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Flexible demand response programs modeling in competitive electricity markets

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ABSTRACT

In recent years, extensive researches have been conducted on implementation of demand response programs (DRPs), aimed to electricity price reduction, transmission lines congestion resolving, security enhancement and improvement of market liquidity. Basically, DRPs are divided into two main categories namely, incentive-based programs (IBPs) and time-based rate programs (TBRPs). Mathematical modeling of these programs helps regulators and market policy makers to evaluate the impact of price responsive loads on the market and system operational conditions. In this paper, an economic model of price/incentive responsive loads is derived based on the concept of flexible price elasticity of demand and customer benefit function. The mathematical model for flexible price elasticity of demand is presented to calculate each of the demand response (DR) program's elasticity based on the electricity price before and after implementing DRPs. In the proposed model, a demand ratio parameter has been introduced to determine the appropriate values of incentive and penalty in IBPs according to the level of demand. Furthermore, the importance of determining optimum participation level of customers in different DRPs has been investigated. The proposed model together with the strategy success index (SSI) has been applied to provide an opportunity for major players of the market, i.e. independent system operator (ISO), utilities and customers to select their favorite programs that satisfy their desires. In order to evaluate the performance of the proposed model, numerical studies are conducted on the Iranian interconnected network load profile on the annual peak day of the year 2007.

1. Introduction

A common feature of the electricity wholesale markets is the lack of price responsiveness measured by the value of demand elasticity [1]. This is not only due to the peculiar characteristics of the commodity, such as no storability, lack of good substitutes, and the relatively small impact of electricity bill on the typical customer's budget, but also to the relation between wholesale and retail markets. Since end users simply do not see the "true" spot prices, they cannot use these prices when making decisions regarding power withdrawal; this "inelastic" behavior is transmitted to retailers, which have legal obligations to serve their customers and therefore to the wholesale demand. Furthermore, the lack of interest from customers in considering the real price of electricity makes it difficult to implement demand elasticity improvement measures [2].

In these circumstances, DRPs are useful tools that can be activated within a relatively short time at critical system conditions to provide the much needed system demand reduction. The idea is to make it attractive for customers to use less power during periods of peak load [3]. In a DRP, the customer signs a contract with the local utility or the ISO to reduce its demand when requested. The utility benefit is reduction of peak load and thereby, saving costly generation reserves, restoring quality of service and ensuring reliability. The customer benefits from reduction in its energy demand and particularly from incentives provided by the local utility or the ISO. Economic and reliability benefits of implementing DRPs are illustrated, in terms of market clearing curves in Fig. 1.

In order to evaluate the impact of DRPs on the network and market characteristics such as load profile, transmission congestion, reserve margin etc., developing of price responsive demand model seems to be necessary. Economic models of price responsive loads have been addressed in [1,4–9]. In these studies the price elasticity of demand has been considered as a predetermined constant value. However, for more realistic characterization of the demand economic model it is needed to adopt a flexible price elasticity of demand.

In this paper, an economic model of price responsive loads has been derived by using the concepts of "price elasticity of demand", and "customer benefit function". In our previous studies [10,11], the predetermined constant price elasticity of demand was applied for studying different DRPs. In this paper, more realistic model of

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Nomenclature

$A(i)$	incentive of DR programs in ith hour (\$/kW h)
a_i,b_i	coefficients of linear demand curve
B_0 (i)	customer's income when the demand is at nominal value ($d_0(i)$) (\$)
$B(d(i))$	customer's income in ith hour (\$)
$d_0(i)$	initial demand value in ith hour (kW h)
$d(i)$	customer demand in ith hour (kW h)
E	price elasticity of the demand
E (i,i)	self elasticity of the ith period
E (i,j)	calculated cross elasticity of the ith period versus jth period
i	ith period
IC (i)	incentive-based programs contract level (kW h)
j	jth period
k	kth period
K	coefficient of iso-elastic demand curve
M	total days of running demand response programs
m,n	coefficients to adjust the effect of penalty and incentive in IBPs, respectively
N	number of different electricity prices in the market
$p(\Delta d\ (i))$	total incentive for customers in ith hour (\$)
$P_0(i)$	initial electricity price in ith hour (\$/kW h)
$P(i)$	spot electricity price in ith hour (\$/kW h)
Pen (i)	penalty in ith hour (\$/kW h)
PEN $(\Delta d(i))$	total penalty for customers who do not curtail load according to predetermined contract level
$S(d\ (i))$	customer's benefit in ith hour (\$)
$St_k(i)$	value of performance of kth important strategy for the ith period
SI	strategy index
SSI	strategy success index that is the normalized value of the SI factor
α	coefficients of iso-elastic demand curve
Γ_i	demand ratio parameter in ith hour
φ_T	participation level that is a scalar in the range of [0, 1]
η_d	maximal deferrable loads during peak hours

price responsive loads is developed by introducing the concept of flexible price elasticity of demand. The proposed model is called flexible, because the price elasticity of demand should be calculated for each of DRPs based on the electricity price before and after implementing programs. Furthermore, a flexible strategy for determining the values of incentive and penalty in IBPs has been presented. The proposed model can be used for analyzing the impact of DRPs on load profile characteristics. The attractiveness of DRPs for different stakeholders (i.e. ISO, utility and customer) depends on the load characteristic and is a function of the electricity price, the value of incentive and penalty. Also, the importance of determining optimum participation level of customers in different DRPs has been addressed in this paper. The priority of implementing DRPs differs for each individual stakeholder with regard to his benefits. Here, a procedure for prioritizing different DRPs is presented from the view point of each stakeholder. The geometric average utility function (GAUF) is applied for prioritizing of programs using strategy index (SI) and strategy success index (SSI).

The remainder of the paper is organized as follows. Section 2 provides a brief background on demand response programs. In Section 3, flexible responsive load economic model is derived. Section 4 is devoted to numerical studies considering different scenarios for price, incentives, penalties and programs' potential. Finally, Section 5 concludes the paper.

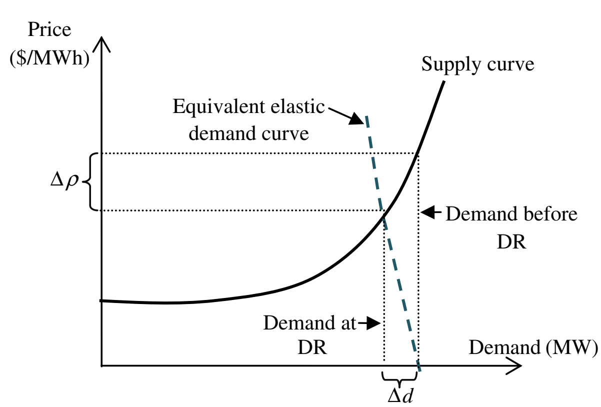

Fig. 1. Impact of demand response programs on spot electricity price.

2. A primer on demand response programs

Demand response programs are divided into two basic categories namely; time-based rate programs (TBRPs), and incentive-based programs (IBPs) [12]. Each of these categories is composed of several programs as indicated in Fig. 2.

In time-based rate programs, i.e. Time of Use (TOU), Real Time Pricing (RTP), and Critical Peak Pricing (CPP) programs, the electricity price changes for different periods according to the electricity supply cost. TOU rates establish two or more daily periods that reflect hours when the system load is higher (peak) or lower (off-peak), and charge a higher rate during peak hours. RTP rates vary continuously during the day reflecting the wholesale price of electricity. CPP is an overlay on either TOU or flat pricing. CPP uses real-time prices at times of extreme system peak.

Incentive-based programs include; Direct Load Control (DLC), Emergency Demand Response Program (EDRP), Capacity Market Program (CAP), Interruptible/Curtailable (I/C) service, Demand Bidding (DB), and Ancillary Service (A/S) program. The aforementioned programs can be classified into three main subgroups namely; voluntary, mandatory and market clearing programs. DLC and EDRP are voluntary programs which mean that if customers do not curtail consumption, they are not penalized. I/C and CAP are mandatory programs and enrolled customers are subject to penalties if they do not curtail consumption when directed. DB and A/S are market clearing programs, where large customers are encouraged to offer or to provide load reductions at a price at which they are willing to be curtailed, or to identify how much load they would be willing to curtail at posted prices. A/S program allows customer to bid load curtailment in electricity market as operating reserve. DLC refers to a program in which a utility or system operator remotely shuts down or cycles a customer's electrical equipment on short notice to address system or local reliability contingencies in exchange for an incentive payment or bill credit. Customers on I/C service rates receive a rate discount or bill credit in exchange for agreeing to reduce load during system contingencies. If customers do not curtail, they can be penalized. DB program encourages large customers to offer load reductions at a price at which they are willing to be curtailed, or to identify how much load they would be willing to curtail at posted prices. EDRP provides incentive payments to customers for reducing their loads during reliability triggered events, but curtailment is voluntary.

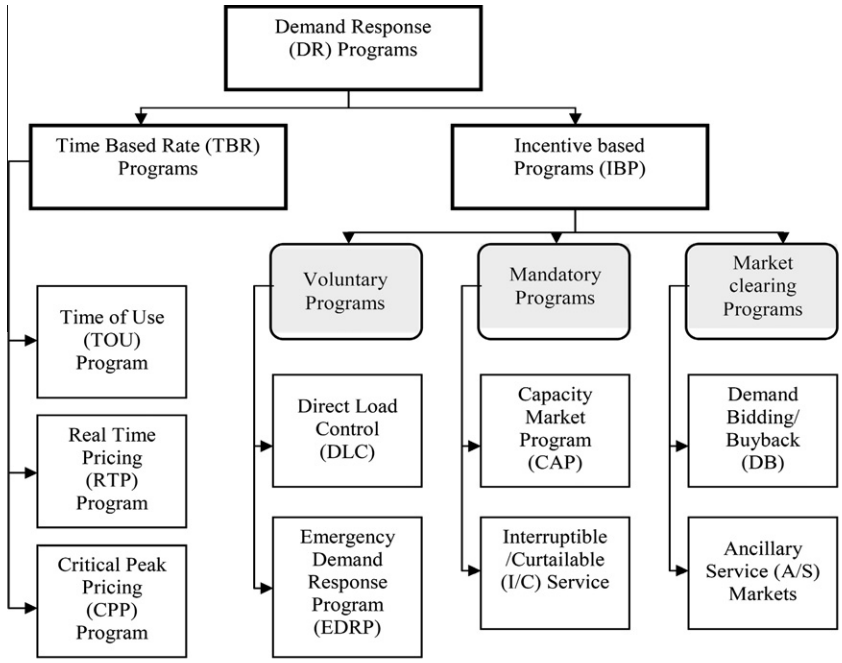

Fig. 2. Categories of demand response programs.

In CAP, customers commit to provide prespecified load reductions during system contingencies, and are subject to penalties if they do not curtail consumption when directed. A/S program allows customers to bid load curtailments in ISO 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 called by ISO, and may be paid the spot market electricity price. More detailed explanations of DRPs can be found in [12].

3. Responsive load economic model

In order to evaluate the impact of participation of customers in DRPs on load profile characteristics, development of responsive load economic model seems to be necessary. Schweppe and his co-workers formulized and developed the concept of spot pricing of electricity in 1989. They envisaged a system where customers would adjust their demand up or down depending on the spot price [13]. Kirschen showed how this model could be taken into consideration when scheduling generation and setting the price of electricity in a pool based electricity market [14]. In our previous studies [10,11], an economic model of price responsive loads was developed considering the incentive and penalty for IBPs. In this paper, the above models are extended to include a flexible price elasticity of demand for each program. In the proposed model, variable penalties and incentives are assigned based on the level of demand. For achieving the benefits of implementing DRPs from each stakeholder's point of view, a scalar in the range of [0, 1] is defined for determining the customer participation level in each DR program.

3.1. Price elasticity of demand

Elasticity is defined as the demand sensitivity with respect to the price [15]:

$$E(i,i) = E_{ii} = \frac{P(i)}{d(i)} \frac{\partial d(i)}{\partial P(i)} \tag{1}$$

According to Eq. (1), the price elasticity of the ith period versus jth period can be defined as [15]:

$$E(i,j) = E_{ij} = \frac{\partial d(i)}{\partial P(j)} \frac{P(j)}{d(i)} \tag{2}$$

If the electricity price varies for different periods, then the demand reacts one of the followings [16]:

Some loads are not able to move from one period to another (e.g. illuminating loads) and they could be only on or off. So, such loads have sensitivity just in a single period and it is called "self elasticity", which always has a negative value. Some consumptions could be transferred from the peak period to the off-peak or low periods (e.g. process loads). Such behavior is called multi period sensitivity and it is evaluated by "cross elasticity" which is always positive [17]. Accordingly, for a 24 h scheduling period, the self and cross elasticities can be arranged in a 24 by 24 matrix as below [6].

$$\begin{bmatrix} \Delta d(1) \\ \Delta d(2) \\ \Delta d(i) \\ \cdots \\ \Delta d(24) \end{bmatrix} = \begin{bmatrix} E(1,1) & E(1,2) & \cdots & \cdots & E(1,24) \\ E(2,1) & E(2,2) & \cdots & \cdots & \cdots \\ \cdots & \cdots & E(i,j) & \cdots & \cdots \\ \cdots & \cdots & \cdots & \cdots & \cdots \\ E(24,1) & \cdots & E(24,j) & \cdots & E(24,24) \end{bmatrix} \times \begin{bmatrix} \Delta P(1) \\ \Delta P(2) \\ \Delta P(j) \\ \cdots \\ \Delta P(24) \end{bmatrix} \tag{3}$$

The diagonal elements of the above elasticity matrix represent the self elasticity and the off-diagonal elements correspond to the cross elasticity. Column j of this matrix indicates how a change in price during the single period j affects the demand in other periods.

The two most commonly used mathematical functions for representing a downward sloping price (P) versus demand (d) are the linear ($d(i) = -a_i P(i) + b_i$) and the iso-elastic ($d(i) = KP(i)^{-\alpha}$) models. Since both of these functions are introduced in numerous standard economics textbooks, typically one of the two is selected when a demand curve is needed in an inventory/pricing model. There is seldom any justification on why one function is picked instead of the other, or on whether either of the two is appropriate at all as a demand curve.

In this paper, the linear function of demand curve (i.e. $d(i) = -a_i P(i) + b_i$) is considered. Hence, by using Eq. (1), the self elasticity of demand can be represented as:

$$E(i,i) = \frac{-a_i P(i)}{-a_i P(i) + b_i} \tag{4}$$

It should be notified that the price elasticity of demand is always measured at a spot price. Although the slope of the demand curve is constant in the linear equation of demand curve, but the elasticity of demand is not the same at different prices and will be increased by decreasing of the demand. For example, suppose that a_i and b_i are equal to 4 and 2000, respectively. By using Eq. (4), when $P(i)$ is equal to 100 and 200, $E(i,i)$ is calculated as −0.0204 and −0.0417, respectively. As shown in this example, by increasing of the price, although the demand consumption is decreased but the absolute value of the price elasticity of demand has been increased. This concept is used in this paper and for each of DRPs, a specific elasticity matrix has been calculated before implementation of programs.

For extracting the formulation of the cross elasticity of demand, the following procedure is proposed. Suppose that the electricity market offers the electricity power in three different prices as $P(i)$, $P(j)$ and $P(k)$ for valley, off-peak and peak periods, respectively. On the other hand, suppose that each customer has the ability to pay maximum I ($) for consuming of electricity in the predetermined period (day, month, etc.). When the electricity price is equal to $P(i)$ $/kW h, a typical customer uses $d(i)$ kilowatt hours of electricity and similarly, for the electricity prices of $P(j)$ $/kW h and $P(k)$ $/kW h, the customer uses $d(j)$ and $d(k)$ kilowatt hours of electricity, respectively. The above explanations can be expressed mathematically as following:

$$P(i)d(i) + P(j)d(j) + P(k)d(k) = I \tag{5}$$

Then, the mathematical formulation for price elasticity of the ith period (e.g. valley) versus jth period (e.g. off-peak) can be defined as following:

$$P(i) = \frac{-d(i) + b_i}{a_i} \tag{6}$$

$$d(j) = -a_i P(j) + b_i \tag{7}$$

$$d(k) = -a_i P(k) + b_i \tag{8}$$

By substitution of Eqs. (6)–(8) in Eq. (5), we will have:

$$\frac{-d(i) + b_i}{a_i} d(i) + P(j)[-a_i P(j) + b_i] + P(k)[-a_i P(k) + b_i] = I \tag{9}$$

which can be extended as

$$-d(i)^2 + b_i d(i) - a_i^2 (P(j)^2 + P(k)^2) + a_i b_i (P(j) + P(k)) - a_i I = 0 \tag{10}$$

Solving Eq. (10) for $d(i)$ and differentiating the result with respect to $P(j)$ yields

$$\frac{\partial d(i)}{\partial P(j)} = \frac{-2a_i^2 P(j) + a_i b_i}{\{b_i^2 + 4[-a_i^2 (P(j)^2 + P(k)^2) + a_i b_i (P(j) + P(k)) - a_i I]\}^{1/2}} \tag{11}$$

Then, using Eq. (2), the cross elasticity of demand (ith period versus jth period) can be formulated as:

$$E(i,j) = \frac{-2a_i^2 P(j) + a_i b_i}{\{b_i^2 + 4[-a_i^2 (P(j)^2 + P(k)^2) + a_i b_i (P(j) + P(k)) - a_i I]\}^{1/2}} \times \frac{P(j)}{-a_i P(i) + b_i} \tag{12}$$

Eq. (12) can be extended for a market with N different electricity prices as following:

$$E(i,j) = \frac{-2a_i^2 P(j) + a_i b_i}{\{b_i^2 + 4[-a_i^2 (P(j)^2 + P(k)^2) + a_i.b_i (P(j) + P(k)) - a_i.I + \sum_{\substack{L=1 \\ L \neq i,j}}^{N} -a_i^2 P(L)^2 + a_i b_i P(L)]\}^{1/2}} \times \frac{P(j)}{-a_i P(i) + b_i} \quad L = 1\ldots,i\ldots,j\ldots,N \tag{13}$$

3.2. Modeling of single period elastic loads

Suppose that the customer changes his demand from $d_0(i)$ (initial value) to $d(i)$, based on the value which is considered for the incentive and the penalty mentioned in the contract. Therefore, the demand change will be:

$$\Delta d(i) = d(i) - d_0(i) \tag{14}$$

If $A(i)$ $ is paid as incentive to the customer in ith hour for each kW h load reduction, the total incentive for participating in incentive-based programs will be as:

$$p(\Delta d(i)) = A(i)[d(i) - d_0(i)] \tag{15}$$

If the customer who has been enrolled in the mentioned DRPs does not commit to his obligations according to the contract, he will be faced with a penalty. If the contract level for the ith hour and the penalty for the same period be denoted by IC(i) and pen(i), respectively, then the total penalty, PEN($\Delta d(i)$), will be accounted as following:

$$\mathrm{PEN}(\Delta d(i)) = pen(i).\{IC(i) - [d_0(i) - d(i)]\} \tag{16}$$

In this paper, a parameter namely demand ratio, "Γ_i", is introduced for determining the value of the incentive and the penalty in each hour of scheduling period as:

$$\Gamma_i = \frac{d_0(i)}{Max\{d_0(\tau)\}} \quad \tau \in \{1, 2 \ldots i \ldots T\} \tag{17}$$

Using Eq. (17), Eqs. (15) and (16) can be modified as following:

$$p(\Delta d(i)) = \Gamma_i^n A(i)[d(i) - d_0(i)] \tag{18}$$

$$\mathrm{PEN}(\Delta d(i)) = \Gamma_i^m \mathrm{pen(i)}.\{IC(i) - [d_0(i) - d(i)] \tag{19}$$

where n and m in Eqs. (18) and (19) are applied to adjust the effect of incentives and penalties in DRPs. If $B(d(i))$ be the income of customer during ith hour from the use of $d(i)$ kWh of electricity, then the customer's benefit, S($d(i)$), for the ith hour will be as

$$S(d(i)) = B(d(i)) - d(i)P(i) + p(\Delta d(i)) - PEN(\Delta d(i)) \tag{20}$$

According to the classical optimization rules, to maximize the customer's benefit, $\partial S/\partial d(i)$ should be equal to zero; therefore,

$$\frac{\partial S(d(i))}{\partial d(i)} = \frac{\partial B(d(i))}{\partial d(i)} - P(i) + \frac{\partial p}{\partial d(i)} - \frac{\partial PEN}{\partial d(i)} = 0 \tag{21}$$

Solving Eq. (21) for $\partial B(d(i))/\partial d(i)$ yields:

$$\frac{\partial B(d(i))}{\partial d(i)} = P(i) + \Gamma_i^n A(i) + \Gamma_i^m \mathrm{pen(i)} \tag{22}$$

The benefit function, most often used, is the quadratic benefit function [13]:

$$B(d(i)) = B_0(i) + P_0(i)[d(i) - d_0(i)]\left\{1 + \frac{d(i) - d_0(i)}{2E(i)d_0(i)}\right\} \tag{23}$$

By differentiating the above equation and solving for $\partial B/\partial d(i)$ and substituting the result in Eq. (22) we will have:

$$P(i) + \Gamma_i^n A(i) + \Gamma_i^m \mathrm{pen}(i) = P_0(i)\left\{1 + \frac{d(i) - d_0(i)}{E(i)d_0(i)}\right\} \tag{24}$$

Therefore, customer's consumption will be as following:

$$d(i) = d_0(i)\left\{1 + E(i,i)\frac{[P(i) - P_0(i) + \Gamma_i^n A(i) + \Gamma_i^m \mathrm{pen}(i)]}{P_0(i)}\right\} \tag{25}$$

Substitution of Eq. (4) in Eq. (25) yields

$$d(i) = d_0(i)\left\{1 - \frac{a_i P(i)[P(i) - P_0(i) + \Gamma_i^n A(i) + \Gamma_i^m \mathrm{pen}(i)]}{-a_i P(i) P_0(i) + b_i P_0(i)}\right\} \tag{26}$$

3.3. Modeling of multi period elastic loads

According to the definition of the cross elasticity in Eq. (2), with the linearity assumption we have:

$$\frac{\partial d(i)}{\partial P(j)}: \quad \text{constant for } i,j = 1,2,\ldots,24$$

which implies the following linear relationship between the prices and demands:

$$d(i) = d_0(i)\left\{1 + \sum_{\substack{j=1 \\ i\neq j}}^{24} E(i,j)\cdot\frac{[P(j) - P_0(j) + \Gamma_i^n A(j) + \Gamma_i^m \mathrm{pen}(j)]}{P_0(j)}\right\} \tag{27}$$

Substituting Eq. (13) in Eq. (27) results in:

$$d(i) = d_0(i)\left\{1 + \sum_{\substack{j=1 \\ i\neq j}}^{24} \frac{[-2a_i^2 P(j)^2 + a_i b_i P(j)][P(j) - P_0(j) + \Gamma_i^n A(j) + \Gamma_i^m \mathrm{pen}(j)][-a_i P(i) P_0(j) + b_i P_0(j)]^{-1}}{\{b_i^2 + 4[-a_i^2 (P(j)^2 + P(k)^2) + a_i \cdot b_i (P(j) + P(k)) - a_i \cdot I + \sum_{\substack{L=1 \\ L\neq i,j}}^{N} -a_i^2 P(L)^2 + a_i b_i P(L)]\}^{1/2}}\right\} \tag{28}$$

3.4. Flexible responsive load economic model

By combining Eqs. (25) and (27), we will have the responsive load economic model as following:

$$d(i) = d_0(i)\left\{1 + E(i,i)\frac{[P(i) - P_0(i) + \Gamma_i^n A(i) + \Gamma_i^m \mathrm{pen}(i)]}{P_0(i)} + \sum_{\substack{j=1 \\ i\neq j}}^{24} E(i,j)\frac{[P(j) - P_0(j) + \Gamma_i^n A(j) + \Gamma_i^m \mathrm{pen}(j)]}{P_0(j)}\right\} \tag{29}$$

In Eq. (29), $d_0(i)$ can be presented as following:

$$d_0(i) = \varphi_T \eta_d d_0^{Total}(i) \tag{30}$$

where φ_T is a scalar in the range of [0, 1], the larger φ_T the more willingly will the customers choose to shift consumption from peak hours to off-peak hours. η_d represents the maximal deferrable loads during peak hours and $d_0^{Total}(i)$ is the base load before implementing DRPs. Using Eq. (30), Eq. (29) can be rewritten as:

$$d(i) = \varphi_T \eta_d d_0^{Total}(i)\left\{1 + E(i,i)\frac{[P(i) - P_0(i) + \Gamma_i^n A(i) + \Gamma_i^m \mathrm{pen}(i)]}{P_0(i)} + \sum_{\substack{j=1 \\ i\neq j}}^{24} E(i,j)\frac{[P(j) - P_0(j) + \Gamma_i^n A(j) + \Gamma_i^m \mathrm{pen}(j)]}{P_0(j)}\right\} \quad i = 1,2,\ldots,24. \tag{31}$$

By substituting of Eqs. (4) and (13) in Eq. (31), we will have the flexible responsive load economic model as following:

$$d_0(i) = \varphi_T \eta_d d_0^{Total}(i)\left\{1 - \frac{a_i P(i)[P(i) - P_0(i) + \Gamma_i^n A(i) + \Gamma_i^m \mathrm{pen}(i)]}{-a_i P(i) P_0(i) + b_i P_0(i)} + \sum_{\substack{j=1 \\ i\neq j}}^{24} \frac{[-2a_i^2 P(j)^2 + a_i b_i P(j)][P(j) - P_0(j) + \Gamma_i^n A(j) + \Gamma_i^m \mathrm{pen}(j)][-a_i P(i) P_0(j) + b_i P_0(j)]^{-1}}{\{b_i^2 + 4[-a_i^2 (P(j)^2 + P(k)^2) + a_i . b_i (P(j) + P(k)) - a_i . I + \sum_{\substack{L=1 \\ L\neq i,j}}^{N} -a_i^2 P(L)^2 + a_i b_i P(L)]\}^{1/2}}\right\} \tag{32}$$

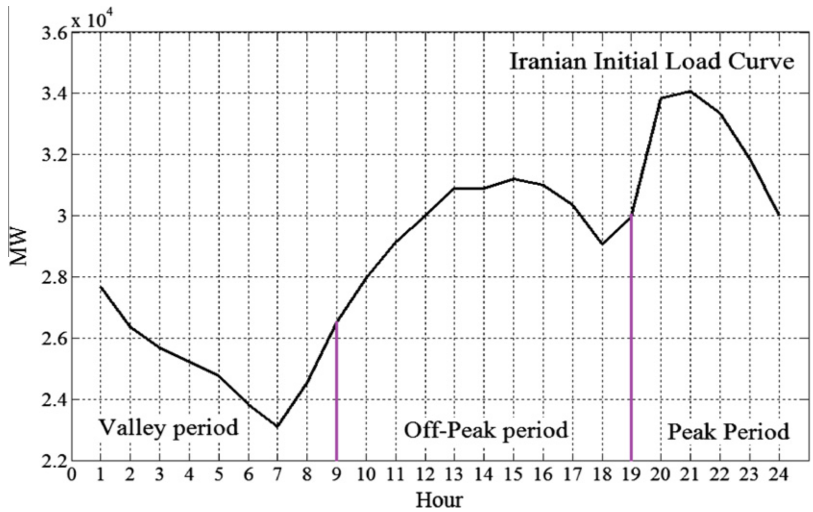

Fig. 3. Iranian network load curve on annual peak day 28/08/2007.

Table 1
Statements of portfolio of DR programs.

Groups no.	Programs no.	Programs $\eta_d = 0.1$ $\varphi_T = 1, 0.7, 0.5$	Electricity price ($\mathscr{R}$/kW h)	Incentive value ($\mathscr{R}$/kW h)	Penalty value ($\mathscr{R}$/kW h)
0	0	Initial load (Base case)	160 flat Rate	0	0
1. TBR	1	TOU	40, 160, 400 at Valley, off Peak and Peak Periods respectively	0	0
	2	CPP	800 at 20, 21, 22 o'clock	0	0
	3	RTP	40, 40, 40, 40, 20, 20, 20, 20, 160, 160, 160, 160, 200, 200, 200, 200, 160, 160, 160,500,500,500,160,160 at 1 to 24 respectively	0	0
	4	TOU + CPP	40, 160, 400 at Valley, off Peak, Peak Periods and 800 at 20,21,22 o'clock	0	0
2. IBP	5	DLC	160 flat Rate	200	0
	6	EDRP	160 flat Rate	400	0
	7	CAP	160 flat Rate	100	50
	8	I/C	160 flat Rate	200	100
3. TBR + IBP	9	CPP + EDRP	800 at 20, 21, 22 o'clock	400	0
	10	RTP + CAP	40,40,40,40,20,20,20,20,160,160,160,160,200,200,200,200,160, 160,160,500,500 500,160,160 at 1 to 24 respectively	100	50

3.5. Strategy selection

Beyond the broad improvements in market efficiency and market linkages, demand response creates multiple benefits for market participants and for the general efficiency and operation of electricity markets. To achieve the above benefits, different strategies are considered for reduction of the load during system peak, reduction of energy consumption, improvement of system load factor and reduction of distance between peak and valley, etc. On the other hand, different scenarios for price, incentives, penalties and participation level of customers are compared with each other. The program prioritizing is different from each of DR stakeholders (i.e. ISO/utility/customer) point of view. For program prioritizing, the Geometric Average Utility Function (GAUF) is applied using strategy index (SI) and strategy success index (SSI) as defined by the following equations [18]:

$$SI = \sum_{i=1}^{24} St_1(i) \times St_2(i) \times \cdots \times St_k(i) \tag{33}$$

$$SSI = \frac{\sum_{i=1}^{M} SI(i)}{\sum_{i=1}^{M} SI(\max)} \tag{34}$$

where $St_k\,(i)$ represents the value of performance of kth important strategy from individual stakeholder point of view for the ith period, and M represents the total days of running the programs. SSI coefficient represents the normalized value of the SI factor. Briefly, the higher the SSI coefficient, the better the profit of each stakeholder.

4. Numerical studies

In this section, the actual peak load curve of the Iranian power grid on 28/08/2007 (annual peak load), has been used for our simulation studies [19]. Fig. 3 represents the aforementioned load curve which is divided into three different periods, namely valley period (00:00 am–9:00 am), off-peak period (9:00 am–7:00 pm) and peak period (7:00 pm–12:00 pm).

The electricity price in Iran in 2007 was 150 Rails[1]/kW h as flat rate tariff, 400 $\mathscr{R}$/kW h in peak period, 160 $\mathscr{R}$/kW h in off-peak period and 40 $\mathscr{R}$/kW h in valley periods as TOU tariffs [20]. The maximal deferrable loads during peak hours is considered to be 10% of the total load and according to φ_T, the customer potential for participating in DRPs is equal to 10%, 7% or 5% of the total load. Accordingly, ISO will be able to reduce the network peak load about 3400 MW in the instance of peak around 9:00 pm to increase the reserve margin and reduce the possibility of load shedding. Several programs have been considered as indicated in Table 1. These programs are divided into three groups. In base case, flat rate prices are implemented,

[1] Unit of Iranian currency equal to 0.01 cent denoted by $\mathscr{R}$.

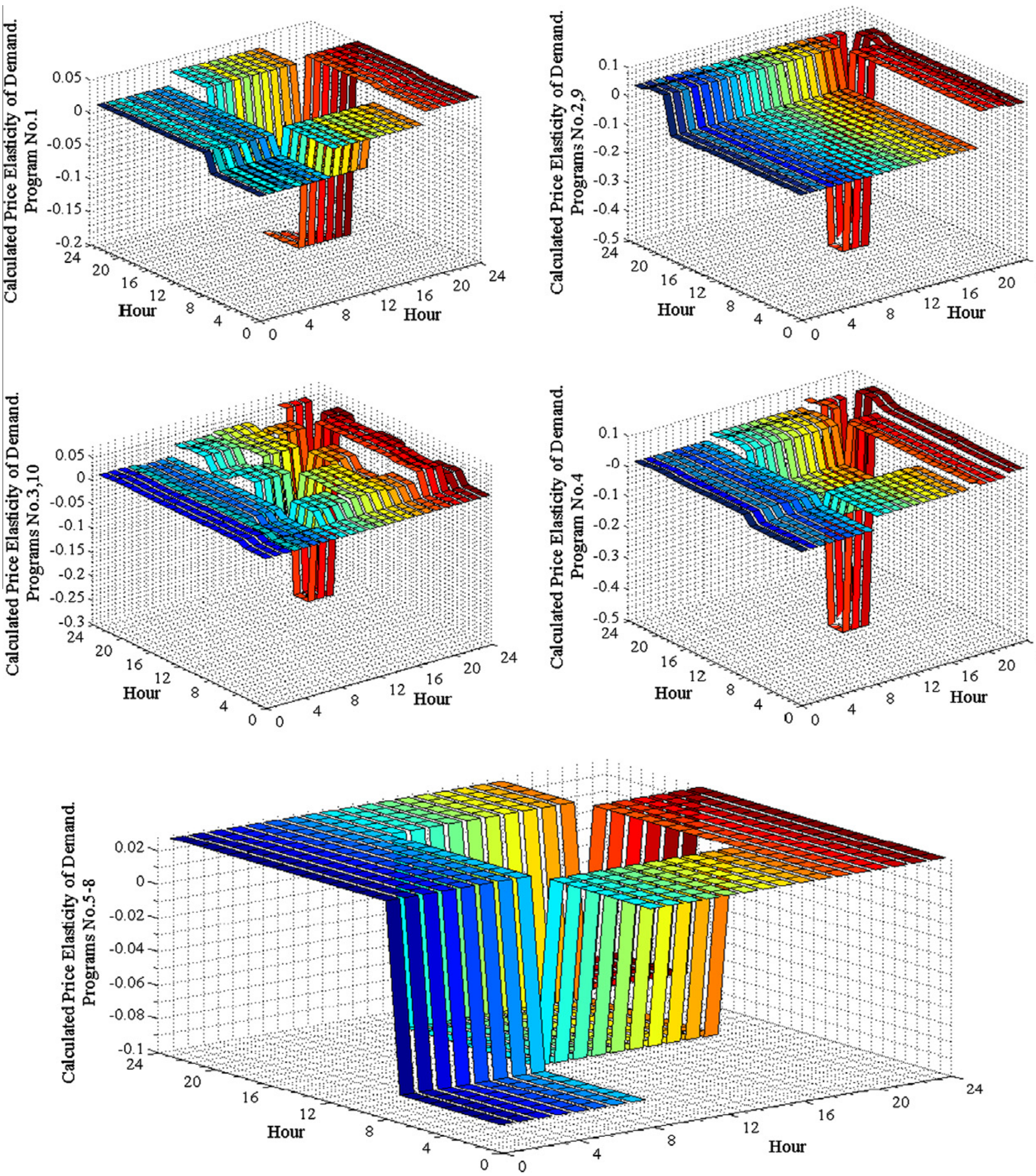

Fig. 4. Flexible price elasticity of demand for DR programs.

where no DRP is adopted. Group #1 is the TBR class which includes TOU, CPP, RTP and combined TOU and CPP programs. Group #2 is the IBPs class, which includes DLC, EDRP, CAP and I/C programs. Group #3 is combination of TBR and IBP programs as indicated in Table 1. These are widely used programs in power markets [21,22]. In this study, the constant coefficients of the linear function of demand curve i.e. "a_i" and "b_i" are assumed to be 5 and 10,000, respectively. Before implementing DRPs, based on Eqs. (4) and (13), the price elasticities of demand are calculated for each of programs as shown in Fig. 4. These elasticities are called flexible, i.e. they can be replaced with new ones when the electricity price changes. This flexible property of the price elasticity of demand helps the stakeholders (i.e. ISO/utility/customer) to select the best DRPs from their point of view to obtain their predetermined objectives. Investigation of the results of Fig. 4 reveals that the elasticity of the demand is sensitive to the electricity price according to the variation of electricity price as indicated in Table 1. Using the proposed flexible responsive load economic model, the impact of the mentioned demand response programs on the load curve characteristics are shown in Figs. 5–9 for participation level of 1 and 0.7.

4.1. Analysis of the results

In this part, we will discuss on the results obtained through numerical studies from both "economical" and "load profile characteristics" view points. Several economic indices namely, electri-

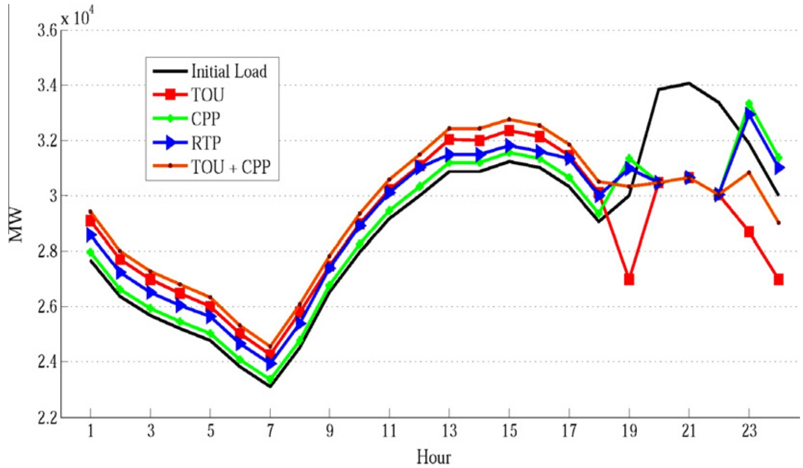

Fig. 5. The impact of TBR programs (Group #1, $\varphi_T = 1$) on load profile.

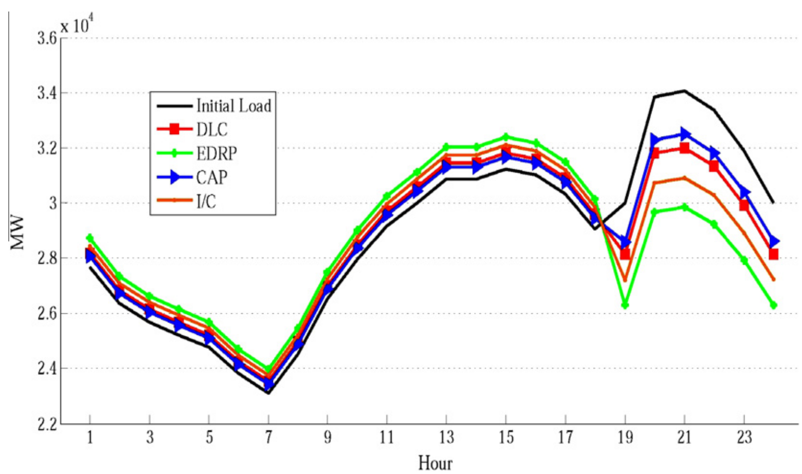

Fig. 6. The impact of IBP programs (Group #2, $\varphi_T = 1$) on load profile.

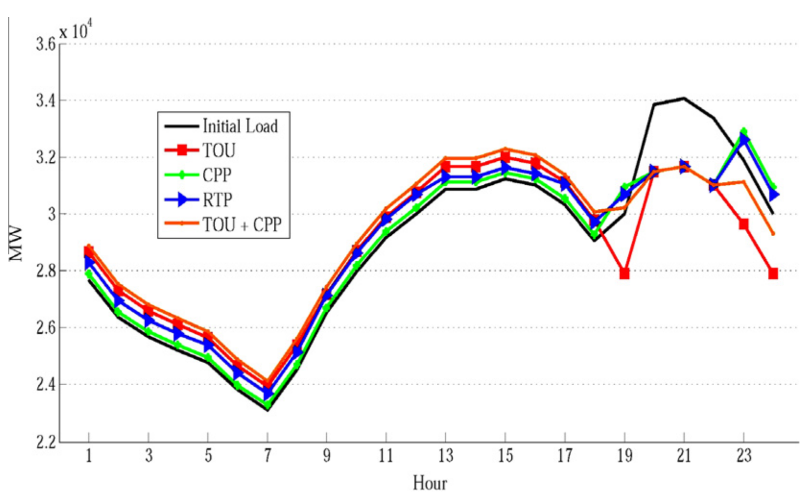

Fig. 7. The impact of TBR programs (Group #1, $\varphi_T = 0.7$) on load profile.

cal energy consumption cost, benefits and losses of the customers and revenue of the utility are calculated, before and after implementing DRPs. Furthermore, several technical indices namely, peak reduction, electrical energy consumption reduction, load factor, and peak to valley distance are evaluated for each scenario. Tables 2–4 compare the performance of the proposed flexible DR model using the above economical and technical indices for various values of φ_T fin different scenarios.

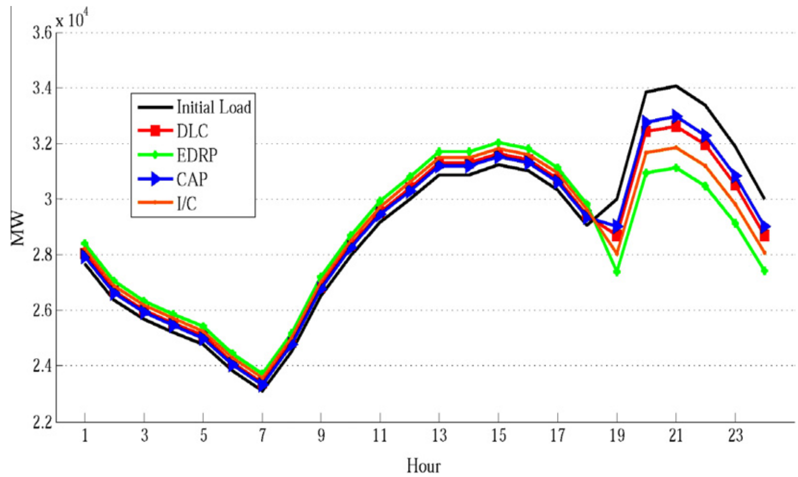

Fig. 8. The impact of IBP programs (Group #2, $\varphi_T = 0.7$) on load profile.

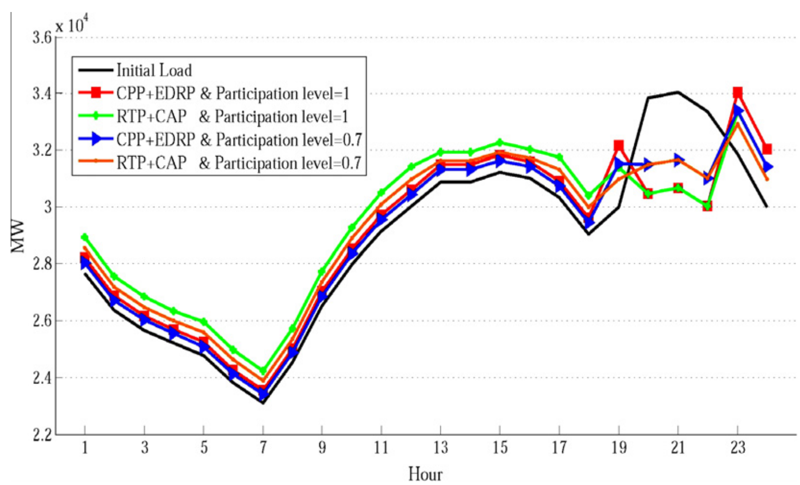

Fig. 9. The impact of programs Group #3 on load profile.

Table 2
Economical comparison of the programs.

Programs no.	Programs ($m = n = 1$)	Customer bill (million $\mathscr{R}$) φ_T			DR incentive value (Million $\mathscr{R}$) φ_T			Customer benefit (million $\mathscr{R}$) φ_T		
		1	0.7	0.5	1	0.7	0.5	1	0.7	0.5
0	Initial load	110,604	110,604	110,604	0	0	0	0	0	0
1	TOU	127,227	128,903	130,021	0	0	0	−16,623	−18,299	−19,417
2	CPP	168,811	170,791	172,112	0	0	0	−58,207	−60,187	−61,508
3	RTP	120,958	121,849	122,444	0	0	0	−10,354	−11,245	−11,840
4	TOU + CPP	167,404	169,178	170,362	0	0	0	−56,798	−58,575	−59,758
5	DLC	110,212	110,330	110,408	2118	1483	1059	2509	1756	1255
6	EDRP	109,776	110,024	110,190	8586	6010	4293	9414	6590	4707
7	CAP	110,293	110,386	110,448	807	565	403	1117	782	558
8	I/C	109,983	110,169	110,293	3222	2256	1611	3843	2690	1921
9	CPP + EDRP	169,875	171,536	131,379	3298	2309	3298	−55,973	−58,623	−17,757
10	RTP + CAP	121,963	122,552	122,946	994	696	497	−10,364	−11,252	−11,845

4.1.1. Base case

The first rows in Tables 2–4 present the base case with actual load curve (Fig. 3), where no DR program is implemented. Tables 3 and 4 show that the base case has the lowest load factor (84.5%), the maximum distance between peak and valley (10,951 MW) and the maximum peak value (34,058 MW). These three indices will be improved after implementation of DR programs as follows.

4.1.2. Program 1

As it can be seen from Tables 3 and 4, in program 1 (TOU program), the maximum peak reduction (6.02%) and the maximum increase in load factor (6.6%) are achieved when $\varphi_T = 0.7$ in compare with the base case. Here, the minimum distance between peak and valley (8075 MW) is obtained for $\varphi_T = 1$ in compare with the other programs. According to Table 2, for this case, the minimum costumers' total cost is 127,227 million $\mathscr{R}$, and the customers' benefit

Table 3
Economical and technical comparison of the programs.

Programs no.	Programs ($m = n = 1$)	Utility revenue (Million ℛ) φ_T			Peak (MW) φ_T			Peak reduction (%) φ_T		
		1	0.7	0.5	1	0.7	0.5	1	0.7	0.5
0	Initial load	110,604	110,604	110,604	34,058	34,058	34,058	0	0	0
1	TOU	127,227	128,903	130,021	32,351	32,010	32,355	5.02	6.02	5.01
2	CPP	168,811	170,791	172,112	33,319	32,885	32,595	2.17	3.45	4.29
3	RTP	120,958	121,849	122,444	32,926	32,610	32,399	3.32	4.25	4.87
4	TOU + CPP	167,404	169,178	170,362	32,760	32,297	32,354	3.8	5.17	5
5	DLC	108,094	108,847	109,349	32,002	32,619	33,030	6.04	4.23	3.02
6	EDRP	101,190	104,014	105,897	32,382	32,032	31,958	4.92	5.95	6.17
7	CAP	109,486	109,821	110,045	32,483	32,955	33,270	4.62	3.24	2.31
8	I/C	106,761	107,913	108,682	32,090	31,853	32,483	5.78	6.47	4.62
9	CPP + EDRP	166,575	169,227	170,994	34,036	33,386	32,954	0.06	1.97	3.24
10	RTP + CAP	120,967	121,856	122,449	33,362	32,915	32,617	2.04	3.36	4.23

Table 4
Technical comparison of the programs.

Programs no.	Programs ($m = n = 1$)	Energy consumption (MW h) φ_T			Energy reduction (%) φ_T			Load factor (%) φ_T			Peak to valley (MW) φ_T		
		1	0.7	0.5	1	0.7	0.5	1	0.7	0.5	1	0.7	0.5
0	Initial load	691,273	691,273	691,273	0	0	0	84.5	84.5	84.5	10,951	10,951	10,951
1	TOU	692,592	692,448	692,112	−0.22	−0.15	−0.11	89.3	90.1	89.2	8075	8085	8663
2	CPP	690,513	690,741	690,893	0.1	0.07	0.05	86.4	87.5	88.3	9971	9609	9368
3	RTP	699,168	696,799	695,220	−0.99	−0.71	−0.51	88.5	89.0	89.4	8998	8928	8882
4	TOU + CPP	706,801	702,143	699,037	−1.98	−1.4	−0.99	89.9	90.6	90.0	8203	8174	8523
5	DLC	688,826	689,560	690,049	0.32	0.22	0.15	89.7	88.1	87.0	8462	9209	9707
6	EDRP	686,098	687,651	688,686	0.66	0.47	0.34	88.3	89.5	89.8	8410	8319	8418
7	CAP	689,332	689,915	690,303	0.25	0.17	0.12	88.4	87.2	86.4	9051	9621	10,001
8	I/C	687,392	688,556	689,332	0.51	0.36	0.25	89.25	90.1	88.4	8334	8292	9051
9	CPP + EDRP	696,167	695,398	694,220	−0.72	−0.51	−0.37	85.35	86.79	87.78	10,483	9967	9624
10	RTP + CAP	707,096	702,348	699,184	−1.97	−1.40	−1.02	88.31	88.91	89.32	9140	9028	8952

is −16,623 million ℛ, which means that the customers' loss is equal to 16,623 million ℛ for $\varphi_T = 1$. In this program, the customer energy consumption is increased at least 0.11% for $\varphi_T = 0.5$.

4.1.3. Program 2

In this case, CPP program is implemented in hours 20, 21, and 22. The results of Tables 2–4, show that the load profile characteristics are improved, but the costumer cost is increased at least by 58,207 million ℛ for $\varphi_T = 1$. As it is shown in Table 2, in this case, a maximum increasing of the costumers' cost is achieved in comparison with other programs, and by decreasing of participation level, the customers' cost has been increased which shows an inverse relation between participation level and costumer cost in this program. When $\varphi_T = 0.5$, the maximum total cost of costumers is achieved in compare with other programs which is due to imposing high price of electricity in CPP program. As shown in Table 3, by decreasing of customers' participation level, the load reduction of this program will be increased and stand in the allowable level. The maximum distance between peak and valley (9971 MW) is achieved for $\varphi_T = 1$ and by decreasing of customers' participation level, this technical parameter which is important for ISO will have descending behavior.

4.1.4. Program 3

For RTP program, the load profile characteristic is improved. As it can be seen from Tables 3 and 4, in program 3, by decreasing of customers' participation level, i.e. $\varphi_T = 0.5$ the peak reduction index is increased with a maximum value equal to 4.87%, minimum distance between peak and valley (8882 MW) and maximum 5.8% increase in load factor, in compare with the base case. According to Table 2, for this case, the minimum costumers' total cost is 120,958 million ℛ, and the customers' benefit is −10,354 million ℛ for $\varphi_T = 1$. In this program, the customers' energy consumption is increased at least 0.51% for $\varphi_T = 0.5$.

4.1.5. Program 4

In this case, TOU and CPP programs are implemented simultaneously. As shown in Table 4, it can be seen that maximum load factor (90.6%) for participation level of 0.7 and maximum energy consumption (706,801 MW h) for $\varphi_T = 1$ have been obtained in compare with other programs. In this program, the customers' energy consumption is increased by 1.98% for $\varphi_T = 1$ in compare with the base case, which is considerably more than the other DRPs.

4.1.6. Program 5

In this case, DLC program is implemented. Here, we assume 200 ℛ/kW h and zero ℛ/kW h as the incentive and penalty, respectively. In other words, in this program it is considered that ISO prizes the customers for load reduction, but does not penalize their violence. By applying the proposed model (Eq. (32)) on the initial load curve, maximum peak reduction (2056 MW) is obtained (6.04% reduction) when $\varphi_T = 1$. The results show that the load profile characteristics are improved and maximum customers' benefit in this program is equal to 2509 million ℛ for $\varphi_T = 1$.

4.1.7. Program 6

When EDPR is implemented, we assume ISO pays 400 ℛ/kWh as the incentive for load reduction, and applies zero ℛ/kWh as the penalty, which means that ISO does not penalize their violence if customers do not reduce the load based on predetermined level in the contract. The result of running the program is shown in Figs. 6 and 8 for $\varphi_T = 1$ and 0.7, respectively. As it can be seen from Tables 2 and 4, in this case, the maximum costumers' benefit (9414 million ℛ) and maximum energy reduction (0.66%) are

Table 5
Defining scenarios according to the programs and value of φ_T.

Program. no.	1			2			3			4			5		
φ_T	1	0.7	0.5	1	0.7	0.5	1	0.7	0.5	1	0.7	0.5	1	0.7	0.5
Scenario. no.	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
Program. no.	6			7			8			9			10		
φ_T	1	0.7	0.5	1	0.7	0.5	1	0.7	0.5	1	0.7	0.5	1	0.7	0.5
Scenario. no.	16	17	18	19	20	21	22	23	24	25	26	27	28	29	30

Table 6
Prioritizing of scenarios from individual stakeholder point of view.

Customer				Utility				ISO			
Electricity bill Priority 1–15		Energy consumption Priority 16–30		Revenue Priority 1–15		Load factor Priority 16–30		Distance between peak to valley Priority 1–15		Peak load reduction Priority 16–30	
Scenario no.	SSI (%)	Scenario no.	SSI (%)	Scenario no.	SSI (%)	Scenario no.	SSI (%)	Scenario no.	SSI (%)	Scenario no.	SSI (%)
16	100	9	80.38	12	100	8	70.74	23	100	30	60.52
22	99.62	29	80.24	11	99.93	28	70.39	2	95.26	10	59.48
17	99.55	30	79.75	6	99.11	7	69.78	18	93.81	14	58.77
23	99.29	1	74.45	27	99.05	23	63.40	17	91.58	6	58.70
18	99.25	2	72.53	10	98.13	13	63.21	13	91.36	29	47.58
13	99.2	3	71.28	5	97.47	19	63.13	22	88.78	7	47.29
24	99.06	10	43	26	97.3	24	62.66	11	81.03	5	45.91
19	99.06	4	42.29	4	95.05	14	62.54	1	79.49	27	43.12
14	98.99	11	42.1	25	94.76	20	62.47	12	75.14	20	43.09
20	98.89	25	41.81	2	75.76	22	62.14	16	74.92	15	39.82
15	98.85	12	41.52	3	75.57	15	62.07	3	73.91	21	29.61
21	98.78	5	41.31	1	74.04	21	62.03	9	70.23	28	28.61
7	98.3	26	40.96	30	71.77	18	62	24	65.43	4	27.87
8	81.12	27	40.48	9	71.39	17	60.66	19	65.43	26	25.31
28	80.97	6	40.68	29	71.21	16	58.25	8	60.98	25	0.78

achieved for $\varphi_T = 1$ in compare with other programs. Here, the ISO has paid a maximum incentive value (8586 million $\mathscr{R}$) for $\varphi_T = 1$. The maximum peak reduction in this program is equal to 6.17% for $\varphi_T = 0.5$ in compare with the base case.

4.1.8. Program 7

In this case, CAP is implemented and it is assumed that ISO pays 100 $\mathscr{R}$/kW h as the incentive for load reduction, and applies 50 $\mathscr{R}$/kW h as the penalty, if customers do not reduce the load based on the predetermined level in the contract. The result of running the program is shown in Figs. 6 and 8 for $\varphi_T = 1$ and 0.7, respectively. For this case, as indicated in Tables 2–4, maximum 4.62% peak reduction, maximum 0.25% energy consumption reduction, 88.4% load factor, and maximum costumers' benefit (1117 million $\mathscr{R}$) are achieved when $\varphi_T = 1$ in compare with the base case. In program 7, the maximum distance between peak and valley (10,001 MW) is achieved for $\varphi_T = 0.5$ in compare with the base case.

4.1.9. Program 8

After implementing I/C program, the load profile characteristic is improved and costumers' benefit is in a desired state. For I/C program, as indicated in Table 3, maximum peak reduction (6.47%) is achieved for $\varphi_T = 0.7$ in compare with other programs. It can be seen from Table 4 that maximum 0.51% energy reduction for $\varphi_T = 1$, minimum distance between peak and valley (8292 MW) and maximum 6.6% increase in load factor are achieved for $\varphi_T = 0.7$ in compare with the base case.

4.1.10. Program 9

In this case, CPP and EDRP are implemented simultaneously. It can be seen from Table 4 that after implementing program 9, the customers' energy consumption is increased at least 0.37% for $\varphi_T = 0.5$ in compare with the base case. This program has the lowest load reduction (0.06%) and maximum distance between peak and valley (10,483 MW) for $\varphi_T = 1$ in compare with other programs. Here, the maximum load factor (87.78%) is achieved for $\varphi_T = 0.5$ in compare with the base case.

4.1.11. Program 10

In this case, RTP and CAP are implemented simultaneously where the maximum load factor (89.32%) and the minimum distance between peak and valley (8952 MW) have been obtained for $\varphi_T = 0.5$. In this case, the energy consumption is increased at least 1.02% for $\varphi_T = 0.5$. It can be seen from Tables. 3 and 4 that the maximum peak reduction index (4.23%) and maximum increase in load factor (5.7%), are achieved for $\varphi_T = 0.5$ in compare with the base case. According to Table 2, the minimum costumers' total cost and the customers' benefit are equal to 121,963 and −10,364 million $\mathscr{R}$ for $\varphi_T = 1$, respectively.

From the above discussions, it can be concluded that the optimum participation level is different from each of stakeholders' point of view. In Section 4.2, we will discuss more about the optimum participation level of customers in each of DRPs from the view point of different stakeholders.

4.2. Prioritizing of scenarios

Table 5 represents the relation between the number of programs and scenarios based on the value of φ_T. Since ISO has the primary responsibility of maintaining the security of the system, peak load reduction and the distance between the peak and the valley have relative priority from his point of view. From utility point of view, the revenue as well as the load factor have relative importance. The electricity bill and energy consumption have relative importance from customers' perspective. Hence, the strategy success index (SSI) as defined by Eq. (34) is represented in Table 6

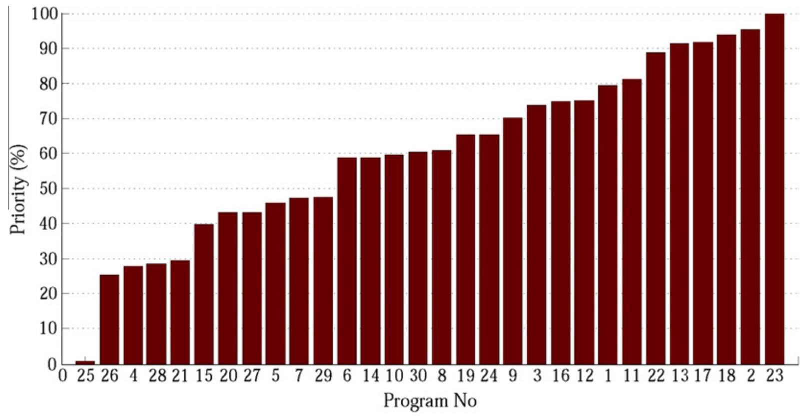

Fig. 10. Priority of programs (ISO point of view).

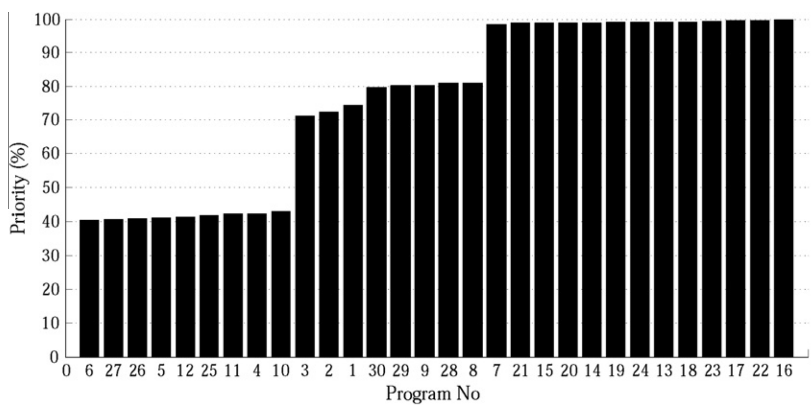

Fig. 11. Priority of programs (customer point of view).

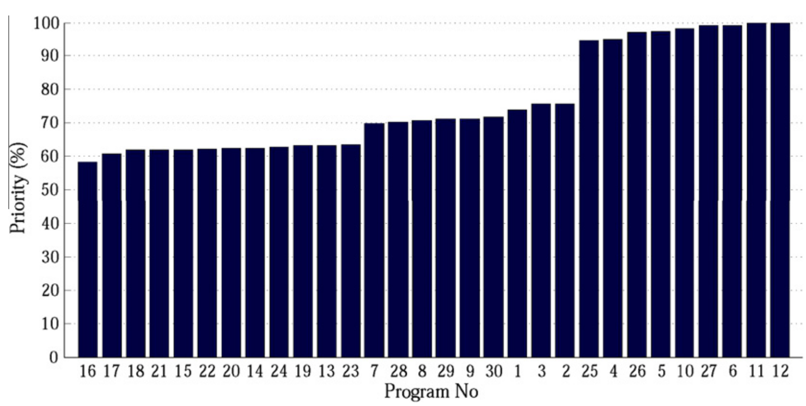

Fig. 12. Priority of programs (utility point of view).

using the results of Tables 2–4 from the view point of different stakeholders.

The sorted priorities from individual stakeholder's point of view are depicted in Figs. 10–12. Each of stakeholders chooses relevant strategy according to his policies based on the results of scenario analysis as indicated in Figs. 10–12. Investigation of the above figures reveals that for different stakeholders, priorities of scenarios depend on different decision signals like the electricity price, participation level of customers, incentive and the penalty values determined for DRPs. In practice, when some restrictions exist for implementation of certain program with higher priority, an individual stakeholder can choose other program with lower priority.

5. Conclusion

In this paper, a new economic model for price and incentive responsive loads has been derived based on the concepts of flexible price elasticity of demand and customer benefit function. This model can be used for the purpose of improving the load profile characteristics as well as satisfaction of customers. It has been shown that the customers' demand depends on different decision signals like the electricity price, participation level of customers, incentive and the penalty values determined for DRPs. The mathematical model for flexible price elasticity of demand has been developed to calculate the elasticity of each demand response program based on the electricity price before and after implementing DRPs. In the proposed model, a parameter has been introduced for flexible assigning of incentive and penalty in IBPs based on the level of demand. By using the proposed economic model, the market regulator can simulate the behavior of customers for different electricity prices, incentives, penalties and participation level of customers. DRP stakeholders may have different benefits by implementing the programs, hence, the priority of each individual stakeholder has been determined using strategy success index (SSI). The performance of the proposed model was investigated through numerical study using Iranian interconnected network load profile on the annual peak day of the year 2007.

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