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Electricity demand response and security of supply

ERSE (ENEA Ricerca sul Sistema Elettrico) with contributions of FEEM

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Abstract

What is Demand Response

Demand Response is the active role of the energy end-users in responding to signals coming from the market (prices) or to emergency signals coming from (transmission/distribution) system operators, asking for a load reduction to help facing criticalities, congestion and reduce black out risks.
In other words, Demand Response refers to the changes of the electric load profile by end-use customers with respect to their normal consumption patterns, in response to electricity price variations over time, or to signals coming from the system when its security or reliability is jeopardized, according to programs designed to obtain a lower electricity use by incentive payments. These programs concur to relieve the system from undesired or unexpected critical conditions, such as scarcity of fuel supply, unavailable or insufficient power reserve, grid congestion, breakdowns.
Demand Response represents a form of elasticity of demand to price signals which derives from actions carried out by the customer in response to them; the response can be tightly time-related to the price signal or delayed with respect to it.

Advantages of Demand Response for security and efficiency of supply

There are several advantages connected to Demand Response (DR): the most remarkable of them are outlined below.

Reduction of investments in generation, transmission and distribution

Demand Response's main beneficial effect is to reduce demand in peak load / high price periods, possibly moving part of it to less critical / lower price hours. A lower peak load:

- increases reserve margin (thus increasing security of supply) and, in the longer term, reduces the need for investments in new generation capacity;
- reduces the stress (and possible congestion) on both transmission and distribution networks, delaying the need for network expansions;
- reduces the necessity of dispatching costly and low efficiency power plants during peak hours, thus reducing also fuel consumption and CO_2 emissions.

Moreover, the reduced urgency allows for a longer time to evaluate investments in new infrastructures, so that there are greater chances of fine-tuning to new circumstances, with more gradual and economically efficient changes.
In addition, Demand Response programs are normally deployed very rapidly (months) and with limited costs, if compared to the years required for new generation and network investments.
According to recent evaluations, the benefits of a flexible demand in terms of reduced investments overcome the costs to encourage its implementation by an order of magnitude. In the particular case of the USA, the advantages of a specific type of tariff used in DR programs, the Time-of-Use (TOU) tariff, have been estimated around 15

billions dollars per year, with a contribution to the curtailment of the national peak demand of more than 45 GW (see /31, 32/).

Peak shaving and consequent improvement of market efficiency

Peak shaving can be obtained by DR in ***Market Led*** programs (or *economic/voluntary programs*), where the users respond to price signals (in the form of real time prices, structured tariffs or contractual agreements) with a timing compatible with the hourly price definition and consumption planning, i.e. in the order of hours or even days. Here the user's action is always voluntary, only depending on either the individual sensitivity to the price level or his willingness to pay for the commodity.

Several tariff schemes are also studied according to their ability to induce demand response with short or long advance notice. A third category includes variable tariff schemes, such as Time-of-Use and Real-Time tariffs. Time-of-Use tariff schemes induce a long term demand elasticity, in the order of months, whereas Real-Time tariffs or Critical-Peak-Pricing tariffs may have elasticity effect in the short run (hours or days).

Some studies report values of elasticity between -0.1 and -0.2 within 1 to 3 years and between -0.3 and -0.7 for the longer term (10 years of more). In other words, this means that an increase of 10% of the energy price can bring about a decrease of consumption of, respectively, 1-2% and of 3-7%. The greater response potential in the longer term is consistent with the expected behavior of consumers who, facing persistent price signals, tend to invest in more efficient equipments and to make a better use of energy /23/.

Of course, an increased demand elasticity reduces the possibility of exercising market power by producers, thus improving market efficiency, and also reduces price volatility and the related risk.

DR can also play a major role not only in day ahead energy markets, but also in reserve / balancing markets, where it can compete with generation in providing ancillary services, thus increasing efficiency of such markets, too (see also in the following).

Quite interesting evaluations of the potential which can be activated by DR programs are shown in published reports /8, 9, 10, 12/. In fact, in the Nordel system, in 2004 about 2000 MW of tunable load were available as operating reserve and further 1600 MW could have been activated by means of other programs. This was a total tunable load of about 3600 MW, equal to about 5.3% of the total peak load over the whole area (about 68000 MW). Nevertheless, it was estimated that at least further 8000 MW could have been potentially involved by means of suitable short-term programs, that means an amount of about 15% of the peak load of the whole Nordel system.

A well known European DR program is the *"Tempo"* tariff, which has been fostered in France by EdF since 1995. This tariff pertains to the Critical-Peak-Pricing class. It entails, during the year, 300 *"blue"* days (at a low tariff), 43 *"white"* days (at a medium tariff) and 22 *"red"* days (at a much higher tariff); these days are decided by EdF within 16:30 of the previous day. This tariff is applied to about 500000 users; 350000 of them are households. The typical average curtailment of demand in the "red" days is about 1 kW per dwelling.

Increase of reliability due to flexible resources, which allow operators to meet contingencies

Increase in reliability can be attained by DR in ***System Led*** programs (or *reliability/emergency programs*), which are designed to provide operating reserve capacity; in such a case, the reduction of electricity consumption offered by consumers will be used to face power grid emergencies such as serious congestion problems, faults of system components or pending brown / blackouts, in the same way as generation resources do.

The Transmission System Operator (or even the local Distributor), in the context of his responsibility concerning the system security, requests actions that are authoritatively carried out. Therefore, once the participant has subscribed the program, these fast and often automated actions are mandatory and cannot be refused. The very short reaction time required (from fractions of seconds to minutes) is generally not compatible with market operation. The compensation for the service provided is often determined through regulatory provisions and it is collected from the entire users community by means of a tariff component. As an example, the Italian Interruptible Service corresponds exactly to this scheme.

These kinds of programs are also active in vertically integrated electric systems, because they are very important for the system security. Moreover, another advantage of DR as a fast reserve service is also given by its location, since DR resources are usually concentrated in load centers, i.e. in the most congested regions where the need of fast reserve is more crucial.

The costs of Interruptible Rates (IR), or of similar DR programs devoted to fast reserve services, are systematically much less than those deriving from the installation of an equivalent new generation capacity. This is another reason why DR can reduce the need for investments in generation, as above mentioned.

Surveys carried out in the USA and Canada /81/ showed that IR programs can bring about reductions of peak demand ranging in most cases from 4% to about 5% in the commercial and industrial sectors, while the impact of Direct Load Control (DLC) programs on reductions of peak demand ranges from more than 0% to about 10% in the residential sector. A similar evaluation for DLC programs was performed on a very restricted sample of the commercial / industrial sector, with an impact of these programs ranging between 1% and 9% of the peak demand.

Improvements in the efficiency of balancing and ancillary services markets

The elastic behavior of demand can bring advantages to the electricity system also from other viewpoints.

As above mentioned, DR can play an important role not only in the main (typically, day ahead) energy markets, but also in the balancing and in the ancillary services markets.

In such a case, DR can provide ex-ante (with respect to real time) resources to resolve foreseen congestion and to set up adequate operating reserve margins, while in real time it can actively concur to balance generation and load, as well as to effectively tackle with contingencies.

Balancing and ancillary services have traditionally been provided only by generators. Moreover, the importance for security of supply of such kind of services makes the related markets much more profitable (per unit of energy) than energy markets (both day ahead and over-the-counter bilateral markets). Thus, the participation of new players, such as DR, in such markets can increase the level of competition and reduce the possibility of market power exercise by producers, thus greatly increasing market efficiency. In fact, it must be taken into account that ancillary services markets are more exposed to “local” market power exercise by producers, since the location in the network of a generator can be very important for the provision of the service the System

Operator needs, regardless of the position in the economic merit order of the related bid submitted by the generator. The location of DR in load centers, i.e. exactly where the power must go, makes it a valuable resource from the system operation point of view.

Barriers to development of Demand Response

Many barriers to development of Demand Response has been identified and studied. A summary of them and of the suggested actions to overcome them is shown in the table below.

	Common Challenges	Suggested Actions
1	Consumer Awareness - Don't know what DR is - Unaware of their demand flexibility - Unaware of how they can benefit from DR	- Develop case studies showing how others have participated and benefited - Initiate awareness campaign (radio, billboards, news reports, seminars)
2	Price Signals - Consumers accustomed to fixed price per kWh - Wholesale to retail disconnection - Limited use of locational pricing	- Use DR programs and tariff pricing that link consumer behavior with electricity prices - Initiate trials to test local market adoption
3	Meter Data - Several meters in use today do not record hourly intervals - Limited use of data exchange standards - Limited incentives to make new investments	- Load profiling methods can be used in some circumstances - Allow meter owners to recover costs for upgrades - If AMR is used, make sure their functionalities work with the desired DR programs prior to installation
4	Market Operations - DR may be precluded from participating in the wholesale market - DR must conform to supply side market rules (e.g. large trading blocks)	- Use trials to demonstrate DR ability to serve the wholesale market

1 Generalities on Demand Response

1.1 Foreword

The present report deals with "Demand Response" as a means to achieve greater security of supply in the electricity system, as well as greater economic efficiency and more sustainability, in terms of reduction of CO_2 emissions.
In fact, demand reduction in several cases can be considered the faster, cheaper and cleaner equivalent of increased generation.
Processes aimed to make demand flexible require to take into account the multifaceted features of the problem, such as:

- characteristics of consumers representing the demand, depending on the considered sector (industry, commerce, households, etc.),
- technologies and economics,
- tariff options,
- information and awareness actions needed for gathering participation to Demand Response programs.

All these aspects are considered in the studies which are synthesized in this report according to the following organization:

- the elastic features of demand and its consequences on the energy market and on the security of the energy system are considered in chapter 2, together with the classification of the different kinds of Demand Response programs;
- the main functionalities to be incorporated into Demand Response programs and the technologies which enable these functionalities are discussed in chapter 3;
- an international survey of the products and services for the implementation of Demand Response programs is considered in chapter 4;
- chapter 5 deals with a description of business models involving the management of Demand Response programs;
- an evaluation of technological and non-technological barriers to participation, flexibilization and management of demand is carried out in chapter 6;
- An overview of the key economic principles odf Demand Response in electricity markets is provided in chapter 7.
- finally, some criteria and guidelines for the design of Demand Response programs are outlined in chapter 7.

1.2 Definitions and classification of Demand Response

When talking about Demand Response, it is fundamental to define which product is to be sold and bought. The product of DR is the reduction (or even the increase) of the electrical consumption by the end-user with respect to the baseline consumption pattern. The reduction is triggered by a specific signal (either a price signal or a operative request). This product can be bought by System or Grid Operators in order to face production shortage, congestion, emergencies or black-out risks, in a similar way as they request an increase of electricity production from generating units. The Demand Response product is also of interest for the energy traders, because it helps them to carry out more profitable energy procurement strategies.

Therefore, the seller of the DR program is the electricity user and the ultimate buyer is the grid operator or the trader. In the middle some intermediate commercial or contractual entities can be present, as it will be described later.
The user is able to produce his/her response by shutting down some of the electrical appliances he/she is using, by turning on a local generator or, at a more sophisticate level, by controlling his total power consumption and/or production by means of an *intelligent energy manager*. The energy manager will take appropriate decisions considering the compulsory or voluntary nature of the received request, and will optimize the economical aspects of the action, with respect to the specific program to which he/she is responding.
Demand Response embraces a wide variety of contractual and service agreements based on the voluntary participation of the users to specific programs. In order to classify the variety of these programs, we will stick to a scheme widely accepted in the international community.
We assume that the main goals of the electric system can be expressed by two statements:

- to ensure security of supply,
- to foster an efficient electricity market.

According to this scheme, the user accepts to modify his consumption level in order to contribute to the reliability and/or to the security of the electric system (***system led*** programs). Otherwise, he/she can be motivated by price signals coming from the electricity market (***market led*** programs). This scheme makes easier to analyze Demand Response, with respect to regulatory, economical and contractual aspects. A schematic classification of Demand Response programs is reported in Figure 1, where the different options are reported according to the operational time interval in which the load changes can take place after the signal has been received.

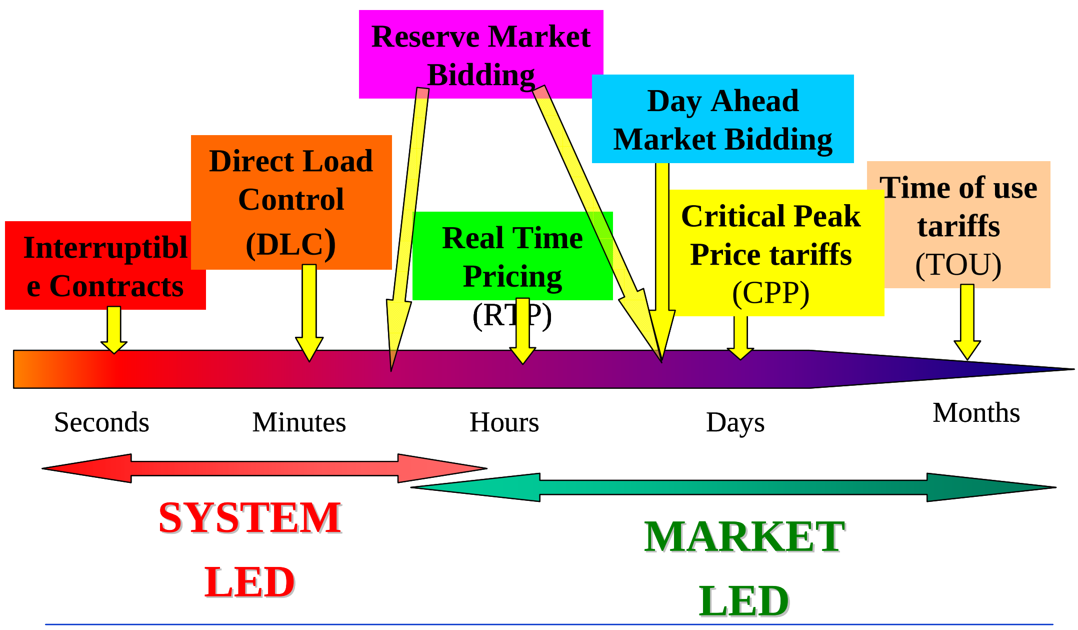

Figure 1 – Classification of “System Led” / “Market Led” Demand Response programs

System Led programs (or *reliability/emergency programs*) are designed to provide operating reserve capacity, i.e. the reduction of electricity consumption offered by consumers will be used to face power grid emergencies such as serious congestion problems, faults of system components or pending brown / blackouts, in the same way as generation resources do.
The Transmission System Operator (or even the local Distributor), in the context of his responsibility concerning the system security, requests actions that are authoritatively carried out. Therefore, once the participant has subscribed the program, these fast and often automated actions are mandatory and cannot be refused. The very short reaction time required (from fractions of seconds to minutes) is generally not compatible with market operation. The compensation for the service provided is often determined through regulatory provisions and it is collected from the entire users community by means of a tariff component. As an example, the Italian Interruptible Service corresponds exactly to this scheme.
These kinds of programs are also active in vertically integrated electric systems, because they are very important for the system security. Moreover, another advantage of DR as a fast reserve service is also given by its location, since DR resources are usually concentrated in the most congested regions, i.e. where the need of fast reserve is more crucial.

Differently, in ***Market Led*** programs (or *economic/voluntary programs*) the users respond to price signals (in the form of real time prices, structured tariffs or contractual agreements) with a timing compatible with the hourly price definition and consumption planning, i.e. in the order of hours or even days. Here the user's action is always voluntary, only depending on either the individual sensitivity to the price level or his willingness to pay for the commodity.
Nevertheless, the voluntary character of the response requires an oversized set of participants with respect to the one theoretically strictly necessary to obtain the necessary amount of load reduction.
Typical demand-side actors for these programs are large customers who have direct access to the power exchange, or smaller customers participating to a Demand Response program launched by their supplier or by an "aggregator", who has the task to enroll a number of active consumers and to resell to the Grid Operator the Demand Response services provided by such consumers as a whole.
Usually, this kind of users opt to react to variable energy prices, very often on a hourly basis. They will then receive early information on prices some minutes, some hours, some days or even some months[1] before the real time.
Several tariff schemes are also studied according to their ability to induce demand response with short or long advance notice. A third category includes variable tariff schemes, such as Time-of-Use and Real-Time tariffs. Time-of-Use tariff schemes induce a long term demand elasticity, in the order of months, whereas Real-Time tariffs or Critical-Peak-Pricing tariffs may have elasticity effect in the short run (hours or days).

Further classifications can be devised based on either the type of market sessions where Demand Response actions may be bidden or according to the complexity of the technology needed to implement them. Nevertheless, the above scheme is widely

[1] In this case, the term "future" is frequently used.

deemed sufficient for a rough but exhaustive classification of Demand Response actions.
The classification of actions as either *System Led* or *Market Led* is fundamental in the analysis of Demand Response.
First of all, *System Led* actions are activated by the System or by the Local Grid Operators, with the aim of ensuring the security of supply. Such actions are therefore mandatory for the participants to the related DR programs and they do not depend on the cost corresponding to the specific action.
Moreover, these actions must be performed in very short times, which are incompatible with usual market timing. For this reason, the Grid Operator usually contracts the service among the elements of a Safety Plan; such contracts are often acknowledged on an annual or lump-sum basis. The nature of these actions, so tightly connected to security, grants the Grid Operator an unbreakable right to cut down or to cut off the contracted power load, within previously agreed times and ways.
The *Interruptible Load* programs comply exactly with these criteria: the *interruptible* user accepts the installation and costs of a cut off device, which is activated under unquestionable decisions of the Grid Operator in exchange for a lump sum remuneration.
In the case of *Market Led* actions, instead, the user responds to economic signals such as real time prices, tariff plans or commercial mechanisms of other kind (e.g. "bidding call options"). In these cases, the response is always voluntary and the price threshold which activates the action is individually negotiated. Besides, these actions are triggered with periods ranging from minutes to days, according to the needed time for the exchange of communications.
At the international level, efforts are in progress aimed at encouraging and developing an elastic behavior of demand and at evaluating its dynamics, value, costs and impact on the electric system. The international research activities refer to economic, financial, technological and operational aspects of Demand Response, though several experimental projects and regional-wide / nation-wide operational plans are being performed. Some examples, identified in the international framework, will be presented in this report.

1.3 Costs and benefits of an elastic demand

The benefits deriving from an elastic demand are strictly related to the main characteristics of liberalized electricity markets; in particular, some benefits pertain to the overall system and others pertain to specific actors of the system.
One of the most challenging issue in this field is the allocation of the value of Demand Response to each component of the electric system and more in particular the share to be allocated to the elastic behavior of consumers. The process aimed at identifying this value is essential in acquiring and maintaining the needed resources to achieve an elastic demand.
Some of the main advantages related to an elastic demand are discussed below.

Advantages for the market

- Market price reduction: an elastic demand can cut down price peaks (that could be severe in case of lack of generation capacity / insufficient reserve margins), thus reducing price volatility and the related risks.

- Reduction of market power exercise: an elastic demand can reduce the possibility of dominant producers to exercise market power, thus increasing market competitiveness and efficiency. Moreover the participation of demand response resources to balancing and ancillary services markets can increase the level of competition also in such markets, whose services have traditionally been provided by producers only.
- Portfolio benefits: the variety of actions related to Demand Response increases the mix of resources available to market players, with positive effects on risk management.
- Better services for the client: end-users have more options to choose, in addition to the simple purchase of energy, and they can get interesting pay-backs for their energy management actions.

Advantages for the electric system

- Reduction of investment needs: Demand Response's main beneficial effect is to reduce demand in peak load / high price periods, possibly moving part of it to less critical / lower price hours. A lower peak load:
  - increases reserve margin (thus increasing security of supply) and, in the longer term, reduces the need for investments in new generation capacity;
  - reduces the stress (and possible congestion) on both transmission and distribution networks, delaying the need for network expansions.
- Better planning actions: a lower demand, reducing criticalities, allows for a longer time to evaluate investments in new infrastructures, so that there are greater chances of fine-tuning to new circumstances, with more gradual and economically efficient changes.
- Faster and cheaper deployment: Demand Response programs are normally deployed very rapidly (months) and with limited costs, if compared to the years required for new generation and network investments.
- Increased short-term security of supply: Demand Response actions are equivalent to faster peak generators and are greatly beneficial in critical conditions, giving more chances to avoid brown / blackouts.
- Locational value: another advantage of Demand Response as a fast reserve service is also given by its location, since DR resources are usually concentrated in load centers, i.e. in the most congested regions where the need of fast reserve is more crucial.
- Environmental benefits: DR reduces the necessity of dispatching costly and low efficiency power plants during peak hours, thus reducing also fuel consumption and CO_2 emissions.
- Insurance value: the cost of extreme events[2] can be reduced without resorting to investments in infrastructures; the related insurance costs are reduced accordingly.

[2] The events characterized by a low probability of occurrence but with severe economic consequences.

Contrary to the aforementioned advantages, which benefit all the actors of the power system, the costs of Demand Response programs are typically borne by specific actors. They can be classified into two categories:

- start-up costs, that concern the design of the program and the purchase of the equipments and of the software needed for its implementation;
- operation costs, related to the remuneration of participants and to the management of the program itself.

Some evaluations of the costs of DR programs are available in the literature /1/. In some cases, they are expressed as costs per unit of responsive load. Very often Demand Response costs are compared with the cost of installation of new peak generation capacity: this kind of comparison turns out to be effective in showing the advantages of DR as an actual resource, in particular if it is used with a role of power reserve.

A univocal approach for the cost-benefit analysis of Demand Response programs is still under study /1/,/2/,/3/. One of the main aspects under discussion, for example, concerns the assessment of the attained benefits in terms of increased reliability, better system management and operation, risk reduction, avoided damages and environmental advantages.

Moreover, most players in this sector agree that costs are classified more easily if reference is made to two main categories:

- technologies for metering and communication,
- design and implementation of a Demand Response program.

Nevertheless, also this scheme leads to some divergence of opinions on who should bear the costs of the technologies and of their maintenance (and till what extent).

Finally, when costs are shared proportionally to the number of energy meters, small consumers are penalized. On the contrary, if costs are shared proportionally to consumptions, large customers could face much higher costs than the actual ones for the installed equipments.

2 Price elasticity of demand and its role in the market

2.1 Role of demand in electricity markets[3]

In a market economy prices of goods depend on the related supply and demand curves. In a well functioning market, both Demand and Supply evolve dynamically towards an equilibrium. An elastic behavior of demand means substantially a reduction of purchases when prices overcome given levels (or, conversely, an increase of purchases in case of lower prices).

This behavior brings about a helpful stabilizing effect on the prices and it very effectively prevents dominant players from exercising excessive market power, in particular in markets where a high price volatility occurs on a daily or hourly scale (e.g. fruit, fresh fish, gasoline or microchip markets). As a matter of facts, a market cannot be considered really competitive if demand does not play its role accordingly. This role becomes crucial when restrictions of goods supply occur and very high increase of prices turns out to be very likely.

Electric power is a quite peculiar good, which differs from the other ones since it has to be produced, transported, distributed and consumed at the same time. In fact, this kind of energy cannot be stored on a large scale with reasonably priced technologies, with the only exception of pumped storage hydro power plants. Thus, policies of stock handling and management cannot be implemented and, as a consequence, the production system and the related infrastructures have necessarily to be designed and built to fulfill the peak demand increased by the reserve margin.

Besides, transportation and distribution of electric power, due to limited capacity which may cause congestion, are tightly constrained by the technical balance requirement between supply and withdrawal on a local scale too.

All these peculiarities, together with the significant difference of marginal production costs of different generation technologies and with the inherent oligopolistic nature of electricity markets, bring about a remarkable price volatility, since electricity demand has typically been quite inelastic.

Thus, a flexible demand which is capable of decreasing when prices arise can play a very important role in reducing the criticalities of the power system during peak conditions, increase its security and reliability and improve market efficiency.

In fact, as above mentioned, Demand Response (in the wholesale market) can mitigate the exercise of market power from the supply side. The fact that price elasticity is negatively correlated with market power is well known in economics. A simple measure of market power is the Lerner index, given by the difference between price and marginal cost over the level of prices. It is easy to show the inverse relation between the (absolute) value of elasticity and the Lerner index starting from a simple profit maximisation problem.[4]

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[3] FEEM contributed to this section.

[4]
$$\max_q \pi(q) = p(q)q - c(q)$$
$$p(q) + p'(q)q = c'$$
$$\frac{p(q) - c'}{p(q)} = -\frac{p'(q)q}{p(q)}$$
$$L = -\frac{1}{\varepsilon}$$

$$L = \frac{p(q) - c'}{p(q)} = -\frac{1}{\varepsilon} \qquad [17]$$

The interest has been posed on the estimation of the potential market power of a specific electricity market. One usual theoretical framework for such an estimation is the supply function oligopoly model by Klemperer and Meyer (1989). In this context, an increase of demand elasticity has the same effect (on prices) as an increase of competition (in the sense of a move from Cournot to Bertrand competition). However, Wolfram (1999), with reference to the British market, found evidence that prices were much closer to marginal costs than what oligopoly models predict, suggesting that the bidding strategies may be significantly affected by the threat of entry and the threat of regulatory intervention in the market.

All types of demand response programs can improve market performance in terms of reduced market power. The potential market power is typically higher during peak load periods because there is more pressure to find adequate generation. Withholding such scarce generation resources from the day-ahead market or from the hour-ahead one and releasing them in the balancing or reserve market for a high price can be effective if no customer is able to counter that strategy be relinquishing his scheduled load to the TSO. Fostering the participation of large consumers into real time markets is thus the best alternative to entry of new producers to fight market power abuses.

In the long term, demand response induced by TOU pricing contributes to flatten the load duration curve, reducing the difference between the maximum and average load, and thus may have a role in reducing the scarcity rents typically associated with the peak periods. However, it is in the short term (and real time) that demand response becomes particularly relevant to control market power abuses in the day-ahead or in the real time market. Short term demand response due to the application of RTP (or CPP) can help to reduce volatility of wholesale prices.

2.2 Effects of absence of an elastic demand

It is widely agreed that a market with no active participation of demand, or with a demand characterized by a scarce elasticity to price, lacks one of the most important mechanisms for its stability. As a matter of facts, many of the problems occurred during the liberalization of the electricity markets in the USA and in Europe (e.g. lack of production capacity, inadequate grid development, market power abuse, etc.) were worsened by the inadequate participation of demand to the different electricity markets (namely: energy, balancing and ancillary services markets).

The reasons for this can be summarized as lack of economic incentives and of standard technological solutions for consumers to respond to price signals with an organized approach. Among the concurrent causes of such a situation, we can mention the following:

- due to their traditions, education or to plain practice, companies in charge of planning and operating the electricity systems are inclined to ensure the needed equilibrium between generation and load on the basis of mere adjustments of the generation that, being more “concentrated”, is deemed more easily “controllable”; instead, they tend to neglect the opportunities offered by a responsive demand;

- in several cases, tariff schemes proposed by suppliers to end-users are designed to mask the effects of hourly price variability, thus damping or vanishing any economic signal that would encourage demand flexibility;
- the unavoidable time delay between consumption and billing hinders a direct feedback between consumption habits and their economic consequences;
- a prejudice is widely diffused concerning the reduction of operating flexibility and/or of comfort induced by some forms of adjustment of demand;
- similarly, it is common opinion that the benefits of Demand Response do not pay back enough the relevant costs; in fact, the technologies for real-time management of prices and consumptions are commonly considered very expensive.

2.3 Definitions and evaluation of the elasticity of demand[5]

Elasticity can be expressed in different ways. *Own-price* elasticity indicates the ratio between the percentage change in the load over the percentage change in the price level, and is expected to be negative. When considering the time variability of electricity prices it can be useful to have information on the degree of substitutability across time-periods. To this extent, *cross-price* elasticity indicates the ratio between the percentage change in the demand during a certain time period (e.g. peak demand) over the percentage change in the price level in another time period (e.g. off-peak price). A positive value in cross-price elasticity implies that electricity consumption during the two time-periods are substitutes, otherwise they are complements. Another measure of substitutability across time is the elasticity of substitution, which takes on only positive values and is the ratio between the percentage change in the relative usage in two time periods (e.g. the ratio of the peak to off-peak demand) and the percentage change in the relative prices (e.g. the ratio of the off-peak price to peak price).

The interest in the estimation of electricity demand elasticity is early dated in economics, such that surveys of empirical works were already published in Taylor (1975), Bohi and Zimmermann (1984) and Sweeney (1984). In general, the focus of these pioneer analyses was investigating the substitutability of energy with other factors, in a context of time invariant rates. Then, the attention has been dedicated to the possibility of substitution between peak and non-peak usage. The majority of these studies consider a TOU static framework (among the others: Aigner, 1984; Aigner et al., 1994; Parks and Weitzel, 1984), but more recent works concern demand response to dynamic pricing (Herriges et al., 1993; Patrick and Wolak, 2001; King and Shatrawka, 1994; Schwarz et al, 2002; Taylor et al., 2005).

When considering time differentiated prices, they can produce a reallocation of energy consumption between different hours or different days, and this kind of substitution does not necessarily involve a change in the total consumption. Since energy yields different levels of utility depending on when it is consumed (say, for example, the utility of heating in a cold or a warm day), energy consumed today can be considered as a different good with respect to energy consumed tomorrow. In other words, demand can be decomposed, in the more simple case, in peak and off-peak demand.

Generally, electricity is assumed to be separable from other goods (because of the lack of correspondingly accurate information on other commodities), thus it is possible to define a sub-utility function concerning kilowatt-hours consumption of electricity at

[5] FEEM contributed to this section.

different times of a certain basic unit of observation (a day, a week, a month). The representative consumer is therefore assumed to optimally choose the time allocation of electricity during the basic unit of observation. This leads to a system of demand equations (one for each pricing period), that can be estimated in order to calculate own price and cross price elasticities. Alternatively, the starting point can be the specification of a cost function where inputs are different times of use of electricity. In this case, it is possible to derive the input demand system.

To describe more in detail the theoretical framework, the utility function can be written as follows:

$$u = U(x,z) = U[e(x),z] \qquad [19]$$

where x = (x1, x2,… xh) is a vector of the quantities of electricity consumed during h time intervals, z is a vector of non-electricity goods, and e(x) is homogeneous of degree one in x. Thus, U(.) is homothetically separable in x, a necessary and sufficient condition to validate a decentralised two-stage budgeting approach to the electricity demand approach.[6] The first stage involves the allocation of total expenditure (y) between electricity and non-electricity goods. The maximisation process yields the indirect utility function, homothetically separable in the electricity prices.

$$\{\max_{x,z} U(x,z) \text{ subject to } px + qz = y\} \Rightarrow V(p,q,y) = V[g(p)/y, q/y] \qquad [20]$$

where g(p), homogeneous of degree one, is a price index function for electricity.
The second stage concerns the maximisation of the sub-function e(x) subject to the constraint px=m, where m is the optimal total expenditure in electricity determined in stage one. This allows determining the optimal time allocation of electricity. By applying Roy's identity to [20] and after some algebraic steps[7], the demand functions for electricity in a particular time period are obtained:

$$x_i = \frac{m(\partial g / \partial p_i)}{\sum_{i=1}^{r} (\partial g / \partial p_i) p_i} \qquad [21]$$

This demand system gives all the necessary information to measure consumers' substitution response. The choice of the functional form g(p) is only restricted to be homogeneous of degree one, and it has been specified in a number of ways, for example:

a) constant elasticity of substitution (CES)

$$g(p) = \left(\sum_{i=1}^{r} \alpha_i p_i^{-\rho} \right)^{-1/\rho} \qquad [22]$$

b) translogarithmic

$$\ln g(p) = \sum_{i=1}^{r} \alpha_i \ln p_i + 1/2 \sum_{i=1}^{r} \sum_{j=1}^{r} \beta_{ij} \ln p_i \ln p_j \qquad [23]$$

[6] For a non-homothetic approach see Mountain and Lawson (1992)
[7] See Parks and Weitzel (1984)

c) generalised Leontief

$$g(p)=\sum_{i=1}^{r}\sum_{j=1}^{r}a_{ij}\,p_i^{1/2}\,p_j^{1/2}$$

[24]

Of course the last two functional forms are more flexible, at the cost of a higher parameterisation of the model.
The starting point can also be the specification of a cost function where inputs are different times of use of electricity (this approach is more proper for industrial customers). In this case the standard theory of production allows to derive the demand for electricity (in each hour or alternative period of time) as an input via the Shephard's lemma.

$$x_{i,h}=\frac{\partial C}{\partial g(p)}\cdot\frac{\partial g(p)}{\partial p_{d,h}}=C_p\cdot\frac{\partial g(p)}{\partial p_{d,h}}$$

[25]

As already mentioned, in the case of incentive based programs it can be difficult to estimate elasticity since demand reduction are not directly related to percentage change. Therefore, demand response is usually measured by the physical amount of load reduced, (e.g. load reduction in absolute value, percentage of demand reduction with respect to the total consumption). These values are useful to compare different types of demand response programs, but, given the number of peculiarities characterising them, they remain imperfect measures. To define the optimal design of such programs, indeed, one would need to estimate more specific indicators, trying to isolate the effect on demand response of each component of the program (e.g. the frequency of events, the penalties in case of non-reduction, the lag between the event announcement and its realisation, ...) and to understand their interrelation.

As for *own-price* elasticity of electricity demand, a survey of the relevant literature (see /23/÷/29/) has been carried out and a synthesis of its outcome is presented below.
First of all, it is important to consider the time scale on the evaluation of the elasticity.
Some studies report values of elasticity between -0.1 and -0.2 within 1 to 3 years and between -0.3 and -0.7 for the longer term (10 years of more). In other words, this means that an increase of 10% of the energy price can bring about a decrease of consumption of, respectively, 1-2% and of 3-7%. The greater response potential in the longer term is consistent with the expected behavior of consumers who, facing persistent price signals, tend to invest in more efficient equipments and to make a better use of energy /23/.
These studies also show that the elasticity of demand is a non-symmetric function of the price variation, in the sense that a decease or an increase of price of e.g. 1% does not produce identical but opposite variations of consumptions.
Moreover, this dependence is of a non-linear kind, in the sense that the response to a small variation of prices is not proportional to the response to a higher variation.
Finally, it must be remarked that different classes of consumers will be likely to respond in different ways to the same increase of the energy price, depending on the value they assign to the use of energy.
Nevertheless, it should be pointed out that most of the literature reviewed refers to empirical evaluations of the elasticity in case of small price variations in non-liberalized electricity markets where price were regulated or unchanged for long times. In this case, elasticity is more related to the amount of energy consumption in relatively long periods

than to short-term variation of power withdrawal. This sort of evaluation can hardly describe the demand behavior responding to broad and sudden price increases on a time scale of hours, which in fact is the kind of elasticity under analysis to be stimulated in Demand Response programs.

In fact some studies concerning the application of more advanced pricing strategies showed higher elasticity values up to -0.9 during specific time periods characterized by specific tariff schemes.

A very interesting analysis carried out in Switzerland /30/ demonstrated that a significant level of Demand Response can hardly be attained by a uniform and generalized increase of prices. On the contrary, a remarkable elastic behavior may be expected in response to significant price variations focused over shorter periods (days, weeks or seasons).

Of course, flexibility of consumption may differ among end-users according to:

- the specific use of the energy,
- the possibility to defer part of the consumptions,
- the availability of backup generators,
- the possibility of fuel switching to other energy vectors,
- the possibility of storing energy in other forms, such as thermal, mechanical or chemical.

The above studies on elasticity showed that the most effective way to induce a dynamic response of the energy demand is to expose it to short-term price variations that occur in the organized markets. Conversely, a consumer exposed to flat (even if on average high) or seldom variable prices would not able to perceive the critical conditions of energy supply (which instead would be evidenced by the high short-term prices of the commodity itself) and to adequately respond to it.

Nevertheless, the problem of exposing consumers to the prices defined in the power exchanges has complex implications and requirements, both regulatory and technological, concerning data communication, metering, billing, automation, etc.

These complications prevent a remarkably high share of customers from performing an actual real-time response to variable prices. In practice, an organized response of consumers could be achieved, provided that two basic requirements are fulfilled:

- consumers are given an economic signal, in terms of either price or incentive;
- consumers are equipped with suitable technological tools that make them able to respond.

Finally, the information aspects (such as promotional campaigns) of Demand Response programs play a critical role: a poor or ill-focused information will be likely to prelude to scarce participation.

It must be remarked that the industrial sector already has a good awareness as well as a certain habit to manage consumptions according to “Time-Of-Use” tariffs, also due to the relevance that electricity may have in production costs.

Conversely, much less attention is generally paid to an “intelligent” energy management by other classes of users, such as households, which are more “dispersed” but very important as a whole.

It should also be pointed out that the relevance of the economic advantages of a well managed consumption for the industrial sector is much more evident than the savings on the bill that a household user could get. So, the industrial user will more likely be attracted by a Demand Response program than a household one, even if a sufficiently large aggregation of households could have a considerable weight from the overall system point of view.

2.4 The economic rationale for time differentiated pricing[8]

Peak load refers to a moment where the demand for electricity is higher than usual. The time frame under consideration can be the year (summer vs. winter), the week (business vs. week-end), the day (morning vs. noon) or even the hour (TV pick-up). Revolving and unexpected demand peaks are not limited to electricity, they also occur for phone calls or leisure services such as air transport or lodging. The problem created by a peak for the provision of these services is their non-storability.[9] In addition, electricity highlights several peculiarity related to the need of ensuring the balance of supply and demand in real time and to the complexity of the transmission system.

The economic issue created by the existence of peak load is that infrastructure (capacity) must be greatly increased with respect to the base level in order to serve the extra demand without rationing clients or force them to queue or delay their consumption. To mitigate this problem, one can set time-differentiated prices i.e., raise the peak price and lower the off-peak one so as to shave the peak and fill the valley.

For more than a century, economists have shown great interest for the peak load problem whose theoretical solution calls on price differentiation over time or some form of rationing (or both). In this section we summarise the main results of the economic literature which applies to the electricity market, with the aim of explaining systematically how price signals should vary to achieve efficiency.

In the theoretical literature, we found basically three motivations in favour of time-differentiated pricing:

a) The definition of the system capacity and the efficient use of resources;

b) The ability to contribute to the balancing of the system and the improvement in reliability;

c) The potential reduction of market power behaviour of generators in the wholesale spot market.

2.4.1 The definition of System Capacity and the Theory of Peak Load Pricing

Non-storability implies that the consumption of electricity must be equal to the production at any time. This implies that the productive structure must be shaped according to the characteristic fluctuations of demand; in particular the peak demand is a key information when defining the amount of capacity to be installed.

The demand for electricity is traditionally described by the *load duration curve*, which measures the number of hours per year the total load is at or above any given level of

[8] This section has been prepared by FEEM.
[9] To be precise, storage is very costly so not economical to solve the problem at hand.

demand. Even if it does not include information on the sequence of the load levels,[10] it gives information about the peak-level demand and its duration and it is crucial to the long-term capacity planning. The ability of the system to meet the aggregate requirements in the long run is defined as the *adequacy* of the electric system. Figure 2 represents a typical situation for a country where the peak is in the winter: the first graph plots the time series of loads during a year, while the second graph is the load duration curve, which represents the frequency of demand levels (in this case, the "average" line in the picture corresponds to the median value of load). The difference between the installed capacity and the maximum load is usually called the *planning reserve margin*, a key value when evaluating the level of adequacy of the electricity system (Oren, 2003). The difference between the available capacity and the load (at any moment) is instead the *operating reserve margin* and is related to the issue of *reliability*, i.e. the ability of the system to withstand contingencies.

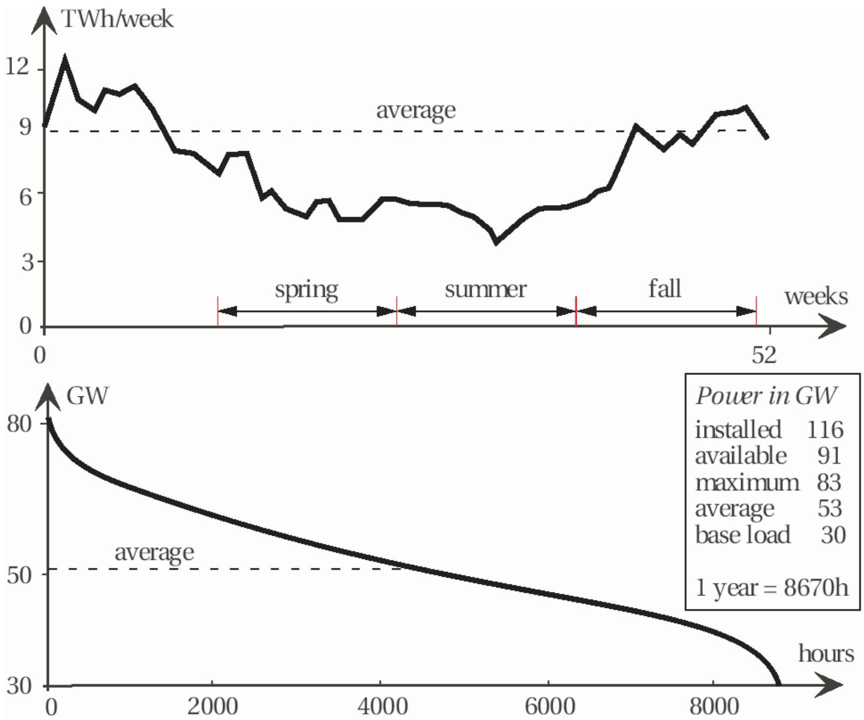

Figure 2 – Time series of loads and the load duration curve

The load duration curve is independent from any consideration about the price levels; however, price can be an instrument to induce modifications in the load duration curve (e.g., on the basis of production costs). The problem of the optimal definition of (installed) capacity provides a first motivation for having time differentiated prices (charging higher price during high-load periods) and it represents the basic result of the classical peak load pricing theory (Boiteux 1949, Steiner, 1957; Williamson, 1966).

The theory of peak load pricing originated in the context of regulated industry with reference to the need of finding an appropriate pricing policy leading to the correct amount of physical capacity and its efficient utilisation, covering the full social costs of the resources used. The basic suggestion is to charge in each period the long-run

[10] For example, the same curve can describe wide daily swings in demand and little seasonal variation or wide seasonal variations and limited daily swings.

marginal cost of production, unless the price differential is such to induce a shift in the peak periods (in that case, the price differential should be set in a way to have equal demand during peak and potential peak periods). In other words, high-load users should pay all capacity (fixed) costs, while low-load users should only pay the marginal costs of production.

More in general, all this strand of literature answers to the question of optimal pricing from the point of view of a regulator with perfect information on cost structure and demand[11]. As pointed out by Crew et al. (1995), an underlying common approach to derive efficient prices can be defined, which follows from the maximisation of an explicit social welfare function.

$$\underset{p}{\mathrm{Max}}\, W = TR + S - TC \qquad [1]$$

where W is the net social benefit, given by the sum of producer surplus (TR-TC, total revenue – total costs) and consumers' surplus (S). [1] is typically constrained by a breakeven constraint for the production sector. Indeed, peak-load pricing can be viewed as a form of Ramsey pricing: the peculiarity of peak-load analysis is that the welfare maximisation refers to the provision of a vector of products differentiated only by the time of consumption.

A separable form is used to represent the preferences of consumers:

$$U(x,m,\theta) = V(x,\theta) + m, \qquad \theta \in \Theta \qquad [2]$$

where x = (x1, …, xT) is the vector of goods supplied by the regulated sector (i.e. the consumption of electricity in the different time-periods) and m is an Hicksian aggregate representing the utility from all other goods. θ is a parameter that allows for consumers' heterogeneity, with $f(\theta)$ being the density of consumers of type θ.
The Ramsey problem can be stated as:

$$\underset{p\geq 0}{Max}\, W(p) = \int_{\theta}\left[V(x(p,\theta),\theta - \sum_{T} p_i x_i(p,\theta)\right] f(\theta)d\theta + \Pi(p) \qquad [3]$$

subject to $\Pi(p) = \sum_{T} p_i x_i(p) - C(x) \geq \Pi_0$

where C(x) is the cost function and Π_0 is some desired profit level (e.g. 0).

[11] In the case of stochastic realisations of supply and demand, the perfect information is referred to the knowledge of probability structure.

Author(s)	Main assumptions of the model	Results for prices and capacity
Steiner (1957)	No uncertainty on demand and supply (deterministic peak load) Demands are taken as given functions of prices. Costs are linear and there is only 1 technology available: b is the operating marginal cost and β is the per-day cost of providing a unit of capacity	1) $p_{op}^* = b$ $p_p^* = b + \beta$ $K^* = x_p(b + \beta)$ as long as $x_{op}(p_{op}^*) < x_p(p_p^*)$ 2) If this condition does not hold, then the shifting peak case arise: $p_{op}^* + p_p^* = 2b + \beta$ $p_p^* > p_{op}^*$ $K^* = x_p(p_p^*) =$ $x_{op}(p_{op}^*)$
Crew and Kleindorfer (1976)	Extension to multiple technologies. N technologies are available, such that: $\beta_1 > \beta_2 > \ldots > \beta_N$ $b_1 < b_2 \ldots < b_N$	For the two technology case: $b_1 < p_{op}^* < b_2 < b_2 + \beta_2 = p_p^* < b_1 + \beta_2$ More options in technology imply therefore a *lower peak price* and a *higher off-peak price*
Kleindorfer and Fernando (1993)[12]	Extension to take into account uncertainty on demand and supply. This involves possibility of outage and the need for rationing. Endogenous determination of the optimal level of reliability.	Results similar to the deterministic case, but with short-run marginal cost including the expected outage cost. 1 period, 1 technology example: $p^* = b + \beta/a + \Lambda$ where: a = availability factor Λ = excess of willingness to pay over price for unserved energy to the marginal consumer
Shy (2001)	Demand in different periods are not independent. Endogenous choice of consuming during the peak or during the off-peak period. Introduction of a time discount factor (ρ) and a “flexibility” index (δ)	$p_{op}^* = b$ $p_p^* = b + \beta(1+\rho)/2$ $K^* = x_p(p_p^*)$ Peak price is lower (and optimal capacity greater) than in the basic case (unless ρ=1)
Notation: p_{op}, p_p = respectively, off peak and peak prices; K = capacity b = marginal cost; β = per-day cost of an additional unit of capacity		

Table 1 – Peak load pricing in the economic literature

The solution of [3] yields the first-best price schedule[13]:

$$\sum_{j \in T} \frac{p_j - c_j}{p_j} \eta_{ij} = -\kappa \qquad \forall i \in T \qquad [4]$$

[12] Built on the basis of previous works: Brown and Johnson (1969), Vissher (1973)
[13] In the sense that, when coupled with appropriate lump-sum transfers, the Ramsey solution can Pareto dominate every other linear price schedule and lump-sum transfer schedule satisfying the profit constraint.

where η_{ij} is the cross-elasticity between consumption in two different periods, and κ is the so-called Ramsey number, which is positive except when the profit constraint is not binding. [4] implies that, as long as products are substitutes over time ($\eta_{ij}>0$, for $i\neq j$), price will always exceed marginal cost in all period, except at the unconstrained welfare optimum.

Table 1 briefly summarises the evolution of the theory of peak load pricing, providing the results on optimal prices and capacity under alternative assumptions, with reference to the simplified case of 2 time-periods.

The original model assumed the availability of a unique technology; having more than one type of technology to meet demand actually mitigates the price differential needed between peak and off peak (Crew and Kleindorfer, 1976). In fact, peak demand can be satisfied with smaller generators (peakers) whose investment costs are lower, even if their operating costs are higher. Note that in this case, however, price differentiation is justified not only in terms of covering the long-run capacity costs, but also in terms of short-run marginal costs.

2.4.2 Uncertainty, Reliability and Real Time Pricing

Steiner (1957) considered a deterministic peak load, i.e. without uncertainty on demand and supply. A natural development of the theory is the consideration of stochastic realisations of demand and supply (Brown and Johnson, 1969; Vissher, 1973; Kleindorfer and Fernando, 1993), which highlights a common issue when talking about electricity, reliability. The uncertainty concerns both the demand side, since unpredictable events can impact on the usual consumption patterns (e.g. extreme temperature), and the supply side, because generation and transmission capacity availability fluctuates (e.g. generation plant outages or transmission line failures). The peculiarity of the electricity service is that an unbalance between supply and demand causes problems that, if not corrected, leads to a blackout; for this reason a certain level of operating reserves is needed.

On the one hand, uncertainty adds a further role for price flexibility; on the other hand, since it may be the case that demand exceeds the supply, some form of rationing may be desired to avoid the realisations of unforeseen states of excess demand (i.e., blackouts).

First of all, expected outage costs should be incorporated in prices; since these costs are typically higher during high-demand states, this would imply a higher price at the peak. However, in this setting, price assumes a role which goes further to that of being cost reflective. In fact, prices become an instrument of demand management that can be actively promoted to reduce the probability of having unforeseen blackouts (and therefore to improve reliability). Actually, the problem takes a dynamic aspect since it would be necessary to adjust prices in *real time*, to take into account of the stochastic variations in the demand-supply balance. The concept of real time pricing was first introduced by Vickrey (1971), who argued that it yields a first-best outcome in a world where there are no transaction costs, customers are risk neutral and can respond optimally to price signals. All these hypothesis are very restrictive; however it is important to recognize that real time pricing can improve reliability contributing to the solution (at least partial) of the uncertainty concerning the balancing of demand and supply.

The uncertainty also implies that ensuring 100% reliability to all consumers can be too costly and therefore inefficient. Joskow and Tirole (2004) demonstrated that rationing of price-insensitive consumers may be optimal if peak periods are infrequent: in this case, the peak price would tend to infinity and the discrepancy with the average price would be too large to make it socially optimal to serve the consumers.

2.4.3 The Theory of Transmission Prices

Price can be an instrument of demand management not only over time, but also over the spatial distribution of the electrical network. Given the interconnections over the network and the local variability of demand and supply, Bohn et al. (1984) proposed a model to derive the optimal price at each node of the network (locational marginal pricing, LMP). This pricing system, which considers the transmission constraints over the network, provides a means to solve the problem of congestion over the lines (congestion management).

The work of Bohn et al. (1984), as revisited in Schweppe et al. (1988), is at the basis of the theory of transmission prices, whose review is behind the scope of this document and is extensively summarized for example in Hsu (1997) or in the book of Stoft (2002). Here we just want to point out that what makes transmission prices complicated are the physical laws governing power flow in an interconnected network (i.e. the Kirchoff's laws), simplifying the main insights of the theory.

The approach to derive optimal pricing follows the standard welfare criterion of maximising consumers' plus producers' surplus, constrained to the energy balance and to the network constraints at each location (transmission constraints). The Lagrangian multipliers of the various constraint can be interpreted, as usual, as shadow prices. The solution gives the optimal spot price at each node, and can be described in the following way :

pi* = [social cost of additional demand at a general location]
x [1 + incremental losses caused by node i]
+ [transmission constraint terms, summed over lines]

The first term refers to the Langragian multiplier associated to the energy balance constraint, representing the shadow price of an additional unit of demand. This value is the same at each node, and turns out to be the optimum at each consumer location if there are not incremental losses associated to an increase in demand, and no transmission constraint is binding. The second term accounts for different effect on losses of an increase of demand at the various consumer locations, thus charging a higher price to customers whose demand generate a higher marginal loss in the network. Finally, the third term considers the transmission constraints related to the limited physical capacity of the network. Each node can experience congestion, i.e. the constraint can be binding, and in this case the shadow price of an additional unit of transmission capacity will not be 0. The congestion charge at each location is defined as a weighted average of all Lagrangian multipliers: this implies that this component of the LMP can be different from 0 also in a node which does not directly experienced congestion. Potentially, given the network interconnections, it is sufficient to have congestion in a single node to generate positive (or negative) congestion charges at each different node. The same optimisation process is repeated over time (real-time pricing), generating different energy price at each location and in each time-period (e.g. each hour) as a consequence of the modified conditions of demand and supply over the network.

2.4.4 Wholesale vs. Retail Electricity Prices

Up to now, we have talked about the theoretical reasons in favour of peak load pricing and real time pricing, but without taking into account the nature of restructured electricity markets. We find a wholesale market, which we may assume to be substantially inspired by the economic principles described so far, and a retail market, where end-consumers face pricing structures which can be significantly different from the wholesale cost. This situation poses the problem of the correlation between the price signals formed in these two markets. Hourly pricing (almost real time) is commonly used in wholesale markets, whereas retail markets are still characterised by (often regulated) flat tariffs.

Borenstein and Holland (2004) point out that traditional results of the theory (described in this section) carry over immediately to a deregulated market only if all customers are on real time pricing (that is, in the absence of a retail market). Moreover, since the competition among generators can be imperfect, the possibilities of market power abuses can be exacerbated in the presence of low connection between wholesale price variations and retail price actually paid by consumers (Borenstein and Bushnell, 1999; Day et al., 2001). This provides a further role for promoting time differentiated *retail* prices, which can be an instrument to favour demand responsiveness in the spot wholesale market and therefore to limit the potential for market power by the supply side.

It is interesting to point out that, within the problem of connection between retail and wholesale market, the literature has focused on the question of the desirability of (de)regulation of retail market: is it better to promote retail competition or to regulate retail tariffs? Here we present more in detail the model proposed by Borenstein and Holland (2004) regarding the impact on efficiency of competitive power markets of having some customers on time-invariant pricing. In their framework, a fraction α of the customers pays real time prices and the remaining share (1-α) faces a flat retail rate ($\bar{p}$)[14]. The fraction α is an exogenous number over the interval [0,1], and the aggregate demand is therefore given by:

$$\tilde{x}_t(p_t,\bar{p}) = \alpha x_t(p_t) + (1-\alpha)x_t(\bar{p}) \qquad [5]$$

The model assumes the following structure of the market:

a) there is perfect competition among generators. Coherently with the previous sections, the cost of installing a unit of daily capacity is β and generators can produce up to the installed capacity with a marginal operating cost equal to b;
b) each hour (t), generators sell electricity in the wholesale pool market at a price w_t;
c) retail sector is assumed to have no costs other than the wholesale cost of electricity, and firms engage in retail competition.

[14] The fraction of customers on real time pricing is assumed to react optimally to price signals.

Competition among retailers forces equilibrium real time price p_t^e to be equal to the wholesale prices w_t. The zero profit condition[15] for the retail sector yields the equilibrium flat rate ($\bar{p}^e$), which is equal to the *demand*-weighted average wholesale price [7].

$$\Pi_{retail} = \sum_t \alpha[x_t(p_t)(p_t - w_t) + (1-\alpha)[x_t(\bar{p})(\bar{p} - w_t)] \quad [6]$$

$$\bar{p}^e = \sum_t w_t \left\{ x_t(\bar{p}^e) / \sum_t x_t(\bar{p}^e) \right\} \quad [7]$$

In the wholesale market, the intersection between demand and supply yields the short-run competitive equilibrium:

$$(w_t^e - b)\,[x_t(w_t^e, \bar{p}^e) - K] = 0 \quad \text{for each period t} \quad [8]$$

Condition [8] implies that whenever there is enough installed capacity, the wholesale price will be equal to the marginal cost; instead, when demand is higher than K, the wholesale price will increase until the demand/supply balance is achieved. Thus, generators make short-run profits, while in the long the zero profit condition holds:

$$\sum_t (w_t^e - b)\,[x_t(w_t^e, \bar{p}^e)] = \beta K \quad [9a]$$

which can be rewritten as[16]:

$$\sum_t (w_t^e - b) = \beta \quad [9b]$$

As in the classical peak load theory, prices include the capacity payment only at the peak. The inefficiency comes from the retail market, and in particular from the determination of the flat rate. Borenstein and Holland (2003, 2004) demonstrated that a competitive market fails to achieve the second-best optimum given the constraint of having a share of customers paying time-invariant prices. Indeed, if a social planner were to choose the prices p_t^* and ($\bar{p}^*$) that maximise social welfare, in the short run, he would have solved the following optimisation procedure:

$$\max_{p_t, \bar{p}} \sum_t [\tilde{U}(\tilde{x}_t(p, \bar{p}) - b\tilde{x}_t(p, \bar{p})] - \beta K \text{ s.t. } \tilde{x}_t(p, \bar{p}) \le K \text{ for all t} \quad [10]$$

$$p_t^* = b + \lambda_t \quad [11]$$

$$\bar{p}^* = \left. \sum_t p_t^* \frac{dx_t(\bar{p}^*)}{d\bar{p}^*} \middle/ \sum_t \frac{dx_t(\bar{p}^*)}{d\bar{p}^*} \right. \quad [12]$$

The real-time prices are equal to the marginal cost whenever the capacity constraint is not binding (λ_t is the shadow price of capacity, and is positive only when installed capacity is not enough to face the demand for that period). As to the optimal flat rate, it is the average of the real-time (wholesale) prices weighted by the *slope* of the demand: thus, difference between [12] and [7] comes from the different weights used, and $\bar{p}^*$ can be higher or lower than $\bar{p}^e$.

In the long run, the second best would be implemented when [10] is maximised also with respect to the amount of capacity K, and yields a further first order condition:

---

[15] Note that the assumptions on retail sector imply that zero profit condition holds also in the short run (there are no fixed costs).

[16] This is possible because margins are positive only when $x_t(w_t^e, \bar{p}^e) = K$

$$\sum_t \lambda_t = \beta \qquad [13]$$

The inefficiency in the long run still comes from the determination of the flat rate and from the comparison between [12] and [7]. At the same time, also the optimal capacity can be either higher or lower than the competitive equilibrium capacity, depending on the relation between equilibrium and socially optimal flat rates: if $\bar{p}^* > \bar{p}^e$, then $K^* < K^e$ and vice versa. For example, if we are in a long run competitive equilibrium (so that condition [9b] holds) and $\bar{p}^* > \bar{p}^e$, then a regulator may try to improve welfare by increasing the flat retail price. This would reduce demand from flat rate consumers and, since in the short run the wholesale equilibrium price is derived from the supply/demand balance (condition [8]), w_t would decrease in all periods when capacity was fully utilised[17]. Thus, condition [9b] does not hold anymore, because there is excess of capacity: the long run equilibrium would imply therefore a lower amount of capacity.

Summarising, a regulator with *perfect information* on demand curves can perform better than a competitive market, given the constraint of flat rate consumers. From one hand, this gap worsens in a situation of oligopoly among generators. The part of consumers on flat rate is inelastic to changes in wholesale prices; an inelastic wholesale demand carries with it a higher possibility for the supply-side to exert market power. From the other hand, the quality of information available to the regulator is crucial to perform better than the market. Moreover, Joskow and Tirole (2004) show that the results of inefficiency in a competitive market can be overcome if the retailers are not constrained to offer linear prices, but are allowed to propose two-part tariffs. However, in their model they also allow for rationing, and in particular the result of efficiency is conditional to the non-rationing of consumers facing real time pricing.

The model of Joskow and Tirole (2004) can be seen as a modification of Borenstein and Holland (2004). They allow for different values of rationing for real-time ($\hat{\psi}_t$) and flat-rate consumers ($\bar{\psi}_t$)[18].

$$\max_{p_t, \bar{p}, \hat{\psi}_t, \bar{\psi}_t} \int_t f_t [\tilde{U}(\tilde{x}_t(p_t, \bar{p}, \hat{\psi}_t, \bar{\psi}_t) - b\tilde{x}_t(p_t, \bar{p}, \hat{\psi}_t, \bar{\psi}_t)]dt - \beta K$$

$$\text{s.t.} \quad \tilde{x}_t(\cdot) \le K \quad \text{for all t} \qquad [14]$$

The results of this maximisation imply that price sensitive consumers (facing real time prices) should never be rationed ($\hat{\psi}_t$ =1). Instead, for flat-rate consumers:

$$\text{either} \quad \frac{\partial \tilde{U}_t / \partial \bar{\psi}_t}{\partial \tilde{x}_t / \partial \bar{\psi}_t} = p_t \qquad \text{or} \quad \bar{\psi}_t = 1 \qquad [15]$$

Thus, in case of rationing, the real time price must be equal to the marginal surplus associated with a unit increase in supply to the (flat-rate) consumers (i.e. the value of lost load, VOLL). To see that rationing can be optimal, suppose that blackouts can be

[17] Consider a peak period when there is a problem of excess demand. In the absence of rationing, prices in the wholesale market must raise to reduce the consumption of real time consumers, until the demand/supply balance is obtained. When the flat rate increases, the demand will be lower in all time-periods, and also during peak periods. Then, the problem of excess demand will be mitigated, and a lower wholesale price would be needed to achieve the balance.

[18] In the model, they also allow for more complex technology (production costs and investment costs are different between baseload and peakers), however this aspect can be simplified to our purposes.

perfectly anticipated (foreseen rolling blackouts). In this case, it is fair to assume that both utility and demand are linear in ψ_t, which implies that VOLL is simply the average gross consumer surplus19. Rationing is preferred to market clearing prices mechanisms if and only if the value of lost load is lower then the market clearing price. In the case of only two time-period, rationing should arise only in the peak, and it would be optimal if:

$$U_p(x_p(\bar{p})) < p_p x_p(\bar{p}) \qquad [16]$$

where the subscript p indicates the peak period. If the frequency of peak tends to zero, then peak price goes to infinite, while the optimal flat rate is still bounded; thus the right hand side of [16] is infinitely high and the condition for optimal rationing is verified.

2.5 Classification of Demand Response programs

Terms as Demand Side Management, Demand Response, Load Management, Demand Side Bidding /33/, /34/ are used worldwide for “programs aimed at achieving and handling an elastic demand”. This assortment of expressions is sometimes chance of misunderstandings.

Similarly, different terms are used to refer to supply contracts and relevant pricing plans, in particular with reference to the economic reward paid to an elastic behavior of demand.

It is then important to better specify the meaning of Demand Response and the behavior to be addressed.

A fundamental classification is connected to the voluntary or mandatory nature and to the timing of the response action of the user to the system/price signal.

For example, the user may receive an energy price signal relevant to some minutes after, some hours after or a day after; alternatively, he may receive a plain alarm signal aimed at a short-term curtailment of demand.

The user may respond to these signals by means of some automatic equipments, which operate a load decrease, or he/she may decide on a case-by-case basis whether or not to reduce his/her demand. These alternatives are tightly connected to the typical timing of the operations, which can range from a few seconds to hours.

Besides, the contracts between the user and the supplier / utility may involve different forms of incentives or awards for the offered service. This remuneration can range from a lump sum on an annual basis to a “tailored” reward depending on the deviation from a reference baseline load curve. Many other intermediate solutions, based on different energy prices for different system conditions[20], can be devised as well, which outline a quite diversified panorama of choices.

Therefore, Demand Response programs can be classified on the basis of the following main aspects:

- the **voluntary / compulsory** participation to the program,
- the **kind of signal** (economic – e.g. market price – or alarm – e.g. criticality) triggering the load decrease,

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[19] Linearity implies $\tilde{x}_t(\cdot,\psi_t) = \psi_t \breve{x}_t(\cdot)$, thus the derivative with respect to ψ_t yields $\breve{x}_t(\cdot)$. The same reasoning applies to utility, so that $VOLL = \breve{U}(\breve{x}_t(\cdot)) / \breve{x}_t(\cdot)$.

[20] E.g. day / night hours, critical peak hours, etc.

- the **possibility of choosing** whether or not to reduce the load, on a case-by-case basis,
- the **operational time** for implementing the load variation,
- the **measurement** necessary to define the participant "virtuous behavior" to be rewarded,
- the **economic reward** (incentive or profit) for the participant to the program.

A widely adopted scheme, already outlined in section 1.2, considers two large classes of programs:

- **System Led**: curtailment of demand as a response to emergency conditions of the system;
- **Market Led**: a voluntary choice of the user in response to price signals or economic incentives.

In the following, examples of System Led and of Market Led programs are provided.

2.5.1 System Led programs

2.5.1.1 Interruptible rates

Interruptible rates (IRs) are typical System Led programs. Through these programs, utilities generally offer fixed price discounts to customers for reducing their loads to assigned levels during peak demand periods. Customers are usually given from one to two hours advance notice before the start of the required load reduction. Utilities often require multi-year contracts with customers as a condition for the participation to the program, and usually penalize customers if they fail to reduce their loads to the levels specified in their contracts.

Even in a system where the users face variable prices and are able to respond to price variability to some extent, interruption of a certain number of selected loads is required to ensure a secure grid operation. In fact, interruption is expected to occur only in emergency situations when the economic signals do not succeed in sufficiently reducing load or the actions they trigger are not fast enough. Moreover, this kind of service may be implemented regardless of the level of liberalization of the market at hand.

The international context shows different versions of "interruptible" supply. Very often this term is referred to contracts implying a warning message to the user for a system criticality and a request of load curtailment. The complying user is awarded with a fixed or lump sum remuneration and in some cases it is up to the user to decide whether to respond.

In Italy, for example, the *Interruptible Load* programs comply exactly with these criteria: the interruptible user accepts the installation and the costs of a cut-off device, which is activated under unquestionable decision of the System Operator against a fixed remuneration. The participation to the program is voluntary; nevertheless, once the contract is agreed, the response to the interruption signal is compulsory and the control of the contracted load is completely transferred to the System Operator.

The Italian scheme considered two kinds of interruption:

- *"interruption with advance notice"*: the user receives a warning 15' in advance; after this time and in case of failing to respond, the System Operator can remotely interrupt consumption;

- *"instantaneous interruption"*: interruption is triggered without notice by the System Operator and it may occur anytime.

No limit is agreed on the time length and on the number of interruptions that can be requested during the year. The costs borne by the System Operator for these programs are socialized in the tariffs among all consumers.
More generally, interruptible supply contracts involve the formalization of a number restrictions on the frequency and on the duration of the interruptions, in order to ensure a certain degree of protection to the participating customers. These obligations are usually expressed by means of the value of some parameter such as:

- the maximum number of interruptions per month,
- the periods of the year (month/season) when the interruptions may be requested,
- the periods of the day (hours or time bands) when the interruptions may be requested,
- the maximum length of the single interruption.

The evaluation of the quantitative impact of an IR program on demand reduction strongly depends on the particular condition of the electricity system and of the type of consumers enrolled. A survey carried out in the USA and Canada /81/ showed that IR programs can bring about reductions of peak demand ranging in most cases from 4% to about 5% in the commercial and industrial sectors. The results of this evaluation is shown in Figure 3, which also reports the percentage of utilities involved with a given range of peak reduction.

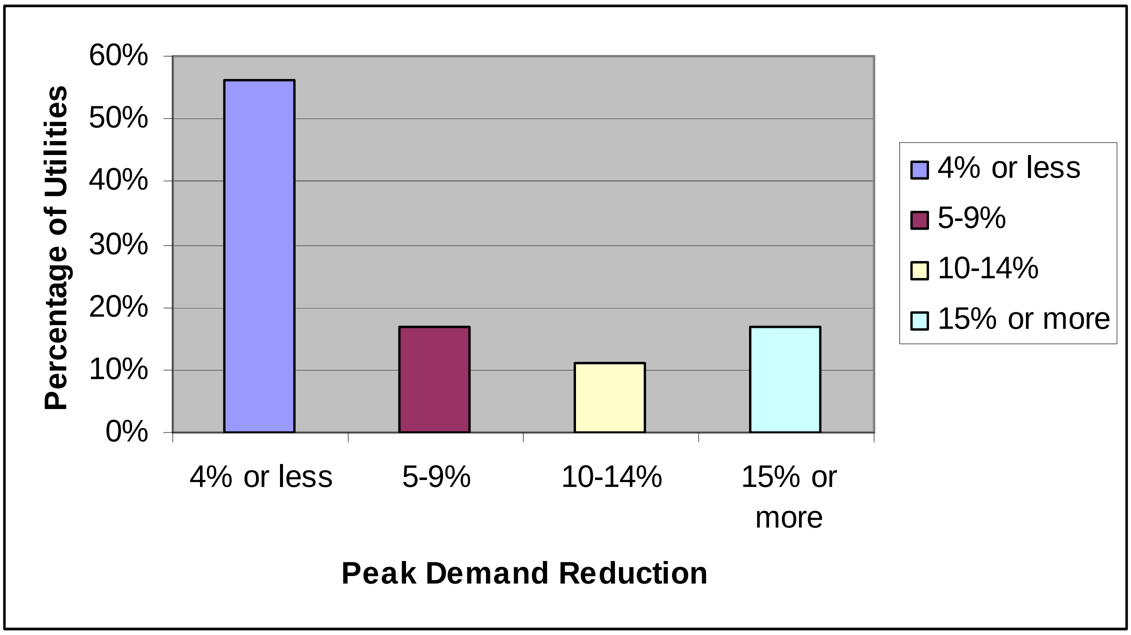

Figure 3 – IR programs: peak demand reduction in the commercial / industrial sectors (source: /81/)

2.5.1.2 Direct Load Control

Through ***Direct Load Control (DLC)*** programs, customers allow their utility to directly control their central air conditioner, water heater, or other types of major electrical equipments. Utilities cycle this equipment on and off using some type of control mechanism during peak demand periods, usually in alternating 15 minute cycles.

Utilities usually offer customers some type of rate discounts as an incentive for these programs. Many utilities have been offering these programs for 10 or more years.
The above mentioned benchmark carried out in the USA and Canada /81/ assesses the impact of DLC programs on reduction of peak demand, which ranges from more than 0% to about 10% in the residential sector. The results of this evaluation are shown in Figure 4, which also reports the percentage of utilities involved with a given range of peak reduction. A similar evaluation for DLC programs was carried out on a very restricted sample of the commercial / industrial sector, leading to an impact of these programs ranging between 1% and 9% of peak demand.

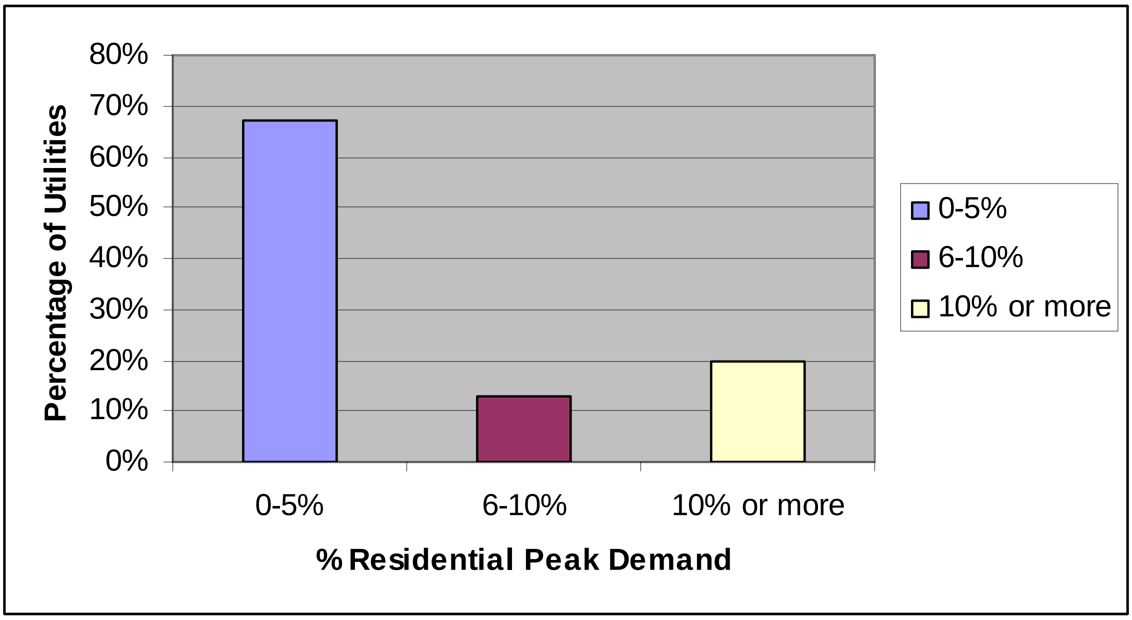

Figure 4 – DLC Programs: peak demand reduction in the residential sector (source: /81/)

2.5.1.3 Demand "Bidding" or "Buy-back" (DBB) programs

The above contractual approaches may seem to disregard the open market mechanisms and their advantages for a flexible demand. Yet, some particular versions of these schemes show less rigid features, e.g. the consumer, once warned for the need of a load curtailment, is allowed to choose to avoid the curtailment by accepting a much higher energy price (till to 50 times the usual price!).
Other versions correspond to ***Demand "Bidding" or "Buy-back" (DBB) programs***. These programs are similar to interruptible rate programs, but are designed to be more flexible and give customers more options. The rate discounts offered to customers are usually linked to spot market electricity prices in some manner. Customer participation is not mandatory and the amount of load reduction during peak periods is not predefined.

The above mentioned benchmark carried out in the USA and Canada /81/ assesses the impact of DBB programs on reduction of peak demand, which ranges from about 3% to about 9% in the commercial and industrial sectors. The results of this evaluation is shown in Figure 5, which also reports the percentage of utilities involved with a given range of peak reduction.

This kind of programs share some characteristics with the "Market Led" ones (see next section 2.5.2). Other program, such as *Demand Reduction Programs*, have features similar to DBB, but they are definitely "Market Led", therefore they will be described in the next section of this report.

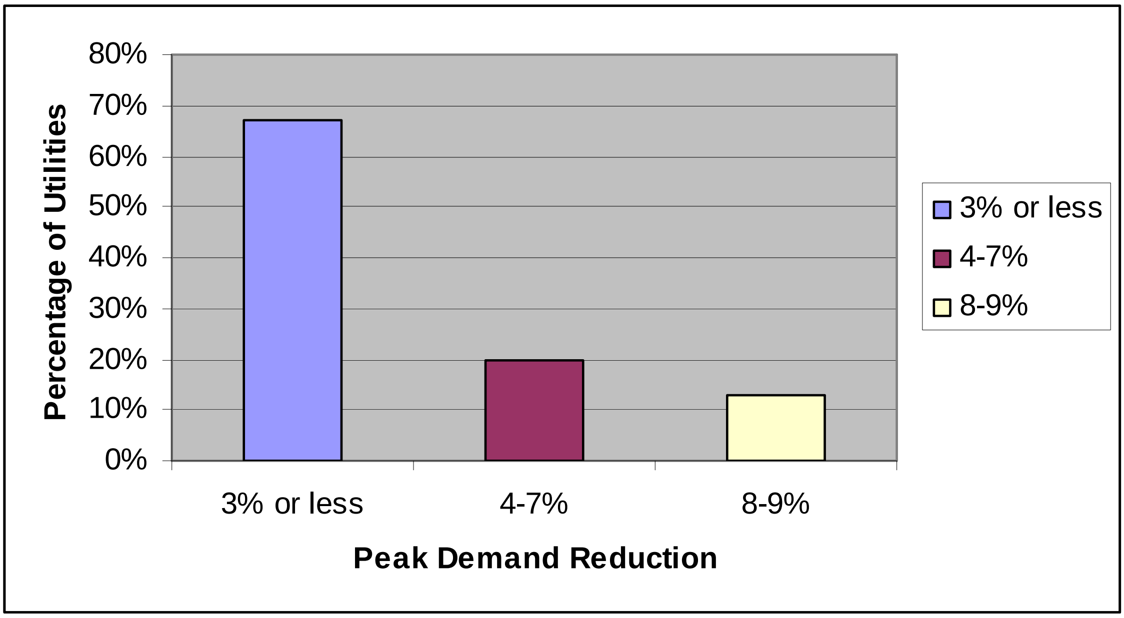

Figure 5 – DBB Programs: peak demand reduction in the commercial / industrial sectors (source: /81/)

2.5.2 Market Led programs: tariff plans and their impact on demand behavior

2.5.2.1 Tariff plans

Electricity prices show a significant variability from day to day and from hour to hour. In particular, they increase as demand approaches the upper limit of generation capacity. In fact, in such a case peak load production units have to be used, that are characterized by a low efficiency and therefore by high marginal production costs[21]. Moreover, when the power system is expected to approach its operative limits e.g. due to a foreseen increase of demand, it is necessary to strengthen the production, transmission and distribution infrastructures with new investments[22].

Yet, consumers seldom face tariffs directly related to the actual short-term electricity prices. Although the tariff plans proposed by utilities and suppliers are quite diversified, they often aim systematically at complying with the consumers' preference for a simple "flat" tariff. Such an approach prevents the consumer from responding to economic incentives when critical conditions occur for the system.

[21] These costs are known as short-term marginal costs.
[22] These costs are known as long-term marginal costs.

Some tariff plans are described in the following, which are specifically finalized at encouraging a collaborative response of demand. These plans can be classified into four categories:

- **RTP: Real-Time Pricing**,
- **TOU: Time-of-Use Pricing,** with or without a component linked to the peak of consumer's demand,
- **CPP: Critical Peak Pricing**, that is, a tariff to be applied to a limited number of days / hours corresponding to critical condition of the system,
- **Demand Reduction Programs**.

Real-Time Pricing (RTP): prices offered through these programs are tied to some type of hourly pricing benchmark, such as the power exchange price or a utility's commercial / industrial hourly pricing rate.
Prices can be communicated well in advance (one day before) or just before the reference period (about ten minutes before). Of course, the more in advance prices are defined, the less they will reflect the real-time electricity price and the less they will show its volatility.
Three kinds of real-time pricing are in force at present:

- the day-ahead pricing,
- the hour-ahead pricing,
- a quasi real-time pricing based on the ancillary services market.

In fact, real-time pricing is the most obvious (and extreme) way to encourage a demand response, nevertheless this approach is not welcome by all consumers that are accustomed to face constant prices; therefore, RTP programs are often disregarded by marketing experts in charge of designing tariff plans.

Time-of-Use (TOU) Pricing. The most common type of TOU pricing is a two time band rate that charges customers an "on-peak" price higher than the standard flat rate during daytime hours, and an "off-peak" price lower than the standard flat rate during nighttime hours and weekends. Some utilities offer a three time band TOU rate, in which, in addition to on-peak and off-peak periods, there is a "shoulder" period with intermediate prices. Many utilities have been offering two time band TOU rates for 20 or more years, while all three time band TOU rates are of relatively recent introduction.
This type of rate is usually updated two or three times a year. For this reason, it can provide neither timely signals for critical system conditions nor for hourly / daily price variations. Then, it hardly mirrors the real market prices: in other words, prices defined so in advance loose their correspondence with those defined by a spot market.
The drawbacks of this mismatch depend on the possibility of consumers to react to more accurate information. For example, TOU rates would still be the best choice in case of industrial plants capable of reacting only with a long-term re-scheduling of production, since real-time pricing would in any case not be able to stimulate any extra response.
On the contrary, TOU rates would not incentivize a possible elastic response in case of flexible consumers able to weekly or monthly re-schedule their processes.
Some implementations of TOU rates include a "power component", that entails a payment dependent on the peak of consumption reached during the billing period. Such an approach is aimed at incentivizing consumers' behaviors able to allow for a reduction of investments in new supply infrastructures, which are strictly connected to

the level of peak demand. The effectiveness of this approach is often threatened by the fact that consumers' peaks are not always synchronous with the system most critical peaks. Moreover, when the consumer reaches its maximum peak of consumption at the beginning of the billing period he/she tends to pay much less attention in controlling possible successive peaks in the rest of the period.
Thus, the efficiency of TOU tariff plans is definitely lower than RTP plans.

Critical Peak Pricing (CPP). CPP rates are similar to TOU rates, but they add a "critical peak" period and rate. The "critical peak" period corresponds only to the 1% (or less) of the hours of the year when the utilities' production costs or power purchase costs are the highest. Electricity prices during this period are higher than the regular TOU on-peak prices. These programs all started in 2001 or later.
Two limitations characterize CPP programs, even if they contribute to make them more acceptable to consumers:

- the maximum prices during critical periods are predefined, therefore they do not reflect a real-time cost of energy;
- the contracts usually define an upper limit to the number of critical peak hours in the year.

2.5.2.2 Demand Reduction Programs

Demand Reduction Programs are activated by the System Operator when critical conditions occur. The System Operator offers a remuneration to consumers willing to reduce their demand when they receive a signal. Usually, a fixed-value reward is agreed, which does not depend on the level of criticality of the system.
These programs consist substantially of a sort of "capacity buy-back", since the consumers' demand curtailment in fact releases a corresponding amount of previously engaged generation capacity.
A weakness of this kind of programs is the complexity in defining the amount of "demand reduction" to be rewarded: in fact, a "not consumed" quantity can hardly be measured. As a consequence, these programs usually include an agreement on the measurement of demand reduction with respect to a reference *baseline* depending on the historical consumptions of the consumer.
The USA experiences in this sector evidenced two sorts of problems:

- due to the voluntary character of the program, it would be subscribed especially by consumers who forecast consumptions lower than the baseline (defined, for example, on the basis of the average consumption of the previous year), and not by consumers who expect growing consumptions and that would be more desirable and effective to enroll: this is a typical case of "reverse selection";
- the customer could be induced to increase his demand when the program is not active, if he is aware that this would increase his baseline: this behavior would be against a rational and efficient use of energy all over the year.

Compulsory (instead of voluntary) participation has been proposed to overcome these drawbacks, even if this solution could raise fairness questions.
Moreover, it has been recommended that the definition of the baseline be dynamic and based on recent periods (e.g. the average of hourly consumptions of the last ten days

when the program is not active), possibly corrected with the actual consumptions during the two hours immediately before the activation of the program.
As an alternative, in case of consumers operating in the power exchange, their hourly demand reduction could be calculated as the difference between their accepted bid (that represent the contractual commitment for withdrawal) and the metered energy really withdrawn in that hour, when the program is active.

2.5.2.3 Comparisons and benchmarks

It must be remarked that Demand Reduction Programs require the same metering technologies and about the same amount of exchanged information with the Market and/or the System Operator as CPP and RTP programs.
Moreover, Demand Reduction Programs involve limited consumer's responsibility, since they refer to a fixed tariff and they reduce the bill starting from this amount. However, the same result could be obtained more effectively by means of CPP or RTP programs, which prevent problems and possible conflicts connected to the definition of the baseline.
In conclusion, the more a tariff plan reflects the behavior of the actual energy prices (in terms of values and time), the more a flexible response to energy prices is effectively fostered.
TOU rates, though much more flexible than a single fixed price, reflect the real behavior of the electricity market prices only in a "damped" and partial way. In fact, TOU rates are fixed well in advance and are corrected only a few times a year. For this reason, they basically refer to the average electricity prices within the reference period and then they fail to signal actual criticalities of the system to the consumer.
Price variability on smaller and smaller time scales could theoretically more effectively encourage a demand flexibility. However, the success of this kind of programs is strongly related to the actual willingness and possibility of consumers to respond accordingly.
The benchmark carried out in the USA and Canada /81/, already mentioned in the previous section 2.5.1, gives some information of the impact of such programs.
Participation in TOU, CPP, RTP and other types of residential DR programs is generally low, ranging from almost zero to 4% of eligible customers. For CPP and RTP programs, the low customer participation is not surprising, as all of these programs have been in operation only for a few years and most of them have been implemented as pilot programs.
Only one surveyed utility has enrolled a significant number of its customers on a voluntary TOU rate. This company estimated that his TOU rate program involved about 6% of his residential peak demand.
Moreover, utilities reported very limited demand reduction estimates for TOU, CPP, and RTP programs in the commercial and industrial sectors. Only one surveyed utility reported an impact of these programs greater than 1% of its commercial / industrial peak demand.
Supplementary information of the impact of RTP programs in the considered sectors can be found in /82/.

2.6 Role of Demand Response aggregators

The single consumer sometimes find it difficult to participate directly and individually to the energy market or to programs aimed at curtailing demand. In fact, participation to the market turns out to be viable only for large consumers, due to the remarkable administrative costs. On the other hand, as far as DR programs are concerned, small or residential consumers must face different problems concerning communication, information, operation and management.

Nevertheless, a Demand Response *aggregator* (or provider) can allow this wide class of consumers to participate to DR programs acting as an intermediary between the consumers and the power exchange or between the consumer and the utility.

His most usual skills range from coordinating this pool of users to transmitting them information and signals to trigger the response. Normally, the aggregator is also able to negotiate a contract or an agreement on behalf of the consumers he represents.

This role can be undertaken by an energy supplier, a consortium or any body capable of gathering and involving a significant group of consumers.

The role of aggregators is very important for the implementation of Demand Response programs, due to a number of reasons.

- First of all, System Operators and utilities find it simpler to involve and to correctly inform a small number of aggregators than a wide number of small consumers, in particular during the start-up phases of programs in a region of in a country.
- The aggregator can more effectively enroll consumers by adopting communication strategies specifically tailored for the class of users it represents (consider, for example, a consortium of industrial users located in the same zone). Moreover, the promotion of a change of consumption patterns will become easier with a joint action on grouped consumers than with a multiplicity of individual actions on single consumers: this approach is based on an increased awareness and participation as social values.
- The aggregator can collect, educate or to engage the human resources needed to competently set up Demand Response programs. Alternatively, it may own the knowledge to design programs to be submitted to the System Operator, to utilities or to local suppliers, based on the specific flexible features of his clients' loads. For these reasons, it can be considered a privileged counterpart of the entities interested to implement DR programs.
- Finally, in case the aggregator is also an energy supplier / trader, it can directly offer in the energy, balancing and ancillary services markets the demand side management capabilities of its aggregate of flexible customers.

  The aggregator / supplier will then share the profits of the virtuous behavior of its clients with the clients themselves, according to the commercial clauses of the signed contracts.

2.7 The flexibility of demand as a reserve service

The elastic behavior of demand can bring advantages to the electricity system also from other viewpoints.

As above mentioned, DR can play an important role not only in the main (typically, day ahead) energy markets, but also in the balancing and in the ancillary services markets.

In such a case, DR can provide ex-ante (with respect to real time) resources to resolve foreseen congestion and to set up adequate operating reserve margins, while in real time

it can actively concur to balance generation and load, as well as to effectively tackle with contingencies.
Balancing and ancillary services have traditionally been provided only by generators. Moreover, the importance for security of supply of such kind of services makes the related markets much more profitable (per unit of energy) than energy markets (both day ahead and over-the-counter bilateral markets). Thus, the participation of new players, such as DR, in such markets can increase the level of competition and reduce the possibility of market power exercise by producers, thus greatly increasing market efficiency. In fact, it must be taken into account that ancillary services markets are more exposed to "local" market power exercise by producers, since the location in the network of a generator can be very important for the provision of the service the System Operator needs, regardless of the position in the economic merit order of the related bid submitted by the generator.
Traditionally, System Operators prefer to procure these services from electricity producers for a number of reasons:

- producers turned out to be highly reliable in supplying ancillary services, while flexible load has not yet a track record in this field; since ancillary services are essential for the secure operation of the system, the reliability of their provision is very important;
- the contractual terms and the adopted standards in this sector have traditionally been developed for the production units;
- usually, the organization of System Operators tends to involve preferably a small number of large suppliers, i.e. producers (in this case, the above mentioned aggregators could play an important role).

Nevertheless, Demand Response programs, in particular the *reliability / emergency programs* of the System Led class, are specifically designed to provide operating reserve capacity, complementary to the one provided by generators.
An advantage of the flexibility of demand as a reserve service is also given by its location in load centers, i.e. the most congested regions where the need of reserve is more crucial.
The costs of interruptible rates (or of similar Demand Response programs that can provide reserve services) are systematically much less than those deriving from the installation of new production capacity. Then, the exploitation of this resources can at least contribute to delay the need for new generation units; moreover, it can contribute to relieve system critical conditions in the shorter term, while new generators are being built.
On the other hand, the participation of demand to the ancillary services markets, where possible, is still restricted to quite large industrial or commercial consumers or to aggregators capable of complying with the contractual, metering and communication requirements. Yet, many efforts are being devoted to increasing the number of consumers who can potentially be involved in such Demand Response programs.
For example, FERC[23] proposed in the USA some adaptations to its regulation aimed at qualifying a growing number of consumers for participation.
The National Grid Company, the UK System Operator, devised specific methodologies to encourage participation of demand, in view of a wider market competition and the consequent reduction of the prices of ancillary services.

[23] Federal Energy Regulatory Commission, the US regulatory agency.

3 Demand Response technologies

The main requirements to be met by a Demand Response resource are:

- its ability to react when it is needed,
- the possibility of measuring its response.

Tools and systems have been developed, that range from metering and IT infrastructures able to activate a DR asset, to software products that manage a DR asset portfolio.
It is deemed that the fast growth of the Demand Response industry was made possible by the improvement and wide scale deployment of Internet communications in the late 1990s. Internet technologies made “one-to-many” and “many-to-one” communication capabilities less expensive and more reliable in a very short time.
Prior to the development of the Internet, traditional utility load curtailment programs were dispatched manually, usually by telephone or fax machines. This approach worked and used state of the art technology at the time, but it was labor intensive and prone to human errors.
Today, systems can be set up to monitor energy markets and automatically control load consumption according to user preferences. In addition, with the right equipments and contractual agreements, a control room operator can manage a grid problem by activating Demand Response resources near a specific substation.
The primary reason for using any DR technology is to improve the speed, accuracy, and ease at which DR resources are available as additional energy and capacity in the energy market; this features allow DR to be used in ways that were not viable 10 years ago.

3.1 Functionalities of Demand Response technology

The following basic functionalities need to be incorporated into a DR program:

- notification of the event that triggers the response,
- measurement of the load profile,
- verification of the compliance of the response with the contractual agreement,
- settlement of the economic reward,
- automated load /generator control.

The technologies that enable the above functionalities are:

- Information & Communication Technologies (ICT),
- load management and automatic load / building / plant control technologies,
- Advanced Meter Reading (AMR),
- distributed generation (for back up generators).

In the following each functionality is analyzed in more detail.

3.1.1 Notification

A Demand Response can be activated provided the consumer is properly notified. Notifications can be sent to the user, for example with telephone calls or electronic messaging, or they can be directly sent to a device, such as a residential thermostat.

The important things to consider here are the speed that is required for sending notifications, the volume of notifications that must be sent, and whether a direct intervention of the consumer is required[24].

If a DR program only involves a few participants, a manual solution may be best. However, if there are dozens, hundreds, or even thousands of participants, the best approach could be the use of an automated system.

An automated solution can send out phone calls to hundreds or thousands of individuals almost instantaneously via today's Internet telephony communications. These services also provide the ability to record the time when the notice was sent, the person that received the notice, and provide them with the option of accepting or rejecting the participation (subject to program rules).

The record keeping and event tracking function of some automated notification systems can provide useful documentation when a DR program requires mandatory compliance. These information could be very helpful when significant amounts of money are involved.

3.1.2 Measurement

By definition, Demand Response is provided by end use consumers, therefore it is necessary to measure the energy that the consumers use and when they use it.

There are a variety of ways to measure consumer loads. There are simple ways to do it using *load profiling*, i.e. a statistical sampling methodology used to extrapolate usage patterns of consumer classes. There are also extremely sophisticated SCADA Remote Terminal Units (RTU) that provide load data to a remote control room almost instantaneously.

Assuming that load profiling and RTUs are the extremes, there is a plethora of solutions that fall in between. Recent improvements in communication technologies made some other solutions fast, reliable, and cost effective. Load data can now be transmitted via powerline carrier, radio frequency signals, telephone, and/or the Internet.

There are certainly pros and cons for each of these options, but the existing variety of communication systems allows the DR program designer to use the most suitable solution(s) for his/her DR program portfolio.

It is also likely that different types of DR programs are characterized by different speed requirements for data communication. For example, when DR is used for spinning reserve, the System Operator's control room needs to have almost real-time data transfers. On the other hand, in case of a DR program for residential load control, a monthly data acquisition may be sufficient.

It is also important to ensure that the right data are being collected. As a general rule, the electric industry tends to operate in hourly intervals (e.g. hourly wholesale prices per MWh, etc.). This implies that load measurement should at least be performed at hourly intervals as well. Yet, some DR programs may require 5-15 minute intervals, which exceeds the usual industry standard. Then, it is important to make sure the involved communication mechanisms and the metering devices are consistent with the requirements of the DR program at hand.

[24]For example, if the DR program incorporates automated HVAC controls, then a simple notification on the thermostat informing the consumer that DR has been activated may be sufficient. However, if an industrial consumer is required to shut down a production process within a specific amount of time, then direct communication with a transaction validation process may be more appropriate.

3.1.3 Compliance

The success of a DR program is measured by its quantitative impact on consumptions. Therefore, it is necessary to define the methodology for calculating the consumer's compliance to the DR program requirements (also known as DR event performance level).
There are three basic ways to do this today.

- *Baseline* The baseline methodology is used to pay consumers for load variations with respect to their expected level of consumption. In other words, a consumption forecasting algorithm is used to estimate how much the consumption would be for each hour of the day, based on normal operation. This is then compared with the actual meter measurement for each hour. The DR event performance level would then be calculated as the difference of the two data. Usually the baseline is calculated on the demand of the previous 10 business days. However, this methodology is based on the expected consumption levels and it often faces calculation errors and/or "gaming". The users of this methodology have then developed business rules and monitoring techniques to mitigate these adverse effects.
- *Direct resource metering* If, for example, a consumer has an onsite generator for emergency backup purposes and this generator is activated when the DR event is triggered, then the direct measurement of the generator's production can be used to establish the compliance level. This strategy is generally reserved for onsite generation assets, but it can be used in a variety of other scenarios as well.
- *Real time pricing* In the previous two cases, the consumer is basically selling his/her load reduction or onsite generation to the market. The compensation is related to the deviation from the baseline or to the metered generator's output. Real-time pricing tariffs prove to be the purest form of consumer response. In this case, the consumer is simply charged the hourly energy price for his/her hourly consumption. This strategy is an excellent way to directly match consumer demand with market supply. However, it may also be difficult to implement these programs to all classes of users since electricity tariffs have often complex structures and social policies use the tariffs as a means to protect some classes (e.g. low income) and to incentivize others (e.g. industry). They also tend to normalize costs over a 12 month period.

3.1.4 Settlement

Settlement is basically the system for managing the billing and the payments among the actors involved in the Demand Response programs.
The settlement system should store and process data concerning measurements of consumptions, electricity market prices, event performance levels for compliance and individual contract terms.
Unless the consumer is directly connected with the power exchange, which is usually reserved to the very large consumers, there are two primary settlement flows that require different systems:

- between the power exchange / wholesale market and the DR service provider (e.g. aggregator, distribution company, energy supplier, etc.);
- between the DR service provider and the consumer.

3.1.5 Automated controls

Some people consider this last category optional, while others consider it mandatory. There are a number of technologies available today that can remotely and automatically control predetermined loads. For example, residential load control technologies are available to modulate HVAC, electric water heaters, pool pumps, lighting, etc.
These technologies allow a DR service provider to instantly shed many loads at a time. The concept has also been expanded into many commercial facilities in recent years. For example, several firms produce remote lighting dimmers. These devices can either lower light levels or turn off predetermined light banks.
At a more sophisticated level, building automation control systems can be programmed to respond to electricity market prices instead of just to demand levels. By doing this, they are able to implement strategies based on a trade-off between comfort and cost.

3.2 Technology needs of Demand Response actors

Any actor in the Demand Response business plays a specific role that drives the need for specific technologies. What follows is a brief description of the technology needs of consumers, DR service providers, and System Operators.

3.2.1 Consumers

Consumers tend to use technologies that help monitoring their facilities load levels and control specific energy using equipments.
Monitoring technologies tend to focus on metering devices and on software systems to analyze the load data provided by the meters.
Control technologies range from dedicated controls (e.g. lighting controls) to sophisticated building automation systems.
These systems are also sometimes able to accept a signal from the DR service provider (or a price signal coming from the power exchange) on the basis of which to take automated DR decisions.

3.2.2 DR service providers

DR service providers are in the business to connect consumers to DR opportunities. In order to effectively do this, many of these players use technologies that give them remote control capabilities over specific consumers' loads (e.g. HVAC systems, water heaters, building automation systems, etc.).
They use these systems to aggregate many flexible consumers and then to sell on the market or to the System Operator the resulting "critical mass" in terms of Demand Response capacity.
DR service providers also have two other key needs. First, they need to be able to rapidly communicate with dozens, hundreds and sometimes with thousands of consumers simultaneously in order to alert them about DR events. In order to do this, Internet is a key enabling technology. Moreover, these communication systems need to be able to track who received the notification and when it was received. This audit trail is very important for any dispute resolution process.

Secondly, they need to be able to properly settle transactions with both the wholesale market and with the consumers.

Depending on the DR program in question, some DR service providers use metering devices that can communicate via the Internet in virtually real-time with limited communication costs. On the other hand, if the situation does not require that level of communication speed, they can acquire the information via the normal meter reading cycle.

Regardless of how and when they acquire the data, they will need some type of system to manage the data they receive, to correlate them with the DR event performance level of each consumer, to reconcile them with the wholesale market transactions and to settle payments with their counterparts.

Some Internet based software packages are available that specifically focus on satisfying the above needs.

3.2.3 System Operator

The System Operators tend to have similar needs as DR service providers in that they need to exchange information with third parties, which can be either the DR service providers or directly the individual consumers.

They need to manage large volumes of metering data, they need to validate DR event compliance (sometimes at the consumer level) and they need to properly settle payments with their counterparts.

4 International review of Demand Response experiences

An Implementing Agreement of the International Energy Agency (*Task XIII - Demand Response Resources*) /80/ /81/ to which ERSE participated, provided first-hand information on Demand Response experiences in the different participating countries. Direct contacts with the involved stakeholders improved and widened the available knowledge on practices concerning Demand Response and on relevant projects and programs under way in the industrialized world.

The classification considered in paragraph 2.5 for Demand Response programs is widely accepted within this international context, though a univocal and standardized terminology has not been officially agreed yet, since a debate is still open on several relevant aspects.

The most significant experiences in different countries are reviewed below.

4.1 The USA experience

USA is the richest country in terms of number of DR programs. The dimension of the country and the consolidated presence of a liberalized electricity market are the main reasons.

61 DR programs were reviewed in the USA, which were classified into the following categories:

SYSTEM LED PROGRAMS

- 16 programs devoted to reliability of the system and to reserve services
- 2 programs based on Direct Load Control

MARKET LED PROGRAMS

- 35 programs connected to demand side bidding in the electricity market
- 8 programs of Real Time Pricing, with prices defined by the electricity market

Table 2 reports information about the main characteristics of the four above typologies of DR programs.

	SYSTEM LED		MARKET LED	
	RELIABILITY / RESERVE	**DIRECT LOAD CONTROL**	**DEMAND SIDE BIDDING**	**REAL TIME PRICING**
Sponsor of the program	ISO, Distributors, Regulatory Authorities	Aggregators, Curtailment Services Providers	ISO, Aggregators, Traders, Local Authorities	ISO, Aggregators, Traders, Local Authorities
Eligible participants	Commercial, Industrial, Residential, Aggregators, Consortia	Commercial, Industrial, Residential	Commercial, Industrial, Residential, Governmental, Agricultural	Commercial, Industrial, Residential
Time for advance notice	From 10 minutes to 4 hours	No notice	From 1 hour to 2 days	From 30 minutes to 1 day
Evaluation of compliance	Deviation from baseline	Not applicable	Deviation from baseline	Deviation from baseline
Voluntary / Compulsory	Voluntary / Compulsory + penalties	Compulsory	Voluntary + commitment to a DR program	Voluntary + commitment to a DR program
Minimum threshold for participation	From 100 kW to 3 MW	Not known	From 50 kW to 1 MW	From 250 kW to 5 MW
Tunable load (amount of power peak)	From 0.4% to 1.2%	8%	From 0.4% to 4%	Not applicable

Table 2 – Summary of DR programs reviewed in the USA by the IEA Task XIII

The following Table 3 shows details on four significant DR programs, one for each of the four above typologies.
Two of such programs are sponsored by the New York State System Operator (NYISO):

- the *System Led* program *“Emergency Demand Response Program (EDemand ResponseP)*
- the *Market Led* program *“Day-Ahead Demand Response Program (DADemand ResponseP)”*.

The former program (*EDemand ResponseP*) consists of a mechanism for the load curtailment in emergency conditions. The program involves interruptible loads and back-up producers. It is characterized by a time for advance notice of 2 hours and a length of interruptions of 4 hours. Load reductions are rewarded with the highest between 500 USD/MWh and the current locational marginal price. The base price of 500 USD/MWh has been applied in 2001 and 2002 to almost all the involved loads.
The latter program *(DADemand ResponseP)* allows demand resources to offer their load curtailments in the day-ahead market. This program involved in 2003 an amount of demand equal to 2.6% of the peak load.

	RELIABILITY / RESERVE	DIRECT LOAD CONTROL	DEMAND SIDE BIDDING	REAL TIME PRICING
Program Sponsor	NYISO Emergency Demand Response Program	Xcel Energy C&I interruptible rate program	NYISO Price Response Program	PPL Demand Side Initiative Rider
Total Number of Participants	1111	200000	389	
DG[25] Number of Participants	311	200000	NA	
Number of Participants (Load Shedding)	800		389	
Participating DG[25] (MW)	278	465.3	NA	
Participating Load (MW)	301		NA	
Total participating capacity (MW)	579	465.3	802.1	
Marketplace Peak Demand (MW)	30,983	5593	30,983	
DR Percentage of Peak Demand	2.08%	8.3%	2.6%	
Amount Paid to Participants	$4,000,000		$3,300,000	
Period	May 1, 2001 – Oct 31, 2005		May 1, 2001 – Oct 31, 2003	Weekdays – All Year
Eligible Participants	LSE, Aggregators, Curtailment Service Providers, Customers		LSE (2001 & 2002) expanded to Demand Reduction Providers in 2003	C&I Customers
Eligible Load	>100 KW per NYISO Zone		>1 MW per NYISO Zone	>1 MW
Call criteria	Lack of operating reserve or other emergency state		Participant bid	N/A – Real Time Pricing
Response period	2 hours		Bid by 5 AM the day ahead, notice by noon	Each day, by 5 PM, hourly energy prices are posted for the next day
Respondent option	Voluntary		Voluntary; however, if the customer's bid is accepted, he/she must participate or pay penalties (Locational Marginal Price + 10%)	Voluntary
Duration	Four hours minimum call		As bid	N/A – Real Time pricing
Compensation	The highest between 500 USD/MWh and the current Locational Marginal Price		Greater than LBMP or bid for actual interruption	Customer is exposed to the actual market price for electricity, so indirect compensation occurs if customer reduces or shifts loads
Baseline criteria	The highest 5 of the 10 last days		The highest 5 of the 10 last days	Based upon the previous year's consumption data
Evaluation of compliance	Deviation from the baseline		Deviation from the baseline	Deviation from the baseline
Payment channel	NYISO⇨LSE/CSP⇨end-use customer		NYISO⇨LSE/CSP⇨end-use customer	Net costs or savings are charged on monthly bills
Metering method	Hourly interval meter		Hourly interval meter	Interval meter with phone line
Notification period	2 hours advance notice via the Internet, email, phone, pager		Day ahead notification over the Internet	Interactive website
Software requirement	Internet		Internet connection with the ISO	Internet
Program fees	None specified		None specified	$350 per month

Table 3 – Additional details on four specific DR programs reviewed in the USA by the IEA Task XIII

[25] Distributed Generation.

Some initiatives undertaken in California in the field of DR deserve some particular attention, with special reference to results obtained by Critical Peak Pricing programs.
A 2004 study /5/ reports the results of a pilot Critical Peak Pricing program showing that the elasticity obtained by this program, which was applied 75 hours/year in 15 days, is higher than the one derived by Time-of-Use pricing programs.
This difference seems to show that the signals of load curtailment in a Critical Peak Pricing program, since they are connected to a system emergency situation, are considered by customers more worth of attention and essential for security of supply than the "generic advices" for a rational use of electricity that are provided by TOU tariffs.
This conclusion, greater effectiveness of CPP than TOU, is accepted and shared among several experts /6/. The level of acceptance of this tariff scheme among the residential and commercial users is very good too, with values to about 80% of the involved consumer group.
Savings on the bills are really significant for residential customers with low/medium consumptions, whereas some cases of penalty occurred among high consumption residential customers /7/.
It must be remarked that considerable efforts are in progress in California, aimed at informing the public on the opportunities offered by a rational use of electric energy: this policy is fully in line with the traditional cultural approaches of this State[26].

4.2 Experiences in Nordic Countries

4.2.1 Demand Response to tune consumption

Among the European countries, the Scandinavian ones - Denmark, Norway, Sweden and Finland - belonging to Nordel (the Nordic power system) are particularly active in Demand Response programs.
An interesting evaluation of the potential demand which can be activated by DR programs is shown in published reports /8, 9, 10, 12/.
In fact, in 2004 about 2000 MW of tunable load were available as actual operating reserve and further 1600 MW could have been activated by means of other programs. This corresponded to a total tunable load of about 3600 MW, equal to about 5.3% of the total peak load over the whole area (about 68.000 MW).
Nevertheless, it is estimated that at least further 8000 MW could be potentially involved by means of suitable short-term programs, that means an amount of about 15% of the peak load of the whole Nordel system. In fact, actions are in progress in Nordel countries aimed at activating DR programs, that are considered a strategic resource to handle possible lack of generation capacity[27] in the near future.
A remarkable amount of the tunable load in Scandinavian countries comes from energy-intensive industry, by means of voluntary bids submitted to the day-ahead market, particularly during winter days and high load hours. Denmark is as an exception, since it does not own heavy industries and consequently DR comes from small/medium consumers.

[26] See e.g. the website www.caiso.com of CAISO, the California ISO, and the website www.energy.ca.gov of CEC, the California Energy Commission.
[27] For example in Norway almost all generation capacity is hydroelectric, therefore highly exposed to the variability of rain in different years.

As for household consumers, a reduction of the electricity demand is carried out by switching to other energy sources for hot water and space heating, depending on the prices of electricity. On the other hand, the elasticity deriving from fuel switching is not suitable for response to peak prices occurring in short or very short times.

A growing acceptance of DR programs was observed when high increases of electricity market prices occurred (relatively few in the Nordel market, but more frequent in Western Denmark). The increasing trend of this positive attitude, even for small size consumers, is proportionally related to the frequency of occurrence of these high price events. The acceptance further increases with informational campaigns devoted to improve consumer awareness, that is usual practice in Sweden.

As for tariffs, a solid experience exists in Finland and Eastern Denmark on TOU tariffs in the industrial and in the residential sectors.

Real-Time Pricing programs are operated in Norway: reference is made to day-ahead market prices (with an additional amount covering other costs) in some programs, whereas price adjustments with a two weeks advance notice are carried out in other programs.

In these cases, devices able to automatically respond to the level of electricity prices (e.g. a switch that opens when a predefined price threshold is exceeded) are the most suitable tools for small household users; some examples of this kind of applications are under way in Norway for water heaters.

Less “extreme” experiences in Denmark, Finland and Sweden showed that frequent adjustments of regulated electricity prices can lead as well to some elasticity of demand, though less effectively than with the adoption of RTP.

A pilot project has been running for some years in Denmark in the frame of the European project *SAVE / Efflocom* /11/, which is devoted to electric residential heating. The project involves 25 dwellings and the developed tools allow the user, through an Internet portal, to carry out the following actions:

- to define a different priority degree for heating in five zones of the house,
- to define a possible interruption time for heating, as a function of the corresponding economic reward, which in turn depends on how severe are the market conditions.

The pilot project allows the test of ICT solutions and the evaluation of the characteristics of the user response to the signals concerning the price and the time-span of the interruption. The project is expected to grow with the inclusion of a much higher number of participants.

Load peaks have impact also on transmission and distribution lines. TOU tariffs have been applied also to transmission and distribution services to draw users’ attention (and their response) on such problems. A demand response to this kind of criticality allows to reschedule investments for the development of the grid.

Tariffs are in force in Norway and in Sweden aiming at controlling the maximum load. Typically, consumers of a significant size pay annual tariffs of about 30.000 - 40.000 € per MW of available installed power; then, compliance to these DR programs can bring about for example a 4.000 €/year saving in case of users capable of curtailing their maximum power withdrawal from 1.0 to 0.9 MW.

4.2.2 Demand Response as operating reserve

As above mentioned, Demand Response can provide operating reserve services together with conventional generation units.

For example, *Svenska Kraftnät* (the Swedish TSO) signed bilateral contracts with DR resource suppliers to secure the needed operating reserve /12/. This reserve amounted to 440 MW in the 2003-2004 winter (equal to about 1.5% of the Swedish peak load). Additional *"fast disturbance"* reserve was contracted for about 90 MW.

Fingrid (the Finnish TSO) signed long-term bilateral contracts to secure an amount of DR services of about 1030 MW (in 2004) and some further 70 MW were planned within 2006. Nevertheless, demand offered more capacity than it was needed, showing that there is an additional potential for the development of DR.

Fingrid also purchased 365 MW of *"fast disturbance"* reserve from large industry. This kind of load reduction can be activated with an advance notice of 15 minutes, after the intervention of other regulation resources. 130 MW of this reserve can also be used as automatic "frequency-response" reserve.

Norway implemented a reserve market with the participation of demand. This participation explains the remarkable industrial investments in this sector for the implementation of the required technical and administrative procedures. Besides, Norwegian supply contracts generally refer to a variable price depending on the electricity market; this mechanism automatically stimulates DR programs connected to the seasonal variation of the electricity price.

Statnett (the Norwegian TSO) established in 2000 the *Regulation Capacity Options Market* (*RCOM*), with the goal of ensuring a suitable amount of reserve when voluntary offers are not sufficient. It works according to a model of Demand Side Bidding and involves variable amounts between 500 and 1800 MW, according to the needs. The price is defined by matching supply and demand bids. This market turned out to be very effective in providing a demand-side reserve: in fact, during February 2002 about 70% of reserve (about 1300 MW over a total of 1800 MW) was provided as Demand Response /13/.

Moreover, bilateral agreements were signed by *Statnett* with large industries who are available to an automatic interruption of load in case of criticalities in the transmission grid, for a total of 500 MW located in four critical zones.

In Norway, again, the distribution companies are compelled to offer discounts to clients who accept an Interruptible Rate contract and the corresponding discount depends on the time for advance notice (15 minutes, 2 hours and 12 hours). During the 2001-2002 winter, an amount of about 800 MW was made available as a consequence of this policy, whereas it fell down to 200 MW during the following year, since the overall demand reduced as a response to the very high prices reached by electricity in that period.

On the contrary, in Denmark demand cannot participate to the reserve market.

4.3 Other European countries

A well known European DR program is the *"Tempo"* tariff, which has been implemented in France by *EdF* since 1995. This tariff pertains to the Critical Peak Pricing class.

It entails, during the year, 300 *"blue"* days (with a low tariff), 43 *"white"* days (with a medium tariff) and 22 *"red"* days (with a much higher tariff). The type of each day is defined by EdF within 16:30 of the previous day; when possible, the definition is also given for the following days.

The *"red"* days are placed only between November 1st and March 31st, since the peak load is reached in France during the winter period.

The prices applied to the three tariff groups are very different:

- 5.44 c€/kWh (including taxes) in "blue" days,
- 10.50 c€/kWh in "white" days,
- 45.71 c€/kWh in "red" days.

As a matter of fact, the price of energy in "red" days is 8.4 times higher than in the "blue" days. The "color" of the day is shown on the meter and additional notices can be available by e-mail or through the Internet /14/. Moreover, the electric heating can be directly controlled on the basis of price signals.
This tariff is applied to about 500000 users; 350000 of them are household. The typical average curtailment of demand in the "red" days is about 1 kW per dwelling.

5 Development of business plans concerning Demand Response

This chapter will deal with *DR Business Models*: it will discuss opportunities and challenges for the various players involved in Demand Response, considering the type of services that they intend to provide with an estimate of the future revenue and costs and the obstacles that may prevent to achieve the desired goals.

5.1 What is a DR Business Model

A business model can be defined as the methodology according to which a business provides a product or a service to a consumer. In this context, the business model must identify who is the target customer, how the business will produce the product or the service, and how the business will earn a profit from its efforts.
The number of possible business models is limited only by the creativity and strategy of a business leadership team.
Some businesses are structured so that they make a product and sell it directly to a consumer. For example, vertically integrated electric companies produce power and sell it to the end-user. However, there is a variety of indirect models that can also be profitable. For example, Google, the major Internet search engine, earns most of its revenues from selling targeted advertising space to other businesses, instead of charging the end-user of the search engine. Both of these examples are strong, viable business models. They approach their respective markets in different ways, but they have a clear strategy for product development, sales, and business profitability.
There is also a variety of business models in the Demand Response marketplace. In general, the specific business model tends to be driven by the perspective of the market player that is implementing it. For example, an Energy Retailer may offer DR services in order to help manage its own supply portfolio, while an Energy Service Company may believe it is in a unique position to offer DR services since it has the ability to monitor and control certain consumer loads. Both of these players are certainly in a position to offer DR services, but they would follow different approaches according to their different market perspectives.
In order to set up a DR Business Model, it must be taken into account:

- who is the market player,
- what motivates the market player to enter the business,
- how the market structure works.

These issues will be discussed in the following sections.

5.1.1 Market players

The *Project Guidebook* summarizing the IEA Task XIII results /80/ /81/ identified the following DR market players:

Participating Consumers - By definition, Demand Response is a resource provided by end-use consumers. Consumers can provide the resource by selling back “unused power", by activating onsite generation or by participating in a Real Time Pricing tariff structure.

Local Distribution Companies (LDCs) - These players are natural monopolies responsible for distributing power to the local community. Depending on the market structure, they may be vertically integrated (from the generation to supply) or they may just be responsible for operating the distribution network.

Energy Retailers - These players are responsible for the procurement and scheduling of electricity on behalf of its customers. Again, depending on whether the market is liberalized or not, this role may be included in a vertically integrated company or it may be a stand alone retail marketing company.

Demand Response Service Providers (also called DR Aggregators) - In many cases, the DR Service Provider is either the LDC or an Energy Retailer. However, the growth of the Demand Response sector over the last few years gave birth to a new breed of third party entities. These players aggregate DR capacity by entering into contracts with participating consumers. In some cases, the aggregators have bilateral agreements with the LDC or with Energy Retailers to market and manage DR activities. In other cases, they are able to aggregate the DR capacity and offer it directly to the power exchange like any other generation resource.

Energy Service Companies: These players provide DR technologies that enable DR capacity. By their nature, they market and sell products and services that can help the participating consumers to manage, monitor and activate DR capabilities. Many of these players act as DR Service Providers, too.

System Operator - The system operator is responsible for managing the transmission system to ensure a secure and reliable power supply. In some cases, the system operator also manages a power exchange with energy and / or balancing and ancillary services markets.

There are two other categories that should be taken into account: **Regulators** and **Society**. These entities may not be direct DR market players but the former can influence the development of DR programs by defining rules and the latter is an indirect beneficiary of DR by means of lower total energy costs.

5.1.2 Benefits and challenges of DR

The next thing to consider is how the market players can benefit from DR activities and the challenges they must face.

Participating Consumers

Benefits: The participating consumer is the entity that actually provides Demand Response. This entity generally benefits from a direct economic reward that could be some percentage of the electricity market price, a regular capacity reservation payment / call option, a reduction of electricity rates, a combination of the above, and/or some other mechanisms. However, there is also a growing interest by many consumers to participate to DR efforts simply because it is a good thing to do as a “corporate citizen”. In this case, they may be willing to forgo economic rewards in exchange for the image of a good community partner.

Challenges: The participating consumers will ultimately weigh the benefit of participation with the costs and responsibilities for doing so. In other words, consumers may compare the benefits they receive with the costs they may incur such as labor expenses, technology costs, opportunity costs / production downtime, comfort.

Subcategories:
Participating Consumers can be subdivided into three main groups:

- Large Commercial & Industrial,
- Small Commercial & Industrial,
- Residential.

However, it is important to note that each of these categories can be further refined to industry sectors (e.g. chemicals, pulp & paper, etc.), commercial activities (e.g. tertiary offices, shopping centers, etc.), and residential type (e.g. large apartment building, single family home, etc.).
Given that Participating Consumers comes in many difference types and sizes, it can be helpful to consider the different types of things they will consider when deciding whether to participate to a DR program.

a. Large Commercial & Industrial

1. Typical DR Participation Methods

- Load shedding
- Onsite generation
- Commodity price structures (i.e. RTP, TOU)
- Automated load control

2. Consumer Motivations

These consumers are typically very sophisticated energy users and buyers. They tend to well understand how, when, and where they use energy. Energy also tends to be a significant cost in their operating budget, therefore they actively look for energy at the lowest price.
As such, these consumers are generally willing to reduce consumption and/or activate onsite generation when it is convenient to do so provided that they are fairly rewarded for their efforts, so that the reward is higher than the direct costs they incur to participate to the DR program.
The consumers in this group are generally considered to be the easiest to enroll in a DR program since they can easily identify specific actions they can take to reduce their consumptions. However, since they are sophisticated consumers and they can generally provide large DR capabilities at each location, they will seek for the most competitive offer for their DR resources.

b. Small Commercial & Industrial

1. Typical DR Participation Methods

- Load shedding
- Commodity price structures (i.e. RTP, TOU)
- Automated load control

2. Consumer Motivations

These consumers tend not to be as sophisticated as the larger ones. In their case, energy may be a significant cost, but it may not be one of their most critical business issues. Therefore, energy consumption is important to them, but they generally don't devote significant time and effort to manage it.
Nonetheless, they are generally willing to participate in a DR program provided that they can develop a proper participation strategy.
As a result, the key to enroll these consumers tends to be related to education and service. These consumers need help with understanding how the DR market works, how they can participate, and how they can benefit from it.
It should be noted that this higher degree of service tends to have higher sales and marketing costs for each MW of DR provided. Therefore, the DR Service Provider needs to consider these additional costs when developing its business plan. On the other hand, it may also be able to get greater margins for the additional service provided.

b. Residential

1. Typical DR Participation Methods

- Commodity price structures (i.e. RTP, TOU)
- Automated load control

2. Consumer Motivations

Residential consumers tend to be the least sophisticated energy buyers. In fact, the vast majority of residential consumers probably do not even know what DR is. Nonetheless, they have demonstrated a strong willingness to participate in a variety of load control programs (e.g. air conditioning, electric heating, electric water heaters, etc.).
These consumers may get a small bill reduction for participating to these programs, but it has also been shown that they may participate without economic benefits because "it is good for the community".

Local Distribution Companies (LDCs)

Benefits: LDCs have benefited from DR as a way to improve grid operation, to reduce congestion and criticalities in the short term and to reduce the need for new investments in the longer term.
Moreover DR is one of the least expensive resources LDCs can use, so that it provides an excellent hedge to "high cost, but low frequency" events.

If properly implemented, the strategy of resorting to DR resources can significantly improve the overall economic performance of LDCs.

Challenges: If the LDC is a pure wire company, it may not have the retail sales staff needed to properly market a DR program. DR is a product that must be properly communicated to consumers and it may prove difficult to do that without a competent trained staff.

Energy Retailers

Benefits: Energy Retailers are in a great market position to offer DR services to their clients. They can benefit from DR by including it as a resource in their supply portfolio. This could help them to have an overall lower operating cost, which allows them to be more competitive and ultimately more profitable in the market.
They can do this by improving the accuracy of their daily supply bid schedules and/or using the DR resources in their portfolio to avoid unbalances. Many retailers also use DR as a customer acquisition/retention tool.

Challenges: In order for this strategy to be successful, the Energy Retailer must be strongly committed. Often, this means significant investments in metering, meter data management systems, DR event management systems, and related personnel for operation and maintenance.
Unfortunately, since most liberalized electricity markets are relatively new, many of these players only recently realized the benefits that DR can provide and many are taking advantage of those opportunities.

Demand Response Service Providers (also called DR Aggregators)

Benefits: In some markets, there are firms that have entire businesses built aggregating consumers providing Demand Response and offering it into the energy market. Since DR has a relatively low operating cost when compared to other peaking sources (e.g. gas turbines), aggregators are able to manage a sort of “virtual power plants” with lower operating costs. They also tend to provide other services to their customers together with or acting as an Energy Service Company.

Challenges: One of the biggest challenges DR Service Providers must face is selecting the target markets that will allow for a predictable cash flow.
Some of the markets that are more successful in attracting these players allows for a forward trading of DR capacity, such as Norway, that has a reserve option market, and the United States where some capacity markets are active.
In fact, the business is more risky if it relies only on energy related payments: the risk is that if there are no critical events in a given year, the service provider and the consumers will not get any economic reward.

Energy Service Companies

Benefits: These market players provide energy related products and services to consumers (via the LDC / Retailer or directly). Many of these products and services can be used to enable or improve DR capacity. This could include control systems to manage equipments and/or lighting, energy audits to assess DR implementation strategies and on-site generation installations and maintenance, just to name a few.
Of course, these players can benefit from such an extended range of products and services they can sell in the DR market.

Challenges: DR technologies need DR markets. There is a wide range of technologies that can enable DR capacity, but if that capacity is not valued by the market the remaining business is the improvement of energy efficiency of the consumers' facilities. Of course, this is not necessarily a bad option: it just means that Energy Service Companies will not receive additional revenues from DR capacity.

System Operators

Benefits: The benefits for System Operators in terms of more secure operation, better management of critical conditions and congestion, reduction of the need for investments in the network, increased efficiency of balancing and ancillary services markets, have already been widely discussed in the present report.
For example, ISO-New England used DR resources to deal with transmission congestion problems in Southwest Connecticut, one of the most congested zones in the entire United States, while, as above mentioned, some system operators of the Scandinavian countries use DR for reserve services.

Challenges: The use of Demand Response services for system operation requires a fairly high level of coordination among multiple entities within tight time intervals. This means that a System Operator may have to integrate new communication and metering data systems. The presence of aggregators can help System Operators to reduce the number of relationships with multiple consumers.

Regulators

Benefits: Regulators tend to pursue solutions that benefit society (i.e. reduced costs, increased security of supply, reduced environmental impact, etc.) and reduce market power. DR can provide lower electricity prices when properly used by increasing demand elasticity and mitigating market power of dominant producers.

Challenges: Most regulators have a track record that demonstrates their willingness and interest in promoting DR programs. However, their main challenge seems related to identifying ways to promote DR in the new liberalized market framework when it was not originally designed to support it.

Society

Benefits: It is important to recognize that society as a whole benefits from DR by reducing the overall cost of energy supply and increasing its security.

Challenges: It may be easily demonstrated that a robust Demand Response in a given marketplace can have a dramatic impact on societal energy costs, but if individual actors do not receive the proper incentives to participate the societal benefits may be lost.

5.1.3 Impact of market structure on business models

A. Energy only markets

Some markets, such as Sweden and Australia, operate on an energy only basis (no capacity markets are available). In these markets, the total cost of supply is reflected in the prevailing electricity price and there is a need to incorporate DR because it provides a built in tool to curb market power. Their challenge, however, is to find a way for DR aggregators to have enough certainty in future revenue streams sufficient to allow them to enter the market.
The biggest concern in Sweden, and in other participating countries to IEA Task XIII, is that market prices have not maintained a high enough level long enough to attract participation. This is both good and bad. It is good in that this means that electricity prices are relatively low and new capacity many not be needed in the short term. On the other hand, it is bad in that there will surely be a need for new capacity in the longer term and, while DR may be the lowest cost peaking resource, it will not be available if its growth is not supported. Therefore multiple business model solutions to deal with this challenge are being evaluated in the framework of a Market Design Project.
The Swedish team of IEA Task XIII believes that the use of a “fixed price with the right of return”, a new pricing product that they have developed, will provide proper price signals to consumers without exposing to full market risk. This product was developed as part of their Market Design Project and is described in paragraph 5.3.2 below.
In Australia, an aggregator is working on a way to overcome the revenue certainty issue in an energy only market. The specific details are confidential, but it is believed that it is selling the equivalent of call options to the local distribution companies and/or to the energy retailers on a bilateral basis. This provides it with some revenue certainty for few to no-event years, while positioning it to have the proper capacity when it is actually needed.

B. Capacity based markets

In the context of this section, capacity based markets include any market in which a DR asset can sell its future ability to provide DR. Based on this definition, three DR business models emerge.

a. Market based capacity

In this category, DR programs actively compete in open markets alongside with other supply resources. This makes the price paid for DR capacity a true market based price.
An example that falls in this category is the Norway's Reserve Option Market used by the TSO to ensure security supply. The market rules for the Reserve Option Market allow any resource (generation or DR) to compete on an equal basis. The TSO in this market acquires the right to call the resource as needed.
Another example is the New York ISO's Emergency Demand Response Program. The rules of this program enable DR resources to participate in the structured Installed Capacity market auctions along with other supply side resources.

b. Retail pricing discounts

In this category, the Energy Retailer and/or the Local Distribution Company (LDC) offer the end use consumer a lower consumption rate in exchange for the right to request load reduction when needed.
This concept is widely used with residential load control projects. The consumer gives the Energy Retailer or the LDC the ability to limit its usage of equipments like water heaters, saunas, pool pumps and HVAC in exchange for a lower energy cost.
This strategy is also used by many traditional load curtailment tariffs often targeted at commercial and industrial consumers. These tariffs grant consumers with a lower kWh and/or kW cost in exchange for the right to require a load reduction when it is needed.

c. Bilateral negotiations

In this category, market players directly negotiate for the right to request consumer load reductions as needed. The transactions tend to take place between the TSO and DR Service Providers, acting on behalf of a group of consumers.
In other cases the TSO can set up a tender for the acquisition of interruptible capacity directly from large industrial consumers, such as in Italy.
Another example is the ISO New England's Winter Supplemental Program 2005/2006. According to this program, the ISO solicited bids in a tender for the acquisition of DR capacity to deal with a specific potential capacity shortfall.

5.2 Identification of Demand Response business models

It seems that most markets around the world have independently developed a two-tier approach for marketing DR services. There seems to be a demarcation between the wholesale market (e.g. TSO / power exchange to Energy Retailers / DR Aggregators) and the retail market (Energy Retailers / Local Distribution Companies / DR Aggregators to Participating Consumer).

This separation is quite reasonable. At the wholesale level, DR likely needs to operate on a basis similar to supply side resources in order for it to be included in the market. That's not to say that DR must physically operate like a generator: it simply must have the right market rules to allow its integration into the market. This is consistent with how the wholesale market operates today accommodating technical operational differences among its portfolio of supply resources (e.g. think about the difference between intermittent and programmable generation).
Conversely, at the retail level not all consumers are able to provide the same type of DR. By insulating the consumer from the wholesale market, a DR Service Provider can work with each consumer to tailor a contract and a service level consistent with the consumer's needs and abilities. These contracts will need to meet the DR Service Provider's wholesale obligations, but by aggregating large amounts of consumers it will be able to mitigate potential conflicts.

The business models that can be identified for Demand Response can be categorized along the above discussed classification of *System Led* (or *Reliability / Emergency Products*), *Market Led* programs (or *Economic / Voluntary Products*), and *Time of Use / Real-Time Pricing*.

Reliability / Emergency Products - In these cases, the DR product is generally delivered to the buyer (TSO or DSO) via a direct contract agreement, or via an Aggregator (see Figure 6); otherwise, it can be offered to the appropriate Reserve Market (see Figure 7).

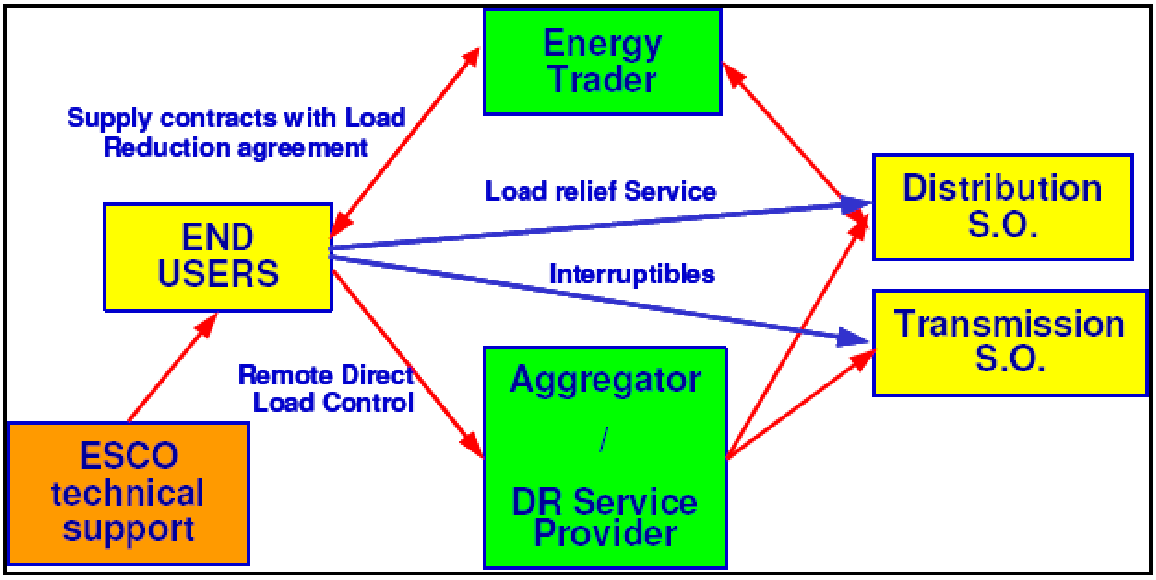

Figure 6 – Direct selling the Demand Response product to the entity that has the responsibility of guarantee the secure operation of the grid

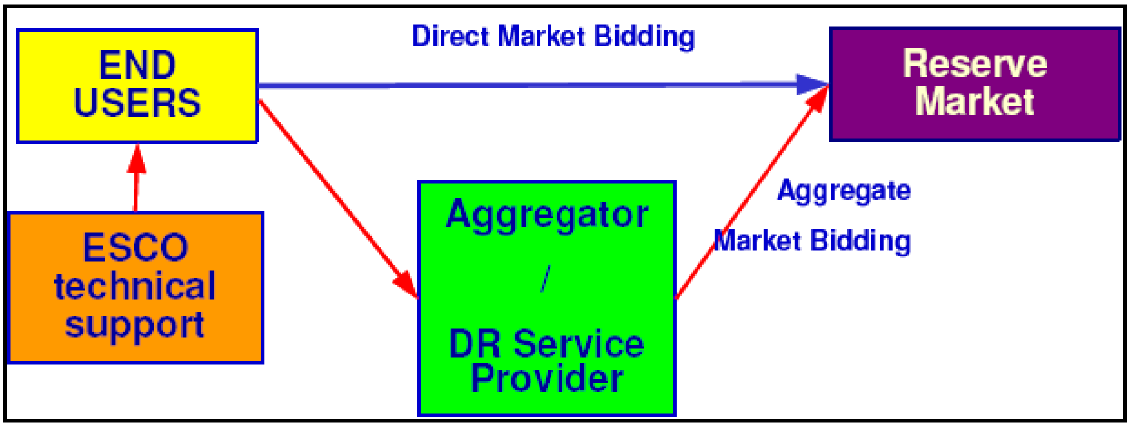

Figure 7 – Selling the DR product to the reserve market

Generally, the service contracted directly with the TSO / DSO (Interruptible Contracts or Load Relief Service) allows for a quick activation of the action (seconds, or fractions of seconds), but it needs to enroll a relatively small number of large consumers, due to communication and time constraints.

The presence of an Aggregator allows the participation of a greater number of small users (for example, with automatic disconnection of water heaters and similar programs, also known as Direct Load Control Programs), but it needs some more time for the action to be implemented, due to the significant communication effort needed to alert all the participating loads.

In many cases a Trader can directly play the role of an Aggregator, coordinating the action of a number of clients and selling the collective response to the TSO / DSO. From a commercial point of view, the aggregators and the traders are a similar intermediate entity.

Within this context, the Energy Service Companies (ESCOs) operate as a technical support to the end user.

The economic agreements in these cases are typically based on a comprehensive remuneration for the entire program, because the TSO / DSO needs to ensure that the product is available for emergency operation for a certain time period (months or years). Therefore, the remuneration usually consists of a reservation payment (or standby capacity payment) plus a remuneration for each single event (operating reserve payment). Alternatively it may consist of a reduced energy rate or a discount throughout the year.

In exchange for the reservation payment, the participating consumer generally gives TSO / DSO the ability to call / dispatch the reliability / emergency products when needed. If the consumer does not perform as expected / contracted when called, he/she may be subject to penalties ranging from a forfeiture of the reservation payment to the payment of damages based on market conditions during the event.

If these products are well designed, they can become liquid and tradable financial products.

The reservation payment provides the consumer with an incentive to enroll because he/she can quickly receive economic benefits and recover the costs of enabling technologies.

Depending on local market conditions, these reservation payments have sometimes exceeded $100,000 USD / MW-year at the highest end and $60,000 USD / MW-year at

the lowest end. Generally, this remuneration is in the same order of magnitude of the costs of an equivalent generation reserve.
In a different scheme, the DR product may be offered directly to the reserve market, by the end user or via an aggregator. In this case the price is defined by the market, depending on the market rules and DR products are in direct competition with other generation resources offered to the market.

Economic / Voluntary Products - These products are designed to impact demand elasticity and therefore, hourly electricity prices. With these products, consumers make decisions on whether to sell their demand response capability based on hourly electricity price signals. These products are being used in day-ahead markets and intra-day markets.
The simplest business model would imply that the customer pays the electricity at the hourly price, that corresponds to a real time pricing scheme. In practice, however, consumers prefer to have fixed electricity consumption rates throughout the year and opt to sell their DR capability during specific hours, when price signals are deemed profitable. Participating consumers will be compensated by receiving some percentage of the market value for the hour(s) they provide the service.
These products also leave the decision whether to participate or not in the hands of the consumer (see Figure 8).

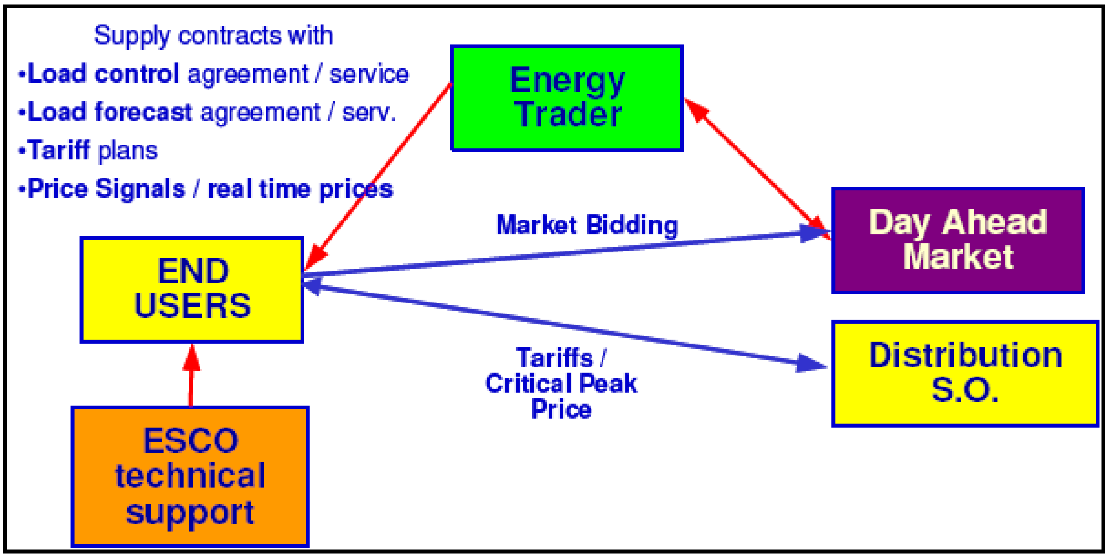

Figure 8 – Customers participation in Market Led Programs

Time of Use / Real-Time Pricing - The main difference with respect to the products above described is that these products link consumers to a price scheme (dependent on wholesale market prices) every hour of the year.
While with the Economic / Voluntary Products consumers sell a reduction of consumption, in this case the consumers decide whether they want to use power, based on current price signals.

5.3 Sample business models

Within the context of the IEA Task XIII, the United States and Sweden have provided the following descriptions of DR business models used in their countries.

5.3.1 DR business models: United States of America

The United States of America is a large country with several regional electric markets. These markets contain almost every combination of market structures in use around the world. As such, the USA is a great place to see multiple DR business model structures (see /**Errore. L'origine riferimento non è stata trovata.**/).

A. Delivery of DR via Economic / Emergency / Reliability Products

Few of the DR business models in the USA are purely market based. Most of the current delivery of DR resources in the USA is done via demand response products at either the wholesale or at the retail level. Most of them are delivered by means of economic or reliability products. The business models include the following.

- *Delivery to the utility under traditional regulation*

A large amount of demand response is delivered in the USA via what are often referred to as *"legacy load control products"*. These normally involve a utility installing communications and control devices on specific customers' end-use equipments. These customers participate in a program where they are rewarded with payments when their load is curtailed.
The business model is simple: the utility internalizes the costs of control devices and of payments to consumers and they become part of the base rate. Vendors may provide the control devices but they are not involved in the operational aspects of the program. These programs have traditionally involved control of the load only by the utility, but advances in technology have resulted in new products where also the customer has direct control over the load and often has the possibility of overriding the control actions coming from the utility.

- *Delivery to the utility under a deregulated market structure*

Where electricity market has been deregulated and customers may chose to purchase electricity from a competitive supplier the incentives for the utility, that in this case is essentially a wire company, are lower than under the traditional vertically integrated structure.
Some utilities act as intermediaries helping their customers to participate to DR programs of the Regional Transmission Operator and receiving a part of the incentives from the operator to cover their costs related to such a service.
Other utilities are beginning to seriously consider DR as an incentive mechanism to reach agreed performance targets, with an approach similar to past efficiency / conservation programs.

- *<u>Delivery to the utility through an aggregator</u>*

In both deregulated markets and in the areas still with a traditional vertical integration, a new model for DR delivery has emerged. It involves a third party being a *"negawatt"* provider to the utility by aggregating a number of customers capable to provide Demand Response services, i.e. an "aggregator" as previously defined in the present report.
The aggregator receives a revenue from the incentives foreseen for the program and/or a share of the customers' savings. This business model is similar to the "performance contracting" model used in the energy efficiency industry in past decades; in fact, some DR companies are taking a "holistic" approach where both DR and energy efficiency measures are incorporated into a comprehensive energy management offer to customers.

- *<u>Delivery to the Regional Transmission Operator through an aggregator</u>*

In several areas of the USA a regional entity exists that manages the transmission network and possibly also the organized wholesale market: the Regional Transmission Operators (RTOs) or the Independent System Operators (ISOs).
DR products used by RTOs / ISOs normally involve an utility or an aggregator acting as intermediary between the customers and the RTOs / ISOs themselves, similarly to the model previously described.

- *<u>Delivery by retail electricity marketers</u>*

In addition to companies whose main business is delivery of DR products (see above), retail marketers in deregulated contexts represent another entity operating with this aim. These marketers may act as intermediaries between the RTO / ISO and the customers. In this way they combine their offer of the energy commodity with an offer of Demand Response products.

- *<u>Third party customer representative</u>*

Some companies have developed a business model only focused on being the intermediary between a utility / RTO / ISO and the customers. They offer no other services and follow the same basic model of taking a share of the incentives / payments for DR services and/or of the customers' bill savings.

B. Delivery of DR via Price Responsiveness

In the USA Price Responsive DR normally refers to dynamic, time-based pricing. These pricing models can vary from traditional time-of-use rates to critical peak pricing to real-time pricing, and there are several variants with new hybrid models being discussed. These business models include the following.

- *<u>RTO / ISO Products</u>*

Regional wholesale market operators have both price responsive DR products and economic / emergency / reliability products. As for the latter products (described

above), intermediaries often exist to complete the business model and facilitate customer participation.
As for price responsive products, with retail prices in the USA still being subject to state (vs. federal) regulation, wholesale DR pricing is seen as having a significant but limited ability to contribute to the development of demand response resources.

- *Utility pricing*

Many if not most utilities have had time-based pricing options available to customers for over two decades, but customer participation is in most cases extremely low, the main reason being that the products are not attractive to customers and they are not aggressively promoted.
The business model for utilities is straightforward and consists of a rate design and of the collection of payments. This model may see greater deployment in the near future since it is supported by the federal energy policy.

- *Market-based pricing*

When a number of states in the USA moved to deregulate and restructure their electricity industry, it was anticipated that this would have led to a more market-based demand response. This has not occurred since there has been a little development of dynamic pricing offers by retail marketers (although some have been more active in providing such kind of offers to their larger customers).
Some states have begun to deploy time-based "default" pricing for customers who choose not to move to the free market. Again, however, large customers have been the primary, if not the only, target of such default pricing.

5.3.2 DR business models: Sweden

The Swedish team participating to IEA Task XIII analyzed the impact of DR in Sweden in a project known as the "Market Design Project". One of the main objectives was to identify potential business models that would allow the development of DR in an energy only market. They have identified the following possible business models (see /20/).

A. Fixed price with the right to return

A model where the customers are exposed to market prices in real time would yield the greatest DR potential. However, such a model exists, but it is not very successful with household customers, even if the electricity spot price is averaged on a monthly basis (and settlement is carried out according to load profiling). In fact, the vast majority of customers choose contracts with price fixed for one year or even longer periods.
A possible alternative model is based on a contract that specifies (e.g. for each season or for each month) an hourly amount of energy (a sort of baseline) that the customer would pay at a fixed price (see Figure 9, red line). Then, in real-time, if the customer consumes more / less energy than the baseline, he/she will buy / sell the difference at the spot price (see Figure 9, green line).
This means that the customer is exposed to the spot price only at the margin and therefore he/she has the incentive to respond to the price signals; nevertheless, the

largest amount of energy is paid at a fixed price, thus hedged against the risk related to price volatility. This seems to be an attractive offer to the customers.

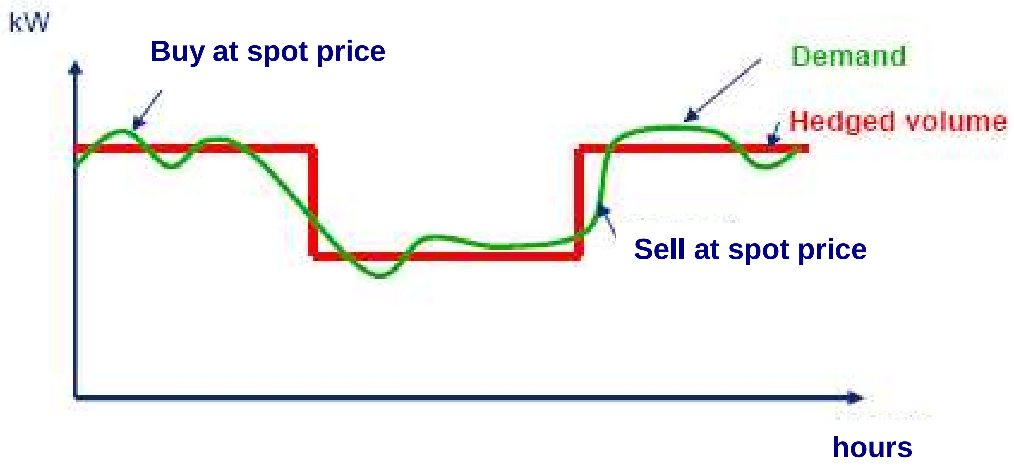

Figure 9 – Fixed price with the right to return

The advantage of such a scheme, compared to the other models outlined in the report, is that demand response can be obtained even in situations when no price peaks arise. The drawback is of course the necessity of providing continuous price information to the customer, making his decision to buy at that price or to curtail the load more difficult.
It is also possible to provide some sort of price signal enhancement in extreme situations, for example in the form of a text warning message, to better draw the customer's attention to events for which a load curtailment is definitely the best choice.

B. Dynamic time-of-use tariff (Critical Peak Pricing)

Dynamic time-of-use tariff has the advantage of giving a clear signal to customers when it is particularly important that they respond. This can be expected to increase their response to such events; moreover, the model is easy for the customers to understand.
The drawback with the dynamic time-of-use tariff is that it does not give any significant signal in situations that are not defined as critical.
In Sweden, the model has been applied in trials within the frame of the Market Design Project. The results of the trials have been very promising. Approximately 20% of the customers (household customers) that were offered this tariff have accepted it. These customers have halved their demand on average during the high price hours.

C. Direct remote control of small customers

In Sweden, there are about 300000 family homes with direct electric heating. Installing control devices for electric heating systems was investigated quite thoroughly during the late 1980's in Sydkraft's project *Toppkap*. The conclusion was that this kind of project is probably cheaper than investing in peak generation.
In the Market Design Project, a system for soft control, still in operation, was tested. The system is functioning as expected. The customers have in general been willing to

participate with only a small compensation. However, the technology costs of the existing systems have been high.
The new metering (AMR and AMM) systems with some kind of two-way communication capabilities that now are being installed can reduce the costs with respect to the ones of the technology tested in the late 80's.

D. Demand sell back

This business model has been tried with large customers in the *Industribud* project and with middle-sized customers in the Market Design Project.
The customer provides information to his electricity supplier about what compensation is required to reduce the consumption. If the spot price is higher than these bids, the electricity supplier can buy demand reduction from the customer instead of buying additional power at the spot price.

6 Evaluation of technological and non-technological barriers to Demand Response

6.1 Foreword

A market barrier can be considered as something that unfairly restricts access to a market. This could occur for example:

- when regulations do not keep up with emerging technologies or industry standards;
- when the incentives for participating in a market are disproportionate to the incentives received by others for complementary services;
- when a dominant market player or group of players unfairly prevents new competitors from entering the market.

The Demand Response industry is relatively new, especially when compared to other supply side options, with which it must find ways to jointly operate. Unfortunately, the market rules and the corresponding technology requirements were designed around existing supply side solutions, so that it was initially difficult to foresee a large scale use of DR. Nevertheless, as the DR industry continues growing and, more importantly, demonstrating its ability to provide a safe and reliable capacity when it is needed, the market finds more and more ways to tackle with some of the initial challenges.

In any case, for a number of reasons DR has not reached its full potential yet. Some reasons are cultural (e.g. "it's new and we don't know what to do"), some reasons are regulatory (e.g. consumers are generally insulated from real-time market conditions) and some reasons are institutional (e.g. DR was not included into many liberalized market transformation processes).

Demand Response resources have had many successes over the last few years. DR has demonstrated an ability to provide reliable peaking / balancing power in several Scandinavian nations, helped the USA power grid to recover from its Northeast blackout in 2003, and Australian researchers have shown, by simulation, that active DR solutions can make their markets more efficient. However, despite these successes, the energy industry has not taken full advantage of the benefits that DR can provide.

Part of the reasons why DR has not received full market adoption is that only recently it has been considered as a physical resource on a par with other capacity resources. However, even though the power grid would benefit from having DR resources in place, the energy markets sometimes disregarded them because they did not conform to traditional trading practices (e.g. 100 MW blocks). Therefore, DR resources have constantly been undervalued in the resource portfolio.

On the other hand, it should be noted that the impossibility for a product to find a market is not necessarily caused by a market barrier. It might be due to a product inability to solve a market problem (e.g. the technology is premature or obsolete) or its cost structure cannot compete with other available solutions.

6.2 Market barrier categories

In the frame of the IEA Implementing Agreement on DSM, Task XIII /80/, DR market barriers have been classified into the following main categories:

- Cultural issues: this would include things such as the fact that consumers' education is lacking, the right supporting technologies are not in place, consumers' behavior is difficult to change and incumbents do not want competition.

- Regulatory issues: this would include things such as the fact that electricity tariffs that are do not adequately reflect market prices, incentives for participation are not in line with benefits and regulatory uncertainty makes it difficult to carry out the needed investments.

- Institutional issues: this would include things such as the fact that DR was not included into the original market design, DR has a small weight relative to other incumbent's resources, some operating practices require large infrastructure investments, there is no agreement on how DR can / should be used and on what it takes for DR to be recognized as a useful resource.

6.3 Common challenges

All IEA Task XIII participants believe that DR is useful and important to their respective markets, but most do not believe that the ultimate solution for developing it has been fully identified.

Part of the reason for this is that DR is a relatively new concept. Load management and load curtailment products have a fairly long history, but incorporating them into recently liberalized market structures has only been occurring for some 10 years. As a result, the energy industry and its consumers are still looking for more efficient ways to make it happen.

A couple of issues that have emerged are the following:

- *Tragedy of the commons*: the biggest problem most people point out is that there is a clear societal benefit deriving from DR, but in some circumstances it is difficult for individual stakeholders to have enough direct benefit to participate.
- *Market liberalization process*: in most cases, the market liberalization process did not consider DR from the onset of market design. This created a supply side mind-set when the business processes and the market infrastructure were developed. This means that DR not only needs to identify how it can help the market, but it must also work with the local institutions to figure out new business processes that are conducive to DR development.

The Task XIII project team discussed a number of issues impacting the development of DR in their local markets (see Table 4). Some of these issues were unique to a market, but there are a few issues that were identified by almost all participants.

	Common Challenges	Suggested Actions
1	Consumer Awareness - Don't know what DR is - Unaware of their demand flexibility - Unaware of how they can benefit from DR	- Develop case studies showing how others have participated and benefited - Initiate awareness campaign (radio, billboards, news reports, seminars)
2	Price Signals - Consumers accustomed to fixed price per kWh - Wholesale to retail disconnection - Limited use of locational pricing	- Use DR programs and tariff pricing that link consumer behavior with electricity prices - Initiate trials to test local market adoption
3	Meter Data - Several meters in use today do not record hourly intervals - Limited use of data exchange standards - Limited incentives to make new investments	- Load profiling methods can be used in some circumstances - Allow meter owners to recover costs for upgrades - If AMR is used, make sure their functionalities work with the desired DR programs prior to installation
4	Market Operations - DR may be precluded from participating in the wholesale market - DR must conform to supply side market rules (e.g. large trading blocks)	- Use trials to demonstrate DR ability to serve the wholesale market

Table 4 – Typical issues impacting the development of DR and suggested actions

Some comments follow.

- Consumer Awareness

The lack of consumer awareness is one of the main challenges facing all participants. Let consumers be segmented into three broad categories: Large Commercial & Industrial, Small Commercial & Industrial and Residential: a key distinction between these classes is their relative sophistication when it comes to buying and using energy.
A consumer's sophistication is normally proportionate to the amount he/she pays for electricity in both absolute terms as well as relative to other expenses. Many large consumers are quite aware of their DR opportunities as well as of their own demand flexibility. But most Small Commercial & Industrial and Residential consumers could not have the same knowledge.
Fortunately, this is probably the easiest barrier to overcame. Assuming that DR programs are established and available, consumer awareness campaigns can quickly educate the masses. The key here is that the campaigns should explain how consumers can benefit from the participation, should suggest ways for them to identify demand flexibility at their facilities and should explain how they can be enrolled. An easy way to do this is by setting up case studies that illustrate the successful experience of others.

- Price Signals

In liberalized economies, the relationship between supply and demand set the price for almost everything people can buy. But in the electric industry most consumers have historically been offered fixed prices for every kWh they consume. This insulates them from the hourly price variations that occur in the market.
Consumers do not bother with this situation, because it gives them a degree of certainty. Unfortunately, it may not be the most efficient way to operate the power system.
It is known that consumers' behavior, and therefore their energy needs, can be modified with the right incentives. In terms of matching between supply and demand, when the price goes up, a percentage of consumers will reduce their usage. There will ultimately be an equilibrium price at which the available supply matches with consumers' demand. Within this context, the issue is to identify the best way to provide price transparency to consumers.
A number of strategies have been used around the world. Schemes such as real time pricing, critical peak pricing, time of use pricing and the Sweden's new "fixed price with the right to return" are all designed to match consumers' behavior with market prices. In addition, options contracts such as Norway's Reserve Option Market and the New York ISO's Emergency Demand Response Program are market based products that will trigger consumer load reductions when the system needs it.

- Meter Data

Hourly metering is not an absolute requirement for a successful DR program. Consumers' consumption can be translated into hourly data on the basis of a number of accepted load profiling techniques. But actual hourly meter measurements would provide a more accurate representation of the consumers' consumption.
Many markets around the world have begun studying or installing wide interval metering networks. For example, the United States 2005 Energy Policy Act required the Federal Energy Regulatory Commission to investigate the extent to which such networks are used in the country, while in Italy the vast majority of consumers is already equipped with "intelligent" interval meters capable of two-way communication.
In many cases, these systems are installed to reduce meter reading costs and to improve the operational efficiency of the local power supplier or of the distribution network. Of course, the same system can also be used to better match consumers' usage with actual market prices.
However, there are a few things that should be considered before the networks are deployed. First, given that the new metering networks will likely cost billions of dollars, it would be wise to make sure that they can support the appropriate DR functional requirements prior to make the investment. Second, the entity that owns and operates the metering network should be allowed to recover the cost of its investment.
The interval meter is an enabling technology for DR. All consumers will benefit from greater price transparency, so it is reasonable to encourage its use. Finally, meter data exchange standards need to be simplified and utilized.
Depending on the market structure, there can be multiple market players that need access to the meter data. ISO-New England uses a simple standard to exchange DR meter data. Similar methods could be used elsewhere to keep infrastructure costs to a minimum.

- Market Operations

It has been remarked several times that DR is a relatively new product. Because of this, the industry is not sure how to use it.

In some markets, DR has been prevented from participating in the wholesale market. For example, Spain does not allow DR to participate in its operating reserve or balancing markets, though they are preparing a pilot project to test such participation.

These concerns are understandable. It is not reasonable to expect an instant adoption. The electricity industry has a responsibility to ensure security of supply, that will not happen if structural changes are constantly being made.

Several markets in the United States had similar concerns when DR was first introduced. However, these concerns began to disappear as the market players used DR products.

The message here is that market trials will help the players to get comfortable with DR. This is a critical step. Additional products can be developed immediately thereafter.

6.4 Survey of DR market barriers

The IEA Task XIII Country Experts were also asked to provide their insights on current barriers to DR in their markets. Their insights are reported in the tables below.

The information has been grouped into the three market barrier categories discussed above, namely Cultural, Regulatory and Institutional Issues; they are reviewed in Table 5, Table 6 and Table 7, respectively.

Country	Barrier	Potential Actions
Australia	Lack of consumer awareness Resistance to reducing summer air conditioning usage	• Continue engaging consumers in demand management trials • Encourage use of technology to simplify multi-site aggregation
Denmark	Consumers desire fixed cost per kWh	Create multi-part pricing with a fixed component plus a reward for DR participation when needed
Finland	Consumers are not aware of their potential demand flexibility	Promote case studies illustrating how consumers can use existing technologies to manage loads
Netherlands	Lack of interval metering and ICT networks	
Norway	Lack of interval metering and need for better data quality and data exchange standardization Need for: o increased customer awareness of DR opportunities o innovative products from retailers including AMR and RLC options	Focus on demand side price elasticity in the "physical" markets (Elspot, Regulation Market)
Spain	Consumers accustomed to fixed pricing Lack of understanding of DR benefits In some cases, current tariffs are lower than actual market prices	Initiate trials and promote consumer successes via case studies
Sweden	Lack of hourly metering; a new law promotes monthly metering (currently some are only read annually), but it does not provide incentives for LDCs to install interval metering	Some LDCs have installed interval meters on their own in order to improve internal supply management efficiency: these could be used for DR purposes as well
USA	The fast pace of technology advancement makes firms afraid of buying the wrong thing	Assess DR needs for the market first then choose technologies that provide that functionalities
USA	DR is a relatively new discipline: more research needed	Continue (and increase) funding DR research activities

Table 5 – DR market barriers: Cultural Issues

Country	Barrier	Potential Actions
Australia	Lack of appropriate price signals No real incentive for electricity suppliers or LDCs to provide the signals	Regulatory intervention to: • include locational price signals • remove price caps • increase interval meter usage
Denmark	LDC is responsible for metering and cannot charge retailers for meter data services, so there is little incentive to install new interval meters	Allow the LDCs to recover costs of interval meters and data management services
Norway	Power system vulnerability focused; the importance of more end user flexibility emphasized	• Make easier to change supplier • Separate invoice from Network Company and Supplier • Allow customers to require hourly metering at a maximum cost (~ 300 €). • Oblige the Network Company, who is responsible for metering, to treat all Suppliers equally
Finland	AMR use is growing, but technical features are not standardized. This makes data exchange difficult and expensive. It may also mean that the system may not always support desired DR functional needs.	• Assess DR needs first, and then design AMR functionalities to meet those needs • Regulator must assess functional specs and pursue data exchange standardization • Regulator can also help by allowing DSOs to cover AMR system costs
Finland	Lack of price transparency at the consumer level Small consumers are settled based on load profiles	• Continue growth in AMR – use it for settlement purposes • Educate consumers on benefits & risks of RTP
Spain	DR is currently not able to bid into the system operation markets (reserves, balancing, etc.)	Initiate trail to demonstrate that it is possible
USA	Retail competition created a vacuum in terms of DR actors and responsibility	System operators have assumed the role of promoting DR activity by default
USA	Some utilities are unable to recover the costs of providing DR services	Given that DR provides benefits to all society, the LDCs should be able to recover their costs

Table 6 – DR market barriers: Regulatory Issues

Country	Barrier	Potential Actions
Australia	Difficult for DR to participate in wholesale market	Encourage DR aggregators to bundle DR loads as a service to distributors and retailers
Denmark	Wholesale market rules favor supply side bids	TSO is working with market participants to develop DR user friendly business rules
Finland	Wholesale and ancillary services markets require 10 MW bids	Allow DR service providers to aggregates loads
Sweden	TSO currently responsible for capacity reserve, but this ends in 2008 and it wishes to terminate this responsibility	Sweden is working on a new Market Design that will promote greater use of RTP
Netherlands	Market liberalization split the utility into different operating units. Their efforts are focused on improving their current operations.	Case studies from other markets can demonstrate how the various actors might develop DR solutions
Norway	Economic incentives for individual market players may not be sufficient to generate interest even though there is significant socio economic benefit	Currently evaluating market design adjustments that may provide greater incentives
USA	Electricity regulation has been based on the “obligation to serve”, this created a supply side oriented marketplace	EPACT 2005 motivated the entire electric industry (FERC, DOE, State PUCs, LDCs) to consider ways to incorporate DR and interval metering

Table 7 – DR market barriers: Institutional Issues

7 Closing remarks: suggestions for DR program design

7.1 Guidelines

The discussion on "best practices" reported in the previous chapters suggests possible actions aimed at removing barriers against DR and at activating programs based on flexible demand. The guidelines for these actions are described below.

According to what already pointed out, the economic signals are fundamental instruments for stimulating a Demand Response. These signals must be designed to be strong enough to have impact, as well as suitable to encourage aware and realistic behaviors.

With respect to a given "average price" of the electricity supply over the billing period, strong signals (i.e. much higher prices – till an order of magnitude – than the base price) over short periods (e. g. two or three hours) are doubtless very effective. Of course, strength and duration of the signals must be tuned on the basis of the desired effect and of the assumed response elasticity of the involved users. In fact, it is well known that the elasticity is strongly dependent on the class of users, according to the foreseen use of electricity and consequently to the actual chance to tune the involved loads.

It must be remarked that very often some regulations exist, aimed at protecting the users from higher expenses as a consequence of an accepted more dynamic tariff. These policies were explained in the past with the fact that the users were hardly in condition to accesses their consumption data in real-time (or anyway in useful time).

Nowadays new technologies tend to overcome this problem and to allow these policies to be removed; users are then able to rationally handle a risk of higher expenses (once the problem of accessing their consumption data is solved), which is a necessary condition for successful plans involving dynamic tariffs.

Another important issue is to allow as many users as possible to access demand flexibility and dynamic tariff programs through differentiated proposals, in order to systematically exploit all the potential of DR resources available among the users.

Straightforward processes are necessarily required and they become even a critical issue in cases where a great number of participants is expected to be involved. Therefore, a great attention must be paid in assuring simple operational features concerning:

- methods to participate to DR programs and to tariff plans, to ensure the feasibility of the actions the user has to perform to respond to the program;
- methods of measuring, accounting and billing the reductions of load relevant to the considered DR program.

To this aim, many experts suggest to widen as much as possible the criteria for eligibility of methods and instrumentation, as long as every interpretation of these criteria is clearly stated and freely negotiated and accepted among the contracting parties of the commercial agreement.

The principle of offering opportunities to participate to the power exchange to both demand-side and supply-side resources leads very often to accept demand among the possible suppliers of ancillary, reserve and dispatching services, at both national and local level.

Finally, very often there is a lack of basic data to evaluate the elasticity of demand to the electricity price, as a response to both fast and daily/monthly variations of price signals. This kind of elasticity, which is likely to be strongly dependent on the class of users and on the kind of tariff or program, can only be determined by means of experimental campaigns.

7.2 General criteria for the design of DR programs

Beyond the above guidelines, some criteria for the design of DR plans are outlined below.
The starting point for a rational design of a plan for the modulation of demand is normally given by a clear vision of the foreseen goals. Though this statement looks rather obvious, often the policies for market management and regulation, billing and measurement tend to preserve protections, habits and privileges and happen not to exploit the resources provided by a responsive demand.
More in particular, a rough check-list of the main items to be defined while designing a DR program can be set up:

- Short-term or long-term features of the pursued elasticity:
  - ability of handling random, irregular and rapid short-term criticalities or ability of controlling a long-term evolution of demand to modify the development of the electricity system (production, transmission and distribution);
  - *peak shaving* or load shifting (e.g. from day to night) targets.
- Quantity of demand which is planned to respond (i.e. amount of elasticity to be activated).
- System conditions which call for elasticity (i.e. grid criticalities, seasonal events, weather emergencies, peak loads, etc.).
- Time-interval for the implementation of DR actions (seconds, minutes, hours, days, seasons).
- The way of communicating signals to activate Demand Response.
- The metering infrastructure necessary to measure the amount of Demand Response.
- The type of tariff scheme and the type of reward for participating consumers.

The following main criteria are suggested in the design of DR programs:

- *Size in participation*: DR programs should be aimed at encouraging participation of any kind of user and, when possible, without technological obligations; that is, any technical agreement among the parties should be accepted, in order not to create eligible and non-eligible classes.
- *Straightforwardness and transparency*: these requirements are fundamental to widen participation as much as possible.
- *Suitable reward*: DR programs should ensure a fair return to the participants.
- *Multiple participations*: the end user should be able to participate to more than one program, both Market Led and System Led.
- *Joint supervision*: the Regulatory Bodies should cooperate with coordinated actions to remove barriers to the implementation of DR programs.
- *Fair DR cost recovery* for the involved actors.

7.3 Closing remarks on the economic features of Demand Response

We would like to remark that in order to efficiently exploit the flexibility of customers it is necessary to consider this asset under all the possible circumstances. This means that the focus should not be limited to a specific function, but it should investigate the potential profitability of all the alternative services that can be offered through demand response.

The value of DR is determined by the contractual conditions under which the service is provided, not by the action of modifying consumption per se. This means that as the final action is the same it is extremely important to allocate it to the best possible function as these are mutually exclusive. This becomes even more relevant as the profit margins for DR are at the moment quite thin and are sometimes not entirely justifying the investments required in infrastructures.

We conclude with the hope that in Europe there could be a serious effort of studying the potential of Demand Response, also considering its impact in an integrated European market, as this type of service can be taken into account also for cross-border transactions.

7.4 Some proposals

On the basis of the above guidelines and criteria and with reference to the most common needs of power systems, some operative proposals can be outlined, aimed at attaining a flexible demand at both national and local level. These proposals are described below.

7.4.1 Implement Critical Peak Pricing and Direct Load Control

The tariff schemes characterized by strong and short signals are defined as *Critical Peak Pricing* schemes, since price peaks are usually related to system criticalities, whatever the origin. With respect to the standard tariff, the electricity price in “normal” days is a bit lower, while in critical days it is much higher, as shown in the following Figure 11.
Normally critical days / hours are defined with a 12-48 hours’ advance notification.

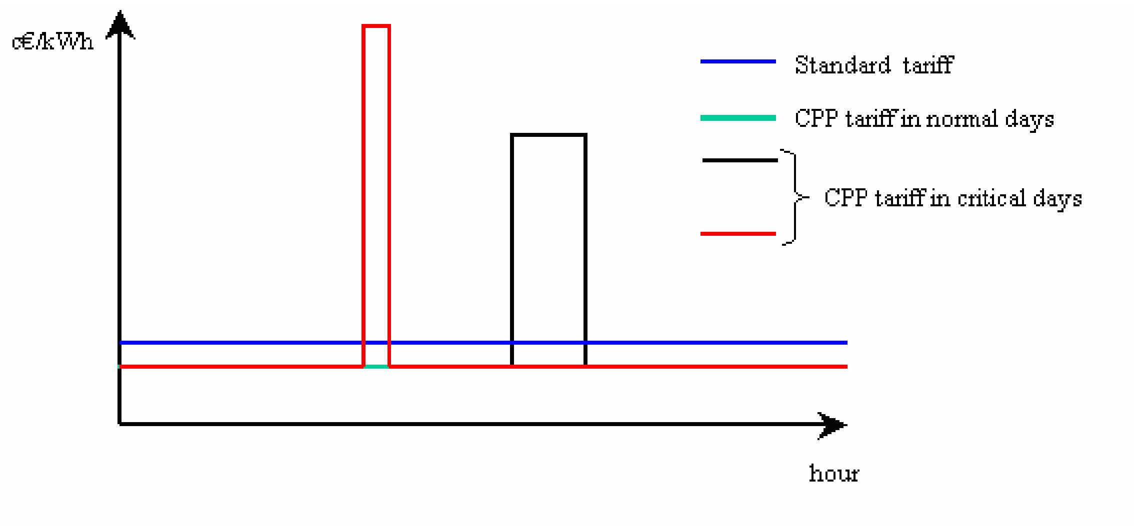

Figure 10 – Typical scheme of Critical Peak Pricing (CPP) tariffs

This type of tariff scheme has been successfully applied in California in a pilot project, as shown in Figure 12. During some afternoon peak hours two different levels of price are applied, depending on the criticality of the day.
Figure 13 shows the type of response which a household user can provide as an effect of this type of tariff scheme.

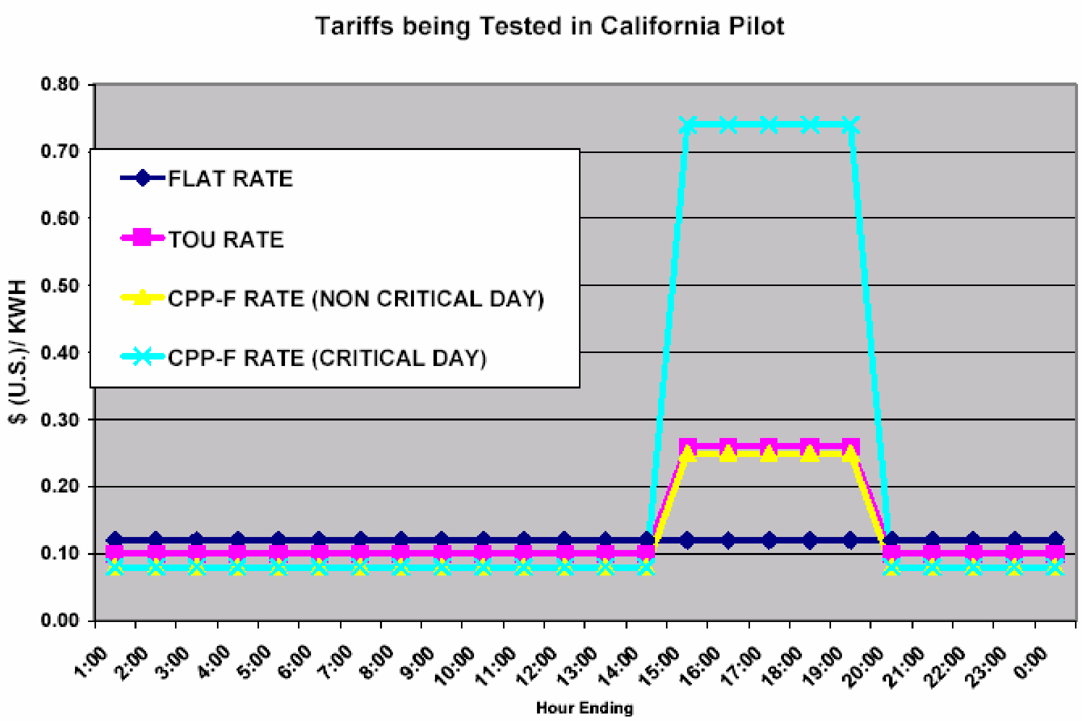

Figure 11 – Tariff scheme implemented in the Californian CPP pilot program

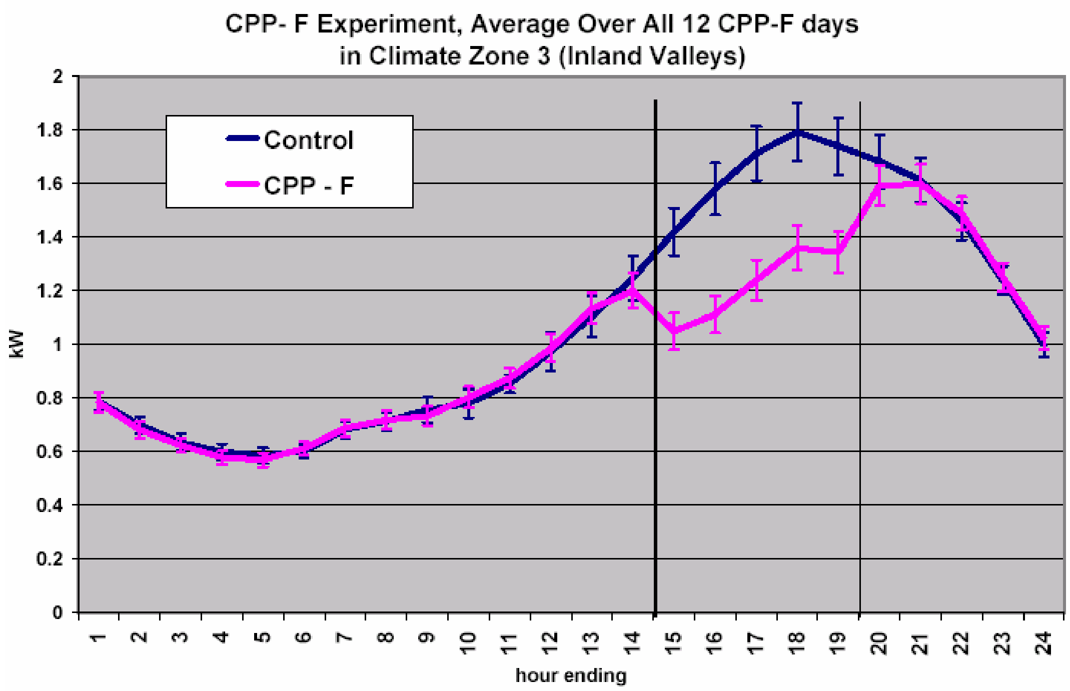

Figure 12– Load curtailment of a household user in the Californian CPP pilot program

Moreover, the CPP tariff can be associated to automatic systems which cut off some selected loads when a signal is send by the meter or when variations of the tariff occur. The users' response is obviously much greater when the tariff is connected to these Direct Load Control systems; moreover, the users are relieved from manual operations whenever a load reduction is requested. Today's technologies can satisfactorily implement these architectures with reasonable costs.
Finally, this kind of tariff plans can be activated during seasonal periods (e.g. summer) and with a possible predefined scheme of peak-price hours (e.g. late morning hours of working days); such strategies ease the understanding of the program and avoid the need of communicating the single critical periods in advance.
Such schemes should be activated on a local scale too, as a relief to highly critical distribution grid overloads (such as in some towns during summer periods) in the form of either supplementary tariff options beyond regulated ones or commercial offers to eligible clients.

7.4.2 Allow participation of demand to the Ancillary Services Market

With no doubts, the most straightforward way to develop Demand Response programs is to allow participation of demand to the Ancillary Services Market (ASM), according to the successful experiences of many countries. In fact, this option brings about a more efficient, since it widens the portfolio of available services.
When this participation finds obstacles, the greatest barrier is very likely the belief that demand is not reliable enough to act as a reserve, despite the success stories e.g. in the Scandinavian countries and in the USA.
Another frequent drawback is a lack of classification of the loads according to their flexibility characteristics, so that to have a sort of standard specification of the capabilities to provide ancillary services, as discussed in the following paragraph.
Once participation to the ASM is allowed, loads could participate either individually or as an aggregate and they could be managed by wholesalers / aggregators.
Thus, opening the ASM to the participation of demand could foster the development of a market of services devoted to demand aggregation. Moreover, it would improve the safety and reliability of the overall power system.

7.4.3 Classify loads according to their flexibility characteristics

Some categories to classify the loads according to their potential and efficiency in DR programs could be very helpful in the phase of designing a DR program. For example, Alvarez /75/ proposed the classification below:

- Long-term planned demand: load forecasting is available months (or years) in advance; this knowledge is useful e.g. for planning investments, etc.
- Medium-term planned demand: load programs are defined 24 hours in advance; they are suitable for the day-ahead market and for the ancillary services market.
- Short-term planned demand: 1 hour before, for real-time balancing; data communication is needed with a load measurement every 5 minutes (e.g. “interruptible” loads with advance notice).

- Real-time dispatchable demand: it can be activated in fractions of a second and it can participate to the ancillary services market (e.g. "interruptible" loads without advance notice).

Such a classification could be considered a first step in the process to allow the participation of demand to the ancillary services market.

7.4.4 Provide services for load curtailment to Distributors, to handle local congestion

Many problems of distribution grid congestion occur at a local level on low/medium voltage, in connection to particularly severe climate events or failure and maintenance operations.
In these cases, the reserve services which the System Operator manages at the national level can hardly be used. On the contrary, the availability of a service aimed at curtailing load in the local network should be carefully considered by distribution companies, since it would prevent more extreme and drastic actions such as rotating black-outs. Moreover, these kind of services are particularly effective, since the resources provided by a flexible demand are mainly concentrated where a congestion is more likely to occur.
A load curtailment service could be organized by the Distributor itself or by an aggregator, provided it is able to enroll a suitable amount of load able to actually and efficiently responding to the grid criticality signals.
Nevertheless, the apparent indifference of utilities in designing and implementing this kind of solutions seems still to act as a remarkable barrier: in this respect, regulatory or legislative interventions would help to overcome such a barrier.
Pilot projects are strongly advised as additional tools able to provide useful and necessary experiences and suggestions, at both national and international level.
The main points to be analyzed are:

- the kind of agreement among the different actors to overcome the above barriers,
- the technological issues,
- the specific cost / benefit evaluation.

7.4.5 Set up pilot projects to assess short-term demand elasticity

The correct implementation of DR programs requires to assess the ability of demand to react in the short-term (e.g. days or hours) to the price signals.
There is often a lack of data on demand responsiveness to short-term and very short-term price signals. On the other hand, the responsiveness to price significantly differs depending on the social and economic context and on the type of involved users.
These data must be obtained on an experimental basis, since it is not possible to extrapolate them from data relevant to other experiences.
An interesting example of the importance of this kind of pilot projects is given by California, who has carried out a pilot program (*California's Statewide Pricing Pilot*) handled by three energy utilities (Pacific Gas and Electric: PG&E, Southern California Edison: SCE, San Diego Gas and Electric: SDG&E) in agreement with the regulatory commission /76/. The aim of the project was to gain experience on response capabilities of household and small commerce consumers to time-of-use (TOU) and critical peak

pricing (CPP) tariffs; a specific objective was to evaluate the economic benefits of installing hourly meters.
The results of the program also allowed to assess the demand responsiveness to a dynamic price with very short-time variations, as a function of the class of users, of the geographic zone, of the technologies and the type of electricity end-uses.
The three utilities that fostered the program operate in three different zones; therefore it is not so surprising that the conclusions derived from the pilot project are quite different:

- PG&E stated that the benefits obtained from DR overcome by far the installation costs of new meters, even with a simple voluntary participation to the flexibility programs;
- SDG&E deemed the investment convenient, provided that a massive participation to the program is ensured;
- SCE on the contrary concluded that the investment is not paid back by the achieved benefits and then it is necessary to implement further functionalities on the meters to justify their installation.

The explanation of these conclusions is rather straightforward: the three utilities serve clients placed in different geographical zones; consequently, they offer a different demand elasticity (due for example to climate and the corresponding need for air conditioning).

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