is covered in Subtask 2 of Task XV.

While network-driven DSM 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 this type of DSM. The two prime objectives for network-driven DSM are:

- to relieve constraints on distribution and/or transmission networks at lower costs than building 'poles and wires' solutions; and/or
- to provide services for electricity network system operators, achieving peak load reductions with various response times for network operational support.

Therefore, this report focuses on the role of network-driven DSM in achieving these two objectives and it does not examine other possible outcomes from implementing network-driven DSM projects.

# 2. SURVEY OF NETWORK-DRIVEN DSM PROJECTS

## 2.1 Composition of the Survey

This report reviews and summarises the results of a sample survey of 64 network-driven DSM projects undertaken worldwide over about the last 15 years. The survey focuses on projects carried out in the seven countries participating in Task XV, but it also includes some projects from other countries. Detailed case studies of these 64 projects are included in Part 2 of this report (page 27). The case studies are also accessible on-line on the Task XV website at: [http://www.ieadsm.org/CaseStudies.aspx](http://www.ieadsm.org/CaseStudies.aspx).

Several of the projects included in the survey were not implemented specifically to deal with network problems. Some projects implemented for other purposes demonstrate relevant DSM measures which could be used effectively for network support. Examples of these types of DSM projects were therefore included in the survey.

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[2] Energy Futures Australia (2004). *Prospectus: Research Project on Network-driven DSM*. Hornsby Heights, NSW Australia, EFA, p 4.

There have been a large number of DSM projects undertaken worldwide over the last 15 years which could be applicable to electricity networks. Therefore, it was necessary to select a sample of projects which demonstrate the use of relevant DSM measures particularly well. The selection of projects for inclusion in the survey took into account the characteristics of the two main objectives for network-driven DSM projects:

- to relieve network constraints; and
- to provide network operational services.

### 2.1.1 Characteristics of Network Constraints

To be effective in relieving network constraints, DSM measures 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.

### 2.1.2 Characteristics of Network Operational Services

DSM measures have the potential to contribute to a range of network operational services, including:

- voltage regulation;
- load following;
- active/reactive power balancing;
- frequency response;
- supplemental reserve; and
- spinning reserve.

In addition, power factor correction may be regarded as a DSM measure.

With the exception of power factor correction, network operational services provided by DSM are required for relatively short periods of up to a couple of hours. They may also have a strong spatial component, with some services (such a voltage regulation) often being required in a specific location. Other network services (such as frequency control) are usually required generally across the network. The required response times also vary from minutes to almost instantaneous.

## 2.2 Classification of Network-driven DSM Projects

A broad range of network-driven DSM projects are included in the survey. The 64 projects are listed in Table 1 and detailed case studies of each project are included in Part 2 of this report (page 104).

The projects included in the survey are classified by the major DSM measure implemented, as follows:

- direct load control;
- distributed generation, including standby generation and cogeneration;
- demand response;
- energy efficiency;
- fuel substitution;
- interruptible loads;
- integrated DSM projects;
- load shifting;
- power factor correction;
- pricing initiatives, including time of use and demand-based tariffs; and
- smart metering;

| Table 1. Network-driven DSM Projects Included in the Survey | |
|---|---|
| **Direct Load Control** | |
| DC01 | Ethos Project Trial of Multimedia Energy Management Systems - Wales, UK |
| DC02 | Sydney CBD Demand Curtailment Project - Australia |
| DC03 | LIPAedge Direct Load Control Program - USA |
| DC04 | Sacramento Peak Corps - USA |
| DC05 | PEF Direct Load Control and Standby Generator Programs - USA |
| DC06 | ETSA Utilities Air Conditioner Direct Load Control Program - Australia |
| DC07 | California Automated Demand Response System Pilot - USA |
| DC08 | Orion Network DSM Program - New Zealand |
| DC09 | Separation of Agricultural Feeders for Load Control - India |
| **Distributed Generation** | |
| DG01 | Nelson Bay Embedded Generation - Australia |
| DG02 | Bromelton Embedded Generation - Australia |
| DG03 | Kerman Photovoltaic Grid-Support Project - USA |
| DG04 | Chicago Energy Reliability and Capacity Account - USA |
| DG05 | Mitigation of Load Shedding in Pune Urban Circle - India |

| Table 1. Network-driven DSM Projects Included in the Survey (continued) | |
|---|---|
| **Demand Response** | |
| DR01 | ISO New England Demand Response Programs - USA |
| DR02 | New York ISO Demand Response Programs - USA |
| DR03 | PJM Load Response Programs - USA |
| DR04 | South Island Demand Side Participation Trial - New Zealand |
| **Energy Efficiency** | |
| EE01 | Efficient Lighting Project DSM Pilot - Poland |
| EE02 | Oncor Standard Offer Program for Residential and Commercial Energy Efficiency - USA |
| EE03 | Oncor Air Conditioning Distributor Market Transformation Program - USA |
| EE04 | Espanola Power Savers Project - Canada |
| EE05 | Katoomba DSM Program - Australia |
| EE06 | Drummoyne Demand Management Project - Australia |
| EE07 | Nashik CFL Pilot Project - India |
| EE08 | Mumbai Efficient Lighting Program - India |
| EE09 | Mumbai Consumer Awareness Campaign - India |
| EE10 | Bangalore Efficient Lighting Program - India |
| **Fuel Substitution** | |
| FS01 | Tahmoor Fuel Substitution Project - Australia |
| FS02 | Binda-Bigga Demand Management Project - Australia |
| FS03 | Paradip Port Substitution of Cooking Fuel Project - India |
| **Interruptible Loads** | |
| IL01 | Load Interruption Contract - Spain |
| IL02 | Flexible Load Interruption Contract - Spain |
| IL03 | Interruptibility Contract for Cogenerators - Spain |
| IL04 | Active / Reactive Power Exchange - Spain |
| IL05 | California Energy Cooperatives - USA |

| Table 1. Network-driven DSM Projects Included in the Survey (continued) | |
|---|---|
| **Integrated DSM Projects** | |
| IP01 | Blacktown DSM Program - Australia |
| IP02 | Castle Hill Demand Management Project - Australia |
| IP03 | Parramatta DSM Program - Australia |
| IP04 | Olympic Peninsula Non-wires Solutions Pilot Projects and GridWise Demonstration - USA |
| IP05 | Brookvale / DeeWhy DSM Program - Australia |
| IP06 | Maine-et-Loire DSM Project - France |
| IP07 | Deferring Network Investment - Finland |
| IP08 | French Riviera DSM Program - France |
| IP09 | Manweb Demand Side Management Project - Wales, United Kingdom |
| IP10 | Coalition of Large Distributors Conservation and Demand Management Programs - Canada |
| IP11 | Pilot Project to Improve Agricultural Pump Set Efficiency - India |
| IP12 | Agricultural Pump Set Efficiency Improvement Program - India |
| **Load Shifting** | |
| LS01 | Winter Peak Demand Reduction Scheme - Ireland |
| LS02 | Eskom DSM Profitable Partnership Programme - South Africa |
| LS03 | TU Electric Thermal Cool Storage Program - USA |
| LS04 | Mad River Valley Project - USA |
| LS05 | Baulkham Hills Substation Deferral Project - Australia |
| **Power Factor Correction** | |
| PC01 | Marayong Power Factor Correction Program - Australia |
| **Pricing Initiatives** | |
| PI01 | California Critical Peak Pricing Tariff for Large Customers - USA |
| PI02 | Loire Time of Use Tariff Program - France |
| PI03 | Queanbeyan Critical Peak Pricing Trial - Australia |
| PI04 | Hourly Demand Tariff - Spain |
| PI05 | End User Flexibility by Efficient Use of Information and Communication Technologies - Norway |
| PI06 | Tempo Electricity Tariff - France |
| PI07 | Reduced Access to Network Tariff - Spain |
| PI08 | EnergyAustralia Pricing Strategy Study - Australia |
| PI09 | California Statewide Pricing Pilot for Small Customers - USA |
| **Smart Metering** | |
| SM01 | Carbon Trust Advanced Metering Trial - United Kingdom |

## 2.3 Direct Load Control

In direct load control programs, direct communication links are connected between the network operator and customers' premises to enable the network operator to remotely shut down or cycle selected electrical equipment (eg air conditioners, water heaters) at short notice.

### 2.5.1 Network Application

Network operators can use direct load control to directly manage loads on the network, thereby providing a flexible demand-side resource. Because the network operator is in direct communication with the loads, direct load control can deliver load reductions highly targeted to specific times of the day and/or to particular geographical locations.

### 2.5.2 Survey Examples

Part 2 of this report contains detailed case studies of nine direct load control projects (see page 46). These are identified and summarised below.

DC01 Ethos Project Trial of Multimedia Energy Management Systems - Wales, United Kingdom
DC02 Sydney CBD Demand Curtailment Project - Australia
DC03 LIPAedge Direct Load Control Program - USA
DC04 Sacramento Peak Corps - USA
DC05 PEF Direct Load Control and Standby Generator Programs – USA
DC06 ETSA Utilities Air Conditioner Direct Load Control Program – Australia
DC07 California Automated Demand Response System Pilot – USA
DC08 Orion Network DSM Program - New Zealand
DC09 Separation of Agricultural Feeders for Load Control – India

The Ethos Project Trial of Multimedia Energy Management Systems in Wales 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.

In the Sydney CBD Demand Curtailment Project in Australia, the local electricity distributor tested 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 established links between a central load control point and the various building management systems. These links enabled 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 6 hours). Demand reductions were rotated across a portfolio of several buildings during the call period, with each building contributing to delivering the total required demand reduction.

The LIPAedge program in the United States was developed to use central control of residential and small commercial air-conditioning thermostats to achieve peak load reduction. The system operator interfaces with the resource through a web-based system. Two-way pagers are used to transmit a curtailment order to 20,000 thermostats and to receive acknowledgment and monitoring information. The thermostats take immediate action or adjust their schedules for future action, depending on what the system operator ordered. The command is received and acted upon by all loads, providing full response within about 90 seconds. This is far faster than generator response, which typically requires a 10-minute ramp time.

The Sacramento Residential Peak Corps program in the United States was initiated in 1979 to address needle peaks in the load on Sacramento's electricity network. The program has now been operating for 26 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.

Progress Energy Florida's direct load control and standby generator programs cover centrally ducted space heating and air conditioning systems, water heaters and pool pumps in the residential sector; and central cooling and chiller systems, interruptible and curtailable loads and standby generation in the commercial and industrial sectors. Direct load control is achieved through a one-way radio paging network for all sectors. Some SCADA control is used on dedicated feeders serving larger industrial customers who are on interruptible tariffs. The direct load control programs allow PEF to reduce peak demand and defer the construction of additional generation capacity.

In the ETSA Utilities Air Conditioner Direct Load Control Program approximately 750 air conditioners in the residential and small commercial sectors were fitted with a load control device, the "Peak Breaker", that switched the air conditioner compressors directly so as to cycle the air conditioners on and off over a range of different time periods. The Peak Breakers were activated in a random sequence when signals were sent via the internet to a public radio station which then transmitted the signals to the Peak Breakers. The system was able to communicate with subsets of the Peak Breakers based on substation, product group or individual customer level.

The California Automated Demand Response System Pilot was a small-scale exploratory program deploying automated energy management technology in 175 California households. The ADRS pilot participants had the GoodWatts system installed in their homes. GoodWatts is an "always on", two-way communicating, automated home climate control system with web-based programming of user preferences for control of home appliances. Via the internet, homeowners with GoodWatts can set climate control and pool or spa pump runtime preferences and view these settings at any time both locally and remotely. Participants can also view whole-house or end-use specific demand in real time and display trends in historical consumption. GoodWatts allows users to view at all times the current electricity price on-line or via the thermostat. It also allows users to program load control devices to automatically respond to changes in electricity prices. For example the devices can be set to automatically reduce load once a threshold electricity price is reached.

To achieve the decoupling of peak and energy demand growth in its service territory, Orion Energy in New Zealand has used a mix of direct load control and pricing initiatives. About 90% of residential electric hot water heaters are controlled through ripple control in which control signals to switch the heating elements on or off are transmitted through the power lines to relays at customers' premises. Orion promotes two direct load control methods for peak reduction through ripple control: peak control water heating; and night only water heating. With peak control water heating, Orion uses the ripple system to switch off water heating elements during peak loading periods when the demand in Orion's network area reaches a certain threshold. With night only water heating, Orion uses the ripple system to switch on water heaters only at night, permanently shifting this load away from peak times.

In 2003, the Government of Gujarat in India announced a scheme called "Jyotigram Yojana" (JGY) to provide continuous three phase power supply to rural areas of the State to improve the quality of life of the rural population. Under the JGY scheme, the Gujarat Government decided to separate agricultural pump set connections from domestic light and fan (DLF) connections by constructing separate 11 KV feeders for agricultural loads. This enabled electricity distributors to implement direct load control of agricultural pumps by establishing schedules specifying the times during the day when each agricultural feeder would be energised. The main objective of implementing this direct load control program was to flatten the load curve to provide sufficient network capacity for the morning and evening peaks.

## 2.4 Distributed Generation

Distributed generators are relatively 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.

### *2.4.1 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. Distributed generation can also reduce network losses, improve utilisation (load factor) of existing transmission and generation assets, provide voltage support on long rural lines and also, with appropriate technology fitted to larger distributed generation plant, provide automatic frequency response.

### *2.4.2 Survey Examples*

Part 2 of this report contains detailed case studies of five distributed generation projects (see page 104) which were implemented specifically to provide network support:

DG01 Nelson Bay Embedded Generation - Australia
DG02 Bromelton Embedded Generation - Australia
DG03 Kerman Photovoltaic Grid-Support Project - USA

DG04 Chicago Energy Reliability and Capacity Account - USA
DG05 Mitigation of Load Shedding in Pune Urban Circle – India

In the Nelson Bay project in Australia, the local electricity distributor installed 6 MVA of diesel generation obtained from a leasing company to reduce loading on long 33kV lines which were about to exceed capacity. The generators were installed in two 3MVA stages and connected to the local 11kV feeder network. The generation is operated whenever the total demand on the 33kV system approaches the limit in order to keep the net demand below the load shedding threshold. The generators will remain in place for about two years until a new transmission line is constructed and then will be removed.

The Bromelton project is similar to the Nelson Bay one. Fifteen 1.825 MVA diesel generators will be installed on vacant land adjacent to Bromelton bulk supply substation to reduce loading on a 110kV transmission line until a second one can be built in about two years time.

The Kerman Photovoltaic Grid-Support Project in California 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.

In the Mitigation of Load Shedding in Pune Urban Circle project in India, the local electricity distributor carried out a project to identify and develop a pilot scheme to mitigate load shedding in Pune. It was intended that the project could be replicated in other cities across Maharashtra State. The project used surplus power available from customers' standby generators and on-site generation during peak hours and made available the grid power for supply to other consumers in Pune by implementing a workable alternative for harnessing distributed generation on a pilot basis.

## 2.5 Demand Response

Demand response comprises short-term actions taken by end-use customers to change (usually reduce) their electricity use in response to high prices in the electricity market; and/or problems on the electricity network. In network-related demand response programs, the network operator notifies customers and demand response providers when short-term load reductions are required.

### *2.5.1 Network Application*

Demand response is typically used by network operators to reduce peak loads, either across the system as a whole or on particular network elements.

### *2.5.2 Survey Examples*

Part 2 of this report contains detailed case studies of four demand response projects (see page 121):

DR01 ISO New England Demand Response Programs - USA
DR02 New York ISO Demand Response Programs - USA
DR03 PJM Load Response Programs - USA
DR04 South Island Demand Side Participation Trial - New Zealand

Under the Demand Response Programs established by the New England Independent System Operator (ISO-NE), 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.

Similar market-driven demand response programs are operated by the New York Independent System Operator and the PJM Interconnection.

In the South Island Demand Side Participation Trial in New Zealand, the transmission system operator, Transpower, is developing a grid support contract product to enable it to evaluate, gain regulatory approval for, and contract with non-transmission alternatives where they provide a reliable and economic means of supporting the network. To assist in developing this contract, Transpower carried out a trial to find out whether DSP could be reliably used to deliver a cost effective solution to assist in transmission investments. The trial involved identifying and contracting with a number of providers of non-transmission alternatives, including distributed generation and load curtailment providers. The trial was run on a real dollars for real megawatt load reductions basis to test the commercial realities of such a product.

## 2.6 Energy Efficiency

The objective of energy efficiency projects is to reduce the quantity of energy used per unit of output or delivered service. As a DSM measure, energy efficiency leads to reduced load levels on electricity networks for the same level of output or service.

### 2.6.1 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. However, energy efficiency projects are difficult to target accurately enough to provide network operational services.

### 2.6.2 Survey Examples

Part 2 of this report contains detailed case studies of 10 energy efficiency projects (see page 164):

EE01 Efficient Lighting Project DSM Pilot - Poland
EE02 Oncor Standard Offer Program for Residential and Commercial Energy Efficiency - USA
EE03 Oncor Air Conditioning Distributor Market Transformation Program - USA
EE04 Espanola Power Savers Project - Canada
EE05 Katoomba DSM Program - Australia
EE06 Drummoyne Demand Management Project – Australia
EE07 Nashik CFL Pilot Project – India
EE08 Mumbai Efficient Lighting Program – India
EE09 Mumbai Consumer Awareness Campaign - India
EE10 Bangalore Efficient Lighting Program – India

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 DSM to Polish electric utilities and, in particular, to introduce the concept of using DSM 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. Three cities and their regional electricity utilities were selected to participate in the DSM pilot; the cities had areas with electricity network capacity problems. Subsidised CFLs were made available to city residents using discount coupons; the largest discounts were available to residents of network constrained areas. Modelling results showed that during the local peak hour on the peak day of the year, load reductions of about 15% were achieved in the target network constrained areas.

The Oncor 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 Oncor Air Conditioning Distributor Market Transformation Program 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.

The Espanola Power Savers Project in Canada 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 Katoomba DSM Project in Australia focussed on energy efficiency in the residential sector and was implemented by the local electricity distributor 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. The local electricity distributor paid for the provision of information about energy efficiency to householder but did not subsidise the cost of energy efficiency devices.

The objective for the Drummoyne Demand Management Project was to implement DSM measures that would maintain network performance at the required level at a lower cost than investing AUD 4 million for an additional transformer at the Drummoyne zone substation. The chosen DSM measure was the installation of compact fluorescent lamps (CFLs) in residential and small number of commercial premises. High power factor, 15 watt CFLs were packaged in boxes of five for distribution to households in the target area. Each household was given one box of five CFLs free of charge. Door-to-door delivery and installation were carried out during specific times and days to maximise the number of people at home.

The Nashik CFL Pilot Project in India also distributed CFLs to residential households. The backbone of the pilot project was a CFL subsidy system, which was designed to persuade a large number of consumers to purchase and install CFLs to replace existing incandescent lamps. Only residential and commercial consumers having no electricity bill arrears were eligible to participate in this project. A limit of five CFLs per consumer was fixed. Two choices, direct purchase or purchase through instalments were offered by MSEDCL to the participating consumers. Several mechanisms were developed to deliver CFLs to urban and rural areas effectively.

Two further CFL distribution projects similar to the Nashik pilot project were carried out in India in Mumbai and Bangalore.

The Mumbai consumer awareness energy saving campaign with the slogan "I Will, Mumbai Will" was launched by two of the three electricity distributor/retailers supplying electricity in Mumbai, together with an electricity generator. The campaign used most popular communications media such as billboard hoardings, press, radio and cinema to maximise exposure across various classes and age groups. The campaign mainly focused upon common habits contributing to electricity demand during the peak load period and to energy wastage.

## 2.7 Fuel Substitution

As a DSM measure, 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.

### *2.7.1 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. As with energy efficiency, fuel substitution projects are difficult to target accurately enough to provide network operational services.

### *2.7.2 Survey Examples*

Part 2 of this report contains detailed case studies of three fuel substitution projects (see page 214):

FS01 Tahmoor Fuel Substitution Project - Australia
FS02 Binda-Bigga Demand Management Project - Australia
FS03 Paradip Port Substitution of Cooking Fuel Project – India

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. The local electricity distributor promoted the use of bottled gas by residential customers for cooking and space heating by arranging and provided subsidies for the installation of bottled gas and appliances. The project succeeded in flattening load growth to a degree, but take-up was less than forecast. During the project, a gas distributor made public overtures about extending reticulated natural gas to the area; this may have discouraged customers from installing bottled gas. Consequently, the program deferred the supply-side system augmentation for a shorter period than forecast.

Many customers in the small rural settlements of Binda and Bigga in Australia were experiencing unacceptable voltage fluctuations. Alleviating this problem would have required extensive reconductoring of the line supplying the area. Capital expenditure was successfully deferred by encouraging residential customers to replace their electrical cooking and room heating appliances with appliances operating on bottled gas.

The Paradip Port Substitution of Cooking Fuel Project was initiated by the Paradip Port Trust. The Trust purchased electricity in bulk from the local distributor/retailer and supplied electricity to its employees for residential use. The objective of the project was to reduce system peak demand by introducing LPG as a domestic cooking fuel through replacing electric stoves used by Trust employees. The project was targeted at cooking in the residential sector because this activity comprised approximately 60% of the electrical usage in each household, adding 3 to 4 MW to the electricity demand. The Trust replaced a total of 2,874 electric cooking stoves with LPG stoves. The entire cost was born by the Trust and was recovered through electricity and cost savings.

## 2.8 Interruptible Loads

End-use customers on interruptibility contracts pay a lower tariff in return for agreeing to allow the electricity supply to specific loads to be interrupted under the terms and conditions specified in the contract.

### *2.8.1 Network Application*

Interruptibility contracts are typically available only to larger industrial and commercial customers. In network demand management, interruptibility is usually used to manage major disturbances on the network, though it could also be used in a more targeted fashion, depending on the provisions of the contract.

### *2.8.2 Survey Examples*

Part 2 of this report contains detailed case studies of five interruptible loads projects (see page 229):

IL01 Load Interruption Contract - Spain
IL02 Flexible Load Interruption Contract - Spain
IL03 Interruptibility Contract for Cogenerators - Spain
IL04 Active / Reactive Power Exchange - Spain
IL05 California Energy Cooperatives - USA

The Load Interruption Contract established by the Spanish transmission system operator is an agreement through which large customers receive a discount on their electricity bills in return for being available to reduce their consumption on request from the system operator. The system operator is responsible for issuing, controlling and supervising all interruption orders. Customers participating in the Load Interruption Contract will must submit to the system operator monthly schedules for hourly energy demand and maintenance planning.

The Flexible Load Interruption Contract in Spain is an extension of the basic Load Interruption Contract. Some provisions of the basic Load Interruption Contract have minimum warning times of 16 hours and 6 hours. Because these are long time periods, system load may have changed between the time the interruption order is sent and when the order is executed. A new Interruption Flexible Management Program has been developed by the transmission system operator in collaboration with large industrial consumers. This program allows customers to reduce their consumption following a specific profile, more appropriate to the real profile of the system load.

The Spanish transmission system operator has recently proposed opening interruptibility contracts to cogenerators. If approved, this will provide the system operator with access to both a load reduction and an increase in generation capacity under one contract when the electricity network is under stress.

The Spanish transmission system operator's Active / Reactive Power Exchange is designed for customers who already participate in Load Interruption Contracts. These customers may be given a partial exemption from reducing their loads during an interruption event if they increase the reactive power they inject into the network to at least three times the active power they are consuming.

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.

## 2.9 Integrated DSM Projects

Integrated DSM projects employ a range of DSM measures appropriate to the objectives they are aiming to achieve.

### *2.9.1 Network Application*

Integrated DSM 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. Depending on the specific DSM measures employed, integrated DSM projects may also be used to provide network operational services.

### *2.9.2 Survey Examples*

Part 2 of this report contains detailed case studies of 12 integrated DSM projects (see page 251):

IP01 Blacktown DSM Program - Australia
IP02 Castle Hill Demand Management Project - Australia
IP03 Parramatta DSM Program - Australia
IP04 Olympic Peninsula Non-wires Solutions Pilot Projects and GridWise Demonstration - USA
IP05 Brookvale / DeeWhy DSM Program - Australia
IP06 Maine-et-Loire DSM Project - France

IP07 Deferring Network Investment - Finland
IP08 French Riviera DSM Program - France
IP09 Manweb Demand Side Management Project - Wales, United Kingdom
IP10 Coalition of Large Distributors Conservation and Demand Management Programs - Canada
IP11 Pilot Project to Improve Agricultural Pump Set Efficiency – India
IP12 Agricultural Pump Set Efficiency Improvement Program – India

Each of these projects aims to use a range of DSM measures to defer the construction of a specific network augmentation or to reduce peak load and/or overall load on a specific network element or network region.

In the Blacktown DSM Program in Australia, the local electricity distributor is seeking to defer the upgrade of a zone substation. The substation comes under pressure during hot weekdays due to heavy air-conditioning loads, but for most of the year operates under capacity. Network customers who have opportunities to reduce peak demand are offered a free energy audit in return for signing a Memorandum of Understanding. Financial incentives are paid for each initiative implemented, based on the verified demand reduction achieved.

In the Castle Hill Demand Management Project in Australia, the local electricity distributor is aiming to defer the requirement to build a new substation despite high levels of load growth caused by increased penetration of air conditioning. The program is targeting the commercial sector, particularly retailers in a large shopping centre. The program is targeting 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. The contracts with the customers are performance based, with payment on verification of demand reductions.

Through the Parramatta DSM Program in Australia, the local electricity distributor is aiming to defer the capital expenditure required to build a new zone substation. The distributor funded and conducted a major survey to identify and establish the opportunities for DSM in the Parramatta central business district. The distributor then made offers to building owners/managers for the implementation of appropriate DSM initiatives. The DSM options considered included 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 Olympic Peninsula project in the United States, the transmission system operator is carrying out several pilot projects to determine whether it is possible to use non-wire solutions to defer a transmission line construction project. The DSM measures employed include: direct load control, demand response, voluntary load curtailments, networked distributed generation and energy efficiency. One particularly interesting DSM measure is the use of Grid-Friendly™ appliances which sense frequency disturbances in the electricity network and reduce load to act as spinning reserve - no communications technology is required beyond the network itself. The demand response, voluntary load curtailment and distributed generation pilot projects will be aggregated by Pacific Northwest National Laboratory into a demonstration of how a future electricity network might function. This demonstration is part of a project of the United States Department of Energy known as GridWise.

With the Brookvale / DeeWhy DSM Program in Australia, the local electricity distributor is aiming to defer capital investment in the local sub-transmission infrastructure. The initiatives are targeting the commercial and industrial sectors and comprise: installation (or repair) of low voltage power factor correction equipment at 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 customers' premises.

The purpose of the Maine-et-Loire DSM Project in France was to defer reinforcing certain overloaded rural feeders. Two categories of DSM measures were implemented: measures undertaken on the network side of the meter; and measures undertaken on the customer side of the meter. Network-related DSM measures included: installing voltage regulators and distributing the single-phase current loads of customers across three phases. The customer-related DSM measures included: shifting the use of appliances and water heaters to off-peak periods; installing electronic "soft" starters for electric motors; distributing compact fluorescent lamps; implementing automatic controllers for domestic boilers; installing a wood-fired boiler; and using portable diesel generators for intermittent generation at selected sites.

The purpose of the project to defer network investment in Finland was to investigate demand-side options available to the distribution utility to defer the investment required to increase the capacity of a defined rural distribution area. The project commenced as an integrated DSM project to investigate the feasibility of implementing a range of DSM options across several customer classes to achieve deferral of investment in a network augmentation. However, because of the unique situation in which one large customer accounted for 50% of the load in the relevant distribution area, only one DSM option was implemented - the installation of a diesel generator for peak clipping at the large customer's site. The effectiveness of this option then became uncertain when the large customer changed electricity supplier and consequently the benefits to the customer of the diesel generator changed.

The French Riviera DSM Program is the largest DSM project in the European Union and possibly the world. Its purpose is to use energy efficiency and renewable energy distributed generation to defer the need to upgrade a major transmission line serving the eastern part of the Provence-Alpes-Côte d'Azur region of France. In May 2006, the state court, after a complaint from an environmental group, refused planning permission for the upgrading of the line. Therefore, at present, the DSM program is the only way to secure supply to this region by keeping load growth within the capacity of the existing line.

The Manweb Demand Side Management Project was designed to evaluate the principles and techniques necessary to introduce a major DSM program. It aimed to reduce peak demand for electricity in the town of Holyhead on Holy Island, just off the west coast of the island of Anglesey in North Wales. The local electricity distributor/retailer offered a range of subsidised or free measures for customers in the residential, commercial / small industrial and large industrial sectors. Measures implemented in the project included compact fluorescent lamps, loft insulation, draught proofing, hot water tank insulation, power factor correction.

In Canada, the Coalition of Large Distributors has implemented a range of conservation and demand management (CDM) programs to support the Government of Ontario's plans to reduce peak electricity demand in the province by 6,300 MW by 2025. The CDM programs implemented by the Coalition members were intended to achieve a range of different objectives. Some programs were designed to reduce the amount of electricity used by residential customers; others were directed to assisting commercial customers reduce their electricity loads; and still others were intended to reduce peak demand on the electricity network.

In India, the Pilot Project to Improve Agricultural Pump Set Efficiency implemented various energy efficiency and power factor correction measures in a small number of agricultural pump sets to identify the impact of these measures in terms of the resulting load reduction and improvement in power factor.

In the Agricultural Pump Set Efficiency Improvement Program in India, staff from the local electricity distributor/retailer conducted a survey of existing pumping systems to identify opportunities to improve efficiency, particularly in relation to power factor and appropriate sizing of motors. A funding mechanism was offered to agricultural customers that provided free of cost pump sets and a mix of 70% debt and 30% equity in the purchase and installation of capacitors and metering. Outreach activity was undertaken jointly with local community institutions to promote and encourage agricultural customers to participate in the program. Customers were given access to pump sets and also provided with information on usage and system parameters for evaluation.

## 2.10 Load Shifting

Load shifting comprises measures that encourage customers to move their use of electricity away from peak periods.

### *2.10.1 Network Application*

Load shifting may be used to reduce peak loads across the whole network, or 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.

### *2.10.2 Survey Examples*

Part 2 of this report contains detailed case studies of five load shifting projects (see page 325):

LS01 Winter Peak Demand Reduction Scheme - Ireland
LS02 Eskom DSM Profitable Partnership Programme - South Africa
LS03 TU Electric Thermal Cool Storage Program - USA
LS04 Mad River Valley Project - USA
LS05 Baulkham Hills Substation Deferral Project - Australia

In the Winter Peak Demand Reduction Scheme in Ireland, large commercial and industrial customers committed to reducing consumption between 5 and 7 pm every business day from November to February. This reduction was achieved through reducing energy use or utilising on-site generation. Customers received a payment for reliably delivering this committed reduction.

In South Africa, the monopoly vertically integrated electricity utility offers financial assistance through the DSM Profitable Partnership Programme to entities that are serious about efficient use of electricity and the resulting financial savings. Both upgrades to existing buildings and the incorporation of efficient systems in new buildings are targeted. The utility funds 100% of all costs for viable load management projects designed to shift electricity consumption to off-peak periods in order to reduce peak loads. Customers are not required to contribute towards the capital expenditure on projects.

The TU Electric 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.

The Mad River Valley Project in the United States 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 Baulkham Hills Substation Deferral Project in Australia 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.

## 2.11 Power Factor Correction

Power factor in alternating current circuits is the ratio of energy consumed (watts) versus the apparent power (volt-amps). In other words, power factor is the percentage of actual energy used compared to the energy flowing through the wires. Power factor correction aims to reduce the difference between the energy consumed and the apparent power so as to reduce energy wastage.

### 2.11.1 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.

### 2.11.2 Survey Example

Several projects reviewed in this report, particularly integrated DSM projects, include power factor correction as part of a range of DSM measures. Part 2 of this report contains a detailed case study of one project which comprised only power factor correction (see page 345):

PC01 Marayong Power Factor Correction Program - Australia

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. The local electricity distributor 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). The distributor paid for the equipment and the installation. This program was implemented without the involvement of customers.

## 2.12 Pricing Initiatives

As a DSM measure, pricing initiatives aim to change customers' energy-using behaviour, particularly to alter the times at which electricity is used.

### 2.12.1 Network Application

Pricing initiatives are typically used to support electricity networks by changing customers' energy-using behaviour to reduce demand at the time of the system peak. Typically, pricing initiatives are applied to particular customer classes across a whole electrical system and are therefore usually not targeted to geographical areas where network constraints occur. However, some work is now being carried out on congestion pricing in which electricity prices are increased in constrained network areas.

### 2.12.2 Survey Examples

Part 2 of this report contains detailed case studies of nine pricing initiative projects (see page 348):

PI01 California Critical Peak Pricing Tariff for Large Customers - USA
PI02 Loire Time of Use Tariff Program - France
PI03 Queanbeyan Critical Peak Pricing Trial - Australia
PI04 Hourly Demand Tariff - Spain
PI05 End User Flexibility by Efficient Use of Information and Communication Technologies - Norway
PI06 Tempo Electricity Tariff - France
PI07 Reduced Access to Network Tariff - Spain
PI08 EnergyAustralia Pricing Strategy Study – Australia
PI09 California Statewide Pricing Pilot for Small Customers – USA

The California Critical Peak Pricing Tariff for Large Customers (CPP) comprised increased prices during 6 or 7 hours of up to 12 "Critical Peak Pricing Days" each year and reduced prices during non-critical-peak periods. A CPP Event could only be activated during summer. To participate in the CPP tariff for large customers, all customers had to have metering capable of recording electricity usage in 15-minute intervals. If customers did not have interval metering at the start of the CPP trial period, each utility provided and installed this free of charge. Customers had to remain on the CPP tariff for a minimum of 12 months; after participating in the CPP tariff for 12 months, customers could opt-off at anytime.

In the Loire Time of Use Tariff Program in France, particular overloaded feeders were selected for application of time of use tariffs. The monopoly the electricity generator and retailer contacted customers by visits and phone calls to collect information about the type and power rating of customer equipment, tariffs used, etc. These data were used by a consulting company to simulate the electrical demand for each feeder. Then tariff changes were simulated to determine the effect on the peak load. Where the simulations of tariff changes indicated possible financial savings for customers, the utility contacted the customers connected to the feeders. The utility proposed to the customers that they change to a two-part time of use tariff (peak and normal rates). Where the customers were already on an existing time of use tariff, the utility proposed a change in the time periods for the peak and normal rates.

The Queanbeyan Critical Peak Pricing Trial in Australia was initiated to investigate the feasibility of promoting peak load reductions by residential sector customers to relieve distribution network constraints. Critical peak periods are called by the electricity retailer when the load on the local network is reaching maximum capacity or when high price events occur in the competitive wholesale electricity market. In the trial, implementation of time of use and critical peak pricing tariffs required the installation of interval meters and in-home information display units in participants' dwellings. The in-home information display unit comprises a LED alphanumeric display which provides customers with specific information about the amount of electricity they are using, and how much it is costing. A beeping sounds alerts customers to the start of a critical peak period.

The Hourly Demand Tariff in Spain consists of different rates for each of seven time of use periods. The transmission system operator has the right to determine the hours of operation of Period 1. That period correspond to peak hours and is the most expensive period of the year. The aim of this tariff is to dissuade customers from using electricity during peak hours by increasing the demand and energy cost components of their electricity bills.

The Norwegian project "End User Flexibility by Efficient Use of Information and Communication Technologies" was a large scale pilot project involving two network operators and six technology vendors. The project included: two way communication to 10,984 mainly residential customers; automated meter reading; and direct load control of water heaters. Customers were offered a choice of a standard or TOU network tariff and/or a standard or hourly spot price retail tariff. The following average load reductions per household were achieved:

- ToU network tariff – 0.18 kWh/h
- hourly spot price for energy – 0.4 - 0.6 kWh/h
- direct load control of water heaters – 0.5 kWh/h
- ToU network tariff plus hourly spot price – 0.3 - 1.0 kWh/h.

The Tempo tariff is the most sophisticated electricity tariff for mass market customers in France. The Tempo tariff enables smoothing of both the annual and daily electricity load curves, therefore reducing marginal generation and network costs. The Tempo tariff has six rates based upon the actual weather on particular days and on hours of use. Each day of the year is colour coded. There are three colours, blue, white and red which correspond to low, medium and high electricity prices. The colour of each day is determined mostly by the electricity generator and retailer based on the forecast of electricity demand for that day - the level of demand is mainly influenced by the weather. The French transmission network operator has the ability to determine the day colour if there is significant congestion on the electricity network.

Under the Reduced Access to Network Tariff measure in Spain, free market customers receive a reduction in their "access to network" tariff in return for reducing their loads automatically following a request from the transmission system operator, and providing reactive power when required by the TSO. The reduced "access to network" tariff provides the TSO with a network operational service.

The purpose of the EnergyAustralia Pricing Strategy Study was to investigate the effectiveness of critical peak pricing (CPP) in achieving peak load reductions on the distribution network. The study included about 750 residential customers and 550 business customers. All had a smart meter with GPRS communications installed in their premises and some had an in-house display connected to the meter by power line carrier technology. The experimental groups comprised:

- a control group;
- a group provided only with information about peak load reductions;
- a group placed on a seasonal TOU tariffs;
- one group placed on a medium critical peak pricing tariff with an in-house display;
- two groups placed on a high critical peak pricing tariff with and without an in house display.

The California Statewide Pricing Pilot (SPP) for Small Customers involved some 2,500 residential and commercial and small industrial customers. The experimental tariffs tested in the SPP included a traditional time of use (TOU) rate and two dynamic pricing rates. Under the TOU rate, the price during the peak period was roughly 70 percent higher than the standard rate and about twice the value of the price during the off-peak period. The dynamic rates included a critical peak pricing (CPP) element that involved a substantially higher peak price for 15 days of the year and a standard TOU rate on all other days. One type of CPP rate had a fixed peak period on both critical and non-critical days and day-ahead customer notification for critical day events. The other type of CPP rate had a variable-length peak period on critical days, which could be called not less than four hours ahead on the day of a critical event.

## 2.13 Smart Metering

Currently, recording the quantities of energy consumed by end-users is mostly carried out by using ***accumulation meters*** which simply record energy consumption progressively over time. However, more advanced meters are increasingly being used. ***Interval meters*** record the quantities of energy consumed over set, frequent time intervals. ***Smart meters*** include, in addition to the interval metering capability, one-way or two-way communications between the energy supplier and the meter.

### 2.13.1 Network Application

There are two ways in which ways in which smart metering can be used to support electricity networks

First, smart meters enable the implementation of time-varying pricing which sends price signals to customers that reflect the underlying costs of generating, transporting and supplying electricity. Price-based demand response programs can reduce or shape customer demand and particularly can reduce peak loads on the electricity network and therefore reduce the amount of investment required in network infrastructure.

Second, analysing data from smart meters provides end-users with detailed information about the ways in which they use electricity and can enable businesses to identify and implement energy, cost and carbon savings. Energy savings reduce the overall load on the electricity network, therefore contributing to supporting the network

### 2.13.2 Survey Example

Several projects reviewed in this report, particularly pricing initiative projects, include time-varying pricing as a DSM measure. Part 2 of this report contains a detailed case study of one project that analysed data from smart metering (see page 409):

SM01 Carbon Trust Advanced Metering Trial - United Kingdom

The Carbon Trust Advanced Metering Trial was carried out to understand the potential benefits of advanced metering for SMEs. During the trial, advanced metering for electricity, gas and water was installed at 582 sites across the United Kingdom. In addition to installing clip-on readers or new advanced meters at sites that did not already have interval metering in place, a variety of different types of energy saving advice were provided to sites during the trial. These services ranged from basic data provision to detailed advice on energy saving communicated through phone calls and site visits. The detailed half-hourly load profile data from advanced metering was used to identify opportunities for energy savings.

## 3. CONCLUSION

The survey of demand management activities which forms the basis of this report showed that network-driven DSM options can effectively:

- achieve load reductions on electricity networks that can be targeted to relieve specific network constraints; and
- provide a range of network operational services, achieving peak load reductions with various response times for network operational support.

The survey also showed that all types of demand DSM measures can be used to relieve network constraints and/or provide network operational services. However, whether a particular DSM measures 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 question of the relative effectiveness of DSM measures in achieving network-related objectives will be examined further in Subtask 2 of Task XV.

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

Since some of the DSM projects included in the survey were implemented many years ago, an attempt was made to locate reports of results monitoring carried out over extended time periods after projects were implemented. Some projects, particularly the Espanola Power Savers Project (page 177), 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 DSM outcomes over time may be less important in a network-driven DSM context than in a situation where DSM is being implemented to achieve environmental objectives, such as abatement of greenhouse gas emissions. Network-driven DSM is usually implemented to achieve deferral of a specific network augmentation project for a defined period or to provide short-term network operational services. In most circumstances, DSM is usually not able to completely avoid a network augmentation because load growth still continues, though at a lower rate, after a DSM project has been implemented. Therefore, a load reduction achieved through DSM is usually only required until the load on the network element reaches its design rating and the network augmentation has to be built.

The survey also showed that there is a relative lack of published performance data or post implementation analysis for network-driven DSM 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 DSM activities against the experience of others and may form a significant barrier to the implementation of cost effective network-driven demand-side management.

# PART 2:
# CASE STUDIES

# FINDING RELEVANT CASE STUDIES

Part 2 of this report contains detailed case studies of 64 network-driven DSM projects. The case studies are also accessible on-line on the Task XV website at: http://www.ieadsm.org/CaseStudies.aspx.

The following tables are provided to assist in finding relevant case studies in this Part 2 of the report. In Table A1 (below), the case studies are classified by the major DSM measure implemented and are shown with their corresponding page numbers. Further classifications of case studies are also presented: by project implementor (Table A2, page 32); by focus of project (Table A3, page 37); by project objective (Table A4, page 40); and by market segment addressed (Table A5, page 43).


| Table A1. Case Studies by Major DSM Measure | | |
|---|---|---|
| **Direct Load Control** | | |
| DC01 | Ethos Project Trial of Multimedia Energy Management Systems - Wales, UK | p 46 |
| DC02 | Sydney CBD Demand Curtailment Project - Australia | p 50 |
| DC03 | LIPAedge Direct Load Control Program - USA | p 54 |
| DC04 | Sacramento Peak Corps - USA | p 61 |
| DC05 | PEF Direct Load Control and Standby Generator Programs - USA | p 65 |
| DC06 | ETSA Utilities Air Conditioner Direct Load Control Program - Australia | p 71 |
| DC07 | California Automated Demand Response System Pilot - USA | p 81 |
| DC08 | Orion Network DSM Program - New Zealand | p 91 |
| DC09 | Separation of Agricultural Feeders for Load Control - India | p 99 |
| **Distributed Generation** | | |
| DG01 | Nelson Bay Embedded Generation - Australia | p 104 |
| DG02 | Bromelton Embedded Generation - Australia | p 107 |
| DG03 | Kerman Photovoltaic Grid-Support Project - USA | p 110 |
| DG04 | Chicago Energy Reliability and Capacity Account - USA | p 113 |
| DG05 | Mitigation of Load Shedding in Pune Urban Circle - India | p 116 |
| **Demand Response** | | |
| DR01 | ISO New England Demand Response Programs - USA | p 121 |
| DR02 | New York ISO Demand Response Programs - USA | p 132 |
| DR03 | PJM Load Response Programs - USA | p 141 |
| DR04 | South Island Demand Side Participation Trial - New Zealand | p 153 |

| Table A1. Case Studies by Major DSM Measure (continued) | | |
|---|---|---|
| **Energy Efficiency** | | |
| EE01 | Efficient Lighting Project DSM Pilot - Poland | p 164 |
| EE02 | Oncor Standard Offer Program for Residential and Commercial Energy Efficiency - USA | p 169 |
| EE03 | Oncor Air Conditioning Distributor Market Transformation Program - USA | p 174 |
| EE04 | Espanola Power Savers Project - Canada | p 177 |
| EE05 | Katoomba DSM Program - Australia | p 184 |
| EE06 | Drummoyne Demand Management Project - Australia | p 187 |
| EE07 | Nashik CFL Pilot Project - India | p 196 |
| EE08 | Mumbai Efficient Lighting Program - India | p 201 |
| EE09 | Mumbai Consumer Awareness Campaign - India | p 204 |
| EE10 | Bangalore Efficient Lighting Program - India | p 211 |
| **Fuel Substitution** | | |
| FS01 | Tahmoor Fuel Substitution Project - Australia | p 214 |
| FS02 | Binda-Bigga Demand Management Project - Australia | p 217 |
| FS03 | Paradip Port Substitution of Cooking Fuel Project - India | p 225 |
| **Interruptible Loads** | | |
| IL01 | Load Interruption Contract - Spain | p 229 |
| IL02 | Flexible Load Interruption Contract - Spain | p 234 |
| IL03 | Interruptibility Contract for Cogenerators - Spain | p 238 |
| IL04 | Active / Reactive Power Exchange - Spain | p 241 |
| IL05 | California Energy Cooperatives - USA | p 245 |
| **Integrated DSM Projects** | | |
| IP01 | Blacktown DSM Program - Australia | p 251 |
| IP02 | Castle Hill Demand Management Project - Australia | p 254 |
| IP03 | Parramatta DSM Program - Australia | p 262 |
| IP04 | Olympic Peninsula Non-wires Solutions Pilot Projects and GridWise Demonstration - USA | p 265 |
| IP05 | Brookvale / DeeWhy DSM Program - Australia | p 274 |
| IP06 | Maine-et-Loire DSM Project - France | p 283 |
| IP07 | Deferring Network Investment - Finland | p 291 |
| IP08 | French Riviera DSM Program - France | p 295 |

| Table A1. Case Studies by Major DSM Measure (continued) | | |
|---|---|---|
| **Integrated DSM Projects (continued)** | | |
| IP09 | Manweb Demand Side Management Project - Wales, United Kingdom | p 306 |
| IP10 | Coalition of Large Distributors Conservation and Demand Management Programs - Canada | p 310 |
| IP11 | Pilot Project to Improve Agricultural Pump Set Efficiency - India | p 316 |
| IP12 | Agricultural Pump Set Efficiency Improvement Program - India | p 321 |
| **Load Shifting** | | |
| LS01 | Winter Peak Demand Reduction Scheme - Ireland | p 325 |
| LS02 | Eskom DSM Profitable Partnership Programme - South Africa | p 330 |
| LS03 | TU Electric Thermal Cool Storage Program - USA | p 334 |
| LS04 | Mad River Valley Project - USA | p 338 |
| LS05 | Baulkham Hills Substation Deferral Project - Australia | p 342 |
| **Power Factor Correction** | | |
| PC01 | Marayong Power Factor Correction Program - Australia | p 345 |
| **Pricing Initiatives** | | |
| PI01 | California Critical Peak Pricing Tariff for Large Customers - USA | p 348 |
| PI02 | Loire Time of Use Tariff Program - France | p 355 |
| PI03 | Queanbeyan Critical Peak Pricing Trial - Australia | p 359 |
| PI04 | Hourly Demand Tariff - Spain | p 364 |
| PI05 | End User Flexibility by Efficient Use of Information and Communication Technologies - Norway | p 368 |
| PI06 | Tempo Electricity Tariff - France | p 378 |
| PI07 | Reduced Access to Network Tariff - Spain | p 384 |
| PI08 | EnergyAustralia Pricing Strategy Study - Australia | p 389 |
| PI09 | California Statewide Pricing Pilot for Small Customers - USA | p 396 |
| **Smart Metering** | | |
| SM01 | Carbon Trust Advanced Metering Trial - United Kingdom | p 409 |

| Table A2. Case Studies by Major DSM Measure and Project Implementor | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Case Study Number | Project Implementor | | | | | | | | | | | Page Number |
| | Distribution Utility | Trans-mission Utility | Regional Network Operator | Independent System Operator | Electricity Retailer/ Supplier | ESCO | End Use Customer(s) | Third Party Aggregator | State or Federal Government Agency | Local Government Municipality | Other | |
| **Direct Load Control** | | | | | | | | | | | | |
| DC01 | √ | | | | | | | | | | | p 46 |
| DC02 | √ | | | | | | | | | | | p 50 |
| DC03 | √ | √ | | | √ | | | | | | | p 54 |
| DC04 | √ | √ | | | | | | | | | | p 61 |
| DC05 | √ | √ | | | √ | | | | | | | p 65 |
| DC06 | √ | | | | | | | | | | | p 71 |
| DC07 | √ | | | | √ | | | | | | | p 81 |
| DC08 | √ | | | | | | | | | | | p 91 |
| DC09 | √ | | | | √ | | | | | | | p 99 |
| **Distributed Generation** | | | | | | | | | | | | |
| DG01 | √ | | | | | | | | | | | p 104 |
| DG02 | √ | | | | | √ | | | | | | p 107 |
| DG03 | √ | √ | | | √ | | | | | | | p 110 |
| DG04 | √ | √ | | | √ | | | | | √ | | p 113 |
| DG05 | √ | | | | √ | | | | | | | p 116 |

| Case Study Number | Project Implementor | | | | | | | | | | | Page Number |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Distribution Utility | Trans-mission Utility | Regional Network Operator | Independent System Operator | Electricity Retailer/ Supplier | ESCO | End Use Customer(s) | Third Party Aggregator | State or Federal Government Agency | Local Government Municipality | Other | |
| **Demand Response** | | | | | | | | | | | | |
| DR01 | | | | √ | | | | | | | | p 121 |
| DR02 | √ | √ | | √ | √ | | | √ | | | | p 132 |
| DR03 | | | | √ | | | | | | | | p 141 |
| DR04 | | √ | | | | | | | | | | p 153 |
| **Energy Efficiency** | | | | | | | | | | | | |
| EE01 | | | | | | | | | | √ | | p 164 |
| EE02 | √ | √ | | | | | | | | | | p 169 |
| EE03 | √ | √ | | | | | | | | | | p 174 |
| EE04 | √ | √ | | | √ | | | | | | | p 177 |
| EE05 | √ | | | | | | | | | | | p 184 |
| EE06 | √ | | | | | | | | | | | p 187 |
| EE07 | √ | | | | √ | | | | | | | p 196 |
| EE08 | √ | | | | √ | | | | | | | p 201 |
| EE09 | √ | | | | √ | | | | | | √ | p 204 |
| EE10 | √ | | | | √ | | | | | | | p 211 |

| Case Study Number | Project Implementor | | | | | | | | | | | Page Number |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Distribution Utility | Trans-mission Utility | Regional Network Operator | Independent System Operator | Electricity Retailer/ Supplier | ESCO | End Use Customer(s) | Third Party Aggregator | State or Federal Government Agency | Local Government Municipality | Other | |
| **Fuel Substitution** | | | | | | | | | | | | |
| FS01 | √ | | | | | | | | | | | p 214 |
| FS02 | | | | | | | | | √ | | | p 217 |
| FS03 | | | | | | | | | | | √ | p 225 |
| **Interruptible Loads** | | | | | | | | | | | | |
| IL01 | | √ | | | | | | | | | | p 229 |
| IL02 | | √ | | | | | | | | | | p 234 |
| IL03 | | √ | | | | | | | | | | p 238 |
| IL04 | | √ | | | | | | | | | | p 241 |
| IL05 | | | | | | | | √ | | | | p 245 |
| **Integrated DSM Projects** | | | | | | | | | | | | |
| IP01 | | | | | | √ | | | | | | p 251 |
| IP02 | | | | | | √ | | | √ | | | p 254 |
| IP03 | | | | | | | | | | | | p 262 |
| IP04 | | √ | | | | | | | √ | | | p 265 |
| IP05 | √ | | | | | | | | | | | p 274 |

| Case Study Number | Project Implementor | | | | | | | | | | | Page Number |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Distribution Utility | Trans-mission Utility | Regional Network Operator | Independent System Operator | Electricity Retailer/ Supplier | ESCO | End Use Customer(s) | Third Party Aggregator | State or Federal Government Agency | Local Government Municipality | Other | |
| **Integrated DSM Projects (continued)** | | | | | | | | | | | | |
| IP06 | √ | √ | | | | | | | | | √ | p 283 |
| IP07 | | | | | | | √ | | | | | p 291 |
| IP08 | √ | | | | | | | | √ | | | p 295 |
| IP09 | √ | | | | √ | | | | | | | p 306 |
| IP10 | √ | | | | √ | | | | | | | p 310 |
| IP11 | √ | | | | √ | | | | | | | p 316 |
| IP12 | √ | | | | √ | | | | | | | p 321 |
| **Load Shifting** | | | | | | | | | | | | |
| LS01 | √ | √ | √ | | | | | | | | | p 325 |
| LS02 | | | | | | √ | | | | | | p 330 |
| LS03 | √ | √ | | | √ | | | | | | | p 334 |
| LS04 | | | | | | | √ | | | | | p 338 |
| LS05 | √ | | | | | | | | | | | p 342 |
| **Power Factor Correction** | | | | | | | | | | | | |
| PC01 | √ | | | | | | | | | | | p 345 |

| Case Study Number | Project Implementor | | | | | | | | | | | Page Number |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Distribution Utility | Trans-mission Utility | Regional Network Operator | Independent System Operator | Electricity Retailer/ Supplier | ESCO | End Use Customer(s) | Third Party Aggregator | State or Federal Government Agency | Local Government Municipality | Other | |
| **Pricing Initiatives** | | | | | | | | | | | | |
| PI01 | √ | √ | | | | | | | | | | p 348 |
| PI02 | √ | √ | | | | | | | √ | | | p 355 |
| PI03 | √ | | | | √ | | | | | | | p 359 |
| PI04 | | √ | | | | | | | | | | p 364 |
| PI05 | √ | | | | | | | | | | | p 368 |
| PI06 | | √ | | | √ | | | | | | | p 378 |
| PI07 | | √ | | | | | | | | | | p 384 |
| PI08 | √ | | | | | | | | | | | p 389 |
| PI09 | √ | | | | √ | | | | | | | p 396 |
| **Smart Metering** | | | | | | | | | | | | |
| SM01 | | | | | | | | | | | √ | p 409 |

| Table A3. Case Studies by Major DSM Measure and Focus of Project | | | | | |
|---|---|---|---|---|---|
| Case Study Number | Focus of Project | | | | Page Number |
| | Network Capacity Limitations | Generation Capacity Limitations | Voltage Fluctuations | Other | |
| **Direct Load Control** | | | | | |
| DC01 | √ | | | | p 46 |
| DC02 | √ | | | | p 50 |
| DC03 | √ | √ | | | p 54 |
| DC04 | √ | | | | p 61 |
| DC05 | √ | √ | | | p 65 |
| DC06 | √ | | | | p 71 |
| DC07 | √ | √ | | | p 81 |
| DC08 | √ | | | | p 91 |
| DC09 | √ | √ | | | p 99 |
| **Distributed Generation** | | | | | |
| DG01 | √ | | | | p 104 |
| DG02 | √ | | | | p 107 |
| DG03 | √ | | √ | | p 110 |
| DG04 | √ | | | | p 113 |
| DG05 | √ | √ | | | p 116 |
| **Demand Response** | | | | | |
| DR01 | √ | √ | | | p 121 |
| DR02 | √ | √ | | | p 132 |
| DR03 | √ | √ | | | p 141 |
| DR04 | √ | | | | p 153 |
| **Energy Efficiency** | | | | | |
| EE01 | √ | | | | p 164 |
| EE02 | √ | | | | p 169 |
| EE03 | √ | | | | p 174 |
| EE04 | √ | √ | | | p 177 |
| EE05 | √ | | | | p 184 |
| EE06 | √ | | | | p 187 |

| Case Study Number | Focus of Project | | | | Page Number |
|---|---|---|---|---|---|
| | Network Capacity Limitations | Generation Capacity Limitations | Voltage Fluctuations | Other | |
| **Energy Efficiency (continued)** | | | | | |
| EE07 | √ | √ | | | p 196 |
| EE08 | √ | √ | | | p 201 |
| EE09 | √ | √ | | | p 204 |
| EE10 | √ | √ | | | p 211 |
| **Fuel Substitution** | | | | | |
| FS01 | √ | | | | p 214 |
| FS02 | √ | | √ | | p 217 |
| FS03 | √ | | | | p 225 |
| **Interruptible Loads** | | | | | |
| IL01 | √ | √ | | | p 229 |
| IL02 | | √ | | | p 234 |
| IL03 | √ | √ | | | p 238 |
| IL04 | | √ | √ | | p 241 |
| IL05 | √ | | | | p 245 |
| **Integrated DSM Projects** | | | | | |
| IP01 | √ | | | | p 251 |
| IP02 | √ | | | | p 254 |
| IP03 | √ | | | | p 262 |
| IP04 | √ | | | | p 265 |
| IP05 | √ | | | | p 274 |
| IP06 | √ | | √ | | p 283 |
| IP07 | √ | | | | p 291 |
| IP08 | √ | | | | p 295 |
| IP09 | √ | | | | p 306 |
| IP10 | √ | | | | p 310 |
| IP11 | √ | √ | | | p 316 |
| IP12 | √ | √ | | | p 321 |

| Case Study Number | Focus of Project | | | | Page Number |
|---|---|---|---|---|---|
| | Network Capacity Limitations | Generation Capacity Limitations | Voltage Fluctuations | Other | |
| **Load Shifting** | | | | | |
| LS01 | √ | √ | | | p 325 |
| LS02 | √ | √ | | | p 330 |
| LS03 | √ | | | | p 334 |
| LS04 | √ | | | | p 338 |
| LS05 | √ | | | | p 342 |
| **Power Factor Correction** | | | | | |
| PC01 | √ | | | | p 345 |
| **Pricing Initiatives** | | | | | |
| PI01 | √ | √ | | | p 348 |
| PI02 | √ | | | | p 355 |
| PI03 | √ | | | | p 359 |
| PI04 | | √ | | | p 364 |
| PI05 | √ | | | | p 368 |
| PI06 | √ | √ | | | p 378 |
| PI07 | | √ | √ | | p 384 |
| PI08 | √ | | | | p 389 |
| PI09 | √ | √ | | | p 396 |
| **Smart Metering** | | | | | |
| SM01 | | | | √ | p 409 |

| **Table A4. Case Studies by Major DSM Measure and Project Objective** | | | | | | |
|---|---|---|---|---|---|---|
| Case Study Number | **Project Objective** | | | | | Page Number |
| | Increasing Operating Reserve | Peak Load Reduction | Overall Load Reduction | Voltage Regulation | Other | |
| **Direct Load Control** | | | | | | |
| DC01 | | √ | | | | p 46 |
| DC02 | | √ | | | | p 50 |
| DC03 | | √ | | | | p 54 |
| DC04 | √ | √ | √ | | | p 61 |
| DC05 | | √ | √ | | | p 65 |
| DC06 | | √ | | | | p 71 |
| DC07 | | √ | | | | p 81 |
| DC08 | | √ | | | | p 91 |
| DC09 | | √ | √ | | | p 99 |
| **Distributed Generation** | | | | | | |
| DG01 | | √ | | | | p 104 |
| DG02 | | √ | | | | p 107 |
| DG03 | | √ | | √ | | p 110 |
| DG04 | | | √ | | | p 113 |
| DG05 | | √ | | | | p 116 |
| **Demand Response** | | | | | | |
| DR01 | | √ | | | | p 121 |
| DR02 | √ | | | | √ | p 132 |
| DR03 | | √ | | | | p 141 |
| DR04 | | √ | | | | p 153 |
| **Energy Efficiency** | | | | | | |
| EE01 | | √ | | | | p 164 |
| EE02 | | | √ | | | p 169 |
| EE03 | | | √ | | | p 174 |
| EE04 | | | √ | | | p 177 |
| EE05 | | | √ | | | p 184 |
| EE06 | | √ | | | | p 187 |

| Case Study Number | Project Objective | | | | | Page Number |
|---|---|---|---|---|---|---|
| | Increasing Operating Reserve | Peak Load Reduction | Overall Load Reduction | Voltage Regulation | Other | |
| **Energy Efficiency (continued** | | | | | | |
| EE07 | | √ | √ | | | p 196 |
| EE08 | | √ | √ | | | p 201 |
| EE09 | | √ | √ | | | p 204 |
| EE10 | | √ | √ | | | p 211 |
| **Fuel Substitution** | | | | | | |
| FS01 | | √ | | | | p 214 |
| FS02 | | √ | | √ | | p 217 |
| FS03 | | √ | | | | p 225 |
| **Interruptible Loads** | | | | | | |
| IL01 | | √ | | | | p 229 |
| IL02 | | √ | | | | p 234 |
| IL03 | √ | √ | | | | p 238 |
| IL04 | | √ | | √ | | p 241 |
| IL05 | | √ | | | | p 245 |
| **Integrated DSM Projects** | | | | | | |
| IP01 | | √ | | | | p 251 |
| IP02 | | √ | | | | p 254 |
| IP03 | | √ | | | | p 262 |
| IP04 | | √ | | | | p 265 |
| IP05 | | √ | | | | p 274 |
| IP06 | | √ | | √ | | p 283 |
| IP07 | | √ | | | | p 291 |
| IP08 | | √ | √ | | | p 295 |
| IP09 | | √ | | | | p 306 |
| IP10 | | √ | √ | | | p 310 |
| IP11 | | √ | √ | | | p 316 |
| IP12 | | √ | √ | | | p 321 |

| Case Study Number | Project Objective | | | | | Page Number |
|---|---|---|---|---|---|---|
| | Increasing Operating Reserve | Peak Load Reduction | Overall Load Reduction | Voltage Regulation | Other | |
| **Load Shifting** | | | | | | |
| LS01 | √ | √ | | | | p 325 |
| LS02 | | √ | √ | | | p 330 |
| LS03 | | √ | | | | p 334 |
| LS04 | | √ | | | | p 338 |
| LS05 | | √ | | | | p 342 |
| **Power Factor Correction** | | | | | | |
| PC01 | | √ | | | | p 345 |
| **Pricing Initiatives** | | | | | | |
| PI01 | | √ | | | | p 348 |
| PI02 | | √ | | | | p 355 |
| PI03 | | √ | | | | p 359 |
| PI04 | | √ | | | | p 364 |
| PI05 | | √ | | | | p 368 |
| PI06 | | √ | | | | p 378 |
| PI07 | | | | √ | | p 384 |
| PI08 | | √ | | | | p 389 |
| PI09 | | √ | | | | p 396 |
| **Smart Metering** | | | | | | |
| SM01 | | | √ | | | p 409 |

| Table A5. Case Studies by Major DSM Measure and Market Segments Addressed | | | | | | | |
|---|---|---|---|---|---|---|---|
| Case Study Number | Market Segments Addressed | | | | | | Page Number |
| | Residential Customers | Commercial and Small Industrial Customers | Agricultural Customers | Large Industrial Customers | Non Customer-related | Other | |
| **Direct Load Control** | | | | | | | |
| DC01 | √ | | | | | | p 46 |
| DC02 | | √ | | | | | p 50 |
| DC03 | √ | √ | | | | | p 54 |
| DC04 | √ | | | | | | p 61 |
| DC05 | √ | √ | | √ | | | p 65 |
| DC06 | √ | √ | | | | | p 71 |
| DC07 | √ | | | | | | p 81 |
| DC08 | √ | √ | | √ | | | p 91 |
| DC09 | | | √ | | | | p 99 |
| **Distributed Generation** | | | | | | | |
| DG01 | | | | | √ | | p 104 |
| DG02 | | | | | √ | | p 107 |
| DG03 | | | | | √ | | p 110 |
| DG04 | | √ | | √ | √ | | p 113 |
| DG05 | | √ | | | | | p 116 |
| **Demand Response** | | | | | | | |
| DR01 | | √ | | √ | | | p 121 |
| DR02 | √ | √ | √ | √ | | | p 132 |
| DR03 | | √ | √ | | | | p 141 |
| DR04 | | √ | | | | | p 153 |
| **Energy Efficiency** | | | | | | | |
| EE01 | √ | | | | | | p 164 |
| EE02 | √ | √ | | | | | p 169 |
| EE03 | √ | √ | | | | √ | p 174 |
| EE04 | √ | √ | | | | | p 177 |
| EE05 | √ | | | | | | p 184 |
| EE06 | √ | √ | | | | | p 187 |

| Case Study Number | Market Segments Addressed | | | | | | Page Number |
|---|---|---|---|---|---|---|---|
| | Residential Customers | Commercial and Small Industrial Customers | Agricultural Customers | Large Industrial Customers | Non Customer-related | Other | |
| **Energy Efficiency (continued)** | | | | | | | |
| EE07 | √ | √ | | | | | p 196 |
| EE08 | √ | √ | | | | | p 201 |
| EE09 | √ | √ | | | | | p 204 |
| EE10 | √ | | | | | | p 211 |
| **Fuel Substitution** | | | | | | | |
| FS01 | √ | | | | | | p 214 |
| FS02 | √ | | | | | | p 217 |
| FS03 | √ | | | | | | p 225 |
| **Interruptible Loads** | | | | | | | |
| IL01 | | | | √ | | | p 229 |
| IL02 | | | | √ | | | p 234 |
| IL03 | | | | √ | | | p 238 |
| IL04 | | | | √ | | | p 241 |
| IL05 | | √ | | √ | | | p 245 |
| **Integrated DSM Projects** | | | | | | | |
| IP01 | | √ | | | | | p 251 |
| IP02 | | √ | | | | | p 254 |
| IP03 | | √ | | | | | p 262 |
| IP04 | √ | √ | | √ | | | p 265 |
| IP05 | | √ | | √ | | | p 274 |
| IP06 | √ | √ | √ | | | | p 283 |
| IP07 | | | | √ | | | p 291 |
| IP08 | √ | √ | | | √ | | p 295 |
| IP09 | √ | √ | | √ | | | p 306 |
| IP10 | √ | √ | | | | | p 310 |
| IP11 | | | √ | | | | p 316 |
| IP12 | | | √ | | | | p 321 |

| Case Study Number | Market Segments Addressed | | | | | | Page Number |
|---|---|---|---|---|---|---|---|
| | Residential Customers | Commercial and Small Industrial Customers | Agricultural Customers | Large Industrial Customers | Non Customer-related | Other | |
| **Load Shifting** | | | | | | | |
| LS01 | | √ | | √ | | | p 325 |
| LS02 | | √ | | | | | p 330 |
| LS03 | | √ | | | | | p 334 |
| LS04 | √ | √ | | | | | p 338 |
| LS05 | | | | √ | | | p 342 |
| **Power Factor Correction** | | | | | | | |
| PC01 | | | | √ | | | p 345 |
| **Pricing Initiatives** | | | | | | | |
| PI01 | | √ | | √ | | | p 348 |
| PI02 | √ | | | | | | p 355 |
| PI03 | √ | | | | | | p 359 |
| PI04 | | | | √ | | | p 364 |
| PI05 | √ | | | | | | p 368 |
| PI06 | √ | √ | | | | | p 378 |
| PI07 | | | | √ | | | p 384 |
| PI08 | √ | | | | | | p 389 |
| PI09 | √ | √ | | | | | p 396 |
| **Smart Metering** | | | | | | | |
| SM01 | | √ | | | | | p 409 |

## DC01 ETHOS PROJECT TRIAL OF MULTIMEDIA ENERGY MANAGEMENT SYSTEMS - WALES, UK

| | |
|---|---|
| **Last updated** | 26 August 2005 |
| **Location of Project** | South Wales, United Kingdom |
| **Year Project Implemented** | 1996 |
| **Year Project Completed** | 1998 |
| **Name of Project Proponent** | SWALEC (South Wales Electricity Company) |
| **Name of Project Implementor** | SWALEC (South Wales Electricity Company) |
| **Type of Project Implementor** | Distribution utility |
| **Purpose of Project** | Deferral of network augmentation |
| **Timing of Project** | Pre contingency |
| **Focus of Project** | Network capacity limitations |
| **Project Objective** | Peak load reduction |
| **Project Target** | Network element |
| **DSM Measure(s) Used** | Direct load control<br>Pricing initiatives |
| **Specific Technology Used** | Storage space heaters<br>Storage water heaters |
| **Market Segments Addressed** | Residential customers |

### 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.

## 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 SWALEC 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

| Residential Customers Participating | Commercial and Small Industrial Customers Participating | Agricultural Customers Participating | Large Industrial Customers Participating | Additional Generation Installed |
|---|---|---|---|---|
| 100 | | | | |

| Peak Load | Peak Load Reduction | Duration of Peak Load Reduction | Overall Load Reduction | Energy Savings | Network Augmentation Deferral |
|---|---|---|---|---|---|
| | | | | | |

## HOW LOAD REDUCTION WAS MEASURED

Interval meter. 30 minute intervals.

## RESULTS ACHIEVED

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. 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.

## CONFIDENCE LEVEL IN ACHIEVING RESULTS

## REPEATABILITY OF RESULTS

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.

## TIME DELAY BEFORE MAXIMUM RESPONSE ACHIEVED

## WEATHER DEPENDENCE

## AVOIDED COSTS

## ACTUAL PROJECT COSTS

## PROJECT COST FROM THE SOCIETAL PERSPECTIVE

## OVERALL PROJECT EFFECTIVENESS

The use of multimedia energy management systems connected to storage space heaters and storage water heaters was successful in providing improved comfort for customers and reducing electricity use in the customers' dwellings. During the trial, SWALEC was able to achieve a 25% reduction in the peak demand on the relevant section of the distribution network. The one attempt to modify the shape of the distribution network demand profile was successful in reducing the night time peak and also in reducing SWALEC's wholesale purchase costs of electricity from the pool. However, it appears that the trial was discontinued before any conclusions could be drawn about its effectiveness in deferring augmentation of the distribution network.

## CONTACTS

## SOURCES

David, A. (1998). *Overall Project Report*. Ethos Project, Esprit European Funding Programme. Cardiff, SWALEC.

## CASE STUDY PREPARATION

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# DC02 SYDNEY CBD DEMAND CURTAILMENT PROJECT - AUSTRALIA

| | |
|---|---|
| **Last updated** | 19 August 2005 |
| **Location of Project** | Sydney central business district, Australia |
| **Year Project Implemented** | 2003 |
| **Year Project Completed** | 2004 |
| **Name of Project Proponent** | EnergyAustralia |
| **Name of Project Implementor** | EnergyAustralia |
| **Type of Project Implementor** | Distribution utility |
| **Purpose of Project** | Deferral of network augmentation |
| **Timing of Project** | Pre contingency |
| **Focus of Project** | Network capacity limitations |
| **Project Objective** | Peak load reduction |
| **Project Target** | Network region |
| **DSM Measure(s) Used** | Direct load control |
| **Specific Technology Used** | Use of linked building management control systems to control HVAC equipment in large office buildings and achieve dispatch of load reductions |
| **Market Segments Addressed** | Commercial and small industrial customers |

## DRIVERS FOR PROJECT

Electrical load in the Sydney central business district (CBD) is growing at approximately 16MVA per year and will face network constraints within about five years in the absence of other action.

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

The project was intended as a concept trial to demonstrate the cost and effectiveness of dispatch of low demand modes in large commercial building as a means to reduce peak demand across the six hour peak period on very hot (40 deg C plus) summer days, while maintaining satisfactory occupant comfort.

## DESCRIPTION OF PROJECT

The building management control systems at four selected CBD buildings were modified to incorporate reduced demand operating modes (typically by switching off one chiller and moderating ventilation and pumping appropriately) and to provide for communications with a central control facility to provide dispatch.

Links were established between a central load control point and the various building management control systems. These links enable direct load control of the systems to reduce electricity demand in the CBD on an at-call basis for short periods (up to 6 hours).

Test operations were carried out to prove up individual modes in early summer and various control strategies were tested when high demand days occurred. Demand reductions were rotated across the portfolio of buildings during the call period, with each building contributing to delivering the total required demand reduction.

Several portfolio curtailment test strategies were developed to determine the best approach. These included:

- 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;
- sequential dispatch and simultaneous dispatch.

Curtailment modes were designed for each building and were pre-programmed into the building management control systems of each building, to be called and cycled when needed by the central control system.

Building owners retained right of veto and could disconnect from the trial at any time.

## RESULTS

| Residential Customers Participating | Commercial and Small Industrial Customers Participating | Agricultural Customers Participating | Large Industrial Customers Participating | Additional Generation Installed |
|---|---|---|---|---|
| | 4 | | | |

| Peak Load | Peak Load Reduction | Duration of Peak Load Reduction | Overall Load Reduction | Energy Savings | Network Augmentation Deferral |
|---|---|---|---|---|---|
| 600 MW | 0.4 MW | 6 hours | | | NA |

## HOW LOAD REDUCTION WAS MEASURED

Other.  Feedback from building management systems and logging meter data.

## RESULTS ACHIEVED

An average 25% reduction in base building demand was typically achieved for approximately 1.5 hours under hot summer conditions without adverse impact on occupant comfort. This equated to approximately 400kVA per building. (Typical building size was 20,000 square metres).

The demand reduction could be sequentially dispatched to achieve a six hour duration demand reduction.

Total expected demand reductions from a full rollout of this approach within the Sydney CBD would yield demand reductions of up to 10MVA.

## CONFIDENCE LEVEL IN ACHIEVING RESULTS

Reliability and repeatability from test to test were not high. Individual building performance was variable and somewhat unreliable. Analysis suggests at least 10% over-subscription would be required to achieve reasonable reliability of reductions. Further operating experience may improve this.

## REPEATABILITY OF RESULTS

Repeatability may be limited by the extent to which the buildings in thre trial were representative of the overall building stock. Response from building owners generally has not been tested. Negative perceptions of impacts on tenants may increase costs as owners demand more reward.

## TIME DELAY BEFORE MAXIMUM RESPONSE ACHIEVED

Not relevant - trial only.

## WEATHER DEPENDENCE

Dispatch only relevant on hot days. Sydney CBD peak may occur at temperatures of 30 degrees C but days of 40+ degrees C also occur. There is some evidence that response is poorer on very hot days as buildings are not maintaining conditions prior to curtailment and comfort is compromised faster.

## AVOIDED COSTS

Cost per kVA of demand reduction was very high, although some unrepresentative costs were incurred in this trial, including significant monitoring upgrades to enable close attention to building performance (total AUD470,000).

Projected future implementation cost is approximately AUD50,000 per building. In the case of the Sydney CBD this would equate to approximately AUD265-545/kVA of demand reduction after accounting for benefits from energy trading and other values, which compares poorly with expected network deferral values of AUD100-200/kVA.

## ACTUAL PROJECT COSTS

EnergyAustralia - AUD470,000

## PROJECT COST FROM THE SOCIETAL PERSPECTIVE

Not calculated.

## OVERALL PROJECT EFFECTIVENESS

The key benefit of the project was 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.

The project demonstrated that the concept was technically feasible. Further work is required to determine if it would be cost effective and viable in the Sydney CBD context.

## CONTACTS

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## SOURCES

## CASE STUDY PREPARATION

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## DC03 LIPAEDGE DIRECT LOAD CONTROL PROGRAM - USA

| | |
|---|---|
| **Last updated** | 2 March 2006 |
| **Location of Project** | Long Island, New York, USA |
| **Year Project Implemented** | 2001 |
| **Year Project Completed** | 2003 |
| **Name of Project Proponent** | Long Island Power Authority (LIPA) |
| **Name of Project Implementor** | Long Island Power Authority (LIPA) |
| **Type of Project Implementor** | Distribution utility<br>Transmission utility<br>Electricity retailer/supplier |
| **Purpose of Project** | Provision of network operational services |
| **Timing of Project** | Pre contingency |
| **Focus of Project** | Network capacity limitations<br>Generation capacity limitations |
| **Project Objective** | Peak load reduction |
| **Project Target** | Whole network |
| **DSM Measure(s) Used** | Interruptible loads<br>Direct load control |
| **Specific Technology Used** | Carrier Comfort Choice Thermostats |
| **Market Segments Addressed** | Residential customers<br>Commercial and small industrial customers |

### DRIVERS FOR PROJECT

To reduce peak demand when generation is insufficient or there are network constraints.

### DESCRIPTION OF PROJECT

Long Island Power Authority (LIPA) developed the LIPAedge program to use central control of residential and small commercial air-conditioning thermostats to achieve peak load reduction. The program commenced in early 2001 and is still operating in late 2005. However, from 31 July 2003 the program was closed to new participants because LIPA has enough air conditioner load under direct load control.

#### Technology

The LIPAedge program uses the programmable ComfortChoice thermostat (see Figure DC03/1, page 55). This was designed by the Carrier Corporation with associated communication infrastructure provided by Silicon Energy to provide emergency peak reduction for utilities.

The system operator uses an internet-based system provided by Silicon Energy to control a demand-side resource comprising about 20,000 thermostat-controlled air conditioners. Skytel two-way pagers are used to transmit a curtailment order to the thermostat and to receive acknowledgment and monitoring information. One or more pager signals are generated and transferred to the SkyTel pager network (see Figure DC03/2, page 55). Commands go via satellite to pager towers, where they are broadcast to the thermostats. The thermostats take immediate action or adjust their schedules for future action, depending on what the system operator ordered. The thermostats log the order and respond via pager, enabling LIPA to monitor the response to the event. The thermostats also collect data every minute on temperature, set point, and power consumption (hourly duty cycle). They retain this information as hourly averages and report it to the utility. The thermostat itself holds 7 days of hourly data.


**Figure DC03/1. ComfortChoice Thermostat Used in the LIPAedge Program**

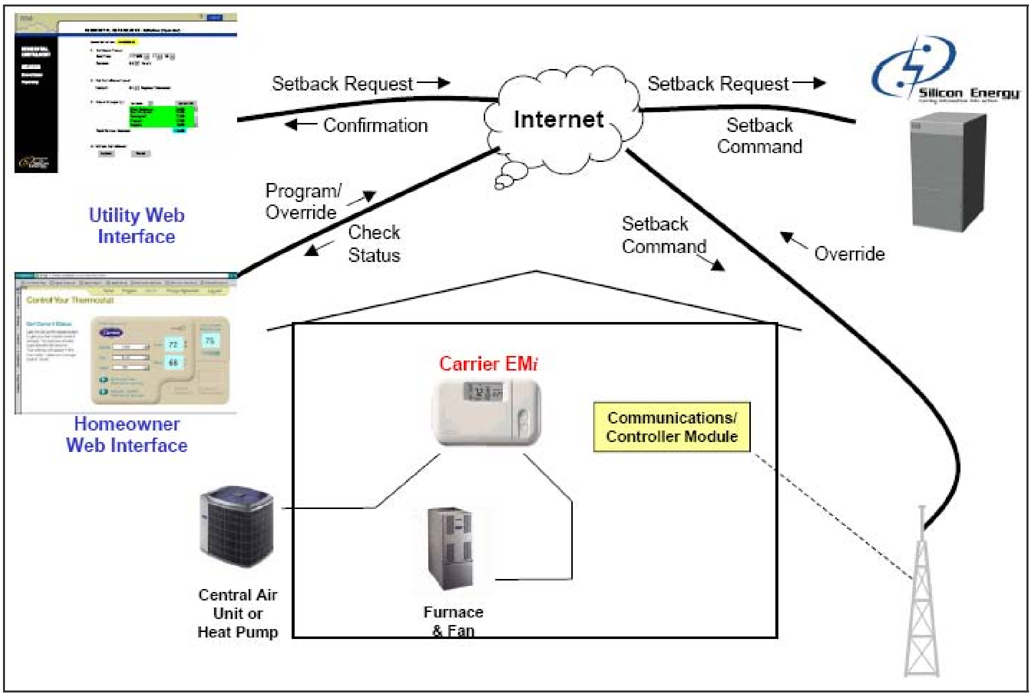


**Figure DC03/2. The Carrier/Silicon Energy Direct Load Control System**

For a summer load curtailment, the system operator might send a command at 9:00 am directing all thermostats to move their set points up 4 degrees, starting at 2:00 pm and ending at 6:00 pm. Alternatively, the system operator could send a command directing all thermostats to completely curtail immediately. The command would be received and acted upon by all loads, providing full response within about 90 seconds. This is far faster than generator response, which typically requires a 10-minute ramp time.

Thermostats can be addressed individually, in groups, or in total. This important advantage provides both flexibility and speed. System operator commands that are addressed to the entire resource are implemented through a single page that all thermostats receive. Similarly, 15 subgroups can be addressed if response is required in a specific area to alleviate a transmission constraint. Thermostats can be addressed individually as well. This capability is useful for monitoring the performance of the system (each thermostat is checked weekly for a “heartbeat”).

The customer also receives benefits. The thermostat is fully programmable and remotely accessible, with all of the associated energy savings and convenience benefits. A web-based remote interface is provided for customer interaction. Customers can also override curtailment events. This feature appears to be important to gain customer acceptance and it probably increases the reliability benefit.

The system operator can block overrides if necessary. Typically. this is not done for demand curtailment events, but it may be useful for spinning reserve events.

Two-way paging communication enables the utility to monitor load performance both during response events and under normal conditions. Response from the thermostats is staggered over a time period set by the utility to avoid overwhelming the paging system. It typically requires 90 minutes for 20,000 thermostats to respond. Thus the system provides for performance monitoring but not in the 2 to 8-second intervals typical for large generators.

Communication is more reliable from the system operator to the thermostat than from the thermostat to the system operator. The pager tower has a 500-W transmitter, while the thermostat's transmitter is only 1 W. The thermostat makes four attempts to report back if the pager tower fails to receive any of its signals.  The thermostat continues to take control actions and respond to new commands even if return communication is lost. Hence the system is more reliable than would be indicated by the list of “failed” units generated by the "heartbeat" report. About 4% to 5% of the thermostats fail to report back.

## The LIPAedge Program

The LIPAedge program is the largest residential direct load control program in the USA using two-way communication. Two-way communication allows LIPA to monitor capability and response. It also enables customers to control their individual thermostats via the Internet, a benefit that motivates participation.

The LIPAedge program is available for Residential Central Air Conditioning customers and Small Business customers, though the program is now closed to new participants. Customers who sign up to the LIPAedge program receive a ComfortChoice thermostat and installation free of charge. Customers also receive a one-time bonus payment of USD 25 (residential customers) or USD 50 (small commercial customers). During 2001, LIPAedge customers were offered an opportunity to earn a USD 20 cash reward for each LIPA customer referral they provided who installed a LIPAedge thermostat.

LiPAedge customers agree to have their central air conditioning system adjusted between the hours of 2 pm and 6 pm for a maximum of seven days throughout the four month summer season. Customers have access to a dedicated web page for their thermostat and are able to remotely change the set point of their air conditioner whenever they want.

LIPA initiates curtailment events by either increasing the set point on LIPAedge thermostats by 3 to 4 degrees, or by cycling airconditioner compressors off for a portion of each hour (see Figure DC03/3).

Customers can override curtailment messages sent to their thermostat, though LIPA encourages its customers not to override during a curtailment event. If the customer decides to override the curtailment, the change is recorded by the thermostat and a wireless message is then sent back to the central server.

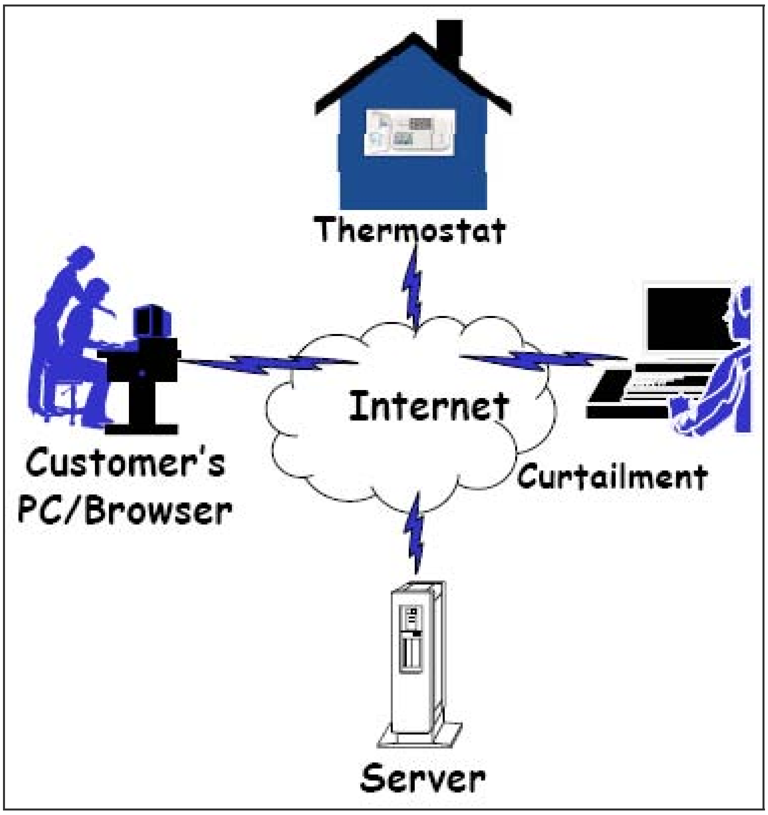


**Figure DC03/3. The Curtailment Process in the LIPAedge Program**

## RESULTS

| Residential Customers Participating | Commercial and Small Industrial Customers Participating | Agricultural Customers Participating | Large Industrial Customers Participating | Additional Generation Installed |
|---|---|---|---|---|
| 20,400 | 3,000 | | | |

| Peak Load | Peak Load Reduction | Duration of Peak Load Reduction | Overall Load Reduction | Energy Savings | Network Augmentation Deferral |
|---|---|---|---|---|---|
| 75 MW | 25 MW | 4 hours | | | |

## HOW LOAD REDUCTION WAS MEASURED

Other. Thermostat reports hourly duty cycle.

## RESULTS ACHIEVED

LIPA collected name-plate power consumption information on the air-conditioning equipment being controlled when it installed the ComfortChoice thermostats for the LIPAedge program. It also directly measured the power consumption of a subset of those loads to estimate the actual load of the aggregation. LIPA determined that the average capacity of residential air-conditioning units being controlled was 3.84 kW, while the average capacity of small commercial units was 6.38 kW. The total 23,400 individual loads had a peak capacity of 97.4 MW if all the units were on at 100% duty cycle.

LIPA monitored the performance of 400 units from 1 May 2002 through 29 September 2002. Hourly data were collected from each unit for duty cycle and facility temperature. Those data were used to estimate the performance of all 23,400 responsive loads. LIPA found that each controlled load provided an average of 1.06 kW of demand reduction (1.03 kW per residential air-conditioner and 1.35 kW per small commercial air-conditioner). LIPA expected 24.9 MW of peak reduction response from the full 23,400 controlled air-conditioners.

LIPA tested the actual performance of the system to reduce energy demand during peak hours on three days during the summer of 2002. It also monitored performance on seven other days to provide baseline data. The results are shown in Tables DC03/1 and DC03/2, page 59. Table DC03/2 shows that an increasing number of residential thermostats were overridden as the 14 August curtailment event continued; the proportion of units overridden increased from 5.7% at 3 pm to 20.8% at 6 pm.

| Table DC03/1. Performance During Curtailment Events in Summer 2002 | | | |
|---|---|---|---|
| | 3 July | 30 July | 14 August |
| Participation (units) | 15,943 | 17,051 | 17,474 |
| Load reduction at 5 pm (MW) | 15,852 | 16,076 | 16,273 |
| Total energy saving over curtailment event (MWh) | 65,883 | 66,493 | 67,463 |

| Table DC03/2. Performance of Residential Units on 14 August 2002 | | | |
|---|---|---|---|
| Hour ending | Units overridden at hour end | Adjusted net kW reduction per unit | Total kW reduction |
| 3 pm | 5.7% | 1.05 | 16,119 |
| 4 pm | 11.5% | 0.98 | 14,942 |
| 5 pm | 17.2% | 0.92 | 14,060 |
| 6 pm | 20.8% | 0.78 | 11,883 |

## CONFIDENCE LEVEL IN ACHIEVING RESULTS

High.

## REPEATABILITY OF RESULTS

Results depend upon ambient temperature, day of the week, and time of day. Once characterized they are repeatable.

## TIME DELAY BEFORE MAXIMUM RESPONSE ACHIEVED

90 seconds.

## WEATHER DEPENDENCE

Because this program controlled air conditioners, the response was highly dependent on temperature.

## AVOIDED COSTS

New peaking generation costs of approximately USD 500/kW.

## ACTUAL PROJECT COSTS

The LIPAedge program cost was USD 515 per residential customer and USD 545 per commercial customer. This yielded a combined average cost of USD 487/kW of demand reduction. LIPA paid all costs.

## PROJECT COST FROM THE SOCIETAL PERSPECTIVE

## OVERALL PROJECT EFFECTIVENESS

Very good.

## CONTACTS

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## SOURCES

LIPAedge program website at: http://www.lipaedge.com/index.asp

Carrier website at: http://www.mytstat.com

Long Island Power Authority 2002. *LIPAedge. PowerPoint presentation to the New York Independent System Operator Price-Responsive Load Working Group*, November 21. Available at:
http://www.nyiso.com/public/archive/webdocs/committees/Price-Responsive%20Load%20WG/2002-11-21/3_lipa_presentation.pdf

## CASE STUDY PREPARATION

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## DC04 SACRAMENTO PEAK CORPS - USA

| | |
|---|---|
| **Last updated** | 26 August 2005 |
| **Location of Project** | Sacramento, California |
| **Year Project Implemented** | 1979 |
| **Year Project Completed** | Continuing |
| **Name of Project Proponent** | Sacramento Municipal Utility District (SMUD) |
| **Name of Project Implementor** | Sacramento Municipal Utility District (SMUD) |
| **Type of Project Implementor** | Distribution utility<br>Transmission utility |
| **Purpose of Project** | Deferral of network augmentation |
| **Timing of Project** | Pre contingency |
| **Focus of Project** | Network capacity limitations |
| **Project Objective** | Increasing operating reserve<br>Peak load reduction<br>Overall load reduction |
| **Project Target** | Network region |
| **DSM Measure(s) Used** | Interruptible loads<br>Direct load control |
| **Specific Technology Used** | Radio controlled air conditioning contactor |
| **Market Segments Addressed** | Residential customers |

### DRIVERS FOR PROJECT

The Peak Corps program 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 degrees Fahrenheit (38 degrees Celsius).

The program was implemented to reduce peak load in anticipation of any type of emergency situation. It is not a market based system. The emergency can be a transmission, distribution or generation emergency.

### 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 degrees Fahrenheit (38 degrees Celsius), 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.

In 2005, the program currently 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

| Residential Customers Participating | Commercial and Small Industrial Customers Participating | Agricultural Customers Participating | Large Industrial Customers Participating | Additional Generation Installed |
|---|---|---|---|---|
| 100,000 | | | | |

| Peak Load | Peak Load Reduction | Duration of Peak Load Reduction | Overall Load Reduction | Energy Savings | Network Augmentation Deferral |
|---|---|---|---|---|---|
| 2,800 MW | 200 MW | As needed | | | |

## HOW LOAD REDUCTION WAS MEASURED

Estimate. Estimate from system metering.

## RESULTS ACHIEVED

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.

In 2005, the Peak Corps system is tested every year. The 200 MW response is achievable on an extremely hot day of 112 degrees Fahrenheit.

## CONFIDENCE LEVEL IN ACHIEVING RESULTS

The MW response is a function of temperature and is predicted by an algorithm. The response is quite accurately predicted based on temperature.

## REPEATABILITY OF RESULTS

The program has been very repeatable.

## TIME DELAY BEFORE MAXIMUM RESPONSE ACHIEVED

The dispatch signal is broadcast by radio, and the response is provided in a few seconds.

## WEATHER DEPENDENCE

The response is a function of weather because the controlled load is air conditioning.

## AVOIDED COSTS

## ACTUAL PROJECT COSTS

In 2005, the annual incentive paid to Peak Corps customers is USD 3.7 million.

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.

## PROJECT COST FROM THE SOCIETAL PERSPECTIVE

## OVERALL PROJECT EFFECTIVENESS

Highly effective.

## CONTACTS

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## SOURCES

Sacramento Municipal Utility District web site at:
http://www.smud.org/residential/saving/peak.html

The Results Center (1994). *Sacramento Municipal District Residential Peak Corps: Profile # 83*. Available at: http://sol.crest.org/efficiency/irt/83.pdf

## CASE STUDY PREPARATION

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# DC05 PEF DIRECT LOAD CONTROL AND STANDBY GENERATOR PROGRAMS - USA

| | |
|---|---|
| **Last updated** | 12 September 2005 |
| **Location of Project** | Florida, USA |
| **Year Project Implemented** | 1981 |
| **Year Project Completed** | Ongoing |
| **Name of Project Proponent** | Progress Energy Florida (PEF) - formerly Florida Power Corporation |
| **Name of Project Implementor** | Progress Energy Florida (PEF) |
| **Type of Project Implementor** | Distribution utility<br>Transmission utility<br>Electricity retailer/supplier |
| **Purpose of Project** | Deferral of network augmentation |
| **Timing of Project** | Pre contingency |
| **Focus of Project** | Network capacity limitations<br>Generation capacity limitations |
| **Project Objective** | Peak load reduction<br>Overall load reduction |
| **Project Target** | Whole network |
| **DSM Measure(s) Used** | Standby generation<br>Interruptible loads<br>Direct load control |
| **Specific Technology Used** | Radio one way paging network |
| **Market Segments Addressed** | Residential customers<br>Commercial and small industrial customers<br>Large industrial customers |

## DRIVERS FOR PROJECT

The Florida *Energy Efficiency and Conservation Act*, passed in 1980, requires the Florida Public Service Commission to adopt goals to increase the efficiency of energy consumption, increase the development of cogeneration, and reduce and control the growth rates of electric consumption and weather-sensitive peak demand.

The Commission must review a utility's conservation goals not less than every five years. Within 90 days of a final Order establishing goals, a utility must submit a demand-side management (DSM) plan which contains conservation and DSM programs designed to meet its numeric goals.

By an Order issued in August 2004, the Florida Public Service Commission approved PEF's latest DSM Plan for meeting its energy conservation goals established by the Commission. The Plan consists of a portfolio of individual DSM programs which include direct load control and standby generator programs in the residential, commercial and industrial sectors.

## DESCRIPTION OF PROJECT

PEF's direct load control and standby generator programs cover

- centrally ducted space heating and air conditioning systems, water heaters and pool pumps in the residential sector
- central cooling and chiller systems, interruptible and curtailable loads and standby generation in the commercial and industrial sectors.

Direct load control is achieved through a one-way radio paging network for all sectors. Some SCADA control is used on dedicated feeders serving larger industrial customers who are on interruptible tariffs.

The direct load control programs allow PEF to reduce peak demand and defer the construction of additional generation and network capacity.

### Residential Energy Management Program

The Residential Energy Management program is a voluntary customer direct load control program that commenced in 1981 and was modified in 1995, 2000 and 2004.

Peak demand is reduced by PEF using radio controlled switches installed on the customers' premises to turn off selected electrical equipment. These controlled interruptions are at PEF's option, during specified time periods, and coincident with hours of peak demand.

Commencing in 2004, PEF is currently only accepting new enrolments in a winter-only component of the Residential Energy Management program. The winter-only component represents a modified, cost-effective version of the previous year-round program. It provides for direct load control of customer's electric water heater and centrally ducted electric space heating systems during the period November through March.

To participate in the winter-only component of the Residential Energy Management Program, customers must:

- utilize both an electric water heater and a centrally ducted electric space heating system; and
- have a minimum average monthly usage of 600 kWh for the months of November through March.

Participants in the winter-only component must include both a central heating system and a water heater in the load control program. Participants in the year-round component were previously able to include any or all of a central heating system, a central air conditioning system, a water heater and a pool pump in the load control program.

PEF installs free of charge a control unit, called an "Energy Management Box", in participants' dwellings. The control unit receives radio signals from PEF's control centre which instruct it to switch the controlled equipment off and on.

During the period November to March, PEF may implement the following interruptions during peak usage periods (6 am to 10 am and 6 pm to 10 pm):

- water heaters: continuous interruption for up to five hours;
- space heating systems: up to 16.5 minutes out of each 30 minute interval.

Participants do not have the ability to override the control unit during a load control event.

Participants receive credits on their electricity bills of up to USD 11.50 per month from November to March. Credits are pro-rated according to monthly usage above 600 kWh. No credits are given for months when usage is below 600 kWh.

### Commercial/Industrial Energy Management Program

The Commercial/Industrial Energy Management Program is a voluntary customer direct load control program that is restricted to existing customers as of 20 July 2000.

Peak demand is reduced by PEF using radio controlled switches installed on the customers' premises to turn off central cooling and chiller systems during specified time periods, and coincident with hours of peak demand.

Similarly to the Residential Energy Management Program, participants receive credits on their electricity bills.

### Interruptible Service Program

The Interruptible Service Program is a voluntary customer direct load control program that commenced in its present form in 1996.

The program is available throughout the entire territory served by PEF to any non-residential customer who is willing to have their power interrupted by PEF. PEF has remote control of the circuit breaker or disconnect switch supplying the customer's equipment.

To participate in the Interruptible Service Program, commercial and industrial customers must have an average billing demand of 500 kW or more.

Participants receive a monthly interruptible demand credit based on their billing demand and billing load factor. In 2005, this credit is USD 3.08 per kW against a demand charge of USD 4.70 per kW. Participants who choose not to reduce their load during an interruption event are charged by PEF for their electricity usage at the price paid at that time by PEF for purchased power.

### Curtailable Service Program

The Curtailable Service Program is a voluntary customer direct load control program that commenced in its present form in 1996.

The program is available throughout the entire territory served by PEF to any non-residential customer who agrees to curtail 25% of their average monthly billing demand when required by PEF. PEF has remote control of the circuit breaker or disconnect switch supplying the customer's equipment.

To participate in the Curtailable Service Program, commercial and industrial customers must have an average billing demand of 500 kW or more.

Participants receive a monthly curtailable demand credit based on their curtailment demand and billing load factor. In 2005, this credit is USD 2.31 per kW against a demand charge of USD 5.56 per kW. Participants who choose not to reduce their load during a curtailment event are charged by PEF for their electricity usage at the price paid at that time by PEF for purchased power.

### Standby Generation Program

The Standby Generation Program commenced in 1993 and was modified in 1995. It is a demand control program that reduces PEF's demand based upon the indirect control of customer equipment.

The program is a voluntary program available to all commercial and industrial customers who have on-site generation capability and are willing to reduce their PEF demand when PEF deems it necessary. PEF has no direct control of the customer's equipment, but relies upon the customer to initiate the generation upon being notified by PEF and continue running it until PEF notifies the customer that the generation is no longer needed. PEF does not restrict other use of the equipment by the customer.

To participate in the Standby Generation Program, commercial and industrial customers must have at least 50 kW of standby generation that will allow facility demand reduction at the request of PEF.

Participants receive a monthly credit on their energy bill according to the demonstrated ability of the customer to reduce demand at PEF's request. The credit is based upon the load served by the customer's generator, which would have been served by PEF if the Standby Generation Program were not in operation.

### RESULTS

| Residential Customers Participating | Commercial and Small Industrial Customers Participating | Agricultural Customers Participating | Large Industrial Customers Participating | Additional Generation Installed |
|---|---|---|---|---|
| 400,000 | 460 | | 170 | |

| Peak Load | Peak Load Reduction | Duration of Peak Load Reduction | Overall Load Reduction | Energy Savings | Network Augmentation Deferral |
|---|---|---|---|---|---|
| 10,500 MW | 1,000 MW | Varies with need | | | |

### HOW LOAD REDUCTION WAS MEASURED

Estimate.  Estimates were based on the time/temperature matrix and verified with system load data.

## RESULTS ACHIEVED

PEF's direct load programs are able to reduce system load by approximately 10%.

The direct load control programs:

- improve system reliability;
- have deferred the construction of several generating plants;
- are used to meet State Reserves sharing group obligations;
- meet state regulator requirements for DSM programs.

## CONFIDENCE LEVEL IN ACHIEVING RESULTS

The performance of the direct load control programs varies depending on time of day and temperature. Results are predictable through the use of a time/temperature matrix which was developed by PEF through end-use studies.

## REPEATABILITY OF RESULTS

Results of the direct load control programs are predictable through the use of the time/temperature matrix.

## TIME DELAY BEFORE MAXIMUM RESPONSE ACHIEVED

Because of the size of the direct load control and standby generator programs, they are dispatched according to the load reduction needed. However, the maximum time to drop all enrolled load is less than 5 minutes.

## WEATHER DEPENDENCE

Because participants are not able to override load control signals, customer response in the direct load control programs is not dependent on weather conditions. However, the amount of load reduction required by PEF is very much affected by time of day and temperature.

## AVOIDED COSTS

As measured with the Rate Impact Measure (RIM) test, the benefits of these programs exceed the cost, as required by the State regulator.

## ACTUAL PROJECT COSTS

Annual program costs:

- commercial/industrial: USD 21 million including incentives;
- residential: USD 22 million including incentives.

In 2003, the cost to PEF of purchasing and installing each control unit in the Residential Energy Management Program was USD 182.

## PROJECT COST FROM THE SOCIETAL PERSPECTIVE

Since these programs pass the Rate Impact Measure (RIM) test, they are beneficial to all customers including participants and non-participants.

## OVERALL PROJECT EFFECTIVENESS

The programs provide needed reserve margins and reliability in a cost-effective manner.

## CONTACTS

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## SOURCES

Progress Energy website at:
www.progress-energy.com/custservice/flares/energymgmt/index.asp

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## CASE STUDY PREPARATION

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# DC06 ETSA UTILITIES AIR CONDITIONER DIRECT LOAD CONTROL PROGRAM - AUSTRALIA

| | |
|---|---|
| **Last updated** | 10 October 2008 |
| **Location of Project** | Various suburbs in Adelaide, South Australia |
| **Year Project Implemented** | 2005 |
| **Year Project Completed** | |
| **Name of Project Proponent** | ETSA Utilities |
| **Name of Project Implementor** | ETSA Utilities |
| **Type of Project Implementor** | Distribution utility |
| **Purpose of Project** | Deferral of network augmentation |
| **Timing of Project** | Pre contingency |
| **Focus of Project** | Network capacity limitations |
| **Project Objective** | Peak load reduction |
| **Project Target** | Network region |
| **DSM Measure(s) Used** | Direct load control |
| **Specific Technology Used** | Remote load switching device |
| **Market Segments Addressed** | Residential customers<br>Commercial and small industrial customers |

## DRIVERS FOR PROJECT

South Australia has a very peaky electricity demand profile. Figure DC06/1 shows the electricity demand profile on the ETSA Utilities network on 8 February 2001, when demand peaked at about 2,440 MW. The major contribution to the peak is from the residential sector, particularly air conditioning use on hot days.

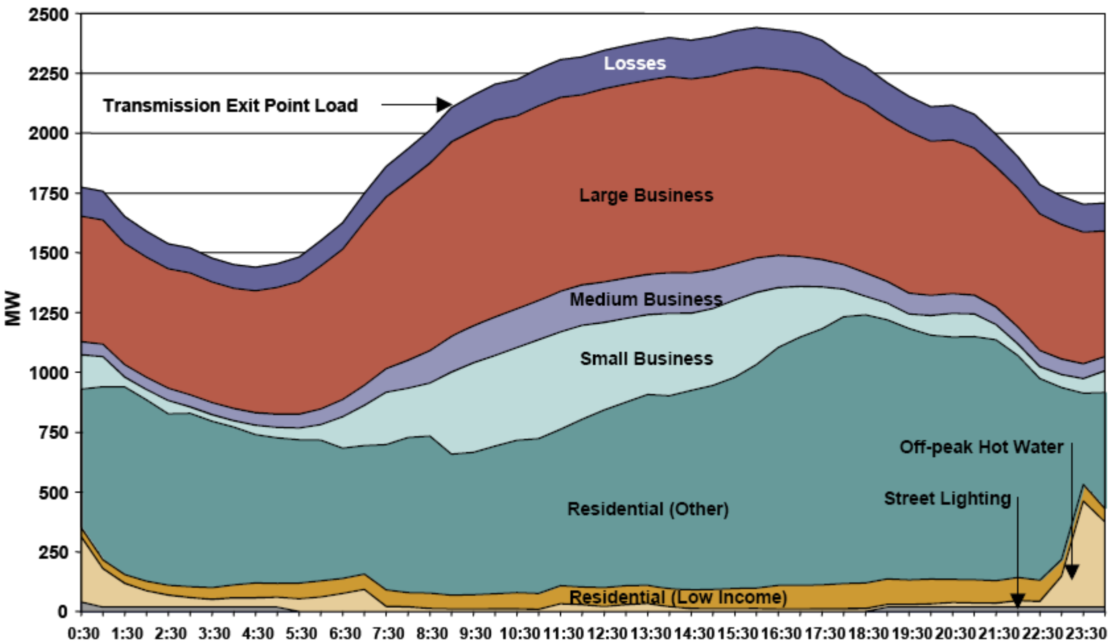


**Figure DC06/1. Peak Day Load Profile for the ETSA Utilities System, 8 February 2001**

For the summer of 2006/07, maximum electricity demand on the South Australian distribution network peaked at 2,563 MW on 16 January 2007. ETSA Utilities estimated that peak demand on very hot days, primarily due to air-conditioning load, was about 1,000 MW greater than average daily peak demand over the summer of 2006/07.

In September 2003, the electricity industry regulator, the Essential Services Commission of South Australia (ESCOSA), established processes that required ETSA Utilities to publish information regarding forecast network limitations or constraints, and to seek proposals for non-network alternatives to address such constraints, including demand side management.

These processes address a significant barrier to successful take-up of DSM opportunities, ie a lack of publicly available information regarding network limitations that might be addressed through DSM. ESCOSA's intention is that DSM providers will be able to assess opportunities and make bids to ETSA Utilities on the basis of the information provided.

The form of regulation imposed on ETSA Utilities by ESCOSA is expressed as a control placed on the average revenue ($/MWh) that ETSA Utilities can earn in a year. This form of regulation provides an incentive to ETSA Utilities to maximise energy sales, and conversely penalises ETSA Utilities if sales are below forecast levels (eg due to greater than expected impact of DSM measures).

To reduce the disincentive to implement DSM, ESCOSA incorporated into its regulatory determination a correction factor designed to reduce the financial risks faced by ETSA Utilities because of variations in forecast sales. This factor is more directly relevant to application of energy efficiency measures than to reduction of peak demand, but may be relevant to peak reduction measures that also reduce energy sales (eg installation of more efficient reverse cycle air conditioners).

In addition, ESCOSA approved an amount of AUD20.4 million (December 2004 values) as operating expenditure over the 2005-2010 regulatory period for ETSA Utilities to trial specified network DSM measures that may reduce the requirement for peak-driven network expansion. The DSM measures mandated by ESCOSA comprised:

- power factor correction;
- direct load control;
- voluntary and curtailable load control;
- standby generation;
- critical peak pricing; and
- aggregation of demand reductions.

## DESCRIPTION OF PROJECT

To implement the DSM program funded through the ESCOSA determination, ETSA Utilities is identifying a range of possible projects within each of the program’s approved categories of DSM measures. The suggested projects are short-listed by a Steering Committee on the basis that the projects are meritorious, are consistent with the regulator's determination, meet budgetary expectations, and have good prospects of producing net benefits in a widespread network roll-out.

In June 2007, the DSM program portfolio consisted of 27 individual projects at various stages of implementation. Several of these projects involved direct load control (DLC) of air conditioners.

### Initial DLC Trial: Summer 2005/06

An initial trial of DLC technology applied to residential air conditioners was launched in the summer of 2005/06. The primary aim of this trial was to determine customer perception of change in comfort levels resulting from the remote management of domestic air conditioners. Secondary aims were:

- to determine the impact on aggregate demand for the sites in the trial;
- to gain experience in the installation and operation of proprietary DLC technology;
- to test the performance of the selected DLC technology; and
- to gain experience in quantification, metrics and verification.

The trial involved 20 residential customers in the Adelaide metropolitan area. Customers were paid an incentive of AUD100 to participate. The customers were recruited by demographic, geographic area and equipment type. During the trial customers were able to contact a named ETSA staff person to provide feedback and to report adverse impact or problems. After the trial customers were de-briefed on the results of the trial and their perceptions were recorded.

A variety of reverse cycle air conditioners (either split or ducted) were included in the trial. Only air conditioners with an electrical load in excess of 2.5 kW were selected. The compressor load of the air conditioners in the trial ranged from 2.5 to 10.3kW, with the average being 4.27kW.

The air conditioners were controlled using Comverge load control units (LCUs) that had the capacity to cycle air conditioner compressors. The LCUs were located external to the customer premises adjacent to the air conditioner compressor unit (see Figure DC06/2, page 74). Each LCU had two integral relays rated at 5 and 30 amps. The relays could be remotely controlled using a variety of communication media. For practical purposes, in this trial ETSA's radio network was used as the communication medium. Each sample site was also fitted with an interval meter for load monitoring purposes.

Application of direct load control occurred during a period of high temperature days in March 2006. Cycling strategies involved compressors being switched off (with fans continuing to operate) for either 7.5 minutes or 15 minutes in each 30 minute period during the late afternoon (see Table DC06/1, page 74).

### Pilot Program: Summer 2006/07

Based on the results of the initial trial, a much larger air conditioner DLC pilot program was developed for the 2006/07 summer. An area in metropolitan Adelaide (Glenelg/Morphettville) was selected for the pilot program. This area was chosen because it is supplied by two substations that are expected to become constrained by 2011. In the absence of initiatives to reduce peak demand, augmentation of the distribution network would be required by that date.


**Figure DC06/2. Comverge Load Control Unit Used in the ETSA Utilities Air Conditioner DLC Trial**

| Table DC06/1. Application of Direct Load Control in the Initial Trial, March 2006 | | | |
|---|---|---|---|
| **Date** | **Time** | **Maximum External Temperature (°C)** | **Cycle** |
| 2 March | 16.15 to 17.15 | 36 | 7.5 min off in 30 min |
| 3 March | 16.05 to 18.05 | 35 | 7.5 min off in 30 min |
| 4 March | 14.15 to 16.15 | 35 | 7.5 min off in 30 min |
| 11 March | 16.30 to 18.30 | 37 | 15 min off in 30 min |
| 12 March | 12.09 to 14.09 | 34 | 15 min off in 30 min |

A target load reduction of 2.2 MVA was established for the pilot program.

The objectives of the pilot program were:

- to further test customer acceptance;
- to gain further experience with DLC technology; and
- to assess the impact and ultimately the potential for wide scale roll out of the technology.

ETSA Utilities initiated the pilot program in June 2006 with a media marketing and community education campaign, entitled “Beat the Peak”. The campaign primarily targeted the 12,000 residential customers in the selected region and was designed to secure volunteers to participate in the program. Participating customers were offered a cash incentive of AUD100. A direct marketing campaign (mailout, local advertising, etc) was also used. The marketing campaign attracted significant media coverage, with general support expressed for DSM.

Approximately 4,000 residential customers expressed interest in participating in the pilot program as a result of the overall marketing campaign. From this response, ETSA Utilities identified about 1,700 residential air conditioners that were suitable for the program, comprising either split or ducted refrigerative systems. In many cases, air conditioners were deemed unsuitable, being either window installed or portable refrigerative systems, ducted or portable evaporative systems, or ceiling fans.

ETSA Utilities also visited every commercial customer in the trial area and identified a further 700 air conditioners in commercial premises that were suitable for the trial.

In total, about 2,400 air conditioners were identified for the pilot program. To monitor demand impacts during the program, ETSA Utilities installed metering equipment in some customer premises, as well as on ten 11 kV feeders and 86 street transformers.

For this pilot program, ETSA Utilities, in conjunction with the Adelaide-based Saab Systems Pty Ltd, developed a small DLC device (the “Peak Breaker”) to be attached to the external compressor of air conditioners (see Figure DC06/3). This device requires only a simple installation procedure lasting up to 30 minutes with no internal access to premises needed.


**Figure DC06/3. Saab Systems “Peak Breaker” Direct Load Control Device Used in the ETSA Utilities Air Conditioner DLC Pilot Program**

However, about half of the 2,400 air conditioners initially deemed suitable for the pilot program were found to be "new generation" units with advanced internal electronic diagnostics that effectively prevented the Peak Breaker from overriding the compressor. These air conditioners were unsuitable for the installation of the Peak Breaker.

The penetration of new generation air conditioners was far higher than had been expected (the air conditioning industry had advised a likely figure of 10%). Ultimately, ETSA Utilities determined that approximately 1,100 (from the sample of 2,400) air conditioners were suitable for installation of the Peak Breaker, while a further 1,160 new generation units would require the development of a different form of DLC device.

For the summer of 2006/07, approximately 750 air conditioners (from the pool of 1,100) were fitted with the simple Peak Breaker device that switched the air conditioner compressors directly. The system for communicating with the devices is shown in Figure DC06/4. The Peak Breakers were activated in a random sequence when signals were sent via the internet to a public radio station which then transmitted the signals to the Peak Breakers. The system was able to communicate with subsets of the Peak Breakers based on substation, product group or individual customer level.

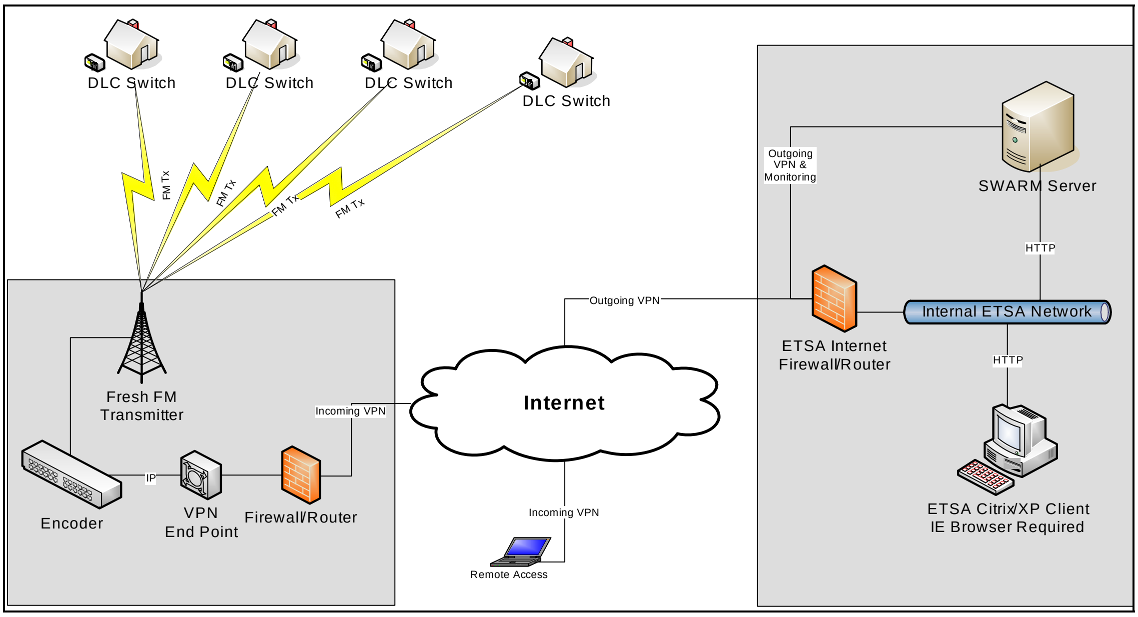


**Figure DC06/4. Communication System for the ETSA Utilities Air Conditioner DLC Pilot Program**

Site level monitoring with interval meters was carried out during peak demand days at 90 randomly selected sites, with the remaining sites being monitored at the street transformer level. Monitoring also occurred through the SCADA system operated by ETSA Utilities to demonstrate the impact at the 66 kV sub-transmission system at times of peak demand. In addition, the distribution transformers and 11 kV substation feeders were equipped with metering equipment with remote communications capability allowing interval data to be collected as required.

Application of direct load control at the 750 sites commenced in December 2006. A range of control strategies were tested at various times on peak demand days, including cycling the air-conditioners for different lengths of time over different periods of the day. The following switching periods were used to assess the impacts of different switching protocols:

8 minutes off in 30 minutes;
15 minutes off in 30 minutes (the ‘normal’ switching period used in the United States);
30 minutes off in 60 minutes – used twice on selected street transformers;
25 minutes off in 60 minutes – used for one period.

Switching of 15 minutes off in 30 minutes was tested on four occasions and no customer complaints were received regarding comfort levels. ETSA Utilities concluded that residential air conditioning customers can sustain that level of switching.

## RESULTS

| Residential Customers Participating | Commercial and Small Industrial Customers Participating | Agricultural Customers Participating | Large Industrial Customers Participating | Additional Generation Installed |
|---|---|---|---|---|
| 750 | Not stated | | | |

| Peak Load | Peak Load Reduction | Duration of Peak Load Reduction | Overall Load Reduction | Energy Savings | Network Augmentation Deferral |
|---|---|---|---|---|---|
| | 40 kW | | | | |

## HOW LOAD REDUCTION WAS MEASURED

Interval meter

## RESULTS ACHIEVED

### Initial Trial

The results of the initial trial showed that the external control of air conditioners significantly reduced the electricity demand of the sample customers, and that no reduction in thermal comfort level accompanied the reduced demand.

For example, Figure DC06/5 (page 78) shows the aggregate demand on 11 March 2006 for the houses involved in the initial trial. Each bar in the chart represents the total average demand in a half-hour period. The area highlighted in red shows the period under direct load control when the air conditioner compressors were switched off for 15 minutes in each 30 minute period. It is clear that aggregate demand was reduced during the control period.

The approximate load reduction resulting from cycling of compressors in the initial trial was 5 kW in a total demand of about 30 kW, ie a reduction of about 17%. Customers reported no reduction in their thermal comfort levels, with several commenting that they noticed no difference at all.

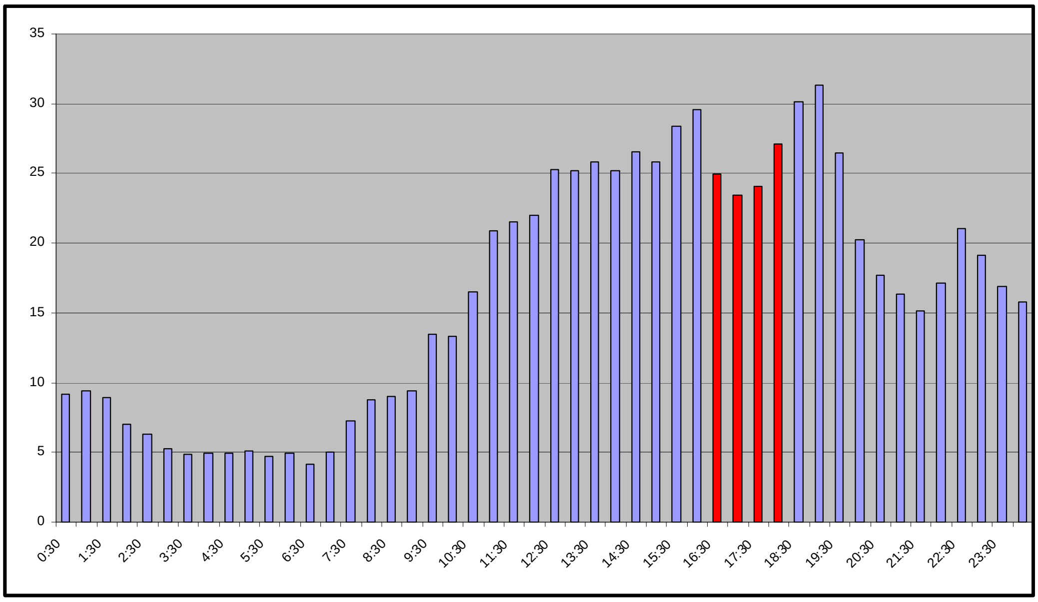

**Figure DC06/5. Aggregate Demand on 11 March 2006 for the Houses Involved in the ETSA Utilities Initial Trial**

## Pilot Program

Figure DC06/6 demonstrates the impacts on peak demand resulting from the cycling of air conditioners in a group of 68 premises during the pilot program. The Figure shows the aggregate load profile, with no load curtailment, for days with maximum temperatures of 35 degrees and 40 degrees Celsius, and the average profile for those two days.

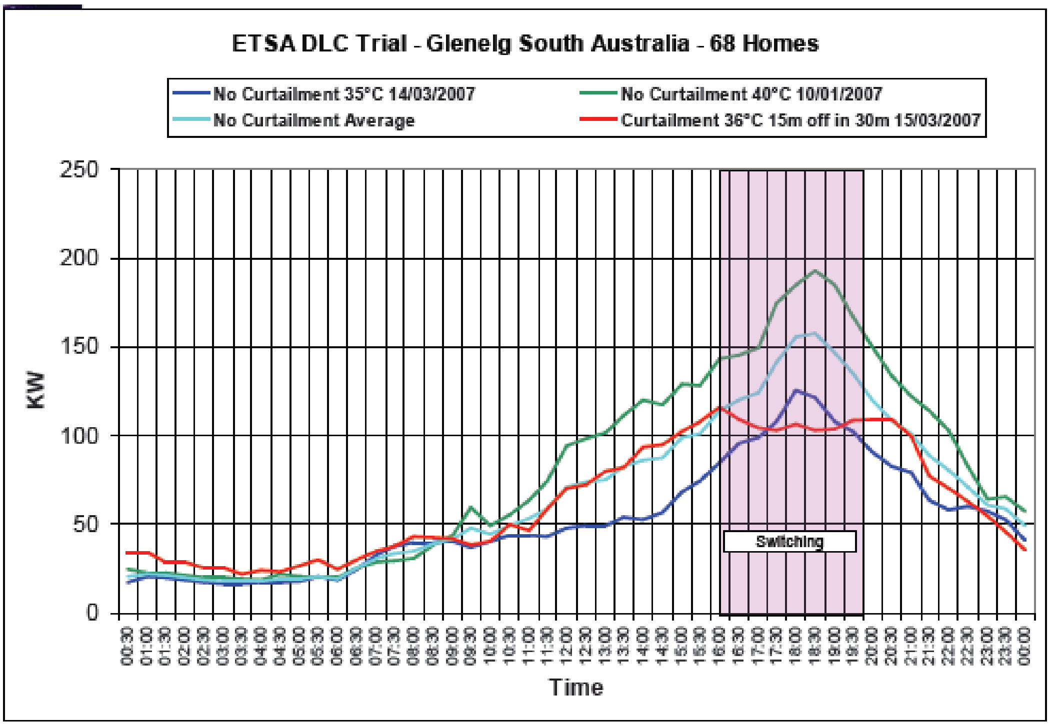


**Figure DC06/6. Load Reductions Achieved in the ETSA Utilities Air Conditioner DLC Pilot Program**

Figure DC06/6 also shows the profile for a day with maximum temperature of 36 degrees Celsius in which the air conditioner at each premises was cycled between 4pm and 7.30pm. A significant reduction in peak demand was achieved for this day, equivalent to about 40 kW, in comparison with the average peak demand of the two days for which there was no air conditioner cycling.

One important conclusion from the pilot program was that achieving effective load reductions requires a random overlapping switching program; non-random switching protocols resulted in a "saw tooth" demand profile.

## CONFIDENCE LEVEL IN ACHIEVING RESULTS

## REPEATABILITY OF RESULTS

## TIME DELAY BEFORE MAXIMUM RESPONSE ACHIEVED

## WEATHER DEPENDENCE

## AVOIDED COSTS

## ACTUAL PROJECT COSTS

## PROJECT COST FROM THE SOCIETAL PERSPECTIVE

## OVERALL PROJECT EFFECTIVENESS

## CONTACTS

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## SOURCES

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## CASE STUDY PREPARATION

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# DC07 CALIFORNIA AUTOMATED DEMAND RESPONSE SYSTEM PILOT - USA

| | |
|---|---|
| **Last updated** | 10 October 2008 |
| **Location of Project** | California, USA |
| **Year Project Implemented** | 2004 |
| **Year Project Completed** | 2005 |
| **Name of Project Proponent** | California Public Utilities Commission |
| **Name of Project Implementor** | Pacific Gas and Electric (PG&E)<br>Southern California Edison (SCE)<br>San Diego Gas and Electric (SDG&E) |
| **Type of Project Implementor** | Distribution utility<br>Electricity retailer/supplier |
| **Purpose of Project** | Provision of network operational services |
| **Timing of Project** | Pre contingency |
| **Focus of Project** | Network capacity limitations<br>Generation capacity limitations |
| **Project Objective** | Peak load reduction |
| **Project Target** | Network element |
| **DSM Measure(s) Used** | Direct load control<br>Pricing initiatives |
| **Specific Technology Used** | Remote load switching devices |
| **Market Segments Addressed** | Residential customers |

## DRIVERS FOR PROJECT

**Note:** This Case Study DC07 covers the impacts of load control technology implemented with pricing initiatives in the residential sector in California. For the impacts of pricing initiatives implemented in California without enabling technology, see Case Study PI01 (page 348) for large customers and Case Study PI09 (page 396) for small customers.

In 2000 and 2001, California experienced a so-called "energy crisis" that comprised short-term shortages of electricity generation capacity following the failure of the introduction of a competitive electricity market in the State. By 2002, the immediate short-term problems had been resolved, but longer-term shortages of both generation and transmission network capacity remained.

Following the energy crisis, the California Public Utilities Commission (CPUC) approved several trials and pilot programs designed to achieve increased demand response in the State. One of these was a pilot of an automated demand response system (ADRS) in the residential sector. The pilot ran from July 2004 to the end of December 2005.

The ADRS pilot was a small-scale exploratory program deploying automated energy management technology in 175 California households. Pacific Gas & Electric (PG&E), Southern California Edison (SCE), and San Diego Gas & Electric (SDG&E) sponsored the program to host 75, 75, and 25 ADRS households respectively.

These three utilities created the ADRS program in response to a decision of the CPUC which required the utilities to develop a plan for evaluating the demand response capabilities of a full scale automated system. The particular role of the ADRS pilot was to help understand how residential customers might help solve the utilities' problem of unpredictable weekday afternoon peak loads during the summer.

The objectives of the ADRS pilot were as follows:

- to identify and rank-order those technical features and capabilities that would make an ADRS most appealing to residential customers and utility system dispatchers;
- to measure the demand response of participants, compare that demand response to other statewide pilots, and assess whether or not deployment of ADRS technology would be both cost-effective and appropriate;
- to gain insight into the overall customer ADRS experience.

The ADRS pilot was closely associated with the Statewide Pricing Pilot (SPP), a pricing experiment with several different time-varying tariff options (see Case Study PI09). The SPP was approved by the CPUC prior to making a decision on full-scale deployment of the automated metering infrastructure required to support such time-varying rates.

## DESCRIPTION OF PROJECT

### Recruitment of Participants

The ADRS pilot participants were first recruited in 2004 from owner-occupied, single-family homes in a warm climate zone, located in neighbourhoods served by appropriate television cable providers (see Figure DC07/1). Householders who participated in the ADRS pilot received incentive payments of USD100 in 2004 and USD125 in 2005.

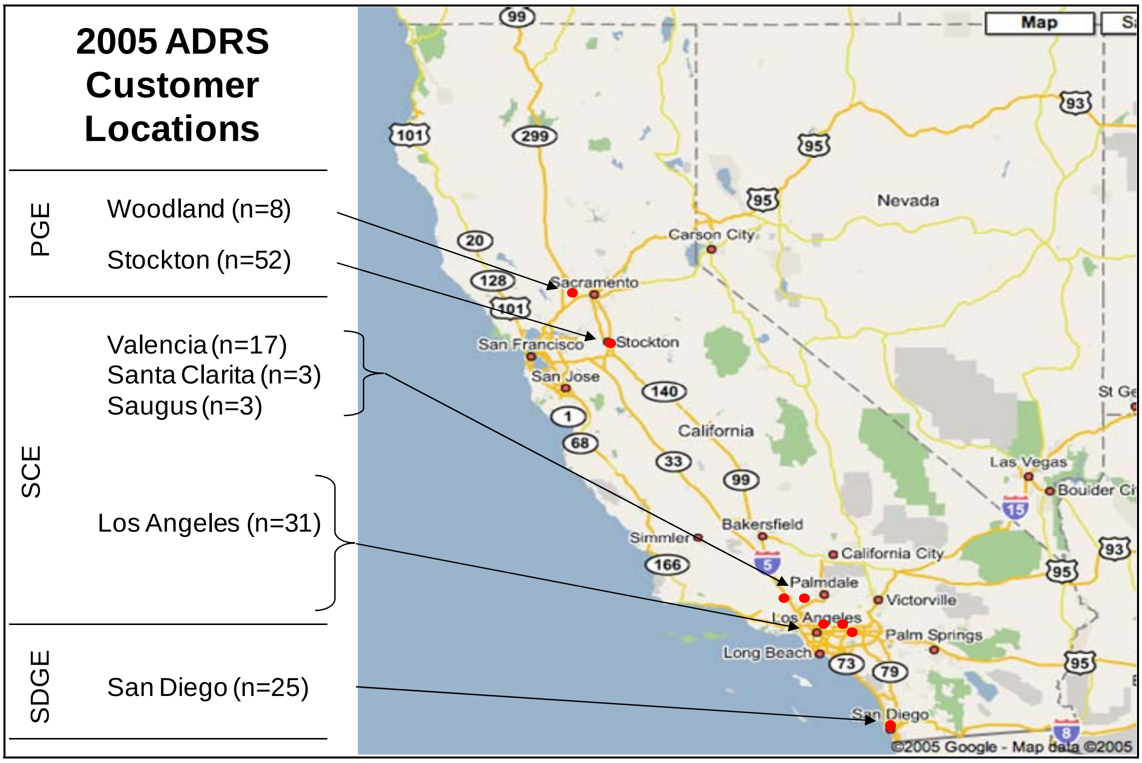


**Figure DC07/1. Locations of Participating Customers in the California ADRS Pilot, 2005**

The original 175 homes that participated in the ADRS pilot were recruited at random regardless of historical consumption, although homes were screened for eligibility with respect to presence of central air conditioning, within prescribed zip codes. Because ADRS technology is capable of controlling end uses in the home in addition to central air conditioning, homes were screened for availability of other loads (ie swimming pool pumps and spas), but not disqualified from participation in their absence.

The ADRS trial was originally scheduled to run to the end of 2004, but was subsequently extended to the end of 2005. Homes used for the 2005 analysis consisted of those households that remained on the ADRS pilot program after the summer of 2004. In rental or sale situations, the ADRS program was offered to incoming residents of existing ADRS homes. However, no additional participant homes were recruited for the 2005 pilot extension.

## Technology

The ADRS pilot participants had the GoodWatts system, an Invensys Climate Controls product, installed in their homes. GoodWatts is an “always on”, two-way communicating, automated home climate control system with web-based programming of user preferences for control of home appliances. Via the internet, homeowners with GoodWatts can set climate control and pool or spa pump runtime preferences and view these settings at any time both locally and remotely. Participants can also view whole-house or end-use specific demand in real time and display trends in historical consumption.

The energy management technology included the following components:

- wireless RF communications network connecting all system components;
- two-way communicating whole-house interval electricity meter capable of recording consumption data in 15-minute intervals;
- wireless internet gateway and cable modem;
- programmable smart thermostats used to control air conditioning loads;
- load control and monitoring (LCM) devices to manage other selected loads (eg pool pumps and spas), where these were present;
- web-enabled user interface and data management software.

GoodWatts allows users to view at all times the current electricity price on-line or via the thermostat. It also allows users to program the thermostat and the pool/spa LCMs to automatically respond to changes in electricity prices. For example the devices can be set to automatically reduce load once a threshold electricity price is reached.

## Tariff Schedule

To complement the installed ADRS technology, ADRS participants were placed on a time-varying electric tariff schedule called CPP-F.

CPP-F was a time-of-use (TOU) tariff, which included a critical peak pricing (CPP) element. Prices were high during the peak period between 2 pm and 7 pm on every weekday (‘non-event’ days). Higher critical peak prices were imposed during the peak period on event days (‘Super Peak’ days).

With slight variations, the CPP-F rate charged ADRS participants USD0.09/kWh in off-peak times, USD0.23/kWh during the peak period on non-event days and USD0.73/kWh during the peak period on Super Peak days. These rates compared with the participantsâ ™ typical previous rate of USD0.13/kWh throughout the day.

Participating households received instruction manuals, online personalised energy information, and access to a customer service help desk to help them cope with the CPP-F tariff.

## Event Dispatch

In 2004, 12 Super Peak events were called and in 2005 there were 11 such events (see Table DC07/1). ADRS customers were notified by phone and email during the day before a Super Peak event.

**Table DC07/1. 2004 and 2005 Super Peak Days in the California ADRS Pilot**

| | July | August | September | October |
|---|---|---|---|---|
| **2004**<br>**12 Days** | 14, Wednesday<br>22, Thursday<br>**26, Monday**<br>**27, Tuesday** | **9, Monday**<br>**10, Tuesday**<br>**11, Wednesday**<br>27, Friday<br>31, Tuesday | **8, Wednesday**<br>**9, Thursday**<br>**10, Friday** | None |
| | | | | |
| **2005**<br>**11 Days** | **12, Tuesday**<br>**13, Wednesday**<br>**14, Thursday**<br>22, Friday | 26, Friday | **28, Wednesday**<br>**29, Thursday** | **6, Thursday**<br>**7, Friday**<br>**13, Thursday**<br>**14, Friday** |

*Back-to-back days are in bold*

## RESULTS

| Residential Customers Participating | Commercial and Small Industrial Customers Participating | Agricultural Customers Participating | Large Industrial Customers Participating | Additional Generation Installed |
|---|---|---|---|---|
| 175 | | | | |

| Peak Load | Peak Load Reduction | Duration of Peak Load Reduction | Overall Load Reduction | Energy Savings | Network Augmentation Deferral |
|---|---|---|---|---|---|
| | | | | | |

## HOW LOAD REDUCTION WAS MEASURED

Interval meter. 15 minute intervals.

## RESULTS ACHIEVED

The results for the ADRS pilot were generally reported as load reductions achieved by "high consumption" households. Households were designated as "high consumption" if average daily usage (ADU) during the summer season was greater than or equal to 24 kWh per day. Households with an ADU of less than 24 kWh per day were designated as "low consumption". At the beginning of the 2004 pilot period on July 1, 2004, there were 51 high consumption ADRS customers from the PG&E service territory, 72 high consumption ADRS customers from SCE, and 7 high consumption ADRS customers from SDG&E.

Figure DC07/2 shows the statewide average peak period load reductions achieved by high consumption households participating in the ADRS pilot during 2004. The households achieved substantial peak load reductions, at least twice as much reduction on Super Peak event days as compared with non-event days.

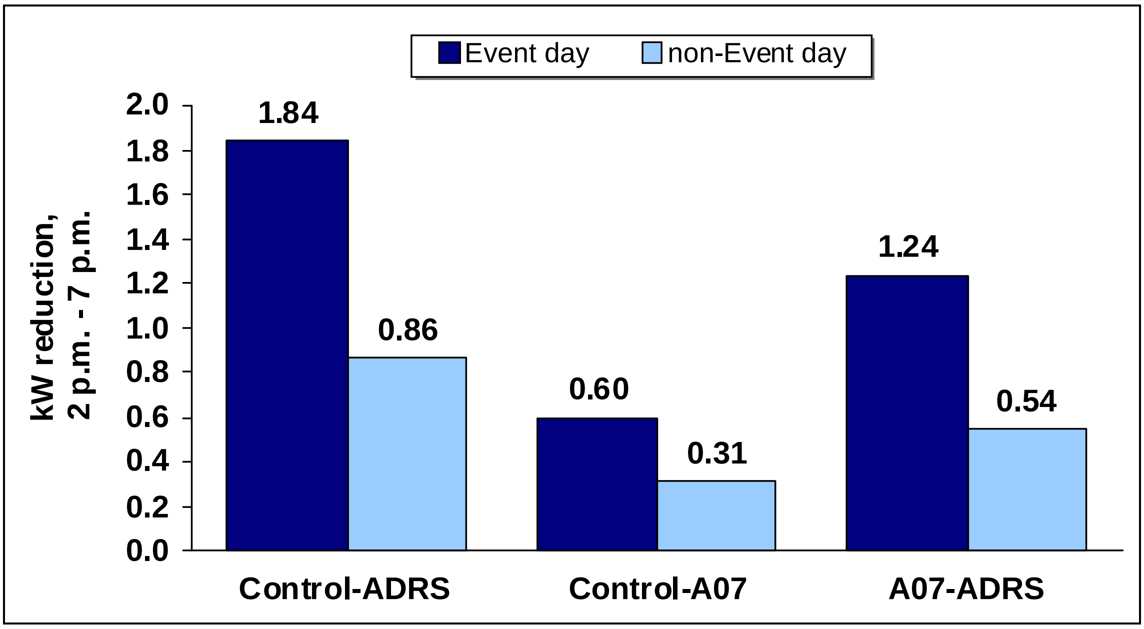


**Figure DC07/2. Statewide Average Peak Period Load Reductions Achieved by High Consumption Households, 2004**

The results shown in Figure DC07/2 were calculated as reductions from the average loads of households in a matching population that did not have an ADRS installed and was not subjected to the CPP-F tariff (identified as "Control" in Figure DC07/2). In 2004 only, the ADRS participants' results were also compared with the load reductions achieved by households from a matching population in the Statewide Pricing Pilot that were on the CPP-F tariff but did not have an ADRS installed (identified as "A07" in Figure DC07/2).

The CPP-F tariff without the ADRS technology had a small effect in achieving load reductions ("Control-AO7" in Figure DC07/2). Adding the ADRS technology to the CPP-F tariff produced a larger load reduction ("AO7-ADRS" in Figure DC07/2) and an even larger load reduction when compared with the population on a standard tariff ("Control-ADRS" in Figure DC07/2).

Figures DC07/3 and DC07/44 show the statewide average peak period load reductions ("Control-ADRS" only) achieved by participating high consumption households in the three utility service territories during 2004 and 2005.

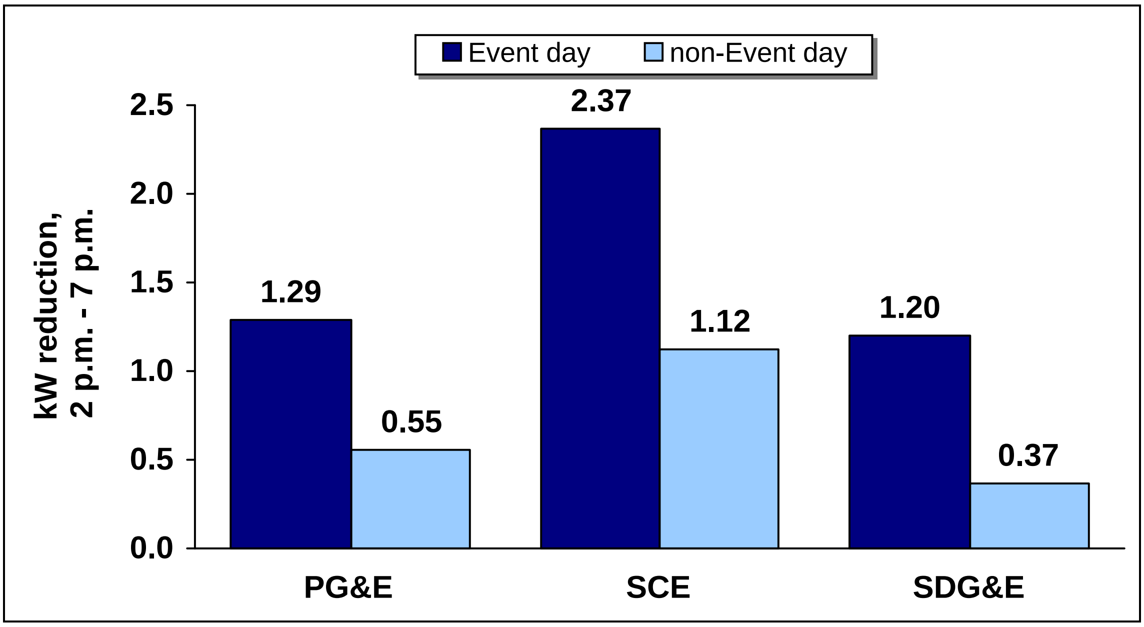


**Figure DC07/3. Statewide Average Peak Period Load Reductions (Control-ADRS only) Achieved by High Consumption Households in Three Utility Service Territories, 2004**

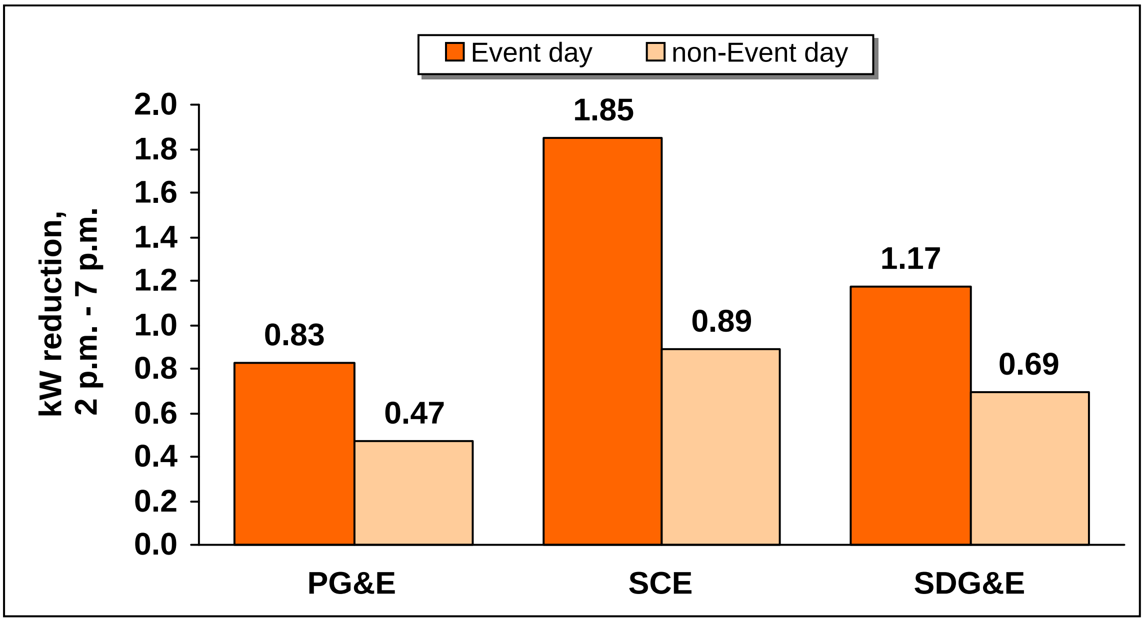


**Figure DC07/4. Statewide Average Peak Period Load Reductions (Control-ADRS only) Achieved by High Consumption Households in Three Utility Service Territories, 2005**

Figures DC07/5 and DC07/6 show the average load profiles of high consumption households on Super Peak event days and on non-event days during 2004 and 2005.

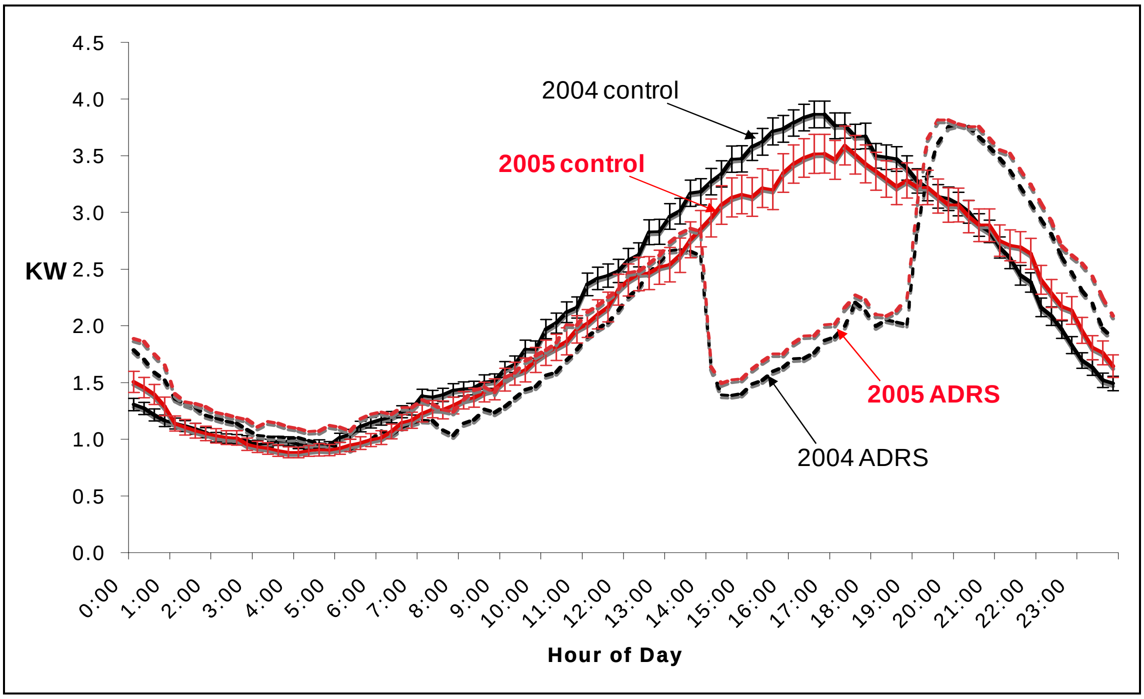


**Figure DC07/5. Average Load Profiles of High Consumption Households on Super Peak Event Days, 2004 and 2005**

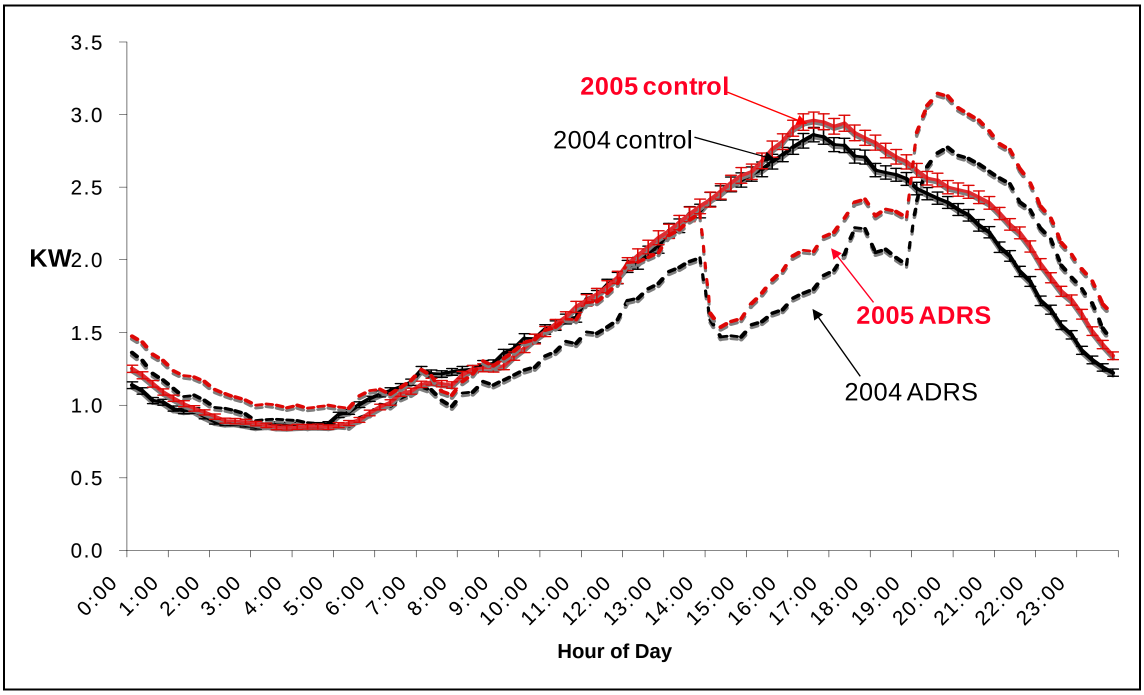


**Figure DC07/6. Average Load Profiles of High Consumption Households on Non-event Days, 2004 and 2005**

During the period July to September 2004, high consumption ADRS households successfully and consistently reduced load relative to control homes by 1.84 kW or 9.21 kWh on average during the Super Peak period across 12 event days, called statewide. This translated to a 51% reduction relative to high consumption control homes statewide.

From July through September 2005, high consumption ADRS households successfully and consistently reduced load relative to control homes by 1.4 kW or 7.1 kWh on average during the Super Peak period, across seven event days, called statewide. This translated to a 43% reduction relative to high consumption control homes statewide.

The average load reduction by high consumption ADRS households was greater in 2004 than 2005, by 25% on Super Peak event days and by 15% on non-event days, statewide. The smaller load reduction on event days in 2005 is attributed mostly to lower loads in control homes in 2005. Average Super Peak period consumption by control households in 2005 decreased by 8% compared to 2004, in spite of the fact that 2005 was a hotter summer on average. The lower average load in control homes on event days in 2005 is counter-intuitive, and this difference in behaviour by control households could not be explained with available data.

In contrast, loads in high consumption ADRS households increased by 7% on average during Super Peak periods in 2005, as expected during a hotter summer.

For both summers, there was a dramatic increase in loads in ADRS homes during the two hours immediately following the Super Peak and peak periods, from 7 pm to 9 pm. At the end of the Super Peak period, the thermostats in ADRS homes automatically reset from their warmer Super Peak setting to their cooler off-peak setting. This resulted in a sudden jump in load at 7 pm as the air conditioners suddenly turned on to meet the new, cooler set point.

This 'overshoot' could cause problems on network elements near their loading limits. In a full-scale implementation of ADRS technology, this issue would have to be managed by modifications to the load control technology to ensure that all the air conditioners did not turn on at the same time.

Figure DC07/7 (page 89) shows estimates of the relative impacts of price and of the ADRS technology in reducing peak load in high consumption households on Super Peak event days in 2004.

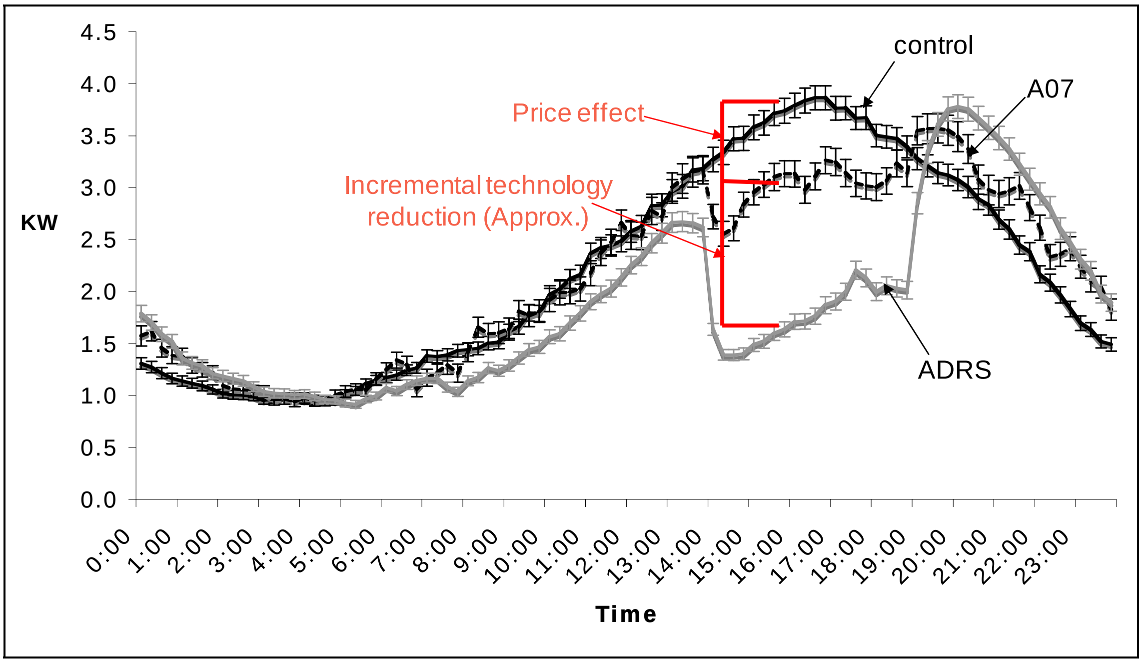


**Figure DC07/7. Impact of Price and Technology in High Consumption Households on Super Peak Event Days, 2004**

## CONFIDENCE LEVEL IN ACHIEVING RESULTS

## REPEATABILITY OF RESULTS

## TIME DELAY BEFORE MAXIMUM RESPONSE ACHIEVED

## WEATHER DEPENDENCE

## AVOIDED COSTS

## ACTUAL PROJECT COSTS

## PROJECT COST FROM THE SOCIETAL PERSPECTIVE

## OVERALL PROJECT EFFECTIVENESS

The California Automated Demand Response System Pilot demonstrated the significant increase in load reductions that can be achieved by using automated load control technology. Figure DC07/7 shows that a significantly higher load reduction can be achieved by using automated load control technology with time-varying pricing, as compared with the impact of pricing alone.

Automated load control technology provides:

- higher load reductions;
- more consistent performance throughout the program and with varying conditions (eg temperatures);
- greater customer control;
- interval metering data available in real-time, which is valuable in a variety of ways.

The key to a successful program is to select a technology system that is cost effective.

## CONTACTS

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## CASE STUDY PREPARATION

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## DC08 ORION NETWORK DSM PROGRAM - NEW ZEALAND

| | |
|---|---|
| **Last updated** | 10 October 2008 |
| **Location of Project** | Central Canterbury region, South Island, New Zealand |
| **Year Project Implemented** | 1990 |
| **Year Project Completed** | |
| **Name of Project Proponent** | Orion New Zealand Ltd |
| **Name of Project Implementor** | Orion New Zealand Ltd |
| **Type of Project Implementor** | Distribution utility |
| **Purpose of Project** | Deferral of network augmentation |
| **Timing of Project** | Pre contingency |
| **Focus of Project** | Network capacity limitations |
| **Project Objective** | Peak load reduction |
| **Project Target** | Whole network |
| **DSM Measure(s) Used** | Direct load control<br>Pricing initiatives |
| **Specific Technology Used** | Direct load control of water heaters |
| **Market Segments Addressed** | Residential customers<br>Commercial and small industrial customers<br>Large industrial customers |

### DRIVERS FOR PROJECT

Orion New Zealand Limited (Orion) owns and operates the electricity distribution network in the central Canterbury region on the South Island of New Zealand. Orion is owned by Christchurch City Council and Selwyn District Council.

Orion's distribution network area covers 8,000 square kilometres of diverse geography, including the city of Christchurch, Banks Peninsula, farming communities and high country regions (see Figure DC08/1.


**Figure DC08/1. Map of New Zealand showing Orion's Network Area (outlined in dark green)**

Orion draws energy from the national high voltage electricity transmission network at 10 grid exit points, ie the transformers that connect distribution load to the transmission network. Orion then transports the energy from the grid exit points to approximately 185,000 homes and businesses through the low voltage distribution network.

In New Zealand as a whole, peak and energy demands on the electricity network have been growing at about the same rates from 1990 (see Figure DC08/2.

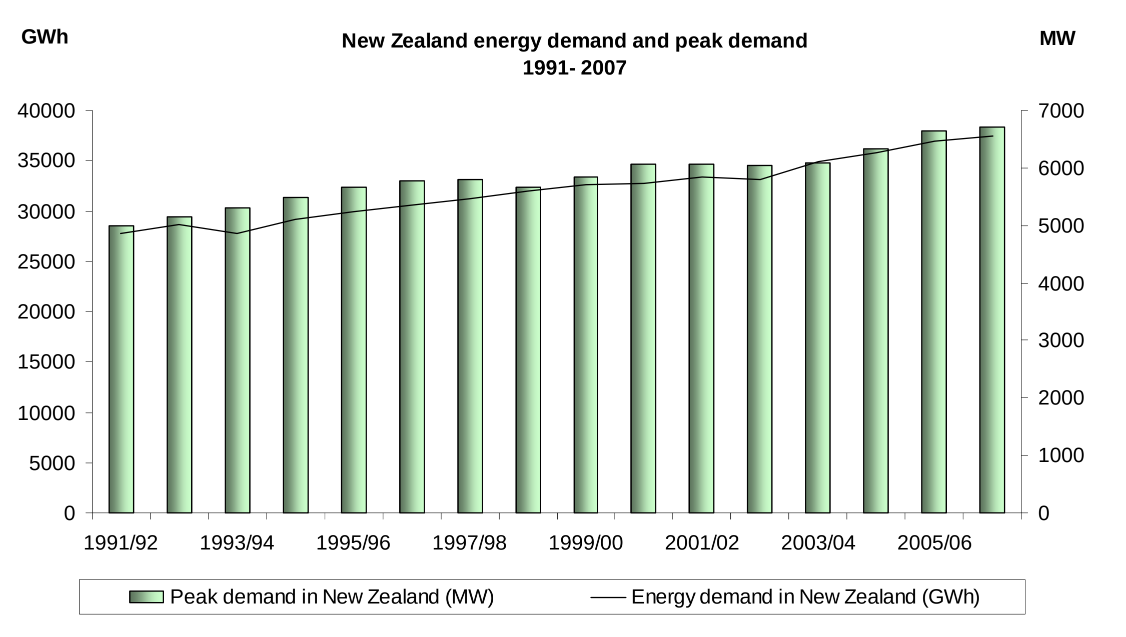


**Figure DC08/2. New Zealand Energy Demand and Peak Demand, 1991 to 2007**

To cover the costs involved in meeting peak demand, the transmission company in New Zealand, Transpower, charges parties connected to the national transmission network based on an average of the 12 highest peaks (by half-hour) over a year at the various grid exit points. This creates an incentive for Transpower customers to minimise peaks.

Since around 1990, Orion has been working actively to limit the growth in peak demand to improve the utilisation of both its distribution network and the national transmission network and consequently reduce the costs per kilowatt-hour of energy delivered to end-use customers in the Orion service territory.

## DESCRIPTION OF PROJECT

To achieve the decoupling of peak and energy demand growth in its service territory, Orion has used a mix of direct load control and pricing initiatives.

### Direct Load Control

In the Orion service territory, about 90% of residential electric hot water heaters are controlled through ripple control in which control signals to switch the heating elements on or off are transmitted through the power lines to relays at customers' premises.

Orion promotes two direct load control methods for peak reduction through ripple control:

- peak control water heating; and
- night only water heating.

### *Peak Control Water Heating*

Peak control water heating is aimed both at consumers who have water heaters with smaller tanks and at consumers who use larger quantities of hot water. For these consumers, Orion uses the ripple system to switch off water heating elements during peak loading periods, and cycles through up to 16 groupings of water heating load to ensure sufficient heating is provided.

Peak load control is used when the demand in Orion's network area reaches a certain threshold; in 2007, this was 570 MW. When the load approached this level, Orion commences switching off water heaters in groups to keep demand from exceeding the threshold level. To limit the potential impacts on customers, Orion cycles the controlled water heaters, switching on one group of water heaters while switching off a different group to maintain the load below the threshold level.

To maintain service standards and encourage appropriate design of hot water systems, Orion has set service level targets whereby it aims to have individual water heaters switched off for no more than seven hours per day, and no more than four hours in any seven hour period. The heating elements in water heaters with tanks larger than 100 litres can be switched off for several hours without customers noticing any reduction in the supply of hot water.

During the period 2005 to 2007, Orion used peak control to switch water heaters for an average of 54 hours a year, typically in the winter months (June to August).

### *Night Only Water Heating*

Night only water heating is aimed at consumers who have water heaters with larger tanks. Orion uses the ripple system to switch on these heaters only at night, permanently shifting this load away from peak times.

This option has been so successful that Orion must progressively stagger switching on the night water heater load over a period of time to avoid setting night-time peaks. In some areas, Orion uses peak control to lower loading levels while night water heating load is being turned on.

Orion also provides an option that includes an afternoon heating boost to night only water heaters to ensure that hot water is available in the evening.

## Pricing Initiatives

### *Controlled Water Heating Loads*

Customers with controlled water heating in the Orion service territory receive pricing incentives delivered through their electricity retailer.

Table DC08/1 shows tariff schedules for the electricity retailer Contact Energy as at May 2008. Contact customers on the Controlled Load tariff save 10% on the standard Anytime Use tariff, under which water heaters are not controlled. Under the Day/Night - Night tariff, used for night only water heating, customers pay only about 50% of the Anytime Use tariff.

**Table DC08/1. Tariff Schedules for the Electricity Retailer Contact Energy as at May 2008**

| Tariff type | Variable price* |
|---|---|
| Anytime use tariff | 19.267 cents/kWh |
| Controlled load tariff | 17.129 cents/kWh |
| Day/night - day tariff | 21.765 cents/kWh |
| Day/night - night tariff | 9.256 cents/kWh |

* All tariffs have a fixed tariff of 60.53 cents a day as well.

### *Commercial and Industrial Loads*

Sometimes the use of direct load control is not enough to keep the load on the Orion network from exceeding the required threshold. During periods when loading levels reach a set threshold, Orion initiates a second load reduction measure based on peak demand pricing and targeting larger commercial and industrial loads. These periods are called "control periods".

Orion has estimated its long run average incremental cost to deliver electricity at peak times, and reflects this cost in its peak demand charges. With this cost-reflective pricing approach, the decision to reinforce the network for load growth is effectively passed to consumers - they can elect to use energy at peak times and accept the cost of delivery, or avoid peak times and save.

The start and end of a control period are signalled to consumers in real-time via ripple signals, text messages and emails. Orion identifies control periods for major customers (those with half-hour metering and loads greater than 250 kVA), and records their average loadings during these periods (typically over a total of 80 to 100 hours per year). This average loading then forms the basis of Orion's control period demand charge, which is currently set at NZD139.20 per kVA per year (for delivery only). Over the duration of the control periods, this equates to a delivered cost of electricity of NZD1.50 to NZD2.00 per kWh, compared with the normal delivered cost of electricity of NZD0.12 to NZD0.20 at other times.

Control periods vary in length and the signal is withdrawn when loading levels fall to lower levels. To help customers respond, Orion provides 10 minutes advance warning for control periods and ensures that each control period lasts for at least 30 minutes. Control periods are only signalled during the core winter months when loading levels peak.

***'General Connections' Loads***

Orion also uses a similar pricing approach for smaller 'general connections' loads, using ripple signals to identify peak periods for demand pricing, and applying charges based on each electricity retailers' reconciled allocation of grid metering during these periods.

## RESULTS

| Residential Customers Participating | Commercial and Small Industrial Customers Participating | Agricultural Customers Participating | Large Industrial Customers Participating | Additional Generation Installed |
|---|---|---|---|---|
| | | | | |

| Peak Load | Peak Load Reduction | Duration of Peak Load Reduction | Overall Load Reduction | Energy Savings | Network Augmentation Deferral |
|---|---|---|---|---|---|
| 630 MW | 120 MW | | | | |

## HOW LOAD REDUCTION WAS MEASURED

## RESULTS ACHIEVED

Orion has been one of the most successful electricity distributors in New Zealand in minimising peak demand growth.

Figure DC08/3 (page 96) shows the results of Orion's efforts, with a noticeable improvement in the load factor (ratio of energy delivered to peak demand) after 1990. Note that the demand is the maximum individual half-hour value, which is somewhat volatile, and consequently the load factor can fluctuate from year to year. On average, the trend in Orion's load factor has been to increase by 0.7% per year since 1990, (50.7% in 1990 to 60.9% in 2008) but this rate of growth has slowed in recent years.

Orion has achieved a 90% penetration for controlled water heating in its service territory. Figure DC08/4 (page 96) shows the impact of peak control measures on a typical cold winter day. On this graph, the blue line shows the actual load level and the red line is a calculated estimate of the load level that would have occurred if peak load control of water heating had not been done. Figure DC08/4 also shows the effect of two control periods in causing end users to shed load.

Because of the DSM measures implemented, Orion is to a high degree able to prevent peak demand from exceeding a set level. Figure DC08/5 (page 96) shows the demand in the Orion service territory for various days in June 2007.

Figure DC08/5 shows that roughly the same peak value is obtained on different days as peak demand is shifted to off-peak periods, either between the morning and afternoon peak or after the afternoon peak. This peak shifting results in lower payments to Transpower and has reduced the requirement for investment in Orion's own network. These effects lead to lower network charges to Orion's end-use customers.

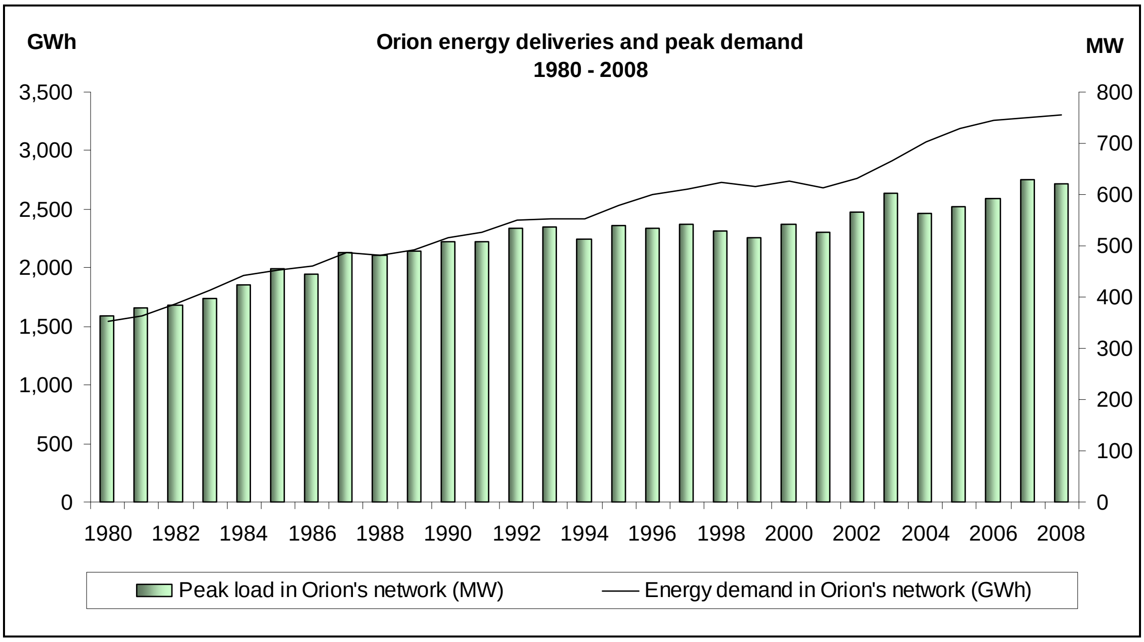


**Figure DC08/3. Orion Energy Deliveries and Peak Demand, 1980 to 2008**

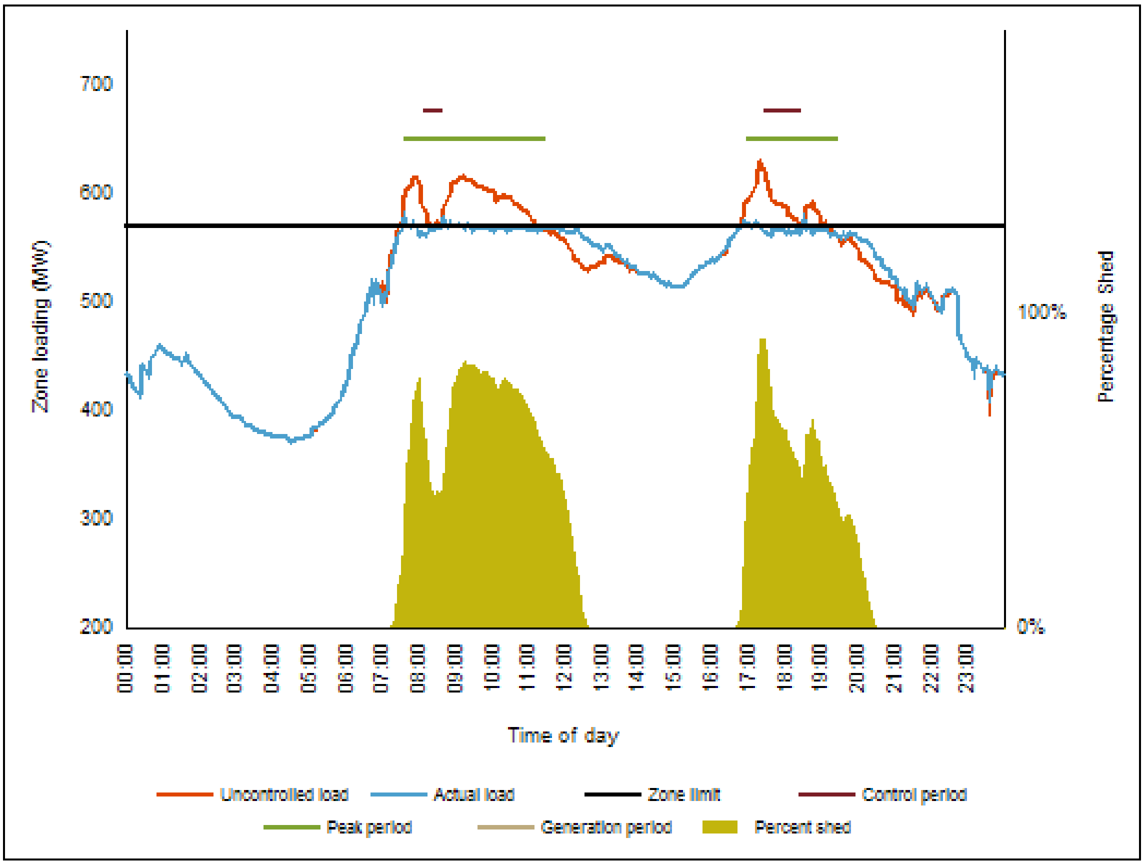


**Figure DC08/4. Orion Daily Load Management Summary, Thursday 28 June 2007**

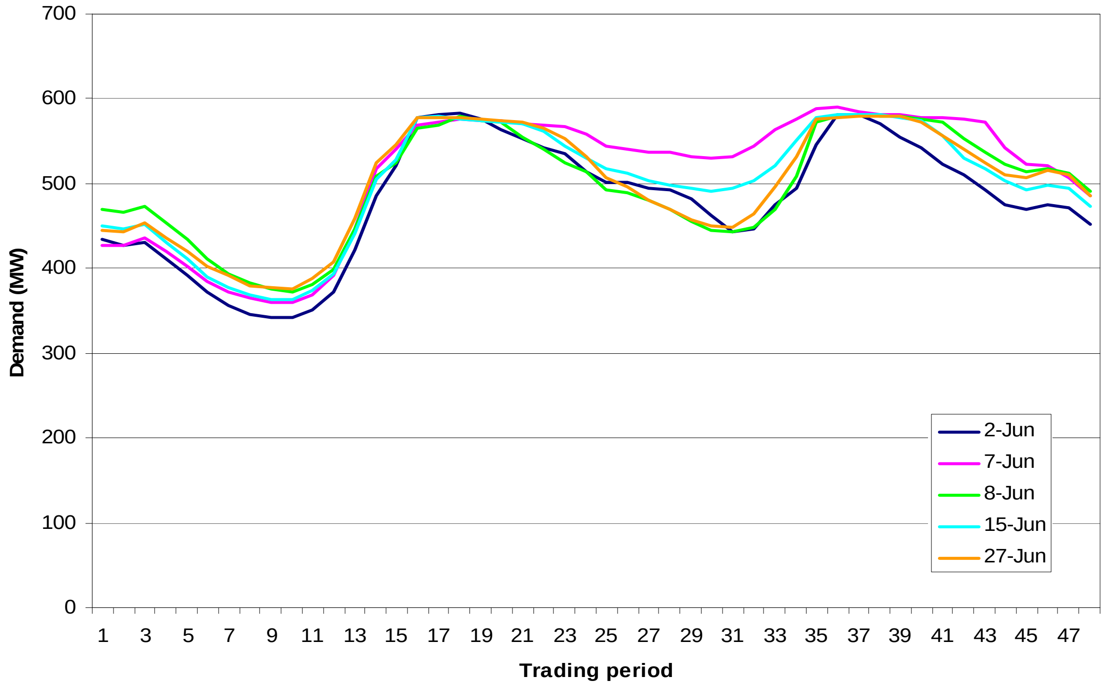


**Figure DC08/5. Peak Demand on Orion's Network on Different Days in June 2007**

## CONFIDENCE LEVEL IN ACHIEVING RESULTS

## REPEATABILITY OF RESULTS

## TIME DELAY BEFORE MAXIMUM RESPONSE ACHIEVED

## WEATHER DEPENDENCE

## AVOIDED COSTS

## ACTUAL PROJECT COSTS

## PROJECT COST FROM THE SOCIETAL PERSPECTIVE

## OVERALL PROJECT EFFECTIVENESS

If Orion's load factor was still at its 1990 value of 50.7%, the peak demand on the network would be 750 MW instead of 630 MW, an increase of 120 MW. Orion estimates that the additional cost for delivery of this peak load would equate to approximately NZD12 million per year for distribution and NZD6 million per year for transmission (or approximately 11% more). This is based on an estimated Long Run Average Incremental Cost (LRAIC) of new transmission capacity of around NZD50/kW and a distribution LRAIC of NZD100/kVA per annum.

Peak load reduction can also provide additional savings from a lower investment requirement for peaking generation (though generation capacity has not been a constraint in the New Zealand market until recently).

## CONTACTS

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## SOURCES

## CASE STUDY PREPARATION

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# DC09 SEPARATION OF AGRICULTURAL FEEDERS FOR LOAD CONTROL - INDIA

| | |
|---|---|
| **Last updated** | 2 October 2008 |
| **Location of Project** | Northern parts of the State of Gujarat, India |
| **Year Project Implemented** | 2005/06 |
| **Year Project Completed** | 2006/07 |
| **Name of Project Proponent** | Government of Gujarat |
| **Name of Project Implementor** | Uttar Gujarat Vij Company Limited (UGVCL) |
| **Type of Project Implementor** | Distribution utility<br>Electricity retailer/supplier |
| **Purpose of Project** | Deferral of network augmentation |
| **Timing of Project** | Post contingency |
| **Focus of Project** | Network capacity limitations<br>Generation capacity limitations |
| **Project Objective** | Peak load reduction<br>Overall load reduction |
| **Project Target** | Whole network |
| **DSM Measure(s) Used** | Direct load control |
| **Specific Technology Used** | Timing schedules for energising agricultural feeders |
| **Market Segments Addressed** | Agricultural customers |

## DRIVERS FOR PROJECT

The Separation of Agricultural Feeders for Load Control project was initiated by the Government of Gujarat and implemented by Uttar Gujarat Vij Company Limited (UGVCL), as well as other electricity distributors in the State of Gujarat.

UGVCL is an electricity distribution/retailing utility owned by the Government of Gujarat. UGVCL provides distribution and retail supply of electricity to a service territory of 49,950 square kilometres in northern parts of the State of Gujarat, supplying 1.9 million customers in 67 talukas (administrative areas), 61 towns and 4,617 villages.

In 2003, the Government of Gujarat announced a scheme called "Jyotigram Yojana" (JGY) to provide continuous three phase power supply to rural areas of the State to improve the quality of life of the rural population. To receive the benefits of JGY, a village Panchayat (local government body) pays a registration fee of INR1000 and up to 30% of the estimated cost of building any augmentation or expansion required to the electricity network, with a maximum payment of INR25,000. The balance of the cost is paid by the Gujarat Government.

Under the JGY scheme, the Gujarat Government decided to separate agricultural pump set connections from domestic light and fan (DLF) connections by constructing separate 11 KV feeders for agricultural loads. This enabled electricity distributors to implement direct load control of agricultural pumps by establishing schedules specifying the times during the day when each agricultural feeder would be energised. The main objective of implementing this direct load control program was to flatten the load curve to provide sufficient network capacity for the morning and evening peaks.

Water pumping load in the agricultural sector in India is important for several reasons. Agricultural pump sets are often supplied by long rural lines which are costly to build and maintain and have large line losses. The electricity supply to pumps is often unmetered and electricity is effectively supplied free of charge. In these cases, electricity distributors have to bear the supply cost and there is no incentive for agricultural customers to use electricity efficiently.

In the particular case of northern Gujarat, UGVCL was facing a power shortage during the morning peak hours. For example, the maximum demand on the UGVCL system during the month of December 2005 was 2100 MW during the morning peak. There was a shortage of capacity during the morning and UGVCL was not able to supply quality power to all consumer categories, leading to load shedding. Load shedding in rural areas was affecting the economic growth of the rural economy.

## DESCRIPTION OF PROJECT

To capture the benefits of the Jyoti Gram Yojna scheme and to provide continuous supply to all non-agricultural consumer categories, UGVCL decided to separate agricultural feeders at the 11 kV level. UGVCL commenced implementation of the project in April 2005 with prior planning and close monitoring to achieve a target of providing a reliable eight hours of supply to all agricultural customers by the end of financial year 2006/07.

To achieve the separation of agricultural feeders, UGVCL constructed the following new electricity network infrastructure:

- 15,461 kilometres of high voltage lines;
- 2,044 kilometres of low voltage lines;
- 2,088 transformers.

This new infrastructure enabled UGVCL to rearrange the power supply timing schedules for 28 agricultural customer groups across a total of 1,950 separate agricultural feeders, as shown in Table DC09/1 (page 101).

## RESULTS

| Residential Customers Participating | Commercial and Small Industrial Customers Participating | Agricultural Customers Participating | Large Industrial Customers Participating | Additional Generation Installed |
|---|---|---|---|---|
| | | | | |

| Peak Load | Peak Load Reduction | Duration of Peak Load Reduction | Overall Load Reduction | Energy Savings | Network Augmentation Deferral |
|---|---|---|---|---|---|
| 2100 MW | 250 MW | 4 hours | | 1521.37 GWh over two years | |

| Table DC09/1. Timing Schedule for Staggered Operation of Agricultural Feeders | | | | |
|---|---|---|---|---|
| **District (Area)** | **Agricultural Customer Group** | **Number of Feeders** | **Maximum Load (MW)** | **Timing of Power Supply (Three Phase)** |
| **Mehasana** | A11 | 86 | 125 | 00:00 to 08:00 |
| | A12 | 84 | 120 | 23:45 to 07:45 |
| | B11 | 80 | 135 | 10:30 to 18:30 |
| | B12 | 90 | 130 | 12:00 to 20:00 |
| **Ahmedabad and Gandhinagar** | C11 | 65 | 90 | 05:15 to 13:15 |
| | C12 | 62 | 85 | 05:45 to 13:45 |
| | C13 | 48 | 80 | 03:45 to 11:45 |
| | D11 | 65 | 85 | 20:45 to 04:45 |
| | D12 | 60 | 95 | 20:15 to 04:15 |
| | D13 | 44 | 63 | 20:30 to 04:30 |
| **Banaskantha (Palanpur)** | K11 | 88 | 110 | 11:15 to 19:15 |
| | K12 | 79 | 115 | 05:30 to 13:30 |
| | L11 | 78 | 120 | 21:30 to 05:30 |
| | L12 | 76 | 122 | 23:30 to 07:30 |
| **Banaskantha (Kansari)** | K13 | 68 | 105 | 04:00 to 12:00 |
| | K14 | 70 | 104 | 02:15 to 10:15 |
| | K15 | 64 | 94 | 00:15 to 08:15 |
| | L13 | 77 | 103 | 23:15 to 07:15 |
| | L14 | 65 | 108 | 20:00 to 04:00 |
| | L15 | 66 | 110 | 13:00 to 21:00 |
| **Sabarkantha** | M11 | 105 | 140 | 12:45 to 20:45 |
| | N11 | 100 | 135 | 04:45 to 12:45 |
| | M12 | 35 | 45 | 14:00 to 18:00 & 03:00 to 07:00 |
| | N12 | 39 | 50 | 08:00 to 12:00 & 21:30 to 01:30 |
| **Patan** | P11 | 76 | 105 | 03:15 to 11:15 |
| | P12 | 73 | 100 | 21:15 to 05:15 |
| | Q11 | 69 | 104 | 12:15 to 20:15 |
| | Q12 | 69 | 98 | 21:45 to 05:45 |

## HOW LOAD REDUCTION WAS MEASURED

## RESULTS ACHIEVED

The rearrangement of the power supply timing schedules for agricultural feeders reduced the maximum demand on the UGVCL system from 2100 MW to 1850 MW and increased the minimum demand from 900 MW to 1450 MW, thereby flattening the load curve throughout the day. This is shown in Figure DC09/1.

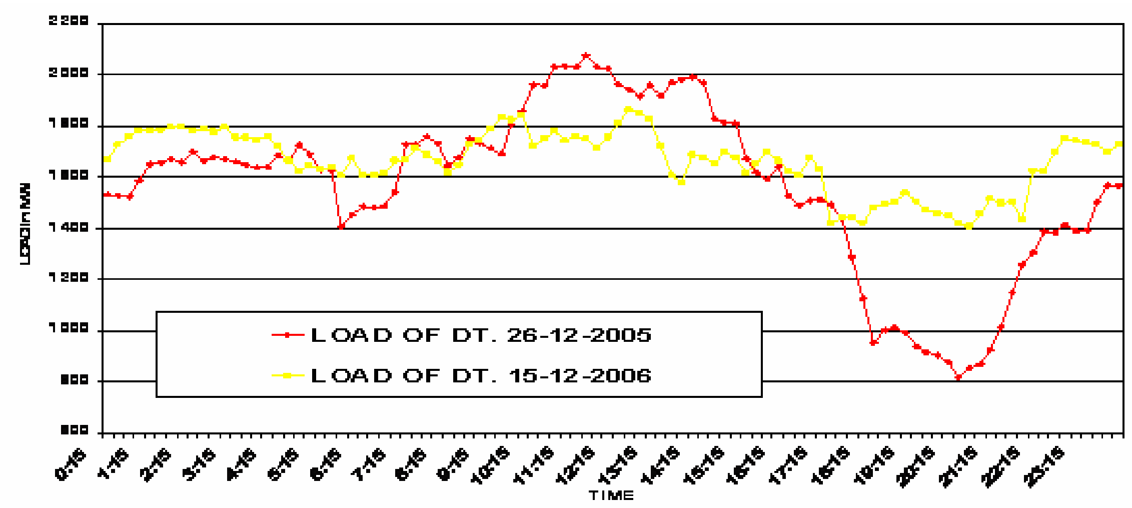


**Figure DC09/1. UGVCL System Load Curve in December 2005 and December 2006**

Table DC09/2 shows that, over the period 2005/06 to 2006/07, despite increases in customer connections, and in energy sales, there was a significant saving of 102 GWh in the quantity of energy that UGVCL purchased and injected into the system to meet customer demand.

**Table DC09/2 Comparison of UGVCL Annual Energy Account**

| | 2005/06 (GWh) | 2006/07 (GWh) |
|---|---|---|
| Total no of customer | 1,943,226 | 2,023,032 |
| Total energy purchased/injected | 12,087 | 11,985 |
| Total energy sales | 8,738 | 9,501 |

Other benefits of the project included:

- a reduction in line losses by about 13.5%, resulting in financial savings to UGVCL of INR4,597 million over two years, which was more than the total cost of constructing the new network infrastructure;
- reduction in overloading of feeders and failure of distribution transformers;
- increased quality of the power supply leading to reduced failure of agricultural pump sets.

## CONFIDENCE LEVEL IN ACHIEVING RESULTS

High

## REPEATABILITY OF RESULTS

## TIME DELAY BEFORE MAXIMUM RESPONSE ACHIEVED

## WEATHER DEPENDENCE

## AVOIDED COSTS

## ACTUAL PROJECT COSTS

Total expenditure by UGVCL on the construction of new electricity network infrastructure was INR2,980 million.

## PROJECT COST FROM THE SOCIETAL PERSPECTIVE

## OVERALL PROJECT EFFECTIVENESS

By implementing the Jyoti Gram Yojna scheme, UGVCL was able to provide a continuous high quality power supply to all non-agricultural consumers in rural areas. This lead to a marked improvement in the standard of living of villagers.

## CONTACTS

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## SOURCES

## CASE STUDY PREPARATION

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## DG01 NELSON BAY EMBEDDED GENERATION - AUSTRALIA

| | |
|---|---|
| **Last updated** | 31 August 2005 |
| **Location of Project** | Nelson Bay, about 200 km north of Sydney, Australia |
| **Year Project Implemented** | 2004 |
| **Year Project Completed** | |
| **Name of Project Proponent** | EnergyAustralia |
| **Name of Project Implementor** | EnergyAustralia |
| **Type of Project Implementor** | Distribution utility |
| **Purpose of Project** | Deferral of network augmentation |
| **Timing of Project** | Pre contingency |
| **Focus of Project** | Network capacity limitations |
| **Project Objective** | Peak load reduction |
| **Project Target** | Network element |
| **DSM Measure(s) Used** | Other distributed generation |
| **Specific Technology Used** | Diesel generator supplied by a leasing company |
| **Market Segments Addressed** | Non-customer related |

### DRIVERS FOR PROJECT

Nelson Bay is a coastal community supplied by long 33kV lines. Demand peaks severely during both winter and summer holiday seasons when the population increases dramatically. Ultimate capacity is limited by the ability of the lines to maintain adequate voltage and loads had reached the level where expected demand was higher than the lines could supply. A new transmission line project had been proposed, but delayed due to unavailability of critical equipment. Forecasts showed that during the 2004 winter (June) holiday period, load shedding would be required, and this situation would be repeated the following summer (December 2004). The embedded generator project was conceived as a means to reduce loading during critical periods to enable maintenance of supply.

### DESCRIPTION OF PROJECT

Six MVA of diesel generation was obtained from a leasing company. The generation was installed in two 3MVA stages and connected to the local 11kV feeder network. The generation was operated whenever the total demand on the 33kV system approached the limit in order to keep the net demand below the load shedding threshold.

### RESULTS

| Residential Customers Participating | Commercial and Small Industrial Customers Participating | Agricultural Customers Participating | Large Industrial Customers Participating | Additional Generation Installed |
|---|---|---|---|---|
| | | | | 6 MW |

| Peak Load | Peak Load Reduction | Duration of Peak Load Reduction | Overall Load Reduction | Energy Savings | Network Augmentation Deferral |
|---|---|---|---|---|---|
| 35 MW | 6 MW | About 5 hours | | | |

## HOW LOAD REDUCTION WAS MEASURED

Interval meter. 30 minute intervals.

## RESULTS ACHIEVED

The generators were dispatched by the system operator at times of peak and prevented load shedding during both the 2004 winter and 2004/05 summer holiday seasons. The generators are scheduled to be removed after winter 2005, when the new line will be installed.

## CONFIDENCE LEVEL IN ACHIEVING RESULTS

Very high - use of fully maintained, leased generators ensured rapid response to problems and high availability.

## REPEATABILITY OF RESULTS

Very high - already this approach has been replicated in three other projects.

## TIME DELAY BEFORE MAXIMUM RESPONSE ACHIEVED

Installation time was 12 weeks, including design, procurement and construction. This was considered a very rapid response to an emerging situation.

## WEATHER DEPENDENCE

Small, although performance is lower in summer due to higher ambient temperatures.

## AVOIDED COSTS

Project was used to maintain supply - the only realistic alternative was load shedding. The effective saving in costs due to the delay in the 33kV line project has been evaluated as AUD1.46 million.

## ACTUAL PROJECT COSTS

EnergyAustralia - total projected cost AUD2.1 million.

## PROJECT COST FROM THE SOCIETAL PERSPECTIVE

Not calculated.

## OVERALL PROJECT EFFECTIVENESS

Project was effective in managing demand and preventing load shedding. This was a relatively expensive option (AUD350/kVA) but flexible and relatively quick to deploy in a range of situations.

## CONTACTS

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## SOURCES

## CASE STUDY PREPARATION

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# DG02 BROMELTON EMBEDDED GENERATION - AUSTRALIA

| | |
|---|---|
| **Last updated** | 26 August 2005 |
| **Location of Project** | Bromelton, Queensland, Australia |
| **Year Project Implemented** | 2005 |
| **Year Project Completed** | |
| **Name of Project Proponent** | ENERGEX and Asset Solutions |
| **Name of Project Implementor** | ENERGEX and Asset Solutions |
| **Type of Project Implementor** | Distribution utility<br>ESCO |
| **Purpose of Project** | Deferral of network augmentation |
| **Timing of Project** | Pre contingency |
| **Focus of Project** | Network capacity limitations |
| **Project Objective** | Peak load reduction |
| **Project Target** | Network region |
| **DSM Measure(s) Used** | Other distributed generation |
| **Specific Technology Used** | Diesel generators |
| **Market Segments Addressed** | Non-customer related |

## DRIVERS FOR PROJECT

Beaudesert 110/33kV bulk supply substation has only one 110kV incoming feeder, F820. Loss of this feeder results in 40MV.A (2006) of unsupplied load after 33kV transfers to adjacent bulk supply substations

A second 110kV incoming feeder was planned but could be built before October 2007 allowing for completion of environmental studies, easement acquisition and stakeholder consultation.

## DESCRIPTION OF PROJECT

15 units of 1.825MVA diesel generators were installed on vacant land adjacent to Bromelton substation. This supplied Bromelton and adjacent zone substations via the 33kV network upon the loss of feeder F820. Generators were provided and installed by Asset Solutions (an energy services company).

## RESULTS

| Residential Customers Participating | Commercial and Small Industrial Customers Participating | Agricultural Customers Participating | Large Industrial Customers Participating | Additional Generation Installed |
|---|---|---|---|---|
| | | | | 27.375 MW |

| Peak Load | Peak Load Reduction | Duration of Peak Load Reduction | Overall Load Reduction | Energy Savings | Network Augmentation Deferral |
|---|---|---|---|---|---|
| | | | | | |

## HOW LOAD REDUCTION WAS MEASURED

Interval meter. 30 minute intervals.

## RESULTS ACHIEVED

Commissioned by November 2005.

## CONFIDENCE LEVEL IN ACHIEVING RESULTS

High level of confidence.

## REPEATABILITY OF RESULTS

High level of repeatability expected in comparable circumstances.

## TIME DELAY BEFORE MAXIMUM RESPONSE ACHIEVED

Less than 5 minutes.

## WEATHER DEPENDENCE

Rated output is based on 40 degrees Celsius ambient.

## AVOIDED COSTS

Avoided cost studies were completed using values of AUD 2.00, AUD 6.00 and AUD 10.00 per kWh of unsupplied energy.

In 2006, avoided costs are AUD 249,781 at AUD 2.00/kWh, AUD 749,343 at AUD 6.00/kWh and AUD 1,248,904 at AUD 10.00/kWh.

In 2010, avoided costs will become AUD 248,095 at AUD 2.00/kWh, AUD 744,275 at AUD 6.00/kWh and AUD 1,240,474 at AUD 10.00/kWh.

Because the generation is contracted for 5 years, it may be possible to defer construction of the second 110kV feeder for up to three years, resulting in deferral benefits of up to AUD 3.63 million (2006 dollars).

## ACTUAL PROJECT COSTS

Availability payment of AUD 724,000 per annum for 5 years, plus connection and fuel costs.

## PROJECT COST FROM THE SOCIETAL PERSPECTIVE

This project gave ENERGEX an opportunity to assess embedded generation as an alternative to network augmentation.

## OVERALL PROJECT EFFECTIVENESS

## CONTACTS

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Asset Solutions - Mr Shane McLaughlin, Manager Generation
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## SOURCES

*ENERGEX Project Approval Report PAR2005-239833* (internal document)

## CASE STUDY PREPARATION

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# DG03 KERMAN PHOTOVOLTAIC GRID-SUPPORT PROJECT - USA

| | |
|---|---|
| **Last updated** | 26 August 2005 |
| **Location of Project** | Kerman (near Fresno), California, USA |
| **Year Project Implemented** | 1993 |
| **Year Project Completed** | 1996 |
| **Name of Project Proponent** | Pacific Gas and Electric Company |
| **Name of Project Implementor** | Pacific Gas and Electric Company |
| **Type of Project Implementor** | Distribution utility<br>Transmission utility<br>Electricity retailer/supplier |
| **Purpose of Project** | Deferral of network augmentation |
| **Timing of Project** | Pre contingency |
| **Focus of Project** | Network capacity limitations<br>Voltage fluctuations |
| **Project Objective** | Peak load reduction<br>Voltage regulation |
| **Project Target** | Network element |
| **DSM Measure(s) Used** | Other distributed generation |
| **Specific Technology Used** | Photovoltaic power plant |
| **Market Segments Addressed** | Non-customer related |

## 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.

## 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

| Residential Customers Participating | Commercial and Small Industrial Customers Participating | Agricultural Customers Participating | Large Industrial Customers Participating | Additional Generation Installed |
|---|---|---|---|---|
| | | | | 0.385 MW |

| Peak Load | Peak Load Reduction | Duration of Peak Load Reduction | Overall Load Reduction | Energy Savings | Network Augmentation Deferral |
|---|---|---|---|---|---|
| | | | | | |

## HOW LOAD REDUCTION WAS MEASURED

## RESULTS ACHIEVED

The results were as follows:

- generation system capacity increased by 385kW;
- PV plant achieved about 25% capacity factor, highly correlated to PG&E loads;
- pollution reduced by 155 tonnes of CO2 and 0.5 tonne of NOx each year;
- energy losses reduced by 58,500 kWh/yr; reactive power losses reduced by 350kVAR;
- transformer cooled by more than 4 degrees Celsius and capacity increased by 410Kw on peak day;
- tap changer maintenance interval increased by more than 10 years;
- transmission system capacity increased by 450kW on peak.

In 1996, the Kerman project was terminated by PG&E, according to news reports because the maintenance costs of about USD 20,000 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.

## CONFIDENCE LEVEL IN ACHIEVING RESULTS

## REPEATABILITY OF RESULTS

Voltage support was predictable; 3 volts provided on a 120V base. The PV plant delivered 90% capacity coincident with peak load-following dispatch.

## TIME DELAY BEFORE MAXIMUM RESPONSE ACHIEVED

## WEATHER DEPENDENCE

## AVOIDED COSTS

## ACTUAL PROJECT COSTS

## PROJECT COST FROM THE SOCIETAL PERSPECTIVE

## OVERALL PROJECT EFFECTIVENESS

## 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.

## CASE STUDY PREPARATION

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## DG04 CHICAGO ENERGY RELIABILITY AND CAPACITY ACCOUNT - USA

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|---|---|
| **Last updated** | 26 August 2005 |
| **Location of Project** | Chicago, Illinois, USA |
| **Year Project Implemented** | Progressively from May 1999 |
| **Year Project Completed** | |
| **Name of Project Proponent** | City of Chicago/Commonwealth Edison |
| **Name of Project Implementor** | Commonwealth Edison |
| **Type of Project Implementor** | Distribution utility<br>Transmission utility<br>Electricity retailer/supplier<br>Local government (municipality) |
| **Purpose of Project** | Deferral of network augmentation |
| **Timing of Project** | Post contingency |
| **Focus of Project** | Network capacity limitations |
| **Project Objective** | Overall load reduction |
| **Project Target** | Whole network |
| **DSM Measure(s) Used** | Standby generation<br>Other distributed generation<br>Energy efficiency |
| **Specific Technology Used** | Energy efficiency measures, standby generation and photovoltaic distributed generation |
| **Market Segments Addressed** | Commercial and small industrial customers<br>Large industrial customers<br>Non-customer related |

### 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 USD1.25 billion in transmission and distribution infrastructure by the year 2004. ComEd also made payments totalling USD100 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.

## DESCRIPTION OF PROJECT

The USD100 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.

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

| Residential Customers Participating | Commercial and Small Industrial Customers Participating | Agricultural Customers Participating | Large Industrial Customers Participating | Additional Generation Installed |
|---|---|---|---|---|
| | | | | 2.75 MW |

| Peak Load | Peak Load Reduction | Duration of Peak Load Reduction | Overall Load Reduction | Energy Savings | Network Augmentation Deferral |
|---|---|---|---|---|---|
| | | | | | |

## HOW LOAD REDUCTION WAS MEASURED

## RESULTS ACHIEVED

## CONFIDENCE LEVEL IN ACHIEVING RESULTS

## REPEATABILITY OF RESULTS

## TIME DELAY BEFORE MAXIMUM RESPONSE ACHIEVED

## WEATHER DEPENDENCE

## AVOIDED COSTS

## ACTUAL PROJECT COSTS

USD 100 million (contribution by ComEd)

## PROJECT COST FROM THE SOCIETAL PERSPECTIVE

## OVERALL PROJECT EFFECTIVENESS

## CONTACTS

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## SOURCES

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

## CASE STUDY PREPARATION

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# DG05 MITIGATION OF LOAD SHEDDING IN PUNE URBAN CIRCLE - INDIA

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|---|---|
| **Last updated** | 2 October 2008 |
| **Location of Project** | Pune, Maharashtra, India |
| **Year Project Implemented** | |
| **Year Project Completed** | |
| **Name of Project Proponent** | Confederation of Indian Industry (CII) |
| **Name of Project Implementor** | Maharashtra State Electricity Distribution Company Limited (MSEDCL) |
| **Type of Project Implementor** | Distribution utility<br>Electricity retailer/supplier |
| **Purpose of Project** | Deferral of network augmentation |
| **Timing of Project** | Post contingency |
| **Focus of Project** | Network capacity limitations<br>Generation capacity limitations |
| **Project Objective** | Peak load reduction |
| **Project Target** | Network element |
| **DSM Measure(s) Used** | Other distributed generation |
| **Specific Technology Used** | Captive / standby generator sets |
| **Market Segments Addressed** | Commercial and small industrial customers |

## DRIVERS FOR PROJECT

The Mitigation of Load Shedding in Pune Urban Circle project was implemented by the Maharashtra State Electricity Distribution Company Limited (MSEDCL).

MSEDCL is responsible for the distribution and retailing of electricity in most of the State of Maharashtra. In the Mumbai region, MSEDCL and two private companies are responsible for distribution and retailing. In financal year 2004/05, MSEDCL supplied power to a consumer base of more than 13.6 million and sold 43,549 gigawatt-hours of electricity.

Maharashtra State has witnessed rapid economic growth in the past decade leading to increase in demand for electricity. But the growth in electricity generation capacity in the State has not kept pace with the demand growth. In 2005/06, Maharashtra State faced a demand/supply gap of around 2600 MW to 3500 MW during the peak hours of the day and 2200 MW during non-peak hours. This deficit led MSEDCL to resort to load shedding across all regions of the State.

Considering that the demand supply gap was expected to prevail for the next five years at least, there was an urgent need to see how best the situation could be mitigated for the entire State. Hence, MSEDCL carried out a project to identify and develop a pilot scheme to mitigate load shedding in the Pune urban circle (see Figure DG05/1, page 117). It was intended that the project could be replicated in other cities across the State based on the performance evaluation of the pilot scheme and incorporating the learning from the pilot scheme.

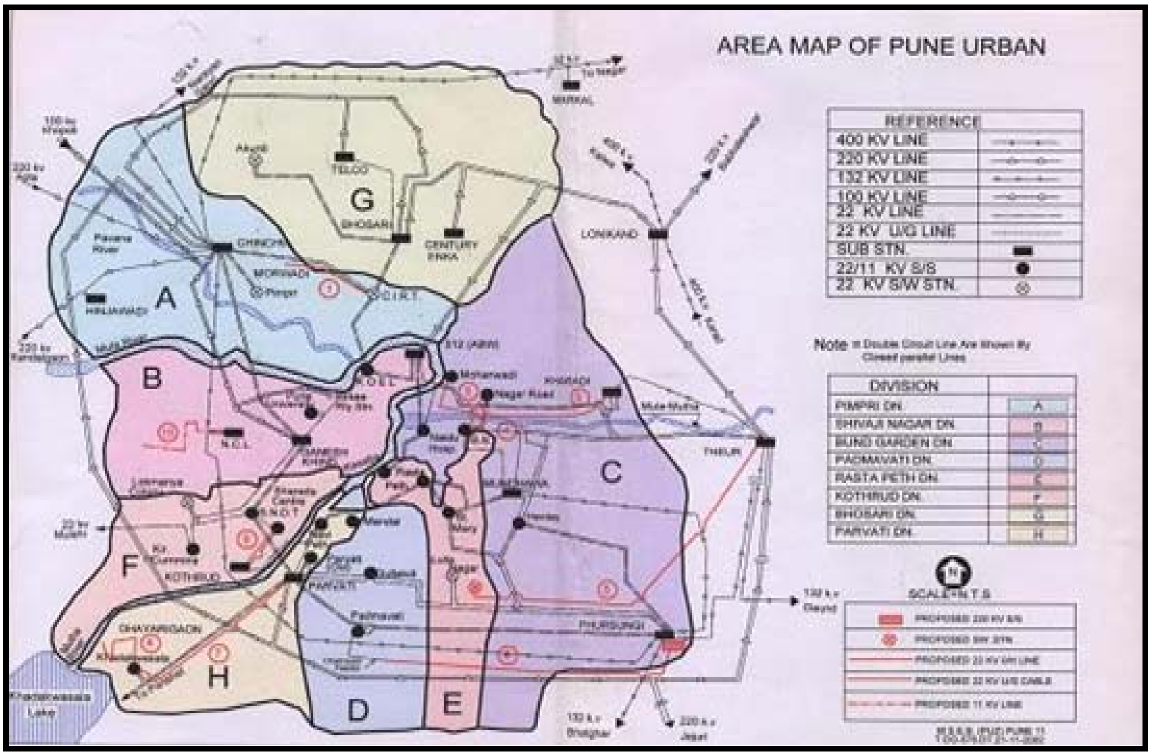


**Figure DG05/1. Map of Pune Urban Circle showing Commercial Divisions and Network Infrastructure**

## DESCRIPTION OF PROJECT

During financial year 2005/06, the total load of Pune urban circle was 751 MW out of which sheddable load was 358 MW while non-sheddable load was 393 MW. Average evening peak load during FY 2005/06 was 834 MW, while the average morning peak during FY 2005/06 was 742 MW. Normal load shedding in Pune was in the range of 1200 MWh/day during FY 2005/06. MSEDCL had taken several demand side management measures and expected to bring down the load shedding in Pune to approximately 1000 to 1100 MWh/day.

The distributed generation model for mitigating load shedding in the Pune urban circle was developed by MSEDCL in consultation with the Confederation of Indian Industry (CII). CII proposed to utilise surplus power available from Captive Power Producers (CPPs) during peak hours and make available the grid power for supply to other consumers in the Pune urban circle by implementing a workable alternative for harnessing distributed generation on a pilot basis.

MSEDCL undertook sensitivity analysis and identified three scenarios for load shedding in Pune of: (1) 180 MWh/day (2) 300 MWh/day and (3) 540 MWh /day, depending upon the power shortage in the State of Maharashtra. MSEDCL found that even in the worst scenario of load shedding of 540 MWh/day, the maximum load shedding was approximately 90 MW.

CII compiled information on the installed capacity of captive / standby generator sets in the premises of high voltage consumers located in the Rasthapet and Ganeshkhind circles of Pune. Total installed capacity of captive / standby gensets was more than

400 MW. CII also found that the top 30 major CPPs had unutilised capacity in excess of 100 MW which was equivalent to the worst case scenario of load shedding.

Based on the above study, CII developed a proposal to mitigate load shedding. CII proposed that industries with captive / standby gensets that were drawing power from the MSEDCL grid on a 24 hour basis should reduce their off-take of power from the grid during certain specified peak periods and instead operate their own generators. The additional grid power made available through this strategy could then be diverted by MSEDCL to low voltage customers to mitigate load shedding. This would eliminate the need for load shedding in the Pune urban circle.

The CPPs would be reimbursed the incremental cost for electricity they generated on-site during the specified peak periods. Payments to CPPs would comprise the difference between the variable cost of running the on-site generator sets and the applicable MSEDCL peak hour variable tariff for the reduction in the quantity of electricity consumed from the grid. The extra costs incurred by MSEDCL in mitigating load shedding would be recovered by ia 'reliability surcharge' on the electricity tariffs for all consumers, including the CPPs, located in the two circles of the Pune urban region.

In implementing this model, MSEDCL established a mini-load dispatch centre to co-ordinate with all the CPPs regarding their output capacities during the specified peak periods. Grid connectivity with a synchronising facility was provided to operate captive / standby generators either in stand-alone mode, island mode or parallel mode. An appropriate protection system was provided to the CPPs so as to safeguard MSEDCL's network against faults, particularly in the case of parallel operation. Export and import meters were installed to monitor the generation / consumption of CPPs to enable the calculation of the payments for incremental costs on an actual basis.

## RESULTS

| Residential Customers Participating | Commercial and Small Industrial Customers Participating | Agricultural Customers Participating | Large Industrial Customers Participating | Additional Generation Installed |
|---|---|---|---|---|
| | | | | |

| Peak Load | Peak Load Reduction | Duration of Peak Load Reduction | Overall Load Reduction | Energy Savings | Network Augmentation Deferral |
|---|---|---|---|---|---|
| 834 MW | | 3.5 hours | | | |

## HOW LOAD REDUCTION WAS MEASURED

## RESULTS ACHIEVED

To determine the tariff increases required, MSEDCL in consultation with CII undertook sensitivity analysis for three different scenario of load shedding, including a detailed analysis of the costs incurred in facilitating generation of additional power by captive units in Pune during the peak periods and making available the grid power for supply to other consumers. The results are shown in Table DG05/1.

| Table DG05/1. Impact on Tariffs for Three Different Scenarios | | | |
|---|---|---|---|
| **Load Shedding (MWh/day)** | **Annualised Load Shedding (MWh/year)** | **Additional Revenue Required (INR)** | **Tariff Increase for all Customer Classes (INR/kWh)** |
| 180 | 64,800 | 4.409 million | 0.14 |
| 300 | 108,000 | 7.349 million | 0.23 |
| 540 | 194,400 | 13.229 million | 0.41 |

MSEDCL had to generate sufficient revenue to cover these costs from the quantities of electricity it transported across the low voltage network. The revenue earned from the two Pune circles had to pay the differential cost of generation by the CPPs and also take care of any cross subsidy (including technical losses and collection efficiency) components and fuel reimbursement charges.

## CONFIDENCE LEVEL IN ACHIEVING RESULTS

## REPEATABILITY OF RESULTS

The repeatability of the results is very high and the use of fully maintained captive / standby power plants ensures rapid response and high availability to mitigate load shedding.

## TIME DELAY BEFORE MAXIMUM RESPONSE ACHIEVED

## WEATHER DEPENDENCE

## AVOIDED COSTS

## ACTUAL PROJECT COSTS

The extra costs incurred comprised the difference between the variable cost of running captive / standby generators and the applicable MSEDCL peak hour variable tariff payable to industrial customers for reductions in the quantity of electricity consumed from the grid. These costs were recovered from all customer categories located in the two Pune urban circles in the form of a 'reliability surcharge'. Table DG05/1 shows that the maximum additional charge was INR0.43 per kWh.

## PROJECT COST FROM THE SOCIETAL PERSPECTIVE

## OVERALL PROJECT EFFECTIVENESS

The project was very effective in managing demand and preventing load shedding. This is a relatively expensive option but flexible enough to deploy in a range of situation. Implementation of this project will avoid investment in transmission and distribution network.

## CONTACTS

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## SOURCES

## CASE STUDY PREPARATION

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# DR01 ISO NEW ENGLAND DEMAND RESPONSE PROGRAMS - USA

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|---|---|
| **Last updated** | 25 August 2005 |
| **Location of Project** | States of Vermont, New Hampshire, Connecticut, Maine, Massachusetts, Rhode Island, USA |
| **Year Project Implemented** | 2003 |
| **Year Project Completed** | Continuing |
| **Name of Project Proponent** | ISO New England Inc |
| **Name of Project Implementor** | ISO New England Inc |
| **Type of Project Implementor** | Independent system operator |
| **Purpose of Project** | Provision of network operational services |
| **Timing of Project** | Pre contingency |
| **Focus of Project** | Network capacity limitations<br>Generation capacity limitations |
| **Project Objective** | Peak load reduction |
| **Project Target** | Whole network |
| **DSM Measure(s) Used** | Standby generation<br>Other distributed generation<br>Interruptible loads<br>Direct load control<br>Other short-term demand response |
| **Specific Technology Used** | Internet based communication of notification to curtail, pagers and automated phone calls. |
| **Market Segments Addressed** | Commercial and small industrial customers<br>Large industrial customers |

## 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:

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

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.

## DESCRIPTION OF PROJECT

### Customer Participation

Electricity customers who participate in ISO New England demand response programs can contribute demand reduction in a variety of ways (see Figure DR01/1):

- 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).

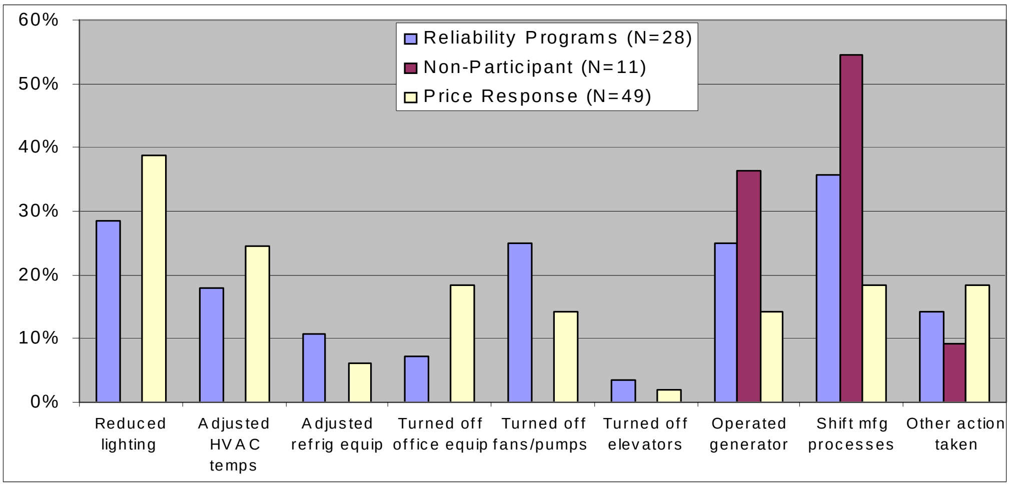


**Figure DR01/1. Actions Undertaken if Customers Are Asked to Curtail**

Customers who wish to participate in a demand response program can do so through an Enrolling Participant. Enrolling Participants can be a local distribution company, Demand Response Provider or a competitive supplier. 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.

## Demand Response Programs

ISO New England introduced several demand response programs in March 2003, concurrent with the introduction of Standard Market Design (SMD). The new programs, which replaced existing demand response programs that had been available since 2001, are organized into two categories, as follows:

- programs that provide reliability, which include the Real-Time Demand Response Program (comprising two sub-programs with 30-minute and 2-hour notice provisions) and the Real-Time Profiled Response Program;
- programs designed to encourage load reduction in response to high real-time wholesale energy prices, which include the Real-Time Price Response Program and the Day Ahead Option (introduced in June 2005).

### *Real-Time Demand Response Program*

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 from ISO New England. 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 real-time locational marginal price applicable to the customer's load zone in the New England Power Pool (NEPOOL). In addition, customers may receive additional credit for installed capacity and reserve margin.

For participants in the Real-Time Demand Response Program, compliance with curtailment events, which are coincident with NEPOOL Operating Procedure No 4 (OP-4) is mandatory. OP-4 applies to conditions that are characterized by expected reserve shortfalls. The program is activated at various Action Steps of OP-4 depending on the program’s notification time and the technology used by the participating customer to accomplish the load reduction. ISO New England guarantees a minimum of two hours of curtailment for each event.

Failure to comply with a curtailment event results in the forfeiture of capacity payments accumulated for the month, and the customer’s curtailment capability going forward is de-rated accordingly.

### *Real-Time Profiled Response Program*

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.

Participants in the Real-Time Profiled Response Program do not need to have five-minute metering capability. Rather, the load response for the individual or group of individual loads can be estimated using an ISO-approved measurement and verification plan. For example, statistical sampling can be used to estimate load reduction for projects such as aggregated residential super-thermostat programs, hot water heaters, pool pumps, and distributed generation.

***Real-Time Price Response Program***

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 during any of the hours of 7 am to 6 pm on non-holiday weekdays.

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.

ISO New England directly informs customers that the eligibility period for the Real-Time Price Response Program is open. A decision to open the eligibility period is typically made late in the day for the next day. Once the eligibility period is opened, ISO New England usually authorizes payments for any load that is curtailed during the entire 11-hour period. However, program rules also permit a shorter eligibility period and declaration of a second event on the same day.

Enrolling Participants and their participating customers are notified of price response events by several means, including e-mail, and by a posting on the ISO New England web site. Some Enrolling Participants notify their program participants of price response events using pagers, automated phone calls, and other means. Meter readings for this program are submitted to the ISO daily or monthly by the Enrolling Participant on the same schedule as other hourly meter data.

***Day Ahead Option***

The Day Ahead Option was introduced in June 2005. This program is designed for customers who can offer (bid) load reductions into the Day-Ahead Energy 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.

Unlike the real-time demand response programs, the Day-Ahead Option is based on electricity prices set in the Day-Ahead Energy Market. This is a financial market where buyers and sellers of electricity can agree upon the price at which they are willing to purchase and deliver electricity for the following day. The Day-Ahead Market allows buyers and sellers to lock in their price and hedge against volatility in the Real-Time Energy Market.

Working through their Enrolling Participant, participating customers develop and submit an “offer” to ISO-NE. The offer specifies the price, amount of curtailment, minimum duration and an optional start-up/shut-down cost at which the customer is willing to reduce their electricity consumption for the following day.

The customer’s offer is compared with the Day-Ahead Market hourly clearing prices in the customer's load zone. If the combination of the customer’s price ($/MWh) and the optional start-up/shut-down cost is less than or equal to the Day-Ahead Market hourly clearing prices, the customer’s offer is accepted or “cleared”.

The offer must be at least 100 kW and could be as high as the amount of load that the customer registered in the Real-Time Price or Demand Response Program. The price offered (including the optional start-up/shut-down cost) must be, on average, between $50 and $1,000 per MWh. A minimum curtailment duration of up to four hours can also be specified.

The Day-Ahead market closes each day at noon, and the results are posted (made available) at approximately 4 pm. If an offer is accepted, the customer's Enrolling Participant is paid the higher of the offer price or the hourly day-ahead real-time locational marginal price ($/MWh) times the offer reduction amount (MW) for each hour the offer was accepted. It is up to the customer and their Enrolling Participant to work out an agreement on how the demand response payments will be shared.

If the customer does not reduce consumption by at least their offer amount when scheduled, their Enrolling Participant is charged the difference between the actual and offer reduction at the hourly real-time locational marginal price (LMP) in the customer's load zone. The hourly real-time LMP can be higher or lower than the offer price.

If the customer reduces consumption by more than the offer amount, their Enrolling Participant is paid the difference between the offer amount and actual reduction at the hourly real-time LMP in the customer's load zone.

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.

### 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 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:

**1. Internet Based Communication System (IBCS)**: 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.

NEPOOL provides financial support to demand response program participants to purchase and maintain metering systems that meet the IBCS requirements. The equipment incentive is either USD 2,200 or USD 2,800, depending upon installation requirements, provided that the facility enrolls a load reduction of at least 100 kW. Participants that commit to a load reduction of 300 kW or greater also receive up to USD 100 per month towards the cost of maintaining the IBCS system.

The IBCS system set up by ISO-NE is an open-architecture system which allows for a variety of vendors to provide participating customers with IBCS services. The system requires either a telephone or LAN connection.

**2. 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.

**3. 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

| Residential Customers Participating | Commercial and Small Industrial Customers Participating | Agricultural Customers Participating | Large Industrial Customers Participating | Additional Generation Installed |
|---|---|---|---|---|
| | 200 | | | |

| Peak Load | Peak Load Reduction | Duration of Peak Load Reduction | Overall Load Reduction | Energy Savings | Network Augmentation Deferral |
|---|---|---|---|---|---|
| 25,500 MW | 108 MW | | | 9,216 MWh | |

## HOW LOAD REDUCTION WAS MEASURED

Interval meter. 5 minute intervals.

## RESULTS ACHIEVED

### Results for Customer Participation

By the end of 2004, approximately 200 electricity customers throughout New England had participated in ISO New England's demand response programs, contributing over 200 MW of load reduction.

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.

### Results for Reliability Programs

In 2004, the ISO did not activate the Real-Time Demand or Profiled Response Programs in response to a system emergency. However, an audit of the programs was conducted on August 20, 2004 (see Figures DR01/2, DR01/3 and DR01/4, page 128).

The audit ran from 11:00 a.m. to 1:30 p.m. for the resources that are required to respond within 30 minutes. The Two-Hour and Profiled Response resources were tested concurrently, but their audit extended through 3:00 p.m. Demand resources were not warned ahead of time that an audit was being scheduled. From the resources' perspective, all aspects of the audit event were identical to a real event.

Overall, a 45.8% response rate was achieved for an average of 349.42 MW of load curtailed, resulting in total payments of USD 168,927. Approximately 33% of the capacity enrolled in the reliability programs overall did not respond during the test event – the majority of the unresponsive capacity was enrolled in the Profiled Response Program.

Performance of resources in the 30-minute Real Time Demand Response Program was substantially better than average – the response rate of these resources was 86.4% on a system-wide basis. Within the Connecticut Load Zone – within which most of these resources are located because of a recent Request for Proposals for resources in Southwest Connecticut – the response rate was greater than 100%. The higher response rates in Connecticut are the result of higher capacity payments and corresponding higher penalties for non-performance applied to demand response resources participating in the Southwest Connecticut Request for Proposals.

In the 30-minute Real Time Demand Response Program, the resources which reduce load by starting emergency generation provided 61% of the overall curtailed capacity during the audit. The resources which reduce load without using emergency generation, provided 33% of the overall curtailed capacity.

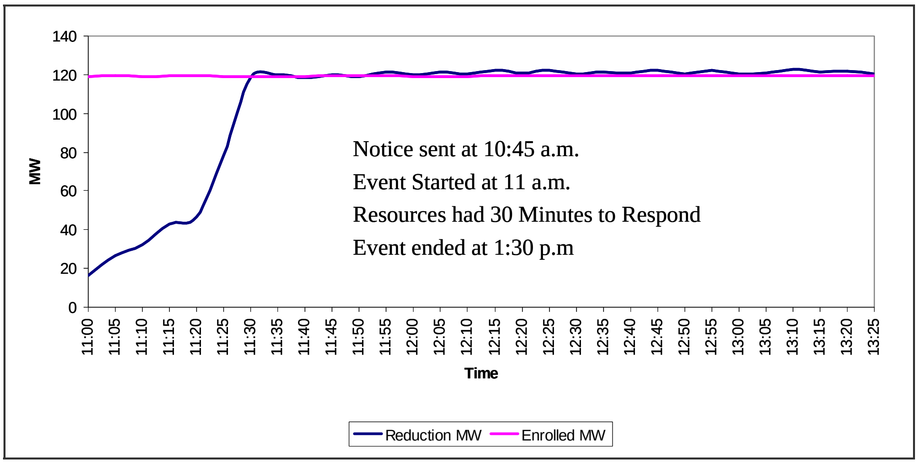


**Figure DR01/2. Performance in August 20 2004 Test - All Resources**

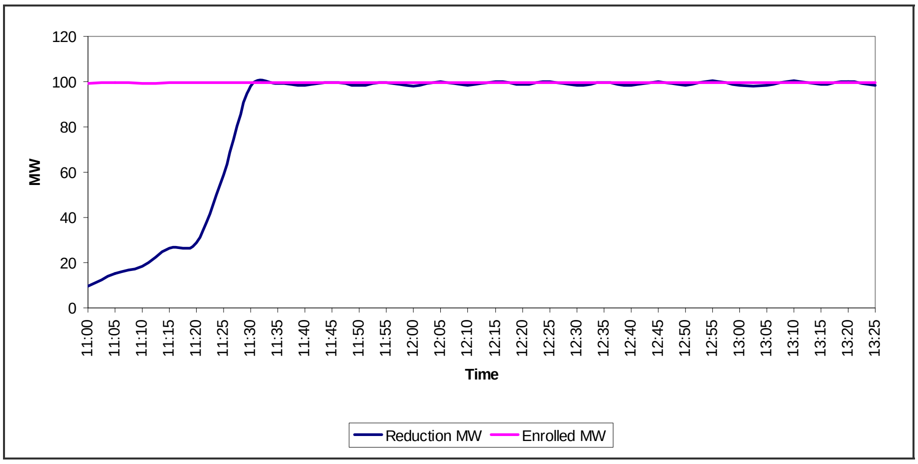


**Figure DR01/3. Performance in August 20 2004 Test - Emergency Generation Only**

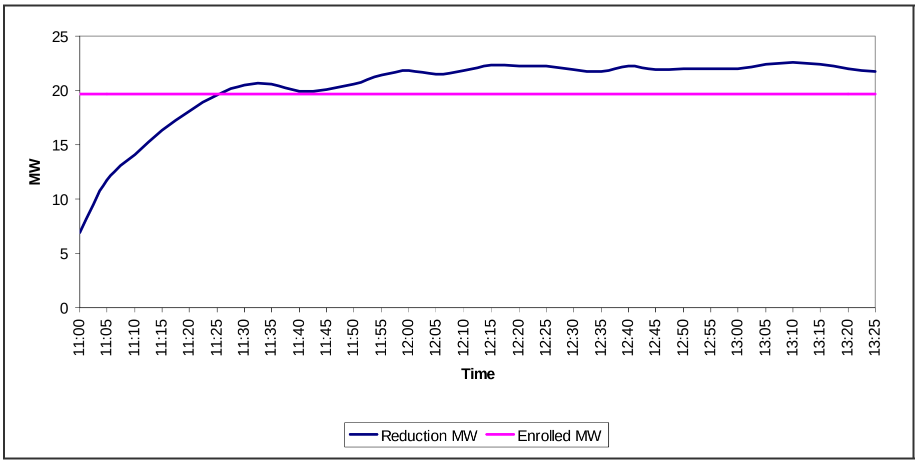


**Figure DR01/4. Performance in August 20 2004 Test - Load Reduction Only**

### Results for Price Programs

During the 2004 program year, from September 2003 to August 2004, ISO New England paid for load curtailments on 56 distinct days for a total of 2,132 event hours and resulting in 9,216 MWh of load curtailments. By comparison, from January to August 2003, there was only 1,950 total MWh of load curtailment.

The Subscribed Performance Index is the actual load curtailed divided by the enrolled load. During the 2004 program year, the index was 0.36. The amount of load reduction that assets provided, relative to their total energy consumption was low, 0.09.

During the 2004 program year, the number of participants curtailing during event hours ranged from a minimum of 44 (November 2003) to a maximum of 337 (January 2004).

In August 2004, 367 assets were enrolled in the program, but only about 40% of those assets actually curtailed during an event in the 2004 program year. The average asset curtailment was 0.19 MWh per hour.

During the 2004 program year, events were called in all but two months, March and July 2004. January 2004 had the most event days (16) followed by November 2003 (14), October 2003 and June 2004 (6), February 2004 (5), December 2003 (3), May and August 2004 (2), and finally April 2004 with only one event.

The total event respondent count was highest in January 2004 (332 assets curtailed), closely followed by September 2003 (333) and February 2004 (334). The events declared in the middle of January 2004, were in large part due to a severe cold snap that resulted in the interruption of natural gas supplies to some generators, which caused prices to rise, reaching USD 900 or more in some hours.

### CONFIDENCE LEVEL IN ACHIEVING RESULTS

### REPEATABILITY OF RESULTS

In the Real-Time Price Response Program, both the number of assets that curtailed and the size of the curtailed load varied widely from event to event.

### TIME DELAY BEFORE MAXIMUM RESPONSE ACHIEVED

In the Real-Time Demand Response Program, the time delay is 30 minutes or two hours depending on the program option selected.

### WEATHER DEPENDENCE

In the Real-Time Price Response Program, the highest level of participation was in the winter months, especially December 2003 and January 2004.

### AVOIDED COSTS

In the Real-Time Price Response Program, the value of the benefits in NEPOOL realized through load curtailment was over four times the payments made by ISO New England to participants for curtailing load. The program payments were about USD 1 million, and the total benefits were valued at nearly USD 5 million.

## ACTUAL PROJECT COSTS

### Costs for Reliability Programs

Total payments by ISO New England for the August 2004 test were USD 168,927. Costs from the ISO's perspective include the incentive payments made and the financial support provided to demand response program participants to enable them to purchase and maintain metering systems that meet the IBCS requirements. Customer costs are unknown.

### Costs for Price Programs

During the 2004 program year, participants in the Real-Time Price Response Program were paid a total of USD 1,040,206, or about USD 21/participant-hour. The average price paid for curtailments was USD 113/MWh (USD 0.113/kWh).

## PROJECT COST FROM THE SOCIETAL PERSPECTIVE

## OVERALL PROJECT EFFECTIVENESS

### Effectiveness of Reliability Programs

In the reliability programs, 30-minute demand response resources were highly effective, particularly those located in Southwest Connecticut (SWCT), which receive supplemental capacity payments through a 4-year contract with the ISO. In addition to higher capacity payments, these SWCT resources have more substantial penalties for non-performance. The 2-hour and profiled response resources were less effective.

Note that the reliability programs are being used in Southwest Connecticut to address the lack of sufficient transmission infrastructure. The programs are targeted not only at the whole network, but also to address specific regions on a load zone basis.

### Effectiveness of Price Programs

The Real-Time Price Response Program was quite effective in reducing market volatility, and provided benefits in NEPOOL valued at nearly five times the payment to participants. Note that the program is targeted at both the whole network and network regions implemented on a load zone basis.

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## CASE STUDY PREPARATION

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## DR02 NEW YORK ISO DEMAND RESPONSE PROGRAMS - USA

| | |
|---|---|
| **Last updated** | 2 September 2005 |
| **Location of Project** | New York, USA |
| **Year Project Implemented** | 2001 |
| **Year Project Completed** | Continuing |
| **Name of Project Proponent** | New York Independent System Operator |
| **Name of Project Implementor** | Aggregators<br>Load Serving Entities<br>Transmission Owners |
| **Type of Project Implementor** | Distribution utility<br>Transmission utility<br>Independent system operator<br>Electricity retailer/supplier<br>Third party aggregator |
| **Purpose of Project** | Provision of network operational services |
| **Timing of Project** | Post contingency |
| **Focus of Project** | Network capacity limitations<br>Generation capacity limitations |
| **Project Objective** | Increasing operating reserve<br>Other: Response to contingencies |
| **Project Target** | Network region |
| **DSM Measure(s) Used** | Standby generation<br>Cogeneration<br>Other distributed generation<br>Interruptible loads<br>Direct load control<br>Other short-term demand response<br>Pricing initiatives |
| **Specific Technology Used** | Automated notification system |
| **Market Segments Addressed** | Residential customers<br>Commercial and small industrial customers<br>Agricultural customers<br>Large industrial customers |

### DRIVERS FOR PROJECT

The New York Independent System Operator (NYISO) operates three demand response programs:

- the Emergency Demand Response Program (EDRP);
- the Installed Capacity Special Case Resources (ICAP-SCR) program; and
- the Day-Ahead Demand Response Program (DADRP).

The two reliability demand response programs, EDRP and ICAP-SCR, are controlled by NYISO and are intended to provide system operators with additional resources that can be deployed in the event of energy shortages to maintain the reliability of the system.

The economic demand response program, DADRP, is controlled by customers and allows energy users to bid their load reductions, or "negawatts", into the day-ahead energy market just as generators do. Offers that are determined to be economic are paid the market clearing price. DADRP allows flexible loads to effectively increase the amount of supply in the market and thereby moderate prices.

## DESCRIPTION OF PROJECT

### Emergency Demand Response Program

The Emergency Demand Response Program (EDRP) pays participants to reduce load during specific times when electric service in New York State could be jeopardized. During these "declared events", participants are expected, though not obligated, to either reduce electricity consumption and/or transfer load to an onsite generator for a minimum of four hours.

Retail customers who agree to participate in EDRP are enrolled through one of four types of Curtailment Service Providers:

- through a Load Serving Entity (eg an electricity retailer), either the LSE currently serving the customer's load or another LSE; or
- through an NYISO-approved Curtailment Customer Aggregator; or
- directly as a Direct Customer of the NYISO; or
- directly as a NYISO-approved Curtailment Program End Use Customer.

Curtailment Service Providers should be able to provide load reduction of at least 100 kW per Zone and be able to respond within two hours of emergency notification.

NYISO makes payments for performance in demand response programs directly to Curtailment Service Providers. Arrangements for paying retail customers vary among providers.

Usually, a Curtailment Service Providers will give notice to participating retail customers the day prior to an expected emergency program event. NYISO must give Curtailment Service Providers notice no less than two hours in advance of the time specified to reduce load and providers are generally able to pass on this notice to retail customers. When the program is activated, participants receive a confirmation notice indicating that participation is needed.

During emergency program events, performance is based on how much metered load is reduced. Metered load during the event hours, is compared with a customer baseline (CBL, a statistical estimate of how much electricity would have been used during the same time period.) The difference between metered load and CBL is the basis for payment.

Performance during emergency program events is measured on an hourly basis and payment is computed on the higher of either USD 500/MWh, or the wholesale electricity price in the customer’s area, during the time of the event.

Since this program is strictly voluntary, there is no obligation to reduce load when an emergency event is declared; similarly, there is no penalty for non-performance.

## Installed Capacity Special Case Resources Program

The Installed Capacity Special Case Resources (ICAP-SCR) program pays participants to provide their load reduction capability for a specified contract period. Program participants receive payments for both the load reduction capacity and for the actual reduced energy usage they achieve during an event called by NYISO.

To register for the ICAP-SCR program, participants commit to a load reduction of a minimum of 100 kW with 100 kW increments, subject to a one-hour verification either through an actual event or a test called by NYISO.

Retail customers who agree to participate in the ICAP-SCR progam are enrolled through one of three types of Responsible Interface Providers:

- through a Load Serving Entity (eg an electricity retailer), either the LSE currently serving the customer's load or another LSE; or
- through an NYISO-approved Curtailment Customer Aggregator; or
- directly as a Direct Customer of NYISO.

Based upon system condition forecasts, participants are notified to curtail their registered capacity by using on-site generation and/or reducing electricity consumption to a firm power level. Any under-performance results in a penalty.

NYISO must provide Responsible Interface Providers advance notice 21 hours before any anticipated need for curtailment and the RIPs are usually able to pass on this notice to participating retail customers. A confirmation notice is provided a minimum of two hours before the actual event begins.

The participant’s metered load during the event hours is compared with the registered firm-power level, or the metered generator output is compared with its registered output level. Any under-performance of either load curtailment efforts, or generator output, results in a reduction, or "derate", of any future capacity claims. Such a "derate" requires the customer to fulfill any contractual obligations entered into for capacity and will result in a proportional reduction of any future long-term contractual payments.

When a participant initially registers for ICAP-SCR, the Responsible Interface Provider calculates an unforced capacity obligation (UCAP) that is based upon the participant’s claimed load reduction capability, line losses, and historical program performance. The UCAP is then sold into wholesale capacity markets where payment rates vary according to a participant’s location in the State and the contract period.

A minimum price guarantee, or strike price, is submitted by the participant for each load reduction resource they have registered in the ICAP-SCR program. Price guarantees may be revised monthly. Registered ICAP-SCR resources are eligible for an energy payment at the minimum price guarantee, up to $500/MWh. Energy payments are computed using the same performance calculations as EDRP.

If less than all the registered ICAP-SCR resources are needed in a selected zone, the number required to serve the need is called in ascending order based on the minimum price guarantees submitted by participants.

ICAP-SCR calls are separate from EDRP events and ICAP-SCR resources are called first. Participants may participate in either EDRP or ICAP-SCR, but not both. If a registered ICAP-SCR resource has not been contracted in a given month, that resource is eligible for energy payments during EDRP events.

## Day-Ahead Demand Response Program

The Day-Ahead Demand Response Program (DADRP) offers participants an opportunity to bid load reduction capability into New York State's wholesale electricity market. Participants submit bids by 5.00 am specifying the hours and amount of load curtailment they are offering for the next day, and the price at which they are willing to curtail. The bid price must be $75/MWh or higher.

These load reduction bids compete in the wholesale electricity market with generators' offers to meet the State's electricity demand. If the load reduction bid is a less expensive alternative than a generator's offer, it is accepted and the bidder is scheduled to reduce load during the hours specified the following day.

Retail customers who agree to participate in DADRP are enrolled through one of three types of program providers:

- through a Load Serving Entity (eg an electricity retailer), either the LSE currently serving the customer's load or another LSE; or
- through a qualified Demand Reduction Provider (aggregator) which must bid total demand reduction resources of at least 1 MW; or
- directly as a Direct Customer of the NYISO (minimum bid of 1 MW).

For retail customers, the bid amount, term, frequency of submitted bids and use of generation may be subject to some restrictions, based on each program provider's rules and regulations. When a curtailment bid is accepted, the program provider notifies the retail customer of the scheduled load curtailment.

Since a load reduction bid was accepted in the day-ahead wholesale electricity market, participants are obligated to meet the posted load-reduction schedule. Any shortfall is charged the higher of either the day-ahead, or spot-market price.

Customer performance during scheduled load reductions is calculated on an hourly basis, at the wholesale price for electricity in the day-ahead market, during those hours scheduled. Participant metered load during the event hours is compared with a customer baseline (CBL, a statistical estimate of the amount of electricity that would have been used during the same time period.) The difference between the two is determined to be the level of load curtailment and is the basis of payment.

Participants may specify a minimum payment, called the "curtailment initiation cost", as a condition for being scheduled for one or more hours in a specified block of consecutive hours. Generally, in such cases, the full block is scheduled and the participant receives the higher of the curtailment initiation cost or the hourly locational-based marginal prices times the scheduled load.

### Metering Requirements

Direct participants in the NYISO demand response programs must have interval metering capable of hourly measurements. Retail customers participating through an aggregator do not require interval metering and other validation methods may be used (eg statistical sampling).

## RESULTS

| Residential Customers Participating | Commercial and Small Industrial Customers Participating | Agricultural Customers Participating | Large Industrial Customers Participating | Additional Generation Installed |
|---|---|---|---|---|
| | 2,000 | | 8 | |

| Peak Load | Peak Load Reduction | Duration of Peak Load Reduction | Overall Load Reduction | Energy Savings | Network Augmentation Deferral |
|---|---|---|---|---|---|
| 31,000 MW | | | 1,754 MW | | |

## HOW LOAD REDUCTION WAS MEASURED

Interval meter.  60 minute intervals.

## RESULTS ACHIEVED

### Participation

In February 2005, there was a total of 1,754 MW load reduction capacity registered in the NYISO demand response programs (see Table DR02/1). This represents about 2,000 customers enrolled through 44 Curtailment Service Providers.

**Table DR02/1. Participation in NYISO Demand Response Programs as at February 2005**

| Curtailment Service Providers | Registered Load Reduction Capability for ERDP/ICAP-SCR | Registered Load Reduction Capability for DADRP |
|---|---|---|
| 17 Aggregators | 406.3 MW | 0 MW |
| 11 Load Serving Entities | 250.5 MW | 46.5 MW |
| 8 Direct Customers | 126.3 MW | 8.0 MW |
| 8 Transmission Owners | 594.3 MW | 322.4 MW |
| **Total** | **1,377.4 MW** | **376.9 MW** |

### ERDP/ICAP-SCR

The performance of the two reliability demand response programs, ERDP and ICAP-SCR, in events between 2001 and 2003 is shown in Table DR02/2, page 137. There were no events called in 2004.

The load curtailed under these programs increased each year between 2001 and 2003. In 2003, the programs played a significant role in assisting to restore the system after the widespread blackout on 13 August.

| Table DR02/2. Performance of ERDP/ICAP-SCR, 2001 to 2003 | | | | |
|---|---|---|---|---|
| **Year** | **Participants/ Registered Capability** | **Events** | **Load Curtailed** | **Payments** |
| 2001 | 292<br>712 MW | 23 hours | ~425 MW | USD 4.2 million |
| 2002 | 1,711<br>1,481 MW | 22 hours | ~668 MW | USD 3.3 million |
| 2003 | 1536<br>1708 MW | 22 hours | ~700 MW | USD 7.2 million |

## DADRP

The average scheduled hourly DADRP bids (in MW) by season between 2001 and 2004 are shown in Figure DR02/1. A pattern emerged over this period. Few bids are scheduled in the spring and autumn, when Day Ahead Market prices are relatively low, and a greater number of bids are scheduled in the summer and winter, when prices are higher. In addition, the imposition of a minimum bid price in 2002 reduced overall the number of bids that were scheduled.

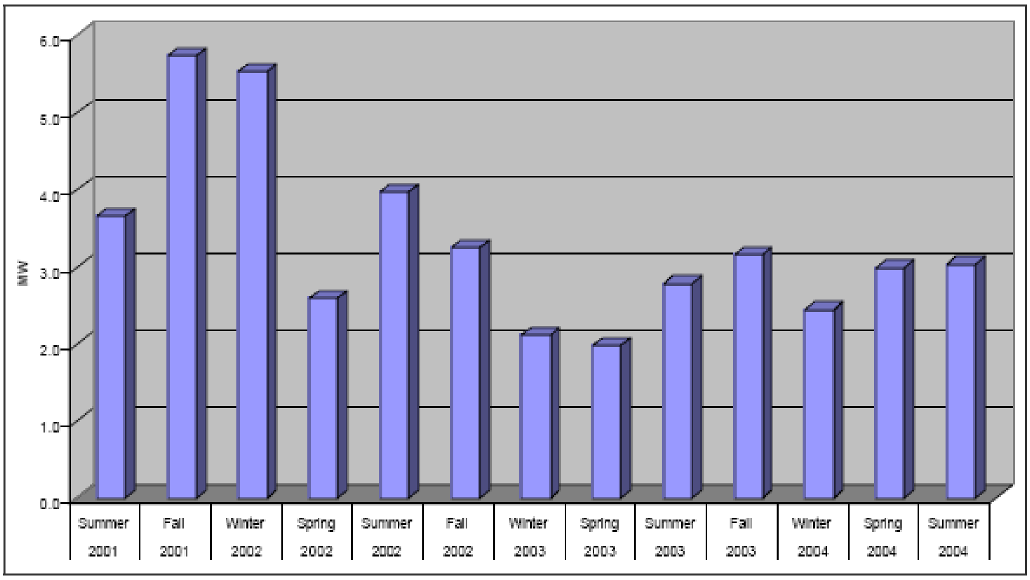


**Figure DR02/1. Average Scheduled Hourly DADRP Bids (MW) by Season**

Overall, fewer DADRP bids were scheduled in 2004 compared with previous years, largely due to the lower price volatility of the Day Ahead Market. DADRP bids were scheduled a total of 1,275 hours during the reporting period 1 September, 2003 to 31 August, 2004, which resulted in 3,535 MWh of load reductions and an average hourly reduction of 2.77 MW.

Figure DR02/2 shows the total scheduled DADRP bids (in MWh) by time of day. In 2002, the bids occurred throughout the day and night with a peak in the middle of the day. In 2003 and 2004, the bids occurred only during the day with a peak in the late afternoon. The imposition of the minimum bid price, together with the general reduction in price volatility, is largely responsible for the reduction in the number of overnight bids.

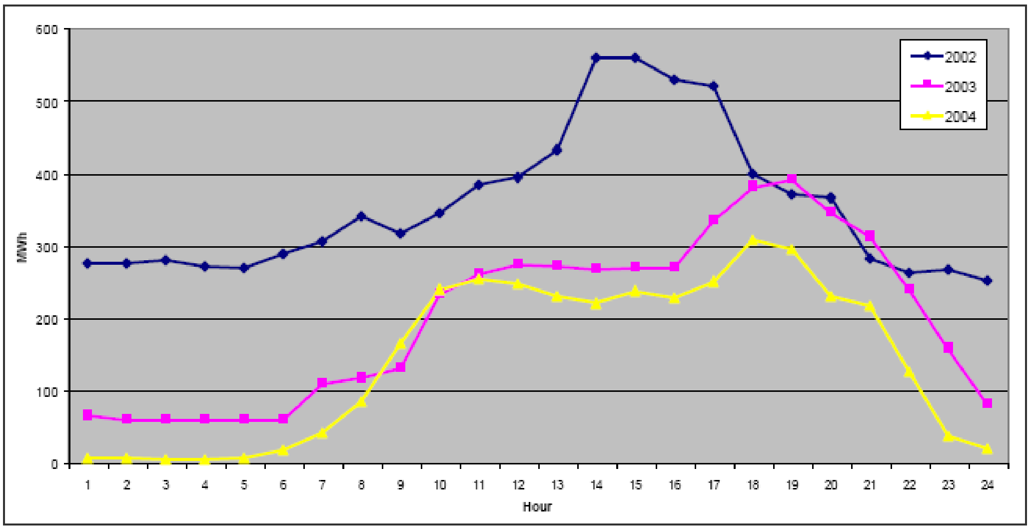


**Figure DR02/2. Total Scheduled DADRP Bids (MWh) by Time of Day**

## CONFIDENCE LEVEL IN ACHIEVING RESULTS

NYISO uses an automated notification system for communication of emergency/reliability events to program participants. This system has proven reliable in achieving high levels of performance in the reliability demand response programs. NYISO does not see the need for near real-time communication of response/metering data and such systems are not required for participation in emergency/reliability programs.

Participation in ERDP prepares customers for the ICAP-SCR program. Experience with ERDP curtailments provides the basis for accurate and achievable ICAP-SCR registration.

## REPEATABILITY OF RESULTS

When the ICAP-SCR program was called in 2003 it was very repeatable.

## TIME DELAY BEFORE MAXIMUM RESPONSE ACHIEVED

## WEATHER DEPENDENCE

## AVOIDED COSTS

## ACTUAL PROJECT COSTS

The total program costs for EDRP/ICAP-SCR and DADRP between 2001 and 2004 are shown in Tables DR02/3 and DR02/4.

**Table DR02/3. Program Costs and Benefits for ERDP/ICAP-SCR**

| | 2001 (USD) | 2002 (USD | 2003 (USD) | 2004 (USD) | 2001 to 2004 (USD) |
|---|---|---|---|---|---|
| Labour | 58,603 | 58,603 | 58,603 | 48,717 | 224,525 |
| Payments to participants | 4,167,079 | 3,513,508 | 7,344,377 | 0 | 15,024,964 |
| Consulting | 0 | 86,667 | 86,667 | 86,667 | 260,001 |
| Software, Maintenance | 0 | 113,000 | 26,000 | 40,000 | 179,000 |
| **Total program costs** | **4,225,682** | **3,771,777** | **7,515,646** | **175,384** | **15,688,487** |
| **Market Impact** | **8,159,000** | **7,028,000** | **60,137,000** | **0** | **75,324,000** |

**Table DR02/4. Program Costs and Benefits for DADRP**

| | 2001 (USD) | 2002 (USD | 2003 (USD) | 2004 (USD) | 2001 to 2004 (USD) |
|---|---|---|---|---|---|
| Labour | 20,453 | 9,818 | 9,818 | 12,272 | 52,360 |
| Payments to participants | 217,487 | 110,216 | 263,311 | 120,136 | 711,150 |
| Consulting | 0 | 43,333 | 43,333 | 43,333 | 130,000 |
| **Total program costs** | **237,940** | **163,367** | **316,462** | **175,741** | **893,510** |
| **Market Impact** | **1,570,998** | **439,094** | **207,331** | **32,802** | **2,250,225** |

In 2003, USD 7.3 million was paid to EDRP and ICAP-SCR program participants for two summer events, on 15th and 16th August. There were no payments in 2004, because no events were called.

In 2003, USD 263,000 in payments was distributed among the 27 DADRP participants. In 2004, the payments to DADRP participants totalled USD 120,000.

## PROJECT COST FROM THE SOCIETAL PERSPECTIVE

## OVERALL PROJECT EFFECTIVENESS

Tables DR02/3 and DR02/4 show the benefits of the NYISO demand response programs as dollar values for market impact over the period 2001 to 2004.

In general, the EDRP/ICAP-SCR programs showed a payback within six months during the period 2001 to 2003. While costs continue to be incurred each year, it is possible to have a year with no measured benefit as occurred in 2004 due to the lack of demand response events. Since earlier years reflected a relatively short payback, the lack of events over a 2-3 year period would still provide a positive payback to the marketplace.

DADRP is trending toward longer payback periods as a direct result of the lack of opportunity for demand-side resources to schedule reductions at cost-effective prices. The absence of these opportunities does not reflect problems with program design or implementation; they reinforce the basic balance between supply and demand, with current market conditions resulting in lower energy prices and price volatilities.

## CONTACTS

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## SOURCES

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## CASE STUDY PREPARATION

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## DR03 PJM LOAD RESPONSE PROGRAMS - USA

| | |
|---|---|
| **Last updated** | 12 September 2005 |
| **Location of Project** | Implemented as allowed by regulatory agencies in Delaware, Indiana, Illinois, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia and the District of Columbia |
| **Year Project Implemented** | 2002 |
| **Year Project Completed** | Continuing |
| **Name of Project Proponent** | PJM Interconnection LLC |
| **Name of Project Implementor** | Load Serving Entities<br>Curtailment Service Providers |
| **Type of Project Implementor** | Independent system operator |
| **Purpose of Project** | Provision of network operational services |
| **Timing of Project** | Pre contingency |
| **Focus of Project** | Network capacity limitations<br>Generation capacity limitations |
| **Project Objective** | Peak load reduction |
| **Project Target** | Network region |
| **DSM Measure(s) Used** | Standby generation<br>Cogeneration<br>Other distributed generation<br>Interruptible loads<br>Pricing initiatives<br>Other: Customer response to hourly locational marginal price. |
| **Specific Technology Used** | Website and email |
| **Market Segments Addressed** | Commercial and small industrial customers<br>Large industrial customers |

### DRIVERS FOR PROJECT

PJM Interconnection LLC is a regional transmission organization (RTO) that serves all or parts of Delaware, Indiana, Illinois, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia and the District of Columbia.

The PJM Interconnection:

- ensures the reliability of North America's largest centrally dispatched control area by managing the movement of electricity;
- operates the largest competitive wholesale electricity market in the world;
- plans generation and transmission expansion to ensure reliability; and
- provides real-time information to its members and customers to support their decision-making.

PJM operates two load response programs:

- the Emergency Load Response Program; and
- the Economic Load Response Program.

The PJM load response programs do not focus directly on network capacity limitations, but are designed to ensure the effective operation of an energy market. Nevertheless, the programs do support the electricity network during times of system constraints.

## DESCRIPTION OF PROJECT

### Participation

End-use customers who wish to participate in the PJM load response programs may offer one or both of two types of distributed resources:

- load reductions; and
- distributed generation.

End-use customers are enrolled in PJM load response programs by one of four types of qualified participants in the PJM wholesale electricity market:

- transmission owners (utilities); or
- Curtailment Service Providers (CSPs); or
- Load Serving Entities (LSEs) - eg electricity retailers;or
- the independent system operator (ie PJM).

End-use customers must complete a registration form which states the kW quantity of load reduction or distributed generation they are offering to the program and the Locational Marginal Price (LMP), in $/MW, at which the load will be reduced or the generation supplied.

Payments under load response programs are made by PJM to the end-use customer or its representative (LSE/CSP). In the event the CSP or LSE is the party to be paid but is not the load reducer, the portion of the payment that will be transferred from the LSE/CSP to the end-use customer that actually reduced load is arranged between the LSE/CSP and the end-use customer.

End-use customers may not be registered simultaneously in the Economic Load Response Program and the Emergency Load Response Program. However, an end-use customer may switch programs upon one day notice if it has participated in the same load response program for 15 consecutive days.

End-use customers participating in the PJM load response programs must have interval metering capable of hourly measurements.

The actual load reduction achieved by a program participant is measured by comparing metered load against a Customer Baseline Load (CBL). The CBL is determined using an average of the last five weekdays. There is also a weekend/holiday CBL.

PJM also considers customers without hourly metering for participation in a pilot load response program for up to two years per customer, provided the customers or their representatives propose an alternate method for measuring hourly load reductions. Alternate measurement mechanisms are approved by PJM on a case-by-case basis. Participation in the non-hourly metered customer pilot is limited to 25MW aggregate load reduction over the PJM region and across all load response programs.

## Load Response Programs

Table DR03/1 presents a comparison of the PJM load response programs.

**Table DR03/1. Comparison of PJM Load Response Programs**

| Program | Participation | Payment to Load Reducer | Cost to Energy Market | Risks to Load Reducer |
|---|---|---|---|---|
| **Emergency** | **Emergency event** | PJM pays higher of Zonal LMP or $500/MWh | Costs recovered for emergency purchases in excess of LMP are allocated among PJM market buyers in proportion to their increase in net purchases | **No Charges for Non Performance** |
| **Economic** | **Day-Ahead Market**<br>**Rea-Time Market dispatched by PJM** | **If Zonal LMP < $75/MWh,**<br>PJM pays LMP - Retail Rate [Retail Rate = Generation + Transmission]<br>**If Zonal LMP > = $75/MWh,**<br>PJM pays LMP | **If Zonal LMP < $75/MWh,**<br>PJM recovers LMP less Retail Rate from LSE<br>**If Zonal LMP > = $75/MWh,**<br>PJM recovers LMP less Retail Rate from LSE<br>PJM recovers Retail Rate from all LSEs in zone | **Charges for Non Performance:**<br>If load reduction is committed in Day-Ahead Market and does not perform in real time<br>**Real-Time LMP * Shortfall**<br>**+**<br>**Balancing Operating Reserves Charges** |
| **Economic – Real-Time LMP Based Customers** | **Real-Time Market only**<br>***Must be dispatched by PJM*** | ***For duration of the load reduction dispatched by PJM,***<br>**Actual Savings**<br>**[**RT LMP * MW Reduction]<br>**-**<br>**Total Bid Value**<br>[(Strike Price * MW Reduction) + Shutdown Costs ] | Costs recovered from Operating Reserves in the Real-Time Energy Market | **No Charges for Non Performance** |

### *Emergency Load Response Program*

The PJM Emergency Load Response Program enables participants that reduce load during emergency conditions to receive payment for those reductions.

To participate in the program, the distributed resource must:

- be capable of reducing at least 100 kW of load; and
- be capable of receiving PJM notification to participate during emergency conditions.

PJM initiates a request for load reduction following the declaration of Maximum Emergency Generation. A request is implemented whenever generation is needed that is greater than the highest economic incremental cost. PJM posts the request for load reduction on the PJM web site and through automatically generated emails. The minimum duration of a load reduction request is two hours.

Payment for reducing load is based on the actual kWh relief provided plus an adjustment for losses. The magnitude of relief provided could be less than, equal to, or greater than the kW amount declared on the Emergency Load Response Program Registration form.

PJM pays the higher of the appropriate zonal Locational Marginal Price (LMP) or $500/MWh to the PJM Member that nominates the load. Payment is equal to the measured reduction (either measured output of backup generation or the difference between the measured load the hour before the reduction and each hour during the reduction) adjusted for losses times the higher of the appropriate zonal Locational Marginal Price (LMP) or $500/MWh.

### *Economic Load Response Program*

The PJM Economic Load Response Program is designed to provide an incentive to customers or curtailment service providers to enhance the ability and opportunity for customers to reduce consumption when PJM locational marginal prices (LMP) are high.

The Economic Load Response Program purposefully incorporates incentives that are greater than strict economics would provide for the same curtailment. This departure from economics is justified to overcome initial barriers to end-use customer load response. This program is not intended to be a permanent fix to the lack of load response seen in the PJM markets today. The designers of this program contemplate that when the existing market barriers are removed and end-use customers are better able to respond to real time prices, the need for this program and others like it will disappear. Until that happens, however, programs like this are necessary for fully functioning markets.

The Economic Load Response Program is not based on the declaration of emergency conditions in PJM, but rather on the economic decisions of the PJM market participants. That is, the participants in the program are responsible for determining the conditions under which load reductions will actually take place and implementing the reductions should those conditions arise. The prime indicator of such conditions is assumed to be the locational marginal price (LMP) of energy on the PJM system.

In order to maintain adequate system control, PJM operators must know the amount of load expected to be reduced at varying price levels. These amounts may change on a daily basis. An end-use customer or its representative (LSE/CSP) is therefore responsible for maintaining the load reduction information associated with the end-use customer signed up for the program, including the amount and the price at which load might be reduced.

The Load Response Program Registration/Update web site is used for this purpose. PJM utilizes the data that has been submitted via the web site to compile daily aggregate load reductions on a zonal basis for use in operations.

#### Real-time Option

The Real Time Option of the Economic Load Response Program provides a mechanism by which any qualified market participant may offer customers the opportunity to commit to a reduction of the load they draw from the PJM system during times of high prices and receive payments based on real time LMP for the reductions.

End-use customers participating in the Real-time Option may choose to reduce load whenever their zonal LMP dictates that it is economically beneficial for them to do so, or they may choose to be dispatched by PJM. Load reductions under this program are not eligible to set real time price on the PJM system unless metered directly by PJM.

The end-use customer or its representative (LSE/CSP) sends an email to PJM concurrent with, or up to one hour immediately prior to, beginning the load reduction and also sends another email to PJM at the end of the load reduction.

Reimbursement for reducing load is based on the actual kWh relief provided in excess of committed day-ahead load reductions plus the adjustment for losses.

If the real-time LMP is less than $75/MWh, the end-use customer (or its representative (LSE/CSP)) that curtails load in real time is paid by PJM the real-time LMP less an amount equal to the applicable generation and transmission charges. If the real-time LMP is greater than or equal to $75/MWh, the payment is the real-time LMP.

In cases where the load response is dispatched by PJM, payment is not less than the total value of the load response bid, including any submitted start-up cost.

**Day-ahead Option**

The Day Ahead Option of the Economic Load Response Program provides a mechanism by which any qualified market participant may offer customers the opportunity to reduce the load they draw from the PJM system in advance of real time operations and receive payments based on day ahead time LMP for the reductions.

PJM accepts demand reduction bids from an end-use customer or its representative (LSE/CSP) for a specific MW curtailment (in minimum increments of 0.1 MW). The demand reduction bid include the day-ahead LMP above which the end-use customer will not consume, and may also include a start-up cost and/or a minimum number of contiguous hours for which the load reduction must be committed.

The objective function for day-ahead commitment software is to reduce the day-ahead bid load by the amount of a demand reduction bid when the total cost over the 24-hour dispatch day is reduced compared to serving that load. The total cost includes paying the demand reduction bid for the length of the minimum commitment time as well as any start-up cost. Thus, curtailments are not scheduled unless they reduce total day-ahead production costs.

Demand reduction bids can set day-ahead LMP in the same way as a comparably bid generator.

Reimbursement for reducing load is based on the reductions of kWh committed in the Day Ahead Market.

An end-use customer or its representative (LSE/CSP) that submits a day-ahead demand reduction bid that is accepted by PJM when the day-ahead LMP is less than $75 MWh is paid by PJM the day-ahead LMP less an amount equal to the applicable generation and transmission charges. If the day-ahead LMP is greater than or equal to $75/MWh, the payment is the day-ahead LMP.

Total payments to end-use customers or their representatives (LSEs/CSPs) for accepted day ahead load response bids will not be less than the total value of the load response bid, including any submitted start-up cost.

## RESULTS

| Residential Customers Participating | Commercial and Small Industrial Customers Participating | Agricultural Customers Participating | Large Industrial Customers Participating | Additional Generation Installed |
|---|---|---|---|---|
| | 6,324 | | | |

| Peak Load | Peak Load Reduction | Duration of Peak Load Reduction | Overall Load Reduction | Energy Savings | Network Augmentation Deferral |
|---|---|---|---|---|---|
| 130,580 MW | 3,902 MW | 4,123 hours per annum | 3,902 MW | 31,719 MWh | |

## HOW LOAD REDUCTION WAS MEASURED

Interval meter. 60 minute intervals.

## RESULTS ACHIEVED

### Participation

Participation in the PJM load response programs grew significantly during the period 2002 to 2005, as measured by total number of participants and MW enrolled in the program (see Table DR03/2). The number of participants in the Emergency Program increased from 61 to 4,301 over this period and in the Economic Program the increase was from 116 to 2,023 participants. The enrolled capacity in the Emergency Program increased from 548 MW to 1,738 MW between 2002 and 2005 and in the Economic Program the increase was from 337 MW to 2,119 MW.

**Table DR03/2. Registered Participants in Load Response Programs**

| Year | Emergency Program | | Economic Program | |
|---|---|---|---|---|
| | New Registered Sites | Additional MW | New Registered Sites | Additional MW |
| 2002 | 61 | 548 | 116 | 337 |
| 2003 | 168 | 659 | 245 | 724 |
| 2004 | 4,147 | 1,124 | 1,784 | 1,395 |
| 2005* | 4,301 | 1,783 | 2,023 | 2,119 |

* To 1 June 2005

## Load Reductions

Table DR03/3 shows the actual load reductions and associated payments under the Economic Program from 2002 to 2004. The level of load reductions increased from 6,462 MWh in 2002 to 31,719 MWh in 2004. Consistent with lower system LMPs, payments per MWh decreased 64 percent from 2002 to 2003, and 19 percent from 2003 to 2004. The MWh of actual load reductions per MW enrolled in the Economic Program increased about 40 percent in 2003 and about 10 percent in 2004.

**Table DR03/3. Performance of Economic Program Participants**

| Year | Total MWh | Total Payments | $/MWh |
|---|---|---|---|
| 2002 | 6,462 | USD 761,977 | USD 118 |
| 2003 | 19,290 | USD 827,179 | USD 43 |
| 2004 | 31,719 | USD 1,096,573 | USD 35 |

Figures DR03/1, DR03/2 and DR03/3 (pages 148 to 150) show the actual load reductions achieved in the Economic Program over the first seven months of 2004 on a daily basis and compared with the level of the LMP and with the total load on the PJM system. During this period there were no requests for load reduction in the Emergency Program.

## Payments

Table DR03/4 shows the payments to participants in the Emergency Program and the Economic Program. Payments have steadily declined in the Emergency Program, reflecting the continuing reduction in the number of requests for load reduction in emergency situations. In contrast, payments to participants in the Economic Program have increased progressively, reflecting the continuing increase in voluntary load reductions by participants under this program.

**Table DR03/4. Payments to Program Participants**

| Year | Emergency Program | Economic Program | Total |
|---|---|---|---|
| 2002 | USD 282,756 | USD 761,977 | USD 1,044,753 |
| 2003 | USD 26,613 | USD 827,179 | USD 853,792 |
| 2004 | USD 0 | USD 1,096,573 | USD 1,096,573 |

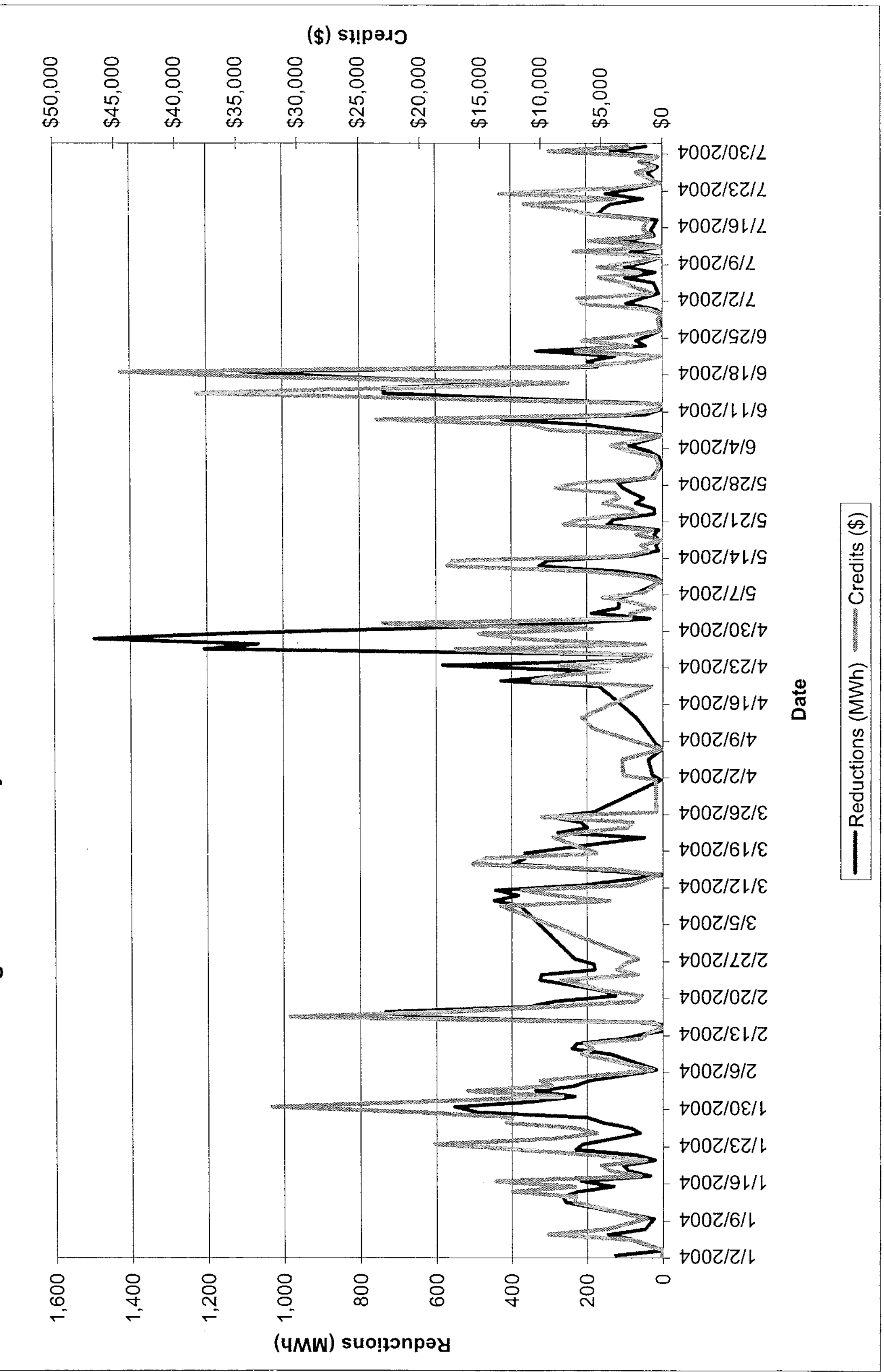



**Figure 1: 2004 Daily Economic Reductions and Credits**

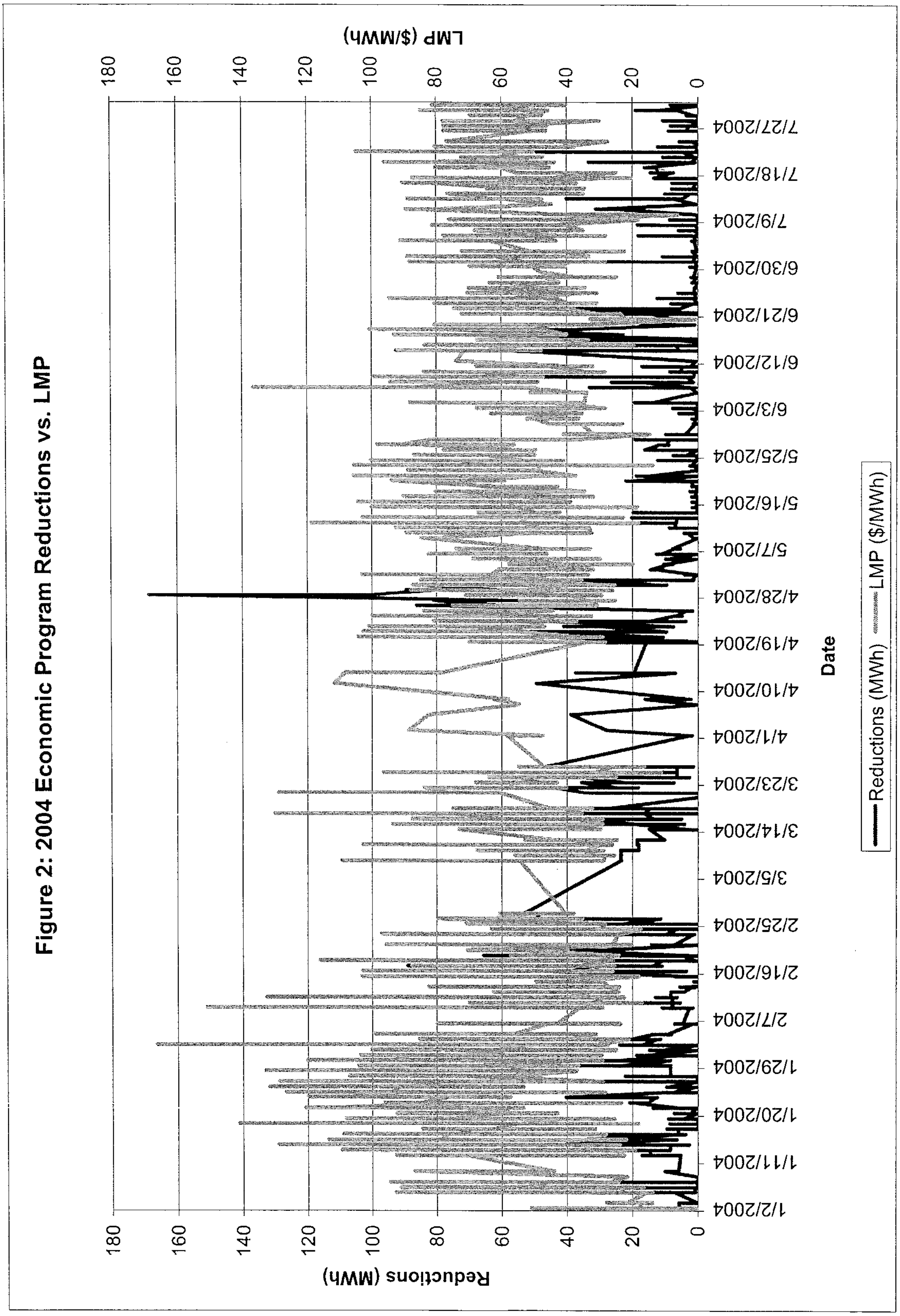
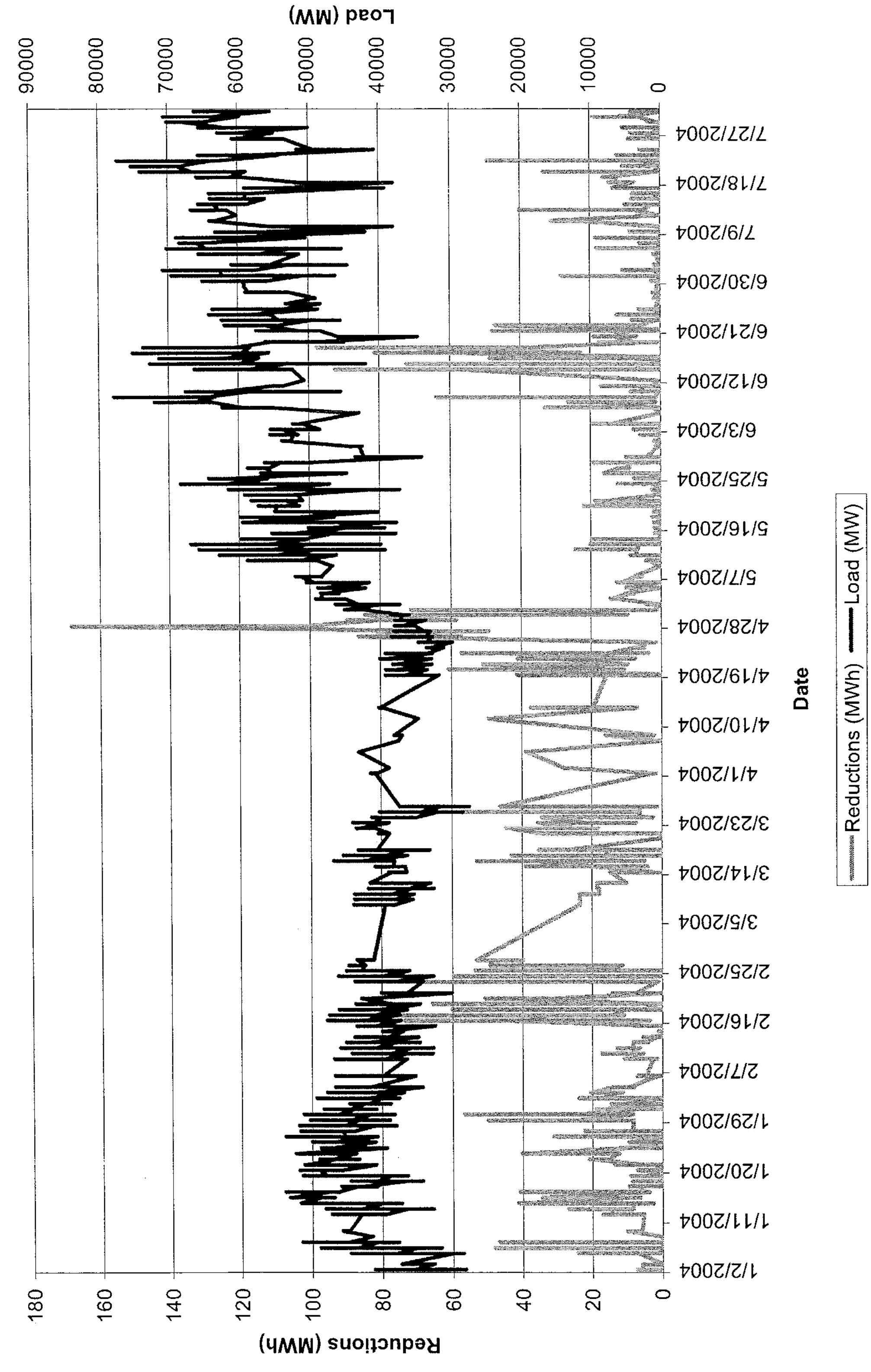



**Figure 2: 2004 Economic Program Reductions vs. LMP**

**Figure 3: 2004 Economic Program Reductions vs. Load**



## CONFIDENCE LEVEL IN ACHIEVING RESULTS

In the Economic Program, the results were achieved by customers making their own choice to curtail based on market conditions. There is a high confidence level that customers will continue to respond to economic incentives.

## REPEATABILITY OF RESULTS

Participation and load reductions in the Economic Program have grown steadily over the years.

## TIME DELAY BEFORE MAXIMUM RESPONSE ACHIEVED

Not applicable.

## WEATHER DEPENDENCE

There is a Weather Sensitive Adjustment (WSA) to increase or decrease the customer baseline. PJM has an analysis method to determine the WSA, or the customer may suggest an alternate method.

## AVOIDED COSTS

The benefits of the Economic Program when measured as the impact in reducing overall market prices were much larger than the costs. These benefits are a direct function of prevailing market price levels and will thus increase if prices rise compared to 2004 levels or decrease if prices decrease compared to 2004 levels.

The evaluation of the benefits associated with overall market price reductions must consider that these benefits do not necessarily represent an increase in market efficiency but represent a transfer from generation to load over the short term. Whether this results in a lower overall market cost in the long run remains to be seen.

Regardless, the potential benefits of increasing demand side responsiveness in improved efficiency of the market are extremely large and certainly exceed the relatively small program costs by a wide margin. These benefit calculations do not include any calculation of reliability benefits of the demand side programs. It was not necessary to make such a calculation to demonstrate that there are substantial net benefits to the Economic Program.

## ACTUAL PROJECT COSTS

In summary, direct administrative costs for the PJM Economic Program were about USD 1 per MWh of actual load reductions during the period 2002 to 2004. Payments to participants were about USD 13 per MWh of load reductions in 2002, about USD 6 per MWh of load reductions in 2003, and about USD 4 per MWh of load reductions in 2004. Thus, total program costs were approximately USD 14 per MWh of load reductions in 2002, about USD 7 per MWh in 2003, and about USD 5 per MWh in 2004.

## PROJECT COST FROM THE SOCIETAL PERSPECTIVE

There is no cost, but rather a benefit from the societal perspective. The impact on overall market prices provided a much larger benefit than the program cost.

## OVERALL PROJECT EFFECTIVENESS

The program is effective at providing a consumer response to price on a locational basis.

## CONTACTS

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## CASE STUDY PREPARATION

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# DR04 SOUTH ISLAND DEMAND SIDE PARTICIPATION TRIAL - NEW ZEALAND

| | |
|---|---|
| **Last updated** | 3 October 2008 |
| **Location of Project** | Upper South Island, New Zealand |
| **Year Project Implemented** | 2007 |
| **Year Project Completed** | |
| **Name of Project Proponent** | Transpower New Zealand |
| **Name of Project Implementor** | Transpower New Zealand |
| **Type of Project Implementor** | Transmission utility |
| **Purpose of Project** | Deferral of network augmentation |
| **Timing of Project** | Pre contingency |
| **Focus of Project** | Network capacity limitations |
| **Project Objective** | Peak load reduction |
| **Project Target** | Network region |
| **DSM Measure(s) Used** | Standby generation<br>Other distributed generation<br>Other short-term demand response |
| **Specific Technology Used** | Standby generation<br>Manual switching of loads |
| **Market Segments Addressed** | Commercial and small industrial customers |

## DRIVERS FOR PROJECT

Transpower is the owner and operator of New Zealand's national transmission network, which spans both the North and South Islands of New Zealand. Transpower is also the system operator for the New Zealand power system.

In New Zealand, as in many other jurisdictions worldwide, the lack of significant investment for many years coupled with strong demand growth and the long lead time for transmission projects has led to many investments across the national transmission network becoming urgent. There is uncertainty about the time required to plan, obtain regulatory approval, obtain the necessary designations, consents, easements and property, and to build and commission a network transmission asset (ie a new transmission line, substation etc).

Part F of the *Electricity Governance Rules* enables Transpower, as the owner of New Zealand's national transmission network, to obtain regulatory approval to recover the costs of contracting for non-transmission solutions to address reliability needs. Under these rules, Transpower has to demonstrate that any non-transmission alternatives considered are technically feasible and reasonably practicable, likely to proceed, expected to provide similar benefits, and expected to enable the deferment of the proposed investment by at least one year. The Government Policy Statement of October 2006 states further that security of supply must be able to be maintained if the non-transmission alternative is delayed or does not proceed.

Transpower is developing a grid support contract product to enable it to evaluate, gain regulatory approval for, and contract with non-transmission alternatives where they provide a reliable and economic means of supporting the network.

Transpower has experience in the system implications of generation and large industrial demand response, but not in demand side participation (DSP). Transpower defines DSP to include both reductions in small-scale loads and generation by distributed and embedded generators. Transpower therefore developed a plan for a DSP trial. The objective of the trial was to find out whether DSP could be reliably used to deliver a cost effective solution to assist in transmission investments. The trial was run on a real dollars for real megawatt load reductions basis to test the commercial realities of such a product.

## DESCRIPTION OF PROJECT

### The DSP Trial

The DSP trial comprised testing DSP in the upper South Island in two stages:

- a pilot during winter 2007 (the pilot); and
- a trial during winter 2008 (the 2008 trial).

The upper South Island (see Figure DR04/1) was selected as, at the time, it was considered the most likely area for first use of a grid support contract.


**Figure DR04/1. The Upper South Island of New Zealand**

In May 2007, Transpower submitted a request to the Electricity Commission for approval to recover up to NZD8.27 million in costs to undertake this trial including consequential development of the grid support contract product. The Commission approved this in June 2007.

In parallel with this request for funding, Transpower issued an expression of interest (EOI) and request for proposals (RFP) to potential providers of demand side participation. This parallel process was necessary to enable Transpower to complete a demand side participation pilot during the winter of 2007.

## Purpose of the 2007 Pilot

The purpose of the winter 2007 pilot was to determine the reliability of small-scale demand side participation (DSP) and its aggregation for the purpose of developing and refining the grid support contract product. It was envisaged that the pilot would also provide useful information on:

- the volume of DSP available;
- the different types of DSP available;
- the responsiveness of different types of DSP to calls;
- call mechanisms and notice periods;
- interaction with other load management programs and other markets;
- the effect of DSP on market spot price;
- the price curve for DSP;
- the processes required to ensure a competitive procurement of offers;
- the logistics required to deploy DSP;
- aggregation of DSP sources to provide reliability;
- verification issues;
- peak load forecasting accuracy;
- DSP issues specific to the upper South Island ; and
- contractual and payment issues.

The scope of the pilot involved a small number of DSP providers with only limited calls on their services. The pilot could therefore not provide complete information on all these issues. Nevertheless the pilot process was designed and managed to maximise learnings with regard to the issues.

## Nature of DSP Sought

To maximise learnings, Transpower targeted a mix of industrial, commercial and residential DSP (either load reductions or distributed generation) connected to a range of substations and anticipated selecting more than one DSP provider to achieve this.

Transpower targeted 10 to 20 MW of DSP which was approximately equivalent to half a year’s load growth in the upper South Island. Because of the short notice to potential providers, Transpower requested a minimum of one megawatt of DSP from each provider.

Proponents could choose to provide DSP by combining contracts with individual DSP sources into a portfolio so the contract requirements for volume and reliability could be met. Proponents could choose to contract with DSP sources for larger quantities than their contract with Transpower in order to ensure that they could deliver to Transpower their contracted amounts. For the pilot, to maximise learnings, Transpower also required proponents to supply information on the nature of their DSP sources.

## EOI and RFP Process

Transpower issued an expression of interest (EOI) document in May 2007 to which responders could indicate their interest in participating in the pilot. Transpower then ran a workshop for potential DSP providers in Christchurch to outline Transpower's intentions regarding the pilot and to obtain feedback for the request for proposals (RFP).

The RFP was issued to potential providers on 5 June 2007. The intention of the RFP was to allow flexibility of approach while ensuring that Transpower could contract for reliable and verifiable DSP.

The RFP requested proposals for the supply of between 10 MW and 20 MW of DSP in the upper South Island region to meet the following requirements:

- proposed DSP sources had to be available between 1 July and 31 August 2007;
- proposals had to be for a minimum of 1 MW of aggregated DSP from each proponent;
- proposed sources had to be additional to any DSP currently used or contracted through any other mechanism or contract. Proponents could not offer DSP already contracted such as that involved in ancillary services markets, other load management programs, automatic under frequency load shedding or any obligations under the Electricity Governance Rules (EGRs);
- proposed sources had to be exclusive and not be used or contracted for any other demand management arrangement over the period of the contract. Proponents could not offer DSP already committed to contracted ancillary services markets, or existing load management schemes (eg ripple load control of hot water heating during high load periods) or required to meet any obligations under the EGRs; and
- proponents were required to provide details of how they would verify the quantity and duration of the DSP they provided in response to each call. Payment was conditional on satisfactory verification and based on the minimum DSP delivered in each call period.

For simplicity, given time constraints, payments were offered for DSP delivery only. A minimum of six to eight two hour calls were guaranteed, so that providers could be assured of a minimum level of payment.

## Evaluation of Proposals

Prior to the closing date for proposals, an evaluation process and accompanying probity process were developed.

In the first stage of the evaluation, non-complying DSP sources were removed with the remainder individually evaluated using a predefined template which provided for scoring under the headings of:

- verification methodology;
- cost per MW of DSP per hour;
- feasibility, reliability and likelihood of the DSP source being commissioned in time;
- ability to respond to calls;

- times available during the day;
- days available; and
- significant limitations.

The resulting scores were then moderated to ensure criteria assessment on a common basis. The scores were consolidated and the sources were then ranked accordingly.

In the second stage of the evaluation, mutually exclusive DSP sources were removed from consideration and, within budget, sources were selected as the basis for negotiating commercial contracts. Subsequently, certain sources were removed from further consideration due to incompatible conditions.

### Selection of DSP Providers

By the RFP closing date of 25 June 2007, proposals for 35 DSP sources were received from eight potential DSP providers. The potential providers comprised lines companies (ie electricity distributors), independent aggregators and generator/retailers.

Three DSP sources were found to be non-conforming with the requirements of the RFP. Of the remaining 32 DSP sources, 14 sources from five DSP providers were selected, connected to nine different Transpower substations. The contracted DSP by source type are shown in Figure DR04/2.

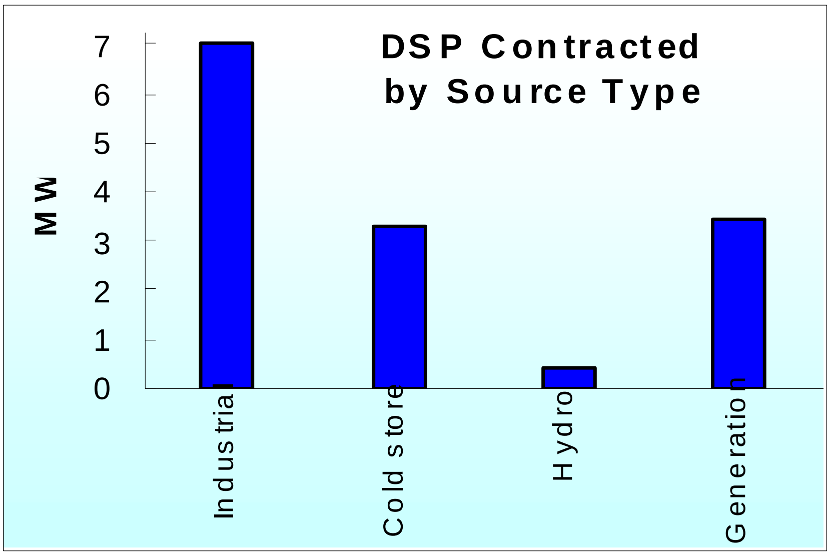


**Figure DR043/2. Contracted Demand Side Participation**

The five selected providers were awarded contracts for supply of 14.2 MW of DSP. These contracts were for a maximum total of NZD1.14 million of DSP payments based on eight two hour calls for every DSP source.

The contracted DSP providers were:

- TrustPower (generator / retailer);
- Marlborough Lines (distributor);
- Simply Energy (generator / retailer);
- Energy Response (independent aggregator);
- Buller Electricity Ltd (distributor).

### Operation of the Pilot

As part of a future grid support contract, DSP would be called as required to prevent load exceeding the transmission system's capacity to supply. To simulate this operational procedure, calls in the 2007 Pilot were artificially structured to test delivery at various times, days and notice periods corresponding approximately but not necessarily exactly with peak times on the transmission system.

The call process involved a Transpower operational team deciding the call strategy weekly based on expected demand and long-term weather forecasts. This call strategy was then given to the System Operator for actioning but could be changed depending on system conditions on the nominated day. The System Operator actioned the calls by notifying the regional operating centre who in turn notified the DSP providers who communicated the request to their suppliers.

The call strategy was developed taking into consideration the following factors:
the results for previous calls;

- the number of calls remaining and the time left for pilot completion;
- likely times of peak system demand as indicated by the System Operator demand forecasts, the weather forecast and Meteorological Service data;
- the need to test different time periods (eg morning versus afternoon, consecutive days versus single days, different days of the week);
- calling on the half hour or off the half hour;
- the selection of DSP sources;
- the notice periods for DSP providers – especially where providers offered lower rates for longer notice periods; and
- meeting the minimum contractual requirements in the contracts.

### RESULTS

| Residential Customers Participating | Commercial and Small Industrial Customers Participating | Agricultural Customers Participating | Large Industrial Customers Participating | Additional Generation Installed |
|---|---|---|---|---|
| | 14 | | | |

| Peak Load | Peak Load Reduction | Duration of Peak Load Reduction | Overall Load Reduction | Energy Savings | Network Augmentation Deferral |
|---|---|---|---|---|---|
| 1050 MW | 14.2 MW | | | | |

### HOW LOAD REDUCTION WAS MEASURED

Other. Individual verification methods established by each DSP provider.

## RESULTS ACHIEVED

Over July and August 2007, Transpower made eight calls, requesting DSP for two hour durations per event at times likely to coincide with system peak loads. Table DR04/1 shows the calls made by Transpower, the lead times provided and the timing of each call. Transpower's operators used phone and fax to signal DSP requests to the providers who in turn notified their suppliers by various means.

**Table DR04/1. Calls Made by Transpower in the 2007 DSP Trial**

| Date (2007) | Call No | Conditions | Start | Finish | Notice | MW Requested |
|---|---|---|---|---|---|---|
| 24 July | 1 | All [a] | 17.00 | 19.00 | 2 hours | 14.20 |
| 31 July | 2 | 2 hr notice | 17.15 | 19.15 | 24 hours | 7.75 |
| | | 24 hr notice [b] | 17.15 | 19.15 | 2 hours | 6.45 |
| 6 August | 3 | All | 17.45 | 19.45 | 2 hours | 14.20 |
| 7 August | 4 | 2 hr notice | 16.45 | 18.45 | 24 hours | 7.75 |
| | | 24 hr notice | 16.45 | 18.45 | 2 hours | 6.45 |
| 8 August | 5 | 2 hr notice | 17.15 | 19.15 | 24 hours | 7.75 |
| | | 24 hr notice | 17.15 | 19.15 | 2 hours | 6.45 |
| 13 August | 6 | 24 hr notice (most) [c] | 17.00 | 19.00 | 24 hours | 11.40 |
| | | 2 hr notice | 17.00 | 19.00 | 2 hours | 2.80 |
| 14 August | 7 | Morning [d] | 07.30 | 09.30 | 2 hours | 10.20 |
| 23 August | 8 | Morning | 07.00 | 09.00 | 6 hours | 6.78 |
| | | Evening [e] | 18.00 | 20.00 | 2 hours | 4.60 |

[a] "All" – all sources were called from all providers
[b] "24 hr notice" – some sources offered cheaper rates if called with 24 hours rather than 2 hours notice
[c] "24 hr notice (most)"– all sources except those which had specified not to be called with 24 hours notice
[d] "Morning" – some sources were not available for morning calls
[e] "Evening" – some sources not available in the morning were called in the evening on 23 August
[f] One call was abandoned by the System Operator due to a grid emergency

Transpower made the first call just five days after the contracts were entered into so providers did not have time to test any of their DSP sources before the first call. Providers responded to calls from Transpower by calling their suppliers and later submitting verification reports to Transpower some time after the event.

Table DR04/2 (page 160) shows the actual delivery of DSP for each call made by Transpower. The delivery by each type of DSP source is shown in Table DR04/3 (page 160).

| Table DR04/2. Delivered Demand Side Participation in the 2007 Trial | | | | |
|---|---|---|---|---|
| **Date (2007)** | **Call No** | **MW Requested** | **MW Delivered** | **Response Rate** |
| 24 July | 1 | 14.2 | 10.8 | 76% |
| 31 July | 2 | 14.2 | 11.0 | 78% |
| 6 August | 3 | 14.2 | 10.9 | 77% |
| 7 August | 4 | 14.2 | 10.8 | 76% |
| 8 August | 5 | 14.2 | 8.5 | 60% |
| 13 August | 6 | 14.2 | 10.4 | 74% |
| 14 August | 7 | 10.2 | 4.4 | 43% |
| 23 August | 8 | 11.7 | 6.2 | 53% |
| **Total** | | **106.9** | **73.0** | **68%** |

| Table DR04/3. Delivered Demand Side Participation by Source in the 2007 DSP Trial | | | | | |
|---|---|---|---|---|---|
| **Source Type** | **No Sources** | **MW Requested** | **No Source Calls[a]** | **No Zero Responses** | **Response Rate** |
| Industrial | 5 | 7.0 | 38 | 3 | 72% |
| Cold Store | 4 | 3.3 | 32 | 6 | 47% |
| Hydro | 2 | 0.4 | 16 | 4 | 41% |
| Generation | 5 | 3.5 | 34 | 1 | 88% |
| **Total** | **16** | **14.2** | **120** | **14** | **68%** |

[a] "Source call" – a call for one source

## CONFIDENCE LEVEL IN ACHIEVING RESULTS

## REPEATABILITY OF RESULTS

## TIME DELAY BEFORE MAXIMUM RESPONSE ACHIEVED

## WEATHER DEPENDENCE

## AVOIDED COSTS

## ACTUAL PROJECT COSTS

In the contracts, payment was stated to be based on the minimum level of DSP provided during a call period. This reflected applying DSP to reduce system load by a nominated amount. For the pilot, this applied on a source by source basis; some providers chose to aggregate loads to establish sources.

Figure DR04/3 shows the prices for the 35 DSP sources offered in order of increasing price. For the few sources for which different rates were offered for different notice periods, rates for the shortest notice period are plotted. As the pilot was for learning purposes, different sources were called based on a range of factors of which cost was only one. The graph is not therefore representative of the costs actually incurred in the pilot.

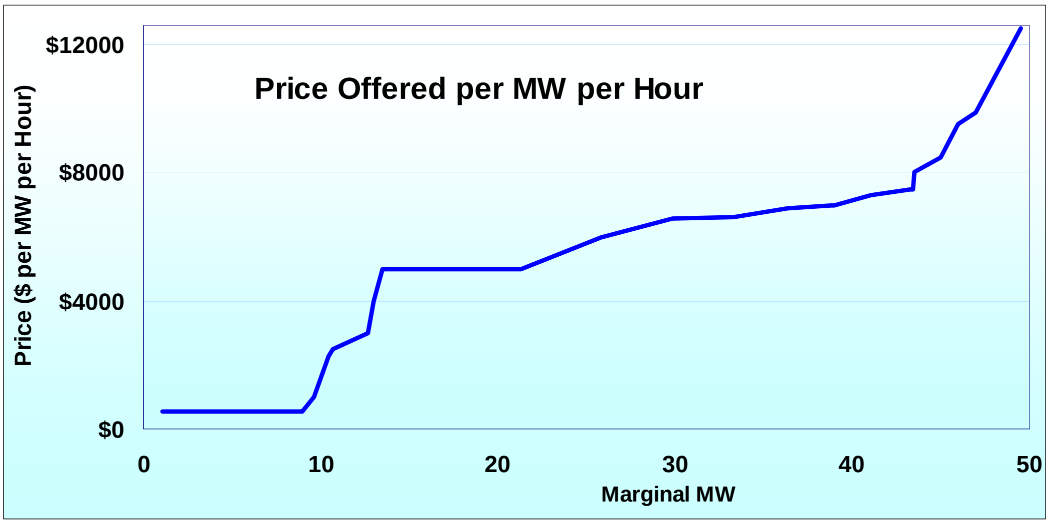


**Figure DR04/3. Price Offered for Each Additional Megawatt of Demand Side Participation**

Transpower contracted 14 DSP sources for a total of 14.2 MW of DSP. The prices per MW per hour of DSP, plotted cumulatively, are shown in Figure DR04/4 (page 162). For example, to procure the cheapest 7 MW of DSP for one hour would cost a total of about $21,000, or $3000 per MW per hour. However, because price was not the only factor considered in calling sources, this graph is also not representative of the actual costs incurred in the pilot.

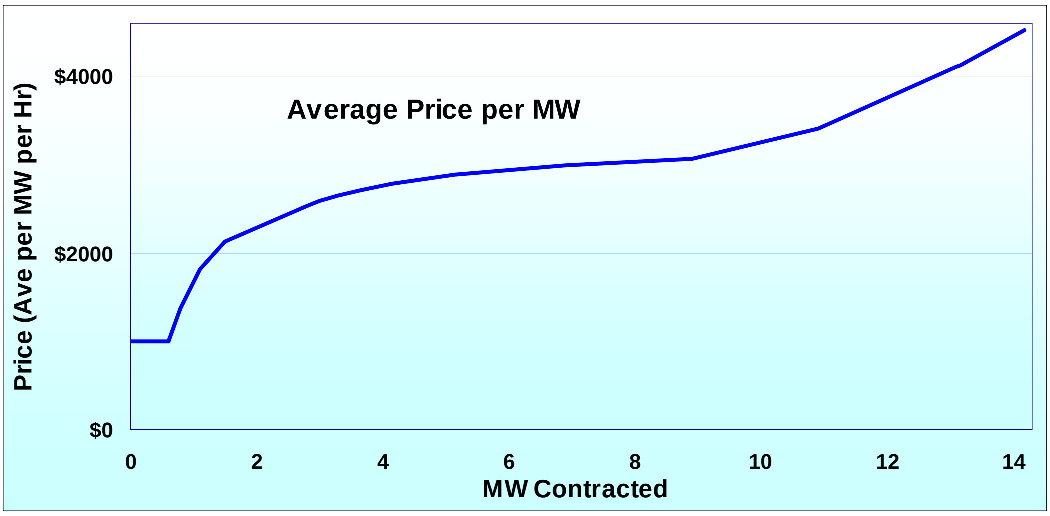


**Figure DR04/4. Average Cost of Contracted Demand Side Participation**

## PROJECT COST FROM THE SOCIETAL PERSPECTIVE

## OVERALL PROJECT EFFECTIVENESS

### Assessment of the 2007 Trial

The 2007 DSP Pilot was successful given the limited preparation time. Over the duration of the whole Pilot, providers delivered 68% of the DSP called by Transpower. The most reliable of the DSP sources used was standby generation which delivered 88% of the volume contracted. The least reliable source was small hydro generation which delivered 41% of the volume contracted. The relatively low level of overall reliability reflected in part the short notice given to DSP providers as well as the "reasonable endeavours" basis of the Pilot.

### Development of the 2008 Trial

The Winter 2008 Trial will share the same objectives as the 2007 Pilot. However, key differences will be:

- more realistic preparation time of some six months from request for information (RFI) to start of trial period in June 2008;
- testing of DSP sources prior to the start of the trial period;
- allowing a more varied pricing structure with availability, cancellation and delivery payments;
- a focus on testing aggregators' ability to aggregate, and sources' ability to be aggregated;
- a realistic call mechanism.

In the 2007 Pilot, Transpower accepted DSP sources down to 1 MW in size, and therefore in effect acted as the aggregator for multiple, small sources. Transpower's intention for grid support contracts (assuming that a DSP solution is selected) is to contract with an aggregator, as aggregators have better knowledge of the sources and so can better manage portfolios. Aggregators may be lines companies (ie distributors), retailers or other parties who have the capability to aggregate DSP for offer to Transpower in return for payment.

For the 2008 Trial, a number of blocks of DSP, each with a minimum size of 10 MW, is being sought. Each block will be made up of one or, more likely, multiple small sources. Transpower's calls for DSP will be by block, not by source.

The call mechanism used in the 2007 Pilot was highly artificial. In the 2008 Trial, this will be replaced by a call mechanism designed to reflect (as much as possible without affecting grid security) how calls are likely to be made for DSP through a real grid support contract. A nominal capacity threshold or constraint will be set, and the system operator will call DSP capacity to manage that constraint as if it were real.

While the calls in the 2008 Trial can be expected to coincide with morning and/or evening system peak loads, the days, number of consecutive days, and size and duration of events will be determined by external factors, notably cold weather. This will not only make the calls more realistic from a provider's point of view, but will also test the system operator's ability to forecast DSP need.

### Development of the Grid Support Contract Product

During 2008, Transpower will undertake stakeholder engagement on a grid support contract product, incorporating the learnings of the 2007 DSP pilot and the early stages of the 2008 DSP trial. It is planned to have the grid support contract product available to be offered from late 2008. From then, Transpower will be able to offer RFPs for non-transmission alternatives for consideration in developing future grid upgrade proposals, and in cases of build or high-demand risk.

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## SOURCES

Documents relevant to the 2007 DSP Plot, the grid support contract and the 2008 DSP Trial are available on Transpower's Grid New Zealand web site at
http://www.gridnewzealand.co.nz/n348.html

## CASE STUDY PREPARATION

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# EE01 EFFICIENT LIGHTING PROJECT DSM PILOT - POLAND

| | |
|---|---|
| **Last updated** | 26 August 2005 |
| **Location of Project** | Cities of Chelmno, Elk and Zywiec, Poland |
| **Year Project Implemented** | 1996 |
| **Year Project Completed** | 1997 |
| **Name of Project Proponent** | International Finance Corporation |
| **Name of Project Implementor** | Municipal governments of Chelmno, Elk and Zywiec |
| **Type of Project Implementor** | Local government (municipality) |
| **Purpose of Project** | Deferral of network augmentation |
| **Timing of Project** | Pre contingency |
| **Focus of Project** | Network capacity limitations |
| **Project Objective** | Peak load reduction |
| **Project Target** | Network region |
| **DSM Measure(s) Used** | Energy efficiency |
| **Specific Technology Used** | Compact fluorescent lamps |
| **Market Segments Addressed** | Residential customers |

## 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.

## 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 (about 55% and 45% respectively), were delivered only to those residents living in the target areas. The C coupons (about 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

| Residential Customers Participating | Commercial and Small Industrial Customers Participating | Agricultural Customers Participating | Large Industrial Customers Participating | Additional Generation Installed |
|---|---|---|---|---|
| 8,500 | | | | |

| Peak Load | Peak Load Reduction | Duration of Peak Load Reduction | Overall Load Reduction | Energy Savings | Network Augmentation Deferral |
|---|---|---|---|---|---|
| | | | 2.43 MW | | |

## HOW LOAD REDUCTION WAS MEASURED

Other. Modelled lighting load shapes.

## RESULTS ACHIEVED

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 these areas continued to grow strongly until the supply limitation was encountered.

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.

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.

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.

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.

## CONFIDENCE LEVEL IN ACHIEVING RESULTS

Modelling was carried out of future net present cost outcomes and their probabilities, assuming a 10-year analysis horizon, for both a DSM and No DSM scenario at a particular site in Chelmno called Parkowa 2. The DSM scenario reflected the net present costs of grid upgrades, DSM program costs, and net lost revenues from pursuing a strategy of implementing the DSM pilot in the first year and then upgrading the grid only when subsequent load growth consumed existing grid capacity. The No DSM scenario reflected the net present costs of only grid upgrades, based on pursuit of a “business-as-usual” strategy.

The mode (most likely cost) of the distribution for the DSM scenario occurred at about PLN140,000 (about USD47,000) and had a probability of occurrence of about 20%. On the other hand, the mode of the No DSM distribution was substantially higher, at about PLN170,000 and had a much higher probability of occurrence at about 45%.

Therefore, it is highly probable that a DSM strategy would result in lower net present costs than a No DSM strategy for the Parkowa 2 site.

## REPEATABILITY OF RESULTS

## TIME DELAY BEFORE MAXIMUM RESPONSE ACHIEVED

## WEATHER DEPENDENCE

## AVOIDED COSTS

## ACTUAL PROJECT COSTS

USD 100,000 (1996 dollars) of PELP funding paid by the project proponent, International Finance Corporation.

## PROJECT COST FROM THE SOCIETAL PERSPECTIVE

## OVERALL PROJECT EFFECTIVENESS

Lack of quantitative data for the actual project results (as distinct from modelling results) makes it difficult to assess the effectiveness of this project as compared with other network-driven DSM projects. However, the project proponent appeared to be happy with the reductions in peak load of about 15% in the target areas. Unfortunately no information is available in the project reports about whether these peak load reductions resulted in the actual deferral of any planned network augmentations.

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## CASE STUDY PREPARATION

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# EE02 ONCOR STANDARD OFFER PROGRAM FOR RESIDENTIAL AND COMMERCIAL ENERGY EFFICIENCY - USA

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|---|---|
| **Last updated** | 20 September 2005 |
| **Location of Project** | Texas, USA |
| **Year Project Implemented** | 2002 |
| **Year Project Completed** | |
| **Name of Project Proponent** | Oncor Electric Delivery Company (a subsidiary of TXU Corp responsible for electricity transmission and distribution) |
| **Name of Project Implementor** | Oncor Electric Delivery Company |
| **Type of Project Implementor** | Distribution utility<br>Transmission utility |
| **Purpose of Project** | Deferral of network augmentation |
| **Timing of Project** | Pre contingency |
| **Focus of Project** | Network capacity limitations |
| **Project Objective** | Overall load reduction |
| **Project Target** | Whole network |
| **DSM Measure(s) Used** | Energy efficiency |
| **Specific Technology Used** | Energy efficiency measures |
| **Market Segments Addressed** | Residential customers<br>Commercial and small industrial customers |

## 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.

## 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 (eg 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; the dollars per kilowatt-hour and dollars per kilowatt incentive rates are based on 50% of Oncor's avoided costs. The payment for demand reductions is based on peak demand.

The incentive levels offered during 2003 and 2004 were as follows:
Energy USD 270.00 per kilowatt-hour
Demand USD 0.0925 per kilowatt.

## RESULTS

| Residential Customers Participating | Commercial and Small Industrial Customers Participating | Agricultural Customers Participating | Large Industrial Customers Participating | Additional Generation Installed |
|---|---|---|---|---|
| | | | | |

| Peak Load | Peak Load Reduction | Duration of Peak Load Reduction | Overall Load Reduction | Energy Savings | Network Augmentation Deferral |
|---|---|---|---|---|---|
| | | | | | |

## HOW LOAD REDUCTION WAS MEASURED

## RESULTS ACHIEVED

## CONFIDENCE LEVEL IN ACHIEVING RESULTS

## REPEATABILITY OF RESULTS

## TIME DELAY BEFORE MAXIMUM RESPONSE ACHIEVED

## WEATHER DEPENDENCE

## AVOIDED COSTS

## ACTUAL PROJECT COSTS

Available funds for incentive payments:
2003: USD 4,775,469
2004: USD 6,333,346

## PROJECT COST FROM THE SOCIETAL PERSPECTIVE

## OVERALL PROJECT EFFECTIVENESS

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## SOURCES

Oncor's website at: http://www.oncorgroup.com/electricity/teem/res/default.asp

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## CASE STUDY PREPARATION

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# EE03 ONCOR AIR CONDITIONING DISTRIBUTOR MARKET TRANSFORMATION PROGRAM - USA

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|---|---|
| **Last updated** | 20 September 2005 |
| **Location of Project** | Texas, USA |
| **Year Project Implemented** | 2003 |
| **Year Project Completed** | |
| **Name of Project Proponent** | Oncor Electric Delivery Company (a subsidiary of TXU Corp responsible for electricity transmission and distribution) |
| **Name of Project Implementor** | Oncor Electric Delivery Company |
| **Type of Project Implementor** | Distribution utility<br>Transmission utility |
| **Purpose of Project** | Deferral of network augmentation |
| **Timing of Project** | Pre contingency |
| **Focus of Project** | Network capacity limitations |
| **Project Objective** | Overall load reduction |
| **Project Target** | Whole network |
| **DSM Measure(s) Used** | Energy efficiency |
| **Specific Technology Used** | High efficiency air conditioners |
| **Market Segments Addressed** | Residential customers<br>Commercial and small industrial customers<br>Other: Distributors of air conditioners |

## 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.

## 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.

## RESULTS

| Residential Customers Participating | Commercial and Small Industrial Customers Participating | Agricultural Customers Participating | Large Industrial Customers Participating | Additional Generation Installed |
|---|---|---|---|---|
| | | | | |

| Peak Load | Peak Load Reduction | Duration of Peak Load Reduction | Overall Load Reduction | Energy Savings | Network Augmentation Deferral |
|---|---|---|---|---|---|
| | | | | | |

## HOW LOAD REDUCTION WAS MEASURED

## RESULTS ACHIEVED

## CONFIDENCE LEVEL IN ACHIEVING RESULTS

## REPEATABILITY OF RESULTS

## TIME DELAY BEFORE MAXIMUM RESPONSE ACHIEVED

## WEATHER DEPENDENCE

## AVOIDED COSTS

## ACTUAL PROJECT COSTS

Incentive budget of USD 4,000,000 for the 2004 program.

## PROJECT COST FROM THE SOCIETAL PERSPECTIVE

## OVERALL PROJECT EFFECTIVENESS

## CONTACTS

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## SOURCES

Oncor’s website at: http://www.oncorgroup.com/electricity/teem/mtp/acdistributors.asp

## CASE STUDY PREPARATION

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## EE04 ESPANOLA POWER SAVERS PROJECT - CANADA

| | |
|---|---|
| **Last updated** | 20 September 2005 |
| **Location of Project** | Espanola, Ontario, Canada |
| **Year Project Implemented** | 1991 |
| **Year Project Completed** | 1993 |
| **Name of Project Proponent** | Ontario Hydro/Espanola Hydro |
| **Name of Project Implementor** | Ontario Hydro/Espanola Hydro |
| **Type of Project Implementor** | Distribution utility<br>Transmission utility<br>Electricity retailer/supplier |
| **Purpose of Project** | Deferral of network augmentation |
| **Timing of Project** | Pre contingency |
| **Focus of Project** | Network capacity limitations<br>Generation capacity limitations |
| **Project Objective** | Overall load reduction |
| **Project Target** | Network region |
| **DSM Measure(s) Used** | Energy efficiency |
| **Specific Technology Used** | A range of energy efficiency measures |
| **Market Segments Addressed** | Residential customers<br>Commercial and small industrial customers |

### 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 DSM 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.

### DESCRIPTION OF PROJECT

The township of Espanola is a pulp and paper community situated on the Spanish River in north eastern Ontario approximately 500 km north of Toronto. In the early 1990s, when this project was carried out, Espanola had a population of about 6,000.

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.

The 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

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 Launch

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.

## Project Delivery

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

- making contact with the project office to request an energy audit;
- a visit by a qualified energy auditor/contractor team to recommend energy efficiency measures to be installed;
- approval of work by the home/business owner by signing an agreement with the general contractor;
- installation of energy efficient measures by qualified contractors; and
- 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. Each classification had its own audit form. 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).

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

| Residential Customers Participating | Commercial and Small Industrial Customers Participating | Agricultural Customers Participating | Large Industrial Customers Participating | Additional Generation Installed |
|---|---|---|---|---|
| | | | | |

| Peak Load | Peak Load Reduction | Duration of Peak Load Reduction | Overall Load Reduction | Energy Savings | Network Augmentation Deferral |
|---|---|---|---|---|---|
| | | | | | |

## HOW LOAD REDUCTION WAS MEASURED

## RESULTS ACHIEVED

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.

Detailed results are shown in Table EE04/1.

| Table EE04/1. Detailed Results from the Espanola Power Savers Project | | | | |
|---|---|---|---|---|
| **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 |

## CONFIDENCE LEVEL IN ACHIEVING RESULTS

## REPEATABILITY OF RESULTS

## TIME DELAY BEFORE MAXIMUM RESPONSE ACHIEVED

## WEATHER DEPENDENCE

## AVOIDED COSTS

## ACTUAL PROJECT COSTS

USD 9.4 million (1992 dollars).

## PROJECT COST FROM THE SOCIETAL PERSPECTIVE

## OVERALL PROJECT EFFECTIVENESS

## CONTACTS

## SOURCES

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The Results Center (1992). *Ontario Hydro Espanola Power Savers Project: Profile # 16.* Available at: http://sol.crest.org/efficiency/irt/16.pdf

## CASE STUDY PREPARATION

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## EE05 KATOOMBA DSM PROGRAM - AUSTRALIA

| | |
|---|---|
| **Last updated** | 20 September 2005 |
| **Location of Project** | Katoomba, Blue Mountains, about 100 kilometres west of Sydney |
| **Year Project Implemented** | 1998 |
| **Year Project Completed** | 2003 |
| **Name of Project Proponent** | Integral Energy |
| **Name of Project Implementor** | Integral Energy |
| **Type of Project Implementor** | Distribution utility |
| **Purpose of Project** | Deferral of network augmentation |
| **Timing of Project** | Pre contingency |
| **Focus of Project** | Network capacity limitations |
| **Project Objective** | Overall load reduction |
| **Project Target** | Network element |
| **DSM Measure(s) Used** | Energy efficiency |
| **Specific Technology Used** | A range of energy efficiency technologies |
| **Market Segments Addressed** | Residential customers |

### DRIVERS FOR PROJECT

In the late 1990s, the electricity distribution network in the Katoomba area of the Blue Mountains west of Sydney had limited capacity. Because of continuing load growth, a new transmission substation was constructed at Katoomba North in 1996/97.

In 1998, Integral Energy launched a DSM program, focussing on energy efficiency in the residential sector, in an attempt to defer further augmentation of the network.

### DESCRIPTION OF PROJECT

The program employed one full-time advocate of energy efficiency measures who provided advice to homeowners and builders from a shopfront in the main street of Katoomba. The program developed a register of energy efficiency equipment vendors and installers who could sell items such as insulation, double glazed windows, alternative fuel appliances, high efficiency light fittings and heat pumps. The program also ran educational programs and used publicity on radio.

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 energy equipment and appliances.

A secondary benefit was the register of energy efficiency equipment vendors and installers. This was provided to customers thereby giving them additional confidence regarding energy savings. Integral Energy also ensured that the registered firms 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

| Residential Customers Participating | Commercial and Small Industrial Customers Participating | Agricultural Customers Participating | Large Industrial Customers Participating | Additional Generation Installed |
|---|---|---|---|---|
| Several thousand | | | | |

| Peak Load | Peak Load Reduction | Duration of Peak Load Reduction | Overall Load Reduction | Energy Savings | Network Augmentation Deferral |
|---|---|---|---|---|---|
| | | | | | |

## HOW LOAD REDUCTION WAS MEASURED

## RESULTS ACHIEVED

The program ran from 1998 for about five years and energy efficiency advice was given to thousands of customers over this period.

The program was successful in achieving reductions in winter peak period loads, particularly space heating loads. However, the summer load continued to grow.

The program successfully deferred additional capital works in the Katoomba area – including the construction of a second feeder and second transformer – until 2006/07.

## CONFIDENCE LEVEL IN ACHIEVING RESULTS

## REPEATABILITY OF RESULTS

## TIME DELAY BEFORE MAXIMUM RESPONSE ACHIEVED

## WEATHER DEPENDENCE

## AVOIDED COSTS

## ACTUAL PROJECT COSTS

AUD 350,000 salary and administrative costs paid by Integral Energy (AUD 70,000 per annum)

## PROJECT COST FROM THE SOCIETAL PERSPECTIVE

## OVERALL PROJECT EFFECTIVENESS

## CONTACTS

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## SOURCES

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

Personal communication, Frank Bucca, Integral Energy

## CASE STUDY PREPARATION

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# EE06 DRUMMOYNE DEMAND MANAGEMENT PROJECT - AUSTRALIA

| | |
|---|---|
| **Last updated** | 27 August 2008 |
| **Location of Project** | Drummoyne, a suburb of Sydney, Australia |
| **Year Project Implemented** | 2006 |
| **Year Project Completed** | 2006 |
| **Name of Project Proponent** | EnergyAustralia |
| **Name of Project Implementor** | EnergyAustralia |
| **Type of Project Implementor** | Distribution utility, ESCO |
| **Purpose of Project** | Deferral of network augmentation |
| **Timing of Project** | Pre contingency |
| **Focus of Project** | Network capacity limitations |
| **Project Objective** | Peak load reduction |
| **Project Target** | Network element |
| **DSM Measure(s) Used** | Energy efficiency |
| **Specific Technology Used** | Compact fluorescent lamps |
| **Market Segments Addressed** | Residential customers<br>Commercial and small industrial customers |

## DRIVERS FOR PROJECT

EnergyAustralia's objective for the Drummoyne demand management project was to implement DSM measures that would maintain network performance at the required level at a lower cost than investing AUD4 million for an additional transformer at the Drummoyne zone substation.

The Drummoyne zone substation comprised two 45MVA 132/11kV transformers and was supplied at 132kV from two subtransmission substations. The capacity limits of the substation were 66.6 MVA in summer and 72 MVA in winter.

Peak demand in the Drummoyne area had grown steadily. Loads were growing more rapidly in summer than in winter, but off a lower base. Figure EE06/1 (page 188) shows actual and forecast winter / summer peak load in the Drummoyne area, the loading limits and the expected demand growth. Peak demand was forecast to exceed the capacity limit by 0.5MVA in the winter of 2008 unless action was taken to increase capacity or reduce demand. The forecast summer peak demand indicated no overload issue during the summer in the foreseeable future.

Based on the load profiles, the key drivers for load growth appeared to be a mix of residential loads and a sizeable proportion of retail or commercial load. The area had experienced steady load growth in the years prior to 2005 that might be attributable to new residential development and multi-unit residential construction.

Figure EE06/2 (page 188) shows the electrical load profile of the Drummoyne zone substation on 19 July 2004 - a typical winter peak day. The winter peak demand usually occurred on weekday evenings between 6:00 and 9:30 pm. The peak demand on this day was 66.3MVA. The red line in Figure EE06/2 represents the acceptable winter loading limit for the substation.

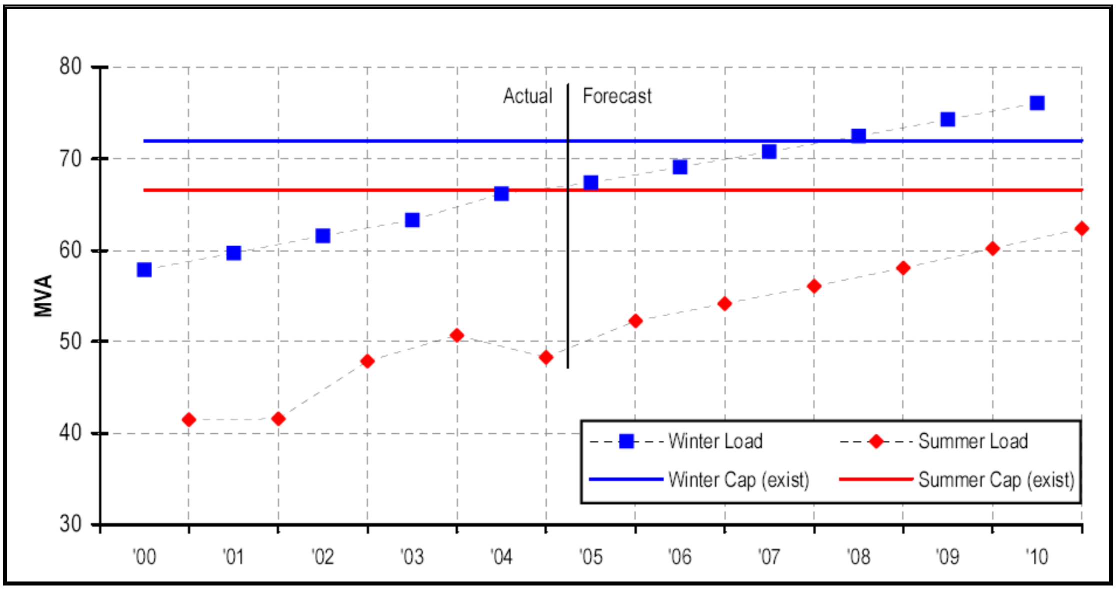


**Figure EE06/1. Forecasted and Expected Peak Demand and Actual Supply Capacity in the Drummoyne Area**

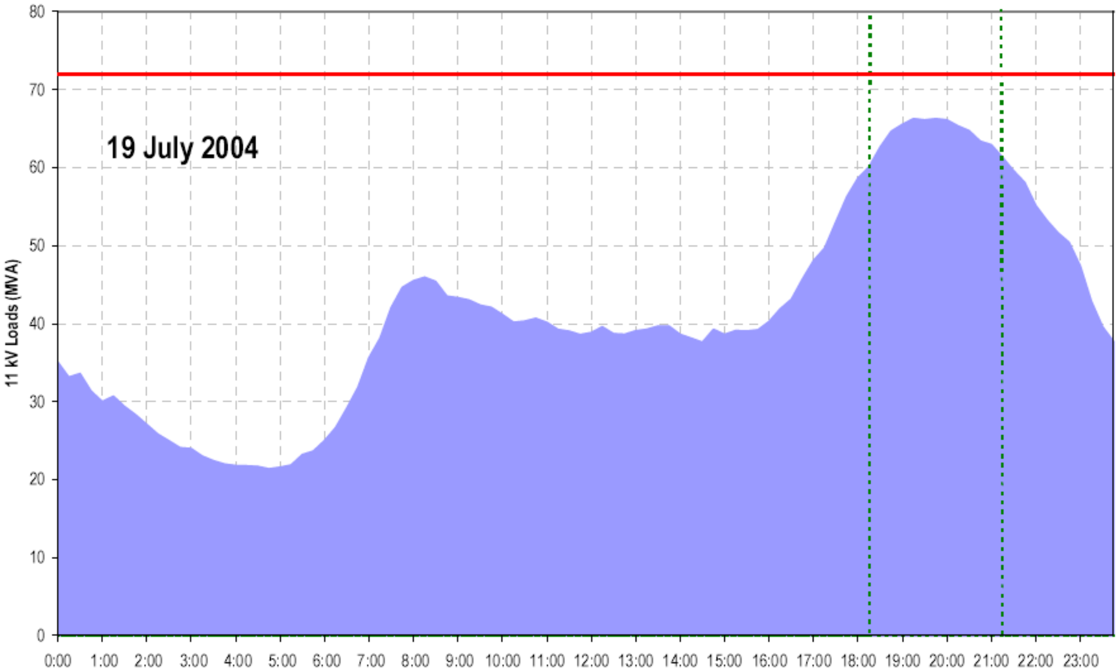


**Figure EE06/2. Typical Winter Load Profile at Drummoyne Zone Substation**

Figure EE06/3 shows the electrical load profile of the zone substation on 8 February 2005 - a typical summer peak day. Summer peak demand usually occurred later in the evening as compared with a winter day – in this case 8:45pm. The peak demand on this day was 48.3MVA. The red line in Figure EE06/3 represents the acceptable summer loading limit for the substation.

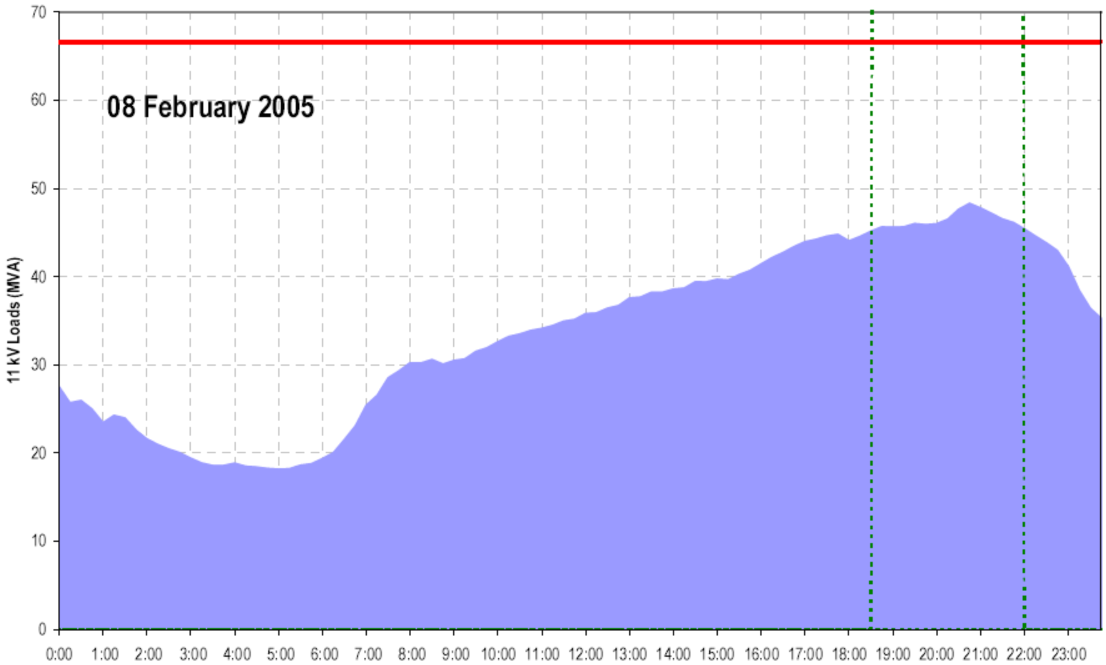


**Figure EE06/3. Typical Summer Load Profile at Drummoyne Zone Substation**

Both winter and summer peak loads occurred relatively infrequently and were of short duration. In winter 2004, the top 5% of load was reached on two separate days, lasting 0.5 and 2.5 hours (totalling three hours). In summer 2004/05, the top 5% of load was also reached on two separate days, lasting 1.5 and 2.5 hours (totalling four hours).

The preferred supply side solution was to install a third transformer in the Drummoyne zone substation and extend the 11kV switchboard at an estimated cost of AUD4 million. A final decision to proceed would need to be made before the end of 2006 to enable the installation to be completed before winter 2008.

To defer this investment by one year (that is until 2009), EnergyAustralia would need to implement demand reductions totalling 500kVA prior to winter 2008. Because a decision had to be made by late 2006, EnergyAustralia would also need to be confident before then that the demand reductions were going to be delivered in time.

Further deferral would require a 2.3MVA reduction in peak demand before winter 2009 and a 3.7MVA reduction before winter 2010. All demand reductions would have to be effective on winter evenings.

In assessing the cost effectiveness of options, the cost to EnergyAustralia of the DSM options was compared to the value of the avoided costs from the change in timing of supply side expenditure. This provided a broad indication of the level of funding that might be available for a portfolio of DSM projects. However, the determination of cost effectiveness is complex and the value EnergyAustralia assigned to individual projects might be higher or lower than this figure.

The value of avoided costs at various levels of demand reduction is shown in Figure EE06/4. A 0.5MVA reduction would enable a one year deferral and have a value of about AUD280,000 or AUD550/kVA (2005 values). For a two year deferral, the value rose to about AUD540,000, but significantly larger demand reductions would be required and the relative value reduced to approximately AUD220/kVA. To be considered cost effective, the overall cost to EnergyAustralia of the required portfolio DSM options had to be below these amounts.

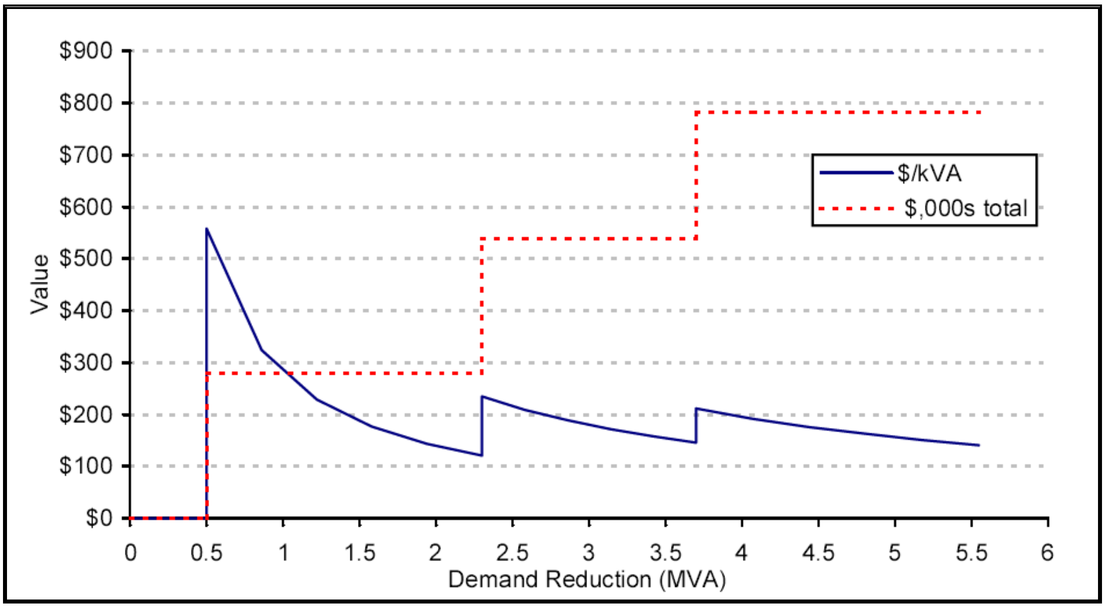


**Figure EE06/4. Value of Avoided Distribution Costs for Various Levels of Demand Reduction**

## DESCRIPTION OF PROJECT

### Investigation of DSM Options

EnergyAustralia's overall investigation approach identified potentially cost-effective DSM options, analysed each of the options and their potential impact and cost, and then shortlisted the options that might form feasible DSM projects. The most cost-effective DSM options were then developed further and compared with the supply-side solution.

EnergyAustralia prepared a Demand Management Options Consultation Paper seeking proposals for DSM options capable of contributing to deferring the construction of a new transformer at Drummoyne zone substation. The consultation paper was advertised in July 2005 in newspapers and on EnergyAustralia's website. Notifications were also sent to parties in the EnergyAustralia register of organisations interested in DSM. Nine submissions were received.

In addition, EnergyAustralia identified 20 major customers in the Drummoyne area, based on their peak demands, visited their sites and collected information about their usage of energy and possible DSM options.

Using these various sources and information from experience in other areas, EnergyAustralia assembled a list of DSM options for analysis. Each of the options was assessed in relation to the likely size of demand reduction that would result at the time of network peak at the Drummoyne zone substation. The cost to EnergyAustralia of establishing and utilising each option at this level for varying periods of availability from one to three years was also estimated. Based on these estimates, EnergyAustralia ranked the options and compared them to the value of deferring the proposed investment.

Eight possible DSM options were identified:

- Contracting with customers who had standby diesel generators to enable the use of the generators to provide short period demand reduction when required.
- Installation of power factor correction equipment at customers' premises.
- Installation of fixed dimming systems for commercial lighting.
- Upgrading of commercial lighting systems using retrofitted efficient lighting kits.
- Peak load control by advanced control system.
- Peak demand reduction by using advanced residential metering and control devices.
- Residential compact fluorescent lamp (CFL) direct distribution program.
- Installation of thermal storage systems.

Table EE06/1 (page 192) summarises the estimated size and cost of each identified DSM option.

Figure EE06/5 (page 192) compares the cost and demand reduction impact of the identified DSM options with the value of avoided distribution costs. Stacking the options from lowest relative cost to highest showed that sufficient demand reduction to achieve a one year deferral could be identified at a lower cost than the value of the avoided costs. However, a two year deferral would be unlikely to be cost effective.

Figure EE06/5 suggests that all demand reductions would be cumulative. However, because several of the identified DSM options targeted the same opportunities, some demand reductions would not be cumulative. Therefore, achieving sufficient demand reductions for a two year deferral would be more difficult and more expensive than Figure EE06/5 indicates.

On the basis of this analysis, the power factor correction project and the first of the CFL proposals appeared likely to be cost effective. The CFL project was selected for implementation.

| Table EE06/1. DSM Options Identified in the Drummoyne Demand Management Project | | | | | |
|---|---|---|---|---|---|
| **DSM Options** | **Winter Peak Load Reduction** | **Total Cost to EA (SNPV)** | **Cost to EA ($/kVA)** | **No of Customers Involved** | **Time for Implementation** |
| Ice storage system | 40kVA | – | – | 1 | 1 to 2 years |
| Power factor correction | 66kVA | AUD9,400 | AUD142 | 5 | 1 to 2 years |
| Residential CFL program Proposal 1 | 1,052kVA | AUD180,000 | AUD171 | 10,000 | 1 to 2 years |
| Residential CFL program Proposal 2 | 1,165kVA | AUD295,000 | AUD253 | 12,500 | 1 to 2 years |
| Peak load control by advanced control system | 234kVA | AUD44,000 to AUD89,000 | AUD187 to AUD380 | 3 | 1 to 2 years |
| Standby diesel generator | 170kVA | AUD67,000 | AUD394 | 1 | 1 to 2 years |
| Combined demand reduction projects | 600kVA | AUD238,000 | AUD398 | 2,226 | 1 to 2 years |
| Fixed dimming for lighting system | 175kVA | AUD87,500 | AUD500 | 17 | 1 to 2 years |
| Installation of Cent-a-Meter energy monitoring device | 712kVA | AUD706,000 | AUD992 | 9,410 | 1 to 2 years |
| Upgrade of lighting system | 106kVA | AUD123,700 | AUD1,166 | 11 | 1 to 2 years |

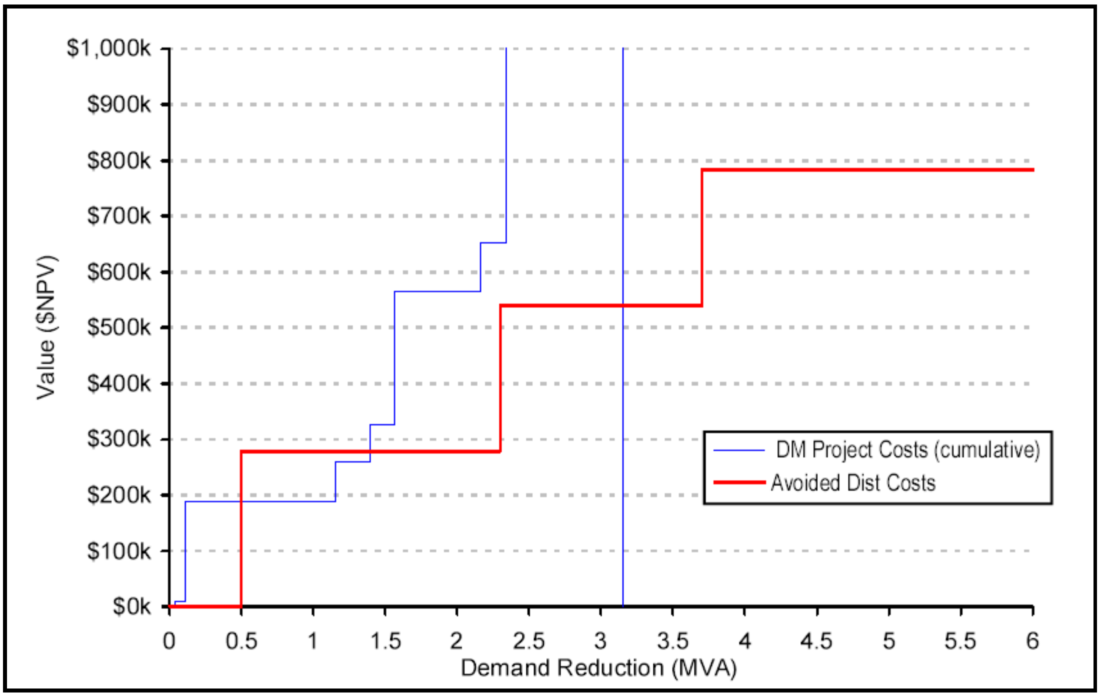


**Figure EE06/5. Cost and Demand Reduction Impact of DSM Options Compared with the Value of Avoided Distribution Costs**

## Installation of CFLs

Mass distributions of CFLs to households had become common in the State of New South Wales as a way of creating tradeable emission abatement certificates under a State-wide emission trading scheme. However, in the Drummoyne project, the distribution of CFLs was much more closely targeted and monitored to ensure that the lamps were actually installed.

The project was initiated by EnergyAustralia's network business rather than by its retailer arm, even though the abatement certificates generated were used by the retail business to help meet its obligations under the New South Wales emission trading scheme.

The CFL installations were carried out by a third party contractor who had proposed the measure in response to EnergyAustralia's Demand Management Options Consultation Paper.

The CFL project commenced with an advertising campaign in the target area that involved local municipal councils. Marketing activities were employed to promote the program, including posters sent to local businesses, letterbox drops, calling cards, outdoor banners, press advertisements and targeted media reations.

High power factor, 15 watt CFLs were packaged in boxes of five for distribution to households in the target area. Each household was given one box of five CFLs free of charge. Door-to-door delivery and installation were carried out during specific times and days to maximise the number of people at home.

For each box of CFLs delivered, delivery staff completed forms that included the householders' names, addresses and signatures plus answers to a short survey. The signed forms provided verification of the number of boxes of CFLs distributed. For households where no one was home, a flyer containing project information and a mail order form was left at the house. A follow-up phone survey was conducted during the delivery period to assess how many CFLs were actually installed.

## RESULTS

| Residential Customers Participating | Commercial and Small Industrial Customers Participating | Agricultural Customers Participating | Large Industrial Customers Participating | Additional Generation Installed |
|---|---|---|---|---|
| 5,747 | 118 | | | |

| Peak Load | Peak Load Reduction | Duration of Peak Load Reduction | Overall Load Reduction | Energy Savings | Network Augmentation Deferral |
|---|---|---|---|---|---|
| | 0.9 MVA | | | | |

## HOW LOAD REDUCTION WAS MEASURED

Other. Based on analysing SCADA data in Drummoyne, it was estimated that the winter peak demand reduction was 0.9 MVA at 9 pm.

## RESULTS ACHIEVED

The overall penetration rate for the installation of CFLs was about 26.1%. The project installed 81,347 CFL in 5,865 properties and achieved an estimated 0.9 MVA reduction in winter evening peak demand (153 VA per household).

## CONFIDENCE LEVEL IN ACHIEVING RESULTS

High

## REPEATABILITY OF RESULTS

High

## TIME DELAY BEFORE MAXIMUM RESPONSE ACHIEVED

## WEATHER DEPENDENCE

## AVOIDED COSTS

## ACTUAL PROJECT COSTS

The total cost of the program to EnergyAustralia was AUD315,254 at an average cost of AUD350/kVA load reduction, including AUD305/kVA as the cost of the external contractor and AUD45/kVA as the cost of internal project management by EnergyAustralia.

The final external contractor cost of AUD305/kVA was different from the initial estimate of AUD171/kVA in Table EE06/1 (page 192). The main reason was that the scope of work of the project was changed in negotiations with the contractor during project development. The original scope of work comprised only the distribution of CFLs. The revised scope of work comprised door-to-door distribution plus installation of CFLs in customer premises. This increased the level of certainty about whether the lamps were actually installed.

## PROJECT COST FROM THE SOCIETAL PERSPECTIVE

## OVERALL PROJECT EFFECTIVENESS

## CONTACTS

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## SOURCES

EnergyAustralia (2005). *Demand Management Options for Drummoyne Area*. Sydney, EnergyAustralia.

EnergyAustralia (2006). *Demand Management Investigation Report: Drummoyne*. Sydney, EnergyAustralia.

## CASE STUDY PREPARATION

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## EE07 NASHIK CFL PILOT PROJECT - INDIA

| | |
|---|---|
| **Last updated** | 3 October 2008 |
| **Location of Project** | Nashik, Maharashtra, India |
| **Year Project Implemented** | 2005/06 |
| **Year Project Completed** | 2006/07 |
| **Name of Project Proponent** | Maharashtra State Electricity Distribution Company Limited (MSEDCL) |
| **Name of Project Implementor** | MSEDCL through various agencies (ESCOs) identified via a competitive bidding process |
| **Type of Project Implementor** | Distribution utility<br>Electricity retailer/supplier |
| **Purpose of Project** | Deferral of network augmentation |
| **Timing of Project** | Post contingency |
| **Focus of Project** | Network capacity limitations<br>Generation capacity limitations |
| **Project Objective** | Peak load reduction, Overall load reduction |
| **Project Target** | Network region |
| **DSM Measure(s) Used** | Energy efficiency |
| **Specific Technology Used** | Compact Fluorescent Lamps (CFLs) |
| **Market Segments Addressed** | Residential customers<br>Commercial and small industrial customers |

### DRIVERS FOR PROJECT

The pilot CFL program was developed by the Maharashtra State Electricity Distribution Company Limited (MSEDCL) partnered with various agencies (energy service companies) identified and short listed via a competitive bidding process.

MSEDCL is responsible for the distribution and retailing of electricity in most of the State of Maharashtra. In the Mumbai region, MSEDCL and two private companies are responsible for distribution and retailing. In financal year 2004/05, MSEDCL supplied power to a consumer base of more than 13.6 million and sold 43,549 gigawatt-hours of electricity.

Maharashtra State faces a considerable demand/supply gap during both peak and off-peak periods. To bridge the demand/supply gap and to reduce load shedding, MSEDCL wanted to implement a State level CFL program by making CFLs available to residential and small commercial sector consumers at discounted rates. The main objective of the proposed state level CFL programme was to reduce demand during peak hours.

Before undertaking the State-wide program, MSEDCL decided to implement a pilot CFL programme in Nashik to understand various issues and to learn lessons from any mistakes made during the implementation of the pilot project.

In addition, the project was implemented for the following other reasons and benefits:

- to reduce the demand/supply gap;
- to reduce the load shedding problem;
- to create awareness among MSEDCL consumers about energy conservation;
- to reduce system peak demand; and
- to flatten the load curve.

## DESCRIPTION OF PROJECT

Selection of the agencies (ESCOs) through which CFLs were distributed was carried out via a competitive bidding process and prices were fixed by the process. Bids were invited for the entire state-wide program and the bids were evaluated on the basis of quality, price and warranty, and the retail networks established by the bidders. Five suppliers were selected and Expressions of Interest were invited from these selected suppliers for the Nashik CFL pilot project. Pricing and terms for the Nashik program were the same as for the state-wide program.

MSEDCL in partnership with energy service companies (ESCOs), launched the pilot CFL program in Nashik at the end of 2005. MSEDCL decided to distribute 300,000 CFLs in the Nashik district.

The backbone of the pilot DSM programme was a CFL subsidy system, which was designed to persuade a large number of consumers to purchase and install CFLs to replace existing incandescent lamps. Only residential and commercial consumers having no electricity bill arrears were eligible to participate in this project.

A limit of five CFLs per consumer was fixed. Two choices, direct purchase or purchase through instalments were offered by MSEDCL to the participating consumers. Several mechanisms were developed to deliver CFLs to urban and rural areas effectively. These delivery mechanisms included:

- CFLs available at bill collection centres;
- door to door sales by members of a women's micro-credit entrepreneurial group, Bachat Gut, organised by the ESCOs;
- CFLs available at retail shops;
- CFLs available at meetings organised by MSEDCL to publicise the CFL pilot program.

The pilot program enabled approximately 100,000 residential and commercial sector consumers to purchase low-priced CFL lamps with a 12 months warranty. MSEDCL supported the 12 months warranty to its consumers. MSEDCL did not contribute financially to the pilot program but provided a communication facility as well as a montlhy instalment payment facility through electricity bills.

A tracking and monitoring system was established as part of the pilot project to record the project data and carry out general oversight of the project. The objective of the tracking and monitoring process was to evaluate the overall impact of the ongoing pilot project and to implement mid-courses corrections.

The following steps were undertaken by MSEDCL as a part of the tracking and monitoring process:

- consumers signed a one page purchase agreement when they received the CFLs;
- the retailer collected all purchase agreements and sent them to the supplier's regional sales office (RSO);
- the RSO submitted a list of the purchase agreements and an invoice to a sub-division officer (SDO) of MSEDCL on a CD;
- the SDO passed the CD to MSEDCL's IT department;

- the IT department merged this data with billing data and the consumers' instalment amounts were included in their electricity bills.

## RESULTS

| Residential Customers Participating | Commercial and Small Industrial Customers Participating | Agricultural Customers Participating | Large Industrial Customers Participating | Additional Generation Installed |
|---|---|---|---|---|
| More than 80,000 | 20,000 | | | |

| Peak Load | Peak Load Reduction | Duration of Peak Load Reduction | Overall Load Reduction | Energy Savings | Network Augmentation Deferral |
|---|---|---|---|---|---|
| | 7 to 9 MW | | 7 to 9 MW | 12 to 16 MWh | |

## HOW LOAD REDUCTION WAS MEASURED

Estimate. Engineering calculation.

## RESULTS ACHIEVED

Three suppliers distributed approximately 380,000 CFLs (15 and 20 Watt) and these were sold through the various sales channels. Approximately 95% of total sales were by instalment payments and 95% of these sales were to residential consumers. A large proportion of the CFLs were used to replace fluorescent tube lights. Only about 24% of CFLs in urban areas and 41% in rural areas were used to replace incandescent lamps.

A detailed survey was carried out to identify the hours of use and time of use of the CFLs, and the wattage of the replaced lamps, to identify the actual energy savings achieved. Monitoring and evaluation results showed that about 100,000 residential and commercial consumers participated in the pilot project. The project resulted in savings of 12 to 16 megawatt-hours of energy per year and 7 to 9 megawatts of peak load reduction.

Reductions in electricity bills of around 79% for urban consumers and 81% for rural consumer were achieved. Bill reductions from energy savings became the most important motivation factor from the consumer point of view.

Further detailed results of the Nashik CFL pilot project are shown in Table EE07/1 (page 199).

| Table EE07/1. Results of Nashik CFL Pilot Project | | |
|---|---|---|
| **Statistic** | **Urban Areas** | **Rural Areas** |
| Number of CFLs sold per participating consumer | 3.8 | 3.9 |
| Number of CFLs replacing incandescent lamps | 0.9 | 1.6 |
| Usage of CFLs overall (hours per day) | 4.6 | 4.9 |
| Energy savings per CFL overall (kWh per month) | 2.5 | 3.4 |
| Peak load savings per CFL overall (Watts) | 18.2 | 23.3 |

## CONFIDENCE LEVEL IN ACHIEVING RESULTS

High

## REPEATABILITY OF RESULTS

The main reason for the implementation of the Nashik DSM pilot project was to understand various issues and to learn lessons from any mistakes. Repeatability of the results of the pilot project is very likely but monitoring and verification needs to be carried out by professional companies to measure the exact impact of the implementation. MSEDCL proposed to extend the CFL programme to four major districts: Aurangabad, Kolhapur, Nagpur and Pune.

## TIME DELAY BEFORE MAXIMUM RESPONSE ACHIEVED

## WEATHER DEPENDENCE

## AVOIDED COSTS

## ACTUAL PROJECT COSTS

In the Nashik CFL pilot project, MSEDCL acted as a facilitator between consumers and the implementing agencies (ESCOs) but did not make any direct financial contribution to the project. The financial impact on MSEDCL was limited to the costs involved in providing the instalment payment facility through electricity bills.

## PROJECT COST FROM THE SOCIETAL PERSPECTIVE

## OVERALL PROJECT EFFECTIVENESS

Prayas, a not for profit organisation, carried out an assessment of the effectiveness of the Nashik CFL pilot project. The assessment of the project's design, procedures and systems was carried out by means of a survey questionnaire, in-depth interview of participants, non-participants, manufacturers, retailers, MSEDCL's staff and Bachat Gut sales women to identify the overall impact of the pilot project.

Prayas identified the following positive aspects of the pilot project:

- high penetration rates of CFLs were achieved in poor neighbourhoods;
- awareness of CFLs and their energy savings features increased greatly;
- the use of Bachat Gut women to sell CFLs door to door was a very innovative delivery mechanism;
- there were significant but lower than expected savings (mostly because fluorescent tubes were replaced instead of incandescent lamps);
- the potential for installation of CFLs is significant (an average of 1.5 incandescent lamps per rural household are currently installed.)

Prayas concluded that MSEDCL has recognized the importance of energy efficiency and taken an important step in promoting DSM. Like most pilot projects, the Nashik project should be seen as an opportunity to test an hypothesis and learn from mistakes prior to undertaking a state-wide program.

## CONTACTS

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## SOURCES

## CASE STUDY PREPARATION

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## EE08 MUMBAI EFFICIENT LIGHTING PROGRAM - INDIA

| | |
|---|---|
| **Last updated** | 18 September 2008 |
| **Location of Project** | Reliance Energy supply area, North Mumbai, India |
| **Year Project Implemented** | 2006/07 |
| **Year Project Completed** | 2006/07 |
| **Name of Project Proponent** | Reliance Energy Limited |
| **Name of Project Implementor** | Reliance Energy Limited |
| **Type of Project Implementor** | Distribution utility<br>Electricity retailer/supplier |
| **Purpose of Project** | Deferral of network augmentation |
| **Timing of Project** | Post contingency |
| **Focus of Project** | Network capacity limitations, Generation capacity limitations |
| **Project Objective** | Peak load reduction<br>Overall load reduction |
| **Project Target** | Network element |
| **DSM Measure(s) Used** | Energy efficiency |
| **Specific Technology Used** | Compact fluorescent lamps (CFLs) |
| **Market Segments Addressed** | Residential customers<br>Commercial and small industrial customers |

### DRIVERS FOR PROJECT

Maharashtra State has witnessed rapid economic growth in the past decade leading to increased demand for electricity. But the growth in electricity generation capacity in the State has not kept pace with the demand growth. Consequently, load shedding is carried out for 4 to 10 hours each day in various parts of Maharashtra.

The city of Mumbai has so far been spared from load shedding, as the three electricity distributor/retailer licensees supplying the Mumbai region have been able to meet their energy requirements through their own generation and by sourcing power from external agencies. However, due to the national shortage of generation capacity in India of 14,000 MW, the availability of additional generation from external sources is uncertain.

In April and May 2006 there was an expected demand/supply gap in the Mumbai region of 250 to 275 MW during peak hours. If the external generation required to bridge this gap was not available, load shedding would have become inevitable in the city of Mumbai and particularly in Reliance Energy's supply area. This scenario was expected to become an annual event, and would become increasingly worse with continuous load growth.

To deal with this situation, various initiatives were implemented to achieve strategic energy conservation and peak clipping. The Mumbai Efficient Lighting Program was one of these initiatives.

## DESCRIPTION OF PROJECT

Under the Mumbai Efficient Lighting Program, Reliance Energy Limited (REL) offered up to three 15 watt CFLs per consumer at a discounted price. REL negotiated with M/s. Bajaj Electricals a unit retail price of INR82 for 15 watt CFLs, compared with the market price of INR160. REL offered only one model of CFL with a warranty of one year for sale under this program.

REL promoted the scheme by providing a coupon in the monthly electricity bills of consumers that could be exchanged for a maximum of three discounted price CFLs. The coupon was valid only if the consumer had no outstanding arrears on their electricity bill. To purchase the CFLs, consumers visited one of a number of designated outlets (distributors for M/s. Bajaj Electricals).

The cost of each CFL purchased through this scheme was recovered from consumers through their monthly electricity bills. Payments were made in 11 instalments of INR7 each plus a last instalment of INR5. However, for those who paid nine monthly instalments before due dates, the last three months of instalments amounting to INR19 were waived, thus encouraging consumers to participate in the program.

## RESULTS

| Residential Customers Participating | Commercial and Small Industrial Customers Participating | Agricultural Customers Participating | Large Industrial Customers Participating | Additional Generation Installed |
|---|---|---|---|---|
| 177,764 | 18,880 | | 49 | |

| Peak Load | Peak Load Reduction | Duration of Peak Load Reduction | Overall Load Reduction | Energy Savings | Network Augmentation Deferral |
|---|---|---|---|---|---|
| 1,315 MW | 7.55 MW | 4 hours | 10.79 MW | 16.85 GWh/year | |

## HOW LOAD REDUCTION WAS MEASURED

Other. Consumer survey.

## RESULTS ACHIEVED

The energy savings and demand reduction achieved by the project were calculated on the basis of the findings of a consumer survey and were estimated at 16.85 gigawatt-hours per year of energy savings and 10.79 megawatt of overall demand reduction. These benefits will recur over the life of the CFLs.

## CONFIDENCE LEVEL IN ACHIEVING RESULTS

Medium

## REPEATABILITY OF RESULTS

The program is repeatable on a large scale.

## TIME DELAY BEFORE MAXIMUM RESPONSE ACHIEVED

No time delay because 80% of the CFLs were sold during first phase of the program between April and May 2006. Given that consumers were paying for the CFLs, it is highly likely that the lamps were installed immediately.

## WEATHER DEPENDENCE

Not applicable.

## AVOIDED COSTS

## ACTUAL PROJECT COSTS

Reliance Energy Limited: INR11.7 million
Consumer: INR38.9 million

## PROJECT COST FROM THE SOCIETAL PERSPECTIVE

## OVERALL PROJECT EFFECTIVENESS

The project was successful in achieving strategic energy conservation.

## CONTACTS

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## SOURCES

Internal reports and documents, Reliance Energy Limited.

## CASE STUDY PREPARATION

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# EE09 MUMBAI CONSUMER AWARENESS CAMPAIGN - INDIA

| | |
|---|---|
| **Last updated** | 3 October 2008 |
| **Location of Project** | City of Mumbai, India |
| **Year Project Implemented** | March 2007 |
| **Year Project Completed** | May 2007 |
| **Name of Project Proponent** | Reliance Energy Limited (REL)<br>Brihan Mumbai Electric Supply & Transport Undertaking (BEST)<br>Tata Power Company Limited (TPC) |
| **Name of Project Implementor** | Reliance Energy Limited (REL)<br>Brihan Mumbai Electric Supply & Transport Undertaking (BEST)<br>Tata Power Company Limited (TPC) |
| **Type of Project Implementor** | Distribution utility<br>Electricity retailer/supplier<br>Electricity generator |
| **Purpose of Project** | Deferral of network augmentation |
| **Timing of Project** | Post contingency |
| **Focus of Project** | Network capacity limitations<br>Generation capacity limitations |
| **Project Objective** | Peak load reduction<br>Overall load reduction |
| **Project Target** | Network element |
| **DSM Measure(s) Used** | Public awareness campaign |
| **Specific Technology Used** | |
| **Market Segments Addressed** | Residential customers<br>Commercial and small industrial customers |

## DRIVERS FOR PROJECT

Maharashtra State has witnessed rapid economic growth in the past decade leading to increased demand for electricity. But the growth in electricity generation capacity in the State has not kept pace with the demand growth. Consequently, load shedding is carried out for 4 to 10 hours each day in various parts of Maharashtra.

The city of Mumbai has so far been spared from load shedding, as the three electricity distributor/retailer licensees supplying the Mumbai region have been able to meet their energy requirements through their own generation and by sourcing power from external agencies. However, due to the national shortage of generation capacity in India of 14,000 MW, the availability of additional generation from external sources is uncertain.

In April and May each year there is an expected demand/supply gap in the Mumbai region of 250 to 275 MW during peak hours. If the external generation required to bridge this gap is not available, load shedding will become inevitable in the city of Mumbai.

To deal with this situation, various initiatives were implemented to achieve strategic energy conservation and peak clipping. The Mumbai Consumer Awareness Campaign was one of these initiatives.

## DESCRIPTION OF PROJECT

In light of the power shortage and cuts expected in the summer of 2007, it was necessary to create awareness about the situation and a sense of responsibility in the Mumbaikar (people of Mumbai).

The "I Will, Mumbai Will" energy saving campaign was launched in March 2007 by two of the three electricity distributor/retailers supplying electricity in Mumbai, the privately owned company Reliance Energy Limited (REL) and the municipally owned Brihan Mumbai Electric Supply & Transport Undertaking (BEST), together with the privately owned electricity generator, Tata Power Company Limited (TPC).

The campaign used most popular communications media such as billboard hoardings, press, radio and cinema to maximise exposure across various classes and age groups.

The campaign mainly focused upon common habits contributing to electricity demand during the peak load period and to energy wastage. The following energy saving messages were highlighted:

- keep air conditioner thermostats at 24 degrees Celsius or higher;
- switch off all appliances at the plug point;
- minimise usage of appliances between 10 am and 8 pm.

Some of the publicity and advertising items used in the campaign are shown in Figures EE09/1 (page 206)and EE09/2 (page 207).

## RESULTS

| Residential Customers Participating | Commercial and Small Industrial Customers Participating | Agricultural Customers Participating | Large Industrial Customers Participating | Additional Generation Installed |
|---|---|---|---|---|
| | | | | |

| Peak Load | Peak Load Reduction | Duration of Peak Load Reduction | Overall Load Reduction | Energy Savings | Network Augmentation Deferral |
|---|---|---|---|---|---|
| | | | | | |

## HOW LOAD REDUCTION WAS MEASURED

Other. Consumer survey.

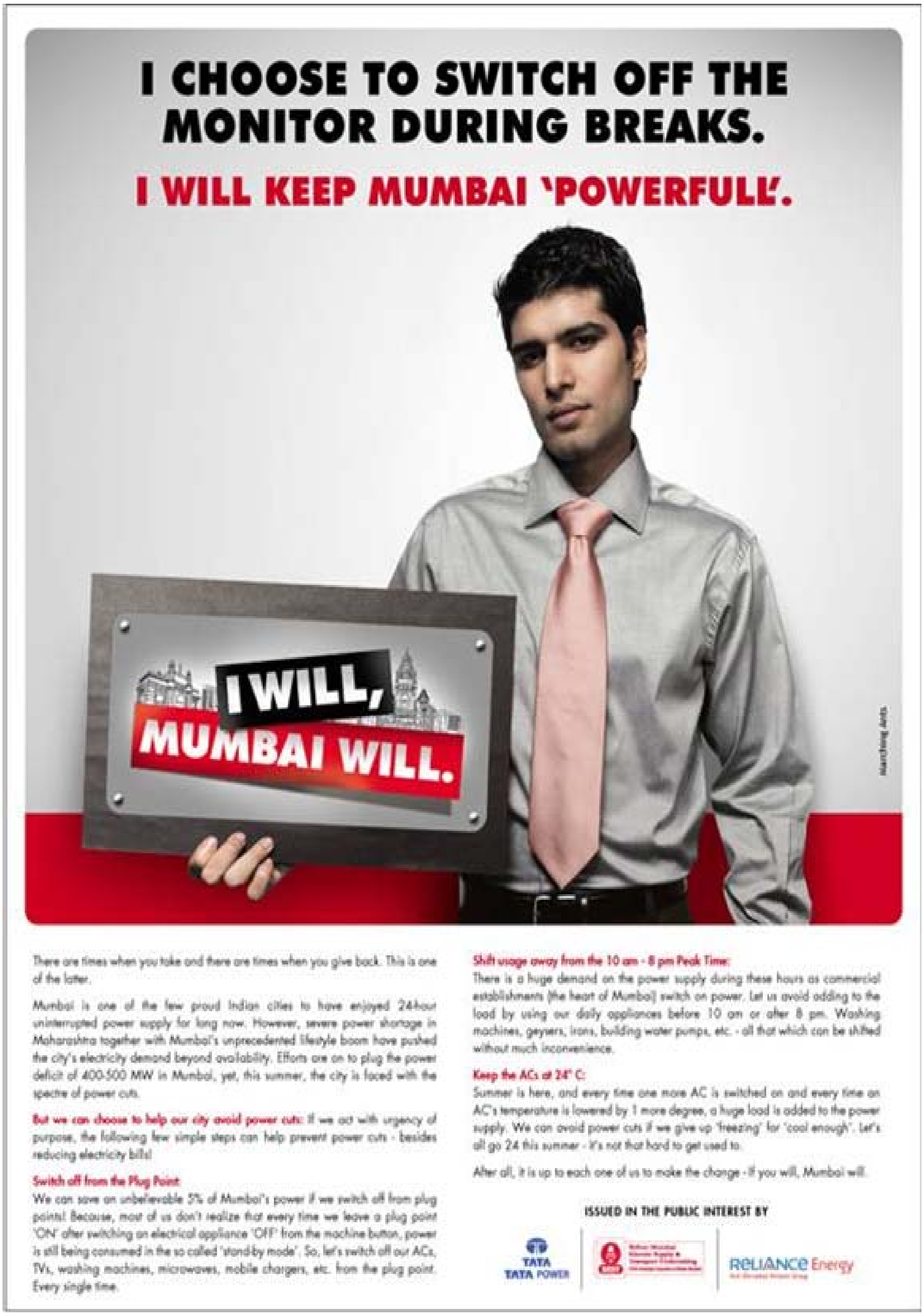


**Figure EE09/1. Press Advertisement**


**Door Stickers**


**Poster / Standee**

**Front View**

**Rear View**

**Figure EE09/2. Publicity Material**

## RESULTS ACHIEVED

REL appointed Drshti Strategic Research Services Pvt. Ltd. to carry out an assessment of the impact of the campaign. Quantitative research in the form of a structured questionnaire was used after the launch of advertising. The research was launched in mid May 2007 and was concluded in the first week of June 2007.

The research objective was to test the effectiveness of the messages communicated through the Mumbai Consumer Awareness Campaign on the citizens of Mumbai, in relation to:

- awareness about the current power shortage;
- belief that they are capable of saving electricity;
- awareness of different methods to conserve power;
- belief that it is a joint effort to conserve electricity;
- the call for action to conserve power.

The campaign was assessed in terms of the changes in the following parameters amongst the target group:

- awareness of the campaign;
- attitude to and beliefs about electricity supply / problems / conservation;
- behaviour towards electricity conservation.

The research found that people in Mumbai had an underlying awareness regarding the power shortage. However, this awareness had not translated into a strong belief that power cuts can actually happen and some action needs to be taken to avoid it.

Two key messages that were registered through the campaign and that were being acted upon were:

- to switch off appliances at the plug point; and
- to keep air conditioning at 24 degrees Celsius.

Table EE09/1 (page 209)shows the awareness generated for each message conveyed through the campaign, categorised by the type of communications media used.

Table EE09/2 (page 209) shows the awareness generated in different geographical areas of Mumbai about the possibility of a power shortage and the possibility of power cuts.

| Table EE09/1. Awareness Generated by Different Types of Media Campaign | | | | |
|---|---|---|---|---|
| Awareness of the Following Messages | Press | Hoard-ings | Radio | Cinema |
| | n=315 | n=474 | n=274 | n=22 |
| Shut down all appliances from the plug to save power | 79% | 72% | 44% | 64% |
| Keep the temperature at 24 degrees | 9% | 25% | 27% | 5% |
| Don't misuse the power supply | 8% | 6% | 3% | 9% |
| Mumbai can be powerful to save power | 6% | 5% | 2% | 0% |
| If we save power there will be no shortage | 2% | 25% | 30% | 0% |
| Always use less from 10 am to 8 pm daily | 1% | 5% | 8% | 5% |
| Don't know | 2% | 0% | 9% | 19% |

| Table EE09/2. Awareness in Different Geographical Areas of Mumbai | | | | |
|---|---|---|---|---|
| Answer | All (n=1201) | Town (n=397) | Central (n=427) | Western (n=377) |
| Awareness about possibility of power shortage | | | | |
| Yes | 95% | 99% | 90% | 95% |
| No | 5% | 1% | 10% | 5% |
| Awareness about possibility of power cuts | | | | |
| Yes | 95% | 98% | 30% | 96% |
| No | 5% | 91% | 1% | 4% |

The impact of the Mumbai Consumer Awareness Campaign can be quantified from the results from the electricity usage behaviour survey, which showed that, of the people surveyed:

- 74% had started keeping their air conditioners at 24 degrees Celsius or more;
- 86% had started keeping their refrigerator thermostat set for medium cooling;
- 90% had started switching off various appliances from the plug point (ranging from TVs to mobile phone chargers);
- 90% had started avoiding water pump usage between 10 am and 8 pm;
- 80% had started optimising water heater usage by taking baths in succession; and
- 90% had started turning off lights when not in use.

## CONFIDENCE LEVEL IN ACHIEVING RESULTS

## REPEATABILITY OF RESULTS

## TIME DELAY BEFORE MAXIMUM RESPONSE ACHIEVED

## WEATHER DEPENDENCE

In general, media campaigns are more effective when implemented immediately preceding and during summer (for cooling loads) and winter (for heating loads).

## AVOIDED COSTS

## ACTUAL PROJECT COSTS

The three project proponents, REL, BEST and TPC each contributed INR45 million to equally share the total cost for the campaign of INR135 million.

## PROJECT COST FROM THE SOCIETAL PERSPECTIVE

## OVERALL PROJECT EFFECTIVENESS

The project was successful in achieving the objectives to educate people about the possibility of power cuts in Mumbai and to motivate them to take actions towards conservation of energy.

## CONTACTS

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## SOURCES

## CASE STUDY PREPARATION

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## EE10 BANGALORE EFFICIENT LIGHTING PROGRAM - INDIA

| | |
|---|---|
| **Last updated** | 4 October 2008 |
| **Location of Project** | Bangalore, Karnataka, India |
| **Year Project Implemented** | December 2004 |
| **Year Project Completed** | September 2005 |
| **Name of Project Proponent** | Bureau of Energy Efficiency, Ministry of Power, Government of India |
| **Name of Project Implementor** | Bangalore Electricity Supply Company (BESCOM) |
| **Type of Project Implementor** | Distribution utility<br>Electricity retailer/supplier |
| **Purpose of Project** | Deferral of network augmentation |
| **Timing of Project** | Post contingency |
| **Focus of Project** | Network capacity limitations<br>Generation capacity limitations |
| **Project Objective** | Peak load reduction<br>Overall load reduction |
| **Project Target** | Network element |
| **DSM Measure(s) Used** | Energy efficiency |
| **Specific Technology Used** | Compact fluorescent lamps (CFLs) |
| **Market Segments Addressed** | Residential customers |

### DRIVERS FOR PROJECT

The Bangalore Efficient Lighting Program was developed by Bangalore Electricity Supply Company (BESCOM) partnered with the Government of India's Bureau of Energy Efficiency (BEE) under bilateral funding from USAID.

BESCOM is an electricity distribution/retailing utility undertaking owned by the Government of Karnataka. The Karnataka State Government owns five distribution/retailing utilities and BESCOM is the largest. BESCOM is responsible for power distribution in six districts of Karnataka and its service territory covers an area of 41,092 square kilometres with a population of over 16.8 million.

The Bangalore Efficient Lighting Program was developed to demonstrate the first utility-driven efficient product branding and promotion in India by accelerating the introduction of compact fluorescent lamps (CFLs) in Bangalore.

The objective of the program was to promote efficient lighting among Indian domestic consumers by facilitating the removal of barriers to CFL uptake, such as high prices and the threat from cheap, low quality imported CFLs. On a wider scale, the project aimed to facilitate the creation of a business model for utility-driven DSM programs in India

### DESCRIPTION OF PROJECT

The Bangalore Efficient Lighting Program comprised a CFL subsidy scheme, which was designed to persuade large number of customers to purchase and install CFLs by replacing existing incandescent lamps. BESCOM customers were issued with vouchers that could be redeemed for low price CFLs.

BESCOM undertook the following steps before the launch of the program:

- short-listing of suppliers based on a competitive tendering process;
- design of a joint marketing campaign and training of BESCOM officials in program implementation;
- design of a tamper-proof hologram to be used on the subsidised CFLs.

Three suppliers were selected to provide CFLs for the program by using their distributors and retailers as outlets for BESCOM customers to purchase discounted CFLs with a twelve month warranty. BESCOM supported the twelve month warranty to its customers, also bringing down prevailing market prices by almost 20%. Customers repaid the cost of the CFLs in nine monthly instalments.

BESCOM appointed three dedicated staff to oversee the program in addition to periodic top management review. The USAID technical assistance funded a consultant who also helped BESCOM to keep the program under regular review.

After the launch of the programme BESCOM carried out:

- a focused marketing campaign in specific geographical areas within the BESCOM urban territory;
- sensitisation workshops for Residents' Welfare Associations;
- training of BESCOM consumer centre staff on procedures for issuing vouchers to customers and on methods for tracking program progress.

BESCOM was able to ensure participation of some Residents' Welfare Associations in promoting this initiative to a wider base of consumers.

Program monitoring and evaluation was undertaken to evaluate the benefits to the utility, the customer benefits and the effectiveness of the financing and repayment scheme. Billing analysis was carried out by a consultant to evaluate the system benefits, customers' acceptance of the program and the effectiveness of BESCOM's procedures and systems. A consumer survey was undertaken to estimate CFL performance based on the daily operating hours of individual lamps. This survey was carried out continuously for a period of around 60 days between August and September 2005.

## RESULTS

| Residential Customers Participating | Commercial and Small Industrial Customers Participating | Agricultural Customers Participating | Large Industrial Customers Participating | Additional Generation Installed |
|---|---|---|---|---|
| More than 50,000 | | | | |

| Peak Load | Peak Load Reduction | Duration of Peak Load Reduction | Overall Load Reduction | Energy Savings | Network Augmentation Deferral |
|---|---|---|---|---|---|
| | | | 13.4 MW | 24.3 GWh | |

## HOW LOAD REDUCTION WAS MEASURED

Estimate. Daily lamp use was obtained from the survey of participants and energy savings were calculated from engineering estimates.

## RESULTS ACHIEVED

Participating suppliers reported an increase in CFL sales by over 100%, resulting in additional sales of 300,000 CFLs. Monitoring and evaluation results showed that more than 50,000 individual consumers participated in the program resulting in energy savings of 24.3 gigawatt-hours and a demand reduction of around 13.4 MW.

## CONFIDENCE LEVEL IN ACHIEVING RESULTS

High

## REPEATABILITY OF RESULTS

## TIME DELAY BEFORE MAXIMUM RESPONSE ACHIEVED

## WEATHER DEPENDENCE

## AVOIDED COSTS

## ACTUAL PROJECT COSTS

BESCOM did not contribute financially to the program and the only cost to BESCOM was staff time. Participating suppliers contributed INR1.5 million.

## PROJECT COST FROM THE SOCIETAL PERSPECTIVE

## OVERALL PROJECT EFFECTIVENESS

Lack of detailed quantitative data makes it difficult to assess the effectiveness of the Bangalore Efficient Lighting Program as compared with other network-driven DSM projects. However, implementation of the program resulted in reduced electricity bills and increased availability of low cost, high quality CFLs to customers under utility branding and warranty support. The program also provided benefits to the utility in peak load reduction and improved customer relations and to society through reduced greenhouse gas emissions.

## CONTACTS

## SOURCES

## CASE STUDY PREPARATION

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# FS01 TAHMOOR FUEL SUBSTITUTION PROJECT - AUSTRALIA

| | |
|---|---|
| **Last updated** | 31 August 2005 |
| **Location of Project** | Tahmoor, about 70 km south of Sydney, Australia |
| **Year Project Implemented** | 1998 |
| **Year Project Completed** | 2001 |
| **Name of Project Proponent** | Integral Energy |
| **Name of Project Implementor** | Integral Energy |
| **Type of Project Implementor** | Distribution utility |
| **Purpose of Project** | Deferral of network augmentation |
| **Timing of Project** | Pre contingency |
| **Focus of Project** | Network capacity limitations |
| **Project Objective** | Peak load reduction |
| **Project Target** | Network element |
| **DSM Measure(s) Used** | Fuel substitution |
| **Specific Technology Used** | Bottled gas cooking and space heating appliances |
| **Market Segments Addressed** | Residential customers |

## DRIVERS FOR PROJECT

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

## 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 AUD150 for the installation of bottled gas plus AUD150 per gas appliance.

## RESULTS

| Residential Customers Participating | Commercial and Small Industrial Customers Participating | Agricultural Customers Participating | Large Industrial Customers Participating | Additional Generation Installed |
|---|---|---|---|---|
| 100 | | | | |

| Peak Load | Peak Load Reduction | Duration of Peak Load Reduction | Overall Load Reduction | Energy Savings | Network Augmentation Deferral |
|---|---|---|---|---|---|
| | | | | | |

## HOW LOAD REDUCTION WAS MEASURED

## RESULTS ACHIEVED

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 distribution network augmentation for a shorter period than had originally been forecast. Consequently, the augmentation was undertaken in 2003/04.

## CONFIDENCE LEVEL IN ACHIEVING RESULTS

Low - customer response was less than expected.

## REPEATABILITY OF RESULTS

May be repeatable with a more aggressive marketing program.

## TIME DELAY BEFORE MAXIMUM RESPONSE ACHIEVED

## WEATHER DEPENDENCE

## AVOIDED COSTS

## ACTUAL PROJECT COSTS

Integral Energy - AUD 40,000 subsidies paid to customers plus AUD 18,000 administrative costs.

## PROJECT COST FROM THE SOCIETAL PERSPECTIVE

Not calculated.

## OVERALL PROJECT EFFECTIVENESS

## CONTACTS

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## SOURCES

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

Personal communication, Frank Bucca, Integral Energy.

## CASE STUDY PREPARATION

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## FS02 BINDA-BIGGA DSM PROJECT - AUSTRALIA

| | |
|---|---|
| **Last updated** | 12 July 2006 |
| **Location of Project** | The rural communities of Binda and Bigga near Crookwell in New South Wales, Australia |
| **Year Project Implemented** | 2004 |
| **Year Project Completed** | 2005 |
| **Name of Project Proponent** | Country Energy |
| **Name of Project Implementor** | New South Wales Sustainable Energy Development Authority (now the Department of Environment and Climate Change) |
| **Type of Project Implementor** | Third party aggregator<br>State or federal government agency |
| **Purpose of Project** | Deferral of network augmentation |
| **Timing of Project** | Pre contingency |
| **Focus of Project** | Voltage fluctuations |
| **Project Objective** | Peak load reduction<br>Voltage regulation |
| **Project Target** | Network element |
| **DSM Measure(s) Used** | Energy efficiency<br>Fuel substitution |
| **Specific Technology Used** | |
| **Market Segments Addressed** | Residential customers |

### DRIVERS FOR PROJECT

Binda and Bigga are two small rural settlements near Crookwell about 230 km south-west of Sydney. The Binda-Bigga area has about 250 electricity customers, mostly residential.

The electricity line that runs from Binda to Bigga and then further on to Grabine was installed several years ago by Country Energy. Overall load growth on the line was relatively low but, as peak electricity use increased in the area, the line was reaching its maximum capacity. The base electrical load used for the line was 750kVA, however peak demand had been registered at 1,000kVA.

Fault levels and voltage levels were a concern along the line, especially during storm events, due to the length of the line and the rugged country through which the line passes. Many customers in Binda and Bigga were experiencing unacceptable voltage fluctuations which could be resolved only by extensive reconductoring of the line.

Country Energy contracted SEDA in 2004 to relieve the electrical demand on the Crookwell to Grabine feeder during times of winter evening peaks. The aim of the contract was to defer the need for the upgrade of the Crookwell to Grabine feeder by reducing the demand for energy during the winter evening peak periods (the four hours from 6 pm to 10 pm).

## DESCRIPTION OF PROJECT

### Initial Investigation

There are two winter peaks on the Crookwell to Grabine feeder, one around midnight due to off-peak hot water controlled loads and an evening peak (see Figure FS02/1). The evening peak tends to occur on days when the minimum temperature drops as low as minus 9 degrees Celsius.

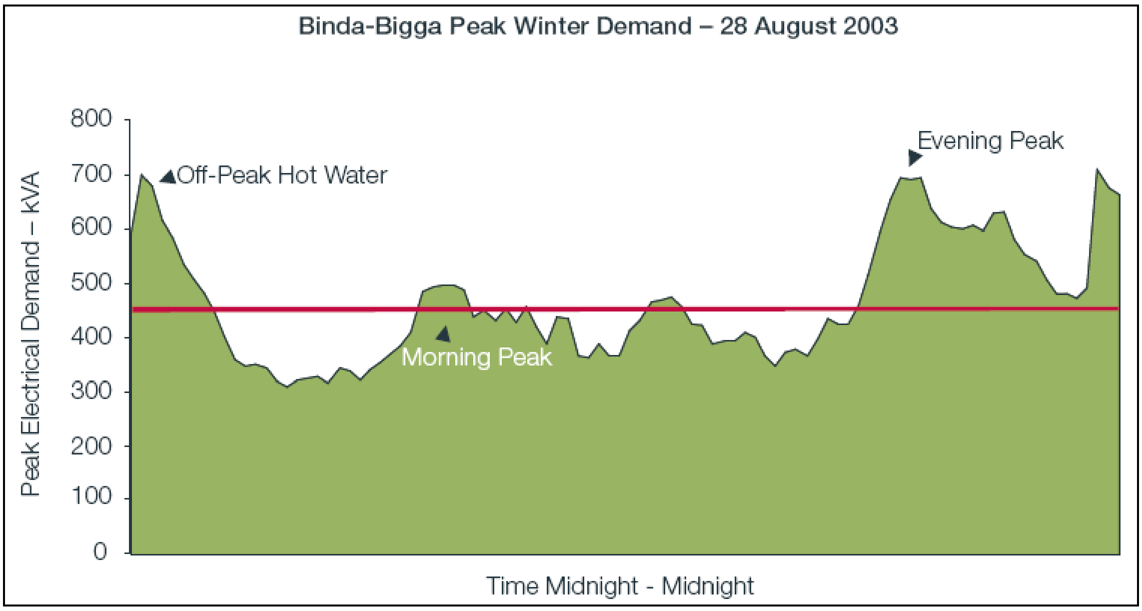


**Figure FS02/1. Peak Winter Demand on the Crookwell to Grabine Feeder**

In January 2004, SEDA conducted a survey of Binda and Bigga residents to explore what might have been causing the peaks in electricity demand during winter evenings. Results showed that a typical winter energy bill was over AUD 250 each quarter – a large percentage due to room heating and cooking end-uses.

### Project Objectives

The following objectives were established for the project:

- to reduce the electricity load on Country Energy's Crookwell to Grabine feeder by 200kVA by 2006 during winter evening peaks (the four hours from 6 pm to 10 pm);
- to deliver real benefits to rural customers through reducing their energy consumption and improving the quality of supply for residents on the Crookwell to Grabine feeder;
- to reduce greenhouse gas emissions through fuel substitution of electric appliances to gas.

## DSM Strategies

Two DSM strategies were investigated:

- **Cogeneration Option:** the installation of a cogeneration plant at the Grabine State Recreation Park to achieve a reduction of 100kVA in peak electrical demand; and
- **Domestic Solution:** a range of strategies to facilitate the uptake of energy efficient products and measures, primarily achieved through fuel substitution of residential appliances from electricity to bottled gas to achieve a reduction of another 100kVA in peak electrical demand.

After an initial investigation, the Cogeneration Option proved uneconomic, so the Domestic Solution was the method by which the total required demand reduction of 200kVA was sought.

The Domestic Solution facilitated the uptake of energy efficient products and measures by residents through a range of residential DSM strategies. It integrated the following strategies:

- developing an Energy Saver Package;
- engaging local project partners;
- offering Energy Smart Home audits;
- implementing marketing and communications campaigns; and
- holding community forums in Binda and Bigga.

## Energy Saver Package

The Energy Saver Package was developed as the primary mechanism to achieve the required demand management reduction of 200kVA. To reduce the demand on the electricity feeder during the peak time, the Package was structured around appliances that would reduce electricity demand from residents cooking an evening meal and heating their homes.

The Energy Saver Package enabled residents to affordably switch from electric to gas appliances (see Figure FS02/2, page 220). It offered residents:

- discounted gas room heaters and cooking stoves (a maximum of two appliances per household);
- free installation of gas appliances and gas bottles, and removal of electrical appliances for metal recycling; and
- gas credits of AUD 170 per appliance – equivalent to free gas for a year.

To achieve the peak demand reduction target of 200kVA, the installation of 98 gas appliances was required.

| Appliance | Rec. Retail Price | Price in Energy Saver Package (excl. GST) | Saving to the customer |
|---|---|---|---|
| Rinnai Granada (unflued heater) | $899 | $250 | $649 |
| Rinnai EnergySaver (flued heater) | $1,699 | $1,000 | $699 |
| Chef Stove | $699 | $250 | $449 |
| Rinnai Granada + Chef Stove | $1,598 | $470 | $1,128 |
| Rinnai EnergySaver + Chef Stove | $2,398 | $1,200 | $1,198 |

**Figure FS02/2. Cost of Gas Appliances Offered in the Energy Saver Package**

Customers were required to meet a number of conditions to qualify for the Energy Saver Package. They had to:

- be connected to the Crookwell to Grabine Feeder, and be a Country Energy customer;
- agree to surrender their electric heaters and stoves at the time of installation of the new gas appliances;
- commit to leaving gas appliances installed and operational for a period of 5 years; and
- submit signed a Customer Form and payment by 30 September 2004 (extended to 31 October 2004).

The Energy Saver Package was designed to be easy for residents. The new gas appliances were delivered to the customers' homes and the appliances and gas bottles were installed. The old electric appliances were removed during the same visit and taken for recycling.

### Energy Smart Home Audits

Energy Smart Home audits were offered to residents in Binda and Bigga to facilitate the uptake of energy efficient products and measures. The audits also provided the opportunity for residents to have assessed the suitability of their home/appliances for the gas appliance offer.

The three components of an Energy Smart Home audit comprise a Star Rating, a virtual home audit and a personal visit from an Energy Assessor. The audit provides a measure of energy efficiency for a home by comparing its rating to an average. The result is a star rating between 1 and 5, with 5 being the most energy efficient. Moving up just one star can save AUD 150-300 per annum.

Residents were offered an Energy Smart Home audit for AUD 20, rather than the normal AUD 100, and the cost of the audit was redeemable against the purchase of a gas heater or stove (as part of the Energy Saver Package).

### Marketing and Communications

The Energy Saver Package was promoted to residents through a brochure and poster detailing the Energy Saver Package options, advertising two community forums for residents and providing information on Energy Smart Home audits.

Two free community forums were held in Binda and Bigga. Topics covered included:

- the Energy Saver Package;
- Energy Smart Home audits;
- Green Power – electricity generated from renewable sources; and
- tips on saving energy around the home and reducing bills.

The Project Team was on hand to provide additional information on the Energy Saver Package products, gas connections and installations. Gas appliances were on display for residents to view the products included in the Package. Energy efficient prizes were on offer at the forums, including Energy Saver kits which featured a compact fluorescent light bulb, door snake, AAA-rated showerhead and toilet cistern weight.

Finally, a competition was held in which residents could win one of two solar hot water systems. All residents who purchased and qualified for an Energy Saver Package were entered into the competition.

## RESULTS

| Residential Customers Participating | Commercial and Small Industrial Customers Participating | Agricultural Customers Participating | Large Industrial Customers Participating | Additional Generation Installed |
|---|---|---|---|---|
| 70 | | | | |

| Peak Load | Peak Load Reduction | Duration of Peak Load Reduction | Overall Load Reduction | Energy Savings | Network Augmentation Deferral |
|---|---|---|---|---|---|
| | 0.2 MW | 4 hours | 0.2 MW | | |

## HOW LOAD REDUCTION WAS MEASURED

Other. Recloser logs.

## RESULTS ACHIEVED

Overall 70 customers purchased an Energy Saver Package, purchasing 106 appliances in total, between July and October 2004. This exceeded the target of 98 appliances and included:

- 60 unflued room heaters (56%);
- 42 cooking stoves (40%); and
- 4 flued room heaters (4%).

Of the 70 Energy Saver Packages purchased, the most popular package was the "unflued room heater + cooking stove package" (34 customers), followed by the sole purchase of an unflued heater (26 customers) (see Figure FS02/3).

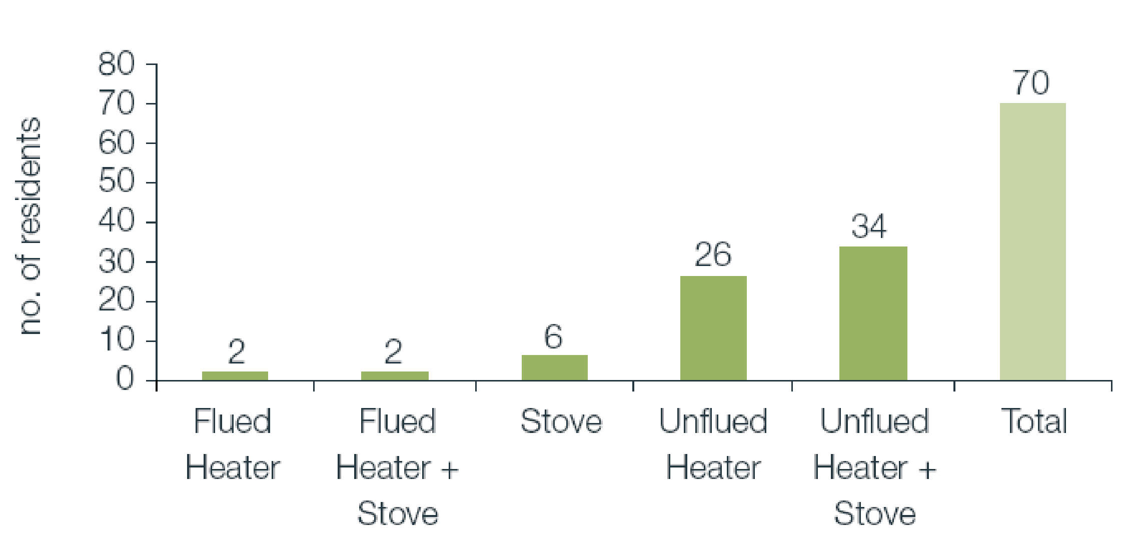


**Figure FS02/3. Type of Energy Saver Package Purchased**

Only 17 customers were already connected to a bottled gas supply with 53 customers requiring gas connection including slab, bottle delivery, piping and wiring.

A total of 106 electric heaters and stoves (64 room heaters and 42 cooking stoves) were removed and recycled at the metal recycling facility at Crookwell Waste and Recycling Centre.

In the week of the 19th to 23rd July 2004, 13 Energy Smart Home audits were conducted, as well as a further six visits to homes to assess suitability of gas appliances being installed if residents purchased an Energy Saver Package. Residents at 16 of the 19 properties visited purchased the Energy Saver Package offer.

Figure FS02/4 (page 223) shows the reduction in the peak load on the Crookwell to Grabine feeder after implementation of the Binda-Bigga Demand Management Project.

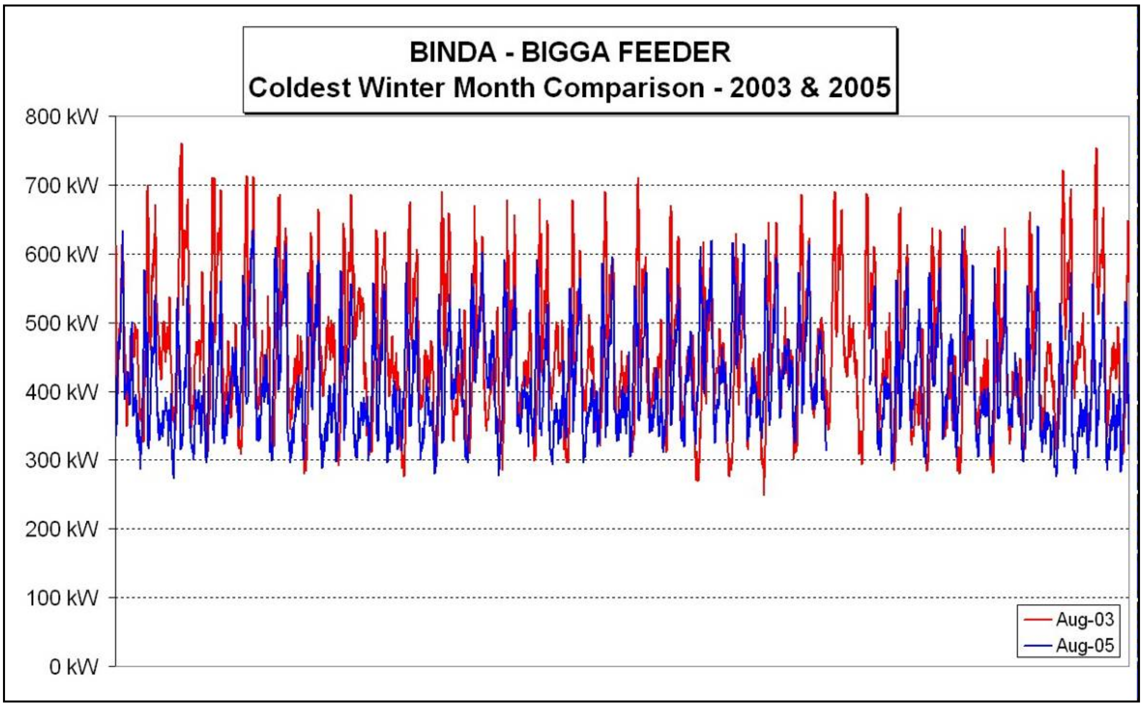


**Figure FS02/4. Load on the Crookwell to Grabine Feeder Before and After Implementation of the Bigga-Bigga DSM Project**

## CONFIDENCE LEVEL IN ACHIEVING RESULTS

## REPEATABILITY OF RESULTS

## TIME DELAY BEFORE MAXIMUM RESPONSE ACHIEVED

12 months

## WEATHER DEPENDENCE

## AVOIDED COSTS

The network augmentation solution to these problems was estimated to cost AUD 412,500 over a 5 year period.

The DSM budget was AUD 108,000 (average rate of $540/kVA reduced). This represents the cost savings of deferring the investment for five years.

## ACTUAL PROJECT COSTS

AUD 108,000 paid by Country Energy.

AUD 28,412 contribution by residents to cost of gas appliances.

## PROJECT COST FROM THE SOCIETAL PERSPECTIVE

## OVERALL PROJECT EFFECTIVENESS

Extremely high take-up rate for fuel substitution.

## CONTACTS

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## SOURCES

Department of Energy Utilities and Sustainability (2005). *Binda-Bigga Demand Management Project: Case Study*. Sydney, DEUS.

## CASE STUDY PREPARATION

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# FS03 PARADIP PORT SUBSTITUTION OF COOKING FUEL PROJECT - INDIA

| | |
|---|---|
| **Last updated** | 4 October 2008 |
| **Location of Project** | Paradip Port, on the Bay of Bengal in Orissa, India |
| **Year Project Implemented** | |
| **Year Project Completed** | |
| **Name of Project Proponent** | Paradip Port Trust |
| **Name of Project Implementor** | Paradip Port Trust |
| **Type of Project Implementor** | Bulk purchase customer of GRIDCO and supplier of electricity to end-users |
| **Purpose of Project** | Deferral of network augmentation |
| **Timing of Project** | Pre contingency |
| **Focus of Project** | Network capacity limitations |
| **Project Objective** | Peak load reduction |
| **Project Target** | Network element |
| **DSM Measure(s) Used** | Fuel substitution |
| **Specific Technology Used** | Substitution of LPG cooking stoves in place of electric stoves |
| **Market Segments Addressed** | Residential customers |

## DRIVERS FOR PROJECT

The Paradip Port Substitution of Cooking Fuel Project was initiated and funded by the Paradip Port Trust.

The Trust was set up by the Government of India to administer the port of Paradip, an autonomous body under the Major Port Trusts Act, 1963. The Trust purchases electricity in bulk from the Grid Corporation of Orissa Limited (GRIDCO) and then supplies electricity directly to its employees for household use. The Trust supplied electricity to its employees at a subsidised average flat rate of INR132 per month and had to bear an annual loss of around INR31 million.

The objective of the Paradip Port Substitution of Cooking Fuel Project was to reduce system peak demand by introducing LPG as a domestic cooking fuel through replacing electric stoves used by Trust employees. The project was targeted at cooking in the residential sector because this activity comprised approximately 60% of the electrical usage in each household. Almost 90% of the 3,592 households in the residential facility provided by the Trust used electric stoves for cooking, adding 3 to 4 MW to the electricity demand.

The maximum contract demand of Paradip Port under its supply contract with GRIDCO was 7.5 MVA. The peak demand often reached 9 to 10 MVA, resulting in penalty charges. The industrial load did not exceed 4 MVA at any point in time but the domestic use exceeded the contract quantity by 2 to 3 MVA during peak periods. Because electric stoves were the largest contributors to the peak demand, replacing these with LPG cooking stoves would result in considerable electricity and cost savings.

## DESCRIPTION OF PROJECT

The replacement package offered by the Paradip Port Trust included both stoves and LPG cylinders. An LPG cylinder bottling plant, with assured gas supplies from Paradip Port, was also established in the area to ensure an adequate supply of LPG cylinders.

The Trust offered its employees the following incentives to move from electric stoves to LPG stoves:

- 100% subsidy on purchase and installation of an LPG stove;
- 100% reimbursement of the cost of the LPG cylinder;
- reduction in the flat rate electricity tariff from INR132 to INR80 per month;
- a limit on electricity consumption under the flat rate tariff fixed at 108 kilowatt-hours per month; consumption above this limit to be charged at the full price of INR3.37 per kilowatt-hour.

As the two-part tariff was introduced, meters were installed to monitor the electricity consumption by individual households and enable accurate charging for electricity consumption.

The Paradip Port Trust was the main stakeholder responsible for the financing, procurement, implementation and monitoring of the project. The housing department of the Trust was responsible for the entire project. The major investment in the project was the procurement and installation of the LPG stoves and electric meters in individual households. T he entire cost was born by the Trust and was recovered through electricity and cost savings.

The end-users in this project were employees of the Trust and thus directly connected to the project implementor. Therefore, it was relatively easy for the Trust to create awareness, and market and control the project. The Trust motivated the end-users in the stove replacement project through various awareness programs.

## RESULTS

| Residential Customers Participating | Commercial and Small Industrial Customers Participating | Agricultural Customers Participating | Large Industrial Customers Participating | Additional Generation Installed |
|---|---|---|---|---|
| 2,874 | | | | |

| Peak Load | Peak Load Reduction | Duration of Peak Load Reduction | Overall Load Reduction | Energy Savings | Network Augmentation Deferral |
|---|---|---|---|---|---|
| | 3.2 MW | | | | |

## HOW LOAD REDUCTION WAS MEASURED

## RESULTS ACHIEVED

The Paradip Port Trust replaced a total of 2,874 electric cooking stoves with LPG stoves. The morning peak was reduced by 2.3 MW and the evening peak by 3.2 MW. The project resulted in ongoing annual savings to the Trust of INR15 million.

## CONFIDENCE LEVEL IN ACHIEVING RESULTS

## REPEATABILITY OF RESULTS

## TIME DELAY BEFORE MAXIMUM RESPONSE ACHIEVED

## WEATHER DEPENDENCE

## AVOIDED COSTS

## ACTUAL PROJECT COSTS

The total implementation cost for the Paradip Port Substitution of Cooking Fuel Project was INR19.7 million. A detailed breakdown of the implementation cost is shown in Table FS03/1. The additional cost of running the project was identified as INR200,000 per year.

**Table FS03/1. Implementation Costs for the Paradip Port Substitution of Cooking Fuel Project**

| Expenditure Item | Cost (INR) |
|---|---|
| LPG gas stoves for 2,874 houses | 3.4 million |
| Enrolment fees for 2,874 houses | 2.9 million |
| Fire resistant panels in huts | 1.3 million |
| Fire extinguishers for huts | 1.0 million |
| Security cages and pipes for LPG cylinders | 1.0 million |
| Electricity meters for 2,874 houses | 9.0 million |
| Publicity and safety training | 1.1 million |
| **Total implementation cost** | **19.7 million** |

The entire cost was born by the Trust and was recovered through electricity and cost savings.

## PROJECT COST FROM THE SOCIETAL PERSPECTIVE

## OVERALL PROJECT EFFECTIVENESS

The project was successful in replacing a total of 2,874 electric cooking stoves with LPG stoves. The morning peak was reduced by 2.3 MW and the evening peak by 3.2 MW. The project resulted in ongoing annual savings to the Paradip Port Trust of INR15 million.

## CONTACTS

## SOURCES

## CASE STUDY PREPARATION

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# IL01 LOAD INTERRUPTION CONTRACT - SPAIN

| | |
|---|---|
| **Last updated** | 27 October 2006 |
| **Location of Project** | Spain |
| **Year Project Implemented** | 1983 |
| **Year Project Completed** | |
| **Name of Project Proponent** | Red Eléctrica de España, S.A. (REE) |
| **Name of Project Implementor** | Red Eléctrica de España, S.A. (REE) |
| **Type of Project Implementor** | Transmission utility |
| **Purpose of Project** | Provision of network operational services |
| **Timing of Project** | Pre contingency |
| **Focus of Project** | Network capacity limitations<br>Generation capacity limitations |
| **Project Objective** | Peak load reduction |
| **Project Target** | Whole network |
| **DSM Measure(s) Used** | Interruptible loads<br>Pricing initiatives |
| **Specific Technology Used** | |
| **Market Segments Addressed** | Large industrial customers |

## DRIVERS FOR PROJECT

The Load Interruption Contract was conceived to provide a demand-side mechanism for large industrial customers. However, until now, it has only been applied as an operational service.

## DESCRIPTION OF PROJECT

The Load Interruption Contract is an agreement through which large customers receive a discount on their electricity bills in return for being available to reduce their consumption on request from the System Operator.

The transmission system operator (REE) is responsible for issuing, controlling and supervising all interruption orders. Customers participating in the Load Interruption Contract will must submit to REE monthly schedules for hourly energy demand and maintenance planning.

Only customers with a specific high voltage tariff contract or with an Hourly Power Tariff contract can participate in a Load Interruption Contract. They include iron, steel and other metal industries, cement and chemical industries, airports, etc.

Customers participating in the Load Interruption Contract will must submit to REE monthly schedules for hourly energy demand and maintenance planning.

There are four types of interruptions possible under the Load Interruption Contract depending on the interruption duration and the warning time:

- Type A. Maximum interruption time: 12 hours Minimum warning time:16 hours
- Type B. Maximum interruption time: 6 hours Minimum warning time: 6 hours
- Type C. Maximum interruption time: 3 hours Minimum warning time: 1 hour
- Type D. Maximum interruption time: 45 minutes Minimum warning time: 5 minutes

Under the Load Interruption Contract, the maximum number of interruptions that can be requested by the System Operator are as follows:
1 per day (12 hours maximum per day)
5 per week (60 hours per week)
120 hours per month
240 hours per year.

Customers are permitted to refuse up to three interruption orders per year. If they have more than three refusals, customers are compelled to return the discount already invoiced which can comprise a large amount of money.

The Load Interruption Contract includes the following provisions:

- Tariff: Hourly Power Tariff or High Voltage General Power Tariff;
- Billing mode;
- Contracted demand level for each period in MW (Pc);
- Maximum demand level during interruption in MW (Pmaxi);
- Interruptible load offered in MW (Pof); this is the difference between the contracted demand level for each period (Pc) and the maximum demand level during the interruption (Pmaxi);
- Hourly discrimination mode;
- Interruption types chosen;
- Following year energy consumption forecast;
- Discount: this is an annual discount expressed as a percentage of the total electricity bill invoiced monthly, and is proportional to the base consumption and the interruptible load offered.

For example, a customer with 5,400 MW of contracted power, all of it interruptible (ie zero consumption during the interruption period) may receive a discount of EUR 433,658:

**Electricity cost without any discounts:** EUR 1,717,798
**Interruptibility discount :** EUR 433,658
**Total annual bill:** EUR 1,284,140

Note that this is a rough estimate only of the amounts payable; in practice the discount may be a different figure because there is uncertainty in calculating the discount. It is calculated as the difference between the same tariffs with and without discount and this is not a realistic hypothesis. If customers had no discounts available on their bills, they would probably select another kind of tariff.

## RESULTS

| Residential Customers Participating | Commercial and Small Industrial Customers Participating | Agricultural Customers Participating | Large Industrial Customers Participating | Additional Generation Installed |
|---|---|---|---|---|
| | | | 84 | |

| Peak Load | Peak Load Reduction | Duration of Peak Load Reduction | Overall Load Reduction | Energy Savings | Network Augmentation Deferral |
|---|---|---|---|---|---|
| 38,067 MW | 1,274 MW | 3 hours | 1,272 MW | 3816 MWh | |

## HOW LOAD REDUCTION WAS MEASURED

Interval meter. 5 minute intervals.

## RESULTS ACHIEVED

In 2005, 187 customers opted for the Load Interruption Contract. The total interruptible load offered by these customers under the Load Interruption Contract was 4,656 MW in high season. However, the system operator considered that the interruptible power available in real time was 80 % of that amount (3,700 MW). Maximum interruptible power is calculated from contracted power data, but customers are not usually consuming the contracted power in peak periods, when interruptible capacity may be required by the operator.

An interruption order was sent by the System Operator on 21 June 2005. The order to interrupt load was sent to 97 clients and 84 (87%) responded by reducing load. The Type C interruption order was sent at 10:15 am and the interruption period went from 11:15 am to 2:15 pm. The load reduction achieved through this interruption was 1,274 MW and the energy saving was 3,816 MWh (see Figure IL01/1, page 232).

## CONFIDENCE LEVEL IN ACHIEVING RESULTS

The overall confidence level regarding achieved results may be considered to be high. However, responses from contracted customers are not assured as they are permitted to refuse up to three interruption orders per year. Another factor which reduces the confidence level is the possibility of failure of the communication system. When the interruption order was sent on 21 June 2005, four customers' communication systems failed (4%) and they did not receive the load interruption order.

## REPEATABILITY OF RESULTS

On 21 June 2005, the Load Interruption Contract was applied fairly well and system load was significantly reduced.

## TIME DELAY BEFORE MAXIMUM RESPONSE ACHIEVED

Depends on the warning time which can be 16 hours, 6 hours, 1 hour or 5 minutes.

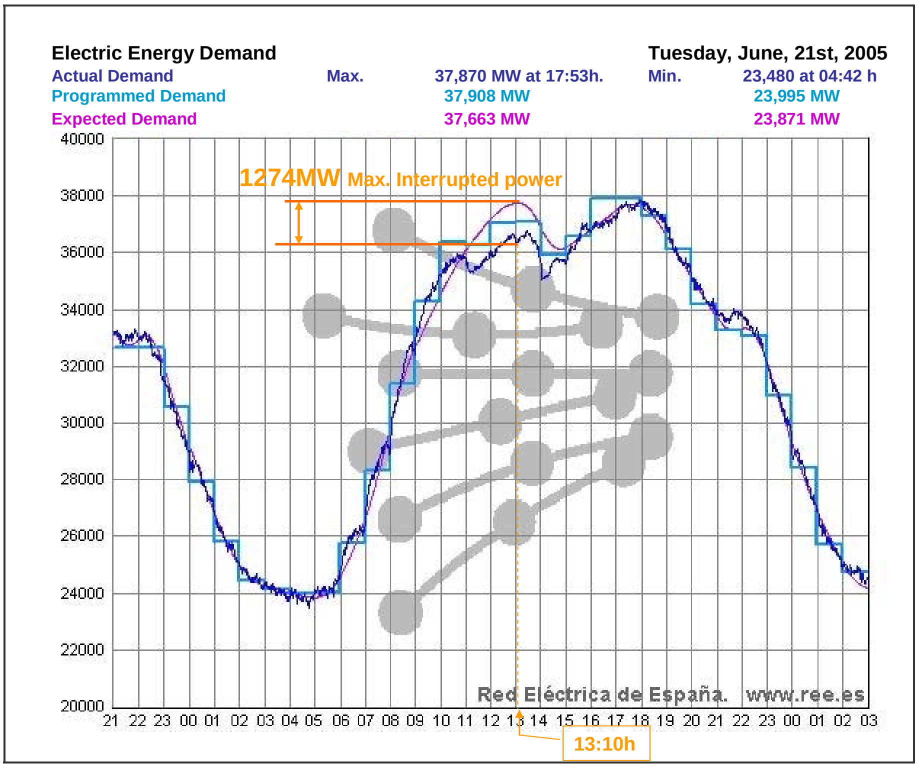


**Figure IL01/1. Load Reduction Achieved through the Load Interruption Contract, 21 June 2005**

## WEATHER DEPENDENCE

Not applicable, except to the extent that customers' load levels are dependent on temperature.

## AVOIDED COSTS

On 21 June 2005, the weighted average marginal price of energy was EUR 80/MWh. REE estimated that the load interruption order achieved an energy saving of 3,816 MWh which resulted in a cost saving of EUR 305,280 for the system. However, this was not an accurate figure, as there were many factors affecting the price and there was uncertainty because REE did not know not know exactly what the energy consumption would have been without the load interruption order.

## ACTUAL PROJECT COSTS

There are no costs for REE. Discounts to customers under the Load Interruption Contract are paid by all customers through the tariff as an operational cost.

## PROJECT COST FROM THE SOCIETAL PERSPECTIVE

## OVERALL PROJECT EFFECTIVENESS

Prior to 2006, because of a lack of information about large industrial customers' load levels in real time, the Load Interruption Contract was not an accurate mechanism as an operational service for reducing load. The System Operator sent an order "blindly" without knowing the actual electricity consumption at that time by the customers under contract.

In real time, when interruption orders are sent to customers, they reduce their consumption to the level agreed in their contracts, at the time the interruption begins. However, the actual load reduction achieved on the transmission network depends on the customers' load levels just before the interruption begins. That information was not available to the System Operator at that time, and was provided by the customers only when the interruption is finished.

A new communication, execution and control system between the System Operator and large industrial customers for interruptible orders was implemented in 2006. This system provides data on customers' loads at the time of interruption and gives the System Operator more confidence about achieving specific levels of load reduction from the Load Interruption Contract.

## CONTACTS

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## SOURCES

Ministerial Decree January 12th 1995
REE Interruption Reports

## CASE STUDY PREPARATION

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# IL02 FLEXIBLE LOAD INTERRUPTION CONTRACT - SPAIN

| | |
|---|---|
| **Last updated** | 27 October 2006 |
| **Location of Project** | Spain |
| **Year Project Implemented** | 2004 |
| **Year Project Completed** | |
| **Name of Project Proponent** | Red Eléctrica de España, S.A. (REE) |
| **Name of Project Implementor** | Red Eléctrica de España, S.A. (REE) |
| **Type of Project Implementor** | Transmission utility |
| **Purpose of Project** | Provision of network operational services |
| **Timing of Project** | Pre contingency |
| **Focus of Project** | Generation capacity limitations |
| **Project Objective** | Peak load reduction |
| **Project Target** | Whole network |
| **DSM Measure(s) Used** | Interruptible loads |
| **Specific Technology Used** | |
| **Market Segments Addressed** | Large industrial customers |

## DRIVERS FOR PROJECT

The Flexible Load Interruption Contract is an extension of the basic Load Interruption Contract described in Case Study IL01, page 229. Under the basic Load Interruption Contract, Type A and B interruptions have minimum warning times of 16 hours and 6 hours respectively. Because these are long time periods, system load may have changed between the time the interruption order is sent and when the order is executed. Consequently, the load reduction needed by the System Operator may be different.

Another problem with Type A and B interruptions is that the interruption times of 12 hours and 6 hours respectively are too long. Interruption orders are sent when the system is stressed and is not able to withstand any contingency. That happens only during peak hours which last up to three hours at the most. Consequently, the long interruption times in Type A and B interruptions have been required only a few times by the System Operator.

Since 2002, a new Interruption Flexible Management Program has been developed by the transmission system operator (REE) in collaboration with large industrial consumers. This program, consisting of new modes for Type A and B interruptions, allows customers to reduce their consumption following a specific profile, more appropriate to the real profile of the system load.

## DESCRIPTION OF PROJECT

The Flexible Load Interruption Contract will be implemented once a new communication, control and measurement system is completed. This system will increase the real-time load and technical information available to both customers and the System Operator and therefore enable further collaboration and development of demand response potential, prediction and certainty.

The transmission system operator (REE) is responsible for issuing, controlling and supervising all interruption orders. Customers participating in the Flexible Load Interruption Contract will must submit to REE monthly schedules for hourly energy demand and maintenance planning.

The basic Load Interruption Contract contains the following provisions:

- Contracted demand level for each period in MW (Pc);
- Maximum consumption during interruption in MW (Pmaxi);
- Interruptible load offered in MW (Pof); this is the difference between the contracted demand level for each period (Pc) and the maximum demand level during the interruption (Pmaxi).

Under the Flexible Load Interruption Contract, the interruption times for Type A and B interruptions will be divided into three periods (see Figure IL02/1). Customer's electricity consumption may be different during these three periods. Customers will have to reduce their loads to the maximum demand level (Pmaxi) during one of the three periods, to half the demand reduction offered (Pof) during another period, and the rest of the time they can maintain their load at the demand level specified in their supply contracts (Pc).

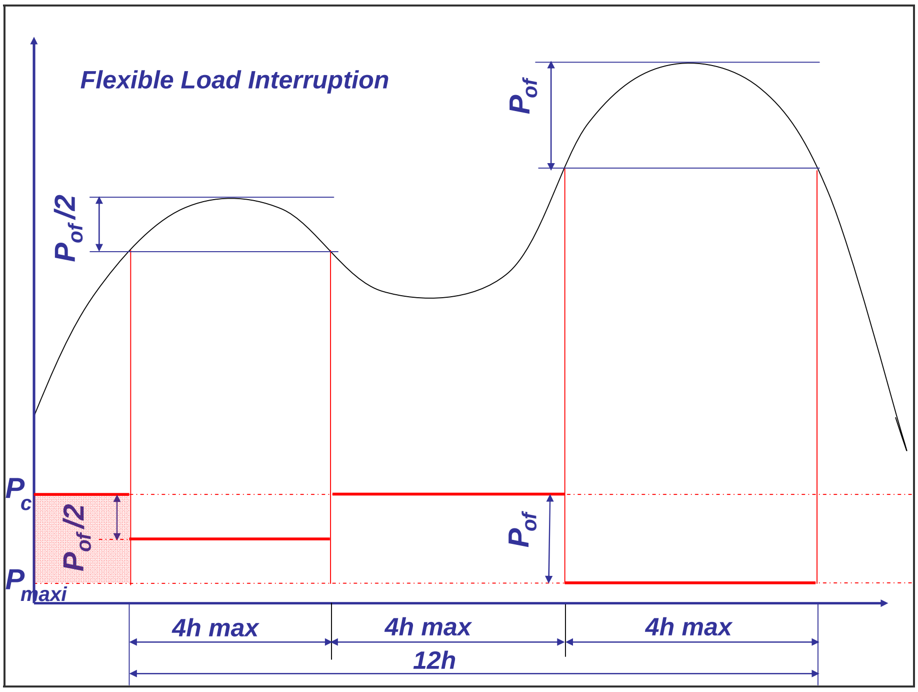


**Figure IL02/1. Interruption Periods under the Flexible Load Interruption Contract**

The timing of, and interruption time during, the three periods will be determined by REE, depending on the type of interruption:

- Type A Interruption: maximum 4 hours at Pmaxi; maximum 4 hours at 50% of Pof; during the remaining time, the customer's load may be increased up to the contracted demand level (Pc);
- Type B Interruption: maximum 3 hours at Pmaxi; maximum 3 hours at 50% of Pof; during the remaining time, the customer's load may be increased up to the contracted demand level (Pc).

Under the Flexible Load Interruption Contract, warning times will remain the same as for the basic Load Interruption Contract, ie 16 hours warning time for Type A interruptions and 6 hours for Type B. REE will have to specify the power profile for the whole requested interruption with 2 hours' notice before the interruption is executed. However, REE is considering inserting a provision into the contract that orders to reduce load to Pmaxi may be sent with only one hour's notice.

As with the basic Load Interruption Contract, the maximum number of interruptions that can be requested by the System Operator are as follows:
1 per day (12 hours maximum per day)
5 per week (60 hours per week)
120 hours per month
240 hours per year.

## RESULTS

| Residential Customers Participating | Commercial and Small Industrial Customers Participating | Agricultural Customers Participating | Large Industrial Customers Participating | Additional Generation Installed |
|---|---|---|---|---|
| | | | | |

| Peak Load | Peak Load Reduction | Duration of Peak Load Reduction | Overall Load Reduction | Energy Savings | Network Augmentation Deferral |
|---|---|---|---|---|---|
| | | | | | |

## HOW LOAD REDUCTION WAS MEASURED

Interval meter. 5 minute intervals.

## RESULTS ACHIEVED

Information available on interruptible loads for Type A and B interruptions shows that the total interruption capacity for both types is over 4600 MW. This power is available in high season from 8 am to 4 pm and from 10 pm to midnight.

As at June 2005, the Flexible Load Interruption Contract has never been implemented, due to the existing inappropriate communication, execution and control system. It is proposed to have all new equipment installed and verified by the end of July 2005.

It is expected that almost all customers who already have Load Interruption Contracts will apply for Flexible Load Interruption Contracts.

## CONFIDENCE LEVEL IN ACHIEVING RESULTS

The overall confidence level regarding achieved results is likely to be higher than with the basic Load Interruption Contract. While customers will still be permitted to refuse up to three interruption orders per year, the probability of failure of the communication system will be lower.

## REPEATABILITY OF RESULTS

## TIME DELAY BEFORE MAXIMUM RESPONSE ACHIEVED

Two hours.

## WEATHER DEPENDENCE

## AVOIDED COSTS

## ACTUAL PROJECT COSTS

There will be no costs for REE. Discounts to customers under the Flexible Load Interruption Contract will be the same as under the basic Load Interruption Contract and will continue to be paid by all customers through the tariff as an operational cost.

## PROJECT COST FROM THE SOCIETAL PERSPECTIVE

## OVERALL PROJECT EFFECTIVENESS

The Flexible Load Interruption Contract is likely to be more effective than the basic Load Interruption Contract. Because the Flexible Load Interruption Contract will only be implemented once a new communication, control and measurement system is completed, the System Operator will be able to send an interruption order with full knowledge of the actual electricity consumption at that time by the customers under contract.

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## SOURCES

Spanish Royal Decree 1802/2003
Ministerial Resolution of July, 28th, 2004

## CASE STUDY PREPARATION

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# IL03 INTERRUPTIBILITY CONTRACT FOR COGENERATORS - SPAIN

| | |
|---|---|
| **Last updated** | 27 October 2006 |
| **Location of Project** | Spain |
| **Year Project Implemented** | Not yet implemented |
| **Year Project Completed** | |
| **Name of Project Proponent** | Red Eléctrica de España, S.A. (REE) |
| **Name of Project Implementor** | Red Eléctrica de España, S.A. (REE) |
| **Type of Project Implementor** | Transmission utility |
| **Purpose of Project** | Provision of network operational services |
| **Timing of Project** | Pre contingency |
| **Focus of Project** | Network capacity limitations<br>Generation capacity limitations |
| **Project Objective** | Increasing operating reserve<br>Peak load reduction |
| **Project Target** | Whole network |
| **DSM Measure(s) Used** | Cogeneration<br>Interruptible loads |
| **Specific Technology Used** | |
| **Market Segments Addressed** | Large industrial customers |

## DRIVERS FOR PROJECT

Red Eléctrica de España (REE) has recently proposed opening interruptibility contracts to cogenerators. This will provide the System Operator with access to both a load reduction and an increase in generation capacity under one contract when the electricity network is under stress.

## DESCRIPTION OF PROJECT

Participation in interruptibility contracts will be available to cogenerators both as consumers and as generators. As consumers, only those cogeneration plants which do not already have a load interruption contract will be allowed to participate in an interruptibility contract. As producers, cogeneration plants participating in an interruptibility contract will have to be able to reduce their electricity consumption and contribute all their generated capacity to the system.

It will be mandatory for cogeneration plants participating in an interruptibility contract to sign only one contract for both sides, as a consumer and as a producer.

As with other load interruption contracts, it will be the System Operator, responsible for the security of supply, who has to determine the load reduction and generation capacity contributions to the system by cogenerators participating in interruptibility contracts. There will be a maximum number of interruptions permitted per year.

## RESULTS

| Residential Customers Participating | Commercial and Small Industrial Customers Participating | Agricultural Customers Participating | Large Industrial Customers Participating | Additional Generation Installed |
|---|---|---|---|---|
| | | | | |

| Peak Load | Peak Load Reduction | Duration of Peak Load Reduction | Overall Load Reduction | Energy Savings | Network Augmentation Deferral |
|---|---|---|---|---|---|
| | | | | | |

## HOW LOAD REDUCTION WAS MEASURED

## RESULTS ACHIEVED

As at September 2006, the proposed interruptibility contract for cogenerators has not yet been implemented. The main reason for this is that most of the big cogeneration plants installed in Spain have an associated production process which is already interruptible as a consumer. There is a large amount of installed capacity in the distribution network but it is not useful for the operation of the system as the operator does not have access to generation data for cogeneration plants in real time.

An interruptibility contract for a cogenerator will not be implemented until a communication and metering system is established between the System Operator and the cogeneration plant.

## CONFIDENCE LEVEL IN ACHIEVING RESULTS

## REPEATABILITY OF RESULTS

Repeatability of results will depend on the reliability of the communication system as well as on the cogenerators' responses so it is difficult to evaluate this aspect.

## TIME DELAY BEFORE MAXIMUM RESPONSE ACHIEVED

## WEATHER DEPENDENCE

## AVOIDED COSTS

## ACTUAL PROJECT COSTS

This mechanism is considered as an operational service that has to be managed by the System Operator. Consequently, the load reduction and generation capacity contributions made by the cogeneration plant must be integrated as a system operational cost at the time the service is rendered.

## PROJECT COST FROM THE SOCIETAL PERSPECTIVE

## OVERALL PROJECT EFFECTIVENESS

## CONTACTS

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## SOURCES

## CASE STUDY PREPARATION

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# IL04 ACTIVE / REACTIVE POWER EXCHANGE - SPAIN

| | |
|---|---|
| **Last updated** | 23 September 2005 |
| **Location of Project** | Spain |
| **Year Project Implemented** | 2002 |
| **Year Project Completed** | |
| **Name of Project Proponent** | Red Eléctrica de España, S.A. (REE) |
| **Name of Project Implementor** | Red Eléctrica de España, S.A. (REE) |
| **Type of Project Implementor** | Transmission utility |
| **Purpose of Project** | Provision of network operational services |
| **Timing of Project** | Pre contingency |
| **Focus of Project** | Generation capacity limitations<br>Voltage fluctuations |
| **Project Objective** | Peak load reduction<br>Voltage regulation |
| **Project Target** | Whole network |
| **DSM Measure(s) Used** | Interruptible loads |
| **Specific Technology Used** | |
| **Market Segments Addressed** | Large industrial customers |

## DRIVERS FOR PROJECT

The objective of Active / Reactive Power Exchange is to provide a mechanism to enable the System Operator to control reactive power in zones where reactive power imbalances are likely.

## DESCRIPTION OF PROJECT

Active / Reactive Power Exchange is designed for customers who already participate in Load Interruption Contracts as described in Case Study IL01, page 229. These customers may be given a partial exemption from reducing their loads during an interruption event if they increase the reactive power they inject into the network to at least three times the active power they are consuming.

## RESULTS

| Residential Customers Participating | Commercial and Small Industrial Customers Participating | Agricultural Customers Participating | Large Industrial Customers Participating | Additional Generation Installed |
|---|---|---|---|---|
| | | | 3 | |

| Peak Load | Peak Load Reduction | Duration of Peak Load Reduction | Overall Load Reduction | Energy Savings | Network Augmentation Deferral |
|---|---|---|---|---|---|
| 33,800 MW | 148 MW | 2 hours | 148 MW | 296 MWh | |

## HOW LOAD REDUCTION WAS MEASURED

Interval meter. 5 minute intervals.

## RESULTS ACHIEVED

On 12 Jun 2003 a Load Interruption Order was sent to 26 customers from the southern region of Spain. The interruption requested by the System Operator was a Type C (1 hour warning time and 3 hour interruption time from 12:15 pm to 3:15 pm).

After the Interruption Order was sent, the System Operator sent another specific order by fax to three customers offering them a partial exemption from reducing load if they injected reactive power into the system. These customers committed to inject as much reactive power as they could into the network.

**Customer 1:** Committed to reduce load by only 30 MW and in return put into operation their 150MVAr capacitor battery. This client managed to achieve the agreement.

**Customer 2:** Committed to a minimum load reduction and to put into operation their 40MVAr capacitor battery. Unfortunately there is no metering of this client so there is no information about whether or not they achieved their commitment.

**Customer 3:** Committed to put into operation their 24MVAr capacitor batteries.

Figure IL04/1 shows the system load curve on the day of this interruption event. During the peak load hours, the total load reduction was 302.678 MW. At the same time 150+40+24 MVAr were injected to the network which is equivalent to another 60MW reduction. So, instead of a system load reduction of 362.678MW, the load reduction was 302.678MW and 214MVAr were injected to the network.

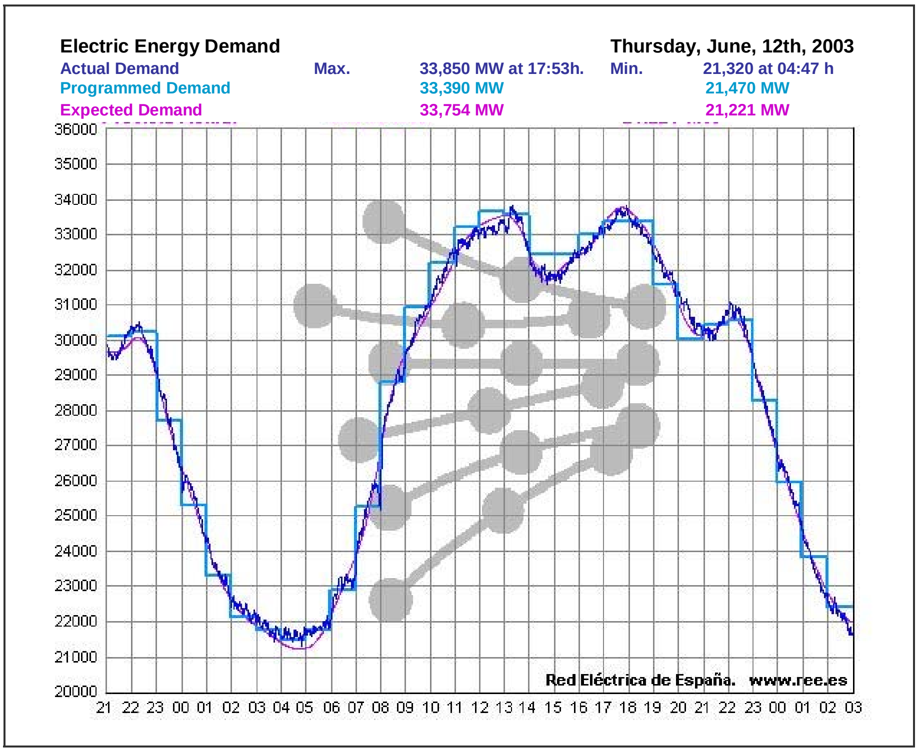


**Figure IL04/1. System Load Curve on the Day of an Interruption Event, 12 June 2003**

## CONFIDENCE LEVEL IN ACHIEVING RESULTS

High. The results achieved can usually be followed in real-time by the System Operator because most of the customers participating in Active / Reactive Power Exchange are large industrial consumers directly connected to the 400kV network, so the SO has real-time measures of their active/reactive consumption/generation.

However, the ability of customers to inject reactive power into the network instead of reducing their loads by as much as specified in their contracts depends on both the state of the system and the customers' production needs. At the time the order is sent, the System Operator and the customer have to agree on whether they prefer active power reduction or reactive power increase.

## REPEATABILITY OF RESULTS

High.

## TIME DELAY BEFORE MAXIMUM RESPONSE ACHIEVED

1 hour.

## WEATHER DEPENDENCE

## AVOIDED COSTS

## ACTUAL PROJECT COSTS

## PROJECT COST FROM THE SOCIETAL PERSPECTIVE

## OVERALL PROJECT EFFECTIVENESS

## CONTACTS

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## SOURCES

Interruption Reports from 12 Jun 2003

31 Oct 2002 Resolution from the Energy Secretary. Operational Procedure 6.1

## CASE STUDY PREPARATION

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# IL05 CALIFORNIA ENERGY COOPERATIVES - USA

| | |
|---|---|
| **Last updated** | 26 August 2005 |
| **Location of Project** | San Francisco, USA (currently) |
| **Year Project Implemented** | The Energy Coalition was formed in 1981 and is still continuing |
| **Year Project Completed** | |
| **Name of Project Proponent** | The Energy Coalition |
| **Name of Project Implementor** | The Energy Coalition |
| **Type of Project Implementor** | Third party aggregator |
| **Purpose of Project** | Provision of network operational services |
| **Timing of Project** | Pre contingency |
| **Focus of Project** | Network capacity limitations |
| **Project Objective** | Peak load reduction |
| **Project Target** | Network region |
| **DSM Measure(s) Used** | Interruptible loads |
| **Specific Technology Used** | |
| **Market Segments Addressed** | Commercial and small industrial customers<br>Large industrial customers |

## DRIVERS FOR PROJECT

The Energy Coalition is a non-profit organisation that was originally formed in 1981 to pool together major end-users into 'energy cooperatives'. Members of these cooperatives worked together to provide load management services to electricity utilities.

The Energy Coalition coordinated the energy use of large commercial and industrial customers and brokered this service to Southern California Edison and other utilities. The Coalition was created by and for large commercial and industrial energy users who wanted to act responsibly to shed load at times of utility capacity constraints through sophisticated management of their facilities. By coordinating their efforts, these users could respond collectively with a high degree of individual flexibility and reliability to calls by the utility to shed load.

When the Energy Coalition was originally established, there was a shortage of generation and network capacity in southern California. During the late 1980s, the situation changed from a shortage to an excess of capacity and in the 1990s interest in the original energy cooperatives faded away. However, interest was revived during the California energy crisis in the early 2000s.

## DESCRIPTION OF PROJECT

### Original Energy Cooperatives Program

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 was originally formally registered – was developed in 1981 when Southern California Edison sought John Phillips' expertise to develop energy cooperatives in Orange County. The Energy Coalition became the facilitator of the energy cooperatives process and worked with large users to develop load-shedding strategies that were sensitive to times of day, times of year, and special processes.

The Energy Coalition 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 worked together to shed loads at critical peak times when called upon by their serving utilities. Each member was 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 used ‘smart’ load management strategies with the least impact on participants. This allowed for customer control and flexibility in load curtailment. For example a cooperative member who undertook critical energy-using processes that would otherwise prohibit them from participating in load curtailment programs could participate in an energy cooperative because, when necessary, their contribution could be provided by another member.

Energy cooperatives were based on computer networks which continuously monitored the individual and collective energy use and load reductions of large users and provided a system for dispatching load reduction capacity. A central computer located at the cooperative's headquarters linked each member of the cooperative to the utility control centre. When the utility requested a load curtailment, the central system evaluated the proportionate load reduction required from each cooperative member to fulfil the utility's requirement. The load reduction ‘game plan’ (or strategy) was then defined, and each member was advised of their respective targets. The central system monitored each member’s load reduction path to assure compliance. If a particular member could not meet their target, the system automatically reallocated that load reduction to other members based on pre-existing priority agreements. In this way, the energy cooperative met its load reduction obligations expediently and with minimal impact on its members.

During a load curtailment, the utility had no information about which cooperative members were providing what levels of load reductions. It was 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 could not 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 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.

## Business Energy Coalition Pilot Program

After the decline of interest in energy cooperatives in the 1990s, interest was revived during the California energy crisis in the early 2000s, particularly as a method of providing short-term network operational services.

The Business Energy Coalition Pilot Program is an initiative between Pacific Gas & Electric (PG&E) and major San Francisco business and civic leaders, facilitated by The Energy Coalition, to demonstrate group load curtailment of 10 MW from the group's coincident peak demand. The one-year test project will recruit San Francisco's 200 biggest energy users, representing 304 MW of demand.

The pilot program is operating from 1 July through 31 December 2005. If it is successful, the Business Energy Coalition will seek California Public Utilities Commission authorization for long-term agreements.

The pilot program incorporates Day-Ahead and Same-Day program objectives. Group curtailment will be triggered to alleviate state, regional, local or feeder-level electricity network constraints.

### *Eligibility*

PG&E's Bundled, Direct Access, and Wholesale customers within the City of San Francisco are eligible to participate in the pilot program. Participants must be able to reduce their demand by a minimum of 200 kW. Customers with a blend of cogeneration and utility services or customers participating in demand response programs will be evaluated on a case-by-case basis. Customers with cogeneration will be eligible based on their utility demand. Non-Firm and Base Interruptible Program customers are not eligible to participate. Standby or back-up generators cannot contribute to demand savings during a program event.

### *Methodology*

An engineering assessment provided and paid for by The Energy Coalition, will be conducted at each participant's facility to identify load that can be curtailed during program events. An engineer will meet with facility operating personnel and help them develop a series of load-shedding protocols, all of which will be tested on a non-critical day.

The evaluation will also determine each member's Firm Service Level (FSL). During a program event, each member will reduce its load to the prescribed Firm Service Level. The load reduction will be the delta between each facility's annual average peak demand for the three previous years and the Firm Service Level.

### *Verification and System Tests*

In late June 2005, the Business Energy Coalition conducted a system test to assure program delivery. If there are no actual curtailments, two-hour tests will be conducted every other month throughout the pilot program period.

### *Notification Time*

Business Energy Coalition members will be given as much advance notice as possible ranging from Day-Ahead to a minimum of an Hour-Ahead. Customers will be notified by pager, email, fax, and phone.

### *Curtailment Frequency Limits*

Maximum frequencies:

- Five hours per program event; one program event per day
- Five program events per month; twenty-five hours per month
- One hundred hours throughout the pilot period

### *Curtailment Window*

12 pm – 8 pm, Monday – Friday, excluding holidays.

### *Incentive Payments*

Each member will receive a capacity payment of $50/kW annually. A payment of 50% will be provided at the end of October 2005, with the balance distributed in January 2006. The average payment for curtailment will be USD 85 per kilowatt-hour.

### *Non-Performance*

Penalties are assessed on the group's load curtailment level rather than individual performance. If the group fails to meet the group's established FSL, the group will draw from its Shortfall Reserve Fund (supported with an additional USD25/kW) to pay Independent System Operator charges and imbalance penalties. Any outstanding balance in the Shortfall Reserve Fund will be proportionately distributed to members at the completion of the pilot program or carried over for an extended program.

### *Triggers*

The program will be triggered for actual or forecasted statewide, regional Northern California, Area 1, or local circuit congestion, failures and shortages throughout the pilot program period. Specifically, the Business Energy Coalition's group load curtailment may be triggered when any of the following occur:

- California Independent System Operator calls a Stage 2 emergency
- California Independent System Operator declares that PG&E's spinning reserves are below 7%
- Forecasted or actual San Francisco temperatures exceeds 78 degrees Fahrenheit
- PG&E declares a localized system emergency
- California Independent System Operator's total forecasted load is greater than 43,000 MW

## RESULTS

| Residential Customers Participating | Commercial and Small Industrial Customers Participating | Agricultural Customers Participating | Large Industrial Customers Participating | Additional Generation Installed |
|---|---|---|---|---|
| | | | | |

| Peak Load | Peak Load Reduction | Duration of Peak Load Reduction | Overall Load Reduction | Energy Savings | Network Augmentation Deferral |
|---|---|---|---|---|---|
| | | | | | |

## HOW LOAD REDUCTION WAS MEASURED

## RESULTS ACHIEVED

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.

## CONFIDENCE LEVEL IN ACHIEVING RESULTS

## REPEATABILITY OF RESULTS

## TIME DELAY BEFORE MAXIMUM RESPONSE ACHIEVED

## WEATHER DEPENDENCE

## AVOIDED COSTS

## ACTUAL PROJECT COSTS

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).

## PROJECT COST FROM THE SOCIETAL PERSPECTIVE

## OVERALL PROJECT EFFECTIVENESS

## CONTACTS

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## SOURCES

The Energy Coalition web site at: http://www.energycoalition.org

The Results Center (1992). *California Energy Coalition Energy Cooperatives: Profile #9.* Available at: http://sol.crest.org/efficiency/irt/9.pdf

## CASE STUDY PREPARATION

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# IP01 BLACKTOWN DSM PROGRAM - AUSTRALIA

| | |
|---|---|
| **Last updated** | 13 September 2005 |
| **Location of Project** | Blacktown and Seven Hills areas of western Sydney, Australia |
| **Year Project Implemented** | 2004 |
| **Year Project Completed** | 2007 |
| **Name of Project Proponent** | Integral Energy |
| **Name of Project Implementor** | Big Switch Projects / Energy Conservation Systems |
| **Type of Project Implementor** | ESCO |
| **Purpose of Project** | Deferral of network augmentation |
| **Timing of Project** | Pre contingency |
| **Focus of Project** | Network capacity limitations |
| **Project Objective** | Peak load reduction |
| **Project Target** | Network region |
| **DSM Measure(s) Used** | Standby generation<br>Cogeneration<br>Direct load control<br>Energy efficiency<br>Power factor correction |
| **Specific Technology Used** | Integrated project using a range of technologies |
| **Market Segments Addressed** | Commercial and small industrial customers |

## DRIVERS FOR PROJECT

Integral Energy is seeking to defer defer AUD 3 million capital expenditure to upgrade a zone substation at Leabons Lane in Blacktown. The substation comes under pressure during hot weekdays due to heavy air-conditioning loads, but for most of the year operates under capacity.

## DESCRIPTION OF PROJECT

The program was publicly advertised by Integral Energy via a Request for Proposals (RFP). Proponents were evaluated and selected on the basis of process, experience, knowledge and cost effectiveness.

Two ESCOs were engaged by Integral Energy to identify demand reduction initiatives within the Blacktown area. Integral Energy provided assistance in the form of customer contacts and the provision of data.

Integral Energy network customers who have opportunities to reduce peak demand are offered a free energy audit in return for signing a Memorandum of Understanding. Financial incentives are paid for each initiative implemented, based on the verified demand reduction achieved.

## RESULTS

| Residential Customers Participating | Commercial and Small Industrial Customers Participating | Agricultural Customers Participating | Large Industrial Customers Participating | Additional Generation Installed |
|---|---|---|---|---|
| | 15 | | | |

| Peak Load | Peak Load Reduction | Duration of Peak Load Reduction | Overall Load Reduction | Energy Savings | Network Augmentation Deferral |
|---|---|---|---|---|---|
| 28 MW | 2 MW | 4 hours | 0.65 MVA | 900 MWh | 36 months |

## HOW LOAD REDUCTION WAS MEASURED

In various ways, depending on the DSM measure.

## RESULTS ACHIEVED

Slow progress (650 kVA demand reduction to date) but targets are being met.

## CONFIDENCE LEVEL IN ACHIEVING RESULTS

Confident in meeting 80% of target.

## REPEATABILITY OF RESULTS

Common repeatable programs.

## TIME DELAY BEFORE MAXIMUM RESPONSE ACHIEVED

Some customers require 24hrs notification for load shedding.

## WEATHER DEPENDENCE

Generation programs.

## AVOIDED COSTS

AUD 350,000

## ACTUAL PROJECT COSTS

AUD 320,000 paid by Integral Energy

## PROJECT COST FROM THE SOCIETAL PERSPECTIVE

Unknown.

## OVERALL PROJECT EFFECTIVENESS

The program is progressing slowly. The lesson learnt is that customers require a lot of convincing to act. The initial energy audit to identify opportunities needs to be free to get the customer involved.

## CONTACTS

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## SOURCES

Integral Energy website at:
http://www.integralenergy.com.au/index.cfm?objectid=11147F0A-8028-BBAF-1A057D86C4F449AF

## CASE STUDY PREPARATION

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# IP02 CASTLE HILL DEMAND MANAGEMENT PROJECT - AUSTRALIA

| | |
|---|---|
| **Last updated** | 11 July 2006 |
| **Location of Project** | Castle Hill, Sydney, Australia |
| **Year Project Implemented** | 2003 |
| **Year Project Completed** | 2006 |
| **Name of Project Proponent** | Integral Energy |
| **Name of Project Implementor** | New South Wales Sustainable Energy Development Authority (SEDA) |
| **Type of Project Implementor** | State or federal government agency |
| **Purpose of Project** | Deferral of network augmentation |
| **Timing of Project** | Pre contingency |
| **Focus of Project** | Network capacity limitations |
| **Project Objective** | Peak load reduction |
| **Project Target** | Network region |
| **DSM Measure(s) Used** | Standby generation<br>Direct load control<br>Energy efficiency<br>Power factor correction<br>Other: Automated control (ie $CO_2$ monitoring) |
| **Specific Technology Used** | Integrated project using a range of technologies |
| **Market Segments Addressed** | Commercial and small industrial customers |

## DRIVERS FOR PROJECT

Castle Hill is a rapidly developing suburb located 32km north west of the Sydney central business district. The Castle Hill local electricity network has 5,320 residential customer connections and 679 business and community connections. Over the five years from 2000 to 2005, electricity consumption in Castle Hill increased by 32% and Integral Energy forecasts showed that this would grow by a further 54% over the subsequent 10 years.

Increasing penetration and use of air conditioners in the Castle Hill commercial centre and surrounding residential areas would result in summer peak loads exceeding system capability. In 2003, Integral Energy forecast it would need to spend AUD 3.2 million to expand the Castle Hill zone substation by summer 2005 because of continued rapid development of the Castle Hill district.

Integral Energy wished to examine whether it would be cheaper to assist local consumers be more efficient in their use of electricity rather than upgrade the electricity network. If not, the Castle Hill substation would be upgraded to ensure growth in energy demand was met.

## DESCRIPTION OF PROJECT

### Castle Hill Local Network

Peak demand in the Castle Hill area is primarily driven by use of domestic and commercial air-conditioning on hot summer days, particularly when there have been several days in a row with temperatures exceeding 35 degrees Celsius (see Figures IP02/1 and IP02/2, page 255).

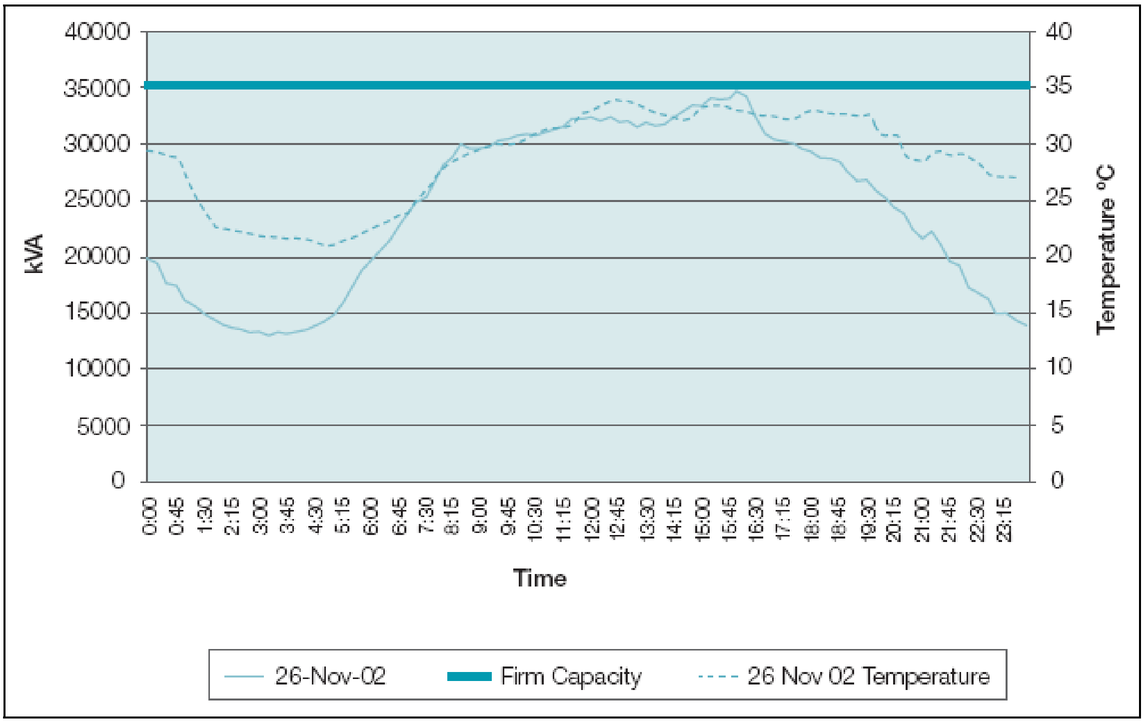


**Figure IP02/1. Castle Hill Zone Substation Profile on a 35 Degrees Celsius Day**

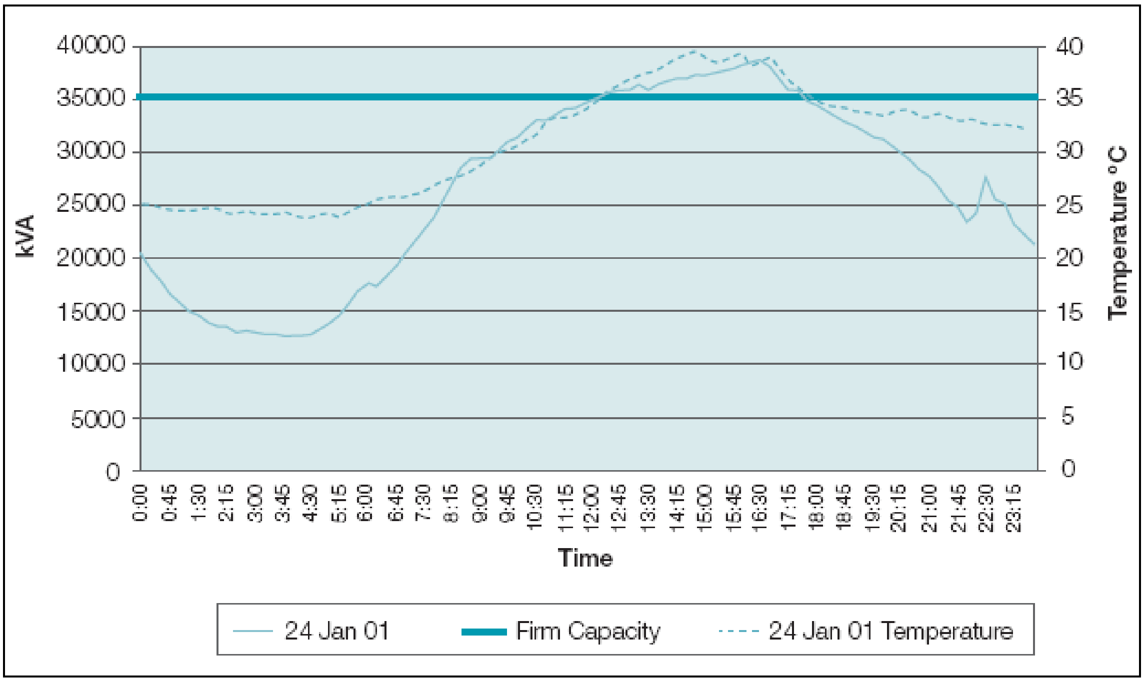


**Figure IP02/2. Castle Hill Zone Substation Profile after Two Consecutive Days at 39 Degrees Celsius**

The effect of air conditioning on peak electricity use on a mild summer day versus a hot summer day is illustrated in Figure IP02/3. Figure IP02/4 shows the forecast growth in demand on the Castle Hill zone substation.

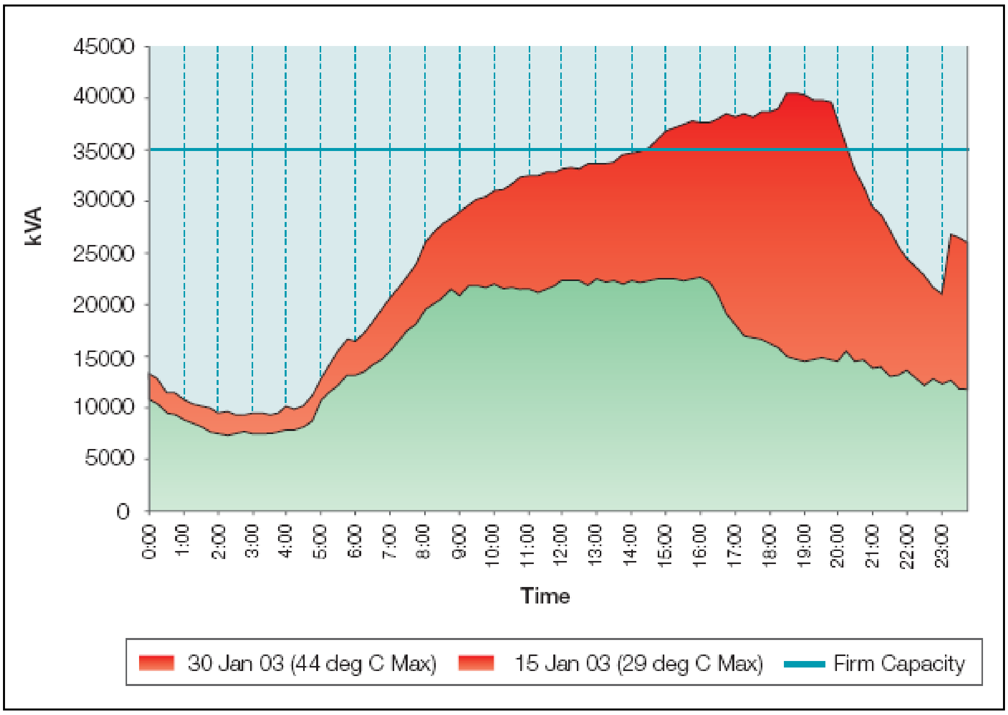


**Figure IP02/3. Castle Hill Zone Substation Profile**
**Hot Day versus Mild Day**

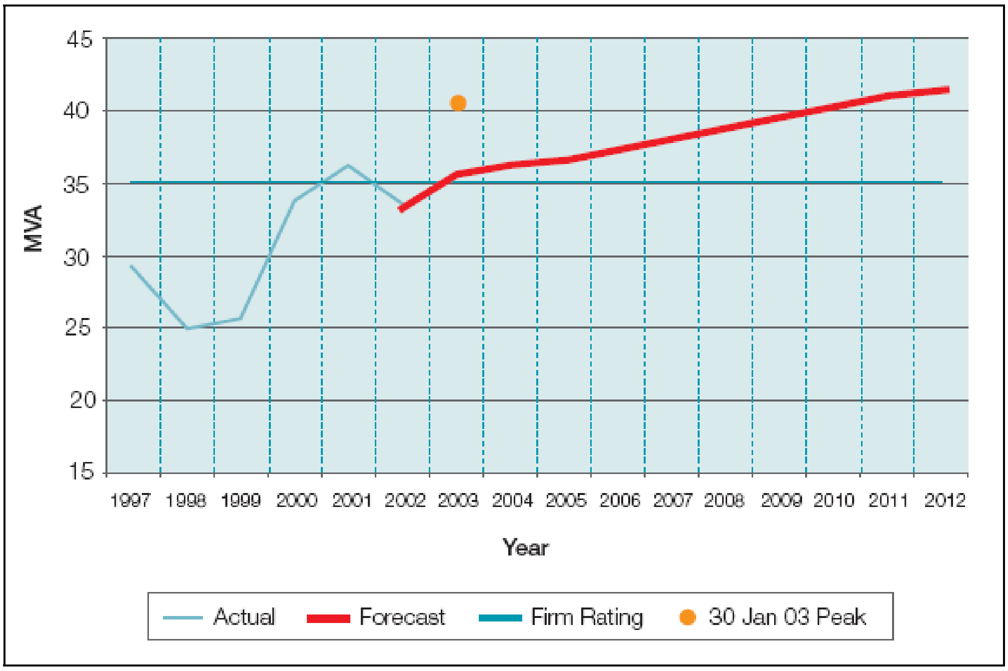


**Figure IP02/4. Castle Hill Zone Substation**
**Actual and Forecast Demand**

## Initial Investigations

Despite the high levels of load growth, initial investigations by Integral Energy indicated that sufficient demand could be curtailed to defer the upgrade of the substation. Reductions in summer peak demand of 1 MVA initially, and further reductions of 0.5 MVA per annum were required to achieve deferral. A notional three-year deferral would provide a budget of sufficient value to warrant proceeding with a DSM option.

Integral Energy determined that a Request for Proposals for DSM strategies was warranted. However, this was supplanted by an offer from a New South Wales Government agency, the Sustainable Energy Development Authority (SEDA), to conduct a DSM program focussed on the commercial sector.

The Castle Hill Demand Management Project was developed via direct negotiation with SEDA. Integral Energy provided information on the level and timing of the required peak demand reduction and the level of financial support available.

## Contractural Arrangements

SEDA was contracted by Integral Energy to work with electricity customers to relieve the peak summer electrical demand on the Castle Hill zone substation by 1,350kVA, approximately 4% of the peak electrical load on the local network, over a 3 year period.

The aim of the contract was to defer the need for the upgrade of the Castle Hill zone substation by reducing the demand for electricity during peak periods, namely from 1pm until 5pm on summer weekdays when the temperature reached or exceeded 35 degrees Celsius.

The overall contract target of 1,350 kVA was divided into three milestones of 450kVA of demand reduction to be achieved by the start of summer each year. The contract allowed for a budget of AUD150 per kVA of peak demand reduction, that is a total of AUD202,500 plus an 'establishment fee' of AUD50,000, bringing the overall project cost to AUD187/kVA.

However, using the framework for treatment of network utilities' DSM expenditure developed by the New South Wales electricity industry regulator, the value of deferring the capital upgrades to the Castle Hill zone substation was worth up to AUD566 per kVA (ie a total of AUD764,000). Consequently, if the contract target of 1,350kVA was exceeded, Integral Energy agreed to make payments of AUD135 per kVA for up to a further 352kVA reduction.

## Program Objectives

The following objectives were set for the Castle Hill Demand Management Project:

- reduce the peak electricity load on Integral Energy's Castle Hill zone substation by 1,350kVA by summer 2005/2006;
- increase the energy efficiency of participating businesses and residents and decrease energy bills;
- reduce greenhouse gas emissions through energy efficiency and/or fuel switching to other energy forms;
- increase investment in sustainable energy technologies and services;

- demonstrate that DSM can be a profitable alternative to supply side solutions for an electricity distribution network facing peak demand constraints.

## DSM Strategies

Three DSM strategies were identified:

- **Commercial/Industrial DSM:** investigate using a modified version of SEDA's award winning Energy Smart Business program to reduce peak demand by major commercial/ industrial customers, primarily through implementation of energy efficiency measures;
- **Distributed Generation:** investigate using existing or hired standby generators to relieve the network at peak times;
- **Residential DSM:** investigate the potential for energy efficiency, appliance interruption and load shifting in local residences.

## Commercial/Industrial DSM

Initial investigations into the top 20 energy users in the area served by the Castle Hill zone substation identified the Castle Towers Shopping Centre and its major retail tenants as potential targets for peak demand management initiatives. The top ten commercial energy users had a combined electrical load of greater than 10MVA. Consequently, 1.35MVA represented an average drop of 13% of their load.

Preliminary walk through energy audits of the shopping centre and the major retail tenants suggested good potential to improve the efficiency of lighting, ventilation and air-conditioning systems. These systems account for an estimated 70% of commercial sector electricity demand during times of the peak summer load on the New South Wales network.

SEDA modified its existing Energy Smart Business program to assist these major energy consumers to identify and implement cost effective peak demand reduction projects.

Business forums and one-on-one meetings with major retail businesses were held during 2003 to recruit partners for the Castle Hill Demand Management Project. Free energy audits were offered to businesses to assess the potential for peak demand reduction and ongoing energy savings.

Following the energy audits, businesses were encouraged to make a public commitment to implement cost effective projects within 2 years. Businesses making this commitment became official "Partners" in the Castle Hill Demand Management Project and were provided with:

- a Partner Support Manager to give ongoing support and technical assistance to implement projects;
- participation in two advertising campaigns on local bus shelters and inside the Castle Towers Shopping Centre, as well as promotion in the project newsletter; and
- a $60/kVA bounty for measured and verified peak demand reductions.

The Project targeted interruptible loads, 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. The contracts with electricity customers were performance based, with payment on verification of demand reduction.

## Distributed Generation

Although initial estimates of peak demand reduction available from commercial businesses looked favourable, it was considered prudent to also investigate distributed generation as a complementary peak demand reduction option.

Recruitment of standby diesel generators able to dispatch at times of peak demand was the main distributed generation option investigated. Other generation options such as gas generation, cogeneration and solar power systems were not pursued because of the time constraints for project implementation and budgetary considerations.

Initial investigations found four standby generators in the Castle Hill area: two tenants at the Castle Towers Shopping Centre and two businesses outside the shopping centre.

The business with the largest capacity of standby generation (250kW) was considered to offer the best potential for a standby generation option. Initial discussions were held with the asset owner and a pre-feasibility study was undertaken based on manual start-up and sychronised, remote start–up options. The pre-feasibility study indicated the net return to the asset owner for generating less than 1MW at peak times in the network and/or at times of high pool prices in the National Electricity Market was negligible and did not warrant the risk or administration required to implement the standby generation option.

Preliminary discussions were also held with Integral Energy about the possibility of using hired generators. Issues such as siting, fuel storage, cabling and grid connection were raised. A hired generator was not considered the ideal option but could be used to generate during peak periods over one summer. This would give energy efficiency options more time to be implemented and/or would make up for any shortfall in the peak demand reduction achieved through these options.

## Residential DSM

Integral Energy, in conjunction with SEDA, had previously undertaken an interruptible residential air conditioning trial with 90 residents in western Sydney. Although this was successful in delivering a demand reduction, the trial raised a range of other issues that needed to be addressed before this option could be a reliable, market accepted solution for peak demand reduction over multiple years and with larger numbers of participants.

Further, as the demand peak in Castle Hill dropped off at close of business around 5pm, it was considered that interrupting residential air-conditioners might not be very effective in reducing the early afternoon component of the peak.

Castle Hill has a high penetration of domestic swimming pools. Therefore, a basic investigation into shifting pool pump loads (approximately 1kVA each) to outside peak times was undertaken, including interviews with local pool equipment suppliers and a limited survey of pool owners.

Overall it was considered to be not financially viable to undertake residential DSM initiatives in the Castle Hill Project, given the budget of $187/kVA and that the commercial DSM initiatives looked more promising for the size, length and timing of peak reduction required.

## RESULTS

| Residential Customers Participating | Commercial and Small Industrial Customers Participating | Agricultural Customers Participating | Large Industrial Customers Participating | Additional Generation Installed |
|---|---|---|---|---|
| | 6 | | | |

| Peak Load | Peak Load Reduction | Duration of Peak Load Reduction | Overall Load Reduction | Energy Savings | Network Augmentation Deferral |
|---|---|---|---|---|---|
| 33 MW | 1.35 MVA | 4 hours | 0.9 MVA | 3,800 MWh | 36 months |

## HOW LOAD REDUCTION WAS MEASURED

Estimate.

## RESULTS ACHIEVED

Fifty-four possible DSM projects were identified with an estimated total load reduction of 5.2 MVA. To achieve the required 1.35 MVA peak load reduction, the top 20 projects were selected. Most of the peak demand reduction projects identified involved lighting, heating, ventilation and air-conditioning (HVAC) or optimisation of building management control systems.

By June 2005, six project partners had been signed up and a total of 900 kVA peak load reduction had been achieved. The project was on track to achieve the target 1.35 MVA reduction by November 2005.

Based on projects with funding approved and currently underway the following results are expected:

- 1,350 kVA of peak demand reduction will be in place by summer 2005/06 at an average cost of $187/kVA;
- around $370,000 in annual energy savings to businesses;
- over $1 million worth of investment in sustainable energy equipment and expertise; and
- over 7,000 tonnes of greenhouse gas reductions per annum.

## CONFIDENCE LEVEL IN ACHIEVING RESULTS

Very confident about achieving target result.

## REPEATABILITY OF RESULTS

Highly repeatable - very common commercial programs.

## TIME DELAY BEFORE MAXIMUM RESPONSE ACHIEVED

Immediate.

## WEATHER DEPENDENCE

No backup generation to date.

## AVOIDED COSTS

AUD 320,000 for a one year deferral of the planned substation.

## ACTUAL PROJECT COSTS

Integral Energy's costs are AUD200,000 to June 2005 and are expected to be AUD300,000 in total by the end of the project. The average budgeted project cost was AUD187/kVA.

## PROJECT COST FROM THE SOCIETAL PERSPECTIVE

Unknown.

## OVERALL PROJECT EFFECTIVENESS

Meeting targets.

## CONTACTS

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## SOURCES

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

Department of Energy Utilities and Sustainability (2005). *Castle Hill Demand Management Project: Case Study*. Sydney, DEUS.

Personal communication, Frank Bucca, Integral Energy.

## CASE STUDY PREPARATION

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# IP03 PARRAMATTA DSM PROGRAM - AUSTRALIA

| | |
|---|---|
| **Last updated** | 26 August 2005 |
| **Location of Project** | Parramatta, western Sydney, Australia |
| **Year Project Implemented** | 2004 |
| **Year Project Completed** | 2007 |
| **Name of Project Proponent** | Integral Energy |
| **Name of Project Implementor** | Total Energy Solutions |
| **Type of Project Implementor** | ESCO |
| **Purpose of Project** | Deferral of network augmentation |
| **Timing of Project** | Pre contingency |
| **Focus of Project** | Network capacity limitations |
| **Project Objective** | Peak load reduction |
| **Project Target** | Network region |
| **DSM Measure(s) Used** | Standby generation<br>Direct load control<br>Energy efficiency<br>Power factor correction |
| **Specific Technology Used** | Integrated project using a range of technologies |
| **Market Segments Addressed** | Commercial and small industrial customers |

## 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 236 MVA, 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.

The Parramatta DSM Program is driven by demand growth and the need to defer capital expenditure required to build a new Parramatta East Zone Substation.

## DESCRIPTION OF PROJECT

Integral Energy cooperated with the New South Wales Government agency the Sustainable Energy Development Authority (SEDA) to develop a Commercial Building Greenhouse Gas Rating Scheme for the area.

As part of this study, Integral funded and conducted a major survey to identify and establish the opportunities for DSM in the Parramatta central business district. Integral personnel accompanied SEDA's consultants to identify opportunities for DSM in office buildings in the Parramatta CBD. Study results indicated that sufficient DSM opportunities existed to possibly defer the need for supply-side augmentation.

Integral made offers to building owners/managers for the implementation of appropriate DSM initiatives. The DSM options considered included 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 issued a Request for Proposals to identify other DSM initiatives and extend the DSM program with the aim of deferring any network augmentation in the area until June 2006. This would constitute a two-year deferral of the capital investment in network infrastructure.

Proposals for DSM projects were evaluated and selected on the basis of process, experience, knowledge and cost effectiveness. Integral paid financial incentives to project proponents based on the verified demand reduction from each DSM initiative implemented.

Integral also provided assistance to project proponents in the form of customer contacts and the provision of data.

## RESULTS

| Residential Customers Participating | Commercial and Small Industrial Customers Participating | Agricultural Customers Participating | Large Industrial Customers Participating | Additional Generation Installed |
|---|---|---|---|---|
| | 6 | | | |

| Peak Load | Peak Load Reduction | Duration of Peak Load Reduction | Overall Load Reduction | Energy Savings | Network Augmentation Deferral |
|---|---|---|---|---|---|
| 45 MW | 3 MVA | 5 hours | 1 MW | | 36 months |

## HOW LOAD REDUCTION WAS MEASURED

Estimate.

## RESULTS ACHIEVED

As at March 2005, predominantly power factor correction projects have been implemented to date. Total peak demand reduction of 455kVA has been achieved.

## CONFIDENCE LEVEL IN ACHIEVING RESULTS

80% confident.

## REPEATABILITY OF RESULTS

Highly repeatable - common programs.

## TIME DELAY BEFORE MAXIMUM RESPONSE ACHIEVED

Immediate.

## WEATHER DEPENDENCE

## AVOIDED COSTS

AUD 800,000 from the deferral of capital investment in network infrastructure.

## ACTUAL PROJECT COSTS

Projected to be AUD 700,000.

## PROJECT COST FROM THE SOCIETAL PERSPECTIVE

Not calculated.

## OVERALL PROJECT EFFECTIVENESS

Progressing slowly.

## CONTACTS

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## SOURCES

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

## CASE STUDY PREPARATION

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# IP04 OLYMPIC PENINSULA NON-WIRES SOLUTIONS PILOT PROJECTS AND GRIDWISE DEMONSTRATION - USA

| | |
|---|---|
| **Last updated** | 30 August 2005 |
| **Location of Project** | East side of the Olympic Peninsula, north-western Washington State, USA |
| **Year Project Implemented** | 2004 |
| **Year Project Completed** | |
| **Name of Project Proponent** | Bonneville Power Authority (BPA) |
| **Name of Project Implementor** | BPA & Pacific Northwest National Laboratory |
| **Type of Project Implementor** | Transmission utility<br>State or federal government agency |
| **Purpose of Project** | Deferral of network augmentation |
| **Timing of Project** | Pre contingency |
| **Focus of Project** | Network capacity limitations |
| **Project Objective** | Peak load reduction |
| **Project Target** | Network region |
| **DSM Measure(s) Used** | Standby generation<br>Direct load control<br>Other short-term demand response<br>Energy efficiency<br>Other: Grid-Friendly™ appliances |
| **Specific Technology Used** | |
| **Market Segments Addressed** | Residential customers<br>Commercial and small industrial customers<br>Large industrial customers |

## DRIVERS FOR PROJECT

The Bonneville Power Administration (BPA) owns and operates 75% of the Pacific Northwest's electricity transmission system that includes more than 15,000 miles of high-voltage transmission lines and 285 substations. At peak usage, the system transports about 30,000 MW of electricity to customers in Oregon, Washington, Idaho and Montana, as well as to parts of Wyoming, Nevada, Utah and California.

In 2001, BPA started considering measures other than building new transmission lines to address load growth, constraints and congestion on the transmission system. Currently, BPA, along with others in the region, is exploring "non-wires solutions" as a way to defer large construction projects (see Figure IP04/1, page 266).

BPA defines non-wires solutions as a broad array of alternatives, including demand response, distributed generation, energy efficiency measures, generation siting and pricing strategies that individually or in combination delay or eliminate the need for upgrades to the transmission system.  BPA and its consultants have developed a screening process and checklist to evaluate a transmission problem area to determine whether it is a candidate for a non-wires solution.

The Olympic Peninsula has received particular attention since it is an environmentally sensitive area with increasing demand for electricity and limited transmission capacity. The capacity of the transmission lines on the Peninsula may become inadequate as early as December 2007, if there is a forced outage of one line during peak periods of cold weather. A significant transmission construction project, including a new 20-mile 230-kV line, is being contemplated on the Peninsula.

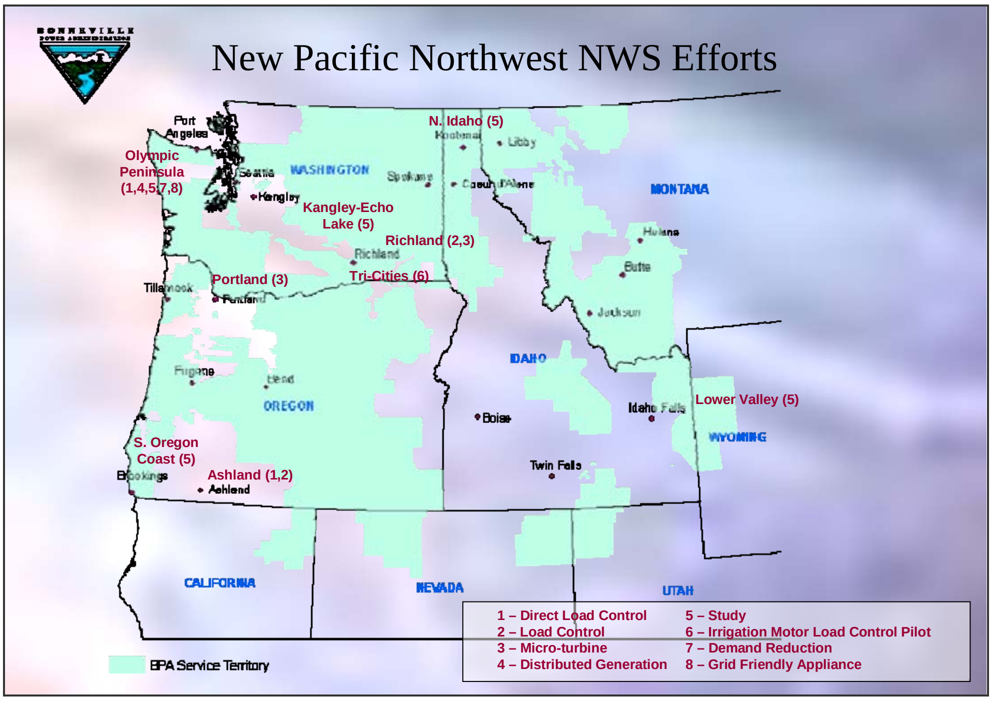


**Figure IP04/1. BPA Non-wires Solutions Activities**

BPA is carrying out several pilot projects to determine whether it is possible to use non-wire solutions to defer the transmission construction project. A peak load reduction of 50 MW is required to achieve a five year deferral. All projects must pass the total resource cost test before they can be implemented.

## DESCRIPTION OF PROJECT

### Non-Wires Solutions Pilot Projects

The following non-wires solutions pilot projects are being carried out on the Olympic Peninsula:

- direct load control;
- demand response;
- voluntary load curtailments;
- networked distributed generation;
- energy efficiency.

#### *Direct Load Control*

The overall target for direct load control on the Olympic Peninsula is 20 MW.

The objectives of the pilot phase of the direct load control project are to demonstrate the reliability and technical feasibility and measure the peak load reduction impacts of direct load control.

To participate in the pilot phase, residential customers must have an electric water heater and heat pump, forced air furnace or baseboard space heating.

The pilot phase aims to obtain 5 MW (2500 sites X 2kW) of curtailable loads in the residential sector by 1 December 2005 from one distribution utility or a combination of utilities.

Direct load control will be accomplished through the use of a one-way radio pager network linked to a direct load control unit located in the dwelling (see Figure IP04/2). The control unit communicates with appliances though power line carrier signals. Controlled end-uses include water heaters, pool pumps and space heating.

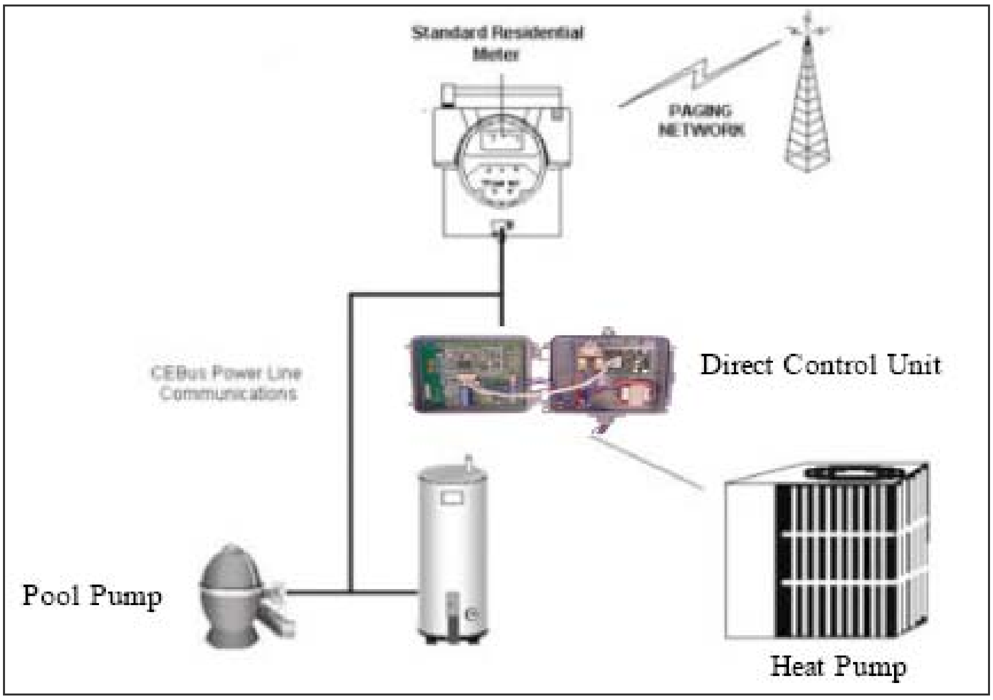


**Figure IP04/2. Olympic Peninsula Direct Load Control System**

### *Demand Response*

The target for demand response on the Olympic Peninsula is 16 MW.

The objectives of the pilot phase of the demand response project are:

- to demonstrate the reliability and technical feasibility and measure the peak load reduction impacts of demand response;
- to use incentives to test the value proposition of demand response for customers; and
- to test the use of Grid-Friendly™ appliance concepts, hardware and responses to automatically reduce load in response to stress on the grid.

To participate in the pilot phase of the demand response project, residential customers must have an electric water heater, heat pump or forced air furnace, a minimum of three people in the dwelling, and a fibre or cable high speed internet connection.

The pilot phase aims to install 250 two-way internet gateways in the residential sector (see Figure IP04/3). The gateways enable automatic control of space heating, air conditioning, water heating and pool pumps in participating dwellings. The gateways also measure the load from individual end-uses in the dwelling.


**Figure IP04/3. Olympic Peninsula Demand Response System**

Demand response will be accomplished through the use of two-way broadband to communicate with the internet gateways. Customers can use the internet to set price levels at which automatic load switching occurs and also to override the automatic settings. This will enable customers to lower energy use and reduce electricity costs.

In addition, 250 Grid-Friendly™ appliances (200 clothes dryers and 50 water heaters) will be installed in 200 participating dwellings. Controllers installed in each Grid-Friendly™ appliance sense frequency disturbances in the electricity network and control the appliances to act as spinning reserve – no communications technology is required beyond the network itself.

The Grid-Friendly™ appliance controller developed at Pacific Northwest National Laboratory is a simple computer chip that senses network conditions by monitoring the frequency of the system and provides automatic demand response in times of disruption. The controller can be installed in appliances that regularly cycle on and off during normal use, so that consumers do not notice when the Grid-Friendly™ device is in operation.

Grid-Friendly™ appliances allow customers to become an integral part of electricity network operations. Grid-Friendly™ controllers can be programmed to autonomously react in fractions of a second when a disturbance is detected. Demand can be rebalanced to match available supply almost instantaneously (within a half-second). This is an improvement over the approximately 30 seconds it currently takes for power plants kept on standby to come up to speed. Grid-Friendly™ controllers can also be programmed to delay restart instead of all coming on at once after a power outage.

### *Voluntary Load Curtailments*

BPA operates a Demand Exchange (DEMX) program that provides commercial and industrial customers with the ability to curtail their load during system emergencies and volatile market conditions.

Under the DEMX program, BPA works with customers to define their load curtailment capability and determine the benefits of participation. DEMX aggregates customers' curtailment potential and represents the aggregated load in the wholesale energy market as a reliability option. DEMX has built an internet-based auction site where participants are alerted to hourly, one day-, and two day-ahead price signals associated with peak load events, and are able to post their willingness to participate at a set price.

In March 2004, BPA ran a successful test using DEMX to reduce congestion on transmission lines on the Olympic Peninsula. A local utility, two paper manufacturing companies and the US Navy voluntarily reduced their transmission loads during a simulated period of severe weather and critical peak demand.
The test occurred over four days. During the test, BPA posted an hourly price per megawatt, giving test participants the chance to accept, reject or counter the offer. Participants then bid to reduce their demand by using backup generation or by shifting load to other hours. BPA was able to purchase an average of 22 MW of peak demand reduction during each hour of the simulated event. This is about one year's load growth on the Olympic Peninsula.

### *Networked Distributed Generation*

The target for distributed generation on the Olympic Peninsula is 4 MW. This will be achieved with 12 units in 10 locations. All units have been identified.

In the pilot phase of the distributed generation project, backup generators will be used at one commercial and one industrial site:

- Sequim Marine Sciences Lab - 0.5 MW backup generators for load shed and transactive control demand response integrated with the generators;
- Port Angeles municipal water supply system - 0.9 MW backup generators in parallel with 0.9 MW demand response from pumps.

### *Energy Efficiency*

The target for energy efficiency on the Olympic Peninsula is 15 MW.

As a general policy, BPA ensures development of all cost-effective energy efficiency in the electrical loads BPA serves across the Pacific Northwest. BPA treats energy efficiency as a resource and defines goals in terms of megawatts of energy efficiency acquired. The bulk of the energy efficiency acquired by BPA is pursued and achieved at the local level in association with local distribution utilities.

BPA will apply these general principles to acquiring peak load reductions on the Olympic Peninsula through energy efficiency programs across the residential, commercial and industrial sectors developed in association with local distribution utilities.

## OLYMPIC PENINSULA GRIDWISE DEMONSTRATION

The demand response, voluntary load curtailment and distributed generation pilot projects on the Olympic Peninsula will be aggregated by Pacific Northwest National Laboratory into a demonstration of how a future electricity network might function. This demonstration is part of a project of the United States Department of Energy known as GridWise.

### *The GridWise Project*

The GridWise project is intended to demonstrate how a modernized electric infrastructure framework with open but secure system architecture, communication techniques, and related standards employed throughout the electricity network can provide value and choices to electricity consumers.

Gridwise envisages a future electric system built upon the fundamental premise that information technology will profoundly transform the planning and operation of electricity networks. Information technology will form a "nervous system" that integrates new distributed technologies—demand response appliances, distributed generation, and storage—with traditional generation, transmission, and distribution assets to share responsibility for managing the network as a collaborative "society" of devices.

### *Olympic Peninsula GridWise Demonstration*

The Olympic Peninsula GridWise demonstration involves testing a system, not just one technology. The intent of the demonstration is to illustrate how a future GridWise electricity network can operate and explore key issues associated with that operation. Field resources, operating with all the associated real world operating challenges, will be dispersed throughout the Olympic Peninsula on various elements of the area's distribution system.

#### Objectives

The objectives for the Olympic Peninsula Gridwise demonstration include:

- to illustrate how the future power grid envisioned by GridWise will function in the next decade;
- to show how a common communications framework can provide economic dispatch of multiple types of resources, integrating them to provide multiple benefits;
- to implement "real-time" economic dispatch through communication of market-like incentives to obtain voluntary, collaborative response from customers;
- to develop an understanding of how multiple resources perform individually and when interacting in near real-time to meet common objectives;
- to understand how economic structures influence the participation of multiple resources;
- to achieve multiple benefits at various levels of the electricity network, including lower generation and wholesale costs, reduced transmission congestion, improved distribution asset utilization and avoided capacity expansion, and better ancillary services and network stability.

**Technical Approach**

The technical approach for the Olympic Peninsula Gridwise demonstration includes:

- real, in-the-field, operating distributed resources – both distributed generation and demand response;
- a virtual, near real-time market operating environment focussed on residential customers backed with real cash consequences to participants;
- provision of incentives to operate the resources in collaboration with the network operator;
- use of computer software to create, in cooperation with local distribution utilities, a "virtual" distribution feeder, as if the non-wires resources involved were literally co-located on a single feeder;
- real-time and historical display of resource operations and costs.

**Virtual Feeder**

Real non-wires assets will be integrated into a "virtual" distribution environment and will appear to perform as resources on a capacity-constrained feeder. Actual measured substation feeder loads from the SCADA system on the Olympic Peninsula will be used as the baseline load. The assets will be managed to an arbitrary limit below the actual physical capacity. A shadow market will dispatch project resources to limit demand below the level of constraint. A "virtual" physical environment with commercially-available power systems analysis tools will simulate impacts on power flows, voltages, etc.

## RESULTS

| Residential Customers Participating | Commercial and Small Industrial Customers Participating | Agricultural Customers Participating | Large Industrial Customers Participating | Additional Generation Installed |
|---|---|---|---|---|
| 2,750 | | | 4 | |

| Peak Load | Peak Load Reduction | Duration of Peak Load Reduction | Overall Load Reduction | Energy Savings | Network Augmentation Deferral |
|---|---|---|---|---|---|
| 1,150 MW | 50 MW | | | | |

## HOW LOAD REDUCTION WAS MEASURED

## RESULTS ACHIEVED

## CONFIDENCE LEVEL IN ACHIEVING RESULTS

## REPEATABILITY OF RESULTS

## TIME DELAY BEFORE MAXIMUM RESPONSE

## WEATHER DEPENDENCE

## AVOIDED COSTS

## ACTUAL PROJECT COSTS

## PROJECT COST FROM THE SOCIETAL PERSPECTIVE

## OVERALL PROJECT EFFECTIVENESS

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## CASE STUDY PREPARATION

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## IP05 BROOKVALE / DEE WHY DSM PROGRAM - AUSTRALIA

| | |
|---|---|
| **Last updated** | 1 September 2005 |
| **Location of Project** | Brookvale / Dee Why - Northern Sydney suburbs, Australia |
| **Year Project Implemented** | 2003 |
| **Year Project Completed** | |
| **Name of Project Proponent** | EnergyAustralia |
| **Name of Project Implementor** | EnergyAustralia |
| **Type of Project Implementor** | Distribution utility |
| **Purpose of Project** | Deferral of network augmentation |
| **Timing of Project** | Pre contingency |
| **Focus of Project** | Network capacity limitations |
| **Project Objective** | Peak load reduction |
| **Project Target** | Network element |
| **DSM Measure(s) Used** | Standby generation<br>Energy efficiency<br>Power factor correction |
| **Specific Technology Used** | |
| **Market Segments Addressed** | Commercial and small industrial customers<br>Large industrial customers |

### DRIVERS FOR PROJECT

The two zone substations in the Brookvale/Dee Why area of northern Sydney are supplied at 33kV from a network of several underground cables. Forecasts indicated that, in the event of the loss of one of the cables at the time of peak demand, load on the remaining cables would exceed their ratings over the summer of 2004/05 (see Figure IP05/1.

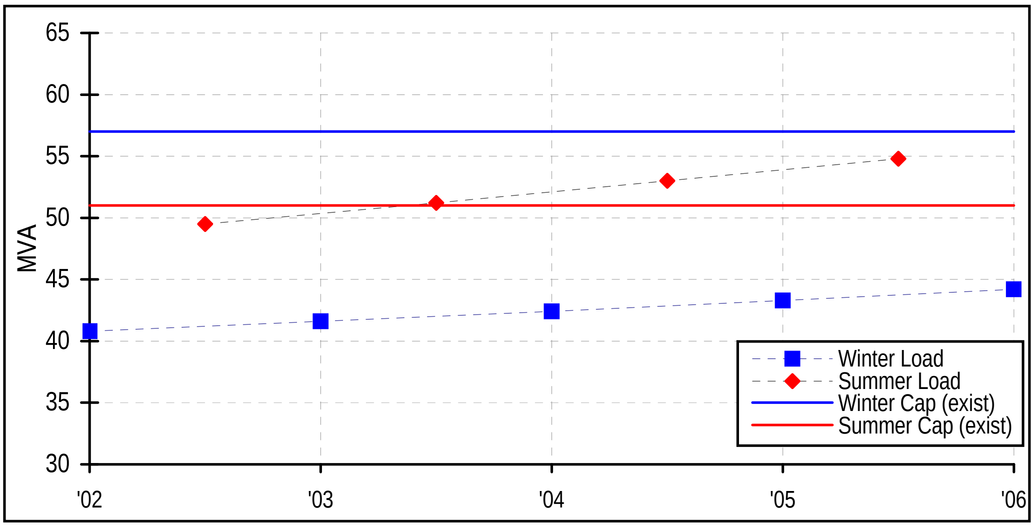


**Figure IP05/1. Supply Capacity and Demand Forecast on Feeder S06 for a First Contingency Outage**

The supply solution was to install two new 33kV cables to break up the network and provide additional capacity at a cost of AUD 6.5 million.

DSM 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 AUD 694,600. The value of DSM is shown in Figure IP05/2 in terms of $/kVA of demand reduction for a range of achieved demand reductions.

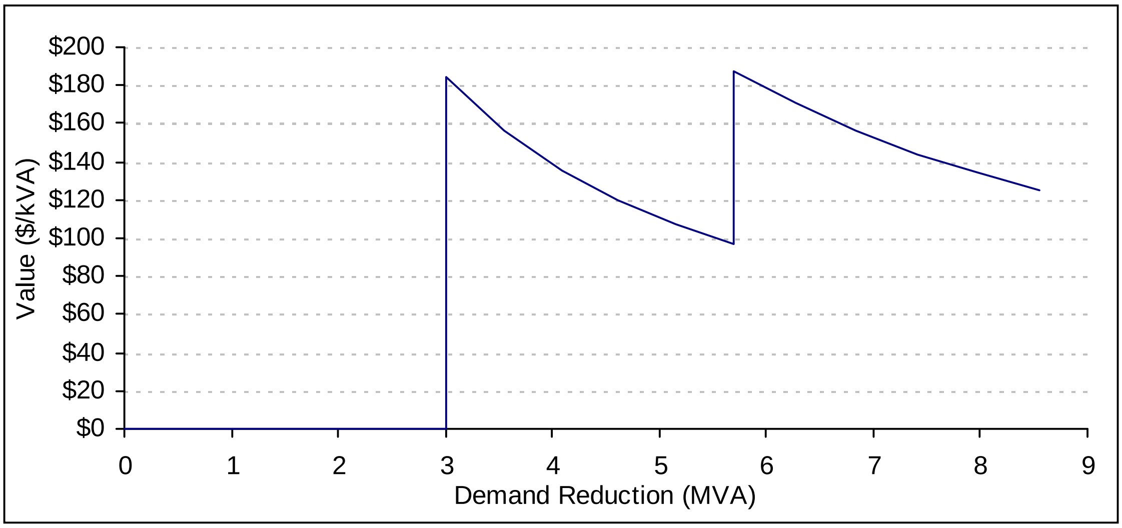


**Figure IP05/2. Value of DSM for One and Two Year Deferrals (Demand Reductions of 3 and 6 MVA)**

The peak load in the area 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 (see Figure IP05/3).

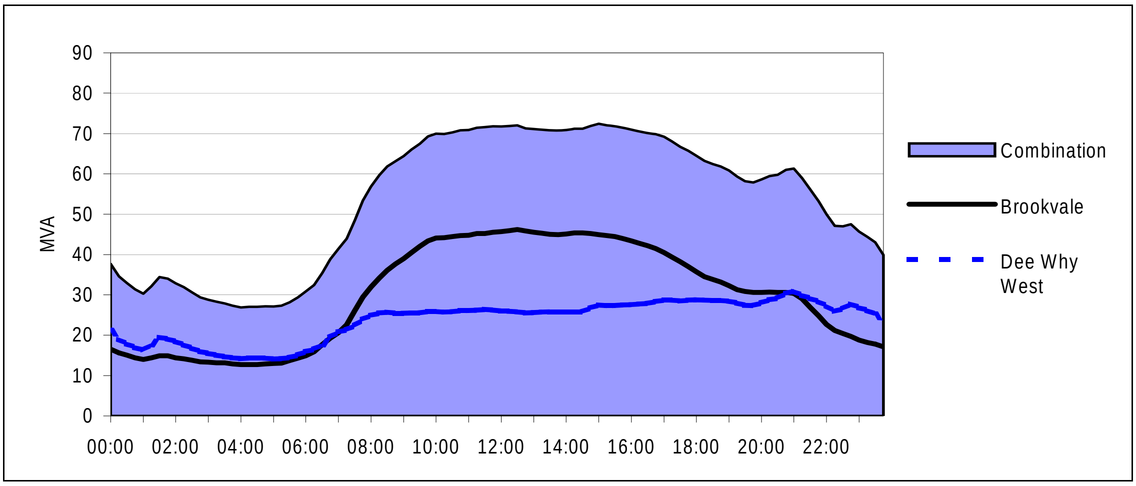


**Figure IP05/3. Load Profiles on the Peak Day, February 2002**

The daily load profile indicates that large commercial / industrial customers in the target areas dominate the electrical demand (see Figures IP05/4 and IP05/5).

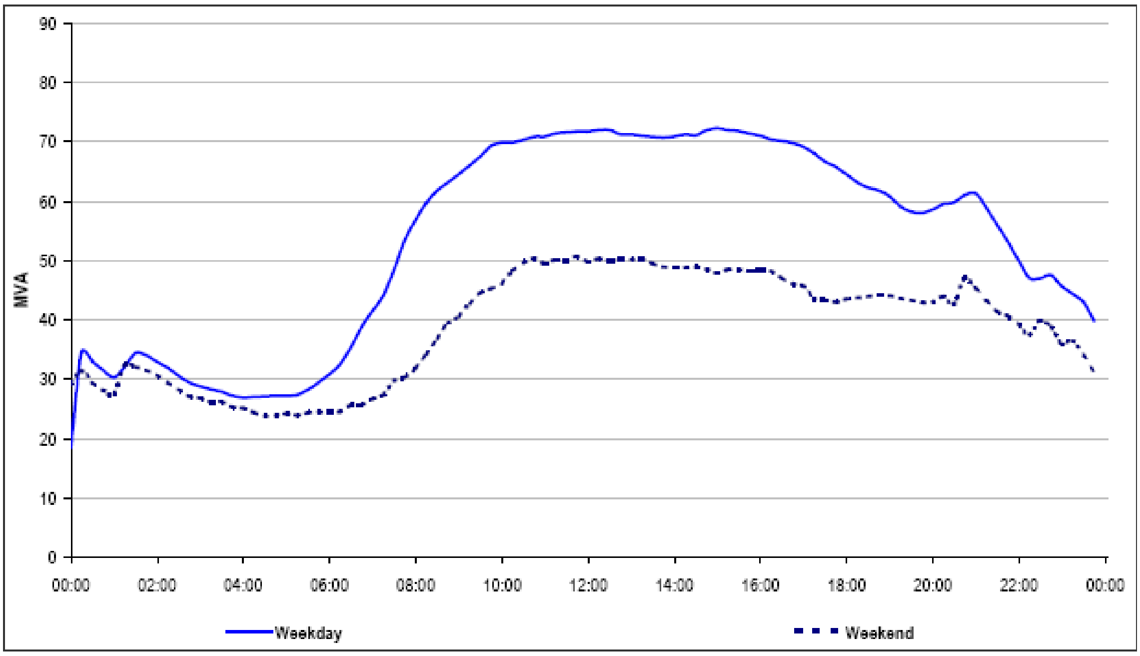


**Figure IP05/4. Weekday and Weekend Load Profiles, February 2002**

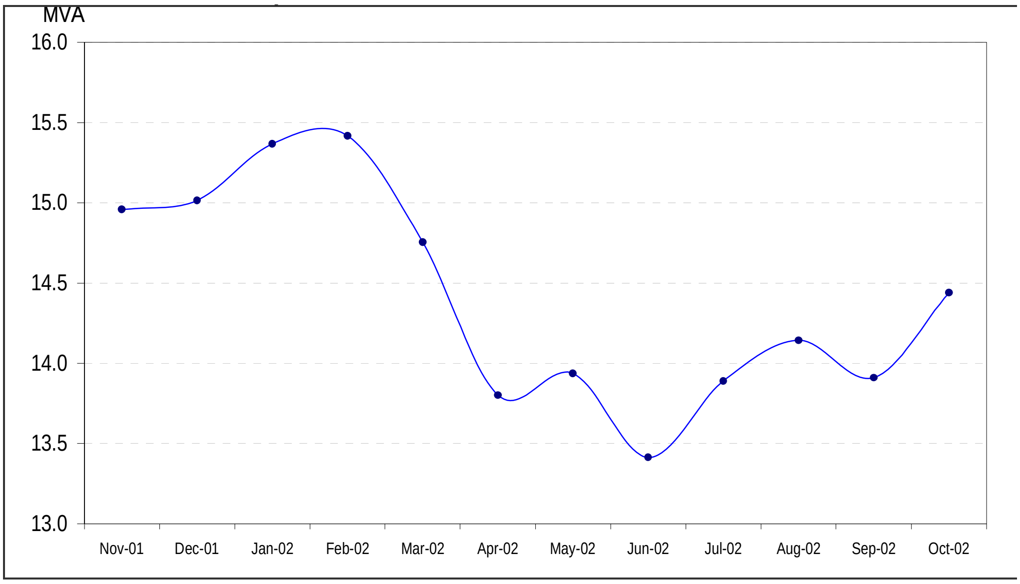


**Figure IP05/5. Monthly Electrical Demand During 2001 and 2002 at 22 Major Customer Sites**

From a public consultation process in December 2002, and field visits by EnergyAustralia officers, a number of potential DSM projects were identified, including:

- energy efficiency;
- power factor correction;
- use of a standby generator.

These projects were implemented as a suite of demand reduction initiatives to enable the deferral of capital investment in network infrastructure.

## DESCRIPTION OF PROJECT

### Energy Efficiency Standard Offer

Based on information from the public consultation conducted as part of the DSM investigation, EnergyAustralia advertised a standard offer of AUD 200/kVA of load reduction for commercial and industrial energy efficiency projects in the target area that could act to reduce summer daytime peak demand.

The standard offer had a minimum subscription threshold of 0.8MVA of load reduction and was open for approximately 11 months or until 1.5MVA had been subscribed.

Project proponents were required to register projects for preliminary approval and allocation of a "place in the queue" since funding was on a first come - first served basis. Proponents were then required to develop their proposals in detail before implementation contracts were signed. Payments to project proponents were partly on completion of installation and partly on demonstration of successful load reduction according to a monitoring and verification process agreed for each project.

### Power Factor Correction

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 was about 2.0MVA. An assessment of the practically achievable levels of LV PFC conducted as part of initial investigations suggested that the likely realised amount of peak demand reduction through PFC was 1.5MVA.

Previous experience in the sale of LV PFC suggested that some form of stimulus additional to the potential economic benefits would be required to ensure that the appropriate customer decision-makers were attentive to a proposal to install PFC at their premises. Hence, the Power Factor Correction Project drew customers' attention to the requirement in the NSW Service and Installation Rules that customers maintain a minimum power factor of 0.9.

The objective was 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 did 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.

EnergyAustralia negotiated with equipment suppliers a bulk contract for supply and installation of customer switchboard power factor correction (PFC) equipment at rates substantially below normal market prices.

Each of the eight commercial and four large industrial customers who agreed to participate was offered a proposal setting out their financial contribution to the undertaking, and the longer-term benefits. Costs were based on the bulk contract and reflected a substantial discount to the prices customers would pay for individual purchases of power factor correction equipment.

The offer also included 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.

### Standby Generator

The existing 1MVA standby generator in large commercial premises operated by Manly Warringah Rugby League Club was identified as one of the potential DSM options to achieve the required 3MVA load reduction.

EnergyAustralia sought and received "in principle" agreement from Manly Warringah Rugby Leagues Club to operate the Club's standby generator during peak periods and transfer the load of the Club (est 800kVA) from the network to the generator without interruption.

The scope of work was to carry out upgrades to the Club's 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.

A commercial contract was negotiated to enable upgrading of the generator control system and communications and to provide for dispatch by EnergyAustralia at times of peak demand.

## RESULTS

| Residential Customers Participating | Commercial and Small Industrial Customers Participating | Agricultural Customers Participating | Large Industrial Customers Participating | Additional Generation Installed |
|---|---|---|---|---|
| | | | | |

| Peak Load | Peak Load Reduction | Duration of Peak Load Reduction | Overall Load Reduction | Energy Savings | Network Augmentation Deferral |
|---|---|---|---|---|---|
| 53 MVA | 1.85 MVA | 7 hours | | | 12 months |

## HOW LOAD REDUCTION WAS MEASURED

Estimate: Power factor correction: analysis of metered data and engineering calculation of impact at Zone Substation. Energy efficiency: verification protocols agreed with project proponents. Verification of impact at Zone Substation by calculation.

## RESULTS ACHIEVED

### Energy Efficiency Standard Offer

As at March 2005, four proposals covering 13 projects have been accepted. These projects are expected to result in a total reduction in demand of 1.25MVA. Approximately 10% of this target has been achieved to date.

### Power Factor Correction

Demand on the critical network elements was reduced by 1.6MVA over the peak period of seven hours at a very low net cost to EnergyAustralia. This provided half of the required amount (3MVA) to achieve a one year deferral.

### Standby Generator

The project was abandoned before the standby generator could be used. A change in Manly Warringah Rugby League Club's circumstances meant that the site containing both the generator and the related substation was planned for redevelopment. In addition, the generator was found to be inadequate to supply the Club's load. No viable alternative connection arrangements were available.

## CONFIDENCE LEVEL IN ACHIEVING RESULTS

### Energy Efficiency Standard Offer

Medium - the accepted projects involve significant interaction with customers' decision-making processes and have many other confounding factors at play.

### Power Factor Correction

Very high.

### Standby Generator

Not relevant due to the abandonment of the project. However, this result demonstrates the vulnerability of such projects to changing customer circumstances.

## REPEATABILITY OF RESULTS

### Energy Efficiency Standard Offer

Not known. Future approaches will probably utilise a higher level of facilitation by EnergyAustralia to shorten development times and increase security of results.

### Power Factor Correction

Very high.

### Standby Generator

In theory, should be repeatable wherever there are appropriate peak demand characteristics and suitable existing standby generation capacity.

## TIME DELAY BEFORE MAXIMUM RESPONSE ACHIEVED

### Energy Efficiency Standard Offer

Long. While the offer was open for 11 months, applications were only received in the last week. Many proponents have been quite slow to develop projects, and for some this has very low priority. Involvement by "helpful" government departments probably delayed the project outcomes.

### Power Factor Correction

Up to one year, mainly driven by customer investment decision making processes. Several customers responded within five days.

### Standby Generator

Approx 12 months to negotiate contracts, specify and contract for technical upgrades etc.

## WEATHER DEPENDENCE

Nil.

## AVOIDED COSTS

The overall DSM program is likely to result in deferral of capital expenditure of AUD 6.5m for one year. The calculated value of this to EnergyAustralia will be AUD 694,600.

Power factor correction provided 53% of the required amount of demand reduction and energy efficiency is scheduled to provide 42%.

## ACTUAL PROJECT COSTS

### Energy Efficiency Standard Offer

Payments to project proponents AUD 200/kVA - total expected expenditure by EnergyAustralia AUD 250,000.

Project development and management costs AUD 55,000 (estimated final total).

### Power Factor Correction

EnergyAustralia AUD 25,600
Customer investment approx AUD 100,000

### Standby Generator

Anticipated total cost to EnergyAustralia was about AUD 160,000.

## PROJECT COST FROM THE SOCIETAL PERSPECTIVE

Not calculated.

## OVERALL PROJECT EFFECTIVENESS

### Energy Efficiency Standard Offer

As at March 2005, the energy efficiency project is not complete and may not realise its potential. Up to 25% of the offered demand reduction is secured, with the remainder still in some doubt.

Responses from project proponents were difficult to elicit and EnergyAustralia concluded that the DSM provider market is immature and will require a more facilitated approach in future projects.

This was the most expensive element of the overall DSM program and could not have been pursued without the very inexpensive demand reductions achieved by the Power Factor Correction project.

### Power Factor Correction

This project provided a highly reliable reduction in peak demand at a very low net cost to EnergyAustralia. It provided 53% of the required amount to realise a deferral of the target investment.

### Standby Generator

The standby generator was to provide 27% of the required amount of demand reduction to defer capital investment in network infrastructure for one year. Fortunately the other projects in the overall DSM program over-performed and deferral may still be possible.

While the standby generator project was a more expensive part of the overall DSM program, this project would have provided an easily quantifiable and relatively reliable source of dispatchable demand reduction.

## CONTACTS

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*Power Factor Correction Project Close Report* (Pat Dunn, EnergyAustralia)

## CASE STUDY PREPARATION

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## IP06 MAINE-ET-LOIRE DSM PROJECT - FRANCE

| | |
|---|---|
| **Last updated** | 1 September 2005 |
| **Location of Project** | Maine-et-Loire Region, France |
| **Year Project Implemented** | 1997 |
| **Year Project Completed** | 2000 |
| **Name of Project Proponent** | SIEML (association of local authorities), Electricité de France (EDF - generation and transmission utility), FACE (a funding body), ADEME (the French Government's energy efficiency agency) |
| **Name of Project Implementor** | FR2E (project management consultant) and EDF |
| **Type of Project Implementor** | Distribution utility<br>Transmission utility<br>Other: Project management consultant |
| **Purpose of Project** | Deferral of network augmentation |
| **Timing of Project** | Pre contingency |
| **Focus of Project** | Network capacity limitations<br>Voltage fluctuations |
| **Project Objective** | Peak load reduction<br>Voltage regulation |
| **Project Target** | Network element |
| **DSM Measure(s) Used** | Other distributed generation<br>Direct load control<br>Energy efficiency<br>Fuel substitution<br>Other: Voltage regulation with transformers |
| **Specific Technology Used** | Voltage regulators, automatic controllers for domestic boilers, electronic soft starters for pump motors, compact fluorescent lamps, wood fired boiler, diesel generators |
| **Market Segments Addressed** | Residential customers<br>Commercial and small industrial customers<br>Agricultural customers |

### DRIVERS FOR PROJECT

An average region (département) in Metropolitan France has 4,000 km of low voltage rural lines serving some 75,000 customers. In many regions, the cost of reinforcing certain overloaded rural feeders is much higher than the annual financial return from each feeder. This provides a significant opportunity for DSM as an alternative to network augmentation and reinforcement.

In rural areas of France, local authorities (municipalities) own the electricity distribution network and are responsible for the distribution of electricity and for network augmentation and reinforcement. Electricity is supplied by Electricité de France (EDF) under concessional contracts with the local authorities. Augmentation and reinforcement of the distribution network is usually undertaken by associations of a number of local authorities (Syndicats Intercommunal d'Electrification), generally at the regional level. (Note that these arrangements will change with the introduction of a competitive electricity market in France.)

Faced with the financial costs of network augmentation and reinforcement, local authorities favour cost-effective alternatives such as DSM projects. Hence the regional association of local authorities Syndicat Intercommunal d'Electrification de Maine-et-Loire (SIEML) participated in the Maine-et-Loire DSM Project.

The funding body Fonds d'Amortissement des Charges d'Électrification (FACE) receives revenue from a tax on the earnings of electricity distributors at the low voltage level; in urban areas this tax is about 2.5% and in rural areas it is about 0.5%. Since 1995, FACE has supported projects aimed at using alternative technical solutions to the augmentation and reinforcement of the low voltage network, because these solutions are economically profitable.

The DSM project in Maine et Loire was one of the first DSM projects in France; it was carried out between 1997 and 2000. The project started due to the voltage drops (up to 35%) experienced by some users.

## DESCRIPTION OF PROJECT

In the Maine-et-Loire region, two criteria were used to select feeders for the DSM project:

- estimated cost of reinforcement more than EUR 10,000 per customer;
- voltage drops between 20% and 35%.

In addition, feeders were sometimes included in the DSM project if they were more than 30 years old.

Four low voltage feeders supplying 26 customers with strong constraints were selected for multiple DSM measures. There were two categories of measures implemented:

- DSM measures undertaken on the network side of the meter;
- DSM measures undertaken on the customer side of the meter.

SIEML/FACE did not have authority to use public funds to undertake DSM measures on the customer side of the electricity meter. Therefore, SIEML/FACE paid for part of the costs of measures undertaken on the network side of the meter, the other part being paid by EDF. All costs for measures undertaken on the customer side of the meter were paid by EDF and Agence de l'Environnement et de la Maîtrise de l'Énergie (ADEME), the French Government's energy efficiency agency.

### Network-related DSM Measures

The network-related DSM measures included:

- installing voltage regulators on the low voltage feeders (see Figure IP06/1, page 285);
- installing voltage regulators on the network side of the meter at customers' premises;
- use of three phase/single phase transformers to distribute the single-phase current loads of customers across three phases (see Figure IP06/2. page 285).

These measures were financed by SIEML/FACE and EDF and implemented by EDF. The three phase/single phase transformers were owned by EDF; they could be recovered and installed on other constrained feeders.

**Figure IP06/1. Voltage regulator**

**Figure IP06/2. Three Phase/Single Phase Transformer**

### Customer-related DSM Measures

The customer-related DSM measures included:

- shifting the use of electric household appliances and water heaters to off-peak periods;
- installing inverters for lighting and data processing end-uses;
- implementing electronic "soft" starters for electric motors (see Figure IP06/3);
- distributing compact fluorescent lamps (90 CFLs among six customers);
- implementing automatic controllers for domestic boilers;
- installing a wood-fired boiler (see Figure IP06/4, page 287);
- using portable diesel generators for intermittent generation at selected sites (see Figure IP06/5, page 287);
- installing a 40 kVA diesel generator at a pig breeding farm.

All equipment installed on the customer side of the electricity meter was owned by the customers. The customers chose the equipment installers and supervised them. The customers sent the bills to EDF and ADEME and were later reimbursed with a subsidy on the cost of the equipment and installation. Some customers installed equipment by themselves, they had to follow specifications from ADEME and EDF to receive the subsidy.


**Figure IP06/3. Electronic "Soft" Starter for Electric Motors**

**Figure IP06/4. Wood-fired Boiler**

**Figure IP06/5. Portable Diesel Generator**

## Organisation of the DSM Project

A project management consultant (FR2E) was engaged to coordinate the whole project, including:

- planning of the project, administrative follow-up: visits to the customers, establishing of technical specifications and subsidy contracts;
- implementation of two measuring campaigns (before and after installation of the DSM measures), analysis of results;
- supervision during and after the implementation of the different DSM measures: assistance with choosing the best equipment, advising customers about selecting equipment installers, supervision and certification of works;
- phone assistance: FR2E were the single contact point for customers during the project;
- technical evaluation, writing technical reports for each feeder and writing the final report of the whole project.

## RESULTS

| Residential Customers Participating | Commercial and Small Industrial Customers Participating | Agricultural Customers Participating | Large Industrial Customers Participating | Additional Generation Installed |
|---|---|---|---|---|
| 26 | | 8 | | |

| Peak Load | Peak Load Reduction | Duration of Peak Load Reduction | Overall Load Reduction | Energy Savings | Network Augmentation Deferral |
|---|---|---|---|---|---|
| | | | | | 84 to 120 months |

## HOW LOAD REDUCTION WAS MEASURED

## RESULTS ACHIEVED

Only the number and duration of voltage drop and unplanned outage events were measured. The results are shown in Tables IP06/1 and IO06/2, page 289.

## CONFIDENCE LEVEL IN ACHIEVING RESULTS

Although the results just after the project was completed were positive, the safety margin for avoiding future network constraints is low because the four feeders selected for the project had very high voltage drops (between 20 and 35%).

## REPEATABILITY OF RESULTS

To make the results reproducible, the selection criterion for voltage drops should be lower: between 10 and 20%.

| **Table IP06/1. Number of Voltage Fluctuation and Unplanned Outage Events** | | | |
|---|---|---|---|
| **Name of feeder** | **Number of Events*** | | **Gains** |
| | **Before DSM** | **After DSM** | **%** |
| La Jumelière | 11,313 | 699 | 94 |
| Coron | 1,469 | 544 | 63 |
| Chanteloup | 3,049 | 81 | 97 |
| Gennes | 1,054 | 41 | 93 |
| * Disturbances outside standards: micro outages, short outages; voltage fluctuations outside standards (230 V -10 %; 230 V +6 %). Sampling rate : 10 milliseconds (ms). All events with a duration higher than 10 ms were analysed and stored. Measurements carried out during seven consecutive days. | | | |

| **Table IP06/2. Duration of Voltage Fluctuation and Unplanned Outage Events** | | | |
|---|---|---|---|
| **Name of feeder** | **Total Duration of Events* (minutes)** | | **Gains** |
| | **Before DSM** | **After DSM** | **%** |
| La Jumelière | 3,514 | 21 | 99 |
| Coron | 953 | 86 | 91 |
| Chanteloup | 1,098 | 6 | 99 |
| Gennes | 1,401 | 9 | 98 |
| * Disturbances outside standards: micro outages, short outages; voltage fluctuations outside standards (230 V -10 %; 230 V +6 %). Sampling rate : 10 milliseconds (ms). All events with a duration higher than 10 ms were analysed and stored. Measurements carried out during seven consecutive days. | | | |

## TIME DELAY BEFORE MAXIMUM RESPONSE ACHIEVED

## WEATHER DEPENDENCE

## AVOIDED COSTS

Cost of the avoided network reinforcements EUR 158,818
Cost of DSM measures EUR 71,040
Deferral of network reinforcement 7 to 10 years
Benefit EUR 7,978

## ACTUAL PROJECT COSTS

SIEML/FACE EUR 10,247
EDF/ADEME EUR 24,145
ADEME EUR 29,361
Customers EUR 7,287
Total EUR 71,040 (inclusive of taxes)

## PROJECT COST FROM THE SOCIETAL PERSPECTIVE

## OVERALL PROJECT EFFECTIVENESS

For this experimental project, the results were technically very good. An investigation conducted six months after the end of the project showed that the customers were very satisfied with the improvement in the quality of supply. The farmers were particularly interested in the innovative nature of the project.

## CONTACTS

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## CASE STUDY PREPARATION

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## IP07 DEFERRING NETWORK INVESTMENT - FINLAND

| | |
|---|---|
| **Last updated** | 13 December 2005 |
| **Location of Project** | Rural area in the Kuopio region of central Finland about 400 km north of Helsinki |
| **Year Project Implemented** | 1995 |
| **Year Project Completed** | 1997 |
| **Name of Project Proponent** | Savon Voima Oy |
| **Name of Project Implementor** | Unknown |
| **Type of Project Implementor** | End-use customer(s) |
| **Purpose of Project** | Deferral of network augmentation |
| **Timing of Project** | Pre contingency |
| **Focus of Project** | Network capacity limitations |
| **Project Objective** | Peak load reduction |
| **Project Target** | Network element |
| **DSM Measure(s) Used** | Other distributed generation<br>Energy efficiency<br>Other |
| **Specific Technology Used** | On-site diesel generator and energy efficiency measures |
| **Market Segments Addressed** | Large industrial customers |

### DRIVERS FOR PROJECT

At the commencement of the project, the demand in the defined rural distribution area could be met without problems but the distribution network was reaching its capacity limit. In addition, the back-up connection to the area was not strong enough to meet the peak demand if the normal mains supply failed.

The purpose of the project was to investigate demand-side options available to the utility to defer the investment required to increase the capacity of the distribution network in this area.

### DESCRIPTION OF PROJECT

Savon Voima Oy, founded in 1947, is an electricity utility located in central Finland which, at the time of this project, was owned by 29 municipalities within its distribution area.

The market consisted of all the customers in the defined rural distribution area. The market structure in this area was exceptional: one large customer accounted for half of the energy used in the rural area and the remaining 250 customers consumed the other half. Therefore, the target group divided naturally into two parts according to the amount of energy consumption: one large customer and 250 small customers in the household and agriculture sectors.

For the large customer, the utility suggested carrying out a thorough energy audit to find and assess all the relevant measures available to, firstly, reduce the customer’s energy bill and, secondly, to address supply security.

The utility proposed two marketing approaches for small customers. In the farming sector, the utility planned to carry out a project, in co-operation with an insurance company, focusing both on security inspection of electrical appliances and energy efficiency in general. For the residential sector, the utility planned a promotion of energy efficient sauna stoves.

The insurance company's aim in participating in a DSM project for agricultural customers was to reduce the number of insurance claims by identifying critical electrical equipment and carrying out repairs before the equipment failed. Failures in electrical equipment are the main cause of fires in the defined rural distribution area.

The large customer operated a saw mill, machine shop and brick works. The financial viability of alternative DSM options applicable for this customer was clarified by a thorough energy audit carried out by the utility staff and paid for by the customer.

Hourly metering data for the customer indicated that peaks in the customer's demand were high and rare, indicating an opportunity for peak clipping by controlling selected loads with timers or by installing a diesel generator to clip the peaks.

The energy audit revealed that, with the installation of a 250 kW peak clipping diesel generator operating for 500 hours per year, the customer's bill savings would exceed the costs of the investment. This recommendation was accepted by the customer and the diesel generator was installed during the project.

Once the DSM opportunities for the large customer were identified and implemented, the work with the small customers was postponed.

## RESULTS

| Residential Customers Participating | Commercial and Small Industrial Customers Participating | Agricultural Customers Participating | Large Industrial Customers Participating | Additional Generation Installed |
|---|---|---|---|---|
| | | | 1 | 0.25 MW |

| Peak Load | Peak Load Reduction | Duration of Peak Load Reduction | Overall Load Reduction | Energy Savings | Network Augmentation Deferral |
|---|---|---|---|---|---|
| | | | | | |

## HOW LOAD REDUCTION WAS MEASURED

## RESULTS ACHIEVED

During the winter period 1996/97 the diesel was used for electricity generation to reduce peaks in the large customer's load.

However, during the course of the project the customer changed electricity supplier. The customer belongs to a nation-wide organisation and, with the restructuring of the electricity market in Finland, the organisation decided to centralise its power procurement to obtain reductions in power costs.

The customer now has another electricity supplier and its energy procurement forms only a part of the total demand of the organisation. The real benefits to the customer of the diesel generator in this situation can be calculated only after a company-wide study in which the total load curve as well as load control practices are taken into account.

Unfortunately, no information is available about whether the customer's actual usage of the diesel generator changed following the change of electricity supplier.

## CONFIDENCE LEVEL IN ACHIEVING RESULTS

## REPEATABILITY OF RESULTS

## TIME DELAY BEFORE MAXIMUM RESPONSE ACHIEVED

## WEATHER DEPENDENCE

## AVOIDED COSTS

## ACTUAL PROJECT COSTS

## PROJECT COST FROM THE SOCIETAL PERSPECTIVE

## OVERALL PROJECT EFFECTIVENESS

This project commenced as an integrated DSM project to investigate the feasibility of implementing a range of DSM options across several customer classes to achieve deferral of investment in a network augmentation.

However, because of the unique situation in which one large customer accounted for 50% of the load in the relevant distribution area, only one DSM option was implemented - the installation of a diesel generator for peak clipping at the large customer's site.

The effectiveness of this option then became uncertain when the large customer changed electricity supplier and consequently the benefits to the customer of the diesel generator changed.

## CONTACTS

## SOURCES

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## CASE STUDY PREPARATION

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## IP08 FRENCH RIVIERA DSM PROGRAM - FRANCE

| | |
|---|---|
| **Last updated** | 31 July 2006 |
| **Location of Project** | Provence-Alpes-Côte d'Azur (PACA) region of France |
| **Year Project Implemented** | 2003 |
| **Year Project Completed** | |
| **Name of Project Proponent** | Préfecture des Alpes-Maritimes and Région Provence-Alpes-Côte d'Azur |
| **Name of Project Implementor** | Agence de l'Environnement et de la Maîtrise de l'Energie (ADEME), Région Provence-Alpes-Côte d'Azur and Electricité de France (EDF) |
| **Type of Project Implementor** | Distribution utility<br>State or federal government agency |
| **Purpose of Project** | Deferral of network augmentation |
| **Timing of Project** | Pre contingency |
| **Focus of Project** | Network capacity limitations |
| **Project Objective** | Peak load reduction<br>Overall load reduction |
| **Project Target** | Network region |
| **DSM Measure(s) Used** | Cogeneration<br>Other distributed generation<br>Energy efficiency |
| **Specific Technology Used** | |
| **Market Segments Addressed** | Residential customers<br>Commercial and small industrial customers<br>Non-customer related (eg installation of additional generation not on a customer site) |

### DRIVERS FOR PROJECT

The Provence-Alpes-Côte d'Azur (PACA) region of France is supplied from Tavel near Avignon, via two 400 kV transmission lines - a southern line which goes to Broc-Carros via Néoules and a northern line which goes as far as Boutre. A 225 kV line completes the ring by connecting Boutre to Broc-Carros (Figure IP08/1).

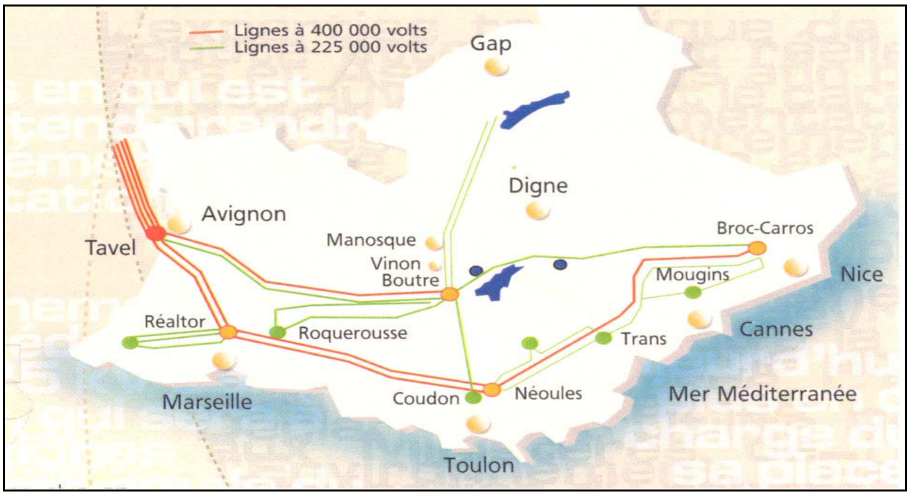


**Figure IP08/1. High Voltage Transmission Lines in the Eastern Part of the Provence-Alpes-Côte d'Azur region of France**

Planning for the upgrading of the Boutre-Carros line to supply increasing load growth in the area commenced in 1983. The initial plan comprised double 400 kV lines on separate easements over 170 km in length. Six route options for the upgraded line were proposed. However, there was strong opposition to this project because the lines would pass through the classified scenic gorges of the Verdon Regional Park.

In 1994, a petition against all the route options collected 3 000 signatures. In January 1997, a seventh route option was proposed. In July and August, a petition was circulated supported by local governments in the area. The petition requested studies of alternatives to the line and 23 000 signatures were obtained, including 12% of tourists in the European Union. In November, the Department of the Environment established a public commission of inquiry into the Boutres-Carros line and the project was suspended.

In 2000, a decision was made on an alternative solution. This comprised:

- replacement of the existing 225 kV line by a single 400 kV line, 100 km in length, on the same easement;
- removal of an existing 150 kV line which accompanied the 225 kV line; and
- implementation of an ambitious DSM and renewable energy distributed generation program called the “Eco-Energy Plan” to slow down the growth in demand.

In May 2006, the state court, after a complaint from an environmental group, refused planning permission for the upgrading of the Boutre-Carros line. Therefore, at present, the DSM program is the only way to secure supply to this region by keeping load growth within the capacity of the existing 250 kV line.

## DESCRIPTION OF PROJECT

The Eco-Energy Plan comprises a very large integrated DSM project (including distributed generation). It is the largest DSM project in the European Union and possibly the world. It has three main objectives:

- to increase the efficiency of electricity usage and to create a critical mass of scientific and technological competence in relation to electricity DSM;
- to modify the electricity-using behaviour of consumers, and building owners and managers;
- to contribute to the development of local renewable energies and to establish a solid basis for future energy choices.

The following description is based on the analysis and program design developed following the initial decision in 2000. Following the refusal of planning permission in 2006, the DSM program will have to be strengthened to meet the new constraints.

### Preliminary Studies

Preliminary studies were carried out in 2001:

- to quantify the level of load reduction required, after the scheduled completion of the new 400 kV line in 2005, to avoid network constraints in the period to 2020;
- to understand the evolution and structure of peak demand in the eastern part of the Provence-Alpes-Côte d'Azur region;

- to quantify the potential load reductions achievable through implementing DSM and distributed generation; and
- to identify a detailed program of DSM and distributed generation measures.

Figure IP08/2 shows that, following the scheduled completion of the new 400 kV line in 2005, with a fault level of n-1 capacity constraints were likely to reappear in the winter of 2018. To avoid a further new line being required before 2020, the Eco-Energy Plan would have to reduce load by 35 MW in winter.

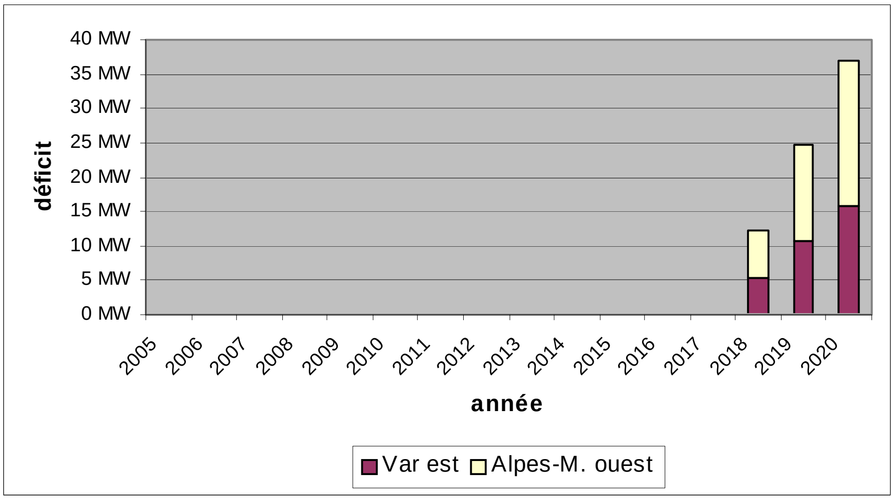


**Figure IP08/2. Capacity Constraints in Winter with Fault Level n-1 Following Scheduled Completion of the New 400 kV Line in 2005**

Figure IP08/3 shows that with a fault level of n-2, capacity constraints were likely to reappear in the summer of 2016. An n-2 fault level is possible in summer because of the risk of forest fires under the southern double circuit 400 kV line. To avoid a further new line being required before 2020, the Eco-Energy Plan would have to reduce load by 130 MW in summer.

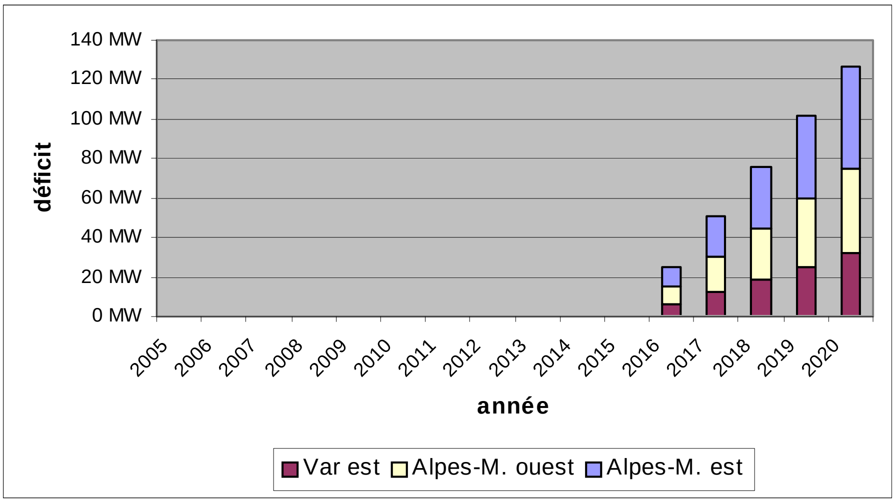


**Figure IP08/3. Capacity Constraints in Summer with Fault Level n-2 Following Scheduled Completion of the New 400 kV Line in 2005**

Figures IP08/4 and IP08/5 show the end-use composition of peak demand in the region in winter and summer. In winter, peak demand is dominated by lighting and heating and in summer air conditioning is dominant with lighting also an important contributor to the peak.

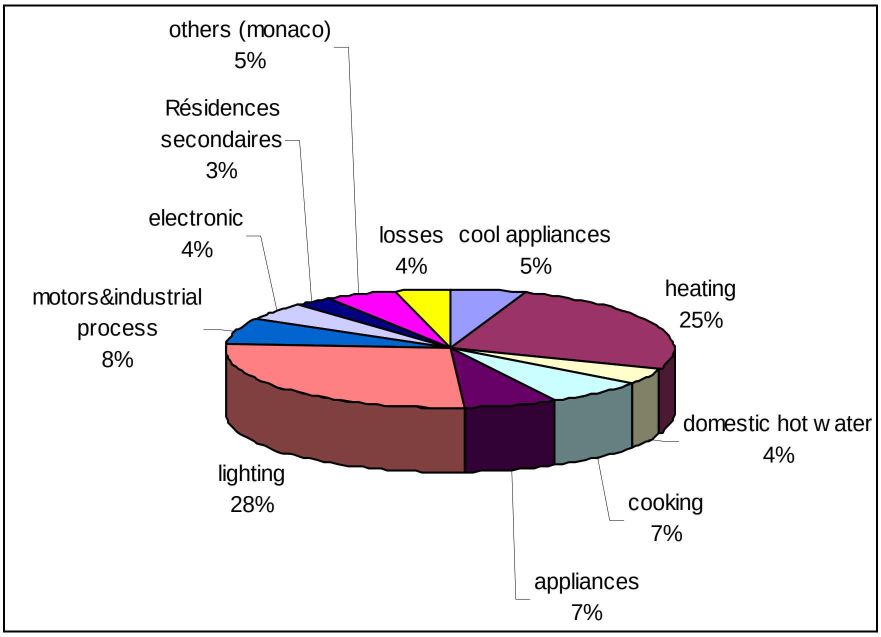


**Figure IP08/4. Winter Peak Demand by End-use in the Eastern Part of the Provence-Alpes-Côte d'Azur Region**

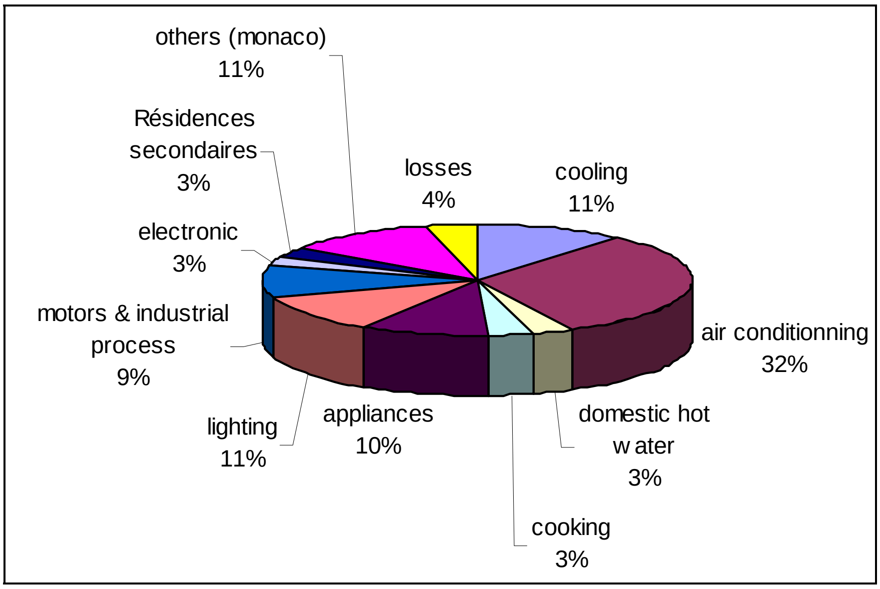


**Figure IP08/5. Summer Peak Demand by End-use in the Eastern Part of the Provence-Alpes-Côte d'Azur Region**

Figure IP08/6 shows forecasts of the potential load reductions achievable through the Eco-Energy Plan by implementing DSM and distributed generation over the period 2005 to 2020. Figure IP08/7 shows a breakdown of the forecast load reductions achievable in winter 2006. Based on these forecasts, the target load reduction to be achieved through the Eco-Energy Plan in winter 2006 was set at 45 MW.

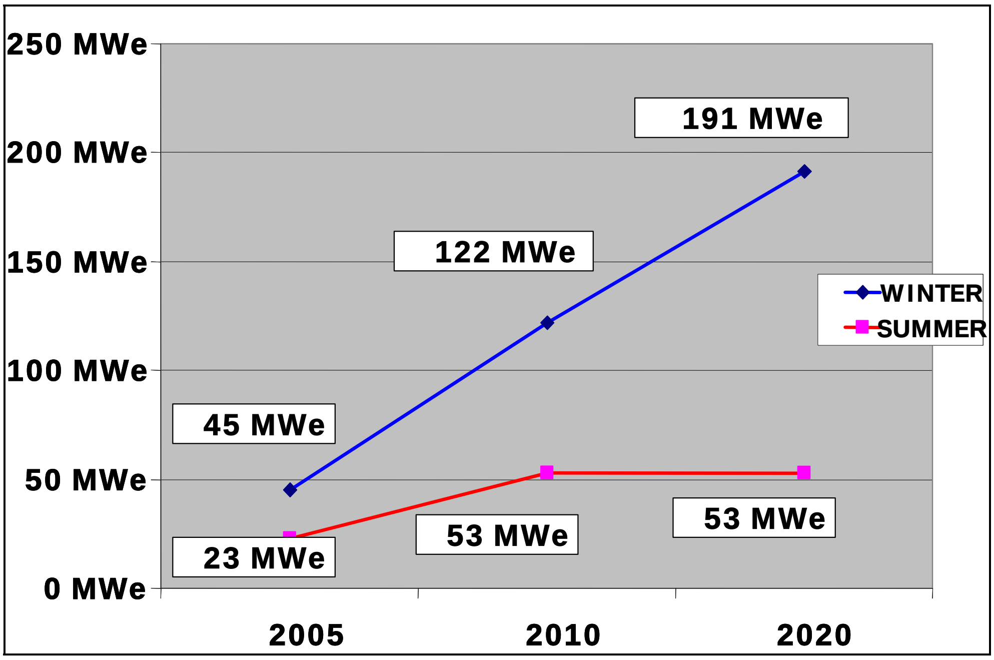


**Figure IP08/6. Forecasts of Potential Load Reductions Achievable through the Eco-Energy Plan 2005 to 2020**

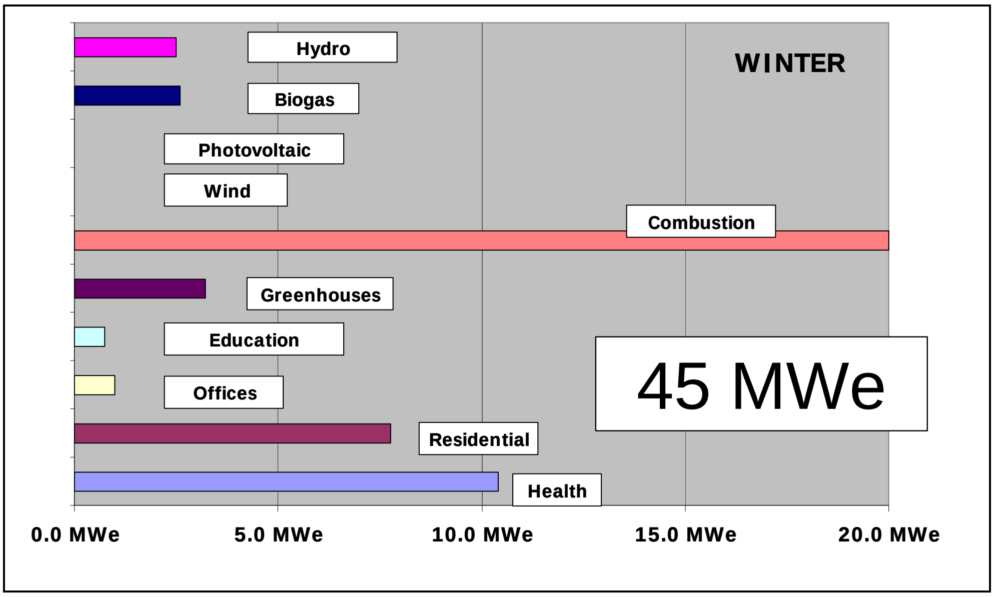


**Figure IP08/7. Forecasts of Potential Load Reductions Achievable through the Eco-Energy Plan in Winter 2006**

## Implementation

The Eco-Energy Plan was launched in March 2003. Initially six priority areas were identified:

- communication and information;
- new building construction;
- efficient lighting and domestic electrical appliances;
- large consumers and distributed generation;
- demonstration projects by the Eco-Energy Plan institutional partners; and
- public housing.

In 2004, a further two priority areas were added:

- existing buildings; and
- tourism.

Figure IP08/8 shows the forecast impacts and costs of the identified DSM measures to be implemented through the Eco-Energy Plan.

| | Impact on Winter Peak (MW) | Impact on Summer Peak (MW) | Impact on Consumption (GWh) | Public Funding (M€) |
|---|---|---|---|---|
| Communication and information campaigns | | | | 2.9 |
| Increasing awareness and training of engineering departments and installers | | | | 3.6 |
| Demonstration energy management projects in State and local authorities, EDF and ADEME | 26 | 5.5 | 52.5 | 4.6 |
| Specific measures for new residential and commercial buildings | 1.2 | 0.1 | 2.5 | 7.6 |
| Large-scale dissemination of CFLs in social sector | 2.3 | 0.5 | 6 | 2 |
| Promotion of efficient lighting in commercial sector | 24 | 12 | 72 | 1.8 |
| Promotion of CFLs and energy efficient white goods | 57 | 8 | 115 | 3.6 |
| Energy efficient retrofitting in residential and commercial sectors | 41 | 11.5 | 125 | 9.1 |
| Energy efficient retrofitting in tourism sector | 3 | 2.3 | 9 | 2.6 |
| Domestic hot water | | 15 | 5 | 3.3 |
| Wood heating | 8 | | 7 | 2.1 |
| Specific measures for large industrial and commercial consumers | 16.5 | 11 | | 2.3 |
| Cogeneration, biogas, hydro installations | 45 | 23 | | 3 |
| Photovoltaic installations | 0 | 0.3 | | 0.9 |
| Evaluation | | | | 3 |
| **Total** | 224 | 89.2 | 394 | 52.4 |

**Figure IP08/8. Forecast Impacts and Costs of Identified DSM Measures**

### *Communication and Information*

A general public information campaign was launched on 18 March 2003. Each year, the campaign is implemented in two waves on a seasonal basis: summer and winter. The campaign includes: paid advertisements in newspapers, and on radio and television; information booklets and posters; a quarterly newsletter; a telephone information centre; a website; energy audit software for residential dwellings; and displays in shopping centres and fairs (see Figure IP08/9).


**Figure IP08/9. Eco-Energy Plan Information Stall at a Shopping Centre**

Targeted educational material on energy saving has been produced for use by school children, including information on how to carry out energy saving projects at home. These projects are intended to influence whole families to save energy not just the children.

### *New Building Construction*

Targeted information material on energy efficient lighting has been developed for engineering and building design firms. Software has been developed to enable the design of energy efficient communities. Promotional material has been produced to assist building designers to convince their customers to invest in energy efficient buildings.

### *Efficient Lighting and Domestic Electrical Appliances*

Negotiations with lamp manufacturers enabled energy efficient lamps to be offered at a 20% discounted price in the Alpes-Maritime region. The Eco-Energy Plan has also made available loans to cover the cost of energy efficient lighting installations; loans of between EUR 2 000 and EUR 16 000 are available at interest rates of 2.5% over three years or 3.5% over five years.

### Large Consumers and Distributed Generation

A working group on cogeneration has been established and a technical/economic study has been completed to identify the potential for the development of small cogeneration installations (200-300 kW) in the region. This study investigated simplifying procedures for connection to the low voltage network and examined tariff options for purchases of electricity generated by cogeneration plants.

A study of the potential for increased hydro-electricity generation in the region has also been completed. This study investigated increasing the capacity of existing hydro power stations and installing new power stations on irrigation canals, drinking water supply infrastructure and rivers.

Finally, ADEME and the regional government have financed the installation of 40 grid-connected photovoltaic modules in the region.

### Demonstration Projects

A database of about 100 public sector buildings in the region has been established, including colleges, hospitals and offices owned by the national, regional and local governments, Electricité de France (EDF), Gas de France and ADEME. An initial analysis of the information in the database identified that some facility managers were interested in carrying out energy efficiency and DSM demonstration projects. Consequently, an initial program of feasibility studies has been launched. In particular, the regional government, EDF and ADEME are financing 80% of the cost of feasibility studies in hospitals. In addition 12 colleges in the Alpes-Maritimes have voluntarily agreed to undertake DSM feasibility studies.

In late 2004, EDF carried out energy audits of its highest energy-using buildings in the region. The first implementation of energy saving measures aims to save 7% of electricity usage (600 MWh) per annum. EDF is also carrying out an internal awareness campaign about energy saving for its staff. This initiative aims to change the behaviour of EDF staff in administrative buildings without implementing costly technical measures. At the completion of this program, EDF will prepare a kit about energy saving measures that will be made available to private sector companies and local communities.

In March 2003, the Eco-Energy Plan partners brought together 29 local communities in the Alpes-Maritimes region to encourage them to undertake effective DSM measures. The first stage of this program required the communities to take a simple action in one of three areas of their own operations: investigation of opportunities for interruptibility; the installation of energy efficient lighting in one or more of their facilities, or the management of street lighting. In the second stage, the communities could undertake basic measures directed to residents in their areas.

### Public Housing

The Eco-Energy Plan has been working with managers of public housing to improve the energy efficiency of their properties so as to reduce the energy bills of their tenants. This is particularly important when existing properties are renovated. To assist the property managers, it is proposed to develop specific DSM measures for public housing, starting with quick energy audits of the properties to identify major DSM options.

### *Existing Buildings*

The Eco-Energy Plan has developed a book of technical solutions applicable to the Mediterranean area that assist the design of buildings adapted to the local climatic conditions and which make use of local renewable energies.

To develop the energy services industry in the Alpes-Maritimes region, a database was constructed to identify a range of products and services that enable energy savings in residential and commercial buildings. The database is available on the internet and it is also possible to purchase the products on-line. Prior to the development of the database, there were few energy service companies (ESCOs) in the Alpes-Maritimes region. Now several new ESCOs have been established.

### *Tourism*

In January 2004, an engineering and design firm Fludia was commissioned to assist the hotel sector to better understand and control their consumption of electricity. Individual hotels were provided by mail with small recording devices which they used for three weeks and then returned to Fludia. The recordings were analysed and individual reports were provided to each hotel detailing the characteristics of the hotel's electricity use and identifying anomalies and opportunities for energy saving. Some hotels also benefited from individual telephone consultations. Some energy saving measures generally applicable across the hotel sector were identified, eg switching off coffee machines when not in use and reducing the use of water-heaters in the middle of the day and when the hotels had low occupancy rates.

## RESULTS

| Residential Customers Participating | Commercial and Small Industrial Customers Participating | Agricultural Customers Participating | Large Industrial Customers Participating | Additional Generation Installed |
|---|---|---|---|---|
| | | | | |

| Peak Load | Peak Load Reduction | Duration of Peak Load Reduction | Overall Load Reduction | Energy Savings | Network Augmentation Deferral |
|---|---|---|---|---|---|
| | Reduction of 7.5% in winter; no reduction in summer | | | | |

## HOW LOAD REDUCTION WAS MEASURED

Estimate. The actual peak load is measured on the transmission network and compared to the initial estimate of the peak load if the DSM program were not implemented.

## RESULTS ACHIEVED

## CONFIDENCE LEVEL IN ACHIEVING RESULTS

Medium: the DSM program is too recent to have enough feedback.

## REPEATABILITY OF RESULTS

## TIME DELAY BEFORE MAXIMUM RESPONSE ACHIEVED

## WEATHER DEPENDENCE

## AVOIDED COSTS

## ACTUAL PROJECT COSTS

The budget for implementation of the Eco-Energy Plan is EUR 6 million. The project is financed by the regional government of Provence-Alpes-Côte d'Azur, Agence de l'Environnement et de la Maîtrise de l'Energie (ADEME) and Electricité de France (EDF).

## PROJECT COST FROM THE SOCIETAL PERSPECTIVE

## OVERALL PROJECT EFFECTIVENESS

## CONTACTS

## SOURCES

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## CASE STUDY PREPARATION

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# IP09 MANWEB DEMAND SIDE MANAGEMENT PROJECT - WALES, UNITED KINGDOM

| | |
|---|---|
| **Last updated** | 4 October 2008 |
| **Location of Project** | Holyhead, Anglesey, North Wales |
| **Year Project Implemented** | 1993 |
| **Year Project Completed** | 1993 |
| **Name of Project Proponent** | Manweb plc |
| **Name of Project Implementor** | Manweb plc |
| **Type of Project Implementor** | Distribution utility, Electricity retailer/supplier |
| **Purpose of Project** | Deferral of network augmentation |
| **Timing of Project** | Pre contingency |
| **Focus of Project** | Network capacity limitations |
| **Project Objective** | Peak load reduction |
| **Project Target** | Network region |
| **DSM Measure(s) Used** | Energy efficiency, Power factor correction |
| **Specific Technology Used** | Compact fluorescent lamps<br>Loft insulation<br>Draught proofing<br>Hot water tank insulation<br>Power factor correction |
| **Market Segments Addressed** | Residential customers<br>Commercial and small industrial customers<br>Large industrial customers |

## DRIVERS FOR PROJECT

Manweb plc (formerly the Merseyside and North Wales Electricity Board) was the regional electricity distributor and supplier (ie retailer) for Merseyside, North Wales and parts of Cheshire in the United Kingdom. It is now part of Scottish Power.

The Manweb DSM project was designed to evaluate the principles and techniques necessary to introduce a major DSM program. It aimed to reduce peak demand for electricity in the town of Holyhead on Holy Island, just off the west coast of the island of Anglesey in North Wales.

At the time in 1993, Holyhead was an economically depressed town, comprising mostly low-income households (3496 homes in all), small businesses and a number of major industrial loads. The largest single load on the island was a school, followed by the port (a departure point for sea-going ferries to Northern Ireland) and three or four other industrial sites. The project was an alternative to a major investment program in electricity distribution that would otherwise have been required to cope with increasing electricity demand in the area.

## DESCRIPTION OF PROJECT

Market research for the project commenced in 1992. A survey of 600 residential customers was undertaken to establish base data on penetration of energy efficiency measures and the age and condition of the appliance stock. An audit of lighting use was also carried out.

Marketing was carried out before implementation, based mainly on experience in the United States, to discover the best methods to achieve maximum penetration of the measures used in the project. Marketing was mainly by direct mailings, but also through local radio, TV and newspapers, and local schools.

Implementation of measures began in 1993 and lasted for approximately one year. Measures implemented in the project included, for the residential sector:

- an offer of two compact fluorescent lamps (CFLs) for each household, installed in their home, at a price of GBP0.75 each compared with the normal retail price of GBP10.60 (1993 prices);
- an offer, for electrically heated households, of loft insulation and draught proofing at a price of GBP30.90 compared with an average price of GBP160;
- free hot-water tank insulation for households using electricity for water heating; and
- rebates of up to GBP50 on energy efficient appliances.

For the small business sector, measures offered were:

- a free insulation jacket for each hot water tank;
- two CFLs at GBP0.75 each; and
- a free lighting audit.

Customers in the larger industrial/commercial sector were offered:

- a free energy audit;
- subsidies on energy saving measures; and
- subsidies on power-factor correction equipment.

The subsidies in the industrial/commercial sectors were set at levels to provide a 12 month payback on the customer's investment.

## RESULTS

| Residential Customers Participating | Commercial and Small Industrial Customers Participating | Agricultural Customers Participating | Large Industrial Customers Participating | Additional Generation Installed |
|---|---|---|---|---|
| | | | | |

| Peak Load | Peak Load Reduction | Duration of Peak Load Reduction | Overall Load Reduction | Energy Savings | Network Augmentation Deferral |
|---|---|---|---|---|---|
| | 808 kVA | | | | |

## HOW LOAD REDUCTION WAS MEASURED

Other. Measured at distribution transformers.

## RESULTS ACHIEVED

The project achieved a 10% reduction in maximum daily demand, of which 30% was from the residential sector, 13% from the small business sector and 57% from the industrial/commercial sector. The reduction measured at the distribution transformers was 374 kVA, with a further 88 kVA achieved after the end of the project with late implementation by one industrial consumer.

- Several new developments in the area led to increased load growth during the time scale of the project. These comprised:
- expansion of the port (256 kVA);
- new motive power at an industrial site (30 kVA);
- increase in ownership of domestic appliances (40 kVA); and
- expansion of the housing stock (20 kVA).

The net reduction from the implemented measures was therefore the measured decrease (374 kVA) plus the load growth (346 kVA). Including the 88 kVA implemented after the project, the total reduction was 808 kVA.

Post project research was carried out to see the how much energy was being saved and whether advice and installed measures were still being used.

In the residential market the penetration of the CFLs reached 79%, leading to savings of 88 kVA. Water cylinder insulation saved 47 kVA with a penetration rate of 84%. Draught proofing and loft insulation were less well taken up with penetration rates of 20% and 30% respectively. All the insulation measures will, however, be sustained, whereas the return of CFLs to higher prices meant that many of these would not be replaced (53% were sustained according to Manweb). The uptake of the subsidised energy efficient appliances was estimated to be negligible.

The small business market was less ready to take up measures on offer. CFLs reached only 24% penetration and insulation of water cylinders 17%. A small number of businesses (6%) undertook lighting refurbishment programs resulting in a saving of 92 kVA and 7.4 kVA for water cylinder insulation and CFLs respectively.

In the industrial sector there were fewer potential consumers to involve, but those that took up the offers saved significant amounts of electricity, accounting for 57% of the total saved by the project. 60% of the peak demand was saved by just four sites using power factor correction. In total this sector saved 282 kVA from power factor correction, 125 kVA through lighting programs and 55 kVA from other measures.

## CONFIDENCE LEVEL IN ACHIEVING RESULTS

## REPEATABILITY OF RESULTS

## TIME DELAY BEFORE MAXIMUM RESPONSE ACHIEVED

## WEATHER DEPENDENCE

## AVOIDED COSTS

## ACTUAL PROJECT COSTS

The project was partly funded under the European Commission's SAVE program, with the rest of the finance coming from Manweb itself. Total expenditure on the project was GBP243,000 (1993 values).

The average costs for load reductions were as follows:

- residential sector, GBP512/kVA;
- small businesses, GBP507/kVA;
- larger industrial consumers, GBP126/kVA.

These figures are somewhat distorted by the high level of the subsidy for CFLs in the residential and small business sectors. Power factor correction in the industrial sector proved to be particularly effective in reducing peak demand and avoiding investment in new supply capacity.

## PROJECT COST FROM THE SOCIETAL PERSPECTIVE

## OVERALL PROJECT EFFECTIVENESS

The Manweb DSM project reduced peak demand by 808 kVA (of which 346 kVA was load growth) and further investment in plant was deemed unnecessary. The project was considered a success because it achieved its aim of avoiding investment in further plant by reducing peak demand by 10%. The project achieved this result with a smaller range of measures than anticipated. Appliance rebates did not lead to increased uptake of energy efficient appliances and the small business sector proved to be more difficult to involve in the project than expected.

## CONTACTS

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## CASE STUDY PREPARATION

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# IP10 COALITION OF LARGE DISTRIBUTORS CONSERVATION AND DEMAND MANAGEMENT PROGRAMS - CANADA

| | |
|---|---|
| **Last updated** | 4 October 2008 |
| **Location of Project** | Southern Ontario, Canada |
| **Year Project Implemented** | 2005 |
| **Year Project Completed** | 2007 |
| **Name of Project Proponent** | Coalition of Large Distributors, Ontario, Canada |
| **Name of Project Implementor** | Enersource Hydro Mississauga<br>Horizon Utilities<br>Hydro Ottawa<br>PowerStream<br>Toronto Hydro-Electric System Limited<br>Veridian Connections |
| **Type of Project Implementor** | Distribution utility, Electricity retailer/supplier |
| **Purpose of Project** | Deferral of network augmentation |
| **Timing of Project** | Pre contingency |
| **Focus of Project** | Network capacity limitations |
| **Project Objective** | Peak load reduction<br>Overall load reduction |
| **Project Target** | Network region |
| **DSM Measure(s) Used** | Interruptible loads<br>Direct load control<br>Energy efficiency |
| **Specific Technology Used** | Compact fluorescent lamps<br>Programmable thermostats,<br>Load limiting switches |
| **Market Segments Addressed** | Residential customers<br>Commercial and small industrial customers |

## DRIVERS FOR PROJECT

In Ontario, between 2001 and 2004, three rate adjustments (“tranches”) were made in relation to customers’ electricity bills. These rate adjustments were necessary to assist local electricity distributors establish themselves as commercial business enterprises, following the introduction in 1998 of the Electricity Act that restructured the electricity industry in Ontario. Electricity distributors in Ontario both manage the distribution network and act as electricity retailers, selling electricity directly to end-use customers. There are also independent retailers that compete with distributors to supply electricity to end-use customers.

As a condition on applying the third tranche adjustment, the Province of Ontario mandated distributors to invest in conservation and demand management (CDM) programs, beginning in 2005. Distributors were required to invest in local CDM programs the equivalent of one year’s rate adjustment from the third tranche. Oversight for third tranche spending is provided by the Ontario Energy Board.

Consequently in 2005, Ontario electricity distributors brought forward, and the Board approved, requests for CAD163 million in funding for CDM activities The Board subsequently provided processes for distributors to apply for additional funding for CDM activities as part of the 2006 and 2007 distribution rate adjustment processes.

In March 2007, the Ontario Energy Board confirmed its ongoing role in CDM activities by electricity distributors. The Board is responsible for:

- the review and approval of spending levels and proposed CDM programs;
- reporting guidelines;
- program evaluation; and
- the review and approval of applications by distributors for recovery of some of their CDM-related costs through two regulatory mechanisms: the Lost Revenue Adjustment Mechanism and the Shared Savings Mechanism.

The Lost Revenue Adjustment Mechanism is a retrospective adjustment which is designed to recover revenues lost from distributor-supported CDM activities in a prior year. It is designed to compensate a distributor only for unforecasted lost revenues associated with CDM activities undertaken by the distributor within its licensed service area. Forecasted reductions in revenue resulting from CDM activities are included in the standard mechanism through which distributors recover fixed distribution costs. This mechanism comprises both fixed and variable rates, which are set based on a forecast of consumption, including natural changes in energy efficiency.

The Shared Savings Mechanism is a shareholder incentive that encourages distributors to pursue CDM programs. This mechanism is available for customer focused initiatives that are funded through distribution rates and where the costs of the initiatives are expensed, such as efficiency improvements in the use of electricity.

## DESCRIPTION OF PROJECT

The Coalition of Large Distributors (CLD) consists of six of Ontario's largest electricity distributors: Enersource Hydro Mississauga, Horizon Utilities, Hydro Ottawa, PowerStream, Toronto Hydro-Electric System Limited and Veridian Connections. The members of the Coalition provide electricity for 40 per cent of Ontario's electricity customers.

In 2005, the Coalition set out to design and deliver a comprehensive portfolio of conservation and demand management activities as part of its Ontario Energy Board approved third tranche programs. Since that time the CLD has invested more than CAD72 million to help build a culture of energy conservation in Ontario.

The CLD's goal is to continue to develop, incubate, pilot and fully implement CDM programs that support the Government of Ontario's plans to reduce peak electricity demand in the province by 6,300 MW by 2025.

The CDM programs implemented by the members of the Coalition of Large Distributors were intended to achieve a range of different objectives. Some programs were designed to reduce the amount of electricity used by residential customers; others were directed to assisting commercial customers reduce their electricity loads; and still others were intended to reduce peak demand on the electricity network.

### Peaksaver

Developed, piloted and licensed in Canada by Toronto Hydro-Electric System, Peaksaver® is a residential and small commercial peak demand reduction program. Peaksaver® was one of the first CDM programs mandated to be rolled out across Ontario.

A demand limiting switch or programmable thermostat is installed on a home's central air conditioner. During critical times (typically on hot summer days), a signal is sent to the device to reduce the amount of electricity used by energy-intensive air conditioners without causing a noticeable temperature change to the homeowner.

**Results in CLD Members' Service Areas to December 2007**
Total CLD customers signed up: 35,258
Total demand reduction: 26.7 MW

### Fridge Bounty

Developed and piloted by Hydro Ottawa, this program was designed to encourage residential customers to remove energy inefficient refrigerators (in many cases a home's second refrigerator) from their homes. In its second year of operation, the program was expanded to include freezers as well as refrigerators. This program is now offered as a standard program throughout Ontario by the Ontario Power Authority under the name The Great Refrigerator Roundup.

Customers can book an appointment by calling a central number or register online. Arrangements are made to have the appliance removed and disposed of in an environmentally responsible manner, with almost all materials recycled.

**Results in CLD Members' Service Areas to December 2007**
Total number of fridges and freezers removed: 15,579
Total energy savings: 18.2 GWh

### Water Heater Tune-Up

Developed and piloted by Enersource in 2005, the Water Heater Tune-Up program provided an opportunity for residential customers to reduce the energy used by the appliance responsible for the second largest electricity usage in most Ontario homes – the electric water heater.

Enersource created a special kit containing a water heater insulating blanket, pipe wrap, low flow shower head, faucet aerators and a tip sheet, and promoted the program widely throughout its service territory.

**Results in CLD Members' Service Areas to December 2007**
Total number of electric water heater tune-ups: 10,250
Total energy savings: 19.6 GWh

### EnerShift

Developed and piloted by PowerStream in partnership with Rodan Energy and Metering Solutions, EnerShift™ is a demand response service for large commercial, industrial and institutional customers who want to reduce or shift their electricity load during peak demand periods.

PowerStream identifies customers that may be suitable for peak shaving or load shifting. Rodan personnel work in tandem with these customers to identify where non-critical load can be eliminated during peak periods. Once customers agree to implement these recommendations, PowerStream with the assistance of Rodan acts as an aggregator when the Independent Electricity System Operator gives the signal to reduce peak load.

**Results in CLD Members' Service Areas to December 2007**
Total of 3.5 MW peak demand contracted.

### PowerWISE Business Incentive Program

Developed by the CLD and piloted by Hydro Ottawa, the PowerWISE® Business Incentive Program was designed to provide a financial incentive to large customers who perform energy-efficient retrofits at their facilities. The program is now also managed outside Toronto by the Ontario Power Authority under the name Electricity Retrofit Incentive Program.

Businesses submit an application outlining their plans to retrofit lighting, heating/cooling, or refrigeration equipment based on guidelines provided by their local distribution companies. The plans must be approved before any financial incentive is provided. Kilowatt savings must be measurable, and are rewarded with a kilowatt-based financial incentive.

**Results in CLD Members' Service Areas to December 2007**
Total number of approved applications: 242
Total demand reduction: 10.8 MW

### PowerWISE Starter Kits

Developed and piloted by Veridian, the PowerWISE® Starter Kit program was designed to introduce residential customers to basic energy conservation concepts, provide them with conservation tips and familiarize them with compact fluorescent lights (CFLs).

The PowerWISE® Starter Kits were distributed at community events and local food banks.

**Results in CLD Members' Service Areas to December 2007**
Total number of CFLs distributed: 2,501,977
Total energy savings: 260 GWh

### Summer Savings (Residential)

Developed and piloted by Toronto Hydro-Electric System (under the name Summer Challenge), Summer Savings is an energy-savings program that rewards customers for reducing their electricity consumption during the hot summer months when the electricity grid can become constrained.

Residential customers eligible for the program are automatically registered with their local distribution company. The utility tracks customers' consumption from July 1 to August 31. Customers who reduce their energy use by 10 per cent receive a 10 per cent rebate on their autumn electricity bill.

**Results in CLD Members' Service Areas to December 2007**
Participation in 2006: 153,637
Total energy savings 2007: 79.4 GWh

## RESULTS

| Residential Customers Participating | Commercial and Small Industrial Customers Participating | Agricultural Customers Participating | Large Industrial Customers Participating | Additional Generation Installed |
|---|---|---|---|---|
| | | | | |

| Peak Load | Peak Load Reduction | Duration of Peak Load Reduction | Overall Load Reduction | Energy Savings | Network Augmentation Deferral |
|---|---|---|---|---|---|
| | 114 MW | | | 527 GWh | |

## HOW LOAD REDUCTION WAS MEASURED

## RESULTS ACHIEVED

Over the period 2005 to 2007, the Coalition of Large Distributors conservation and demand management programs achieved 114 megawatts of peak demand reduction and more than 527 gigawatt-hours of electricity saved. These figures include results from additional CDM programs not described above.

Specific results included:

- 15,579 fridges and freezers were retired;
- 18,168 air conditioners were removed from service;
- 5,258 Peaksaver residential load control devices were installed;
- 133,388 seasonal incandescent light strings were retired from service;
- 992,230 retail coupons were redeemed;
- 2.5 million compact fluorescent bulbs were provided through mass market programs.

## CONFIDENCE LEVEL IN ACHIEVING RESULTS

## REPEATABILITY OF RESULTS

## TIME DELAY BEFORE MAXIMUM RESPONSE ACHIEVED

## WEATHER DEPENDENCE

## AVOIDED COSTS

## ACTUAL PROJECT COSTS

Over the period 2005 to 2007, CAD72.7 million was invested in 'third tranche' conservation and demand management programs by the Coalition of Large Distributors.

## PROJECT COST FROM THE SOCIETAL PERSPECTIVE

## OVERALL PROJECT EFFECTIVENESS

From 2005 to 2007, the Coalition of Large Distributors designed, piloted and rolled out conservation and demand management programs to 1.7 million customers in the most populous region of the Province olf Ontario.

In 2005, the Coalition members invested roughly 25 per cent of their combined Ontario Energy Board-approved third tranche spending in the development of a core group of prototype conservation and demand management programs. By the end of 2005, this investment had generated 110.5 gigawatt-hours of electricity savings.

In 2006, the CLD team invested a further 57 per cent of third tranche funds and achieved 302.5 gigawatt-hours in electricity savings. By year-end 2007, with 18 per cent of their CDM investment allocation left to spend, the team produced savings of over 83 gigawatt-hours.

By November 2006, four of these pioneering initiatives had proven so successful that the Premier of Ontario and Ontario's Minister of Energy directed the Ontario Power Authority to coordinate the roll-out of these programs Province-wide.

## CONTACTS

## SOURCES

Ontario Energy Board (2008). *Guidelines for Electricity Distributor Conservation and Demand Management*. Ottawa, the Board. Available at: http://www.oeb.gov.on.ca/documents/cases/EB-2008-0037/Board_Guidelines_for_CDM_20080328.pdf

Coalition of Large Distributors (2008). *Leadership, Action, Results. CDM Retrospective Report*. Ottawa, the Coalition. Available at: http://www.powerstream.ca/ContentMgr/images/CLD_CDM_Report_05-07.pdf

## CASE STUDY PREPARATION

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## IP11 PILOT PROJECT TO IMPROVE AGRICULTURAL PUMP SET EFFICIENCY - INDIA

| | |
|---|---|
| **Last updated** | Edupula Paya, Vempali Mandal, Andhra Pradesh, India |
| **Location of Project** | |
| **Year Project Implemented** | |
| **Year Project Completed** | |
| **Name of Project Proponent** | Southern Power Distribution Company of Andhra Pradesh Limited (APSPDCL) |
| **Name of Project Implementor** | Southern Power Distribution Company of Andhra Pradesh Limited (APSPDCL) |
| **Type of Project Implementor** | Distribution utility<br>Electricity retailer/supplier |
| **Purpose of Project** | Deferral of network augmentation |
| **Timing of Project** | Post contingency |
| **Focus of Project** | Network capacity limitations<br>Generation capacity limitations |
| **Project Objective** | Overall load reduction |
| **Project Target** | Network element |
| **DSM Measure(s) Used** | Energy efficiency<br>Power factor correction |
| **Specific Technology Used** | High efficiency pumps and motor sets and capacitor banks |
| **Market Segments Addressed** | Agricultural customers |

### DRIVERS FOR PROJECT

The Pilot Project to Improve Agricultural Pump Set Efficiency was initiated and driven by the Southern Power Distribution Company of Andhra Pradesh Limited (APSPDCL).

APSPDCL is an electricity distribution/retailing utility owned by the Government of Andhra Pradesh that supplies electricity in six districts of the State of Andhra Pradesh. The APSPDCL distribution network supplies customers spread across 84,331 square kilometres, representing 326 mandals (administrative areas), 6177 villages and 86 parliamentary constituencies.

APSPDCL carried out the Pilot Project to Improve Agricultural Pump Set Efficiency to implement various energy efficiency and power factor correction measures in agricultural pump sets and to identify the impact of these measures in terms of the resulting load reduction and improvement in power factor.

Water pumping load in the agricultural sector in India is important for several reasons. Agricultural pump sets are often supplied by long rural lines which are costly to build and maintain and have large line losses. The electricity supply to pumps is often unmetered and electricity is effectively supplied free of charge. In these cases, electricity distributors have to bear the supply cost and there is no incentive for agricultural customers to use electricity efficiently.

## DESCRIPTION OF PROJECT

APSPDCL identified 23 agricultural pump sets with capacities ranging from 5 to 12.5 horsepower (HP) for the implementation of the pilot program. All these pump sets were fitted with 65 mm galvanised iron pipe and a submersible type of motor without a capacitor. The pumps were drawing water from bore wells of 90 mm diameter and depths of 54 to 60 metres. The available water table was at a depth of 20 metres.

APSPDCL implemented various energy efficiency and power factor correction measures on 15 out of the total of 23 pump sets. These measures included:

- installation of a frictioness foot valve;
- installation of high density polyethylene (HDPE) piping for suction and delivery;
- installation of pump and motor sets with a Bureau of Indian Standards mark of quality; and
- installation of capacitors of adequate ratings.

Table IP11/1 summarises the number of pumps of different sizes with and without energy efficiency and power factor correction measures implemented.

**Table IP11/1. Pump Sets Used in the DSM Pilot Project**

| Size of Pump (HP) | With Measures | Without Measures | Total |
|---|---|---|---|
| 5.0 | 0 | 1 | 1 |
| 7.5 | 2 | 0 | 2 |
| 10 | 8 | 5 | 13 |
| 12.5 | 5 | 2 | 7 |
| **Total** | **15** | **8** | **23** |

APSPDCL established performance parameters and carried out detailed performance evaluation of five 10 HP pump sets before and after energy efficiency and power factor correction measures were implemented.

APSPDCL installed high accuracy energy meters on each pump set for the real time measurement of voltage, current, power factor and energy. Venturi meters and U-tube manometers were installed at the delivery point of each pump set for the measurement of the discharge volume from the pump in litres per second.

APSPDCL staff measured the energy consumption and time taken by all pump sets to fill a 221 litre barrel with water, calculated the discharge from each pump and compared this for pumps with and without the energy efficiency and power factor correction measures implemented.

## RESULTS

| Residential Customers Participating | Commercial and Small Industrial Customers Participating | Agricultural Customers Participating | Large Industrial Customers Participating | Additional Generation Installed |
|---|---|---|---|---|
| | | | | |

| Peak Load | Peak Load Reduction | Duration of Peak Load Reduction | Overall Load Reduction | Energy Savings | Network Augmentation Deferral |
|---|---|---|---|---|---|
| | | | | | |

## HOW LOAD REDUCTION WAS MEASURED

## RESULTS ACHIEVED

The energy consumption and discharge volumes of five 10 HP pump sets with and without the energy efficiency and power factor correction measures are shown in Figures IP11/1 and IP11/2 (page 319).

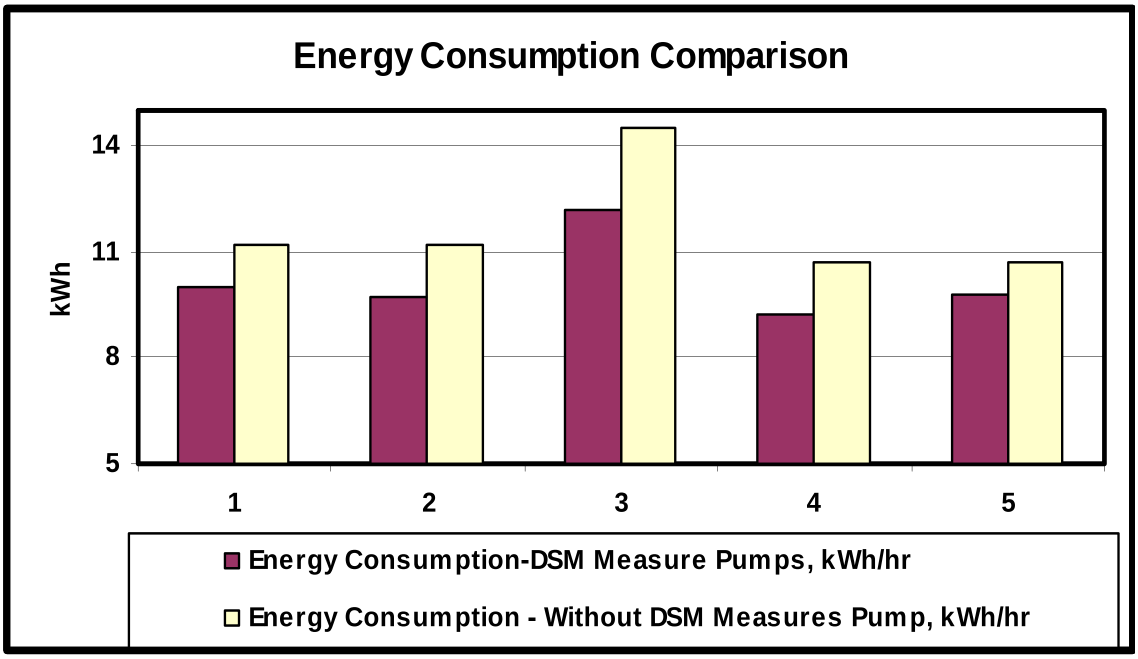


**Figure IP11/1. Energy Consumption of 10 HP Pumps With and Without Energy Efficiency and Power Factor Correction Measures**

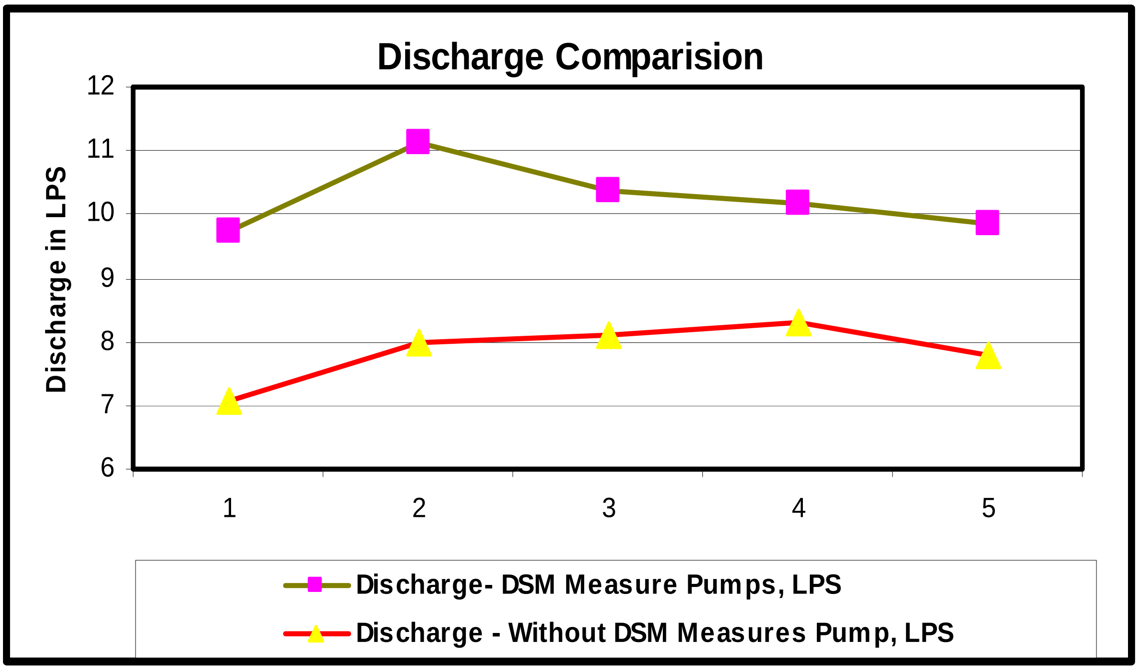


**Figure IP11/2. Discharge Volume from 10 HP Pumps With and Without Energy Efficiency and Power Factor Correction Measures**

Analysis of the performance data collected during the pilot project, enabled the calculation of an "Energy Index", comprising the energy consumption per Unit of Irrigation Work, ie the work done in lifting a volume of one hectare-centimetre of water through a static of head of one meter. Figure IP11/3 presents the results of these calculations for five 10 HP pump sets with and without the energy efficiency and power factor correction measures.

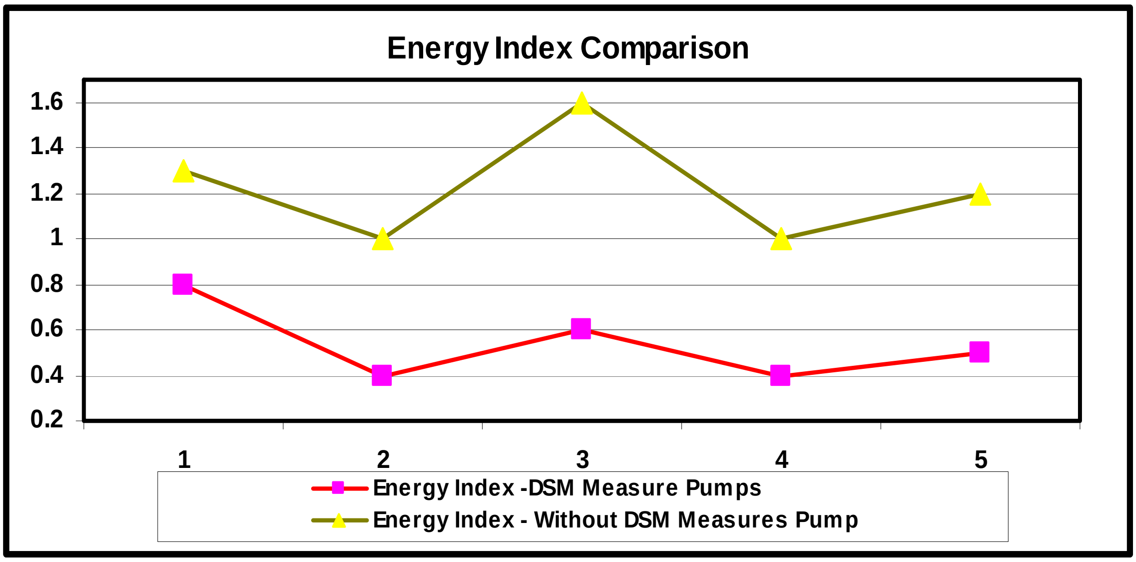


**Figure IP11/3. Energy Index of 10 HP Pumps With and Without Energy Efficiency and Power Factor Correction Measures**

There was a 15.8% saving in energy consumption and a 28% increase in the discharge for pump sets fitted with the energy efficiency and power factor correction measures. The increased discharge resulted in a reduction in the operating hours of the pump sets for the same area of land irrigated.

## CONFIDENCE LEVEL IN ACHIEVING RESULTS

## REPEATABILITY OF RESULTS

## TIME DELAY BEFORE MAXIMUM RESPONSE ACHIEVED

## WEATHER DEPENDENCE

## AVOIDED COSTS

## ACTUAL PROJECT COSTS

## PROJECT COST FROM THE SOCIETAL PERSPECTIVE

## OVERALL PROJECT EFFECTIVENESS

The pilot project was successful in achieving the objective of assessing the load reduction and improvement in power factor achieved by implementing various energy efficiency and power factor correction measures in the agricultural pump sets.

## CONTACTS

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## SOURCES

## CASE STUDY PREPARATION

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# IP12 AGRICULTURAL PUMP SET EFFICIENCY IMPROVEMENT PROGRAM - INDIA

| | |
|---|---|
| **Last updated** | 5 October 2008 |
| **Location of Project** | Greater Noida, a sub-city of Delhi, Uttar Pradesh, India |
| **Year Project Implemented** | 2004/05 |
| **Year Project Completed** | 2007/08 |
| **Name of Project Proponent** | Noida Power Company Limited (NPCL) |
| **Name of Project Implementor** | Noida Power Company Limited (NPCL) |
| **Type of Project Implementor** | Distribution utility<br>Electricity retailer/supplier |
| **Purpose of Project** | Deferral of network augmentation |
| **Timing of Project** | Post contingency |
| **Focus of Project** | Network capacity limitations<br>Generation capacity limitations |
| **Project Objective** | Overall load reduction |
| **Project Target** | Network element |
| **DSM Measure(s) Used** | Energy efficiency<br>Power factor correction |
| **Specific Technology Used** | Efficiency improvements to agricultural pump sets<br>Power factor correction |
| **Market Segments Addressed** | Agricultural customers |

## DRIVERS FOR PROJECT

The Agricultural Pump Set Efficiency Improvement Program was developed by the Noida Power Company Limited (NPCL), facilitated by USAID and World Bank experts and implemented with participation by companies manufacturing energy efficient pumps and other equipment, and by financial institutions.

NPCL is an electricity distribution/retailing utility privately owned by RPG Group since 1993. NPCL provides services to the Greater Noida region of Uttar Pradesh. It provides transmission and distribution services to about 335 square kilometres of Greater Noida city and 118 neighbouring villages, supplying around 23,000 customers in 2003/04, increasing to approximately 40,000 customers in 2007/08.

Total energy supplied by NPCL is distributed as follow: 12% for agricultural pump sets; 64% for large industry and 24% for residential, institutional and small industry consumers.

Water pumping load in the agricultural sector in India is important for several reasons. Agricultural pump sets are often supplied by long rural lines which are costly to build and maintain and have large line losses. The electricity supply to pumps is often unmetered and electricity is effectively supplied free of charge. In these cases, electricity distributors have to bear the supply cost and there is no incentive for agricultural customers to use electricity efficiently.

In the specific case of NPCL, the distribution system servicing the agricultural sector was characterised by high line losses, wastage of energy in running pump sets (7500 kWh per agricultural consumer per annum), low revenue generation (selling price of INR0.46 per kWh against purchase cost of INR2.97) and high levels of theft and pilferage of electricity.

The main objectives of the Agricultural Pump Set Efficiency Improvement Program were:

- to achieve energy savings by improving the electrical performance of the pump motors through high efficiency;
- to increase the power factor above the average of 0.65 for conventional agricultural pump sets;
- to reduce line losses by converting low voltage supply to high voltage; and
- to inculcate responsible behaviour by customers towards the use of electricity and water by deploying metering at pump sets.

## DESCRIPTION OF PROJECT

The program was designed to showcase the benefits available from improving agricultural pump set performance through retrofitting with high efficiency motors of an optimum size matched to the average load of the pump.

NPCL staff conducted a survey of existing pumping systems to identify opportunities to improve efficiency, particularly in relation to power factor and appropriate sizing of motors.

Existing conventional belt-driven motor shaft coupled pump sets of 7.4 horsepower capacity were replaced with new higher efficiency, lower capacity 3.0 horsepower mono block pump sets. Additional capacitors to increase the power factor to 0.85 were also installed with a metering system for the pump station. High voltage lines on the power distribution system in the area were extended, while insulated low voltage lines were installed at the grid connection point of the pumping systems.

A funding mechanism was offered to agricultural customers that provided free of cost pump sets and a mix of 70% debt and 30% equity in the purchase and installation of capacitors and metering.

NPCL provided the conceptual design, technical support and administration for the program. NPCL staff carried out the evaluation of the potential for extending the high voltage distribution system. Pump set suppliers verified the efficiency levels of existing pumping systems.

Outreach activity was undertaken jointly by NPCL and local community institutions to promote and encourage agricultural customers to participate in the program. Customers were given access to pump sets and also provided with information on usage and system parameters for evaluation.

Monitoring and evaluation was undertaken to monitor progress and to report on the impact of the program. NPCL used an energy audit as one of the monitoring and evaluation tools. Data output was taken from meters installed at local substations and hourly performance was recorded from pump station logbooks.

NPCL used in-house technical personnel to analyse operational reports from the field and relied on local community organisations for assistance and guidance.

## RESULTS

| Residential Customers Participating | Commercial and Small Industrial Customers Participating | Agricultural Customers Participating | Large Industrial Customers Participating | Additional Generation Installed |
|---|---|---|---|---|
| | | 100 | | |

| Peak Load | Peak Load Reduction | Duration of Peak Load Reduction | Overall Load Reduction | Energy Savings | Network Augmentation Deferral |
|---|---|---|---|---|---|
| 469 kW | 276 kW | 8 hours | | 370.6 kWh | |

## HOW LOAD REDUCTION WAS MEASURED

Other. Data output was taken from meters installed at local substations and hourly performance was recorded from pump station logbooks.

## RESULTS ACHIEVED

Table IP12/1 presents a summary of the results achieved for replacement of a conventional 7.4 horsepower pump set with a high efficiency 3.0 horsepower pump set.

**Table IP12/1. Summary of Results Achieved for Replacement of a Conventional 7.4 HP Pump Set With a High Efficiency 3.0 HP Pump Set**

| Parameter | Result Achieved |
|---|---|
| Pump motor capacity | Reduced by 4.5 HP |
| Power factor | Increased from 0.65 to 0.85 |
| Water yield | Increased from 17 litres per second to 21 litres per second |
| Energy consumption | Reduced from 10,800 kWh to 3,510 kWh per year |

## CONFIDENCE LEVEL IN ACHIEVING RESULTS

## REPEATABILITY OF RESULTS

## TIME DELAY BEFORE MAXIMUM RESPONSE ACHIEVED

## WEATHER DEPENDENCE

No direct correlation with weather. However, it was easier to convince farmers to participate in the program during the summer season.

## AVOIDED COSTS

## ACTUAL PROJECT COSTS

Table IP12/2 shows the total cost for replacement of a conventional 7.4 horsepower pump set with a high efficiency 3.0 horsepower pump set.

| **Table IP12/2. Total Cost for Replacement of a Conventional 7.4 HP Pump Set With a High Efficiency 3.0 HP Pump Set** | |
|---|---|
| **Expenditure Item** | **Actual Cost** |
| New mono block pump set | INR8,500 |
| New high voltage line and transformer | INR75,000 |
| Metering arrangements | INR8,000 |
| **Total** | **INR91,500** |

## PROJECT COST FROM THE SOCIETAL PERSPECTIVE

## OVERALL PROJECT EFFECTIVENESS

From the perspective of NPCL, the reduction in peak load and energy demand resulting from the implementation of this program:

- reduced the cost of supplying electricity;
- fostered customers relations; and
- contributed environmental benefits to society.

## CONTACTS

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## SOURCES

## CASE STUDY PREPARATION

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# LS01 WINTER PEAK DEMAND REDUCTION SCHEME - IRELAND

| | |
|---|---|
| **Last updated** | 26 August 2005 |
| **Location of Project** | Republic of Ireland |
| **Year Project Implemented** | 2003 |
| **Year Project Completed** | |
| **Name of Project Proponent** | Electricity Supply Board National Grid (ESB NG) |
| **Name of Project Implementor** | Electricity Supply Board National Grid (ESB NG) |
| **Type of Project Implementor** | Distribution utility<br>Transmission utility<br>Regional network operator |
| **Purpose of Project** | Deferral of network augmentation |
| **Timing of Project** | Pre contingency |
| **Focus of Project** | Network capacity limitations<br>Generation capacity limitations |
| **Project Objective** | Increasing operating reserve<br>Peak load reduction |
| **Project Target** | Whole network |
| **DSM Measure(s) Used** | Standby generation<br>Interruptible loads |
| **Specific Technology Used** | |
| **Market Segments Addressed** | Commercial and small industrial customers<br>Large industrial customers |

## DRIVERS FOR PROJECT

Winter demand is very "peaky" in Ireland. Ensuring security of supply is expensive. Encouraging customers to manage electricity usage can reduce costs.

## DESCRIPTION OF PROJECT

In 2003/04, the Winter Peak Demand Reduction Scheme (WPDRS) was open to:

- customers in the eligible market (ie large commercial and industrial customers);
- who were supplied by one of the three independent electricity suppliers (ie retailers);
- who had appropriate interval metering (ie quarter-hour metering).

A similar scheme, the Winter Demand Reduction Initiative, was available to customers supplied by the incumbent electricity supplier, ESB Public Electricity Supply (ESB PES).

Customers applied in advance through their supplier to join the WPDRS. In 2003/04, each customer committed to reducing consumption between 5 and 7 pm every business day from November to February. This reduction was achieved through reducing energy use or utilising on-site generation.

Customers received a payment for reliably delivering this committed reduction. In 2003/04, the total available payment was EUR210 per megawatt-hour of load reduction. Of this total, EUR160 per megawatt was a reliability payment and EUR50 per megawatt-hour was an energy payment.

## RESULTS

| Residential Customers Participating | Commercial and Small Industrial Customers Participating | Agricultural Customers Participating | Large Industrial Customers Participating | Additional Generation Installed |
|---|---|---|---|---|
| | | | 186 | |

| Peak Load | Peak Load Reduction | Duration of Peak Load Reduction | Overall Load Reduction | Energy Savings | Network Augmentation Deferral |
|---|---|---|---|---|---|
| 4,320 MW | 80 MW | 2 hours | | | |

## HOW LOAD REDUCTION WAS MEASURED

Interval meter. 15 minute intervals.

## RESULTS ACHIEVED

In 2003/04, a total of 639 customers was eligible to take part in WPDRS and 186 (29%) signed up. A total of 106MW of committed load reduction was offered by these customers, whose total baseline demand was 410MW.

The four largest contributors to the eligible load reductions offered were from: cement and paper industries (38% of eligible customers reductions offered), manufacturers of agricultural products (24%), office/banking/retail (23%) and refrigeration/meat industry (17%) (see Figure LS01/1).

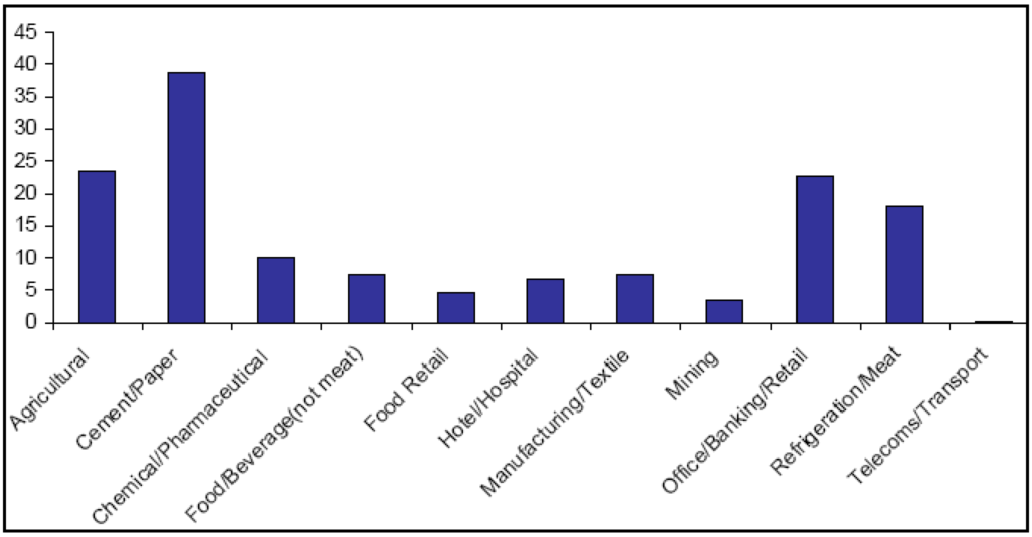


**Figure LS01/1. Percentage of Eligible Load Offered**

Of those customers who signed up to the WPDRS, 29% succeeded in reliably reducing consumption to their committed level and earned full payment. A further 9% curtailed to their committed level on average, but had high daily variation in their curtailment. A further 19% set their committed level incorrectly, but had low variation in their curtailment. A further 18% set their committed level incorrectly, and also had high day-on-day variation in their curtailment. Finally, 25% of participants entirely failed to curtail.

No overall change in participants' methods of curtailing load was evident over the four months.

Four participants exported electricity from on-site generators to the grid and produced roughly 13MW of load reduction between them.

In 2003/04, the WPDRS paid out a total of EUR2.4million to the participants (customers), comprising EUR610,000 in energy payments plus EUR2,392,000 in reliability payments, less EUR598,000 in capped reliability rebates. This yielded a cost of EUR180 per megawatt-hour reduction. The three independent electricity suppliers received a 5% administration payment of EUR120,000.

Overall, those participants who were successful earned nearly EUR20,000 each over the four winter months, making it a lucrative scheme for those who could curtail their consumption to committed levels.

In 2003/04, the peak load reduction achieved was an average of 82.5MW in November, 83.0MW in December, 84.4MW in January and 81.3MW in February. This was 1.85% of the winter peak load of 4320MW.

Compared with 2002/03, the peak on the system was reduced by about 80 MW and its shape was altered from a sharp peak occurring at about 5.30 pm to a flatter peak occurring from about 5.30 to about 6.30 pm (see Figure LS01/2, page 328). The demand reduction achieved through the WPDRS led to the 2003/2004 winter peak being 1.8% lower than the 2002/03 peak, even though demand for the entire year increased by roughly 3% (see Figure LS01/3, page 328).

## CONFIDENCE LEVEL IN ACHIEVING RESULTS

## REPEATABILITY OF RESULTS

The load reduction achieved was quite reliable on a daily basis; 95% of the time, the achieved load reduction lay between 72MW and 88MW.

## TIME DELAY BEFORE MAXIMUM RESPONSE ACHIEVED

## WEATHER DEPENDENCE

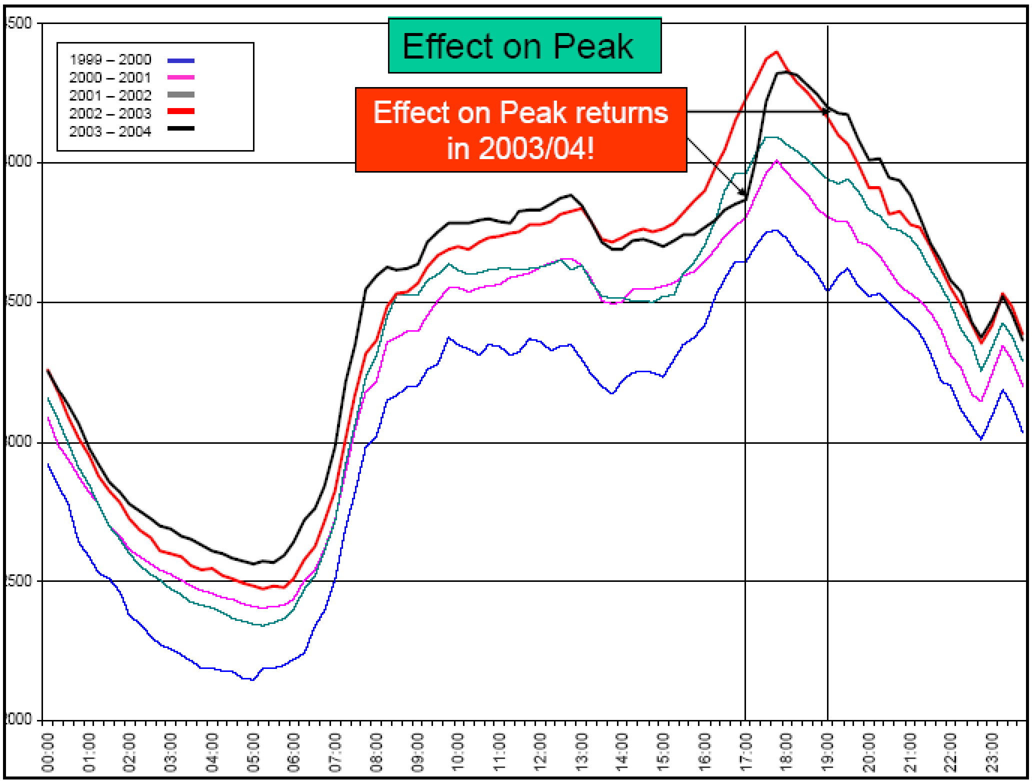


**Figure LS01/2. Effect on Winter Peak**

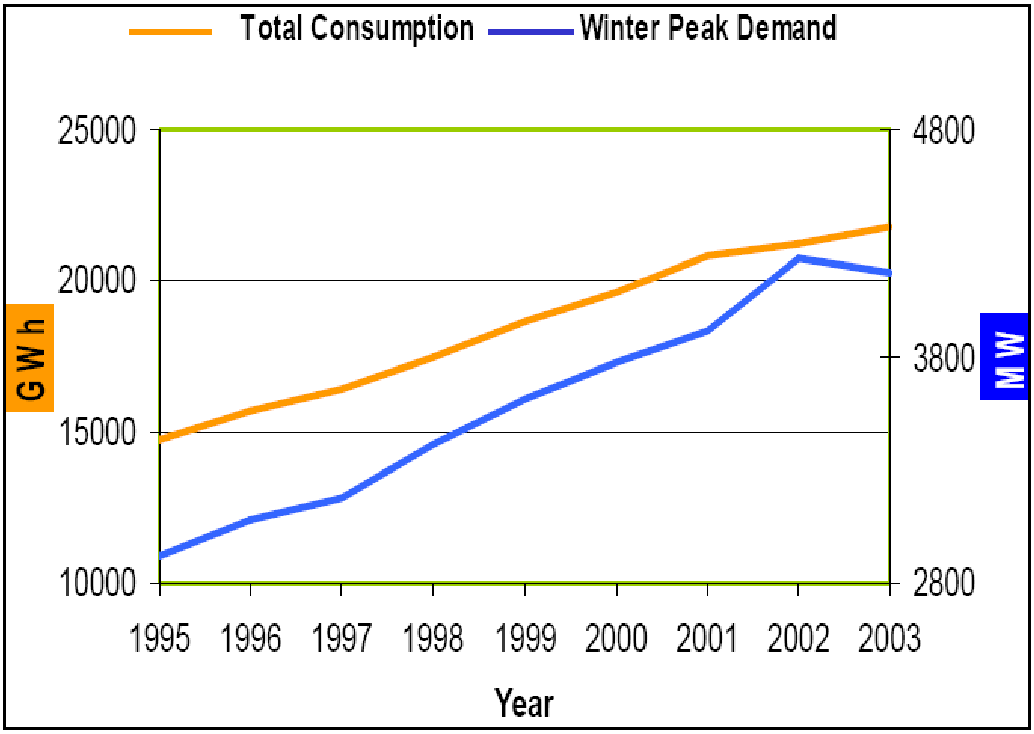


**Figure LS01/3. Reduction in Winter Peak Demand**

## AVOIDED COSTS

Costs paid by ESB NG:
- EUR2.4 million paid to customers
- EUR120,000 paid to independent electricity suppliers

## ACTUAL PROJECT COSTS

## PROJECT COST FROM THE SOCIETAL PERSPECTIVE

## OVERALL PROJECT EFFECTIVENESS

## CONTACTS

## SOURCES

Electricity Supply Board National Grid (2004). *Results of the Winter Peak Demand Reduction Scheme (WPDRS) Season 2003/04*. Document available at: http://www.eirgrid.com/EirGridPortal/uploads/Regulation and Pricing/2003_04 WPDRS Results.pdf

Electricity Supply Board National Grid (2004). *WPDRS 2004/05: Introduction to WPDRS and Results from 2003/04*. Presentation available at: http://www.eirgrid.com/EirGridPortal/uploads/Regulation and Pricing/2004 WS1 - Intro and Results.pdf

Walsh. M. (2004). *Ancillary Services & Demand Side Management*. Presentation available at: http://www.eirgrid.com/eirgridportal/uploads/regulation and pricing/Michael walsh - as and dsm.pdf

## CASE STUDY PREPARATION

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# LS02 ESKOM DSM PROFITABLE PARTNERSHIP PROGRAMME - SOUTH AFRICA

| | |
|---|---|
| **Last updated** | 26 August 2005 |
| **Location of Project** | South Africa |
| **Year Project Implemented** | |
| **Year Project Completed** | |
| **Name of Project Proponent** | Eskom |
| **Name of Project Implementor** | Various ESCOs |
| **Type of Project Implementor** | ESCO |
| **Purpose of Project** | Deferral of network augmentation |
| **Timing of Project** | Pre contingency |
| **Focus of Project** | Network capacity limitations<br>Generation capacity limitations |
| **Project Objective** | Peak load reduction<br>Overall load reduction |
| **Project Target** | Whole network |
| **DSM Measure(s) Used** | Energy efficiency |
| **Specific Technology Used** | |
| **Market Segments Addressed** | Commercial and small industrial customers |

## DRIVERS FOR PROJECT

The benefit to Eskom from DSM initiatives is the capital expenditure deferral of building both generation capacity and transmission lines and upgrades for the distribution network. This benefit will also affect South Africa a whole as electricity price increases will be at a lower rate, the emission of harmful gases will be reduced, and less water will be used for the generation of electricity. This is in line with South Africa's goal to remain as one of the lowest cost suppliers of electricity in the world.

## DESCRIPTION OF PROJECT

Eskom offers financial assistance through the DSM Profitable Partnership Programme to entities that are serious about efficient use of electricity and the resulting financial savings.

Both upgrades to existing buildings and the incorporation of efficient systems in new buildings are targeted. At present renewable energy, co-generation, dual fuel systems and power factor correction are not considered as DSM interventions, but discussions are being held to clarify these matters in the future.

Minimum energy savings of 500 kW per project, or group of projects, is an indicator for individual projects to be approved for participation by Eskom. However this may be reduced at Eskom's discretion, depending on the type of project undertaken.

Eskom offers the following financial assistance for approved projects through the DSM Profitable Partnership Programme. The customer assumes ownership of all assets immediately after installation.

## Load Management Projects

Eskom funds 100% of all costs for viable load management projects designed to shift electricity consumption to off-peak periods in order to reduce peak loads. The customer is not required to contribute towards the capex of the project. The customer will be responsible for the insurance of the assets and maintenance of such assets through an ESCO in accordance with the Eskom DSM agreement.

## Energy Efficient Projects

Eskom funds 100% of all costs for viable energy efficiency projects designed to make business and buildings more electricity efficient and reduce electricity consumption. However the customer benefiting from the energy efficiency project must pay 50% of the capex of the project (excluding all monitoring and verification costs) to Eskom over the life of the contract.

Energy services companies (ESCOs) assist customers with the implementation of DSM projects. The ESCO is the party responsible for identifying projects and quantifying potential peak load reductions. After acceptance of the proposal by the client, the ESCO submits the project to Eskom for approval and subsequent implementation. Customers not wishing to employ an external ESCO are also eligible to register their own ESCO. Eskom is developing a set of benchmark criteria for the registration of ESCOs.

Proposed DSM projects are evaluated by technical and financial experts and assessed to ensure that the solution is possible and sustainable. This requirement places the responsibility on the ESCO to carry out sufficient research and feasibility studies to generate adequate information to enable the technical experts to evaluate the project.

An initial one page proposal is required from the ESCO to enable Eskom to evaluate the project. If this is approved, the ESCO then submits a more detailed project proposal. The project proposal must include as a minimum, capital budget and MW savings to be attained. The cost per megawatt is evaluated and ESCOs need to ensure that the optimal solution is implemented.

Measurement and verification of the performance of implemented DSM projects is carried out by contracted South African universities. The contractor establishes a baseline before the project commences. The baseline is the actual energy use by the customer under certain conditions before the DSM intervention. The baseline takes into account various customer scenarios. This is done to ensure that when, for example, production levels differ, this will be reflected in the measured savings. After the implementation of the DSM project, the actual energy use is measured and compared to the baseline. The difference between the baseline and the actual use is the savings achieved by the installed equipment. All parties involved have access to the measurements to ensure transparency.

The goal of the DSM Profitable Partnership Programme is to achieve deferral of generation and network capacity expansion. Funded projects must be sustainable to ensure that the deferral assumption is correct. The effect of only sustaining a project for a few years could lead to an increase in peak demand, resulting in power shortages.

## RESULTS

| Residential Customers Participating | Commercial and Small Industrial Customers Participating | Agricultural Customers Participating | Large Industrial Customers Participating | Additional Generation Installed |
|---|---|---|---|---|
| | | | | |

| Peak Load | Peak Load Reduction | Duration of Peak Load Reduction | Overall Load Reduction | Energy Savings | Network Augmentation Deferral |
|---|---|---|---|---|---|
| | | | | | |

## HOW LOAD REDUCTION WAS MEASURED

## RESULTS ACHIEVED

## CONFIDENCE LEVEL IN ACHIEVING RESULTS

## REPEATABILITY OF RESULTS

## TIME DELAY BEFORE MAXIMUM RESPONSE ACHIEVED

## WEATHER DEPENDENCE

## AVOIDED COSTS

## ACTUAL PROJECT COSTS

## PROJECT COST FROM THE SOCIETAL PERSPECTIVE

## OVERALL PROJECT EFFECTIVENESS

## CONTACTS

## SOURCES

Eskom DSM website at: http://www.eskomdsm.co.za

Eskom DSM (2004) *Project Information Guide.* Version 8.

## CASE STUDY PREPARATION

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## LS03 TU ELECTRIC THERMAL COOL STORAGE PROGRAM - USA

| | |
|---|---|
| **Last updated** | 2 March 2006 |
| **Location of Project** | Dallas-Fort Worth and part of Texas, USA |
| **Year Project Implemented** | 1982 |
| **Year Project Completed** | Late 1990s |
| **Name of 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) |
| **Name of Project Implementor** | TU Electric |
| **Type of Project Implementor** | Distribution utility<br>Transmission utility<br>Electricity retailer/supplier |
| **Purpose of Project** | Deferral of network augmentation |
| **Timing of Project** | Pre contingency |
| **Focus of Project** | Network capacity limitations |
| **Project Objective** | Peak load reduction |
| **Project Target** | Network region |
| **DSM Measure(s) Used** | Other short-term demand response |
| **Specific Technology Used** | Thermal cool storage using off-peak production of chilled water or ice |
| **Market Segments Addressed** | Commercial and small industrial customers |

### 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).

### 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 of commercial buildings, 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

| Residential Customers Participating | Commercial and Small Industrial Customers Participating | Agricultural Customers Participating | Large Industrial Customers Participating | Additional Generation Installed |
|---|---|---|---|---|
| | 205 (in 1992) | | | |

| Peak Load | Peak Load Reduction | Duration of Peak Load Reduction | Overall Load Reduction | Energy Savings | Network Augmentation Deferral |
|---|---|---|---|---|---|
| | 70.5 MW | | | | |

## HOW LOAD REDUCTION WAS MEASURED

## RESULTS ACHIEVED

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.

## CONFIDENCE LEVEL IN ACHIEVING RESULTS

## REPEATABILITY OF RESULTS

## TIME DELAY BEFORE MAXIMUM RESPONSE ACHIEVED

## WEATHER DEPENDENCE

## AVOIDED COSTS

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.

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.

## ACTUAL PROJECT COSTS

## PROJECT COST FROM THE SOCIETAL PERSPECTIVE

## OVERALL PROJECT EFFECTIVENESS

## CONTACTS

## SOURCES

The Results Center (1993). *TU Electric Thermal Cool Storage: Profile # 52*. Available at: http://sol.crest.org/efficiency/irt/52.pdf

## CASE STUDY PREPARATION

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## LS04 MAD RIVER VALLEY PROJECT - USA

| | |
|---|---|
| **Last updated** | 26 August 2005 |
| **Location of Project** | Warren, Vermont, USA |
| **Year Project Implemented** | 1989 |
| **Year Project Completed** | 1996 |
| **Name of Project Proponent** | Green Mountain Power/Sugarbush Resort |
| **Name of Project Implementor** | Sugarbush Resort |
| **Type of Project Implementor** | End-use customer(s) |
| **Purpose of Project** | Deferral of network augmentation |
| **Timing of Project** | Pre contingency |
| **Focus of Project** | Network capacity limitations |
| **Project Objective** | Peak load reduction |
| **Project Target** | Network element |
| **DSM Measure(s) Used** | Interruptible loads<br>Energy efficiency<br>Fuel substitution |
| **Specific Technology Used** | Conversion of electric hot water heaters and electric space heating in buildings to alternative fuels plus other technologies |
| **Market Segments Addressed** | Residential customers<br>Commercial and small industrial customers |

### 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 USD 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.

## 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

| Residential Customers Participating | Commercial and Small Industrial Customers Participating | Agricultural Customers Participating | Large Industrial Customers Participating | Additional Generation Installed |
|---|---|---|---|---|
| | | | | |

| Peak Load | Peak Load Reduction | Duration of Peak Load Reduction | Overall Load Reduction | Energy Savings | Network Augmentation Deferral |
|---|---|---|---|---|---|
| | | | | | |

## HOW LOAD REDUCTION WAS MEASURED

## RESULTS ACHIEVED

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%). Between 1989 and 1996 demand 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.

## CONFIDENCE LEVEL IN ACHIEVING RESULTS

## REPEATABILITY OF RESULTS

## TIME DELAY BEFORE MAXIMUM RESPONSE ACHIEVED

## WEATHER DEPENDENCE

## AVOIDED COSTS

## ACTUAL PROJECT COSTS

## PROJECT COST FROM THE SOCIETAL PERSPECTIVE

## OVERALL PROJECT EFFECTIVENESS

## 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

## CASE STUDY PREPARATION

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# LS05 BAULKHAM HILLS SUBSTATION DEFERRAL PROJECT - AUSTRALIA

| | |
|---|---|
| **Last updated** | 26 August 2005 |
| **Location of Project** | Baulkham Hills, Sydney, Australia |
| **Year Project Implemented** | 1998 |
| **Year Project Completed** | 2005 |
| **Name of Project Proponent** | Integral Energy |
| **Name of Project Implementor** | Integral Energy |
| **Type of Project Implementor** | Distribution utility |
| **Purpose of Project** | Deferral of network augmentation |
| **Timing of Project** | Pre contingency |
| **Focus of Project** | Network capacity limitations |
| **Project Objective** | Peak load reduction |
| **Project Target** | Network element |
| **DSM Measure(s) Used** | Interruptible loads |
| **Specific Technology Used** | Interruption of a major industrial load |
| **Market Segments Addressed** | Large industrial customers |

## DRIVERS FOR PROJECT

This program was undertaken to defer a AUD 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.

## DESCRIPTION OF PROJECT

This DSM program 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 1 pm and 5 pm the following day. The customer is able to implement load shifting by speeding up production prior to the event and then slowing it down during the peak.

## RESULTS

| Residential Customers Participating | Commercial and Small Industrial Customers Participating | Agricultural Customers Participating | Large Industrial Customers Participating | Additional Generation Installed |
|---|---|---|---|---|
| | | | 1 | |

| Peak Load | Peak Load Reduction | Duration of Peak Load Reduction | Overall Load Reduction | Energy Savings | Network Augmentation Deferral |
|---|---|---|---|---|---|
| | 4 MW | | | | |

## HOW LOAD REDUCTION WAS MEASURED

## RESULTS ACHIEVED

The agreement with this one customer achieved peak load reductions of between 3.5 and 4.5 MVA.

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

## CONFIDENCE LEVEL IN ACHIEVING RESULTS

High.

## REPEATABILITY OF RESULTS

High - provided the 24 hours notice is given by Integral, the customer is able to provide the load reduction when required.

## TIME DELAY BEFORE MAXIMUM RESPONSE ACHIEVED

## WEATHER DEPENDENCE

None.

## AVOIDED COSTS

## ACTUAL PROJECT COSTS

The majority of the cost of the program was the payments made to the participating customer which totalled AUD 70,000. An additional cost of approximately AUD 10,000 was incurred in setting up and initiating the program.

## PROJECT COST FROM THE SOCIETAL PERSPECTIVE

## OVERALL PROJECT EFFECTIVENESS

Very effective, relatively low cost program which depended on a unique situation where a single customer was able to interrupt a very large load.

## CONTACTS

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## SOURCES

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

Personal communication, Frank Bucca, Integral Energy.

## CASE STUDY PREPARATION

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# PC01 MARAYONG POWER FACTOR CORRECTION PROGRAM - AUSTRALIA

| | |
|---|---|
| **Last updated** | 26 August 2005 |
| **Location of Project** | Marayong, western Sydney, Australia |
| **Year Project Implemented** | 2000 |
| **Year Project Completed** | 2000 |
| **Name of Project Proponent** | Integral Energy |
| **Name of Project Implementor** | Integral Energy |
| **Type of Project Implementor** | Distribution utility |
| **Purpose of Project** | Deferral of network augmentation |
| **Timing of Project** | Pre contingency |
| **Focus of Project** | Network capacity limitations |
| **Project Objective** | Peak load reduction |
| **Project Target** | Network element |
| **DSM Measure(s) Used** | Power factor correction |
| **Specific Technology Used** | Installation of power factor correction equipment in the low voltage network outside customers' premises (not on the customer side of the meter) |
| **Market Segments Addressed** | Large industrial customers |

## DRIVERS FOR PROJECT

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.

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.

## DESCRIPTION OF PROJECT

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 DSM opportunity in this area.

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.

This program was implemented without the involvement of customers.

## RESULTS

| Residential Customers Participating | Commercial and Small Industrial Customers Participating | Agricultural Customers Participating | Large Industrial Customers Participating | Additional Generation Installed |
|---|---|---|---|---|
| | | | | |

| Peak Load | Peak Load Reduction | Duration of Peak Load Reduction | Overall Load Reduction | Energy Savings | Network Augmentation Deferral |
|---|---|---|---|---|---|
| | | | | | 72 months |

## HOW LOAD REDUCTION WAS MEASURED

## RESULTS ACHIEVED

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.

## CONFIDENCE LEVEL IN ACHIEVING RESULTS

High - the project was completely controlled by Integral Energy and did not require the involvement of customers.

## REPEATABILITY OF RESULTS

## TIME DELAY BEFORE MAXIMUM RESPONSE ACHIEVED

## WEATHER DEPENDENCE

## AVOIDED COSTS

## ACTUAL PROJECT COSTS

Not known.

## PROJECT COST FROM THE SOCIETAL PERSPECTIVE

## OVERALL PROJECT EFFECTIVENESS

The project was highly effective. However, the action taken was on the utility side of the meter rather than on the customer's side. Therefore it is questionable whether the project was DSM.

## CONTACTS

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## SOURCES

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

Personal communication, Frank Bucca, Integral Energy.

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# PI01 CALIFORNIA CRITICAL PEAK PRICING TARIFF FOR LARGE CUSTOMERS - USA

| | |
|---|---|
| **Last updated** | 5 October 2008 |
| **Location of Project** | California, USA |
| **Year Project Implemented** | 2003 |
| **Year Project Completed** | |
| **Name of Project Proponent** | California Energy Commission |
| **Name of Project Implementor** | Pacific Gas and Electric (PG&E), San Diego Gas and Electric (SDG&E), Southern California Edison (SCE) |
| **Type of Project Implementor** | Distribution utility<br>Transmission utility |
| **Purpose of Project** | Deferral of network augmentation |
| **Timing of Project** | Pre contingency |
| **Focus of Project** | Network capacity limitations<br>Generation capacity limitations |
| **Project Objective** | Peak load reduction |
| **Project Target** | Whole network |
| **DSM Measure(s) Used** | Pricing initiatives |
| **Specific Technology Used** | |
| **Market Segments Addressed** | Commercial and small industrial customers<br>Large industrial customers |

## DRIVERS FOR PROJECT

**Note:** This Case Study PI01 covers pricing initiatives for large customers in California. For similar pricing initiatives for small customers in California see Case Study PI09 (page 396) and for the impacts of load control technology implemented with pricing initiatives in the residential sector in California see Case Study DC07 (page 81).

In 2000 and 2001, California experienced a so-called "energy crisis" that comprised short-term shortages of electricity generation capacity following the failure of the intoduction of a competitive electricity market in the State. By 2002, the immediate short-term problems had been resolved, but longer-term shortages of both generation and transmission network capacity remained.

One of the lessons gleaned from California's energy crisis was that the lack of demand response in retail markets makes it very difficult to clear wholesale markets at reasonable prices. One method for introducing demand response in retail markets is time-varying pricing.

With this in mind, the California Public Utilities Commission (CPUC) in June 2002, adopted an Order Instituting Rulemaking on "policies and practices for advanced metering, demand response, and dynamic pricing" and initiated a proceeding in July designed to introduce demand response into California's electricity market.

As part of this proceeding, three working groups were charged with developing specific tariff proposals to achieve increased demand response in the state. The objective of Working Group 2 was to evaluate demand response programs for large customers with demand exceeding 200 kilowatts.

In June 2003, the Commission authorized a Critical Peak Pricing (CPP) tariff for large customers proposed by the three California investor-owned utilities, as well as several other demand response-related programs. Large customers are defined by the Commission as having average monthly demands of 200 kW or greater.

A statewide demand response measurement and evaluation (M&E) effort also began in 2003, comprising a comprehensive monitoring and evaluation plan. The plan outlined M&E activities in an effort to provide information that would improve the cost-effectiveness of demand response activities going forward.

The goal underlying all of the demand response programs is to provide California with greater flexibility in responding to periods of high peak electricity demand. The objective in rolling out these specific programs relatively quickly with limited formal rate design research was to achieve a "quick win" that would:

- take advantage of the new interval meters installed in customers premises with peak demand over 200 kW (100kW for SDG&E);
- give both customers and utilities experience in implementing statewide demand response programs;
- deliver significant load reductions for summer 2004; and
- make a significant contribution to achieving the California Public Utilities Commission's overall price-responsive demand response goals (which ramp up to 5 percent of system peak by 2007).

## DESCRIPTION OF PROJECT

The CPP tariff for large customers comprised increased prices during 6 or 7 hours of up to 12 "Critical Peak Pricing Days" each year and reduced prices during non-critical-peak periods. A CPP event could only be activated during summer. For PG&E customers, the reduced prices applied in summer only; for SCE and SDG&E customers, the reduced prices applied year-round.

To participate in the CPP tariff for large customers, all customers had to have metering capable of recording electricity usage in 15-minute intervals. If customers did not have interval metering at the start of the CPP trial period, each utility provided and installed this free of charge. PG&E and SCE customers had to have an annual maximum demand greater than 200 kW; for SDG&E customers the threshold was 100 kW of annual maximum demand. The CPP tariff was not available to direct access customers. Customers had remain on the CPP tariff for a minimum of 12 months; after participating in the CPP tariff for 12 months, customers could opt-off at any time.

There were two levels of Critical Peak Pricing periods. In SCE's and PG&E's programs they were High-Price Periods (3 to 6 pm) and Moderate-Price Periods (Noon to 3 pm). In SDG&E's program, they were Period 1 (3 to 6 pm) and Period 2 (11 am to 3 pm).

Specific price levels in the tariff were applied based on participating customers' Otherwise Applicable Tariff (OAT). The amounts and percentages of rate credits and charges varied among the utilities:

- PG&E's energy rates during the High Price Periods were five times the Otherwise Applicable Tariff (OAT) and three times the OAT during Moderate Price Periods. At other times during the summer, PG&E's On-peak and Part-peak energy rates for CPP participants were reduced by over 22 percent and over 3 percent respectively.

- SCE's rates were about 6.7 times the OAT during CPP High Price Periods and 2.0 times the OAT during CPP Moderate Price Periods. At other times during the year, the CPP rates were about 9.3 percent less than OAT energy rates.
- SDG&E's energy rates were 10.0 times the OAT during CPP Period 1 (i.e., the high price period) and 3.79 times OAT for CPP Period 2. At other times during the year, the CPP rates were about 9.5 percent less than OAT energy rates.

Bill Protection was available to customers during the first 14 months the customer was participating in the CPP tariff. Bill Protection provided that participating customers would pay no more for energy than they would have had they remained on their OAT.

Each utility determined the day before whether there would be a Critical Peak Pricing Day the next day. There were a number of 'triggers' that might activate a CPP event, including high system demand and/or low generation supply, system emergency testing, high market prices, and forecasted temperature reaching a set threshold level at specific locations. A utility could adjust the temperature threshold up or down over the course of the summer, as necessary, to achieve the targeted program event maximum of 12 CPP events per summer season. A utility could also activate a CCP event at its discretion.

Each utility notified CPP participants of Critical Peak Pricing Days according to slightly different schedules. SDG&E e-mailed its participants by 4pm the day before, SCE telephoned and e-mailed or paged starting at 3pm and PG&E e-mailed and paged its participants by 5pm.

## RESULTS

| Residential Customers Participating | Commercial and Small Industrial Customers Participating | Agricultural Customers Participating | Large Industrial Customers Participating | Additional Generation Installed |
|---|---|---|---|---|
| | 206 | | | |

| Peak Load | Peak Load Reduction | Duration of Peak Load Reduction | Overall Load Reduction | Energy Savings | Network Augmentation Deferral |
|---|---|---|---|---|---|
| 44,000 MW | 8.3 MW | 6 hours | 8.3 MW | | |

## HOW LOAD REDUCTION WAS MEASURED

Interval meter. 15 minute intervals.

## RESULTS ACHIEVED

### CPP Events

The number of CPP Events called in 2004 ranged from five and six for PG&E and SDG&E, respectively, to 12 for SCE (see Table PI01/1, page 351). However, three of the PG&E events were called on consecutive days during which time temperatures significantly decreased.

**Table PI01/1. Critical Peak Pricing Events in 2004**

| Utility | Event | Event Type | Event Trigger | Event Date | Event Hours | Participants |
|---|---|---|---|---|---|---|
| SDG&E | CPP - #1 | day-ahead notice | Utility Discretion | 07/13/04 | 11-6 pm | 41 |
| | CPP - #2 | day-ahead notice | Utility Discretion | 07/22/04 | 11-6 pm | 42 |
| | CPP - #3 | day-ahead notice | Utility Discretion | 08/11/04 | 11-6 pm | 47 |
| | CPP - #4 | day-ahead notice | Utility Discretion | 09/01/04 | 11-6 pm | 47 |
| | CPP - #5 | day-ahead notice | Utility Discretion | 09/08/04 | 11-6 pm | 47 |
| | CPP - #6 | day-ahead notice | Utility Discretion | 09/23/04 | 11-6 pm | 48 |
| SCE | CPP #1 | day-ahead notice | Temperature | 07/14/04 | 12-6 pm | 8 |
| | CPP #2 | day-ahead notice | System Constraint | 07/22/04 | 12-6 pm | 7 |
| | CPP #3 | 2-day notice | Temperature | 08/11/04 | 12-6 pm | 8 |
| | CPP #4 | 2-day notice | Temperature | 08/12/04 | 12-6 pm | 8 |
| | CPP #5 | 2-day notice | Temperature | 09/03/04 | 12-6 pm | 8 |
| | CPP #6 | 2-day notice | Temperature | 09/09/04 | 12-6 pm | 8 |
| | CPP #7 | 2-day notice | Temperature | 09/10/04 | 12-6 pm | 8 |
| | CPP #8 | 2-day notice | Temperature | 09/13/04 | 12-6 pm | 8 |
| | CPP #9 | 2-day notice | Temperature | 09/14/04 | 12-6 pm | 8 |
| | CPP #10 | 2-day notice | Temperature | 09/23/04 | 12-6 pm | 8 |
| | CPP #11 | 2-day notice | Temperature | 09/24/04 | 12-6 pm | 8 |
| | CPP #12 | 2-day notice | Temperature | 09/27/04 | 12-6 pm | 8 |
| PG&E | CPP #1 | day-ahead notice | Temperature | 08/27/04 | 12-6 pm | 112 |
| | CPP #2 | day-ahead notice | Temperature | 09/08/04 | 12-6 pm | 119 |
| | CPP #3 | day-ahead notice | Temperature | 09/09/04 | 12-6 pm | 119 |
| | CPP #4 | day-ahead notice | Temperature | 09/10/04 | 12-6 pm | 119 |
| | CPP #5 | day-ahead notice | Temperature | 10/13/04 | 12-6 pm | 129 |

## Participation Levels

Only 1 percent of eligible accounts participated in CPP for summer 2004; however, participation was higher among larger customers. Participation varied greatly by utility, 2 percent of eligible PG&E accounts signed up (146 accounts), 1 percent of SDG&E (52 accounts), and only 0.1 percent (8 accounts) for SCE. Although there are some differences in tariff design across the utilities, the differences in potential customer savings for PG&E and SCE are similar and do not explain the difference in program penetration levels.

## Load Reduction Impacts

A 10-day baseline methodology was used to calculate each customer's baseline energy usage. The baseline was determined on an hourly basis using the customer's own average energy usage for the three highest total energy usage days out of the 10 days prior to a CPP Event (excluding other CPP days or days the customer was paid to reduce power or the customer was subject to a rotating outage). The baseline was then subtracted from the actual amount of kWh used for that hour during the CPP Event to determine the actual kWh reduction.

The overall estimated load reduction across all three utilities attributed to the CPP tariff in 2004 is roughly 8 MW (see Table PI01/2, page 352). PG&E accounts for 60 percent of the estimated impact, SDG&E 30 percent, and SCE 10 percent. On a percentage basis, the average impacts range widely across the three utilities. For PG&E and SDG&E, which had the vast majority of CPP participants, average percent savings ranged from a few percent up to 20 percent depending on the utility and event.

**Table PI01/2. Average Demand Reductions Attributed to CPP Tariff (based on 10-day Adjusted Baseline)**

| | | Average Hourly Reduction - 10-Day Adjusted Baseline | | | | | |
|---|---|---|---|---|---|---|---|
| | | Average Hourly Reduction and Baseline (MW's) | | | Distribution of Individual Percent Reduction Impacts | | |
| Utility | CPP Events | Estimated Impact | Estimated Load | Percent Reduction | Median | 25th Percentile | 75th Percentile |
| PG&E | #1 & #2 | 4.9 | 100 | 5% | 1% | -5% | 9% |
| SDG&E | #1 - #6 | 2.5 | 16.7 | 15% | 1% | -1% | 22% |
| SCE* | #1 - #12 | 0.9 | 1.7 | 55% | 9% | 0% | 73% |

* SCE numbers based on 7 accounts

For planning purposes and reporting to the California Public Utilities Commission, the utilities used an impact estimate for CPP that was 15 percent of load.

For SDG&E, the average impact using the 10-Day Adjusted Baseline across six CPP events was 15 percent.

For PG&E, the 15 percent figure was on the higher end of what might be expected, for the particular customers in the 2004 participant cohort. The mean impact estimated using the 10-Day Adjusted Baseline was 5 percent of load based on the first two event days (event days for which there is more confidence in the estimates). Even if all four event days were used (of which the latter two were believed to be overstated), the mean impact was 9 percent.

For SCE, it is difficult to assess if the 15 percent value used by the utilities was appropriate due to the small number of participants in the CPP tariff. Although the impact was estimated to be 55 percent of load, this value was driven primarily by a single customer. The median impact was 9 percent and the inter-quartile range was zero to 73 percent. Therefore, for SCE, 15 percent was likely to be a better value for planning purposes than 55 percent.

## Level of Compensation

The monetary incentive to customers to reduce load in the CPP tariff program was relatively small, particularly as compared to customers' annual electricity bills and other costs of doing business. Savings were roughly 1 to 2 percent for most customers. A market survey of non-participants showed very low levels of customer willingness to make load reductions in exchange for bill savings of a percent or two a year.

There is evidence that the levels and form of compensation may not have motivated a larger share of the eligible market to participate in the CPP tariff program because customers believed that their costs of participating in the programs and taking associated demand response actions might exceed the corresponding financial incentives/

There was consistent evidence that end users faced both fixed and variable costs associated with demand response actions.

Fixed costs were associated with developing a demand response action plan, which may require a variety of engineering and financial analyses, as well as implementation of fixed elements of the plan (for example, programming energy management systems or other control systems, purchase of new equipment, modification of existing equipment, etc.).

Variable costs included costs associated with carrying out the demand response actions, which could include costs associated with lost or deferred production, decreased worker productivity, as well as the costs of physically carrying out the reductions (in cases where they were not automated).

### Barriers to Participation

Based on the results of the non-participant survey, customers indicated that there are numerous barriers that limit their ability and willingness to participate in demand response programs. In rating potential barriers to participation and implementation, the number one concern for the market as a whole was "Effects on Products or Productivity". The next largest concerns were "Amount of Potential Bill Savings", "Level of On-peak Prices or Non-performance Penalties", and "Inability to Reduce Peak Loads". The least significant concern reported was "Inadequate Program Information".

## CONFIDENCE LEVEL IN ACHIEVING RESULTS

When each of the CPP participants was asked about their likelihood of taking demand reduction actions in future CPP events, 84 percent responded that they were either somewhat or very likely to take actions for future events. Only 4 percent of participants reported they were not at all likely to take action and 7 percent reported they were somewhat unlikely.

## REPEATABILITY OF RESULTS

## TIME DELAY BEFORE MAXIMUM RESPONSE ACHIEVED

## WEATHER DEPENDENCE

One issue relating to the low frequency of CPP events was the appropriateness of the temperature trigger that determined how often the program was called. There were indications that the triggers for some regions were set relatively high, resulting in the program being rarely called. In SDG&E’s territory, for example, the CPP program was triggered when the forecast temperature for a certain location reached 91 degrees Fahrenheit (33 degrees Celsius); however the forecast temperature for that location had not been as high as 91 degrees in the preceding five years.

## AVOIDED COSTS

## ACTUAL PROJECT COSTS

## PROJECT COST FROM THE SOCIETAL PERSPECTIVE

## OVERALL PROJECT EFFECTIVENESS

The evaluation results pointed to significant challenges associated with achieving high levels of participation in, and load reduction from, the CPP tariff program. At the same time, the process of designing, marketing and implementing the 2004 CPP tariff program provided all the utilities with valuable experience and customer feedback that would help them to continue to improve the demand response portfolio in the future.

Although adoption takes time and this program was actively marketed only from late 2003, the evaluation results showed that the CPP tariff did not make as large a contribution to achieving overall demand response goals as desired. Based on the evaluation results, the market required stronger motivation, knowledge, and capability in order for the CPP tariff program to make large contributions to the price-responsive demand response goals.

However, the narrow range of CPP events in 2004 and, in some cases, small potentially unrepresentative mix of participant types, limited the extent to which summer 2004 experiences and program impacts could be projected into the future.

## CONTACTS

PG&E: Susan McNicoll (415) 973-7404

## SOURCES

Quantum Consulting (2004). *Working Group 2 Demand Response Program Evaluation - Program Year 2004. Final Report*. Available at: www.energy.ca.gov/demandresponse/documents/working_group_documents/2004-12-21_WG2_2004_REPORT.PDF

## CASE STUDY PREPARATION

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## PI02 LOIRE TIME OF USE TARIFF PROGRAM - FRANCE

| | |
|---|---|
| **Last updated** | 19 September 2005 |
| **Location of Project** | Loire Region, France |
| **Year Project Implemented** | 1998 |
| **Year Project Completed** | 2003 |
| **Name of Project Proponent** | SIEL (association of local authorities)<br>Electricité de France (EDF - generation and transmission utility)<br>FACE (a funding body) |
| **Name of Project Implementor** | SIEL and EDF |
| **Type of Project Implementor** | Distribution utility<br>Transmission utility<br>Local government (municipality) |
| **Purpose of Project** | Deferral of network augmentation |
| **Timing of Project** | Pre contingency |
| **Focus of Project** | Network capacity limitations |
| **Project Objective** | Peak load reduction |
| **Project Target** | Network element |
| **DSM Measure(s) Used** | Energy efficiency<br>Pricing initiatives |
| **Specific Technology Used** | |
| **Market Segments Addressed** | Residential customers |

### DRIVERS FOR PROJECT

An average region (département) in Metropolitan France has 4,000 km of low voltage rural lines serving some 75,000 customers. In many regions, the cost of reinforcing certain overloaded rural feeders is much higher than the annual financial return from each feeder. This provides a significant opportunity for DSM as an alternative to network augmentation and reinforcement.

In rural areas of France, local authorities (municipalities) own the electricity distribution network and are responsible for the distribution of electricity and for network augmentation and reinforcement. Electricity is supplied by Electricité de France (EDF) under concessional contracts with the local authorities. Augmentation and reinforcement of the distribution network is usually undertaken by associations of a number of local authorities (Syndicats Intercommunal d'Energies), generally at the regional level. (Note that these arrangements will change with the introduction of a competitive electricity market in France.)

Faced with the financial costs of network augmentation and reinforcement, local authorities favour cost-effective alternatives such as DSM projects. Hence the regional association of local authorities Syndicat Intercommunal d'Energies du département de la Loire (SIEL) participated in the Loire Time of Use Tariff Program.

The funding body Fonds d'Amortissement des Charges d'Électrification (FACE) receives revenue from a tax on the earnings of electricity distributors at the low voltage level; in urban areas this tax is about 2.5% and in rural areas it is about 0.5%. Since 1995, FACE has supported projects aimed at using alternative technical solutions to the augmentation and reinforcement of the low voltage network, because these solutions are economically profitable.

## DESCRIPTION OF PROJECT

In the Loire region, three criteria were used to select the feeders for DSM measures:

- number of customers per feeder less than 20;
- length of feeder more than 500 metres;
- voltage drop of -8% to -12% at the departure of the feeder.

Following simulations carried out by EDF with the computer programs GDO and BAGHEERA, 53 low voltage feeders in the Loire region supplying 946 customers were selected. EDF then contacted customers by visits and phone calls to collect information about the type and power rating of customer equipment, tariffs used, etc.

These data were used by a consulting company to simulate the electrical demand for each feeder. The load curve was disaggregated by end-use with the software EVE, the development of which was funded by the French Government energy efficiency agency ADEME. Then tariff changes were simulated to determine the effect on the peak load.

Where the simulations of tariff changes indicated possible financial savings for customers, EDF contacted the customers connected to the feeders. EDF proposed to the customers that they change to a two-part time of use tariff (peak and normal rates). Where the customers were already on an existing time of use tariff, EDF proposed a change in the time periods for the peak and normal rates.

SIEL assisted with the program by implementing a range of communication and awareness measures:

- development and distribution of 34,000 brochures;
- mailing of documentation and information;
- establishment of offices in the town hall dedicated to the DSM program;
- design of a DSM web site;
- distribution of compact fluorescent lamps to customers who agreed to participate in the program.

## RESULTS

| Residential Customers Participating | Commercial and Small Industrial Customers Participating | Agricultural Customers Participating | Large Industrial Customers Participating | Additional Generation Installed |
|---|---|---|---|---|
| 946 | | | | |

| Peak Load | Peak Load Reduction | Duration of Peak Load Reduction | Overall Load Reduction | Energy Savings | Network Augmentation Deferral |
|---|---|---|---|---|---|
| | | | | | More than 60 months |

## HOW LOAD REDUCTION WAS MEASURED

Estimate.

## RESULTS ACHIEVED

The simulations showed that in 31 of the 53 feeders selected (58%), DSM measures could defer the requirement for reinforcement for more than 5 years.

Following the simulations, 25% of the customers were contacted by EDF to implement the change of tariffs, and 15% accepted the changes.

## CONFIDENCE LEVEL IN ACHIEVING RESULTS

## REPEATABILITY OF RESULTS

## TIME DELAY BEFORE MAXIMUM RESPONSE ACHIEVED

## WEATHER DEPENDENCE

## AVOIDED COSTS

The cost benefit of the DSM program was calculated as:
B = IR-(Imde + TLE + IRn)
Where:
B: benefit of the operation
IR: cost of reinforcement today
Imde: cost of DSM program today
TLE: present value of lost local tax on the electricity consumption, interest rate : 8%
n: number of years of deferral of reinforcement
IRn: cost today of reinforcement at the year n, interest rate : 8%.

The cost benefit analysis showed:
Total cost of the program: EUR 241,889
Cost of the program for feeders with reinforcement deferral more than 5 years: EUR 1,855,685
Benefit: EUR 213,785

## ACTUAL PROJECT COSTS

FACE : 70 % of the total cost
SIEL : 30% of the total cost

## PROJECT COST FROM THE SOCIETAL PERSPECTIVE

## OVERALL PROJECT EFFECTIVENESS

After the success of this project, SIEL decided to implement DSM programs in two other areas of the Loire region. In these programs, the level of voltage drop as a criterion to select the feeders was changed to -2% to +5%.

## CONTACTS

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## SOURCES

ADEME/EDF (2004). *Guide méthodologique pour la réalisation d'opérations MDE micro*.

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## CASE STUDY PREPARATION

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# PI03 QUEANBEYAN CRITICAL PEAK PRICING TRIAL - AUSTRALIA

| | |
|---|---|
| **Last updated** | 7 July 2006 |
| **Location of Project** | Queanbeyan and Jerrabomberra, New South Wales, Australia |
| **Year Project Implemented** | 2004 |
| **Year Project Completed** | |
| **Name of Project Proponent** | Country Energy |
| **Name of Project Implementor** | Country Energy |
| **Type of Project Implementor** | Distribution utility<br>Electricity retailer/supplier |
| **Purpose of Project** | Deferral of network augmentation |
| **Timing of Project** | Pre contingency |
| **Focus of Project** | Network capacity limitations |
| **Project Objective** | Peak load reduction |
| **Project Target** | Network region |
| **DSM Measure(s) Used** | Pricing initiatives |
| **Specific Technology Used** | Interval meter and pricing information display unit |
| **Market Segments Addressed** | Residential customers |

## DRIVERS FOR PROJECT

The Queanbeyan Critical Peak Pricing Trial was initiated to investigate the feasibility of promoting peak load reductions by residential sector customers to relieve distribution network constraints in the Queanbeyan area.

## DESCRIPTION OF PROJECT

The trial involved applying seasonal time of use and critical peak pricing tariffs to about 200 households in Queanbeyan and Jerrabomberra, two suburbs located near the city of Canberra in eastern Australia.

Two seasonal tariff schedules were applied. In summer, the peak period was from 2 pm to 8 pm to coincide with the period of maximum use of domestic air conditioners. I n winter the peak period was from 7 am to 9 am and 5 pm to 8 pm to coincide with the period of maximum use of domestic space heaters.

Critical peak periods were called by Country Energy when the load on the local network was reaching maximum capacity or when high price events occurred in the competitive wholesale electricity market. Critical peak periods could be called for a maximum of 12 times per year; customers were given a minimum 2 hours notice.

The tariff levels were as follows:

**Off Peak:** AUD 0.0703/kWh
**Shoulder:** AUD 0.127/kWh
**Peak:** AUD 0.1887/kWh
**Critical Peak:** 0.3774/kWh

The standard tariffs applied by Country Energy to residential dwellings were flat rate block tariffs based on readings from simple accumulation meters. In the trial, implementation of time of use and critical peak pricing tariffs required the installation of interval meters and in-home information display units in participants' dwellings (see Figure PI03/1). The installation of this new technology was paid for by Country Energy.


**Figure PI03/1. Technology Used in the Queanbeyan Trial**

The interval meters measure energy use in half hour blocks. Each meter was directly connected to a two-way communications unit using mobile phone technology that enables Country Energy to send and receive messages to and from the meter. This technology allowed automatic meter reading. It was also used to signal an upcoming critical peak period and instruct the meter to adjust its tariff.

The in-home information display unit, called a Home Energy Monitor (see Figure PI03/2, page 361), communicated with the interval meter through power line carrier technology. It plugged into any power socket and was about the size of a regular wall phone. The Home Energy Monitor comprises a LED alphanumeric display which provided customers with specific information about the amount of electricity they were using, and how much it was costing. It also included green, amber, and red LED lights which showed customers whether they were using electricity at low, medium, or high prices, corresponding to off peak/shoulder, peak and critical peak tariffs. A beeping sounds alerted customers to the start of a critical peak period.

Customers who participated in the trial were instructed to keep an eye on the Home Energy Monitor and adjust their electricity usage to avoid high tariff periods and capitalise on the lower tariffs. Some tips were provided about how to reduce electricity usage during high price periods.

Customers were also provided with a Participant Gift Pack that included compact fluorescent lamps, energy timers an energy efficiency thermometer, an energy wise calculator, CD-ROM, and an energy wise brochure.

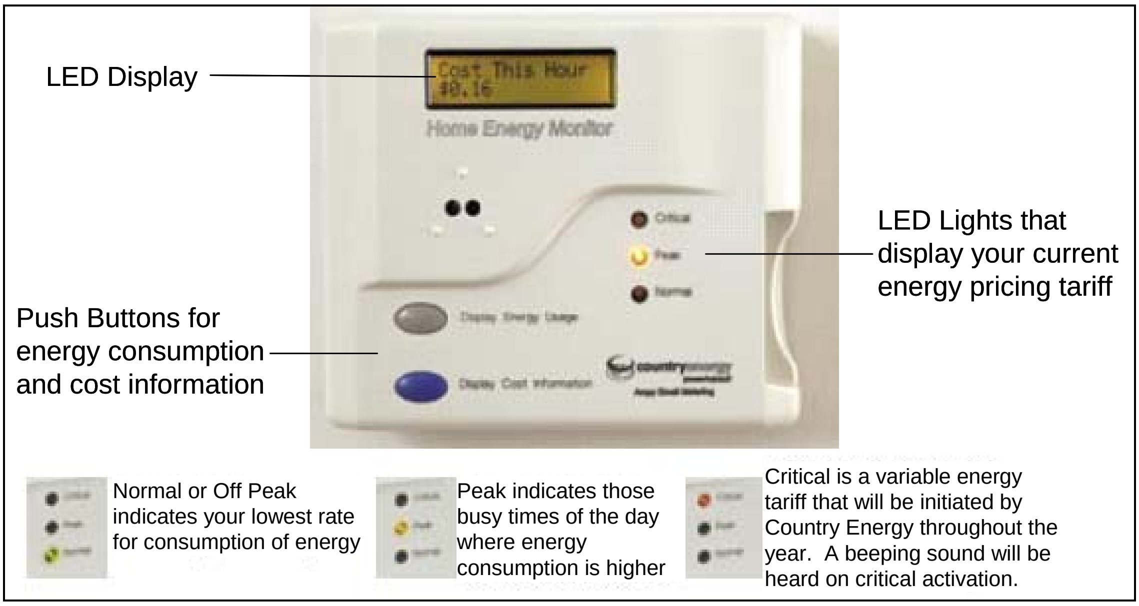


**Figure PI03/2. Home Energy Monitor Used in the Queanbeyan Trial**

Country Energy advised customers participating in the trial that, depending on their current tariff, they could expect to save between AUD 10 and AUD 120 per annum.

## RESULTS

| Residential Customers Participating | Commercial and Small Industrial Customers Participating | Agricultural Customers Participating | Large Industrial Customers Participating | Additional Generation Installed |
|---|---|---|---|---|
| 200 | | | | |

| Peak Load | Peak Load Reduction | Duration of Peak Load Reduction | Overall Load Reduction | Energy Savings | Network Augmentation Deferral |
|---|---|---|---|---|---|
| | | | | | |

## HOW LOAD REDUCTION WAS MEASURED

Interval meter. 30 minute intervals.

## RESULTS ACHIEVED

Country Energy reported that the results of the trial showed mixed, but mainly positive results. The results varied from customer to customer with the majority achieving a saving. Illustrations of the impact of critical peak pricing (CPP) alerts are shown in Figures PI03/3 and PI03/4 (page 362). In both cases, demand decreased significantly during the CPP period, but increased after the end of the period. On 1 February 2006, the increase in demand resulted in a peak later in the evening that was higher than that on the comparison day without a CPP event. Detailed analysis is yet to be completed.

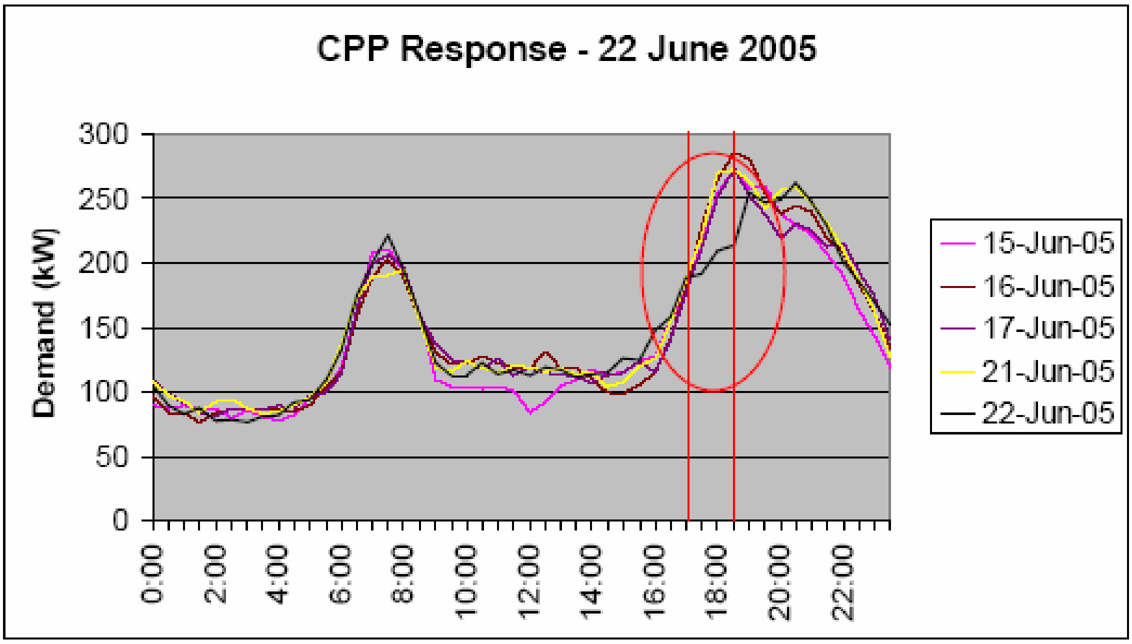


**Figure PI03/3. Impact of 22 June 2005 CPP Event in the Queanbeyan Trial**

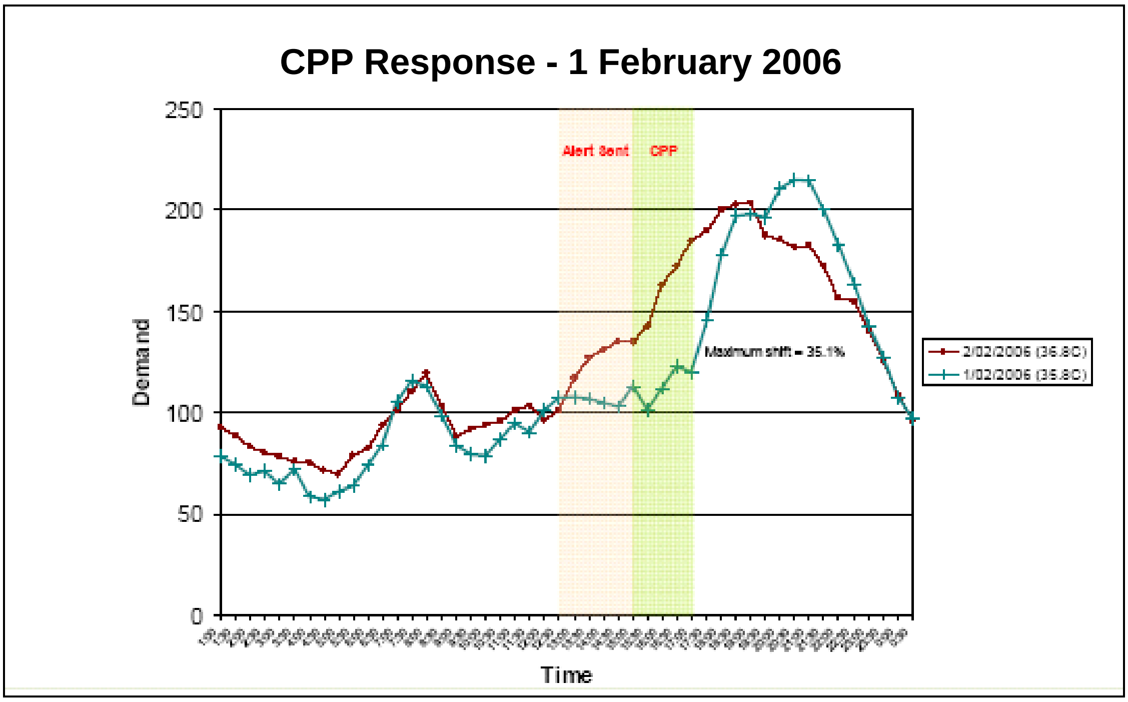


**Figure PI03/4. Impact of 1 February 2006 CPP Event in the Queanbeyan Trial**

## CONFIDENCE LEVEL IN ACHIEVING RESULTS

## REPEATABILITY OF RESULTS

## TIME DELAY BEFORE MAXIMUM RESPONSE ACHIEVED

## WEATHER DEPENDENCE

## AVOIDED COSTS

## ACTUAL PROJECT COSTS

## PROJECT COST FROM THE SOCIETAL PERSPECTIVE

## OVERALL PROJECT EFFECTIVENESS

## CONTACTS

## SOURCES

Country Energy (2004). *The Country Energy Home Energy Efficiency Trial*. Customer Brochure. Queanbeyan, Country Energy.

Soussou, R. (2006). *Country Energy: Home Efficiency Trial in Queanbeyan*. Presentation to the Demand Response and DSM Conference, Sydney 27 to 28 March.

## CASE STUDY PREPARATION

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## PI04 HOURLY DEMAND TARIFF - SPAIN

| | |
|---|---|
| **Last updated** | 31 August 2005 |
| **Location of Project** | Spain |
| **Year Project Implemented** | 1994 |
| **Year Project Completed** | |
| **Name of Project Proponent** | Red Eléctrica de España (REE) |
| **Name of Project Implementor** | Red Eléctrica de España (REE) |
| **Type of Project Implementor** | Transmission utility |
| **Purpose of Project** | Provision of network operational services |
| **Timing of Project** | Pre contingency |
| **Focus of Project** | Generation capacity limitations |
| **Project Objective** | Peak load reduction |
| **Project Target** | Whole network |
| **DSM Measure(s) Used** | Pricing initiatives |
| **Specific Technology Used** | |
| **Market Segments Addressed** | Large industrial customers |

### DRIVERS FOR PROJECT

The Hourly Demand Tariff is based on dividing the 365 days of the year into four different types and the 8760 hours in a year into seven time of use periods. The Spanish transmission system operator, Red Eléctrica de España, has the right to determine the days on which Period 1 applies. Period 1 is defined as 13 hours per day between 8 am and midnight on 23 weekdays per year during summer. This period constitutes a “super peak” and is the most expensive period of the year.

The aim of this measure is to dissuade customers from using electricity during peak hours by increasing the demand and energy cost components of their electricity bills.

### DESCRIPTION OF PROJECT

The Hourly Demand Tariff has four components:

- a demand component calculated as the customer's maximum demand in each time of use period multiplied by the rate for that period;
- an energy component calculated as the energy consumed in a time of use period multiplied by the rate for that period;
- an interruptibility discount; and
- if applicable, a reactive power discount.

The time of use rates for the Hourly Demand Tariff are based on dividing the 365 days of the year into four different types (see Table PI04/1, page 365) and the 8760 hours in a year into seven time of use periods (see Table PI04/2, page 365). For each period, there is a contracted demand level and a different rate for each of the demand and energy components of the tariff. Table PI04/3 (page 365) shows the time of use rates applicable in 2005. Rates for each period are reviewed every year.

The Hourly Demand Tariff rates do not vary with the voltage level of the customer's connection nor with the customer's contracted demand level.

| Table PI04/1. Time of Use Day Types for Hourly Demand Tariff | |
|---|---|
| **Day Type** | **Definition** |
| Type A | Monday to Friday working days during high season (considered to be peak days) |
| Type B | Monday to Friday working days during medium season |
| Type C | Monday to Friday working days during low season, except in August |
| Type D | Saturdays, Sundays, holidays and August |

| Table PI04/2. Time of Use Periods for Hourly Demand Tariff | |
|---|---|
| **Period** | **Duration** |
| 1 | 13 hours per day between 8 am and midnight on 23 Type A days per year determined by Red Eléctrica de España (REE). These Period 1 days have to be announced by at least the Friday of the week before. Up to 5 of these days per year may be announced by REE the day before. |
| 2 | From 4 pm to 10 pm (6 hours per day) on the Type A days not included in Period 1. |
| 3 | From 8 am to 4 pm and from 10 pm to midnight (10 hours a day) on the Type A days included in Period 2. Also includes the remaining 3 hours per day between 8 am and midnight on the Type A days included in Period 1. |
| 4 | From 4 pm to 10 pm (6 hours a day) on Type B days. |
| 5 | From 8 am to 4 pm and from 10 pm to midnight (10 hours a day) on Type B days. |
| 6 | From 8 am to midnight (16 hours a day) on Type C days. |
| 7 | The rest of the hours which have not been included in any other period. |

| Table PI04/3. Rates for the Demand and Energy Components of the Hourly Demand Tariff | | | | | | | |
|---|---|---|---|---|---|---|---|
| **Component** | **Period 1** | **Period 2** | **Period 3** | **Period 4** | **Period 5** | **Period 6** | **Period 7** |
| Demand (EUR/kW/year) | 31.712734 | 21.137602 | 18.118851 | 12.682563 | 12.682563 | 12.682563 | 9.752409 |
| Energy (EUR/kWh) | 0.177518 | 0.061463 | 0.061641 | 0.055122 | 0.0362 | 0.023543 | 0.018543 |

To be eligible for the Hourly Power Tariff, customers have to comply with the following requirements:

1. The customer's contracted demand level must be greater than 20MW during a minimum of one time of use period.
2. The customer's contracted demand level must be greater than 5MW for all seven time of use periods.
3. The customer's contracted demand level during a time of use period must be greater than that in the preceding period:
   P7>P6>P5>P4>P3>P2>P1.
4. The customer's premises must be equipped with adequate measurement and control systems.

The loads of all customers on the Hourly Power Tariff are interruptible.

## RESULTS

| Residential Customers Participating | Commercial and Small Industrial Customers Participating | Agricultural Customers Participating | Large Industrial Customers Participating | Additional Generation Installed |
|---|---|---|---|---|
| | | | 87 | |

| Peak Load | Peak Load Reduction | Duration of Peak Load Reduction | Overall Load Reduction | Energy Savings | Network Augmentation Deferral |
|---|---|---|---|---|---|
| | | | | | |

## HOW LOAD REDUCTION WAS MEASURED

## RESULTS ACHIEVED

In 2005, there are 87 customers on the Hourly Demand Tariff contract. Contracted demand totals 1,337 MW during Period 1. If all contracted customers reduced their consumption by 50% during peak hours there would be a demand reduction of 668 MW. However, there is no information available on the actual load reductions achieved through the Hourly Demand Tariff.

This measure was last applied in 2001. However, the Hourly Demand Tariff was not as effective in achieving peak load reductions as interruptibility contracts.

In general, large industrial customers found it was not profitable to reduce production to make savings on their electricity bills. Financial losses through reduced production were likely to be greater than the increase in their electricity bills during Period 1. Furthermore, there is no penalty in the Hourly Demand Tariff contract for customers who do not reduce their electricity usage during Period 1.

## CONFIDENCE LEVEL IN ACHIEVING RESULTS

## REPEATABILITY OF RESULTS

REE has the right to determine 23 high cost Period 1 days per year, given sufficient notice.

## TIME DELAY BEFORE MAXIMUM RESPONSE ACHIEVED

## WEATHER DEPENDENCE

## AVOIDED COSTS

## ACTUAL PROJECT COSTS

## PROJECT COST FROM THE SOCIETAL PERSPECTIVE

## OVERALL PROJECT EFFECTIVENESS

Low - it is difficult to achieve significant peak load reductions through this mechanism.

## CONTACTS

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## SOURCES

Ministerial Decree January 12th 1995
Spanish Royal Decree 2392/2004
REE Clients Register

## CASE STUDY PREPARATION

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# PI05 END USER FLEXIBILITY BY EFFICIENT USE OF INFORMATION AND COMMUNICATION TECHNOLOGIES - NORWAY

| | |
|---|---|
| **Last updated** | 25 August 2005 |
| **Location of Project** | Two distribution network areas, Norway |
| **Year Project Implemented** | 2001 |
| **Year Project Completed** | 2004 |
| **Name of Project Proponent** | SINTEF Energy Research |
| **Name of Project Implementor** | Buskerud Kraftnett AS and Skagerak Energi Nett AS |
| **Type of Project Implementor** | Distribution utility |
| **Purpose of Project** | Deferral of network augmentation |
| **Timing of Project** | Pre contingency |
| **Focus of Project** | Network capacity limitations |
| **Project Objective** | Peak load reduction |
| **Project Target** | Network region |
| **DSM Measure(s) Used** | Direct load control<br>Pricing initiatives |
| **Specific Technology Used** | Remote load control of water heaters |
| **Market Segments Addressed** | Residential customers |

## DRIVERS FOR PROJECT

In the Nordic power market, the bid curves in the day ahead market (Elspot) are rather steep in the higher price ranges, which means that price elasticity is very low. The tight peak power balance, periods with shortage of energy, and very little investment in new production capacity has focused attention towards increased price elasticity on the demand side. The purpose of this pilot project was to investigate manual and automatic demand response to prices in the day ahead market.

## DESCRIPTION OF PROJECT

This was a large scale pilot project involving two network operators and six technology vendors (see Figure PI05/1, page 369).

The project included:

- two way communication to 10,984 mainly residential customers using radio, PLC, GSM, GPRS and PSTN;
- automated meter reading with hourly readings;
- a separate channel for direct load control of water heaters.

In Norway, the electricity industry has been unbundled with separate network service providers and energy retailers supplying end use customers. Customers therefore receive electricity bills containing four main components based on:

- a network tariff;
- a retail energy tariff;
- value added tax (VAT); and
- government charges.

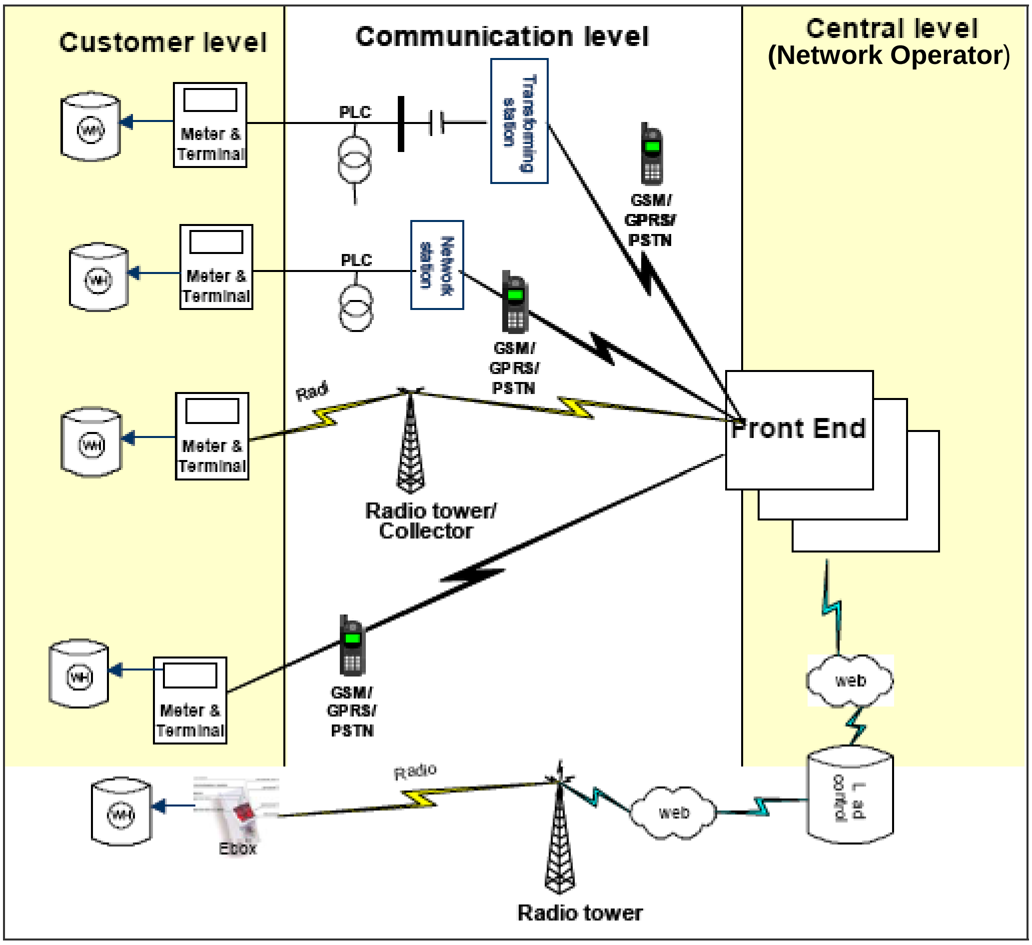


**Figure PI05/1. Information and Communication Technologies Used in the Project**

The residential customers involved in the pilot project were offered a specially designed time of use (ToU) network tariff. This tariff consisted of three components:

- a fixed component;
- a component for network losses; and
- an energy-related component which was only activated during peak periods.

The TOU network tariff had a two-level rate structure (see Figure PI05/2 page 370). The rates were:

- a peak price of about NOK 0.88 (excluding VAT) during peak load periods (defined as 7 to 11 am and 4 to 8 pm on working days from November to April); and
- an off-peak price of NOK 0.02 (excluding VAT) in all other hours of working days, weekends and holidays.

The 44:1 differential between the peak and off-peak network tariff was very large. However, when the retail energy tariff, VAT and government charges components were added to the customers' electricity bills, this differential was reduced to about 3:1.

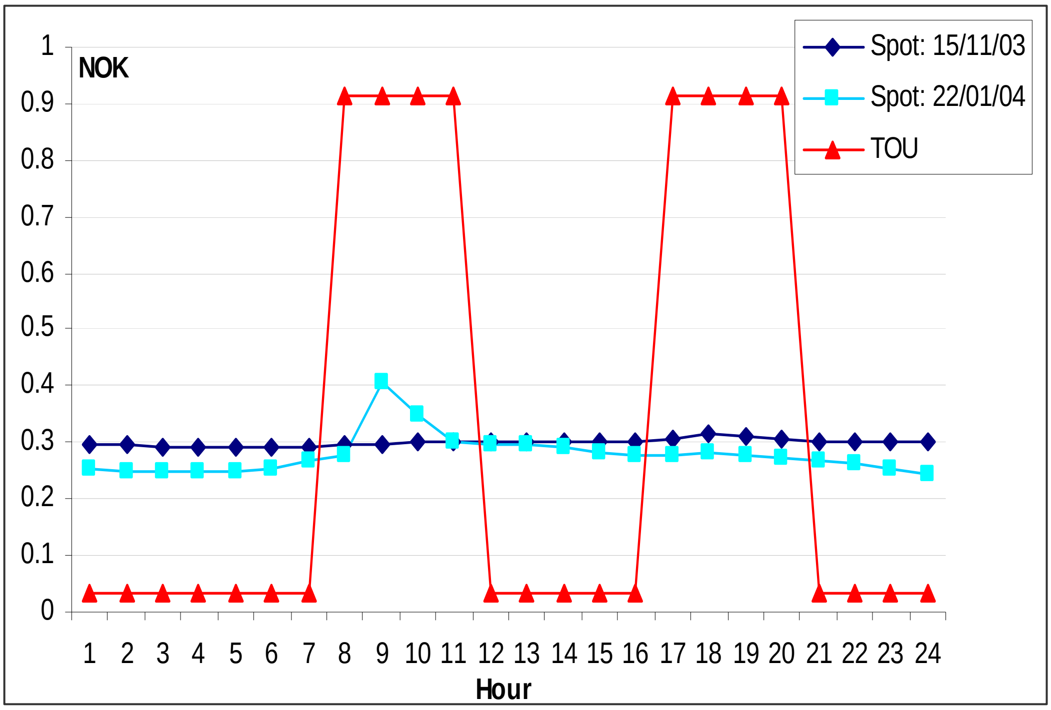


**Figure PI05/2. Tariffs Used in the Project**

In addition, the energy retailers in the area offered customer contracts based on the spot prices in the electricity market on an hourly basis.

One of the retailers also offered an hourly spot price in combination with remote controlled automatic disconnection (load control) of water heaters in the periods from 9 to 11 am and 5 to 7 pm on week days. The energy spot price was expected to be high during these periods. Load control of water heaters was available to 50% of the customers in the pilot project.

Load control operated through a separate channel to automated meter reading and required an agreement with the network operator to carry out the remote load control in the specified periods. Load control was implemented for short test periods of between two and three days several weeks apart (see Figure PI05/3).

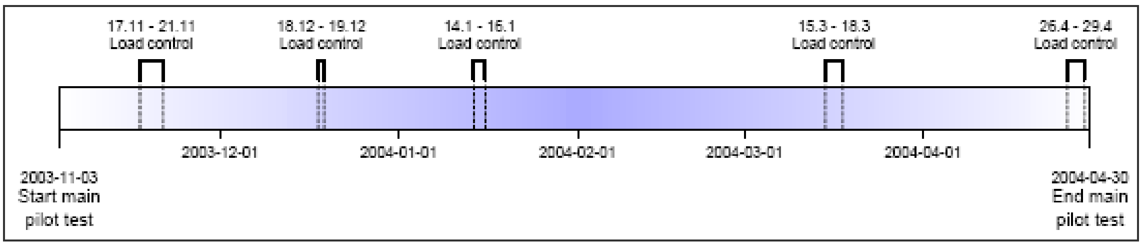


**Figure PI05/3. Test Periods for Load Control**

The two network operators offered slightly different load control options (see Figures PI05/4 and PI05/5).

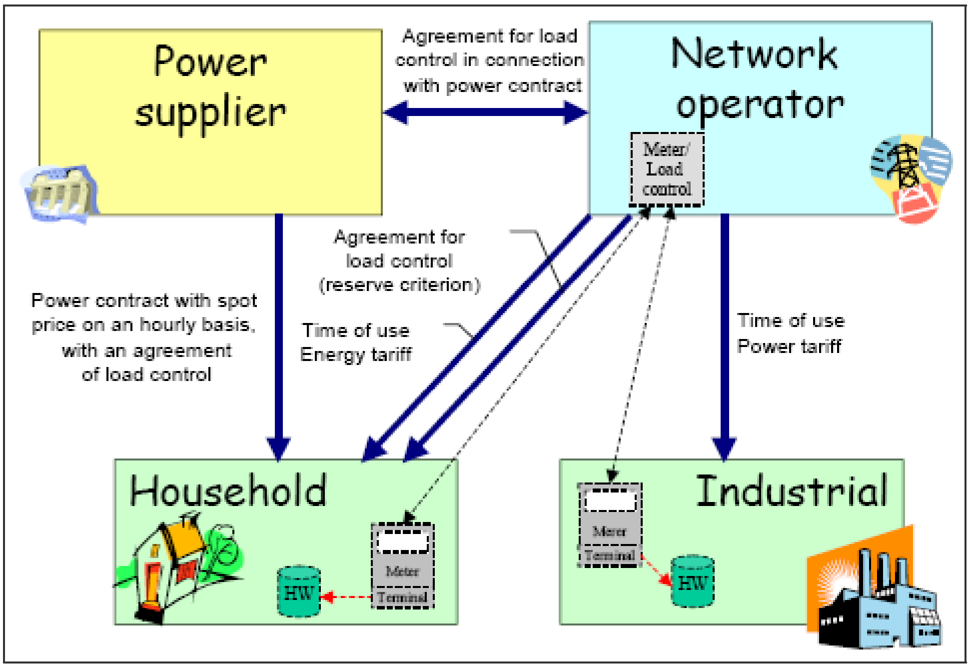


**Figure PI05/4. Tariff and Load Control Arrangements for Buskerud Kraftnett AS**

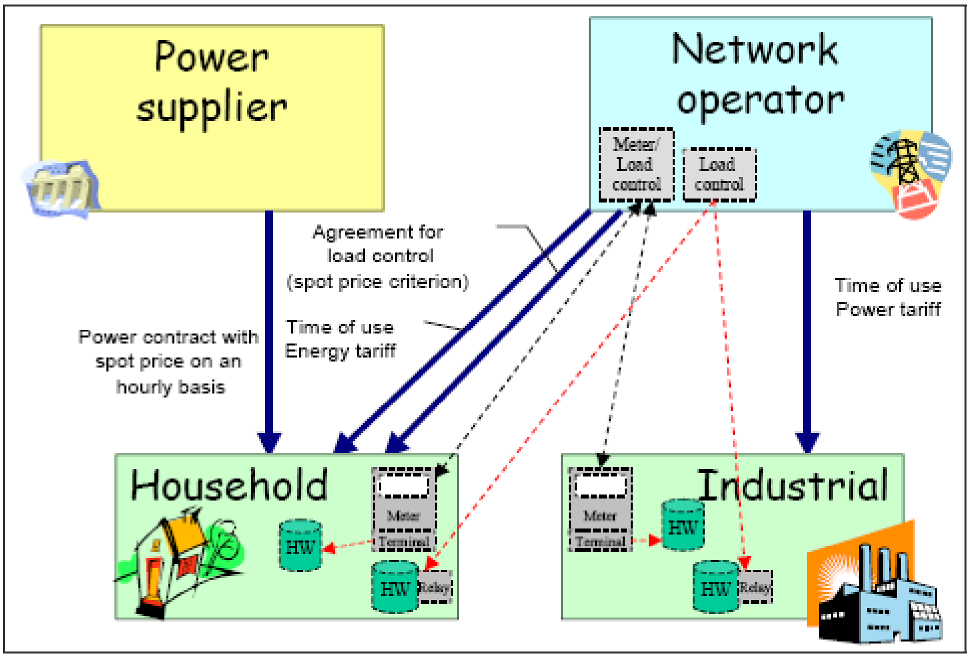


**Figure PI05/5. Tariff and Load Control Arrangements for Skagerak Energi Nett AS**

Water heaters were switched off as follows:

- Buskerud Kraftnett AS: during the hour with the highest energy spot price plus the hour before or after;
- Skagerak Energi Nett AS: during two hours in the peak load periods when the energy spot price reached a predefined limit.

In the case of Skagerak, the energy spot price limit was initially set at 0.0625 NOK/kWh. However, spot prices during the test period were low with little volatility. In the last months of the pilot project the spot price limit was removed and the water heaters were disconnected for two hours every morning and evening, when the spot prices were highest.

Therefore, there were five possible tariff options from which customers in the pilot project could choose:

- ToU network tariff and standard-offer energy tariff; or
- ToU network tariff and spot price energy tariff; or
- ToU network tariff, spot price energy tariff and direct load control of water heaters; or
- standard-offer network tariff and spot price energy tariff; or
- standard-offer network tariff, spot price energy tariff and direct load control of water heaters.

## RESULTS

| Residential Customers Participating | Commercial and Small Industrial Customers Participating | Agricultural Customers Participating | Large Industrial Customers Participating | Additional Generation Installed |
|---|---|---|---|---|
| 10,894 | | | | |

| Peak Load | Peak Load Reduction | Duration of Peak Load Reduction | Overall Load Reduction | Energy Savings | Network Augmentation Deferral |
|---|---|---|---|---|---|
| | 3.2 MW | | | | |

## HOW LOAD REDUCTION WAS MEASURED

Interval meter. 60 minute intervals.

## RESULTS ACHIEVED

The main test period was from November 2003 to March 2004. During this period, the average load reductions per household achieved through the various options were as follows:

Buskerud Kraftnett AS
ToU network tariff - approx 0.18 kWh/h
Hourly spot price for energy - approx 0.6 kWh/h
Direct load control of water heaters - approx 0.5 kWh/h
ToU network tariff plus hourly spot price for energy - approx 1 kWh/h

Skagerak Energi Nett AS
ToU network tariff - approx 0.18 kWh/h
Hourly spot price for energy - approx 0.4 kWh/h
Direct load control of water heaters - approx 0.57 kWh/h
ToU network tariff plus hourly spot price for energy - approx 0.3 kWh/h

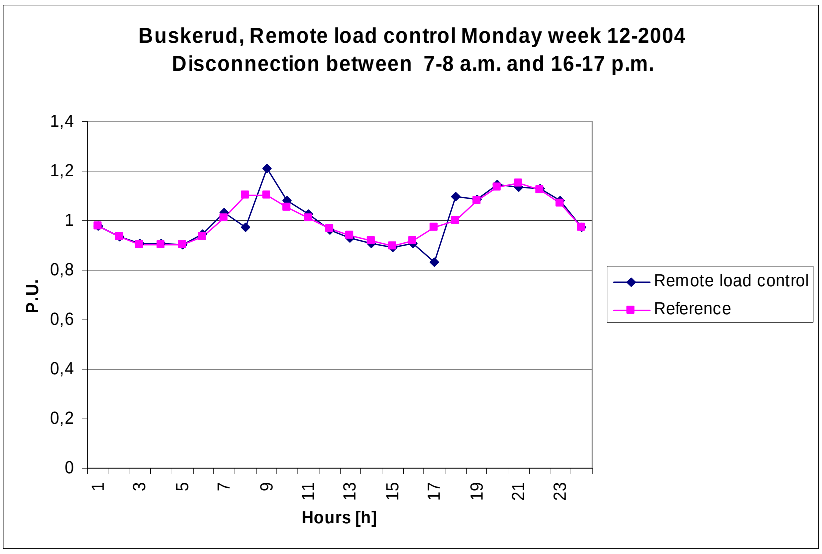


**Figure PI05/6. Results for Load Control**

In Figure PI05/6, the results are for residential customers with both TOU network tariff and spot price energy tariff and load control. The reference curve is based on consumption by similar customers in the same period and the same location. Compared with the reference group, electricity use by the load control group is reduced during the two peak load periods. The reduction is 12% in the morning and 14% in the afternoon. Number of customers: 1230.

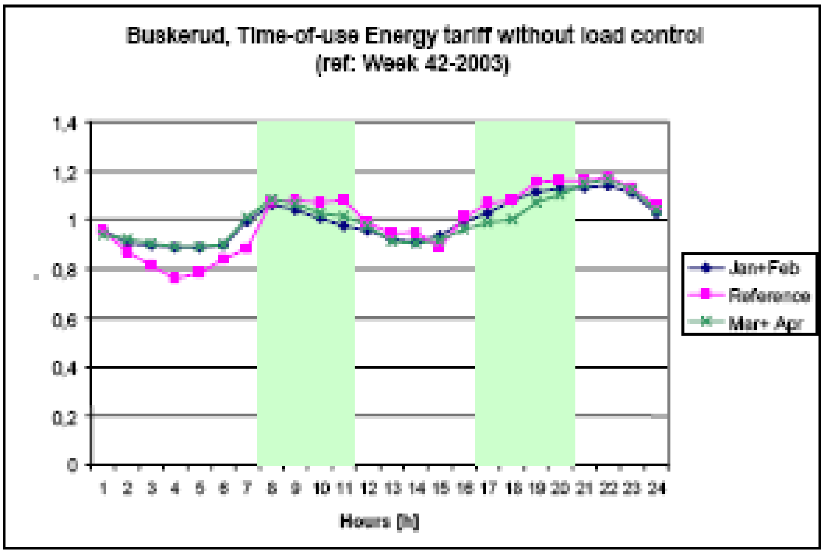


**Figure PI05/7. Results for TOU Network Tariff Without Load Control**

In Figure PI05/7, the results are for residential customers with TOU network tariff and standard-offer energy tariff with no load control. Compared with the reference group, electricity use by the TOU network tariff group is reduced during the two peak load periods. The reduction is 10% in the morning and 7% in the afternoon. Number of customers: 39.

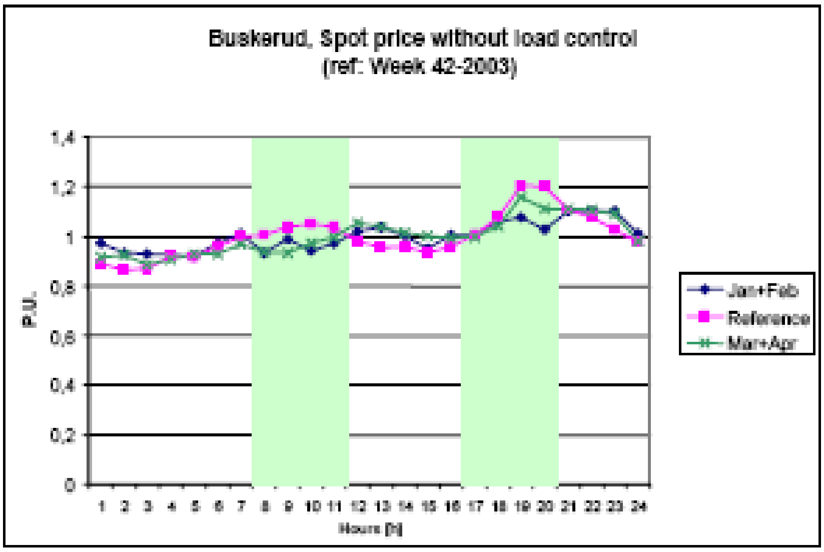


**Figure PI05/8. Results for Spot Price Energy Tariff Without Load Control**

In Figure PI05/8, the results are for residential customers with standard-offer network tariff and spot price energy tariff with no load control. Compared with the reference group, electricity use by the spot price energy tariff group is reduced during the two peak load periods. The reduction is 15% in the morning and 22% in the afternoon. Number of customers: 17.

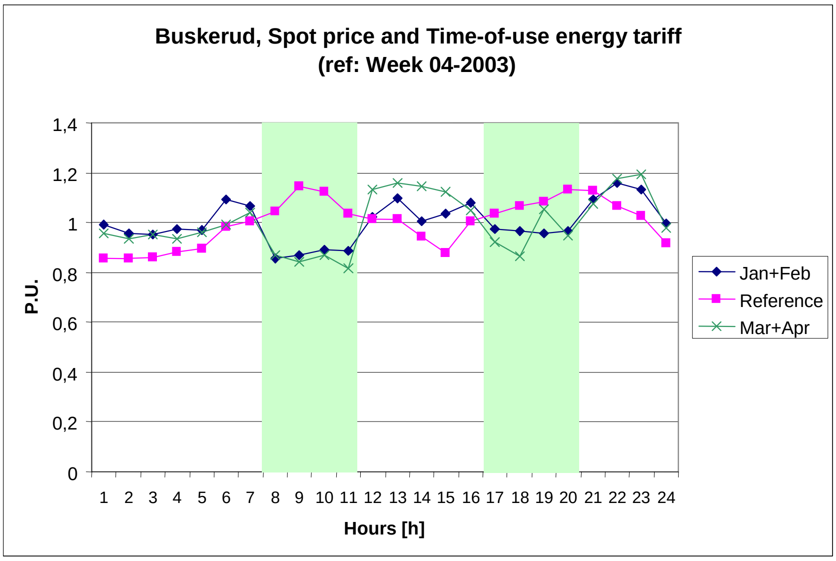


**Figure PI05/9. Results for TOU Network Tariff and Spot Price Energy Tariff Without Load Control**

In Figure PI05/9, the results are for residential customers with TOU network tariff and spot price energy tariff with no load control. Compared with the reference group, electricity use by the TOU network tariff/spot price energy tariff group is considerably reduced during the two peak load periods. The reduction is 35% in the morning and 31% in the afternoon. Number of customers: 6.

The largest response was achieved for the households with both the ToU network tariff and the hourly energy spot price and no direct load control of water heaters. However, only a very small number of customers (6 out of 10,894) chose this option and it is possible that these were households with an interest in the issue and the willingness and ability to modify their energy-using behaviour.

For those customers who were offered remote controlled automatic disconnection of water heaters, the average load reduction from water heaters was estimated to be about 0.5 kWh/h during peak periods.

The load curves for the customers with direct load control showed some increases in load towards the end of peak periods. This increased load was probably caused by the simultaneous reconnection of the water heaters with a loss of diversity in the water heater load as a result.

In addition, the decision to disconnect the water heaters to coincide with the two most expensive hours for the energy spot price meant that the water heater reconnection took place when the TOU network price was still high and remained high for the first hour after reconnection.

## CONFIDENCE LEVEL IN ACHIEVING RESULTS

95% confidence interval was achieved for the major results, such as remote load control of electrical water heaters during special test weeks.

## REPEATABILITY OF RESULTS

A large experimental area with installed technology for automatic meter reading and remote load control was established in the pilot project. To improve the results from the project, the tests will be continued in a follow-up project (project period: 2005-2008). This will make it possible to perform different tests for at least one more winter.

## TIME DELAY BEFORE MAXIMUM RESPONSE ACHIEVED

## WEATHER DEPENDENCE

In the pilot project, electrical water heaters were disconnected by remote load control. The electricity consumption for electrical water heaters is not dependent on the outdoor temperature.

## AVOIDED COSTS

Expected cost savings from installation of technology for automatic meter reading and remote load control are:

- reduced costs for metering and settlement of electricity consumption
- postponed investments in the distribution network;
- reduced costs for electrical losses due to more accurate metering.

## ACTUAL PROJECT COSTS

The cost/benefit analyses show average annual costs in the pilot project of about NOK 680 per customer (calculated over 10 years with 8.5% interest). This comprises about NOK 450 in annualised investment costs (ie cost of equipment plus installation) and about NOK 230 for operational costs. All costs were paid by the relevant network operator.

## PROJECT COST FROM THE SOCIETAL PERSPECTIVE

In the pilot project, the average reduction in electrical consumption per household was 0.5 kWh/h. Taking network losses into account, this is equivalent to 0.6 kWh/h in reduced electricity generation.

Assuming there are 2 million household customers in Norway, and 50% of these install technology for remote load control, the estimated potential for peak load reduction through remote load control in the residential sector in Norway is 600 MW (an average of 0.3 kWh/h per customer).

The data from the pilot project enables an estimate of the average annual cost to achieve peak load reduction in the residential sector across Norway of NOK 680/customer/year ÷ 0.3 kWh/h/customer = NOK 2,260/kW.

This estimate is from a pilot project with many technological and organisational challenges. It is expected that lessons learned from the pilot project will make it possible to improve this figure considerably in future projects.

## OVERALL PROJECT EFFECTIVENESS

## CONTACTS

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## SOURCES

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## CASE STUDY PREPARATION

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## PI06 TEMPO ELECTRICITY TARIFF - FRANCE

| | |
|---|---|
| **Last updated** | 26 August 2005 |
| **Location of Project** | Whole of France |
| **Year Project Implemented** | 1989 (experimental); 1993 (launch); 1995 (generally available) |
| **Year Project Completed** | |
| **Name of Project Proponent** | Electricité de France (EDF) |
| **Name of Project Implementor** | EDF and Réseau de Transport d'Electricité (RTE) |
| **Type of Project Implementor** | Transmission utility<br>Electricity retailer/supplier |
| **Purpose of Project** | Deferral of network augmentation |
| **Timing of Project** | Pre contingency |
| **Focus of Project** | Network capacity limitations<br>Generation capacity limitations |
| **Project Objective** | Peak load reduction |
| **Project Target** | Whole network |
| **DSM Measure(s) Used** | Pricing initiatives |
| **Specific Technology Used** | Weather-related time-of-use tariff |
| **Market Segments Addressed** | Residential customers<br>Commercial and small industrial customers |

### DRIVERS FOR PROJECT

Since the 1960s, EDF has been moving towards real-time pricing of electricity linked to marginal costs of supply. Consequently, electricity customers in France have been motivated to reduce their consumption when the generation costs are high and during congestion on the electricity network.

Tempo is the most sophisticated tariff for mass market customers in the present context of a monopoly by EDF in the generation and retail supply of electricity in France.

The Tempo tariff enables smoothing of both the annual and daily electricity load curves, therefore reducing marginal generation and network costs.

### DESCRIPTION OF PROJECT

In France, electricity bills for residential and small business customers include a standing charge determined by the level of maximum demand (in kVA) nominated by the customer (*puissance souscrite*), and an energy usage charge based on the type of tariff chosen by the customer (*type d'abonnement*).

There are three types of electricity contract from which residential and small business customers can choose.

### Option Base

This is the simplest of the three contract types with the lowest standing charge and a flat rate for electricity usage all the time throughout the day and year. It is more suitable for lower usage, smaller homes and holiday homes with only occasional usage.

## Option Heures Creuses (Option HC)

This is a two-part time-of-use tariff with normal (*heures pleines*) and off-peak (*heures creuses*) rates. The standing charge is slightly higher than that of Option Base, but this is offset against a lower off-peak rate for part of the day. The off-peak period is from 10 pm until 6 am each night and, in some regions, also at midday.

Option HC is usually used in conjunction with a water heater operated by ripple control so that the heating element is switched on only during off-peak periods.

Option HC suits the majority of houses used full time where heating is non-electric.

## Option Tempo

This is a quite complicated charging system with six rates of electricity pricing based upon the actual weather on particular days and on hours of use.

Under Option Tempo, each day of the year is colour coded. There are three colours, blue (*jours bleus*), white (*jours blancs*) and red (*jours rouges*) which correspond to low, medium and high electricity prices.

The colour of each day is determined mostly by EDF based on the forecast of electricity demand for that day - the level of demand is mainly influenced by the weather. RTE, the French transmission network operator (formerly a division of EDF), also has the ability to determine the day colour if there is significant congestion on the electricity network.

In addition to a colour, each day also has normal and off-peak periods based on Option HC outlined above, with 10pm until 6am being the off-peak period.

The rules for the Option Tempo are as follows:

- the Tempo year starts on 1st September;
- the Tempo day starts at 6 am;
- the number of days per year of each colour is fixed - there are 300 blue days, 43 white days and 22 red days;
- Sunday is always a blue day;
- red days cannot fall on a holiday, weekend or more than 5 weekdays in a row.

On blue days, the electricity price is by far the lowest - during the off-peak period on a blue day the price is extremely low.

On white days, the price is higher than under Option Base or Option HC.

On red days, the price is very high to encourage lower electricity usage - the normal rate on red days is over 10 times that of the off-peak rate on blue days. Red days are usually the coldest days in winter.

In June 2005, the prices for electricity purchased under Option Tempo are as follows (see Figure PI06/1):
- Blue days off-peak: 2.99 euro cents
- Blue days normal: 3.81 euro cents
- White days off-peak: 6.51 euro cents
- White days normal: 7.79 euro cents
- Red days off-peak: 12.42 euro cents
- Red days normal: 35.46 euro cents

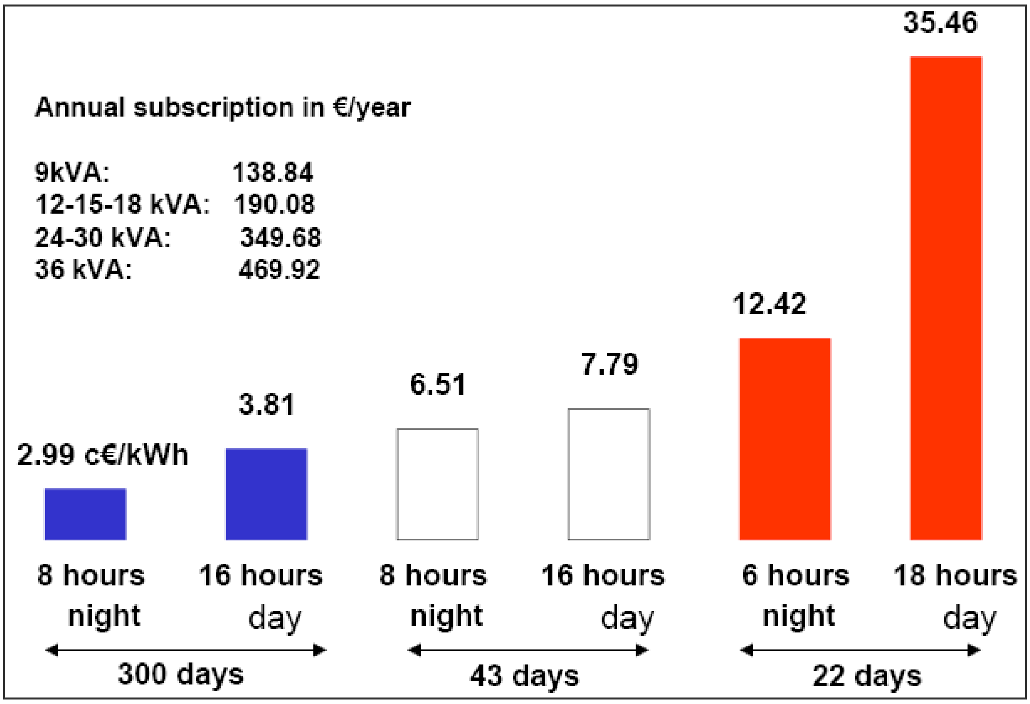


**Figure PI06/1. Tempo Tariff Rates**

There are four different versions of Option Tempo, depending on the metering, communications and load control equipment installed at the customer's premises:

- standard Tempo (the customer has only an electronic interval meter);
- dual energy Tempo (the customer's space-heating boiler can be switched from one energy source to another);
- thermostat tempo (the customer has load control equipment which is able to adjust space heating and water heating loads according to the electricity price);
- comfort Tempo (the customer has a sophisticated energy controller).

Customers who choose Option Tempo are informed each night about the colour for the next day. At 8 pm a signal is sent down powerlines using a ripple control system. Most Tempo customers have a display unit that plugs into any power socket and picks up the signal. The display unit shows the day colour with lights, both for the current day and (from 8pm) for the next day. An (optional) beep informs the consumer if the following day will be a red day. The display unit also shows whether or not the current electricity price is at the off-peak rate.

For older systems without a display unit the information is available over the telephone or via the internet.

Customers can adjust their electricity consumption manually by switching off appliances, adjusting thermostat settings, etc. Some customers who have the necessary communications and load control equipment are able to select load control programs which enable automatic connection and disconnection of separate water-heating and space-heating circuits.

Option Tempo is for high use households, such as very large houses, and those with electric heating and full time occupation, and for small business customers.

## RESULTS

| Residential Customers Participating | Commercial and Small Industrial Customers Participating | Agricultural Customers Participating | Large Industrial Customers Participating | Additional Generation Installed |
|---|---|---|---|---|
| 350,000 | 100,000 | | | |

| Peak Load | Peak Load Reduction | Duration of Peak Load Reduction | Overall Load Reduction | Energy Savings | Network Augmentation Deferral |
|---|---|---|---|---|---|
| | 450 MW | | | | |

## HOW LOAD REDUCTION WAS MEASURED

Interval meter.

## RESULTS ACHIEVED

Compared with blue days, the Tempo tariff has led to a reduction in electricity consumption of 15% on white days and 45% on red days, on average 1 kW per customer (see Figure PI06/2, page 382).

Tempo customers have saved 10% on average on their electricity bill and 90% of the customers are satisfied with the tariff. However, customers do not appreciate red days occurring consecutively.

## CONFIDENCE LEVEL IN ACHIEVING RESULTS

## REPEATABILITY OF RESULTS

## TIME DELAY BEFORE MAXIMUM RESPONSE ACHIEVED

## WEATHER DEPENDENCE

The Tempo tariff is weather-related so the response is entirely dependent on the weather.

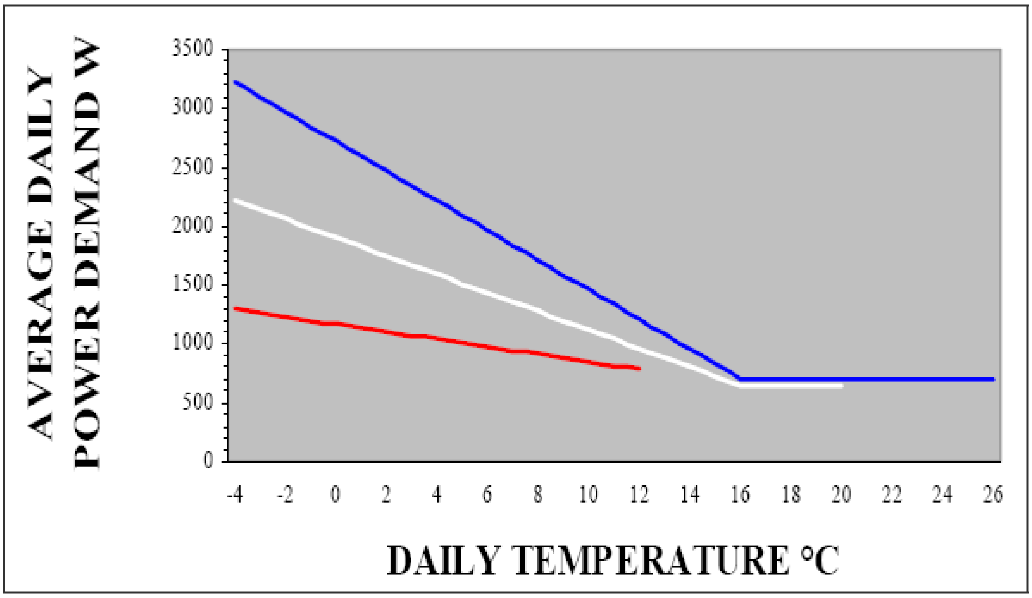


**Figure PI06/2. Tempo Customer Power Demand vs Outdoor Temperature**

## AVOIDED COSTS

## ACTUAL PROJECT COSTS

## PROJECT COST FROM THE SOCIETAL PERSPECTIVE

## OVERALL PROJECT EFFECTIVENESS

While the Tempo tariff has been successful, less than 20% of electricity customers in France have chosen Tempo. Tempo customers have very particular customer profiles and are interested in managing their energy use. They are prepared to constrain their lifestyles to make comparatively small financial savings relative to their incomes.

The Tempo tariff was designed specifically for the situation where EDF is a monopolistic generator and retail supplier of electricity. However, it is not adapted to an open market situation.

In particular, in the French open electricity market :

- the network use of system charge does not vary between seasons; and
- the value of peak load reduction is not reflected in spot prices for energy which are less volatile than the marginal costs of supply.

If EDF needs to manage its global load curve in an open electricity market, it will probably have to develop other types of dynamic pricing for mass market customers. The feedback from Tempo customers will be very useful in developing new customer which include electricity supply and services.

## CONTACTS

## SOURCES

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## CASE STUDY PREPARATION

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## PI07 REDUCED ACCESS TO NETWORK TARIFF - SPAIN

| | |
|---|---|
| **Last updated** | 27 October 2006 |
| **Location of Project** | Spain |
| **Year Project Implemented** | 1998 |
| **Year Project Completed** | |
| **Name of Project Proponent** | Red Eléctrica de España, S.A. (REE) |
| **Name of Project Implementor** | Red Eléctrica de España, S.A. (REE) |
| **Type of Project Implementor** | Transmission utility |
| **Purpose of Project** | Provision of network operational services |
| **Timing of Project** | Pre contingency |
| **Focus of Project** | Generation capacity limitations<br>Voltage fluctuations |
| **Project Objective** | Voltage regulation |
| **Project Target** | Whole network |
| **DSM Measure(s) Used** | Power factor correction<br>Pricing initiatives |
| **Specific Technology Used** | |
| **Market Segments Addressed** | Large industrial customers |

### DRIVERS FOR PROJECT

Under the current partial market liberalization in Spain, only "Qualified Customers" are free to choose their suppliers. Until the market is fully opened, Qualified Customers are those with total annual consumption greater than 1 GWh.

To reduce the risks of market dominance and predatory behaviour in a fully operational and competitive electricity market in Spain, it was necessary to ensure that all customers paid non-discriminatory "access to network" tariffs at both the transmission and distribution levels. These tariffs are applicable to all system users participating in the market.

The provision of a reduced access to network tariff provides free market customers with a demand side management mechanism. Free market customers receive a reduction in their access to network tariff in return for providing an operational service (reducing their loads automatically following a request from the transmission system operator, and providing reactive power when required by the TSO).

### DESCRIPTION OF PROJECT

There are five types of high voltage general access to network tariffs according to the voltage level of the customer's connection (see Table PI07/1, page 385). The time of use rates for these tariffs are based on six periods into which the 8,760 hours of the year are divided (see Table PI07/2, page 385). The rates have demand, active energy and reactive energy components which are shown in Tables PI07/3 to PI07/5 (page 386).

| Table PI07/1. High Voltage General Access to Network Tariffs | |
|---|---|
| **Voltage Level** | **Tariff** |
| >= 1 kV to < 36 kV | 6.1 |
| >= 36 kV to < 72.5 kV | 6.2 |
| >= 72.5 kV to < 145 kV | 6.3 |
| >= 145 kV | 6.4 |
| Cross-border exchanges | 6.5 |

| Table PI07/2. Time of Use Periods for Access to Network Tariffs | |
|---|---|
| **Period** | **Duration** |
| 1 | From 4 pm to 10 pm (6 hours per day) from Monday to Friday working days in high season |
| 2 | From 8 am to 4 pm and from 10 pm to midnight (10 hours per day) from Monday to Friday working days in high season |
| 3 | From 9 am to 3 pm (6 hours a day) from Monday to Friday working days in medium season |
| 4 | From 8 am to 9 am and from 3 pm to midnight (10 hours a day) from Monday to Friday working days in medium season |
| 5 | From 8 am to midnight (16 hours a day) from Monday to Friday working days in low season, except in August |
| 6 | The rest of the hours (from zero to 8 hours a day) which have not been included in any other period (valley hours) |

| Table PI07/3. Rates for Demand Component of Access to Network Tariffs (EUR/kW/year) | | | | | | |
|---|---|---|---|---|---|---|
| **Tariff** | **Period 1** | **Period 2** | **Period 3** | **Period 4** | **Period 5** | **Period 6** |
| 6.1 | 10,493 | 5,252 | 3,846 | 3,846 | 3,846 | 1,752 |
| 6.2 | 8,761 | 4,383 | 3,211 | 3,211 | 3,211 | 1,463 |
| 6.3 | 8,039 | 4,022 | 2,945 | 2,945 | 2,945 | 1,343 |
| 6.4 | 7,316 | 3,661 | 2,679 | 2,679 | 2,679 | 1,222 |
| 6.5 | 0.713 | 0.713 | 0.324 | 0.324 | 0.324 | 0.324 |

| Table PI07/4. Rates for Active Energy Component of Access to Network Tariffs (EUR cents/kWh) | | | | | | |
|---|---|---|---|---|---|---|
| **Tariff** | **Period 1** | **Period 2** | **Period 3** | **Period 4** | **Period 5** | **Period 6** |
| 6.1 | 1.7967 | 1.6810 | 1.4990 | 0.9866 | 0.6448 | 0.5015 |
| 6.2 | 1.5013 | 1.4063 | 1.2543 | 0.8235 | 0.5385 | 0.4181 |
| 6.3 | 1.3810 | 1.2860 | 1.1530 | 0.7539 | 0.4942 | 0.3864 |
| 6.4 | 1.2543 | 1.1719 | 1.0453 | 0.6905 | 0.4498 | 0.3485 |
| 6.5 | 0.1848 | 0.1848 | 0.0957 | 0.0957 | 0.0957 | 0.0957 |

| Table PI07/5. Rates for Reactive Energy Component of Access to Network Tariffs | |
|---|---|
| **Reactive Energy** | **Rate (EUR/kVA rh)** |
| For cos phi < 0.95 to cos phi = 0.90 | 0.000010 |
| For cos phi < 0.90 to cos phi = 0.85 | 0.012531 |
| For cos phi < 0.85 to cos phi = 0.80 | 0.025063 |
| For cos phi < 0.80 | 0.037594 |

The fifth tariff (Tariff 6.5), which is almost ten times cheaper than the next cheapest one, was initially conceived for cross-border exchanges. Qualified Customers can also become eligible for this tariff if they sign a special agreement with the TSO and the Distributor. In addition, there is no reactive energy component in the tariff for these customers, so electricity bills are considerably lower than for other access to network tariffs.

The agreement for customers on the reduced access to network tariff includes the following conditions:

1. Only eligible customers can opt for this kind of tariff.
2. The customer's contracted demand level during a time of use period must be greater than or equal to that in the preceding period: P6>=P5>=P4>=P3>=P2>=P1.
3. The customer's annual consumption in time of use Period 6 (valley hours) must be greater than or equal to 50 GWh.
4. The customer must commit to change the voltage level of their network connection to higher than 145kV if required by the TSO and if it is technically possible.
5. The customer must commit to operate reactive power correction equipment on request from the TSO or the Distribution System Operator during periods when the system is under stress.
6. The customer must commit to installing frequency relays which can be automatically disconnected by the TSO or the Distributor under previously agreed conditions, eg when there is a fault on the system.

## RESULTS

| Residential Customers Participating | Commercial and Small Industrial Customers Participating | Agricultural Customers Participating | Large Industrial Customers Participating | Additional Generation Installed |
|---|---|---|---|---|
| | | | 39 | |

| Peak Load | Peak Load Reduction | Duration of Peak Load Reduction | Overall Load Reduction | Energy Savings | Network Augmentation Deferral |
|---|---|---|---|---|---|
| | | | | | |

## HOW LOAD REDUCTION WAS MEASURED

## RESULTS ACHIEVED

In July 2005, there are 39 qualified customers who have opted for this reduced access to network tariff.

Information is available on the contracted load reduction for three customers (there is no more available information at the moment):

**Customer 1**
Minimum disconnectable load: 2.3 MW
Maximum disconnectable load: 19.4 MW

**Customer 2**
Minimum disconnectable load: 1.2 MW
Maximum disconnectable load: 10.5 MW

**Customer 3**
Minimum disconnectable load: 2.5 MW
Maximum disconnectable load: 21.5 MW

## CONFIDENCE LEVEL IN ACHIEVING RESULTS

## REPEATABILITY OF RESULTS

## TIME DELAY BEFORE MAXIMUM RESPONSE ACHIEVED

## WEATHER DEPENDENCE

## AVOIDED COSTS

## ACTUAL PROJECT COSTS

## PROJECT COST FROM THE SOCIETAL PERSPECTIVE

This tariff covers all costs deriving from activities needed to guarantee the supply, permanent costs of the system and diversification and security of supply costs.

## OVERALL PROJECT EFFECTIVENESS

## CONTACTS

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## SOURCES

Spanish Royal Decree 1164/2001

## CASE STUDY PREPARATION

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## PI08 ENERGYAUSTRALIA PRICING STRATEGY STUDY - AUSTRALIA

| | |
|---|---|
| **Last updated** | 5 October 2008 |
| **Location of Project** | Sydney, Central Coast and Newcastle, New South Wales, Australia |
| **Year Project Implemented** | 2006 |
| **Year Project Completed** | |
| **Name of Project Proponent** | EnergyAustralia |
| **Name of Project Implementor** | EnergyAustralia |
| **Type of Project Implementor** | Distribution utility |
| **Purpose of Project** | Deferral of network augmentation |
| **Timing of Project** | Pre contingency |
| **Focus of Project** | Network capacity limitations |
| **Project Objective** | Overall load reduction |
| **Project Target** | Whole network |
| **DSM Measure(s) Used** | Pricing initiatives |
| **Specific Technology Used** | Smart meters |
| **Market Segments Addressed** | Residential customers |

### DRIVERS FOR PROJECT

EnergyAustralia comprises two businesses, an energy retailer that sells electricity and gas to retail customers and an electricity distributor that owns and manages an electricity distribution network covering the eastern part of metropolitan Sydney, the New South Wales Central Coast and the regional city of Newcastle.

Peak loads on the Energy Australia distribution network are growing. Figure PI08/1 (page 390) shows the annual aggregated load curve for the distribution network on weekdays in 2005/06; peak loads above 5000MW are coloured red. In winter, quite narrow peaks occur in the early evening caused by the use of electricity for space heating and cooking. In summer, broader peaks occur across most of the working day caused mainly by increased use of air conditioning. Figure PI08/2 (page 390) demonstrates this more clearly by showing the occurrence during 2006/07 of peak loads above 5000MW.

The Pricing Strategy Study was initiated by EnergyAustralia's distribution business to investigate whether pricing measures could be used to reduce peak loads on the network.

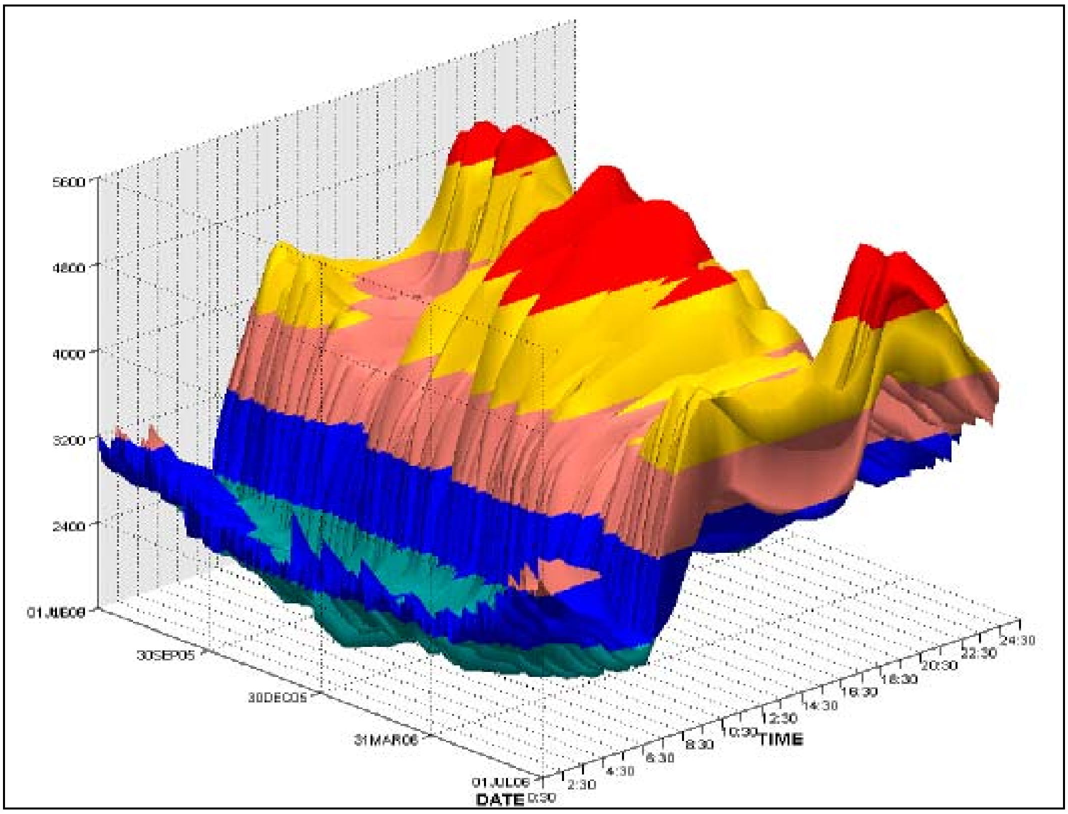


**Figure PI08/1. Aggregated Load Profile for the EnergyAustralia Network, July 2005 to June 2006**

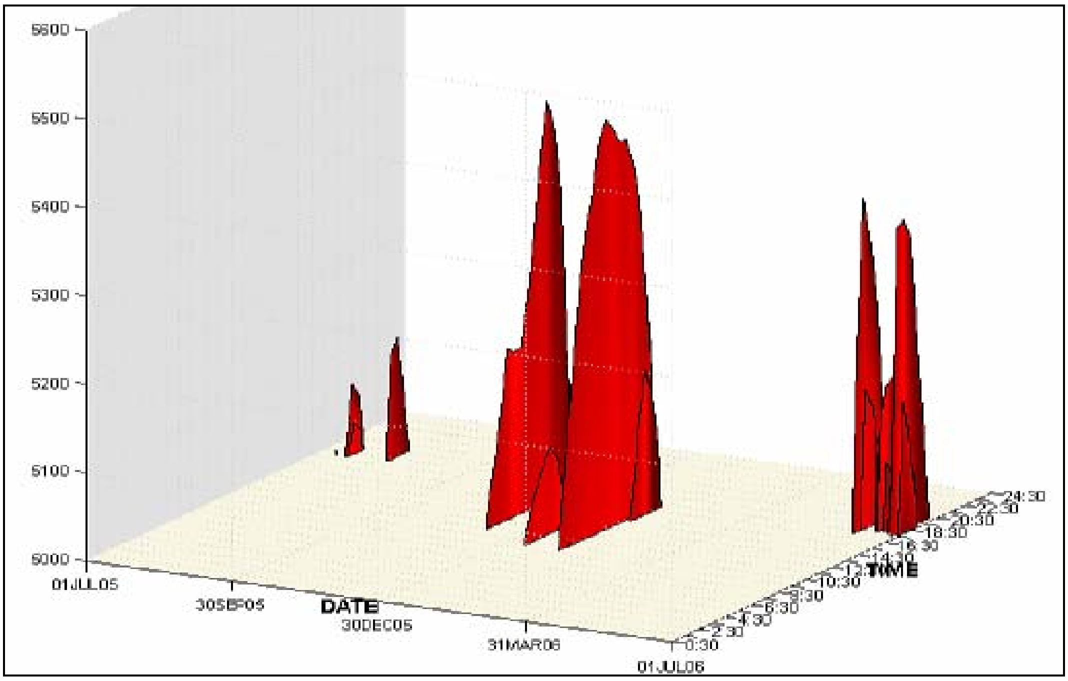


**Figure PI08/2. Peak Loads above 5000MW on the EnergyAustralia Network, July 2005 to June 2006**

## DESCRIPTION OF PROJECT

The purpose of the EnergyAustralia Strategic Pricing Study was to investigate the effectiveness of critical peak pricing (CPP) in achieving peak load reductions on the distribution network. EnergyAustralia refers to critical peak pricing as 'dynamic peak pricing' (DPP).

The study included about 750 residential customers and 550 business customers. All had a smart meter with GPRS communications installed in their premises and some had an in-house display connected to the meter by power line carrier technology.

The experimental groups comprised:

- a control group;
- a group provided only with information about peak load reductions;
- a group placed on a seasonal TOU tariffs;
- one group placed on a medium critical peak pricing tariff with an in-house display;
- two groups placed on a high critical peak pricing tariff with and without an in house display.

The price levels for the critical peak pricing (CPP) tariffs are shown in Table PI08/1. In the case of the DPP-M tariff the critical peak price level was set at 1052% of the Shoulder rate and for the DPP-H tariff the multiple was 2352%. The latter was one of the highest multiples set in any CPP tariff worldwide. The 'shock' price of AUD2.00 per kilowatt-hour provided a stimulus for customers to manage or reduce consumption during peak events.

**Table PI08/1. Tariffs Schedules Used in the EnergyAustralia Pricing Strategy Study**

| Tariff Component | SAC ($/day) | Peak (¢/kwh) | Shoulder (¢/kwh) | Off peak (¢/kwh) |
|---|---|---|---|---|
| **Tariff EA057 powerAlert medium (DPP-M)** | | | | |
| **NUoS** | 0.128 | 40 | 3.13 | 2.885 |
| **Retail** | 0.192 | 60 | 6.37 | 4.615 |
| **Total** | 0.32 | 100 | 9.5 | 7.5 |
| **Tariff EA058 powerAlert high (DPP-H)** | | | | |
| **NUoS** | 0.128 | 80 | 2.8 | 2.3 |
| **Retail** | 0.192 | 120 | 5.7 | 4.2 |
| **Total** | 0.32 | 200 | 8.5 | 6.5 |
| SAC = System availability charge<br>NUoS = Network use of system charge | | | | |

## RESULTS

| Residential Customers Participating | Commercial and Small Industrial Customers Participating | Agricultural Customers Participating | Large Industrial Customers Participating | Additional Generation Installed |
|---|---|---|---|---|
| 750 | 550 | | | |

| Peak Load | Peak Load Reduction | Duration of Peak Load Reduction | Overall Load Reduction | Energy Savings | Network Augmentation Deferral |
|---|---|---|---|---|---|
| | | | | | |

## HOW LOAD REDUCTION WAS MEASURED

Interval meter.

## RESULTS ACHIEVED

Some initial results with the DPP-H tariff are shown in Figure PI08/3 and Figure PI08/4 (page 393). Demand decreased significantly during the critical peak period, but increased after the end of the period. On 22 February 2007, the reduction in peak demand was lower than on 11 January. This was probably because the temperature on 22 February was lower and therefore there was less discretionary load available (eg from air conditioning) that could be reduced.

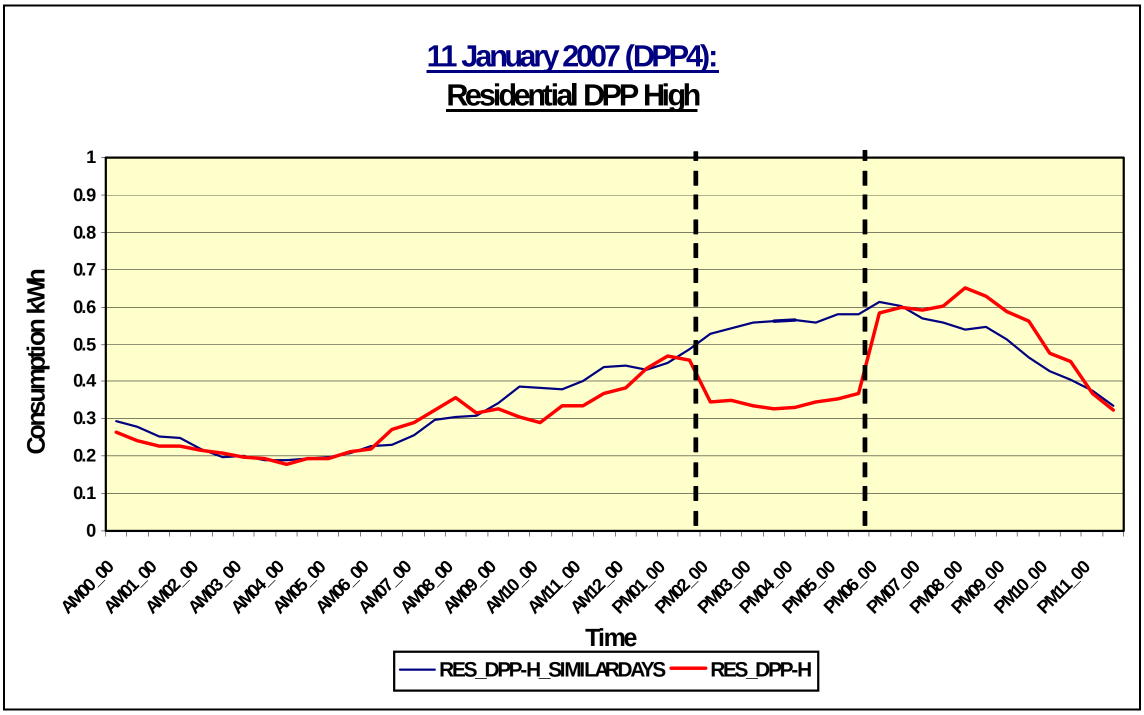


**Figure PI08/3. Impact of 11 January 2007 CPP Event in the EnergyAustralia Pricing Strategy Study**

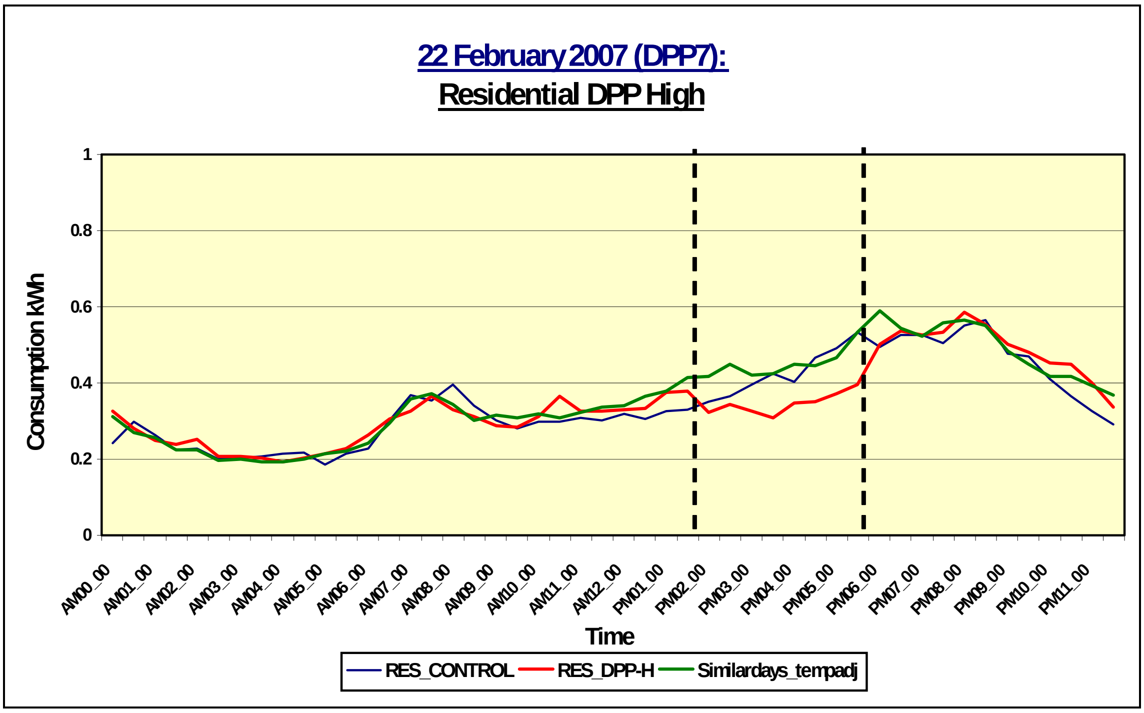


**Figure PI08/4. Impact of 22 February 2007 CPP Event in the EnergyAustralia Pricing Strategy Study**

Figure PI08/5 shows the average percentage consumption reductions on a day with a critical peak event, for three situations:

- households with the medium DPP tariff plus an in-house display (DPPM);
- households with the high DPP tariff plus an in-house display (DPPH); and
- households with the high DPP tariff and no in-house display (DPPH-NIHD).

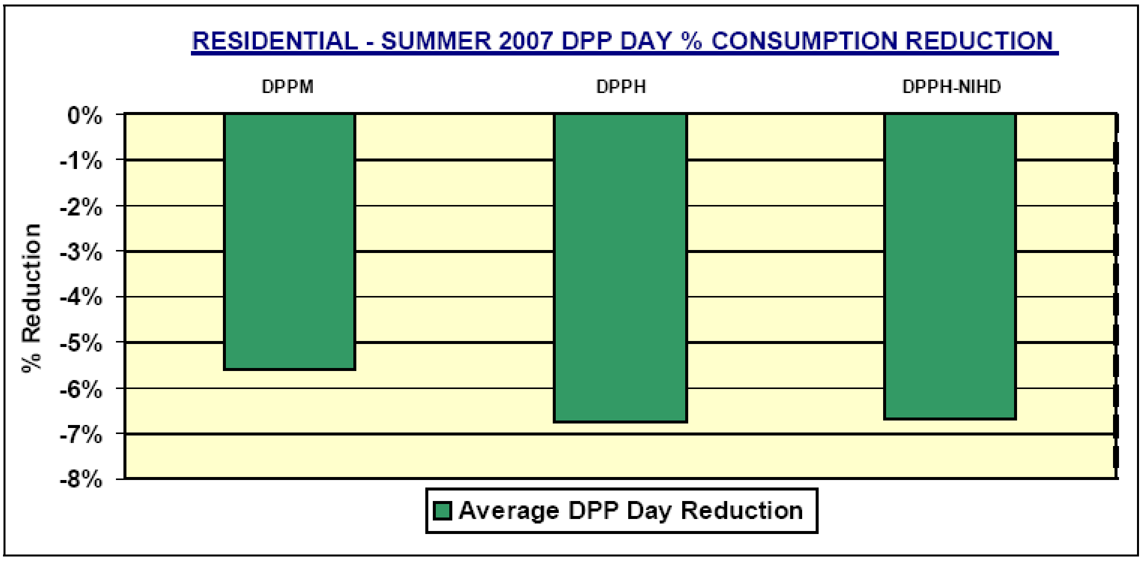


**Figure PI08/5. Average Reductions in Consumption on Days with a CPP Event in the EnergyAustralia Pricing Strategy Study**

Figure PI08/5 shows that, in summer, DPP tariffs achieved reductions in consumption during critical peak periods equivalent to reductions in total daily energy use on days with a critical peak event of between 5.5% and 7.8%. The majority of this reduction came from energy conservation. On critical peak days, there was not a great deal of shifting of consumption from the critical peak period to shoulder, off-peak or non-peak periods.

The EnergyAustralia study also found that energy consumption during the critical peak period was between 21% and 25% of the total average daily consumption on non-critical peak days.

## CONFIDENCE LEVEL IN ACHIEVING RESULTS

## REPEATABILITY OF RESULTS

## TIME DELAY BEFORE MAXIMUM RESPONSE ACHIEVED

## WEATHER DEPENDENCE

## AVOIDED COSTS

## ACTUAL PROJECT COSTS

## PROJECT COST FROM THE SOCIETAL PERSPECTIVE

## OVERALL PROJECT EFFECTIVENESS

## CONTACTS

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## SOURCES

Amos, Chris (2006). *Advanced Tariff Design*. Presentation to Workshop on Advanced Metering. University of NSW, Sydney, 17 May.

Miller, A. (2007a). *Strategic Pricing Study (SPS): Demand Response Results*. Presentation to EnergyAustralia Retailer Information Forum. Sydney, 9 May.

Miller, A. (2007b). *Summer and Winter Demand Response from EnergyAustralia's Strategic Pricing Study*. Presentation to Demand Response and DSM Conference. Adelaide, 20 June.

## CASE STUDY PREPARATION

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# PI09 CALIFORNIA STATEWIDE PRICING PILOT FOR SMALL CUSTOMERS - USA

| | |
|---|---|
| **Last updated** | 5 October 2008 |
| **Location of Project** | California, USA |
| **Year Project Implemented** | 2003 |
| **Year Project Completed** | 2005 |
| **Name of Project Proponent** | California Public Utilities Commission |
| **Name of Project Implementor** | Pacific Gas and Electric (PG&E)<br>Southern California Edison (SCE)<br>San Diego Gas and Electric (SDG&E) |
| **Type of Project Implementor** | Distribution utility<br>Electricity retailer/supplier |
| **Purpose of Project** | Deferral of network augmentation |
| **Timing of Project** | Pre contingency |
| **Focus of Project** | Network capacity limitations<br>Generation capacity limitations |
| **Project Objective** | Peak load reduction |
| **Project Target** | Whole network |
| **DSM Measure(s) Used** | Direct load control<br>Pricing initiatives |
| **Specific Technology Used** | Smart thermostats<br>Other direct load control devices |
| **Market Segments Addressed** | Residential customers<br>Commercial and small industrial customers |

## DRIVERS FOR PROJECT

**Note:** This Case Study PI09 covers pricing initiatives for small customers in California. For similar pricing initiatives for large customers in California see Case Study PI01 (page 348) and for the impacts of load control technology implemented with pricing initiatives in the residential sector in California see Case Study DC07 (page 81).

In 2000 and 2001, California experienced a so-called "energy crisis" that comprised short-term shortages of electricity generation capacity following the failure of the introduction of a competitive electricity market in the State. By 2002, the immediate short-term problems had been resolved, but longer-term shortages of both generation and transmission network capacity remained.

One of the lessons gleaned from California’s energy crisis was that the lack of demand response in retail markets makes it very difficult to clear wholesale markets at reasonable prices. One method for introducing demand response in retail markets is time-varying pricing.

With this in mind, the California Public Utilities Commission (CPUC) in June 2002, adopted an Order Instituting Rulemaking on "policies and practices for advanced metering, demand response, and dynamic pricing" and initiated a proceeding in July designed to introduce demand response into California’s electricity market.

As part of this proceeding, three working groups were charged with developing specific tariff proposals to achieve increased demand response in the state. The mission of Working Group 3 (WG3) was to develop a dynamic tariff (or set of tariffs) for residential and small commercial and industrial customers with demand less than 200 kilowatts.

WG3 included representatives from the State's three investor-owned utilities, Pacific Gas and Electric (PG&E), Southern California Edison (SCE) and San Diego Gas and Electric (SDG&E), the two regulatory commissions, the CPUC and the California Energy Commission, equipment vendors, and other interested parties.

In December 2002, WG3 recommended that the State conduct a carefully designed pricing experiment with different tariff options prior to making a decision on full-scale deployment of the automated metering infrastructure required to support such time-varying rates.

The decision was made to implement a statewide experiment rather than utility-specific experiments to better leverage scarce budget resources and also to ensure consistency in results across the State. The CPUC approved the experiment, called the Statewide Pricing Pilot (SPP), in March, 2003. The SPP involved some 2,500 customers and ran from July 2003 to December 2004 for residential customers and to December 2005 for commercial and industrial customers.

The SPP had three primary objectives:

- to estimate the average impact of time-varying rates on energy use by rate period and develop models that can be used to predict impacts under alternative pricing plans;
- to determine customer preferences for tariff attributes and market shares for specific TOU and dynamic tariffs, control technologies and information treatments under alternative deployment strategies;
- to evaluate the effectiveness of, and customer perceptions of, specific pilot features and materials, including enrolment and educational material, bill formats, web information, and tariff features.

## DESCRIPTION OF PROJECT

### Customer Enrolment

Customers to be enrolled in the SPP were selected through a stratified sample design. A primary customer was randomly drawn from each of the strata. Nine or more alternative customers, intended to be statistical clones, were also identified.

An enrolment package was mailed to each selected customer with the aim of obtaining an affirmative response regarding the willingness of the customer to participate. Consequently, the SPP was a voluntary program but one predicated on an opt-out rather than an opt-in recruitment strategy.

The enrolment package informed customers that they had been selected to participate in an important statewide research project that would test new electricity pricing plans. The package indicated that participants would be given a payment totalling USD175 (USD500 for commercial and industrial customers above 20 kilowatt demand) in three installments spanning a period of 12 months. The first installment of USD25 was tied to the completion of a survey. The second installment of USD75 for residential customers, was paid to customers that stayed on the rate through the end of summer 2003 and the third installment was paid to all customers who remained on the rate through April 2004.

In the enrolment package, customers were asked to telephone or mail in a reply card to affirm their willingness to participate in the experiment. If a customer did not call the toll-free number or mail in the reply card, a recruitment consultant retained by the utilities made three attempts to call the customer to affirm their participation in the pilot. If a customer could not be reached after a 14-day deadline passed, they were dropped from the experiment and the recruitment process moved on to one of the statistical clones to try and fill that slot.

Once enrolled, customers were provided with a ‘welcome package’ containing information on how to benefit from the new rate structures. They were also provided with a "shadow" electricity bill. Welcome packages varied by rate type and utility. A chart in each package provided information about the rates that the typical customer would be expected to face during the pilot.

### Tariff Structures

The experimental tariffs tested in the SPP included a traditional time of use (TOU) rate and two dynamic pricing rates.

The TOU rates were implemented among a statewide sample of customers. Under the TOU rate, the price during the peak period was roughly 70 percent higher than the standard rate and about twice the value of the price during the off-peak period.

The dynamic rates included a critical peak pricing (CPP) element that involved a substantially higher peak price (about USD0.50 to USD0.75 per kilowatt-hour) for 15 days of the year and a standard TOU rate on all other days.

One type of CPP rate (CPP-F) was implemented among a statewide sample of customers. The CPP-F rate had a fixed peak period on both critical and non-critical days and day-ahead customer notification for critical day events. The peak period for residential customers was between 2 pm and 7 pm weekday afternoons and the peak period for commercial and industrial customers was from noon to 6 pm on weekdays.

The other type of CPP rate (CPP-V) was implemented for residential customers only in the SDG&E service territory. The CPP-V rate had a variable-length peak period on critical days, which could be called not less than four hours ahead on the day of a critical event.

For commercial and industrial customers, CPP-V and TOU tariffs were implemented only in the SCE service territory. The C&I customer population was segmented into two groups: customers with peak demands less than 20 kilowatts (LT20) and customers with peak demands between 20 and 200 kilowatts (GT20).

All SPP rates were seasonally differentiated with summer running from May through October inclusive for residential customers, and from the first Sunday in June through the first Sunday in October for commercial and industrial customers.

The CPUC placed a number of constraints on the rate design process in order to address the concerns of various constituencies within WG3. Specifically, the experimental rates were required to satisfy three constraints:

- be revenue neutral for the class-average customer over a calendar year, in the absence of any change in the customer’s load shape;

- not change the bill of low and high users by more than 5 percent in either direction, in the absence of any change in the load shape; and
- provide customers with an opportunity to reduce their bills by 10 percent if they reduced or shifted peak usage by 30 percent.

### Information Only Program

In addition to the pricing initiatives described above, an 'Information Only' program for residential customers was also tested. This program was implemented only in the PG&E service territory. The program involved notifying customers on critical days and asking them to avoid energy use during the peak period. However, prices were the same on critical days as they were on all other days and customers did not face time-varying prices on any day.

### Enabling Technology

CPP-V customers had the option of having an enabling technology installed free of charge to help facilitate demand response.

One group of residential CPP-V customers ("Track A") could choose to go on the CPP-V rate with or without the installation of an enabling technology. Customers who chose a technology were given the option of having a load control device installed on their central air conditioner, their electric water heater or their pool pump.

Track A residential CPP-V customers were single family households using more than 600 kilowatt-hours of electricity per month. These relatively high energy-using households were different from the general population in their geographical area and from the statewide population.

A second group of CPP-V residential customers ("Track C") were recruited from participants in a pre-existing smart thermostat pilot. All Track C customers lived in single-family households with central air conditioning and had smart thermostats that automatically adjusted their air conditioning setting when critical peak prices were in effect. These households were not representative of the general population of households, either in their geographical area or for the state as a whole.

There were also two groups of commercial and industrial customers on the CPP-V tariff. The Track A sample was recruited from the general population while the Track C sample was drawn from a pre-existing smart thermostat pilot. All Track C commercial and industrial customers had central air conditioning and smart thermostats. Most Track A customers had central air conditioning but only about half selected the smart thermostat technology option.

### Critical Peak Dispatch

CPP-F and CPP-V rates were dispatched simultaneously about half the time. For residential CPP-V Track C customers, the length of the dispatch period on critical event days was either two hours or five hours. For commercial and industrial CPP-V customers, two, four and five hour dispatch periods were implemented.

A total of 12 events were called for each CPP rate during the summer months (May to October) and three were called in the winter. Thus, a total of 27 critical days were called for customers who stayed in the pilot for the entire trial period of two summers and one winter. Critical days were chosen based on weather forecasts, system reliability conditions, the requirement to have a total of 12 days in the summer and to have a variety of days in the week.

In the summer of 2003, all critical events were single days, ie events were never called on consecutive days. Following this initial period, concerns arose about whether behavioural response to critical day prices would change if events were called on consecutive days, such as might occur during a heat wave. To investigate this issue, in the summer of 2004, one two-day event and two three-day events were called.

Table PI09/1 (page 401) summarises the critical events that were called for each customer group throughout the pilot. The numbers in each cell indicate the timing and duration of each critical event. All CPP-F events ran for the entire peak period on critical days. CPP-V events varied with respect to start time and duration.

## RESULTS

| Residential Customers Participating | Commercial and Small Industrial Customers Participating | Agricultural Customers Participating | Large Industrial Customers Participating | Additional Generation Installed |
|---|---|---|---|---|
| 1861 | 630 | | | |

| Peak Load | Peak Load Reduction | Duration of Peak Load Reduction | Overall Load Reduction | Energy Savings | Network Augmentation Deferral |
|---|---|---|---|---|---|
| | | | | | |

## HOW LOAD REDUCTION WAS MEASURED

| Table PI09/1. Summary of Critical Peak Pricing Events in the California Statewide Pricing Pilot | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| Critical Event Date | Residential CPP-F | | | | | Residential CPP-V | | C&I CPP-V | |
| | Zone 1 | Zone 2 | Zone 3 | Zone 4 | Track B | Track A | Track C | Track A | Track C |
| 07/10/03 | 2-7 | 2-7 | 2-7 | 2-7 | n/a | n/a | 2-4 | n/a | 2-6 |
| 07/17/03 | 2-7 | 2-7 | 2-7 | 2-7 | n/a | n/a | 2-4 | n/a | 2-4 |
| 07/28/03 | n/a | 2-7 | 2-7 | 2-7 | n/a | n/a | 2-7 | n/a | 1-6 |
| 08/08/03 | n/a | 2-7 | 2-7 | 2-7 | n/a | n/a | 3-5 | n/a | 3-5 |
| 08/14/03 | n/a | n/a | n/a | N/a | n/a | n/a | n/a | n/a | 1-6 |
| 08/15/03 | n/a | n/a | n/a | N/a | n/a | n/a | 2-7 | n/a | 2-6 |
| 08/18/03 | 2-7 | 2-7 | 2-7 | 2-7 | n/a | n/a | n/a | n/a | n/a |
| 08/27/03 | 2-7 | 2-7 | 2-7 | 2-7 | n/a | n/a | 4-6 | n/a | 4-6 |
| 09/03/03 | 2-7 | 2-7 | 2-7 | 2-7 | n/a | n/a | 2-7 | n/a | 1-6 |
| 09/11/03 | 2-7 | n/a | n/a | N/a | n/a | n/a | n/a | n/a | 1-6 |
| 09/12/03 | 2-7 | 2-7 | 2-7 | 2-7 | 2-7 | n/a | 2-7 | n/a | 4-6 |
| 09/18/03 | 2-7 | n/a | n/a | N/a | 2-7 | n/a | n/a | n/a | n/a |
| 09/19/03 | n/a | n/a | n/a | n/a | n/a | n/a | n/a | n/a | 4-6 |
| 09/22/03 | 2-7 | 2-7 | 2-7 | 2-7 | n/a | n/a | n/a | n/a | n/a |
| 09/29/03 | n/a | n/a | n/a | n/a | n/a | n/a | 2-7 | n/a | 1-6 |
| 10/09/03 | 2-7 | 2-7 | 2-7 | 2-7 | 2-7 | n/a | 3-5 | n/a | n/a |
| 10/14/03 | 2-7 | 2-7 | 2-7 | 2-7 | 2-7 | n/a | 2-7 | n/a | n/a |
| 10/20/03 | 2-7 | 2-7 | 2-7 | 2-7 | 2-7 | n/a | 3-5 | n/a | n/a |
| 10/21/03 | n/a | n/a | n/a | n/a | 2-7 | n/a | n/a | n/a | n/a |
| 01/06/04 | 2-7 | 2-7 | 2-7 | 2-7 | 2-7 | n/a | 2-7 | n/a | 1-6 |
| 01/26/04 | 2-7 | 2-7 | 2-7 | 2-7 | 2-7 | n/a | 2-7 | n/a | 1-6 |
| 01/27/04 | n/a | n/a | n/a | n/a | 2-7 | n/a | n/a | n/a | n/a |
| 02/03/04 | 2-7 | 2-7 | 2-7 | 2-7 | 2-7 | n/a | 2-7 | n/a | 1-6 |
| 07/14/04 | 2-7 | 2-7 | 2-7 | 2-7 | 2-7 | 2-6 | 2-6 | 1-6 | 1-6 |
| 07/22/04 | 2-7 | 2-7 | 2-7 | 2-7 | 2-7 | 2-7 | 2-7 | 1-6 | 1-6 |
| 07/26/04 | 2-7 | 2-7 | 2-7 | 2-7 | 2-7 | 3-5 | 3-5 | 3-5 | 3-5 |
| 07/27/04 | 2-7 | 2-7 | 2-7 | 2-7 | 2-7 | 3-5 | 3-5 | 3-5 | 3-5 |
| 08/09/04 | 2-7 | 2-7 | 2-7 | 2-7 | 2-7 | 2-7 | 2-7 | 1-6 | 1-6 |
| 08/10/04 | 2-7 | 2-7 | 2-7 | 2-7 | 2-7 | 2-7 | 2-7 | 1-6 | 1-6 |
| 08/11/04 | 2-7 | 2-7 | 2-7 | 2-7 | 2-7 | 4-6 | 4-6 | 4-6 | 4-6 |
| 08/27/04 | 2-7 | 2-7 | 2-7 | 2-7 | 2-7 | 4-6 | 4-6 | 4-6 | 4-6 |
| 08/31/04 | 2-7 | 2-7 | 2-7 | 2-7 | 2-7 | 2-7 | 2-7 | 1-6 | 1-6 |
| 09/08/04 | 2-7 | 2-7 | 2-7 | 2-7 | 2-7 | 4-7 | 4-7 | 1-6 | 1-6 |
| 09/09/04 | 2-7 | 2-7 | 2-7 | 2-7 | 2-7 | 4-6 | 4-6 | 4-6 | 4-6 |
| 09/10/04 | 2-7 | 2-7 | 2-7 | 2-7 | 2-7 | 2-6 | 2-6 | 4-6 | 4-6 |

## RESULTS ACHIEVED

### Impacts on Residential Energy Use

#### *CPP-F Impacts*

Figure PI09/1 summarises the impact of the average CPP-F prices on energy use by residential customer during the peak period on critical peak and normal weekdays. Across the whole of California, the estimated average reduction in peak-period energy use on critical peak days was 13.1 percent and the average reduction on normal (ie non-critical peak) weekdays was 4.7 percent.

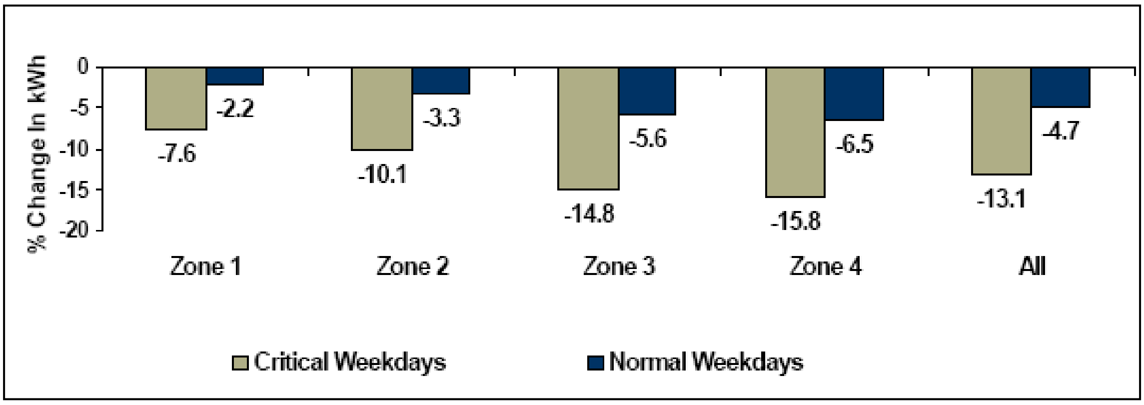


**Figure PI09/1. Percent Change in Residential Peak-Period Energy Use under the CPP-F Rate in the California Statewide Pricing Pilot**

Impacts varied across different climate zones within California. On critical peak days, the reduction in peak-period energy consumption varied from a low of 7.6 percent in the relatively mild climate of zone 1 to a high of 15.8 percent in the hot climate of zone 4. On normal weekdays, the reduction varied across climate zones from a low of 2.2 percent to a high of 6.5 percent.

Following are other key findings for the impact of the CPP-F rate on energy use by residential customers:

- demand response impacts were lower in the winter than in the summer, and lower during the milder winter months of November, March and April (the ‘outer winter’) than during the colder months of December, January and February (the ‘inner winter’);
- average impacts on critical days were greater during the hot summer months of July through September (the ‘inner summer’) than during the milder months of May, June and October (the ‘outer summer’) – the greater responsiveness in the inner summer is probably due primarily to the influence of air conditioning;
- differences in impacts across days when two or three critical peak days were called in a row (as might occur during a heat wave) were not statistically significant;
- households with central air conditioning were more price responsive and produced greater absolute and percentage reductions in peak-period energy use than did households without air conditioning;
- there was essentially no change in total energy use across the entire year based on average SPP prices, ie the reduction in energy use during high-price periods was almost exactly offset by increases in energy use during off-peak periods.

### *TOU Impacts*

During the the inner summer in 2003, the average reduction in peak-period energy use by residential customers resulting from TOU rates was 5.9 percent. This value is comparable to the result for the CPP-F tariff on normal (ie non-critical peak) weekdays when prices were similar to those for the TOU rates. However, in the summer of 2004, the TOU rate impact almost completely disappeared (a reduction of only 0.6 percent). During winter in both 2003 and 2004, TOU impacts were comparable to the normal weekday winter impacts for the CPP-F rate.

Drawing firm conclusions about the impact of TOU rates was somewhat complicated by the fact that the TOU sample sizes were small relative to the CPP-F sample sizes. Further complicating the analysis was that the variation in daily TOU prices over time was quite small, which made it difficult to obtain precise estimates of daily price responsiveness. In short, there were reasons to take the analysis of the impacts of TOU rates on residential energy use during peak periods with a “grain of salt.”

On the other hand, if the TOU results were accurate, they have very important policy implications, since they suggested that the relatively modest TOU prices tested in this experiment did not have sustainable impacts on energy use by residential customers.

### *CPP-V Impacts*

The CPP-V rate was tested among two different populations of residential customers, both within the SDG&E service territory. "Track A" customers were drawn from a population with average summer energy use exceeding 600 kilowatt-hours per month. Some Track A customers took up an option to install a control device placed on their central air conditioner, their electric water heater or their pool pump. "Track C" customers had previously volunteered for a smart thermostat pilot and all had smart thermostats and central air conditioning.

Following are key findings for the impacts of the CPP-V rate on peak-period energy use on critical peak days:

- the reduction in energy use for Track A customers was almost 16 percent, which is about 25 percent higher than with the CPP-F rate;
- the reduction in energy use for Track C customers was about 27 percent. Roughly two-thirds of this reduction could be attributed to the smart thermostat and the remainder was attributable to price-induced behavioural changes.

Comparisons between the impacts of the CPP-V rates on energy use by Track A and Track C customers and between the impacts of CPP-V and CPP-F rates must be made carefully due to differences in sample composition. However, the Track C results suggest that impacts are significantly larger with enabling technology than without it.

The 27 percent average reduction in energy use for the CPP-V rate with Track C customers is roughly double the 13 percent impact for the CPP-F rate. It is also substantially larger than the reduction achieved with the CPP-V rate and Track A customers, where only some customers took advantage of the enabling technology offer.

### *Information Only Impacts*

The Information Only program was included primarily to cross check the results with the CPP-F rate. Specifically, the purpose was to determine whether simply appealing for a reduction in energy use on critical days might produce significant impacts on energy use in the peak period, even in the absence of any price incentive.

Information Only customers were given educational material about how to reduce loads during peak periods, and they were notified in the same manner as CPP-F customers when critical days were called. However, participants were not placed on time-varying rates.

The Information Only program was implemented in two climate zones in the PG&E service territory. In 2003, demand response was statistically significant in one of the two zones, while in the other zone it was not. In 2004, there was no evidence of any response in either zone.

From these results, it is possible to conclude that there is little demand response to requests to reduce energy use in the absence of a price signal. This conclusion is strengthened if the statistically significant impact in 2003 in a single climate zone is considered to be an anomaly.

### *Summary of Residential Results*

Table PI09/2 (page 405) summarises the key findings on reductions in peak-period energy use by residential customers resulting from the various tariff options tested in the Statewide Pricing Pilot.

## Impacts on Commercial and Industrial Energy Use

The sample of commercial and industrial customers was segmented into two size strata, customers with demand below 20 kilowatts (the LT20 segment) and customers with demand between 20 and 200 kW (the GT20 segment). About one third of LT20 customers and about 60 percent of GT20 customers had smart thermostats.

With the CPP-V rate for C&I customers, on most weekdays a peak-period price was in effect between noon and 6 pm. On critical peak days, a significantly higher peak-period price was in effect for either 2 or 5 hours, all of which fell within the noon to 6 pm time period.

Prices changed over the two summers (2004 and 2005) during which the CPP-V rate was tested. The average standard price for LT20 customers across the two summers was about USD0.17/kWh and the average critical peak price was almost USD1.00/kWh. For GT20 customers, the standard average price was USD0.16/kWh and the critical peak price was about USD0.60/kWh.

**Table PI09/2. Summary of Peak-Period Impacts by Treatment Type for Residential Customers in the California Statewide Pricing Pilot**

| Treatment | Day Type | Avg. Price (¢/kWh)[1] | Impacts | Comments |
|---|---|---|---|---|
| Track A CPP-F | Critical Weekday | P = 59<br>OP = 9<br>D = 23<br>C = 13 | -13.1% average summer<br>-14.4% inner summer<br>-8.1% outer summer | No statistically significant difference for inner summer between 2003 and 2004 (differences across the two years can not be estimated for the outer summer or the average summer) |
| | Normal Weekday | P = 22<br>OP = 9<br>D = 12<br>C = 13 | -4.7% average summer<br>-5.5% inner summer<br>-2.3% outer summer | Difference between critical & normal days is primarily due to price differences and secondarily to differences in weather |
| Track A TOU | All Weekdays | P = 22<br>OP = 10<br>D = 13<br>C = 13 | -5.9% inner summer 2003<br>-0.6% inner summer 2004<br>-4.2% outer summer 2003/04 | Results are suspect because of the small sample size and observed variation in underlying model coefficients across the two summers. Recommend using normal weekday CPP-F model to predict for TOU rate. |
| Track A CPP-V | Critical Weekday | P = 65<br>OP = 10<br>D = 23<br>C= 14 | -15.8% average summer 2004<br>Represents average across households with and without enabling technology—could not separate price & technology impacts | Not directly comparable to CPP-F results due to differences in population (CAC saturation for CPP-V treatment group twice that of CPP-F; CPP-V average income much higher; 2/3 of CPP-V customers had enabling tech.; all households located in SDG&E service territory) |
| | Normal Weekday | P = 24<br>OP = 10<br>D = 14<br>C = 14 | -6.7% average summer 2004 | See above comments about population differences |
| Track C CPP-V | Critical Weekday | Same as for Track A | -27.2% combined tech & price impact for average summer 2003/04<br>-16.9% impact for tech only<br>-11.9% incremental impact of price over & above tech impact | Not directly comparable to Track A results due to population differences (All Track C customers are single family households with CAC located in SDG&E service territory).<br>Some evidence that impacts fell between 2003 & 2004 |
| | Normal Weekday | Same as for Track A | -4.5% average summer 2003/04 | See above comments about population differences |
| Track A Info Only | Critical Weekday | 13 for all periods | Statistically significant response in one of two climate zones in 2003. No response in 2004. | Analysis provides no evidence of sustainable response in the absence of price signals. |

### *Reductions in Peak-period Energy Use*

Following are the key findings for C&I customers who participated in both summer periods:

- there was no statistically significant difference in price responsiveness in 2004 and 2005 for customers who participated in both summers;
- the average reduction in peak-period energy use on critical peak days for LT20 customers was 6.59 percent and the average reduction for GT20 customers was 5.47 percent.

For all customers participating in 2004, 2005 or both summers, the key findings were as follows:

- there was no statistically significant difference in price responsiveness between the two summers for the LT20 pooled population. However, for the GT20 segment, there was a statistically significant drop in price responsiveness between 2004 and 2005 summers;

- the average reduction in peak-period energy use on critical peak days for the LT20 segment was 4.83 percent, while the average reduction for GT20 customers was 6.75 percent.

### *Impact of Enabling Technology*

The enabling technology (smart thermostats) offered to C&I customers during the Statewide Pricing Pilot had a significant impact on demand response for both the small and medium customer segments. Specifically:

- LT20 customers were not price responsive at all on normal weekdays, nor were LT20 customers without enabling technology price responsive on critical peak days;
- LT20 customers with enabling technology displayed a significant level of price responsiveness on critical peak days, reducing peak-period energy use on critical peak days by more than 13 percent;
- GT20 customers displayed a modest level of price responsiveness on normal weekdays and there was no statistically significant difference in price response between normal weekdays and critical peak days for GT20 customers without enabling technology;
- the average reduction in peak-period energy use on critical peak days for GT20 customers without enabling technology was 4.93 percent;
- GT20 customers with enabling technology were roughly twice as price responsive on critical peak days as customers without technology, the average reduction in peak-period energy use was 9.57 percent.

### *Impacts on Multi-day Critical Events*

The analysis also examined how LT20 and GT20 customers behaved across the first, second and third days of a multi-day critical event:

- LT20 customers displayed a modest level of price responsiveness on stand-alone critical peak days and the first day of a multi-day event cycle. However, there was no evidence of price responsiveness on the second or third days of a multi-day event;
- GT20 customers, in contrast, displayed no statistically significant difference in price responsiveness across the first, second and third days of a multi-day critical event.

### *Impacts on Two- and Five-hour Events*

With respect to differences in price responsiveness between two-hour and five-hour critical events:

- for LT20 customers. there was no statistically significant difference in price responsiveness;
- for GT20 customers, there was a statistically significant difference, with responsiveness being much greater with two-hour events than with five-hour events.

## CONFIDENCE LEVEL IN ACHIEVING RESULTS

## REPEATABILITY OF RESULTS

## TIME DELAY BEFORE MAXIMUM RESPONSE ACHIEVED

## WEATHER DEPENDENCE

## AVOIDED COSTS

## ACTUAL PROJECT COSTS

## PROJECT COST FROM THE SOCIETAL PERSPECTIVE

## OVERALL PROJECT EFFECTIVENESS

Following are some general conclusions from the Statewide Pricing Pilot:

- customer did respond to time-varying prices, despite 25 years of DSM in California, the energy crisis of 2000/2001, increasing block tariff rates with tail prices above 20 cents/kWh and some of the highest average electricity prices in the United States;
- there was still more to give, but demand response impacts were less than might have been obtained 30 years earlier, based on previous pricing studies;
- customers understood the rates enough to respond, in spite of their complexity;
- information without price incentives did not produce sustainable load shifting;
- the magnitude of customer response varied with customer characteristics: central air conditioning was a key driver of demand response, high users who had more appliances had more load to shift;
- the CPP-F tariff did not have a measurable effect on overall annual energy use, ie people increased energy use during off-peak periods by almost exactly the same amount that they decreased energy use during peak periods;
- the impacts persisted across years and especially across multi-day critical events;
- impacts from standard TOU rates were not sustained across two summers;
- when offered an enabling technology for free, not everyone took it;
- significant impacts were achieved in the absence of enabling technology, but impacts were larger with the technology;
- most customers liked the time-varying rates and, when given an opportunity to continue on the rate (even in the absence of incentives and with the requirement to pay for the metering), most have chosen to stay.

## CONTACTS

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## CASE STUDY PREPARATION

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# SM01 CARBON TRUST ADVANCED METERING TRIAL - UNITED KINGDOM

| | |
|---|---|
| **Last updated** | 5 October 2008 |
| **Location of Project** | Various locations throughout the United Kingdom |
| **Year Project Implemented** | 2004 |
| **Year Project Completed** | 2006 |
| **Name of Project Proponent** | The Carbon Trust |
| **Name of Project Implementor** | The Carbon Trust |
| **Type of Project Implementor** | Government-owned independent company |
| **Purpose of Project** | N/A |
| **Timing of Project** | N/A |
| **Focus of Project** | To understand the potential benefits of advanced metering for SMEs |
| **Project Objective** | Overall load reduction |
| **Project Target** | Whole network |
| **DSM Measure(s) Used** | Energy efficiency |
| **Specific Technology Used** | Advanced metering |
| **Market Segments Addressed** | Commercial and small industrial customers |

## DRIVERS FOR PROJECT

The Carbon Trust was set up by the United Kingdom Government in 2001 as an independent company and is funded by various government agencies. The Trust's mission is to accelerate the move to a low carbon economy by working with organisations to reduce carbon emissions and develop commercial low carbon technologies.

From 2004 to 2006, the Carbon Trust carried out the first UK field trial of advanced metering for small and medium enterprise (SME) end-users. The trial aimed to demonstrate the potential benefits of the technology and understand the business case for encouraging widespread adoption of advanced metering by SMEs.

The trial was devised with the following high-level objectives:

- to understand the potential benefits of advanced metering for SMEs;
- to stimulate market demand by demonstrating that advanced metering can reduce energy consumption and costs;
- to help understand the barriers to broader uptake and how they might be overcome;
- to identify the nature of advanced metering services which yield the best savings;
- to develop case studies, highlighting the advantages of advanced metering;
- to quantify the potential UK-wide carbon savings attributable to advanced metering in the SME community; and
- to identify potential policy measures to stimulate uptake.

The Carbon Trust advanced metering trial was unusual in that it was implemented by a government-owned independent company rather than an energy business and it focussed on savings in total energy use rather than peak load reductions. The trial is included in the Task XV case study database because it clearly demonstrates how advanced metering can enable businesses to identify energy, cost and carbon savings by providing detailed information about the ways in which they use electricity.

## DESCRIPTION OF PROJECT

To deliver the field trial, the Carbon Trust contracted with seven consortia, all of which were already operating commercially in the metering market in the United Kingdom. The delivery consortia each recruited portfolios of SMEs or SME-like sites and installed advanced metering for electricity, gas and water at these sites as appropriate (not all utilities were metered at every site). A total of 582 sites across the United Kingdom were involved in the trial.

A total of 64 trial participants already had advanced electricity meters installed. For these sites no meter installation was necessary; all that was required was access to the existing half-hourly data. These sites were treated as a control group to investigate differences in use of advanced metering services between sites with and without existing interval metering. The findings from these sites were excluded from the bulk of the analysis in order to understand the potential for advanced metering in the SME sector where sites do not currently have interval metering in place.

Of the remaining sites, 73 made use of ‘pulsed-output’ meters with the capability to record half-hourly data through the use of clip-on readers. These readers enabled half-hourly data to be obtained without the need for upgrading the primary meter. At the remaining 455 sites, existing manually read meters were replaced with new advanced meters.

In addition to installing clip-on readers or new advanced meters at sites that did not already have interval metering in place, a variety of different types of energy saving advice were provided to sites during the trial. These services ranged from basic data provision to detailed advice on energy saving communicated through phone calls and site visits. Following are summaries of the types of energy saving advice provided.

**Data Only**. (134 sites, including 39 sites with pre-existing interval meters). The most basic offering was the provision of metered data only, normally via a website. Simple online tools were provided to allow sites to conduct basic analysis of their energy use profiles.

**Data and Advice**. (112 sites, including one site with a pre-existing interval meter). This intermediate level of service typically consisted of data provision together with a review of the site energy consumption and some basic energy saving recommendations relating to the site's energy use profile. This information was normally communicated via email.

**Personal Contact.** (336 sites, including four sites with pre-existing interval meters). This level of service involved two-way communications with the site including detailed discussion of the energy use profiles, either via telephone or site visits. The delivery consortia provided site-specific recommendations and advice.

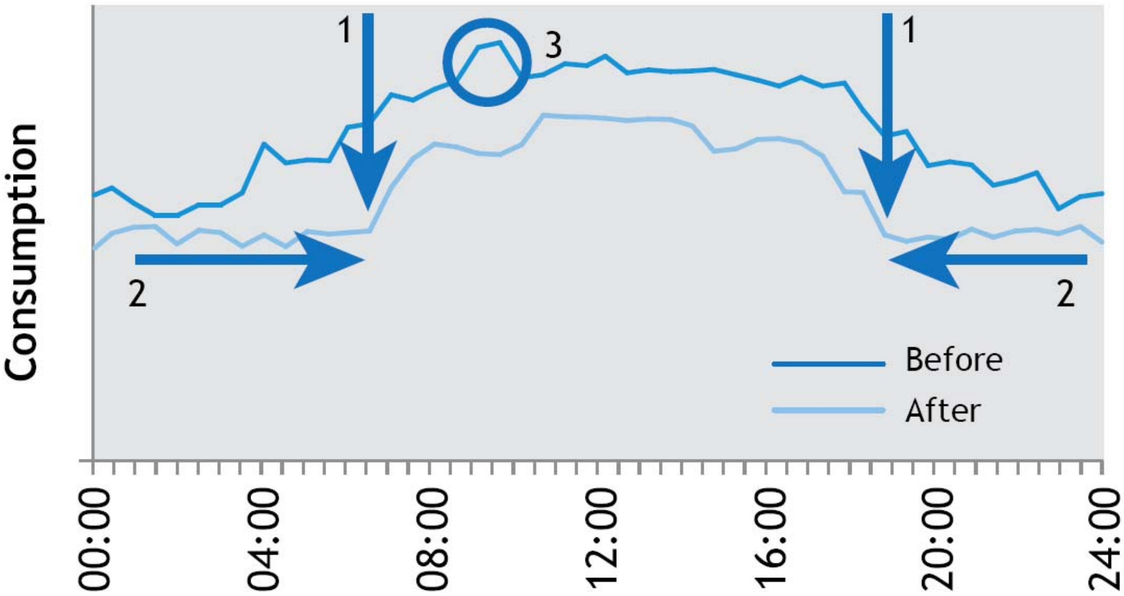


**Figure SM01/1. Using Load Profile Data from Advanced Metering to Identify Opportunities for Energy Savings**

Figure SM01/1 shows how detailed half-hourly load profile data from advanced metering was used to identify opportunities for energy savings. Three key types of potential energy saving measures (corresponding to the numbers in Figure SM01/1) could be derived from advanced meter data:

1. **Base load reductions** – the overall base load of the site could be studied and reduced, for example, by identifying unnecessary constant energy use.

2. **Process optimisation** – the load profile could be used to identify what equipment is running and when. Altering the start-up and shutdown times of key processes and equipment could reduce consumption by limiting the duration of high energy usage at the start and end of working schedules.

3. **Peak usage reduction** – the load profile could be used to analyse timings and frequencies to identify the causes of peaks in energy usage, such as particular activities or equipment.

The consortia completed log books for each site, tracking the estimated energy savings for each recommendation and the extent to which each recommendation was successfully implemented.

A case study was also produced for each site to describe the overall actions taken and associated savings made. These case studies recorded the situation at the site prior to installation of advanced metering, including details about the organisation and annual energy consumption levels. Case studies included graphical data showing energy consumption and areas where potential savings had been identified. They also included the financial case for implementing energy saving actions and the levels of potential savings in terms of energy consumption, carbon emissions and costs.

As part of this process, the consortia reviewed the half-hourly meter data to identify and validate actual energy savings achieved. Where it was not possible to implement energy saving recommendations, the reasons for this were discussed with the site personnel and recorded for reference.

## RESULTS

| Residential Customers Participating | Commercial and Small Industrial Customers Participating | Agricultural Customers Participating | Large Industrial Customers Participating | Additional Generation Installed |
|---|---|---|---|---|
| | 582 | | | |

| Peak Load | Peak Load Reduction | Duration of Peak Load Reduction | Overall Load Reduction | Energy Savings | Network Augmentation Deferral |
|---|---|---|---|---|---|
| | | | | | |

## HOW LOAD REDUCTION WAS MEASURED

Interval meter. 30 minute intervals.

## RESULTS ACHIEVED

Detailed results of the energy savings identified and successfully implemented by the SMEs involved in the trial are shown in Figures SM01/2 and SM01/3 (page 413).

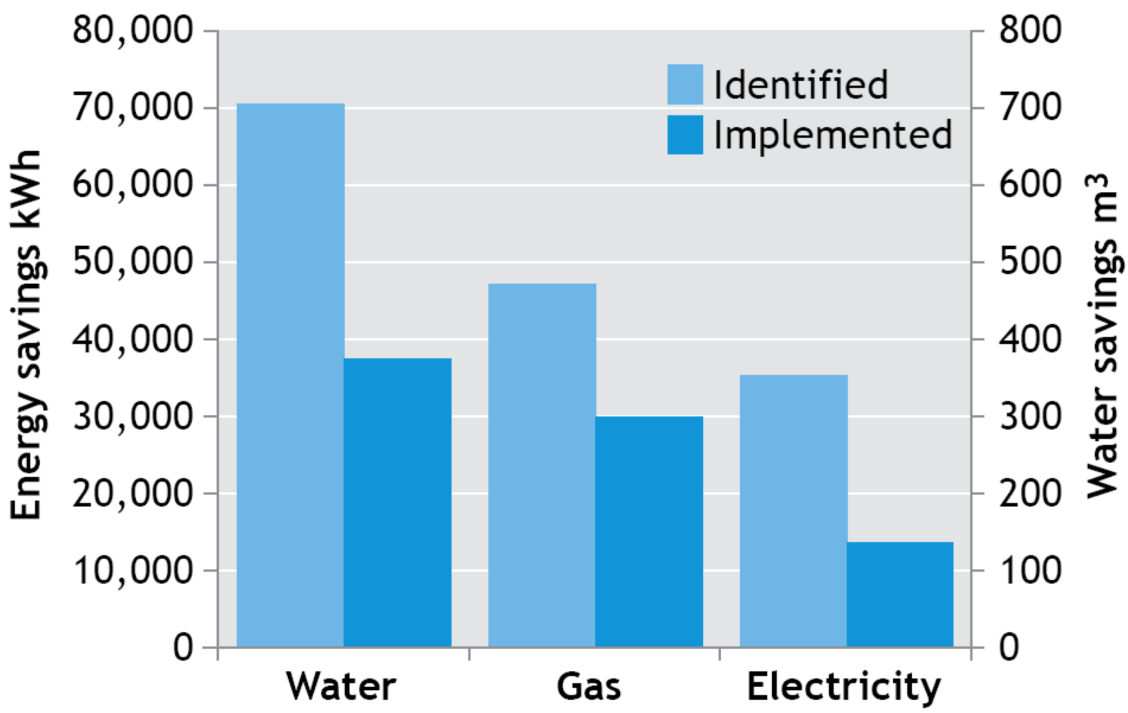


**Figure SM01/2. Average Annual Energy Savings per Site in the Carbon Trust Advanced Metering Trial**

Figure SM01/2 shows that, on average, sites in the trial saved around 13,500 kilowatt-hours of electricity and 30,000 kilowatt-hours of gas per year by using the information gained from advanced metering. This equates to annual total savings across all sites in the trial of about 7,860 megawatt-hours of electricity and 17,460 megawatt-hours of gas.

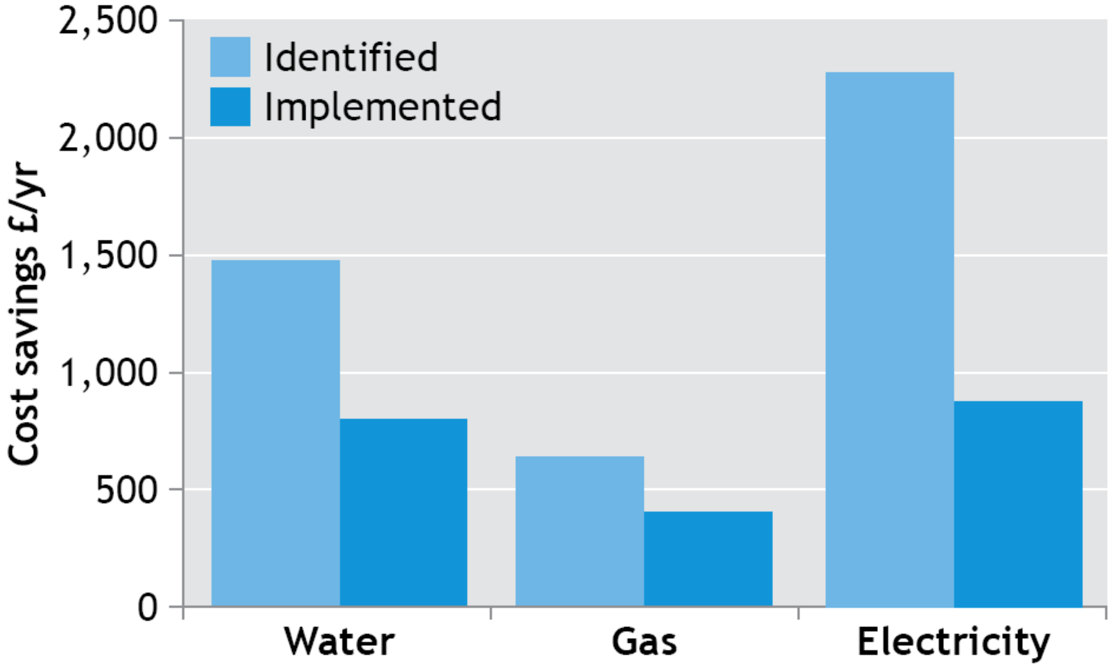


**Figure SM01/3. Average Annual Cost Savings per Site in the Carbon Trust Advanced Metering Trial**

Figure SM01/3 shows the average cost savings identified and implemented per year. On average, sites in the trial saved around GBP870 on their electricity bills and GBP405 on their gas bills per year.

Figure SM01/4 (page 414) shows the percentage carbon savings achieved by the type of energy saving advice provided. The way in which energy saving advice was delivered to SMEs resulted in marked differences in the savings achieved.

The Data Only service, where customers were simply provided with remote online access to their energy usage data, led to the lowest levels of savings. However, even here 10% energy savings were identified and 3% implemented on average. These were significant savings, especially as this service was considerably less resource-intensive for the service provider to deliver.

Most notably, the Data and Advice service, where energy saving advice was provided remotely via email, led to the highest levels of energy savings, with an average of 15% savings identified and 7.5% successfully implemented. These savings are higher than those achieved for the Personal Contact service, in which advice was provided directly via site visits and telephone calls, where an average of 12.5% savings were identified and 5% implemented successfully. This is a significant finding and there appears to be two key potential reasons for this result.

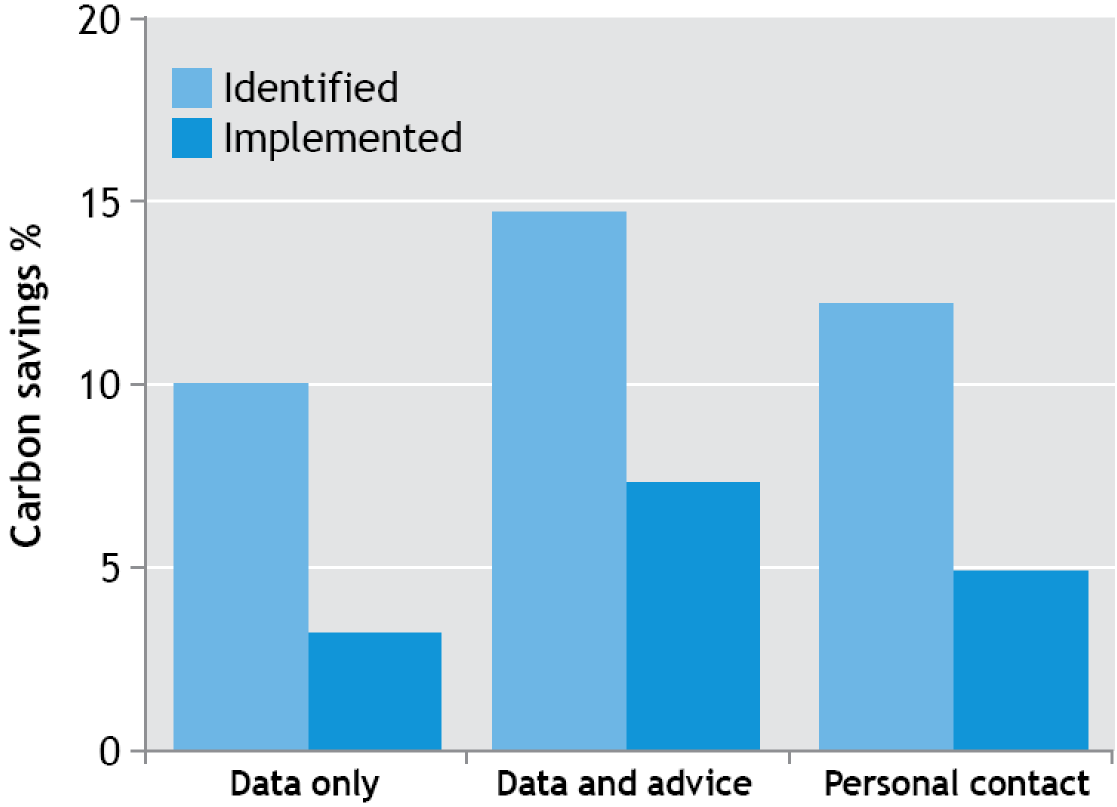


**Figure SM01/4. Carbon Savings by Type of Energy Saving Advice Provided in the Carbon Trust Advanced Metering Trial**

Firstly, when service companies provide advice via site visits and telephone calls, the advice is generally highly customised and there is a tendency to focus on high value-added recommendations. These are likely to lead to more complex process-based changes or more expensive investment-based actions. There is also less focus on providing generic energy saving recommendations, such as simple information-based or process-based changes. However, it seems that many SMEs, and especially those with limited prior experience of energy saving, can benefit from these "quick win" generic actions.

Secondly, energy saving advice which arrives via email is readily available and more likely to be looked at and acted upon directly than more conventional energy audit reports. This is especially true when the email contains simple, intuitive graphical information, such as daily energy consumption profiles. Also, the email format allows the information to be easily forwarded on to staff within the organisation to take the relevant actions, for example operations or facilities management personnel.

A key implication of this finding is the possibility of providing advanced metering services at significantly lower costs in the future. The email service model is highly scalable and it would appear feasible that automated systems could be used to analyse SME energy usage profiles, identify appropriate recommendations and automatically email these to the customer, with supporting graphical evidence. Such an automated service, backed up with call centre support, would allow for a significantly lower-cost service model than one involving on-site or telephone-based analysis and discussion.

This model for delivering energy saving advice could be easily adapted to deliver advice on reducing peak loads rather than reducing overall energy consumption.

## CONFIDENCE LEVEL IN ACHIEVING RESULTS

## REPEATABILITY OF RESULTS

## TIME DELAY BEFORE MAXIMUM RESPONSE ACHIEVED

## WEATHER DEPENDENCE

## AVOIDED COSTS

## ACTUAL PROJECT COSTS

## PROJECT COST FROM THE SOCIETAL PERSPECTIVE

## OVERALL PROJECT EFFECTIVENESS

The Carbon Trust trial is a good example of what can be achieved if advanced meters are actively used for data monitoring, collection and analysis as part of a comprehensive program focussed on realising energy savings. The systems developed for the trial could be easily adapted to deliver advice on reducing peak loads rather than reducing overall energy consumption.

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## SOURCES

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## CASE STUDY PREPARATION

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