Price-Controlled Energy Management of Smart Homes for Maximizing Profit of a GENCO

Mehdi Rahmani-Andebili, *Member, IEEE*, and Haiying Shen, *Senior Member, IEEE*

***Abstract*—In this paper, price-controlled energy management is investigated in a bi-level optimization framework, that is, energy scheduling problem of smart homes (SHs) and generation scheduling and unit commitment (UC) problems of a generation company (GENCO). SHs as the responsive customers (respect to the energy management) include a variety of sources such as photovoltaic (PV) panels, diesel generator, and battery as an energy storage. In addition, SHs are able to transact electricity with the GENCO through the power system. In this paper, the goal of GENCO is to design an optimal energy management scheme (optimal price of electricity) to maximize its daily profit. Herein, each SH reacts to the energy management scheme and reschedules its energy resources to minimize its daily operation cost. In this paper, a scenario-based stochastic optimization approach is applied in the energy scheduling problem of an SH to address the variability and uncertainty issues of the PV panels. Also, a combination of genetic algorithm (GA) and linear programming is applied as the optimization tool for the energy scheduling problem of an SH. Moreover, lambda-iteration economic dispatch and GA techniques are applied to solve the generation scheduling and UC problems of the GENCO, respectively. The numerical study demonstrates that in order to reach the maximum profit of GENCO, the energy management must be optimally designed and implemented; otherwise, the energy management scheme may result in detriment. Moreover, it is shown that each SH is able to get benefit from the energy management scheme and minimize its daily operation cost.**

***Index Terms*—Energy scheduling, generation company (GENCO), generation scheduling, renewables, smart home (SH), stochastic optimization, unit commitment (UC).**

I. INTRODUCTION

NOWADAYS, conventional power systems are being restructured and changed into the smart grids to improve the reliability and efficiency of the power systems that results in social, economic, and environmental benefits. A smart grid is an electricity network that uses advanced technologies to monitor and manage the electricity generation from all sources to meet the varying electricity demands of end users [1]. Smart grids coordinate the needs and capabilities of all generators, grid operators, end users, and power market stakeholders to operate all parts of the system as efficiently as possible while maximizing system reliability and stability [1].

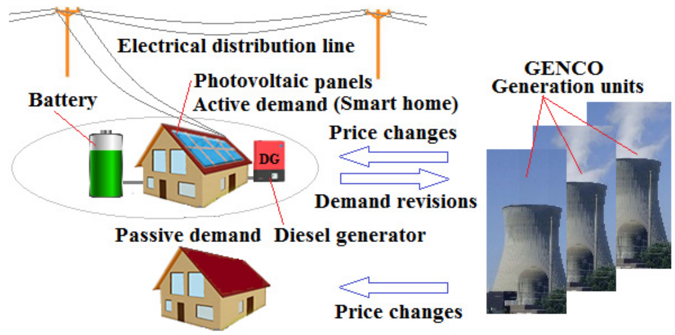


Fig. 1. Schematic of price-controlled energy management of SHs.

The schematic of problem is shown in Fig. 1. As can be seen, one part of demand of system is related to active end users (responsive to energy management schemes) such as smart homes (SHs) and another part of demand is concerned with passive and conventional end users that do not react to the energy management schemes. The generation company (GENCO) submits the price-controlled energy management scheme to the SHs, then the SHs react and reschedule their energy resources that include diesel generator (DG), battery, photovoltaic (PV) panels, and electricity transaction with the GENCO. Next, the GENCO receives feedback (total demand of system) from the SHs and solve its generation scheduling and unit commitment (UC) problems for the current scheme of energy management. This process is repeated for every possible price-controlled energy management scheme. Finally, the optimal scheme of energy management is identified based on the maximum profit of GENCO.

The main challenges of the world today are quickly using up the vast but finite amount of fossil fuels and the related environmental issues including global warming, climate changes, and atmosphere pollution [2]. Energy management has a significant potential for achieving benefits from economic and environmental viewpoints, thus it is considered as the first priority in all the energy policy decisions [3], [4]. It is able to reduce overall costs of energy supply, increase spinning and nonspinning reserves margin, and mitigate electricity

Manuscript received November 19, 2016; revised January 23, 2017; accepted March 31, 2017. This work was supported in part by the National Science Foundation under Grant NSF-1404981, Grant IIS-1354123, and Grant CNS-1254006, in part by the IBM Faculty Award under Grant 5501145, and in part by the Microsoft Research Faculty Fellowship under Grant 8300751. This paper was recommended by Associate Editor L. L. Lai. *(Corresponding author: Mehdi Rahmani-Andebili.)*

M. Rahmani-Andebili is with the Department of Electrical and Computer Engineering, Clemson University, Clemson, SC 29631 USA (e-mail: mehdir@g.clemson.edu).

H. Shen is with the Department of Computer Science, University of Virginia, Charlottesville, VA 22904 USA (e-mail: hs6ms@virginia.edu).

Color versions of one or more of the figures in this paper are available online at http://ieeexplore.ieee.org.

Digital Object Identifier 10.1109/TSMC.2017.2690622

price volatility [3]. Also, it achieves environmental goals by deferring commitment of polluted generation units, leading to increased energy efficiency and reduced greenhouse gas emissions [3].

Generation scheduling problem of generation units involves finding the least-cost dispatch of available generation power units to meet the electrical load demand [5]. In addition, UC is an optimization problem that produces physical generator commitment decisions to minimize the overall cost of serving forecasted net load demand subject to operational constraints on generation units and power system [6].

However, in the previously published studies, the reaction and rescheduling energy resources of SHs with respect to the energy management schemes have not been investigated from a GENCO's viewpoint. In this paper, the value of electricity price at peak period is changed by the GENCO to encourage the SHs to reschedule their energy resources and reshape their demand pattern. By implementing this price-controlled energy management, the overall profit of the GENCO not only depends on the cost of generation scheduling and UC problems but also the values of new electricity prices and the amount of sold electrical energy to the end users. Therefore, finding an optimal scheme for the energy management needs to be investigated.

An SH, as one part of the smart grid on the demand side, can deliver its extra energy to the grid and sell it to the power system, but at a lower price compared to the price purchased from the system [7]. However, there are some challenges in solving the energy scheduling problem of an SH that include variability and uncertainty issues of power of PV panels installed on the roof of an SH. Herein, we address these issues by applying a scenario-based stochastic optimization approach. Also, a combination of genetic algorithm (GA) and linear programming (GA-LP) is applied as the optimization tool for the energy scheduling problem of an SH.

Determining the demand of system (sum of the demands of SHs and passive end users) that depends on the fluctuated demand of SHs (due to variable power of PV panels and reaction of SHs to the energy management scheme) is one of the challenges of the generation scheduling and UC problems of the GENCO. In addition, modeling the economic and technical constraints of generation units are the others challenges of the GENCO that make the problem a mixed-integer non-LP (MINLP) problem. In this paper, lambda-iteration economic dispatch and GA approaches are applied to solve the generation scheduling and UC problems of the GENCO, respectively.

II. Literature Review and Related Work

Some studies have summarized the existing research on demand response [8], [9]. Demand response is generally referred to the response and reaction of end user customers to the energy management schemes. The study presented in [8] has investigated the coordination of energy efficiency strategy (applying efficient appliances and device) and demand response, and also it has discussed the barriers for this coordination. In [9], the works performed for demand response in the U.S. electric power markets have been investigated.

In [10]–[14], energy management schemes have been investigated on the residential customers. In [10], a proposed controller that curtails peak load and saves electricity cost has been presented. In [11] and [13], an energy hub model (for supplying both electricity and heat demands) for a residential home has been presented. In [12], electricity peak demand reduction during summer, as an energy management scheme, in the Japanese residential sector has been investigated. In [14], the value of incentive is announced to the customers via the wireless sensors, installed in the residential systems, for load reduction. However, in above mentioned studies, the effects of energy management of end users on the generation scheduling problem of a GENCO has not been investigated.

The studies presented in [15]–[18] propose energy management schemes for direct load control of customers in order to increase the penetration of renewable energy resources (wind power) into the power system for different objective functions. In [15], the value of demand that must be shifted from peak period to off peak period is determined by the independent system operator using direct load control to mitigate power transmission congestions and enhance the utilization of wind generation. In this paper, the problem has been defined as a mixed-integer LP to minimize the total operation cost of system. In [16], the elasticity of demand has been considered to adjust the demand profile in response to price changes to increase the amount of wind power that can be economically injected. Also, herein, the wind power uncertainty is managed at a lower cost by adjusting electricity consumption in case of wind forecast errors. In [17] and [18], demand response has been incorporated with wind power to provide more cost-effective carbon emission reduction on a case study based on Texas power system. In these papers, it has been demonstrated that, while wind variability can increase the price, demand response can be an alternative to provide the opposite effect to help reduce that price volatility. Nonetheless, in the above mentioned studies, the energy management schemes have not been investigated in the generation scheduling problem and they have not been studied from a GENCO's point of view.

In [19]–[22], the optimal value of incentive is designed to motivate the end users to reduce their demand at peak period to minimize the daily cost of generation scheduling and UC problems. UC and generation scheduling problems determine the status of each generation unit for being "on" or "off" and the generation level of each unit, respectively. In [19] and [20], the reaction of end users has been modeled based on the price elasticity of demand and their social welfare in the UC and generation scheduling problem. In these papers, linear function has been considered in the benefit function of the end users customers. Also, it has been demonstrated that the cooperation of GENCO with the end users and implementing an optimal scheme of energy management in combined emission and generation scheduling problem has a high potential for reducing cost of power generation and carbon emission level of the thermal power plants. In [21] and [22], nonlinear models for benefit function of the end user customers have been considered in the generation scheduling and UC problems. In these papers, it is concluded that obtaining the minimum cost for system using an unsuitable scheme of demand response program or unrealistic model of responsive load is not possible. In addition, in [22], it is recommended that comprehensive studies and modeling are needed to realistically characterize the responsive end users behavioral model. Nevertheless, in the above mentioned papers, the reaction of end users has been modeled using just some pure mathematical and static models, but the demand of active end users (such as SHs) dynamically changes due to rescheduling of their energy resources (for minimizing their operation cost) and variable power of renewables.

In [23] and [24], the benefits of energy management and demand response have been investigated in the power markets. In [23], the U.S. Department of Energy studied the benefits of implementing demand response programs. These benefits include participant financial benefits (cost savings and incentive payments earned by the customers), market-wide financial benefits (lower wholesale market prices), reliability benefits (operational security and adequacy savings), and market performance benefits (mitigating suppliers' ability to exercise market power on customers). In [24], the impact of demand response on market clearing and locational marginal price of a power system has been investigated. In this paper, demand response has been formulated as the linear price-sensitive demand bidding curves that includes load shifting and load curtailment. Nonetheless, the energy management of SHs has not been investigated in generation scheduling and UC problems of the GENCO. In [25], just a UC problem has been solved without considering demand response.

In [26]–[31], just the energy scheduling problem of an SH has been investigated; however, the effects of energy scheduling of SHs on the generation scheduling and UC problems of a GENCO have not been investigated. In [32], optimal energy retrofit plan has been applied to a real stock of public buildings in Bari, Italy, based on efficiency, sustainability, comfort of occupants, and the available financial resources. In [33], in order to determine the time and value of purchasing electricity from the grid in a cyber-physical system, the real-time grid electricity prices along with the predicted value of demand and supply are utilized in an optimization-based decision maker.

Compared to the previous studies, the presented study in this paper is the first study that considers the interaction between a GENCO and SHs through the price-controlled energy management to maximize the daily profit of the GENCO and minimize the operation cost of each SH.

III. Proposed Technique

The proposed optimization technique for solving the complex problem is a bi-level optimization framework that are presented and described in the following.

A. Proposed Technique for Solving Generation Scheduling and UC Problems of GENCO

1) Price-Controlled Energy Management: For every scheme of price-controlled energy management [modifying the electricity price at peak using ρ^{EM}, as can be seen in (1)] introduced by the GENCO, the SHs react and optimally reschedule their energy resources. Then, the energy scheduling and UC problems of the GENCO are optimally solved. The energy management of SHs is performed for every possible value of ρ^{EM}, and finally the optimal scheme of energy management (optimal value of ρ^{EM}) is determined based on the maximum value of profit of the GENCO over the operation period (one day). Herein, ρ^{EM}, as the variable of price-controlled energy management scheme, can take zero, positive, and negative values. Algorithm 1 presents the pseudo code for finding the optimal scheme of energy management of SHs by the GENCO

$$\widetilde{\pi}_t = \begin{cases} \pi_t + \rho^{\mathrm{EM}} & t \in \text{peak period} \\ \pi_t & t \notin \text{peak period.} \end{cases} \quad (1)$$

Algorithm 1 Pseudo Code for Finding the Optimal Scheme of Energy Management of SHs

1: Set the value of $\rho^{EM} = \rho^{EM}_{MIN}$.
2: $\rho^{EM} = \rho^{EM} + 1$.
3: Update the electricity price ($\widetilde{\pi}$) using (1).
4: SHs react and reschedule their energy resources and change their electricity transaction with the GENCO to minimize their daily operation costs *//Presented in Section III.B.*
5: Update the demand of SHs (D^{SHs}), and consequently demand of system ($D^{SHs} + D^{PASS}$).
6: Solve the generation scheduling and UC problems of the GENCO to maximize its daily profit using GA. *//Presented in Sections III.A.2 and III.A.3.*
7: Go to Step 2, if $\rho^{EM} < \rho^{EM}_{MAX}$
8: Determine optimal value of ρ^{EM} based on the maximum daily profit of GENCO.

2) Optimization Technique for UC Problem of the GENCO: The UC problem is as an optimization problem that determines the statuses of generation units to minimize the overall cost of system considering the operational constraints of generation units and the system. Herein, GA is applied to solve the UC problem of the GENCO. The objective function of the GENCO is maximizing its daily profit that includes income from selling electricity to the customers and cost terms due to fuel cost, emission cost, and start-up and shut-down costs of generation units. Therefore, the GENCO needs to design an optimal price-controlled energy management scheme (optimal scheme of electricity price) to maximize its electricity selling income, and also to optimally schedule its generation units to minimize their operation costs.

Herein, a chromosome is defined as the representative of statuses of the generation units at every hour of the operation period (variable of the problem), as can be seen in Fig. 2. In this regard, "1" means on and "0" means off for each generation unit (G1–G6). Also, the daily profit of GENCO is defined as the fitness of every chromosome, and then the GA tries to maximize the fitness of chromosomes.

In the following, the steps for applying the GA in the UC problem of the GENCO are presented and described. The problem inputs are the hourly demand level of system (sum of hourly demand of passive end users and the updated hourly demand of SHs due to their reaction with respect to the energy

	G1	G2	...	G6
1	0/1	0/1	0/1	0/1
2	0/1	0/1	0/1	0/1
⋮	⋮	⋮	⋮	⋮
24	0/1	0/1	0/1	0/1

Fig. 2. Structure of chromosome in the applied GA for UC problem of the GENCO.

management scheme) and all the technical data of the generation units and problem presented in Table III. Also, the outputs of problem include the optimal generation level of each generation unit at every hour of a day that maximize the daily profit of GENCO.

Step 1 (Obtaining the Primary Data):

1) *Parameters for Applying GA:* These parameters include the mutation probability of the genes (θ^{Mut}) and the size of the population (n_c) as the number of the chromosomes.
2) *Parameters of the System Under Study:* The values of all the parameters of the generation system and problem are obtained (Table III). Also, the value of variable of energy management (ρ^{EM}) is selected.
3) *Updating Demand Level of the End Users:* The demand level of system including sum of demand of passive customers and the updated demand of active customers (SHs) is determined.
4) *Initial Population:* The chromosomes of the population (Fig. 2) are initialized with random binary values (0 or 1).

Step 2 (Updating the Population):

1) *Applying Crossover Operator:* The crossover operator is applied on every two chromosomes to reproduce two new chromosomes as the offspring.
2) *Applying Mutation Operator:* The mutation operator is applied on every gene of every chromosome of the population with the definite probability θ^{Mut}.

Step 3 (Selecting New Population):

1) *Evaluating Fitness of Every Chromosome:* For every chromosome, the generation scheduling problem of the GENCO is solved using lambda-iteration economic dispatch algorithm (presented in Section III-A3) [34] and if all the constraints of problem and system presented in (21)–(28) are satisfied, the fitness (fit_c) of chromosome (the total daily profit of GENCO) is calculated.
2) *Applying Selection Process:* The chromosomes are selected using the probabilistic fitness-based selection (PFBS) technique, where the fitter chromosomes are more likely to be chosen. Herein, r_c is a random number between [0, 100] generated for the chromosome (c)

$$a_c = \begin{cases} 1 & \theta_c^{\text{PFBS}} > r_c \\ 0 & \theta_c^{\text{PFBS}} < r_c. \end{cases} \tag{2}$$

The value of selection probability of every chromosome (θ_c^{PFBS}) is determined using (3), which is proportional to the fitness of the chromosome. Herein, n_c is the number of chromosomes in the population and a_c is the acceptance indicator of a chromosome for the new population

$$\theta_c^{\text{PFBS}} = \frac{\text{fit}_c}{\text{Max}\{\text{fit}_1, \ldots, \text{fit}_{nc}\}} \times 100. \tag{3}$$

Step 4 (Checking Termination Criterion): In this step, the convergence status of the optimization procedure is checked. Based on this, the values of improvement in the fitness of the chromosomes of the old and new populations are computed and if there is no significant improvement in them, the optimization process is finished, otherwise, the algorithm is continued from step 2.

Step 5 (Introducing the Outcome): The consequences include the maximum value of daily profit of GENCO, the optimal commitment status and optimal generation level of units at every hour of the day.

3) Optimization Technique for Generation Scheduling Problem of the GENCO Using Lambda-Iteration Economic Dispatch: Herein, the status of generation units (determined by the GA in Section III-A2) and the demand level of system and all the technical data of generation units (presented in Table III) are the input of problem. Moreover, the outputs include the optimal generation level of each generation unit at every hour of the day.

When the statuses of generation units are determined by GA, lambda-iteration economic dispatch method [34] is applied to solve the generation scheduling problem of the GENCO. The lambda-iteration economic dispatch includes finding the real power generation for each generation unit to minimize the total cost of the generation system subject to the equality constraint (supply demand balance constraint) and inequality constraints (upper and lower power limits of every generation units) [34]. Herein, P, Cost^F, and Cost^E are the power level, fuel cost, and emission cost of a generation unit, respectively. Also, D is the total demand of system. In addition, g and Ng are the indices of a generation unit and total number of units of the GENCO, respectively

$$\min \left\{ \sum_{g=1}^{Ng} \text{Cost}_{g,t}^F + \text{Cost}_{g,t}^E \right\} \tag{4}$$

$$\text{subject to} \sum_{g=1}^{Ng} P_{g,t} = D_t. \tag{5}$$

The lambda-iteration economic dispatch method considers the equality constraint and solves the generation scheduling problem iteratively using the Lagrangian multipliers, as can be seen in (6)–(8). The marginal generation cost of system (λ) is the change in the total cost that arises when the amount of electricity produced is incremented by one power unit (1 MW). Herein, λ is a variable and its optimal value results in the minimum cost of problem

$$L_t = \sum_{g=1}^{Ng} \left(\text{Cost}_{g,t}^F + \text{Cost}_{g,t}^E \right) + \lambda \times \left(D_t - \sum_{g=1}^{Ng} P_{g,t} \right) \tag{6}$$

$$\frac{\partial L_t}{\partial P_{g,t}} = 0, \quad \forall g \tag{7}$$

$$\frac{\partial L_t}{\partial \lambda} = 0, \quad \forall g. \tag{8}$$

This article has been accepted for inclusion in a future issue of this journal. Content is final as presented, with the exception of pagination.

Solving (6)–(8) result in (9) and (10)

$$\sum_{g=1}^{Ng} P_{g,t} = D_t \tag{9}$$

$$\frac{\partial\left(\mathrm{Cost}_{g,t}^{F} + \mathrm{Cost}_{g,t}^{E}\right)}{\partial P_{g,t}} = \lambda, \quad \forall g. \tag{10}$$

The generation units have minimum and maximum limits on their generation level that must be considered in the generation scheduling problem. Herein, the Kuhn–Tucker conditions [presented in (11)] complete the Lagrangian multipliers by adding the inequality constraints (minimum and maximum generation limits of every UNIT) as the additional terms, as can be seen in (11) [34]

$$\begin{cases} \dfrac{\partial\left(\mathrm{Cost}_{g,t}^{F} + \mathrm{Cost}_{g,t}^{E}\right)}{\partial P_{g,t}} \le \lambda \quad P_{g,t} = P_g^{\max} \\ \dfrac{\partial\left(\mathrm{Cost}_{g,t}^{F} + \mathrm{Cost}_{g,t}^{E}\right)}{\partial P_{g,t}} = \lambda \quad P_g^{\min} \le P_{g,t} \le P_g^{\max} \\ \dfrac{\partial\left(\mathrm{Cost}_{g,t}^{F} + \mathrm{Cost}_{g,t}^{E}\right)}{\partial P_{g,t}} \ge \lambda \quad P_{g,t} = P_g^{\min}. \end{cases} \tag{11}$$

By solving equality constraints [presented in (9) and (10)] and inequality constraint [presented in (11)], the lambda-iteration economic dispatch method outputs the optimal generation level of each generation unit.

B. Proposed Technique for Solving Energy Scheduling Problem of SH

In the following, different parts of the proposed technique for solving energy scheduling problem of an SH is presented.

1) Scenario-Based Stochastic Optimization: In this paper, in order to address the uncertainty and variability concerned with the power of PV panels, a scenario-based stochastic optimization approach is applied. Herein, a large number of effective and diverse scenarios are comprehensively defined for addressing the predictions uncertainties.

a) Forecasting value of uncertain states: The power of PV panels depends on the value of solar irradiance that it absorbs. However, solar irradiance has a large degree of variability and uncertainty. Herein, based on the historical values of solar irradiances, the value of solar irradiances (ρ) over the optimization time horizon [for every 5-min step of the next 2 h (n_τ is 24)] are predicted using the neural network available in MATLAB. The historical data of the solar irradiances are the real solar irradiances recorded in Clemson, SC, USA, in July 2014. About 70% of the data is used for training the neural network and 30% of the data is used for validation and testing. The set of predicted solar irradiances ($\widetilde{\rho}$) are presented in (12). Herein, 288 5-min steps indicate one day as the operation period

$$\left\{\widetilde{\rho}_{t+1}, \ldots, \widetilde{\rho}_{t+n_\tau}\right\}, n_\tau = 24, t \in T, T = \{1, \ldots, 288\}. \tag{12}$$

b) Modeling uncertainties of forecasted data: Fig. 3 illustrates the predicted and measured solar irradiances for the current time step (t, with a 5-min time duration) and past time steps $(1, 2, \ldots, t-1)$, and also the predicted solar irradiances for every time step of the optimization time horizon $(t+1, \ldots, t+n_\tau)$. The previously forecasted solar irradiances ($\widetilde{\rho}$) are compared with the real solar irradiances (measured data) and the values of error of the predictions are calculated. Next, the mean value of the prediction errors (μ^{Er}) is calculated. The value of μ^{Er} is updated in the next predictions in the optimization procedure of the problem over the operation period $(1, 2, \ldots, t, \ldots, 288)$.

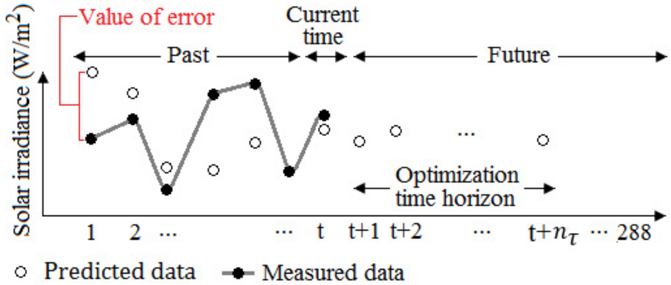
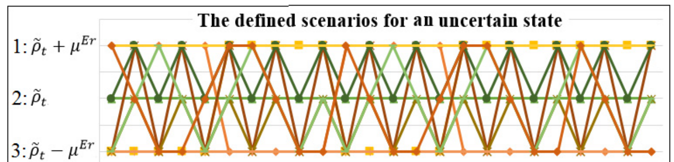


Fig. 3. Predicted data, measured data, and value of the prediction error.



	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	3	3	3	3	3	1	1	1	1	1	3	3	3	3	3	1	1	1	1	1	1	1	1	1
2	1	1	1	1	1	3	3	3	3	3	1	1	1	1	1	3	3	3	3	3	3	3	3	3
3	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
4	1	3	1	3	1	3	1	3	1	3	1	3	1	3	1	3	1	3	1	3	1	3	1	3
5	1	2	1	2	1	2	1	2	1	2	1	2	1	2	1	2	1	2	1	2	1	2	1	2
6	2	3	2	3	2	3	2	3	2	3	2	3	2	3	2	3	2	3	2	3	2	3	2	3
7	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
8	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3
9	1	2	3	2	1	2	3	2	1	2	1	2	3	2	1	2	3	2	1	2	3	2	1	2
10	3	2	1	1	2	3	3	2	1	1	3	2	1	1	2	3	3	2	1	1	3	2	1	1

Fig. 4. Defined scenarios for the uncertain state of the problem (solar irradiance) at every time step (every 5 min) over the optimization time horizon (next 2 h).

The important factor in defining the scenarios is comprehensively considering the most probable values for the estimated solar irradiances over the optimization time horizon. In other words, the defined scenarios should consider almost all the possibilities for the estimated values of uncertain state of the problem, and also they should have diversity (no similarity). Herein, the estimated values of solar irradiance are considered to be about under, equal to, and above its predicted values ($\widetilde{\rho}_t + \mu^{\mathrm{Er}}$, $\widetilde{\rho}_t$, $\widetilde{\rho}_t - \mu^{\mathrm{Er}}$), as the most logical values. In addition, it is considered that the estimated values can be changed over the time steps of optimization time horizon. Based on this, ten diverse scenarios ($s \in S, S = \{1, \ldots, n_s\}, n_s = 10$) are defined for the estimated solar irradiances with equal occurrence probabilities (Ω^{PV}), that is, each 10%. Fig. 4 shows the defined scenarios for the uncertain state of the problem (solar irradiance) at every time step (every 5 min) over the optimization time horizon (next 2 h). In this figure, the codes 1, "2," and "3" represent $\widetilde{\rho}_t + \mu^{\mathrm{Er}}$, $\widetilde{\rho}_t$, and $\widetilde{\rho}_t - \mu^{\mathrm{Er}}$, respectively.

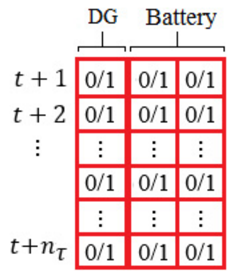


Fig. 5. Structure of defined chromosome in the applied GA.

In fact, at every time step (t), the problem is solved ten times and every time, one of the scenarios is applied for the value of solar irradiances, and finally the operation cost of SH is calculated as the expected value of operation costs of the ten scenarios.

C. Optimization Technique for Energy Scheduling of SH

Herein, the demand level of SH and all the technical data of energy resources of SH (DG, battery, and PV panels) presented in Table I and Figs. 7–10 are the input of problem and the outputs include the optimal generation level of energy resources and optimal electricity transaction of SH with GENCO.

The energy scheduling problem of the SH is an MINLP problem. The discrete variables of the problem and the continuous variables of the problem are presented in (13) and (14), respectively. Herein, x^{DG} and x^{B} are the status of DG and battery and P^{DG}, P^{B}, and P^{Grid} are the power of DG, power of battery, and power transacted between the SH and GENCO. The values of 0 and 1 for x^{DG} mean off and on, respectively. Also, the values of "-1," "0," and 1 for x^{B} mean charging, idle, and discharging, respectively

$$\left\{\begin{matrix} x_t^{\text{DG}} & \cdots & x_{t+n_\tau}^{\text{DG}} \\ x_t^{B} & \cdots & x_{t+n_\tau}^{B} \end{matrix}\right\} \tag{13}$$

$$\left\{\begin{matrix} P_t^{\text{DG}} & \cdots & P_{t+n_\tau}^{\text{DG}} \\ P_t^{B} & \cdots & P_{t+n_\tau}^{B} \\ P_t^{\text{Grid}} & \cdots & P_{t+n_\tau}^{\text{Grid}} \end{matrix}\right\}. \tag{14}$$

In this paper, similar to the optimization technique presented in this paper, GA-LP technique as the combination of GA and LP is applied to solve the energy scheduling problem of the SH. Based on this, the dimensions of chromosome defined in the GA are $n_\tau \times 3$, as can be seen in Fig. 5. Herein, one bit (gene) for indicating the status of DG (0 for off and 1 for on) and 2 bits for indicating the status of battery ("00" and "10" for idle, "01" for discharging, and "11" for charging) are considered. The procedure for applying GA in the energy scheduling problem of an SH is similar to one presented in Section III-A2.

IV. Mathematical Formulation

In this section, the mathematical formulations for UC problem of a GENCO and energy scheduling problem of an SH are presented.

A. Mathematical Formulation for UC Problem of GENCO

1) Objective Function of GENCO: The objective function of the GENCO over the operation period (one day) is presented in (15). As can be seen, it includes income due to selling electricity to the customers, 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

$$\text{OF} = \max \sum_{t=1}^{Nt} \left[\text{Income}_t^{\text{SELL}} - \sum_{g=1}^{Ng} \left[\begin{matrix} \text{Cost}_{g,t}^{F} + \text{Cost}_{g,t}^{E} \\ + \text{Cost}_{g,t}^{\text{STU}} + \text{Cost}_{g,t}^{\text{SHD}} \end{matrix} \right] \right]. \tag{15}$$

2) Income and Cost Terms of GENCO: In the following, the income and cost terms of the objective function are described.

a) Income of GENCO due to selling electricity: The income term is related to the selling electrical energy to all the end users. Thus, the income term depends on the values of demand of passive customers (D_t^{PASS}), demand of SHs (D_t^{SHs}), and the price of electricity at every hour of a day. The value of $\widetilde{\pi}_t$, as the updated value of electricity price at every hour of the day, has been defined in (1)

$$\text{Income}_t^{\text{SELL}} = \sum_{t=1}^{Nt} \left[D_t^{\text{PASS}} + D_t^{\text{SHs}} \right] \times \widetilde{\pi}_t. \tag{16}$$

b) Fuel cost of generation units: The fuel cost of every generation unit (Cost^{F}) is a quadratic polynomial of power unit (P) [6], [34]. In other words, the generation unit consumes more fuel per power unit when its power is in the upper level compared to the value of consumed fuel per power unit in the lower level. α_1^F, α_2^F, and α_3^F are fuel cost coefficients of the generation unit and g is index of a generation unit

$$\text{Cost}_{g,t}^{F} = \alpha_{1,g}^{F} \times \left(P_{g,t}\right)^2 + \alpha_{2,g}^{F} \times \left(P_{g,t}\right) + \alpha_{3,g}^{F}. \tag{17}$$

c) Greenhouse gas emissions cost of generation units: The greenhouse gas emissions cost of every generation unit is a quadratic polynomial of power unit (P) [6], [34]. α_1^E, α_2^E, and α_3^E are emission coefficients of the generation unit and β^E is emission cost factor

$$\text{Cost}_{g,t}^{E} = \beta^{E} \times \left(\alpha_{1,g}^{E} \times \left(P_{g,t}\right)^2 + \alpha_{2,g}^{E} \times \left(P_{g,t}\right) + \alpha_{3,g}^{E}\right). \tag{18}$$

d) Start-up cost and shut-down cost of generation units: The start-up cost of a de-committed unit (Cost^{STU}) and shut-down cost of a committed unit (Cost^{SHD}) at every hour of the operation period are presented in (19) and (20), respectively. In other words, starting a generation unit up or shutting a generation unit down is not free and imposes costs about C^{STU} and C^{SHD}, respectively. Herein, x^{G} indicates the status of generation unit, where 1 and 0 mean on and off, respectively

$$\text{Cost}_{g,t}^{\text{STU}} = C_g^{\text{STU}} \times \left(1 - x_{g,t-1}^{G}\right) \times x_{g,t}^{G} \tag{19}$$

$$\text{Cost}_{g,t}^{\text{SHD}} = C_g^{\text{SHD}} \times x_{g,t-1}^{G} \times \left(1 - x_{g,t}^{G}\right). \tag{20}$$

3) Constraints of System in Operation Problem: In the following, the system and generation units' constraints are presented and explained.

a) 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 as follows:

$$\sum_{g=1}^{Ng} P_{g,t} \times x_{g,t}^{G} = D_t^{\mathrm{PASS}} + D_t^{\mathrm{SHs}}. \tag{21}$$

b) System minimum generation constraint: The constraint of minimum power of the system generated by the on units for every hour of the operation period is presented as follows:

$$\sum_{g=1}^{Ng} P_g^{\min} \times x_{g,t}^{G} \leq D_t^{\mathrm{PASS}} + D_t^{\mathrm{SHs}}. \tag{22}$$

c) System maximum generation constraint considering spinning reserve: The maximum generation of the power system considering spinning reserve level (SR) provided by the *on* units for every hour of the operation period is presented as follows:

$$\sum_{g=1}^{Ng} P_g^{\max} \times x_{g,t}^{G} \geq D_t^{\mathrm{PASS}} + D_t^{\mathrm{SHs}} + \mathrm{SR}_t. \tag{23}$$

d) Generation units' power constraint: The maximum and minimum power constraints of every generation unit at every hour of the operation period is presented as follows:

$$P_g^{\min} \leq P_{g,t} \leq P_g^{\max}. \tag{24}$$

e) Generation units' ramp-up rate and ramp-down rate constraints: The ramp-up rate (RUR) and ramp-down rate (RDR) constraints of every generation unit at every hour of the operation period are presented as follows, respectively:

$$\left(P_{g,t+1} - P_{g,t}\right) \leq \mathrm{RUR}_g \tag{25}$$

$$\left(P_{g,t} - P_{g,t+1}\right) \leq \mathrm{RDR}_g. \tag{26}$$

f) Generation units' minimum "off time" and minimum "on time" constraints: The minimum off time (MDT) and minimum on time (MUT) constraints of every generation unit at every hour of the operation period are presented as follows:

$$\mathrm{OFFT}_{g,t} \geq \mathrm{MDT}_g \tag{27}$$

$$\mathrm{ONT}_{g,t} \geq \mathrm{MUT}_g. \tag{28}$$

B. Mathematical Formulation for Energy Scheduling of SH

1) Objective Function of SH: As can be seen in (29), the objective function (OF) of an SH is minimizing operation cost terms in every scenario ($s \in S$) weighted by the corresponding occurrence probability (Ω^{PV}) over the optimization time horizon (next 2 h). In other words, the optimization problem is solved for every scenario of power (solar irradiance) of PV panels [presented in (12) and Fig. 4] and then the value of cost terms are multiplied with the value of probability of scenario. The cost terms include fuel cost of DG (C^{F_DG}), emission cost of DG (C^{E_DG}), start-up cost of DG ($C^{\mathrm{STU\_DG}}$), shut-down cost of DG ($C^{\mathrm{SHD\_DG}}$), switching cost of battery ($C^{\mathrm{SW\_}B}$), and the value of income or cost due to electricity transaction with GENCO ($P^{\mathrm{Grid}} \times \acute{\pi}$)

$$\mathrm{OF} = \min\left\{\sum_{s\in S} \Omega_{t,s}^{\mathrm{PV}} \times \sum_{t=1}^{n_\tau} \left\{\begin{array}{l} \left[C_{t,s}^{F\_\mathrm{DG}}\right] + \left[C_{t,s}^{E\_\mathrm{DG}}\right] \\ + \left[\left(1 - x_{t-1,s}^{\mathrm{DG}}\right) \times x_{t,s}^{\mathrm{DG}} \times C^{\mathrm{STU\_DG}}\right] \\ + \left[x_{t-1,s}^{\mathrm{DG}} \times \left(1 - x_{t,s}^{\mathrm{DG}}\right) \times C^{\mathrm{SHD\_DG}}\right] \\ + \left[\acute{x}_{t,s}^{B} \times C^{\mathrm{SW\_}B}\right] + \left[P_{t,s}^{\mathrm{Grid}} \times \acute{\pi}_{t,s}\right] \end{array}\right\}\right\} \tag{29}$$

where

$$\acute{x}_{t,s}^{B} = \begin{cases} 0 & x_{t-1,s}^{B} = x_{t,s}^{B} \\ 1 & x_{t-1,s}^{B} \neq x_{t,s}^{B} \end{cases} \tag{30}$$

$$\acute{\pi}_{t,s}^{\mathrm{GENCO}} = \begin{cases} \pi_t^{\mathrm{GENCO}} & P_{t,s}^{\mathrm{Grid}} > 0 \\ \varphi \times \pi_t^{\mathrm{GENCO}} & P_{t,s}^{\mathrm{Grid}} < 0. \end{cases} \tag{31}$$

The switching of battery ($\acute{x}^{B}$) is determined using (30). If the status of battery in the current time step (x_t^{B}) is the same as the previous time step (x_{t-1}^{B}), the switching indicator is zero; otherwise, it is one.

In (31), φ is the coefficient applied by the GENCO to determine the price of selling power to the GENCO by an SH based on the net energy metering (NEM) plan [7]. In the NEM plan, every SH can deliver its extra power to the grid and sell it to the GENCO at a lower price compared to the purchasing price from the GENCO [7]. Herein, $P^{\mathrm{Grid}} > 0$ means that the SH purchases power from the GENCO and $P^{\mathrm{Grid}} < 0$ means that the SH sells power to the GENCO.

The fuel cost function and carbon emissions function of every DG are quadratic polynomials presented in (32) and (33), respectively [6], [34]. Herein, the set of z_1^F, z_2^F, z_3^F and z_1^E, z_2^E, z_3^E are the fuel cost coefficients and carbon emissions coefficients of the DG, respectively. Also, β^E is the value of penalty for carbon emissions

$$C_{t,s}^{F\_\mathrm{DG}} = z_1^F \times \left(P_{t,s}^{G}\right)^2 + z_2^F \times \left(P_{t,s}^{G}\right) + z_3^F \tag{32}$$

$$C_{t,s}^{E\_\mathrm{DG}} = \beta^E \times \left(z_1^E \times \left(P_{t,s}^{G}\right)^2 + z_2^E \times \left(P_{t,s}^{G}\right) + z_3^E\right). \tag{33}$$

The value of switching cost of the battery is determined based on the value of total cumulative ampere-hours throughput of the battery (ξ^B) in its life cycle and the value of the initial price of the battery (Pr^B). In fact, considering this cost term prevents the battery from unnecessary switching that is harmful to its life span

$$C^{\mathrm{SW\_}B} = \frac{\mathrm{Pr}^{B}{}^{B}}{\xi}. \tag{34}$$

2) Constraints of the Problem: In the following, the constraints of problem that must be held in every SH and at every time step of the operation period are presented and described.

This article has been accepted for inclusion in a future issue of this journal. Content is final as presented, with the exception of pagination.

a) Supply demand balance: The sum of power of the DG, the power of the PV panels, the power of the battery, and the transacted power with the GENCO through the grid must be equal to load demand (P^L) for every SH and in each time step of the operation period

$$\left(x_{t,s}^{\mathrm{DG}} \times P_{t,s}^{\mathrm{DG}}\right) + \left(x_{t,s}^{B} \times P_{t,s}^{B}\right) + P_{t,s}^{\mathrm{PV}} + P_{t,s}^{\mathrm{Grid}} = P_t^L. \quad (35)$$

The output power of the PV panels (P^{PV}) is a nonlinear function of the estimated solar irradiance (ρ), as can be seen in (36) [35]. Herein, ρ^{st} and ρ^{c} are the solar irradiance in the standard environment set as 1000 W/m^2 and certain solar irradiance point set as 150 W/m^2. Also, $\overline{P^{\mathrm{PV}}}$ indicates the rated power of the PV panels

$$P_{t,s}^{\mathrm{PV}} = \begin{cases} \overline{P^{\mathrm{PV}}} \times \frac{(\rho_{t,s})^2}{\rho^{st} \times \rho^{c}} & \rho_{t,s} \le \rho^{c} \\ \overline{P^{\mathrm{PV}}} \times \frac{\rho_{t,s}}{\rho^{st}} & \rho_{t,s} > \rho^{c}. \end{cases} \quad (36)$$

b) Power limits of the DG: The maximum power limit ($\overline{P^{\mathrm{DG}}}$) and minimum power limit ($\underline{P^{\mathrm{DG}}}$) of a DG are presented in (37). In other words, the DG cannot generate power beyond the limits

$$\underline{P^{\mathrm{DG}}} \le P_{t,s}^{\mathrm{DG}} \le \overline{P^{\mathrm{DG}}}. \quad (37)$$

c) Minimum up/down time limits of the DG: The duration that the DG is continuously on ($\triangle t^{\mathrm{DG\_ON}}$) and off ($\triangle t^{\mathrm{DG\_OFF}}$) must be more than the rated minimum up time ($\mathrm{MUT}^{\mathrm{DG}}$) and minimum down time ($\mathrm{MDT}^{\mathrm{DG}}$), as can be seen in (38) and (39), respectively. In other words, the DG cannot be started up immediately after it has been shut down and vice versa. Also, the time interval that the DG is continuously on (or off) is determined based on the time that has passed from the last start-up time (or shut-down time) of the DG

$$\triangle t_s^{\mathrm{DG\_ON}} \ge \mathrm{MUT}^{\mathrm{DG}} \quad (38)$$
$$\triangle t_s^{\mathrm{DG\_OFF}} \ge \mathrm{MDT}^{\mathrm{DG}}. \quad (39)$$

d) Power limits of the battery: The battery can act as a load or generator by being charged or discharged, respectively; however, the value of power of the battery must be in the rated range, as can be seen in (40). Herein, $\overline{P^B}$ is the value of rated power of the battery

$$-\overline{P^B} \le P_{t,s}^{B} \le \overline{P^B}. \quad (40)$$

e) Depth of discharge limit of the battery: In order to prolong the life time of the battery, the battery must not be discharged more than the allowable depth of discharge (DOD). Moreover, the battery has a definite capacity that cannot be charged more than that, as can be seen in the following equation:

$$\mathrm{DOD}^B \le \mathrm{SOC}_{t,s}^{B} \le 100. \quad (41)$$

V. Simulation and Results

All the simulations are conducted in MATLAB environment using an Intel Xeon Sever with 64-GB RAM. The number of chromosomes in the population (n_c) and the value of mutation probability of the genes (θ^{Mut}) in the applied GA are considered about 100% and 10%, respectively.

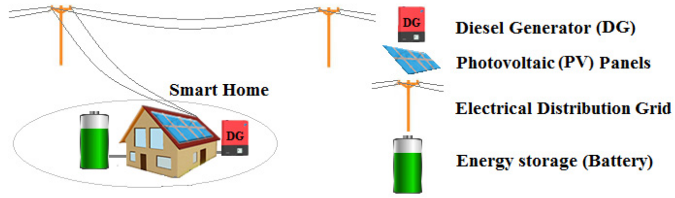


Fig. 6. Structure an SH that includes different energy resources.

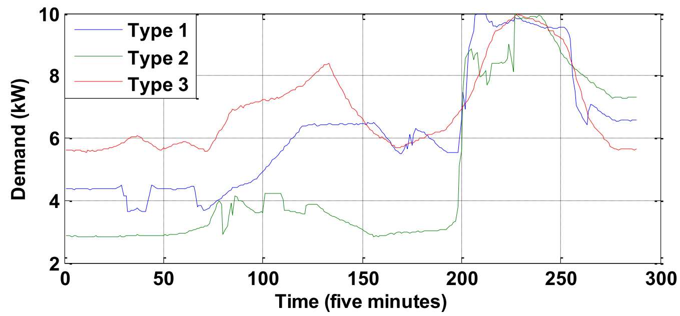


Fig. 7. Demand level (kW) of SHs with types 1–3 at every 5-min step of the operation period (one day).

A. Energy Scheduling Problem of the SHs

1) Characteristics of the SHs: Fig. 6 illustrates the structure of an SH that includes PV panels installed on the roof of SH, an energy storage like a battery, DG, and access to the electrical distribution grid. The technical data of three types of SHs are presented in Table I. The value of penalty for carbon emissions (β^E) in Table I is based on the introduced value by California Air Resources Board auction of greenhouse gas emissions [36]. Also, Cap^B indicates the value of capacity of the battery.

Fig. 7 shows demand level of SHs (types 1–3). Moreover, the forecasted power pattern for the PV panels of the SHs (types 1–3) at every 5-min step of the operation period (one day) are shown in Figs. 8–10, respectively. As can be seen, the amount of generated power of PV panels is zero in some period of time due to nightfall. The mean value of prediction errors (μ^{Er}) related to the solar irradiances is considered about 10%.

In addition, Fig. 11 illustrates the electricity price proposed by the GENCO at every hour of the operation period (before energy management). Herein, the hourly electricity prices introduced to the end users are 10% more than hourly marginal cost of the generation system, as the hourly profit of the GENCO. Considering the demand level of all end users presented in Fig. 12, the marginal cost of generation system are determined by solving the generation scheduling and UC problems of the GENCO before energy management of SHs. The updated electricity price (due to implementing energy management) will be determined based on (1) and the initial electricity price (presented in Fig. 11).

2) Results: Table II presents the daily operation cost of SHs before price-controlled energy management. In addition, Figs. 13 and 14 illustrate the optimal schedule of energy sources before energy management of SHs for types 1 and 3, respectively. As can be seen, the DGs are started up and

This article has been accepted for inclusion in a future issue of this journal. Content is final as presented, with the exception of pagination.

TABLE I
TECHNICAL DATA OF SHs WITH DIFFERENT TYPES OF SOURCES

-	Parameter	Unit	Type 1	Type 2	Type 3
DG	z_1^F	¢/kWh^2	0.324	0.491	0.843
	z_2^F	¢/kWh	41.66	40.85	46.04
	z_3^F	¢	0	0	0
	z_1^E	kg/kWh^2	0.07	0.08	0.09
	z_2^E	kg/kWh	1.39	1.61	1.94
	z_3^E	kg	0	0	0
	$\underline{P^{DG}}$	kW	15	10	5
	$\overline{P^{DG}}$	kW	40	30	20
	MUT^{DG}	Minute	10	10	10
	MDT^{DG}	Minute	10	10	10
	C^{STU_DG}	\$	1	1	1
	C^{SHD_DG}	\$	1	1	1
	β^E	¢/kg	1		
Battery	$\overline{P^B}$	kW	10		
	Cap^B	kWh	200		
	DOD^B	%	20		
	Pr^B	\$	20,000		
	ξ^B	Ah	100,000		
PV panels	$\overline{P^{PV}}$	kW	10		
Access to grid	P^{Grid}	kW	Yes		
	φ	-	0.8		
Number of SHs			5000	5000	5000

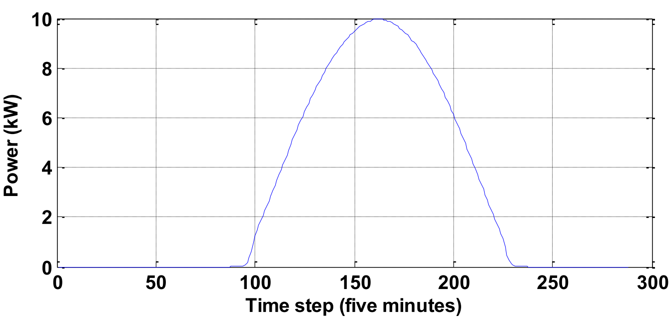


Fig. 8. Forecasted power pattern for the PV panels (type 1) in a purely sunny day at every 5-min step of the operation period (one day).

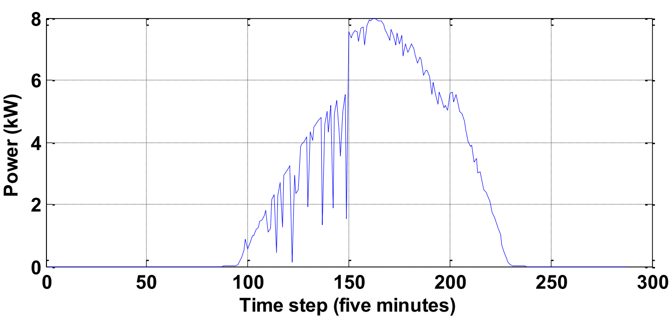


Fig. 9. Forecasted power pattern for the PV panels (type 2) in a cloudy day at every 5-min step of the operation period (one day).

shut down and batteries are switched into charging/discharging modes throughout the operation period; however, the DG of SH with type 1 is applied more than the DG of SH with type 3, since the DG of SH 1 generates electricity in lower cost. Also, as can be seen in Table II, the SH with type 2 and the SH with type 3 has the least and the most daily operation costs, respectively. The optimal schedule of energy resources of SHs

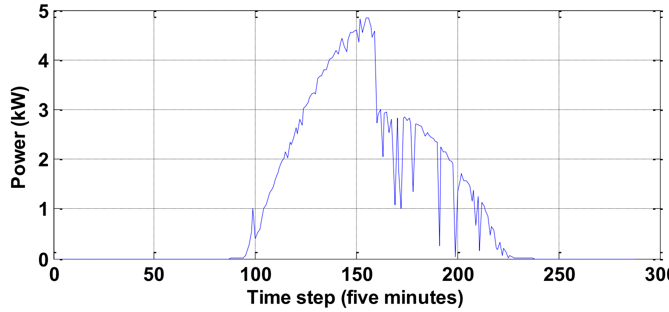


Fig. 10. Forecasted power pattern for the PV panels (type 3) in a cloudy day at every 5-min step of the operation period (one day).

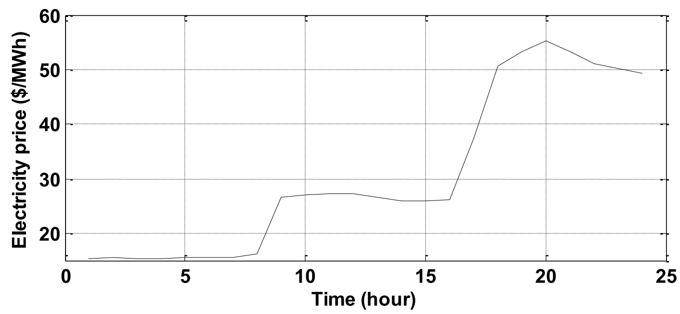


Fig. 11. Electricity price proposed by the GENCO at every hour of the operation period (one day), before energy management.

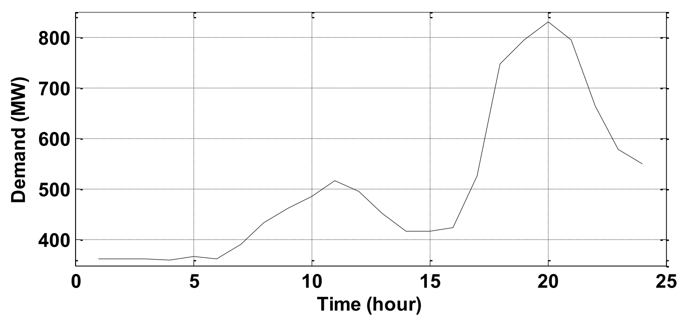


Fig. 12. Hourly demand level of end users (MW).

TABLE II
DAILY OPERATION COST (\$) OF SHs BEFORE ENERGY MANAGEMENT

	SH (Type 1)	SH (Type 2)	SH (Type 3)
Operation cost (\$/day)	17.07	14.23	29.11

after implementation of optimal energy management scheme will be shown in Figs. 18 and 19.

B. Generation Scheduling and UC Problems of the GENCO

1) Characteristics of the Generation System: The technical characteristics of the generation units including the fuel cost coefficient of generation units, the emission coefficient of generation units, the power limits of units, the minimum up/down time of units, the ramp up rate and ramp down rate of units, the start-up cost and shut-down cost of units, and the initial status of units are presented in Table III. Positive and negative numbers for the status of units mean on and off, respectively.

Moreover, the minimum value of spinning reserve at every hour of a day is assumed to be 10% of demand at the

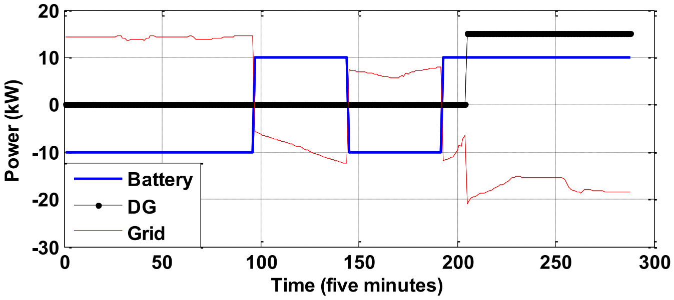


Fig. 13. Demand level and the optimally scheduled power of DG and battery at every 5-min step of the operation period (one day) for an SH with type 1 (before EM).

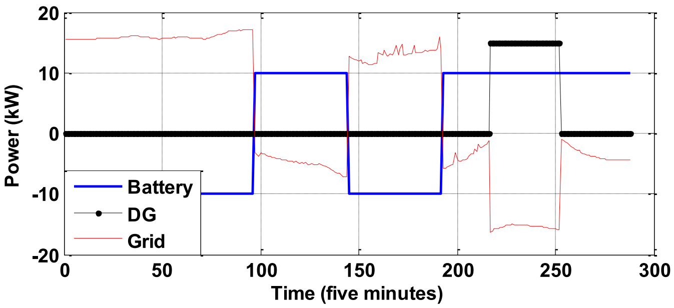


Fig. 14. Demand level and the optimally scheduled power of DG and battery at every 5-min step of the operation period (one day) for an SH with type 3 (before EM).

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 [36]. The number of chromosomes of GA (for indicating the status of generation units over the operation period) in the population (n_c) and the value of mutation probability of genes (θ^{Mut}) are considered to be 100% and 10%, respectively.

2) Results:

a) Without energy management: Table IV presents the generation level of units at every hour of the operation period (one day) before energy management. As can be seen, generators G1–G5 as the least expensive generation units are operated all the day, while G6 as the most expensive and pollutant generation unit is utilized just in a short period of time. In this condition, the daily profit of GENCO is determined about \$6684. Fig. 15 illustrates the convergence trend for the optimization problem of the GENCO before EM. Herein, the value of fitness of the best chromosome of the population as the daily profit of the GENCO (\$) is shown. As can be seen, the trend is leveled after 84 times updating.

b) With optimal energy management: After optimal price-controlled energy management of responsive end users (SHs), it is realized that the optimal scheme of energy management is considering −3 \$/MWh for the value of ρ^{EM}, as is shown in Fig. 16. In other words, the electricity prices should be decreased at peak period instead of being increased. In this condition (implementation of optimal scheme of price-controlled energy management), the daily profit of GENCO is calculated about \$14 243/day, which has 113% increase compared to before energy management. In fact, although the

TABLE III
TECHNICAL CHARACTERISTICS OF THE GENERATION UNITS

-	G1	G2	G3	G4	G5	G6
α_1^F (\$/MWh^2)	0.00048	0.00031	0.00200	0.00211	0.00398	0.00712
α_2^F (\$/MWh)	16.19	17.26	16.60	16.50	19.70	22.26
α_3^F (\$)	1000	970	700	680	450	370
α_1^E(Ton/MWh^2)	0.0005	0.0005	0.0005	0.0005	0.0010	0.0020
α_2^E (Ton/MW)	0.4050	0.4320	0.4150	0.4120	0.4930	0.5560
α_3^E (Ton)	0.3000	0.4250	0.4500	0.7000	0.7250	0.9250
P^{min} (MW)	75	75	15	15	15	10
P^{max} (MW)	200	200	120	100	100	80
MUT (h)	5	5	5	5	5	3
MDT (h)	-5	-5	-5	-5	-5	-3
RUR (MW/h)	125	125	120	75	50	10
RDR (MW/h)	125	125	120	75	50	10
C^{STU} (\$)	4500	5000	550	560	900	170
C^{SHD} (\$)	4500	5000	550	560	900	170
Initial status	+24	+24	+24	+24	+24	-7

TABLE IV
GENERATION LEVEL OF UNITS (MW) BEFORE ENERGY MANAGEMENT

Hour	G1	G2	G3	G4	G5	G6
1	200	143	120	100	15	0
2	200	144	120	100	15	0
3	200	143	120	100	15	0
4	200	142	120	100	15	0
5	200	150	120	100	15	0
6	200	145	120	100	15	0
7	200	176	120	100	15	0
8	200	200	120	100	33	10
9	158	75	51	69	15	10
10	160	75	52	70	15	10
11	169	75	59	77	15	0
12	152	75	46	64	15	0
13	200	150	120	100	15	0
14	200	104	120	100	15	0
15	200	112	120	100	15	0
16	200	132	120	100	15	0
17	172	75	62	79	15	0
18	200	101	120	100	15	0
19	200	110	120	100	15	0
20	200	169	120	100	15	0
21	200	126	120	100	15	0
22	200	75	94	100	15	0
23	164	75	56	73	15	0
24	200	103	15	15	15	0

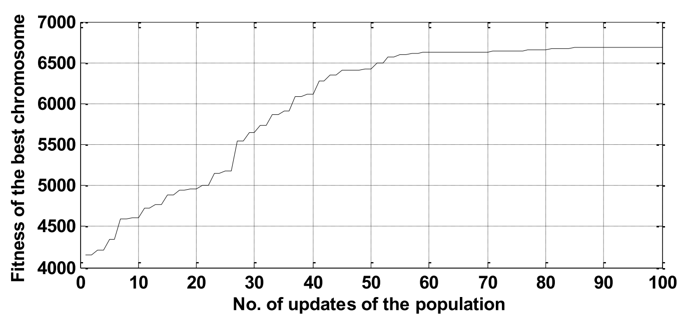


Fig. 15. Convergence trend for the optimization problem of GENCO before EM.

electricity is sold at the lower prices at peak period, the overall profit of GENCO is increased due to selling more electrical energy to the active end users (SHs).

The generation level of units at every hour of the operation period after optimal energy management scheme ($\rho^{\mathrm{EM}} =$

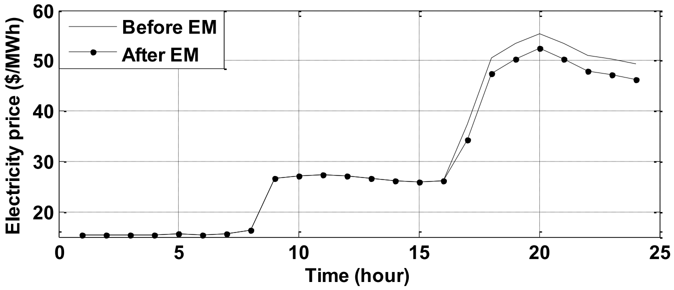


Fig. 16. Electricity price proposed by the GENCO before and after optimal energy management at every hour of the operation period (one day).

TABLE V
GENERATION LEVEL OF UNITS (MW) AFTER OPTIMAL ENERGY MANAGEMENT

Hour	G1	G2	G3	G4	G5	G6
1	200	143	120	100	15	0
2	200	144	120	100	15	0
3	200	143	120	100	15	0
4	200	142	120	100	15	0
5	200	150	120	100	15	0
6	200	145	120	100	15	0
7	200	176	120	100	15	0
8	200	200	120	100	33	10
9	158	75	51	69	15	10
10	160	75	52	70	15	10
11	169	75	59	77	15	0
12	152	75	46	64	15	0
13	200	150	120	100	15	0
14	200	104	120	100	15	0
15	200	112	120	100	15	0
16	200	132	120	100	15	0
17	172	75	62	79	15	0
18	200	200	120	100	56	10
19	200	175	120	100	15	10
20	200	200	120	100	49	10
21	200	200	120	100	16	0
22	200	199	120	100	15	0
23	200	98	120	100	15	0
24	200	184	15	85	15	0

−3 $/MWh) are presented in Table V. As can be seen, the generation level of all the units are increased and even the most expensive and pollutant unit (G6) is started up and applied in some hours of the peak period. The reason is related to decreasing the utilization of DGs of SHs (as can be seen in Figs. 18 and 19) and increasing electricity purchase from the GENCO due lower price proposed by the GENCO. The demand level of passive end users (with constant demand pattern) and active end users (SHs) before and after optimal energy management, and also the total demand of system before and after optimal energy management at every hour of the operation period (one day) are shown in Fig. 17. The demand of SHs and the total demand of system before and after energy management are overlapped between 1 and 17 h. By looking at Figs. 18 and 19, it is realized that SH (type 1) decreases the utilization of its DG and SH (type 3) shuts down its DG in the whole operation period.

Table VI presents the daily operation cost of SHs (with different types) and daily profit of GENCO before and after

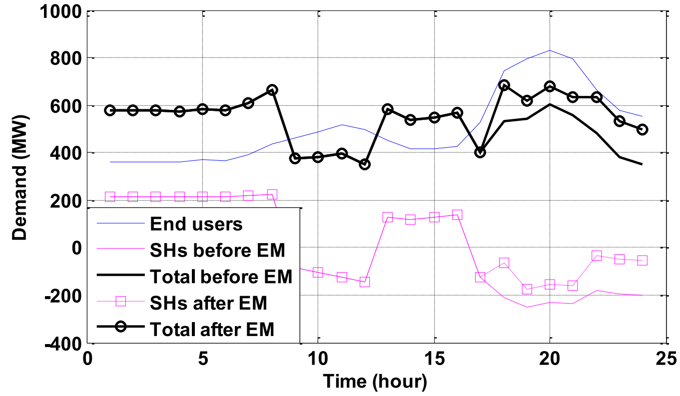


Fig. 17. Demand of passive end users, demand of active end users (SHs) before and after optimal energy management, and total demand of system before and after optimal energy management in MW at every hour of the operation period (one day).

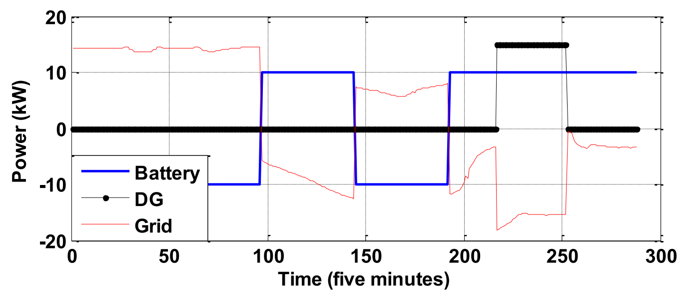


Fig. 18. Demand level and the optimally scheduled power of DG and battery at every 5-min step of the operation period (one day) for an SH with type 1 (after optimal EM).

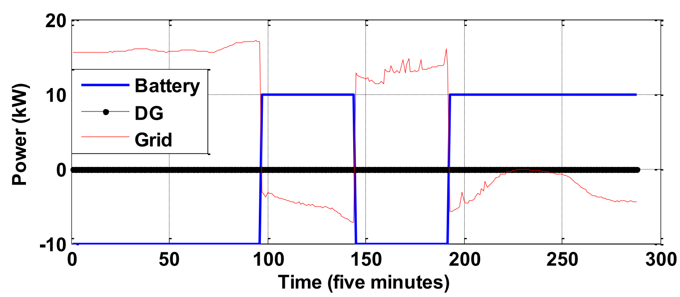


Fig. 19. Demand level and the optimally scheduled power of DG and battery at every 5-min step of the operation period (one day) for an SH with type 3 (after optimal EM).

optimal energy management. As can be seen, the daily operation costs of all types of SHs are decreased and daily profit of GENCO is increased after optimal scheme of energy management. In other words, the social welfare of the complex system (consisting of GENCO and SHs) is increased after optimal energy management scheme.

c) Sensitivity and complexity analyses: The sensitivity plot of daily profit of GENCO with respect to the value of ρ^{EM} ($/MWh) is shown in Fig. 20. As can be seen, −3 $/MWh is the optimal value for ρ^{EM}. In other words, the electricity should be sold to the customers in a less price at peak period based on (1). As can be seen, the curve is a nonlinear function of ρ^{EM}. In other words, the relation between the daily profit of GENCO and the price-controlled energy management

TABLE VI
DAILY OPERATION COST ($) OF SHS WITH DIFFERENT TYPES AND DAILY PROFIT OF GENCO ($) BEFORE AND AFTER OPTIMAL ENERGY MANAGEMENT

	Before EM	After optimal EM
Operation cost of SH (Type 1) in $/day	17.07	14.53
Operation cost of SH (Type 2) in $/day	14.23	12.17
Operation cost of SH (Type 3) in $/day	29.11	23.31
Operation profit of GENCO in $/day	6684	14243

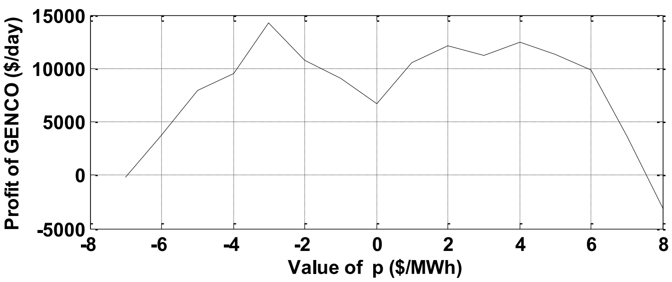


Fig. 20. Value of profit of the GENCO with respect to value of ρ^{EM} ($/MWh).

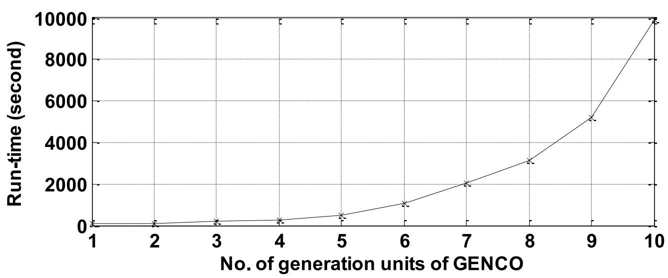


Fig. 21. Complexity analysis of the optimization algorithm presented for the GENCO based on the run-time (second) of the optimization algorithm with respect to the number of generation units of the GENCO.

scheme is not direct and determining the optimal scheme is not possible without investigating it. Therefore, the optimal value of ρ^{EM} must be probed, since a predetermined scheme of energy management may not be efficient. In addition, a random energy management scheme might bring about detriment for the GENCO, as can be seen in Fig. 20 for $\rho^{\text{EM}} \leq -7$ and $\rho^{\text{EM}} \geq 8$.

Fig. 21 illustrates the complexity analysis for the optimization algorithm of the GENCO (presented in Section III-A) based on the run-time (second) of algorithm with respect to the number of generation units of the GENCO. Herein, the number of types of SHs is the same as it is in the study (three). As can be seen, the run-time of problem is exponentially increased as the number of generation units of the GENCO is increased. In addition, Fig. 22 shows the complexity analysis for the optimization algorithm of the GENCO based on the run-time (second) of the algorithm with respect to the number of types of SH in the system. Herein, the number of generation units is the same as it is in the study (six). As can be observed, the relation between them is almost linear.

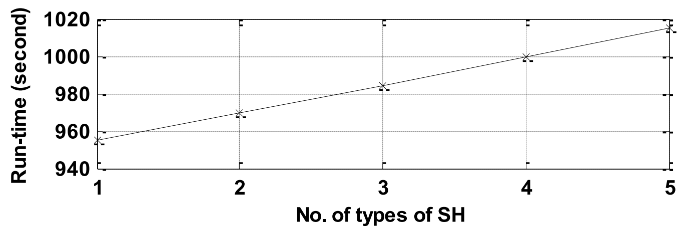


Fig. 22. Complexity analysis of the optimization algorithm presented for the GENCO based on the run-time (second) of the optimization algorithm with respect to the number of types of SH in the system.

VI. CONCLUSION

In this paper, price-controlled energy management of responsive customers (SHs) was investigated in the generation scheduling and UC problems of a GENCO to maximize the daily profit of GENCO. Due to electricity price changes, each SH reacted and rescheduled its own energy resources to minimize its daily operation cost applying a scenario-based stochastic optimization approach. In addition, the generation scheduling and UC problems of GENCO were solved using lambda-iteration economic dispatch and GA, respectively.

The simulation results demonstrated that optimal price-controlled energy management of the responsive end users (SHs) in the generation scheduling and UC problem is noticeably advantageous for the GENCO and even for the SHs, since it can increase the profit of GENCO and decrease the operation cost of every type of SH.

In order to maximize the daily profit of GENCO, it was proven that the value of profit is a nonlinear function of ρ^{EM} (variable of energy management scheme). In other words, the relation between the daily profit of GENCO and the price-controlled energy management scheme is not predictable, thus a default scheme of energy management will not lead to the favorable results and the optimal scheme must be investigated.

It was intriguing to find out that in order to maximize the daily profit of GENCO, the electricity price at peak period must be decreased to motivate the SHs to purchase more electrical energy from the GENCO. In fact, although the electricity is sold in a lower price at peak period, the overall profit of GENCO is increased due to selling more electrical energy to the SHs.

As the extended and future work of this paper, it is recommended to model the reaction of other types of end users (in addition to SHs) based on the price elasticity of demand and their social welfare.

REFERENCES

[1] International Energy Agency. (2011). *Technology Roadmap, Smart Grids*. [Online]. Available: https://www.iea.org/publications/freepublications/publication/smartgrids_roadmap.pdf

[2] A. Shah, Energy security, accessed on Nov. 2016. [Online]. Available: http://www.globalissues.org/article/595/energy-security

[3] IEA. *Strategic Plan for the IEA Demand-Side Management Program 2008-2012*. Accessed on Nov. 2016. [Online]. Available: http://www.ieadsm.org

[4] "Worldwide survey of network-driven demand-side management projects," IEA-DSM, Washington, DC, USA, Tech. Rep. 1, Nov. 2006.

[5] M. Muslu, "Economic dispatch with environmental considerations: Tradeoff curves and emission reduction rates," *Elect. Power Syst. Res.*, vol. 71, no. 2, pp. 153–158, 2004.

[6] A. J. Wood and B. F. Wollenberg, *Power Generation, Operation, Control*. New York, NY, USA: Wiley, 1984.

[7] *Federal Energy Regulatory Commission*. [Online]. Available: http://www.ferc.gov/industries/electric/indus-act/section-1241.pdf

[8] C. Goldman, M. Reid, R. Levy, and A. Silverstein, "Coordination of energy efficiency and demand response," Ernest Orlando Lawrence Berkeley Nat. Lab., Jan. 2010. [Online]. Available: https://emp.lbl.gov

[9] P. Cappers, C. A. Goldman, and D. Kathan, "Demand response in U.S. electricity markets: Empirical evidence," *Energy*, vol. 35, no. 4, pp. 1526–1535, 2010.

[10] J. H. Yoon, R. Bladick, and A. Novoselac, "Demand response for residential buildings based on dynamic price of electricity," *Energy Build.*, vol. 80, pp. 531–541, Sep. 2014.

[11] M. Rastegar and M. Fotuhi-Firuzabad, "Load management in a residential energy hub with renewable distributed energy resources," *Energy Build.*, vol. 107, pp. 234–242, Nov. 2015.

[12] A. Taniguchi *et al.*, "Estimation of the contribution of the residential sector to summer peak demand reduction in Japan using an energy end-use simulation model," *Energy Build.*, vol. 112, pp. 80–92, Jan. 2016.

[13] F. Brahman, M. Honarmand, and S. Jadid, "Optimal electrical and thermal energy management of a residential energy hub, integrating demand response and energy storage system," *Energy Build.*, vol. 90, pp. 65–75, Mar. 2015.

[14] A. Keshtkar, S. Arzanpour, F. Keshtkar, and P. Ahmadi, "Smart residential load reduction via fuzzy logic, wireless sensors, and smart grid incentives," *Energy Build.*, vol. 104, pp. 165–180, Oct. 2015.

[15] Z. Zhao and L. Wu, "Impacts of high penetration wind generation and demand response on LMPs in day-ahead market," *IEEE Trans. Smart Grid*, vol. 5, no. 1, pp. 220–229, Jan. 2014.

[16] C. D. Jonghe, B. F. Hobbs, and R. Belmans, "Value of price responsive load for wind integration in unit commitment," *IEEE Trans. Power Syst.*, vol. 29, no. 2, pp. 675–685, Mar. 2014.

[17] S. H. Madaeni and R. Sioshansi, "Using demand response to improve the emission benefits of wind," *IEEE Trans. Power Syst.*, vol. 28, no. 2, pp. 1385–1394, May 2013.

[18] F. H. Magnago, J. Alemany, and J. Lin, "Impact of demand response resources on unit commitment and dispatch in a day-ahead electricity market," *Int. J. Elect. Power Energy Syst.*, vol. 68, pp. 142–149, Jun. 2015.

[19] M. Rahmani-Andebili, A. Abdollahi, and M. P. Moghaddam, "An investigation of implementing emergency demand response programs (EDRP) in unit commitment problem," in *Proc. IEEE PES Gen. Meeting*, San Diego, CA, USA, Jul. 2011, pp. 1–7.

[20] M. Rahmani-Andebili and G. K. Venayagamoorthy, "Combined emission and economic dispatch incorporating demand side resources," in *Proc. IEEE Clemson PSC*, Clemson, SC, USA, Mar. 2015, pp. 1–6.

[21] M. Rahmani-Andebili, "Investigating effects of responsive loads models on unit commitment collaborated with demand-side resources," *IET Gener. Transm. Distrib.*, vol. 7, no. 4, pp. 420–430, Apr. 2013.

[22] M. Rahmani-Andebili, "Nonlinear demand response programs for residential customers with nonlinear behavioral models," *Energy Build.*, vol. 119, pp. 352–362, May 2016.

[23] "Benefits of demand response in electricity markets and recommendations for achieving them, a report to the U.S. congress, section 1252, energy policy act of 2005," U.S. Dept. Energy, Washington, DC, USA, Tech. Rep. LBNL–1252d, Feb. 2006.

[24] L. Wu "Impact of price-based demand response on market clearing and locational marginal prices," *IET Gener. Transm. Distrib.*, vol. 7, no. 10, pp. 1087–1095, Oct. 2013.

[25] T. Miyamoto, K. Mori, S. Kitamura, and Y. Izui, "Solving distributed unit commitment problem with Walrasian auction," *IEEE Trans. Syst., Man, Cybern., Syst.*, vol. 46, no. 8, pp. 1088–1097, Aug. 2016.

[26] Y. Liu *et al.*, "Game-theoretic market-driven smart home scheduling considering energy balancing," *IEEE Syst. J.*, to be published, doi: 10.1109/JSYST.2015.2418032.

[27] M. A. A. Pedrasa, T. D. Spooner, and I. F. MacGill, "Coordinated scheduling of residential distributed energy resources to optimize smart home energy services," *IEEE Trans. Smart Grid*, vol. 1, no. 2, pp. 134–143, Sep. 2010.

[28] N. Gatsis and G. B. Giannakis, "Residential load control: Distributed scheduling and convergence with lost AMI messages," *IEEE Trans. Smart Grid*, vol. 3, no. 2, pp. 770–786, Jun. 2012.

[29] T.-H. Chang, M. Alizadeh, and A. Scaglione, "Real-time power balancing via decentralized coordinated home energy scheduling," *IEEE Trans. Smart Grid*, vol. 4, no. 3, pp. 1490–1504, Sep. 2013.

[30] M. Rahmani-Andebili and H. Shen, "Energy scheduling for a smart home applying stochastic model predictive control," in *Proc. 6th Int. Workshop Context-Aware Perform. Eng. Internet of Things (ContextQoS) Conjunction (ICCCN),* Waikoloa, HI, USA, Aug. 2016, pp. 1–6.

[31] T. Cui *et al.*, "Optimal co-scheduling of HVAC control and battery management for energy-efficient buildings considering state-of-health degradation," in *Proc. 21st Asia South Pac. Design Autom. Conf. (ASP-DAC)*, Jan. 2016, pp. 775–780.

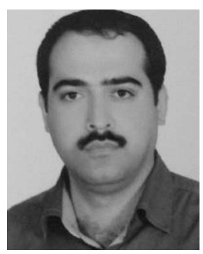
[32] R. Carli, M. Dotoli, R. Pellegrino, and L. Ranieri, "A decision making technique to optimize a buildings' stock energy efficiency," *IEEE Trans. Syst., Man, Cybern., Syst.*, to be published, doi: 10.1109/TSMC.2016.2521836.

[33] C.-K. Tham and T. Luo, "Sensing-driven energy purchasing in smart grid cyber-physical system," *IEEE Trans. Syst., Man, Cybern., Syst.*, vol. 43, no. 4, pp. 773–784, Jul. 2013.

[34] H. Saadat, *Power System Analysis*. Boston, MA, USA: McGraw-Hill, Apr. 2009.

[35] R.-H. Liang and J.-H. Liao, "A fuzzy-optimization approach for generation scheduling with wind and solar energy systems," *IEEE Trans. Power Syst.*, vol. 22, no. 4, pp. 1665–1674, Nov. 2007.

[36] *U.S. Energy Information Administration (EIA)*. Accessed on Oct. 2015. [Online]. Available: http://www.eia.gov/todayinenergy/detail.cfm?id=9310



Mehdi Rahmani-Andebili (M'16) was born in Tabriz, Iran, in 1984. He received the M.Sc. degree from Tarbiat Modares University, Tehran, Iran, in 2011, and the Ph.D. degree from Clemson University, Clemson, SC, USA, in 2016, both in electrical engineering (power system).

He has been a Guest Assistant Professor with the Sharif University of Technology, Tehran since 2016. His current research interests include smart grid, power system operation and planning, advanced optimization techniques in power system, demand side management, and integration of renewables and plug-in electric vehicles.

Haiying Shen (SM'13) received the B.S. degree in computer science and engineering from Tongji University, Shanghai, China, in 2000, and the M.S. and Ph.D. degrees in computer engineering from Wayne State University, Detroit, MI, USA, in 2004 and 2006, respectively.

She is currently an Associate Professor with the Department of Computer Science, University of Virginia, Charlottesville, VA, USA. Her current research interests include distributed computer systems and computer networks with an emphasis on P2P and content delivery networks, mobile computing, wireless sensor networks, and grid and cloud computing.

Dr. Shen was the Program Co-Chair for a number of international conferences and a member of the program committees of many leading conferences. She is a Microsoft Faculty Fellow of 2010, and a member of ACM.