Energy Management of End Users Modeling their Reaction from a GENCO's Point of View

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***Abstract*- In this study, price-controlled energy management problem of the end users are investigated in the generation scheduling and unit commitment problems of a generation company (GENCO) to minimize its overall cost. Herein, the reaction of end users with respect to the energy management schemes is modeled considering different mathematical behavioral models for the end users. It is shown that price-controlled energy management of end users has a considerable potential for minimizing the operation cost of a GENCO. In addition, it is proven that just an optimal scheme of energy management is able to result in the minimum value of operation cost for the GENCO.**

***Index Terms*- Generation company (GENCO), generation scheduling problem, behavioral models, modeling reaction of end users, price-controlled energy management.**

I. Introduction

The energy scheduling problem of generation units involves finding the least-cost dispatch of available generation power plants to meet the electrical load demand [1]. Energy management, including price-based energy management schemes or incentive-based approaches, is considered as the first precedence in all the energy policy decisions due to its benefits from economic and environmental viewpoints [2-3]. Energy management is able to reduce overall costs of energy supply, increase reserve margin, and mitigate electricity price volatility [2]. Also, it achieves environmental goals by deferring commitment of polluted generation units, leading to increased energy efficiency and reduced greenhouse gas emissions [2].

Some studies have investigated the potential of energy management [4-5]. The U.S. federal energy regulatory commission estimates that the contribution from the existing customers in the U.S. is around 41000 MW equal to 5.8% of the 2008 summer peak demand [4]. A study presented in [5] shows that incentive-based energy management is responsible for 93% of peak load reduction in the U.S. The studies presented in [6-10] have investigated the effects of energy management on the residential customers' demand.

In [11-12], the authors have determined value of demand for shifting from the peak period to other periods by direct load control for congestion management and increasing utilization of wind power. In [13-16], energy management has been investigated in the generation scheduling problem by modeling the reaction of end user customers with respect to the value of incentive for demand reduction at peak period. However, in the above mentioned studies, different behavior and reaction of end users with respect to electricity price changes has not been modeled in the generation scheduling problem from a generation company's (GENCO's) viewpoint.

In this study, price-controlled energy management of end users is investigated in the generation scheduling problem of generation units considering different mathematical behavioral models (linear, power, exponential, and logarithmic) for the end users. The behavior of end users is modeled from a GENCO's point of view based on the social welfare of end users and their price elasticity of demand. Herein, the values of electricity prices in the valley and peak periods are decreased and increased, respectively, to encourage the end users to shift their demands from the peak period to the valley period. By having this phenomenon, the demand profile of the system becomes more flat and the overall cost of generation system is decreased, since fuel consumption and emission level of the generation units are polynomial functions.

The paper is organized as follows. In Section II, the models for price-controlled energy management of end users with different behavioral reactions are presented. In addition, the proposed technique for solving the generation scheduling problem of a GENCO is presented. In Section III, the mathematical formulation for generation scheduling problem of a GENCO is presented. The numerical study is conducted in Section IV, and Section V concludes the paper.

II. Proposed Technique

A. Price-Controlled Energy Management Modeling

Price elasticity of demand is defined as the demand sensitivity respect to the price [17], as can be seen in equation (1).

$$E=\frac{\partial\widetilde{D}/D}{\partial\tilde{\pi}/\pi}=\frac{\partial\widetilde{D}}{\partial\tilde{\pi}}\times\frac{\pi}{D} \tag{1}$$

Herein, D is the initial demand level, $\widetilde{D}$ is the demand level after introducing the new price, π is the initial price, and $\tilde{\pi}$ is the value of new price. If the electricity price varies at different periods (valley, off-peak, and peak periods), the reactions of an end users are as follow [18]:

- One part of demand of the end user (such as lighting or cooling/heating demands for every type of end users) cannot be transferred to other periods and it can be only "on" or "off" in the same period. Elasticity of such demand does not have any sensitivity to the electricity prices in other periods [17].
- Another part of demand of the end user (such as demand of cleaning appliances) can be transferred from one period to other periods. Elasticity of this part of demand, which has sensitivity to the electricity prices of other periods, is called "cross elasticity" [17].

In this regard, the self-elasticity at time t ($E_{t,t}$) and the cross elasticity between time t and t' ($E_{t,t'}$) can be written as equations (2) and (3), respectively [17]:

$$E_{t,t}=\frac{\widetilde{D}_t-D_t}{\tilde{\pi}_t-\pi_t}\times\frac{\pi_t}{D_t}\leq 0 \tag{2}$$

$$E_{t,t'}=\frac{\widetilde{D}_t-D_t}{\tilde{\pi}_{t'}-\pi_{t'}}\times\frac{\pi_{t'}}{D_t}\geq 0 \tag{3}$$

In this study, price-controlled energy management of the end users is modeled based on their maximum social welfare and price elasticity of demand. The social welfare of an end user is defined as equation (4) that includes benefit function of the end user due to consuming electricity (and consequently producing and selling commodities) subtracted by the value of electricity bill. Herein, t indicates the time in one hour scale.

$$SW_t^{Model} = BF_t^{Model} - \tilde{\pi}_t \times \tilde{D}_t^{Model} \tag{4}$$

In addition, SW_t^{Model} denotes the social welfare of an end user at time t considering the behavior model of end user (linear, power, logarithmic and exponential model). Moreover, BF_t^{Model} indicates the benefit function of end user at time t considering its model. Also, $\tilde{\pi}_t \times \tilde{D}_t^{Model}$ designates the cost of electricity bill of the end user with the known behavioral model, and $\tilde{\pi}_t$ and $\tilde{D}_t^{Model}$ are the electricity price and the amount of electricity consumed by the end user at time t, respectively.

In mathematics, a Taylor series or Taylor expansion is a representation of a function as an infinite sum of terms that are calculated from the values of the function's derivatives at a single point. Based on this, herein, BF_t^{Model} is represented by its related Taylor series while the terms after the second term is neglected due their small values compared to the first and second terms. The Taylor expansions of BF_t^{Model} for the first two terms considering linear, power, exponential, and logarithmic models for the behavioral model of end user are presented in equations (5)-(8) in Table I [19]. In these equations, the constant value of benefit function is indicated by $BF_{0,t}$.

TABLE I

TAYLOR EXPANSIONS OF BENEFIT FUNCTION FOR THE FIRST TWO TERMS CONSIDERING DIFFERENT MODELS FOR THE BEHAVIOR OF END USER [19].

Model	Gross surplus function	Equation
Linear	$BF_t^{Lin} = BF_{0,t}^{Lin} + \pi_t \times (\tilde{D}_t^{Lin} - D_t^{Lin}) + \frac{\pi_t}{2 \times E_{t,t} \times D_t^{Lin}} \times (\tilde{D}_t^{Lin} - D_t^{Lin})^2$	(5)
Power	$BF_t^{Pow} = BF_{0,t}^{Pow} + \frac{\pi_t \times \tilde{D}_t^{Pow}}{1 + \frac{1}{E_{t,t}}} \times \left(\left(\frac{\tilde{D}_t^{Pow}}{D_t^{Pow}}\right)^{\frac{1}{E_{t,t}}} - 1\right)$	(6)
Exponential	$BF_t^{Exp} = BF_{0,t}^{Exp} + \pi_t \times \tilde{D}_t^{Exp} \times \left(1 + \frac{1}{E_{t,t}} \times \left(ln\left(\frac{\tilde{D}_t^{Exp}}{D_t^{Exp}}\right) - 1\right)\right)$	(7)
Logarithmic	$BF_t^{Log} = BF_{0,t}^{Log} + \pi_t \times D_t^{Log} \times E_{t,t} \times e^{\frac{\tilde{D}_t^{Log} - D_t^{Log}}{D_t^{Log} \times E_{t,t}} - 1}$	(8)

Based on the classical optimization theory, in order to maximize the value of SW_t^{Model} with respect to $\tilde{D}_t^{Model}$, value of $\frac{\partial SW_t^{Model}}{\partial \tilde{D}_t^{Model}}$ must be equal to zero. In other words, equation (9) needs to be solved.

$$\frac{\partial BF_t^{Model}}{\partial \tilde{D}_t^{Model}} = \tilde{\pi}_t \tag{9}$$

End User with Linear Behavioral Model: Differentiating equation (5) with respect to $\tilde{D}_t^{Lin}$ results in equation (10).

$$\frac{\partial BF_t^{Lin}}{\partial \tilde{D}_t^{Lin}} = \pi_t \times \left(1 + \frac{\tilde{D}_t^{Lin} - D_t^{Lin}}{E_{t,t} \times D_t^{Lin}}\right) \tag{10}$$

Combining equations (9) and (10) leads to equation (11).

$$\tilde{D}_t^{Lin} = D_t^{Lin} \times \left(1 + \frac{\tilde{\pi}_t - \pi_t}{\pi_t} \times E_{t,t}\right) \tag{11}$$

The complete model is achieved by considering all the times, as can be seen in equation (12).

$$\tilde{D}_t^{Lin} = D_t^{Lin} \times \left(1 + \sum_{t'=1}^{24} \frac{\tilde{\pi}_{t'} - \pi_{t'}}{\pi_{t'}} \times E_{t,t'}\right) \tag{12}$$

End User with Power Behavioral Model: Differentiating equation (6) with respect to $\tilde{D}_t^{Pow}$ results in equation (13).

$$\frac{\partial BF_t^{Pow}}{\partial \tilde{D}_t^{Pow}} = \frac{\pi_t}{1 + \frac{1}{E_{t,t}}} \times \left(\left(\frac{\tilde{D}_t^{Pow}}{D_t^{Pow}}\right)^{\frac{1}{E_{t,t}}} - 1 + \frac{1}{E_{t,t}} \times \left(\frac{\tilde{D}_t^{Pow}}{D_t^{Pow}}\right)^{\frac{1}{E_{t,t}}}\right) \tag{13}$$

Since the realistic value of elasticity is too small compared to the value of 1, the value of first and third terms in the parenthesis are dominant. Thus, the equation (13) can be approximated as following:

$$\frac{\partial BF_t^{Pow}}{\partial \tilde{D}_t^{Pow}} \cong \frac{\pi_t}{1 + \frac{1}{E_{t,t}}} \times \left(\left(\frac{\tilde{D}_t^{Pow}}{D_t^{Pow}}\right)^{\frac{1}{E_{t,t}}} + \frac{1}{E_{t,t}} \times \left(\frac{\tilde{D}_t^{Pow}}{D_t^{Pow}}\right)^{\frac{1}{E_{t,t}}}\right) \tag{14}$$

Simplification of the equation (14) results in equation (15):

$$\frac{\partial BF_t^{Pow}}{\partial \tilde{D}_t^{Pow}} \cong \pi_t \times \left(\frac{\tilde{D}_t^{Pow}}{D_t^{Pow}}\right)^{\frac{1}{E_{t,t}}} \tag{15}$$

Combining equations (10) and (15) results in equation (16).

$$\tilde{D}_t^{Pow} \cong D_t^{Pow} \times \left(\frac{\tilde{\pi}_t}{\pi_t}\right)^{E_{t,t}} \tag{16}$$

The complete model is obtained by considering all the times presented in equation (17).

$$\tilde{D}_t^{Pow} \cong D_t^{Pow} \times \prod_{t'=1}^{24} \left(\frac{\tilde{\pi}_{t'}}{\pi_{t'}}\right)^{E_{t,t'}} \tag{17}$$

End User with Exponential Behavioral Model: Differentiating equation (7) with respect to $\tilde{D}_t^{Exp}$ results in equation (18).

$$\frac{\partial BF_t^{Exp}}{\partial \tilde{D}_t^{Exp}} = \pi_t \times \left(1 + \frac{1}{E_{t,t}} \times ln\left(\frac{\tilde{D}_t^{Exp}}{D_t^{Exp}}\right)\right) \tag{18}$$

Combining equations (10) and (18) results in equation (19).

$$\tilde{D}_t^{Exp} = D_t^{Exp} \times e^{\frac{\tilde{\pi}_t - \pi_t}{\pi_t} \times E_{t,t}} \tag{19}$$

The complete model is achieved by considering all the times presented in equation (20).

$$\tilde{D}_t^{Exp} = D_t^{Exp} \times e^{\sum_{t'=1}^{24} \frac{\tilde{\pi}_{t'} - \pi_{t'}}{\pi_{t'}} \times E_{t,t'}} \tag{20}$$

End User with Logarithmic Behavioral Model: Differentiating equation (8) with respect to $\tilde{D}_t^{Log}$ results in equation (21).

$$\frac{\partial BF_t^{Log}}{\partial \tilde{D}_t^{Log}} = \pi_t \times e^{\frac{\tilde{D}_t^{Log} - D_t^{Log}}{D_t^{Log} \times E_{t,t}} - 1} \tag{21}$$

Combining equations (9) and (21) gives equation (22).

$$\tilde{D}_t^{Log} = D_t^{Log} \times \left(1 + \left(ln\left(\frac{\tilde{\pi}_t}{\pi_t}\right)\right) \times E_{t,t}\right) \tag{22}$$

The complete model is achieved by considering all the times, as can be seen in equation (23).

$$\tilde{D}_t^{Log} = D_t^{Log} \times \left(1 + \sum_{t'=1}^{24} \left(ln\left(\frac{\tilde{\pi}_{t'}}{\pi_{t'}}\right)\right) \times E_{t,t'}\right) \tag{23}$$

As can be seen in equations (12), (17), (20) and (23), if the electricity prices in different periods are the same, the end user will not change its demand pattern, since there is not any encouragement.

In the price-controlled energy management, the prices of electricity at peak and valley periods are changed using ρ^{EM}, as can be seen in (24). In other words, the price-controlled energy management includes decreasing the electricity price at valley period and increasing the electricity price at peak period.

$$\tilde{\pi}_t = \begin{cases} \pi_t - \rho^{EM} & t \in Valley \\ \pi_t & t \in Off-peak \\ \pi_t + \rho^{EM} & t \in Peak \end{cases} \quad (24)$$

B. Optimization Technique

Herein, GA is applied to solve the optimization problem. The value of objective function (the total cost of generation system over the operation period (one day)) is defined as the fitness of a chromosome, and then it is tried to maximize the fitness of chromosome. The defined chromosome is presented in Fig. 1. The outputs of GA include the minimum value of total cost of generation system over the operation period (one day), the optimal generation level of units and the optimal demand level of the end users with a behaviour model.

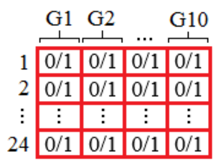

Fig. 1. The structure of chromosome in the applied GA.

After energy management (modifying the electricity prices at peak and valley periods using ρ^{EM}), the end users react and revise their demand level. In other words, they shift part of their demand from the peak period (more expensive electricity) to off-peak and valley periods (cheaper electricity). Herein, the problem is solved and optimized for every possible value of ρ^{EM} and then, the optimal scheme of energy management (optimal value of ρ^{EM}) is determined based on the minimum value of total cost of generation system over the operation period (one day). TABLE II presents the pseudo code for finding the optimal scheme of energy management of end users by the GENCO.

TABLE II
The pseudo code for finding the optimal scheme of energy management of end users.

1: Set the value of $\rho^{EM} = 0$.
2: $\rho^{EM} = \rho^{EM} + 1$.
3: Update the electricity price at every period ($\tilde{\pi}$) using (24).
4: Update the system demand ($\tilde{D}^{Model}$) using (12), (17), (20), and (23) for und users with linear, power, exponential, and logarithmic behaviors, respectively.
5: Solve the optimization problem and determine the minimum daily operation cost of GENCO using GA.
6: Go to Step 2, if $\rho^{EM} < \rho^{EM}_{MAX}$. //$\rho^{EM}_{MAX}$ *is determined based on the initial electricity price at valley period.*
7: Determine optimal value of ρ^{EM} based on the minimum daily operation cost of GENCO.

III. Mathematical Formulation

A. Objective Function of the Problem

The objective function of the problem over the operation period (one day) is presented in (25). As can be seen, it includes energy management cost of end users (i.e., difference in income of GENCO), the fuel cost of generation units, the greenhouse gas emissions cost of generation units, the start-up cost of de-committed units, and the shut down cost of committed units.

$$OF = \sum_{t=1}^{Nt} \left[Cost_t^{EM} + \sum_{g=1}^{Ng} \left[\begin{matrix} Cost_{g,t}^{F} + Cost_{g,t}^{E} \\ +Cost_{g,t}^{STU} + Cost_{g,t}^{SHD} \end{matrix} \right] \right] \quad (25)$$

B. Cost Terms of the Objective Function

Cost of energy management of end users:

Energy management of end users may result in cost or profit for the GENCO when the income of sold electrical energy decreases or increases after energy management, respectively, as can be seen in equation (26).

$$Cost_t^{EM} = \sum_{Model} \left[D_t^{Model} \times \pi_t - \tilde{D}_t^{Model} \times \tilde{\pi}_t \right] \quad (26)$$

Fuel cost of generation units:

The fuel cost of every generation unit ($Cost_{g,t}^{F}$), which is in "on" status ($x_{g,t}^{G} = 1$), is a quadratic polynomial [20]. In other words, the generation unit consumes more fuel per power unit when its power is in the upper level of power compared to the value of consumed fuel per power unit in the lower level.

$$Cost_{g,t}^{F} = \left(\alpha_{1,g}^{F} \times \left(P_{g,t}\right)^2 + \alpha_{2,g}^{F} \times \left(P_{g,t}\right) + \alpha_{3,g}^{F} \right) \times x_{g,t}^{G} \quad (27)$$

Greenhouse gas emissions cost of generation units:

The greenhouse gas emissions cost of every generation unit ($Cost_{g,t}^{E}$), which is in "on" status ($x_{g,t}^{G} = 1$), is a quadratic polynomial [20].

$$Cost_{g,t}^{E} = \beta^{E} \times \left(\alpha_{1,g}^{E} \times \left(P_{g,t}\right)^2 + \alpha_{2,g}^{E} \times \left(P_{g,t}\right) + \alpha_{3,g}^{E} \right) \times x_{g,t}^{G} \quad (28)$$

Start-up cost and shut down cost of generation units:

$$Cost_{g,t}^{STU} = C_g^{STU} \times \left(1 - x_{g,t-1}^{G}\right) \times x_{g,t}^{G} \quad (29)$$

$$Cost_{g,t}^{SHD} = C_g^{SHD} \times x_{g,t-1}^{G} \times \left(1 - x_{g,t}^{G}\right) \quad (30)$$

C. Constraints of the Problem

System power balance constraint:

The power-demand balance constraint of the system that must be held in every time step of the operation period is presented in (31). This constraint is applicable for the problem with ($x^{EM} = 1$) and without ($x^{EM} = 0$) energy management of end users.

$$\sum_{g=1}^{Ng} P_{g,t} \times x_{g,t}^{G} = \sum_{Model} \left(D_t^{Model} \times (1 - x^{EM}) + \tilde{D}_t^{Model} \times x^{EM} \right) \quad (31)$$

System minimum generation constraint:

$$\sum_{g=1}^{Ng} P_g^{min} \times x_{g,t}^{G} \leq \sum_{Model} \left(D_t^{Model} \times (1 - x^{EM}) + \tilde{D}_t^{Model} \times x^{EM} \right) \quad (32)$$

System maximum generation constraint with spinning reserve:

$$\sum_{g=1}^{Ng} P_g^{max} \times x_{g,t}^{G} \geq \sum_{Model} \left(D_t^{Model} \times (1 - x^{EM}) + \tilde{D}_t^{Model} \times x^{EM} \right) + SR_t \quad (33)$$

Generation units' power constraint:

$$\left(P_g^{min} \leq P_g(t) \leq P_g^{max} \right) \times x_{g,t}^{G} \quad (34)$$

Ramp-up rate and ramp-down rate constraints:

$$\left(\left(P_{g,t+1} - P_{g,t} \right) \leq RUR_g \right) \times x_{g,t}^{G} \quad (35)$$

$$\left(\left(P_{g,t} - P_{g,t+1} \right) \leq RDR_g \right) \times x_{g,t}^{G} \quad (36)$$

Minimum "off time" and minimum "on time" constraints:

$$OFFT_{g,t} \geq MDT_g \quad (37)$$

$$ONT_{g,t} \geq MUT_g \quad (38)$$

IV. Simulation and Results

A. Characteristics of the System

The technical characteristics of generation units are presented in TABLE III. Moreover, the minimum value of spinning reserve at every hour of a day is assumed about 10% of demand at the same hour. Furthermore, the value of penalty for greenhouse gas emissions is assumed about \$10 per ton based on the California Air Resources Board auction of greenhouse gas emissions [21]. In addition, the value of self and cross price elasticity of demand of end users at valley, off-peak, and peak periods are presented in TABLE IV, which are based on [18] after some revisions.

Fig. 2 illustrates the daily demand profile (p.u.) of different types of end users. The characteristics of demand of different end users are given in TABLE V. Herein, the considered behavioral model for every type of end user is arbitrary due to lack of real data regarding this subject. The number of chromosomes in the population (n_c) and the value of mutation probability of genes (θ^{Mut}) are assumed to be about 100 and 10%, respectively.

TABLE III
THE TECHNICAL CHARACTERISTICS OF GENERATION UNITS.

Generation unit	G1	G2	G3	G4	G5
α_1^F (\$/MWh^2)	0.00048	0.00031	0.00200	0.00211	0.00398
α_2^F (\$/MWh)	16.19	17.26	16.60	16.50	19.70
α_3^F (\$)	1000	970	700	680	450
α_1^E (Ton/MWh^2)	0.0005	0.0005	0.0005	0.0005	0.0010
α_2^E (Ton/MWh)	0.4050	0.4320	0.4150	0.4120	0.4930
α_3^E (Ton)	0.3000	0.4250	0.4500	0.7000	0.7250
P^{min} (MW)	75	75	15	15	15
P^{max} (MW)	230	230	65	65	80
MUT (h)	5	5	5	5	5
MDT (h)	5	5	5	5	5
RUR (MW/h)	80	70	70	60	60
RDR (MW/h)	80	70	70	60	60
C^{STU} (\$)	4500	5000	550	560	900
C^{SHD} (\$)	4500	5000	550	560	900
Initial status	+24	+24	+24	+24	+24
Generation unit	G6	G7	G8	G9	G10
α_1^F (\$/MWh^2)	0.00712	0.00790	0.00813	0.00822	0.00873
α_2^F (\$/MWh)	22.26	27.74	25.92	27.27	27.79
α_3^F (\$)	370	480	660	665	670
α_1^E (Ton/MWh^2)	0.0020	0.0020	0.0024	0.0025	0.0025
α_2^E (Ton/MWh)	0.5560	1.6940	1.6480	1.6820	1.6950
α_3^E (Ton)	0.9250	1.2000	1.6500	1.6625	1.7750
P^{min} (MW)	10	10	10	10	10
P^{max} (MW)	40	40	25	25	25
MUT (h)	3	3	1	1	1
MDT (h)	3	3	1	1	1
RUR (MW/h)	20	20	10	10	10
RDR (MW/h)	20	20	10	10	10
C^{STU} (\$)	170	260	30	30	30
C^{SHD} (\$)	170	260	30	30	30
Initial status	-1	-2	-1	-2	-3

TABLE IV
SELF AND CROSS PRICE ELASTICITY OF DEMAND OF END USERS AT DIFFERENT PERIODS.

Period	Valley (h:1-8)	Off-peak (h:9-17)	Peak (h:18-24)
Valley	-0.1450	0.0080	0.2230
Off-peak	0.0130	-0.0900	0.0355
Peak	0.1050	0.0040	-0.1500

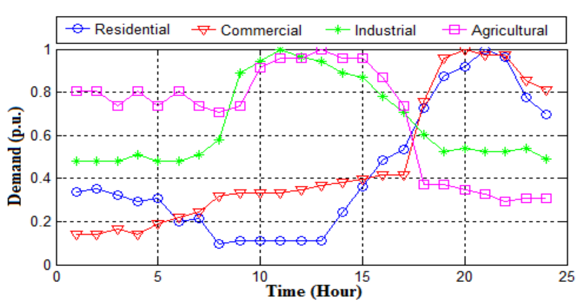

Fig. 2. The daily demand profile (p.u.) of different types of end users.

TABLE V
THE RATED DEMAND OF EVERY TYPE OF END USER, TOTAL NUMBER OF END USERS WITH EACH TYPE, AND BEHAVIORAL MODEL OF EVERY TYPE OF END USER.

-	Res.	Com.	Ind.	Agr.
Rated demand (kW)	25	15	1000	500
Number of end users	10320	20600	273	226
Behavioural model	Lin.	Pow.	Exp.	Log.

B. Simulating the Problem

1) Solving the Problem without Energy Management

The total cost of system (\$/day) and total value of greenhouse gas emissions (Ton/day) are presented in TABLE VI. The value of electricity price at every period is determined based on the average value of hourly marginal costs at the same period. Based on this, the electricity prices are calculated about \$21.3/MWh, \$23.1/MWh, and \$27.3/MWh for valley, off-peak, and peak periods, respectively. As can be seen, because of the initial value of electricity at valley period, the value of ρ_{MAX}^{EM} must be \$21/MWh in the presented pseudo code in TABLE II, since the value of electricity price cannot be negative, as can be realized from (24).

TABLE VI
RESULTS OF THE PROBLEM SIMULATION WITH AND WITHOUT ENERGY MANAGEMENT OF END USERS.

-	Before EM	After optimal EM	Reduction
Generation cost (\$/day)	377,290	361,793	15,497
Energy management cost	0	-5,543	-
Total cost of system	377,290	356,250	21,040
Total emissions (Ton/day)	6,538	6,358	180

2) Solving the Problem with Optimal Energy Management

The total cost of the system (\$/day) and total value of greenhouse gas emissions (Ton/day) after optimal scheme of price-controlled energy management of the end users are presented in TABLE VI. As can be seen, generation cost is decreased about \$15,497/day. In addition, the energy management of end users increases the income of GENCO about \$5,543/day. Therefore, the total cost of system is decreased about \$21,040/day.

The reason for reduction of generation cost is leveling the demand profile of the system due to energy management, since the fuel cost and greenhouse gas emissions of the generation units are quadratic polynomial functions, as can be seen in equations (27) and (28). In other words, a more flat power demand profile will cause less fuel consumption and less greenhouse gas emissions for the units, with the same amount of energy demand over the operation period (one day).

Herein, the optimal scheme of price-controlled energy management of the end users is considering \$12/MWh for the value of ρ^{EM}. Based on this, the electricity prices at valley, off-peak and peak periods are changed into \$9.3/MWh, \$23.1/MWh, and \$39.3/MWh, respectively, as can be seen in Table VII. In other words, the electricity prices at valley period and peak period are decreased and increased, respectively to motivate the end users to transfer their demand from the peak period to the valley period.

Fig 3 shows the hourly demand level of residential, commercial, industrial, and agricultural end users before and after optimal scheme of price-controlled energy management. As can be seen, every type of end user with any behavioral model has shifted some of its demand from the peak period to the off-peak and valley periods; however, the percentage of transferred demand is different for every type of end user.

TABLE VII
THE OPTIMAL SCHEME OF PRICE-CONTROLLED ENERGY MANAGEMENT OF THE END USERS.

	Valley period	Off-peak period	Peak period
Electricity price before EM (\$/MWh)	21.3	23.1	27.3
Electricity price after optimal EM (\$/MWh)	9.3	23.1	39.3

TABLE VIII presents the generation level of units for the optimal scheme of price-controlled energy management (ρ^{EM}=\$12/MWh). Herein, the highlighted values indicate the differences in the generation level of the units compared to their values before energy management. Moreover, the highlighted squares indicate the differences in the commitment status of units compared to their values before energy management. As can be seen, after optimal energy management, the most expensive and pollutant units (G7-G10) are kept off in the whole operation period. In addition, due to transferring demand from the peak period to other periods, the generation level of the least expensive and the least pollutant units (G1-G4) are increased in the off-peak and valley periods.

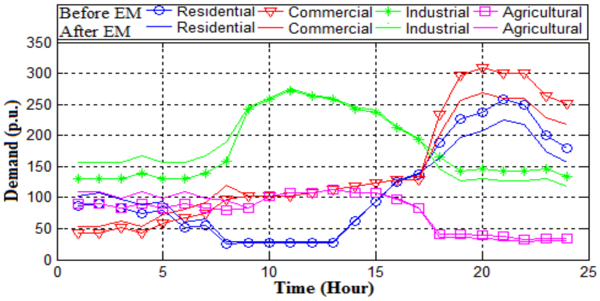

Fig. 3. The hourly demand level of residential, industrial, commercial, and agricultural end users before and after optimal scheme of price-controlled energy management.

TABLE VIII
THE POWER LEVEL OF UNITS (MW) WITH OPTIMAL SCHEME OF PRICE-CONTROLLED ENERGY MANAGEMENT OF END USERS.

Hour	G1	G2	G3	G4	G5	G6	G7	G8	G9	G10
1	203	75	65	65	15	0	0	0	0	0
2	208	75	65	65	15	0	0	0	0	0
3	198	75	65	65	15	0	0	0	0	0
4	198	75	65	65	15	0	0	0	0	0
5	203	75	65	65	15	0	0	0	0	0
6	190	75	65	65	15	0	0	0	0	0
7	204	75	65	65	15	0	0	0	0	0
8	216	75	65	65	15	0	0	0	0	0
9	230	86	65	65	15	0	0	0	0	0
10	230	121	65	65	15	0	0	0	0	0
11	230	141	65	65	15	0	0	0	0	0
12	230	136	65	65	15	0	0	0	0	0
13	230	141	65	65	15	0	0	0	0	0
14	230	162	65	65	15	0	0	0	0	0
15	230	192	65	65	15	0	0	0	0	0
16	230	194	65	65	15	0	0	0	0	0
17	230	172	65	65	15	0	0	0	0	0
18	230	175	65	65	15	0	0	0	0	0
19	230	230	65	65	18	10	0	0	0	0
20	230	230	65	65	40	10	0	0	0	0
21	230	230	65	65	46	10	0	0	0	0
22	230	230	65	65	34	10	0	0	0	0
23	230	190	65	65	15	0	0	0	0	0
24	230	149	65	65	15	0	0	0	0	0

Fig. 4 illustrates the sensitivity plot of total cost of system with respect to the value of ρ^{EM} (\$/MWh). As can be seen, the plot is not a linear function of ρ^{EM} and \$12/MWh is the only optimal value for ρ^{EM}. In other words, the optimal value of ρ^{EM} needs to be investigated and incidental values will not be efficient.

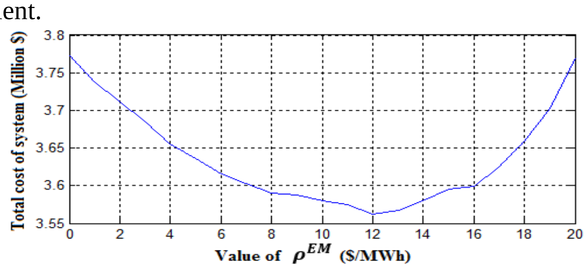

Fig. 4. Sensitivity analysis for the total cost of system with respect to the value of ρ^{EM} (\$/MWh).

V. CONCLUSION

Price-controlled energy management of the end users in the generation scheduling problem is noticeably advantageous, since it can decrease the total cost of system and the greenhouse gas emissions level of the generation units. In order to minimize the total cost of system managed by the generation company, we proposed and implemented optimal scheme of price-controlled energy management. In addition, we realistically modeled the behavior of end users since the end users with different behavioral models have dissimilar reactions to the energy management schemes, and consequently different value for the total cost of system will be obtained. Our numerical studies confirm the effectiveness of proposed approach in minimizing the total cost of system.

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