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Unit commitment considering the emergency demand response programs and interruptible/curtailable loads

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Abstract: After restructuring the power systems, demand response programs form the main part of consumption management programs. This is because these programs are by nature particularly suitable for adapting to the new structure in power system management. These programs are considered as a suitable solution for solving some problems in power system restructuring. Unit commitment (UC) programs are used for power production with minimum cost. In this paper, after presenting an overview of demand response methods, a mechanism is proposed for simultaneous execution of the UC program, emergency demand response programs, and interruptible/curtailable loads. The proposed mechanism, in addition to decreasing the payment costs, ensures a flat load curve and increases system reliability.

Key words: Emergency demand response, minimum cost, demand side management, interruptible/curtailable load

1. Introduction

Demand-side management consists of activities that are designed by electrical utilities for changing the quantity or time of electrical consumption to the benefit of society, customers, and utilities [1]. The simultaneous contribution of customers in the auction market with utilization of demand response programs (DRPs) including emergency DRPs (EDRPs) and interruptible/curtailable (I/C) programs result in a decrease in the production costs of independent system operators (ISO) and payment costs of customers. Demand response (DR) can change the form of electrical energy consumption in such a way that maximum efficiency in consumption is obtained in peak times, loads are managed, the peak is decreased in the system, and, if required, distributed generation is linked to the circuit [2]. Generally, the aim of DR is decreasing power consumption during critical hours. Two factors that can encourage support from customers is the change in price at retail level and execution of consumption incentive programs for the customers to save electricity during the critical hours.

In this paper, first minimization methods of the offered costs and DR, especially EDR and I/C load methods, are reviewed. Then the mathematical models of EDRP and I/C loads are explained. Afterwards, the solution method and linearization method of cost function are discussed. Finally, the mixed integer linear programming (MILP) technique is used for execution of a short-term unit commitment (UC) program taking into account the offering cost mechanism (OCM) and its simultaneous execution with EDRP and I/C loads. The proposed model is simulated in MATLAB using the branch and cut method as an effective method in MILP solution problems.

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1.1. Minimization of the offered cost

In most electrical energy markets, a minimization cost mechanism is used based on the offered production units to obtain the market operation point. This mechanism has the largest utilization in the electrical industry after restructuring and, despite the differences in its application in different markets, it is based on the same theoretical underpinnings, having a structure similar to that of UC used in vertically integrated utilities. In fact, UC is used for the identification of the on/off situation of units and their output power. The only important constraint here is supplying the load of customers with the minimum power generation cost. Presently, most ISOs minimize the offers cost to identify winning offers and their generation levels. If the OCM is real, the offered costs mechanism will lead to economically favorable results and simultaneously attempts for decreasing costs, but if the producers' offers do not conform to their cost function and some of them, for any reason, change the basis of their offering, the OCM will lead to results that are not optimum or are incongruent with the operator's objective.

1.2. Demand response

The US Department of Energy defines DR as the change in electricity consumption from the normal consumption pattern by customers in response to changes in the price for electricity or in response to costs determined for electricity as an incentive for reducing electricity consumption (during the time when prices for electricity are high or the reliability of the system is at risk) [3]. The importance of DR lies in the reduction in interruptions, reduction in production costs, leveling of the load curve, helping stability in market prices, putting off the establishment of new power plants, economizing in the costs for production resources, etc. DR can be divided into two general broad categories based on the way customers contribute in changing the electricity consumption pattern. These programs are executed by two different methods, namely price-based DR and incentive-based DR, which are discussed here.

Most electricity customers have no information on electrical prices, which vary every moment, treating the electricity as a commodity presented with a constant price. Therefore, they find no incentive for changing their electricity consumption pattern in response to these prices. Price-based DRPs induce the incentive in the end users, encouraging them to make changes in their consumption pattern. In this method, no payment is made by electricity utilities to customers for their contribution. These programs are designed to make electricity price uniform at different hours. Price-based DR involves various tariffs including the real-time price, time of use (TOU), critical peak pricing, emergency day critical peak pricing, and emergency day pricing [4,5].

Incentive-based DRPs induce the incentive in customers to reduce consumption. Unlike price-based programs, incentive-based DRPs do not deal with price signals. In fact, they generally provide suitable tools for electrical utilities and customers to control the load during an emergency so that they could keep system reliability and manage payments. These programs consider some motivations for customers' voluntary contributions in reducing the load. The payments may be in the form of discounts on bill for coming hours, prepayment, or calculating the reduced load. These programs could also involve penalties. Incentive-based DRPs cover a range of programs including direct load control (DLC), I/C service, demand bidding programs, EDRP, capacity market programs, and ancillary service market programs [6,7].

1.3. Literature review

An economic model for two DR programs, namely an I/C program and a capacity market program, was developed in [4]. In [5], a model was proposed for combined TOU and EDRP programs to show that demand

and load shape could be changed due to the ISO policy in the running of DR programs. An optimum TOU program was applied for the Iranian power system in [6]. In [7] a stochastic model was presented to schedule reserve provided by DR resources in a wholesale electricity market. In [8], a model was proposed for evaluating the effects of EDRP on system and load point reliability of a deregulated power system. In [9] a new procedure for enhancing spinning reserve by means of a DLC program was presented.

2. Modeling of emergency demand response programs

Execution of emergency response programs considering the potential of customers' contributions to the program leads to reduction in consumption during the peak hours and transferring of the load to some other times, therefore flattening the load curve. The concept of elasticity is used for showing the relationship between load sensitivity and fluctuations in price, which is defined by Eq.n (1) [9]:

$$E = \frac{\rho_0}{d_0}\frac{\partial d}{\partial \rho}, \tag{1}$$

where E is price elasticity of the demand, ρ is spot electricity price ($/MWh), d is customer demand (MWh), and the zero index in every symbol is initial quantity.

According to Eq. (1), price elasticity in the ith period compared with the jth period is determined based on Eq. (2):

$$E(i,j) = \frac{\rho_0(i,j)}{d_0(i)}\frac{\partial d(i)}{\partial \rho(j)}. \tag{2}$$

Here $E(i,i)$ and $E(i,j)$ are self-elasticity and cross-elasticity, respectively. If electricity prices change in different periods, the load can respond accordingly in two ways [10]:

a) Some of the loads cannot be transferred to other hours (e.g., lamps) and they can be either turned on or off. Therefore, such loads only have a single-period sensitivity and their elasticity is called self-elasticity; based on Eq. (3) they always take a negative value:

$$E(i,i) = \frac{\Delta d_i}{\Delta \rho_i} \leq 0. \tag{3}$$

b) Some loads, unlike those of the first group, can be transferred from the peak periods to the off-peak or low periods (e.g., process loads). Such behavior is called multiperiodic sensitivity and their elasticity, called cross-elasticity, has a positive value based on Eq. (4):

$$E(i,j) = \frac{\Delta d_i}{\Delta \rho_j} \geq 0. \tag{4}$$

2.1. Modeling of single-period EDRPs

In this section, it is assumed that customers change their demand from $d_0(t)$ to $d(i)$ based on the incentive payments and penalties mentioned in the contract (Eq. (5)) [11]:

$$\Delta d(i) = d(i) - d_0(i). \tag{5}$$

Total payments to the customers as the incentive for their contributions in DRPs are calculated using Eq. (6):

$$P(\Delta d(i)) = A(i) \times [\Delta d(i)], \tag{6}$$

where $A(i)$ is payment as incentive to the customer in the ith hour for each MWh load reduction. If a customer registers for participation in the DRP but does not commit to his obligations to the contract, he will be faced with a penalty. It is assumed that the load a customer is entitled to reduce according to the contract is *IC(i)* and the penalty for not conforming to the contract is *pen(i)* based on \$/MWh. Total penalty charged to the customer is calculated using Eq. (7):

$$PEN(\Delta d(i)) = pen(i) \times \{IC(i) - \Delta d(i)\}, \tag{7}$$

where *IC(i)* and *pen(i)* are the contract level for the ith hour and the penalty for the same period, respectively. If $B(d(i))$ is customer revenue in hour i for selling the interruption and $d(i)$ is customer demand in the same hour, the customer's net profit $(S(i))$ in that hour is calculated using Eq. (8):

$$S(i) = B(d(i)) - d(i) \cdot \rho(i) + P(\Delta d(i)) - PEN(\Delta d(i)). \tag{8}$$

According to the optimization rule, maximum profit for the customer is obtained once the derivative of Eq. (8) to demand load equals zero; therefore:

$$\frac{\partial S(i)}{\partial d(i)} = \frac{\partial B(d(i))}{\partial d(i)} - \rho(i) + \frac{\partial P}{\partial d(i)} - \frac{\partial PEN}{\partial d(i)} = 0. \tag{9}$$

With differentiation of Eqs. (6) and (7) and the subsequent replacements in Eq. (9), Eq. (10) is obtained:

$$\frac{\partial B(d(i))}{\partial d(i)} = \rho(i) + pen(i) + A(i). \tag{10}$$

With Taylor's series expansion for degree 2 function of customer income, benefit values of customers are obtained from Eq. (11):

$$B(d(i)) = B(d_0(i)) + \frac{\partial B(d_0(i))}{\partial d(i)} \Delta d(i) + \frac{1}{2} \frac{\partial^2 B(d_0(i))}{\partial d^2(i)} (\Delta d(i))^2. \tag{11}$$

The customer's benefit before DRP execution is determined using Eqs. (12) and (13):

$$S_0(d(i)) = B(d_0(i)) - d_0(i).\rho_0(i), \tag{12}$$

$$\frac{\partial S_0}{\partial d(i)} = \frac{\partial B(d_0(i))}{\partial d(i)} - \rho_0(i) = 0. \tag{13}$$

Eventually, the required equations are obtained as Eqs. (14) and (15):

$$\frac{\partial B(d_0(i))}{\partial d} = \rho_0, \tag{14}$$

$$\frac{\partial^2 B}{\partial d^2} = \frac{\partial \rho}{\partial d} = \frac{1}{E} \frac{\rho_0}{d_0}. \tag{15}$$

Replacing Eqs. (14) and (15) in Eq. (11), the income degree 2 function is obtained as in Eq. (16):

$$B(d(i)) = B_0(i) + \rho_0(i) \times \Delta d(i) \times \{1 + \frac{\Delta d(i)}{2E(i)d_0(i)}\}. \tag{16}$$

Through differentiation of Eq. (16) and setting it equal to Eq. (10), customer demand while taking part in the DRP is obtained using Eq. (17):

$$d(i) = d_0(i) \times \{1 + E(i,i) \times \frac{[\rho(i) - \rho_0(i) + A(i) + pen(i)]}{\rho_0(i)}\}. \tag{17}$$

Eq. (17) shows the optimum customer's consumption considering incentive and penalty payments based on which customer profit will be maximum. In Eq. (17) if the value of $A(i)$ equals zero, $d(i)$ will be equal to $d_0(i)$.

2.2. Modeling of multiperiod EDRPs

In multiperiod models, cross-elasticity $E(ij)$ must be calculated for the *ith* hour relative to all periods. Therefore, this model can be defined as in Eq. (18):

$$d(i) = d_0(i) \times \{1 + \sum_{\substack{j=1 \\ j \neq i}}^{24} E(i,j) \times \frac{[\rho(j) - \rho_0(j) + A(j) + pen(j)]}{\rho_0(j)}\}. \tag{18}$$

Combining Eqs. (17) and (18) results in the economic model of EDRP, which is obtained using Eq. (19):

$$d(i) = d_0(i) \times \{1 + E(i,i) \times \frac{[\rho(i) - \rho_0(i) + A(i) + pen(i)]}{\rho_0(i)} + \sum_{\substack{j=1 \\ j \neq i}}^{24} E(i,j) \times \frac{[\rho(j) - \rho_0(j) + A(j) + pen(j)]}{\rho_0(j)}\}. \tag{19}$$

3. I/C loads demand response model

If existing generation units in the network cannot supply the required demand, the existing load in the bus could be interrupted or decreased. In each bus, the interrupted values for different hours are determined and Eq. (20) is used for this purpose [12,13]:

$$IL_{bt} = \begin{cases} 0, & \text{if } P_{bt}^D - P_{bt}^G - \sum_{l=1}^{Nb} S_{lb} f_{lt} \leq 0 \\ P_{bt}^D - P_{bt}^G - \sum_{l=1}^{Nb} S_{lb} f_{lt}, & \text{otherwise} \end{cases}, \tag{20}$$

where f_{lt} is the power flow of line l at time t, S_{lb} is the binary variable (0, 1), t is the index of time, Nb is the number of buses, P_{bt}^D is the demand of bus b in time t, P_{bt}^G is the power generated by bus b at time t, and IL_{bt} is the curtailable load by bus b at time t.

The value of the I/C load in each bus cannot exceed its demand at time t.

3.1. Limitation of I/C loads and related contracts

From the point of view of the ISO, utilization of the I/C load will lead to increased system reliability and reduced operation costs. On the other hand, customers are after savings in the cost of energy and receiving a reward from these contacts, but they are not inclined to curtail the load always and at any time the operator requires. Consequently, in the contracts signed between the ISO and customers, some limitations are determined for the curtailed load to be used on the next day. Some of these contracts following the IEEE 798 standard include maximum time for curtailing the load per day, maximum load decreased in a bus, maximum times the load is interrupted in a day, and maximum duration the load is interrupted in each interruption [14].

4. Market auction of wholesale electrical energy based on the OCM

In this mechanism both energy and startup costs are minimized. To solve the problem of optimization, some constraints need to be taken into account, which are as follows: equality of generated power and demand load, generation power of each unit, incremental ramp up rate, decrement ramp down rate, minimum up time, minimum down time, and securing the reserve.

Considering these constraints makes it possible to solve the problem of optimization through the UC method and identify the generation level of each unit. Because of the integer and binary variables and since there are nonlinear terms in the function and constraints such as minimum on/off time of the units, optimization is a mixed nonlinear and integer problem. Various methods are proposed for solving these problems and one of them is explained as follows.

5. Solution method

UC is a mixed nonlinear-integer problem. Therefore, it is not possible to solve it directly through common optimization methods (Lagrange relaxation, dynamic programming, etc.). One of the highly effective methods for solving these problems is the branch and cut method, which is utilized for solving linearized problems involving binary variables and integer. For this purpose, first nonlinear relations and constraints are linearized and then the solution is explained.

5.1. Cost function

The cost function of thermal generation units is a quadratic equation ($/h) as follows:

$$F_i(P_i(t)) = c_i + b_i.P_i(t) + a_i.P_i(t)^2, \tag{21}$$

where c_i ($/h), b_i (($/MWh), and a_i (($/MW^{2}h) are constant, having different values for each generation unit.

5.2. Cost function linearization of generation units

The nonlinear cost function of generation units is shown in Figure 1 using several straight lines. Therefore, the cost function is converted to a multipiece line where the generation power limit of each section has a specific value. Consequently, Eq. (21) is modified as (22):

$$F_i(P_i(t)) = F_i(P_{i\ \min}(t)) + \sum_{m=1}^{NSG} P_m(i,t).s_m(i,t), \tag{22}$$

where NSG is the number of pieces of lines in each unit, m is the index for each piece of line, and $s_m(i,t)$ is the slope for piece of line m.

The constraint for generation power of each section is obtained using Eq. (23):

$$0 \leq P_m(i,t) \leq P_{m,\max}(i,t) \;\; \forall t \in NT, i \in NG, \tag{23}$$

where $P_{m,\max}(i,t)$ is the maximum generated power of section m.

5.3. Cost function linearization of EDRP

The cost function of the EDRP is obtained by replacement of Eq. (6) in Eq. (19), which is presented as Eq. (24). As observed in Eq. (24), the cost is a quadratic function of the incentive quantity, which, just like the generation units cost function, can be linearized (Figure 2):

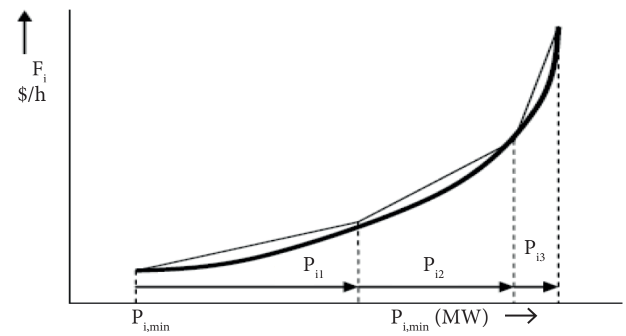

Figure 1. Linearization model of cost function.

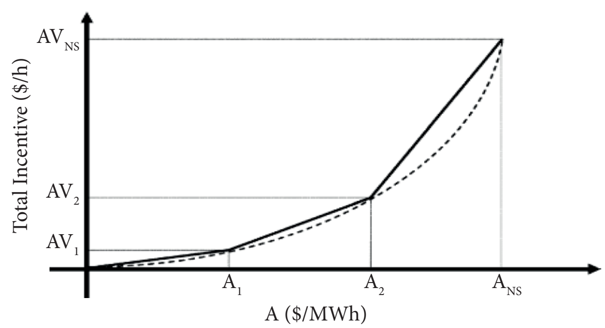

Figure 2. EDRP cost curve.

$$C_{EDRP} = -A^2(t) \times d_0(t) \times \sum_{j=1}^{NT} \frac{E(t,j)}{\rho_0(j)}. \tag{24}$$

Consequently, the quadratic incentive cost function of Eq. (24) is obtained as linear Eq. (25):

$$C_{EDRP} = \sum_{m=1}^{NS} AS_m(t).A_m(t), \tag{25}$$

where NS and AS_m are the numbers of pieces of lines and the slope of each linearized section. A_m is the amount of incentive for each section m. The incentive cost of Eq. (25) is added to the objective function to obtain optimum incentive.

5.4. Simultaneous execution UC and DRPs

The amount of I/C load in bus b at time t is shown with IL_{bt}. If the incentive ($/MWh) for I/C load in each bus (b) is ILP_{bt}, the incentive cost function of I/C loads are obtained using Eq. (26):

$$C_{IL} = \sum_{t=1}^{NT} IL_{bt}.ILP_{bt}. \tag{26}$$

Multiplication of each of the coefficients w_i and w_f by incentive costs makes it possible to add them to the cost function as in Eq. (27) to observe the effect of simultaneous execution of UC programs and DRPs in the output:

$$\min_{\{P_i(t)\}} \sum_{t=1}^{NT} \{ \sum_{i=1}^{NG} [F_i(P_{i\,\min}(t)) + \sum_{m=1}^{NSG} P_m(i,t).s_m(i,t) + y_i(t).SU_i(t) + z_i(t).SD_i(t)] + w_i \cdot C_{EDRP} + w_f.C_{IL}\}. \quad (27)$$

Eq. (27) shows the simultaneous execution of the OCM and DRPs. Whenever DRPs are incorporated, the coefficients w_i and w_f equal one. Adding these programs causes some changes in equality constraints of demand and generation power, which is modified below this equation. The incentive cost in execution of the EDRP is obtained using Eq. (28), where η is the percentage of participation of the customers:

$$\sum_{i=1}^{NG} P_i(t).u_i(t) = (1-\eta) \times d_0(t) + \eta \times d_0(i) \times \{1 + \sum_{j=1}^{NT} E(i,j) \times \frac{[\rho(j) - \rho_0(j) + A(j) - pen(j)}{\rho_0(j)}\} - IL_{bt}, \quad (28)$$

Also, for the reserve constraint, Eq. (29) is obtained:

$$\sum_{i=1}^{NG} P_{\max}(i,t).u(i,t) \geq res(t) + (1-\eta) \times d_0(t) + \eta \times d_0(i) \times \{1 + \sum_{j=1}^{NT} E(i,j) \times \frac{[\rho(j) - \rho_0(j) + A(j) - pen(j)]}{\rho_0(j)}\}$$
$$+ IL_{bt} \ \forall t = 1, ..., NT \ , \ i = 1, ..., NG. \quad (29)$$

Using these constraints and Eq. (29), one can solve the optimization problem.

6. Numerical results

In this section, for evaluation of the proposed model, a 24-bus IEEE reliability test system (RTS) is used. The required data for this system consist of generation units, transmission lines, and the load profile utilized from [15]. A generation characteristic of the units in the form of a quadratic function of the generation power of the units was used in place of the offer for prices by generation units. Reserve quantity for every hour is assumed as 10% of the demand load at that hour [16].

6.1. Results of execution OCM

Both 400 MW units are initially on and the solution of the UC program is accomplished with linear constraints. In order to use this function in MILP, linearization was done as explained earlier in this paper. Table 1 shows the execution results of the OCM for payments and offered costs.

Table 1. Results of execution of UC.

Mechanism	Total Offers Costs ($)	Total Customer Payments ($)
OCM	476,944.9466	1,328,152.612

6.2. Results of simultaneous execution OCM and EDRP

The load profile in the model is divided into different periods, namely low load period (0100–0800 hours), peak period (0900–1900 hours), and off peak (2000–0000 hours). The cost of energy for 24 h is the same as the market auction price obtained from the UC without execution of DRPs. The cost model of DRPs is divided into 20 sections and it is assumed that 30% of customers contributed in the EDRP. Table 2 shows the system elasticity in different periods [17].

Table 2. Quantity of elasticity in different periods.

Hour	1–8	9–19	20–24
1–8	–0.1	0.016	0.012
9-19	0.016	–0.1	0.01
20-24	0.012	0.01	–0.1

Table 3 shows the results of simultaneous execution of the UC and EDRP. The amount of incentive designated for customers in exchange for decreasing the load during the peak period and transferring to the off-peak period is calculated as 25.6 $/MWh with simultaneous execution of the OCM and EDRP. As Table 3 suggests, customers' contributions in UC programs with utilization of the EDRP decrease $2891 in generation costs related to the ISO as well as in customer payment costs.

Table 3. Results of simultaneous execution of UC and EDRP.

Mechanism	A* ($/MWh)	Total Incentive ($)	Total Offer Costs ($)	Total Customer Payments ($)
OCM+EDPR	25.6	10,508.3	474,053.91	1,160,786.39

Simultaneous execution of the OCM and EDRP results in 12.6% decrease in payment costs in comparison with the UC without execution of the EDRP. Figure 3 shows the changes in customer load curve before and after execution of the EDRP for OCM. Evidently, through execution of the EDRP, the peak load is decreased and transferred to other times, making the load curve flatter.

6.3. Result of simultaneous execution of OCM and I/C loads

Four hours were designated for a peak period of 11 h in I/C loads. The maximum quantity of load interruption was considered as 5% of the relevant load at the same hour and the incentive for I/C load was considered 25 $/MWh. Figure 4 shows the effect of execution of the OCM program with I/C loads on the load curve. As the figure suggests, with simultaneous execution of OCM and I/C programs at hours 11, 12, 13, and 16 the load was interrupted or curtailed. The quantity of interrupted load at different times is also shown in Table 4. Table 5 shows the results of contribution of I/C loads for the OCM.

Table 4. Quantity of I/C load in simultaneous EDRP and I/C loads.

Mechanism	Interruptible/curtailable (MW)				
	Hour 11	Hour 12	Hour 13	Hour 14	Hour 16
OCM	86.4	96.4	74.4	-	30.4

Additional cost arising from execution of the DRP for the ISO by OCM is calculated as $7190. However, the sum generation costs of the ISO decline by $3525. In fact, instead of generating more power in the peak

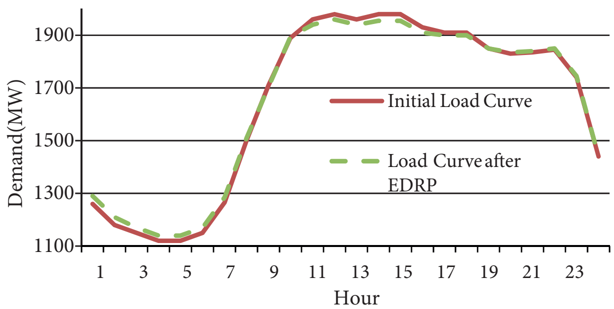

Figure 3. Load curve with simultaneous execution of OCM and EDRP.

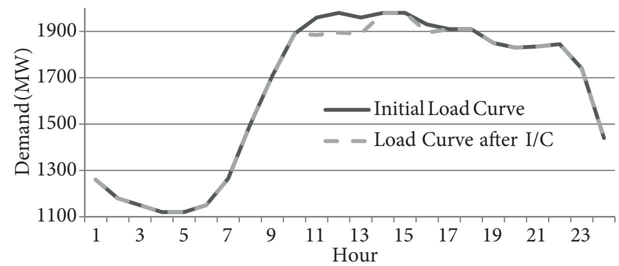

Figure 4. Execution of OCM program considering I/C loads.

Table 5. Results of execution of UC considering the I/C loads.

Mechanism	A* ($/MWh)	Total Incentive ($)	Total Offer Costs ($)	Total Customer Payments ($)
OCM+I/C	25	7190	473,420.0329	1,248,995.46

period, the load demand is reduced with the contribution of customers, and in spite of the additional incentive cost that the ISO pays, total generation cost decreases in comparison with the UC without DRPs. Payments are also decreased by 6% in comparison with the OCM method.

6.4. Results of simultaneous execution of OCM and EDRP and I/C loads

Table 6 shows the results of simultaneous execution of UC programs, DRPs, and I/C loads. The quantity of interrupted load at different times is also shown in Table 7.

Table 6. Results of execution of UC, EDRP, and I/C loads.

Mechanism	A* ($/MWh)	Total Incentive ($)	I/C Loads Incentive ($)	Total Offer Costs ($)	Total Customer Payments ($)
OCM+EDRP+I/C	6.24	3717.3	9755.6	469,160.08	1,065,440.76

Table 7. Quantity of I/C load in simultaneous EDRP and I/C loads.

Mechanism	Interruptible/curtailable (MW)				
	Hour 11	Hour 12	Hour 13	Hour 14	Hour 16
OCM+EDRP+I/C	-	99.2	92.62	99.2	99.2

Based on the findings of the study, it is observed that in simultaneous execution of the two DRPs, despite paying incentive to customers, the generation cost of the ISO is less than the execution of each DRP alone and also when no DRPs are executed. Moreover, customer payments have shown a considerable decrease. Optimum incentive given to customers for their contribution in EDRPs was 6.24 $/MWh for OCM. Figure 5 shows the effect of execution of DRPs on load curve for the proposed mechanism. Load curve is flatter and customers have transferred their consumed load from the peak to a low load period.

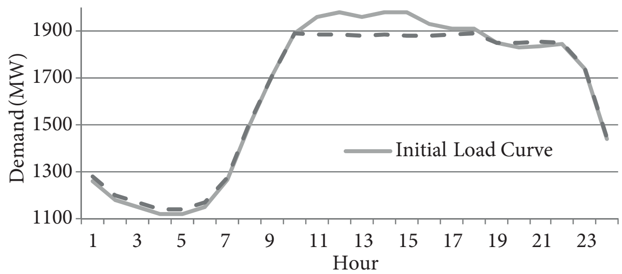

Figure 5. The load curve for execution of OCM taking into account I/C loads and EDRP.

Results for the 24-bus IEEE system are summarized in Table 8.

Table 8. Results of execution of the program for the 24-bus IEEE system.

Mechanism	EDRP optimal incentive ($/MWh)	Total EDRP incentive ($)	Total I/C incentive ($)	Total Payment ($)
OCM	-	-	-	1,328,152.62
OCM+EDRP	25.6	11,768.43	-	1,164,786.39
OCM+I/C	-	-	7190	1,248,995.36
OCM+EDRP+I/C	6.24	3717.3	9755.6	1,065,440.76

7. Conclusion

In this paper, a mathematical model is proposed considering DRPs for UC under OCM with the main purpose of decreasing the customers' payment costs. This decrease in payment costs is achieved through a change in the generation power of the units and their on/off status at different hours and consequently decreasing market auction price. The contribution of the customers in the market and their influence on the generated power and costs under DRPs lead to receiving incentives and consequently decreasing the payment and production costs of the ISO. This contribution flattens the load curve, increasing the system reliability and clipping the peak. For investigation of the effectiveness of the proposed method, different scenarios were presented for simultaneous execution of UC programs (OCM) and DRPs and the obtained results were discussed. Simulations yielded the following outputs:

- Simultaneous execution of UC programs and DRPs flattens load curve, clips the peak, decreases the units' generation costs, increases the system reliability, and also reduces the payment costs of consumption.
- Through taking part in DRPs, customers receive incentives from the ISO in return for decreasing their consumption in the peak period and transferring it to off-peak times. This encourages them to contribute in programs and decrease their payment costs.

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