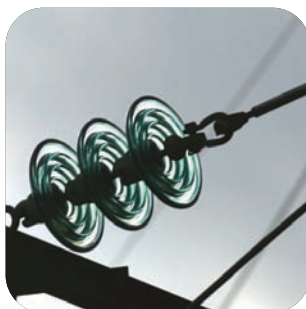


# A Scoping Study: Demand Side Measures for Small Business and Residential Customers on Ireland's Electrical System



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November 2005

Report prepared for Sustainable Energy Ireland by, KEMA Limited, in collaboration with the UK Department of Trade and Industry.

**dti**

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## **Background to this Report**

This report is based on 'A Scoping Study: Demand Side Measures on the UK Electrical System' which KEMA produced for the UK Department of Trade and Industry Technology Programme: New and Renewable Energy, which is managed by Future Energy Solutions. KEMA wishes to thank the DTI for giving their permission to use much of the original document so as to stimulate wider debate on this important issue. The views and judgements expressed in this report are those of KEMA and do not necessarily reflect those of the DTI, Future Energy Solutions, or Sustainable Energy Ireland.

## Executive Summary

This report was commissioned by Sustainable Energy Ireland to consider the opportunities for Demand Side Management in Ireland for small business and residential customers. In the context of this report Demand Side Management (DSM) has been defined as the ability to modify and control patterns of usage i.e. the ability to temporarily reduce and shift customer demand (kW), without necessarily reducing overall energy consumption (kWh). This contrasts with many international DSM programmes that may target a reduction in overall consumption as part of a wider energy efficiency initiative rather than focussing on peak demand.

Demand Side Management has a number of potential benefits to stakeholders. This includes reduced costs of electricity, increased security of supply at times of network stress, deferred network investment, and simplified outage management (particularly where there are large amounts of intermittent generation). In addition, DSM could also deliver important non financial benefits, such as carbon savings, through reduced reliance on inefficient generation plant and increased energy efficiency as customers become more aware of their usage patterns.

Despite this range of benefits there have been low rates of adoption for DSM initiatives in Ireland, particularly in the residential and small business sectors of the market. A number of factors have contributed to this low adoption rate of which the key elements identified in our research were:

- Lack of infrastructure – meters, control technology and settlements;
- Low levels of residential competition and customers ability to frequently change supplier;
- Relatively low customer demand elasticities, i.e. low changes in demand relative to price movements.

Whilst these factors present difficulties in developing small customer DSM programmes, there does appear to be more progress being made in other international markets where initiatives have been led by market participants, governments and other central bodies and organisations. Market conditions are starting to change and in particular the introduction of the All Island Market and more transparent wholesale competition may assist in the development of retail competition at the domestic level. Utilising our international experience and recognising current planned market developments we have suggested, at a high level, three potential DSM Programmes for Ireland.

- A customer initiated DSM Programme – where the customer chooses to reduce peak demand in response to price signals;
- A supplier initiated DSM Programme – where the supplier has direct control over a number of element of customers equipment or appliances, which it will operate to reduce peak demand when energy prices are high;
- A distributor initiated DSM programme – where the distributor has control over a number of customer appliances which it will operate to reduce peak demand on the network to avoid reinforcement or outages.

All of these suggested DSM schemes will need to be considered further and developed to a greater level of detail before feasible pilot schemes can be developed, all face some barriers and the business case remains to be

proven for any of these programmes to be viable as standalone private sector investments. However, to assist the development of DSM for small customers the following initiatives are recommended.

- (i) Further research into quantifying the key costs and benefits – A more detailed examination of the key costs and benefits is needed in order to establish the business case for potential programmes. This could include examination of the national benefits that will arise from such programmes and the justification for government support for some of the investment that may be required to facilitate these DSM Programmes.
- (ii) Agreement on potential solutions to the key barriers undermining DSM adoption – Removing such barriers could facilitate the adoption of DSM programmes and will also highlight any show-stoppers that preclude the adoption of any forms of DSM. This includes the need to ensure the All Island Market gives suppliers and customers the ability to predict periods of high market prices and therefore the information needed for deciding when to reduce demand.
- (iii) Investigation of smart metering benefits – A key decision on the feasibility of the customer initiated DSM programmes will be the allocation of cost for smart metering. Research is needed on the wider benefits of smart meters to help with the business case for customer initiated DSM.
- (iv) Developing a tender process to operate a pilot programme - At least one of the recommended programmes should be progressed to pilot stage with a tender for suppliers to operate the programme. Our initial assessment is that this should be the customer initiated DSM and the best place to host and monitor this trial would be in the Dundalk Sustainable Energy Zone. The choice of programme should be re-examined after the analysis performed in (i) – (iii) above.
- (v) Investigation into the feasibility of a joint incentive scheme – As an alternative to the discrete programmes suggested it may be possible to combine distributor and supplier control whereby both the distributor and the supplier gain benefit from the demand management.

A detailed description of this further research along with the tender process for the customer initiated programme is contained in the conclusions chapter of this document.

# **1 Introduction**

## **1.1 Background**

Sustainable Energy Ireland has commissioned KEMA to produce a scoping Study on Demand Side Measures on Ireland's Electrical System focusing on residential and small business customers. This builds on a report produced for the DTI looking at issues in the UK Market. In the context of this report Demand Side Management has been defined as the ability to modify and control patterns of usage i.e. the ability to temporarily reduce and shift customer demand (kW), without necessarily reducing overall energy consumption (kWh). This contrasts with many international DSM programmes that may target a reduction in overall consumption as part of a wider energy efficiency initiative rather than focussing on peak demand.

Demand Side Management has a number of potential benefits to stakeholders. This includes reduced costs of electricity, increased security of supply at times of network stress, deferred network investment, and simplified outage management (particularly where there are large amounts of intermittent generation). In addition, DSM could also deliver important non financial benefits, such as carbon savings, through reduced reliance on inefficient generation plant and increased energy efficiency as customers become more aware of their usage patterns.

Despite this range of benefits there has been a low rate of adoption for DSM initiatives in Ireland, particularly in the residential and small business sectors of the market. Whilst, there are clearly difficulties in developing appropriate DSM schemes targeted at smaller customers, there does appear to be more progress being made in some international markets. This lack of DSM could be seen as a missed opportunity for both the Irish electricity sector and the economy as a whole in terms of the wider environmental benefits DSM may deliver. However, it can also be a costly venture and an informed decision needs to be made as to whether support in this area represents a good investment for Ireland.

## **1.2 Objectives of this study**

This study will provide an international review of the use of Demand Side Management in order to consider the potential expansion of DSM in Ireland with a particular focus on the small medium enterprises (SME) and residential markets. The study will consider costs and benefits of different programmes as well as barriers to their adoption. One aspect to consider in each programme will be the potential for intermittent generation to be used in conjunction with DSM.

As this report is a scoping study it concludes with a number of recommendations as to where future research could be focused if DSM is to expand in the SME and residential sectors in Ireland.

## **1.3 Scope of Document**

This document is KEMA Limited's report on the potential for DSM on Ireland's Electrical System. The report can be seen as consisting of three main sections.

The first section is the review of Demand Side Measure in Ireland and four other liberalised regions. The regions chosen were the UK, USA, Australia and Scandinavia. As demonstrated in the later sections these regions represent a good cross section of countries with different incentives for DSM and a range of innovative programmes operating in both pilot and fully implemented format. Where relevant we have also used examples from other European countries where they provide practical lessons for Ireland. The focus of

the international review has primarily been programmes for SME and residential customers as these could provide key insights for the development of potential Ireland based schemes. These are explored more fully in chapters 2-5.

The second section provides an overview as to how residential and SME DSM programmes could operate in Ireland. The document considers three types of DSM programmes initiated by different market participants with different incentives for those seeking to influence customer demand. These are all based on programmes that have been piloted or developed in our international references, but they have been adapted to make them more suitable for the Irish market. The report will consider the high-level costs and benefits of each programme as well as the perceived barriers to adoption. The assessment of barriers highlights a mixture of generic problems to implementing DSM programmes and specific barriers associated with the Irish trading arrangements and market structures. In the context of the Ireland market this report will also consider to what degree it is feasible to make intermittent generation a part of any of the DSM programmes.

The final section of this report provides a high-level assessment of the most promising opportunities for Ireland and identifies the next steps that would be necessary to explore these opportunities further to turn them into viable schemes. This will include recommendations on how to conduct pilot programmes and how a more thorough quantification of the benefits of DSM could be undertaken.

In undertaking this Study the following forms of information have been utilised:

- KEMA's direct experience of having implemented a number of DSM programmes in international markets;
- Material already published on DSM programmes;
- Information relating to the operation of the Irish electricity market; and
- Discussions with key stakeholders in Ireland's electricity sector.

A list of the documents used as reference material for this report is contained in Appendix C.

## **1.4 Structure of the Document**

The structure of the remainder of this document is as follows:

- Section 2 describes the current Irish DSM programmes including the reasons for their limited utilisation by the SME and residential sectors;
- Section 3 describes DSM programmes in the UK;
- Section 4 describes DSM programmes in the USA;
- Section 5 describes DSM Programmes in Australia;
- Section 6 describes DSM programmes in Scandinavia;
- Sections 7 outlines potential DSM programmes for Ireland and the associated technological requirements;

- Section 8 provides a qualitative assessment of the economic and non economic costs and benefits of these programmes including identification of where further research is needed to better quantify any calculations;
- Section 9 is an assessment of the economic, sociological, technical and regulatory barriers to the adoption of DSM and solutions to overcome these barriers;
- Section 10 considers the potential for joint programmes involving DSM and DG; and
- Section 11 draws conclusions as to which DSM opportunities should be explored further, recommendations for pilot programmes and the most suitable areas to consider for future research.

In addition the following appendices are included as part of this report

- Appendix A contains a table of Irish and international programmes that have been assessed as part of this scoping study;
- Appendix B explains the calculations used for valuing the benefits from DSM;
- Appendix C is the list of references used for producing this report; and
- Appendix D is a glossary and a list of key acronyms.

## **2 Current Ireland DSM Programmes**

### **2.1 Introduction**

There are a number of formal DSM activities that already exist in the Irish Market. These are primarily run by a variety of different sections within ESB and can be seen as having a number of key aims for the programmes sponsors including:

- Reducing energy costs (allowing the use of off-peak unit);
- Increasing security of supply by minimising peak demand; and
- Provision of Ancillary Services.

Most of these programmes are aimed only at relatively low numbers of large customers due to the availability of appropriate metering equipment and administrative complexities, although some do have potential for smaller customers. This chapter analyses each of the existing DSM programmes and is divided into the organisation that is responsible for the programmes. This is structured as:

- ESB Customer Supply (and independent suppliers);
- ESB National Grid; and
- ESB Power Generation – ‘PowerGen’

In addition large customers may also manage their demand outside of formal DSM schemes. Large customers work with suppliers and tariff consultants to assess their energy requirements with a view to reducing demand or changing their profile thus providing the opportunity to reduce cost.

Whilst these schemes have been grouped into organisation responsible for running them it needs to be clear that independent suppliers play a role in most of these programmes. These are highlighted in all the relevant programmes below.

### **2.2 ESB Customer Supply**

#### **2.2.1 Winter Demand Reduction Incentive**

This is a programme operated by ESB Customer Supply for the benefits of their maximum demand business customers. It provides an incentive for customers to reduce demand during peak periods. The justification for this Programme is the cost to ESB PowerGen to supply electricity for the short winter peak period (Ref. 43).

The WDRI programme operates for 2 billing periods Nov/Dec and Jan/Feb. Under the WDRI Programme each customer’s Maximum Demand (MD) is measured for 2 hours each day from 5 to 7 PM. This is instead of the normal MD tariffs where demand during these periods is measured in the period from 8AM to 9PM. In order to participate customers need a minimum maximum demand of 30kW.

Key attractions for the customer suggested by ESB are:

- substantial savings on winter electricity costs;
- no charge for participation; and
- No penalty should demand reductions not be achieved.

ESB Customer Supply recommends a number of mechanisms for reducing demand including water and space heating, lighting and refrigeration. For these customers an important method to show a reduction in demand is utilising the standby generation during this period.

The level of saving will be dependent on the customer's current Maximum Demand, which will generally be dependent on voltage. The table below represents the Table of Demand savings for each kW that a customer reduces demand during the winter billing period.

	Nov/Dec 2004	Jan/Feb 2005
Low Voltage	€22.17	€19.37
Medium Voltage	€14.71	€15.34
High Voltage 38 kV	€15.59	€15.17
High Voltage 110 kV	€15.66	€15.80

ESB Customer Supply provides the example of the saving from a low voltage customer with a normal MD of 500kW. For the November/December period this customer is able to reduce MD between 5-7PM down to 30kW. This represent a drop of 470kW on the customer's normal charge for MD which results in a customer's saving for the Nov –Dec 2004 billing periods of  $22.17 * 470 = €10,420$ . (Ref. 43)

This scheme can lead to significant savings for customers. However, one of the areas of concern with this type of initiative is free-riders. The scheme can encourage consumers with individual peaks outside the system peaks nominated by ESB as Public Electricity Supplier (PES) to take up the scheme even if they have no intention of changing their consumption patterns (Ref. 42)

Unlike some of the other DSM programmes this does not require QH meters. However, the requirement for MD meters and reduction of at least 30kW will mean it is not applicable for most small business and residential customers.

### **2.2.2 NightSaver**

ESB Customer Supply have for many years offered a NightSaver tariff to both residential and business customers and this scheme is also offered by Independent suppliers. This offers a reduced night time rate for electricity that is less than half of the standard daytime rate. The NightSaver period runs for 9 hours between 11pm – 8am in the winter and 12pm – 9am in the summer. An example of the level of reduction is shown by ESB's Urban Domestic charges which are 13.85c/kWh during the day and just 6.16c/kWh during the NightSaver periods. Independent suppliers will match these low night time tariffs in their electricity tariffs. These charges reflects both the lower demand for electricity at night, which allows more efficient plant to be used at night and importantly the DUoS tariffs which are significantly lower during NightSaver periods. The DUoS charging periods are aligned with the NightSaver periods and in 2005 the unit charges for an Urban Domestic costs are 3.498c/kWh during the day and 0.448c/kWh at night (Ref. 50). This saving of

3c per unit used at night accounts for almost half the overall price differential that ESB Customer Supply and independent suppliers offer to customers for using night time units.

In order to be able to obtain a discounted night time rate, customers require a 2-register meter. These meters are electromechanical and a timer is used to switch between the day and night registers (Ref. 48). These meters are slightly more expensive than standard meters and customers get a higher standing charge. ESB Customer Supply estimated that customers would need to transfer just three units a day from day consumption to night time consumption to justify the higher standing charge associated with these meters as compared to the flat tariff.

When Independent suppliers commence supply to metering points at small premises, they tend to offer a tariff to reflect the existing metering arrangements. This is due to the costs of switching meters which in 2005 was 277 euros for switching to a Double Tariff meter to read day and night and a cost of 183 euros to swap a Double Tariff meter for a single tariff meter (Ref. 49). As these customers can switch to alternative suppliers instantly these costs represent a large disincentive for the supplier to change metering. Independent suppliers therefore continue with the NightSaver periods even if it does not reflect their costs of purchasing energy and can lead to them losing money on night time units supplied

A key limitation on the operation of the NightSaver programme is that all the meters are pre set with the times for cheap electricity and there is no ability to dynamically switch any of the meters. Suppliers cannot therefore use the scheme to help manage their consumption and purchases of electricity around the night time period. This is therefore a relatively crude mechanism for DSM.

## **2.3 ESB National Grid**

ESB National Grid sponsors two types of DSM programmes. The first type is focused on reducing peak demand which enhances the security of the system. The second type of programme is provision of ancillary services to ESBNG.

### **2.3.1 Winter Peak Demand Reduction Programme**

The Winter Peak Demand Reduction scheme was introduced in the winter of 2003. The aim of the scheme is to reduce peak demand between 17:00 and 19:00 hours on business days between 1 November and the 25 March. The scheme is aimed at large business and industrial customers and provides a reward for reducing consumption between these periods. This reward is in the form of a payment made by ESB National Grid to Suppliers (ESB Customer Supply and Independent Suppliers) that is then passed on to customers. A minimum criterion for customers to participate is QH metering with remote communications.

Under this scheme customers' baseline consumption is calculated from consumption patterns from the previous winter. This baseline consumption is a MW figure that will apply throughout the two hour period. Customers then need to select a Committed Level to reduce their demand which can vary between 0 MW and the baseline. This Committed Level can vary from week to week (previously monthly), but needs to be notified in advance.

Payments for reducing demand are made up of three components:

- Reliability Payments;
- Reliability Rebate (a deduction); and
- Profile Payment.

### Reliability Payments

The reliability payment is a reward for reducing your consumption reliably down to the Committed Level during the 17:00 to 19:00 period. To maximise payments under this programme customers need to set their Committed Level at a point they can realistically achieve that is just above their new consumption level they are operating to under the scheme. Any consistent gap between the Committed Level and their actual consumption level will represent an energy reduction for which they will not receive a reliability payment. In 2005/06 customer will be paid a Reliability Rate of €179/MW per hour, for each of the two hours of peak reduction. This is available for each of the 97 days that the programme operated. This is best demonstrated in the example given at the ESB National Grid Workshop (Ref 51).

Baseline	1MW
Target Load Reduction	Down to 0.4MW (Committed Level)
Committed Quantity	$1 - 0.4 = 0.6$
Reliability Payment Rate	€179/MW
Daily Reliability Payment	$0.6 * €179 * 2 = €214.8$
Winter Reliability Payment	$€214.8 * 97 = €20,835.6$

### Reliability Rebate

Reliability rebates are designed to penalise customers who do not deliver the energy reduction they have agreed as part of their Committed Level. This is set at the rate of €1790/MW per hour for 2005/06 and is applied for the full two hours on the day the customer breaches their Committed Level. However, the meter readings are averaged over each half hour and customer will only be deemed to have breached their Committed Level if this average figure for the half hour is above the Committed Level. In addition there is a tolerance of 2% of the Committed Quantity allowed.

The Reliability Rebates are subtracted from the earlier calculated Reliability Payments. Customers cannot be liable for payments to ESB National Grid under this scheme and rebate payments are limited to 5 times the daily reliability payments to encourage customers to reduce demand even if they had breached earlier in a month. An example of this calculation is given below from the WPDRS Workshop.

Committed Level	0.4MW
Actual Max Demand	0.5MW
Level of breach	0.1MW
Rebate rate	€1790/MW per hour
Rebate for the day	$0.1 * 1790 * 2 = €358$

## Profile Payment

This is an additional payment rewarding changes in energy consumption patterns over the peak period. It requires ESB National Grid to calculate an Energy Benchmark Ratio, which is the ratio of peak consumption (17:00 hours to 19:00 hours) to average off peak consumption (9:00 to 16:00 and 20:00 to 22:00 hours) based on the previous winter's data. The Energy Benchmark (the Benchmark) reflects energy consumption measured in MWh within the delivery period and is calculated daily.

The daily Profile Payment then requires the following calculations:

### 1. Daily Benchmark Energy

Benchmark Energy = (Average half hour consumption between 9:00am – 4:00pm and 8:00pm – 10:00pm) \*  
Energy Benchmark Ratio

### 2. Profile Payment

Profile Payment = (Benchmark Energy – Average half-hour consumption in MWh between 5:00pm and 7:00pm) \* Profile Payment Rate

The Profile Payment is calculated for each of the four half hours between 5pm and 7pm and the results are summed to give the total Profile Payment for the day

The Profile Payment Rates in 2005/06 are €80 euros per MWh. These payments are protected from Reliability Rebates provided a customer earns a Reliability Payment or a Profile Payment on at least 5 days of the month. An example calculation given at the WPDRS Workshop is shown below.

Average off peak consumption	1155.5 KW
Benchmark ratio	0.951 (Calculated by ESBNG)
Energy Benchmark	$1155.5 * 0.951 = 1100$ KW
Actual consumption	400 KW
Reduction from benchmark	$700 * 2 = 1,400$ KWh
Profile Payment	$1,400 * 6.3$ cents = €88.2

There were a total of 1059 customers that were eligible to take part in the WPDRS in 2004/05 and of this eligible group 22% (236) did participate. This led to an average of a 100 MW reduction each day at a total cost of €4.1m euros paid to customers and €207k to suppliers reflecting their administration costs. Customers need to choose whether to be involved in this programme or the ESB Customer Supply programme (WDRI), as they are not allowed to participate in both. In addition customers need not to be supplied using electricity produced by a Virtual Independent Power Provider (VIPPP) which disqualifies some large customers.

ESB National Grid's customer feedback found that larger customers were able to accurately monitor their performance and avoid breaching their Committed Level. Some of these customers had the help of Energy Management Systems, other were successful without. Some smaller customers did have problems trying to accurately estimate their Committed Level, but tended to improve with experience of the scheme.

Despite the success of this scheme the metering requirements and the high admin costs for each customer means that it is only really suitable for large customers.

### 2.3.2 Short Term Active Response (STAR) Programme

The STAR Programme is operated by ESB National Grid to allow large electricity customers to be interrupted and provide Ancillary Services. It commenced in 2004 and replaces the Interruptible Load Scheme that was operated by ESB over the last 20 years. The purpose of the programme is to provide very quick response to maintain system frequency in the event of a generator trip. This programme operates all year round not just for the winter peak.

Customers who participate in the STAR scheme need to have control arrangements that will allow their load to be disconnected by a low frequency relay. Typically this control equipment and the metering will cost around €9,000 and the customer needs to pay for this. However, this should be dwarfed by the potential savings as shown below. The customer is allowed to separate out interruptible from non-interruptible load, but the non-interruptible load will need to be measured separately as it will not be part of this programme.

Customers have a contract with ESB National Grid and are paid for the energy they make available for the interruption. The programme runs from 07:00-24:00 daily and the customer receives no notice of an interruption. The duration of an interruption will depend on conditions on the electrical networks but would typically last for approximately 5 minutes and customers should expect around 10-20 interruptions per annum.

In total there are 39 electricity customers that provide 55 MW of automatic load response. This includes cement works, cold storage facilities, mines, quarries and general manufacturing. The availability reward for such services is based on the level of demand reduction available, irrespective of utilisation. There are also additional payments should customer get interrupted more than 20 times per annum. The payment rate for these services in 2005 is €7.08/MWh for the energy consumed by the interruptible load during the scheme operating times. Example payments given by ESB National Grid are as follows (Ref: 46).

**Table 1 Illustrative Annual Scheme Payments 2005**

	Average Load	Approximate Annual Energy Consumption (07:00-24:00)	Annual Payment (ex. VAT) (Consumption * Payment rate €7.08 MWh)
Large Provider	16.1MW	100,000 MWh	€708,000
Medium Provider	1.9MW	12,000 MWh	€84,960
Small Provider	0.3MW	2,000 MWh	€14,160

ESB National Grid currently have all the customers they require for this programme following a competitive procurement in 2003 which gave 3 year contracts starting in 2004 and lasting till 2007. The small number of customers and the high costs of participation indicate that this programme will not attract small business or residential customers.

## 2.4 ESB Power Generation

### 2.4.1 Powersave

ESB Power Generation has for many years operated a 'Powersave' scheme which provided an incentive to ESB customers to reduce demand during peak electricity periods. This service has now been extended to include Independent Suppliers as ESB Power Generation now offers a 'back to back' contract to licensed suppliers allowing them to offer Powersave to their customers (Ref 47). This programme is separate from the WDRI or WPDRS Programmes and customers can participate in both POWERSAVE and these programmes.

Under the Powersave programme customers can receive payments if they can reduce demand by 100kW or more either by reducing consumption or running your standby generator. Suppliers will try to give at least 30 minutes notice of each Powersave period and an estimate of its duration of each interruption. Customers can then decide if they wish to reduce demand over this period.

Powersave periods typically last from 2-16 hours on Mondays to Fridays. Customers have to reduce by at least 100kW for at least 2 hours in one of three consecutive Powersave periods. Payments depend on difference between customer's electricity consumption (kWh) in the notified Powersave period and the customer's average kWh consumption incurred in the same periods on the same day of the week over the previous 4 weeks. The payments for 2005 are 63.5c per kWh reduced during peak periods<sup>1</sup> and 25.4c per kWh during other periods.

The first time these Powersave periods are called the response from customers is normally good with 60-70MW reductions being achieved. If a number of these periods are called in a reasonably short time then the amount of customers prepared to respond tends to reduce. Independent Suppliers did not seem concerned that the Powersave programme may distort their own energy purchases, but this could be due to relatively low customer numbers and the way the current settlement system operates.

As with other programmes this is only really applicable to large customers as the programme requires a 100kW reduction in demand. Customer will also need to have QH metering in order to be able to prove this reduction in demand which would exclude small customers.

## **2.5 The All Island Market**

The introduction of the All Island Market creates the possibility for greater demand side participation from two directions. Firstly, the design of the market may encourage suppliers to offer customers competitive contracts on the condition that the supplier is able to manage the customers' demand. Secondly, large customers may become participants directly in the gross pool and choose to be exposed to any market prices that exist. Both of these options are considered below.

### **2.5.1 Increased Supplier Demand Side Management**

Two of the key benefits claimed for the All Island Market in the High Level Design document were the delivery of predictable and stable trading arrangements alongside energy prices being set competitively. The competitive setting of price was based on the expectation that the gross mandatory pool would lead to bidding at marginal cost (Ref 54).

This competitive setting of prices should lead suppliers to take actions to reduce demand at high price periods so as to minimise their costs. Evidence from other Pool markets shows that innovative suppliers have predicted periods of high prices and offered competitive tariffs that require customers to reduce demand following instruction from suppliers. During non peak periods customers' electricity prices would be cheaper reflecting the lower costs suppliers face in purchasing electricity in the market at these times. Many different variations of these tariffs could exist that would require customer demand reductions for different lengths of time and with different notice periods. However, a pre-requisite to being able to offer these services is an accurate forecast of times of high prices.

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<sup>1</sup> Peak periods are 11:30-12:30 Mar-Oct and 17:00-19:00 Nov –Feb.

One market design difficulty that may reduce the incentive for suppliers to offer DSM based tariffs is the predictability of prices. The All-Island Market design currently advocates an ex-post Pool, which means that prices will not be known until after the event. This is not an insurmountable problem if these prices are predictable, but it is made more complex by the size of the participants groups that are price takers and will not therefore be active in the price-setting arrangements. The current design suggests that two key groups; some renewable generators and the Moyle interconnector may be excluded from the price-setting arrangements. This may create undue volatility as potential marginal energy is not explicitly taken account of in price-setting. The interconnector alone has a net transfer capacity of 400MW and the absence of this volume in the price setting arrangements (either when the interconnector is exporting or when it is importing) will have a significant impact on price. As a minimum interconnector volumes should be included in the price-setting arrangements which will reduce some of the volatility. However, the key issue that appears to be driving the thinking in this area is the mismatch between the gate-closure times for the new wholesale arrangements in Ireland and those currently in place in GB; it is unclear at this juncture how this issue will be dealt with and as such some potential volatility is likely to remain.

In addition to the energy price there is also considerable uncertainty about the pricing of capacity. It is agreed that there will be a capacity 'pot' that will be collected from participants over the year based on fixed and variable elements. There are currently considerable uncertainties around how this 'pot' will be divided up in different periods over the year, the amount of the 'pot' allocated to the fixed and variable elements, how these variable are allocated to each trading periods and how this 'pot' will be capped. Capacity charges could be a large element of supplier costs so it is important this is derived in a way that is predictable, which would then facilitate suppliers managing customer demand away from periods of high capacity charging.

If suppliers feel they are able to predict prices well and do develop these tariffs offerings they are likely to be targeted at large customers. Suppliers will want to see evidence of reductions in demand and for this to show up clearly in the settlement calculations. This will require interval metering. In addition it will be complex for suppliers to design these programmes and there will be costs of participation in terms of being able to receive instructions to reduce demand. These factors mean in the short term the DSM programmes are likely to be focused on larger customers.

In the longer term smaller customers may have equipment or appliances that could be controllable by suppliers with the load reductions captured in settlements. This is discussed from chapter seven onwards in this document. In this case the existence of a transparent All Island Market with variable and predictable prices will be a key pre-requisite for these programmes to be beneficial to suppliers.

### **2.5.2 Direct Demand Side Participation**

The high level design for the All Island market stated that demand side bidding would be allowed in the SEM design. However, consideration is needed as to whether the market design will suit demand side participation and the requirements placed on customers that wish to participate as direct participants in the market

The first issue on whether the design will suit demand side participation will depend on the predictability factors indicated in section 2.5.1. If customers are confident when they receive the day ahead schedule of the likelihood of being called off and expected prices (clearly this will not be firm, but a good price range should be possible) then they are more likely to participate.

The second key issue is the requirements needed to be able to participate. This issue is partly based around the complexity of the market arrangement and whether a company that does not specialise in electricity markets can understand the rules, but it is also determined by metering and infrastructure requirements for each customer. It is expected that customers will need to have QH meters in order to prove reductions in demand. However, they may also require operational SCADA equipment to receive and act on instructions, which would be an additional cost that may put participant off. One related concern is that there may be limitations on on-site generation, which many large customers rely on and would wish to run alongside participating in the Pool.

The schemes are only likely to be of interest to large customers due to the metering requirements and complexity.

## **3 Current UK DSM Programmes**

### **3.1 Introduction**

Analysis undertaken by National Grid Transco (NGT) in preparing their demand forecast suggests that there is the potential for the shedding of up to 2 GW of load at peak electricity prices should circumstance warrant. Approximately 1 GW of these potential reductions are based on the existing DSM Programmes, which are primarily aimed at large customers with Half Hour meters.

Some of these programmes are used by the small business and residential sectors of the market and others have the potential to be used at a lower consumption level, which would increase the possible size of demand reductions. This chapter examines these existing DSM programmes and is divided into three sections depending on the end objective of the DSM Programmes being considered. These are:

- Programmes designed to shift load to save energy or balancing costs;
- Programmes designed to save network costs; and
- Programmes designed to gain income from ancillary services

### **3.2 Reducing Energy and Balancing Costs**

#### **3.2.1 Night Time Heating with Dynamic Load Switching**

Wholesale electricity prices are significantly cheaper at night time and customers can therefore benefit for consuming their energy at these times with cheaper tariffs offered by all major UK suppliers. These tariffs are usually variants of Economy Seven Tariffs which provides seven cheap hours of night time electricity. Traditionally Economy Seven Tariffs were developed to support night time storage heaters, which led to an increased domestic night time load giving a more balanced use of the electricity network across the day. More recently there has been a preference for gas central heating rather than electric heating, which has meant that many customers who are on Economy Seven Tariffs no longer have a large night time load. It can be seen that lack of availability of natural gas is closely linked with customer reliance on electric space and water heating. In areas not served by gas networks, electric heating is more commonplace which merited the development of more sophisticated off-peak tariffs.

In order to be able to obtain a discounted night time rate, customers require a 2-register meter. The simplest form of this meter would be an electromechanical rotating disk type meter with Time Switches, although since the mid 1980's a Radio Teleswitch (RTS) or Radio Telemeters with a radio teleswitch internally have become more common. With the radio teleswitched meters an operating system known as the Central Teleswitch Control Unit is used to compile switching patterns for groups of meters, which are then provided to the BBC for onward transmission on Radio 4 Longwave (Ref. 1).

Initially the timing device provided both load control for any heating circuits and rate switching. Some later applications have a separate circuit where the heating load can be measured separately from the other circuits (Ref. 3), although this obviously requires corresponding revisions to household wiring. This last development is important in enabling the suppliers to separately meter and control this heating load and therefore gain more flexibility over when this electricity is taken. For example customers may be offered seven hours night time heat but these may be over a ten hour period allowing the suppliers to purchase energy economically.

In order to be useful for demand side measures there is a need for a large number of small customers to have controllable demand. It is estimated that there are around 4.5m customers with multi-rate energy tariffs. In addition there are also around 3.5m prepayment customers which also have the possibility of Economy 7 type tariffs (Ref. 3). Two problems exist for dynamic load management in the UK. One is that only around 5-10% of customers with RTS meters have sufficiently flexible contracts to allow dynamic load management. These contracts could be re-negotiated but it is unlikely in practice that the suppliers are aware of the metering arrangements at individual SME or residential premises. The more complex problem is that some meters are time of use tariff RTS Meters rather than 'double' RTS meters dedicated to heating load only. If these time of use meters are dynamically managed then the entire customer load is affected including domestic appliances etc, which may not be acceptable to the consumer. These times of use tariff meters are in the majority in England and Wales (Ref 3).

In the south of Scotland there is more dynamic switching of load and companies are using RTS to respond to weather forecasts or periods of cheap generation. The switching regimes of such RTS equipped metering systems are initiated by the incumbent supplier, irrespective of whether the customer contracts with an alternative supplier. Should the new supplier wish to sponsor (and control) their own Group Code (dynamic or otherwise) then the new supplier must gain access to an unallocated Group Code and reconfigure (or change) the relevant customer meters. Typical costs for such a meter visit would be in the region of £30. There are also smaller costs for setting up the group code and broadcasting the signals as well as making sure that customer are on contracts that allow dynamic management of load (Ref. 2). These costs combined with the inability to tie customers in to long term contracts and the complexities of some distributors requiring control of some of their codes to manage network constraints has meant that dynamic teleswitch control is not utilised extensively by most suppliers.

### **3.2.2 Utilising NETA Mechanisms**

One of the key selling points for the development of the New Electricity Trading Arrangements (NETA) was the introduction of a two-sided market where an appropriate level of supply and demand interaction would take place. It was envisaged that this interaction would take place in the forwards and futures markets and in the Balancing Mechanism, where participants could elect to offer services directly to the system operator.

#### **Forwards and Futures Markets**

The arrangements under the Pool stifled customers' ability to decide on the level of security of supply they required and forced most of them (those not supplied on Pool Price related tariffs) to accept a level of security implied by the administered Value of Lost Load. Moreover, this centrally administered treatment of security of supply effectively meant that all suppliers faced the same level of security, which it was felt was stifling incentives upon suppliers to develop innovative tariff structures with their customers. Under the NETA arrangements it was envisaged that incentives to manage risk would be sharpened and the development of a more innovative and liquid contracts market would in turn create greater incentives on suppliers to facilitate demand response.

In developing the NETA mechanism it was recognised that much of the early focus on extending explicit demand response would be on those parties with half-hourly meters, as it was thought that suppliers would initially wish to focus on those customers where the pattern of consumption could be readily observed. It was noted that as experience developed that it would be possible to extend such arrangements to the smaller customers probably by introducing half-hour meters as metering costs fell.

As expected many trading parties entered the electricity market on or around the implementation of NETA and saw the opportunity to offer risk management services to half-hourly metered customers, allowing them to play a more active role in managing their price risk. With the incentives that the NETA arrangements created the key driver for generators and suppliers was to hedge their exposure to price fluctuations both through managing their imbalance price risk and their exposure to forward markets.

A number of Consolidators<sup>2</sup> entered the market with a view to realising the potential of the demand-side. However, the arrival of these parties happened to correspond to a period when prices fell to historic lows which meant that many traditionally price responsive customers were happy to take fixed price contracts from suppliers at relatively low prices and lock these in for as long as possible thus reducing their need to proactively manage their price risk and/or contemplate active demand management strategies.

Additionally, many of the half-hourly industrial customers tended to procure energy as they would any other raw material necessary for their business. They would issue tenders and benchmark prices rather than developing demand management strategies for various portions of their load. Even some of the more innovative consumers struggled to convince their businesses that it was possible to actively manage price through management of their consumption patterns (other than through the more traditional load management tariffs discussed in section 2.3). Experience demonstrated that it was difficult to overcome this cultural barrier when prices were at low levels. This ethos, the falling prices and other external factors (such as the withdrawal from the UK of many largely American Utilities who had been offering risk and load management services and large scale supply businesses mergers) led to the withdrawal of many consolidation businesses from the market, leaving only the more traditional vertically integrated suppliers who had less of an incentive to offer innovative products.

### **Balancing Mechanism Participation**

In addition to active participation in the forwards and futures markets, provision was made for companies to actively participate in the Balancing Mechanism and compete with generator bids and offers. The Balancing Mechanism was designed to be principally a tool where the system operator would seek to balance the system in real time and would call upon bids and offers from suppliers and generators to actively manage their load in particular locations at particular times.

Participation in the Balancing Mechanism is in general voluntary with signatories to the Balancing & Settlement Code being entitled to submit offers and bids in respect of any power flows through meters for which they are deemed to be responsible. It was envisaged that NGC's role in energy balancing would diminish over time as participants became familiar with the new arrangements and as gate closure times reduced. However it was expected that NGC would continue to play a substantive role in managing constraints on the transmission system and to take actions to correct sudden deviations of supply or demand within timescales of less than an hour.

Much consideration was given at the time of NETA implementation to the role of the demand-side in this mechanism. Many participants on the demand-side commented that they would only be able to take control over part of their consumption. Moreover they commented that the rate at which their demand could change might well be greater than the rate at which their controllable consumption might vary. These factors suggested that it might be impractical for demand-side participants to submit a single Physical

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<sup>2</sup> Consolidation is a process where the partial or total outputs of a number of generators or the demand side are combined into one energy account. Because over and under-producing accounts are combined, the variations in output tend to cancel each other out, resulting in a relatively stable aggregate output.

Notification (PN) and many solutions were muted to allow those with less controllable consumption (or indeed controllable generation) to submit two notifications thus allowing them to identify the controllable portion of their load. The concept of “Quiescent Final Physical Notifications” was muted, which would allow those parties with variable consumption and or generation patterns to participate in the Balancing Mechanism.

Despite this aspiration for a two sided market in the Balancing Mechanism, in the first year of operation of NETA only 0.15% of the offers accepted by NGC have come from the demand-side (Ref. 9). There is little evidence that this low level of activity has picked up more recently and a number of reasons can be put forward for this low level of activity:

- The need for a co-operative supplier to bid into the Balancing Mechanism (BM) on behalf of the customers. Only licensed participants can bid into the BM, so a customer would need to convince a supplier of the benefit of allowing it to bid into the BM and be prepared to deal with the administration this involved. This is on top of the difficulties of the customers being able to turn down demand quickly once its bids were accepted in the BM.
- The need to bid into the market as a single BMU located in a Grid Supply Point Group rather than being allowed to aggregate load from dispersed sites across the country. NGT needs location specific load in order to utilise the demand changes particularly to overcome constraints. This makes it difficult for a group of smaller sites in different GSP Groups to reach a level at which their bids may be utilised by NGT.
- For domestic customers the settlement process relies on profiling rules which have limitations particularly the fact that they are designed for static half hourly boundaries. This could make it difficult for RTS bids to be properly settled.
- Meter splitting was included as part of the balancing and settlement code rules, which would have enabled one supplier to be able to take control of the flexible load and participate in the Balancing Mechanism. Unfortunately, many suppliers put re-openers in their supply contracts with customers which meant their existing suppliers would wish to re-negotiate the entire contract if the load and profile of demand were changed in any way.

The lack of use of the BM even by large customers and the market rules for aggregation indicates that this is unlikely to be a useful mechanism for SME or residential customers even if they had HH meters.

### **3.3 Network Initiatives**

#### **3.3.1 Transmission Network Costs**

Many suppliers operate programmes that are designed to reduce payments of Transmission Network Use of System Charges. These charges reflect the cost of installing, operating and maintaining the Transmission System (Ref. 4). The charges are split between generation and demand with the demand side paying 73% of the total. Demand Charges depend on whether a customer is HH or NHH (Non Half Hourly) metered. HH customer are charged based on their value at system peak conditions, which NGT maintain is the driver for the vast majority of transmission investment costs (Ref.5). However this also creates an opportunity for customers to manage their demand.

The demand charges for a HH customer are the average of their HH metered demand in what is defined as the triad multiplied by the current £/kW tariff. Each Triad is the three HH settlement periods of highest transmission system demand in a financial year. The settlement periods need to be between November and February and be separated from each other by at least 10 working days (Ref. 4). Suppliers and customers therefore have an incentive to reduce their demand during Triad periods resulting in lower Transmission Network Use of System (TNUoS) charges. The commercial arrangements between suppliers and customers will determine respective TNUoS exposures.

A number of suppliers offer services that include Triad management. The exact details of each programme varies, but typically involve the suppliers informing the customer of a number of HH periods that may align with national peak demand thus enabling customers to reduce their demand in those periods. The extent of this load management is significant, but the exact size is open to some debate. In the winter of 2001/02 National Grid estimated that about 800 MW of load management was occurring. However, the Energy Intensive Users Group (EIUG) put the figures as high as 1,500 MW (Ref. 5). Such demand shifts have the ability to move the timing and magnitude of national peak demand.

NHH customers are charged according to their NHH consumption from 16:00 – 19:00 each year. They consequently do not have the same incentive to reduce demand in any one peak period.

### **3.3.2 Distribution Network Investment Avoidance**

There are a number of specific instances where distributors have invested in DSM rather than investing in their infrastructure. The most famous example is the Holyhead Power Project for Holy Island located on the island of Anglesey in North West Wales. Details of this scheme are given below as a demonstration of how DSM could defer or replace expenditure on the distribution network.

In the early 1990's Manweb had the prospect of needing a new transformer in Holy Island at a cost of £850k including network provision. As an alternative to the new transformer Manweb decided to undertake a DSM Project with the aim of reducing peak demand. This Project was partly funded by the European Commission's SAVE programme as well as Manweb and cost just under £250k in total. The project achieved its aim by reducing peak demand by 808 kVA (of which 346 kVA was load growth). Further investment in plant was therefore not necessary.

The scheme included a number of different mechanisms for saving power:

- i) Two energy efficient light bulbs per household/small business sold and installed for 75p compared with a retail cost of £10.60;
- ii) Low cost insulation, hot water tank lagging and comprehensive draught proofing;
- iii) Trade in for old electrical appliances to energy efficient models; and
- iv) Free energy audits for industry and commerce and subsidies for energy saving measures.

The demand reduction represented 10% of daily peak demand and was split by the following sectors, 30% residential, 13% small business and 57% industrial/commercial customers. It is worth noting that the average costs per kVA saved was residential sector £512, small business £507 and large industrial customers £126 (Ref. 38, 39).

The lower relative cost from industrial customers suggests that these customers would be the initial place that distribution businesses would look for demand reduction. However, technology changes and efficiency programmes already undertaken by large customers may now have changed the relative costs of different DSM investments from the early 1990s. Despite the success of this programme there has not been a significant amount of DSM utilised by distributors for either large or small customers.

### **3.4 Providing Frequency Response and Reserve**

#### **3.4.1 Frequency Response**

Suppliers can provide non mandatory frequency response services. These services can be firm requiring you to shed load when required by NGT, or optional giving the participants discretion on whether the service is provided. These demand services can be initiated automatically from large customers using low frequency relays, which automatically shed load for pre-determined low frequency events. (Ref. 18)

Customers who provide these services have to be prepared to be interrupted between 10 and 30 times a year. The participants that provide these services are normally large flexible industrial load that can meet the changing demand requirements. In 2002 there was an estimate of at least 10 demand side providers of this service (Ref. 22). Despite the recent involvement of some aggregators such as Gaz de France to facilitate slightly smaller sites participating in this service there is unlikely to be any role for SMEs or residential customers due to the equipment requirement and size of load reduction needed for each participant.

#### **3.4.2 Demand Turndown**

There have so far been two trials of a new Demand Turndown Pilot Programme. These were conducted in the summer of 2004 and winter 2005. They were introduced as an alternative to NGT letting warming contracts and were aimed at large demand customers, aggregators and/or small generators. It was designed to give the demand-side a better opportunity to provide balancing services by giving them a longer lead time than the balancing mechanism provided.

In the summer trial participants needed to turndown a minimum of 100MW over a service period that ran from the summer morning peak of 09:30 to 13:30 and was split into two separate windows. The period lasted for 17 weeks and there needed to be a single contracting party and point of despatch with identified demand sites. The key difference for the winter trial was that there was only one fixed window when participants were supposed to offer to reduce demand, but with optional windows for the rest of the day

The two participants in the programmes (Npower and Gaz de France) were aggregators who in the summer had a combined maximum capacity of 99.6MW across 12 sites (the 100 MW target was relaxed). The service was instructed eight times (7 utilisation and 1 standby) over the summer period with a cost of £140k. The winter trial also failed to deliver the size of response required with the same two participants failing to get the required 100MW.

Three reasons were put forward for the lower than anticipated level of participation:

- Supply contract negotiations that coincided with Demand Turndown Trial Periods;
- Service Providers reluctant to provide a new service; and
- Operational drivers outweighing the payments from providing these services (Ref. 6)

NGT are not running a pilot again this summer and are currently considering the results. It is unlikely to be particularly useful for the SME customers as there are significant administration requirements to participate in the programme.

### **3.4.3 Fast Reserve**

To provide Fast Reserve customers need to deliver a rapid reduction in consumption after receipt of an electronic despatch instruction from NGT. The power reduction needs to start within 2 minutes of the instruction and needs to deliver in excess of 25MW/minute and be sustainable for at least 15 minutes. The size of the ramp rate and minimum block size has meant that this service has typically only been provided by a few very large customers.

NGT did a trial of small customers in 2002/03 based on small customers using water/space heating initiated by Radio Teleswitch and a small part initiated by Cyclocontrol<sup>3</sup>. Both services could only be provided during the Off-peak period when there was load to be interrupted. A contract was signed for 300 MW of Fast Reserve via Teleswitch with the potential to switch off a heating programme for a short time period of time. The Cyclocontrol worked in a similar way with interruption of heating load. The Fast Reserve still needed to meet the minimum criteria of delivering 50 MW within 2 minutes and be sustainable for 15 minutes. (Ref. 23)

The RTS programme also included staggering off peak switching to smooth rapid demand changes that would occur if all switching occurs at the same time. A contract was signed for a trial of 600MW of this service over the winter period.

The fact that NGT are no longer using small customers for these Fast Reserve services indicates that these trials were not completely successful. This may have been down to contractual issues on control of teleswitches (i.e. ownership and who has control) and the limited off-peak time in which these services were available for switching. In addition infrastructure constraints limit the ability of the market participants to schedule demand changes within short timescales.

### **3.4.4 Standing Reserve**

Standing Reserve comes from participants capable of synchronising and providing NGT's level of output for at least 20 minutes. On the Demand Side this involves reducing load when requested by NGT. There is an annual competitive auction for Standing Reserves that split the year into five seasons and work days and non working days. Providers of Standing Reserve need to be able to reduce demand by at least 3MW (this can be a set of sites), respond to instructions within twenty minutes, provide reserve for at least 2 hours and have a recovery time of no more than 20 hours. Service providers also need to be able to do this at least three times a week.

The demand side has been making a significant and growing contribution to Standing Reserve. In 2003/04 571MW of demand was contracted for standing reserve compared to 464MW for 2002/03. This represented a 29% share of the total market for Standing Reserve (Ref. 34).

Although Standing Reserve has been successful in terms of encouraging significant amounts of demand side participation the size requirements will still be too large for SME and residential customers. Whilst the level of demand side participation in the Standing Reserve markets appears impressive it should be recognised

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<sup>3</sup> Cyclocontrol is Power Frequency Communication technology. It is designed for the secure central control of a number of end point devices across a high/medium or low voltage network (Ref. 14)

that the visible demand reduction is often achieved by increasing the output of on-site embedded (standby) generation without necessarily reducing on-site demand.

## 4 American DSM Experience

In the US there are already a number of Load Management and Load Response programmes most of which have been in operation for several years. The majority of these are aimed at large customers with interval meters; however there are a number of programmes for residential and small business customers. Many of the US programmes that are designed for smaller customers are directly controlling a specific end-use such as heating or cooling. In the US load response programmes can be run by any of the following entities:

- An Independent System Operator (ISO);
- A distribution and transmission company;
- A vertically integrated utility;
- A governmental agency; and
- Independent energy services companies.

Clearly each programme operator will have different incentives and have designed their programmes accordingly. This chapter describes a number of these US programmes based on a cross section of operating entities and US States. It is focussed primarily at those applicable to small businesses and residential customers. Additional detail on each of these programmes can be found in Appendix A. As the cost, benefits and barriers vary dramatically across each programme, no attempt has been made to summarise these variables. Details, where publicly available, are contained in Appendix A with relevant examples to the UK market drawn out explicitly in chapters 8 and 9.

### 4.1 Introduction

The following US Load Response/ Load Management programmes were reviewed in detail for this study:

- Pennsylvania, New Jersey and Maryland (PJM) Load Response Programme;
- Austin Energy Power Partner Programme;
- California Public Utilities Commission Statewide Pricing Pilot;
- ISO New England's Load Response Programme;
- Long Island Power Authority LIPAedge Programme;
- California Public Utilities Commission Enhanced Automation Initiative; and
- Utah Power's (PacificCorps/ Scottish Power) Cool Keeper.

These programmes were organised by ISO's such as the PJM and ISO New England Programmes, State agencies such as the California Public Utilities Commission and by independent energy services companies such as Utah Power's Cool Keeper Programme.

An Overview of the features of each programme is provided in Table 4.1.

**Table 4-1 US Demand Side Programmes Reviewed for this Study**

<b>Programme Name</b>	<b>Sponsor</b>	<b>Type of Customer</b>	<b>Type of Programme</b>	<b>Role of other parties</b>
PJM Load Response Programme	PJM (ISO)	Mostly large customers	Price responsive – day ahead Real time price option Emergency Programmes	Marketed by distribution companies, suppliers and aggregators
Austin Energy Power Partners Programme	Municipal Utility	Residential and Small Business	Load control via smart thermostat Initiated via radio signal	HVAC (heating ventilation and air conditioning ) contractors used for installation
California state-wide Pricing Pilot	California Public Utility Commission	Residential and Small Business	Price responsive – 3-4 time periods plus critical peak pricing	Marketed by the distribution utilities
ISO New England Load Response Programmes	ISO New England	Large customers for the most part Smaller customers in Group Programme	Individual reliability Programme Group Reliability Programme which was done via a bid Real time pricing option	Marketed by distribution companies, suppliers and aggregators
Long Island Power LIPAedge	Long Island Power Authority ( Distribution Company)	Residential and small business	Load control via smart thermostat Initiated via wireless	
CA Enhanced Automation Project	California Public Utility Commission	Small and Medium Businesses	Incentive paid to save energy/ shift load by using building control systems	Sponsored by the utilities, marketed by an energy services company
Utah Power’s Cool Keeper	Utah Power	Residential and small business	Constrained area- Programme controls AC load via thermostat	Independent energy services company runs Programme and is paid on performance basis

## 4.2 Aims of the Programmes

The objectives of the DSM programmes reviewed fell into the following categories:

- Programmes that reduce a specific end use load such as air conditioning;
- Programmes that are truly price responsive – customers receive a real time or time of use price;
- Emergency programmes; and
- Programmes designed to defer system upgrades.

Programmes that reduce a certain end-use are most common in the US for smaller customers. The main area of control is central air conditioning of small business and residential customers. There are also programmes for smaller commercial customers where load is initiated by using the building control systems such as the heating ventilation and air-conditioning (HVAC) control, refrigeration controls and lighting controls. Residential water heating and space heating is also initiated in systems that are winter peaking or dual peaking. These types of programmes are done at an overall system operator level, an individual utility level and on a targeted distribution feeder.

The larger price responsive programmes in the US are generally those for industrial and commercial customers where:

- There are real time pricing tariffs in States such as Georgia;
- The customer already has an interval meter; and
- ISO's such as PJM, New York (NY) and New England (NE) have constraints in parts of their systems.

Price responsive programmes for smaller customers have generally been large scale pilot programmes such as the California Public Utilities Commission (CPUC) State-side Pricing Programme and the Puget Sound Programme. Impressive results were seen particularly in the California Programme, but this was at a high cost per customer.

Emergency programmes are used typically at the ISO or control area level on days of extremely high prices. The NE, NY and PJM ISO's all have programmes of this nature. In this case customers may reduce demand and utilise their standby generation on these days and get paid the market price for their power. They are generally notified either a day ahead of time or in some Programmes with 1-2 hours notification. Some of these programmes are voluntary with no penalties, others do have penalties.

Finally there are a number of Programmes that were designed to defer distribution upgrades. Some of these are based on reducing load on a given feeder or control area such as Utah Power and one of the ISO NE programmes. Others such as the PJM Programme were designed at the overall system operator level to provide relief through out an entire area.

### **4.3 Range of Technologies used**

Three major types of technologies were used in the Programmes that were reviewed in the US. These were:

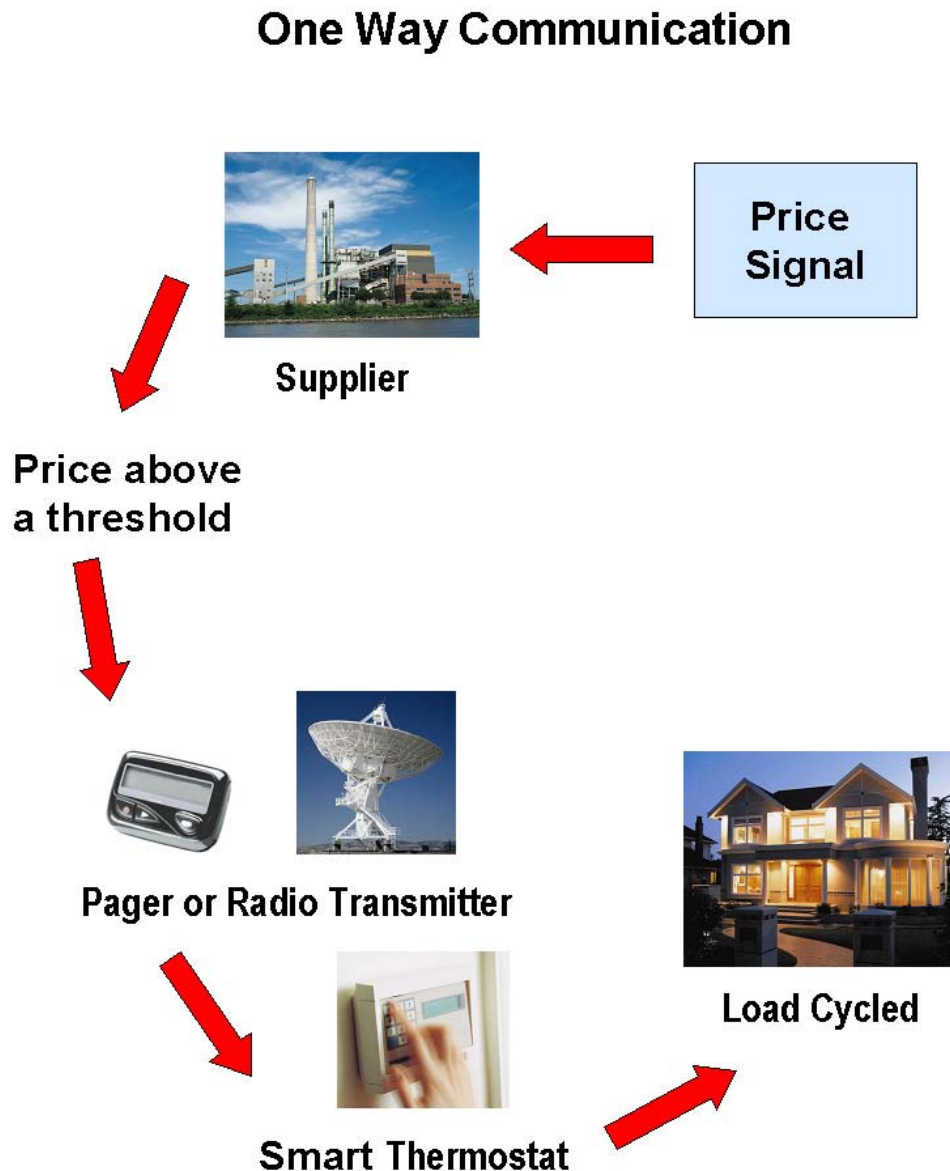
#### **Control technologies**

The direct load control programmes that control air-conditioning or other end uses can include: smart devices such as smart thermostats, switches on devices such as water heaters and controls of systems via the internet. These controls generally must interact with the communications technology. In the small customer price responsive programmes, customers were in some cases given controls such as thermostats to assist them with managing their loads. In the price responsive programme that involved large customers, such as the PJM and New England ISO Programmes, customers generally used their own building control systems such as HVAC and lighting controls to shed load. In the California State-wide Pricing Pilot a small subset of customers were enabled with automated demand response system that included a two way house meter and wireless internet gateway that were connected to smart thermostats and controls for other appliances such as water heating and pool pump.

## Communication technologies

The communications technologies used in these programmes included the internet, paging systems, and even FM radio control. An example is provided in Figure 4.1 of a one-way communication system. In the direct control situations the communication was with the control device. In price responsive programmes the communication was used to provide the price signals to the entity that was controlling the load. Many of the programmes for smaller customers also provided educational materials on how to manage loads.

Figure 4-1



## Metering Technology

Many of the load control only programmes did not require additional metering as the device that controls the load is accessed via pager, radio control or the internet. All of the price responsive programmes reviewed did require some type of either time of use, real time or other types of advanced metering. In some cases

such as the NE ISO Programme, some of the participating large customers did have meters that were capable of being able to collect load data hourly, but as their standard rates were not based on hourly prices, there was no communication device to give the customer their load in real time. In these cases additional software and communication was provided to the customer so that they were able to view their loads real time.

Also some of the utilities in the ISO NE region provided enhanced metering services on a fee for service basis as well as the software that enables customers to view their load. Massachusetts Electric, a subsidiary of National Grid USA, provide enhanced metering for a one time fee of \$132-270 based on the type of existing metering and software for a onetime fee of \$321.

#### **4.4 Example 1: Case Study California State-wide Pricing Program**

This section provides a summary of the California Public Utilities Commission (CPUC) State-wide Pricing Programme. This Programme was a very comprehensive pilot that started in 2003 to evaluate the potential peak demand reduction benefits of time-based rates and continues to this day. The main objectives of the Programme are:

- To enhance system reliability;
- To reduce power purchases and consumer costs; and
- To protect the environment.

Some of the basic enrolment requirements include: the bill payer must occupy the home for residential customers (to avoid renting/owner complications over electricity decisions); customers can not be planning to move locations within the next six months; and customers are required to provide a land-based phone number where they could be reached for notifications of a "Shift & Save" event (where super peak prices would be in effect if a CAL ISO emergency was declared). A maximum of 90 hours per year anytime during the noon-6 p.m. peak for Commercial & Industrial customers; and a max of 15 days per year for residential customers could be declared a "super peak" time where prices were set as high as 75 cents per kWh to deter or encourage usage shifting.

All customers targeted receive a free advanced digital electric meter designed to facilitate energy information and management. Website portals were established for enrolled customers through their utility websites to check their usage online, using a password-protected login. Residential and commercial customers are given a free Honeywell programmable thermostat. Adjustments to thermostats are encouraged by providing tips on pre-cooling and pre-settings.

The initial sample was designed to be 2,500 random customers across residential and commercial customers in all of the three participating Investor Owned Utilities.

The pilot pricing was designed as an "opt-out" programme, but required an enrolment centre to confirm enrolment in writing. Each enrolled customer (the metered accounts were the unit of analysis for all customers) was randomly assigned into one of the following tariffs: Time of Use (with a peak and off-peak price), Critical Peak Pricing (with a peak, off-peak, and "super peak" price – invoked a limited number of days per year for residential customers and an limited number of hours per year for commercial customers when a load emergency was declared by the CAL ISO), or an "Information Only" group where they received all programme information with no rate change.

Taking into account the tariff (Time of Use, Critical Peak Pricing (fixed and variable versions), rate (summer vs. winter peaking areas), customer class (residential vs. C&I) and service territory), there were 32 permutations of customer types and charges assessed within the pilot.

Peak load reductions ranged from 12 % to 40 % of baseline peak usage for different customer groups. The level of reduction was a function of the rate, weather, types of appliances and availability and use of demand response measures. This programme had a very comprehensive evaluation plan.

The Pilot demonstrated that residential and small to medium C&I customers understand and overwhelmingly prefer dynamic rates to existing tiered rates. Sending dynamic prices to residential customers led to average peak savings of 14% and bill savings of \$60 per year. This has been an expensive programme with an overall cost of approximately \$20 Million. (Ref. 32)

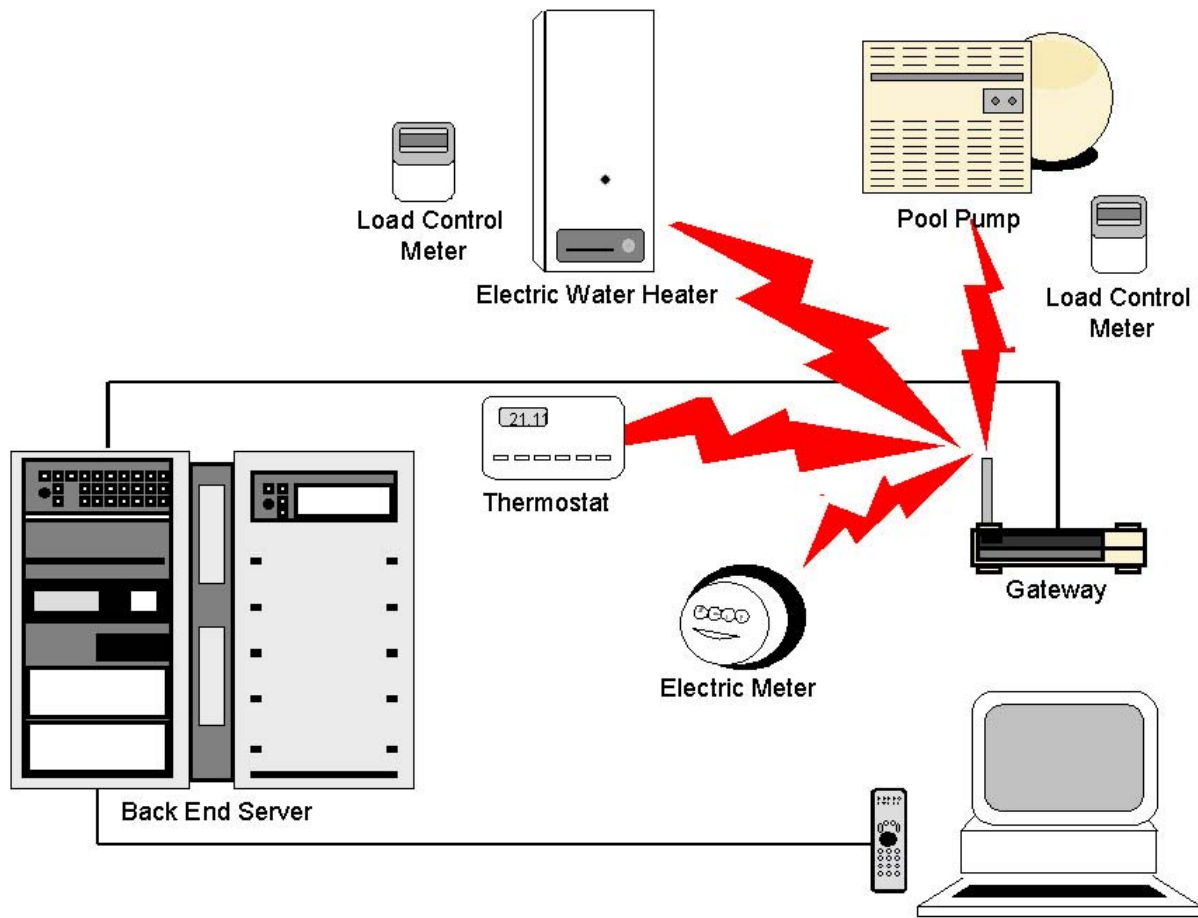
The Programme had a substantial educational component. Customers received tips on how to reduce use and were sent monthly e-mail alerts and bill inserts. The free thermostat provided for additional comfort as well as cost savings.

Small subsets of participants were equipped with advanced demand response technology which included:

- Two way communicating whole house meter;
- Wireless internet gateway and cable modem;
- Smart Thermostats;
- Load control and monitoring devices; and
- Web –enabled user interface and data management software

This configuration is shown in Figure 4.2

**Figure 4-2 Overview of Automated Demand Response System**



These customers could view real time interval demand and trends in historical consumption and had the ability to set climate control and pool run-time preferences. These customers saved up to 18 % more energy than other pilot customers who did not have the equipment. On super peak days they used 26 % less peak energy than other pilot customers. (Ref. 31)

#### **4.5 Example 2: Case study Austin Energy Power Partners**

This section describes the Austin Energy Power Partners programme. Austin Energy is a municipal utility located in Austin Texas. This Programme uses programmable thermostats to cycle air-conditioning load. Peak load reduction is the major objective.

Secondary objectives are to:

- Broaden the utility's portfolio of rate options;
- Obtain compensation as balancing energy market resource; and.
- Encourage use of programmable thermostats.

The air-conditioning systems were cycled on a 33 percent duty cycle (10 minutes out of every 30) by a radio signal. The Programme is open to residential and small commercial customers with a central air-conditioning (CAC) load of 10 tons or less. Customers were given a free Honeywell Superstat™ programmable thermostat. Customers were also given free CAC checks to test the compatibility of the thermostat. The value of the thermostat and installation is \$200- 300.

To date over 30,000 customers have participated in the Programme and the Programme is cost-effective using the benefit cost test that is used by Austin Energy. The estimate Programme savings are about 1 KW per customer at time of control compared to average consumption of around 5kW. This is a good example of a large scale control Programme that can control load effectively without using advanced metering.

## 5 Scandinavian DSM Experience

This chapter provides a summary of the Scandinavian programmes that were reviewed for this study. In parts of Scandinavia there is already wide-scale advanced metering, which removes some of the barriers to these types of programmes. Times of use rates are also more common in Scandinavia than in the United States, particularly for electrically heated homes.

### 5.1 Introduction

The following programmes were reviewed for this study:

- 1) Skanska Energi's Critical Peak Pricing Programme;
- 2) Vattenfall's Demand Response Programme;
- 3) Danish Pilot Project – Demand Response in Electrically Heated Homes;
- 4) Norwegian Pilot – DSM in Oslo; and
- 5) Norwegian Pilot- New technology for controlling power loads in Oslo.

These programmes are a mix of price responsive, load control and energy efficiency. The price responsive programmes provide examples of the possible programme options if advanced metering were more available. All programmes reviewed are summarized in Table 5-1.

**Table 5-1 Scandinavian Programmes Reviewed**

Programme Name	Sponsor	Type of Customer	Type of Programme	Technology used
<b>Critical Peak Pricing</b>	Skansk Energi	Large Business Customers	Critical Peak Pricing for 40 hours per year	Use of hourly meters.  Software used to notify customers
<b>Demand Response Pilot</b>	Vattenfall	Residential electrically heated homes and small business	Real time spot market based pilot	Use of Hourly meters  Building automation systems used
<b>Danish Pilot Project</b>	Elkraft, Eltra, Seas, Energy Piano	Residential space heat customers	Automatic Demand Response	Customer can control system via the internet  Mobile phone network used for control and daily remote meter reading
<b>Implementation of DSM in Oslo</b>	Viken Nett, and the Norwegian Research Council	DSM for commercial, multi-family and residential customers. Load control, energy efficiency, smart house applications	Load control, energy efficiency, smart house applications  Objective was grid deferral	Remote load control was used in some cases  Ebox based on internet and wireless radio communication was also used

<b>Load control in Oslo</b>	Viken Nett	Remote load control for Commercial customers	Remote load control	Controls loads with backup systems such as electric boilers  Control is done automatically via radio communication and the internet
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## 5.2 Aims of the Programmes

The primary objectives of these programmes are:

- To reduce peak demand by providing time differentiated price signals to customers of all classes;
- Creating competition in the supply of control services;
- Reducing the demand for new investment in the grid; and
- Testing the load response of these customers to be better able to predict demand response in the future.

These programmes will provide a basis for future programmes as hourly metering becomes more common.

## 5.3 Range of Technologies used

### Communications and Control Technologies

These programmes included both one-way and two-way communication systems. For example the Ebox/ Smart house component of the DSM in Oslo project was implemented in 17 row houses. These homes were able to control their water heating and heating loads via the Internet. The Ebox contains a data processor, thermostat, radio receiver, on/off switch, a clock and a display. The load control can be based on the temperature of the room or the time. There is also an override button so that the customer can override the system. (Ref. 28) The Le Key system used in the Norwegian Load Control Pilot uses a wireless radio system for its two way communication.

### Metering

The price responsive programmes such as the Critical Peak Pricing programme and the Vattenfall Demand Response Pilot include more complex metering systems. In the Danish Pilot Programme described below the mobile phone system was used for daily meter reading.

### Energy Efficiency and Load Management Technologies

In the Oslo DSM project traditional energy efficiency measures were installed in some of the participating commercial customers. These included:

- Control of heating
- Lighting Controls

- Lighting replacement
- EMS systems; and
- Use of building automation systems to control loads.

#### **5.4 Example 1: Case Study Danish Pilot Programme**

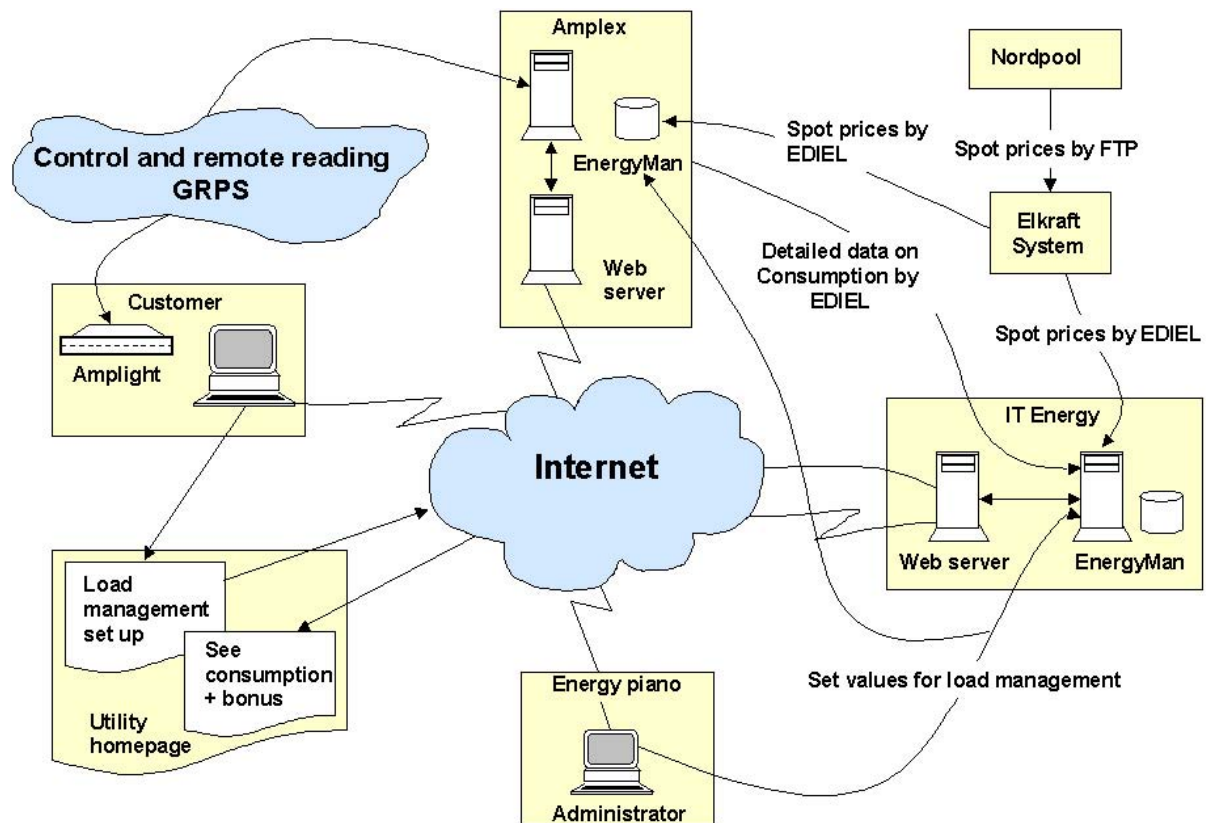
This section describes the Danish Pilot Programme. This Programme was sponsored by Elkraft System, Eltra, Seas, and Energy Piano; Seas is the network company. Elkraft and Elatra are TSO's. Energy Piano managed the actual implementation of the pilot. (Ref 28)

The pilot programme was automatic price driven control of electric heating in 25 houses. Specific parameters included:

- Consumption must be > 16,000 kWh/yr;
- Individual setting controls the duration of each interruption;
- Price driven control of 5 zones of electric heating;
- 3 price levels;
- 2 time periods (morning/afternoon);
- The ability to override control; and
- 100 hours of high prices in this winter (guaranteed).

The goal was a 5 kW peak demand reduction per household on a cold day. A schematic of the IT configuration is provided in Figure 5.1.

**Figure 5-1 Overview of the Danish Pilot**



NordPool provides spot price information in real time that is loaded in real time to software the customers can access to make decisions about shifting or reducing load. The utility facilitates the meters and the platform for network data and settles with NordPool.

## 5.5 Example 2: Oslo DSM

The primary objective of this project was to avoid / defer planned grid reinforcement with the use of DSM actions. The secondary objective was to increase knowledge of customer behaviour. This project had three main components:

- an experiment in a multi-family complex to control electric water boiler using smart house technology;
- an experiment in a row of 17 houses to control space and water heating via smart house technology; and
- An experiment with commercial customers to reduce load and shift load. (Ref 28).

Grid capacity was forecast with and without the DSM and the costs of implementing DSM were compared to the reinforcement of the grid. Initial estimates indicated that DSM could defer investment cost effectively.

Smart house concepts were used in the two residential experiments. In the first experiment the equipment consisted of a load controller, a transmitter, and relays in the fuse box of each apartment building. The network company was able to control the water heater loads with no impact on hot water consumption. In the second experiment an Ebox was used to control water heating and heating and customers could set the controls via the Internet. This was a two way system with a wireless radio to control the load. The Ebox contains a data processor, a thermostat, a radio receiver, a switch and a display. The combined residential experiments cut peak usage by 15 %.

The commercial programme used audits to identify opportunities in target buildings. The measures that were installed include both efficiency improvements and the use of enhanced automation to control loads. It was estimated that these measure would save 28 % of peak usage by 2003.

The overall cost was estimated to be 73.9 Euros/ kW. This compares to 110 Euros/ kW for grid reinforcement in the area, which suggests that the network operator faced reinforcement constraints.

## **6 Australian DSM Experience**

### **6.1 Introduction**

On a national level, Australia recently developed a framework for more energy efficiency and has performed specific research and stakeholder outreach geared towards furthering demand response. The Australian Ministerial Council on Energy (MCE) has endorsed a National Framework for Energy Efficiency (NFEE) that consists of a comprehensive package of measures covering the residential, commercial and industrial sectors. This framework is designed to overcome the barriers and challenges that prevent the market delivering the actual economic potential of energy efficiency. Extensive stakeholder consultations were used to inform the development of the Framework. These measures constitute the first stage of NFEE and will be implemented from 2005 to 2007. (Ref. 33)

In addition, Australia is part of multi-national project developing methods for utilising demand-side management (DSM) and demand response resources as alternatives to augmenting electricity networks by building 'poles and wires'. The project is identifying and developing a wide range of DSM tools and measures which can be used to relieve network constraints, including energy efficiency, demand response, fuel switching, distributed generation and power factor correction.

There are also local efforts to amend energy market regulatory frameworks to incentivise and allow energy retailers and distributors to recover the full cost of implemented energy efficiency and demand-side management measures and to treat those measures on an equivalent basis with supply or grid reinforcement options. (Ref. 32).

The Australian programmes that were reviewed for this study were:

- Bairnsdale Power Station;
- Tahmoor Fuel Substitution Project;
- Castle Hill Demand Management Project;
- Baulkham Hills Substation Deferral;
- Western Sydney Interruptible Air Conditioning Rebate Trial; and
- Sydney CBD Curtailment Project.

These programmes include interruptible programmes, fuel-switching programmes, air conditioning incentives and distributed generation.

A summary of these programmes is provided in Table 6-1.

**Table 6-1 Overview of Australian Programmes Reviewed**

<b>Programme Name</b>	<b>Sponsor</b>	<b>Type of Customer</b>	<b>Programme Type</b>	<b>Role of Other Parties</b>
<b>Bairnesdale Power Station</b>	Duke Energy	Distributed Generation	DG installed to provide network support	TXU runs network
<b>Tahmoor Fuel Substitution</b>	Integral Energy	Residential	Fuel switching from electric to gas for cooking and space heat	
<b>Castle Hill Demand Management</b>	Integral Energy	Large customers	Used to defer distribution upgrades Includes interruptible loads DG, AC cycling and upgraded lighting, HVAC and power factor correction	Programme is run by the Department of Energy, Utilities and Sustainability
<b>Baulkham Hills Substation Deferral</b>	Integral Energy	1 large industrial Customer	Interruptible rate Used to defer distribution upgrade	
<b>Western Sydney Interruptible AC Rebate Trial</b>	Integral Energy	Residential customers	Payment to shed AC load via pager and ripple control	
<b>Sydney CBD Demand Curtailment Project</b>	Energy Australia	Commercial and Industrial	Use of remote control AC and other building systems to reduce demand	

## **6.2 Aims of the Programmes**

The major objectives of these programmes were to:

- Reduce load at time of system peak;
- Defer distribution system upgrades;
- Increase system reliability; and
- Test new technologies and systems.

The Australian programmes are good examples of the various methods that can be used to defer distribution system upgrades including installing a distributed generation system in a constrained area,

switching fuel from electric to gas as well as using more conventional methods such as controlling air conditioning and lighting systems.

### **6.3 Range of Technologies Used**

The technologies used in these programmes are quite varied and include:

- Fuel switching from electric to gas;
- Use of ripple control and pagers to control air conditioning through the thermostat;
- Use of building systems such as lighting and air conditioning to respond to prices or to shed load;
- Distributed generation specifically for network support;
- Interruptible rates;
- Use of customer owned standby generation, when needed; and
- Energy efficiency measures such as upgrades of air conditioning systems, lighting systems and power factor correction.

These programmes are for the most part focused on using more traditional load management and energy efficiency measures to reduce load, rather than using price responsiveness. For that reason metering played less of a central role in these programmes than in the Scandinavian studies. The Castle Hill demand management programme is a good example of using energy efficiency, load control, interruptible rates and standby generation in combination to reduce overall load in a congested area.

### **6.4 Example 1: Case Study Tahmoor Fuel Substitution Project**

The Tahmoor Fuel Substitution Programme was utilised in the region to the south west of Sydney. This programme was sponsored by Integral Energy and aimed to defer augmentation of the distribution network by controlling growth in the winter evening peak demand and managing a low load factor.

The key mechanism for achieving this peak load reduction was to persuade residential customers to use an alternative fuel, bottled gas, for cooking and space heating. To encourage this change Integral Energy arranged for the installation of bottled gas and appliances and gave subsidies of \$150 for customers' installation of bottled gas plus \$150 per bottled gas appliance.

The programme succeeded to some extent in flattening load growth, but take-up was much less than had been hoped. The key barrier was the hints by the State's primary gas distributor about extending reticulated natural gas to the area. Even though these plans didn't materialize, the possibility of natural gas prevented customers from making decisions in favour of Integral's bottled gas solution.

In the end approximately 100 customers participated in the Programme at a cost of \$40,000 in incentives and \$18,000 in administration costs. Due to the low take up of customers the programme only deferred the supply-side system upgrades for a shorter period of time with augmentation eventually needed in 2003/04 (Ref. 41).

## 6.5 Example 2: Case Study Castle Hill Demand Management Project

The Castle Hill Demand Management Project was sponsored by Integral Energy who provided funding to the NSW Sustainable Energy Development Authority (now the NSW Department of Energy, Utilities, and Sustainability (DEUS)) to conduct a demand management programme focused on the commercial sector. The Programme utilises a number of mechanism for reducing demand this includes:

- Interruptible loads;
- Existing standby generators;
- Installation of high efficiency air conditioning (and the upgrading of existing air conditioning systems); and
- Installation of efficient lighting and power factor correction equipment in new and replacement applications.

DEUS use face-to-face meetings and on-site energy audits to identify opportunities in buildings. (Ref 31, 41)

The programme is needed due to increasing penetration and use of air conditioners in the Castle Hill commercial centre and surrounding residential areas in western Sydney, which will result in summer peak loads exceeding system capability. Despite the high levels of load growth, initial assessments indicated that sufficient demand could be curtailed to defer the installation of additional network infrastructure. The programme needed to deliver reductions in summer peak demand of 1 MVA initially, and further reductions of 0.5 MVA per annum for the following 2 years to defer the supply-side augmentations that were otherwise anticipated (Ref . 41).

This programme started in 2003 and costs to date are approximately \$300,000. It may be expanded to smaller commercial customers over time. The programme is expected to defer supply-side system upgrades until November 2009 and is an example of using multiple technologies to reduce load in a congested area without using more complex metering.

## **7 Potential DSM Programmes for Small Customers in Ireland**

### **7.1 Introduction**

Whilst there are a number of DSM programmes currently operating in Ireland these are primarily for large customers who can demonstrate their response with appropriate metering. With the exception of the Nightsaver programme there is little being done to encourage small businesses and residential customers to change the way they use electricity and share any benefits of lower energy costs or payment for reducing consumption.

This chapter outlines three possible programmes for smaller customers based on models that have been used overseas. Each of the potential programmes is initiated by different participants and has different but complementary objectives. All of the schemes are based around energy management for the direct benefit of the controller rather than provision of ancillary services to ESB National Grid.

The three suggested programmes are:

- Customer initiated DSM;
- Supplier initiated DSM; and
- Distributor initiated DSM

The section below outlines a high level structure including the basis of the programme, objectives of the programme and how it could operate. Clearly a far more detailed analysis would be needed before starting any pilot programmes, but this chapter provides an overview of what one variant of the programmes would look like and the pre-requisites for the programme to operate.

### **7.2 Customer Initiated DSM**

The first potential programme is based on the Pilot programme from California and Sweden and the French Tempo Tariff<sup>4</sup>. This will be a peak pricing programme designed to encourage participants to reduce their consumption at times of high prices. It will require all customers to have HH meters and be able to receive pricing information to enable them to change their consumption patterns. A supplier will need to offer tariffs to incentivise customers to reduce demand, but the actual demand reduction will be determined by customer action.

The exact details of what the customer tariffs may look like would need to be decided by participants, but a sensible structure and one that is assumed in the rest of this analysis is:

- Low standard rate tariff (in comparison with normal rates):
- Higher peak time tariff (from 14:00 to 19:00); and
- Critical time periods with very high prices potentially capped at 75c/KWh

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<sup>4</sup> The Tempo tariff option was a pilot and then a tariff option offered and taken up by about 300,000 French consumers by 2004. This divides the year into 300 blue days (least expensive), 43 white days (medium price) and 22 red days (highest price) and into two fixed period of day and night. Customers have meters that record these 6 time period with a box that can indicate the colour of the next day (Ref. 28).

The purpose of the higher peak price tariff would be to encourage residential or small business customers to routinely change the time they undertake various activities. This would encourage customers to get into the habit of setting appliances or undertaking energy intensive tasks at non peak times, but would not be quite as restrictive as the Nightsaver type tariffs that require the use only at night times. This would allow activities to be re-scheduled during the day. The higher peak tariffs would then be notified to the customer nearer to the time they arise. For the majority of customer this would be mainly on-line but could be sent to a few customers via a phone call, text or fax. It would be necessary for customers to sign up for 12 month periods as the majority of higher prices will generally be in the winter season.

The purpose of the critical time periods is to reduce demand during the few periods of absolute peak demand and peak prices. This should allow suppliers to reduce their purchase costs for electricity and pass this on to customers with lower tariffs during other parts of the year. This can be done by persuading customers to reduce consumption by charging high prices. There may be an issue on how far in advance the suppliers know of high prices and therefore when it would be able to give the right pricing signals. The new All Island Market is planning to have a day-ahead schedule that will allow suppliers to have a good view as to expected prices early on (4pm previous day) and therefore gives them the ability to provide customers with pricing signals to reduce demand.

To allow customers to respond to the critical time period they would need to be warned in advance of peak price periods. It is suggested that these notice periods for critical peak prices should initially be 24 hours so as to allow sufficient time for customer actions and for different communication methods to be used as not all customers may have on-line access to signals. Customers could be given the choice of three communications methods (Internet, text message, and phone) to receive information about these critical peak prices. During the pilot it may be possible to reduce this notice period to allow customers to respond to short term price increases as they happen in the wholesale market.

If customers are taking action to reduce demand then the key infrastructure requirements to capture this reduction is a QH 'smart meter'. As a minimum it should have the following functionality:

- The ability to record and store Quarter Hour consumption;
- The ability to display the information in a useful format for customers;
- Ability to receive cost signals from suppliers; and
- Small enough to be installed in an accessible place.

In addition to a smart meter some form of information device would be needed to allow customer to interpret what their consumption data means. As well as current information on prices customers would also receive detailed monthly bills that would show a breakdown of the costs they have incurred over the last month. These would reinforce the message for customers about how much energy they were using and where the key costs were being incurred, which should encourage them to change their time of use of electricity. In an ideal situation the customer would also have control over some key variables that would affect consumption e.g. remote control of temperature for those with electric heating.

### **7.3 Supplier Initiated DSM**

Under this programme suppliers would have control over some key customer appliances with the ability to reduce demand. Some analysis is needed over whether the programme could operate with conventional 2 rate meters or whether accurate settlement would require QH meters.

This programme would be based on those that exist in Austin, Texas and New England. One difficulty in trying to produce comparable programmes to the US is that they are normally based around suppliers controlling and cycling air conditioning load, or swimming pool pumps, neither of which is a major part of Ireland's peak demand. The Irish equivalent (heating and water load) is not always switched on at peak times so the option of decreasing this load is not available. However, Ireland is starting to see an increase in air conditioning for many small businesses and there may also be other appliances such as refrigeration that are controllable. This newer controllable load combined with the traditional storage heating and water heating may create an opportunity for suppliers to operate DSM and control customer load.

The key benefit for the supplier would be the ability to reduce demand during times of high prices and therefore save energy purchasing costs. These reduced costs should be passed on to customers in the form of more competitive tariffs in order to encourage them to allow their load to be managed.

The way this programme would work is that the supplier would have control over a number of appliances or circuits in the house. It would be important that these were isolated circuits or appliances as customers would not consent to all electrical appliances being switched off. Such flexible load would need to be metered separately if to minimise cost it was decided to try and use QH meters. This would be made more complex by the customer having the ability to over-ride suppliers' instructions for load control. The settlement process would need to be adjusted to find some way of modelling the controllable demand and ensure the supplier was rewarded for reducing consumption in a particular QH.

### **7.4 Distributor Initiated DSM**

The third programme is distributor led demand reduction recognising the potential savings from avoided or deferred network reinforcement if they are able to reduce peak demand to remove the problem. This is consistent with the EU Directive on end use efficiency that recognises the need to increase the opportunities for electricity distribution companies to 'choose demand management instead of supply and distribution system investments as a means to meet expected increased demand.' (Ref. 25)

The mechanisms for operation will be similar to those used for supplier initiated DSM. Distributors could have contracts with consumers that enable them to take control of some load. As with supplier initiated DSM, in the case of residential customers this is likely to be storage and water heating as well as some appliances such as refrigerators. A difficult issue may be in persuading enough customers on one distribution feeder to sign up to a demand reduction scheme.

The key difference from a customer perspective between supplier control and distributor control demand response will be the level and timing of interruptions may be far less frequent as there may be few occasions when the demand exceeds the capacity of the network. It may also be possible to combine DSM with storage and intermittent generation to reduce further the number of calls that are needed to reduce demand.

This programme has no reliance on QH meters. The purpose of the programme is not about switching demand to get cheap power, but about reducing demand to keep the network stable. This level of demand switching is also likely to be small in terms of the effect of demand. It therefore may be less important that the reduction can be properly captured in settlement.

One potential issue is whether a customer could be part of more than one programme. This would occur if both the distributor and supplier wanted to have control of the customer's load. Further thought is needed as to how these programmes could be combined and which participant would remain in control of the customers' controllable load. It should be recognised that the extent to which demand reductions are achieved is far more critical to the distributor than the supplier in order to avoid overloading network components. Consequently, where supplier and distributor programmes co-exist it will be important that supplier instructions do not take precedence over distributor actions.

## 8 Assessment of Costs and Benefits

### 8.1 Introduction

The costs and benefits of the different DSM programmes will vary depending on which of the three potential programmes is adopted. Many of these costs and benefits will be common to more than one of the programmes, although the degree to which they will be incurred will alter. A table at the start of each of sections 8.2 to 8.5 indicates how the costs and benefit apply to the three potential DSM programmes and is divided into economic and non-economic costs and benefits. A fuller qualitative explanation and scope of each the cost and benefits is provided below.

The focus of this evaluation of costs and benefits is on small business and residential customers, so some potential benefits may not emerge in the absence of the larger industrial sector. Within the limitations of this scoping study it is not possible to provide detailed figures for some of the costs and benefits. Consideration of what further research could be undertaken to provide a more detailed view on these costs and benefits is contained in Chapter 11.

### 8.2 Economic Benefits

The five potential economic benefits identified for the DSM Programmes are summarised below.

**Table 8-1 Economic Benefits from DSM**

<b>Benefits/Applicable Programme</b>	<b>Customer Initiated DSM</b>	<b>Supplier Initiated DSM</b>	<b>Distributor Initiated DSM</b>
Purchasing energy at low cost times	Y	Y	P
Encouraging use of less energy	Y	P	N
Avoiding network reinforcement	P	P	Y
Providing reserve	N	P	N
Mitigation market power	P	P	N

#### **Purchasing Energy at low costs times**

A significant saving for suppliers (which should be passed on to customers) is the ability to purchase energy at cheaper times and in particular to avoid very high prices that may occur at peak times. This is likely to be more obvious with the All Island market which should provide transparent and clear prices at which the whole market is clearing for electricity. In the absence of this central pool a good alternative indicator to identify these price differences is the Top Up prices published by ESB National Grid.

<sup>5</sup> Potentially Applicable means that the benefit/cost may be delivered depending on how the programme is implemented.

The table below utilises the HH Top Up prices and calculates a time weighted average for day time prices, (7am – 7pm) night time prices (7pm- 7am) and afternoon peak prices charged by ESB National Grid for Top up<sup>6</sup>. The differential between peak prices and off-peak prices is significantly higher when a more focused time slot (such as winter afternoons) was used to compare with night time prices. However, a more general peak/off-peak figure has been used in later calculations to give prudent valuations of the benefits that DSM could have for load shifting. The size of the peak/off-peak differences suggests there is scope for DSM initiatives to be successful were suppliers to encourage consumption during off peak times. Interestingly the difference is also increasing between 2004 and 2005 suggesting a more favourable time for investing in DSM. These saving can be captured in both the customer initiated and supplier initiated programmes.

**Table 8-2 Peak/Off-Peak Electricity Prices**

<b>Year</b>	<b>Peak 7AM- 7PM €MWh</b>	<b>Off Peak 7PM- 7AM €MWh</b>	<b>Afternoon Peak €MWh</b>	<b>Difference Peak/Off-Peak €MWh</b>
<b>2004</b>	60.62	45.29	70.56	15.33
<b>2005</b>	67.34	50.04	81.65	17.3

### **Reducing Electricity Consumption**

This report has focused on demand responsiveness in terms of shifting demand. However, a very important side effect of smart meters and DSM programmes is an overall reduction in demand as customers become more aware of their consumption patterns and therefore make more effort to manage demand. As an example the California Public Utilities (CPUC) State-wide Pricing Pilot provided customers with an on-line tool to better understand their energy usage. In the CPUC’s Enhanced Automation Programme customers are paid to reduce their energy usage during peak times by using control equipment of their lighting and HVAC systems. Experience has shown that customers do not then increase their lighting or air conditioning consumption to make up for lower consumption in earlier periods giving rise to an overall reduction in consumption. This is a very significant costs saving as is demonstrated in the estimation of benefits in Appendix B.

A demonstration of this benefit is seen from the smart metering programme and DSM initiatives in Italy. As well as shifting time of use, it was found that a customer who is made more aware of the cost of energy will reduce energy consumption by between 5-10% (Ref.35).

### **Avoiding Reinforcement and Outage Management – Distribution level**

Distribution demand reductions have the potential for sizeable savings if ESB Networks can avoid paying to reinforce the network. This is likely to be the case if additional load connects to the network and without load management there is the likelihood of exceeding the capacity of the network, but it may also be

<sup>6</sup> Source [www.eirgrid.ie](http://www.eirgrid.ie) – Peak and base load prices are time weighted average price for Top up for working days only published on the EirGrid website. Peak times has been calculated as 07:00 to 19:00, off peak 19.00 to 0700. 2005 data runs covers the period up to the end of July. Afternoon peak is 16:00 to 19:00.

possible to avoid investment where existing infrastructure needs to be replaced. There are examples from Australia of deferment of investment for a number of years. E.g. Integral Energy ran a Programme with one large customer from 1998-2005 at Baulkham Hills. This avoided paying \$1.7m Australian dollars in network reinforcement needed for a new substation.

Whilst this scheme involved a large customer, similar programmes could be used for a mixture of large and small customers to elicit similar savings. US programmes of this nature are also starting to take hold.

### **Cheapest mechanism for providing frequency response and reserve (market efficiency)**

The STAR contracts that ESB National Grid utilise to allow the demand side to participate are seen as a cost effective mechanism to obtain frequency response and demonstrate the willingness for ESB National Grid to utilise the demand side. Of the three new DSM Programmes proposed it is only the Supplier led programme that has the possibility to be used for providing additional reserve to ESB National Grid instead of generation. However, it should be noted that it may be difficult to build up a sufficient customer base to make this useful to ESB National Grid, who really need a minimum size of reducible load ideally at a specified location on the Network. This needs to be set against the rewards for customers for providing further reserve which could be spread very thinly with a large number of customers. Average reserve costs are also likely to fall further when the All Island market opens and a single level of reserve will be needed for the larger market. Conversely, the increased penetration of intermittent renewable generation may serve to increase the size and value of reserve markets.

### **Mitigation Market Power**

The final potential economic benefit from DSM is the mitigation of market power from dominant generation. Analysis of the Californian energy crisis identified market power of generation and gas assets along with the inelasticity of demand as major contributors to price spikes and power shortages. These observers suggested that demand response mechanisms could work as a key method for diminishing the predictability of price movements against system demand and hence the ability of generators to 'game the system' (Ref. 24).

The introduction of the All Island market should help reduce market power in a number of ways only one of which relies on the Demand Side. Firstly, there will be more generation companies competing in the market, although the market will still remain fairly oligopolistic. Secondly, and potentially more significantly, the design of the new market should be more transparent with the expectation that generators will bid close to their marginal cost. This will allow the regulators to spot any instance of market abuse. Finally the design of the market will also allow the demand side to participate in the market which gives them the opportunity to offer bids and therefore cap the level which they will pay for generation. The exact rules of demand side participation and the degree to which they will participate in the market, including smaller customers, still needs to be determined. It is likely that there may be a requirement for QH metering, which will at least initially restrict any involvement from small participants.

One final point on market power is that even with a more competitive wholesale market there may still be market power that DSM could assist in reducing. Further detailed analysis is needed to determine whether or not local monopolies exist in particular areas of the network, or whether particular plant portfolios cause particular issues when managing the network, e.g. all the peaking plant may be vested in the hands of one company, or local monopolies may exist behind particular constraints on the network.

### Indicative Values for the Benefits of DSM

Deriving a value for the benefits from DSM is a difficult calculation and will vary for each DSM programme assessed. Key to obtaining a sensible figure will be the assumption made on potential take up of the programme and the impact this will make on demand during peak periods. In our assessment of potential benefits it is assumed that 10% of customers may sign up to a DSM programme, that this will result in a drop in demand of 10% during the peak periods which make up 20% of the day.

The benefits that can be readily quantified come from two main sources. These are:

- Peak Energy saved by a reduction in demand due to DSM; and
- Peak Energy switched to Off-Peak periods due to DSM.

No attempt has been made to quantify economic benefits from reduced distribution network investment or market dominance as they are viewed as too uncertain. These estimates are therefore only applicable to the customer initiated and supplier initiated programmes.

The size of the benefits depends on whether commercial customers are included or excluded. In addition different scenarios are assessed based on the percentage of energy that is switched to Off-Peak periods rather than saved. A range of benefits is contained in the table below along with the total benefit assuming a programme ran for 10 years.

**Table 8-3 Range of Potential Benefits from DSM**

	<b>Electricity Saved (not consumed)</b>	<b>Electricity Switched to Off- Peak Period</b>	<b>Annual Saving</b>	<b>10 Year Saving</b>
<b>Consumption with Commercial</b>	€520k - €1.45m p/a	€80k - €260k p/a	€650k - 1.6m p/a	€6.5m - €16m
<b>Consumption without Commercial</b>	€245 - €685k p/a	€40k - €125k p/a	€305k - €760k p/a	€3m - €7.6m

More detail of why these assumptions have been chosen and how the benefits are calculated is contained in Appendix B.

### 8.3 Economic Costs

The potential economic costs vary dramatically across schemes. The key ones identified are:

**Table 8-4 Economic Costs from DSM**

<b>Economic Costs/Applicable Programme</b> Key Y=Applicable, N=Not Applicable, P=Potentially Applicable	<b>Customer Initiated DSM</b>	<b>Supplier Initiated DSM</b>	<b>Distributor Initiated DSM</b>
Smart Metering technology	Y	P	N
Control equipment and incentives for participation	N	P	Y
Suppliers billing system	Y	P	N
Administration and marketing Costs	Y	Y	Y
Small businesses changing operating times	Y	P	P
Changes to the Settlement Process	N	Y	N

#### **Smart metering technology and communications**

The most significant cost for customer's voluntary demand reduction will be the metering equipment needed to capture their reduction in demand in the expensive periods. Costs of QH meters have fallen dramatically in the last few years, but still represent a significant investment which is why they have not been widely adopted beyond those with mandatory requirements. This may change if Ireland adopted a nationwide metering programme.

The best indication of the potential costs of an Irish smart metering programme can be seen from the experience in Italy. ENEL created the Telegestore Project that will install 30 million smart meters. This programme lasts 5 years and cost 2.1 billion Euros (Ref. 13) but this included the costs of concentrators and modems installed in secondary substations and the central system to gather and send data from/to the concentrators<sup>7</sup> and manage the system. Vincenzo Cannatelli stated that "The sheer size of the project (30 million meters) has allowed us to benefit from economies of scale. We are paying the same amount for the electronic meters as we would normally pay for an electro-mechanical meter. This price is much lower than other electronic meters available on the market" (Ref. 35).

The ENEL experience works out at a cost per installed meter (including associated equipment) of under 70 Euros. Whilst the Ireland market is clearly smaller than Italy the economies of scale should not be significantly different and technology costs may even have reduced further over the last couple of years. The ENEL programme was built on a business plan which, due to the range of benefits, guaranteed a payback period of five years based on the current electricity pricing and regulatory rules (Ref. 35).

<sup>7</sup> Concentrators are used to manage the communication towards the central system and to the electronic meters. The concentrator questions the electronic meter in a master-slave manner (Ref. 35).

A similarity that Ireland shares with Italy is a single company responsible for distribution and provision of metering services. ESB networks by installing smart meters are able to gain the range of benefits that exist such as reduced theft, low data collection cost and facilitating retail competition. This is an advantage over countries such as the UK that have a number of separate Meter Operators who may have no relationship with the distribution business and cannot therefore reap the wider benefits that smart meters can provide.

Some investigation of the extra costs of Time of Use (TOU)<sup>8</sup> meters against 24 hour single register meters was made in the CER's investigation of electricity tariff structures. The report ascribed extra costs to TOU meters associated with their lower life time. It was felt that the benefits accruing from TOU pricing outweighed the extra costs for annual consumption above 5,000 kWh. The Commission felt that the installation of TOU meters should be investigated further, but noted there were other costs as well as the meters that needed to be assessed. They also recognised the implication of the timing of any programme and the potential costs of stranded assets (Ref. 48). The commission did state that it intended to explore the issues around TOU meter further with industry and carry out a thorough cost-benefit analysis.

### **Control equipment and incentives for participants**

The supplier and distributor programmes are likely to require some incentives to encourage customers to take part, beyond that of lower tariffs. These incentives are often provided in the form of free or subsidised equipment that both benefit the customer and allows the DSM programme to operate. In the US typical supplier initiated schemes involved providing the customers with free programmable thermostat and free air conditioning checks. These were typically worth approximately US \$150-200 including installation.

The incentives may be particularly important for distributor initiated demand programmes where it may not be possible to reduce DUoS tariffs to a level sufficient to encourage a change in behaviour. A good example is the Tahmoor Fuel Substitution programme in Australia where the distribution company, Integral Energy, arranged for the installation of bottled gas and appliances and provided subsidies of \$150 for the installation of bottled gas plus \$150 per appliance. In the UK a local area board, Manweb, provided heavily subsidised light bulbs, electrical appliances and insulation as part of its programme to reduce demand in Holy Island.

### **Administration and Marketing costs**

Administration and marketing of these DSM programmes could easily add considerable costs. International examples include:

**Table 8-5 Administration and Marketing Costs from DSM**

<b>Programme</b>	<b>No of customers</b>	<b>Admin Cost</b>
Baulkham Hills, Sydney, Australia – Agreement large customer to shed load 1998-2005	1	\$100,000 US
Western Sydney Interruptible Air Conditioning Trial – 2001 (One-off trial)	90	\$15,000 Aus

<sup>8</sup> It is not clear from the report what functionality is included in the TOU meters but it is assumed this would have the functionality required for the smart meters in the customer initiated programme.

In terms of administration costs, it is likely that the customer initiated programme will have the highest costs. International examples (e.g. California) showed very high administration costs for designing and operating the pilot programmes, particularly if the cost of information provision to customer is included. In addition, there is also the cost of notifying any critical peak prices, possibly through a range of communication methods to ensure all customers have the latest price information. Many of these costs may be fixed rather than variable so they may not be that significant if, in the long term, they were shared among a large number of customers.

One significant infrastructure cost could relate to the modification of billing systems should this prove necessary. Although many suppliers have billing systems that accommodate more disaggregated tariffs at the half-hourly level, these may not be applicable for the small business and residential customers. As an example there were complications with billing even a small number (90 customers) of air conditioning rebates in Western Sydney Australia. Suppliers may be keen to maintain simple tariffs to remove the risk of having to modify their systems, rather than introducing more time of use rates that though more cost reflective could increase billing system costs.

The highest marketing costs per customer would fall on the distribution initiated programme. This programme would need a concentrated marketing effort, as it would be necessary to convince a large percentage of customers in a small area to engage in DSM. The Supplier and customer initiated programmes could attract participation from broad range of customers and Suppliers would have regular contact with these customers from a billing, marketing and sales perspective already. In principle this should therefore imply a lower cost per participant due to the economies of scale and also from the perspective that there would be reduced costs from identifying and making contact with those customers.

In the US there are several experiments using third parties to provide these types of programmes for smaller customers. Utah Power is conducting two experiments where most of the programme activities are carried out by a third party vendor where that vendor is paid for performance based on actual results. Results are determined by metering a sample of the participating customers. In one case air conditioning is initiated for small commercial and residential customers. In the second experiment HVAC and lighting controls are used to reduce load. The ISO New England went out to bid for their aggregated load Programme and for vendors to handle all administration and marketing and are paid on the basis of performance. This is one option that could be considered as a way to develop an energy services industry that can stand on its own.

### **Costs for small business of changing time of operation**

There may be costs for small businesses if they choose to reduce their consumption of electricity during peak periods. This could be additional overtime to keep staff available until later in the evening or a change in shift patterns to finish earlier in the day. It is difficult to calculate how many of these will end up being real costs and how many of these will be management issues that rely on flexibility of the firm rather than actually increasing the cost of production.

The size of this cost will depend on the type of business. In any pilot scheme it may be possible to target customers with SIC codes that appear to be more suitable for changing times of operation with little direct economic cost. Many larger Irish businesses are already used to being flexible and reducing their consumption during peak periods to obtain the benefits from the WPDRS, WDRI or Powersave programmes. The acceptance of these programmes may make it easier for smaller customers to get used to responding to other price signals through the customer initiated programme or have demand reduced through the supplier initiated programmes.

## **Changes to the Settlement Process**

The customer initiated programmes will require QH meters and should allow the energy consumption of smaller customers to be calculated in the same way as large customers. There may be an issue over the processing speed and time to perform the calculations for how much energy each customer has taken in each half hour. However, this should be mainly a problem with aggregation that with better computing technology this should not be difficult to solve. More problematic may be the impact on the settlement process for the supplier initiated programme if this is implemented without QH Smart meters.

Many of the load control programmes based around air conditioning or heating control have not required QH meters, but have continued with conventional metering with the calculations performed in settlements to determine any load changes. One method may be to utilise a two register meter that could be controlled remotely to record consumption of switchable appliances and household circuits. A record would then be needed to be kept in settlements of the times of switching of appliance so as to correctly allocate this switched load to the correct time periods.

There is a number of areas of complication with the profiling route. This will include;

- Not all the switchable load will always be operating at the same time. E.g. water or storage heating will only be on at a certain time refrigeration will be on most of the time (albeit intermittently). An additional register for each piece of switchable load may therefore be needed;
- The need for customers to be able to over-ride any switchable load; and
- Lack of metering infrastructure that is currently dynamically switched.

These issues are not insurmountable with conventional meters, but a detailed comparison of the cost and savings from running the programme with conventional meters should be made with the settlement costs that may be needed. The fact that Ireland does not have experience of teleswitched infrastructure suggests that this may be an inappropriate approach to adopt in Ireland, especially given the functionality advantages of more modern technology. It may be more sensible and cost effective to insist on smart meters that can record QH consumption for the supplier initiated programmes as well as the customer initiated programme.

For the distributor initiated programmes it may be acceptable for the load to be switched without a significant impact on suppliers' energy take calculations. No change to meters or settlements may therefore be possible.

## 8.4 Non Economic Benefits

The following non-economic benefits were identified:

**Table 8-6 Non Economic Benefits from DSM**

<b>Non Economic Benefits/Applicable Programme</b> Key Y=Applicable, N=Not Applicable, P=Potentially Applicable	<b>Customer Initiated DSM</b>	<b>Supplier Initiated DSM</b>	<b>Distributor Initiated DSM</b>
Carbon Savings from not utilising inefficient peaking plant and using less power	Y	Y	P
System Reliability	Y	Y	Y
Visual benefits due to reduced investment (less new lines and power plants)	Y	Y	Y

### **Carbon savings from more efficient plant and using less power**

DSM will reduce the peak demand on the system. Depending on other economic factors (such as relative price of fuels and carbon permits), peaking units will normally be the most inefficient in the fleet of generating plants. If DSM reduces the amount of time that less efficient plant needs to operate, and allow more efficient plant to be run instead, then there will be an overall carbon saving.

More significant in Carbon terms than the switching of consumption to off-peak periods is the reduction in consumption that occurs as a by-product of DSM Programmes. This was explored in the economic section as there is a significant economic saving to customers in using less electricity.

Utilising the same assumptions as were made for assessment of the economic benefit an estimate can be made for the Carbon benefit that DSM may deliver in terms of saved electricity<sup>9</sup>. This is based on a SEI Calculation for 2004 of grid electricity producing 0.629 tonnes CO<sub>2</sub> per MWh. The following range of environmental benefits was derived. This is for the customer initiated and supplier initiated programmes only.

<sup>9</sup> No attempt has been made to quantify the carbon benefit for switched electricity. This will depend heavily on the relative price of fuels and may not necessarily lead to a drop in carbon if gas CCGT peaking plants were replaced by Coal base load plants.

**Table 8-7 Potential Reduction in Carbon from DSM**

	<b>Annual Carbon Saving</b>	<b>10 Year Saving</b>
<b>Consumption with Commercial</b>	4,800 -13,600 tonnes CO <sub>2</sub> p/a	48,000 – 136,000 tonnes CO <sub>2</sub>
<b>Consumption without Commercial</b>	2,300 – 6,400 tonnes CO <sub>2</sub> p/a	23,000 – 64,000 tonnes CO <sub>2</sub>

Further details of these calculations are available in Appendix B.

**System reliability**

The ability for customers to reduce demand can enhance reliability of the electric systems by providing reductions in times of system stress. In the extreme this reduces the possible need for Rota disconnections. This requirement for system stability is a major driver behind a number of the DSM programmes that already exist in Ireland.

One limitation to this benefit of increased reliability would occur if DSM measures were used extensively by distribution businesses to avoid network reinforcements. This could potentially result in increased asset utilisation and loadings on network components, which could reduce reliability and have the potential to increase network losses.

**Visual benefits from less new lines and power station**

The growth in the environmental movements and local campaign to stop ‘unsightly’ developments has made planning permission for new power station and transmission lines increasingly difficult. A good example of this was the difficulty in building the North Yorkshire transmission line in the UK. If DSM reduces the need for extra power it should reduce the need for new power stations and new transmissions lines.

A limitation to this benefit is that new power stations may not be built solely to meet increased peak demand, but for other commercial reasons. This is particularly true of some of the renewable power stations whose construction may be dependent on the support mechanisms put in place to assist different technologies.

## 8.5 Non Economic Costs

Only one non-economic cost was identified for DSM, even this could potentially be quantified and made economic.

**Table 8-8 Non Economic Costs from DSM**

<b>Non Economic cost/Applicable Programme</b> Key Y=Applicable, N=Not Applicable, P=Potentially Applicable	<b>Customer Initiated DSM</b>	<b>Supplier Initiated DSM</b>	<b>Distributor Initiated DSM</b>
Customer time spent in managing process	Y	N	N

### Customer time spent monitoring consumption and altering patterns of consumption

In the customer initiated programme if domestic customers spend time monitoring their consumption and alter the way of living in response to price signals, e.g. changing washing machines time, then there are two potential costs to them. First there is the cost associated with the time spent examining pricing information such that they are able to assess whether or not to shift their consumption patterns. Secondly there is the convenience cost to them of having to shift their pattern of usage and perhaps run appliances at times that are less than optimal from the management of the household perspective. This inconvenience cost is likely to be relatively small for early adopters of DSM otherwise they would keep consuming according to past patterns of consumption and remain on a traditional tariff.

## 8.6 Summary

**The most significant costs and benefits for the three programme types are summarised below.**

### Customer Initiated Programmes

For the customer initiated programme the most significant cost will be the installation of smart meters. The cost per meter would be reduced if there was a nationwide policy and agreement on recovering costs, but as explained in the barriers chapter this is likely to require regulatory change. The other significant costs will be the administration costs of providing the information necessary for these sorts of programmes to be utilised most beneficially by the participants. This will be largely a fixed cost so any large-scale programme may not find this a significant hurdle as the average cost per customer could quickly be reduced. However, early pilot programmes may find this set up cost to be high.

A key benefit from the customer-initiated programme will be the opportunity to purchase energy at cheaper times. Quantification of this will require further research on the elasticity of customer demand, but it should deliver economic benefits from energy used in non peak periods and energy that is saved. Alongside these financial benefits are the non-economic benefits such as carbon reduction and visual improvements that may encourage the more environmental aware consumers to participate.

### **Supplier Initiated Programmes**

In the supplier initiated programme a key cost is likely to be the control infrastructure required to operate the scheme. Alongside this will either be the metering cost of smart meters or the settlement costs if a cost efficient way is found of capturing the demand reduction and settling using conventional meters. The final important cost will be the administrative burden of operating the scheme, including any potential modifications to billing systems in order to offer tariffs that reward customers for being prepared to reduce demand when required. This cost should not be ignored as suppliers will have recently invested in their billing systems to cope with the competitive market and changes to these systems could be expensive.

The key benefit will be the ability to purchase energy at cheaper times and in particular to reduce demand at times of very high energy prices.

### **Distributor Initiated Programmes**

As with the supplier initiated DSM programmes a key cost will be the control infrastructure and the incentives required to persuade participants to join the scheme. Distributors may not be able to sufficiently reward customers through lower DUoS tariffs as these make up a small part of the bill. Direct financial incentives or contributions towards appliances may be needed. The size of any required incentives would be an interesting area for further research. The other significant cost for this programme could be the marketing costs involved in persuading customers related to the particular distribution reinforcement to agree to have their load reduced. This may require a doorstep persuasion approach that would be expensive and would need to be carefully done to avoid concerns by the CER.

The key benefit would be to the avoidance of network reinforcements. Quantifying this benefit will be hard and would require discussions with distribution companies to seek their view on the size of this benefit and where it could potentially be obtained. Customers would also gain in terms of system reliability.

## 9 Barriers and Solutions to Suggested DSM Programmes

### 9.1 Overview of the Barriers

In the section below we analyse what the barriers are to our proposed DSM programmes and provide recommendations on how they might be overcome. These barriers will vary depending on which type of programme is being assessed. The diagrams below show at a high level what the barriers are divided up into Regulatory (R), Commercial (C) Sociological (S) and Technological (T) barriers.

**Figure 9-1 Customer Initiated Demand Reduction**

<b>R</b>	<b>C</b>	<p><b>Facilitators</b></p> <ul style="list-style-type: none"> <li>•Government supported smart meter programme (mandatory)</li> <li>•Agreed recovery rate for new meters and comms infrastructure</li> <li>•Changing the switching rules</li> <li>•Education for customers on financial and social benefits from managing their demand</li> <li>•Funding to help service providers develop information services required</li> <li>•Pilot to increase use of technology, identify best solutions and reduce costs</li> <li>•Higher cost electricity</li> </ul>
<ul style="list-style-type: none"> <li>•Customer switching rules</li> <li>•Recovering costs of new metering assets</li> <li>•Customer protection concerns</li> </ul>	<ul style="list-style-type: none"> <li>•Costs of smart meters</li> <li>•Competition &amp; tariffs</li> <li>•Low prices</li> <li>•Information Service Provider to help customers make choices</li> </ul>	
<b>S</b>	<b>T</b>	
<ul style="list-style-type: none"> <li>•Customers prepared to modify their consumption behaviour</li> <li>•Price elasticity of customers</li> </ul>	<ul style="list-style-type: none"> <li>•Smart meters being widely adopted</li> <li>•Remote access to appliances or thermostats giving easy control</li> </ul>	

**Figure 9-2 Supplier Initiated Demand Reduction**

<b>R</b>	<b>C</b>	<p><b>Facilitators</b></p> <ul style="list-style-type: none"> <li>•Changes to the switching rules</li> <li>•Market arrangement that produce higher and predictable prices</li> <li>•Agreed recovery rate for new meters and comms infrastructure</li> <li>•Education for customers on financial and social benefits of allowing load reduction</li> <li>•Wholesale rules that suit demand side participation</li> <li>•Ensure new premises built with circuit that can be switched off</li> <li>•Pilot to increase use of technology, identify best solutions and reduce costs</li> <li>•Higher cost of electricity</li> </ul>
<ul style="list-style-type: none"> <li>•Customer switching rules</li> <li>•Customer Protection Concerns</li> <li>•Wholesale Market Rules</li> <li>•Settlement requirement</li> </ul>	<ul style="list-style-type: none"> <li>•Cost of smart meters</li> <li>•Cost of control infrastructure</li> <li>•Low and unpredictable prices for peak power</li> <li>•Tariffs that reward customers</li> </ul>	
<b>S</b>	<b>T</b>	
<ul style="list-style-type: none"> <li>•Domestic Customers prepared to lose some control on load</li> <li>•SME prepared to allow supplier to interrupt normal working</li> <li>•Price elasticity of customers</li> </ul>	<ul style="list-style-type: none"> <li>•Whether separate circuits exist that suppliers could control</li> <li>•Innovative communication for control of customer load</li> <li>•Appliance that can be switched off</li> </ul>	

**Figure 9-3 Distributor Initiated Demand Reduction**

<b>R</b>	<b>C</b>	<p><b>Facilitators</b></p> <ul style="list-style-type: none"> <li>•Determine contractual issues between supplier/customer and distributor</li> <li>• Price Control Reviews to provide right incentives</li> <li>•Agreed recovery rate for new comms and meters</li> <li>• Develop incentives for customers</li> <li>•Education for customers on financial and social benefits from allowing load reduction</li> <li>• Ensure new premises built with circuit that can be switched off</li> <li>• Pilot to increase use of technology, identify best solutions and reduce costs</li> </ul>
<ul style="list-style-type: none"> <li>•Customer protection concerns</li> <li>•Lack of distributor incentives</li> </ul>	<ul style="list-style-type: none"> <li>•Cost of control technology</li> <li>•Contract with customers</li> <li>•Fast growing network demand</li> </ul>	
<b>S</b>	<b>T</b>	
<ul style="list-style-type: none"> <li>•Domestic Customers prepared to lose some control on load</li> <li>•SME prepared to allow distributor to interrupt normal working</li> </ul>	<ul style="list-style-type: none"> <li>•Whether separate circuits exist that distributors could control</li> <li>•Innovative communication for control of customer load</li> </ul>	

A fuller description of each of these barriers and the recommended solutions is described in sections 9.2-9.5 below. These have been grouped into similar barriers where the solutions are applicable

## 9.2 Regulatory Barriers and Solutions

As a summary there are six regulatory barriers that needed to be overcome and the table below shows these barriers in the context of each of the programmes. Regulatory in this context has been defined as licences, codes and market rules.

**Table 9-1 Regulatory Barriers and Solutions**

Barrier/Applicable Programme	Customer Initiated DSM	Supplier Initiated DSM	Distributor Initiated DSM
Customer switching rule	Y	Y	N
Recovering costs of new metering assets	Y	P	N
Customer Protection concerns	Y	Y	Y
Participation in the Wholesale Market	N	Y	N
Distributors Incentives	N	N	Y
Changing Settlement Requirements	N	Y	P

## **Customer Switching Rules**

The Irish market rules allow customers to switch supplier without notice being given to the old supplier. One of the concerns on both the supplier and customer initiated programmes is that the supplier would need to invest significant resources to enable customer participation in the programme with no guarantee that the customer will remain with the supplier over a time period long enough to recover the investment. This is particularly important if the supplier needs to pay for the installation of the meter.

The Irish market has only recently been opened to domestic competition and there is currently little customer switching. The degree to which this will be a barrier has yet to be established, but in similar market such as the UK it has been seen as a problem. Some form of lock-in for the customer may be needed where the supplier invests in the premises to enable participation in a DSM programme. The difficulty may be in finding a balance between allowing the supplier to recover any investment and not unfairly tying the customer into a contract with the supplier. It is interesting to note that very few suppliers in the US in regions where utilities are not vertically integrated provide these services to customers.

One method of mitigating a large part of this risk would be for ESB Networks as meter operator to be the provider of the smart meter (and possibly information to use the meter) and for ESB Networks operator to sign a long-term contract with the customer. There is still a difficulty in this long term contracting approach in that there would be an administrative and financial risk for ESB Networks, particularly with smaller business or residential customers that may move or go bankrupt. This risk is not currently rewarded in the price control incentives of ESB Networks.

## **Recovering costs of new metering assets**

This issue relates to the need for smart meters and how these costs could be recovered. Suppliers or even ESB Networks will be reluctant to install smart meters with communication technology unless they know they are able to recover the higher costs associated with this investment when compared with the low cost of conventional meters. Even with the customer rule switching issue being resolved there is still the problem that the tariff charged to customers will be less competitive if ESB Networks has to charge a much higher standing charge to cover the full costs for these assets.

This cost may not be a relevant consideration if the EU draft directive on energy end-use efficiency and energy services is enacted. Article 13 of this directive required that all end-use customers should be provided with competitively priced individual meters, which accurately reflect the customer's actual consumption and actual time of use. This would also require billing to reflect actual consumption in understandable terms and be frequent enough to enable customers to regulate their own energy consumption (Ref 25). However, the latest discussion on this directive on the 28 June 2005 scrapped the binding elements of this proposal so the impact may not be as extensive as some commentators had previously envisaged (Ref. 10, 26).

In the absence of a powerful EU directive to facilitate the introduction of "smart meters" it may be worth considering the introduction of a government policy to encourage such innovations. The commercial section below considers the cost benefit justification for this decision. There would be a number of detailed issues to address related to the costs of stranded assets for ESB Networks who own the current metering stock, many of which will still have a number of years of useful life over which the cost of the asset would be recovered. Consideration could be given to a gradual replacement program aligned with normal meter replacement timescales that would minimise the one-off costs that need to be passed to customers.

## **Customer Protection Concerns**

This breaks down into two potential concerns that could arise in these schemes namely:

- Acceptability of charging customers High Rates for peak electricity; and
- Acceptability of interruptions;

The proposed customer initiated demand reduction schemes would require high charging rates at peak periods to try and reduce demand. Currently the majority of residential customers are supplied by ESB customer supply under tariffs that are capped by the CER. Agreement would be needed for ESB Customer Supply to offer innovative tariffs with higher peak and lower standard rates. Alternatively independent supplier could offer these tariffs but with low level of retail competition and reluctance from customers to move from the incumbent suppliers this may delay any significant take up of the programme.

With the supplier and distributor initiated schemes there will be some limits to the acceptability of when customers can be interrupted and what appliances can be interrupted. It would be important to ensure that essential appliances were not turned off and that customers had the ability to override switched off appliances to provide services like heating. Provided there were separate circuits or appliances and customers could be shown to be made aware of the control given to the supplier/ distributor then this is unlikely to be an issue.

## **Participation in the Wholesale Market**

One of the potential benefits of suppliers operating a DSM programme will be to utilise these demand side reduction in the wholesale market so as to reduce their electricity purchase costs. This is best examined in terms of the way the All Island market will operate from 2007 and what barriers it may provide. As well as suppliers operating in the new wholesale market large customers may also participate directly, although this is not required by any of the potential programmes proposed in this report as it was aimed at smaller customers.

The new All Island Market is a gross mandatory Pool that is intended to deliver predictable and stable trading arrangements with energy pricing set competitively. As was noted in section 2.5 there is evidence from other Gross Pool Markets that innovative suppliers do emerge to offer tariffs that reflect their costs including reductions for customers who are prepared to have their demand reduced at times of peak prices.

An important pre-requisite for development of these tariffs rewarding customer demand reductions is a transparent market with prices that suppliers can predict. The All Island Market appears to be a move towards this transparent market. However, it is important to ensure that the pricing mechanism is as inclusive as possible (ideally including the Moyle interconnector) to aid predictability. Associated with this the rules for the capacity mechanism should also make these prices and the settlement periods to which they apply predictable for suppliers.

## **ESB Network Incentives**

Currently ESB Networks has a number of regulatory reasons not to utilise DSM rather than reinforce the network. These include:

- Regulatory incentive to increase the asset base on which their future returns would be based;

- Regulatory incentive to decrease operational costs (which an on-going DSM programme would increase); and
- Successful DSM programmes leading to higher asset utilisation and hence higher losses.

In addition ESB Networks have no experience of operating DSM programmes so this will require new skill sets.

Three mechanisms could be used jointly to overcome this barrier. Firstly, ESB Networks could have a licence condition that requires them to first consider using DSM rather than simply reinforcing the network. This would be similar to the approach adopted in Australia. Secondly, alongside any licence conditions there would need to be a regulatory framework that recognised this saving and allowed the distributor to capture the benefit. This would need to apply even if the DSM programme only deferred the investment for a short period of time. Finally as this is a new solution there may also be the opportunity to provide ESB Networks with direct targeted management incentives to reduce costs by using this type of innovation.

The CER have recently published their decision paper on Distribution System Operator Revenues for 2006-2010 (Ref. 55). It is therefore unlikely that any changes will be made before 2010. However, consideration should be given to how DSM could be introduced into the incentive scheme post 2010 to avoid reinforcement of the network.

### **Changing Settlement Requirements**

One potential barrier to DSM is changes to the settlement system that may be needed to accommodate these DSM Programmes. Customer initiated DSM will be settled in the same way as current QH metered customers. Hence with the exception of potential processing issues with a very large number of these customers there should be no impact on settlements for this programme. This will also be the case if the supplier initiated programme utilise smart meters.

If the supplier initiated programme is implemented using conventional meters then the settlement changes may be complex. Currently two rate meters have all the night rate consumption at one time with no chunking of the profile to spread the register over a number of periods. The move from this position to one where the second register can record demand from appliances at different times of the day is a large step. This calculation is important as suppliers will need to see a reduction in their calculated energy to reflect the DSM actions they have taken. This could be an expensive change for settlements, although needs to be investigated further as there may be some potential solutions. The alternative option of just using QH meters may end up being more cost efficient than trying to change settlements.

On the distributor initiated programmes it will be simpler to not adjust settlements and hide any error in the rounding calculations. Any difference will be minor as this is likely to involve only a small amount of customers.

### **9.3 Commercial Barriers and Solutions**

As a summary there are six commercial barriers that needed to be overcome and the table below shows these barriers in the context of each of the programmes.

**Table 9-2 Commercial Barriers and Solutions**

<b>Barrier/Applicable Programme</b>	<b>Customer Initiated DSM</b>	<b>Supplier Initiated DSM</b>	<b>Distributor Initiated DSM</b>
Key Y=Applicable, N=Not Applicable, P=Potentially Applicable			
Costs of smart meters	Y	P	N
Low levels of residential competition and innovative tariffs	Y	Y	N
Costs of control technology	P	Y	Y
Volatile and predictable energy prices	Y	Y	N
Relationship issues with customers and suppliers	N	N	Y
Fast Growing Network Demand	N	N	Y

**Costs of Smart Meters**

A key barrier to the adoption of customer led DSM is the cost of smart meters. The costs of these meters were explored in the chapter eight and could represent a large investment in Ireland’s infrastructure were such meters to be fitted to each meter point. Any initiative to fit Smart Meters should be assessed on the basis of a range of benefits which arise alongside those that come from DSM. This range of benefits will vary depending on the exact functionality of the smart meter, but could include:

- Energy reduction as customers use less energy;
- Potential for reduced data collection costs (no data collectors);
- Greater protection to vulnerable members of the community (no rogue inspectors);
- Lower customer complaints as billed on actual reads;
- Ability for the customer to have precise calculations of energy cost to help with budgeting;
- Lower levels of theft due to easier detection; and
- Potential to be used to meter small scale generation – i.e. export and import.

As stated in the earlier section on recovering costs it may be worthwhile to consider a government policy to encourage such meters. The cost benefit analysis would be based around the potentially significant energy savings that could be realised and how this will assist with emissions targets and promoting the more

efficient use of energy. The savings in this area could potentially be more significant than the saving that arise from other energy efficiency measures promoted by governments and regulators.

One concern from a nationwide smart metering scheme is that some customers may find their bills increase as they become more cost reflective. This would need to be dealt with by government policy on support for these individuals.

### **Costs of Control Technology and equipment**

There are a number of different control technologies and equipment that could be used to give suppliers/distributors control over different equipment. Different control mechanisms include pager, wireless and the Internet all of which are proven technologies as demonstrated in Appendix A. The barriers may be the costs of implementation of these devices and the ease of customer switching, which could result in the supplier paying for the technology and the customer switching supplier within a month. This implementation costs is likely to be based as much on the costs of any home visit rather the cost of the equipment itself, so removing the equipment is not an option.

There are methods for mitigating this barrier including a long tie-in with the customer or the ability to recover the cost if the customer switches. Additionally, some form of central funding or allowance for this equipment may be needed to facilitate its introduction during any pilot programme being conducted. An initial support mechanism could be justified to overcome the split of benefit that may occur between participants in a liberalised markets as well as rewarding some of the environmental benefits that would occur with controlling and reducing peak energy load.

### **Volatile and Predictable Energy Prices**

One of the key benefits for suppliers from DSM is the ability to avoid purchasing energy at expensive times and delay this purchase until off-peak periods when energy is cheap. In order for benefit to exist there needs to be a significant difference between the costs of peak power and off-peak power. Ideally there also needs these prices to be predictable in order that supplier can prepare customers to reduce their demand.

The new All Island Market should help in making prices a lot more transparent and predictable as plant should be bidding at marginal cost. The degree of volatility has yet to be determined, but if it reflects costs the market price would expect to be higher at peak times and lower when only the more efficient base load plant is running. Current discussion on the way that capacity payments are made will also impact the charges being made to suppliers for peak times supply and could make the energy plus capacity payment charges more volatile. This will depend on how the capacity charges are spread over different time periods.

### **Low levels of residential competition and the provision of Tariffs and Information**

A pre-requisite to the customer-initiated programme is the need for a supplier to offer tariffs that incentivise customer behaviour. Alongside these tariffs there is also a need for an information provider, which could be the supplier, to provide the customer with up to date information on costs and peak pricing periods. In the case of the supplier initiated programmes there is a need for an innovative supplier to design a DSM programme, organising for the correct control equipment to be established and offering tariffs that reward customer for agreeing to their load being controlled.

These programmes require suppliers to be actively chasing customers. Despite the fact that the Irish market has been opened for residential competition since early 2005, there has been very little customer switching away from ESB Customer Supply. The lack of activity from Independent Suppliers is likely to be due to the limited margin on customers especially once the acquisition costs are taken into account. The new wholesale market may change the economics of purchasing generation which may help develop competition. In addition the ability to offer DSM tariffs and programmes that reward customers in different way could encourage supplier participation, but these programmes may be expensive to develop.

At the small business and residential customer levels the costs (administration and marketing) and risks of providing new innovative tariffs for a small number of customers are likely to outweigh any benefits even if the infrastructure such as QH meters was already available. Supplier would gain experience through such initiatives which could be applied to further DSM projects. However, in order to expand the adoption of DSM quickly it is important that any lessons from pilot programmes are shared across the industry. It is therefore recommended that to encourage suppliers to be more active in the domestic market and particularly to engage in DSM programmes that some central funding be made available to make a contribution towards these programmes.

### **Relationship with Customers and Suppliers**

For the distributor led schemes there is an issue about the nature of the contractual relationships that would need to be put in place for the DSM schemes to be effective. Firstly, there is an issue about the nature of the contract between distributors and small customers. Secondly, there is the potential impact on suppliers' energy calculations if distributors reduce customer demand without this information being properly provided to suppliers.

Small customers do have an agreement with ESB Networks. However, this does not include the right to control load. In the event that the distribution business needed to reduce demand at a particular feeder it would need to contact a large number of customers in a small area. This could be done by a concentrated local marketing campaign and at this stage the distribution business would enter into a direct commercial relationship with the customer.

The second contractual issue is if DSM schemes are introduced by the distributor directly, there could be a potential impact on suppliers' energy calculations. It is hard to establish the materiality of this issue and the extent of the barrier as it will depend how settlement takes account of the reduction in demand and will depend on how many customers are involved and their size. If it became an issue then some mechanism for distributors informing supplier of demand downturns would be needed.

### **Fast Growing Network Demand**

One of the concerns facing ESB Networks is that they are operating in a fast growing market and that a DSM programme may only be a short term solution with reinforcement needed in the short term anyway. International experience suggests that this fast growth does not need to be a barrier to DSM.

Australia also has circumstances similar to Ireland with areas of fast growing demand. For example in Castle Hill in Sydney they had a problem caused by increased residential and commercial load, which they overcame using a mixture of interruptible loads, standby generators, efficient lighting and high efficiency air conditioning. This had the benefit of deferring upgrades until 2009. ESB Networks may be able to benefits

in similar ways and may be able to justify this based on the cost of capital between investing in 2003 and making the investment in 2009.

## 9.4 Sociological Barriers and Solutions

There are three sociological barriers that needed to be overcome and the table below shows these barriers in the context of each of the programmes.

**Table 9-3 Sociological Barriers and Solutions**

Barrier/Applicable Programme Key Y=Applicable, N=Not Applicable, P=Potentially Applicable	Customer	Supplier	Distributor
	Initiated DSM	Initiated DSM	Initiated DSM
Customers prepared to modify their behaviour	Y	N	N
Customers prepared to have appliances interrupted	N	Y	Y
Price elasticity of customers	Y	P	P

### Customers prepared to modify their behaviour

The customer-initiated scheme requires consumers to spend time thinking about their electricity bill and take action to reduce demand at the appropriate time in response to price signals. One issue may be finding customers that would be prepared to modify their behaviour as for many consumers the electricity bill is a relatively small part of household expenditure and it is not something to which they pay much attention.

Persuading consumers to modify their behaviour could be targeted from 3 directions

- The inclusion of the critical peak price should provide a financial incentive for customers to reduce their demand at peak time;
- Education about the environmental benefits from DSM in terms of lower carbon from using more efficient plants and less new lines and power stations; and
- Information about their usage. Once customers are better informed and realise how much energy different appliances use they may change their usage pattern to reduce demand. An important part of the scheme in California was the monthly bill scorecard showing how much energy was used by different appliances and what could be saved by managing how these appliances are used.

It will be possible to design all of these elements into a pilot programme for a customer initiated scheme. One of the key issues here is making it easy for customers, which suggests marketing effort from suppliers that will need to offer tariffs for these programmes. These barriers could be reduced by having customers in an area that is already involved with energy efficiency and low carbon initiatives such as the Sustainable Energy Zone at Dundalk (Ref. 52). This would also assist with suppliers being able to target the right customers more easily as they are all in one small location.

### Customers prepared to have some equipment interrupted

The supplier and distributor initiated programmes will rely on customers that are prepared to have part of their electricity load interrupted. Much of the load that will be controlled is likely to be in areas such as water and storage heating, air conditioning, or appliances such as refrigeration, which could be controlled without a significant impact on the customers. However, customers would need to be convinced of this minimal impact.

Two ways to overcome these barriers are:

- Tariffs or incentives that customers can understand and see the benefit from being interrupted. As an example the interruptible Air conditioning rebate trial in Western Sydney saw each customer receive an incentive payment of \$150 and an energy smart kit.
- Information that allows them to clearly understand the implications of demand side reduction and the benefits both to them but also to the wider society in terms of lower carbon or less new power lines.

### Customers Price Elasticity

Analysis of more efficient and economic use of electricity and therefore the viability of some of the DSM schemes contemplated will depend largely on the responsiveness of consumption to price changes.

Establishing the level of demand responsiveness will be an important determinant in validating the viability of any proposed schemes. Some estimates of responsiveness have been undertaken and analysis undertaken in the UK in 1999 suggested a price elasticity of demand of 0.1, this corresponds to a 1% drop in demand for every 10% increase in price. (Ref. 29). Further more detailed analysis might be warranted as part of the cost benefit analysis for the proposed pilot scheme. Independent research projects in European countries (Ref 30) also corroborate this low level of elasticity of demand, although they do indicate some scope for responsive behaviour.

## 9.5 Technological Barriers and Solutions

There are two technological barriers that needed to be overcome and the table below shows these barriers in the context of each of the programmes.

**Table 9-4 Technological Barriers and Solutions**

Barrier/Applicable Programme	Customer		Supplier		Distributor	
	Initiated	DSM	Initiated	DSM	Initiated	DSM
Control Technologies	P		Y		Y	
Controllable Appliances	P		Y		Y	

## **Control Technologies**

The distributor and supplier initiated schemes rely on control technologies in order to increase or decrease the loads of the customers. This control technology may also be useful for the customer initiated demand reduction programme with customers being able to remotely decrease load. Evidence from international programmes shows that a number of different control technologies has been proven to work well. However, these technologies have not been extensively used in Ireland and need to be proven and become more widespread to reduce costs.

An example of this type of control technology in a DSM programme is given by the “comfortchoice” solution. This consists of software, a 2 way communications network and a programmable thermostat that can be installed in the customer’s home and used to adjust the temperature remotely. This was used by the Long Island Power Authority and elsewhere in the states as part of their DSM Programmes. A number of these control technologies using equipment from different manufacturers could be tested as part of a pilot to see how well they operate and to what degree they are applicable to the Irish market.

## **Controllable Appliances**

One barrier to the wider adoption of DSM is the low number of DSM enabled appliances. With the exception of water heating and space heating there is little load that is currently controlled remotely. This is an issue both in the quantity of controllable load listed above, but also when that load is operating, as there may be little reduction available at times of peak demand when high prices would be expected.

One area where suppliers may have potential to control load is in cold appliances. In the UK just over 15% of domestic consumption is consumed by fridges and freezer – the cold appliances (Ref. 37). A similar amount is likely to be used by Irish consumers. In recent years energy efficiency labelling has helped to increase the energy efficiency of these appliances, (and therefore the controllable load), but the appliances are getting larger and the stock of appliances has tended to increase.

An increase in controllable fridges clearly would have potential to be a switchable load. There are already DSM appliances including cold appliances on the market in the UK. As an example the LG Internet Family advertises the digital home network systems that connect and communicate via power line communication. This includes a fridge freezer, microwave, washing machine and air conditioner. If all 4 are connected the consumer would have full access to the digital appliances remotely so could change the temperature or turn on washing remotely. Whilst these appliances already exist and operate they are not in general use and are expensive. As these appliances are normally a rush purchase (replacing an old broken one) customers will be more concerned on short term price rather than long term benefits.

In operating any pilot programme it may therefore be useful to ensure that some households had access to this equipment or similar equipment to demonstrate the energy savings as well as suppliers investing in the technology to remotely control the appliances. This pilot demonstration may also help in convincing the public that it is safe to turn off fridges and freezers for a period of time. It may be that a long term EU policy of only making controllable devices would be required to make this market work,

Proponents of dynamic demand control argue that air conditioners, water heaters and refrigeration loads could be aggregated and provide a simple and cost effective way of managing the power grid. A key supporter of this dynamic demand technology is a not for profit company DynamicDemand. They point out that this controllable load could in future be used to smooth the supply from renewable power. The

problem is that there is currently no secure financial incentive for this technology, even though it could provide ancillary services type benefits that the market does reward. DynamicDemand argue for governments, regulators, academics and system operators to jointly come up with a market mechanism to reward dynamic demand control and that once dynamic demand control is established the company believes that no public funding would be required as it provides a low cost alternative to services already paid for (Ref. 36).

Two concerns still exist with the drive for dynamic demand, even if the above claims are correct. Firstly, it is not clear at what level dynamic demand control will be established and how much it may cost to reach this point. Secondly, ESB National Grid also needs to be convinced of the ability of these appliances to deliver ancillary services. Further research is therefore needed to investigate the usefulness of these devices.

## **9.6 Summary**

Two related key barriers for customer initiated DSM programmes are the costs of smart meters and the ease of customer switching. Both of these barriers have solutions. The customer switching rules may not be important if the most significant investment, the smart meter, was already installed. This could be achieved by a national metering programme, or agreement that ESB Networks could invest in smart meters and recover the increased costs.

There is a current problem with a lack of retail competition in the domestic sector with a question mark over the ability of independent suppliers to make an adequate margin in the domestic sector. This may be helped both by the opportunities provided by smart meters and the introduction of the new wholesale market. The smart meters may encourage suppliers to offer innovative tariffs that they can supply cheaply and allow savings to be passed on to customers. The necessity of being innovative to profitably gain customers may also encourage suppliers to develop the information services that are needed. A successful pilot programme with some support may be needed to provide some initiative to the market and encourage independent suppliers to participate.

For supplier initiated programmes the key barriers are likely to be the customer switching rule alongside the cost of communication technology and appliances. There is likely to be significant investment by the suppliers in each household that joins a DSM Programme and the suppliers will not want these customers to move to a new supplier. Reducing the cost of the control technology and introducing national standards that could allow it to be introduced widely by someone other than supplier is likely to require a government lead. A national lead may also be needed on either a smart meter programme or a change to settlement to allow the supplier initiated programmes to be correctly settled and therefore provide the right incentives for suppliers to participate.

A final technical problem for suppliers is being able to reduce sufficient demand at peak time. It may be difficult to find sufficient controllable demand from residential customers at peak times without newer appliances or more remote control than currently exist. Many of the appliances that could be controlled such as storage or water heating will often not be operating at peak times so cannot be used for a demand reduction. Achieving the necessary demand reduction may require programmes that have a mixture of residential, small business customers and possibly larger customers.

In distributor initiated programmes the key barriers are likely to be the costs of the control technology and customer incentives, price control incentives and being able to reduce sufficient demand at peak times. The costs of the control technology and customer incentives will need to be compared with the costs of

reinforcing the network and managing outages which in general is relatively low. These low costs changes in situations where environmental planning or terrain related factors constrain network developments and reinforcements can then be expensive. In the longer term distribution businesses would need a price control that would support this type of behaviour which would add to operational costs. The technical issue of being able to reduce demand at peak times could be solved in the same way as the supplier initiated programme by utilising a mixture of residential, small business and possibly larger customers.

## 10 Opportunities for Intermittent Generation

Intermittent generation, in particular wind generation provides an important part of Ireland's generation capacity and it would be beneficial to combine this with a DSM programme to overcome some of its limitations. Unfortunately, this review of international schemes showed limited evidence of any joint DSM and intermittent generation development. Schemes such as the Castle Hill Demand Management scheme in Sydney and some of the Ireland programmes such as WPDRS or WDRI had participants utilising their own standby generation when reducing their demand. However, these are not intermittent generation, which is more difficult to combine with DSM.

This chapter considers the benefits and problems of DSM and intermittent generation working together for each of the proposed programmes.

### 10.1 Supplier Initiated Schemes

Suppliers could potentially utilise intermittent generation that they own or control alongside DSM to help ensure their generation purchases meet their customer demand and therefore avoid paying Top Up or receiving Spill payments under the current arrangements. If suppliers know that some of the intermittent generation that they had bilateral contracts with was not operating then they could reduce demand and stay in balance. There are a number of immediate problems that may make this less attractive particularly to small customers

Firstly a lot of this intermittent generation could be wind generation. Figures from the BWEA website indicate that a modern wind turbine can produce electricity around 70-85% of the time, but the amount generated will depend on wind speed. Over the course of a year it will generate around 30% of the theoretical maximum output (Ref. 7). Whilst small businesses and household may be prepared to be interrupted occasionally for the right incentives, this level of intermittency and variable output is likely to be too high to balance with DSM. This may balance out with a selection of intermittent generation in different parts of the country, but this may be complex for the supplier to manage.

Secondly, the demand that can be reduced needs to be always available, as some of the intermittent generation may be potentially producing all day e.g. wind. This interruption will be a problem if there is no or little reducible load available at the time that it is required. This may be the case if the only customers to be interrupted are domestic customers in the morning when their water and storage load may not be available. A mixture of business and domestic customers will therefore be necessary if any balancing scheme with intermittent generation was considered.

The final issue is that the upcoming All Island Market means that all energy will be settled at Pool Prices. Whilst, it is likely that there will be financial contracts for difference behind this market that may still encourage suppliers to match demand with purchased generation. However, the financial exposure of not matching may not be as great as may be seen under bilateral markets.

### 10.2 Distributor Initiated Schemes

Distributor initiated DSM alongside intermittent generation may have more potential as the purpose would be to ensure that cables were not being overloaded. However, to reduce load on particular pieces of the network the reducible load would need to be co-located and would need to be sufficiently flexible to operate at a time when such an overload occurred. For a programme with intermittent generation and DSM

this would require DSM to be enforced only when load was high and the generation was not available. This is likely to be far less frequently than required under the supplier initiated programmes which may be aiming to balance every HH rather than not exceed a specific cable tolerance.

One issue is that if the load being supplied is a mixture of residential and business it is likely that peak demand will be at 16:00 – 19:00. If the DSM scheme is only aimed at residential customers it may not be possible to reduce enough demand at this point as it is unlikely that easily switchable loads such as heating will be operating. In addition some loads may only be capable of being switched off for short periods of time. E.g. refrigeration, so some form of cycling may be needed. However, programmes that used both domestic and small business customers may be able to provide the level of reductions required particularly if they were relatively infrequent events.

### **10.3 Customer Initiated Schemes**

The customer initiated Schemes would not directly interact with intermittent generation. However, there are potentially two ways that this type of programme may have a beneficial impact, although it would require a small variation on the deployment of the programmes as described in Section 7. It also may take a longer time period for schemes including intermittent generation to be developed.

The first mechanism for interacting with intermittent generation is for the suppliers to offer a lower tariff when the generation is available. The programme proposed had a single off peak tariff for simplicity, but more complex schemes could incorporate this functionality. Assuming the supplier is also purchasing the energy from the intermittent generators then they could offer a lower tariff when this electricity is available. The problem with this benefit is that the All Island market may have priority despatch for wind generation who will simply get the Pool Price. This will reduce the supplier benefit from bilaterally matching supply with demand. Whether intermittent generators wish to engage in Contract for Difference to ensure a minimum price for their output remains to be seen, but may be difficult to strike because of the uncontrollable nature of the generation. An additional difficulty is that customers may also need to respond to very short term price signals as the intermittent generation becomes available.

The second impact is that the voluntary demand reduction will help customers understand more about their energy consumption. If customers become interested in energy consumption then this may stimulate their interest in small scale distributed generation such as PV or micro-wind. In addition the QH metering needed for the customer initiated demand reduction may also be applicable for micro-generation as it may be possible for smart meters to record both import and export consumption/production separately. Consideration could be given to a combined pilot scheme for DSM and micro-generation to see how the combined costs and benefits turn out.

### **10.4 Opportunities for Non-Intermittent Distributed Generation**

The focus of this chapter has looked at intermittent generation and how this could be utilised with DSM. Alongside the opportunities to use intermittent generation with DSM there could also be an opportunity for small technology such as mini-CHP to work with DSM. This could be similar to the way large customers use their stand-by generation when reserve is requested by NGT.

Mini-CHP could work alongside any of the programmes envisaged above to increase the perceived drop in demand by incorporating an increasing in generation from small business and residential customers. In the customer initiated programme customers would be informed of peak pricing period and would utilise their

mini-CHP generators to decreasing demand. If the customer was also getting paid for generation and these payments went up at peak price times then customer may end up minimising demand and exporting generation to the grid to obtain maximum value. In the supplier initiated or distributor initiated programmes the supplier/distributor would automatically turn on the mini-CHP generation to act in the same way as the demand reduction. If the situation occurred with many thousands of CHP installed throughout the country then this could give a huge boost to the potential of DSM as each household could deliver a change in demand that together would allow for suppliers to engage in DSM without inconveniencing the customer.

Further investigation is needed of the potential for mini-CHP before making it a key part of any DSM programme.

## 11 Options for Future Consideration

### 11.1 Current Position

Ireland currently has little opportunity for small business and residential customers to engage in DSM. Recent international pilots suggest that there is potential for a number of different types of programme that would bring benefits to all participants. However, all of these programmes face some barriers and the business case remains to be proven for these programmes as a standalone private sector investment in the short term. A number of key factors have contributed to this low adoption rate for small scale DSM initiatives in Ireland:

- Lack of infrastructure – meters, control technology and settlements;
- Low levels of residential competition and customers ability to frequently change supplier;
- Relatively low customer demand elasticities, i.e. low changes in demand relative to price movements.

Whilst these factors present difficulties in developing small customer DSM programmes, there does appear to be more progress being made in other international markets where initiatives have been led by market participants, governments and other central bodies and organisations. Market conditions are starting to change and in particular the introduction of the All Island Market and more transparent wholesale competition may assist in the development of domestic competition. Utilising our international experience and recognising current planned market developments we have suggested, at a high level, three potential DSM Programmes for Ireland.

All of these suggested DSM schemes will need to be considered further and developed to a greater level of detail before feasible pilot schemes can be developed, all face some barriers and the business case remains to be proven for any of these programmes to be viable as standalone private sector investments. However, to assist the development of DSM for small customers the following initiatives are recommended.

- (i) Further research into quantifying the key costs and benefits – A more detailed examination of the key costs and benefits is needed in order to establish the business case for potential programmes. This could include examination of the national benefits that will arise from such programmes and the justification for government support for some of the investment that may be required to facilitate these DSM Programmes.
- (ii) Agreement on potential solutions to the key barriers undermining DSM adoption – Removing such barriers could facilitate the adoption of DSM programmes and will also highlight any show-stoppers that preclude the adoption of any forms of DSM.
- (iii) Investigation of smart metering benefits – A key decision on the feasibility of the customer initiated DSM programmes will be the allocation of cost for smart metering. Research is needed on the wider benefits of smart meters to help with the business case for customer initiated DSM.
- (iv) Developing a tender process to operate a pilot programme - At least one of the recommended programmes should be progressed to pilot stage with a tender for suppliers to operate the programme. Our initial assessment is that this should be the customer initiated DSM and the best

place to host and monitor this trial would be in the Dundalk Sustainable Energy Zone. The choice of programme should be re-examined after the analysis performed in (i) – (iii) above.

- (v) Investigation into the feasibility of a joint incentive scheme – As an alternative to the Programme suggested it may be possible to combine distributor and supplier control whereby both the distributor and the supplier gain benefit from the demand management.

The remainder of this chapter details our recommendations for the focus of additional research based on the evidence from this scoping study.

## **11.2 Further Research into Quantifying Key Costs and Benefits**

This report has described qualitatively the costs and benefits that may be obtained from a range of potential DSM schemes. The next step before developing programmes further is to perform a more detailed analysis of the following key costs and benefits to help justify the business case. The exact costs and benefits will depend on which programme types were being pursued and the technology required which could vary from scheme to scheme.

- Costs of smart meters – An investigation is needed into the costs of smart meters under different assumption regarding functionality and adoption level. The evidence from the Italian experience is that the costs can be brought down by a significant sum if commitment is made to large volumes of meters. This assumption and particularly the extent of the reduction needs to be investigated. This research into cost should be tied into the work suggested in Section 10.4.
- Costs of control technology – An investigation is needed into the costs and range of different control technologies available to control load. This needs to look at different types of equipment, costs on a per unit basis and applicability to the Irish Market. A key focus should be on what is possible in the area of heating, water heating and lighting which makes up a significant proportion of domestic customers demand.
- Cost of changes to the Settlement process – One area that needs to be investigated is whether the supplier initiated programme can operate without QH meters. In addition the impact on settlement from smart meters of the customer initiated programme or supplier initiated programme should be confirmed. Determining these impacts will require detailed discussions with the settlement operator and will also necessitate developing some or all of the potential programmes to a greater level of detail such that the impact on settlement systems can be properly considered. The design of the programmes may also reflect whether the savings can be captured in settlement calculations with minimal change.
- Quantification of the energy purchasing costs saving by changing customer consumption profiles – In order to fully understand the benefits that DSM could bring there is a need to do a quantitative examination of the energy cost that could be saved over a typical year. This should attempt to compare the highest price HH periods in a day with other HH periods to which demand could be moved. This will be made more difficult to achieve in the short terms with the change to the All Island market. In this analysis assumptions would need to be made about how much of a customer load could be delayed and by how much. Calculations could then be made on a daily basis to see what the best case scenario may be for changing energy use during the day. It would also be sensible to consider in these calculations the size of the benefit associated with a reduction in energy use that typically occurs with these types of programme.

- Costs that could be saved by avoiding Distribution network reinforcements or outages. – The range of these theoretical costs varies significantly depending on what assumptions are made on the size and type of reinforcement that could be saved by utilising DSM. It is also important to meet with ESB Networks to discuss both how feasible it is to utilise DSM to avoid reinforcement and outages and the size of costs that may be saved.

### **11.3 Agreements on Solutions for Key Barriers**

Before investment in any of the schemes there is a need for confidence that the barriers can be overcome. Key areas that should be further investigated include:

- Domestic competition and customer switching– There is a need to persuade suppliers to become more involved in the residential sector and then to operate DSM Programmes. The introduction of wholesale competition may help encourage suppliers into the residential sector if it allows them to purchase electricity more efficiently. The existence of smart meters and/or the ability to invest in smart meters and DSM Control technology, with a lock in for the customer, should provide an additional stimulus to competition as supplier could offer more innovative tariffs and share the reward with customers. The ability to allow customers to switch freely was put in place to protect consumers, but does act as a barrier to the development of DSM programmes. Further discussions on alternative protection that could be put in place should be agreed with the CER to remove this barrier and encourage suppliers to come forward with innovative DSM programmes.
- Mechanism for supporting large scale investment in metering assets – Alongside the investigation of the cost of smart meters is how this cost could be recovered from customers. This investigation should consider which market participants would be best positioned to invest in the meters, what the charge could be and how that would compare with current metering and data aggregation charges. In addition there is a need to deal with stranded assets if the smart meters replace conventional meters that have not been fully depreciated. This should be linked to section 10.4.
- All Island Market – To encourage suppliers to engage in Demand Side Management it is important to ensure that the delivered market design produces predictable and transparent prices. To assist with this the pricing mechanism should be as inclusive as possible and the Capacity mechanism charging needs to be derived in a predictable way that enables suppliers to reduce customers' demand at times of forecasted high capacity charges.
- Recovering the costs of Control technology – Linked to the calculation of costs and overcoming the lack of restriction on customer switching are a number of questions on how to recover the costs of control technology. How will this control technology be charged to the customers and still make for a competitive tariff? Over how many years could suppliers/distributors tie customers in to recover the costs of control technology? One areas to consider is how and whether distributors and suppliers could work together to obtain both the benefits of mitigating price risk and avoiding the need for reinforcement.
- ESB Networks Price Control Incentives - A barrier to distributor initiated DSM is the price control and the incentives for ESB Networks to invest in the network rather than undertake DSM. Discussions with the CER and ESB Networks on possible incentives for active management of distribution networks and how to encourage DSM rather than reinforcement of the network are needed to overcome these issues. As with the costs section there is a need to discuss with the distributors whether there are any true costs savings in relation to future investment and outage management.

- Price elasticity of customers – In order for the customer initiated DSM to work the customer needs to reduce demand in response to price signals. Traditionally electricity customers are always perceived as having very low elasticity of demand. However, the success of smart metering programmes in California and the demand for the Tempo tariff in France suggests that customers are prepared to change their consumption habits for the right incentives. The only real way to test this will be as part of a pilot programme and it is suggested that different customers have different tariffs within the pilot with a study done to see the impact on customer consumption. In the shorter term it would be sensible to investigate further some of the customer initiated Programmes particularly in Northern and Western Europe to see their impact on consumption and price elasticity. It is important not to draw conclusions solely against international customers that have air conditioning or pool load that are not a feature of Ireland’s peak demand.

#### **11.4 Investigation of Smart Metering Benefits**

The key infrastructure enabler to facilitate customer initiated DSM is the introduction of smart meters. Whilst the costs of smart meters are falling they remain high relative to small business and residential customer bills. However, as well as facilitating DSM, smart meters also have a number of potential benefits including:

- Energy reduction as customers use less energy;
- Potential for reduced data collection costs (no data collectors);
- Greater protection to vulnerable members of the community (no rogue inspectors);
- Lower customer complaints as billed on actual reads;
- Ability for the customer to have precise calculations of energy cost to help with budgeting;
- Lower levels of theft due to easier detection; and
- Potential to be used to meter small scale generation – i.e. export and import.

Whether these benefits will be delivered will depend partly on the functionality of the meters and partly on way that suppliers, data collectors, distributors and customers may deploy and utilise these meters. An important area of research is to quantify the different benefits that accrue from smart meters and consider how the costs of smart meters could be allocated to those that extract value, or alternatively whether there should be enough end customer benefit for it to be a legitimate part of the bill. This research is not strictly part of DSM, but having smart meters already in existence would make the business case for customer initiated DSM much stronger.

#### **11.5 Widening the Scope of Research**

This report was a scoping study with a relatively narrow scope in terms of type of customers and definition of what is defined as DSM. In future investigations it may be possible to expand the scope and consider wider possibilities associated with DSM.

The scope of this report was focused solely on small business and domestic customers. However, there will be a wider possibility of higher levels of demand reduction if larger customers were also included in any future studies or pilot programmes. In particular making the scheme all inclusive would give both a larger

quantity of demand to reduce and customers that may be prepared to reduce demand at different times of the day to small business and domestic customers.

The second linked area requiring more investigation is wider energy efficiency developments aimed at reducing energy demand at a total level, rather than peak load shaving. Whilst a by-product of reductions in peak load is a saving in electricity consumption, there are likely to be larger gains in energy reduction if a DSM and energy efficiency programme were introduced at the same time. It would be sensible to provide energy efficiency advice when introducing a DSM programme and investigate whether this reduces customer demand. The introduction of smart meters with customers being able to witness their consumption (and ideally cost) as different appliances are switched on may help customers to reduce demand as they instantly see the financial benefits.

## **11.6 Pilot for Customer Initiated Demand Side Management**

The first step in any roll-out of DSM is a pilot programme that would demonstrate how the scheme would work and the benefits that it could bring. This should also provide important lessons about customers' elasticity of demand, response to short term price signal and the benefits of different types of media for providing information to customers. However, for any pilot programme to be feasible it would require government funding. The suggested piece of research is to provide the detailed design for a pilot scheme. The section below provides our recommendations on the minimum detail required for any pilot.

A key principal of any pilot programme is that it should be openly reported on with information on the results available to the whole industry. Whilst the supplier leading the programme may seek to make a profit it is more important that the results should be used to inform any national debate on policy such as smart meters, controllable technology and the need to alter regulation such as the 28-day rule. These rule changes and investment will have a significant impact on the electricity markets and it is important they are made on the basis of the best available information that a pilot could provide.

Key elements of the suggested pilot which will need further refinement are:

- QH meters – Customers should be given QH meters in order that they can track and understand their consumption. Ideally these should be positioned somewhere that the customer has easy access to in order to make them more aware of their consumption.
- Peak charging – the pilot should have a form of peak pricing that encourages customers to reduce demand to varying degrees. This can then be studied to assess the price elasticity of electricity customers.
- Good demographic cross section of customers and statistically significant sample – It is important that any pilot has a good mixture of consumer particularly by income and age group to see how these groups respond to price signals. Different socio-economic groups may have very different levels of price elasticity and this should be tested as part of the pilot. In addition as well as small business and domestic customers it is suggested that this is extended to include larger customers to see if they have a better response to prices signals.
- Up to date customer information on charging and billing – Any pilot needs to provide customers with up to date information on charging and billing. This should be done as a minimum on a monthly basis, but ideally more regularly to get customer buy-in to controlling their consumption.

The bills should demonstrate savings against typical consumption ideally both in financial cost and environmental costs e.g. Carbon saving and what this represents.

- Provision of pricing information to the customers (Internet, phone, mail) – The pilot would need to have a mixture of mechanisms for informing customers of high price periods. It would be useful to see which of these methods for delivering information on peak prices to customers has the most success in delivering demand reduction.
- Energy efficiency advice – If operating a pilot it would be sensible to also provide energy efficiency advice to customers to see what is achievable with provision of the benefits of both DSM and energy efficiency.

It is suggested that a high level set of rules and sample tariffs types are designed and then discussed with potential participants including suppliers, customers, ESB Networks and meter operator. A more detailed design can then be developed and a tender issued to suppliers that details a number of key criteria including as a minimum:

- Number of customers;
- Duration of the Pilot;
- Reporting requirements;
- Information to be provided to customers; and
- Range of tariffs expected.

Suppliers would then respond to the RFP, with the relevant government department sponsoring the scheme that provides the best value for the Ireland. A number of suppliers have already indicated that they would be keen in participating in this type of scheme.

An ideal place to site this Pilot would be in the Dundalk Sustainable Energy Zone that is being set up. This will include refurbishment of old houses and new houses built to high energy efficiency standards as well as a number of small businesses. It is already planned to have advanced metering technologies, which is one of the major expenses. In addition some of the premises will also have renewable generation or CHP allowing the pilot to also understand the benefits from combining DSM with intermittent or distributed generation. (Ref. 52). With the large number of initiatives it should be easier to get consumers engaged in understanding their consumption, the costs (environmental and economic) associated with it and how they can benefit from changing their behaviour.

## **11.7 Investigation of a Joint Supplier/Distributor Programme**

A final area to consider is how any joint scheme could operate that captured the benefits from the distributor and supplier scheme and ideally facilitated the involvement of intermittent generation. This scheme would be based around one party having control of the appliances for the benefit of all users. In the event of conflicting instructions the distributor initiated responses would need to take precedence to ensure network integrity is maintained.

A framework could be adapted that tried to value the benefits that each participant obtained from the DSM Programme with the costs being shared accordingly. Each participant would then need to provide funding for the equipment and organisation according to the benefits they would extract from the operation of the programme. This may work best if the programme was run by an independent Energy Services Company rather than one market participant who would design the programme to meet their goals. The emergence of energy services companies operating DSM programmes in the US suggests there would be participants prepared to independently operate these programmes and this option should be further investigated.

## **Appendix A: Irish and International DSM Programmes**

### **Ireland Demand Management Services**

The following demand management schemes are utilised in Ireland:

NightSaver;

PowerSave;

Short Term Active Response (STAR);

Winter Peak Demand Reduction Scheme; and

Winter Demand Reduction Incentive.

## NightSaver -

<b>Program Name</b>	NightSaver.
<b>Sponsoring Organisation:</b>	ESB Customer Supply.  Independent Suppliers also offer a low Night usage rate that reflects the rates offered by ESB Customers supply.
<b>How the DSM schemes operate</b>	Customers pay a higher standing charge every two months on their electricity. In return they have the cheaper night time electricity, which is priced at less than half the daytime rate. The cheap rate electricity is available between the hours of 11 p.m. and 8 a.m. (Wintertime) and between midnight and 9 a.m. (Summertime).  A large part (around 50%) of the saving offered to customers reflect the lower DUoS charges that ESB Networks make for consuming electricity during these night time.  ESB Customers supply calculate that to make savings with NightSaver a customer will need to transfer just under three units of electricity a day to NightSaver hours to offset the higher standard charge. ESB recommend that using electricity for water heating is the easiest way to transfer usage to night hours.
<b>Purpose of the DSM Scheme</b>	Allow suppliers to spread demand more evenly.
<b>Dates of operation of the Scheme</b>	All year round but different times between summer and winter.
<b>Eligibility Requirements/ Control Strategy</b>	Two rate meter.
<b>Type, size and number of customers targeted</b>	Domestic and small business customers.
<b>Role of Market Actors</b>	ESB Networks offer distribution tariffs that are lower during this night time period.
<b>Costs of the scheme</b>	Two rate meters are slightly more expensive than standard.
<b>Benefits to participants</b>	Get cheaper night time electricity. Day time rates are the same level as on standard tariff.
<b>Level of take up of the scheme</b>	The majority of customers have single rate meters.
<b>Barriers to 'take up' and how these have been addressed</b>	Some customers not keen on the added cost of two rate meters.
<b>Marketing</b>	Information available from suppliers.
<b>More information</b>	ESB website. Information has been available in ESB shops, but these are in the process of being closed down. Independent suppliers have tariff information that is available on their websites.

**Powersave –**

<b>Program Name</b>	Powersave
<b>Sponsoring Organisation:</b>	ESB National Grid (run by ESB Customer Supply and other suppliers).
<b>How the DSM schemes operate</b>	<p>Customers receive payments if they reduce demand by 100kW or more when requested to do by the supplier as part of a Powersave period. Suppliers aim to provide at least 30 minutes notice and give an indication of the estimate of the duration of the Powersave period.</p> <p>POWERSAVE periods typically last from 2-16 hours on Monday-Friday. The reduction is voluntary after the receipt of an instruction. Customers need to provide a reduction for at least 2 hours in at least one of three consecutive Powersave periods in order to stay on the Powersave register.</p> <p>Payments will depend on the decrease in electricity consumption and whether the reduced consumption occurs inside peak hours. During peak hours (Peak periods are 11:30 -12:30 Mar-Oct, 17:00-19:00 Nov – Feb) customers receive 63.5 cents for each kWh reduced. During other periods customers receive 25.4 cents per kWh. The reduction in consumption is based on the customer's consumption in the notified Powersave period and the customer's average kWh consumption during the same periods in the previous 4 weeks.</p>
<b>Purpose of the DSM Scheme</b>	Helps to ensure a continued high level of reliability.
<b>Dates of operation of the Scheme</b>	All year round.
<b>Eligibility Requirements/ Control Strategy</b>	<p>Customer need to have suitable metering and telecommunications equipment.</p> <p>Need to be able to reduce demand by 100kW or more (could involve running standby generation).</p>
<b>Type, size and number of customers targeted</b>	Fairly large customers to be able to reduce demand by the amount specified.
<b>Role of Market Actors</b>	Suppliers operate the programme even though it is funded by ESB Power Generation.
<b>Role of distributed generation</b>	Standby generation may be used to reduce consumption.
<b>Costs of the scheme</b>	Not known.
<b>Benefits to participants</b>	Customers get paid to reduce consumption.

<b>Level of take up of the scheme</b>	Not known.
<b>Barriers to 'take up' and how these have been addressed</b>	Customers switching supplier from ESB Customer Supply who traditionally ran the programme. The programme is now available to all independent suppliers with a back to back contract with ESB Power Generation.
<b>Marketing</b>	Scheme although operated by ESB National Grid is administered and managed by ESB Customer Supply or independent suppliers.
<b>More information</b>	<a href="mailto:business@esb.ie">business@esb.ie</a>

### Short Term Active Response

<b>Program Name</b>	Short Term Active Response (STAR).
<b>Sponsoring Organisation:</b>	ESB National Grid.
<b>How the DSM schemes operate</b>	<p>The loss or tripping of a generator causes a demand-supply imbalance which results in the system frequency falling rapidly. It is during this initial drop that the load contracted under the STAR scheme is disconnected. In the minutes after this incident the system frequency recovers back to 50Hz as generation comes back on line to replace the lost generation. At this point the load disconnected is then reconnected.</p> <p>Customers enter into a contract with the TSO and are paid for the energy they make available for interruption. The customer receives no notice of an interruption. The duration of the interruption will typically last around 5 minutes and customers can expect around 10-20 interruptions per annum.</p> <p>The payment rate for these service is €7.08MWh</p>
<b>Purpose of the DSM Scheme</b>	This is used to cope with an initial drop in system frequency.
<b>Dates of operation of the Scheme</b>	<p>This programme commenced in 2004. It replaced an Interruptible Load Scheme that was operated by ESB NG over the last 20 years.</p> <p>Contracts have been let by competitive procurement for 3 years.</p>
<b>Eligibility Requirements/ Control Strategy</b>	<p>Customer need to have electrical switchgear that allows their load to be disconnected by a circuit breaker.</p> <p>Interruptible load needs to be separately metered from non interruptible load.</p>
<b>Type, size and number of customers targeted</b>	<p>ESB NG has contracts with 39 electricity customers to provide 55 MW of automatic load response.</p> <p>This is the full reduction they required.</p>
<b>Role of Market Actors</b>	None.
<b>Role of distributed generation</b>	None.
<b>Costs of the scheme</b>	Not known, but cost competitive when compared to alternative off generation on stand-by.
<b>Benefits to participants</b>	Customers receive payments for this service.
<b>Level of take up of the scheme</b>	ESB National Grid has all the customers they want for this service.

<b>Barriers to 'take up' and how these have been addressed</b>	Programme fully subscribed so no significant barriers.
<b>Marketing</b>	A competitive procurement process was held by ESB NG in late 2003. This attracted all the customers that were required.
<b>More information</b>	TSO Customer Relations Team <a href="http://www.eirgrid.com">www.eirgrid.com</a>

### Winter Demand Reduction Incentive -

<b>Program Name</b>	Winter Demand Reduction Incentive.
<b>Sponsoring Organisation:</b>	ESB Customer Supply (although benefit ESB Power Generation)
<b>How the DSM schemes operate</b>	The programme operates for 2 billing periods Nov/Dec and Jan/Feb. As part of this programme customers' Maximum Demand is only measured for 2 hours each day between 5pm to 7pm, Monday to Friday. Reducing demand just in these 2 periods can result in a reduction in your overall bill when compared to your standard Maximum Demand Tariff which will be based on the period from 8am to 9pm. The minimum billed MD is 30kW.
<b>Purpose of the DSM Scheme</b>	This programme reduces the cost to ESB PowerGen to supply electricity for the short winter peak period.
<b>Dates of operation of the Scheme</b>	Nov-Dec and Jan-Feb. Annual programme run by ESB Customer supply
<b>Eligibility Requirements/ Control Strategy</b>	Need a meter that records Maximum Demand
<b>Type, size and number of customers targeted</b>	Customers with MD tariffs can be low voltage or high voltage.
<b>Role of Market Actors</b>	None.
<b>Role of distributed generation</b>	Customers are encouraged to use their standby generation between 4.45pm and 7.15pm.
<b>Costs of the scheme</b>	Not known.
<b>Benefits to participants</b>	Reduced Maximum Demand Tariffs.
<b>Level of take up of the scheme</b>	Approx 250 out of 3,000 eligible customers utilize this scheme. Numbers are increasing.
<b>Barriers to 'take up' and how these have been addressed</b>	One barrier to take up is that customers can't be a participant in both the WPDRS programme and the WDRI programme. Customers need to decide which scheme is the most appropriate.
<b>Marketing</b>	ESB Customer Supply have a Winter Demand Helpline.
<b>More information</b>	<a href="mailto:winterdemand@esb.ie">winterdemand@esb.ie</a>

### Winter Peak Demand Reduction Scheme-

<b>Program Name</b>	Winter Peak Demand Reduction Scheme.
<b>Sponsoring Organisation:</b>	ESB National Grid.
<b>How the DSM schemes operate</b>	<p>Customers volunteer to sign up for the WPDRS. The latest programme runs for 5 months from the 1 November 2005 until the 24<sup>th</sup> March 2006, without the Christmas week.</p> <p>Customers are paid for reducing their load below their normal level. Load reductions are measured as the difference between the customers' actual consumption and an assessment of what it would have been without the WPDRS.</p> <p>Baseline consumption is calculated from consumption patterns from the previous winter. This figure will apply throughout the 17:00 to 19:00 periods. Customers need to select a Committed Level which is the level that they are prepared to reduce their consumption by in this period. The Committed Level can vary between 0 MW and the baseline and can vary from week to week providing it is done in advance.</p> <p>Payments to customers are then made up of 3 components.</p> <ul style="list-style-type: none"> <li>• Reliability Payments – Customers are paid a reliability rate (2005/06 €179MW per hour) multiplied by the difference between their baseline position and the committed level.</li> <li>• Reliability Rebate – This is a payment from the customer to ESBNG that applies if the customer breaches the committed level. It is set at ten times the reliability payment (€1790MW per hour) to encourage customers to stick to the committed level</li> <li>• Profile Payment – This is an additional payment for reduction in energy consumption in the peak period. To achieve this ESBNG calculate an Energy Benchmark which is the ratio of peak consumption to average off peak consumption. The customer receives payments for consumption below the Energy Benchmark. Payments in 2005/06 were 80 euros per MWh.</li> </ul> <p>A customer will never end up owing money even if they do not reduce consumption over the period 17:00 to 19:00.</p>
<b>Purpose of the DSM Scheme</b>	The scheme aims to reduce peak demand in the winter between 17:00 and 19:00. This is for reason of high generating cost rather than reducing transmission costs.
<b>Dates of operation of the Scheme</b>	In operation 2003/04, 2004/05 and 2005/06.

<b>Eligibility Requirements/ Control Strategy</b>	<p>Customers need to have a QH meter with active remote communications.</p> <p>Customers cannot be supplied under a V.I.P.P contract.</p> <p>Customers cannot be a member of this programme and the Winter Demand Reduction Incentive.</p>
<b>Type, size and number of customers targeted</b>	Large customers. Total of 236 customers took part from 1059 that were eligible.
<b>Role of Market Actors</b>	Suppliers receive 5% of the payments made to customers. This is to cover their costs of operating the programme.
<b>Role of distributed generation</b>	<p>None.</p> <p>However many customer could potentially use stand-by generation to help achieve the demand reduction (or reduce demand further).</p>
<b>Costs of the scheme</b>	<p>2004/05</p> <p>Customers received €4.1m</p> <p>Suppliers received €207k</p>
<b>Benefits to participants</b>	<p>Additional source of revenue for customers.</p> <p>Successful for the ESB National Grid in lowering Peak Demand (Average 100 MW reduction each day Nov-Feb 80MW March 2004/05)</p>
<b>Level of take up of the scheme</b>	236 Customers participate in 2004/05 out of 1059 that were eligible to take part.
<b>Barriers to 'take up' and how these have been addressed</b>	<p>QH Meters needed by participants.</p> <p>Concern that if a customer has 4 large breaches early in the month they may have no incentive to reduce consumption as this will be more that the reliability payments. However, customers will still receive energy payments throughout the month which provides some incentives to keep reducing consumption for the rest of the month.</p>
<b>Marketing</b>	ESBNG run a number of workshops to inform customers of the benefits of this programme. Customers are informed of these workshops through direct marketing 'invitation' as well as these workshops being advertised in the national press. In addition ESBNG write articles about the scheme and have developed a brochure for customers.
<b>More information</b>	<a href="http://www.eirgrid.com">www.eirgrid.com</a>

## **UK Demand Management Services**

The following demand management schemes are utilised in the UK:

Balancing Mechanism;

Demand Turndown;

Distribution Network Avoidance;

Fast Reserve;

Frequency Response;

Night Time Economy Seven;

Standing Reserve; and

Triad Avoidance.

## Balancing Mechanism

<b>Programme Name</b>	Participation in the Balancing Mechanism.
<b>Sponsoring Organisation:</b>	NGT (and the Supplier of the customer).
<b>How the DSM schemes operate</b>	NETA was intended to be a 2 sided market with NGT balancing the system using bids and offers from both generation and the demand side of the market.  Suppliers submit offers for the demand BMU to reduce their load. If NGT accept these offers then the customers need to make this reduction or else be out of balance.
<b>Purpose of the DSM Scheme</b>	NGT can utilize the demand side of the market to help keep the system in balance.
<b>Dates of operation of the Scheme</b>	In operation since NETA went live in March 2001.
<b>Eligibility Requirements/ Control Strategy</b>	Normally participants will have a HH Meter and ability to turn down demand. Needs a Supplier to bid into the BM on the customers' behalf.
<b>Type, size and number of customers targeted</b>	Only a few very large customers have participated in the BM.
<b>Role of Market Actors</b>	Require supplier to submit bids/offer on behalf of the customer.
<b>Role of distributed generation</b>	None.
<b>Costs of the scheme</b>	NGT will accept the cheapest bids/offers. The involvement of the demand side represents increased competition so there should be a saving to the industry.
<b>Benefits to participants</b>	Additional source of revenue.
<b>Level of take up of the scheme</b>	Very few active participants.
<b>Barriers to 'take up' and how these have been addressed</b>	<ul style="list-style-type: none"> <li>• Only licensed suppliers can participate in the BM. This activity therefore requires agreement from the supplier to place bids/offer.</li> <li>• Risk of potentially high imbalance payments if they failed to deliver</li> <li>• Participants can not receive balancing services availability payments and participate in the balancing mechanism</li> </ul> <p>Requirement to segregate demand side participants in separate BMUs in order to provide sufficient resolution to confirm demand reduction was actually achieved.</p>
<b>Marketing</b>	Large Customers are aware of the opportunity to participate in the balancing mechanism through groups such as the MEUC.
<b>More information</b>	<a href="http://www.elexon.co.uk">www.elexon.co.uk</a> <a href="http://www.ofgem.gov.uk">www.ofgem.gov.uk</a>

## Demand Turndown -

<b>Programme Name</b>	Demand Turndown Pilot Scheme.
<b>Sponsoring Organisation:</b>	National Grid Transco.
<b>How the DSM schemes operate</b>	<p>This scheme is aimed at large demand customers, aggregators and/or small generators. Participants have to offer to turn down demand for a minimum of 2 hour periods.</p> <p>The winter scheme had a single 2 hour fixed window of availability from 9:00 to 11:00 and an optional window/zone at either side of this fixed window. The summer trial had 2 turndown periods from 09:30 to 11:30 and from 11:30 to 13:30. The change in the size of the windows from the summer to winter reflects feedback from participants.</p>
<b>Purpose of the DSM Scheme</b>	<p>The scheme was designed to give the demand side a better opportunity to provide balancing services.</p> <p>If this current trial is successful then NGT have indicated that they may make this trial an enduring service that would compete with warming or hot standby contracts and be a source of contingency reserve for the delivery of active power.</p>
<b>Dates of operation of the Scheme</b>	<p>Latest trial ran from the end of November 2004 to end of March 2005.</p> <p>The first trial was run from 5 April to 30 July 2004.</p>
<b>Eligibility Requirements/ Control Strategy</b>	<p>Each participant needs to provide:</p> <ul style="list-style-type: none"> <li>• 100MW of turndown capacity (this has been relaxed so far);</li> <li>• Sustainable for up to 2 hours;</li> <li>• Single contracting counterparty and point of dispatch; and</li> <li>• Identified demand sites.</li> </ul> <p>Participating demand sites cannot participate in other services at the same time (i.e. need to avoid double payments).</p>
<b>Type, size and number of customers targeted</b>	<p>Large customers with HH metering (preferably minute by minute).</p> <p>Potentially small generators.</p> <p>.</p>
<b>Role of Market Actors</b>	Aggregators are needed to combine demand from demand sites and potentially generators.
<b>Role of distributed generation</b>	Potential for small generators to be involved but no evidence that they have been so far. Could potentially see a role for large customers having their own standby generation that they use alongside this scheme).
<b>Costs of the scheme</b>	<p>The report on the first trial of the pilot scheme has the preliminary settlement figures giving a total spend of £140k. This breaks down into:</p> <ul style="list-style-type: none"> <li>• Availability Payments - £36k</li> <li>• Standby Payments - £30k</li> <li>• Utilisation Payments - £74k.</li> </ul>

<b>Benefits to participants</b>	Payments from NGT.
<b>Level of take up of the scheme</b>	<p>Disappointing for the first trial. Pilot scheme had 2 aggregators (Gaz de France and Npower) and involved seven site operators.</p> <p>The average daily availability was the 66 MW for the first 2 hour period and 48MW for the second period with maximum availability achieved of 87.6MW and 75.5MW in the respective periods.</p>
<b>Barriers to 'take up' and how these have been addressed</b>	<ul style="list-style-type: none"> <li>• Supply contract negotiations that coincided with the Demand Turndown trial periods</li> <li>• Providers reluctant to provide a new service</li> <li>• Operational drivers outweighed the gains from payments for this service</li> </ul>
<b>Marketing</b>	Promoted at Ofgem's Demand Side Working Group and NGT's Operational Forum.
<b>More information</b>	<a href="http://www.nationalgrid.com">www.nationalgrid.com</a> <a href="http://www.ofgem.gov.uk">www.ofgem.gov.uk</a>

## Distribution Network Avoidance (Anglesey) -

<b>Programme Name</b>	Distribution Network Avoidance at Anglesey
<b>Sponsoring Organisation:</b>	MANWEB
<b>How the DSM schemes operate</b>	<p>The scheme had a number of different methods designed to reduce peak demand on the island. This includes:</p> <p><b>Households</b></p> <ul style="list-style-type: none"> <li>• Offer of 2 energy efficient light bulbs per household</li> <li>• Offer of cheap loft insulation and draught proofing</li> <li>• Free water tank insulation</li> <li>• Rebates on energy efficient appliances</li> </ul> <p><b>Small Business Sector</b></p> <ul style="list-style-type: none"> <li>• Offer of 2 energy efficient light bulbs per household</li> <li>• Free water tank insulation</li> <li>• A free lighting audit</li> </ul> <p><b>Large Business Sector</b></p> <ul style="list-style-type: none"> <li>• Free energy audit</li> <li>• Subsidies on energy saving measures</li> <li>• Subsidies on power factor correction equipment</li> </ul>
<b>Purpose of the DSM Scheme</b>	Avoid or defer investment in a new transformer at Holy Island
<b>Dates of operation of the Scheme</b>	Programme started in 1993 and ran for approximately one year.
<b>Eligibility Requirements/ Control Strategy</b>	<p>Most electricity customers were eligible for the programme and there were no special metering requirement.</p> <p>Customers needed to be electrically heated to be eligible for some of the insulation.</p>
<b>Type, size and number of customers targeted</b>	The programme targeted both residential and business customers including industrial and commercial customers.
<b>Role of Market Actors</b>	National Energy Action was responsible for draught proofing and insulation Prince's Trust was used for distributing the light bulbs.
<b>Role of distributed generation</b>	None
<b>Costs of the scheme</b>	£250k

<b>Benefits to participants</b>	Cheap mechanism for customers to save electricity. Free advice and discounted appliances. Manweb were able to defer network investment.
<b>Level of take up of the scheme</b>	Good participation rate achieved – Energy Savings Trust reported following take up: <ul style="list-style-type: none"> <li>• Residential customers had penetration rates of 79% for light bulbs, water cylinder insulation of 84%, but lower rates for draught proofing 20% and insulation 30%.</li> <li>• Small business market penetration rates were 24% light bulbs, 17% water cylinders, 6% lighting refurbishment</li> <li>• Industrial customers who were involved saved significant amounts of energy. 60% of the peak demand was saved by just 4 sites.</li> </ul>
<b>Barriers to 'take up' and how these have been addressed</b>	Persuading customers of the benefits of these demand side initiatives. To overcome this, a dedicated mobile unit and a Manweb shop were used for sales and marketing of the programme.
<b>Marketing</b>	Mainly by direct mail, but also local radio, TV, press and local schools. Also the mobile unit applied above.
<b>More information</b>	Aine Kelly and Simon Marvin 'Demand Side Management: The Electricity Sector and Town Planning' School of Architecture, Planning & Landscape, University of Newcastle upon Tyne  Energy Savings Trust 'Energy Efficiency and Jobs: UK Issues and Case Studies' A report by the Association for the Conservation of Energy to the Energy Savings Trust, Sept 2000

## Fast Reserve -

<b>Programme Name</b>	Fast Reserve.
<b>Sponsoring Organisation:</b>	National Grid Transco.
<b>How the DSM schemes operate</b>	<p>This scheme is aimed at both generation and supply.</p> <p>It requires rapid reduction in consumption after receipt of an electronic dispatch instruction from NGT. This power delivery needs to start within 2 minutes of instruction, deliver in excess of 25MW/minute and be sustainable for a minimum of 15 minutes.</p> <p>It is proven scheme for very large customers who have their processes controlled by direct circuit breakers.</p> <p>There was a trial in 2002/03 for small customers. One element was around short term interruptions and was based on water/space heating control by radio teleswitch/Cyclocontrol. These small customers could only provide fast reserve during off peak periods. It is also mainly applicable during the winter periods as it is based on the heating load. Trial was for 300MW from RTS customers and 50MW by Cyclocontrol.</p> <p>The other element of the small customer trial was off-peak demand profiling using 600MW of teleswitch demand. This involved the off peak switching being staggered to smooth any rapid demand changes that would occur if all switching occurred at the same time.</p>
<b>Purpose of the DSM Scheme</b>	Fast Reserve is required by NGT to help keep the system in balance.
<b>Dates of operation of the Scheme</b>	<p>All year round.</p> <p>Small customers were trialled in 2002/03.</p>
<b>Eligibility Requirements/ Control Strategy</b>	<p>NGT list the follow eligibility criteria for Fast Reserve:</p> <ul style="list-style-type: none"> <li>• Capability to start Fast Reserve delivery within 2 minutes of instruction</li> <li>• Delivery rate of Fast Reserve &gt; 25MW / minute</li> <li>• Capability to sustain output for &gt; 15 minutes</li> <li>• Capability to halt or start to unwind Fast Reserve delivery within 2 minutes of instruction</li> <li>• Unwind rate of Fast Reserve &gt; 25MW / minute</li> <li>• Minimum single instructable block size of 50MW or aggregation of more than one unit to create an aggregated unit with a size of 70MW</li> <li>• Electronic despatch</li> <li>• Measurable &amp; Demonstrable Fast Reserve delivery</li> </ul> <p>Limitations of utilisation of Fast Reserve.</p>
<b>Type, size and number of customers targeted</b>	<p>Very large customers that meet the requirements.</p> <p>Large groups of small customers for the trial.</p>
<b>Role of Market Actors</b>	Potential role for aggregators.

<b>Role of distributed generation</b>	None.
<b>Costs of the scheme</b>	Non Tendered Fast Reserve contracted on a bilateral basis from Service providers was worth £2.7m in availability payments in June 2005.
<b>Benefits to participants</b>	Payments from NGT.
<b>Level of take up of the scheme</b>	Fast Reserve mainly provided by generators rather than demand side.
<b>Barriers to 'take up' and how these have been addressed</b>	Technical qualification criteria are onerous and restrict demand side involvement. Most Fast Reserve provided by a small number of generating units.
<b>Marketing</b>	NGT's Operational Forum and the Demand Side Working Group.
<b>More information</b>	<a href="http://www.nationalgrid.com">www.nationalgrid.com</a> <a href="http://www.ofgem.gov.uk">www.ofgem.gov.uk</a>

## Frequency Response -

<b>Programme Name</b>	Frequency Response.
<b>Sponsoring Organisation:</b>	National Grid Transco.
<b>How the DSM schemes operate</b>	<p>Suppliers can compete with generators to provide the non mandatory frequency response services. These services can either be firm or optional. The firm contracts mean that you have to shed load when required by NGT, the optional contracts give the participant some discretion on whether the service is provided.</p> <p>Customers who provide these services have to be prepared for their demand to be interrupted for up to 30 minutes several times a week. However, in practice the sites are interrupted between 10 and 30 times a year. (There is also only partial site interruption).</p> <p>These demand services can be initiated automatically from large customers using low frequency relays, which automatically shed load for pre-determined low frequency events.</p> <p>Suppliers are rewarded based on Holding (availability) and Response Energy Payments (not necessarily the supplier – NGT may pay the demand side provider directly or an aggregator). With optional contracts the holding payments are restricted to when the provider makes the service available.</p>
<b>Purpose of the DSM Scheme</b>	NGT need to maintain frequency at 50 Hz and will endeavour to find the most cost effective way to achieve this. Utilising the demand side helps in broadening the potential market and reduces the need to use the more expensive mandatory service that generators provide. The LF relay approach is designed to alleviate frequency problems at times of high system stress, not a normal network condition.
<b>Dates of operation of the Scheme</b>	All year round. Has been utilized for many years.
<b>Eligibility Requirements/ Control Strategy</b>	Large customers. HH meters.
<b>Type, size and number of customers targeted</b>	The participants that normally provide these services are large flexible industrial load that can meet the changing demand requirements. Recently some aggregators such as Gas de France have been facilitating smaller sites being involved.
<b>Role of Market Actors</b>	Aggregators have started to play a role in this service.
<b>Role of distributed generation</b>	None directly – (could potentially see a role of large customers having their own standby generation that they use alongside this scheme).
<b>Costs of the scheme</b>	In June 2005 £1.8m was spent on Mandatory frequency response and £1.5m was spent on Commercial frequency response.

<b>Benefits to participants</b>	Payments from NGT.
<b>Level of take up of the scheme</b>	In 2002 there was an estimate of at least 10 demand side providers of this service (Ref 22).  NGT stated that these volumes have been steadily growing.
<b>Barriers to 'take up' and how these have been addressed</b>	Being prepared to be interrupted by NGT. Size required to be useful to NGT and the sole agent requirement HH Metering requirements.
<b>Marketing</b>	NGT have information on their website. Large users should be aware of the potential for these services through their lobbying groups such as Energy Intensive Users Group.
<b>More information</b>	<a href="http://www.nationalgrid.com">www.nationalgrid.com</a> <a href="http://www.ofgem.gov.uk">www.ofgem.gov.uk</a>

## Night team Economy Seven -

<b>Programme Name</b>	Economy 7 (different versions exist).
<b>Sponsoring Organisation:</b>	Suppliers.
<b>How the DSM schemes operate</b>	<p>Customers have two rate meters that record their usage separately at night and during the day. Electricity used during the night is cheaper than during the day encouraging customers to use more electricity at off peak times typically this is for seven hours between such as 00:30 to 07:30.</p> <p>The largest part of this load may be electric heating which would be set to come on during the night. Some customers will have separate circuits for this load, but otherwise they will need to set the heating to come on when the Economy Seven tariffs are in operation. The customer may also set appliances such as washing machines/dishwashers to come on during the night. These appliances would typically be done during using a timer. Not all houses with Economy Seven meters have electric heating.</p> <p>Some customers will have teleswitch meters which will have an electrical circuit or tariff that is switched by radio circuit (e.g. off peak storage heating load). Suppliers are able to control the switching time of meters by the use of group codes. Either the supplier can sponsor its own group codes or can utilize existing codes provided by other supply companies. National radio signals (radio 4) are used to transmit the switching times of these restricted times and the times for reduced tariffs.</p> <p>For customer without teleswitch meters, the seven hours of night time load are pre-set and will require a change on the meter to alter the time at which this happens. This tends to be expensive (as a meter operator will need to visit the premises) and so the times are rarely changed.</p>
<b>Purpose of the DSM Scheme</b>	<p>Balances load out more evenly across the day. Allows suppliers to purchase cheaper night time power and stop distribution companies needing to reinforce the network.</p> <p>For teleswitched meters it also provides controllability of load. This allows distribution businesses to avoid too much peak demand on the network. It also allows suppliers to purchase energy at cheaper prices and moves load around to match energy purchases.</p>
<b>Dates of operation of the Scheme</b>	All year round.
<b>Eligibility Requirements/ Control Strategy</b>	<p>Two rate meter.</p> <p>Teleswitch customers need to have a meter with a radio teleswitch and preferably a separate electrical circuit that can be switched.</p>
<b>Type, size and number of customers targeted</b>	Domestic and small business customers. Many millions.
<b>Role of Market Actors</b>	Meter operators need to ensure meters are set to record cheap rate electricity at the right time.

	Teleswitch Agent needed to control switching times.
<b>Role of distributed generation</b>	None.
<b>Costs of the scheme</b>	Two rate meters and radio teleswitches slightly more expensive than standard meters.  Additional costs if meters need to be visited to change the time regime at which they are set.  Need to pay for the teleswitch signals being sent out.
<b>Benefits to participants</b>	Get cheaper night time electricity (day time electricity is normally more expensive).
<b>Level of take up of the scheme</b>	High, particularly in certain locations. Many newly built house in the 1980s had electric heating that come on at night and consequently they had two rate meters and benefit from economy seven tariffs.  Higher penetrations in areas without mains gas supplies, i.e. more customers reliant on electric space/water heating. This provides much greater demand response.
<b>Barriers to 'take up' and how these have been addressed</b>	A key barrier to expansion has been the dramatic rise of gas central heating rather than electric. This has replaced some of the existing electric heaters that used to operate on economy 7.  The fact that heating is not on a separate circuit may make it harder to dynamically switch this heating.  Setting up codes for teleswitching.  Market competition – Competing suppliers do not know exact switching times, thus complicating demand forecasting and increasing non-incumbent balancing market exposures.  28-day rules means could invest in setting up teleswitch customers and they may leave.
<b>Marketing</b>	Campaigns used to be run by the PESs to encourage electric heating. Most suppliers also have an economy seven type tariff to reward customers that use night time electricity.  Limited marketing of teleswitching functionality. (Seen as too complicated with little initial investment and no guarantee that customers will remain loyal).
<b>More information</b>	Supplier websites. Some suppliers also offer deals on electric heating Radio Teleswitch Sub Group Meeting (Available from Ofgem)

## Standing Reserve -

<b>Programme Name</b>	Standing Reserve.
<b>Sponsoring Organisation:</b>	National Grid Transco.
<b>How the DSM schemes operate</b>	<p>Standing reserve is sourced from participants capable of synchronizing and providing the TSO's required level of output for at least 20 minutes. Demand side participants can provide this reserve by offering to reduce load when requested by NGT.</p> <p>There is an annual competitive auction for standing reserve. This auction splits the year into five seasons, into working days and non working days and the period into which the Standing Reserve is needed. These periods are referred to as availability periods. Participants bid (availability and utilization) to provide standing reserve during these periods.</p>
<b>Purpose of the DSM Scheme</b>	During parts of the day NGT will require extra power to deal with actual demand being higher than expected or generation not meeting the expected level. Some of this requirement is met by contracting for standing reserve of which demand reduction is a part.
<b>Dates of operation of the Scheme</b>	Scheme is utilised all year round.
<b>Eligibility Requirements/ Control Strategy</b>	<p>Providers of standing reserve need to be able to meet the following criteria</p> <p>Reduce demand by at least 3MW (this can be from a set of sites but needs a minimum aggregate of 3MW)</p> <ul style="list-style-type: none"> <li>• Response time to demand reduction of 20 minutes or less</li> <li>• Provide reserve for at least 2 hours</li> <li>• Recovery time of no more than 20 hours</li> <li>• Provide standing reserve at least 3 times a week.</li> </ul>
<b>Type, size and number of customers targeted</b>	Large HH Customers.
<b>Role of Market Actors</b>	None.
<b>Role of distributed generation</b>	None – although potentially standby generation could be utilized when called for standing reserve. Virtually all standing reserve from the demand side is provided by DG.
<b>Costs of the scheme</b>	In the latest month June 2005 £3.4m was spent on Standing Reserve availability payments.
<b>Benefits to participants</b>	Participants get paid. The amount will depend on whether the demand site is also a participant in the BM. Stand by generators get paid to test their plant. Characterized by low availability payments and high utilization.

<b>Level of take up of the scheme</b>	See market reports.
<b>Barriers to 'take up' and how these have been addressed</b>	Infrastructure requirements. Steady increase in small-scale distribution connected customer participation although predominantly provided from DG.
<b>Marketing</b>	Major users are aware of the schemes.
<b>More information</b>	<a href="http://www.nationalgridinfo.co.uk/balancing/pdfs/Standing_Reserve_Market_Report_2004-2005.pdf">http://www.nationalgridinfo.co.uk/balancing/pdfs/Standing_Reserve_Market_Report_2004-2005.pdf</a> <a href="http://www.ofgem.gov.uk">www.ofgem.gov.uk</a>

## Triad Avoidance -

<b>Programme Name</b>	Triad Avoidance – Different suppliers have slightly different schemes for load shedding all based around minimizing peak demand.
<b>Sponsoring Organisation:</b>	National Grid (Indirectly).
<b>How the DSM schemes operate</b>	<p>National Grid charge HH customers (through their supplier) for TNUoS based on electricity usage at the three half hours of peak demand (the Triad).</p> <p>The Triad is the three settlement periods of highest transmission system demand. These three settlement periods needs to be separated from each other by at least 10 clear days from November to February of the Financial Year.</p> <p>Suppliers offer load management services that will predict a number of occasions when the triad is likely to occur. The Supplier will notify the customer who will have the option of reducing demand.</p> <p>Contracts expose the customer and the supplier to variable TNUoS charge risk. How this risk is shared varies between supplier offerings. Typically, customers are incentivised to reduce demand during triad avoidance periods for significant reductions in TNUoS charge.</p>
<b>Purpose of the DSM Scheme</b>	One of the key drivers of transmission investment is the level of peak demand. This scheme will facilitate customers reducing their peak demand leading to lower TNUoS charges.
<b>Dates of operation of the Scheme</b>	1990 onwards.
<b>Eligibility Requirements/ Control Strategy</b>	Need HH metering.
<b>Type, size and number of customers targeted</b>	The need for HH metering means that it will be large customer. However, there are over 70,000 HH meters installed so this is a fairly large potential customer base.
<b>Role of Market Actors</b>	Suppliers are needed to offer these load management services as part of their product offerings.
<b>Role of distributed generation</b>	None directly. In the same way that demand reduction is instructed, distribution connected customers are also incentivised to run their on-site generation during load management periods, thus reducing their demand further.
<b>Costs of the scheme</b>	The costs could be seen as more of an opportunity costs in terms of an alternative mechanism for dividing up the costs of Transmission User of System.
<b>Benefits to participants</b>	Lower Transmission Use of System charges.

<b>Level of take up of the scheme</b>	<p>A well utilized scheme, particularly among larger customers. There was some discussion in 2002 about discontinuing the scheme, but there was a lot of support for the current arrangements. Historically the result has been to reduce the system peak by up to 1700 MW. In 2001/02 NGT put this as 800MW was occurring although other respondents put the figure at up to 1,500 MW (Ref. 5).</p> <p>An interesting feature of such schemes is that customer response to triad avoidance instructions is such that the timing of each Triad can be influenced, i.e. load management reduces and moves the timing of peak demand (thereby making Triad forecasting more challenging).</p>
<b>Barriers to 'take up' and how these have been addressed</b>	<ul style="list-style-type: none"> <li>• HH Meter</li> <li>• Desire to be interrupted (reduce load) when requested by the suppliers who are guessing the triad periods</li> </ul> <p>A mandatory HH metering programme for large customer in the run up to full retail competition has increased the number of customer that have the appropriate metering.</p>
<b>Marketing</b>	<ul style="list-style-type: none"> <li>• Suppliers contact customers and offer innovative (lower) tariffs that require customers to agree to be interrupted a number of times based on when Suppliers believe the triad will occur.</li> </ul>
<b>More information</b>	<p><a href="http://www.nationalgrid.com">www.nationalgrid.com</a>  <a href="http://www.ofgem.gov.uk">www.ofgem.gov.uk</a>  Suppliers will have detail of the schemes they operate to promote load reduction at expected Triads.</p>

## **Australia**

The Australian programs that were reviewed for this study were:

1. Bairnsdale Power Station
2. Tahmoor Fuel Substitution Project
3. Castle Hill Demand Management Project
4. Baulkham Hills Substation Deferral
5. Western Sydney Interruptible Air Conditioning Rebate Trial
6. Sydney CBD Curtailment Project

### Bairnsdale Power Station (Distributed Generation)

<b>Programme Name</b>	Bairnsdale Power Station
<b>Sponsoring Organisation:</b>	Duke Energy International (Power Producer)
<b>How the DSM schemes operate</b>	<p>To meet local electricity demand, Duke Energy International chose to build a new distributed generation station. This provided a significant advantage to the local distribution network as it avoided the alternative option of needing to build a 150 KM 220 Kv transmission line from the Latrobe Valley to Bairnsdale.</p> <p>The power station has 2 x 43MW units and operates as a peaking plant as well as providing network support to the local distribution network operated by TXU. A network support agreement is in place with TXU that requires the power station to operate during periods when the local network is under pressure.</p> <p>The project includes a Static Var Compensator that improves reliability for local businesses and community.</p>
<b>Purpose of the DSM Scheme<sup>10</sup></b>	DG to avoid T&D investment.
<b>Dates of operation of the Scheme</b>	2002-current.
<b>Eligibility Requirements/ Control Strategy</b>	Not applicable.
<b>Type, size and number of customers targeted</b>	1 large power station.
<b>Role of Market Actors</b>	Not applicable.
<b>Role of distributed generation</b>	Relies on a distributed generator when the network is under pressure.
<b>Costs of the scheme</b>	~\$75 million (although most of this is the power station costs which is not just to avoid network reinforcement).
<b>Benefits to participants</b>	<ul style="list-style-type: none"> <li>• Duke gained by building a power station that could provide higher peak price power to Victoria.</li> <li>• TXU gained in having generation available to support the network and therefore avoided network investment.</li> <li>• Customers gain from improved reliability.</li> <li>• Environmental gain from a gas fired station that would replace coal generation.</li> </ul>
<b>Level of take up of the scheme</b>	Not applicable.

<sup>10</sup> Taken from: Demand Management Activities Applicable to Electricity Networks. Prepared for the Demand Management and Planning Project by Energy Futures Australia. 2004.

<b>Barriers to 'take up' and how these have been addressed</b>	Not applicable.
<b>Marketing</b>	Agreement between power station and network company.
<b>More information</b>	<a href="http://www.alinta.net.au/organisation/indPower/bairnsdale.aspx">http://www.alinta.net.au/organisation/indPower/bairnsdale.aspx</a> <a href="http://www.efa.com.au/Library/DMAactivitiesApplicElecNetworks.pdf">http://www.efa.com.au/Library/DMAactivitiesApplicElecNetworks.pdf</a>

### Tahmoor Fuel Substitution Project, New South Wales (Load Management)

<b>Programme Name</b>	Tahmoor Fuel Substitution Project <sup>11</sup> .
<b>Sponsoring Organisation:</b>	Integral Energy.
<b>How the DSM schemes operate</b>	The Programme aimed to reduce peak demand by flattening the energy load. The key mechanism for achieving this was to persuade residential customers to use an alternative fuel, bottled gas, for cooking and space heating. To encourage this change Integral Energy arranged for the installation of bottled gas and appliances and gave subsidies of \$150 for customers' installation of bottled gas plus \$150 per bottled gas appliance.
<b>Purpose of the DSM Scheme</b>	The purpose of the Programme was to defer augmentation of the distribution network. It aimed to do this by controlling growth in the winter evening peak demand.
<b>Dates of operation of the Scheme</b>	1998-2001
<b>Eligibility Requirements/ Control Strategy</b>	Selected customers.
<b>Type, size and number of customers targeted</b>	100 residential customers.
<b>Role of Market Actors</b>	None.
<b>Role of distributed generation</b>	None.
<b>Costs of the scheme</b>	\$40,000 subsidies paid to customers \$18,000 administrative costs.
<b>Benefits to participants</b>	Customers benefited from subsidies for installation of bottled gas and appliances Integral Energy benefited from deferred network investment.
<b>Level of take up of the scheme</b>	~100 customers.
<b>Barriers to 'take up' and how these have been addressed</b>	A key barrier was the hints by the State's primary gas distributor about extending reticulated natural gas to the area. Even though these plans didn't materialize, the possibility of natural gas prevented customers from making decisions in favour of Integral's bottled gas solution. This barrier was not really addressed.  Due to the low take up of customers the programme only deferred the supply-side system upgrades for a shorter period of time with augmentation eventually needed in 2003/04.
<b>Marketing</b>	Customers were sent a personalised letter that gave details of subsidies available from Integral and the costs of bottled gas appliances.

<sup>11</sup> Taken from: Demand Management Activities Applicable to Electricity Networks. Prepared for the Demand Management and Planning Project by Energy Futures Australia. 2004.

**More information**

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<http://www.efa.com.au/Library/DMActivitiesApplicElecNetworks.pdf>

## Castle Hill Demand Management Project, Sydney (Load Management)

<b>Programme Name</b>	Castle Hill Demand Management Project <sup>12</sup> .
<b>Sponsoring Organisation:</b>	Integral Energy.
<b>How the DSM schemes operate</b>	<p>Integral Energy provided funding to the NSW Sustainable Energy Development Authority (now the NSW Department of Energy, Utilities, and Sustainability (DEUS)) to conduct a demand management programme focused on the commercial sector.</p> <p>The Programme utilize a number of mechanism for reducing demand this includes:</p> <ul style="list-style-type: none"> <li>• Interruptible loads;</li> <li>• Existing standby generators;</li> <li>• Installation of high efficiency air conditioning (and the upgrading of existing air conditioning systems); and</li> <li>• Installation of efficient lighting and power factor correction equipment in new and replacement applications.</li> </ul>
<b>Purpose of the DSM Scheme</b>	<p>Growth in air conditioning in and around the Castle Hill area meant that summer peak loads could exceed the system capability. Despite high load growth the initial assessment suggested that sufficient demand could be reduced to postpone the investment in additional network infrastructure.</p> <p>The targets were an initial reduction of 1MVA in summer peak demand with further reductions of 0.5MVA p/a in subsequent years with a plan for the programme to run for 3 years.</p> <p>The programme is expected to defer supply-side system upgrades until November 2009.</p>
<b>Dates of operation of the Scheme</b>	2003 to 2006.
<b>Eligibility Requirements/ Control Strategy</b>	Varied depending on types of participant
<b>Type, size and number of customers targeted</b>	Once the Programme has established itself with larger commercial customers, it will then be expanded to smaller customers.
<b>Role of Market Actors</b>	DEUS administers the program.
<b>Role of distributed generation</b>	One component is back-up generators used during peak periods.
<b>Costs of the scheme</b>	\$300,000.
<b>Benefits to participants</b>	<ul style="list-style-type: none"> <li>• Deferred T&amp;D investment</li> <li>• Increased reliability</li> </ul>

<sup>12</sup> Taken directly from: Demand Management Activities Applicable to Electricity Networks. Prepared for the Demand Management and Planning Project by Energy Futures Australia. 2004.

<b>Level of take up of the scheme</b>	Sufficient to meet load shredding targets.
<b>Barriers to 'take up' and how these have been addressed</b>	Cost and education barriers address by outreach.
<b>Marketing</b>	DEUS had face to face meetings with and performed site audits of commercial sector customers to identify DM opportunities.
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### Baulkham Hills Substation Deferral, Sydney (Interruptible Load)

<b>Programme Name</b>	Baulkham Hills, Sydney, Australia <sup>13</sup> .
<b>Sponsoring Organisation:</b>	Integral Energy.
<b>How the DSM schemes operate</b>	This program is an agreement with one major industrial customer to reduce load when required for network purposes. This customer uses large furnaces and puts a substantial peak demand of 12 MVA on the network. Integral Energy has an agreement with the customer to shed load between 1pm and 5pm when given 24 hours notice. The customer is able to achieve this load reduction by speeding up production prior to the time period and then slowing it down from its average rate during the peak period.
<b>Purpose of the DSM Scheme</b>	The program was introduced to defer a \$1.7m network augmentation project. The area had seen a growth in summer afternoon peak demand, which meant that a new zone substation would be required in the absence of a demand reduction programme.
<b>Dates of operation of the Scheme</b>	The agreement with the customer was originally scheduled to operate from 1998 to 2003. The agreement has since been extended by two years to 2005.
<b>Eligibility Requirements/ Control Strategy</b>	Agreement with one large customer.
<b>Type, size and number of customers targeted</b>	One major industrial customer.
<b>Role of Market Actors</b>	Not applicable.
<b>Role of distributed generation</b>	None.
<b>Costs of the scheme</b>	The majority of the cost of the Programme has been the payments made to the participating customer which total ~\$100,000. Another approximately \$10,000 was incurred in setting up and initiating the program.
<b>Benefits to participants</b>	<ul style="list-style-type: none"> <li>• Deferred T&amp;D investment</li> <li>• The agreement with this one customer has achieved peak load reductions of between 3.5 and 4.5 MVA.</li> </ul>
<b>Level of take up of the scheme</b>	One customer which was the aim of the Programme.
<b>Barriers to 'take up' and how these have been addressed</b>	Not applicable.

<sup>13</sup> Taken from: Demand Management Activities Applicable to Electricity Networks. Prepared for the Demand Management and Planning Project by Energy Futures Australia. 2004.

<b>Marketing</b>	Agreement with 1 customer so no real marketing.
<b>More information</b>	Frank Bucca Demand Management & Utilisation Manager System Development Department Integral Energy PO Box 6366 Blacktown NSW 2148 Tel: 02 9853 6566 Fax: 02 9853 6099 E-mail: <a href="mailto:bucca@integral.com.au">bucca@integral.com.au</a>  <a href="http://www.efa.com.au/Library/DMAactivitiesApplicElecNetworks.pdf">http://www.efa.com.au/Library/DMAactivitiesApplicElecNetworks.pdf</a>

### Western Sydney Interruptible Air Conditioning Rebate Trial (Interruptible Load)

<b>Programme Name</b>	Western Sydney Interruptible Air Conditioning Rebate Trial <sup>14</sup> .
<b>Sponsoring Organisation:</b>	Integral Energy.
<b>How the DSM schemes operate</b>	<p>This was a trial of residential customers in 2 suburbs of western Sydney. The programme used 2 control technologies, pager and ripple control to reduce demand. The trial comprised six load shedding events of approximately 30 minutes each. Ninety residential customers were selected to participate in the trial.</p> <p>At the conclusion of the trial, customers received the \$150 incentive payment on receipt of their responses to a final questionnaire about their experiences during the trial. This included some customers that were just a control sample and whose air conditioning was not actually cycled.</p>
<b>Purpose of the DSM Scheme</b>	<p>Air conditioners create large peak loads and distributors are keen to find mechanisms for managing this load and reducing system peaks. Integral Energy therefore sponsored a trial of air-conditioning cycling to reduce the system peak by definite agreed amounts. The trial investigated the suitability of an air conditioner cycling programme for both network issues (i.e. deferring capital expenditure) and for retail issues (i.e. reducing exposure to high pool prices).</p> <p>The trial focused on the technical and commercial feasibility of direct control methods to cycle residential air conditioners and tested</p> <ul style="list-style-type: none"> <li>• the reliability and response time of the cycling equipment;</li> <li>• the impact of air conditioner cycling on the load profile; and</li> <li>• Customer experience of interrupting air conditioners on hot days.</li> </ul>
<b>Dates of operation of the Scheme</b>	2001.
<b>Eligibility Requirements/ Control Strategy</b>	Need to have air conditioning.
<b>Type, size and number of customers targeted</b>	90 residential customers.
<b>Role of Market Actors</b>	None.
<b>Role of distributed generation</b>	None.
<b>Costs of the scheme</b>	\$13,500 incentive payments to customers plus \$15,000 administration cost.
<b>Benefits to participants</b>	<ul style="list-style-type: none"> <li>• Customers received an incentive payment;</li> <li>• Integral received load shedding capability and knowledge of how future larger programmes could work.</li> </ul>

<sup>14</sup> Taken directly from: Demand Management Activities Applicable to Electricity Networks. Prepared for the Demand Management and Planning Project by Energy Futures Australia. 2004.

<b>Level of take up of the scheme</b>	90 Customers.
<b>Barriers to 'take up' and how these have been addressed</b>	<p>Potential inconvenience to customers which was overcome by direct financial incentive.</p> <p>The trial was found to have a high level of administration cost due to customer inquiries and information gathering.</p>
<b>Marketing</b>	Residential customers were contacted by letter which offered an incentive payment of \$150. Customers completed an initial questionnaire and their responses determined whether they were selected. Selected customers also had an energy smart kit installed.
<b>More information</b>	<p>Frank Bucca  Demand Management &amp; Utilisation Manager System Development Department  Integral Energy  PO Box 6366  Blacktown NSW 2148  Tel: 02 9853 6566  Fax: 02 9853 6099  E-mail: <a href="mailto:bucca@integral.com.au">bucca@integral.com.au</a>  <a href="http://www.efa.com.au/Library/DMActivitiesApplicElecNetworks.pdf">http://www.efa.com.au/Library/DMActivitiesApplicElecNetworks.pdf</a></p>

## Sydney CBD Demand Curtailment Project (Interruptible Load)

<b>Programme Name</b>	Sydney Central Business District (CBD) Demand Curtailment Project <sup>15</sup> .
<b>Sponsoring Organisation:</b>	EnergyAustralia.
<b>How the DSM schemes operate</b>	<p>Two EnergyAustralia buildings and two government buildings were selected for this CBD demand curtailment project. This project aims to reduce peak demand by remote control of air conditioning plant and other major plant in the selected buildings.</p> <p>The project will establish links between a central load control point and the various building management systems. This will enable direct load control of the building management systems and the ability to reduce electricity demand in the CBD on an at-call basis for short periods (up to 5 hours).</p> <p>It is expected to be able to rotate the demand reductions across the portfolio of buildings during the call period, with each building contributing to delivering the total required demand reduction. Several different load curtailment test strategies have been developed to determine the best approach.</p>
<b>Purpose of the DSM Scheme</b>	The trial was run to assess the individual building and combined demand response of a portfolio of businesses. This included the thermal responses of the buildings under different scenarios and the extent of 'bounce back' following demand reduction events.
<b>Dates of operation of the Scheme</b>	Ongoing since December 2003.
<b>Eligibility Requirements/ Control Strategy</b>	Selected building which will need building management software.
<b>Type, size and number of customers targeted</b>	Four Commercial buildings selected initially.
<b>Role of Market Actors</b>	None.
<b>Role of distributed generation</b>	None.
<b>Costs of the scheme</b>	Not Known.
<b>Benefits to participants</b>	EnergyAustralia paid for the upgrades to the building management software at the government buildings. All of the participant buildings gain from ongoing energy savings achieved through optimizing the normal operating regimes of their building management systems.
<b>Level of take up of the scheme</b>	Not Known.

<sup>15</sup> Taken directly from: Demand Management Activities Applicable to Electricity Networks. Prepared for the Demand Management and Planning Project by Energy Futures Australia. 2004.

<b>Barriers to 'take up' and how these have been addressed</b>	Lack of building management software in some premises. Overcome by EnergyAustralia paying for the software.
<b>Marketing</b>	Not available.
<b>More information</b>	<p>Pat Dunn  Project Manager Demand Management  EnergyAustralia  L14, 570 George St, Sydney  Tel: (02) 9269 7369  Fax: (02) 9269 7372  E-mail: <a href="mailto:pdunn@energy.com.au">pdunn@energy.com.au</a>  <a href="http://www.energy.com.au">http://www.energy.com.au</a>  <a href="http://www.efa.com.au/Library/DMActivitiesApplicElecNetworks.pdf">http://www.efa.com.au/Library/DMActivitiesApplicElecNetworks.pdf</a></p>

**The following Scandinavian programs were reviewed in detail for this project:**

- 6) Skanska Energi's Critical Peak Pricing Program
- 7) Vattenfall's Demand Response Program
- 8) Danish Pilot programme
- 9) Implementation of DSM in Oslo
- 10) Load Control in Oslo

**Skånska Energi's "Critical Peak Pricing" Pilot  
Sweden**

<b>Programme Name</b>	Critical Peak Pricing.
<b>Sponsoring Organisation:</b>	Skånska Energi.
<b>How the DR schemes operate</b>	A maximum 40 hours per year, customers in this pilot are notified of a higher than usual ("Critical") peak price a day before and are therefore given the opportunity to shift or reduce electricity load to avoid high peaks that range from 3,000 – 5,000 SEK per MWh. No additional technology is added for participating customers; this is simply a tariff that includes information and notification to yield savings for customers if they are reactive to notifications.
<b>Purpose of the DR Scheme</b>	The pilot was designed to study the elasticity of customer energy usage and other aspects of notification and usage software when customers are faced with high peak pricing a limited number of hours (40) per year.
<b>Dates of operation of the Scheme</b>	Effective July 2006 (legislative effective date) all customer with main fuses > 63 A must have hourly meters installed; beginning July 2009, all meters must be read once per month for billing. Effective dates and duration of CPP pilot unclear.
<b>Eligibility Requirements/ Control Strategy</b>	Hourly meters already installed. There may have been a specific sample plan and an opt-in or opt-out voluntary strategy for recruiting the pilot, but that information is not clear.
<b>Type, size and number of customers targeted</b>	The Skanska Energi CPP pilot targets 100 large non-residential customers who already have hourly meters.
<b>Role of Market Actors</b>	Skanska Energi provides online and called day-before notifications and tracks the energy usage of each pilot participant.
<b>Role of distributed generation</b>	None.
<b>Costs of the scheme</b>	Not available.
<b>Benefits to participants</b>	<ul style="list-style-type: none"> <li>• Incentives for pilot customers to reduce peak consumption (and reap savings) through the disincentive of a high critical peak price 40 max hours per year.</li> <li>• Benefit for Skanska to study the effectiveness and logistics of price signals and information on customer behaviour.</li> <li>•</li> </ul>
<b>Level of take up of the scheme</b>	Not available. Pilot has not been rolled out.
<b>Barriers to 'take up' and how these have been addressed</b>	Current price levels (and limited peaks) do not drive incentives for demand response in Sweden. Pilots such as Skanska's are being conducted by several utilities to test the degree of customer responsiveness to price and information signals.

<b>Marketing</b>	Not known.
<b>More information</b>	<p>Overview of Barriers to Demand Response in Sweden &amp; overview of pilot project:  <a href="http://www.energy.sintef.no/arr/Capacity/pdf/DR%20-%20Market%20design%20aspects.pdf">http://www.energy.sintef.no/arr/Capacity/pdf/DR%20-%20Market%20design%20aspects.pdf</a></p> <p>Scandinavian DRR policy and regulatory opportunities (See Slide 9 for brief overview of metering development to support DRR in Sweden):  <a href="http://www.energy.sintef.no/arr/Capacity/pdf/Nordic%20Regulatory%20perspectives.pdf">http://www.energy.sintef.no/arr/Capacity/pdf/Nordic%20Regulatory%20perspectives.pdf</a></p>

**Vattenfall's "MAHIS" (Demand Response Pilot)**  
**Finland**

<b>Programme Name</b>	MAHIS (Field trials of demand response to spot market price based real-time tariffs).
<b>Sponsoring Organisation:</b>	Vattenfall.
<b>How the DR schemes operate</b>	<p>MAHIS, a field trials of spot market price based real-time tariffs includes a pilot with 10 small customers and non-residential customers, including: 5 electrically heated detached houses; 5 electrically heated apartments in a row house; and larger buildings connected in the district heating network, apartment buildings, services (consisting apartments for elderly people, elementary school, health centre).</p> <ul style="list-style-type: none"> <li>• Meters and building automation systems are installed and working, data is being collected</li> <li>• The 10 small customers have chosen the spot price based energy tariff.</li> <li>• Tuning of the systems and development of models and response methods continues</li> </ul>
<b>Purpose of the DR Scheme</b>	The purpose is to study and develop solutions that enable the use of load control potential in the electricity market.
<b>Dates of operation of the Scheme</b>	2004—2006.
<b>Eligibility Requirements/ Control Strategy</b>	Selected customers were given meters that record their hourly demand.
<b>Type, size and number of customers targeted</b>	10 small customers.
<b>Role of Market Actors</b>	None.
<b>Role of distributed generation</b>	None.
<b>Costs of the scheme</b>	Not available.
<b>Benefits to participants</b>	Spot price tariff gives opportunity to save money.
<b>Level of take up of the scheme</b>	Achieved target number of customer for small trial.
<b>Barriers to 'take up' and how these have been addressed</b>	<p>Few barriers to this Programme as it was a small scale trial.</p> <p>On a general perspective</p> <ul style="list-style-type: none"> <li>• Implementing hourly price response is too expensive for small customers, because of high electricity metering costs and other costs.</li> <li>• Slow response of many floor temperature measurements due to lousy instrument installation practices in building automation. (response modelling needed)</li> </ul>

	<ul style="list-style-type: none"> <li>• A low and stable energy price especially this winter in the Nordic electricity market has meant that the incentive to shift load is too small.</li> <li>• The TSO does actively participate in project steering and is organizing meetings on demand elasticity (demand elasticity forum, twice a year) and a seminar in April 2005.</li> </ul>
<b>Marketing</b>	<p>A forum on demand response was organised (meets 3 times per year – first meeting in April 2005) to pursue the following objectives as it relates to the status and future of Demand Response in Finland:</p> <ul style="list-style-type: none"> <li>• Serve as a single point-of-contact for information exchange among different stakeholders to vet projects and discuss DR/AMR opportunities/projects;</li> <li>• Identify and develop DR projects</li> <li>• Serve as a steering group for pushing DR developments forward and a source for follow-up on expert issues.</li> </ul>
<b>More information</b>	<p>Demand Response in Finland  <a href="http://www.energy.sintef.no/arr/Capacity/pdf/DR%20activities%20in%20Finland.pdf">http://www.energy.sintef.no/arr/Capacity/pdf/DR%20activities%20in%20Finland.pdf</a></p>

## Denmark

<b>Programme Name</b>	Danish Pilot Programme.
<b>Sponsoring Organisations:</b>	Elkraft System, Eltra, Seas, and Energy Piano.
<b>How the DR schemes operate</b>	Automatic, price driven control of electric heating 25 single family houses with direct electric heating: <ul style="list-style-type: none"> <li>• Consumption &gt; 16,000 kWh/yr</li> <li>• Individual setting controls the duration of interruption</li> <li>• Price driven control of 5 zones of electric heating</li> <li>• 3 price levels</li> <li>• 2 time periods (morning/afternoon)</li> <li>• Possible to override control</li> <li>• 100 hours of high prices in this winter (guaranteed)</li> <li>• Goal = 5 kW reduction per household (cold day)</li> </ul>
<b>Purpose of the DR Scheme</b>	Demand response is aimed at <ul style="list-style-type: none"> <li>• Better integration of electricity produced by wind turbines.</li> <li>• Creating stronger competition in relation to supply of control services.</li> <li>• Reducing the demand for investments in new capacity in grids and at power plants.</li> </ul>
<b>Dates of operation of the Scheme</b>	Duration of EFFLOCOM project not clear. Ekraft had previously conducted and industrial customer DR pilot that lasted 20 months, ending in January 2003.
<b>Eligibility Requirements/ Control Strategy</b>	Targeted pilot customer have an annual usage of 16,000 kWh/yr.
<b>Type, size and number of customers targeted</b>	29,000 customers across Denmark have hourly metering (this represents about 50% of total peak load). Targets for EFFLOCOM 25 residential customers initially.
<b>Role of Market Actors</b>	NordPool provides spot price information in real time, which is loaded in real time to software the customers can access to make decisions about shifting or reducing load. The utility facilitates the meters and the platform for network data and settles with NordPool.
<b>Role of distributed generation</b>	None at this time. However, Elkraft's website indicates, "In the future it may pay many companies to have their own mini-CHP plant, and domestic customers will have a greater possibility of organizing their electricity consumption on the basis of the hourly prices for electricity, which means using most electricity when the spot prices are lowest."  Elkraft System has received offers from back-up generators for <ul style="list-style-type: none"> <li>• 40 MW backup generation and</li> <li>• 3 MW demand response</li> </ul>
<b>Costs of the scheme</b>	Investment in the order of 650 Euro (if 1,000 houses). Overall cost of the pilot is not clear.
<b>Benefits to participants</b>	<ul style="list-style-type: none"> <li>• Security of supply</li> <li>• Price and load availability competition when transmission lines are full</li> <li>• Reduce abuse of market power</li> <li>• Set the price in situations with high demand</li> </ul>

<b>Level of take up of the scheme</b>	Not available.
<b>Barriers to 'take up' and how these have been addressed</b>	<p>Eastern Denmark (because of its proximity to the Swedish grid) represents more Demand Response potential than Western Denmark at this time.</p> <ul style="list-style-type: none"> <li>• •"Old" set-up: <ul style="list-style-type: none"> <li>– Fixed compensation</li> <li>– Fixed activation (decided by utility)</li> </ul> </li> <li>• •"New" set-up being developed: <ul style="list-style-type: none"> <li>– Compensation based on price and actual reactions</li> <li>– Individual preferences</li> <li>– Possible to override</li> </ul> </li> </ul>
<b>Marketing</b>	Not clear. Since implementation is not broad-based, mass marketing is not required.
<b>More information</b>	<p>Whitepaper overview of DRR potential, recommendations in the Danish market:  <a href="http://www.eltra.dk/media(16183,1033)/Nordel_-_Dansk_TSO-plan_GB_ny.pdf">http://www.eltra.dk/media(16183,1033)/Nordel_-_Dansk_TSO-plan_GB_ny.pdf</a></p> <p>EFFLOCOM Overview:  <a href="http://www.nordpool.com/courses/Presentations/NPSeminar_Dec03/Elkraft%20SystemDec03.pdf">http://www.nordpool.com/courses/Presentations/NPSeminar_Dec03/Elkraft%20SystemDec03.pdf</a></p> <p>Summary of EKraft's industrial DR Programme (no longer in effect):  <a href="http://www.elkraft-system.dk/Elkraft/UK/ElecSysUK.nsf/0/8e44122b19ed76c8c1256cbd00499e19?OpenDocument">http://www.elkraft-system.dk/Elkraft/UK/ElecSysUK.nsf/0/8e44122b19ed76c8c1256cbd00499e19?OpenDocument</a></p> <p>October 2003 DR whitepaper, background of Danish market and projections for market penetration:  <a href="http://www.elkraft.dk/Elkraft/UK/Publications.nsf/0/DFE676301A821867C1256DB10037F97C/\$File/Demand+Response+and+the+need+for+intelligent+appliances.pdf!OpenElement">http://www.elkraft.dk/Elkraft/UK/Publications.nsf/0/DFE676301A821867C1256DB10037F97C/\$File/Demand+Response+and+the+need+for+intelligent+appliances.pdf!OpenElement</a></p>

## Implementation of DSM in Oslo

<b>Programme Name</b>	DSM in Oslo.
<b>Sponsoring Organisation:</b>	Viken Nett and the Norwegian Research Council.
<b>How the DR schemes operate</b>	The Programme reduces demand and energy in a selected area of Oslo <ul style="list-style-type: none"> <li>• Smart home technology used in residential sector</li> <li>• Energy efficiency measures installed in Commercial sector</li> </ul>
<b>Purpose of the DR Scheme</b>	<ul style="list-style-type: none"> <li>• To defer distribution upgrades</li> <li>• Testing Customer response</li> </ul>
<b>Dates of operation of the Scheme</b>	1998-2001.
<b>Eligibility Requirements/ Control Strategy</b>	This project had three major components <ol style="list-style-type: none"> <li>1) Controlling water heat in an apartment complex using smart house technology</li> <li>2) Controlling water heat and space heat in 17 row houses using smart house technology using an Ebox technology</li> <li>3) Reducing load and controlling load in 40 commercial customers.</li> </ol>
<b>Type, size and number of customers targeted</b>	156 apartments, 17 row houses, 40 commercial customers.
<b>Role of Market Actors</b>	None.
<b>Role of distributed generation</b>	None.
<b>Costs of the scheme</b>	1.5 Million euros.
<b>Benefits to participants</b>	<ul style="list-style-type: none"> <li>• Reduced electric bills</li> <li>• Better use electricity</li> </ul>
<b>Level of take up of the scheme</b>	Pilot – cost of pilot was 73.9 Euros/ kW compared to the upgrade cost of 110 Euros/ kW.
<b>Barriers to 'take up' and how these have been addressed</b>	<p>Some customers were sceptical of the Ebox technology and did not use it.</p> <p>Row house customers were invited to educational meetings to increase usage of Ebox.</p> <p>Commercial Audits were performed in Commercial buildings to educate customers about the technologies.</p>
<b>Marketing</b>	Not available.
<b>More information</b>	See results from EFFLCOM Pilots <a href="http://www.efflocom.com/pdf/EFFLOCOM%20report%20no.%207%20Pilot%20Results.pdf">http://www.efflocom.com/pdf/EFFLOCOM%20report%20no.%207%20Pilot%20Results.pdf</a>

## Load Control in Oslo

<b>Programme Name</b>	DSM in Oslo.
<b>Sponsoring Organisation:</b>	Viken Nett.
<b>How the DR schemes operate</b>	The Programme reduces demand and energy in a selected area of Oslo. This Programme tested remote control of commercial loads using two –way communication that used wireless and the mobile phone network called Le Key.
<b>Purpose of the DR Scheme</b>	<ul style="list-style-type: none"> <li>• To defer distribution upgrades</li> <li>• Testing Customer response</li> </ul>
<b>Dates of operation of the Scheme</b>	2000-2004.
<b>Eligibility Requirements/ Control Strategy</b>	Selected customer needed to be given communication technology.
<b>Type, size and number of customers targeted</b>	Offered to 14 commercial customers
<b>Role of Market Actors</b>	None.
<b>Role of distributed generation</b>	Unclear – may have been used in some cases.
<b>Costs of the scheme</b>	62,000 Euros.
<b>Benefits to participants</b>	<ul style="list-style-type: none"> <li>• Reduced electric bills</li> <li>• Better use electricity</li> </ul>
<b>Level of take up of the scheme</b>	Participating customers significantly reduced load.
<b>Barriers to ‘take up’ and how these have been addressed</b>	Commercial Audits were performed in Commercial buildings to educate customers about the technologies.
<b>Marketing</b>	Not available.
<b>More information</b>	See results from EFFLOCOM Pilots. <a href="http://www.efflocom.com/pdf/EFFLOCOM%20report%20no.%207%20Pilot%20Results.pdf">http://www.efflocom.com/pdf/EFFLOCOM%20report%20no.%207%20Pilot%20Results.pdf</a>

**The following US Load Response/ Load Management Programs were reviewed in detail for this study:**

- 1) PJM Load Response Programs
- 2) Austin Energy Power Partner Program
- 3) California Public Utilities Commission State-wide Pricing Pilot
- 4) ISO New England's Load Response Programs
- 5) Long Island Power Authority LIPAedge program
- 6) California Public Utilities Commission Enhanced Automation Initiative
- 7) Utah Power's ( PacificCorps/ Scottish Power) Cool Keeper

## PJM Load Response

<b>Programme Name</b>	PJM Load Response Programs.
<b>Sponsoring Organisation:</b>	Pennsylvania, New Jersey and Maryland Power Grid.
<b>How the DSM schemes operate</b>	PJM has 3 main programs. One is a price response Programme with day-ahead notification. The second is a price response Programme with real-time price option. The third Programme is an emergency Programme where participants are called in the event of an emergency.
<b>Purpose of the DSM Scheme</b>	Peak load reduction is the major objective. Secondary objectives are to: <ul style="list-style-type: none"> <li>• Obtain compensation as balancing energy market resource;</li> <li>• Encourage use of load response technologies; and</li> <li>• Encourage use of more sophisticated metering.</li> </ul>
<b>Dates of operation of the Scheme</b>	2002-current for these programs.
<b>Eligibility Requirements/ Control Strategy</b>	End- use customers must be able to shed at least 100 kW.  End-use customers in the price responsive Programme need interval metering.  Suppliers/distribution companies/ aggregators must belong to PJM.  In the emergency programs if the customer is not metered by PJM they must submit metering data within 60 days to be paid.
<b>Types of customers targeted</b>	Generally large business customers are targeted for these programs.
<b>Role of Market Actors</b>	Local distribution companies, aggregators, and competitive supplies play a large role in marketing the individual programs.
<b>Role of distributed generation</b>	DG is used by some larger customers to shed load.
<b>Costs of the scheme</b>	Varies based on need for performance.
<b>Benefits to participants</b>	Incentive payments - most guaranteed the greater of the real time price or a minimum in 2004 over 1/3 of real time price takes received over \$75/mwh.
<b>Level of take up of the scheme</b>	Price Responsive programs – 2113 MW Emergency Programme – 1783 MW  94 % of MWh reductions under the price responsive Programme were under the real time option.
<b>Barriers to 'take up' and how these have been addressed</b>	Split incentives (between disco/ Transco / genco/ marketers) – to some extent addressed by having the distribution companies, aggregators and suppliers market the program.

<b>Marketing</b>	Main marketing channels were distribution companies, suppliers and aggregator account managers. PJM staff worked closely on co-marketing of all Programme elements <ul style="list-style-type: none"><li>• Meetings held with industry groups</li><li>• Web sites of PJM and other parties</li></ul>
<b>More information</b>	<a href="http://www.pjm.com/services/demand-response/demand-response.html">http://www.pjm.com/services/demand-response/demand-response.html</a>

## Austin Energy Power Partner

<b>Programme Name</b>	Austin Energy Power Partner.
<b>Sponsoring Organisation:</b>	Austin Energy.
<b>How the DR schemes operate</b>	Air Conditioning is reduced at time of system peak using a programmable thermostat.
<b>Purpose of the DR Scheme</b>	Peak load reduction is the major objective Secondary objectives are to: <ul style="list-style-type: none"> <li>• Broaden the utility's portfolio of rate options.</li> <li>• Obtain compensation as balancing energy market resource.</li> <li>• Encourage use of programmable thermostats.</li> </ul>
<b>Dates of operation of the Scheme</b>	2003 – Current.
<b>Eligibility Requirements/ Control Strategy</b>	<ul style="list-style-type: none"> <li>• Residential or commercial with CAC 10 tons or less</li> <li>• Customers were given a free Honeywell Superstat™ programmable thermostat.</li> <li>• Customers were also given free AC checks for programmable thermostat compatibility and free programmable thermostat repair/replacement.</li> <li>• Most common cycling/set-point protocol: 33% duty cycle (10 minutes/half hour). Daily Cycling Window: 4–8 PM (residential), 3–8 PM (commercial). Cycling Season/Limits: No restrictions on # of days.</li> </ul>
<b>Type, size and number of customers targeted</b>	<ul style="list-style-type: none"> <li>• Residential or commercial with CAC 10 tons or less, in good working order, and not controlled by another building automation system.</li> <li>• Municipal accounts with small tonnage CACs are also eligible.</li> <li>• Residential multifamily housing.</li> </ul>
<b>Role of Market Actors</b>	Used for AC check up and repair
<b>Role of distributed generation</b>	None
<b>Costs of the scheme</b>	
<b>Benefits to participants</b>	B/C data not readily available – similar scheme also in Texas had B/C of 1.1 Customer benefits include new thermostat, reduced bills, and AC check.
<b>Level of take up of the scheme</b>	30,000 customers.
<b>Barriers to 'take up' and how these have been addressed</b>	<ul style="list-style-type: none"> <li>• Free thermostat removed cost barrier</li> <li>• Programmable thermostat also increased comfort</li> <li>• Customers receive free repairs/ replacement of thermostats to remove informational barriers</li> </ul>

<b>Marketing</b>	Main marketing method was direct mail <ul style="list-style-type: none"><li>• Web site, bill stuffers, bill newsletter were also used as channels by the utility</li><li>• Meeting were held with HVAC contractors</li><li>• Trade shows</li></ul>
<b>More information</b>	<a href="http://www.austinenergy.com/Energy%20Efficiency/Programs/Power%20Partner/index.htm">http://www.austinenergy.com/Energy%20Efficiency/Programs/Power%20Partner/index.htm</a>

## California Public Utilities Commission

<b>Programme Name</b>	State-wide Pricing Pilot Programme (SPP)
<b>Sponsoring Organisation:</b>	The California Public Utilities Commission and the California Energy Commission. Implemented by the three large investor owned utilities (IOUs) in the state: Southern California Edison (SCE), San Diego Gas and Electric (SDG&E) and Pacific Gas and Electric (PG&E).
<b>How the DR schemes operate</b>	<ul style="list-style-type: none"> <li>• Nexus Energy Software was chosen to provide a Web-based energy bill analysis system for customers on the pricing pilot. Based on customer-provided survey information and hourly meter data, customers receive a monthly bill "Scorecard" with a personalized examination of the costs of air conditioning, lighting and other appliances during critical peak periods, and what can be saved by managing how those appliances are used.</li> <li>• A refined version of the software is being deployed this year on a larger sample of customers, including a personalized Web page for each participant, as well as monthly e-mails and notices the evening before a "Critical Peak" day, when rates are especially high from 2 to 7 p.m. for residential customers (the peak is noon to 6 p.m. for non-residential customers). Customers without Internet access will receive mail reports.</li> <li>• Opinion Dynamics and EPRI Solutions are providing market research and evaluation services to determine the effectiveness of the bill information, comparing the participating customers to a control group of similar customers on the same rate.</li> </ul>
<b>Purpose of the DR Scheme</b>	<p>The project is part of the California State-wide Pricing Pilot begun in 2003 to evaluate the potential peak demand reduction benefits of time-based rates. This tool will be beneficial and will enhance the value of an advanced meter infrastructure (AMI) currently under consideration for all homes and businesses in California.</p> <p>Core objectives are:</p> <ul style="list-style-type: none"> <li>– Enhance system reliability</li> <li>– Reduce power purchases and consumer costs</li> <li>– Protect the environment</li> </ul>
<b>Dates of operation of the Scheme</b>	2003-current.

<b>Eligibility Requirements/ Control Strategy</b>	<ul style="list-style-type: none"> <li>• Basic enrolment requirements included: the bill payer must occupy the home for residential customers (to avoid renting/owner complications over electricity decisions); customers could not be planning to move locations within the next six months; and customers were required to provide a land-based phone number where they could be reached for notifications of a “Shift &amp; Save” event (where super peak prices would be in effect if a CAL ISO emergency was declared). A maximum of 90 hours per year anytime during the noon-6 p.m. peak for C&amp;I customers; and a max of 15 days per year for residential customers could be declared a “super peak” time where prices were set as high as .75 cents per kWh to deter or encourage usage shifting.</li> <li>• All customers targeted (see targeting scheme) received a free advanced digital electric meter designed to facilitate energy information and management. Website portals were established for enrolled customers through their utility websites to check their usage online, using a password-protected login.</li> <li>• Residential and commercial customers were given a free Honeywell programmable thermostat. Adjustments to thermostats were encouraged by providing tips on pre-cooling and presetting (see marketing materials).</li> </ul>
<b>Type, size and number of customers targeted</b>	<ul style="list-style-type: none"> <li>• The initial marketing and enrollment for the pilot was premised on a sample design of 2,500 random customers, across residential and commercial classes in all three IOU territories participating in the program, with a 10x over sample to fill each “slot.”</li> <li>• The pilot pricing was designed as an “opt-out” program, but required an enrolment centre operated by KEMA to confirm enrolment in writing. Each enrolled customer (the metered accounts were the unit of analysis for all customers) was randomly assigned into one of the following tariffs: Time of Use (with a peak and off-peak price), Critical Peak Pricing (with a peak, off-peak, and “super peak” price – invoked a limited number of days per year for residential customers and an limited number of hours per year for commercial customers when a load emergency was declared by the CAL ISO), or an “Information Only” group where they received all Programme information with no rate change.</li> <li>• Taking into account the tariff (TOU, CPP (fixed and variable versions), rate (summer vs. winter peaking areas), customer class (residential vs. C&amp;I) and service territory (SCE, PG&amp;E, SDG&amp;E), there were 32 permutations of customer enrolment in the pilot.</li> </ul>
<b>Role of Market Actors</b>	<p>The project sponsors of the pilot were critical in designing the pilot sample and collaborating to develop enrolment and marketing materials for pilot participation and retention. The three IOUs dedicated website portals to house customer billing and usage information in near-real time.</p>
<b>Role of distributed generation</b>	<p>None.</p>
<b>Costs of the scheme</b>	<p>Approximately \$20 million.</p>
<b>Benefits to participants</b>	<p>Customer benefits include new meters, programmable thermostat, reduced bills, and more information about how to lower their electricity use and therefore reduce their electric bills.</p>

<b>Level of take up of the scheme</b>	<ul style="list-style-type: none"> <li>• Sending dynamic rates to customers achieved average peak load reductions ranging from 12% to 40% of baseline peak usage for different customer cohorts. The degree of reduction depended on the tariff rate, weather, customer appliance holdings, and availability and use of demand response controls.</li> <li>• Residential and small to medium C&amp;I customers understand and overwhelmingly prefer dynamic rates to existing inverted tier rates. Sending dynamic prices to residential customers led to average peak savings of 14% and bill savings of \$60 per year.</li> </ul>
<b>Barriers to 'take up' and how these have been addressed</b>	<ul style="list-style-type: none"> <li>• Free thermostat removed cost barrier</li> <li>• Programmable thermostat also increased comfort</li> <li>• Customers receive tips on how to reduce electricity use when enrolling in the program, and monthly e-mail alerts and bill inserts; this addresses the barrier that customers do not understand how electricity is measured, priced, or how their usage patterns affect their cost.</li> </ul>
<b>Marketing</b>	<ul style="list-style-type: none"> <li>• Main marketing method was direct mail</li> <li>• Web site, bill stuffers, and initial marketing handbook also explained the role customers could play in reducing their electricity use and costs. These guides were customized by customer type, region, and rate treatment.</li> </ul>
<b>More information</b>	<ul style="list-style-type: none"> <li>• Overview of the background of this Programme in the context of Demand Response regulatory efforts in CA: <a href="http://www.energy.ca.gov/papers/2004-08-31_ROSENFELD_ACEEE.PDF">http://www.energy.ca.gov/papers/2004-08-31_ROSENFELD_ACEEE.PDF</a></li> <li>• Comprehensive evaluation results from this pilot program: <a href="http://www.nwcouncil.org/energy/dr/library/drrc_presentation.pdf">http://www.nwcouncil.org/energy/dr/library/drrc_presentation.pdf</a></li> </ul>

## ISO New England

<b>Programme Name</b>	ISO New England Load Response Programs
<b>Sponsoring Organisation:</b>	ISO New England.
<b>How the DSM schemes operate</b>	2 Reliability programs – individual customer and groups 1 Price Based – real time pricing program
<b>Purpose of the DSM Scheme</b>	<b>Peak load reduction is the major objective</b> Secondary objectives are to: <ul style="list-style-type: none"> <li>• Obtain compensation as balancing energy market resource.</li> <li>• Encourage use of load response technologies</li> <li>• Encourage use of more sophisticated metering</li> </ul>
<b>Dates of operation of the Scheme</b>	2003-current for these programs.
<b>Eligibility Requirements/ Control Strategy</b>	Reliability Based Programs  For the Individual program <ul style="list-style-type: none"> <li>• Must shed at least 100 kw</li> <li>• Notification period of either 30 minutes or 2 hours</li> <li>• Notified by the ISO control room</li> <li>• Paid for performance including capacity payment</li> <li>• 5 minute data collected via internet based communications</li> </ul> For the Group program <ul style="list-style-type: none"> <li>• Must shed at least 200 kw as a group</li> <li>• Notification period of 2 hours</li> <li>• Notified by the ISO control room</li> <li>• Paid for performance</li> <li>• Performance determined statistically</li> </ul> Real time Price Response <ul style="list-style-type: none"> <li>• Must shed at least 100 kw</li> <li>• Voluntary response</li> <li>• Notified by the ISO when prices exceed a certain level</li> <li>• Paid greater of real time price or a guaranteed minimum</li> <li>• Hourly data submitted daily or monthly</li> </ul>
<b>Types of customers targeted</b>	<ul style="list-style-type: none"> <li>• For Individual Reliability – larger C/I customers</li> <li>• For Group Reliability – all customer classes</li> <li>• For Price Based – larger C/I customers</li> </ul> Group Programme was in a targeted area.
<b>Role of Market Actors</b>	Group Programme was bid out to energy services providers. Local distribution companies play large role in marketing the individual program.
<b>Role of distributed generation</b>	Is used by some larger customers - have been concerns about emissions by state regulators.

<b>Costs of the scheme</b>	Varies based on need for performance.
<b>Benefits to participants</b>	Incentive payments - most guaranteed the greater of the real time price or a minimum.  Minimum was .50/kwh for 30 minute notification individual response, .35/ kwh for 2 hour notification individual, .10/ kwh for group and real time
<b>Level of take up of the scheme</b>	368.2 MW 534 customers/ groups
<b>Barriers to 'take up' and how these have been addressed</b>	<ul style="list-style-type: none"> <li>• Split incentives (between disco/ Transco / genco/ marketers) – to some extent addressed by having the distribution companies market the Programme – still limited activities by marketers.</li> <li>• Bid Programme in South-western Connecticut brought in a new model and more market actors.</li> </ul>
<b>Marketing</b>	<ul style="list-style-type: none"> <li>• Main marketing channels were distribution account managers and third parties for group program</li> <li>• ISO staff worked closely on co-marketing of all Programme elements</li> <li>• Meetings held with industry groups</li> <li>• Meetings help by distribution utilities and ISO</li> <li>• Web sites of ISO and distribution utilities</li> </ul>
<b>More information</b>	<a href="http://www.isone.com/Load_Response/Demand_Response_Program_Brochure_and_Customer_Tools/ISO_New_England_2004_Demand_Response_Programs.pdf">http://www.isone.com/Load_Response/Demand_Response_Program_Brochure_and_Customer_Tools/ISO_New_England_2004_Demand_Response_Programs.pdf</a>

## Long Island Power Authority LIPAedge

<b>Programme Name</b>	Long Island Power Authority LIPAedge.
<b>Sponsoring Organisation:</b>	Long Island Power Authority.
<b>How the DR schemes operate</b>	Air Conditioning is reduced at time of system peak using a programmable thermostat Pool pumps are controlled.
<b>Purpose of the DR Scheme</b>	Peak load reduction is the major objective Secondary objectives are to: <ul style="list-style-type: none"> <li>• Improve public relations.</li> <li>• Obtain compensation as load curtailment resource</li> <li>• Encourage use of programmable thermostats.</li> </ul>
<b>Dates of operation of the Scheme</b>	
<b>Eligibility Requirements/ Control Strategy</b>	<ul style="list-style-type: none"> <li>• Residential or commercial with CAC 25 tons or less</li> <li>• Customers were given a free Comfort Choice programmable thermostat.</li> <li>• Pool pumps.</li> <li>• Most common cycling/set-point protocol: For the CAC a 50% duty cycle (15 minutes on/15 minutes off) is most common, but 6 other cycling options. Pool pump is turned off for the duration of the cycling event.</li> <li>• Daily Cycling Window: 2–6 PM.</li> <li>• Cycling Season/Limits: Maximum of 7 cycling events/summer.</li> </ul>
<b>Type, size and number of customers targeted</b>	<ul style="list-style-type: none"> <li>• Residential or commercial with CAC &lt; 25 tons</li> <li>• Retail chains</li> </ul>
<b>Role of Market Actors</b>	Limited.
<b>Role of distributed generation</b>	None.
<b>Costs of the scheme</b>	Not available.
<b>Benefits to participants</b>	<ul style="list-style-type: none"> <li>• Free Comfort Choice programmable thermostat.</li> <li>• \$25 yearly for participants with pool pumps.</li> <li>• Internet access to their thermostat</li> <li>• No costs to customers</li> </ul>
<b>Level of take up of the scheme</b>	26,500 thermostats. 2,675 Pool pumps.

<b>Barriers to 'take up' and how these have been addressed</b>	Free thermostat removed cost barrier. Programmable thermostat also increased comfort
<b>Marketing</b>	<ul style="list-style-type: none"> <li>• Main marketing method was the web site.</li> <li>• Direct mail, bill stuffers, bill newsletter, newspaper ads, home shows and community events.</li> </ul>
<b>More information</b>	<a href="http://www.lipower.org/cei/lipaedge.html">http://www.lipower.org/cei/lipaedge.html</a>

## California Public Utilities Commission

<b>Programme Name</b>	Enhanced Automation Initiative
<b>Sponsoring Organisation:</b>	California Public Utilities Commission
<b>How the DSM schemes operate</b>	Incentive payments are made to end-use customers who are willing to shed load and energy during peak periods. This Programme is focused on shedding load by using building automation systems such as HVAC controls and lighting controls.
<b>Purpose of the DSM Scheme</b>	<p><b>Long-term Energy Savings is the major objective</b> (funded through the energy efficiency public goods charge)</p> <p>Secondary objectives are to:</p> <ul style="list-style-type: none"> <li>• Test pilot concept that need for incentives for controls upgrades is unmet</li> <li>• Increase demand response capability for end users</li> <li>• Achieve permanent peak reduction</li> <li>• Increase sophistication of end user automation and controls.</li> </ul>
<b>Dates of operation of the Scheme</b>	2004-current.
<b>Eligibility Requirements/ Control Strategy</b>	<p>Eligible customers must be:</p> <ul style="list-style-type: none"> <li>• Located within two defined utility territories who pay into the California public goods fund</li> <li>• Have at least 100,000 square feet of conditioned space OR over 500 kW</li> <li>• Have an existing building automation or energy management system (BAS or EMS).</li> </ul> <p>Eligible project categories:</p> <ul style="list-style-type: none"> <li>• HVAC, lighting, or other system controls</li> <li>• Establishing remote access to control systems</li> <li>• Energy information systems</li> <li>• Networking multiple sites, systems, or buildings</li> </ul> <p>Incentives are available for new projects only, and must be upgrading an existing energy management system.</p>
<b>Types of customers targeted</b>	Larger C/I customers (over 500 kW)
<b>Role of Market Actors</b>	Group Programme was bid out to energy services providers Local distribution companies play large role in marketing the individual programme.
<b>Role of distributed generation</b>	Not addressed by the programme.
<b>Costs of the scheme</b>	\$1.4 million.
<b>Benefits to participants</b>	Incentive payments of up to 9¢/kWh for first year energy savings achieved through hardware and software upgrades to energy management systems. Incentives are capped at 50% of project costs.

<b>Level of take up of the scheme</b>	13.4 million kWh; 2.5 MW 6 customers to date, ongoing enrolment.
<b>Barriers to 'take up' and how these have been addressed</b>	Addresses customer information and/or search costs and performance uncertainty by providing free detailed technical assistance and energy savings calculations. <ul style="list-style-type: none"> <li>• Addresses lack of access to capital/first cost by providing financial incentives that cover up to 50% of project costs</li> <li>• Addresses controls measures that are not usually covered in other incentive programs due to the complex energy savings calculations required.</li> </ul>
<b>Marketing</b>	<ul style="list-style-type: none"> <li>• Main marketing channels were local vendors and contractors with existing relationships with their customers.</li> <li>• Utility account representatives also provided referrals as current utility programs do not address these types of controls measures.</li> <li>• Meetings held with industry groups</li> <li>• Web site with Programme information and request forms was major entry point</li> </ul>
<b>More information</b>	<a href="http://www.eainitiative.com">http://www.eainitiative.com</a>

### Cool keeper - Utah Power

<b>Programme Name</b>	Cool Keeper.
<b>Sponsoring Organisation:</b>	Utah Power (PacifiCorp).
<b>How the DR schemes operate</b>	This is an outsourced program. The utility pays a vendor on a performance-basis for 10 years based on measured results. The load reduction is generated by the cycling of residential and small C/I CAC.
<b>Purpose of the DR Scheme</b>	<ul style="list-style-type: none"> <li>Peak load reduction is the major objective</li> </ul> <p>Prove outsourced Programme is viable.</p>
<b>Dates of operation of the Scheme</b>	2003 – current
<b>Eligibility Requirements/ Control Strategy</b>	Residential or commercial with CAC
<b>Type, size and number of customers targeted</b>	Residential or commercial with CAC in a targeted area varies by size of CAC unit – around 1 Kw per unit
<b>Role of Market Actors</b>	Outsourced Programme – market actor (Comverge) implements all aspects of the scheme
<b>Role of distributed generation</b>	None.
<b>Costs of the scheme</b>	Not available.
<b>Benefits to participants</b>	Customer benefits include new thermostat, reduced bills.
<b>Level of take up of the scheme</b>	15 % market penetration of customers with CAC in target area. 50 MW in place – long- term contract for 90 MW.
<b>Barriers to ‘take up’ and how these have been addressed</b>	Free thermostat removed cost barrier.
<b>Marketing</b>	All marketing done by third party vendor with assistance from utility.
<b>More information</b>	<a href="http://www.comverge.com/success/utahpower.php">http://www.comverge.com/success/utahpower.php</a>

## Appendix B - Economic and Environmental Benefits

This Appendix provides an approximate valuation of the potential benefits arising from DSM undertaken at residential and small business premises. It is based on prices for Top up electricity. The assessment has looked at the benefits from reduced consumption and switched demand. The other economic benefits such as reduced distribution investment costs or market dominance cannot be derived without significant further research. This valuation therefore relates only to the customer initiated and supplier initiated programmes.

The following assumptions and calculations have been used for the analysis.

**Total Customer Consumption** - Two different scenarios have been run both of which are based on data from Sustainable Energy Ireland from 2004. The first set of scenarios assumes that applicable demand includes commercial customers and uses a total consumption of 15.4 TWh p/a for Ireland. The second set is just residential commercial customers and is based on 7.3 TWh p/a Ireland. It is inevitable that some of these commercial customers will be large, although it is not possible to tell what proportion from the larger figures.

**Customers Signed Up** – Scenarios have been run with 5 and 10% of customers signed up to the programme. This is regarded as a realistic maximum based on overseas experience.

**TWh Controlled** – This is a calculation multiplying the percentage of customers signed up to the programme by the total customer load.

**Consumption at Peak Periods** – It is assumed that reductions in consumption will occur at peak price periods. This is likely to be no more than 20% per day for participating customers. There is an argument that customer participation in DSM programmes will encourage better management of energy at other times of the day, but this is difficult to quantify and has therefore been excluded from this analysis.

**Reduction in Peak Demand (%)** - The Californian Price Responsive Programme found peak load reductions ranging from 12-40% of baseline peak usage. The small-scale experiment in Oslo found a reduction of peak usage of 15%. These calculations have assumed a conservative 10% reduction in peak demand as Ireland is likely to have less heating and cooling load than Norway or California.

**Reduction in Consumption (Peak MWh)** – This is a calculation of the reduction in consumption during the peak periods. This is calculated by multiplying the number of TWh being controlled by the percentage consumption in peak periods and the percentage reduction in peak demand.

**Energy Saved/ Energy Shifted** – Two scenarios have been used in assessing the split between the amount of energy that will be shifted to a later off-peak period and the amount that will be saved as consumers will no longer consume this power. The first scenario assumes 50% of the reduction in peak energy is saved and the second assumes 70%. The remainder of the energy is shifted to a non-peak period. This is consistent with our international experience.

**Total MWh Saved/Shifted** – This is a calculation of MWh saved based on the percentage of electricity saved or shifted multiplied by the reduction in consumption in the peak period.

**Value per MWh Saved** – This is based on an average peak time price for electricity purchased as Top up in the Ireland market in 2005 (January- July). This is sourced from the Eirgrid websites and uses time weighted

averages day ahead for working days only. Peak time is defined as 07:00 -19:00. This gives a value per peak MWh of 67 euros.

**Value per MWh Shifted** – This is the difference between the cost of an off-peak period and the cost of a peak price period based on the top up prices from January to July 2005. This is sourced from the ESB National Grid website and uses time weighted averages day ahead for working days only. This gives a value per shifted MWh of 17 euros.

**Total Value of Energy Saved** – This is the value of each MWh saved multiplied by the number of MWhs saved.

**Total Value of Energy Shifted** – This is the value of each MWh shifted multiplied by the number of MWhs shifted.

**Total Financial Benefits** - This is a sum of the total value of energy shifted and total value of energy saved.

**Environmental Benefit of Energy Saved** – This is based on Energy Saved multiplied by 0.629 tonnes per MWh. This is the grid average emissions factor provided by Sustainable Energy Ireland.

## Benefits from DSM Programme including Commercial Customers

Approximate Annual Benefit from a DSM Programme Including Commercial Customers				
Total Customer Consumption (TWh)	15.4	15.4	15.4	15.4
Customers Signed Up	5%	10%	5%	10%
TWh Controlled	0.77	1.54	0.77	1.54
Consumption at Peak Prices Periods	20%	20%	20%	20%
Reduction in Peak Demand	10%	10%	10%	10%
Reduction in Consumption for Peak MWh	15400	30800	15400	30800
Energy Saved	50%	50%	70%	70%
Energy Shifted	50%	50%	30%	30%
Total MWh Saved	7700	15400	10780	21560
Total MWh Shifted	7700	15400	4620	9240
Value per MWh Saved	67	67	67	67
Value per MWh Shifted	17	17	17	17
Total Value of Energy Saved	515,900	1,031,800	722,260	1,444,520
Total Value of Energy Shifted	130,900	261,800	78,540	157,080
Total Financial Benefit €	646,800	1,293,600	800,800	1,601,600
CO <sub>2</sub> emission saving tonnes	4,843	9,687	6,781	13,561
<b>Range of Benefits</b>	<b>€650k - 1.6m p/a</b>			
<b>Assuming 10 years of benefit*</b>	<b>€6.5m - 16m</b>			
<b>CO<sub>2</sub> emission saving tonnes</b>	<b>4,800 - 13,600 tonnes</b>			
<b>Total CO<sub>2</sub> Saved 10 Year Programme</b>	<b>48,000 - 136,000 tonnes</b>			
<b>*No discounting factor has been applied</b>				

## Benefits from DSM Programme without Commercial Customers

<b>Approximate Annual Benefit from a DSM Programme Without Commercial Customers</b>				
<b>Total Customer Consumption (TWh)</b>	7.3	7.3	7.3	7.3
<b>Customers Signed Up</b>	5%	10%	5%	10%
<b>TWh Controlled</b>	0.365	0.73	0.365	0.73
<b>Consumption at Peak Prices Periods</b>	20%	20%	20%	20%
<b>Reduction in Peak Demand</b>	10%	10%	10%	10%
<b>Reduction in Consumption for Peak MWh</b>	7300	14600	7300	14600
<b>Energy Saved</b>	50%	50%	70%	70%
<b>Energy Shifted</b>	50%	50%	30%	30%
<b>Total MWh Saved</b>	3650	7300	5110	10220
<b>Total MWh Shifted</b>	3650	7300	2190	4380
<b>Value per MWh Saved €</b>	67	67	67	67
<b>Value per MWh Shifted €</b>	17	17	17	17
<b>Total Value of Energy Saved</b>	244,550	489,100	342,370	684,740
<b>Total Value of Energy Shifted</b>	62,050	124,100	37,230	74,460
<b>Total Financial Benefit €</b>	306,600	613,200	379,600	759,200
<b>CO<sub>2</sub> emission saving tonnes</b>	2,296	4,592	3,214	6,428
<b>Range of Benefits</b>	<b>€306k - €760k p/a</b>			
<b>Assuming 10 years of benefit*</b>	<b>€3m - 7.6m</b>			
<b>CO<sub>2</sub> emission saving tonnes</b>	<b>2,300 - 6,400 tonnes p/a</b>			
<b>Total CO<sub>2</sub> Saved 10 Year Programme</b>	<b>23,000 - 64,000 tonnes</b>			
<b>*No discounting factor has been applied</b>				

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## Appendix D – Glossary and Acronyms

**All Island Market** – New wholesale market arrangement based on a Gross Mandatory Pool that will be established covering the whole of Ireland from 2007.

**Customer Initiated Programme** – A DSM programme where the customer is responsible for initiating the reduction in demand. This programme still relies on suppliers offering tariffs that give price signals for customers to reduce demand, but the choice to reduce consumption rests with the customers.

**Demand Side Management (DSM)** – DSM is the ability to temporarily reduce and shift customer demand (kW), without necessarily reducing overall energy consumption (kWh).

**Distribution Use of System** – A variable per unit charge made by distribution companies for using the distribution network.

**Distributor Initiated Programme** – A DSM programme where the distributor is responsible for initiating the demand reduction by having control over some of a customers' equipment or appliances.

**Double Tariff Meter** – A meter with 2 registers capable of recording night and day consumption. Also known as a 2-rate meter.

**Half Hour Customer** – The Half Hour refers to the interval that the meter records a customers' consumption of electricity. This allows suppliers to give price incentives to encourage the customer to use less power in the Half Hour and for that lower consumption to be recorded in settlements. In the UK HH meters are mandatory for large customers.

**Maximum Demand** – The maximum amount of electricity the customer consumes. This is often one of the charges applied to large customers and is normally measured in kW.

**NETA** – The New Electricity Trading Arrangements introduced in the UK as a replacement to the Pool Market. This is a bilateral market with self despatch. It was intended to be a 2-sided market that would encourage demand side involvement.

**Quarter Hour Customer** – The quarter Hour refers to the interval that the meter records a customers' consumption of electricity. This allows suppliers to give price incentives to encourage the customer to use less power in the quarter hour and for that lower consumption to be recorded in settlements. Settlement is currently done on a Half Hour basis so quarter hourly meter readings are aggregated up. In Ireland quarter hour meters are common for large customers.

**Radio Teleswitch** – These devices are used with 2-rate meters and are capable of receiving signals that switch when cheap rate electricity is supplied to the customer premises. They are operated using codes transmitted on national radio signals.

**Single Tariff Meter** – A meter with a single register that is only able to record total consumption between meter readings.

**Smart Metering - QH** or HH meters that record and display customers' consumption so that they can get settled for actual consumption in each HH. Meters will need as a minimum to have the ability to record and

store QH/HH Consumption, display information in a useful format for customers, receive costs signals from suppliers and be small enough to be accessible for customers.

**Supplier Initiated Programme** – A DSM programme where the supplier is responsible for initiating the demand reduction by having control over some of a customers’ equipment or appliances.

**Transmission Network Use of System** – A variable per unit charge made by National Grid for using the transmission network.

### Key Acronyms

Acronym	Meaning
CAC	Central Air Conditioning
CAL	California
DG	Distributed Generation
DSM	Demand Side Management
DTI	Department of Trade and Industry
DUoS	Distribution Use of System
EIUG	Energy Intensive Users Group
ISO	Independent System Operator
kW	Kilowatt
HH	Half Hour
HVAC	Heating Ventilation & Air Conditioning
MD	Maximum Demand
NETA	New Electricity Trading Arrangements
NGC	National Grid Company
NGT	National Grid Transco
QH	Quarter Hour
PES	Public Electricity Supplier
PJM	Pennsylvania- New Jersey- Maryland
RTS	Radio Teleswitch
SME	Small Medium Enterprise
TNUoS	Transmission Network Use of System

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