Optimal Emergency Demand Response Program Integrated with Multi-Objective Dynamic Economic Emission Dispatch Problem

E. Dehnavi, H. Abdi*, F. Mohammadi

Department of Electrical Engineering, Engineering Faculty, Razi University, Kermanshah, Iran

ABSTRACT

Nowadays, demand response programs (DRPs) play an important role in price reduction and reliability improvement. In this paper, an optimal integrated model for the emergency demand response program (EDRP) and dynamic economic emission dispatch (DEED) problem has been developed. Customer's behavior is modeled based on the price elasticity matrix (PEM) by which the level of DRP is determined for a given type of customer. Valve-point loading effect, prohibited operating zones (POZs), and the other non-linear constraints make the DEED problem into a non-convex and non-smooth multi-objective optimization problem. In the proposed model, the fuel cost and emission are minimized and the optimal incentive is determined simultaneously. The imperialist competitive algorithm (ICA) has solved the combined problem. The proposed model is applied on a ten units test system and results indicate the practical benefits of the proposed model. Finally, depending on different policies, DRPs are prioritized by using strategy success indices.

1. INTRODUCTION

Determining the optimal incentive in the incentive-based demand response programs (DRPs) should be based on a feasible and economical approach. Otherwise, it may impose a high additional cost at the supply side, create new peak when DRP ends [1], and decrease the network reliability [2].1 Due to the natures of the emergency DRP (EDRP) and dynamic economic emission dispatch (DEED) problems which focus on the demand side and supply side respectively, for a more comprehensive and effective investigation, integrating these two problems seems very useful. In other words, in the combined model, the fuel cost and emission are minimized and the optimal incentive is determined simultaneously. Modeling the customer's behavior based on price elasticity

matrix (PEM) is one of the most feasible and powerful methods in this field [3-6].

EDRP and direct load control (DLC) are both voluntary incentive-based DRPs and there is no difference between their modeling. In other words these two programs have a same modeling as will be developed in the part two in this paper. Actually the ways of implementing of these two programs by independent system operator (ISO) is the main difference between them. In DLC, ISO directly controls some special loads which have possibility of being controlled remotely and this is not possible for all kind of loads. In EDRP, ISO motivates customers to reduce, interrupt, or shift their loads and it is possible for all kind of loads. On the other hand when EDRP is implemented, people have more social welfare in comparison to DLC. For the time-based DRPs like time of use (TOU), real time pricing (RTP), and critical peak pricing (CPP), instead of the optimal incentive, the optimal electricity price is determined during different periods.

A time-based DRP has been implemented in [7] to serve the power and heat demands of the customer with minimum cost. In the proposed DRP, the amount of responsive load can vary in different time intervals. The aim of the proposed DRP is to shift the load from high market price time intervals to the low market price time intervals. Actually they have presented the short-term hourly scheduling of industrial and commercial customers with cogeneration facilities, conventional power units, and heat-only units.

Real time pricing (RTP) program has been investigated in [8]. They have presented a combined scheduling and bidding algorithm for constructing the bidding curve of an electric utility that participated in the day-ahead energy markets.

In Ref. [9] EDRP and Interruptible/Curtail able (I/C) programs have been implemented in the unit commitment (UC) problem. Then, the effects of these two DRPs have been compared in the long-term UC problem with fuel constraints. The proposed methodology has been formulated as a mixed integer linear problem and implemented in GAMS environment.

A robust optimization approach has been proposed in Ref. [10] for decision making of electricity retailers. Meanwhile, considering the effect of DRP on total procurement cost, an optimal bidding strategy is proposed of electricity retailers with the time-based model of DRP in the electricity market. Also, it is considered that the consumers only participate in TOU programs. Moreover, rather than using the forecasted prices as inputs, the upper and lower limits of pool prices have been considered for the uncertainty modeling in their proposed model.

Up to now many works have been carried out based on the UC problem integrating with DRPs [11-15].

As mentioned above, the UC problem integrating with DRP has been investigated a lot. But, there are few works related to the economic dispatch problem integrating with the DRPs to appoint the optimal incentive or price and get the minimum generation cost. Y. Chen and J. Li [16] compared three formulations of the security constrained economic dispatch for facilitating participation of DRRs in the Midwest ISOs energy and the ancillary service market. They mainly focused on the interruptible loads [16]. A. Ashfaq et al. [17] presented a combined model of the economic dispatch problem integrating with demand side response. In their model, at the peak hours, the price signal is set by the generation company one hour ahead and sent to the residential area. They have neglected some constraints in the economic dispatch problem and like the pervious mentioned work the emission objective of the generating units has not been taken into account. Also, in their model just peak hours have been considered and it has not been applied to the whole day. N.I. Nwulu and X. Xia [18] investigated the game theory based DR integrating with the economic and environmental dispatch [18]. Game theory is the study of strategic decision making introduced by John von Neumann in 1928. Specifically, it is the study of mathematical models of conflict and cooperation between intelligent rational decision-makers. One of the main drawbacks of this theory is the difficulty of using it as a basis for estimation. In other words, after modeling, the model will not be so clear and in realistic systems may not be so helpful. Also, in Ref. [18] the valve-point loading effect and POZs have not been considered in their model. Also, their combined model is not so clear and by paying incentives to the customers, at the all hours of the operation, the demand is decreased which may not be always realistic, practical and economical. Also, this may not be based on the ISO point of view. In fact, customers who participate in DRPs can decrease or shift their demand during peak hours to off-peak hours. Actually they have neglected the shift-able loads.

Soft computing methods have higher capability of solving the non-linear multi-objective problems than the traditional methods and usually can optimally solve non-convex and non-smooth cost functions. Particle swarm optimization [19], gravitational search [20], artificial bee colony [21], harmony search [22], intelligent tuned harmony search (ITHS) [23], spiral [24], and imperialist competitive algorithm (ICA) [25-27] are some of these optimization algorithms. Among the mentioned optimization algorithms, ICA is a new one

introduced in 2007 by E. A. Gargari [25]. It has a good performance in solving optimization problems in different areas such as DG planning, plate-fin heat exchangers design, template matching and electromagnetic problems [26, 27].

The major contributions of this paper are: (i) Integration of EDRP with the multi-objective DEED problem to schedule the online generators power output and determine the optimal incentive. (ii) The effectiveness of the final model is shown by applying it on the ten unit's test system in three different case studies. (iii) Investigation the effects of the EDRP-DEED model on the improvement of the load curve characteristics. (iv) Prioritizing of DRPs based on different policies by using the strategy success indices. Moreover, although valve point loading effect and POZ have been considered in DEED problem, but they have not been considered in an integrated model of DEED and DRPs. Actually addition of these constraints are the innovation of this paper.

The rest of this paper is organized as follows. In Section 2, the economic model of the price-based and incentive-based DRPs is developed based on PEM and the customer's benefit function. Formulation of the DEED problem is presented in Section 3. In Section 4 the optimal model through combining of DEED and EDRP including their constraints is developed. The characteristics of the test system are introduced in Section 5. Numerical simulation and results are presented in Section 6. Finlay, in Section 7 the conclusion is drawn.

2. ECONOMIC MODEL OF RESPONSIVE LOAD

To obtain the optimal consumption at the demand side, the elasticity is defined as the sensitivity of the demand respect to the price as Eq. (1) [2, 4, and 28].

$$E\left(t,t'\right)=\frac{\rho_0\left(t'\right)}{d_0\left(t\right)}\frac{\partial d\left(t\right)}{\partial\rho\left(t'\right)} \quad \begin{cases} E\left(t,t'\right)\le 0\, if\ t=t' \\ E\left(t,t'\right)\ge 0\, if\ t\ne t' \end{cases} \quad (1)$$

where, E is the elasticity, $d(t)$ and $d_0(t)$ are the customer demands after implementing DRP and before it, during period t, $\rho(t')$ and $\rho_0(t')$ are the elasticity price and the initial electricity price during period t', respectively.

For 24 hours in a day, self and cross elasticity values can be given as a 24×24 matrix as Eq. (2).

$$\begin{bmatrix} \frac{\Delta d\,(1)}{d_0\,(1)} \\ \frac{\Delta d\,(2)}{d_0\,(2)} \\ \frac{\Delta d\,(3)}{d_0\,(3)} \\ \dots \\ \frac{\Delta d\,(24)}{d_0\,(24)} \end{bmatrix} = \begin{bmatrix} E\,(1,1) & \cdots & E\,(1,24) \\ \vdots & \ddots & \vdots \\ E\,(24,1) & \cdots & E\,(24,24) \end{bmatrix} \times \begin{bmatrix} \frac{\Delta \rho\,(1)}{\rho_0\,(1)} \\ \frac{\Delta \rho\,(2)}{\rho_0\,(2)} \\ \frac{\Delta \rho\,(3)}{\rho_0\,(3)} \\ \dots \\ \frac{\Delta \rho\,(24)}{\rho_0\,(24)} \end{bmatrix} \quad (2)$$

2.1. Modeling of single period elastic loads

In this case, the total revenue for the customers who participate in the DRPs will be calculated as Eq. (3) based on the hourly incentive rate. In other words, DRPs create a motivation for customers to reduce their consumption. The total payment given to the customers is as Eq. (3) [28].

$$INC\left(\Delta d\left(t\right)\right)=inc\left(t\right)\times\left[\Delta d\left(t\right)\right] \quad (3)$$

where, $inc(t)$ is the amount of the incentive for reducing the consumption per $MW.h$, $\Delta d(t)$ is the amount of the reduced load.

Some programs consider a penalty for the customers who promise to participate in the DRP, but they don't (Eq. (4)). Most of the DRPs like EDRP and DLC are implemented voluntary. So, customers' are not penalized if they don't participate in DRPs (if they don't reduce or cut their consumption during peak hours). But, a DRP can be implemented mandatorily which means that if customers' don't reduce their consumption during peak hours they will be penalized by an additional cost in their electricity bill. Some examples of mandatory programs are capacity market program (CAP) and interruptible / curtail-able (I/C) service programs.

$$PEN\left(\Delta d\left(t\right)\right)=pen\left(t\right)\times\left\{IC\left(t\right)-\left[\Delta d\left(t\right)\right]\right\} \quad (4)$$

where, $IC(t)$ is the amount of the demand which the customer is responsive to reduce or shift.

Consumers who participate in DRP, increase their production benefit, decrease their consumption, and receive the reward from the system operator. Thus, the net-profit of the customer is as Eq. (5) which is related to the customer's income because of electricity consumption and producing their commodities.

$$\begin{aligned} NP(t) &= B\left(d\left(t\right)\right)-d\left(t\right)\rho\left(t\right)+INC\left(\Delta d\left(t\right)\right) \\ &\quad -PEN\left(\Delta d\left(t\right)\right) \end{aligned} \quad (5)$$

where, B is the profit which customers obtain by consuming power.

To maximize the customer benefit, the derivative of Eq. (5) should be zero.

$$\frac{\partial NP}{\partial d(t)} = \frac{\partial B(d(t))}{\partial d(t)} - \rho(t) + \frac{\partial INC}{\partial d(t)} - \frac{\partial PEN}{\partial d(t)} = 0 \quad (6)$$

$$\frac{\partial B(d(t))}{\partial d(t)} = \rho(t) + inc(t) + pen(t) \quad (7)$$

As mentioned before, it is assumed that $B(d(t))$ is customer's benefit from the use of electricity during tth hour. Taylor series of B is given by Eq. (8).

$$B(d(t)) = B(d_0(t)) + \frac{\partial B(d_0(t))}{\partial d(t)}[d(t) - d_0(t)] + \frac{1}{2}\frac{\partial^2 B(d_0(t))}{\partial d^2(t)}[d(t) - d_0(t)]^2 \quad (8)$$

To obtain the optimal consumption by which the customers get the maximum profit, from Eq. (8):

$$B(d(t)) = B(d_0(t)) + \rho_0(t)[d(t) - d_0(t)] + \frac{1}{2}\frac{\rho_0(t)}{E(t,t)d_0(t)}[d(t) - d_0(t)]^2 \quad (9)$$

Differentiating:

$$\frac{\partial B(d(t))}{\partial d(t)} = \rho_0(t)\left(1 + \frac{d(t) - d_0(t)}{E(t,t)d_0(t)}\right) \quad (10)$$

By combining Eqs. (10) and (7), for the single-period model of the load can be obtained:

$$d(t) = d_0(t) \times \left(1 + \frac{\rho(t) - \rho_0(t) + inc(t) + pen(t)}{\rho_0(t)}E(t,t)\right) \quad (11)$$

2.2. Modeling of multi period elastic loads

Now, to consider shift-able loads in the, then we will have the multi period model as the following equation:

$$d(t) = d_0(t) \times \left\{1 + \sum_{\substack{t'=1 \\ t' \neq t}}^{24} E(t,t') \times \frac{[\rho(t') - \rho_0(t') + inc(t') - pen(t')]}{\rho_0(t')}\right\} \quad (12)$$

2.3. Load economic model

Finally, the combined model including the single and multi- period models of the load (considering curtail-able, interruptible, and shift-able loads) is given by Eq. (13).

$$d(t) = d_0(t) \times \left\{1 + \frac{\rho(t) - \rho_0(t) + inc(t) - pen(t)}{\rho_0(t)}E(t,t) + \sum_{\substack{t'=1 \\ t' \neq t}}^{24} E(t,t') \times \frac{[\rho(t') - \rho_0(t') + inc(t') - pen(t')]}{\rho_0(t')}\right\} \quad (13)$$

Equation (11) is the single period elastic load model which considers just interruptible or curtail able (I/C) loads. Eq. (12) is for multi-period elastic load model which considers just shift-able loads. Eq. (13) is the combined model included both single and multi-periods models which consider both (I/C) and shift-able loads. In this paper the combined model is taken into account.

3. DYNAMIC ECONOMIC EMISSION DISPATCH FORMULATION

When the valve-point, loading effect is taken into account, the total fuel cost over the whole dispatch period is as follows.

$$\min \sum_{t=1}^{T}\sum_{i=1}^{Ng} F_i\left(P_{i,t}\right) \quad (14)$$

$$F_i(P_{i,t}) = a_i + b_i P_{i,t} + c_i P_{i,t}^2 + \left|d_i \sin\left(e_i\left(P_i^{min} - P_{i,t}\right)\right)\right| \quad (15)$$

where, a_i, b_i, c_i, d_i and e_i are the fuel cost coefficients of the ith unit, P_i^{min} is the minimum power generation, $P_{i,t}$ is the power output of the ith unit during the t-th time interval, N_g and T are the number of the generating units and the dispatch interval, respectively.

The atmospheric pollution caused by the fossil-fired generator contains carbon dioxide CO_2, nitrogen oxides NO_x, sulfur oxides SO_x, etc. The environmental objective is as follows.

$$\min \sum_{t=1}^{T}\sum_{i=1}^{Ng} E_i\left(P_{i,t}\right) \quad (16)$$

$$E_i(P_{i,t}) = \alpha_i + \beta_i P_{i,t} + \gamma_i P_{i,t}^2 + \eta_i \exp\left(\delta_i P_{i,t}\right) \quad (17)$$

where, $\alpha_i, \beta_i, \gamma_i, \eta_i$, and δ_i are coefficients of the emission issue for the i-th unit.

4. THE COMBINED MODEL OF EDRP INTEGRATED WITH THE DEED PROBLEM

The cost of implementing EDRP is as Eq. (18).

$$C_{EDRP}(t) = (d_0(t) - d(t))inc(t) \quad (18)$$

The multi-objective optimization problem can be changed to a single objective function using a penalty factor as follows:

$$\min TOF\left(P_{i,t}\right)=$$

$$\sum_{t=1}^{T}\left\{\begin{array}{l}\omega_{F}\times\left[\sum_{i=1}^{N_{g}}\left\{\begin{array}{l}a_{i}+b_{i}P_{i,t}+c_{i}\left(P_{i,t}\right)^{2}\\+\left|d_{i}\sin\left(e_{i}\left(P_{i}^{min}-P_{i,t}\right)\right)\right|\end{array}\right\}\right]\\+\omega_{F}\times C_{EDRP}\left(t\right)\\+\omega_{E}\times\sum_{i=1}^{N_{g}}\left[pff\left(i\right)*\left(\begin{array}{l}\alpha_{i}+\beta_{i}P_{i,t}+\\\gamma_{i}\left(P_{i,t}\right)^{2}+\eta_{i}\exp\left(\delta_{i}P_{i,t}\right)\end{array}\right)\right]\end{array}\right\}\quad(19)$$

where,

$$\omega_{F}+\omega_{E}=1 \quad (20)$$

The first and second terms in Eq. (19) are cost functions ($) and the third term is emission (Ib). Therefore, to have same unit for cost and emission i.e. in dollar, the third term's unit should be changed from Ib to $. Therefore, that is why a price penalty factor (*pff*) is used. In other words, *pff* changes the unit of third term in Eq. (19) from Ib to $ [29].

$$pff\left(i\right)=\frac{F_{i}\left(P_{i}^{max}\right)}{E_{i}\left(P_{i}^{max}\right)}$$

$$=\frac{a_{i}+b_{i}P_{i}^{max}+c_{i}\left(P_{i}^{max}\right)^{2}+\left|d_{i}\sin\left(e_{i}\left(P_{i}^{min}-P_{i}^{max}\right)\right)\right|}{\alpha_{i}+\beta_{i}P_{i}^{max}+\gamma_{i}\left(P_{i}^{max}\right)^{2}+\eta_{i}\exp\left(\delta_{i}P_{i}^{max}\right)}\quad(21)$$

4.1. Constraints

The DEED problem should satisfy the following equality and inequality constraints.

4.1.1. Power balance constraint

The total power output should be equal to the predicted load demand plus the total losses.

$$\sum_{i=1}^{N_{g}}P_{i}\left(t\right)=d\left(t\right)+P_{L}\left(t\right);t=1,...T \quad (22)$$

where, $d(t)$ and $P_{L}(t)$ are the load demand and the power loss of transmission line at the t-th time interval. Generally $P_{L}(t)$ is calculated by Kron's loss formula, which can be given as Eq. (23).

$$P_{L}\left(t\right)=\sum_{i=1}^{N_{g}}\sum_{j=1}^{N_{g}}P_{i}\left(t\right)B_{ij}P_{j}\left(t\right) \quad (23)$$

where, $B_{i,j}$ is the power loss coefficient of the transmission network.

4.1.2. Incentive limits

For EDRP program, the incentives paid to the customers should be in a feasible range.

$$inc\left(t\right)^{min}\leq inc\left(t\right)\leq inc\left(t\right)^{max} \quad (24)$$

Referring to [32] *inc(t)*^{min} and *inc(t)*^{max} are usually considered to be $0.1\times\rho_{0}(t)$ and $10\times\rho_{0}(t)$, respectively.

4.1.3. Power generation limits

Generators power output is limited by its upper and lower generation limits.

$$P_{i}^{min}\leq P_{i,t}\leq P_{i}^{max}\quad i=1,2...N_{g} \quad (25)$$

where, P_{i}^{min} and P_{i}^{max} are the lower and upper generation limits for the ith unit.

4.1.4. Prohibited operation zones constraint

In practice, generators should not work in some POZs. The main reason of this limitation is the vibration of the shaft bearing. So, generators should work in the feasible operating zones as given by Eq. (26).

$$\begin{cases}P_{i}^{min}\leq P_{i}^{t}\leq P_{i,1}^{l}\\P_{i,k-1}^{u}\leq P_{i}^{t}\leq P_{i,k}^{l};i=1,...,Ng;t=1,...,T\\P_{i,M}^{u}\leq P_{i}^{t}\leq P_{i}^{max}\end{cases}\quad(26)$$

where, $P_{i,k}^{l}$ and $P_{i,k}^{u}$ are the lower and upper limits of the kth POZ respectively, M is the number of POZs for the ith unit.

4.1.5. Generator ramp rate limits

Generator longevity is effectively influenced by the thermal stress. The increase and decrease rates of the generator power output are usually called the ramp-up and ramp-down, respectively. So, the operating range of the i-th unit is as Eq. (27).

$$\begin{cases}P_{i}^{t}-P_{i}^{t-1}\leq UR_{i}\\P_{i}^{t-1}-P_{i}^{t}\leq DR_{i}\end{cases}\quad(27)$$

where, UR_{i} and DR_{i} are the up-ramp and down-ramp limits of the i-th unit, respectively and are usually expressed in MW/h.

4.2. Solving the DEED-EDRP problem

In this part a general procedure for solving the DEED-EDRP problem by the population-based meta-heuristic algorithms is presented. In fact, the population includes some possible solutions of the optimization problem. The population size is determined by the number of possible solutions. The possible solutions in ICA are called countries, in PSO particles, in ABC artificial bees, etc. Also,

every possible solution is called a candidate. In DEED-EDRP, every scheduled generating unit output at each hour comprises a component of the population. In other words, it is a candidate for DEED-EDRP optimization problem at each hour. The kth candidate (PG_k) at each hour is defined as Eq. (28).

$$PG_k = \left[P_{k,1}, P_{k,2}, \ldots, P_{k,j}, \ldots, P_{k,N_g} \right], k = 1,2 \ldots M' \quad (28)$$

where, PG_k is the current position of the kth vector, N_g is the number of generation units, M' is the population size, j is the generator number, and P_{kj} is the power output of the jth generation unit.

Constraint Eq. (22) can be handled by using a penalty term in Eq. (29). Thus, the evaluation function used in DEED-EDRP can be written as Eq. (29).

$$EF\left(P_{i,t}\right) = \sum_{t=1}^{T} \left\{ \begin{array}{c} \sum_{i=1}^{N_g} TOF\left(P_{i,t}\right) + \\ K_n \, abs\left(\sum_{i=1}^{N_g} P_{i,t} - P_{D,t} - P_{L,t}\right) \end{array} \right\} \quad (29)$$

where, K_n is the penalty factor, which is a positive real number. The amount of K_n at each hour increases with the algorithm iterations. If the constraint Eq. (22) is nonzero, the amount of the second term in Eq. (29) will be nonzero, too. In other words, a candidate which doesn't meet the constraint Eq. (22) will have a large evaluation function and more likely will be discarded. On the other hand, a candidate which meets the constraint Eq. (22) will have a relatively small evaluation function and consequently will be kept. K_n can be written as Eq. (30).

$$K_n = 1000 \times \sqrt{n} \, ; n = 1, \ldots N_{iter} \quad (30)$$

where, N_{iter} is the maximum number of iterations at each hour.

To ensure meeting of constraints Eqs. (25) - (27), before calculating the evaluation function of each candidate by Eq. (29), the power generation outputs of each candidate should be in the acceptable ranges specified by constraints Eqs. (25) - (27). If a candidate meets the constraints Eqs. (25) - (27), its evaluation function will be determined by Eq. (29). Otherwise, its evaluation function will be penalized by a large number. For more information about ICA, refer to [25-27]. The solution method for EDRP-

DEED problem can be summarized in some steps as following.

Step 1: Defining technical units' data, daily load demand, $\rho_0(t)$, PEM, load model, participation percentage (μ), and initial incentive (is set to zero by ISO). Moreover, in ICA optimization, the initial population which is a set of possible solutions of the EDRP-DED problem, is defined based on the pervious section.

Step 2: Increasing the amount of incentive by ISO and determining the hourly demand and total incentive. Also, generation costs are determined by the supply side in this step.

Step 3: Solving the EDRP-DED problem by ICA and determining the optimal generation power outputs which are announced to the supply side.

Step 4: Continuing the process from step 2 until the minimum cost of generation units is obtained and the optimal incentive is determined by ISO.

5. TEST SYSTEM

To show the correctness, features, and practical benefits of the proposed model, it is applied on the ten unit's test system. The test system is taken from [30, 31] with some modifications. The characteristics of the test system are given as Table 1-2. Also, the elements of PEM are like Table 3. The daily load curve is divided into the peak period (9 A.M. - 14 P.M. & 19 P.M. - 24 P.M.), the off-peak period (5 A.M. - 9 A.M. & 14 P.M. - 19 P.M), and the valley period (0 A.M.-5 A.M.). DR implementation potential (μ) is considered 20%. It means that 20 percent of the customers participate in the DRP. The initial electricity price (ρ_0) is as Fig. 1 [32]. Also, the transmission line losses coefficients of the ten-unit test system are as Eq. (31).

$$B = \begin{bmatrix} 49 & 14 & 15 & 15 & 16 & 17 & 17 & 18 & 19 & 20 \\ 14 & 45 & 16 & 16 & 17 & 15 & 15 & 16 & 18 & 18 \\ 15 & 16 & 39 & 10 & 12 & 12 & 14 & 14 & 16 & 16 \\ 15 & 16 & 10 & 40 & 14 & 10 & 11 & 12 & 14 & 15 \\ 16 & 17 & 12 & 14 & 35 & 11 & 13 & 13 & 15 & 16 \\ 17 & 15 & 12 & 10 & 11 & 36 & 12 & 12 & 14 & 15 \\ 17 & 15 & 14 & 11 & 13 & 12 & 38 & 16 & 16 & 18 \\ 18 & 16 & 14 & 12 & 13 & 12 & 38 & 16 & 16 & 18 \\ 19 & 18 & 16 & 14 & 15 & 14 & 16 & 15 & 42 & 19 \\ 20 & 18 & 16 & 15 & 16 & 15 & 18 & 16 & 19 & 44 \end{bmatrix} \times 10^{-6} \quad (31)$$

Table 1. Ten-unit test system characteristics (a)

Units	P_{max} (MW)	P_{min} (MW)	a_i ($/h)	b_i ($/MWh)	c_i ($/(M$h$)^2 h$)
1	455	150	1000	16.19	0.00084

2	455	150	970	17.26	0.00031
3	130	20	700	16.6	0.002
4	130	20	680	16.5	0.00211
5	162	25	450	19.7	0.00398
6	80	20	370	22.26	0.00712
7	85	25	480	27.74	0.00079
8	55	10	660	25.92	0.00413
9	55	10	665	27.27	0.00222
10	55	10	670	27.79	0.00173

Units	d_i ($/h)	e_i (rad/MW)	POZs (MW)
1	40	0.0141	—
2	60	0.0136	[185-210], [275-305], [410-420]
3	30	0.0128	—
4	20	0.0152	[25-40], [55-70], [75-85]
5	20	0.0163	—
6	30	0.0148	[30-45] , [50-65]
7	30	0.0168	[35-50] , [55-70]
8	32	0.0162	[15-25] , [35-45]
9	25	0.0178	—
10	33	0.0174	—

Table 2. Ten-unit test system characteristics (b)

Units	α_i (lb/h)	β_i (lb/MWh)	γ_i (lb/(Mh)²h)	η_i (lb/h)
1	42.8955	-0.5112	0.00460	0.25470
2	42.8955	-0.5112	0.00460	0.25470
3	40.2669	-0.5455	0.00680	0.24990
4	40.2669	-0.5455	0.00680	0.24800
5	13.8593	0.3277	0.00420	0.24970
6	13.8593	0.3277	0.00420	0.24970
7	330.0056	-3.9023	0.04652	0.25163
8	330.0056	-3.9023	0.04652	0.25163
9	350.0056	-3.9524	0.04652	0.25475
10	360.0012	-3.9864	0.04702	0.25475

Units	δ_i (1/MW)	UR (MW/h)	DR (MW/h)
1	0.01234	80	80
2	0.01234	80	80
3	0.01203	50	50
4	0.01290	50	50
5	0.01200	50	50
6	0.01200	30	30
7	0.01215	30	30
8	0.01215	30	30
9	0.01234	30	30
10	0.01234	30	30

Table 3. Self and cross elasticity values.

	Peak	Off-peak	Valley
Peak	-0.10	0.016	0.012
Off-peak	0.016	-0.10	0.01
Valley	0.012	0.01	-0.10

6. NUMERICAL SIMULATION AND RESULTS

In this paper, the cost based, emission based, and cost-emission based DEED integrated with EDRP through three different case studies are investigated. On the other hand, the effects of the elasticity values

and incentives on the results are evaluated. The initial daily load demand is as Fig. 2.
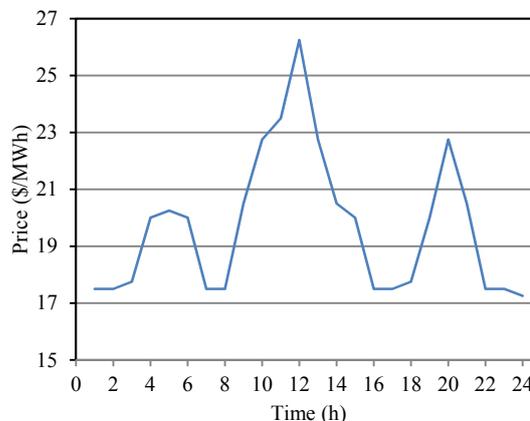
Fig. 1. Initial electricity price ($/MWh)
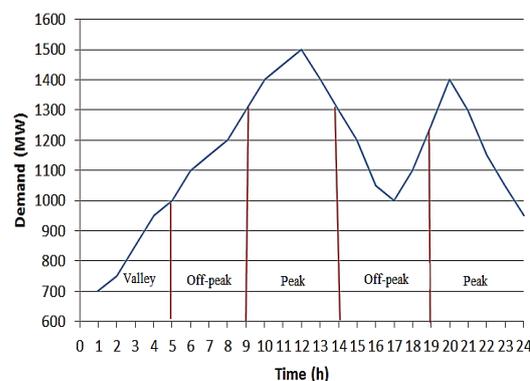
Fig. 2. Daily load curve

Three different groups with different values of PEM have been taken into account. In each case study, ten scenarios have been defined with different PEMs and incentives. Scenario 1 is the base case without implementing EDRP, scenarios 2-4 (group one with a PEM equals to E as Table 2) have incentives 4, 8, and 12 $/MWh, scenarios 5-7 (group two with PEM equals to $0.5 \times E$) have incentives 4, 8, and 12 $/MWh, scenarios 8-10 (group three with PEM equals to $2 \times E$) have incentives 4, 8, and 12 $/MWh, respectively.

To investigate the impacts of implementing EDRP on the load curve characteristics, some factors are defined as following. To evaluate the smoothness of the load curve, the load factor is defined as Eq. (32). Ideally, it is 100% which implies that at all hours of the operation the amount of demand is constant and does not change throughout the day.

$$Load - factor\% = 100 \times \left(\frac{\sum_{t=1}^{T} d(t)}{T \times d^{max}(t)} \right) \quad (32)$$

Peak-to-valley, peak-compensate, and deviation-of-peak-to-valley are the other important factors which are defined as Eqs. (33) - (35).

$$Peak - to - valley\% = 100 \times \left(\frac{d^{max}(t) - d^{min}(t)}{d^{max} ax(t)} \right) \quad (33)$$

$$Peak - compensate\% = 100 \times \left(\frac{d_0^{max}(t) - d^{max}(t)}{d_0^{max}(t)} \right) \quad (34)$$

$$Deviation - of - peak - to - valley\% = 100 \times \left(1 - \frac{d^{max}(t) - d^{min}(t)}{d_0^{max}(t) - d_0^{min}(t)} \right) \quad (35)$$

DRPs are usually prioritized by ISO to compare the performance value of the DR strategies. Therefore, in this paper to prioritize scenarios, the strategy index (SI) and strategy success index (SSI) are defined as Eqs. (36) and (37), respectively.

$$SI = \sum_{t=1}^{24} \left(St_1(t) \right)^{w_1} \times \left(St_2(t) \right)^{w_2} \times \ldots \left(St_k(t) \right)^{w_k} \quad (36)$$

$$SSI = \frac{\sum_{i=1}^{N} SI(i)}{\sum_{i=1}^{N} SI(max)} \times 100 \quad (37)$$

where, $S_i(t)$ is the performance value of the scenario in the period t, W_k is the weighting for the k-th attribute, N is the total days of DRPs implementation, and SSI represents the normalized value of SI. The higher SSI represents the better profit.

6.1. Case study one: cost based DEED integrated with EDRP

In this case, the effects of implementing EDRP on the overall cost of the generation units are evaluated. So, ω_F and ω_E are considered to be 1 and 0, respectively. Results are shown in Table 4. In all scenarios, after implementing EDRP, the total cost reduces. Implanting EDRP imposes an additional cost (C_{EDRP}) which is paid as the incentive to the customers. But, the total cost which is sum of the cost of the generating units and the total incentive, reduces. Scenario 9 has the most reduction of the total cost by 17411.0128\$ (679111.1848-661700.1720) and scenario 5 has the least one by 4014.4215 \$ (679111.1848-675096.7633). On the other hand, the customer's benefit in each group increases with the incentive value and PEM and decreases with the generation cost of units. For

example, scenario 10 has the most total incentive (35839.3653 \$) and scenario 5 has the least one (995.5379\$).

Table 4. Scenarios' performance in the case one

Scenario	Total generation cost ($)	Total incentive ($)	Total cost ($)
1	679111.1848	—	679111.1848
2	669700.6678	1991.0758	671691.7437
3	660272.7458	7964.3034	668237.0492
4	651999.4772	17919.6826	669919.1599
5	674101.2254	995.5379	675096.7633
6	669686.4824	3982.1517	673668.6341
7	665398.5145	8959.8413	674358.3558
8	661476.1561	3982.1517	665458.3078
9	645771.5652	15928.6068	661700.1720
10	635583.916	35839.3653	671423.2813

The optimal incentives for three different groups are determined as shown in Table 5. Also, in all scenarios total losses decreases, too. All characteristics of the load curve are improved for three groups as shown in Table 6.

Table 5. Groups' performance for the optimal incentives in the case one

Group	Optimal incentive ($/MWh)	Total generation cost ($)	Total incentive ($)
Base case	—	679111.1848	—
One	7.75	660626.9668	7474.3121
Two	10.32	665495.0939	6623.0299
Three	5.87	652631.6164	8590.4034
Group	Total cost ($)	Total power losses(MW)	
Base case	679111.1848	769.7731	
One	668101.2789	739.4306	—
Two	672118.1237	740.8757	
Three	661222.0198	693.7434	

Table 6. Load curve's characteristics in the case one

Group	Load factor	Peak to valley	Peak compensate	Deviation of peak to valley
Base case	76.39	53.33	—	—
One	80.15	49.11	7.48	14.80
Two	78.10	51.41	3.55	7.03
Three	81.33	46.46	11.34	22.77

The load curves before and after implementing EDRP for three different groups (for their optimal incentives) are shown in Fig. 3. Customers with the highest PEM have more willingness to reduce or shift their consumption during peak hours (group three of the customers) and vice versa (group two of the customers). Actually, by implementing the EDRP, the load curve smoothens which improves the network reliability.
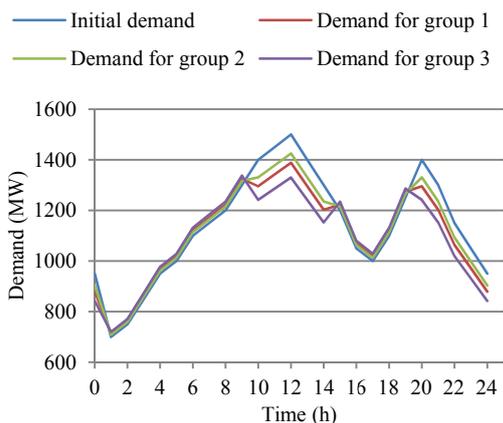
Fig. 3. The load curve before and after implementing EDRP for three different groups

6.2. Case study 2: emission-based DEED integrated with EDRP

In this case, the impact of implementing EDRP on reducing the emission is considered. It should be noted that in this case, the objective of implementing EDRP is 10 percent reduction of the initial emission. The initial emission before implementing EDRP is 49352.0551 Ib and in this case, the objective is to reduce it to 44416.8496 Ib. In this regard, ω_F and ω_E are considered to be 0 and 1, respectively. Results are shown in Table 7. Determining the optimal incentive is necessary from ISO point of view. From Table 7, it can be seen that the emission level of the generation units is decreased proportional to the elasticity of demand and the value of the incentive. For example, scenario 10 with larger PEM and incentive (2×E and 12 $/MWh, respectively) has the most emission reduction by 11.05 % among the other ones.

6.3. Case study three: cost-emission based DEED integrated with EDRP

In this case, the cost-emission based DEED integrated with EDRP is investigated. Thus, there is a trade-off between the cost and the emission. In other words, ω_F and ω_E are both considered to be 0.5. But, depending on the system operator, different weights can be assigned too. Results are shown in Table 8. The objective function for the group three of customers reduces more. It is because of the fact that they have larger PEM which means that they have more willingness to reduce their consumption during the peak period or shift it to the valley or off-peak periods.

Table 7. Scenarios' performance in the case two

Sce.	Total emission (Ib)	Emission reduction%	Optimal incentive for 10 % emission reduction ($/MWh)	Total incentive ($) for 10 % emission reduction ($/MWh)
1	49352.0551	—	—	—
2	47892.3518	2.96	16.27	32941.4664
3	47203.6674	4.35		
4	45796.2286	7.21		
5	48956.6215	0.8	35.76	79566.9749
6	48528.7325	1.66		
7	47495.8976	3.76		
8	47294.4441	4.17	11.46	32686.3971
9	45554.8574	7.69		
10	43901.3077	11.05		

6.4. Prioritizing scenarios

Comparing the performance value of the scenarios using SSI coefficient is investigated in this part. For the best scenario, SSI is considered to be 100 % and for the other ones, it is calculated using Eqs. (36) and (37). Prioritizing of different scenarios based on different policies has been shown in Fig. 4. Here, reducing the total cost, emission, and objective function (case 1-3), energy reduction, load factor, and peak compensate are assumed as the important policies. As it is shown in Fig. 4, different policies have different priorities. In practice when there are some restrictions in implementing a higher priority scenario, ISO can choose another one with lower priority.

Cost-Emission Reduction - Case 3

Energy Reduction

Load Factor

Peak Compensate
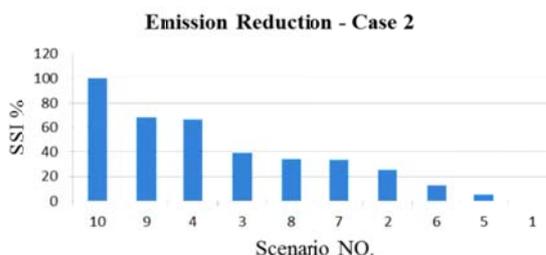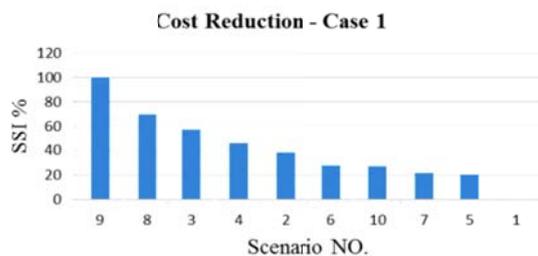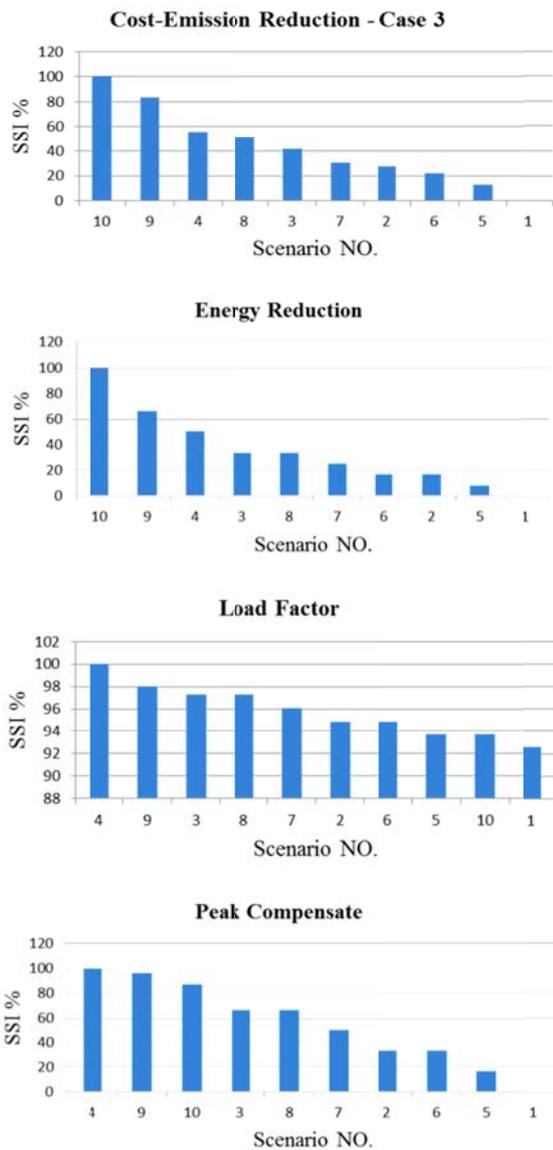
Fig. 4. Prioritizing of different scenarios based on different policies

Table 8. Scenarios' performance in the case three

Scenario	Total generation cost ($)	Total emission (lb)	Total incentive ($)
1	704386.6962	50752.9645	—
2	696378.1907	48965.6393	1991.0758
3	689097.4902	48083.3675	7964.3034
4	680312.5354	47426.8710	17919.6826
5	700936.9077	49775.3354	995.5379
6	695982.5925	49333.6351	3982.1517
7	691859.4736	48648.8467	8959.8413
8	689319.6233	48194.3079	3982.1517
9	673854.3426	46561.6077	15928.6068
10	655339.0089	45418.4736	35839.3653
Scenario	Objective function	Optimal incentive ($/MWh)	
1	638283.5824	—	

2	627284.3415	
3	621368.4799	16.44
4	615560.2359	
5	633206.8812	
6	629264.0664	22.03
7	625897.6729	
8	618088.7175	
9	604602.4641	12.53
10	597376.9502	

7. CONCLUSION

DRPs' capabilities such as the cost reduction and reliability improvement have made them into important priorities for the electricity markets. In this paper EDRP was integrated to the DEED problem to minimize the fuel cost and emission and appoint the optimal incentive simultaneously.

In fact, the combined model is a win-win situation for both the customers and the generation companies. It is because of the fact that implementing DRPs not only decreases the total generation cost and emission but also increases the customer's benefit and network reliability. By applying the proposed model on the ten-unit system, some analyses were carried out to investigate the impacts of some important factors such as the elasticity values and incentives on the results. Also, prioritizing of different scenarios based on different policies was presented by using strategy success indices. Results showed the effectiveness and practical benefits of the proposed model. In the future work, the price-based DRPs such as the time of use (TOU) program will be integrated with the DEED problem. In this model instead of the optimal incentive, the optimal price during different periods is determined.

APPENDIX A
Generators' optimal scheduling for case 1 (before and after implementing EDRP).

Table 9. Optimal generators power output (case 1, without implementing EDRP)

Hour	P_1(MW)	P_2(MW)	P_3(MW)	P_4(MW)	P_5(MW)	P_6(MW)	P_7(MW)	P_8(MW)	P_9(MW)	P_{10}(MW)
1	198.3231	241.684	31.63968	94.59544	27.19408	25.49634	26.8687	45	10.26797	10
2	150	247.7146	49.83891	110.7146	34.63525	65	27.30336	45	21.64562	10
3	230	167.7146	99.51208	110.4738	83.34554	65	53.15977	28.24109	16.64621	10.49327
4	310	222.6107	68.41978	85	101.9436	77.48763	33.43801	45	15.70465	10

5	390	267.0335	52.33952	85	101.6804	47.48763	30.61284	15	10.19548	24.39218
6	433.8736	347.0335	50.11793	92.06238	56.89958	28.54348	33.46109	45	27.28848	15.57493
7	446.6911	345.5086	75.58416	112.9852	56.08574	26.88016	32.65191	31.60081	40.43256	13.77038
8	366.6911	425.5086	98.37808	103.086	106.0857	65	29.89463	13.56929	15.49595	10
9	367.0852	430.1813	118.431	89.70195	156.0857	68.29093	29.53957	45	10	24.07745
10	447.0852	420.5234	128.4045	123.2035	133.2943	65	70	30.52909	10	16.76485
11	455	443.6234	130	111.8638	136.884	65	70	12.54559	33.12652	40.32668
12	455	449.4167	130	126.3022	162	65.24816	71.82764	45	35.87504	10.32668
13	452.9055	389.4062	129.8111	119.1658	125.3109	65	76.56733	50.54382	13.80363	21.79765
14	455	400.4528	114.9359	85	80.23671	65	70.1974	34.32804	10	24.65694
15	375	442.6851	64.9359	122.8244	50.6497	73.36889	52.6237	12.72644	15.00224	24.50812
16	301.8589	377.1026	114.9359	85.98152	35.88778	65	30.40196	32.65795	19.08779	12.50596
17	381.8589	329.3905	64.9359	70.42312	29.41574	65	30.78129	12.12719	19.96428	20.55156
18	405.0488	394.5353	95.00446	46.83145	26.91788	69.63742	51.6138	13.84193	13.9593	12.51913
19	455	436.1718	46.09915	96.83145	76.91788	65	70	12.6892	18.38966	11.26751
20	455	437.4784	96.09915	124.533	116.9341	77.66695	70	45	10	12.62963
21	455	394.2677	94.5559	102.0265	79.42167	74.46078	70	15	12.40555	42.62963
22	375.745	397.9068	74.50345	89.71224	77.12804	49.73815	70	10.98237	12.08122	23.45051
23	392.2455	374.1333	62.13671	46.03439	78.53448	25.33387	50.02141	26.8977	10.26565	11.73639
24	312.2455	307.1181	108.4851	72.7076	28.53448	65	30.08306	11.00563	11.13948	24.57502

Table 10. Optimal generators power output (case 1, group 1, incentive 7.75 $/MWh, after implementing EDRP)

Hour	P_1(MW)	P_2(MW)	P_3(MW)	P_4(MW)	P_5(MW)	P_6(MW)	P_7(MW)	P_8(MW)	P_9(MW)	P_{10}(MW)
1	159.8035	226.6205	85.82839	48.51468	57.2006	22.95584	26.69639	46.18369	21.64581	21.47983
2	239.8035	179.4035	60.54318	85	44.8248	29.9754	29.40787	53.08889	18.88343	28.18016
3	299.2614	259.4035	31.77494	85	43.34917	27.70434	50.01592	30.67103	36.29844	11.24974
4	379.2614	182.563	64.44217	85	93.34917	49.67918	34.08422	45.07673	23.30656	22.96594
5	299.2614	262.563	114.4422	85	125.3316	24.51648	32.31975	50.47622	22.14551	15.03279
6	379.2614	320.7022	70.89777	108.1699	75.33159	65	26.909	31.35368	48.05633	15.96953
7	371.5328	400.7022	50.6717	99.26182	84.44543	65	32.46259	49.30955	27.98502	14.20571
8	426.4736	382.9169	51.28612	110.4204	96.25642	65	25.51265	45	30.0347	16.4447
9	455	452.0681	101.2861	98.48865	46.25642	65	27.24451	32.80284	55	24.35663
10	455	425.0122	102.4829	85	96.25642	46.83228	31.781	34.70053	25.72526	32.87751
11	417.6214	400.1585	112.6041	127.3472	146.2564	65	30.68051	52.05293	20.68154	10.01162
12	430.0328	422.7976	127.0438	97.44613	142.8555	66.77055	27.93882	49.91953	31.27763	35.84971
13	350.0328	408.3643	129.9616	111.1635	162	65	28.89328	45	12.19888	20.03089
14	430.0328	328.3643	97.95841	93.85765	112	72.77545	31.50753	15	21.81147	33.06842
15	357.5289	408.3643	125.3128	102.6092	72.24709	69.51408	34.69267	45	21.79396	10.99171
16	323.6045	375.7817	116.0473	85	27.09675	65	32.01686	15	20.62362	28.75407
17	271.9672	438.765	56.47937	85.94941	34.48164	46.23864	54.02472	11.16455	17.65936	20.58893
18	351.9672	358.765	106.4794	104.2435	84.48164	28.46595	31.19196	45	21.08438	10
19	389.0167	438.765	126.9681	107.086	44.83316	65	70	15	31.66874	13.99587
20	455	430.5116	89.23892	119.4467	25.21213	65	84.02351	26.13844	31.05067	10
21	420.2483	355.867	107.5968	124.5094	75.21213	46.34431	70	14.22062	10.2291	12.23036
22	384.2155	349.7336	108.9581	74.50942	25.21213	21.9332	52.42813	30.218	17.73097	26.37444
23	304.2155	269.7336	97.37275	112.9782	75.21213	24.17103	34.51549	14.37614	39.02653	20.92095
24	224.2155	234.2253	79.80722	122.3652	125.2121	24.19863	28.64941	27.8196	17.39608	11.38794

REFERENCES

[1] H. Falsafi, A. Zakariazadeh and Sh. Jadid, "The role of demand response in single and multi-objective wind-thermal generation scheduling: A stochastic programming," *Energy*, vol. 64, pp. 853-867, 2013.

[2] M. Joung and J. Kim, "Assessing demand response and smart metering impacts on long-term electricity market prices and system reliability," *Applied Energy*, vol. 101, pp. 441-448, 2013.

[3] A.K. David and Y.C. Lee, "Dynamic tariffs theory of utility-consumer interaction," *IEEE Transactions on Power System*, vol. 4, pp. 904-911, 1989.

[4] A.K. David and Y.Z. Li, "Effect of inter-temporal factors on the real time pricing of electricity," *IEEE Transactions on Power System*, vol. 1, pp. 44-52, 1993.

[5] N. Venkatesan, J. Solanki and S. Kh. Solanki, "Residential demand response model and impact on voltage profile and losses of an electric distribution network," *Applied Energy*, vol. 96, pp. 84-91, 2012.

[6] M. Parvania, M. Fotuhi-Firuzabad and M. Shahidehpour, "Optimal demand response aggregation in wholesale electricity markets," *IEEE Transactions on Smart Grid*, vol. 4, pp. 1957-1965, 2013.

[7] M. Alipour, K. Zare and B. Mohammadi-Ivatloo, "Short term scheduling of combined heat and power generation units in the presence of demand response programs," *Energy*, vol. 71, pp. 289-301, 2014.

[8] M. Kazemi, B. Mohammadi-Ivatloo and M. Ehsan, "Risk constrained strategic bidding of Gencos considering demand response," *IEEE Transactions on Power Systems,* vol. 30.1, pp. 376-384,

2015.

[9] M. M. Sahebi, E.A. Duki, M. Kia, A. Soroudi and M. Ehsan, "Simultaneous emergency dem-and response programming and unit commit-ent programming in comparison with interrup-tible load contracts," *IET Generation, Transmission & Distribution*, vol. 6.7, pp. 605-611, 2012.

[10] S. Nojavan, B. Mohammadi-Ivatloo and K. Zare, "Optimal bidding strategy of electricity retailers using robust optimization approach considering time of use rate demand response programs under market price uncertainties," *IET Generation, Transmission & Distribution*, vol. 9.4, pp. 328-338, 2015.

[11] M. Parvania and M. Fotuhi Firuzabad, "Demand response scheduling by stochastic SCUC," *IEEE Transactions on Smart Grid*, vol. 1, pp. 89-98, 2010.

[12] F. H. Magnago, J. Alemany and J. Lin, "Impact of demand response resources on unit commitment and dispatch in a day-ahead electricity market," *International Journal of Electrical Power and Energy Systems*, vol. 68, pp. 142-149, 2015.

[13] H.R. Arasteh, M. Parsa Moghaddam, M.K.Sheikh-El-Eslami and A. Abdollahi, "Integrating commercial demand response resources with unit commitment," *Electrical Power and Energy Systems*, vol. 51, pp. 153-161, 2013.

[14] J. Aghaei and M.I. Alizadeh. "Robust n-k contingency constrained unit commitment with ancillary service demand response program," *IET Generation, Transmission & Distribution*, vol. 8, pp. 1928-1936, 2014.

[15] Ch. Zhao, J. Wang, J.P. Watson and Y. Guan, "Multi-stage robust unit commitment considering wind and demand response uncertainties," *IEEE Transactions on Power Systems*, vol. 28, pp. 2708-2717, 2013.

[16] Y. Chen and J. Li. "Comparison of security constrained economic dispatch formulations to incorporate reliability standards on demand response resources into Midwest ISO co-optimized energy and ancillary service market," *Electric Power Systems Research*, vol. 81, pp. 1786-1795, 2011.

[17] A. Ashfaq, S. Yingyun and A. Zia Khan, "Optimization of economic dispatch problem integrated with stochastic demand side response," in Proceedings of the *IEEE International Conference on Intelligent Energy and Power Systems*, pp. 116-121, 2014.

[18] N. I. Nwulu and X. Xia, "Multi-objective dynamic economic emission dispatch of electric power generation integrated with game theory based demand response programs," *Energy Conversion and Management*, vol. 89, pp. 963-974, 2015.

[19] H. Khorramdel, B. Khorramdel, M. T. Khorrami and H. Rastegar, "A multi-objective economic load dispatch considering accessibility of wind power with here-and-now (hn) approach," *Journal of Operation and Automation in Power Engineering*, vol. 2, pp. 49-59, 2014.

[20] Sh. Jiang, Zh. Ji and Y. Shen, "A novel hybrid particle swarm optimization and gravitational search algorithm for solving economic emission load dispatch problems with various practical constraints," *International Journal of Electrical Power & Energy Systems*, vol. 55, pp. 628-644, 2014.

[21] D. C. Secui, "A new modified artificial bee colony algorithm for the economic dispatch problem," *Energy Conversion and Management*, vol. 89, pp. 43-62, 2014.

[22] L. Wang and L.P. Li, "An effective differential harmony search algorithm for the solving non-convex economic load dispatch problems," *International Journal of Electrical Power & Energy Systems*, vol. 44 pp. 832-843, 2013.

[23] A. Hatefi and R. Kazemzadeh, "Intelligent tuned harmony search for solving economic dispatch problem with valve-point effects and prohibited operating zones," *Journal of Operation and Automation in Power Engineering*, vol. 1, pp. 84-95, 2013.

[24] L. Benasla, A. Belmadani and M. Rahli, "Spiral optimization algorithm for solving combined economic and emission dispatch," *International Journal of Electrical Power & Energy Systems*, vol. 62, pp. 163-174, 2014.

[25] A. Gargari, "Imperialist competitive algorithm: An algorithm for optimization\ inspired by imperialistic competition," in Proceedings of the *IEEE Congress on Evolutionary Computation,* pp. 4661-4667, 2007.

[26] B. Mohammadi-ivatloo, A. Rabiee, A. Soroudi and M. Ehsan, "Imperialist competitive algorithm for solving non-convex dynamic economic power dispatch," *Energy*, vol. 44, pp. 228-240, 2012.

[27] R. Roche, L. Idoumghar, B. Blunier, and A. Miraoui. "Imperialist competitive algorithm for dynamic optimization of economic dispatch in power systems," *Springer-Verlag Berlin Heidelberg*, vol. 7401, pp. 217-228, 2012,

[28] H. Aalami, M. Parsa Moghadam and G. R. Yousefi, "Modeling and prioritizing demand response programs in power markets," *Electric Power System Research*, vol. 80, pp. 426-435, 2010.

[29] N. Pandita, A. Tripathia, Sh. Tapaswia and M. Panditb, "An improved bacterial foraging algorithm for combined static/dynamic environmental economic dispatch," *Applied Soft Computing*, vol. 12, pp. 3500-3513, 2012.

[30] A. Abdollahi, M. Parsa Moghaddam, M. Rashidinejad and M. K. Sheikh-El-Eslami, "Investigation of economic and environmental-driven demand response measures incorporating

UC," *IEEE Transactions on Smart Grid*, vol. 3, pp. 12-25, 2012.

[31] R. Zhang, J. Zhou, L. Mo, Sh. Ouyang and X. Liao, "Economic environmental dispatch using an enhanced multi-objective cultural algorithm,"

Electric Power Systems Research, vol. 99, pp. 18-29, 2013.

[32] Staff Report, "Assessment of demand response and advanced metering," *FERC*, Available: http://www.FERC.gov Dec. 2008.