Implications of Electricity Demand Response Experiment Structures for Commercial Customers

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Abstract

To avoid unnecessary investments in transmission and generation resources, a good solution is to apply Demand Response programs to reduce the demand for electricity at peak hours, when generating electricity is more costly. Customers do not see how the electricity prices change on the real-time market, since most of them pay a flat rate based on the average price of electricity, therefore Demand Response programs can offer incentives to consumers to reduce their usage at peak hours, through rebates or as a response to higher electricity prices. For the residential customers, these programs yield positive results because users reduce their load at peak hours and, in some cases, they shift their usage to lower price periods. For industrial customers, the Demand Response programs there have not been as numerous experiments as for the residential sector, but they still yield a positive usage reduction.

1. Introduction

Electricity cannot be stored in large amounts, so it must be produced when it is demanded. At high demand periods, more costly generators are dispatched. For many utilities, peak demands occur during the afternoon hours of hot summer days. Therefore, the marginal cost of producing electricity varies across the day. Meanwhile, the price the customers pay for the electricity remains constant for months at a time, regardless of the cost of generating the electricity they use at that specific time. This leads to an inefficient market behavior, since the gap between the wholesale and retail electricity prices can be very large and customers are subsidizing and being subsidized, while under-using electricity at low cost periods and over-using it at high cost periods. Estimates place the magnitude of the deadweight loss from time-invariant retail electricity prices in the tens of billions of dollars annually in the U.S. (Jessoe et al., 2011). As a consequence, inefficient capital investments in generation and transmission resources have to be made to guarantee reliability, to avoid congestion and potential blackouts at high load periods.

At the Philadelphia Navy Yard there is a similar situation. There is a potential congestion problem in the two substations that feed the electricity. One of these substations is close to reaching its maximum capacity limit, getting congested during peak periods in the year, when the load is too high for the system to handle and customers are forced to reduce their electricity usage temporarily. Some of this congestion could be alleviated by transferring some of the load to the other substation, but this would be only a temporary solution because that substation will feed several new developments at the Navy Yard, additional to its current load. A clear solution for this congestion problem is to reduce the load that both substations handle.

If the market is allowed to respond, marginal-cost based prices will spur more efficient energy use, and in turn help to mitigate energy crisis episodes, like those generated by blackouts (Taylor et al., 2005). A potential solution for this problem is to develop a Demand Response program that allows customers to reduce their electricity usage, through real-time pricing or offering incentives.

2. Demand Response Overview

Demand Response (DR) is understood as the changes in electricity usage by end-use customers from their normal consumption patterns in response to changes in the price of electricity over time (Albadi et al., 2008). A customer can respond by reducing its electricity demand, by changing its usage habits, for example, shifting electricity usage from peak hours to lower price periods. Or, customers can also respond without voluntarily changing their usage pattern, for example, by letting the utility change the thermostat of the air conditioning or heating system during peak periods. Also, customers that have their own generation resources can use them on periods of higher electricity prices. All of those actions contribute to the reduction of electricity peak demand.

Most DR programs require the installation of technology devices that allow two-way communication between the utility and the customer, to inform them about price changes or any other information the utility deems necessary or allowing the utility to make changes in the customer's thermostat. The customer can receive a notification through a message displayed on the screen of the in-home display or through a change of the color code assigned to different price levels shown on a device, such as an energy orb. Other devices measure, store and transmit the interval use data of each customer to the utility. The latter are known as smart meters.

To quantify the response of each customer, there are three necessary measure components of the electricity usage: the baseline, the actual use and the load reduction. The baseline represents the amount of electricity that a customer would have consumed in the absence of a request to reduce the consumption. The actual use is the amount of electricity that the consumer used during the event. And the load reduction is the difference between the baseline and the actual use measurements for each customer at a determined event.

Some DR program modalities are listed below (Albadi et al., 2008):

- Price-based programs: these include time-of-use (TOU), critical-peak pricing (CPP) and real-time pricing (RTP) tariffs. When customers are given the information on price changes, their usage pattern adjusts to reduce demand at higher electricity price periods.
- Incentive-based programs: customers get paid to reduce the usage at determined periods established by the electricity provider. This includes peak-time rebates (PTR), direct load control, interruptible/curtailable (I/C) service, demand bidding/buyback programs, emergency demand response programs, capacity market programs, and ancillary services market programs.

The most common price-based program is the TOU rate, which is a simplified version of RTP. Here, two or three periods in the day are assigned as low, medium and high demand, and higher prices are charged to the customers on the high demand periods. Rates reflect the average cost of generating and delivering power during those time periods. The consumer will use the electricity when its marginal benefit is highest, but it is forced to pay a high price if that time corresponds to a system peak, unless it shifts its usage to off-peak hours to pay a lower price. These benefits are often not clearly described to the user; as a consequence there is no full internalization by the customers, so the programs do not achieve meaningful results (Jessoe et al., 2011).

Critical Peak Pricing, or CPP, includes a higher electricity price during the peak period superimposed on TOU or standard flat rates. The higher price is charged on a determined amount of hours several days a year, called events. These events are called especially on hot summer weekdays, except holidays, when the forecasted peak demand is too high and supply prices are very high in consequence, and/or when system reliability is compromised. The customer gets a notification prior to the event via e-mail, text message or through a technology device to indicate a change in electricity price for a determined period of the day. The users have incentives to curtail their electricity usage during the event periods; further, usage is expected to be reduced during peak hours in general, when the CPP is applied in addition to TOU rates. This program has been proved to offer significant electricity usage reduction, compared to other DR programs.

Real Time Pricing programs are based on charging the customers a price for electricity that reflects the variations on the wholesale price, at a high frequency. RTP customers are informed of the electricity prices on a day-ahead or hour-ahead basis, through the same means as the CPP program does. A goal of this program is to charge prices such that the user internalizes the externality of wholesale price changes, by shifting usage from higher price periods to off-peak periods. RTP can eliminate the inefficient gap between wholesale and retail prices, by transmitting the changes in the marginal cost to retail consumers.

Among the incentive-based programs, Peak Time Rebate (PTR) consists of giving the customer a rebate for each unit of electricity that is not used during the peak period. Normally, these rebates are offered to the customers enrolled in the program during a determined number of event days a year. If participants manage to reduce their typical consumption during the peak hours, they get a determined amount of money or billing credit per kWh reduced below their baseline. As before, this program requires customers to be notified prior to the event days.

In the direct load control, the program operator remotely shuts down or cycles a customer's electrical equipment (e.g. air conditioner, heating system, water heater) on short notice. This type of program is primarily offered to residential or small commercial customers.

The interruptible/curtailable service comprises curtailment options integrated into retail tariffs that provide a fixed rate discount or bill credit for customers who agree to reduce load during system contingencies. Penalties maybe assessed for failure to curtail load. Interruptible programs are traditionally offered only to the largest commercial and industrial customers.

The demand bidding/buyback programs require customers to offer bids to curtail based on wholesale electricity market prices or an equivalent. The main difference between this program and the interruptible/curtailable service is found in the incentive offered: the latter offers a fixed amount as a bill credit or rate discount, while the incentives for the demand bidding/buyback programs are based on prices from the real-time market, which vary across time. This program is mainly offered to large customers, with over one megawatt of electricity usage.

Emergency demand response consists in providing incentive payments to customers for load reductions during periods when reserve shortfalls arise. These programs may include a penalty for non-compliance with the amount of electricity usage required to reduce.

In the capacity market programs the customers offer the utility blocks of load curtailments as system capacity to replace conventional generation or delivery resources. Customers typically receive the notification to curtail on the same day of events. Incentives usually consist of up-front reservation payments, and face penalties for failure to curtail when called upon to do so.

At the ancillary services market programs, customers bid load curtailments in the ISO/RTO markets as operating reserves. If their bids are accepted, they are paid the market price for committing to be on standby. If their load curtailments are needed, they are notified by the ISO/RTO, and may be paid the spot market energy price for the amount of electricity they do not use.

One of the most important benefits from the DR programs is the improvement of resource efficiency on electricity generation, transmission and distribution, since customers are able to align the value they give to electricity with the price they pay for it. Overall, benefits from DR response programs can be gathered in four groups (DOE, 2006):

- Participant financial services: translated into bill savings and incentives earned by customers. Some customers might increase their electricity usage, without increasing their bills if they do so at lower price periods.
- Market-wide financial benefits: overall electricity prices are lower resulting from a more efficient utilization of the available infrastructure, reducing the need from dispatching the most expensive generation sources. Demand response avoids and/or defers the need for upgrades in transmission and distribution infrastructure, then those cost savings will be enjoyed by all customers.
- Reliability benefits: customers can contribute to reduce the risk of outages and electricity interruption. Operators gain savings from increased resource adequacy and reduction in the likelihood of forced outages.
- Market performance benefits: price signals decrease producers' opportunities to exploit market power, reducing volatility of prices in the spot market.

The costs of deploying DR program can be categorized as follows (DOE, 2006):

- Participant costs:
    - One-time initial cost of installing enabling technology and devising a response plan. Participants may have to incur some initial costs if they have to cover the cost of installing smart meters, programmable thermostats, peak load controls, energy management systems, price display and communication devices, onsite generation units, etc. Implementing an effective response plan or strategy in case

an event is called may also require initial resource investment. Technical support for these activities is usually provided by program administrators.

  - Recurring costs associated with the inconvenience of having to reduce demand, potential reduction in business associated with reduction, halting, or rescheduling of operations, and potential costs of on-site generation.

- Program administrator costs:
  - One-time initial cost of installing metering and communication infrastructure and billing system, and devising customer education initiatives. The program administrator will often have to bear all or some of the costs of installing enabling technology, as well as devising an effective educational program to inform eligible customers of the potential benefits of DR programs and to teach them how to respond to market signals.
  - Recurring costs of program administration, marketing, incentive payments and evaluation of results.

In 2004, utilities reported spending $515 million on load management programs. This represents a 10 percent decrease from the early to mid-1990s (DOE, 2006). Figure 1 below demonstrates the actual and potential costs (implementation) and benefits (usage reduction) of DR program implementation for U.S. utilities between 1996 and 2004.

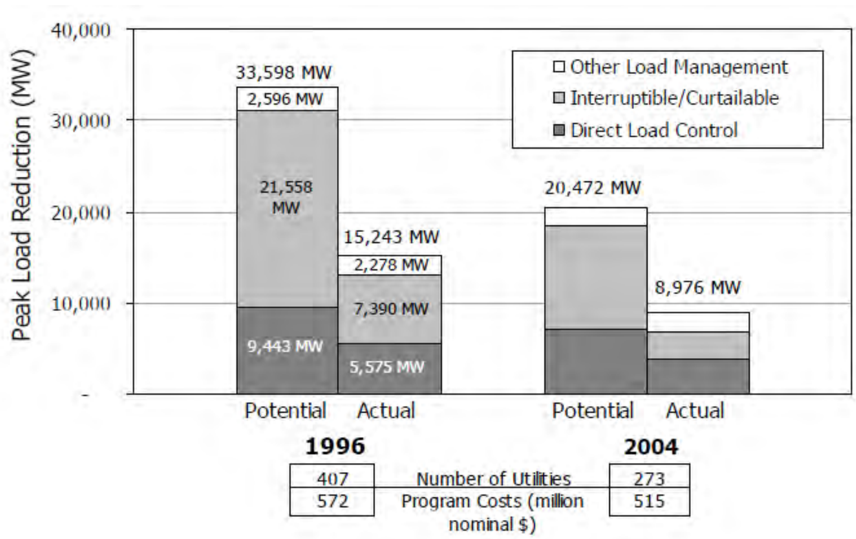

Figure 1. Existing U.S. Demand Response potential (DOE, 2006).

3. Industry overview

There have been several DR pilot programs tested across the US. They have been implemented largely within the residential sector, since residential customers have more discretion over their electricity usage and are therefore better able to shift their demand from on-peak to off-peak periods, as compared to commercial or industrial customers that may be constrained by a continuous process flow or other operational considerations that supersede variations in electricity prices.

Residential demand response studies revealed that a program's success depends first and foremost on its ability to integrate consumer education initiatives that allow people to understand why electricity prices are changing and how to best to respond to such changes (Faruqui et al., 2010). Other factors of DR program success include the magnitude of price changes, presence of central air conditioning, and availability of enabling technologies, such as two-way programmable thermostats and devices that allow programming several appliances remotely.

Most DR experiments for residential customers yield positive usage reduction results because of customers' flexibility in shifting their demand for electricity, which may not be as easy for commercial and industrial segments. Central results from residential DR studies can be summarized as follows:

- TOU rates lead to a drop in peak demand between 3% to 6%;
- CPP rates lead to a drop in peak demand of 13% to 20%; and
- CPP rates coupled with enabling technologies lead to a drop in peak demand of 27% to 44%.

Although these pricing experiments are largely heterogeneous in their designs and there is a variation in their experimental quality, the conclusion is very clear: residential customers respond to changes in electricity prices by changing their electricity usage (Faruqui et al., 2010).

Faruqui et al. analyzed fifteen demand response programs, evaluating the residential customers that participated on them. In the experiments, the critical peak hours occur typically during the top 1% of the hours of the year, where 9% to 17% of the annual peak demand is concentrated. By analyzing the Constant Elasticity of Substitution (CES), and accounting for the fact that each experiment had its own unique weather conditions and unique appliances holding, the results indicate that customers respond to higher prices during peak periods by reducing usage at those times and/or shifting the demand to the off-peak periods. Customer response was higher in warmer climates and for customers with homes powered exclusively by electricity. The CES for the average customer was around 0.14, indicating that a one percent increase in the ratio of peak to off-peak prices resulted in a 0.14% reduction in electricity usage. Overall elasticity ranged between 0.07 and 0.21, with the lower values observed for mild weather regions and customers with fewer electric appliances.

Before 2009, the only three pilots for non-residential customers performed in the U.S. were the California Statewide Pricing Pilot (SPP), Baltimore Gas and Electric's Smart Energy Pricing pilot and Connecticut Light & Power's Plan-It Wise Energy Program (Faruqui et al., 2010). Each pilot had different structure and rate designs, like Time-Of-Use (TOU) and Critical Peak Pricing (CPP) rates as well as Peak Time Rebates (PTR).

In the California SPP pilot, the small and medium commercial and industrial customers were assigned to TOU and CPP rates, where the CPP rate came with the option of enabling technology installed free of charge. The pilot was designed as a combined effort of three utilities and two regulatory agencies, and ran from July 2003 to December 2004, with 2,500 customers, including residential, small commercial and industrial (C&I) and medium C&I. For those C&I customers on the CPP rate, the rate had a variable peak period and day of notification. The peak reduction among those customers on CPP rates ranged from 1.5% to 14.3%.

The Baltimore Gas and Electric (BG&E) pilot ran during the summer of 2009. It tested only the peak time rebate rate for commercial customers, with and without a smart thermostat technology, where customers received $1.50 for every kWh they reduced below their baseline consumption. This pilot included 352 commercial customers in the final sample, of which 263 were treatment and 89 were control. Commercial customers on the PTR rate reduced their peak load by 2.7%, and this increases to 7% with the addition of the smart thermostat technology.

The Connecticut Light & Power (CL&P), part of Northeastern Utilities, ran the voluntary rate program called Plan-It Wise Energy, to test the interest of residential and C&I customers and their response to dynamic pricing. The pilot ran from June to August 2009. The program tested a PTR and peak time pricing (PTP), which was similar to critical peak pricing, for small commercial and industrial customers. The PTP rate was offered with and without technology.

The peak reduction in the pilot ranges from 1.7% to 7.2%. The reductions are highest for the PTP rate with enabling technology.

When grouping these results by pilot, controlling for pilot design and location, the results suggest that on the whole, the SPP impacts were higher than the BGE and CL&P results, reaching a 14% peak reduction. Though, this pilot grouping ignores the impact of rate type, technology, and other important factors. Viewing the results by rate type and enabling technology, allows seeing the range of impacts of specific rate offerings. Just like residential customers, commercial and industrial customers respond the most to CPP rates when combined with enabling technology, reducing peak load up to 14.3%. While the TOU rate produces the smallest impacts, with peak reductions of only around 2%. So, it is clear that the commercial and industrial customers do respond to the dynamic pricing rates by lowering their peak demand.

In California in 2009 the Sacramento Municipal Utility District (SMUD) designed a demand response program for large, medium and small commercial customers with two tariff options for peak hours on event days: Critical Peak Pricing and Control of Air Conditioner Thermostats (ACC, by 2 and 4 degrees), where participants in the latter option got installed a communication thermostat controlled by SMUD (Herter et. al, 2009). The results yielded that customers with enabling technology had more important usage and load changes than those customers without enabling technology. Participants with the controlled thermostat reduced their load considerably more than participants without the thermostat during events, without increasing their overall usage during event days, reaching over 25% of load reduction. The study group included retail stores, business offices and restaurants. The first two businesses had a greater response by lowering their electricity load during critical peak periods, compared to restaurants. For customers in the CPP program, the own-price elasticity of demand was estimated at 0.313 for offices; 0.007 for restaurants; and 0.060 for retail stores. This means, for example, that the offices lowered their demand around 0.3%, on average, per 1% increase in prices during critical peak days. These results show that the retail stores and the offices are the businesses that had a greater response by lowering their electricity load during critical peak periods, comparing to restaurants. This study also concluded that enabling technology contributes to a higher reduction in electricity demand.

A summary of the results obtained from this experiment are shown in the table below:

Table 1. Sacramento SMUD experiment participants energy savings

Business Type	**Program**	**Average Monthly kWh**		**2007 – 2008 Difference in usage**		**2007 – 2008 Difference corrected for Non-Participant change**
		Summer 2007	Summer 2008	(ΔkWh)	(%)	(%)
Office	None	1025	976	49	-5%	
	4° ACC	934	631	303	-32%	-27%
	CPP	1061	668	393	-37%	-32%
Restaurant	None	3340	3252	88	-3%	
	4° ACC	3249	2907	342	-11%	-8%
	CPP	3377	2944	432	-13%	-10%
Retail	None	1754	1716	38	-2%	
	4° ACC	1663	1370	292	-18%	-15%
	CPP	1790	1408	383	-21%	-19%
Average	4° ACC and CPP	1543	1197	346	-23%	-20%

*Statistically significant kWh savings with $\alpha = 0.05$

Taylor et al. (2005) obtained hourly information from commercial and industrial customers who had up to 8 years of experience on the voluntary Duke Energy Hourly Pricing (HP) real-time pricing rates program, which provided day-ahead notice of the next day's hourly prices. They determined that high real-time prices lead to reduced consumption during typical peak demand hours. Taylor et al. (2005) examined how the response increases with experience, in particular, hourly elasticity and demand. Such information is considered to be useful for long-term planning. As customers gain experience with hourly pricing, they show larger load reductions during higher priced hours. As compared to a TOU rate, net benefits are $14,000 per customer per month, approximately 4% of the average customers' bill, and considered much greater than metering costs.

In Europe, there have also been some studies on demand response programs for residential and industrial customers (Torriti et al., 2009). In the UK the most important move towards demand response is a government order that requests the installation of smart meters for every household and industries before 2013. Italy is the European country with the highest penetration of smart meters, with around 90% of the meters already installed. There, the DR programs have had three options: Interruptible Programmes for large industry customers, where participants are asked to reduce their loads to predefined values, facing penalties if the customers do not respond to the program; the second option is Load Shedding Programmes where the load is shed automatically in emergency situations, and the third is Time-Of-Use rates, all of the programs yielded positive results in reducing demand for electricity. In future plans, the energy regulator entity will apply a tariff system with higher prices for peak periods and lower prices for off-peak hours.

In Spain, the Direct Control of Load mechanism implies that the regulator entity can request industries to limit their demand for a determined number of hours, with a notification in advance and a maximum number of hours and requests per year, established between the regulator and the customer. This includes the possibility for customers to bid load curtailment in the spot market and be paid real-time prices. Another program applied is the time-of-use tariff, where the rates are based on the 8,760h in a year divided into seven TOU periods. This option turned out to be unviable for industrial customers, whose losses on reduced production were higher than the savings from shifting their load to lower price periods. However, in Europe there seems to be potential for a large number of customers, including industrial and commercial, involved in demand response programs with compensations consisting of prices and thoughtful shifts in their demand to lower peak loads. Their advantage on this regard is the deployment at a big scale of smart meters, which makes it possible to apply DR programs by allowing utilities to measure and store real-time interval data.

Other programs offered to commercial and industrial customers included the block-and-index tariff (Barbose et al., 2006), where customers are willing to expose some of their load to real-time prices, by purchasing blocks of load at a fixed price and pay hourly spot market prices for usage in each hour above their block level, with a flexible and customized design of the hours and days of the weeks within the blocks as well as the size of the blocks, relative to their total load. The factors driving the customer demand for hourly priced supply contracts include the interest of customers in guaranteed savings off the default RTP rate, some of them just wait for the right moment to engage in a fixed-price contract without the risks of the RTP, and some customers consider that the premium for a fixed-price contract is greater than the value they place on the price certainty of such contracts.

4. Conclusions

Although some of the demand response programs have been applied to the commercial and industrial segments without achieving dramatic results, there is a lot of room for improvement. There is a huge potential at the Philadelphia Navy Yard that will allow us to design a successful demand response program on which customers can participate and learn how to use electricity in a more efficient way, understanding the real value of it. The challenge is in designing the program to fit a diversity of customers, which allows them to mold the program to their own needs, based on their own process flow. The successful application of a DR program will contribute with the efficient utilization of the current transmission and distribution resources, avoiding the congestion of the system without the need for further expansion. An additional benefit is that this program has the potential to become a reference for DR programs applied at a national scale.

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