Subtask 5
Demand "available" and "turndown" Validation Mechanisms for Market Bidding of Smaller Customer Demand

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IEA DSM REPORT - EXECUTIVE SUMMARY

TASK XI SUBTASK 5

DEMAND "AVAILABLE" AND "TURNDOWN" VALIDATION MECHANISMS FOR MARKET BIDDING OF SMALLER CUSTOMER DEMAND

Background

A large amount of work has been and is being carried out in many countries to enable customers to participate in energy markets by modifying demand in response to price and other motivators. The difficulty in measuring the Demand Response (DR) of customers is seen by many to be a barrier to demand side participation in Demand Side Bidding markets.

Demand Side Bidding (DSB) is the formalisation of DR where contracts are put in place between customers and System Operators/Suppliers so as to deliver more reliable DR, which can be used to meet capacity constraints or as alternatives to generation.

Mechanisms are required to validate both that demand is "available" as a Demand Side Bid and that the demand was "turned down" when requested, as defined in the contract.

Objectives

The objectives of Subtask 5 are to identify and develop mechanisms which can be used to validate that smaller customer demand is "available" for demand change and also following instruction that the demand has "turned down".

Approach

Demand Side Bidding as presently implemented requires defined blocks of demand or generation to be made "available" to System Operators and contracted for DR "turndown" or switch on during agreed time periods.

DR cannot be considered for DSB unless it can be validated as "available" and "turned down".

Smaller customer DR validation on an individual basis is particularly challenging because, in most situations, the demand will be inhibited rather than interrupted. In the case of many white goods, the process cannot be interrupted, once started, and with thermostat set points, there is a probability of the thermostat being on or off when the control signal is received.

Approach (cont'd)

Consequently, it will be difficult to relate together the switching instruction and demand change.

Models of load response, based on empirical information gained from pilots and/or trials, would therefore seem to be appropriate for determining the level of demand "available" for demand response initiatives involving either manual or remote control of customer energy end-uses. Measuring the load response of an aggregated group of customers would also be a possibility.

Results

There are several mechanisms by which DR suitable for DSB can be delivered. Some of these have differing technical and equipment requirements for their operation, as well as for validation of the DR produced.

It is evident from Chapters 2, 3 and 5 that validation requirements of DR, in order for it to be used as DSB, should not present fundamental barriers to the adoption of smaller customer DSB in generation markets. In principle DR validation can be done based on control group measurement, statistical modelling and Grid substation measurements of demand "turndown" in response to DR motivator signals on specific days and at specific times. These routes use different metering "Smartness" levels together with remote/automatic control and communication of price signals. However, there is a significant need to understand and develop customer behaviour change in response to TOU price signals and remote/automatic and manual switching.

Manual responses to DR motivators are considered unsuitable for DSB.

One way, broadcast communication would be sufficient for end use switching of demand for DSB.

Implications

There are many issues to be resolved in order to motivate customer participation in DSB and the provision of communication enabled end uses and infrastructure. There may be some scope for considering the use of customer, manually switched DR as an interim measure for delivering some DSB and obtaining experience. This option is not considered viable for the long term. This process would require estimates to be made of customer manual switching in response to dynamic, critical price messages.

It is to be recommended that studies and trials of customer response to TOU and critical price signals are performed, which include simple 2 rate meters, remote, meter rate switching and remotely switched white goods and thermostats. In particular, if the level of Demand Response delivered is closely related to the level predicted to be "available", a solid basis can be formed upon which trust in future DR schemes involving domestic customers can be established.

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Appendices

Glossary

AA	Annual Advance
BSC	Balancing and Settlement Code
CCGT	Combined Cycle Gas Turbine
CHP	Combined Heat and Power
DEFRA	Department of Environment, Food and Rural Affairs (UK)
DNO	Distribution Network Operator
DSM	Demand Side Management
DR	Demand Response
DSB	Demand Side Bidding
DTI	Department of Trade and Industry (now Department of Business, Enterprise & Regulatory Performance (DBERR), UK
Economy 7	A scheme whereby electricity used at night is cheaper
Elexon	The organisation that operate the balancing and settlement system (UK)
EEC	Energy Efficiency Commitment (UK)
ESCO	Energy Supply Company
ETSO	European Transmission System Operator
EUMF	End Use Monitoring and Feedback
GAAP	Group Average Annual Consumption
GSP	Grid Supply Point
HH	Half Hourly
kW	Kilowatt
KWh	kilowatthour
MW	Megawatt
MWe	Megawattelectric
NETd	Noon Effective Temperature on Day d (UK)
NHH	Non Half Hourly
Ofgem	The regulator for the energy and gas industry (UK)
Party Agents	Parties who have signed the balancing and settlement Code (UK)
PV	Photovoltaics
SSC	Standard settlement configuration (UK)
TOU	Time of Use

1 Introduction

A large amount of work has been and is being carried out in many countries to enable customers to participate in energy markets by modifying demand in response to price and other motivators. This work is directed at persuading customers to save energy and move demand away from system demand peaks and high price times. Although such demand side flexibility is often considered to be analogous to generation, i.e. demand reduction is equivalent to increased generation output, there is one significant difference; generation output can be directly measured whilst demand non use cannot. Demand reduction can be defined as the difference between the actual level of consumption and what the consumption would have been if a specific demand side response had not been undertaken by the customer. The difficulty in measuring the Demand Response (DR) of customers is seen by many to be a barrier to demand side participation in Demand Side Bidding markets.

The demand elasticity available in response to payment and the resulting profile shape change in shifting demand can be mobilised by System Operators and Suppliers in order to assist with capacity constraints and system balancing. The use of load as a power system operation resource can replace typical power system deployment mechanisms, such as the construction of new generation plants and transmission lines. This is a significant constraint in Spain, as the permission to build new transmission infrastructure is increasingly difficult to obtain. At the moment, the average time required to obtain the permission to build a transmission line is more than five years. This, added to the big increase of demand and in peak load that is being experienced in some geographical locations, makes the work of System Operators challenging.

Demand response mechanisms use specific payments to customers to motivate them to reduce demand at times of generation capacity shortage or high prices. These mechanisms are also applied to switch on standby generation located at customer premises. In this case, the generation is started in response to a price signal or a request associated with a payment and represents a “turndown” of customer demand.

In principle, all demand can be made to respond to price if the price messages are sufficiently strong. However, in reality, price messages can only be as strong as made possible by the cost savings which are delivered by shifting elements of demand. In order to quantify the potential for demand reduction by smaller customers, it is necessary to understand the role of smaller customers in creating system peak demands. This enables more accurate assessments to be made of the DR potential. Small amounts of demand reduction can have a significant impact on market price and system security.

Demand Side Bidding (DSB) is the formalisation of DR where contracts are put in place between customers and System Operators/Suppliers so as to deliver more reliable DR, which can be used to meet capacity constraints or as alternatives to generation. These DSB contracts specify the size, duration and delivery time for specific DR. This activity makes DR more predictable and reliable and hence more valuable to System Operators/Suppliers. Specific payments and penalties by System Operators/Suppliers for delivery and failure of delivery are being put in place as incentives for customers to meet their contracted demand changes.

Mechanisms are required to validate both that demand is “available” (ex ante)as a Demand Side Bid and that the demand was “turned down” (ex post) when requested, as defined in the contract.

The objectives of Subtask 5 are to identify and develop mechanisms which can be used to validate that smaller customer demand is “available” for demand change and also, following instruction, that the demand has “turned down“.

Validation is a significant challenge for smaller customers in part because an Aggregator is needed in order to bid sufficiently large demand blocks to be of interest to System Operators and Suppliers. Aggregators collects blocks of demand from groups of smaller customers and are responsible for managing delivery of the DR as contracted in the DSB. The Aggregator is likely to have a portfolio of customers and demands from which to deliver the contracted demand “turndown”.

2 Demand Side Bidding

DSB enables electricity customers to offer specific changes in demand, at given times, in return for specific rewards. Customers are rewarded for having the flexibility to make short-term, discrete changes in demand, which help deliver secure and reliable electricity supply systems. They are rewarded either by a reduced price for purchase of electricity or by direct payment for actually changing their demand. DSB provides an alternative to generation, by calling on customers to make load reductions. Reserve generators are generally less efficient, and often produce higher CO_2 emissions, than base load plant. There is also an added energy penalty in starting them up and holding them in a state of readiness. DSB can be regarded therefore as a means of optimising overall system energy efficiency, by reducing the need for such plant.

DR cannot be considered for DSB unless it can be validated as "available" and "turned down" in response to specific requests by System Operators.

From a system operator point of view, the following issues require careful attention and have to be taken into account when considering the response from a large number of smaller customers:

- Demand "available"
- Demand activation speed
- Demand "turndown" calculation
- Load recovery or payback
- Implementation cost

The activation speed refers to the time required by the group of customers to activate and actually start the implementation of a demand reduction. This issue determines the type of service that the group could provide. Activation speeds of 10 to 30 minutes could be reasonable for the demand side. These speeds make the response coming from the demand side similar to generators providing secondary regulation services (in terms of response speed). DR can be even faster than that if, for example, frequency relays are connected at the equipment terminals. In this case demand can be comparable to primary regulation.

Remote disconnection of air-conditioners, water-heaters, and heating equipment for example can be accomplished in less than a minute. The limiting factor in this case is the communication channel and customer acceptance. If remote disconnection is used, the response coming from small customers is therefore faster than the one coming from large facilities, which usually perform the load reduction operations manually.

Evaluation of the demand "turndown" executed refers to the necessity to assess the demand that is actually reduced. One of the main difficulties of this evaluation resides in the fact the amount of load that a customer (or group of customers) is reducing, depends on the load that the group would consume if no action was executed. This amount cannot be measured and has to be estimated. The duration of the reduction is also a very important parameter.

The load recovery experienced by a group of customers, when the control action or incentive is released is also important. Some loads do not experience such behaviour, but there are others such as air conditioners that can generate abnormal demand peaks soon after the control action is released or the electricity price reduces. If the peak demand during recovery is large, the System Operator must take it into account. Generators do not experience such issues.

Demand side buyers are purchasers of demand side bids. Such purchasers are involved in wholesale electricity markets and need to balance electricity supply and demand or maintain quality and security of supply. In particular, electricity suppliers, generators, system operators, energy service companies (ESCOs), network companies and balance responsible companies are all potential demand side buyers.

DSB implies ownership by customers of the right to consume a given amount of electricity at a given time. This right is traded by reducing demand; in effect selling the reduction in demand. In order for DSB to be effective in competing with generation to meet demand, it must be delivered with high reliability and predictability. This demand change can be delivered by a remote switching signal or a high price signal sent to customers. DR can only be considered for DSB if the demand to be changed can be validated as "available" and as "turned down" so that reward can be made on an equitable basis.

Some countries operate Balancing Markets to ensure that the amount of electricity generated exactly matches the demand at all times. These markets are managed by System Operators or Suppliers as Balancing Responsible parties. If generation is not sufficient to meet expected demand, System Operators can accept bids from generators to increase output. Alternatively, they can accept bids from customers to reduce demand. The cost of meeting these imbalances is determined by the terms of the bids offered by generators, suppliers and customers.

There are a number of options and trading mechanisms in competitive electricity markets for obtaining generation and demand side bids across a range of durations and notice periods. Scheduled time frames associated with different DSB categories are shown in Fig.1. Here each bid is allocated to one of three main time frames, with the different periods defined as 'months ahead of trading', 'day ahead of trading' and 'within day trading'. The within day trading time-frame can be from several hours to 15 minutes ahead of delivery or immediately at the time of delivery. In some markets, the 'spot' market closure coincides with the end of the day ahead of trading. However, there is a tendency, as markets develop, for this to get closer to the point of delivery.

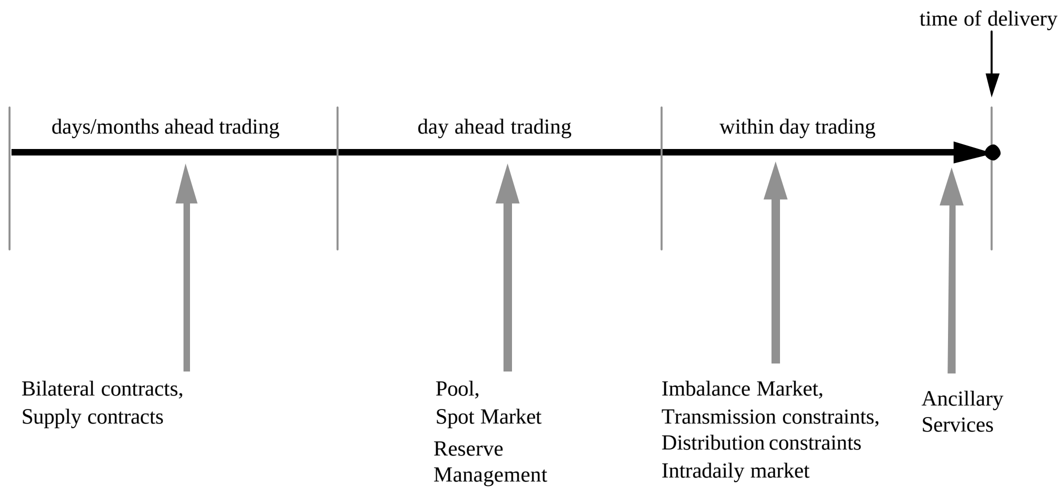

Fig 1 Timescale for bids for different DSB products

Countries with liberalised electricity markets have demand side products available that fall into most, if not all, of these time frames. DSB products are used in the following applications which are described in Appendix 1.

DSB to maintain quality of supply	Ancillary services (various types)
DSB to solve network constraints	Distribution constraints Transmission constraints
DSB for electricity balancing	Balancing markets
DSB for access to market prices	Spot markets

Present demand "turndown" systems require a single instruction from the System Operator to reduce many MW of demand. Demand Side Bidding as presently implemented requires defined blocks of demand or generation to be made "available" to System Operators and contracted for DR "turndown" or switch on during agreed time periods. This process is a dynamic mechanism for modifying demand on a short-term basis in response to System Operator requests.
In Spain, Red Eléctrica de España is starting to study the general characteristics of the future demand response mechanisms for medium and big customers:
The new program will have the following general characteristics:

- The minimum required interruption capacity is likely to be reduced to 1MW.
- The maximum advance notification time will be 2 hours.
- A zero notification time category will be included (frequency relays)
  This would be especially useful in islanded network locations.
- The duration of the interruptions will range from 1 to 12 hours.
- The payments will be based on contracts between Red Electrica de Espana and customers. The payments will depend on the type and value of the service provided by the customers.
- Consumption will be interrupted during approximately 240 hours per year.
- The system should differentiate between different network locations so as to deal with network constraints.

Red Electrica de Espana is also studying new alternatives to include the remote connection of customers' back up generators. The program will also be based on contracts. The minimum power of the generators will be 1MW. The intention is to connect these generators during system contingencies. The system would be based on contracts between Red Electrica de Espana and the customers. The service is intended to be operated frequently. It is likely that the payments will be based on the generated energy, and not the capacity. Therefore, there would not be a firm obligation to participate in the requests.

Where an Aggregator is involved, the Aggregator could be responsible for sending "turndown" requests to customers or to directly switch customer equipment by prior agreement. This methodology requires overall communication between System Operators and customer demands and could be via an Energy Supplier or ESCO acting as an Aggregator. It has to be noted that system operators are not the only entities that could be interested in initiating the implementation of DSB initiatives. Other players such as suppliers or generators exposed to imbalance penalties could also be interested in DSB.

If customer demand is already scheduled automatically for low cost times by, for example, the customer already being on a fixed time, TOU tariff, then the demand changes which result from the price changes are not "available" for DSB in the market at other times. However, automatic processes may be organised to respond to additional demand "turndown" signals from System Operators during the low price periods. DR in response to Dynamic TOU pricing can be considered as "available" demand for DSB because the price messages can be implemented at reasonably short notice to suit capacity constraints etc. These price signals can be considered as similar to direct demand switching by remote signal but with an over ride option allowed for customers.

Demand "turndown" and contracts between customers and Supplier/ Aggregators are based on defined parameters. These parameters for smaller customers could include the frequency of automatic "turndown", its duration, the maximum number per year and the interval between them. Some demand changes would include defined notice times before implementation. Others would involve a warning of a possible instantaneous implementation of an automatic "turndown" during a future defined time period. It is interesting to note that in some existing, trial implementations, customers have flexibility in setting the standby notice and call-off notice required. Thus, a customer may stipulate that they require 12 hours notice to standby for a demand "turndown" instruction for particular end uses, but only 2 hours notice to deliver it.

If "turndown" is only required for critical situations which are rare events, then demand switching instructions may only be issued a few times per year. For participating customers, there would therefore be little incentive to change their consumption pattern or behaviour in anticipation of the possibility of being "turned down". Customers would be likely to override the instruction and stand the penalty, if this option were available. If demand "turndown" orders are issued more frequently, i.e. several times every month, then changes in customer habits would be likely even if override options were allowed. Using a TOU price penalty to dissuade customers from over riding the switching instructions and making demand "not available" and collecting it through the TOU meter by increasing the rate, results in Suppliers collecting the penalty.

Initial "turndown" commands would be initiated by System Operators or other players and then remotely activated by Aggregators. A system of local intelligence and communication enabled appliances at customer premises is required in order to manage the demand of individual end uses. This could be based on the use of a centrally placed controller in the house, with communication to the appliances etc. It could also be based on intelligence located in the individual appliances, or sockets with each controlled directly from an external location and broadcast signal.

Communication and control infrastructures for remote switching and monitoring of demand are likely to be organised and installed by Aggregator businesses. These facilities would then be used by Aggregators/ESCOs to provide the demand management services to System Operators and Suppliers. Aggregators would then reward customers for their participation in delivering the demand changes. Aggregation of demand may have to be carried out in zoned blocks on a geographic basis so as to assist with "validation" at grid metering points and to accommodate possible transmission constraints. With existing demand bidding systems for larger customers, System Operators have confidence that "available" demand will actually "turndown" when requested because contracts are in place between them and larger customers and the demand is metered in near to real time. These contracts are agreed when the demand bids are approved and penalties included for non delivery. Systems for rewarding larger customers rely on individual customer demands being bid and TOU metering (half hour or minute by minute) used to compare pre and during “turndown” demand. This mechanism is impracticable for smaller customers because of the erratic nature of individual smaller customer demand and the costs of TOU metering and verification processes.

Advance notice is usually provided to customers by System Operators when a demand “turndown” request becomes likely. The shorter the notice period required by the customer before “turndown” can be implemented, the more valuable the demand is to System Operators and the larger the payment.

3 Demand Response and DSB

The objectives of delivering smaller customer DR are to save energy, improve overall System efficiency and help deal with demand growth and resulting Generation and Network capacity constraints on a long term basis.

3.1 System Demand in Spain

Figure 2 shows the increase in electricity demand experienced over the last years in the Spanish power system.

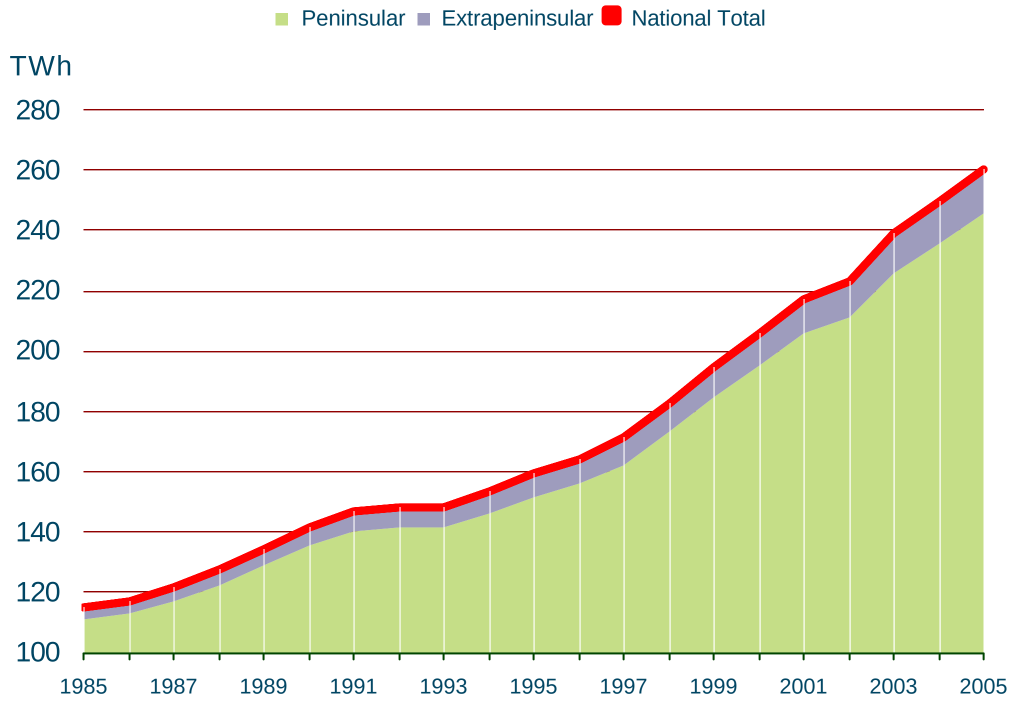

Fig 2 Growth in Electricity Demand in Spain

Figure 3 shows the increase in peak load experienced over the last years in Spain. Both winter and summer peaks are represented (punta invierno and punta verano). The winter peak demand increase was particularly significant from 2004 to 2005.

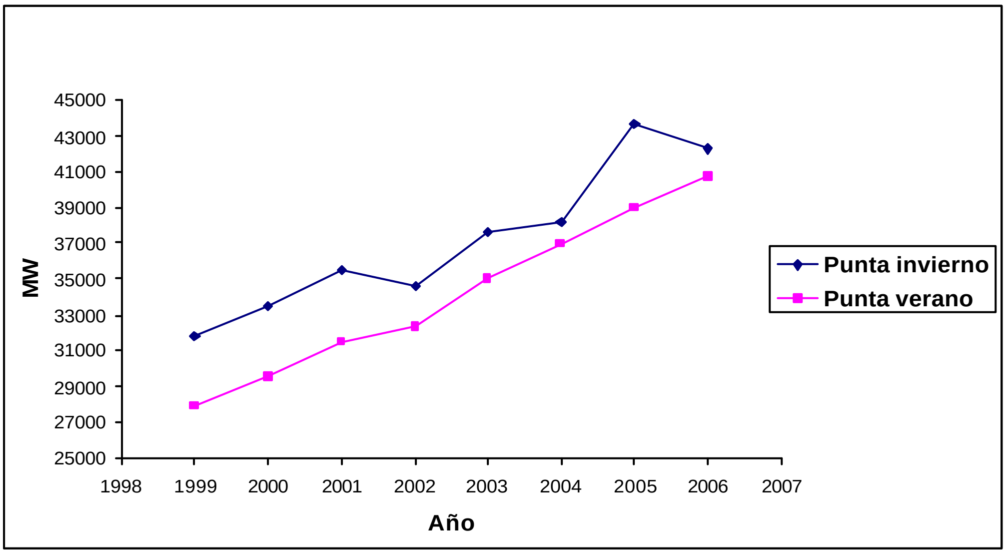

Fig 3 Growth in Peak Demand in Spain

In order to make a significant and measurable impact in the transmission or distribution system, a large amount of residential customers must be aggregated and controlled at the same time. A load reduction of less than 1MW is almost imperceivable at a transmission system level.

In terms of the implementation of control over domestic customers in Spain, very little work has been done. The only effort in trying to modify the load shape of domestic customers has been a fixed TOU rate known as the "night tariff". It provides much cheaper than normal electricity at night and a slightly more expensive tariff during the day. The penetration of this tariff is a 4%.

Regarding active signalling or direct load control of domestic customers, nothing has been done in Spain so far. The situation however is likely to change as Red Electrica de Espana forecasts an increase in the operation costs of the transmission network. This would be the result of the increasing peak demand and the increase in the penetration of intermittent generation.

3.2 Smaller Customer End Use Demand

Examples of relatively short duration DR actions which smaller customers could take or which could be taken for them by automatic or remote switching systems by prior agreement have been identified in IEA, DSM, Task XI Subtask 2. These are:-

- Turn off/down lights
- Turn down heat thermostats (gas/electric)
- Don't use or part-fill kettles, etc
- Turn off / turn down air conditioning (remote inhibit?)
- Reduced shower/bath water
- Washing and dishwashing periods moved (remote inhibit?)
- Cooking period moved/modify cooking appliance use
- Allow embedded generation schedule to be modified (remote switch on)
- Modify cooking appliance use
- Turn down water heating thermostat (gas/electric) (remote inhibit?)
- Turn off refrigeration for short period

- Turn off/inhibit sauna, direct showers (end use inhibit)
- Turndown small commercial processes.

3.3 Smaller Customer End Use Contribution to Peak Demand

An illustration of the potential Demand Response which could be delivered on peak by the average smaller customer in Spain is shown in the Figure 4 below. This shows the contributions to peak demand made by smaller customer, energy end uses and identifies the challenge of persuading customers to make demand “available”. Smaller customers contribute between 7000 and 14000MW to peak demand in Spain. The top 2000 MW of generation capacity in Spain is used for 15 hours per year (2005). Similar percentage usage is the case in other countries.

Watts

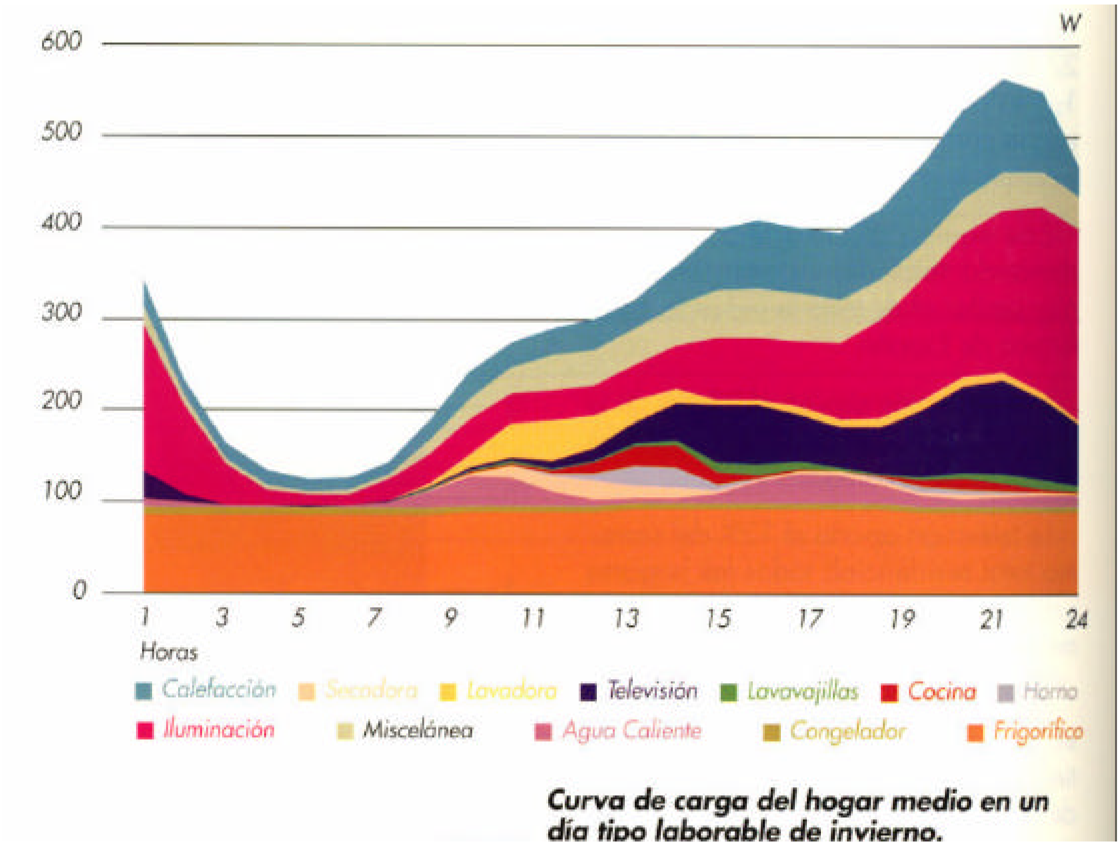

Fig 4 Smaller Customer End Use Contribution to Peak Demand in Spain (watts)

This curve shows demand contributions from:-

Spanish	English
Calefaccion	Space Heating
Lavavajillas	Clothes Washing Machine
Secadora	Tumble Dryer
Television	Television
Lavadora	Dishwasher
Cocina	Cooker
Horna	Oven
Illuminacion	Lighting

Miscelanea	Miscellaneous
Agua Caliente	Water Heating
Congelador	Freezer
Frigorifico	Refrigerator

The range of average demand per customer on peak in different countries has been investigated in IEA, DSM, Task XI, Subtask 2 and shown to be between 450 and 2000 watts.

3.4 Customer Interaction Mechanisms

Some preliminary options are being considered at the moment in Spain as customer interaction mechanisms:

First option:

- An aggregator makes contracts with residential customers that allow the direct load control of appliances such as air conditioners, washing machines, water heaters, dryers, dish-washers, lighting, or electric heating equipment.
- The aggregator guarantees that every time that the System Operator asks for it, a minimum of 1MW of load reduction will be obtained. A minimum reduction of 500kW is also being considered in Spain.
- The System Operator and aggregator make a long term contract (around 3 years) that guarantees the return of the aggregator's investment.
- The payments would have two parts:
    - Capacity payment
    - Payment for the actual reduced energy in each event
- The aggregated load reduction must be provided at the particular network locations where the problems occur.
- The advanced notification time must be as short as possible. The aggregator should install the infrastructure that allows a fast execution of the actions. The limiting factor should be the time required by the communications.
- The question of allowing the override of the control actions by the customers remains open. It would be up to the aggregators to decide the implications and operational problems associated to this possibility. According to a survey carried out in Spain, the possibility to override the control actions is not a very relevant factor for many customers.
- The duration of the aggregated reduction action should be at least 1 hour.
- The contract between System Operator and aggregator should define the number of times that an event can be called. The intention is to obtain as many events as possible.

This first option would be the most valuable for the Spanish system, as it would allow delay in the construction of new transmission, distribution and generation infrastructure.

Second option:

- The structure would be similar to the first option. The differences are that the notification time would be longer (typically 24 hours), and the duration of the reduction also longer (up to 10 hours).
- The aggregator should run the appropriate algorithms that allow a minimum 1MW reduction during the 10 hours of the event.
- The payments would also be based on capacity and actual energy reduction.

This option will also allow Red Electrica de Espana to defer the need for new transmission infrastructure in particular areas, but as the activation time is longer, it would be less valuable and the payments will be smaller.

Third option:

- The third option is also similar, but eliminating the obligation of the aggregator to participate in every event. This eliminates the capacity payment, but allows more flexibility to the aggregators.
- This control option would be used by the System Operator to alleviate global system peaks, and global generation shortage problems.
- The notification time would typically be around one hour, and the duration of the reduction around 4 hours.

Red Electrica de Espana plans to investigate the viability of these three options, and specify demonstration trials for that purpose.

3.5 Smaller customer Demand Response

In the Netherlands during the 1980s and the early 1990s the potentials for load management for smaller customers were estimated. Load curves for two offices and for a group of washing machines at customer premises were developed and are shown in Appendix 2. Also the modelling of customer load curves was carried out. The overall conclusion was that real hour measurements should be available for accurate results (Wijngaart and Blok 1990).

In 2004 Siderius et al concluded that load curves for small customers on a daily or annual base were not available. He estimated that the potential for load management could be about 710 MW growing up to 1.200 MW. The impact of this load demand on the Dutch total is just a few percent (maximum 5%).

In the same year Werven and Scheepers reported on a qualitative monitoring model that attempts to give insight into the adequacy of supply in the Dutch liberalised electricity sector. A relevant point of departure is the demand side fulfilling an important role in the liberalised electricity market. They concluded that knowledge on the potential for demand response as well as information for new potential services such as Direct Load Control and Demand Side Bidding is lacking.

In the Quality and Capacity Plan 2006-2012, TenneT, (Netherlands System Operator) gives special attention to developments in spatial cooling. Spatial cooling is becoming an established feature of service-sector premises (offices and shops). By contrast, domestic air-conditioning remains in its infancy. However, with more than six million households in the Netherlands, the potential impact of home cooling is sizeable. Nevertheless, if over time large numbers of homes and other premises simultaneously operate cooling systems during hot spells, a very substantial additional load will be placed on the grid at the times in question. The load forecasts for the Money Rules scenario take explicit account of the demand growth associated with increasing use of spatial cooling, assuming that by the end of the capacity planning period roughly 10% of homes will be fitted with air conditioning. This could lead to an additional load of as much as 1,200 MW.

Most experience of successful demand response in Netherlands has been gained with large customers that have processes that consume predictable and steady electrical loads. As such, it is relatively straightforward to identify the processes, and thus the load, available for DR. In the Balancing Market only a few producers are active in delivering regulation and reserve power for about 17 GW. Since July 2005 TenneT has had additional turn-down contracts with a small number of industrial companies for about 220 MW. Only large customers with a specific high voltage tariff contract or with an Hourly Power Tariff contract are allowed to participate in service interruptions. They must also offer a power interruption of not less than 5 MW and have the appropriate metering, communication and control equipment. The inclusion of each customer in this program must be accepted by the General Directorate for Energy and Mining Policy in the Ministry of Industry, Trade and Tourism. Currently, more than 200 customers participate in the program, providing a total of 2700 MW of interruption capacity.

In Spain, interruption orders are used to deliver DSB with validation based on "real time" metering.

An example of an interruption order which occurred in Spain on 21 June 2005 is shown in Figure 5. That day, the System Operator sent to 97 clients an interruption order at 10:15 am. The interruption period went from 11:15 am. to 2:15 pm. The load reduction achieved was 1,274 MW and the energy saving was 3,816 MWh.

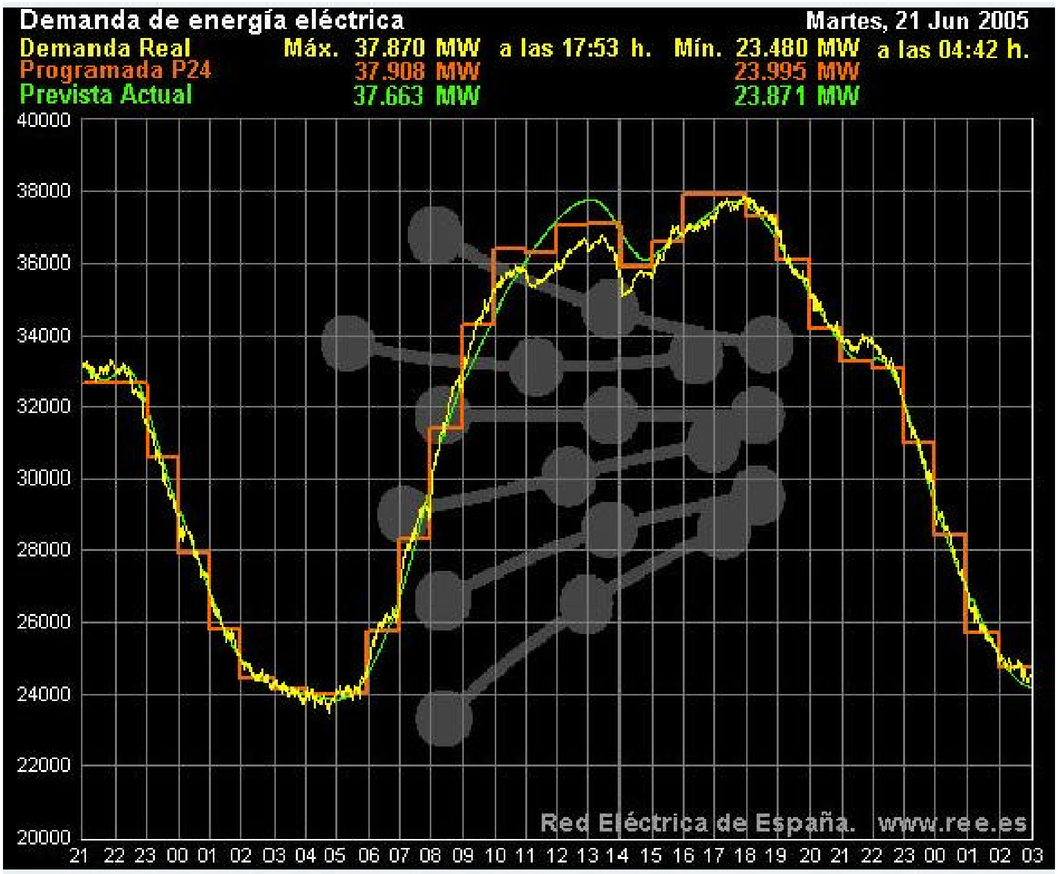

Fig 5 Demand Response impact on System Demand

The green line represents the forecast demand; the staggered red line, the operation hourly scheduling and the yellow one, the instantaneous power demand.

Smaller customer DR validation is particularly challenging because, in most situations, the demand will be inhibited rather than interrupted. Consequently, it will be difficult to relate together the switching instruction and demand change. This inhibiting of demand process is necessary because the majority of smaller customer demands are controlled by thermostats. In the case of many white goods, especially washing machines, the process cannot be interrupted, once started. In the case of remotely changed thermostat set points, there is a probability of the thermostat already being off when the control signal is received.

This inability of correlating demand change (as measured at the smart meter, for example) with receipt of the control signal means that it is very difficult to measure demand "turndown" for individual smaller customers.

3.6 Estimating Demand "Available" (ex ante)

Initial perceptions would suggest that manual demand response actions, for example customer response to a price signal or a request to avoid or reschedule energy consumption would not be predictable, and as such would not be eligible as DSB. However, numerous real time pricing (RTP) programs have been designed in the United States and elsewhere that rely on time of use (TOU) price and usage data for customers to develop statistical methods for estimating the price response parameters for customer demand models. It is claimed that such information can be used to estimate customers' ability and willingness to respond to prices. For example, it has been suggested that developing new pricing designs without accounting for demand response could result in an error of 4 to 10 % in revenue forecast under normal pricing conditions, and as high as 100% under volatile pricing conditions.

Experience of whether and to what extent domestic customers would respond to such real time prices is not available for the UK, and therefore, in the short-term it would seem unlikely that voluntary demand response (i.e. that manually undertaken by customers) would be viable as DSB. In the medium to longer term, however, basic information could be established through the application of pilots, and depending upon the results, used to determine the price response parameters for UK domestic customers for future demand response initiatives.

However, this could be complicated if customers were provided an option to over-ride remote signals to reschedule or interrupt energy end uses.

Models of load response, based on empirical information gained from pilots and/or trials, would therefore seem to be appropriate for determining the level of demand "available" for demand response initiatives involving either manual or remote control of customer energy end-uses. However, demonstrating that the model provides sufficient accuracy in terms of the actual level of demand "turndown" when the demand response initiative is implemented on a wide scale could be difficult.

3.7 Estimating Demand "Turndown" (ex poste)

There is always a risk that demand response delivered is less than that expected, for example as was seen during the Demand Turndown trials undertaken in the UK (see Appendix 3). The majority of experience of demand response initiatives involves larger customers, who typically have time-of-use metering, and thus, metering data available to compare actual demand profiles with and without demand response. Unlike large commercial and industrial customers which have large processes that operate according to predictable schedules, the demand profile of individual households is highly variable, and changes from day to day according to lifestyle patterns. This makes it difficult to detect changes in energy consumption patterns due to specific demand response actions as opposed to those that occur naturally due to changes in social patterns. This variability is demonstrated in Figure 6, which shows the actual demand profile for a single, UK household for five consecutive Thursdays during May 2003. The data represents the average kW demand over each 15 minute interval during the day.

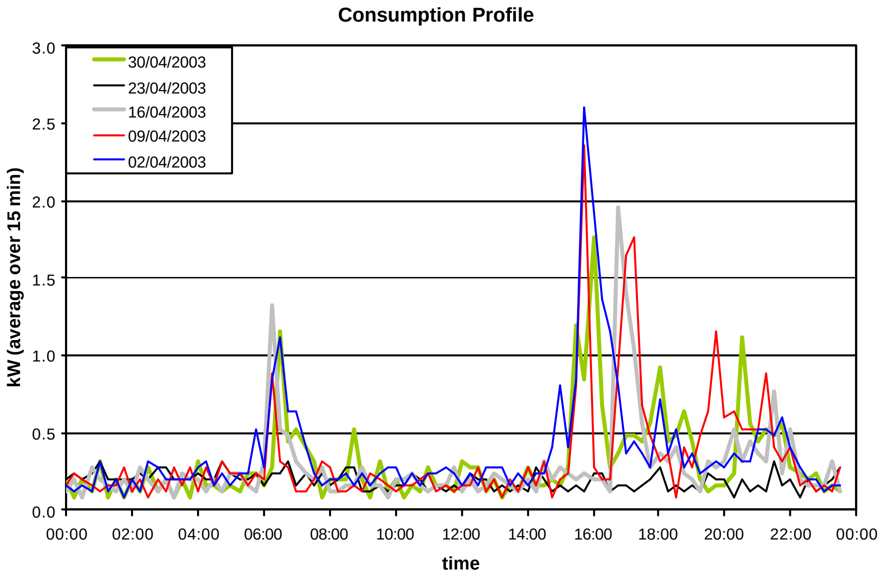

Fig 6 Consumption Profile for a Single UK Household

There is considerable variation in the demand profile of the customer for the five sample days selected, even though the day type (Thursday) is the same. The time of the evening peak varied between approximately 15:45 hours and 16:45 hours and the size of the peak varied between 1.8 kW and 2.6 kW. (The data would suggest that the house was unoccupied on 23/04/2003, therefore this day has been excluded from the analysis).

Demand response measures at the individual household level would involve rescheduling end-uses of typically, 0.5 - 2 kW for a period of a few hours (IEA DSM, Task XI, Subtask 2). Consequently, it would be very difficult (if not impossible) to be able to pick up such demand response changes by analysing the demand profiles of individual households. However, aggregating the demand of a group of households participating in the same DR initiative should enable the amount of DR delivered to be directly measured at large substations. The average profile of the group of households should be significantly different to that of households which do not participate and/or do not undertake DR. Similarly, comparison of the average profile with that given by the standard settlement profile for that group of customers should demonstrate the level of demand response delivered.

Actual measurement of DR at the individual customer level is unlikely to be viable due to the high level of variability that typically occurs and the fact that many of the demand switching operations would be to inhibit demand rather than interrupt it. Because of this it would be more difficult to correlate the demand switching instruction with a change in demand at the meter.

The collection of information to model and estimate DR is not currently available with existing meters, but may be in the not too distant future in the UK, Netherlands and Spain with Government commitments to introduce smart meters in households over the next 5 to 10 years. This would require that smart meters were capable of storing time of use energy usage information (either on a half-hourly or quarter-hourly basis) regardless of whether or not the time of use data was used for settlement purposes. However, it is important to note here that such time of use data would not be required from all households participating in DR, but only from a representative sample of households, as is currently the case for monitoring standard settlement profiles.

The new market model and technical standards for the new metering technology in Netherlands is described in Appendix 4.

Measurement of high levels of actual DR should be possible at GSP Group points, in much the same way that it was done for the radio-teleswitch trials in the UK, provided that the overall level of demand response was of a similar order of magnitude, i.e. 100 MW or more (see Appendix 3).

3.8 DSB suitability of smaller customer DR

IEA, DSM, Subtasks 1, 2 and 3 considered methods for motivating Demand Response. These were feedback to customers of disaggregated end use demands, TOU tariffs and Dynamic Pricing. This latter process offers flexible DR with time varying price motivators and is suited to DSB.

Option 1 (DR motivated by Energy End Use Feedback)
DR is motivated in this case by providing customers with disaggregated energy end use information. This is likely to produce DR for many customers in the form of general energy savings. However the DR will become a general behaviour change and be built into demand forecasts. Because the demand change cannot respond to System Operator requests it cannot be considered “available” to DSB buyers. Consequently this DR will not be “available” for DSB.

Option 2 (DR motivated by Tariff TOU pricing with manual response)
With this option, customers deliver DR in response to Tariff TOU pricing, where TOU price and times information are provided for customers and manual switching of end uses is carried out to save money. These TOU times and prices are fixed for typically many months ahead with the actual amount of DR likely to vary significantly from event to event. This DR is likely to become a general behaviour change by customers in moving demand into lower price periods and be built into demand forecasts. It is not “available” to System Operators to use as a “turndown” resource. Consequently this DR will not be “available” for DSB at high price times.

Option 3 (DR motivated by Dynamic TOU pricing)
There are two different protocols which can be used to deliver DR using Dynamic TOU pricing:-

a) Remote/automatic/manual switching of demand. Customer over ride allowed
If Dynamic TOU Pricing or Critical Peak pricing together with remote or automatic switching of end uses and varying times and prices are used to deliver Demand Response, there will be a significant change in participating customer demand. DR with this option is delivered by providing customers with a display of TOU prices and times which are changeable on a short term basis, typically daily. An option is allowed for customers to over ride the automatic/remote switching instructions, so that the results of this process in terms of Demand Response could be similar to that for TOU metering alone without the automatic/remote switching. However, the price signal is likely to dissuade customers from exercising the override option as a normal activity. The impact of this option will result in flattening of the customer demand curve.

The DR produced by Dynamic TOU Pricing will result in customers or their automatic systems taking specific actions at varying times. Customers could respond to the signal through a variety of mechanisms. These comprise, local automatic switching of demand and remote switching of demand. This means that the DR delivered by this mechanism has the short term option of being requested and delivered or not, depending on whether a price change signal was transmitted or not. A Balance Responsible party would bid the estimated demand change in response to the price or demand switching signal. Consequently this mechanism can be considered as suitable for DSB because the transmitting of the price or demand switching signal can be bid and validated.

Requirements for this option as a DSB mechanism

- Smart meter (Dynamic 2 rate or TOU).
- Remote auto switching of end use demands and meter rate.
- Dynamic times and rates with notice by one way signal.
- Override of demand switch allowed by customer.
- Customer paid for service plus statistical delivery.
- Alarm of high price and notice of automatic/remote switching given to customer.

Strengths

- Provides customer demand flexibility
- Simplicity for customers
- TOU price dissuades customers from using demand in “turndown” time window
- Reasonably predictable demand change.

Weaknesses

- Requires Dynamic 2 rate or TOU metering.
- Requires communication to end uses.
- Requires communication enabled end uses and meter
- Requires a customer display.
- May be less predictable demand change due to override option.

b) Manual switching of demand in response to dynamic TOU pricing

DR with this option is delivered by providing customers with a display of TOU prices and times which are changeable on a short term basis, typically daily. No automatic switching of demand is provided. Remote meter rate switching is provided. Customers would be responsible for manually changing demand in response to the price signals. It seems unlikely that this method for delivering DR and its unpredictability would enable it to be used for DSB but it is a relatively low cost possibility.

The meter rate change signal could also be used to change the rating of a maximum demand limiter which is used for residential customers in some countries to limit maximum demand. In this case it becomes the responsibility of customers to reduce demand and determine end use priority in order to stay within the maximum demand limit. Because this manual demand change would be motivated by customers needing to do it in order to restore supply, it may be possible to include this mechanism within DSB schemes.

Requirements for option as a DSB mechanism

- Smart meter (Dynamic 2 rate or TOU).
- Remote auto switching of meter rate, (or intelligent maximum demand link were fitted) by one way broadcast communication signal.
- Manual demand change by customer in response to price or maximum demand change.
- No specific payment for "turndown".
- Customer advance notification provided of possible high price together with an alarm of actual high price.

Strengths

- Low cost
- Provides customer demand flexibility
- Very simple communications
- Does not require communication enabled end uses

Weaknesses

- Complexity and inconvenience for customers
- Requires dynamic 2 rate or TOU meter or switchable maximum demand link.
- Requires customer display
- Requires communication with meter
- Unpredictable demand change for metered options, (predictable for maximum demand link if no override allowed).

Option 4 (DR motivated by remote switching of demand. No customer override allowed.)

This option is similar to present DSB mechanisms for larger customers which rely on remote switching to deliver the DR and DSB. Because this option allows flexibility in terms of when and if the demand switching signals are transmitted, it can be used as DSB with the timing of the signals forming part of the bidding contract. The actual demand shift will again be statistical but likely to be more predictable than option 3 because of the no override condition.

Requirements for this option as a DSB mechanism

- Simple meter, single rate.
- Remote auto switching of demand end uses by one way signal.
- No override of demand switch signals.
- Customer paid through tariff.
- Alarm of high price and switching given to customer.

Strengths

- Intermediate cost
- Reasonably predictable demand change
- Simplicity for customers

Weaknesses

- Customer may switch on alternative appliances to offset remote switching of appliances, (heating).
- In flexibility for customer
- Requires communication to end uses and communication enabled devices
- Customer display required

Summary

The demand “available” and “turned down” resulting from options 3 and 4 would be aggregated by the Aggregator and bid as DSB. Participating customers would be rewarded simply through reducing their energy costs during high price periods. They could also be rewarded by a direct payment for being involved in the DSB scheme. For option 4, this payment could be made whether or not customers exercised the over ride option on some occasions and decided to pay the high price.

Consideration of how and whether this demand “available” and “turned down” from options 3 and 4 can be validated so as to provide confidence to System Operators of its delivery is considered in Chapter 5.

4 Payment for Demand Side Bidding

Validation of this potential demand change is necessary in order to provide confidence to System Operators that the demand change potential is actually "available" to be "turned down" if and when required. This is a critical activity in order to allow the demand side to fully participate in electricity markets and enable equitable payments to be made to customers or their agents for the service.

The benefits of DSB from a customer perspective are financial as well as providing increased system security. Payments are made in some countries for making demand "available" for turndown as well as for actually delivering "turndown" of demand. Processes in the UK for delivering and being paid for demand side participation by larger customers include pre turndown activity of preparing the customer to make the "turndown". It also includes the actual "turndown" process and timings, "turndown" analysis, validation and customer payment.

Payment for demand "turndown" by smaller customers is important for the viability of demand management participation. Financial payments could be made to participating customers by means of the tariff via Suppliers. Suppliers could contract Aggregators to deliver the demand participation service. It may also be possible for Aggregators to offer the service directly to customers and reward them with direct payments without the involvement of Suppliers. With this arrangement, Aggregators could also seek the cheapest energy Supplier for customers. However, it is likely that any payment scheme would need to be supported by vigorous marketing campaigns promoting the environmental and energy saving value of customer participation in DSB. Payments to participating customers are unlikely to be large with the present levels of reward available in markets. However, these levels could increase in some countries if forecast generation and network capacity shortages actually take place.

Payments made to participating large customers in one demand side bidding field trial were on the basis of :-

- An "availability" payment
- A standby payment
- A "turndown" payment

An "availability" payment was made to reflect the costs incurred by customers of participating in the trial, mainly as a result of the requirement to provide forecasts of demand "available" and post "turndown" demand data. The payment was made on a €/MWh basis. The Standby payment, only paid when a customer was called to standby, was a fixed fee based on per day. The "turndown" payment was made when the customer was given the instruction to reduce demand and was paid on the delivered MWs up to the level of declared "availability". The delivered MW was the difference between the average demand in the two half-hours immediately prior to the instruction to "turndown" and the demand during the service window. Bonus payments were made in another trial if actual "turndown" was close to the contracted value.

For smaller customers, demand Aggregators would be paid for delivering contracted demand changes following System Operator/Supplier instructions. Payments to smaller customers are likely to be most financially viable when the demand participation incentive is included in the tariff and a single rate or two rate meter used.

Payment to Aggregators by System Operators may also be possible by considering "turndown" as a service with only approximate MW values delivered once specific switching instructions to customers had been transmitted and validated. This process is dealt with in more detail in Chapter 5 and is illustrated in Appendix 5, where the demand actually delivered by specific switching instructions sent to customers varied widely depending upon time of day and other factors. These factors included thermostat operations for temperature controlled loads, etc. It is believed that many of these demand variations could be predicted with statistical models, customer profile information, TOU metering data and field trials.

A study by transmission System Operators in Europe (ETSO) estimated guideline payment levels needed to motivate DR for different types of customers. The particular study was carried out by the Netherlands System Operator (Tennet). The levels of market price per kWh estimated to be needed to motivate each type of customer is shown in the Table below.

Customer Type	**System Price Needed (€/kWh)**
Industrial 1	0.3 –0.5
Industrial 2	2.0
Commercial	1.0
Residential	2.8

However, in the same European study, Norway estimated that DR starts to take place at 0.07€/kWh.

In terms of payments, it is quite clear that the strongest incentives for customers to modify their energy usage are the monetary payments. There may however be some customers that are willing to alter their energy usage (or let others do it remotely) in return of no monetary incentive. A clear indication for the latter is the fact that a large percentage of the Spanish population (a 79% according to a survey performed by Red Electrica de Espana) separates and recycles the garbage that they generate. This indicates that there is a clear willingness to contribute to conservation of the environment, even without financial reward, providing it is not too inconvenient.

The survey also provided information about the profile of customers that are most likely to participate in domestic load control programs. The survey showed a clear correlation between customers that recycle their waste and the ones that would be willing to participate in load control initiatives. According to the survey, the social and demographic characteristics of the households (size of the household, age of the head of family, number of occupants, number of children) do not have a significant influence in the motivation to participate. However, the electrical energy usage of the household does affect this willingness. The higher the electricity usage, the higher the willingness.

4.1 Benefits

The benefits associated to the implementation of these types of load control initiatives over domestic customers are listed below:

- Delay in the requirements for new generation, transmission and distribution infrastructure. In terms of generation, the new central plants that are being installed in Spain at the moment are based on CCGT technology (Combined

Cycle Gas Turbines). The building cost of these plants is estimated to be €500/kW. Regarding transmission and distribution, if the load control is achieved in the particular locations where the congestion problems are experienced, there would clearly be avoided costs. The cost of transmission infrastructure varies greatly. In order to obtain construction permission, Red Electrica de Espana is presently obliged to build expensive underground lines in many locations.

- The delay in the construction of new infrastructures also helps to reduce the environmental impact of power supply.

- Offering these new control opportunities, helps to increase customer awareness of the impact of electricity consumption, and may motivate long term energy usage reductions. These issues are treated in the Subtask 1 of Task XI.

- The reduction in consumption at peak time involves a reduction in transmission and distribution losses, even if the interruption events do not involve an actual reduction of the energy consumed by the customers. The reduction in the losses means that less generation resources are used.

- Increase in the operability of networks with high penetration of renewable energy resources. At the moment there is 10GW of wind generation installed in the Spanish power system. The relatively low predictability of the response of wind farms makes the network operation more challenging. Load interruption capabilities support the network operation under these conditions, increasing the amount of renewable generation that can be connected.

- In Spain during peak times, non efficient fuel plants have to be used. A reduction in the need for generation from these plants reduces greenhouse gas emissions.

- The incorporation of new players to power system operation (aggregators) could help increase competition. Aggregators offering interruption capacity would compete with peaking generation plants.

The quantification of the actual economic benefits of DR and DSB depends on the amount of domestic load that is available to be controlled during system peaks. At the present time Red Electrica de Espana is performing end-use characterisation studies in order to accurately calculate this value. The Spanish power system experiences congestion problems both at summer and winter peaks. These peaks occur at different times of the day during summer and winter. The study performed by Red Electrica de Espana is taking these issues into account.

5 Potential Mechanisms for Validating Smaller Customer Demand Side Bidding

Validating that demand is "available" for turndown is a process for providing confidence to System Operators and Aggregators that predicted demand "turndown" will take place when requested. For smaller customers, demand "turndown" is the interruption of demand such as reducing thermostat set points, but also the inhibiting of end uses which may have been ready to switch on during the contracted demand reduction time window (washing machines, etc.). The amount of this DR which can be contracted as DSB depends on how much of it can be validated as "available" and "turned down". If customers have the option to "turndown" or not, then some form of individual customer "validation" may be needed or a penalty incurred by customers exercising the override option in order to dissuade them from using it. This penalty could be financial as a result of TOU metering and dynamic pricing with the "turndown" request accompanied by a high price signal. Again, it may be assumed, that being "not available" where customers have over ridden the switch, could be a rare event, in which case it need not affect the amount of "turndown" offered by Aggregators. It could be included in the form of an agreed uncertainty. However, if a "turndown" instruction is issued on Christmas Eve for example, then the amount of "non availability" could be high, but this may be anticipated through statistics and experience. Uncertainty of demand "turndown" outcome reduces the value of the service to System Operators. However, Aggregators could allow for this risk when bidding the demand service into markets. If remote control of "turndown" is used, via a Supplier or ESCO, then validation of the total "turndown" delivered may be sufficient irrespective of how that demand is delivered. However, there is still a requirement to reward participating customers.

If the contracts between Aggregators and System Operators contain penalty clauses which penalise Aggregators for non-delivery of contracted demand "turndown", then Aggregators have a strong incentive for ensuring that demand is "available". Knowing what demand response actually occurs on a statistical basis when different demand change motivator signals are issued to specific blocks of smaller customers at different times and during different seasons could provide significant confidence of demand "available" and "turndown".

However, if customer demand response is optional (an override is provided) then there may be significant variation in the level of demand "turndown" actually delivered on different occasions. If the demand change switching is automatic in response to a communication signal from the Aggregator with no customer override allowed, then "available" and "turndown" demand will be more predictable but less attractive to customers.

Validation of "turndown" is carried out for larger customers by comparing their actual, daily demand profile before, during and after "turndown". These larger customers have contracts in place with Suppliers for specific kWh consumption in defined time periods, together with TOU metering. Retrospective daily demand profiles based on minute by minute metered readings or half-hourly aggregated data are used for validating that demand "turndown" has been delivered as contracted, and also to permit System Operators to assess the accuracy of the forecast daily load profiles against actual consumption.

The figure below shows an example demand profile for a larger customer requiring two hours notice in order to deliver the contracted demand "turndown".

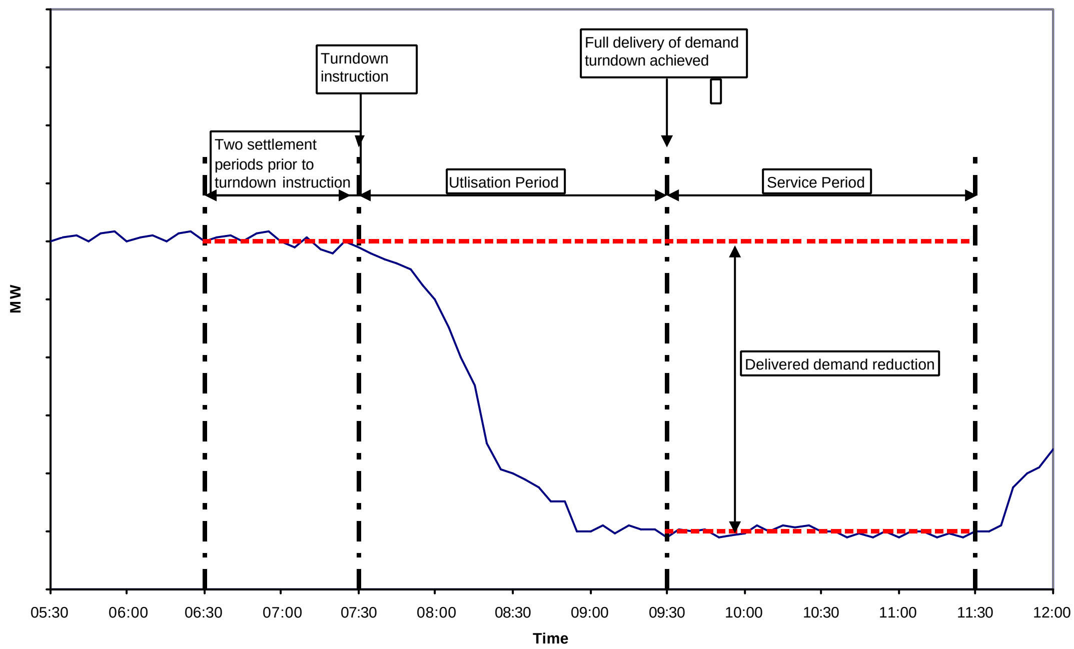

Fig 7 Metering demand "turndown"

Demand Response and Demand Side Bidding, have been the subject of a number of analyses, studies and implementation in the Danish, Nordic and other markets. Part of this analysis has been within the EU EFFLOCOM project where a trial Demand Side Bidding process for smaller customers was established. In this project, single family houses with direct electric heating offered to "turndown" part of the heating through a bidding system using Web-pages. In the project, the System Operator aggregated and validated the demand reductions directly using remote metering. This was possible because it was a pilot project dealing with the large heating demand and with only 25 single family houses participating and the demand was predictable and measurable. Customers had the option to override the demand "turndown" instruction but were penalised by higher energy costs using TOU metering and dynamic pricing. Because of the metering link in the demand management process, it may be necessary for the Aggregator to also be the Supplier or a contractor of the Supplier.

The easiest way from a System Operator point of view would be to transfer the responsibility to the Aggregator by means of a contract.

The experience of the Aggregator and specially the type of control and monitoring used for domestic customers should give him an idea of the demand that is available at the time of an event. Experiences in the USA always refer to summer peak as the control period, and therefore the load available is calculated under such conditions (weekdays, hot-day, afternoon period). One way communication systems used in conjunction with existing real time metered grid points should be acceptable in order to provide a good estimate of the available demand).

If TOU metering and two way communication systems are available, then the estimation of the expected available demand coming from the group could be improved, as the sample size could be bigger. However, the sample size would not need to be the complete population. A balance between the metering and data analysis effort and the accuracy of the estimation should be found.

As explained in IEA DSM Subtask 4 report, the Spanish Government is seriously considering the installation of a complete two way time of use metering infrastructure. It is highly likely that any domestic load control initiative in Spain will come together with the metering infrastructure. This infrastructure would certainly be used in the calculation of the "available" and "turndown" demands.

In Netherlands, in 2007, a start was made to replace all electricity meters over the time period between 2009 and 2014. Thirty five thousand have already been installed with a further twenty six thousand to be installed during 2007. These meters are installed without additional costs for customers and communication will be by power line.

A very important issue when trying to calculate the demand that has actually been reduced by a customer or a group of customers is the baseline. The baseline is defined as the energy that would have been consumed by the customer during a given period in the absence of signals or control actions.

A very simple baseline calculation method, that has been typically used, averages the load consumption data over the previous 10 days prior to the event. Other methods just consider the three days of maximum consumption out of the last ten days. More complicated methods that take the temperature and other factors into account are also being studied.

The predictability of domestic customer consumption helps determination of the actual demand turndown performed by a particular Aggregator. Test events should be performed in the preliminary stages in order to design the required metering strategies. Load reduction orders would be sent to customers contracted by each particular Aggregator. In the first two options of Chapter 3, the events are executed to reduce the loading of particular lines and equipment. Measuring the loading of those lines could provide an accurate indication of the performed reduction. The tests should be used to design the optimal metering samples for each Aggregator that allows acceptable estimation errors.

If the aggregated customers are not located on the same network, the calculation of the demand actually consumed by the group of customers would need to be based on a metered sample of customers, or it could be the direct measurement of all the meters. Simulation and field test should also be performed in order to investigate these issues.

The override capability introduces uncertainty in the calculation. The size of the sample should probably be increased in order to improve the accuracy with this additional variable.

Successful trials have been carried out in the UK, of remotely switching smaller customer heating demands using broadcast radio signals. These trials have shown that "available" demand can be estimated statistically (Appendix 6). However, more work is needed to improve the prediction accuracy. They have also shown that validation of "turndown" can be approximated by reference to grid metering combined with supportive modelling if the switched demand block is reasonably large. These aggregated changes are likely to be at least tens of MW in order to be of interest to System Operators. This modelling needs to include:-

- Information on the actual managed equipment at individual customers, i.e. electrical heating or not, dishwasher, washing machine, number and types of lamps etc.
- Information on the total metered consumption of individual customers.
- Available statistical information regarding the profile of particular customers based on estimated consumption pattern of various appliances and installations.
- Input to the model of the control signals sent to customers.

It seems likely that these methods could be refined to include time of year, weather data and time of day to obtain reasonably accurate estimates of “available” and “turned down” demand. Aggregators and buyers of “turndown” services would develop an understanding of what was likely to be delivered by the implementation of specific switching instructions communicated to specific customers or their end uses of energy at specific times during the day and year.

An alternative mechanism for smaller customer validation for wide scale implementation could be to reward them through the tariff and to have automatic and non over ride implementation of “turndown”. This could remove the requirement for TOU metering to act as a disincentive to override the switching signals.

5.1 Technology needed for smaller customer validation

In terms of the technology needed to implement the three types of customer control actions explained in Chapter 3, and to verify the response, three aspects can be differentiated:

- General communication infrastructure
- Metering
- In-house communication and control systems

General communication infrastructure is being developed in many countries in order to perform TOU tariff and demand switching, remote metering and the provision of customer information. Meters with varying levels of “Smartness” are also being rolled out into the smaller customer sector in order to perform DR motivation and, in some cases, to act as communication gateways to energy end uses.

The issue of the in-house control system is more difficult. A simple system that receives the load control signals and automatically executes the actions could be used, possibly based on “intelligent” plugs.

In order to control these actions, each end use has to communicate with the meter or the communication gateway responsible for receiving the external signals. At the moment the main vendors of house automation systems use proprietary communication and control protocols and standards. The use of an open standard that allows an easy expansion is an essential requirement for large scale roll out.

One alternative could be to use power line communication systems. The X10 standard has been around for several years now, and is the cheapest alternative (although slow and relatively limited). Another alternative could be the use of Zigbee or Bluetooth enabled devices.

There are several mechanisms by which DR suitable for DSB can be delivered. Some of these have differing technical and equipment requirements for their operation, as well as for validation of the DR produced.

5.2 Demand Validation for each DSB Mechanism

Chapter 3 showed that the driver mechanisms for converting DR to DSB were dynamic TOU pricing with manual or automatic switching of demand in response to price. This results in four new options and routes to delivering validated DSB.

DSB Mechanism 1

Remote/automatic switching of end uses with no customer over ride allowed (validation by modelling)

No override of remote demand switching signal is allowed so that validation of "turndown" is based on confirmation that DR switching signals have been transmitted. Delivery of demand block size will always be statistical but Aggregator and SO could agree values based on trials, modelling and experience, (UK trials of storage heating, see Appendix 3). Delivery of service may be a more appropriate way of considering this activity rather than MW. Models would need to be developed to validate demand "available" and "turndown" based on temperature, seasons and time of day. Statistical delivery of DSB is already in place in the UK for collections of arc furnaces (Appendix 6).

Technology and process

- Models of demand change and empirical data needed for validation of "available" and "turndown".
- Remote communication to customer end uses required. Problems of ensuring that the control signals actually switch demand with no customer override.
- End uses are required to be enabled for communications.
- Customers may not accept no override option.
- No TOU metering required.
- No customer display required. May be needed to reward via direct payment by Aggregator to advise customer of next day switching if required.
- Independent Aggregator possibilities.
- One way broadcast communication.

DSB Mechanism 2

Remote/automatic switching of end uses with customer over ride allowed (validation by modelling)

Override of demand switching signals allowed but with cost penalty via TOU meter. Demand "available" and "turndown" estimated on statistical basis and agreed between Aggregators System Operators/ Suppliers. Models would need to be developed as for DSB Mechanism 1.

Technology and Process

- Models of demand change end empirical data needed for validation of "available" and "turndown".
- Provides override option so more acceptable to customers.

- Remote communication to customer end uses required.
- End uses enabled for remote communications.
- TOU metering required.
- Customers rewarded via tariff, via Supplier.
- One way communication.
- Customer display required to present price to customers.
- Aggregator needs to be Supplier or Supplier Agent.

DSB Mechanism 3

Manual switching of end uses by customer (validation by modelling)

Manual demand switching by customers in response to price and a two rate meter (or smart maximum demand link switching) to deliver demand "turndown". Validation will be statistical and demand "available" and "turndown" values would need to be agreed by Aggregator and SO. Validation models would need to be developed.

Technology and Process

- Difficult to use this option for DSB in UK and Netherlands because customer manual response to dynamic pricing is likely to be very variable. In Spain if a remotely switched maximum demand limiter was included, with no customer override of switching signals, then manual response to loss of supply could be considered for DSB by a Supplier acting as an Aggregator.
- Validation in Spain would be via modelling and empirical data.
- Customer responsible for manual switching based on price signals.
- Customer display required.
- Remote communication to end uses not required.
- TOU metering required.
- Customers may not accept manual operations required to avoid cost penalty.
- One way broad cast communication required.
- Models of demand change and empirical data could predict demand change.
- No reward mechanism required in UK and Netherlands.
- Customers in Spain would be rewarded via the tariff.

DSB Mechanism 4

Remote switching of end uses and customer override allowed. (Validation by two way communication)

This option provides two way communication between the largest end uses of energy at customer premises and Aggregator. This communication could operate using several different architectures based on intelligent house controllers. Customers could contract with Aggregators for a range of control strategies to minimise overall energy costs and have an acceptable convenience level. Demand changes would be delivered by communication between Aggregator and end uses. A customer override would be allowed. Validation of demand "available" and "turndown" would be by direct monitoring of end use and override switches and two way communications. Validation would be most effectively carried out by aggregating the measured demands of collections of customers and using processes similar to that for larger customers.

Technology and Process

- Provides override option so more acceptable to customers.
- Two way high speed communication with customer end uses required.

- End uses enabled for communication.
- TOU metering required.
- Customer interactive display required in order to set up demand switching programme.
- Likely to be an expensive option.
- Customer rewarded directly for each delivery of “turndown” in similar way to larger customers.
- Aggregator could be independent of supplier.
- Validation would be via direct measurement and monitoring of specific end uses (high demand).
- Models of DR may still be required in order to include DR in generation capacity forecasting.

6 Cost considerations

Demand Side participation in markets by means of flexible switching of smaller customer demand and allowing it to be bid in competition with generation requires the use of communications and control. Switching of storage, space and water heating by remote, broadcast communications have been carried out for many years in many countries, generally with no allowed override by customers. These switching processes use radio, power line or telephone communication media. Access to the customer demand is usually through a single point of control in customer premises which removes the need for "in house" communications. Generally the switching regime is reasonably non obtrusive. More recent trials have advanced the control to several points within customer premises in order to access items such as heating and cooling thermostats where the set points can be changed. Communicating control nodes need to be included in thermostats and end use devices in order to achieve this. The cost of these items is critical to the viability of smaller customer demand "turndown" using automatic mechanisms. Communication media inside customer premises, based on pico cellular radio, power line and optical have all been used in field trials for this very cost sensitive activity.

6.1 Costs

IEA, DSM Task XI Subtask 2 report, "Time of Use Pricing for Demand Management Delivery", estimated an annual communication and control cost per customer of €50 being incurred for remote switching of a collection of end uses in a customer premises using two-way communication and large volume manufacture. One way communication and simple "on/off" switching would enable lower cost control to be implemented for a reduced number of nodes.

A good example of the cost of a full AMR system is provided by ENEL. ENEL's automatic meter reading system involving 30 million customers in Italy is forecast to cost €2000M. This includes the cost of the 30 million purpose-built digital meters, its installation, and the construction of a completely new PLC communication infrastructure based on ENEL's distribution networks. The system does not include communication or automation within each house. The resulting cost per customer is €66.

The economic viability of the systems must be evaluated taking into account the benefits of automatic meter reading and other utility related functions. ENEL for example has calculated that the overall benefit obtained from the possibility to communicate with its 30 million low voltage customers is €500M per year.

The cost of an intelligent meter with communication capabilities starts at around €10, but typical values for quality meters with computation capabilities range from €50 to €150.

The cost of an intelligent PLC communication-enabled socket starts at €15.

If only remotely switched 2 rate or simple TOU meters are needed to motivate customer participation in demand switching, then these are readily available with communications.

7 Conclusions

It is evident from Chapters 2, 3 and 5 that validation requirements of DR, in order for it to be used as DSB should not present fundamental barriers to the adoption of smaller customer, DSB in generation markets. In principle DR validation can be done based on control group measurement, statistical modelling and Grid substation measurements of demand " turndown" in response to DR motivator signals on specific days and at specific times. However, there is a significant need to understand and develop customer behaviour change in response to Dynamic TOU or Critical price signals and remote/automatic and manual switching so as to increase customer participation.

Some evidence exists which shows that smaller customers will respond to TOU price signals, both manually and by automatic/remote switching. Calls have been made in some countries for such DR to be included in Supplier revenue forecasting and even system design. There is, therefore no reason to believe that such information could not be obtained for other DR initiatives, for example through schemes that involve the remote control of individual appliances. However, widespread acceptance and trust of DR will only be gained through successful application and demonstration that it delivers as promised.

Manual responses to DR motivators are considered unsuitable for DSB, except possibly together with intelligent Maximum Demand links as used in Spain where manual, demand switching is needed to restore supply. For all other motivators, there is a technology requirement for "in house" communication with remote control, enabled end use devices such as white goods and heating and cooling thermostats. Some of these end uses such as heating, air conditioning, showers, some white goods are available on the market already equipped for remote switching (enabling and disabling). However, significant infrastructure investment is needed to enable them to be used for DSB. ESCOs, acting as Demand Aggregators, are considered the most likely source for that infrastructure investment.

In order to implement Dynamic, TOU Pricing and remote switching of end uses, a communication system is required. This system includes provision of communication with end uses of energy, inside customer premises. It is likely to be a number of years before this infrastructure becomes available on a wide scale, although the use of "intelligent plugs" could provide an interim solution. One way, broadcast communication would be sufficient for end use switching (inhibiting demand). Dynamic TOU Pricing could be applied without remote switching but would be more difficult to obtain customer acceptance and participation in demand change.

The validation of demand response involving small customers will in the near future be no longer a barrier to its adoption in The Netherlands. Several studies exist on how customers respond to real time price signals. But the amount of money that could be saved is estimated to be (too) small if there is just a lower tariff for the short period of demand response.

The routes to delivering DR, which can be validated as DSB, have been explored in Chapter 5. These routes use different metering "Smartness" levels together with remote/automatic control and communication of price signals to deliver DR suitable for DSB and can be summarised as :-

- “Smart” metering can be used to motivate DSB. More difficult to use it to validate DSB.

- Validation is probably best carried out, based on statistical modelling, profile information, disaggregated demand, experience and sample group trials.

- Limited “Smartness” metering with Dynamic TOU pricing or possibly just a Critical price and a normal price may be sufficient to deliver DSB.

- Customer response to price messages may be improved if an indication is provided about what end use items would have most impact in reducing demand (crude disaggregation based on monitoring demand step changes).

- Automatic/remote switching of end uses with no customer over ride allowed is a possibility with no validation needed.

- Display and price warning signal to advise customers of forthcoming price change (24 hours ahead) is likely to be needed for Dynamic TOU pricing.

- Direct control of end uses with an optional override allowed but with high prices paid if the option is used.

- Switchable Maximum demand limiter (Spain) with demand changes made manually by customers is a possibility. Using an automatic system to rescheduled end uses is a possibility for DSB provision but likely to be complex.

- ESCOs, as demand Aggregators, install DSB infrastructure for smaller customers and manage DSB as Aggregator. System Operators have a role to play in motivating Aggregators to offer DSB Services.

The overall conclusion from this study is that validation of demand “available” (ex ante) and “turndown” (ex poste) and participation in DSB by smaller customers could be done on the basis of estimating mechanisms and possibly in future by direct measurement mechanisms. There are still many issues to be resolved however, including the motivation of customers to participate in DSB and also the economic provision of communication enabled end uses and infrastructure. There may be some scope for considering the use of customer, manually switched DSB (DSB validation mechanism 3, Chapter 5, Section 5.2) as an interim measure for delivering some DSB and obtaining experience. However this option is not considered viable for the long term. This process would require estimates to be made of customer manual switching in response to a dynamic, critical price message. Field trials of this mechanism would need to be carried out in each country to obtain some understanding of its potential effectiveness.

8 Recommendations

- Governments and Regulators should motivate the performance of studies and trials of customer response to TOU and particularly critical price signals together with simple 2 rate meters and remote, meter rate switching. These field trials would measure the demand response for a group of geographically located customers. This would enable the actual level of demand response to be measured at a system level, for example at substation level or at the local GSP. Individual monitoring of the energy profile of those involved in the trial at half-hourly intervals would enable the average load profile for customers undertaking Demand Response to be established. Evaluation of the average load profile with and without Demand Response will provide a clear indication of whether or not Demand Response can be directly measured. The results of the field trials would provide valuable evidence of the predictability of Demand Response, albeit on a pilot scale. In particular, if the level of Demand Response delivered is closely related to the level of demand predicted to be "available", a solid basis can be formed upon which trust in future demand response schemes involving domestic customers can be established.

- Governments and Regulators should motivate the performance of studies to model customer response to dynamic TOU and Critical pricing messages together with both manual and remote/ automatic switching and assess customer interest.

- Trials should be performed to evaluate customer response to remotely switched end uses such as white goods and thermostats.

- Work should be performed to identify whether the half-hourly data on the end-uses of energy for domestic customers collected by some countries to assist profile settlements is available and accessible. If so, the data can analysed to produce disaggregated customer profiles that can provide a basis for estimating the potential load "available" for specific demand response initiatives. Initiatives could include the rescheduling of dishwasher or washing machine cycles, or short term interruptions to cold appliances such as freezers.

- Studies should be commissioned to determine methodologies for using TOU metering to validate DR for smaller customers.

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APPENDIX 1

DSB to maintain quality of supply – Ancillary services

Control	DSB Frequency and Voltage Ancillary Services involve instantaneous load shedding. Therefore, the control mechanism must be in the form of an automatic switch that turns off the load to a particular circuit when the voltage or frequency reaches specific limits. For most industrial processes, it is possible that switching the load back on must be done manually due to start-up procedures. In which case, it is not necessary for the control mechanism to be able to switch on the load, but it should include some form of notification mechanism that informs customers when they can switch the load on. DSB for reserve may be given a few minutes notice, although control may still be automatic.
Settlement & Monitoring	It is likely that customers will be paid a fee for times when they make demand "available" to provide DSB Ancillary Services. Monitoring may be required to prove that load was "available" and that it was "turned down" in the agreed manner.

DSB to solve network constraints

Control	DSB Network Constraint contracts are most likely to be called upon in the day of actual "turndown", usually in the few hours ahead of the relevant trading period. Nevertheless, there is likely to be sufficient time for customers to plan the necessary load switching that is associated with an accepted bid. This suggests that manual control of the relevant electrical circuit may be sufficient, although some form of automatic control mechanism is preferable. An automatic controller may take the form of a programmable device that ensures no load is taken on the relevant electrical circuit during the time a particular "turndown" is in place.
Settlement & Monitoring	It is likely that customers are paid a fee for times when they make demand "available" to provide DSB Network Constraint services. This is an attractive approach because it is simple to administer. However, the Network Operator (Distribution or Transmission company) may not favour this payment mechanism because a predicted constraint will not always turn out to be an actual constraint. Thus, according to this method a company would be paying for a service they do not actually require in some time periods. Therefore, it may be more appropriate to pay customers for each "turndown. If this approached is implemented, only a simple form of monitoring is required that registers the number of interruptions within a specific time period. However, if customers are paid according to the length of each interruption then more complex metering may be necessary.

DSB for Electricity Balancing

Control	DSB Balancing Market contracts are most likely to be traded from a few hours to 15 minutes ahead of the relevant trading period. Nevertheless, there is likely to be sufficient time for customers to plan the necessary load switching associated with an accepted bid. This suggests that manual control of the relevant electrical circuit may be sufficient, although some form of automatic control mechanism is probably preferable. An automatic controller may take the form of a programmable device that ensures no load is taken on the relevant electrical circuit during the time a particular bid "turndown" is in place.
Settlement & Monitoring	Customers are likely to be paid according to the quantity of load they do not consume, perhaps as a price per kilowatt-hour. Therefore, in order to ensure a customer fulfils their contractual commitments some form of 'avoided' consumption monitoring is necessary. In addition, a means of proving that the customer would normally have taken that load during the "turndown" time is also required. The appropriate metering solution for this task will vary depending on the size of the customer, but it is likely to be either time of day, half hourly or minute-by-minute metering.
Communication	Notification that a bid has been accepted for balancing purposes may be provided by several different communication methods.

DSB for access to market prices

Control	DSB Spot Market contracts are most likely to be traded ahead of the day of actual bid delivery. Therefore, there is sufficient time for customers to plan the necessary load switching that is associated with an accepted bid. This suggests that manual control of the relevant electrical circuit may be sufficient, although some form of automatic control mechanism is probably preferable. An automatic controller may take the form of a programmable device that defines the required load profile on the relevant electrical circuit during the day of actual trading.
Settlement & Monitoring	Usually time of day metering will be required (e.g. half-hourly)
Communication	Customers will receive details of the agreed pricing information just ahead of the day of consumption, by telephone or dedicated communication media. Communication within customer premises (e.g. main signalling or dedicate control wiring) is likely to be required to effect the calculated load profiles.

A potential mechanism for delivering demand "turndown" for smaller customers is presented in the following table:

Making the bid	The Aggregator predicts usage patterns and decides, based on customer agreements, when it will be most advantageous to interrupt supply, taking into account spot prices and the expected demand levels of his customers. The actual mechanism for making the bid is his normal spot market purchase mechanism (either a reduced bid or a negative bid). The bid may be considered as a service with only estimated demand "turndown" potential.
Proving load is "available"	In the general case of Supplier buying "turndown", there is no need to prove load is available - it is the contract position of the Supplier that is important, and hence how much load he buys or sells on the spot market. Where the System Operator is the buyer of "turndown", the total "available" consumption of a geographic group of houses will be estimated. Assumptions will then be made as to how much of this demand can be interrupted to reduce the system peak.
Receiving notification to modify consumption	The customer may not be aware of the "turndown" process (or find it unobtrusive), and so interruptions need to be implemented automatically. A number of systems are available:- • Ripple control (e.g. Finland) • Radio tele-switch (e.g. UK) • Internet (e.g. Norway) • TV (e.g. Norway) • PICO • Cellular radio • In house powerline
Controlling process to modify consumption	In Finland, systems simply disconnect part of the heating supply, and there is no temperature set point control of the heating. Norway and Denmark have investigated changing space temperatures – reducing room set-points for a few hours – rather than giving a hard disconnect. In the UK advanced storage heating control has been used to optimise charging periods against time of day electricity prices communicated to end uses. In Sweden, TOU pricing has been used in trials with manual actions by smaller customers required in order to change demand.
Process recovery	In the Nordic examples in particular there is likely to be a slight increase in use after the interruption period.
Communicating result of "turndown" participation	The householder could receive the benefits of participation via the normal householder billing process. It may also be possible to reward customers by direct payment via an ESCO. However, behind this may lie some complicated calculations.

APPENDIX 2

End Use Load Curves

Examples for load curves in office buildings,1980

Figure 6 Hourly electricity use build-up in office buildings, part of the industry with similar load shape and education, week 50, 1980.

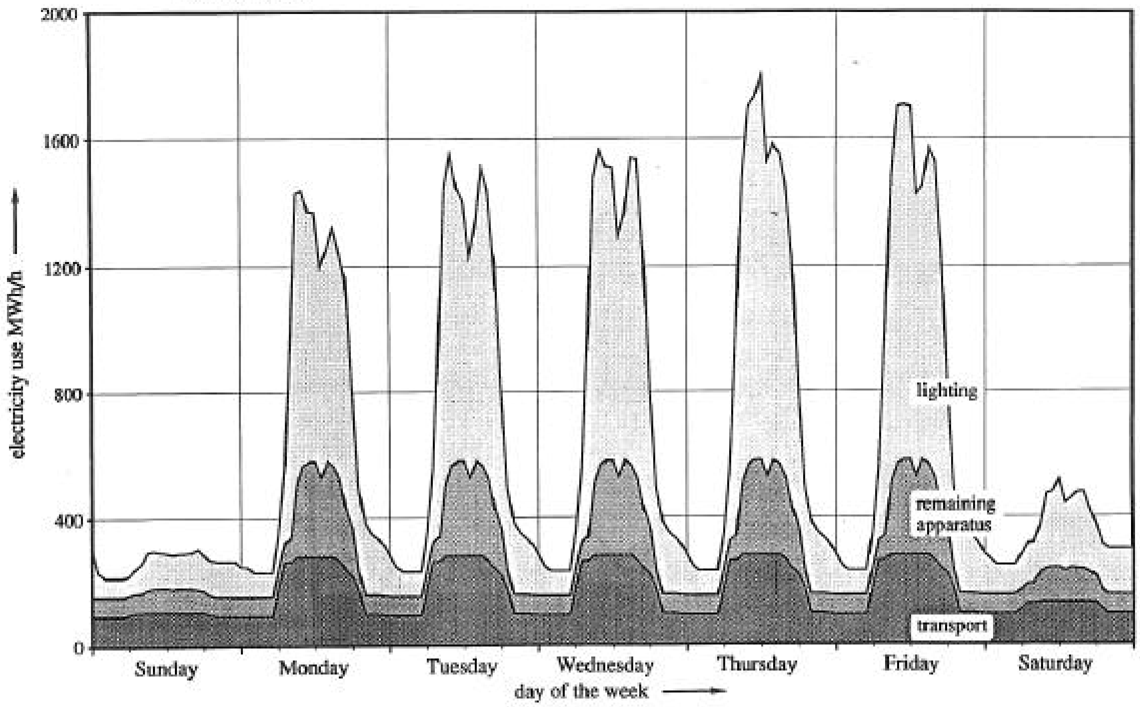
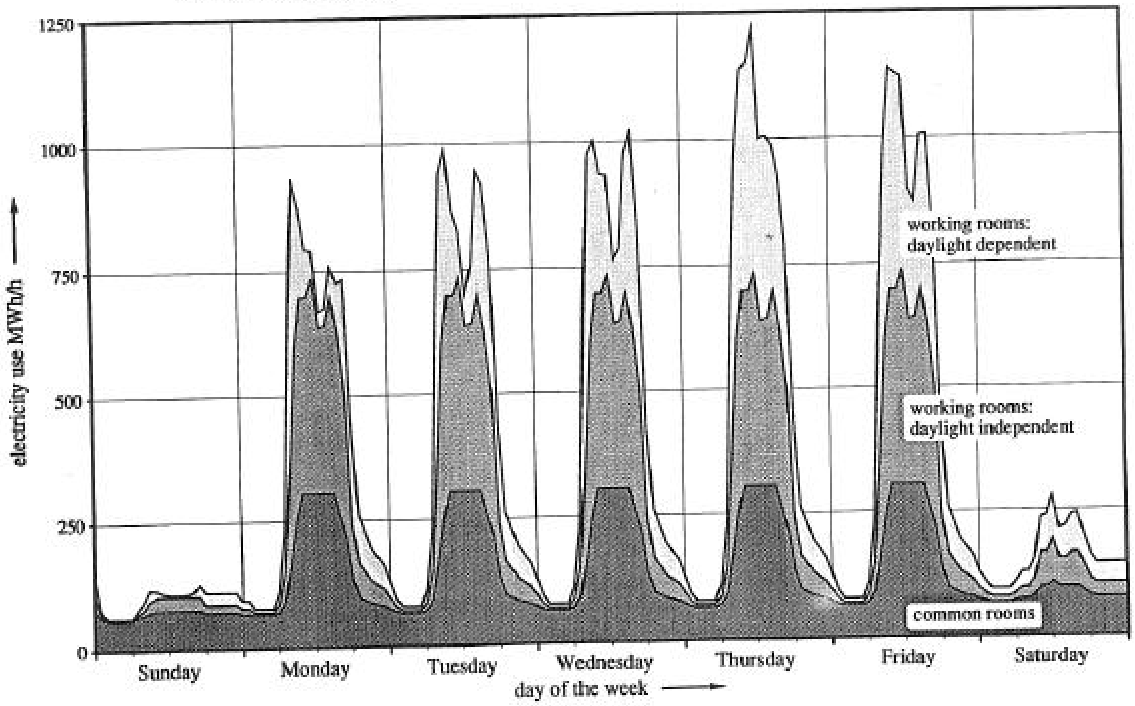
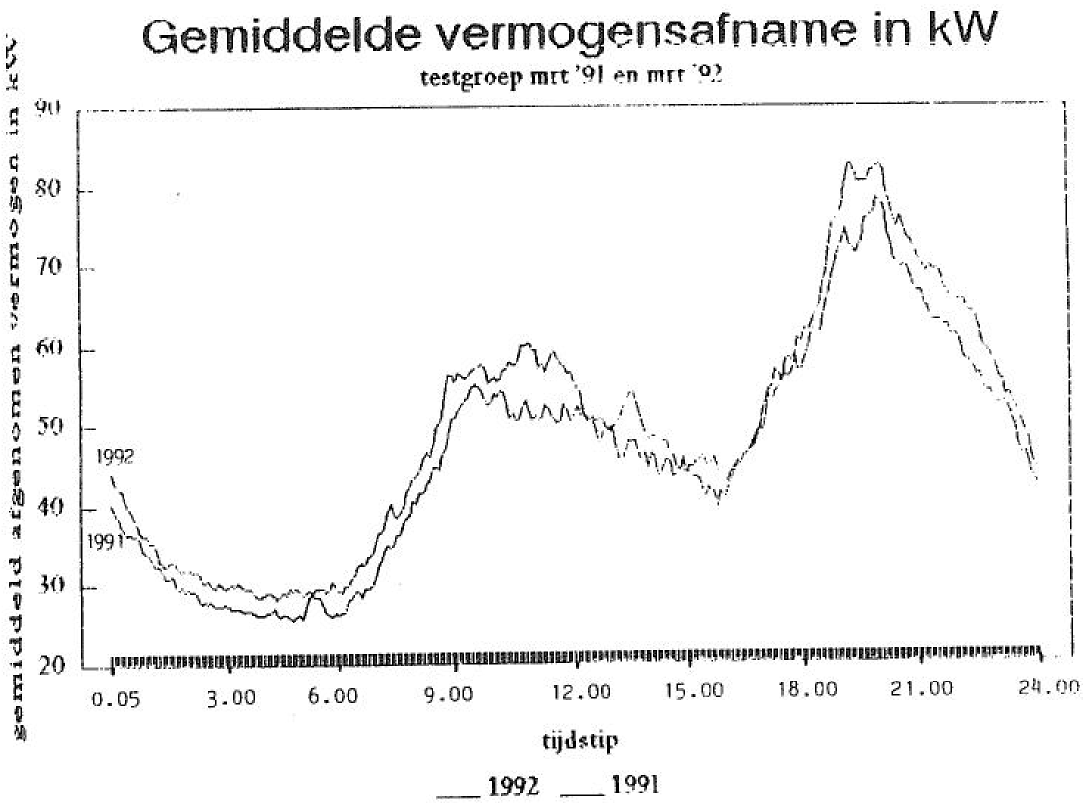


Figure 1 Hourly electricity use build-up of lighting in office buildings, part of the industry with similar load shape and education, week 50, 1980.



Source: Een verkenning van het patroon van het elektriciteitsverbruik in kantoren, Wijngaart, van den R.A. en Blok, K., NWS rapport W-90030, juli 1990, page 11 and 23

Example load curves for washing machines 1991 and 1992



Source: Belastingsturing huishoudens, wasmachinesturing, Eindrapport experiment PGEM, juli 1992, page 15

	March 1991	March 1992
Base load (in kW)	30	30
Peak (in kW)	92	92
Number of households	130	130
Peak per household (W)	708	708
Base load per household (W)	230	230

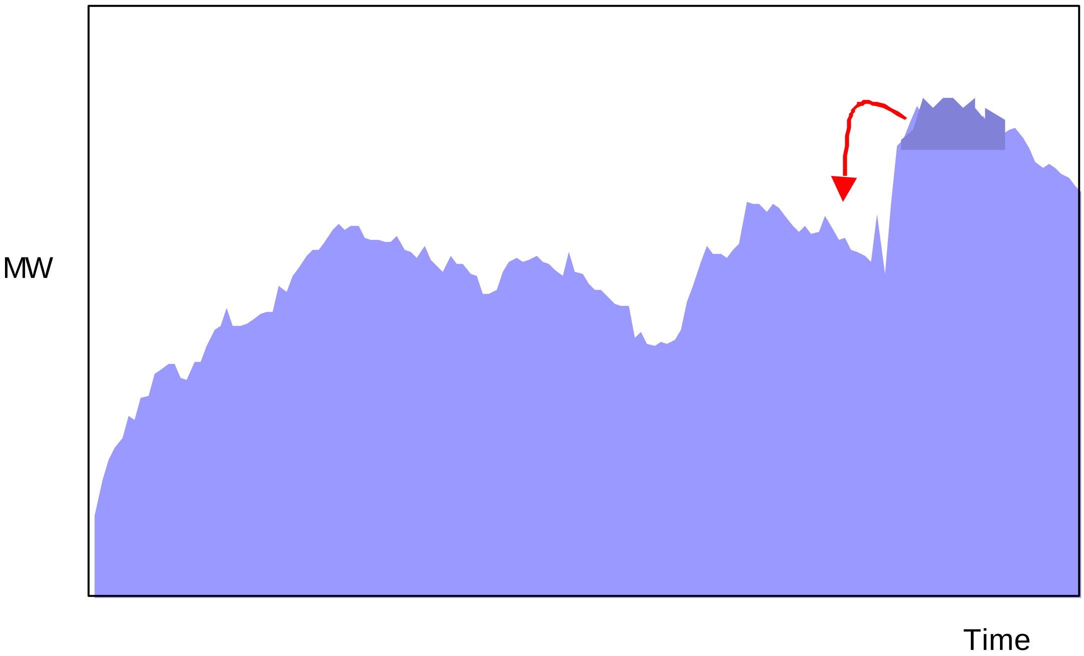
Survey of Washing Machine Demands

APPENDIX 3

Smaller Customer Demand Management Trials in the UK

Demand Profile Trial

This trial involved re-scheduling the nominally off-peak loads to move demand from peak periods into the troughs in the off peak period, as indicated in the figure.

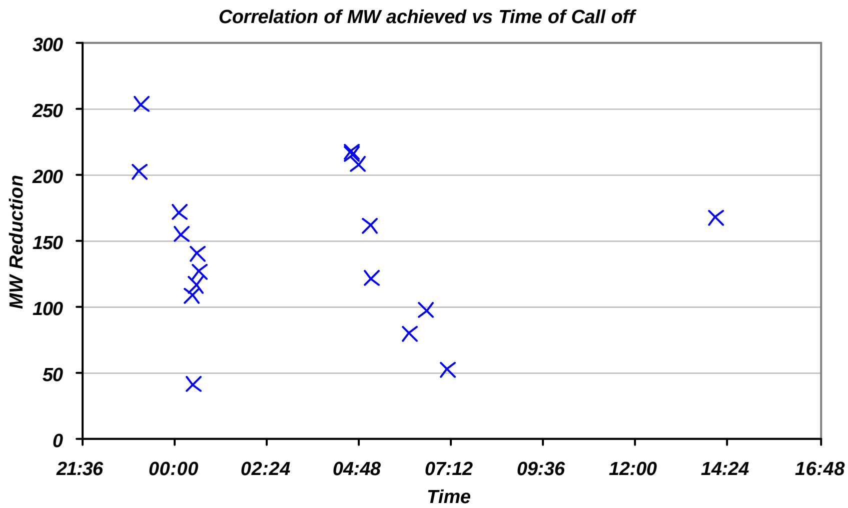


Schematic of the demand profiling trial

The total contracted demand for this service was 600 MW, which represented around 2% of the peak demand during the nominally off-peak period. However, the actual volume delivered was volatile, i.e. it was not possible to be certain the level of demand that would be shifted at any one time. Although, the amount of demand that was shifted during the trial could not be directly metered, comparison of the actual system demand with the system demand determined using profiles did give a good indication of the amount of demand shifted in this way.

Radio Broadcast Trial (Teleswitch)

The aim of this trial was to see if broadcast radio-teleswitching could be used as a means of utilising domestic customer demand "turndown" as a means of providing fast reserve, i.e. for immediate demand dispatch. The trial was considered a great success with between 50MW and 300MW of demand reduction delivered, as shown in the figure.

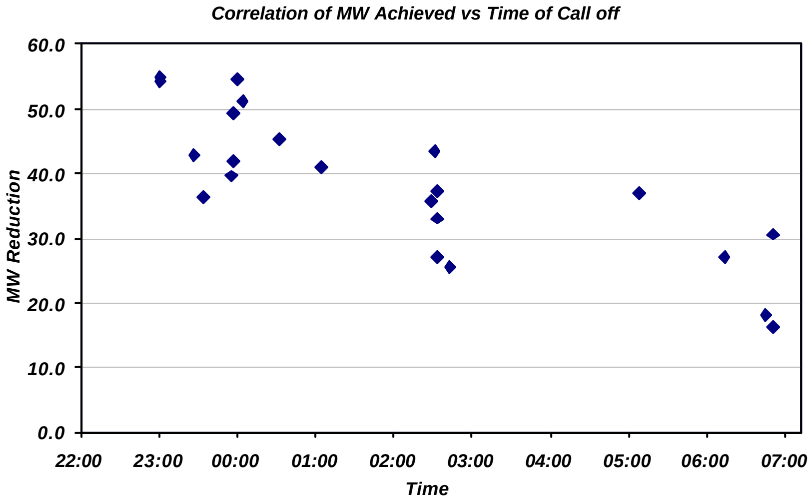


Results of NGC Radio Teleswitch Trial

The trial highlighted limitations of the current Radio Teleswitch equipment due to its age, but that these could never-the-less be ‘engineered around’. There was some concern over the suitability of the Radio-Teleswitch for providing near instantaneous demand reduction. For example, in some regions it could take up to 10 minutes for the Radio Teleswitch broadcast instruction to reach the meter. However, the System Operator noted that delivery was near instantaneous during the trial. As with the demand profile trial, the System Operator noted that the actual volume delivered was volatile, i.e. it was not possible to be certain of the amount of demand that would be reduced at any one time. Although, the amount of demand that was shifted during the trial could not be directly metered, comparison of the actual system demand with the system demand determined using the settlement profiles did give a good indication of the amount of demand shifted in this way.

Cyclo-Control Trial

Cyclo-Control uses Power Line Carrier communication to broadcast messages to customer premises. In this case, the instruction to reduce demand required the System Operator to telephone the Supplier in order to implement the broadcast message, which made the product less than ideal for the System Operator who was looking for near instantaneous demand reductions. As with the other trials, the System Operator raised the volatility of the actual volume delivered as a matter of concern. The figure below summarises the demand reduction that was delivered during the trial based on the time the “turndown” signals were transmitted.



NGC Cyclo-Control Trial Results

It was of note, that the demand provider had flexibility in setting the standby notice and call-off notice required. Thus, a provider may stipulate that they require 12 hours notice to standby for a demand "turndown" instruction, but only 2 hours notice to deliver. Therefore, in the event that a provider, given the instruction to standby, does indeed begin to reduce their demand early in anticipation of a demand "turndown" instruction would be penalised in that they would not receive payment for the true level of demand "turndown" delivered.

In general, the summer trial demonstrated that demand "turndown" was a reliable and dispatchable service; however, the costs were high compared to alternative sources of reserve available during the summer. The total payments made during the trial were:

- Availability payments £36,000
- Standby payments £30,000
- Utilisation payments £74,000

The service was instructed to standby eight times during the 17 week pilot, with the customer called to deliver demand "turndown" on seven of these eight occasions. The total volume of demand "turndown" delivered over was 958 MWh, giving an average utilisation payment of £77/MWh. The average standby payment was equivalent to £28/MWh, although customer were actually paid on a £/day basis. The average availability payment was in the region of £1 - £2/MWh.

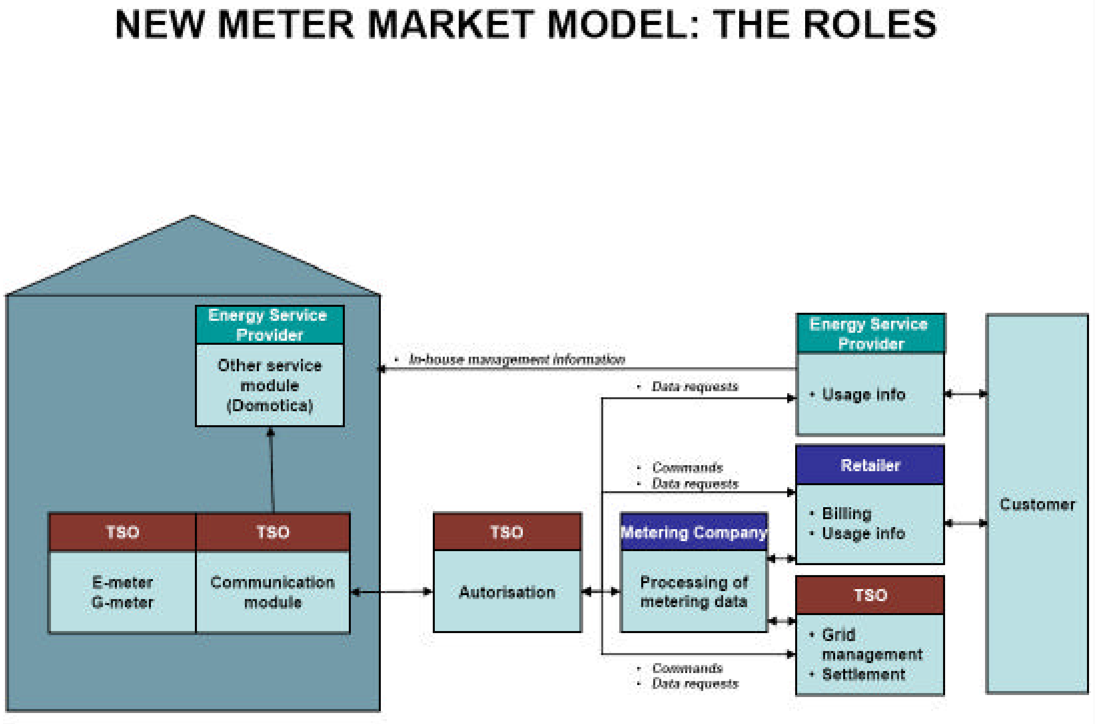
The trial was extended into the winter 2004/2005 period to try to increase liquidity in the scheme. The trial had one fixed window (between 09:00 and 11:00) and optional participation during the remaining hours. During the fixed window, participants were able receive availability, standby and utilisation payments; however during the option zone, participants only received a utilisation payment. The System Operator indicated that utilisation payments would be higher during this winter trial (of the order of £200/MWh) to reflect the increased value of reserve at this time.

Upon completion of the winter trial, National Grid reported that during the two pilot schemes, there was consistent under delivery of the volumes declared "available" by customers. The actual volume of demand "turndown" delivered, compared to the declared availability was in the range of 47–83%. As a consequence, the pilots did not provide the System Operator with sufficient confidence in the ability of the service to fully deliver the declared "turndown".

APPENDIX 4

SMART METERING IN NETHERLANDS

Figure 1: Roles within the new meter market model

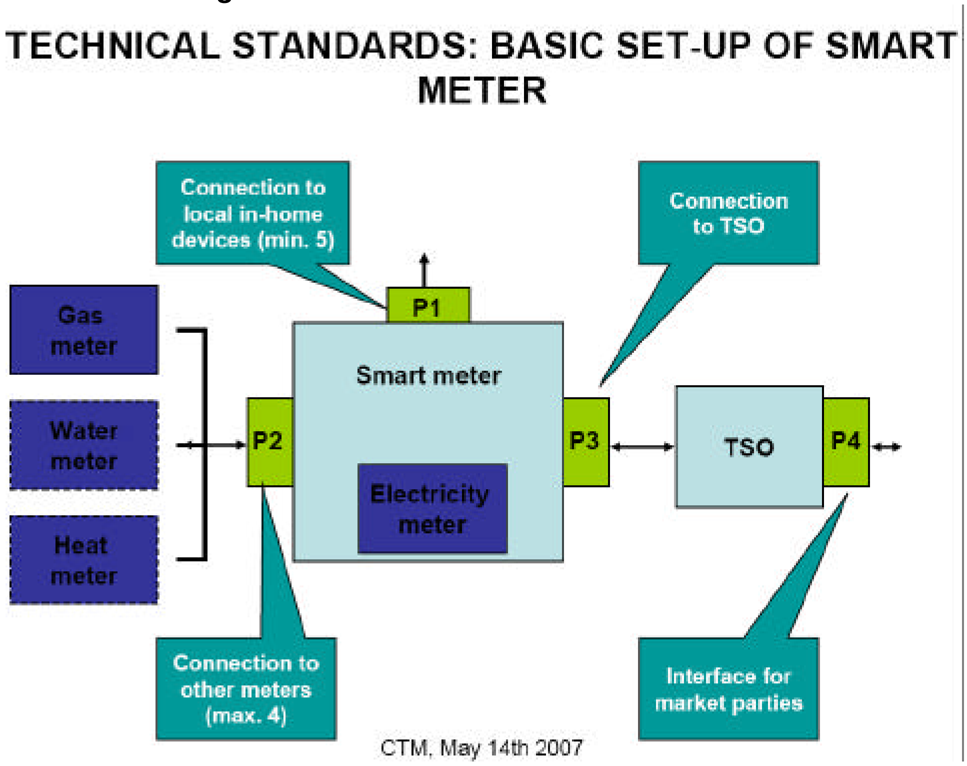


Source: presentation Glimmerveen, May 14, 2007, smart metering conference

Future: smart meters (see Figure 1) will hold a connection to communicate with at least 5 local in-home devices, an interface for market parties and a connection to the transport system operator (TSO). The meter readings and the actual power with a resolution of 0.01 kW is sent every 10 seconds via port P1. No history of this is kept in the metering installation. The interval reading from port P3 is 15 minutes. The relevant information from the Dutch standard for smart meters (prNTA 8130:2007) is included in Annex 3.

With the roll-out of smart meters the technical barriers for measuring the electricity use on-time for small customers will disappear. Also a source to measure a load for a specific appliance for a small customer will become available. Future research should give information on whether aggregated load curves for appliances could be used to determine demand response delivers, or that the appliance-customer specific load should be used. An option also could be to use the total electricity use (on 15 minutes base) for a single small customer.

Figure 2: Technical standards for smart meter



Source: presentation Glimmerveen, May 14, 2007, smart metering conference

Actual meter reading for Smart Meters in the Netherlands

Actual meter readings on request via port P3

The metering installation is able to transmit the latest known meter readings on request via part P3. For electricity this means the actual meter reading at the moment the request reaches the metering installation. For gas this means the latest meter reading that is accessible without extra communication; this reading has a maximum age of 24 hours.

Actual meter readings via port P1

- Via port P1, only the actual meter readings for electricity are offered; this occurs every 10 seconds;
- Meter readings for gas, including date stamp, are offered at least 1 x per 24 hours, where the hourly values for the last 24 hours are also sent;
- As well as the meter readings, the actual power with a resolution of 0.01kW is sent every 10 seconds via port P1. No history of this is kept in the metering installation.

Interval readings

Electricity

The metering installation is suitable for metering electricity.
Interval readings for electricity are not distributed via port P1.
The following interval readings including date and time stamp an be read via port P3.

Interval readings for electricity

	Unit to be shown for communication via port P3	Maximum age of the interval readings	Interval time	Storage capacity in the metering installation
Electricity supplied to the connected party	0.001 kWh	n.a.	15 min.	960 readings
Electricity supplied from the connected party	0.001 kWh	n.a.	15 min.	960 readings

Source: Preliminary Netherlands standard prNTA 8130(e) ICS 17.120.10, januari 2007

APPENDIX 5

Demand Response Example in USA

The New England independent system operator runs several demand response programs. The participation in most of them is only open to big customers that can provide a significant amount of load reduction. Minimum values are in the region of 1MW. In order to increase the available load reduction capacity, in 2003 ISO New England decided to develop a particular programme which is specially designed for aggregators that can provide more than 1MW reduction by adding the efforts of several end-users. Aggregators participating in the program operate direct appliance control methodologies over thousands of domestic customers in order to obtain more than 1MW reduction. The characteristics of the program are the following.

Aggregators are notified 2 hours in advance if a reduction in demand is required. The reduction events take place in the period that goes from 08:00am to 18:00 and last from two to six hours. Aggregators are then responsible for activating the mechanisms that will reduce the total load consumption of the end-users that they control over the event period.

The expected amount of load reduction must be more than 1MW and has to be communicated in advance by the aggregator to ISO New England. The calculation of the demand available is therefore responsibility of the aggregator.

The calculation of the actual obtained demand turndown is not straightforward. ISO New England does not force the installation of interval or remote-metered meters in all the controlled domestic households. The rules of the program state that the aggregator “must install sufficient research metering to provide statistically significant interval data regarding the interruptions”. There is obviously an error associated with this metering procedure, but it is accepted by ISO New England. The obtained load reduction of the group must be sent to ISO New England within 1.5 days of the event taking place. The aggregator is obliged to document the measuring and verification procedure, and ISO New England must review it and approve it on a case by case basis. They developed a manual providing information and guidelines for aggregators about how to monitor and size their samplings. Even if it is obsolete, the manual is still available on their website.

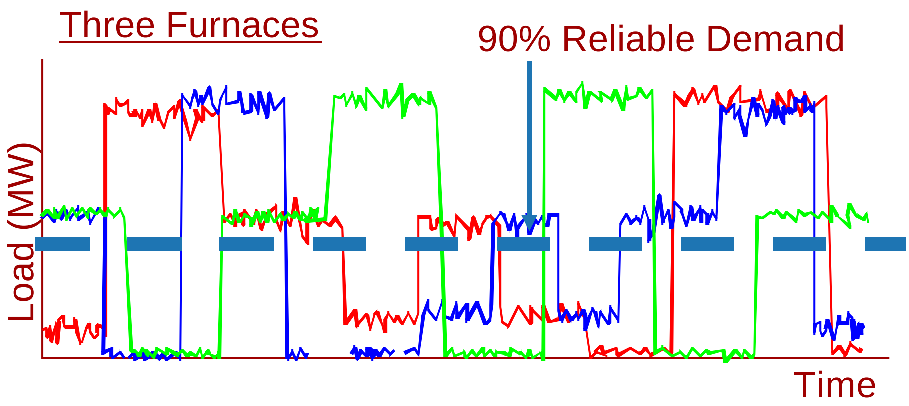
The aggregator is paid a minimum of 10 US cents for every reduced kWh, but if the wholesale electricity market at each hour of the event is higher than that, it receives the market price. It also receives a monthly capacity payment as a result of making the commitment to participate in the reduction events. Typical capacity payment is €1/kW per month. The amount of this payment will depend on the demand declared as “available” by the aggregator. The penalties for performing below the expectations are not economic. The load reduction declared as “available” by the aggregator will be simply reduced for upcoming events accordingly, reducing the amount perceived as capacity payment on the next months.

During the course of the years this program has evolved, and today (2007), ISO New England imposes the installation of smart meters in the premises of all the participating domestic customers. The collection of hourly readings for all the customers is required.

APPENDIX 6

Fast Acting Frequency Response – probabilistic services

Arc furnaces are capable of instantaneous shut down with no adverse effect on plant. However, individual arc furnaces have very high, but irregular, patterns of electricity demand, fluctuating from zero to over 50 MW within a half-hour. This makes them, as individual plant, unsuitable for DSB as frequency response. However, the net load of several arc furnaces, when aggregated together, can provide a predictable load as shown below.



The manner of providing this “probabilistic” DSB service to the System operators is very similar to that used to deliver the “firm” demand of a Cement Works. However, the actual DSB product has been modified to make it more attractive to arc furnace companies - the required duration of the interrupt has been reduced from 30 minutes after an event to only 15 minutes

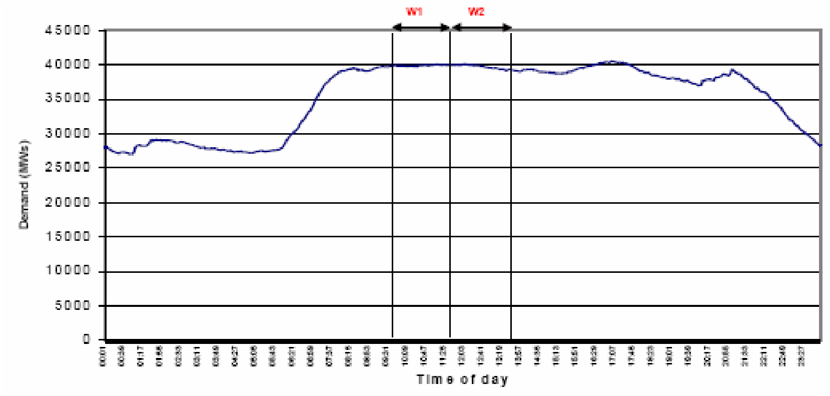
The aggregator totals these offers of availability and relays them to the TSO a week ahead of the availability being offered, but in this case the total availability takes into account the variability in demand, so the value presented to the TSO represents the ‘probable’ load available rather than the actual load.

Demand Turndown

Demand “turndown” was a pilot scheme for the provision of contingency reserve via the reduction of load of large demand users or aggregators of smaller demand sites and/or generation. The pilot scheme took place over the period 5 April 2004 and 30 July 2004 in order to prove the ability of the Demand Side to deliver a reliable, secure, quantifiable and economic service.

The commercial contracts were for a single dispatch and contracting company, with a minimum net “turndown” of 100MW that could be sustained for at least 2 hours during a predefined time window. The minimum aggregated load of 100 MW represented the minimum level of “turndown” that the TSO required in order to deliver an appreciable gain in operating margin.

During the summer months, the service windows were timed to coincide with the summer morning peak hours of 09:30 hours to 13:30 hours, as indicated in the figure below.

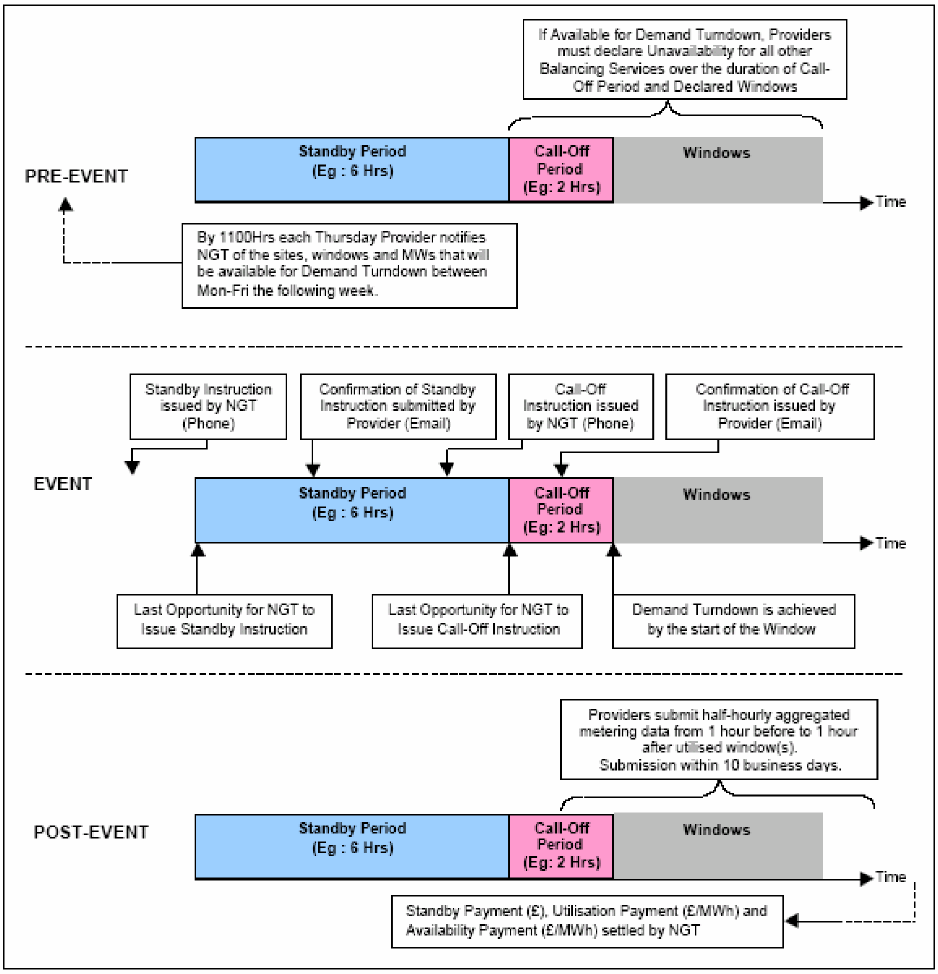


Typical summer demand profile

The aggregator was required to identify the demand sites taking part in the trial primarily to ensure that sites were not providing two demand side services simultaneously, but also to assist the System Operators in their locational analysis of the effect of the demand "turndown" on network constraints. Aggregated meter data was provided to the System Operator
on a minute by minute basis, but half-hourly was also acceptable.

The Demand Turndown mechanism involved two phone call instructions from the System Operator to the Aggregator; a standby instruction and a call-off instruction.

The standby instruction indicated that the demand sites must enter a standby mode and be prepared to receive an instruction to "turndown" demand. The call-off instruction is the term used to deliver the "turndown", and can be issued at any time from the standby instruction up to the start of the stipulated Call-Off Period. The Call-Off period represents the minimum amount of time that the provider requires to deliver the contracted MWs. The providers were free to specify the notice required to enter the standby mode and the notice required to deliver the demand "turndown", a level of flexibility that is not available with other demand side products. The providers were required to inform the System Operator, via e-mail, of the contracted sites, the window and the contracted MWs available for Demand "turndown" one week ahead of time. However, providers are permitted to re-declare their demand "available" up to one day ahead of time (before 17:00), but only if there were problems with the technical capability of the site. The diagram below provides an overview of the process involved in utilising the demand turndown bids.



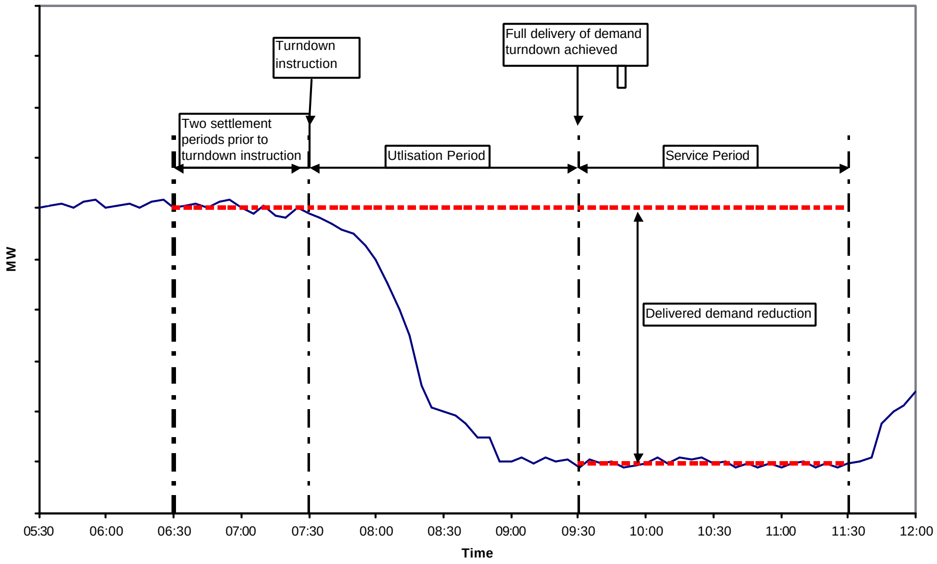
Utilising Events in Demand Turndown Call-Off

Retrospective daily demand profiles based on minute by minute (preferred) metered readings or half-hourly aggregated data were provided for both validation of demand "turndown" as contracted, and also to permit the System Operator to assess the accuracy of the forecast daily load profiles against actual consumption.

Three payments were made to participants in the trial;

- An availability payment
- A standby payment
- An utilisation payment

The availability payment was made to reflect the costs incurred by providers in participating in the trial, mainly as a result of the requirement to provide forecasts of availability and post-event consumption data. The payment was made on a £/MWh basis, contingent that the week-ahead declared availability and the day-ahead re-declared availability was within 10% of the metered MWs. The Standby payment, only paid when a provider was called to standby, was a fixed fee made on a £ per day basis. The utilisation payment was made when the provider was given the instruction to deliver the demand "turndown", and was paid on the delivered MWs up to the level declared available. The delivered MW is the difference between the average demand in the two half-hours immediately prior to the instruction to “turndown” demand and the demand during the service window, as indicated in figure which shows an example demand profile for a customer requiring two hours notice in order to deliver the full demand “turndown”.



Metering demand reduction delivered in the Demand Turndown Trial

APPENDIX 7

**Overview of the International Energy Agency (IEA)
and the IEA Demand-Side Management Programme**

The International Energy Agency

The International Energy Agency (IEA), established in 1974, is an intergovernmental body committed to advancing security of energy supply, economic growth, and environmental sustainability. The policy goals of the IEA include:

- diversity, efficiency, and flexibility within the energy sector,
- the ability to respond promptly and flexibly to energy emergencies,
- environmentally-sustainable provision and use of energy
- development and use of more environmentally-acceptable energy sources,
- improved energy-efficiency,
- research, development and market deployment of new and improved energy technologies, and
- undistorted energy prices
- free and open trade
- co-operation among all energy market participants.

To achieve those goals, the IEA carries out a comprehensive program of energy cooperation and serves as an energy forum for its 26 member counties.

Based in Paris, the IEA is an autonomous entity linked with the Organization for Economic Cooperation and Development (OECD). The main decision-making body is the Governing Board, composed of senior energy officials from each Member Country. A Secretariat, with a staff of energy experts drawn from Member countries and headed by an Executive Director, supports the work of the Governing Board and subordinate bodies.

As part of its program, the IEA provides a framework for more than 40 international collaborative energy research, development and demonstration projects, known as Implementing Agreements, of which the DSM Programme is one. These operate under the IEA's Energy Technology Collaboration Programme which is guided by the Committee on Energy Research and Technology (CERT). In addition, five Working Parties (in Energy Efficiency, End Use, Fossil Fuels, Renewable Energy and Fusion Power) monitor the various collaborative energy agreements, identify new areas for cooperation and advise the CERT on policy matters.

IEA Demand Side Management Programme

The Demand-Side Management (DSM) Programme, which was initiated in 1993, deals with a variety of strategies to reduce energy demand. The following 18 member countries and the European Commission have been working to identify and promote opportunities for DSM:

Australia	Italy
Austria	Japan
Belgium	Korea
Canada	The Netherlands
Denmark	Norway
Finland	Spain
France	Sweden
Greece	United States
India	United Kingdom

Programme Vision: In order to create more reliable and more sustainable energy systems and markets, demand side measures should be the first considered and actively incorporated into energy policies and business strategies.

Programme Mission: To deliver to our stakeholders useful information and effective guidance for crafting and implementing DSM policies and measures, as well as technologies and applications that facilitate energy system operations or needed market transformations.

The Programme's work is organized into two clusters:

- The load shape cluster, and
- The load level cluster.

The 'load shape" cluster includes Tasks that seek to impact the shape of the load curve over very short (minutes-hours-day) to longer (days-week-season) time periods. The "load level" cluster includes Tasks that seek to shift the load curve to lower demand levels or shift loads from one energy system to another.

A total of 15 projects or "Tasks" have been initiated since the beginning of the DSM Programme. The overall program is monitored by an Executive Committee consisting of representatives from each contracting party to the Implementing Agreement. The leadership and management of the individual Tasks are the responsibility of Operating Agents. These Tasks and their respective Operating Agents are:

Task 1 International Database on Demand-Side Management &
Evaluation Guidebook on the Impact of DSM and EE for Kyoto's GHG Targets - *Completed*
Harry Vreuls, NOVEM, the Netherlands

Task 2 Communications Technologies for Demand-Side Management - *Completed*
Richard Formby, EA Technology, United Kingdom

Task 3 Cooperative Procurement of Innovative Technologies for Demand-Side Management – *Completed*
Dr. Hans Westling, Promandat AB, Sweden

Task 4 Development of Improved Methods for Integrating Demand-Side Management into Resource Planning - *Completed*
Grayson Heffner, EPRI, United States

Task 5 Techniques for Implementation of Demand-Side Management Technology in the Marketplace - *Completed*
Juan Comas, FECSA, Spain

Task 6 DSM and Energy Efficiency in Changing Electricity Business Environments – *Completed*
David Crossley, Energy Futures, Australia Pty. Ltd., Australia

Task 7 International Collaboration on Market Transformation - *Completed*
Verney Ryan, BRE, United Kingdom

Task 8 Demand-Side Bidding in a Competitive Electricity Market - *Completed*
Linda Hull, EA Technology Ltd, United Kingdom

Task 9 The Role of Municipalities in a Liberalised System *Completed*
Martin Cahn, Energie Cites, France

Task 10 Performance Contracting *Completed*
Dr. Hans Westling, Promandat AB, Sweden

Task 11 Time of Use Pricing and Energy Use for Demand Management Delivery
Richard Formby, EA Technology Ltd, United Kingdom

Task 12 Energy Standards
To be determined

Task 13 Demand Response Resources - *Completed*
Ross Malme, RETX, United States

Task 14 White Certificates – *Completed*
Antonio Capozza, CESI, Italy

Task 15 Network-Driven DSM
David Crossley, Energy Futures Australia Pty. Ltd, Australia

Task 16 Competitive Energy Services
Jan W. Bleyl, Graz Energy Agency, Austria

Task 17 Integration of Demand Side Management, Distributed Generation, Renewable Energy Sources and Energy Storages
Seppo Kärkkäinen, VTT, Finland

For additional Information contact the DSM Executive Secretary, Anne Bengtson, Box 47096, 100 74 Stockholm, Sweden. Phone: +46 8 510 50830, Fax: +46 8 510 5083**0**. E-mail: anne.bengtson@telia.com

Also, visit the IEA DSM website: http://www.ieadsm.org