A summary of demand response in electricity markets

Article *in* Electric Power Systems Research · November 2008

DOI: 10.1016/j.epsr.2008.04.002

2 authors:


Mohammed Albadi
Sultan Qaboos University


Ehab El-Saadany
University of Waterloo

Electric Power Systems Research 78 (2008) 1989–1996

Contents lists available at ScienceDirect

Electric Power Systems Research

journal homepage: www.elsevier.com/locate/epsr

Review

A summary of demand response in electricity markets

M.H. Albadi*, E.F. El-Saadany

Department of Electrical and Computer Engineering, University of Waterloo, 200 University Ave. W, Waterloo, ON N2L3G1, Canada

ARTICLE INFO

Article history:
Received 19 October 2007
Received in revised form 7 April 2008
Accepted 8 April 2008
Available online 21 May 2008

Keywords:
Demand response
Price elasticity
Real time pricing
Electricity markets

ABSTRACT

This paper presents a summary of Demand Response (DR) in deregulated electricity markets. The definition and the classification of DR as well as potential benefits and associated cost components are presented. In addition, the most common indices used for DR measurement and evaluation are highlighted, and some utilities' experiences with different demand response programs are discussed. Finally, the effect of demand response in electricity prices is highlighted using a simulated case study.

Contents

1. Introduction

For many reasons, electric utilities and power network companies have been forced to restructure their operations from vertically integrated mechanisms to open market systems [1]. With the restructuring and deregulation of the electricity supply industry, the philosophy of operating the system was also changed. The traditional approach was to supply all power demands whenever they occurred, however, the new philosophy states that the system will be most efficient if fluctuations in demand are kept as small as possible.

Reliable operation of the electricity system necessitates a perfect balance between supply and demand in real time. This balance is not easy to achieve given that both supply and demand levels can change rapidly and unexpectedly due to many reasons, such as generation unit forced outages, transmission and distribution line outages, and sudden load changes. The electricity system infrastructure is highly capital intensive; demand side (load) response

* Corresponding author. Tel.: +1 519 888 4567x37059; fax: +1 519 746 3077.
E-mail address: mhhalbad@uwaterloo.ca (M.H. Albadi).

0378-7796/$ – see front matter
doi:10.1016/j.epsr.2008.04.002

is one of the cheaper resources available for operating the system according to the new philosophy.

This paper presents an overview of new flexible resources for operating a reliable system. The paper starts with defining the Demand Response (DR) and how electricity consumers can be responsive. Highlighting different DR programs follows, including classical, new market-based and dynamic pricing scenarios. Potential cost savings and benefits related to different market components are also discussed. Measuring indices are used to assess program success. The paper is concluded with a few selected utilities experience with DR programs.

2. Definition and classification

2.1. Definition

Demand response can be defined 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. 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 electricity consumption pattern modifications by end-use customers that are intended to alter the timing, level of instantaneous demand, or total electricity consumption [3].

2.2. Customer response

There are three general actions by which a customer response can be achieved [2]. Each of these actions involves cost and measures taken by the customer. First, customers can reduce their electricity usage during critical peak periods when prices are high without changing their consumption pattern during other periods. This option involves a temporary loss of comfort. This response is achieved, for instance, when thermostat settings of heaters or air conditioners are temporary changed [4,5]. Secondly, customers may respond to high electricity prices by shifting some of their peak demand operations to off-peak periods, as an example, they shift 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 decides to reschedule some activities and rescheduling costs to make up for lost services are incurred. The third type of customer response is by using onsite generation—customer owned distributed generation [6,7]. Customers who generate their own power may experience no or very little change in their electricity usage pattern; however, from utility prospective, electricity use patterns will change significantly, and demand will appear to be smaller.

2.3. Program classification

Different DR programs are shown in Fig. 1. These programs can be classified into two main categories: Incentive-Based Programs (IBP) and Price-Based Programs (PBP) [2,8]. Some literature papers named these categories as system- and market-led, emergency- and economic-based, or stability- and economic-based DR programs [3,9,10]. IBP are further divided into classical programs and market-based programs. Classical IBP include Direct Load Control programs and Interruptible/Curtailable Load programs. Market-based IBP include Emergency DR Programs, Demand Bidding, Capacity Market, and the 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 with money

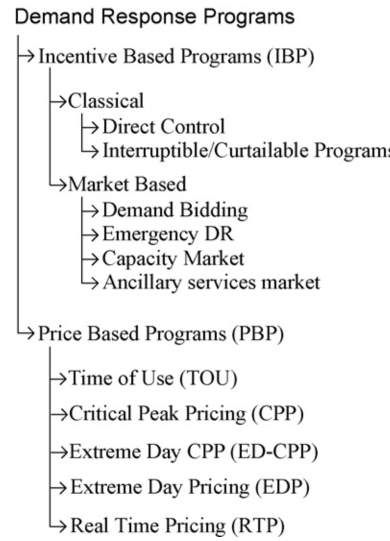

Fig. 1. Classification of demand response programs.

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 includes air conditioners and water heaters. This kind of programs is of interest mainly to residential customers and small commercial customers.

As with Direct Load Control programs, customers participating in Interruptible/Curtailable Programs receive upfront incentive payments or rate discounts. Participants are asked to reduce their load to predefined values. Participants who do not respond can face penalties, depending on the program terms and conditions.

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

Furthermore, 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 penalized if they do not respond to calls for load reduction. Ancillary services market programs allow customers to bid on 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; the rates fluctuate 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 the 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 the TOU rates, which are the rates of electricity price per unit consumption that differ in different blocks of time. The rate during peak periods is higher than the rate during off-peak periods. The simplest TOU rate has two time blocks; the peak and the off-peak. The rate design attempts to reflect the average cost of electricity during different periods. A TOU rate design

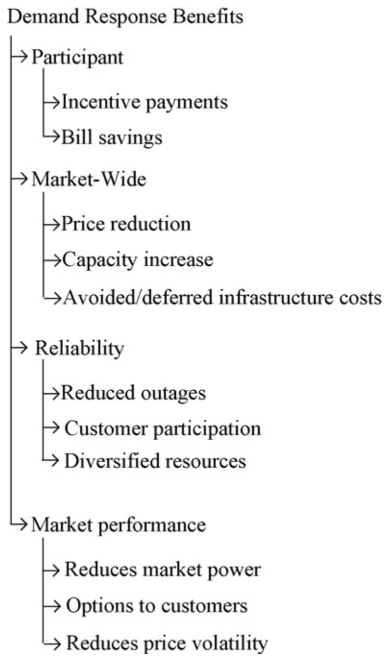

Fig. 2. Benefits associated with DR.

process is described in [11]. CPP rates include a pre-specified higher electricity usage price superimposed on TOU rates or normal flat rates. CPP prices are used during contingencies or high wholesale electricity prices for a limited number of days or hours per year [2,10]. On the other hand, EDP is similar to CPP in having a higher price for electricity and differs from CPP in the fact that the price is in effect for the whole 24 h of the extreme day, which is unknown until a day-ahead [12]. Furthermore, in ED-CPP rates, CPP rates for peak and off-peak periods are called during extreme days. However, a flat rate is used for the other days [12]. RTP are programs in which customers are charged hourly fluctuating prices reflecting the real cost of electricity in the wholesale 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 [13].

3. DR benefits and costs

This section covers and discusses both potential benefits expected from DR programs and the associated cost.

3.1. DR benefits

Fig. 2 summarizes the benefits associated with DR; they 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 [2,8,10,14]. In fact, some participants may experience savings even if they do not change their consumption pattern if their normal consumption during high price peak periods is lower than their class average [12]. Some customers might be able to increase their total energy consumption without having to pay more money by operating more off-peak equipment. Moreover, participants in classical IBP are entitled to receive incentive payments for their participation, while market-based IBP customers will receive payments according to their performance.

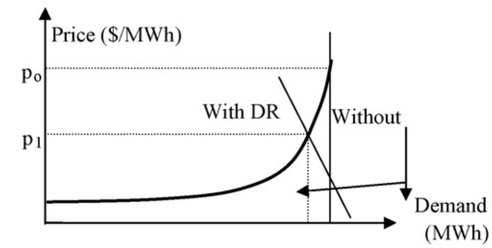

Fig. 3. Simplified effect of DR on electricity market prices.

The benefits of DR programs are not only for program participants; some are market-wide. An overall electricity price reduction is expected eventually because of a more efficient utilization of the available infrastructure, as in, for example, the reduction of demand from expensive electricity generating units. Moreover, DR programs can increase short-term capacity using market-based programs, which 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 [2,3,9]. All of the avoided or deferred costs will be reflected in the price of electricity for all electricity consumers (DR programs participants and non-participants).

Reliability benefits can be considered as one of the market-wide benefits because they affect all market participants. Because of their 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 system reliability, thus reducing forced outages and their consequences [15].

The last category of DR program benefits is improving electricity market performance [16]. DR program 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 with 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 [17]. 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 [18]. It has been reported that a small reduction of demand (5%) could have resulted in a 50% price reduction during the California electricity crisis in 2000–2001 [19]. 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 electricity price, as shown in Fig. 3.

In this example, the original demand curve is represented by a vertical line because it is assumed that the system is without DR programs. DR programs introduce a negative slope on the original demand curve, leading to a small reduction in demand and a huge reduction in price. Although some people might argue about environmental benefits associated with DR programs, those benefits are evident [11]. Environmental benefits of DR programs are numerous and include better land utilization as a result of avoided/deferred new electricity infrastructure such as 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 [2].

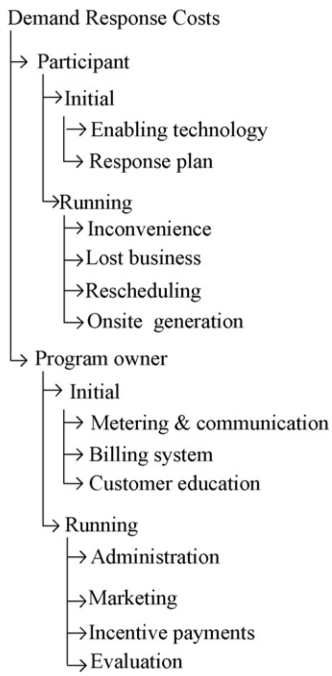

Fig. 4. Classification of DR costs.

3.2. DR costs

Any DR program involves different kind of costs; Fig. 4 shows a classification of DR programs costs, where both DR program owners and participants incur initial and running costs [2]. The program participant might need to install some enabling technologies to participate in a DR program: smart thermostats, peak load controls, energy management systems, and onsite generation units. A response plan or strategy needs to be established so that it can be implemented in case of an 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 decides to reset the thermostat, which results in customer inconvenience that is difficult to quantify. Other event relevant costs are easier to quantify, for instance, lost business or rescheduling of industrial processes or activities. If a participating customer decides 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 necessary before most DR programs are deployed, especially PBP for enabling the system to deal with time varying cost of electricity.

Another important cost component before deploying any DR program is educating eligible customers about the potential benefits of the program. Different DR program choices need to be explained to potential participants and possible demand response strategies need to be defined. A successful DR program depends heavily on customer education. Continuous marketing is important to attract new participants. Further, a continuous evaluation and assessment of DR programs is important to develop a better approach for reaching the ultimate objectives of the programs [2].

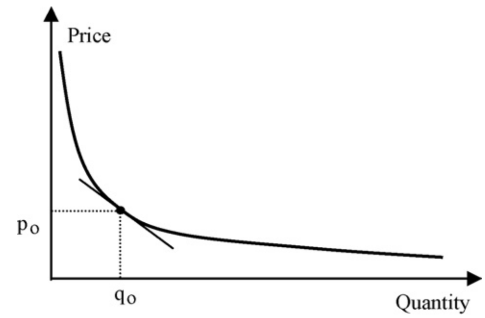

Fig. 5. Price elasticity around (p_o, q_o).

4. DR measurement and simulation

4.1. DR measurement

The ultimate objective of DR programs is to reduce peak demand. Actual peak demand reduction is used as an indication of how successful a DR program is and to compare DR programs in similar situations. 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 ($E = \Delta Q/\Delta P$) [3,19,21]. 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.

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 [3]. This kind of elasticity is important in TOU and CPP pricing programs. In [22], elasticity is divided 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 the price of a certain time interval on electricity consumption during another interval.

Two types of customers are described in [20]: long-range (LR) and short-range (SR) customers. LR customers maximize long-term benefits by deciding their demands considering all pricing periods. SR customers set their demand considering the current pricing period only. However, real world (RW) consumers, described in [22], consider both current prices and the prices of one step into the future.

As Fig. 6 suggests, elasticity is used in conjunction with expected price to modify expected demand; consequently, demand and prices will be reduced if prices are above the equilibrium point (p_o, q_o); see Fig. 5. The equilibrium point is defined as price and

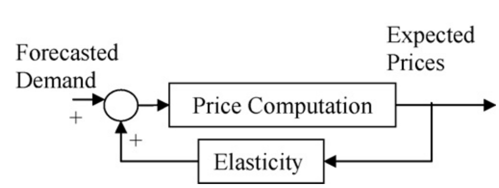

Fig. 6. Effect of price elasticity in price computation.

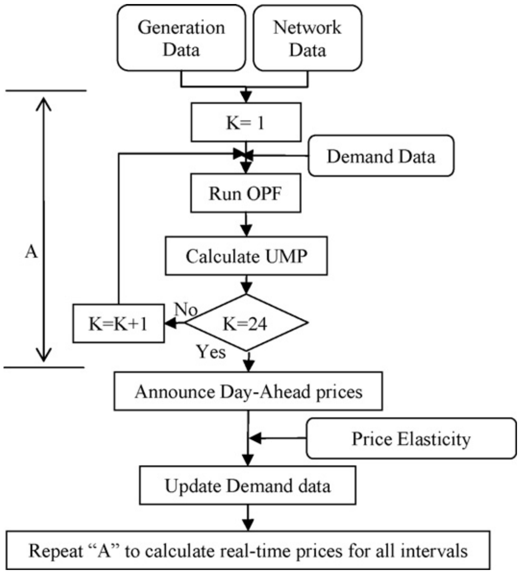

Fig. 7. Simulation flow chart.

demand of the normal case. In this analysis, one equilibrium point is assumed for each period.

4.2. Market simulation

In this analysis, a single-sided uniform market price is considered in which the supply-side submits bids for supplying power to the market operator when the market operator has a forecast of demand [1]. These bids reflect generator cost functions. The operator announces the expected prices for the next 24 h. These prices act as guidelines for customers to respond to in real time, depending on their elasticity and expected prices. This DR is very beneficial as it can reduce market prices as well as costs. The process used for simulating DR is shown in Fig. 7 [23].

4.3. Optimal Power Flow formulation

An Optimal Power Flow (OPF) code was developed in a GAMS environment to simulate market prices. The objective function of the OPF is to minimize the total cost of generation for social welfare maximization [1].

$$J = \sum_{i=1}^{NG} C_i(P_i) \tag{1}$$

$$C_i(P_i) = aP_i^2 + bP_i + c_i \tag{2}$$

where J is the total generation costs; $C_i(P_i)$ is the cost function of generator i; P_i is the power output of generator i, and NG is the number of generators. Generators are assumed to be bidding their true cost of generation. The minimization objective function has the following constraints:

1. Power balance equations

$$P_i - \mathrm{PD}_i = \sum_j \left|V_i\right| \left|V_j\right| Y_{ij} \cos(\vartheta_{i,j} + \delta_j - \delta_i) \tag{3}$$

$$Q_i - \mathrm{QD}_i = -\sum_j \left|V_i\right| \left|V_j\right| Y_{ij} \sin(\vartheta_{i,j} + \delta_j - \delta_i) \tag{4}$$

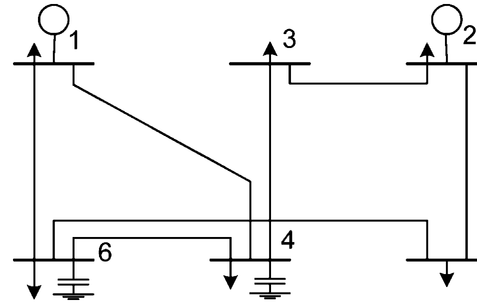

Fig. 8. Six-bus test system.

where V_i is the voltage at bus i; δ is the angle associated with the voltage at relevant busses; Y_{ij} is the element of the Y-bus admittance matrix; θ_{ij} is the angle associated with Y_{ij}; P and Q are real and reactive power generation at bus i, respectively. PD_i and QD_i are real and reactive power demand at bus i, respectively.

2. Generation limits

$$P_i^{\min} \le P_i \le P_i^{\max} \tag{5}$$

$$Q_i^{\min} \le Q_i \le Q_i^{\max} \tag{6}$$

3. Voltage limits

$$V_i^{\min} \le V_i \le V_i^{\max} \quad \forall i \in 1, \ldots, \mathrm{NL} \tag{7}$$

$$\left|V_i\right| = \text{const.} \quad \forall i \in 1, \ldots, \mathrm{NG} \tag{8}$$

NL and NG are the number of load buses and generator buses, respectively. The voltages at load buses are bounded between minimum and maximum values; whereas the voltages at generation buses are kept at constant values.

There are two types of market price formulations: the Locational Marginal Prices (LMP) and the Uniform Market Price (UMP). In an LMP formulation, electricity prices are location dependent. The market price at each bus is represented by the Lagrangian multiplier λ_i of the real power balance constraint at that bus. In an UMP formulation, the market price is the highest value of the bus incremental cost obtained by solving the above model:

$$\rho \le \lambda_i, \quad \forall i \in 1, \ldots, N \tag{9}$$

where ρ represents the uniform electricity market price; λ_i is the incremental cost of generation at bus i, and N is the number of buses in the system.

4.4. Simulation results

A six-bus system, presented in [1], was used for this simulation. The system is presented in Fig. 8, and Tables 1 and 2 show the system data. The generation cost function ($/MWh) of the two generation units is represented by the quadratic functions below.

Table 1
Line data

Line	R (p.u.)	X (p.u.)	B/2 (p.u.)
1–4	0.0662	0.1804	0.003
1–6	0.0945	0.2987	0.005
2–3	0.0210	0.1097	0.004
2–5	0.0824	0.2732	0.004
3–4	0.1070	0.3185	0.005
4–6	0.0639	0.1792	0.001
5–6	0.0340	0.0980	0.004

Table 2
Bus data with S_{base} = 100 MV A

#	Demand (p.u.)		Generation limits (p.u.)			
	PD	QD	P_{max}	P_{min}	Q_{max}	Q_{min}
1	0.73125	0.1950	5.0	1.0	3.0	−0.2
2	0.92625	0.2925	2.5	0.5	1.5	−0.2
3	0.78000	0.3900	0.0	0.0	0.0	0.0
4	1.12125	0.3120	0.0	0.0	0.0	0.0
5	1.26750	0.34125	0.0	0.0	0.0	0.0
6	0.67375	0.24375	0.0	0.0	0.0	0.0

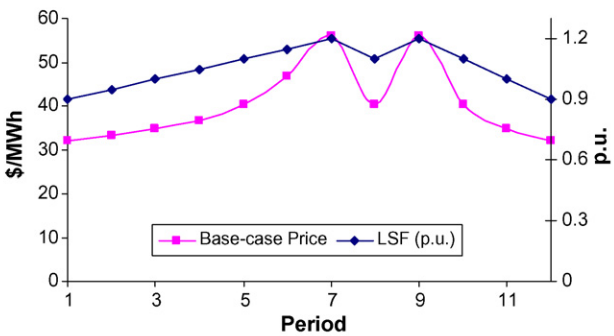

Fig. 9. Base-case simulation results.

$$C_1 = P_1^2 + 8.5P_1 + 5 \tag{10}$$

$$C_2 = 3.4P_2^2 + 25.5P_2 + 9 \tag{11}$$

A Load Scaling Factor (LSF) was used to represent load variation. Simulation results of the base case are shown in Fig. 9. The equilibrium point during each interval is the demand and the price of the base-case scenario. As shown in Fig. 9, 12 price intervals were considered. The figure shows clearly that electricity prices are sensitive to increase in demand. A contingency in the system was introduced by removing line 4–6 from the network data. Obviously, this contingency causes a large increase in market price, with inelastic demand, especially during peak periods (Fig. 10). These high prices will be announced 24 h ahead. Note that we assume that the operator is aware that such a contingency will happen the next day and will last for the whole day.

To illustrate the effect of demand elasticity, loads at all busses are assumed to have the same constant self-elasticity of −0.1, which means that a 100% change in price will reduce the load by 10%. All cross-elasticities are neglected, which means that the customers are of the SR type. After calculating the change in LSF, the OPF model is solved, and the results are shown in Fig. 11.

It is notable that real prices were reduced below contingency prices. Moreover, due to the assumption that customers react in

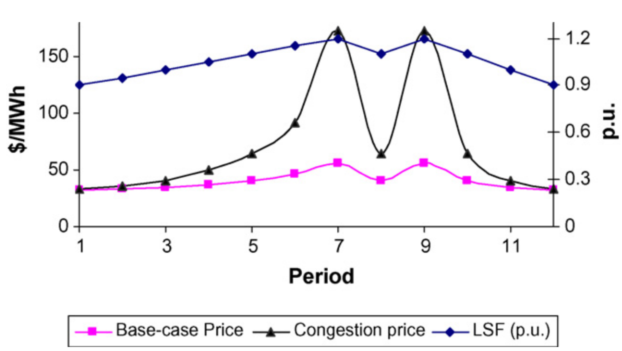

Fig. 10. A comparison between base-case and contingency case prices.

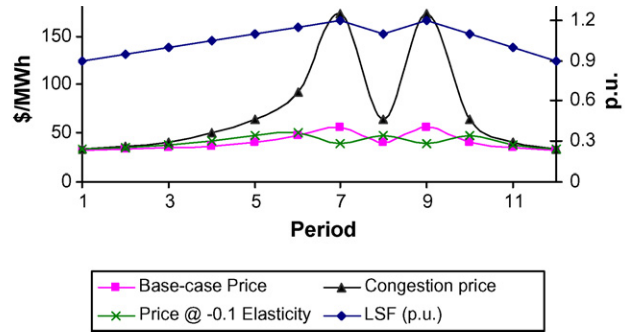

Fig. 11. A comparison between base-case, contingency and prices when loads have −0.1 elasticity.

response to the day-ahead published prices, the very high expected prices of the two peaks were actually reduced even below the base-case prices. However, this will not happen in practice because elasticity is not constant, and it has a lower value during peak periods.

4.5. 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 US$ 7.2 million in incentives to more than 14,000 program participants to release 700 MW peak capacity in the summer of 2003 [12]. The load curtailment programs were estimated providing reliability benefits of more than US$ 50 million on August 15, 2003 [12]. In general, it was reported that the benefits of these programs exceeded the cost by a factor of 7:1 [12]. TOU pricing is the basic PBP and easiest to implement. Electricite De France (EDF) operates what is probably the most successful example of a 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 [12]. In 1993, EDF introduced a CPP pricing program called Tempo 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 during which time electricity is cheaper than the normal TOU prices. Tempo White days are 43 and they are at a slightly higher rates compared to that of normal TOU. Tempo Red days are only 21 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 [12]. This means that a 100% price increase will correspond to 14% reduction in demand. Another experiment, in Florida by the Gulf Power Company, used TOU pricing. Customers were provided with smart thermostats that automatically adjusted the temperature and other loads depending on a price signal. In this program, normal TOU prices were applied 99% of all hours in the year. In the remaining 1% of the hours, the utility had 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 [12]. A comprehensive survey of utility experience with RTP was presented in [17]. 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 bill savings. Encouraging peak demand reduction and load growth comes 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 dropping even lower. The problem of low 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 ones. This survey concluded that big portions of required information about price responsiveness were 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 US$ 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 [17]. Another case study of the Niagara Mohawk RTP program in New York found that the average substitution elasticity was −0.14 [13].

5. Conclusions

DR changes end-use customer electricity consumption patterns from those customers' normal 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 program 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 project more benefits from DR programs, program evaluation studies prove the substantial benefits of these programs. The above case study simulating the effect of elasticity in electricity prices demonstrates the effect of DG programs in cases of system contingency.

Appendix A. List of symbols

$C_i(P_i)$	the cost function of generator *i*
CPP	Critical Peak Pricing
DR	Demand Response
ED-CPP	Extreme Day Critical Peak Pricing
EDF	Electricite De France
EDP	Extreme Day Pricing
IBP	Incentive-Based Programs
J	the total generation costs
LMP	Locational Marginal Prices
LR	long-range customers
LSF	Load Scaling Factor
N	the number of buses in the system
NG	the number of generators
NYISO	New York Independent System Operator
OPF	Optimal Power Flow
P_i	the real power output of generator *i*
PD_i	real power demand at bus *i*
Q_i	The reactive power output of generator *i*
QD_i	reactive power demand at bus *i*
RTP	Real Time Pricing
RW	real world customers
SR	short-range customers
TOU	Time of Use
UMP	Uniform Market Price
V	the bus voltage
Y_{ij}	The element of the Y-bus admittance matrix

Greek symbols

δ	the angle associated with the voltage at relevant busses
λ_i	the incremental cost of generation at bus *i*
θ_{ij}	the angle associated with Y_{ij}
ρ	the uniform electricity market price

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] International Energy Agency, The Power to Choose—Demand Response in Liberalized Electricity Markets, OECD, Paris, 2003.
[4] K. Herter, P. McAuliffe, A. Rosenfeld, An exploratory analysis of California residential customer response to critical peak pricing of electricity, Energy 32 (2007) 25–34.
[5] M. Piette, O. Sezgen, D. Watson, N. Motegi, C. Shockman, Development and Evaluation of Fully Automated Demand Response in Large Facilities, Prepared For California Energy Commission, Public Interest Energy Research (PIER) Program, March 30, 2004 (LBNL-55085).
[6] S. Valero, M. Ortiz, C. Senabre, C. Alvarez, F. Franco, A. Gabaldon, Methods for customer and demand response policies selection in new electricity markets, IET Gen. Transm. Distrib. 1 (2007) 104–110.
[7] O. Sezgen, C.A. Goldman, P. Krishnarao, Option value of electricity demand response, Energy 32 (2007) 108–119.
[8] M.H. Albadi, E.F. El-Saadany, Demand response in electricity markets: an overview, in: IEEE PES GM, Montreal, 2007, pp. 1–5.
[9] Y. Tan, D. Kirschen, Classification of Control for Demand-side Participation, University of Manchester, 29 March 2007.
[10] P. Jazayeri, A. Schellenberg, W.D. Rosehard, J. Doudna, S. Widergren, D. Lawrence, J. Mickey, S. Jones, A survey of load control programs for price and system stability, IEEE Trans. Power Syst. 20 (3) (2005) 1504–1509.
[11] C. Gellings, J. Chamberlin, Demand Side Management: Concepts and Methods, The Fairmont Press Inc., US, 1988.
[12] 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, available online: http://www.worldbank.org.
[13] 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.
[14] D.S. Kirschen, Demand-side view of electricity markets, IEEE Trans. Power Syst. 18 (2003) 520–527.
[15] L. Goel, W. Qiuwei, W. Peng, Reliability enhancement of a deregulated power system considering demand response, in: IEEE PES GM, 2006, pp. 1–6.
[16] K. Spees, L. Lave, Demand response and electricity market efficiency, Electricity J. 20 (2007) 69–85.
[17] G. Barbose, C. Goldman, C. Neenan, A Survey of Utility Experience with Real Time Pricing, Lawrence Berkeley National Laboratory Report No. LBNL-54238, December 2004.
[18] D. Caves, K. Eakin, A. Faruqui, Mitigating price spikes in wholesale markets through market-based pricing in retail markets, Electricity J. 13 (2000) 13–23.
[19] 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.
[20] A.K. David, Y.Z. Li, Consumer rationality assumptions in the real time pricing of electricity, IEE Proc. Gen. Trans. Dist. 139 (1992) 315–322.
[21] M.G. Lijesen, The real-time price elasticity of electricity, Energy Econ. 29 (2007) 249–258.
[22] D.S. Kirschen, G. Strbac, P. Cumperayot, D. Mendes, Factoring the elasticity of demand in electricity prices, IEEE Trans. Power Syst. 15 (2000) 612–617.
[23] E.C. Banda, L.A. Tuan, Modeling of demand response in electricity markets: effects of price elasticity, in: Power and Energy Systems, Florida, January 2007.

Mohamed H. Albadi 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, distributed generation, and power quality.

Ehab F. El-Saadany 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.