Demand Response in Electricity Markets: An Overview

M. H. Albadi, *Student Member, IEEE* and E. F. El-Saadany, *Senior Member, IEEE*

Abstract- **This paper presents an overview of demand response (DR) in electricity market. The definition and a classification of demand response will be presented. Different potential benefits as well as cost components of demand response will be presented. The most common indices used for demand response evaluation are highlighted. Moreover, some utilities experiences with different demand response programs will be presented.**

*Index Terms-***Demand Response, Incentive based programs, Market based programs, Price-based programs, Price elasticity, Real time pricing.**

I. INTRODUCTION

Electric utilities and power network companies have been forced to restructure there operation from vertically integrated mechanisms to open market systems due to many reasons [1]. With restructuring and deregulation of electricity supply industry, the philosophy of operating the system also changed. While the classical philosophy being to supply all the required demand whenever occurs, the new philosophy states that the system will be most efficient if fluctuations in demand is kept as small as possible.

It has been known that reliable operation of the electricity system necessitates a perfect balance between the supply and the load in real time. This is not an easy task given the fact that both supply and demand levels could change rapidly and unexpectedly due to many reasons, such as generation units forced outages, transmission and distribution lines outages and sudden load change. Keeping in mind that electricity system infrastructure is highly capital-intensive; demand side (load) response is one of the available cheaper resources available to operate the system according to the new philosophy.

This paper presents an overview of new flexible resources in operating a reliable system. The paper starts with defining the Demand Response (DR) and how electricity consumer could be responsive. This is followed by highlighting different DR programs. These programs include classical, new market based and dynamic pricing scenarios. Potential cost savings and benefits related to different market components are also discussed. To measure how successful is a program, measuring indices are introduced. This will be followed by few selected utilities experience with DR programs.

The authors are with the Department of Electrical and Computer Engineering, University of Waterloo, Waterloo, ON N2L 3G1, Canada (e-mail: mhhalbad@uwaterloo.ca).

II. WHAT IS DEMAND RESPONSE?

Demand Response (DR) can be defined as the changes in electric usage by end-use customers from their normal consumption patterns in response to changes in the price of electricity over time. Further, DR can be also defined as the incentive payments designed to induce lower electricity use at times of high wholesale market prices or when system reliability is jeopardized [2]. DR includes all intentional modifications to consumption patterns of electricity of end-use customers that are intended to alter the timing, level of instantaneous demand, or the total electricity consumption.

There are three general actions by which a customer response can be achieved. Each of these actions involves cost and measures taken by the customer. First, customer can reduce his electricity usage during critical peak periods when prices are high without changing consumption pattern during other periods. This option involves a temporary loss of comfort. An example of this response is achieved when thermostat setting of heaters or air conditioners are temporary changed. Secondly, customers may respond to high electricity prices by shifting some of their peak demand operations to off-peak periods. An example would be shifting some household activities (e.g. dishwashers, pool pumps) to off-peak periods. The residential customer in this case will bear no loss and will incur no cost. However, this will not be the case if an industrial customer decided to reschedule some of his activities where rescheduling cost will arise to make up for lost services. The third type of customer response is by using onsite generation (customer owned Distributed Generation). By utilizing onsite generation, customers may experience no or very little change in their electricity usage pattern, however, from the utility prospective, electricity pattern will change significantly and demand will appear to be smaller.

Different DR programs are shown in Fig.1. These are Incentive-Based Programs (IBP) and Priced Based Programs (PBP). IBP are further divided into classical programs and market based programs. Classical IBP include Direct Load Control programs and Interruptible/Curtailable programs. Market based IBP includes Emergency DR programs, Demand Bidding, Capacity Market, Ancillary services market. In classical IBP, participating customers receive participation payments usually as a bill credit or discount rate for their participation in the programs. In market based programs, participants are rewarded money for their performance depending on the amount of load reduction during critical conditions.

In Direct Load Control programs, utilities have the ability to remotely shut down participant equipment on a short notice. Typical remotely controlled equipment are air conditioners and water heaters. This kind of programs might be of interest mainly to residential customers and to small commercial customers to some extent.

Demand Response Programs
- Incentive Based Programs (IBP)
  - Classical
    - Direct Control
    - Interruptible/Curtailable Programs
  - Market Based
    - Demand Bidding
    - Emergency DR
    - Capacity Market
    - Ancillary services market
- Price Based Programs (PBP)
  - Time of Use (TOU)
  - Critical Peak Pricing (CPP)
  - Extreme Day CPP (ED-CPP)
  - Extreme Day Pricing (EDP)
  - Real Time Pricing (RTP)

Fig.1: Classification of Demand Response Programs

Similar to Direct Load Control programs, customers participating in Interruptible/Curtailable Programs will receive incentive upfront payments or rate discount. The participants are asked to reduce their load to predefined values. Participants who are not responding might face penalties depending on the program terms and conditions.

Demand Bidding (also called Buyback) programs are programs in which consumers bid specific load reduction in electricity whole sale market. The bid is accepted if it is less than the market price. When a bid is accepted, the customer should curtail his load by the amount specified in the bid or face penalty. On the other hand, in Emergency DR programs, participating customers are paid incentives for measured load reductions during emergency conditions [2].

Further, Capacity Market Programs are offered to customers who can commit to providing pre-specified load reductions when system contingencies arise [2]. Participants usually receive a day-ahead notice of events and are panelized when not responding to load reduction call. Ancillary services market programs allow customers to bid load curtailment in the spot market as operating reserve. When bids are accepted, participants are paid the spot market price for committing to be on standby and are paid spot market energy price if load curtailment is required [2].

PBP programs are based on dynamic pricing rates in which electricity tariffs are not flat, so the rates are fluctuating following the real time cost of electricity. The ultimate objective of these programs is to flatten the demand curve by offering a high price during peak periods and lower prices during off-peak periods. These rates include Time of Use (TOU) rate, Critical Peak Pricing (CPP), Extreme Day Pricing (EDP), Extreme Day CPP (ED-CPP), and Real Time Pricing (RTP). The basic type of PBP is TOU rates. These rates of electricity prices per unit consumption differ in different blocks of time. The rate during peak periods is higher than the rate during other off-peak periods. The simplest TOU rate has two time blocks; the peak and the off-peak. The rate design is aiming towards reflecting the average cost of electricity during different periods. A TOU rate design process is described in [3]. CPP rates include a pre-specified higher electricity usage price superimposed on TOU rates or normal flat rates. CPP prices are called during contingencies or high wholesale electricity prices for a limited number of days or hours per year [2]. On the other hand, EDP is similar to CPP in having a higher price of electricity and differs from CPP in the fact that the price is in effect for the whole 24 hours of the extreme day which is unknown until a day-ahead [4]. Furthermore, in ED-CPP rates, CPP rates for peak and off-peak periods are called during extreme days. However, a flat rate is being used for the other days [4]. RTP are programs in which customers are charged hourly fluctuating prices reflecting the real cost of electricity in the whole sale market. RTP customers are informed about the prices on a day-ahead or hour-ahead basis. Many economists are convinced that RTP programs are the most direct and efficient DR programs suitable for competitive electricity markets and should be the focus of policymakers [5].

III. DR Benefits and Costs

This section will cover and discuss both potential benefits expected from DR programs as well as the associated cost. Figure 2 summarizes the benefits associated with DR. Those benefits fall under four main categories: participant, market-wide, reliability and market performance benefits.

Customers participating in DR programs can expect savings in electricity bills if they reduce their electricity usage during peak periods. In fact, some participants might experience savings even if they do not change their consumption pattern. This will be achieved if their normal consumption during high price peak periods is lower than their class average [4]. Some customers might be able to increase their total energy consumption by operating more off-peak equipment without having to pay more money. Moreover, participants in classical IBP are entitled to receive incentive payments for their participation while market based IBP will receive payments according to their performance.

Benefits of DR programs are not limited to programs participants only, nevertheless some of these benefits are market-wide ones. An overall electricity price reduction is expected eventually. This is due to a more efficient utilization of the available infrastructure. An example would be the reduction of demand from expensive electricity generating units. Moreover, DR programs can increase the short term capacity using market-based programs. This in turn results in an avoided or deferred capacity costs. The cascaded impact of DR programs includes avoided or deferred need for distribution and transmission infrastructure enforcements and upgrades. All of the avoided or deferred costs will be reflected on the price of electricity for all electricity consumers (DR programs participants and non-participants).

Demand Response Benefits

- Participant
  - Incentive payments
  - Bill savings
- Market-Wide
  - Price reduction
  - Capacity increase
  - Avoided/deferred infrastructure costs
- Reliability
  - Reduced outages
  - Customer participation
  - Diversified resources
- Market performance
  - Reduces market power
  - Options to customers
  - Reduces price volatility

Fig.2: Classification of Demand Response benefits

Reliability benefits can be considered as one of the market-wide benefits because it affects all market participants. Because of its importance, we have considered reliability benefits as one category by itself. By having a well designed DR program, participants have the opportunity to help in reducing the risk of outages. Simultaneously and as a consequence, participants are reducing their own risk of being exposed to forced outages and electricity interruption. On the other hand, the operator will have more options and resources to maintain the system reliability, thus reducing forced outage and its consequences.

The last category of DR programs benefits is improving electricity market performance. DR programs participants have more choices in the market even when retail competition is not available. Consumers can manage their consumption since they have the opportunity to affect the market; especially for the market-based programs and dynamic pricing programs. Actually, this was the prime driver for many utilities to offer DR programs especially for large consumers [6]. Another important market improvement is the reduction of price volatility in the spot market. Demand responsiveness reduces the ability of main market players to exercise power in the market. It has been reported that a small reduction of demand by 5% could have been resulted in a 50% price reduction during California electricity crisis in 2000-2001 [7]. This phenomenon is due to the fact that generation cost increases exponentially near maximum generation capacity. A small reduction in demand will result in a big reduction in generation cost and in turn a reduction in price of electricity; as shown in Fig.3.

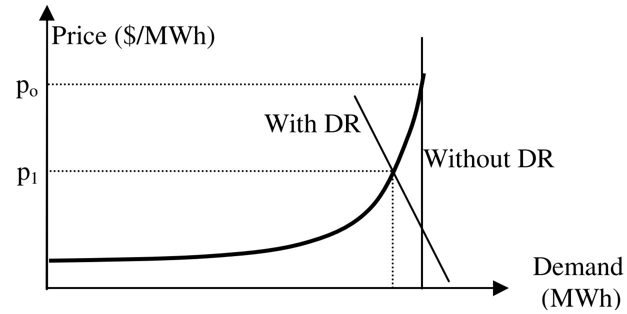


Fig.3: Simplified effect of DR on electricity market prices

In this example, original demand curve is represented by a vertical line because it is assumed that the system is without DR programs. DR programs induce a negative slope on the original demand curve leading to small deduction in demand and a huge reduction in price. Although some might argue about environmental benefits associated with DR programs, those benefits are evident [3]. Environmental benefits of DR programs are numerous including better land utilization as a result of avoided/deferred new electricity infrastructure including generation units and transmission/distribution lines; air and water quality improvement as a result of efficient use of resources; and reduction of natural resources depletion.

Any DR program involves different kind of costs; Fig.4 shows a classification of DR programs costs, where both DR programs owners and participants incur initial and running costs. The program participant might need to install some enabling technologies to participate in a DR program. Enabling technologies might include smart thermostats, peak load control, energy management system, and onsite generation units. A response plan or strategy needs to be established so that it can be implemented in case of event. These initial costs are usually paid by the participant, however, technical assistance should be provided by the program.

Participants running costs are those associated with events. Depending on the response plan, these costs may vary. A reduction of comfort may results if a customer decided to reset the thermostat which results in customer inconvenience that is difficult to be quantified. Other event relevant costs are easier to quantify like lost business or rescheduling industrial processes or activities. If a participating customer decided to use a backup onsite generation unit, fuel and maintenance costs need to be considered. The program owner has to take care of initial and running system wide costs. Most DR programs involve metering and communication costs as initial costs. Utilities need to install advanced metering systems to measure, store and transmit energy usage at required intervals e.g. hourly readings for real time pricings. Running costs of DR programs include administration and management cost of the program. Moreover, incentive payments are considered as part of the running costs of IBP. Upgrading the billing system is a must before deploying most DR programs especially PBP for enabling the system to deal with time varying cost of electricity.

Demand Response Costs

- Participant
  - Initial
    - Enabling technology
    - Response plan
  - Running
    - Inconvenience
    - Lost business
    - Rescheduling
    - Onsite
- Program owner
  - Initial
    - Metering & Communication
    - Billing system
    - Customer education
  - Running
    - Administration
    - Marketing
    - Incentive payments
    - Evaluation

Fig.4: Classification of Demand Response costs

Another important component before deploying any DR program is educating eligible customers about the potential benefits of the program. Different DR programs choices need to be explained to potential participant and possible demand response strategies need to be defined. A successful DR program highly depends on customer education. Continues marketing is important to attract new participants. Further, a continuous evaluation and assessment of DR programs is important to develop a better approach to reach the ultimate objectives of the programs.

IV. DR MEASUREMENT

The ultimate objective of DR programs is to reduce the peak demand. To judge how successful a DR program is and to compare between DR programs having similar situation, the actual peak demand reduction is used as an indicator. To normalize this indicator, the percentage peak demand reduction is used. Percentage and actual peak demand reduction are used to evaluate IBP. In addition to peak load reduction, the performance of dynamic pricing programs is measured using demand price elasticity which represents the sensitivity of customer demand to the price of electricity. This can be found by calculating the ratio of the percent change in demand to the percent change in price ($E=\Delta Q/\Delta P$) [8]. Usually, price-demand curve of any commodity is not linear. Therefore, elasticity is linearized around the initial price-demand balance (q_o, p_o); as seen in Fig.5.

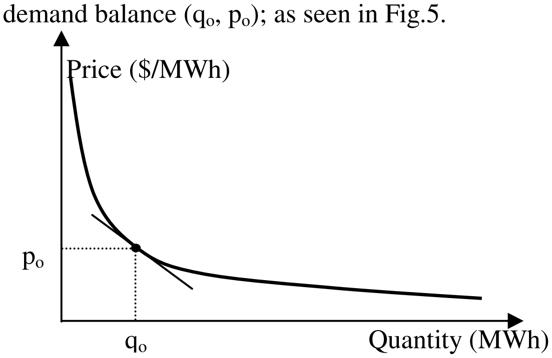


Fig.5: Price elasticity around (p_o,q_o).

The elasticity of a substitution measures the rate at which the customer substitutes off-peak electricity consumption for peak usage in response to a change in the ratio of peak to off-peak prices. This is important in TOU and CPP pricing programs. In [9], elasticity is decomposed into self elasticity and cross elasticity. Self elasticity measures the demand reduction in a certain time interval due to the price of that interval. Cross elasticity measures the effect of price of a certain time interval on electricity consumption during other interval. Another aspect of DR programs evaluation is customer acceptance and enrolment in the program. Without customer participation, DR programs will certainly fail to achieve their ultimate goal of reducing peak demand.

V. DR EXPERIENCES

Three types of DR quantization studies have been distinguished [2]; illustrative studies, integrated resource planning studies and program evaluation studies. It has been shown that program evaluation studies revealed much lower benefits than the other two studies. Illustrative studies assume high penetration rates and long term sustained benefits. Similarly, integrated recourse planning studies consider long term benefits. On the other hand, program evaluation studies do not consider long term benefits and suffer from low penetration rates. Many utilities in North America and around the globe have experiences with IBP. As an example, NYISO IBP paid out $ 27.2 in incentives to more than 14,000 program participants to release 700MW peak capacity in the summer of 2003. The load curtailment programs were estimated providing reliability benefits of more than $ 50 millions on August 15, 2003 [4]. In general, it was reported that the benefits of these programs exceeded the cost by a factor of 7:1 [4]. TOU pricing is the basic PBP and easiest to implement. Electricite De France (EDF) operates probably the most successful example of TOU pricing program. This program was applied to large industrial customers in 1956 and introduced to residential customers in 1965. Currently, it is estimated that one third of its customers are on TOU pricing [4]. In 1993, EDF introduced a CPP pricing program called Temp in which the year is divided into three types of days: Tempo Blue, Tempo White, and Tempo Red. 300 days of the years are Tempo Blue in which electricity are cheaper than the normal TOU prices. Tempo White days are 43 and they are slightly at a higher rates compared to that of normal TOU.

Tempo Red days are only 22 and they are the most expensive. Customers can know the color of the next day by several means. TOU pricing was implemented by many utilities in North America. An experiment implemented in Pennsylvania revealed an average elasticity of substitution of -0.14 [4]. Another experiment in Florida by Gulf Power Company with TOU pricing in which customers were provided with smart thermostats that automatically adjust the temperature and other loads depending on a price signal. In this program, normal TOU prices are applied 99% of all hours in the year. In the remaining 1% of the hours, the utility have the option of charging a critical peak pricing more than the normal peak period price. This program resulted in 42% peak demand reduction during critical peak periods [4]. A comprehensive survey of utility experience with RTP was presented in [6]. This survey covered 43 voluntary real time pricing programs offered in 2003. It has been reported that the most common utility motivation behind these programs was customer satisfaction by providing opportunities for bell savings. Encouraging peak demand reduction and load growth come after the prime motivation. Complying with new regulations was also mentioned as a motivation. It has been reported that penetration rates were low in most programs. In some programs, penetration levels were even getting lower. The problem of program participation was attributed to poor marketing and limited technical assistance provided to help participants managing price volatility. Most RTP participants were large industrial customers and some large institutional customers. This survey concluded that quantities information about price responsiveness is not available in most programs. In Addition, some RTP participants are not price responsive at all. Price responsive customers generally employ on-site generation or simple strategies like rescheduling. Some of these participants were found to be very sensitive to prices as low as \$0.20/kWh. The programs under study were reported to achieve 12-33% aggregate load reduction across a wide range of prices. Only one program was able to generate a load reduction of more than 1% of the utility system peak [6]. Another case study of Niagara Mohawk RTP program in New York found that the average substitution elasticity was -0.14 [5].

VI. Conclusions

DR changes electricity usage by end-use customers from their normal consumption patterns in response to changes in the price of electricity over time, or to incentive payments designed to induce lower electricity use at times of high wholesale market prices or when system reliability is jeopardized. DR programs benefits cover all electricity consumers. DR programs can reduce electricity prices, improve system reliability and reduce price volatility. To employ DR programs, both participants and program owners incur initial and running costs. The performance of DR programs is measured by peak load reduction and demand elasticity. Although illustrative studies and integrated resource planning studies expected more benefits from DR programs, program evaluation studies prove the substantial benefits of these programs.

VII. References

[1] K. Bhattacharya, M. Bollen & J Daalder, Operation of restructured power system, Kluwer Academic Publishers, London, 2001

[2] US Department of Energy, "Benefits of Demand Response in Electricity Markets and Recommendations for Achieving Them", Report to the United States Congress, February 2006. Available online: http://eetd.lbl.gov

[3] C. Gellings and J. Chamberlin, "Demand Side Management: Concepts and Methods", The Fairmont Press Inc, Lilburn, 1988.

[4] Charles River Associates, "Primer on Demand-Side Management with an emphasis on price-responsive programs", Report prepared for The World Bank, Washington, DC, CRA No. D06090. Avalable online: http://www.worldbank.org

[5] E. Bloustein School of Planning and Public Policy, "Assessment of customer response to real time pricing", Rutgers- The State University of New Jersey, June 30, 2005. Available online: http://www.policy.rutgers.edu

[6] G. Barbose et al, "A Survey of Utility Experience with Real Time Pricing", Lawrence Berkeley National Laboratory, December 2004. Available online: http://certs.lbl.gov

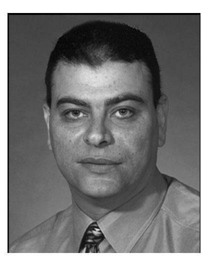
[7] S. Braithwait, K. Eakin, "The role of demand response in electric power market design", Laurits R. Christensen Associates, Prepared for Edison Electric Institute, Madison, October 2002. Available online: http://www.eei.org

[8] A. K. David, Y. Z. Li, "Consumer rationality assumptions in the real time pricing of electricity", IEE Proceedings-Generation, Transmission and Distribution, Volume 139, Issue 4, pp. 315 – 322, July 1992

[9] D.S. Kirschen, G. Strbac, P. Cumperayot, D. Mendes, "Factoring the elasticity of demand in electricity prices", IEEE Transactions on Power System, Volume 15, Issue 2, pp. 612 – 617, May 2000

VIII. Biographies

Mohamed H. Albadi (S'06) was born in Sohar, Oman, in 1976. He received the B.Sc. degree in electrical and computer engineering from Sultan Qaboos University, Muscat, Oman in 2000 and M.Sc. degree in electrical engineering from Faculty of Engineering, Aachen University of Technology, Aachen, Germany in 2003. He is currently pursuing the Ph.D. degree in the Department of Electrical and Computer Engineering, University of Waterloo, Waterloo, ON, Canada. His research interests are energy management, power quality, and distributed generation.



Ehab F. El-Saadany (SM'05) was born in Cairo, Egypt, in 1964. He received the B.Sc. and M.Sc. degrees in electrical engineering from Ain Shams University, Cairo, Egypt, in 1986 and 1990, respectively, and the Ph.D. degree in electrical engineering from the University of Waterloo, Waterloo, ON, Canada, in 1998. Currently, he is an Associate Professor in the Department of Electrical and Computer Engineering, University of Waterloo. His research interests are distribution system control and operation, power quality, distributed generation, power electronics, digital signal processing applications to power systems, and Mechatronics.