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COST-BASED UNIT COMMITMENT CONSIDERING DEMAND-SIDE RESOURCES WITH HARMONY SEARCH ALGORITHM

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Abstract- Integrated resource planning has been performed by electric companies, because of its multifarious benefits in power system operation. Demand Response Resources (DRRs) can be used as a virtual demand side power plant. DRRs are clustered to Incentive-Based Programs (IBPs) and Time-Based Rate Programs (TBRPs). Precise modeling of DRRs helps the system operator to investigate the impact of responsive loads on the power system operation. A multi attribute decision making (MADM) methodology is presented to select a program which reflects Independent System Operator (ISO) perspectives. The cost-based unit commitment (UC) problem with an improved formulation is also introduced to investigate the impacts of DRRs on generation scheduling. The UC problem as a crucial challenge of system operator is solved using harmony search algorithm to determine the role of demand response in generation scheduling. The numerical studies are conducted on the conventional ten-unit test system to confirm the capability of the proposed structure.

Keywords: Demand response (DR), Cost-Based Unit Commitment, Incentive-Based Programs (IBPs), MADM, Harmony Search (HS).

I. INTRODUCTION

Integrated resource planning considers a full range of feasible supply-side and demand-side options and assesses them against a common set of planning objectives and criteria [1, 2]. Demand-side resources can be defined as changes in electric usage by end-use customers from their normal consumption patterns in response to motivations form system operator. Recent evolutions of incorporating demand-side resources into the planning and operation of power systems confirms the important role of these virtual resources in future power systems [3]. Due to advances in metering and communication systems, demand response can provide important services for the ISO within a short time.

The suggestion is to make it attractive for consumers to decrease their consumption during peak load periods [4]. Reviewing the previous literatures reveal a wide range of Demand Response Programs (DRPs) related studies. In the Federal Energy Regulatory Commission (FERC) description, DRPs are clustered to time-based rate programs and incentive-based programs [3]. In these programs, the consumer decreases its consumption when requested. The consumer profit are mainly from motivation provided by the operator.

The cost-based unit commitment problem as a crucial challenge of ISO is studied in this manuscript to investigate the effect of implementing DRPs in the electricity market. The UC determines on/off status of power plants to satisfy the electricity demand [5, 6]. The best program should decrease the operation costs, while satisfying different constraints [5, 7]. Numerous methods have been used in recent papers for solving this problem. When the problem is middle or large size, deterministic techniques are not appropriate. Heuristic methods may have a number of advantages to handle such problem, while the major disadvantage of them is that they cannot assurance the best answer. Hence, hybrid methodologies have been introduced [8].

In this paper, the unit commitment with a different objective function is formulated considering demand response programs and, the harmony search (HS) algorithm is applied to solve such problem. Responsive load economic model is also developed in this manuscript. Economic models of responsive loads for DRPs have been presented in [9-13]. In the previous articles, the linear economic model of price responsive loads has been derived [14, 15].

In this paper, a new nonlinear flexible model of IBPs is extracted using the concepts of demand elasticity and consumer utility function. This form is called flexible because the values of motivations are adjusted based on the level of demand. This paper is modeled the voluntary DRPs namely direct load control (DLC) and emergency demand response programs (EDRPs). Moreover, the system operator use the multi attribute decision making approach by handling a trade-off between different objectives with conflicting nature [16]. In this paper, the entropy method and TOPSIS method have been applied together to give an opportunity for the ISO to select the program with the highest priority that satisfies his desires. The conventional ten-unit test system is applied for the simulation studies to confirm the capability of the suggested framework.

The remainder of the paper is organized as follows: Section II provides a brief background of DRPs. Detailed mathematical formulation is explained in Section III. Section IV is devoted to the optimization algorithm. Section V conducts the numerical simulations. Finally, concluding remarks are drawn in Section VI.

II. BACKGROUND OF DRPS

DRPs can be classified as a set of system operator (usually ISO)-based programs that allow end users to provide interruptible load as a commodity in the electricity market. In FERC 2012 survey, DRPs are classified into two basic clusters: i) time based programs, and ii) incentive based programs. No penalty or incentive is contemplated for customer response in time based programs [17], while IBPs are categorized into three main clusters including voluntary, mandatory and market-based programs. More supplementary details about per type of DRPs and their benefits are provided in [3].

III. MATHEMATICAL FORMULATION

Figure 1 shows the proposed framework for cost-based unit commitment with demand response resources. More explanation about this framework is expressed in the following.

A. Nonlinear Flexible Load Model

In order to assess the role of demand response programs on load profile, improvement of precise load models is essential. Schweppe presented the concept of price elasticity of demand in 1989, where customers would adjust their consumption depending on the electricity market price [18]. Kirschen showed the impact of this model on generation scheduling in an electricity market [19]. A linear responsive load has been modeled in [14, 15]. In this paper, an exponential model of responsive loads is introduced which is more accurate than previously developed linear model. More explanations and clarification about the proposed DRP is provided in the following.

Self-elasticity of demand can be defined as [20]:

$$E(t,t)=\frac{\Pi(t)}{D(t)}\frac{\partial D(t)}{\partial \Pi(t)} \tag{1}$$

The cross elasticity can be also formulated as [1]:

$$E(t,j)=\frac{\Pi(j)}{D(t)}\frac{\partial D(t)}{\partial \Pi(j)} \tag{2}$$

After implementing demand response programs, the consumers decrease their consumption as [1]

$$\Delta D(t)=D_{DR}(t)-D(t) \tag{3}$$

where, "$\Gamma(t)$", is also introduced as [1]:

$$\Gamma(t)=\frac{D(t)}{\max\{D(\tau)\}} \qquad \tau\in\{1,2\ldots t\ldots T\} \tag{4}$$

If $A(t)$ [\$] is paid to consumers as motivation for each kWh load reduction, the whole incentive can be formulated as following [1]:

$$p(\Delta D(t))=\Gamma^{n}(t)A(t)[D(t)-D_{DR}(t)] \qquad \forall t \tag{5}$$

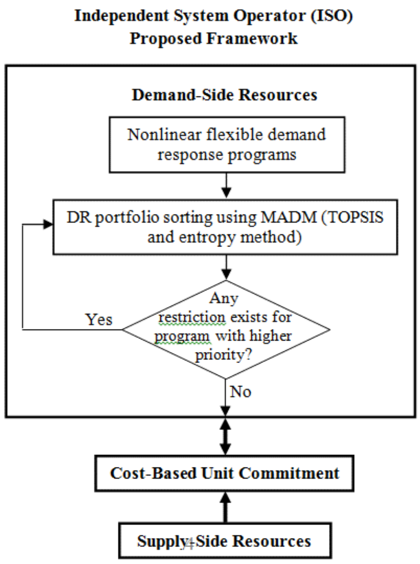

Figure 1. Framework of implementing DRPs from the ISO perspective

The total punishment can be also formulated as [1]:

$$PEN(\Delta D(t))=\Gamma^{m}(t)\,pen(t).\{IC(t)-[D(t)-D_{DR}(t)]\} \quad \forall t \tag{6}$$

The superscripts n and m in Equations (5) and (6) can determine the impact of incentive and penalty in demand response programs. If $B(D_{DR}(t))$ be the utility of consumer during tth hour from the consumption of $D_{DR}(t)$ kWh of electricity, then the customer's benefit, $S(D_{DR}(t))$, for the tth hour can be presented as

$$\begin{aligned}S(D_{DR}(t))&=B(D_{DR}(t))-D_{DR}(t)\Pi_{DR}(t)+\\&+p(\Delta D(t))-PEN(\Delta D(t))\end{aligned} \tag{7}$$

In order to maximize $S(D_{DR}(t))$, we will have:

$$\begin{aligned}&\frac{\partial S(D_{DR}(t))}{\partial D_{DR}(t)}=\frac{\partial B(D_{DR}(t))}{\partial D_{DR}(t)}-\Pi_{DR}(t)+\\&+\frac{\partial p(\Delta D(t))}{\partial D_{DR}(t)}-\frac{\partial PEN(\Delta D(t))}{\partial D_{DR}(t)}=0\end{aligned} \tag{8}$$

The Equation (8) can be rewritten as:

$$\frac{\partial B(D_{DR}(t))}{\partial D_{DR}(t)}=\Pi_{DR}(t)+\Gamma^{n}(t)A(t)+\Gamma^{m}(t)\,pen(t) \tag{9}$$

Here, the exponential utility function, $B(D_{DR}(t))$ is considered as [18]:

$$\begin{aligned}&B(D_{DR}(t))=B_0(t)+\Pi(t)D(t)E(t,t).\\&.\left\{\exp\left[\left(\frac{D_{DR}(t)-D(t)}{E(t,t).D(t)}\right)-1\right]\right\}\end{aligned} \tag{10}$$

where,

$$\begin{aligned}&\frac{\partial B(D_{DR}(t))}{\partial D_{DR}(t)}=\Pi(t)\;D(t)\,E(t,t).\\&.\exp\left(\frac{D_{DR}(t)-D(t)}{E(t,t).D(t)}\right).\left(\frac{1}{E(t,t).D(t)}\right)\end{aligned} \tag{11}$$

From Equation (9) and Equation (11), it can be concluded that:

$$\begin{aligned}&\Pi_{DR}(t)+\Gamma^{n}(t)A(t)+\Gamma^{m}(t)\,pen(t)=\\&=\Pi(t).\exp\left(\frac{D_{DR}(t)-D(t)}{E(t,t).D(t)}\right)\end{aligned} \tag{12}$$

Hence, the single period responsive load model can be presented as:

$$D_{DR}(t) = D(t).\left\{1 + E(t,t).\ln\left(\frac{\Pi_{DR}(t) + \Gamma^n(t)A(t) + \Gamma^m(t)\, pen(t)}{\Pi(t)}\right)\right\} \quad (13)$$

Using the cross elasticity definition, the multi period load model can be also formulated as:

$$D_{DR}(t) = D(t).\left\{1 + \sum_{\substack{j=1 \\ j\neq t}}^{24} E(t,j).\ln\left(\frac{\Pi_{DR}(j) + \Gamma^n(j)A(j) + \Gamma^m(j)\, pen(j)}{\Pi(j)}\right)\right\} \quad (14)$$

By combining Equations (13) and (14) and considering "η" as the penetration rate of demand response programs, we will have:

$$D_{DR}(t) = \eta\, D(t).\left\{1 + \sum_{j=1}^{24} E(t,j).\ln\left(\frac{\Pi_{DR}(j) + \Gamma^n(j)A(j) + \Gamma^m(j)\, pen(j)}{\Pi(j)}\right)\right\} \quad (15)$$

B. Procedure of DRPs Sorting

One of the main aims of system operator is prioritizing different programs [21]. In the proposed strategy of this paper, the attributes are weighted by means of entropy method [22]. A decision matrix, i.e. D_e, can be presented as [15]:

$$D_e = \begin{array}{c} \\ \text{Alternative 1} \\ \vdots \\ \text{Alternative } NAL \end{array} \begin{array}{c} \text{Attribute 1} \quad \cdots \quad \text{Attribute } NAT \\ \begin{bmatrix} \chi_{1,1} & \cdots & \chi_{1,NAT} \\ \cdots & \cdots & \cdots \\ \chi_{NAL,1} & \cdots & \chi_{NAL,NAT} \end{bmatrix} \end{array} \quad (16)$$

Each element of (16) can be normalized as [15]:

$$P_{lk} = \chi_{lk} \Big/ \sum_{l=1}^{NAL} \chi_{lk} \quad (17)$$

Thus, w_k can be achieved as [15]:

$$W_k = \frac{1 + (\ln NAL)^{-1}.\sum_{l=1}^{NAL} [P_l \times \ln P_l]_k}{\sum_{k=1}^{NAT} \{1 + (\ln NAL)^{-1}.\sum_{l=1}^{NAL} [P_l \times \ln P_l]_k\}} \quad (18)$$

Considering the importance factor of each attribute (λ_k), Equation (18) can be modified as

$$IW_k = \frac{\lambda_k W_k}{\sum_{k=1}^{NAT} \lambda_k W_k} \quad (19)$$

In Equation (19), lower weights urge that the impact of the attribute is similar for all of the alternatives and its importance is negligible for decision [15].

In this stage, system operator prioritize DRPs using TOPSIS methodology [23]. Using the TOPSIS procedure, the distances between each alternative and the ideal or anti-ideal solution should be evaluated [15]. The appropriate alternative should have a minimum distance to the ideal point and maximum distance to the anti-ideal point [15]. TOPSIS procedure is provided in details as fallows.

i. Weighted normalized decision matrix can be determined as:

$$P_{lk} = \frac{\chi_{lk}}{\sum_{l=1}^{NAL} \chi_{lk}} \quad (20)$$

ii. The ideal and anti-ideal solutions should be determined in this stage. The ideal solution, v^+_k, is the maximum value for the positive criterion and the minimum value for the negative criterion in each column. Similarly, the anti-ideal solution, v^-_k, is the minimum and the maximum values for the positive and the negative criteria in each column, respectively [15].

iii. C_l factor can be calculated as [15]:

$$C_l = \frac{\sqrt{\sum_{k=1}^{NAT} (v_{lk} - v_k^-)^2}}{\sqrt{\sum_{k=1}^{NAT} (v_{lk} - v_k^+)^2} + \sqrt{\sum_{k=1}^{NAT} (v_{lk} - v_k^-)^2}} \quad (21)$$

$$0 \le C_l \le 1 \qquad \forall\ l = 1, \ldots ..NAL$$

Finally, the alternatives are sorted according to the C_l value.

C. Unit Commitment with Demand Response Programs

C.1. Objective Function

Direct load control and emergency demand response programs are implemented in this paper. Here, the amount of incentive and penalty are considered equal to "A" \$/kWh and zero \$/kWh, respectively. The objective function for the generation scheduling problem with aforementioned DRPs can be presented as:

$$\min \left\{ \begin{array}{l} \sum_{i=1}^{N} \sum_{t=1}^{T} [F(i,t)u(i,t) + \\ + SUC(i,t)u(i,t)(1 - u(i,t-1)) + p(\Delta D(t)) \end{array} \right\} \quad (22)$$

More clarifications about Equation (22) is explained in the following. The operation cost function can be presented as [26]:

$$F(i,t) = a(i) + b(i)P(i,t) + c(i)P^2(i,t) \quad (23)$$

In Equation (23), $a(i)$, $b(i)$ and $c(i)$ are fuel cost coefficients. $u(i,t)$ presents the on/off status of unit i at tth time interval, $u(i,t)$=0 if unit i is off, $u(i,t)$=1 if it is on at t, N is the total number of power generating units to be committed, and T is the time period.

In Equation (22), SUC, HSC and CSC represent the start-up cost, hot start-up costs and cold start-up costs, respectively: [1]

$$SUC(i,t) = \begin{cases} HSC(i), & \text{if } T^D(i,t) \le MD(i)^{ON} \le T^D(i,t) + CST(i) \\ CSC(i), & \text{if } MD(i)^{ON} > T^D(i,t) + CST(i) \end{cases} \quad (24)$$

where $MD(i)^{ON}$ is the duration which the ith unit is continuously on and $T^D(i,t)$ is the minimum down-time of unit i.

The last term of Equation (22) is the value of incentive for implementing DRPs and is formulated as Equation (5).

C.2. Constraints

Different constraints should be considered in the proposed problem, which are presented in the following.

- Power supplied from committed units and demand response resources must satisfy the load demand [2].

$$\sum_{i=1}^{N} P(i,t)u(i,t) = (1-\eta)D(t)+\eta D(t). \left\{ \begin{array}{l} 1+\sum_{j=1}^{24} E(t,j). \\ .\ln\left(\dfrac{\Pi_{DR}(j)+\Gamma^{n}(j)A(j)+\Gamma^{m}(j)\,pen(j)}{\Pi(j)}\right) \end{array} \right\} \forall i, \forall t \qquad (25)$$

- The generation amount of each power plant should be within certain limits, as [2]:

$$\underline{P}(i,t)u(i,t) \le P(i,t) \le \overline{P}(i,t)u(i,t) \quad \forall\, i \in N,\ 1 \le t \le T \quad (26)$$

- $RDR(i)$ and $RUR(i)$ represent the maximum allowed decrease and increase of the output of unit i occurring in one hour, respectively.

$$-RDR(i) \le P(i,t) - P(i,t-1) \le RUR(i) \quad \forall\, i \in N,\ 1 \le t \le T \quad (27)$$

- The minimum up/down time constraints can be defined as following [26]:

$$MD(i)^{ON} \ge T^{U}(i) \qquad \forall i \in N \qquad (28)$$

$$MD(i)^{OFF} \ge T^{D}(i) \qquad \forall i \in N \qquad (29)$$

- Spinning reserve is considered as a deterministic amount for improving the reliability of power system and decreasing the amount of load shedding which can be given by:

$$\sum_{i=1}^{N} \overline{P}(i,t)u(i,t) \ge SR(t) + (1-\eta)D(t) + \eta D(t) \left\{ \begin{array}{l} 1+\sum_{j=1}^{24} E(t,j). \\ \ln\left(\dfrac{\Pi_{DR}(j)+\Gamma^{n}(j)A(j)+\Gamma^{m}(j)\,pen(j)}{\Pi(j)}\right) \end{array} \right\} \qquad (30)$$

$$\forall i \in N,\ 1 \le t \le T$$

IV. OPTIMIZATION TECHNIQUE

In this paper, the harmony search (HS) algorithm is used to handle the UC problem. Figure 2 represents the hierarchy of harmony search algorithm [24, 25].

The details of HS algorithm to unit commitment problem can be explained as follows.

Step 1. In step 1, the optimization problem and HS algorithm parameters such as size of harmony memory (HM), harmony memory considering rate (HMCR) and pitch adjusting rate (PAR) should be initiated [26].

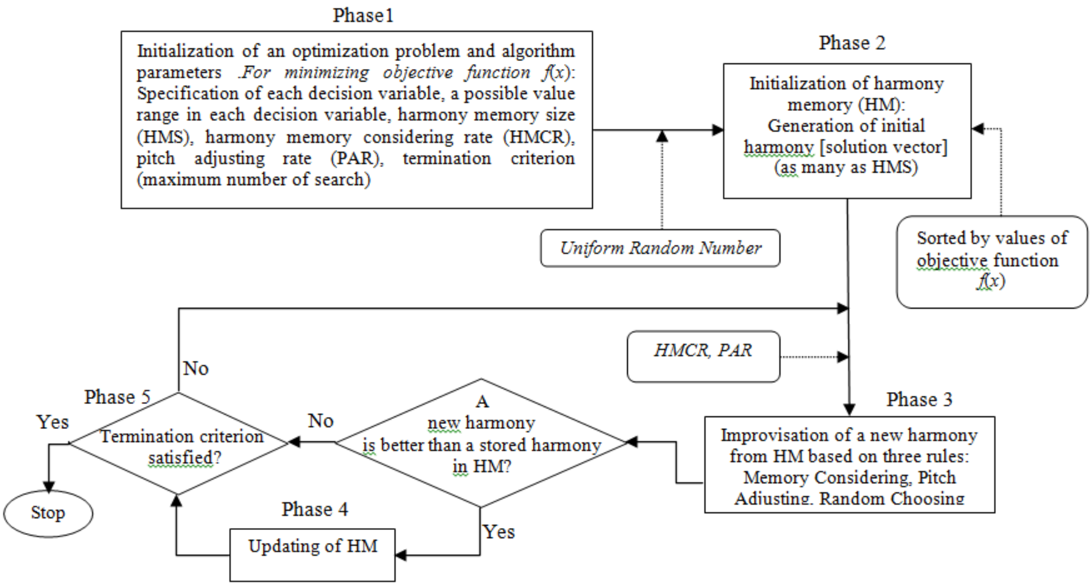

Figure 2. Optimization procedure of the HS algorithm

Step 2. In this step, the HM matrix that the number of its columns is equal to the number of units and each row represents a harmony vector, is initialized randomly. Each variable in HM represent on/off statuses of generators. Since on/off statuses of generators are represented by 1 or 0, respectively, therefore variables in HM are discrete [26].

Step 3. At this step, the units' constraints are checked. For preventing infeasibility of the scheduling at next sequential hours of time horizon, it is assumed that each harmony vector is eligible for that hour then with this scheduling, next hours are considered. If Equation (26) with this scheduling considering min up/down time of units for next hours is satisfied for all hours, the harmony vector do not need any modification and if not, some correction is made for that harmony vector. More explanations are provided in [26].

Step 4. In this step, a lambda iteration method has been used to specify the economic generation of power plants.

Step 5. In this stage, Equation (22) is calculated based on the results of economic dispatch considering start-up costs for units that will be turned on at this hour [26].

Step 6. At this step, new harmony vectors are improved from the HM based on memory considerations, pitch adjustments, and randomization. Since UC is a discrete optimization problem, for generating new harmony vectors discrete variable form of HS algorithm is used here. The next stages are modifying and computing the objective function for determining new harmony vectors [26].

Step 7. New harmony vectors will be compared with harmony vectors in HM from the view point of the objective function. The result of this comparison is that only the stronger vectors from both harmony vectors stored in HM and new harmony vectors sets can be remained [26]. New HM is updated by replacing stronger vectors instead of weaker vectors, which will be removed.

Step 8. The algorithm will be stopped when the termination criterion is satisfied. Otherwise, steps 6 and 7 should be repeated. The maximum number of improvisation should be selected intensively based on the size of the problem and the desired time. More explanations about the HS algorithm can be found in [26].

V. SIMULATION RESULTS

The conventional ten-unit system is applied as a case study. Figure 3 represents the aforementioned load curve which is divided into three different periods, namely valley period (00:00 am–5:00 am), off-peak period (5:00 am–9:00 am & 14:00 pm–19:00 pm) and peak period (9:00 am–14:00 pm & 19:00 pm–24:00 pm) [2]. The implementation potential of demand response program is considered to be 70% and 50%. Several programs have been called as indicated in Table 1 to accentuate the impacts of price elasticity of demand and incentives values on the load curve. The price elasticity of demand is considered as Table 2.

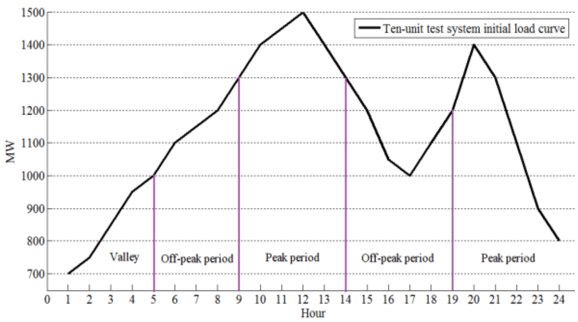

Figure 3. Conventional ten-unit test system load curve [2]

Table 1. Statement of demand response programs

Programs $\forall \eta$ = 0.7, 0.5	Program No	Incentive value ($/MWh)	Price elasticity
		m, n = 1	
DLC/ EDRP	1	4	As Table 2
	2	7	As Table 2
	3	10	As Table 2
	4	4	As 2 value of Table 2
	5	7	As 2 value of Table 2
	6	10	As 2 value of Table 2

Table 2. Price elasticity of demand

Hours \ Hours	1-5	6-9	10-14	15-19	20-24
1-5	-0.08	0.03	0.034	0.03	0.034
6-9	0.03	-0.1	0.04	0.03	0.04
10-14	0.034	0.04	-0.19	0.04	0.01
15-19	0.03	0.03	0.04	-0.11	0.04
20-24	0.034	0.04	0.01	0.03	-0.19

A. Studying the Effect of Proposed DR Model on the Load Curve

The DR incentive value as a economic index is calculated for each of programs by implementing programs. Furthermore, several technical indices namely peak reduction, electrical energy consumption, load factor, and peak to valley distance are evaluated for each program. Tables 3 and 4 compare the performance of load model versus customers' participation level, value of incentive and elasticity.

Base Case: The first rows in Tables 3 and 4 present the base case with nominal load curve (Figure 3), where no demand response program is called. In this case, as shown in Table 4, the load factor is equal to 75.27% which will be increased after implementing some DRPs of Table 1. The energy consumption is 27,100 MWh which is considerably more than the other programs.

Program 1: Here, system operator pays 4 $/MWh as motivation for decreasing the load. As shown in Tables 3 and 4, in program 1, the maximum peak reduction (9.35%), the maximum increase in load factor (7.89%) and the minimum distance between peak and valley (635.02 MW) are achieved when η=0.7 in compare with the other programs. According to Table 3, for this case, the minimum DR incentive value is 3,352.8 $ for η=0.5 in compare with the other programs.

Table 3. Economical and technical comparison of the programs

Programs	Program No	DR Incentive Value ($)		Peak (MW)		Peak Reduction (%)	
		η= 0.7	η=0.5	η=0.7	η=0.5	η=0.7	η=0.5
Base case	Initial load	-	-	1500	1500	-	-
DLC/ EDRP	1	4,693.9	3,352.8	1,359.7	1,399.81	9.35	6.68
	2	13,662.59	9,758.9	1,389.85	1,364.18	7.34	9.05
	3	26,603.17	19,002.2	1,422.47	1,387.48	5.16	7.5
	4	9,387.86	6,705.6	1,408.04	1,377.17	6.13	8.19
	5	27,325.18	19,517.9	1,479.7	1,428.36	1.35	4.77
	6	53,206.3	38,004.5	1,544.95	1,474.9	-2.99	1.67

Table 4. Technical comparison of the programs

Programs	Program No	Energy Consumption (MWh)		Load Factor (%)		Peak to Valley (MW)	
		η= 0.7	η=0.5	η=0.7	η=0.5	η=0.7	η=0.5
Base case	Initial load	27,100	27,100	75.27	75.27	800	800
DLC/ EDRP	1	26,504.6	26,674.7	81.21	79.39	635.02	682.16
	2	26,109.8	26,392.7	78.27	80.62	714.27	653.05
	3	25,750.4	26,136.01	75.42	78.49	792.06	708.62
	4	25,909.3	26,249.55	76.67	79.41	757.65	684.04
	5	25,119.6	25,685.49	70.73	74.92	928.54	806.11

Program 2: As it is shown in Table 4, in this program, a maximum load factor (80.62%) is determined for η=0.5. As presented in Table 3, by decreasing of customers' participation level, the load reduction value will be improved (9.05% for η=0.5). The maximum distance between peak and valley (714.27 MW) is accomplished when η=0.7.

Program 3: As it can be seen from Tables 3 and 4, for η=0.5, the peak reduction index is increased with a maximum value of 7.5% and minimum distance between peak and valley (708.62 MW) and maximum 4.28% increase in load factor are achieved in compare with the base case. After implementing this program, the maximum energy consumption is 26,136.01 MWh for η=0.7 which is considerably decreased in compare with the base case.

Program 4: In this program, we assume the elasticity values as double of the values denoted in Table 2. Here, the minimum distance between peak and valley (684.04 MW) is achieved for η =0.5 which is increased in comparison with program 1 with the single value of elasticity. As shown in Table 4, the maximum load factor (79.41%) and maximum energy consumption (26,249.55 MWh) are achieved for participation level of 0.5 in compare with the base case. In this program, the customers' energy consumption is decreased at least 3.14% when η=0.5.

Program 5: In this case, we assume 7 $/MWh as incentive and the elasticity values as double of program 2. By applying the proposed model (Equation (15)) on the initial load curve, maximum peak reduction is obtained (4.77%) when η=0.5. In this case, the value of energy consumption is decreased in comparison with program 2, which is in the relation with the sensitivity of the results versus elasticity. On the other hand, the value of load factor is decreased at least 0.46% when η=0.7 and the distance between peak and valley is increased 1.01% for η=0.5 in comparison with the base case which can be explicate as the following. In this case, the value of elasticity is increased and hence, the considerable amount of consumption is transferred from the peak period to the off-peak or valley periods. With a significant approximation, the peak period and off-peak period substitute their place with each other after implementing program 5.

Program 6: In this case, the value of load factor is decreased which is in the direct relation with the values of elasticity and incentive. According to Tables 3 and 4, the peak value of load curve (for η=0.7) and distance between peak and valley are increased after implementing this program. In program 6, the value of load factor is decreased at least 5.46% for η=0.5. The result of this program show the importance of intelligent implementing of DRPs from the ISO point of view.

In the next section, we will discuss more about the importance of customers' participation level, value of incentive and price elasticity of demand in each of DRPs from the view point of ISO.

B. Prioritizing of DRPs

Table 5 presents the number of different programs and scenarios. For improving the load profile characteristics as well as customer's benefit, following attributes are considered: "peak reduction, energy consumption, load factor, distance between peak to valley and DR incentive value" [15]. Accordingly, the decision matrix D_e is established using Equation (16) with the results of Tables 3 and 4. The decision matrix represents the performance of each program for each attribute [15]. Then, the attributes are weighted by the entropy method (using Equations (17) and (18)). Table 6 shows the calculated weights of the attributes.

Table 5. Defining scenarios according to the value of η

Program NO	1		2		3		4		5		6	
η	0.7	0.5	0.7	0.5	0.7	0.5	0.7	0.5	0.7	0.5	0.7	0.5
Scenario NO	1	2	3	4	5	6	7	8	9	10	11	12

Table 6. Weights of attributes

Attribute	Peak reduction	Energy consumption	Load factor	Peak to valley	DR Incentive Value
Weight	0.4129	0.0006	0.0038	0.0278	0.5549

Table 7. Improved weights of attributes

Attribute	Peak reduction	Energy consumption	Load factor	Peak to valley	DR Incentive Value
Improved weight	0.6655	0.0003	0.0061	0.0299	0.2982

Since system operator has the main task of maintaining security of the system therefore the weights of attributes should be acceptable from its point of view, otherwise system operator can improve the weights based on its decision [15]. For example, peak load reduction increases the reserve capacity, which will result in increasing the system security margin. According to the above discussion, system operator may consider the importance factor of attributes as below [15]:

$$\lambda_{NAT} = \{0.3\,, 0.1\,, 0.3, 0.2\,, 0.1\} \quad \forall\ NAT\ = 1, 2, 3, 4, 5$$

Based on the above importance factors, the improved weights of attributes are obtained using Equation (19) and can be seen in Table 7 [15].

Using the TOPSIS methodology, the priorities of programs are determined and the results are depicted in Figure 4. Hence, by implementation of scenario 1 with the highest priority, system operator will obtain the desired load profile and also achieves relative satisfaction of consumers. Investigation in the above results reveals that for various policies, different improved weights of attributes will result in different priorities of programs [15].

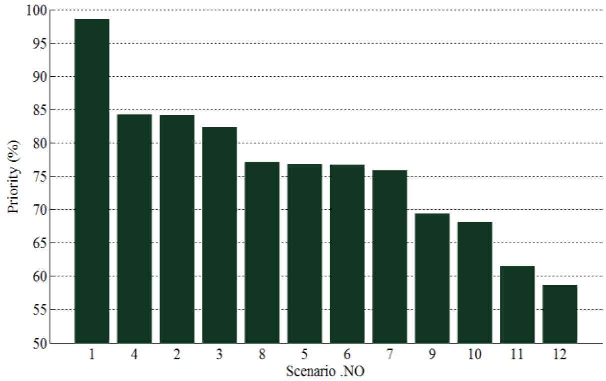

Figure 4. Priority of scenarios from the ISO point of view

C. Cost-Based Unit Commitment Considering Demand Response Programs

In this case, the basic system includes ten units with a scheduling time horizon of 24 hours. The generating units' data are given in [6]. Spinning reserve is held as 10% of the scaled load demand in this case. In the base case without considering demand response programs, the value of operation cost is obtained equal to 563,977$ using the harmony search algorithm. Table 8 presents the units' output powers for 24-h time horizon without implementing DRPs.

After applying the proposed DR economic model and using the results of MADM method which was discussed, the total operation cost of scheduling generation units is decreased after implementation of DRPs as shown in Table 9. As expected, with raising of elasticities, the total value of incentive which should be paid by the ISO is increased by more participation of customers in DRPs. As it is shown in Table 9, the total operation cost of scenarios 7,8 and 9 is considerably less than scenario 1 but, we assume that ISO implements the first scenario with the highest priority (98.57%).

By applying final DR model (Equation (15)), the load curve can be indicated as Figure 5 after implementing scenario 1. As shown in Figure 5, some customers transfer their consumption from the peak period to the off-peak or valley periods and some loads could be only on or off. After implementing scenario 1, the total operation cost of scheduling units is decreased and is equal to 543,457.69 $. On the other hand, the total value of incentive for participation of customers in scenario 1 is equal to 4,693.9 $ which should be paid by the ISO. Hence, the total cost of scenario 1 is equal to 548,151.59 $. Comparing the UC cost in this case with the result of base case (without implementing DRP) shows that the operation cost is decreased about 15,825.41 $.

Table 8. Unit output power for the conventional ten-unit test system without implementing demand response programs

Units	Hours																						
	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
1	455	455	455	455	455	455	455	455	455	455	455	455	455	455	455	455	455	455	455	455	455	455	455	455
2	245	295	370	455	390	360	410	455	455	455	455	455	455	455	455	310	260	360	455	455	455	455	420	345
3	0	0	0	0	0	130	130	130	130	130	130	130	130	130	130	130	130	130	130	130	130	0	0	0
4	0	0	0	0	130	130	130	130	130	130	130	130	130	130	130	130	130	130	130	130	130	0	0	0
5	0	0	25	40	25	25	25	30	85	162	162	162	162	85	30	25	25	25	30	162	85	145	25	0
6	0	0	0	0	0	0	0	0	20	33	73	80	33	20	0	0	0	0	0	33	20	20	0	0
7	0	0	0	0	0	0	0	0	25	25	25	25	25	25	0	0	0	0	0	25	25	25	0	0
8	0	0	0	0	0	0	0	0	0	10	10	43	10	0	0	0	0	0	0	10	0	0	0	0
9	0	0	0	0	0	0	0	0	0	0	10	10	0	0	0	0	0	0	0	0	0	0	0	0
10	0	0	0	0	0	0	0	0	0	0	0	10	0	0	0	0	0	0	0	0	0	0	0	0

Table 9. Comparisons of total cost for different scenarios

Priority 1-6				Priority 7-12			
Scenario No	Cost of Generating Units ($)	Total Incentive ($)	Total Cost ($)	Scenario No	Cost of Generating Units ($)	Total Incentive ($)	Total Cost ($)
Initial Load	563,977	-	563,977	Initial Load	563,977	-	563,977
1	543,457.69	4,693.9	548,151.59	6	537,007.52	19,002.2	556,009.72
4	545,349.86	9,758.9	555,108.76	7	532,956.67	9,387.86	542,344.53
2	550,126.42	3,352.8	553,479.22	9	516,822.02	27,325.18	544,147.2
3	536,508.22	13,662.59	550,170.81	10	529,348.10	19,517.9	548,866.0
8	540,706.31	6,705.6	547,411.91	11	500,385.8	53,206.3	553,592.1
5	533,410.79	26,603.17	560,013.96	12	511,646.8	38,004.5	549,651.3

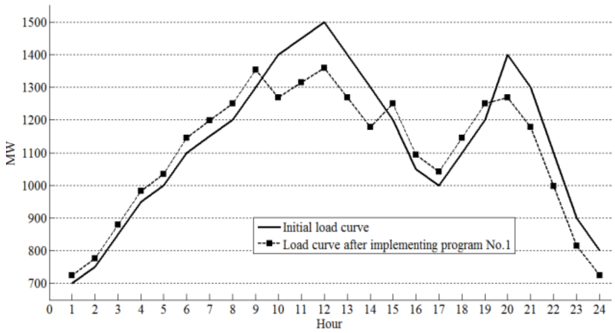

Figure 5. The impact of scenario 1 on the load profile

The output power of generation units is given in Table 10 after implementing scenario 1. The shaded boxes show the difference in the output power of generating units between this case and the base case. Table 11 shows the commitment status of units after implementing scenario 1 with highlighted hourly statuses which are different from the base case. The following reasoning applies to demonstrate the variation of the unit scheduling which is directly related to the limitations of generating units in the presence of DRRs. After implementing DRPs, unit 5 is off in peak periods (hours 23- 24). It means that in these hours, the DRRs are used for satisfying the predetermined demand.

Table 11. Unit schedule after implementing scenario 1

Total Cost =548,151.59 $	
Unit	Hours (1-24)
1-2	1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1
3	0 0 0 0 0 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 0 0 0
4	0 0 0 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 0 0
5	0 0 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 1 0 0
6	0 0 0 0 0 0 0 1 1 1 1 1 0 0 0 0 0 1 1 1 0 0 0 0
7	0 0 0 0 0 0 0 0 0 0 1 1 1 1 1 0 0 0 0 0 0 0 0 0
8	0 0 0 0 0 0 0 0 1 0 0 0 0 0 0 0 0 0 0 1 0 0 0 0
9	0 0 0 0 0 0 0 0 1 0 0 0 0 0 1 0 0 0 1 0 0 0 0 0
10	0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0 0

As shown in Table 11, in hour 9, unit 7 is off and units 8 and 9 which are more expensive in comparison with unit 7 are in the on status. It can be concluded that unit 7 has a minimum up time of three hours and starting up of this unit in hour 9 causes this unit to be on in the peak period and increasing of the generation cost, hence this unit is not called for minimizing the total value of objective function. In this state, the expensive units are not called to satisfy the demand due to reduction in customers' demand after implementing demand response program. For example unit 10 which is the most expensive unit is not committed in this case.

Table 10. Unit output power for the ten-unit case considering demand response program

Units	Hours																							
	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
1	455	455	455	455	455	455	455	455	455	455	455	455	455	455	455	455	455	455	455	455	455	455	455	455
2	270	321	400	374	425	406	455	455	455	455	455	455	455	413	455	354	302	386	455	455	438	387	361	270
3	0	0	0	0	0	130	130	130	130	130	130	130	130	130	130	130	130	130	130	130	130	0	0	0
4	0	0	0	130	130	130	130	130	130	130	130	130	130	130	130	130	130	130	130	130	130	130	0	0
5	0	0	25	25	25	25	28	60	144	79	99	145	74	25	55	25	25	25	60	79	25	25	0	0
6	0	0	0	0	0	0	0	20	20	20	20	20	0	0	0	0	0	20	20	20	0	0	0	0
7	0	0	0	0	0	0	0	0	0	0	25	25	25	25	25	0	0	0	0	0	0	0	0	0
8	0	0	0	0	0	0	0	0	10	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
9	0	0	0	0	0	0	0	0	10	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
10	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

VI. CONCLUSION

In this manuscript, demand response programs have been studied as a virtual power plant which has potential to present substantial benefits in the form of improved economic efficiency in the electricity markets. Based on the price elasticity of demand and customers' benefit function, a new nonlinear flexible economic model of incentive responsive loads has been derived for demand response programs. In the proposed model, the values of motivation and punishment are adjusted based on the stage of consumption.

This model can be used for the purpose of improving the load profile characteristics as well as satisfaction of customers. Prioritizing approach of demand response programs was presented based on MADM techniques including entropy and TOPSIS methods. Independent system operator could prioritize different programs and would choose the best program considering its perspectives. Hence, ISO implements the scenario with the highest priority.

Furthermore, the cost-base unit commitment as a crucial challenge of ISO was studied using the harmony search algorithm to emphasize the benefits of implementing demand response programs in electricity markets. The numerical studies have been conducted on the conventional ten-unit test system. The results presented demonstrate the benefits of customers' response to DRP of ISO.

NOMENCLATURES

$A(t)$: Incentive of demand response program at *t*th hour

$a(i), b(i), c(i)$: Fuel cost coefficients of unit *i*

$B(D_{DR}(t))$: Customer's income of *t*th hour after implementing DRPs

C_l : Priority coefficient in TOPSIS method

$CSC(i)$: Cold start-up cost of unit *i*

$CST(i)$: Cold start-up time of unit *i*

D_e : Decision matrix

$D(t)$: Power demand at *t*th hour
$D_{DR}(t)$: Power demand of *t*th hour after implementing DRPs
$E(t, j)$: Cross elasticity
$E(t,t)$: Self elasticity
$F(i,t)$: Fuel cost function of a unit *i*
$HSC(i)$: Hot start-up cost of unit *i*
i : Denotes a unit
$IC(t)$: Contract level of Incentive-based programs of *t*th hour
$\ln$: Natural logarithm function
$MD(i)^{ON}$: Duration during which the unit *i* is continuously on
$MD(i)^{OFF}$: Duration during which the unit *i* is continuously off
n, m : Coefficients to strengthen the cause of punishment and reward in IBPs
N : Number of units
NAL : Number of alternatives
NAT : Number of attributes
$PEN(DD(t))$: Total punishment for consumers.
$pen(t)$: Penalty of *t*th hour
$p(\Delta D(t))$: Total incentive for customers' participation in DRPs at *t*th hour
$P(i,t)$: Generation of unit in *t*th hour
$\overline{P}(i,t)$: Maximum generating capacity
$\underline{P}(i,t)$: Minimum generating capacity
$RDR(i)$: Ramping down limit of a unit
$RUR(i)$: Ramping up limit of a unit
$SUC(i,t)$: Start-up cost of unit *i*
$S(D_{DR}(t))$: Customer's benefit from implementing DRPs in *t*th hour
$T^D(i,t)$: Minimum down-time of unit *i*
$T^U(i)$: Minimum up-time of unit *i*
T : Number of hours for the scheduling period
$u(i,t)$: Unit status indicator where 1 means on and 0 means off
V_{lk} : Weighted normalized decision matrix
v_k^+ : Ideal solution
v_k^- : Anti-ideal solution
W : Weighting of attributes
χ_{lk} : Performance of the *l*th alternative regarding *k*th attribute
λ_k : Decision maker's importance factor
$\Pi(t)$: Spot electricity price of an hour
$\Gamma(t)$: Demand ratio parameter of *t*th hour
η : Potential of DR programs implementation

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