Evaluation and Acquisition of Network-driven DSM Resources

Research Report No 4
Task XV of the International Energy Agency Demand Side Management Programme

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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 40 Implementing Agreements covering fossil fuel technologies, renewable energy technologies, efficient energy end-use technologies, nuclear fusion science and technology and energy technology information centres.

The IEA Demand-Side Management Programme is one of these collaboration programs. Since 1993, the 19 member countries and the European Commission have been working to clarify and promote opportunities for DSM.

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

A total of 17 Tasks (multi-national collaborative research projects) have been initiated by the IEA DSM Programme, nine 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

* 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 4.

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 four participating countries: Australia, France, 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 vi.

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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EXECUTIVE SUMMARY

In the electricity industry, the term ‘demand-side management’ (DSM) is used to refer to actions which change the electrical demand on the system. Task XV of the IEA DSM Programme, and consequently this report, are concerned with a particular type of DSM – “network-driven DSM”. Network-driven DSM comprises demand-side measures used to relieve network constraints and/or to provide services for electricity network system operators.

This report has two objectives:

- to summarise and review how DSM resources are evaluated, acquired and implemented in participating countries; and
- to develop ‘best practice’ principles, procedures and methodologies for the evaluation and acquisition of network-driven DSM resources.

The survey of practices in Australia, France, Spain and the United States identified a range of processes for evaluating, acquiring and implementing DSM resources to provide support for electricity networks.

Good DSM resource acquisition processes include the following stages:

- assessing the need for DSM resources;
- identifying and evaluating available DSM resources;
- contacting potential providers of DSM resources;
- negotiating the provision of DSM resources; and
- acquiring and implementing the DSM resources.

Best practices within each of these stages are tailored to the nature of each DSM resource and to the specific purpose for which the resource is required.

1. INTRODUCTION

1.1 NETWORK-DRIVEN 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. Task XV of the IEA DSM Programme, and consequently this report, are concerned with a particular type of DSM – "network-driven DSM"[1].

Network-driven DSM comprises demand-side measures used to relieve network constraints and/or to provide services for electricity network system operators. In Task XV, network-driven DSM is defined as follows:

> *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.*

Task XV has identified the following two prime objectives for network-driven DSM:

- 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.

Finally, in Task XV, the following network-driven DSM measures are considered:

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

1.2 FOCUS OF THIS REPORT

This is the fourth report from Task XV and it is intended to achieve the objective of Subtask 4 which is "develop 'best practice' principles, procedures and methodologies for the evaluation and acquisition of network-driven DSM resources[2]."

[1] For a more comprehensive discussion of network-driven DSM see the first report from Task XV: Crossley, D.J. (2006). *Worldwide Survey of Network-driven Demand-side Management Projects*. International Energy Agency Demand Side Management Programme, Task XV Research Report No 1. Hornsby Heights, NSW, Australia, Energy Futures Australia Pty Ltd.

[2] Energy Futures Australia (2004). *Prospectus: Research Project on Network-driven DSM*. Hornsby Heights, NSW Australia, EFA, p 6.

This report has two objectives:

- to summarise and review how DSM resources are evaluated, acquired and implemented in participating countries; and
- to develop 'best practice' principles, procedures and methodologies for the evaluation and acquisition of network-driven DSM resources.

2. PROCESSES FOR EVALUATING, ACQUIRING AND IMPLEMENTING DSM RESOURCES

In Subtask 4 of Task XV, the objective of Activity 4-1 is to collect information about how DSM resources are evaluated, acquired and implemented in participating countries[3]. This section of the report summarises the results from Activity 4-1.

2.1 AUSTRALIA

2.1.1 DSM in Australia

Demand-side management was brought to Australia in 1990 by the former State Electricity Commission of Victoria (SECV), a vertically integrated monopoly utility that was then owned by the Government of the State of Victoria. In the early 1980s, the SECV proposed to build 21 power stations on the Latrobe Valley coalfields by the first quarter of the 21st century. This stimulated an inquiry by a Victorian Parliamentary committee which in 1988 suggested that alternative approaches to meeting future electricity demand in Victoria should be investigated, including DSM[4].

After studying DSM programs in the United States, the SECV decided to implement a US-style DSM program in Victoria (though calling it “demand management” rather than “DSM”). Between 1990 and 1995, with the assistance of US consultants, the SECV designed and implemented the largest DSM program which has yet been seen in Australia. The main purpose of this program was to investigate the potential for DSM to contribute to reducing perceived future shortfalls in generation capacity.

The early 1990s was also the period during which micro-economic reform of the Australian electricity industry was being carried out and competition was being introduced into electricity markets in Australia. In 1992, the *National Grid Protocol*, the initial design of the (competitive) National Electricity Market, stated[5]:

> *Demand management and renewable energy options are intended to have equal opportunity alongside conventional supply-side options to satisfy future requirements. Indeed, such options have advantages in meeting short lead-time requirements*.

This principle became somewhat lost during the turmoil created by the micro-economic reform process and the establishment of the competitive electricity market. The SECV closed its DSM program in 1995 and most of the program staff moved on to work on various reform agendas. Between 1995 and the early 2000s, few DSM programs were implemented by Australian electricity businesses.

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3 Energy Futures Australia (2004). *op cit*.

4 Natural Resources and Environment Committee (1988). *Electricity Supply and Demand Beyond the Mid-1990s*. Melbourne, Parliament of Victoria.

5 National Grid Management Council (1992). *National Grid Protocol: First Issue*, Melbourne, NGMC, p iii.

One exception to this low level of DSM implementation was the use of ripple control remote switching technology to shift residential water heating loads to off-peak periods, particularly to the middle of the night. This is a long-standing network-driven DSM measure which has been used in Australia for over 50 years. In some highly congested distribution networks with aging infrastructure, shifting of hot water load targeted at particular network elements has been used very actively, simply to keep the network operating.

In the early 2000s the attitude of electricity businesses towards DSM started to change with the recognition that coping with rapidly increasing peak loads would require massive investment in electricity network infrastructure. DSM came to be seen as a possibly cheaper and quicker way of relieving some types of network constraints. Consequently, the majority of DSM currently being implemented in Australia is network-driven.

Discrete DSM projects targeted at particular network elements have been increasingly implemented in Australia since the late 1990s. Some State regulators have provided incentives for DNSPs to implement DSM projects for this purpose. Until recently, there has been a particular emphasis on using energy efficiency load reductions to defer network augmentations, such as the construction or upgrading of substations and feeders.

In the future, it is expected that the emphasis will shift to deferring augmentation through short-term demand response load reductions at peak times on targeted network elements, particularly peaks caused by residential air conditioning on hot summer days. Various measures have been trialled to achieve demand response, including direct load control remote switching technologies and pricing initiatives aimed at encouraging changed behaviour by end-use customers.

2.1.2 Processes for Acquiring DSM Resources

As noted in a previous report[6], most electricity networks in Australia are owned, operated and managed by stand-alone businesses that are participants in the National Electricity Market – a competitive wholesale market. The processes used by network businesses in Australia for evaluating, acquiring and implementing DSM resources are governed by the requirements of electricity industry regulators.

Regulation of the electricity industry in Australia is currently in the process of being transferred from several State-based regulators to a single national regulator, the Australian Energy Regulator. Consequently, until recently, distribution network businesses have acquired DSM resources under separate regulatory regimes established in each state, whereas transmission network businesses have operated under a single national regulatory regime.

[6] Crossley, D.J. (2007). *Incorporation of DSM Measures into Network Planning*. International Energy Agency Demand Side Management Programme, Task XV Research Report No 3. Hornsby Heights, NSW, Australia, Energy Futures Australia Pty Ltd.

Despite the diversity of regulatory regimes, processes for evaluating, acquiring and implementing DSM resources are all generally based on a national regulatory framework. Some States have implemented more detailed requirements within the national framework.

2.1.3 National Regulatory Framework for Acquiring DSM Resources

The national regulatory framework for acquiring DSM resources for network-related purposes is defined by the provisions of the *National Electricity Rules*[7]. Chapter 5 of the *Rules* sets out the network development process to be followed for all electricity network assets that are covered by the National Electricity Market[8].

1. Each network operator[9] must analyse the expected future operation of its network(s) over an appropriate planning period, taking into account the relevant forecast loads, any future generation, market network service, demand side and transmission developments and any other relevant data.
2. Each transmission network operator (TNSP) must conduct an annual planning review with each distribution network operator (DNSP) connected to its transmission network within each region. The annual planning review must incorporate the forecast loads submitted by the DNSP and must include a review of the adequacy of existing connection points and relevant parts of the transmission system and planning proposals for future connection points. The minimum planning period for the purposes of the annual planning review is five years for distribution networks and 10 years for transmission networks.
3. Where the necessity for network augmentation or a non-network alternative is identified by the annual planning review, the relevant network operators must undertake joint planning in order to determine network development plans that can be considered by interested parties.
4. The relevant DNSP must consult with interested parties on the possible options, including but not limited to demand side options, generation options and market network service options to address the projected limitations of the relevant distribution system.
5. Each DNSP must carry out an economic cost effectiveness analysis of possible options to identify options that satisfy the Regulatory Test[10], while meeting technical requirements.

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7 Australian Energy Market Commission (2007). *National Electricity Rules Version 13*. Available at: http://www.aemc.gov.au/pdfs/rules/rulesv13.pdf

8 In effect, all electricity network assets in Australia except for those located in Western Australia and the Northern Territory.

9 Referred to in the *Rules* as Transmission Network Service Providers (TNSPs) and Distribution Network Service Providers (DNSPs).

10 The Regulatory Test is an economic cost-benefit test applied by network service providers in the National Electricity Market (NEM) to assess and rank the economic viability of network and non-network options. It is described in detail in: Crossley, D.J. (2007). *Op cit.*

6. The DNSP must prepare a report that is to be made available to interested parties which: (1) includes assessment of all identified options; (2) includes details of the DNSP's preferred proposal and details of its economic cost effectiveness analysis and its consultations; (3) summarises the submissions from the consultations; and (4) recommends the action to be taken.
7. Within 40 business days after the report is made available, certain interested parties may dispute the recommendation of the report in respect of any proposal that is a new large distribution network asset or is reasonably likely to change the distribution use of system service charges by more than 2%.
8. Following the completion of the 40 business day dispute period, the DNSP must arrange for the network options (if any) recommended by its report to be available for service by the agreed time.

2.1.4 NSW Demand Management Code of Practice

The Demand Management Code of Practice[11] in force in the State of New South Wales (NSW) prescribes a formal process to be followed by distribution network operators (DNSPs) in procuring demand-side resources for network support. The process is illustrated in Figure 2.1 (page 7).

The first edition of the Code was published in 1999 and its evolution to the current third edition, published in 2004, has closely followed the corresponding evolution of the *National Electricity Rules* from their origins during the development and implementation of the National Electricity Market during the 1990s.

The third edition of the Code was prepared by a working group comprising representatives from the NSW electricity industry, the NSW electricity industry regulator, electricity users and environmental and consumer groups, facilitated by the NSW Department of Energy, Utilities and Sustainability.

While the first two editions of the Code were purely advisory, the third edition was formally issued in accordance with NSW legislation. This requires DNSPs in NSW to take the Code into account in the development and implementation of their network management plans. In particular, a network management plan must specify where the plan, or its implementation, departs from the provisions of the Code and, if so, what arrangements are in place to ensure an equal or better outcome.

The basis of the Code is a market-based procurement process for demand-side options for electricity system support (including DSM, embedded generation and storage options) and their evaluation at the same time and in the same manner as supply-side options.

The approach in the Code is focused not just on the network, but rather on the electricity system as a whole. Constraints that arise within the distribution network can be addressed by changes in customer behaviour, by changes in equipment used by customers or by installation of small-scale generation at a local level, as well as by augmentation of the distribution network. These options could be devised and implemented by end-use customers or third parties or by the DNSP itself.

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[11] Department of Energy, Utilities and Sustainability (2004). *Demand Management for Electricity Distributors: NSW Code of Practice*. Sydney, DEUS. Available at: www.efa.com.au/Library/DMCode3rdEd.pdf

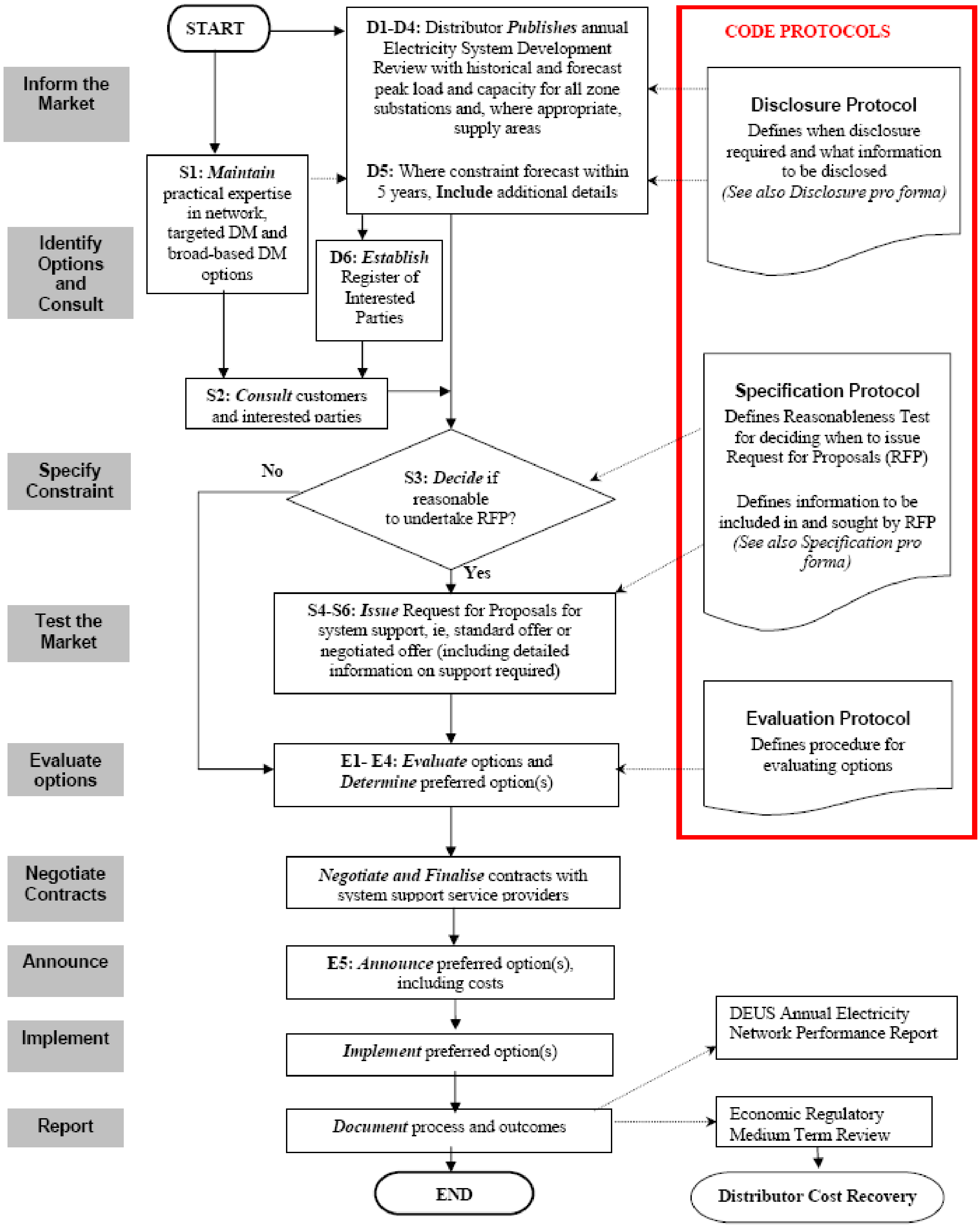

Figure 2.1 Electricity System Development Procedure for Distribution Network Operators in New South Wales, Australia[12]

[12] Department of Energy, Utilities and Sustainability (2004). *Op cit.*

The Code requires DNSPs in New South Wales to:

- publish information that makes transparent the underlying assumptions and decision-making process relating to investments that expand their distribution networks;
- publish detailed information regarding the need for network expansion in a way that enables interested parties to identify likely locations of forthcoming constraints;
- use a formal process to determine whether investigations of demand-side options are warranted for identified emerging constraints, and publish the results;
- carry out investigations of demand-side options that provide opportunities for market participation;
- analyse demand-side and network expansion options on an equal basis according to the published methodology and assumptions and publish the result of those determinations;
- implement demand-side options where they are determined to be cost effective; and
- prepare and publish reports on these activities annually.

Under the Code, there are two types of procurement offers that may be made to providers of demand-side options: negotiable offers and standard offers. For negotiable offers, the distributor and the proponent of a demand-side project (who may also be a network customer) negotiate a contract specifically designed for that particular project. Negotiable offers are more appropriate for larger-scale, relatively complex demand-side projects where the transaction costs and time associated with negotiating a unique contract are relatively insignificant compared with the benefits from the project.

Standard offers specify the conditions for the provision of demand-side resources in advance. Standard offers are usually made on fixed prices, take it or leave it, first come first served basis. Standard offers may be targeted to shorter-term network constraints or to capture demand reduction opportunities that provide longer-term distribution network benefits by delaying future, less well-defined constraints.

A standard offer may be made in conjunction with, prior to, or in place of, a negotiable offer being issued or a constrained area being identified. A subsequent negotiable offer or Request for Proposal may revise the standard offer as the details of the constraint and the requirement to overcome the constraint are more clearly defined.

The Code suggests that DNSPs should make standard offers where the firm rating of the local distribution network will be exceeded within a 10 year forecast period. A standard offer can be made during the early period of a constraint being identified and may be re-evaluated and incorporated into a Request for Proposals in accordance with the timeframe shown in Figure 2.1 (page 7).

2.1.5 Case Study: TransGrid Major Network Augmentation

TransGrid is a transmission network operator (TNSP) owned by the Government of New South Wales. TransGrid owns, operates and manages the high voltage electricity transmission system throughout NSW.

In September 2005, TransGrid published a *Needs Statement* for emerging major transmission network limitations affecting the supply to the Newcastle–Sydney–Wollongong load area[13]. This transmission corridor delivers power to the area of the highest concentration of electricity demand in NSW. As a result of continued growth in electricity consumption, future peak electricity demand delivered via this corridor will outstrip the capability of the current transmission infrastructure.

TransGrid's analysis suggested that the transmission system currently operating at 330kV that serves this corridor will require significant augmentation by the summer of 2008/09. TransGrid proposed to upgrade the transmission system to operate at its design capability of 500kV. In addition to proposing this network solution, TransGrid also committed to investigating the potential for suitable non-network solutions (such as demand response, energy efficiency, and embedded and distributed generation) to provide capacity to address the emerging transmission limitations.

In May 2006, TransGrid issued an *Application Notice* for public consultation on a proposed new large transmission network asset in the Newcastle–Sydney–Wollongong load area[14]. The *Notice* described seven network options and a number of non-network options. None of the non-network options was regarded as sufficiently developed, at that stage, for consideration by the Regulatory Test. However, the *Notice* stated that development of non-network options was continuing.

TransGrid's investigation of non-network solutions involved two major initiatives:

- working with third-party organisations that could provide possible non-network solutions either directly or by organising end-use customers to do so;
- working directly with end-use customers that had the ability to provide potential non-network solutions.

TransGrid carried out a project to identify the magnitude and cost of possible non-network solutions and contracted a consultant specialising in DSM to assist them with the project.

Stage 1 of the project included data gathering, desktop analysis and identification of non-network alternatives that could achieve the objectives. At the conclusion of Stage 1 an assessment was made whether or not it was worthwhile proceeding further and it was agreed to go ahead with Stage 2.

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13 TransGrid (2005). *Emerging Major Transmission Network Limitations in Supplying the Newcastle–Sydney–Wollongong Load Area: Needs Statement.* Available at: http://www.transgrid.com.au/trim/trim191126.pdf.

14 TransGrid (2006a). *Application Notice: Proposed New Large Transmission Network Asset - Development of Supply to the Newcastle–Sydney Wollongong Area*. Available at: http://www.transgrid.com.au/trim/trim210951.pdf

Stage 2 commenced with seeking assistance from various parties in the geographical region under evaluation, including DNSPs, electricity retailers and generators, agencies and interest groups. In addition, a preliminary meeting was held with the Australian Energy Regulator to discuss and better understand the treatment by the regulator of DSM undertaken by a TNSP.

A series of documents were prepared and publicly advertised: a Request for Proposal (RFP), a Network Support Agreement and other ancillary paperwork. These documents were prepared jointly by legal advisers and TransGrid's commercial group, using as a basis the State Government guidelines for tenders.

The RFP was issued in August 2006[15] and sought non-network solutions that in aggregate would provide network support in the Newcastle–Sydney–Wollongong area such that capacity of the current system:

- would remain sufficient to meet the remaining aggregate customer peak demand in the area for an additional one or more years; and
- might enable deferral of the 330 kV to 500 kV conversion.

It was envisaged that these non-network solutions could include:

- reductions in end-use demand, either in the proponent's facility or in the facilities of other end-users as arranged by the proponent, including the use of standby generators located within these facilities, whether or not the generators were synchronised with the grid;
- local generation projects (also referred to as embedded generation) connected to the lower voltage networks supplying end-use proponents;
- larger generation projects which may connect to TransGrid's 330 kV network or to the underlying 132 kV networks owned by DNSPs; and/or
- operational changes and/or plant expansions whereby existing larger generation plant already connected within the constrained area could produce additional output.

The RFP stated that network support was most likely to be required during periods of extremely high system demand, which tend to occur on working weekdays during sustained periods of high temperature in the period from mid-November to mid-March, excluding the period from 24 December through mid January.

Under the RFP, each proposal had to be for the supply of network support (ie load reduction or generation) in the defined geographic area on working weekdays during the specified four month period in the years 2008/09 to 2010/11. The smallest block of network support acceptable to TransGrid was 30 MW. However, to allow smaller participants to participate, the RFP encouraged the formation of aggregating teams who could put forward joint proposals of not less than 30 MW.

15 TransGrid (2006b). *Request for Proposal Number 104/06: Non-Network Solutions in the Newcastle–Sydney–Wollongong Area.* Sydney, TransGrid.

The criteria used to evaluate proposals comprised:

- the magnitude of network support (in MW) to be provided – larger amounts were preferred, subject to consideration of the extent to which the size and/or nature of the resource might reduce the reliability of the aggregate network support portfolio;
- the total expected cost to TransGrid, which was calculated using the prices submitted in the proposal and the expected timing, frequency, and duration of dispatch events;
- the proportion of the total expected cost to TransGrid represented by estimated availability and dispatch payments; proposals in which dispatch payments represented higher proportions of total expected cost were preferred;
- the ability to maintain contracted network support levels for the anticipated frequency and duration of dispatch. The following parameters were regarded as 'pluses':
  - ♦ ability to provide greater frequency of network support;
  - ♦ ability to provide greater duration of network support;
  - ♦ ability to provide more consecutive days (up to three) of network support;
  - ♦ ability to provide network support outside the specified season and hours;
- the notification period required for dispatch of network support; shorter notification periods were preferred;
- the cancellation period for a dispatch order for network support; shorter cancellation lead times were preferred;
- the technical feasibility of the proposed project(s);
- the firmness/reliability of the network support proposed;
- a clear demonstration by the proponent that the network support proposed was being brought forward as a result of funding support from TransGrid relative to business-as-usual conditions;
- the adequacy, accuracy and level of transparency of the proponent's proposed verification plan;
- the degree to which the proponent appeared capable of delivering the amount of network support offered within the desired timeframe for availability of network support; and
- the demonstrated track record of the proponent in similar undertakings.

The RFP also required project proponents to:

- provide development plans (where no plant existed at the time of lodging a response to the RFP);
- develop a verification plan to ensure that what was claimed to be delivered was actually delivered;
- provide metering facilities in accordance with the relevant standards.

The RFP stated that proposals for non-network solutions would only be accepted if the solutions satisfied the applicable regulatory requirements for the adoption of, and recovery of the costs of, such options. In other words, the Australian Energy Regulator would have to approve TransGrid passing through the cost of non-network solutions to its network customers.

The RFP was advertised in a number of daily newspapers (state and national) as well as TransGrid's website. The responses received underwent evaluation by a committee that included members drawn from across all TransGrid's business areas. During the evaluation process, TransGrid met with all proponents on an individual basis to clarify various points in their submissions.

In October 2006, TransGrid issued a final report on the proposed new large transmission network asset[16]. The report proposed the conversion of two existing 330 kV transmission lines to operate at 500 kV. To manage the network limitations in the short term, it was also proposed to continue the development of non-network projects with identified proponents to implement up to 350 MW of network support capability for the Newcastle–Sydney–Wollongong area by 2008/09.

The final report also stated that "the magnitude of non-network projects offered could be sufficient to manage the network limitations over summer 2008/09 and summer 2009/10". TransGrid was able to provide estimates of the overall costs and capacities of certain non-network projects and these estimates enabled the projects to be included as components of options in the Regulatory Test. However, before any non-network solutions could be implemented, the Australian Energy Regulator would have to approve TransGrid passing through the cost of these projects to network customers. At the time of writing, a final decision on the evaluation of the responses to the RFP is yet to be made.

2.2 FRANCE

2.2.1 DSM in France

In France, the transmission network operator, Gestionnaire du Réseau de Transport d'Electricité (RTE), is prevented by its founding legislation from undertaking DSM. Consequently, network-driven DSM has been undertaken by the distribution units of Electricité de France (EDF) and local government-owned rural distributors, usually in collaboration with the French Government's environmental and energy management agency Agence de l'Environnement et de la Maîtrise de l'Energie (ADEME).

DSM has not been used to provide network operational services in France. Network-driven DSM has been used mainly in projects aimed at deferring network augmentation and reinforcement, particularly in rural areas. It is expected that this use will increase in the future as it becomes more difficult to obtain environmental approvals to build new transmission and distribution lines.

EDF also utilises a network-driven DSM measure, the Tempo critical peak pricing tariff, to enable smoothing of both the annual and daily electricity load curves, particularly to reduce load during critical peak periods.

[16] TransGrid (2006c). *Final Report: Proposed New Large Transmission Network Asset - Development of Supply to the Newcastle–Sydney Wollongong Area*. Available at: http://www.transgrid.com.au/trim/trim224993.pdf.

2.2.2 Processes for Acquiring DSM Resources

Processes for acquiring DSM resources for network-related purposes in France rely on directly contacting end-use customers.

Where DSM is used to defer network augmentation, the process involves first analysing the load profile on the affected network element (eg a particular line or substation) to determine the time(s) at which the constraint occurs and the loads contributing to the constraint. Tailored DSM programs are then developed to target reductions in specific loads at the time(s) when the constraint occurs.

Using the Tempo tariff to reduce load during system peaks involves a marketing campaign to encourage end-users to sign up for the tariff and then a communication campaign to inform people about the days when critical peaks will occur.

2.2.3 Case Study: The French Riviera DSM Program

The purpose of the French Riviera DSM program 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[17]. The following description is based on the analysis and program design developed following the initial decision to proceed with the DSM program. This initial decision was based on deferring the need for a further transmission line after a new 400 kV line was built in the mid-2000s. However, planning permission for the new line was refused in May 2006 and the DSM program will have to be strengthened to meet the new constraints.

2.2.3.1 Preliminary Studies

Preliminary studies were carried out in 2001:

- to quantify the level of load reduction required, after the expected 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.

The analysis showed that to avoid a further new line being required before 2020, the DSM program would have to reduce load by 35 MW in winter[18].

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17 A detailed case study of the French Riviera DSM program is included in the first report from Task XV: Crossley, D.J. (2006). *Op cit*.

18 Jean-Pierre Harinck and Bertrand Combes (2003). “Plan Eco-Energie: Programme de Maîtrise de la Demande d’Electricité et de Développement des Energies Renouvelables sur l’Est de la Région Provence-Alpes-Côte d’Azur”. Presentation to *6ème Rencontres Nationales Sciences et Techniques de l’Environnement*. Istres, 28 October. Available at: http://www.planete-sciences.org/enviro/rnste6/ateliers/ppt/plan-eco-nrj.ppt

Figures 2.2 and 2.3 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.

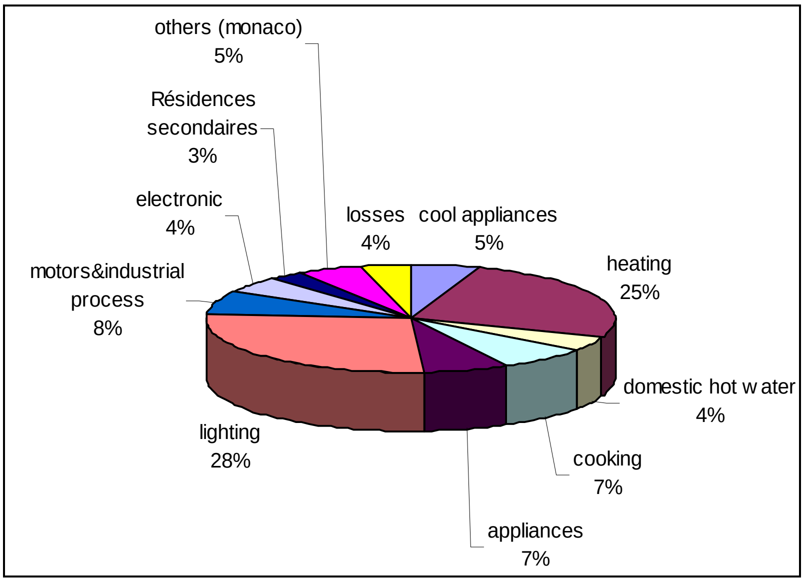

Figure 2.2. Winter Peak Demand by End-use in the Eastern Part of the Provence-Alpes-Côte d'Azur Region[19]

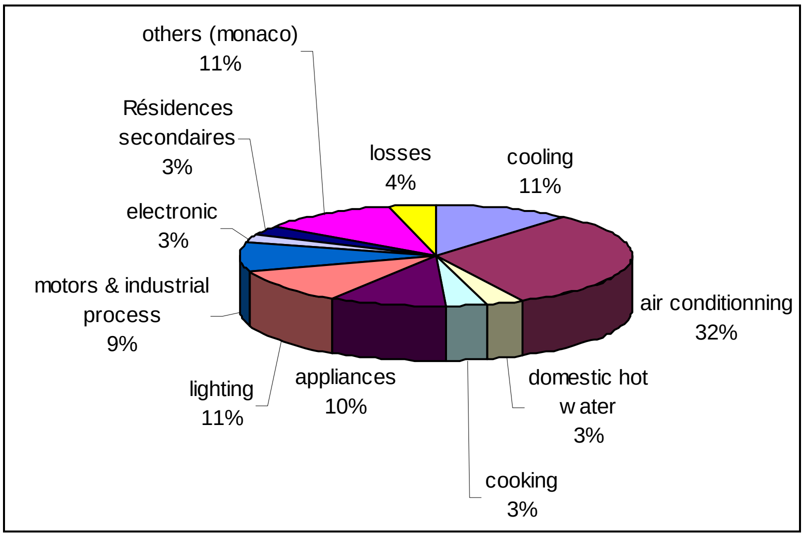

Figure 2.3. Summer Peak Demand by End-use in the Eastern Part of the Provence-Alpes-Côte d'Azur Region[20]

19 Jean-Pierre Harinck and Bertrand Combes (2003). *Op. cit.*

20 Jean-Pierre Harinck and Bertrand Combes (2003). *Op. cit.*

Figure 2.4 shows forecasts of the potential load reductions achievable by implementing DSM and distributed generation over the period 2005 to 2020. Figure 2.5 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 DSM program in winter 2006 was set at 45 MW.

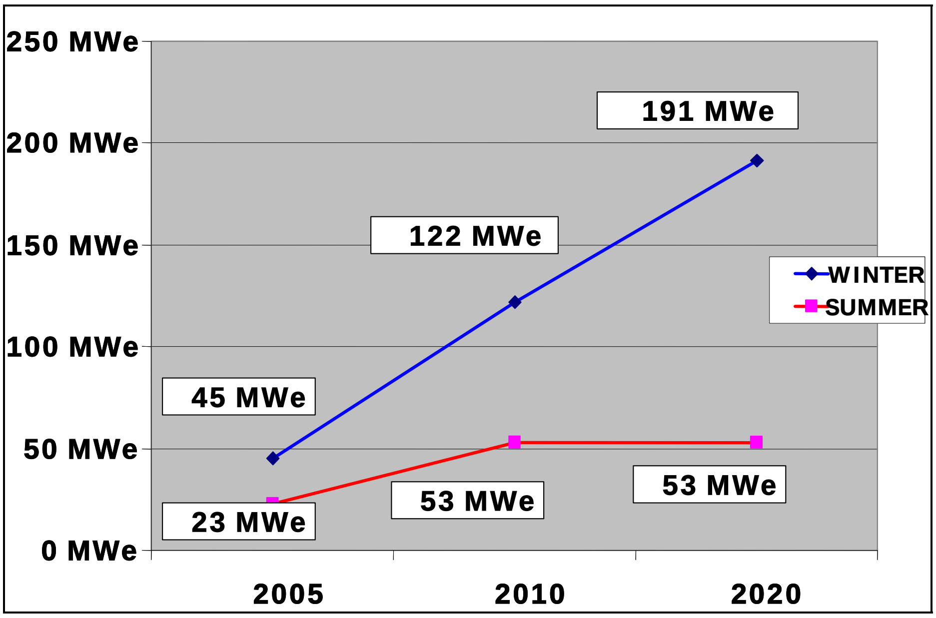

Figure 2.4. Forecasts of Potential Load Reductions Achievable through the French Riviera DSM Program 2005 to 2020[21]

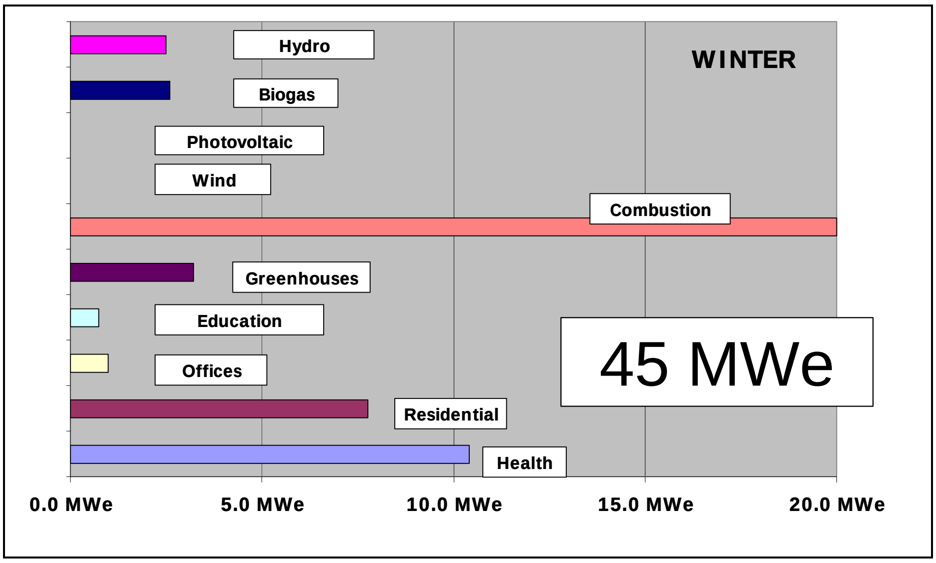

Figure 2.5. Forecasts of Potential Load Reductions Achievable through the French Riviera DSM Program in Winter 2006[22]

21 Jean-Pierre Harinck and Bertrand Combes (2003). *Op. cit.*
22 Jean-Pierre Harinck and Bertrand Combes (2003). *Op. cit.*

2.2.3.2 Implementation

The DSM program was launched in March 2003. Initially, six priority areas were identified[23]:

- communication and information;
- new building construction;
- efficient lighting and domestic electrical appliances;
- large consumers and distributed generation;
- demonstration projects by institutional partners; and
- public housing.

In 2004, a further two priority areas were added:

- existing buildings; and
- tourism.

A general public information campaign was launched on 18 March 2003[24]. 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. 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.

Individual targeted communication and enrolment programs have also been developed for each of the identified priority areas. These include[25]:

- targeted information material on energy efficient lighting for engineering and building design firms;
- negotiations with lamp manufacturers to enable energy efficient lamps to be offered at a 20% discounted price in the Alpes-Maritime region;
- loans to cover the cost of energy efficient lighting installations;
- establishment of a working group on cogeneration and completion of a study to identify the potential for the development of small cogeneration installations (200-300 kW) in the region;
- feasibility studies of energy efficiency and DSM demonstration projects in public buildings;
- facilitation of local communities in the Alpes-Maritimes region to undertake effective DSM measures;
- working with managers of public housing to improve the energy efficiency of their properties;

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23 Plan Éco-Énergie (2005). *Infos.* Newsletter, July edition.

24 ADEME (2006). *Plan Éco-Énergie: Campagne de Communication Grand Public 2003 - 2006.* PowerPoint presentation.

25 Eco-Energy Plan website at: www.planecoenergie.org

- development of 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.

Figure 2.6 shows the forecast impacts and costs of the identified DSM measures to be implemented through the French Riviera DSM program.

	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 2.6. Forecast Impacts and Costs of Identified DSM Measures in the French Riviera DSM Program[26]

[26] Frédéric Rosenstein (2004). "The Transmission Network-Driven DSM Project in the French Riviera". Presentation to IEA DSM Programme Task XV Experts Meeting, Atlanta, Georgia, 11 to 12 October.

2.2.4 Case Study: The Tempo Tariff

Under the Tempo tariff, each day of the year is colour coded[27]. 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 also has the ability to determine the day colour if there is significant congestion on the electricity network.

The Tempo tariff is promoted to high use households, such as very large houses, and those with electric heating and full time occupation, and to small business customers.

Customers who choose the Tempo tariff 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[28].

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.

2.3 SPAIN

2.3.1 DSM in Spain

In Spain, DSM is mainly used at the transmission network level to relieve network constraints and to provide network operational services to the system operator. DSM to defer network augmentations by targeting specific network elements has so far not been used in Spain.

The main opportunity for network-driven DSM in Spain is through the interruptibility program offered by the transmission system operator, Red Eléctrica de España (REE). Under this program, end-use customers obtain a discount for partial interruption of load during periods called by REE.

Eligible customers that are directly connected to the transmission network may also obtain a discount on their network access tariff for operating their reactive compensation equipment when requested by the system operator.

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[27] A detailed case study of the Tempo tariff is included in the first report from Task XV: Crossley, D.J. (2006). *Op cit*.

[28] Kärkkäinen, S. (ed) (2004). *Energy Efficiency and Load Curve Impacts of Commercial Development in Competitive Markets: Results from the EFFLOCOM Pilots*. EU/SAVE 132/01 EFFLOCOM Report No 7. Available at: www.efflocom.com/pdf/EFFLOCOM%20report%20no.%207%20Pilot%20Results.pdf

Currently, end-use customers are able to offer load reductions into the market for solving network constraints in real time. However the participation rate is very low. Eligible customers also have the option to provide voltage control services to the system operator. Customer participation in other ancillary services markets such as the Secondary Regulation Market and the Deviation Management Market are currently under evaluation.

2.3.2 Processes for Acquiring DSM Resources

In Spain, processes for evaluating, acquiring and implementing DSM resources to provide support for electricity networks have so far been implemented only by REE, as the transmission network system operator. These processes comprise market-based programs that provide financial incentives to large end-use customers who provide DSM resources to the system operator.

2.3.3 Case Study: Red Eléctrica de España Interruptibility Program

Red Eléctrica de España has established a program of load interruption contracts under which it may call for loads to be interrupted to cover operational shortfalls in either network or generation capacity[29]. Currently there are about 2600 MW of interruptible load registered in the REE interruptibility program.

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. REE is responsible for issuing, controlling and supervising all interruption orders. Customers participating in the interruptibility program must submit to REE monthly schedules for hourly energy demand and maintenance planning.

The requirements for end-users to participate in the interruptibility program are as follows:

- the interruptible load must be supplied at high voltage under a general tariff;
- the interruptible load offered must be larger than 5MW (in some cases, smaller loads may be accepted);
- the customer site must have adequate facilities to measure the size and duration of any load reductions[30].

Table 2.1 (page 20) shows the four types of interruption options available in the REE interruptibility program.

[29] A detailed case study of the REE interruptibility program is included in the first report from Task XV: Crossley, D.J. (2006). *Op. cit.*

[30] Spanish Ministerial Decree, 12 January 1995.

Table 2.1 Options in the Red Eléctrica de España Interruptibility Program		
Interruption Type	**Maximum Duration of Interruption**	**Advance Notice**
A	12 hours	16 hours
B	6 hours	6 hours
C	3 hours	1 hour
D	45 minutes	5 minutes

The maximum duration of interruption for types A and B is divided into three periods with different load reduction requirements:

Pmaxi: Maximum load demanded will be equal to or lower than the maximum load established in the interruption program.

P50%: Maximum load demanded will be equal to or lower than Pmaxi + 0.5(Pc–Pmaxi), where Pc is the contracted power for the interruption period.

Pc: Maximum load demanded will not be limited by the interruption order.

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. Currently, the Spanish electricity industry regulator and the system operator (REE) are working on developing the interruptibility program to modify contract conditions so new consumers can be included, particularly in the eastern and southern coastal areas of Spain, where summer peak has increased considerably in recent years.

2.4 UNITED STATES

2.4.1 DSM in the United States

From the mid-1980s to the mid-1990s, DSM became a major business in the United States electricity industry. State-based regulators imposed stringent requirements on electricity utilities to implement broadly-targeted, environmentally-driven DSM programs. DSM was seen as being more cost-efficient than supply-side resources and it also had environmental and social benefits.

Many US utilities were required by regulators to undertake "integrated resource planning" (aka "least cost planning") in which supply-side and demand-side options were compared to determine which were the most cost-effective from the societal perspective. Consequently, electricity planning in the United States became a highly legalistic process with armies of lawyers arguing about what should and should not be taken into account in the cost benefit analyses of supply-side and demand-side options.

From the mid-1990s, electricity regulators in the United States began to turn their attention away from DSM and towards electricity market reform. Without the regulatory imperative, US utilities very quickly dropped or substantially reduced implementation of broadly-targeted, environmentally-driven DSM programs. For example, spending on energy efficiency DSM programs[31] by electricity utilities fell by 50 percent from 1994 to 1997[32]. Consequently, policymakers in many US states that adopted electricity industry restructuring also created public benefits funding mechanisms to help ensure the continued implementation of broadly-targeted, environmentally-driven DSM programs.

DSM targeted to relieving network constraints has been implemented in the United States since the mid-1980s. However, until the late 1990s, only a few specifically network-driven DSM programs had been developed. More recently, as problems with ageing network infrastructure become more apparent, increasing numbers of network-driven DSM programs are being implemented. In particular, United States utilities have implemented load management programs that can be used to relieve network constraints as well as to respond to generation capacity shortfalls. These include time-based pricing (primarily TOU), interruptible rates, curtailment programs, and direct load control programs. The most active of these have been direct load control programs, particularly of customer HVAC and residential hot water systems.

With the advent of open access to transmission networks and the development of competitive wholesale electricity markets in many parts of the United States, there has been increasing use of DSM measures to provide short-term network operational services. There is a rapid evolution underway from traditional load management to demand response concepts and programs, and the capabilities that new load control technologies provide to utilities, system operators, customers and other actors in electricity markets[33]. Today, some Independent System Operators conduct demand response programs through which demand-side resources can be offered to the market. This is typically done through a market participant, e.g., a utility, demand response aggregator, or competitive retail supplier[34].

To date, there has not been much use of DSM programs to defer network augmentations in the United States. One pilot project was the Model Energy Communities Program (Delta Project) implemented by the Pacific Gas and Electric Company (PG&E) from 1991 to 1993[35]. The Delta Project successfully deferred capital investment in a substation for at least two years, albeit for a shorter deferral period than originally projected. More recently, some utilities, particularly the Bonneville Power Administration, are again starting to use DSM to defer network augmentations.

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31 As opposed to other types of DSM programs.

32 Kushler. M. and York, D. (2004). State public benefits policies for energy efficiency: What have we learned? *Proceedings of the 2004 ACEEE Summer Study on Energy Efficiency in Buildings*, pp 5-156 to 5-167.

33 Scarpelli, P. (2005). *Op cit.*

34 Detailed case studies of some of these ISO demand response programs are included in the first report from Task XV: Crossley, D.J. (2006). *Op cit.*

35 Kushler, M., York, D. and Vine, E. (2005). Energy-efficiency measures alleviate T&D constraints. *Transmission & Distribution World*, 1 April. Available at: www.tdworld.com/mag/power_energyefficiency_measures_alleviate/index.html

2.4.2 Processes for Acquiring DSM Resources

In the United States, electricity businesses have used a range of processes for evaluating, acquiring and implementing DSM resources to provide support for electricity networks. The processes used in a particular network-driven DSM project depend on the purpose of the project, ie what network-related outcome it is intended to achieve. In the United States, network-driven DSM has generally been used for four purposes:

- relieving network constraints in specific geographical locations;
- reducing peak load across a service territory;
- maintaining and improving overall system reliability across a network region;
- providing ancillary services.

The regulatory treatment of network-driven DSM projects in the United States varies, depending on the (usually State-based) regulator involved. In general, if a DSM option can be shown to have a lower total resource cost than an equivalent network augmentation option, regulators will usually allow the electricity business to include the cost of the demand-side option in the rate base.

In addition, in February 2007, FERC made a ruling (Order No 890) that changed the *Pro Forma Open Access Transmission Tariff* to put demand-side resources, for the first time, on an equal footing with other resources in directly contributing to the reliability and efficient operation and expansion of the United States electricity transmission system[36]. The changes provide that demand-side resources, distributed generation, and other non-generation resources capable of providing the service may provide the ancillary services Reactive Supply and Voltage Control, Regulation and Frequency Response, Energy Imbalances, Spinning Reserves, Supplemental Reserves, and Generator Imbalances.

2.4.3 Relieving Local Constraints

Some network-driven DSM projects in the United States are directed to relieving network constraints in specific geographical locations. Typically, the processes used by network operators to acquire DSM resources in these projects involve first analysing the load profile on the affected network element (eg a particular line or substation) to determine the time(s) at which the constraint occurs and the loads contributing to the constraint. Tailored DSM programs are then developed to target reductions in specific loads at the time(s) when the constraint occurs.

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[36] Federal Energy Regulatory Commission (2007). *February 15, 2007 Open Commission Meeting: Statement of Commissioner Jon Wellinghoff*. Washington DC, FERC.

For example, in the Olympic Peninsula project in the Pacific Northwest[37], the transmission system operator, Bonneville Power Authority (BPA), 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.

BPA, as a transmission network operator, acquires DSM resources mainly by providing incentives to local distribution network operators. The distributors then contact local end-users and negotiate arrangements for the customers to reduce load at relevant times and locations. These arrangements include payment of incentives to customer who participate in DSM programs.

2.4.4 Reducing Peak Loads Across a Service Territory

In many areas of the United States, where electricity industry restructuring has not yet taken place, traditional vertically integrated electricity utilities hold franchises to carry out electricity generation, transmission, distribution and retailing within specified service territories. Many utilities are now increasingly using DSM to provide network support by reducing peak loads across their service territories.

For example, the Long Island Power Authority (LIPA) has developed the LIPAedge program[38] 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.

LIPA acquired the DSM resource by communicating directly with end-use customers. The LIPAedge program was originally made available to Residential Central Air Conditioning customers and Small Business customers. However, the program is now closed to new participants because LIPA has enough air conditioner load under direct load control. Customers who signed up to the LIPAedge program received a thermostat and installation free of charge. Customers also received a one-time bonus payment of USD 25 (residential customers) or USD 50 (small commercial customers). During

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[37] A detailed case study of the Olympic Peninsula project is included in the first report from Task XV: Crossley, D.J. (2006). *Op cit*.

[38] A detailed case study of the LIPAedge program is included in the first report from Task XV: Crossley, D.J. (2006). *Op. cit.*

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.

2.4.5 Maintaining and Improving Overall System Reliability

The restructuring of the electricity industry in some areas of the United States has led to the establishment of independent system operators (ISOs) and regional transmission operators (RTOs) responsible for the operation of electricity transmission systems and, in some cases, also charged with the operation of wholesale electricity markets in geographical regions. These organisations are now routinely implementing market-based processes to acquire DSM resources to maintain and improve overall system reliability at the regional level.

For example, under the demand response programs established by the New England Independent System Operator (ISO-NE)[39], 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.

ISO-NE acquired the DSM resource by using third parties to enrol end-use customers in the various demand response programs on offer. 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 electricity retailer. 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.

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

2.4.6 Providing Ancillary Services

Historically, control area operators in the United States have relied on generation resources to provide ancillary services. Recently, however, technology and other improvements have enabled the use of certain demand-side resources to provide a range of ancillary services, such as spinning reserve and regulation to adjust any imbalances between load and generation.

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[39] A detailed case study of the ISO-NE demand response programs is included in the first report from Task XV: Crossley, D. J. (2006). *Op cit.*

The North American Electric Reliability Council (NERC) prescribes two standards that control areas must meet in order to maintain reliability, namely the Control Performance Standard (CPS) and the Disturbance Control Standard (DCS). NERC does not have any restrictions on the type or size of reserves that must be maintained in order to meet these standards. Instead, it leaves these requirements up to the Regional Reliability Councils. The NERC position, together with the February 2007 ruling by FERC (Order No 890), cleared the way for demand-side resources, distributed generation, and other non-generation resources to provide ancillary services.

In providing ancillary services, demand-side resources function similarly to a generator except that, rather than changing the level of generation output to the grid, the demand resource changes its level of consumption from the grid[40]. For example, to provide spinning reserve, the demand resource must be able to curtail a pre-assigned amount of load within (say) a 10 minute window of notification, and be able to maintain the load curtailment for up to about 30 minutes (although most spinning reserve events are completed in less than 15 minutes). Once the load is restored, it must be immediately readied for curtailment again in case another system contingency occurs.

Although it may seem likely that individual demand-side resources will have a high failure rate to curtail load on short notice, the aggregation of several smaller resources into one larger resource makes it probabilistic that the assigned response will be achieved. This characteristic potentially makes demand-side resources more reliable than conventional generation resources, where the failure of one generator can cause significant loss of ancillary services.

Many ISOs and RTOs in the United States are now developing processes to acquire demand-side resources to provide ancillary services[41]. Typically, this involves modifying the remuneration arrangements in ancillary services markets to cater for the particular characteristics of demand-side resources.

For example, the merit order price in a spinning reserve market is typically determined by summing a generation unit's offer price, opportunity cost, plus any energy consumed while providing the service (applicable to condensers which must consume energy to run the generator as a motor)[42]. For a demand-side resource, the costs incurred in shutting down (lost production etc) would be expected to be included in the offer price. However, since no cost is incurred until the resource shuts down, there would be no further cost component. Since demand resources that are assigned to provide ancillary services would not be able to participate in other markets for load reductions, it may be appropriate to include in the pricing regime for demand-side resources compensation for the cost of any such lost opportunity.

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[40] The PJM Interconnection (2004). *Demand Response as Ancillary Services Whitepaper*. Version 1. Available at: http://www.energetics.com/madri/pdfs/whitepaper_121004.pdf

[41] In May 2006, the PJM Interconnection opened its synchronized reserves and regulation markets to demand response providers.

[42] The PJM Interconnection (2004). *Op. cit.*

The Electric Reliability Council of Texas (ERCOT), allows load to supply up to half the spinning and non-spinning reserve. At present, load supplies 1100 MW of spinning reserve and 1200 MW of non-spinning reserve (the full amount allowed). Table 2.2 summarises the conditions under which the ERCOT Load Acting as a Resource (LAAR) program operates[43].

Table 2.2 ERCOT Load Acting as a Resource (LAAR) Program	
Qualified Loads	Qualified loads must have telemetry on each breaker. As of March 2006, there was 1800 MW of load registered for the ERCOT ancillary services market, including refineries, gas compressors, pumps, plastics manufacturers. ERCOT's total resources comprised 69,000 MW.
Timing	When dispatched as part of the ancillary services market. Responsive Reserve service load must be controlled by under-frequency relays and be able to be manually interrupted in 10 minutes. Non-spinning reserve must be interruptible within 30 minutes.
Metering	Qualified loads must have either an Interval Data Recorder or ERCOT polled settlement, plus telemetry on each breaker. For multiple loads less than 10 MW, calculated MW is allowed. LAAR response is included in the Qualified Scheduling Entity's Schedule Control Error (SCE).
Payment	The value of the LAAR reduction is equal to that of an increase in generation by a generating plant. Any provider of operating reserves selected through an ERCOT ancillary services market is eligible for a capacity payment, regardless of whether the demand side resource is actually curtailed.
Duration	As bid and dispatched.

[43] Kueck, J. and Kirby, B. (2006). *Spinning Reserve from Large Responsive Load.* Presentation to US Department of Energy Visualization and Controls Program Peer Review.

3. BEST PRACTICES IN EVALUATING AND ACQUIRING NETWORK-DRIVEN DSM RESOURCES

Activity 4-2 of Subtask 4 develops 'best practice' principles, procedures and methodologies for the evaluation and acquisition of network-driven DSM resources[44]. This section of the report summarises the results from Activity 4-2.

3.1 STAGES IN ACQUIRING DSM RESOURCES

The survey in Section 2 of practices in Australia, France, Spain and the United States identified a range of processes for evaluating, acquiring and implementing DSM resources to provide support for electricity networks. These processes vary depending on:

- the purpose for which the DSM resources were being acquired;
- commercial practices within the electricity network business acquiring the resources; and
- the applicable regulatory framework.

Given the variation among these factors, it is not possible to identify a single "best practice" for acquiring DSM resources to provide support for electricity networks. However, it is possible to identify the stages involved in a good DSM resource acquisition process. These stages comprise:

- assessing the need for DSM resources;
- identifying and evaluating available DSM resources;
- contacting potential providers of DSM resources;
- negotiating the provision of DSM resources; and
- acquiring and implementing the DSM resources.

3.2 ASSESSING THE NEED FOR DSM RESOURCES

The first stage in using DSM resources to provide support for electricity networks is to assess the need for the resources. The method used to carry out this needs assessment depends on the specific purpose for which the resources are required.

Projects that aim to use DSM resources to relieve specific network constraints (including projects aimed at deferring network augmentations) require information about the timing and geographical locations of those constraints that are likely to become binding over the lifetime of the project. This information can be obtained by analysing network element load profiles and modelling the likely impacts of expected future load growth.

A previous report[45] identified two methods developed in France for carrying out this type of analysis. The first method is based on a local micro-economic analysis of the

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

network. This approach offers good economic efficiency, but requires complex studies and is suitable for only a limited number of network situations. The second method is based on a macro-economic analysis of network/consumption characteristics covering a defined geographical area. This geostatistical type of analysis can be a powerful tool but the geographical localities in which DSM measures will be implemented must be properly defined. The economic efficiency of the analysis will be reduced if some of the DSM measures are applied to parts of the network which are not subject to constraints.

Using DSM resources to provide network operational and ancillary services requires information about the precise nature and timing of the services to be provided. Typically, the demand-side resources are replacing existing supply-side resources and, in these cases, such information is often readily available from the system operator.

3.3 IDENTIFYING AND EVALUATING AVAILABLE DSM RESOURCES

In making a decision to use DSM resources to provide support for electricity networks, detailed information about the available DSM resources is crucial. The type of information required again depends on the specific purpose for which the resources are required.

Projects that aim to relieve specific network constraints require detailed information on the quantity and geographical location of DSM resources, and their availability over time. Such information is usually not readily available and considerable effort may be required to obtain it. Some information about available DSM resources may be obtained from analyses of customer billing records to identify loads that may be interruptible and/or curtailable. However, detailed information is best obtained from on-the-ground customer surveys.

In the Binda Bigga DSM Project in Australia[46], a survey of residents in the communities of Binda and Bigga was carried out to identify households that had electrical room heaters and cooking stoves. Use of these appliances was causing unacceptable voltage fluctuations on a local feeder during winter evenings. The household survey identified the quantity of load that could be removed from the feeder on winter evenings by replacing the electrical appliances with gas ones.

The following information is required about a DSM resource that is used to provide network operational services:

- the quantity of the resource;
- the availability of the resource over time; and
- the extent to which the resource can be relied on (ie its "firmness").

Most DSM resources used to provide network operational services are acquired through open market transactions. The required information about a particular DSM resource is usually made available by the resource provider as part of their market bid.

[45] Crossley, D. J. (2007) *Op. cit.*

[46] A detailed case study of the Binda Bigga DSM Project is included in the first report from Task XV: Crossley, D. J. (2006). *Op cit.*

3.4 CONTACTING POTENTIAL PROVIDERS OF DSM RESOURCES

Once a decision has been made to use DSM resources to provide support for electricity networks, the first step in actually acquiring a resource is to contact potential resource providers. There are several methods that can be used to do this.

One method often used in projects that aim to relieve specific network constraints is to publicly release detailed information about the constraints and the DSM resources required (ie the results of the needs assessment). Potential DSM resource providers are then invited to submit proposals either in response to a detailed Request for Proposals or more generally in response to the publicly released information. In Australia, as noted in Sections 2.1.3 (page 5) and 2.1.4 (page 6), national and State regulatory regimes specify in detail how this must be done.

Another method for contacting potential providers of DSM resources is to actively canvass individual providers. Projects that carry out on-the-ground surveys of potential providers often also encourage identified providers to consider providing DSM resources at the same time as, or soon after, the survey is carried out. Alternatively, known customers with loads that may be interruptible or curtailable can be approached directly.

A third method for contacting potential providers is to establish an open market for DSM resources. Typically, this method is used for DSM resources that provide network operational services. In the United States, as noted in Section 2.4.5 (page 24), most Independent System Operators and Regional Transmission Operators have established markets for ancillary services that now accept bid from providers of DSM resources. The Spanish transmission system operator has established a market for interruptible loads to provide network operational services (see Section 2.3.3, page 19).

Finally, large numbers of potential DSM resource providers can be contacted by building into tariff schedules signals for end-use customers to reduce loads at particular times. The Tempo tariff in France is an example of a critical peak pricing mechanism that can be used to markedly increase electricity prices during times when the transmission system is constrained (see Section 2.2.4, page 18). Time of use and critical peak pricing is now being used routinely by many electricity utilities in the United States.

3.5 NEGOTIATING THE PROVISION OF DSM RESOURCES

Once a network operator has identified a suitable DSM resource and the resource provider has agreed to provide it, the detailed terms for the transaction must be negotiated and settled. The details of these terms are highly dependent on the nature of the resource and the specific purpose for which the resource is required.

For DSM resources that are required only intermittently, typically two types of payments are made: an availability payment for the capacity of load reduction or additional generation made available (measured in MW); and a dispatch payment for the quantity of load reduction or additional generation actually provided in response to a call (measured in MWh). These payments may be negotiated on a case by case basis, or the network operator can specify a schedule of payments through a standard offer (see Section 2.1.4, page 6). For large loads or generators, contracts with the network operator may include highly specific conditions about the availability of the resource, prior notice of calls, discretion in responding to calls, etc.

Terms for DSM resources that are provided permanently vary widely, depending on the particular circumstances. For example, in the Bind Bigga DSM Project referred to in Section 3.3 (page 28), the provided householders with 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.

3.6 ACQUIRING AND IMPLEMENTING DSM RESOURCES

Once the terms for providing a DSM resource have been agreed and settled, the network operator has to actually acquire and implement the resource. The methods for doing this are highly dependent on the nature of the resource.

For DSM resources that are provided permanently, acquisition and implementation is usually a once-only operation, eg the replacement of electrical appliances with gas ones in the Binda Bigga DSM Project.

For DSM resources that are required only intermittently, the network operator must have some method for signalling when the resource is required and the provider must have a method for providing the resource in response to the call.

The provision of the resource may be done automatically, as in the LIPAedge program that uses central control of residential and small commercial air-conditioning thermostats to achieve peak load reduction (see Section 2.4.4, page 23).

In other cases, particularly with large loads, some prior notice from the network operator may be required, and the resource provider may have some discretion specified in their contract with the network operator over whether or not to respond to the call.

Finally, in the case of time varying pricing, it is entirely up to the end-use customer to decide whether or not to respond to the price signal. In this case responses by individual end-users have a much lower level of "firmness" than other types of DSM resource. However, because this type of DSM resource is provided by a large number of individual end-users, the reliability of the aggregate load reduction may be relatively high. With experience over time, it may be possible for the network operator to forecast reasonably accurately the amount of aggregate load reduction that will be achieved in each call.

4. CONCLUSION

The survey of practices in Australia, France, Spain and the United States identified a range of processes for evaluating, acquiring and implementing DSM resources to provide support for electricity networks.

Good DSM resource acquisition processes include the following stages:

- assessing the need for DSM resources;
- identifying and evaluating available DSM resources;
- contacting potential providers of DSM resources;
- negotiating the provision of DSM resources; and
- acquiring and implementing the DSM resources.

Best practices within each of these stages are tailored to the nature of each DSM resource and to the specific purpose for which the resource is required.