EFFECTS OF DEMAND RESPONSE ON THE DISTRIBUTION COMPANY BUSINESS

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INTRODUCTION

The research in the area of demand response (DR) has been intensified in recent years as a result of the annually growing consumption and shortage of generation capacity. Demand response will relieve the stress on the power grid on one side and temporarily eliminate the need to renovate the network and expand generation capacity on the other side. In the European countries, demand response has been implemented mostly for large industrial and commercial customers, whereas for residential customers it is still underdeveloped [1]. Different types of houses, consumption habits, and lack of measurement data make it difficult to estimate the impact of DR of small customers on a distribution company business and remain a significant barrier against DR implementation.

In the literature, demand response is divided into two major types: *incentive-based* and *price-based* [2]. For the residential sector, the most common ways to control the consumption of end users are direct load control (incentive-based) and dynamic pricing rates (price-based).

The price-based and incentive-based demand responses are different by nature. The price-based demand response is a customer-initiated action and occurs on a voluntary basis, taking into account the customer's comfort. The incentive-based DR, on the contrary, is an aggregator-initiated action, where the purpose is to reduce the peak load and finally provide the network security, regardless of the customer's comfort [3]. However, in both types of DR, customers do have an opportunity to override the price or power reduction signal (see Fig.1).

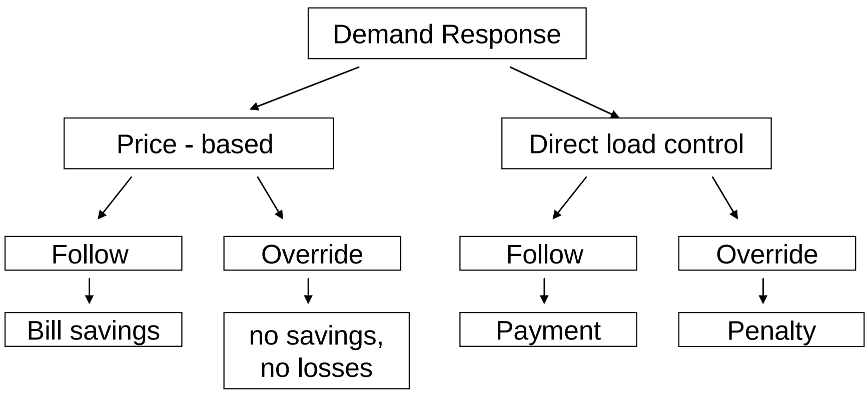

Figure 1. Remuneration scheme.

Only then they are willing to participate in DR programs offered by an aggregator.

This paper aims at estimating the effects of the incentive-based and price-based demand response of residential customers on a distribution company. Local energy storage units are also taken into account, modelled and integrated into the experiment. The studies presented in the paper are based on actual measurements of electricity consumption and analyses of customer load curves and values of a distribution network.

RELEVANCE OF PRICE-BASED AND INCENTIVE-BASED DEMAND RESPONSE IN FINLAND

There is a high DR potential in electric heating in Finland, since the majority of electricity end-customers in rural areas live in houses heated with electricity; a load of this kind has a relatively high energy consumption compared with other domestic appliances, and it can be shifted without disturbing the comfort of the customer. Direct load control (DLC) of heating loads has showed significant potential in the residential sector [4]. With unbundling of retail and network business in 1995, however, incentives for the DLC of heating loads disappeared for distribution companies. Nowadays, when electricity consumption is steadily growing and technology is developing, the issue of peak reduction will become one of the key topics for distribution companies when developing the network planning strategy and managing the company assets. Thus, direct load control will regain its significance and receive incentives for its revival.

In Finland, the majority of customers with electric heating loads choose two- or three-time tariffs. Although these time-of-use tariffs have significantly contributed to reduce the national load variation, they sometimes counteract the system-price variations in time [5]. For this purpose, the opportunities and impacts of the real-time pricing need to be investigated. In Finland, residential customers already have an option to switch to spot-price-based tariffs; moreover, field tests have been carried out in Finland on ten residential customers with electric heating loads and hourly metering options [4]. They demonstrated that there is potential for price demand response, also in the apartment blocks, but the main barriers to implement it for small customers are high costs of hourly metering and balance settlement based on load curves instead of actual loads. This legislative market barrier will be partly overcome from 1 Jan 2014 onwards when at least 80 % of customers within a distribution company will be equipped with smart meters, and hourly interval measurement and settlement will become compulsory for them [6]. This will facilitate the adoption of spot-pricing tariffs for residential customers, and thereby makes the studies of their impact on distribution companies highly relevant today.

TARGET OF THE STUDIES AND BACKGROUND DATA

The main target of the paper is to describe the methodology for defining the effects of incentive-based and price-based DR on distribution fees and reinforcement costs. This is done by analyzing opportunities to decrease the present peak power. The principle of DR analyses is presented in Fig 2.

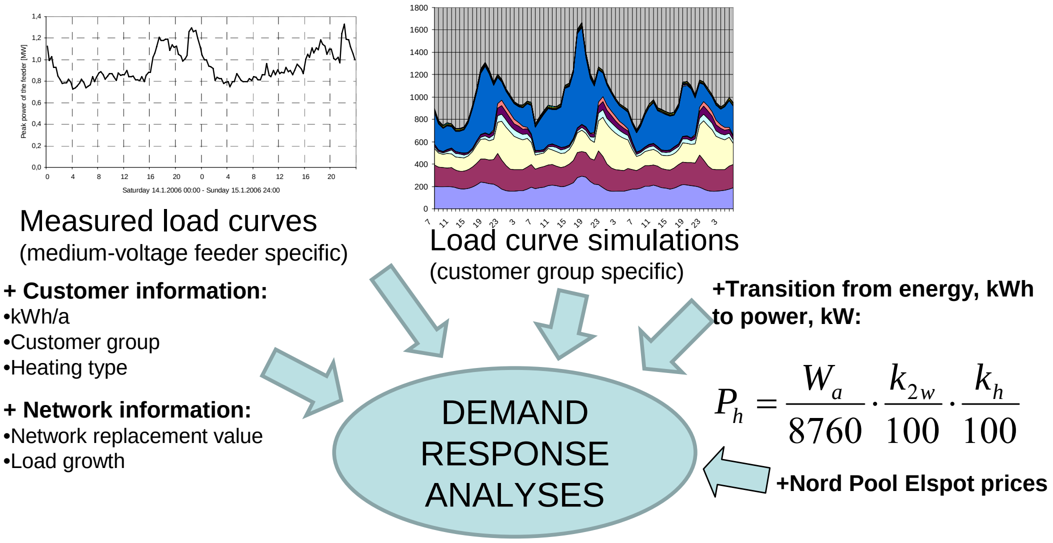

Figure 2. Background data used in analyses [7].

The main idea of the analyses is to combine information of actual feeder specific measured load curve and customer group specific load curve simulations together. The simulated load curves were scaled to the measured curves in order to get realistic power peaks. For price-based demand response analyses, hourly spot prices for the year 2008 [8] were referred to the hourly mean powers for each hour of the year.

After the peak power reduction potential is found, two kinds of benefits can be estimated for the company:

1. Temporary savings as a result of deferred reinforcement investments, which can be put in the network later.
2. Permanent savings obtained annually from peak power reduction and reflected in the end-customer distribution fee cut.

It is necessary to emphasize that permanent savings are possible only when the hourly power remains below the required level during the whole period under consideration. For this purpose, the permanent customer's response to power or price signals is necessary, which in practice is only theoretically possible.

The majority of customers (96 %, 438 in total) supplied by the feeder are residential customers, who live in detached houses with the type of heating shown in Fig. 3, where the load curve of the case 20 kV feeder is presented. Most customers with electric heating loads use the two-time tariff, which can be noticed in their hourly power consumption rise at 22:00 when the night-time tariff starts. Customers with *direct electric heating* loads are equipped with water storage heaters. In this paper, it is assumed that each heater has a volume of 300 litres and a rated power of 3 kW. The households with storage electric heating are equipped with larger water and space storage heaters; their rated power may vary from 5 to 20 kW depending on the household size. The 1-hour and 2-hour shifting has been simulated for both types of customers with electric heating.

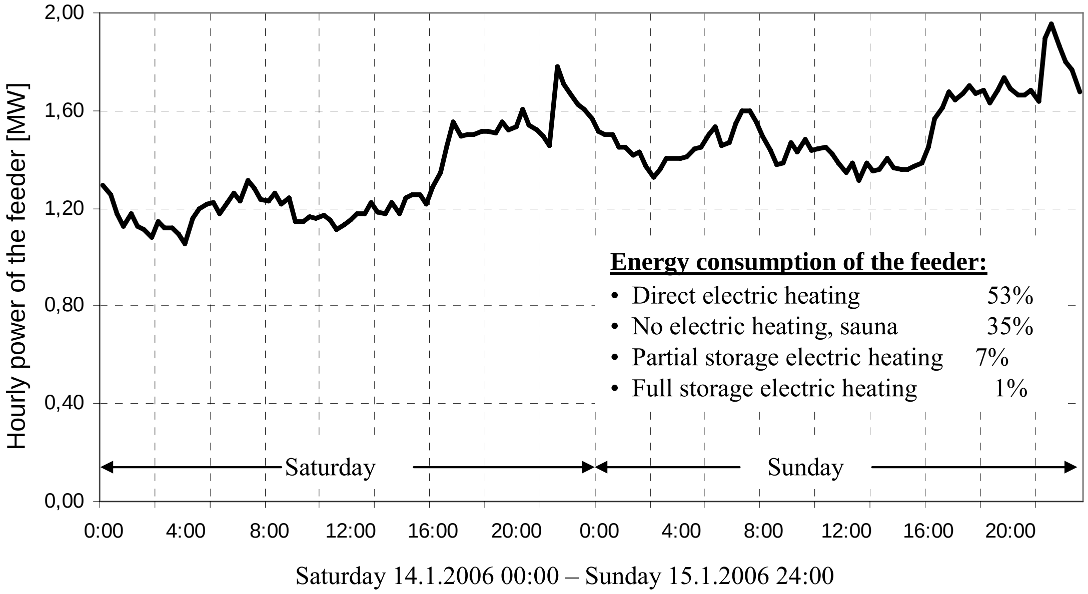

Figure 3. Load curve of the case feeder. Could you change the dates into form 14 Jan 2006?

In the actual network, feeders vary greatly by their number and types of customers, and consequently, by their peak power reduction potential, that is, demand response potential. For this reason, in order to define the DR benefits for the company, the whole network has to be taken into consideration.

INCENTIVE- BASED DEMAND RESPONSE

Demand response potential

The focus of the studies is on the customers with direct, full and partial storage electric heating, since they comprise the major flexible groups in terms of load control. According to the measured load curve, the hourly power increases by 250–300 kW every day of the week after 16:00 (sauna, cooking) and immediately after 22:00 (heating storages) as seen in Fig. 3. In Table 1, the study of the obtained hourly powers of each customer group gives the following contribution of customers with direct and storage electric heating to the peak power at 21:00 and 22:00 on a winter Saturday evening.

Table 1. Contribution of different customer groups to the total peak power of the feeders at 21:00 and 22:00 on a winter Saturday evening.

Type of electric heating of customers	***P*, 21:00, kW**	***P*, 22:00, kW**
Direct, floor heating > 2 kW, water storages 300 l	508 (33 %)	753 (42 %)
Direct, water storages < 300 l	288 (19 %)	269 (15 %)
Partial storage	107 (7 %)	183 (10 %)
Full storage	23 (1.5 %)	60 (3.3 %)
No electric heating, electric sauna	536 (35 %)	464 (26 %)
Total	**1520 (100 %)**	**1780 (100 %)**

Table 1 shows that the hourly power increases partly because of the partial, full storage and direct electric heating loads. The peak reduction potential can be roughly estimated by subtracting the values of hourly powers of the hour 21:00 from the values of the hour 22:00. Taking into account that an increase in consumption also occurs owing to the evening household activities (cooking, lighting, computers, TV, etc.), we assume that about 220 kW of the direct electric heating load and 100 kW of the full and partial storage electric heating load can be controlled.

Direct load control scenarios

The amount of peak power reduction depends on the number of customers simultaneously involved in DR actions. It is worth mentioning that the recovered energy in the following hour may be higher than the energy reduced in the previous hour as a result of the direct load control of water heaters. In the literature this effect is called “cold load pickup”. One of the ways to avoid a new peak power is cycling the control of water heaters [9]. This can be simulated by switching off only some part of water heaters instantaneously. The priority order in turning off heating loads and other appliances, and the possible amount of energy to be shifted is defined by the aggregator according to the information about the customer’s energy and hot water consumption. The first-priority target of the aggregator-based optimization is to level out the load curve, cutting the peaks and filling the valleys. The desired power peak reduction can best be achieved if a customer acts as an active participant of the network via an interactive customer gateway installed on the customer’s premises. The principal assumption of the paper is that all residential customers of the case feeder are equipped with interactive customer gateway infrastructure, which includes AMR and enables two-way communication between the customer and the aggregator. The latter obtains information about each customer’s hourly consumption and can thereby analyze the customer’s contribution to the peak power of the feeder. One of the aggregator’s tasks is to send requests to that number of customers whose total reduction potential will contribute to the power reduction of the peak hour interval (evening peak around 22:00).

In the paper, the amount of shifted load varies from 20 % to 100 % of the value defined in the previous section (320 kW). When shifting the load, it is assumed for simplicity that 100 % of the shifted energy is transferred to the hour when the load is recovered.

Two scenarios have been considered. In the first case, the shifting operations start at 22:00 and stop at 23:00. The second case considers shifting from 22:00 to 00:00.
The simulations have shown that the maximum power peak reduction is possible when 20 % is shifted by one hour or 60 to 100 % is shifted by two hours. The impact on the load curve is illustrated in Fig. 4.

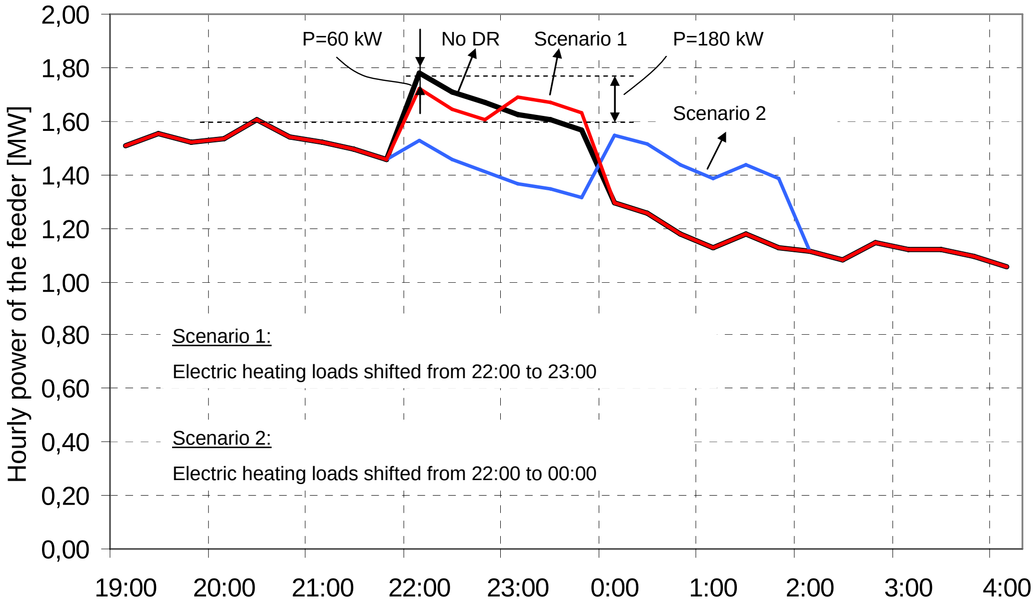

Figure 4. Impact of load control on the load curve. 64 kW is shifted by one hour and 256 kW by two hours.

The calculation results of the other load control scenarios are presented in Table 2.

Table 2. Power peak change in different load control scenarios.

Shifted load	**Number of simultaneously controlled water storage heaters, 3 kW/unit**	**Number of households, storage heating 5–20 kW/house**	**Power peak change, %**	
			Shifting 22–23	Shifting 22–00
100 % – 320 kW	73	20 houses with 5 kW storage heating load – 5 houses with 20 kW storage heating load	9	-9.5
80 % – 256 kW	58	16–4	5.6	-10.1
60 % – 192 kW	44	12–3	2.3	-10.1
40 % – 128 kW	29	8–2	-1.7	-7.2
20 % – 64 kW	14	4–1	-3.4	-3.6

The highest DR potential of the case feeder is limited to 180 kW (10.1 %) because of the peak power of 1.6 MW occurring at 20:00, when no direct load control takes place yet. One way to smooth the peak is to implement real-time pricing on residential customers. This will be presented in the following sections.

PRICE-BASED DEMAND RESPONSE

Elasticity

As already mentioned above, customer groups vary by the type of houses, heating types, consumption level, habits etc. Due to these factors, each customer group will react differently to price changes. This is characterized by the price elasticity of demand, which shows how much power demand is expected to change as a result of the change in price. The power peak reduction is calculated using (1):

$$\Delta P_{ij} = e \cdot \frac{\Delta C_{ij}}{C_i} \cdot P_i \qquad (1)$$

where

ΔP_{ij} - power change from hour i to hour j, MW
e - price demand elasticity of a customer group, p.u.
ΔC - price change against the reference price, €/MWh
C_i - system price of the hour i, €/MWh
P_i - power in the hour i, MW

In this regard, two types of loads will be considered:

- *Inelastic loads* that are almost not affected by changes in price, e < 1;
- *Elastic loads* that are very sensitive to price changes; only a slight change in price causes a dramatic change in demand, e > 1.

The first rough assumptions of elasticity will be made based on the savings that customers get if they react to dynamic prices. Households with a high consumption level are expected to react to both slight and drastic price changes, whereas households with a relatively low consumption level are expected to react only to drastic price changes, since slight changes will not bring them significant savings. As an initial assumption, the critical annual consumption level is set to be 10 000 kWh/a, which is equal to the electricity bill of 1 000 € / a (if the retail price is 10 cents / kWh). The classification is presented in Table 3.

Table 3. Division into elastic and inelastic loads.EH = Electric heating.

Inelastic loads	**Elastic loads**
1. Detached houses, no EH, electric sauna (8 585 kWh) 2. Apartments (1 960 kWh) 3. Detached houses, full storage EH (34 025 kWh)	1. Detached houses, direct EH (18 634 kWh) 2. Detached houses, partial storage EH (22 833 kWh) 3. Terraced houses, no EH, electric sauna (23 370 kWh) 4. Terraced houses, direct EH (12 510 kWh)
251 customers, 2 110 MWh	185 customers, 3 473 MWh

The consideration of customers with full storage electric heating as an elastic load group according to the consumption level may not be appropriate. Their consumption during the day-tariff time from 07:00 to 22:00 remains so low that there are no incentives to change it in reaction to price signals. In this regard, their price response will be considered only for price peaks occurring after 22:00, when electric heating loads are turned on.

Real-time pricing simulation

The real- time pricing has been simulated for residential customers by using area spot prices on the Nord Pool. Before analyzing the spot price curve, the measured system and feeder loads have been combined in a single chart to figure out similarities and differences, as illustrated in Fig. 5. The system load is measured for all electricity customers in Finland [10]. The feeder is located in a rural area, where the majority of customers have electric heating loads. The presented measurements have been done during the week 7–13 Jan 2008. The feeder has two evening peaks. The first one occurs around 5–8 pm because of cooking, lighting, TV and entertainment, and it coincides with the system peak load (see Fig. 5).

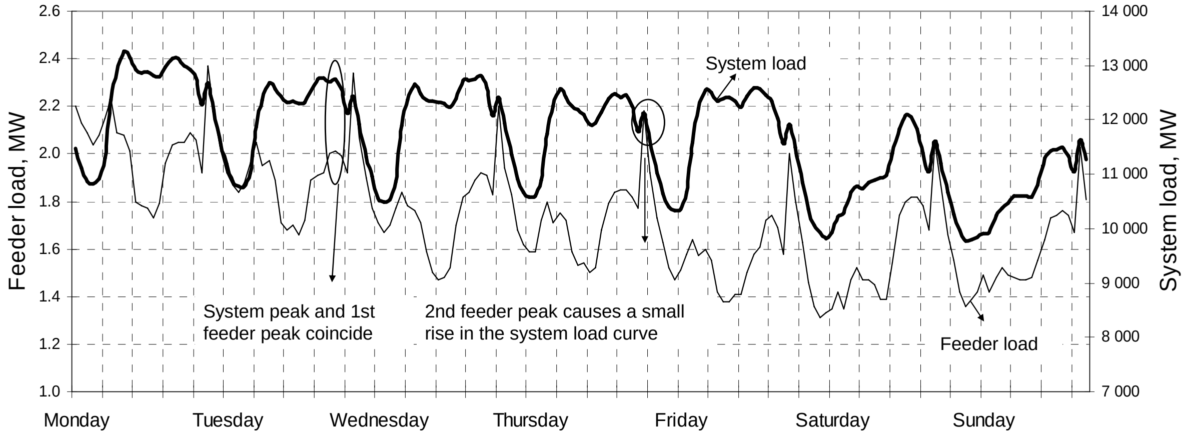

Figure 5. System load and the case feeder load curves.

The second one is observed around 10 pm mostly because of the electric heating storage loads. It causes a minor short-term rise in the system load curve, and it is lower than the earlier evening system load peak. At the system level, most of the public, commercial and some industry customers have already stopped working by this time. Therefore, the spot price does not usually follow this rise in consumption, caused by residential customers, as illustrated in Fig. 6.

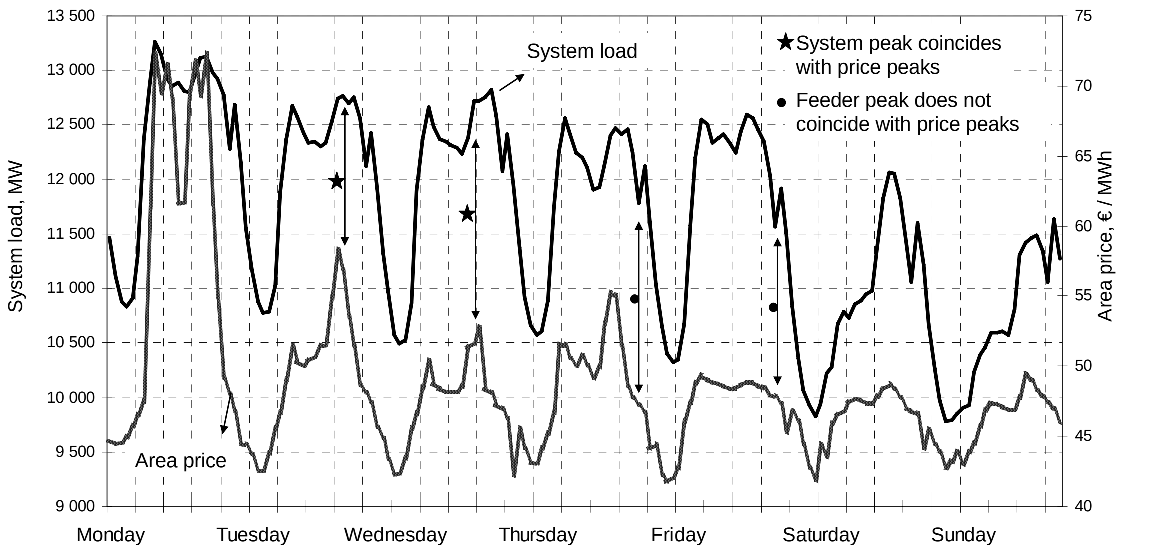

Figure 6. Hourly spot prices and powers on the time scale.

For this reason, real-time pricing does not smooth the feeder's second evening peak since the price curve often counteracts the power profile after 9 or 10 pm. Hence, direct load control activities in addition to real-time pricing are required to smooth the peak power caused by electric heating loads.

The presented price curve is the average price fluctuation and is relatively small during one day. However, high price peaks have occurred several times in Finland already. In winter 2008, the maximum spot price was about 160 €/MWh, and in December 2009, the highest price level was already reaching 250 €/MWh. In winter 2009–2010, the area prices fluctuated between 300 and 1400 €/MWh [8]. The rising price tendency is clearly seen from year to year. Therefore, such critical price situations should be taken into account when studying the impact of the real-time pricing on customers' behavior.

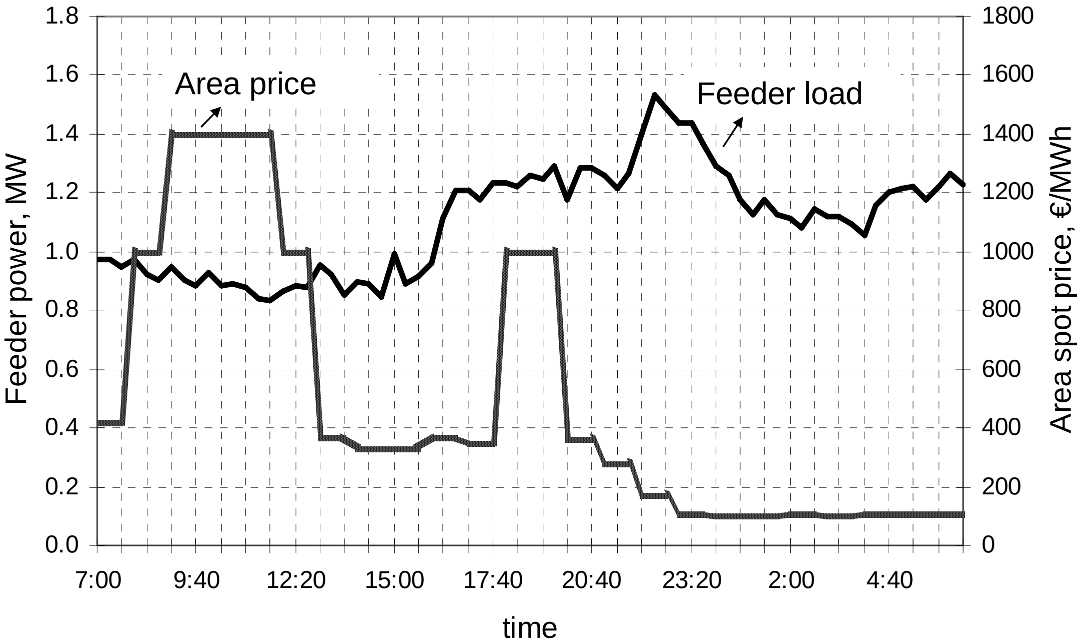

Figure 7 Example of the drastic area price fluctuations on a cold winter day [8].

It is seen in Fig. 7 that the first peak price of the example day is 1000–1400 €/MWh and it occurs from 8 to 13 am, and the second one, 1000 €/MWh, from 5 to 7 pm. Assuming that all customers will react to the morning and evening price signals even if the price changes only by 1 %, in other words, the consumption of elastic and inelastic loads will reduce by 1.2 % and 0.2 %, respectively, the savings for the customer and energy supplier can be estimated. These are presented in Table 4.

Table 4 Impact of customers' price response to the savings. EH=electric heating

Customer type	**Average reduction per hour per customer, W**	**Savings, € /customer**		
		Response to the morning price peak, 8–13 am, 1000-1400 €/MWh	Response to the evening price peak, 6–8 pm, 1000 €/MWh	Response to both price peaks
Direct EH, 163 cust	40	0.26	0.06	0.32
Partial EH, 17 cust	290–470	0.22	0.05	0.27
Terraced houses, no EH, 1 cust	20–30	0.15	0.14	0.29
Terraced houses, direct EH, 2 cust	30–32	0.2	0.05	0.25
Apartments, 17 cust	9–10	0.003	0.0013	0.0031
Detached houses, no EH, 234 cust	17–21	0.012	0.008	0.02
Total savings, for the energy	1.2 % load reduction	50	14	64

supplier,	2.4% load reduction	100	30	130
	3.6% load reduction	150	45	195

Table 4 shows that customers with a low consumption level have no incentives to reduce the load because of only slight savings. For the customers with elastic loads, on the contrary, by just turning off some lamps or switching off a desktop computer, or not using a cooker during the peak hours, a household can save 32 cents per day and more. It has been calculated that the energy supplier has to pay 11854 € for the demanded energy of the case feeder on the example critical price day. The above calculated savings are 0.5 %, 1 % and 1.5 % from the total expenses for a load reduction of 1.2 %, 2.4 % and 3.6 %, respectively.

Price-demand response scenarios

In the future, customers will get information about hourly prices of the coming day, and they will get incentives to decrease their consumption, for instance by shifting the operation of their washing or dish-washing machine, switching temporarily the water storage heater off, putting the electrical sauna off to a later or earlier hour or switching from electric to wood or oil heating.

The following scenarios are possible:

1. A customer is equipped *with enabling technologies*, for instance an intelligent load controller. It receives the spot prices for the next day from the aggregator and carries out the load control according to the customer's preferences. The intelligent load controller can be simulated by carrying out price demand response to the hourly price fluctuation during the day according to the assumed elasticity.

   It should be borne in mind that the amount of load reduction should not be dependent on the short-term hourly price change, but instead defined so that the total costs of the customer are minimized during a certain period of time. This customer-based load control brings up a complicated optimization question which is beyond the scope of this paper. For the sake of simplicity, power reduction will be proportional to the difference between the spot price and a reference price, selected to be the average spot price of the day.

2. A customer has *no enabling technologies*, but still receives information about spot prices through the AMR. Price demand response can then be carried out only when the customer is at home. It has been assumed in the paper that price demand response in this case is carried out in the evenings manually by customers.

In the paper, it is assumed that elasticity is 1.2 for elastic loads and 0.2 for inelastic loads. In other words, the price change of 1 % causes an elastic load reduction of 1.2 % and inelastic load reduction of 0.2 %. The reference price is selected to be the average spot price during the day, for the considered days it is 47 €/MWh.

The effect of price-demand elasticity of elastic loads of the case feeder on the peak power reduction for the second scenario is presented in Fig. 8.

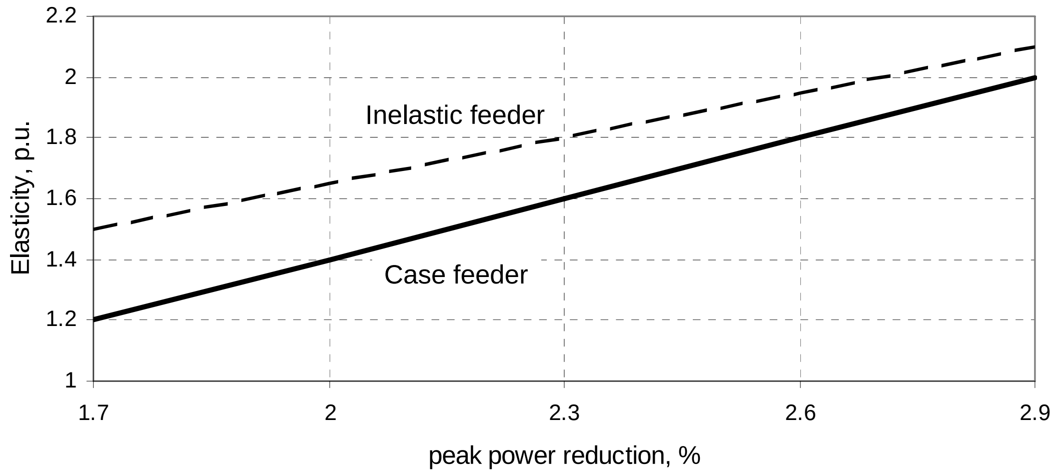

Figure 8. Effect of elasticity on the power peak reduction (no enabling technologies).

We can see in Fig. 8 that each increase in elasticity by 0.2 units produces a 0.3 % higher peak load reduction. This correlation depends strongly on the amount of elastic and inelastic loads on the feeder. The load reduction is quantitatively higher than the change in price if there are more elastic than inelastic loads on a feeder, as it is on the case feeder. In this regard, the term *elastic* and *inelastic feeders* are to be defined. In inelastic feeders there are more inelastic loads than elastic ones; hence, it is less sensitive to the price change, as shown in Fig. 8.

BENEFITS OF COMBINED DIRECT LOAD CONTROL AND PRICE- DEMAND RESPONSE

In the literature, it is mentioned that the two considered types of DR for small customers should function together [11], since the price- based DR results in long-term impacts such as smoothing the morning and evening peaks and filling the day and night valleys, while the incentive-based DR focuses on short-term market conditions, for example peaks caused by electrical heating around 10 pm. In [12], it is estimated that with the direct load control and dynamic pricing, the load reduction is 53 % larger than with the load control alone, and 102 % larger than with dynamic pricing only. In this paper, the impact of both direct load control and dynamic pricing on the power reduction potential will also be estimated.

Having estimated the separate impacts of price-based and incentive-based demand responses on the power peak reduction, the demand response potential needs to be evaluated if both types of demand response are executed at the same time.

Above in this paper it was shown that the maximum peak reduction as a result of direct load control of the case feeder loads is limited to 180 kW (10.1 %) because of the first evening peak power of 1.6 MW occurring at 20:00. The idea is to show that if real-time pricing contributes to smoothing the first peak power, the peak reduction achieved by direct load control can be increased. This is illustrated in Fig. 9, and the calculation results are shown later in Table 5.

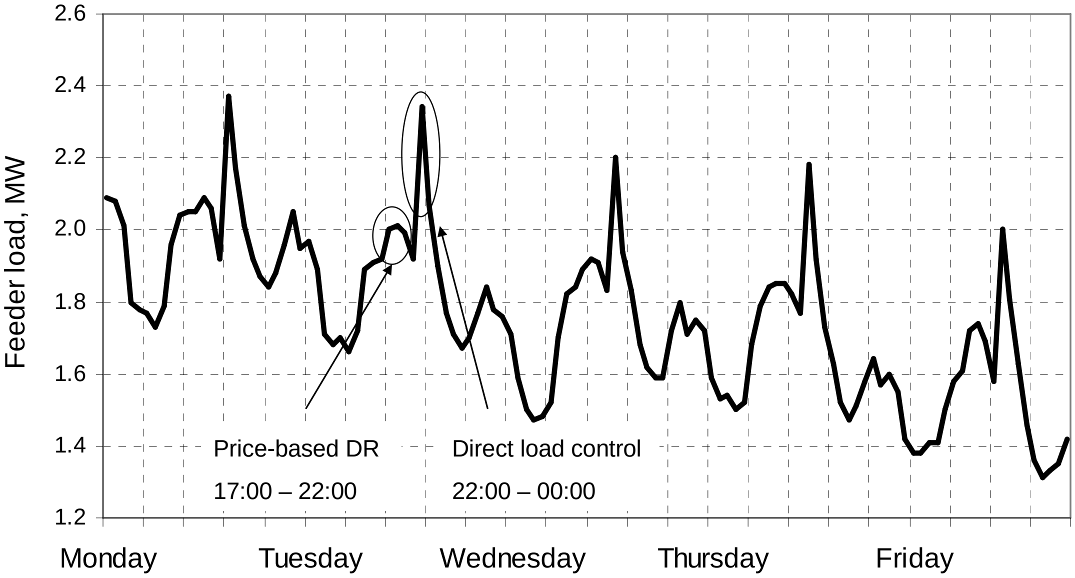

Figure 9. Time occurrence of the price-based demand response and direct load control.

LOCAL ENERGY STORAGE UNITS

Local energy storage units will play a multifunctional role in electricity distribution networks. In this case, we consider them as a means of load levelling. One of the questions of the paper is to quantify the contribution of local energy storages to the power peak reduction. For this purpose, an assumption about the penetration rate and energy content of storages has to be made. The principal assumption is that one detached house might own a 10–20 kWh energy storage unit, which is near to the capacity of an electric car battery. In calculations, 10 kWh units are considered in order not to overestimate the peak power reduction. The penetration rate varies from 5 to 30 %, which will give an energy content of 220 kWh to 1320 kWh, respectively. It has been simulated that charging takes eight hours from 8:00 to 16:00, and discharging –seven hours, from 17:00 to 01:00, with one-hour break when the load is being shifted for the second scenario and continuously for the first scenario. Thus, the maximum peak power reduction can be obtained. Fig. 10 shows how energy storages affect the load curve, with and without load control. The peak reduction is higher in combination with the direct load control, which proves that the value of energy storages is higher when demand response takes place.

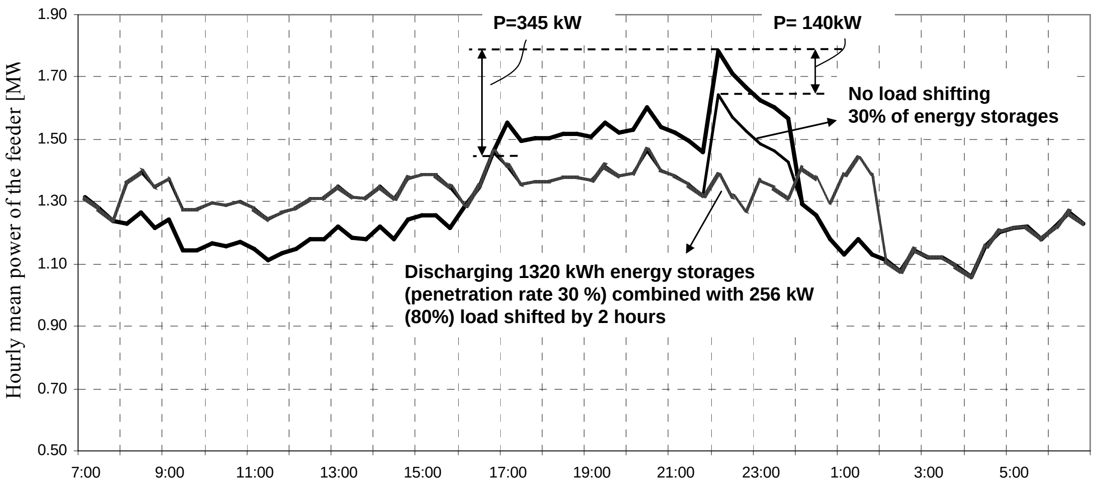

Figure 10. Impact of energy storages on the load curve.

When customers have local energy storages, the customer-based load control becomes more complicated. It is then necessary to know whether the energy storage capacity is sufficient to supply those appliances during the peak price hour. All customers' loads can be divided into two groups, controllable and non-controllable. The assumption about their prioritization from the customer's perspective and consumption values [13] are presented in Fig. 11.

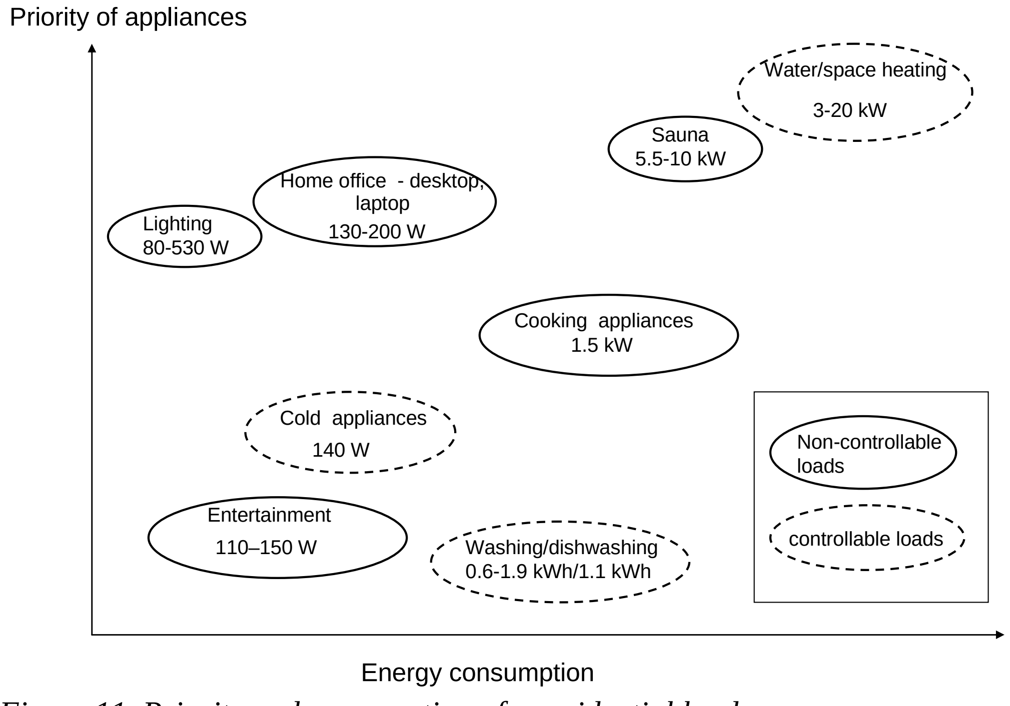

Figure 11. Priority and consumption of a residential load.

After having prioritized the loads and defined their consumption, the types and the most probable combination of appliances supplied by local energy storages during the peak price hour can be suggested. The energy storage should be used at the moment when the price has reached its peak and the customer is not willing to interrupt or shift some of the appliances for the sake of his own comfort. Such appliances might be cooking, sauna, water/space heating, home office and lighting according to the assumed priority (Fig. 11).

DEMAND RESPONSE EFFECTS ON A DISTRIBUTION COMPANY

Effects on distribution fees

The amount of required investments can be estimated by defining the average marginal cost of the network [14]. It is based on the network replacement value and the maximum load of the year, and it describes how much the network capacity has cost for the distribution company per each peak load kilowatt. In the example network, the network value compared with the peak load is 1000 €/kW, which includes the value of medium-voltage and low-voltage networks as well as the primary substation level. If the peak reduction of the network is for instance 176 kW, an estimation of savings in the network investments is:

$$C_{\sum} = NV \text{ x } \Delta P = 1000 \text{ €/kW x } 176 \text{ kW} = 176 \text{ k€}. \tag{2}$$

Considering a period of 10 a and an interest rate 5 %, the annual saving of 176 k€ is 22.8 k€/a. The cut in distribution fees is found as annual savings divided by the annual energy consumption resulting in 0.4 cent/kWh (= 22.8 k€ / 5.7 GWh). In practice, the calculated fee reduction can be achieved only with the permanent customers' response to price or power signals during the reference period of 10 a, which in reality is difficult to achieve and impossible to influence by the aggregator because of the always existing override option that the customers have. The possible solutions to stimulate the customers' activity could be different ways of rewarding them for participation in demand response activities in addition to the electricity bill savings.
The calculation results for the other scenarios are presented in Table 5.

Delay in reinforcement costs

In order to estimate for how long reinforcement investments can be delayed, the load growth rate (r, %) and the demand response potential (ΔP, kW) are required. The peak power in 10 years with the load control actions taken into account can be defined by (3).

$$P_{10} = (P_1 - \Delta P) \cdot (1 + \frac{r}{100})^t \tag{3}$$

where

P_1	hourly mean power of the 1st year of the reference time period, kW
P_{10}	hourly mean power of the 10th year of the reference time period, kW
ΔP	demand response potential, kW
r	load growth rate, % (in this paper 1.5 %)
t	reference time period, a (in this paper 10 a)

After the peak power for the 10th year has been calculated, the delay in reinforcement investments can be defined as the difference between the reference period of 10 a and the number of years in which the peak power without load control actions will occur (Table 5).

Table 5. Effects of demand response on the distribution company.

	Scenario	Peak power reduction		Annual savings k€/a	Distribution fee cut cent/kWh	Delay in investments
		%	kW			
Incentive-based demand response						
No energy storages	I, 20 %	3	60	7.7	0.14	2 a
	II, 80 %	10	180	22.8	0.4	7 a
Energy storages, 5 %	I, 20 %	5	90	11.7	0.2	3.5 a
	II, 80 %	11	208	26.9	0.47	8.4 a
Energy storages, 30 %	I, 20 %	13	250	32.4	0.57	10.1 a
	II, 80 %	19	345	44.7	0.78	14.5 a
Price-based demand response						
Low elasticity	1.2 + 0.2	1.7	30	3.9	0.07	1 a
High elasticity	2.0+0.6	2.98	60	7.7	0.14	2 a
Incentive-based and price-based DR						
No energy storages + low elasticity	I, 20 %	3	60	7.7	0.14	2 a
	II, 80 %	11,9	210	27.2	0.48	8.4 a

The last row of the table shows that the incentive-based DR combined with the price-based DR results in a 1.9 % higher peak power reduction in scenario II compared with the same scenario with just the incentive-based DR. In scenario I with 20 % of the shifted heating load price-response brings no effect, because the second evening peak is still higher than the first peak power.

However, it should be borne in mind that the results depend strongly on the load curve, in other words, on the type, number and consumption behaviour of customers on the feeder. The calculations are primarily used to demonstrate the methodology for defining the effects of demand response on the DSO and quantitatively present their possible limits. These are theoretically possible limits, which depend on the willingness of customers to participate in demand response activities.

Value of local energy storages

Assuming the price of the energy storage units 7 k€/10 kWh, the annual investments for a 10-year period with the 5 % interest rate will vary from 20 to 120 k€ for the penetration rates 5–30 %, respectively. This shows that the benefit for scenario II with 5 % of energy storages is positive and equal to 6.9 k€/a. In the three other scenarios, the energy storages are not profitable since the annual savings from the peak power reduction are lower than the annual investments needed in the energy storages. Figure 12 illustrates how the number of energy storages in the network, when combined with load control, affects the peak power reduction of the feeder and the distribution company annual savings. It shows that the technical profitability is limited to 30 % penetration rate in this case. The higher number of energy storages will reduce the power peak only slightly, and the benefits will decrease because of the rising storage expenses. The 7 % penetration rate corresponds to the balance between annual savings and investments. Thus, this is the maximum number of storages that is beneficial at the present moment.

The cost benefit is strongly dependent on the price of energy storages and the load curve of the present feeder. It can be estimated that the prices of energy storages will decrease in the future.

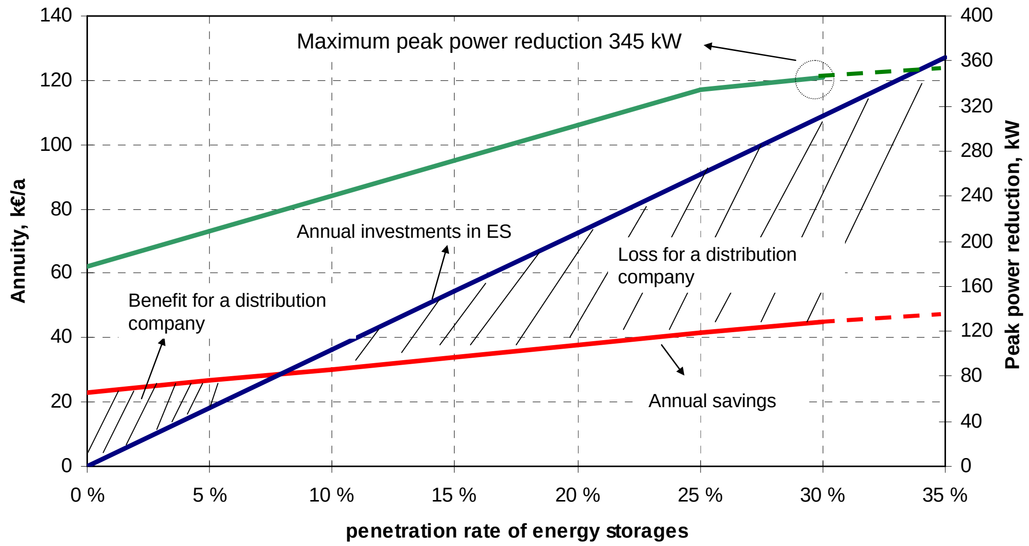

Figure 12. Cost benefit analysis of energy storages.

If the unit price would be half compared with the case price (3.5 k€/a), the maximum beneficial penetration rate rises up to 20 % with the 300 kW reduction potential. This demonstrates that the benefits for the network will be higher when the price of energy storages goes down.

CONCLUSIONS

The main results of the paper are:

1. There are remarkable incentives to control the peak load of electricity distribution networks by demand response. The methodology for defining the effects of demand response on the end-customer distribution fee is described in this paper. The results are strongly dependent on the load curve of customers. In the future, when more customers are equipped with AMR, an analysis based on customer-specific measurement data and the presented methodology will yield more reliable results for a distribution company.

2. It is shown that the peak power of the feeder can be reduced by 10 % by the direct load control of electric heating loads. It can cut the distribution fees of the end-customers by 0.4 cents/kWh and delay the investment costs by 7 a. The cut in distribution fees requires the permanent customers' response, and hence, it can be rather considered as a theoretically possible impact on the DSO. If customers respond also to price signals, the feeder peak can be reduced further by 1 %.

3. The local energy storages show significant impact on the load curve. The optimal penetration rate of energy storages turned out to be 7 % for the present day, when annual savings from peak power reduction are equal to the annual investments in the energy storages. In the future, the storages will bring higher benefits to the network as their price goes down.

4. The further important research question is the impact of local energy storages on the performance of both customers and superior electricity market players (DSO, aggregator, energy supplier). While the information about energy content and penetration rate is needed to estimate the effect on the medium voltage networks, finding the optimal location and distribution of energy storages will demonstrate the challenges and benefits for the low voltage networks.

5. The other important question is to develop a model for an intelligent load controller, that is, to define what kind of activities (shifting/interrupting) should be introduced, for how long time and in which order they should be carried out with home appliances in order to minimize the total energy costs for the end-user.

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