Modeling Price- and Incentive-Based Demand Response Strategies in the Renewable-based Energy Markets

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***Abstract*—This paper models the impacts of Demand Response Programs (DRPs) on the behavior of energy market participants in the electricity markets in the presence of renewable energies. In such oligopolistic environment, market interactions are considered by using a game theoretic model, and the market transactions are cleared by means of a Security Constraint Unit Commitment program (SCUC). One sample is considered from each main category of DRPs consisting of different types of time of use tariffs, real-time pricing, critical peak pricing from Price-Based Demand Response (PBDR), and different types of emergency demand response program tariffs from Incentive Based Demand Response (IBDR) in the presence of the wind farms. It is expected that the numerical results with the presence of renewable energy resources indicate that different types of these DRPs differently affect the oligopolistic behavior of market players that should be studied by the system operators before their implementation. Using Monte Carlo simulation method, several scenarios are generated to show the possible contingencies in Day-Ahead energy market. Then some scenario reduction methods are used for reduction the numbers of scenarios. Finally, a two-stage stochastic model is applied to solve this scheduling in a mixed-integer linear programming through GAMS. Consequently, the effect of demand response in the reduction of the operation cost is proved. The proposed approach is tested on a modified IEEE six-bus system.**

Keywords—Electricity Market; Renewable Resources; Demand Response;

I. NOMENCLATURE

A. Set and Indices

i	Index of generation unit
m	Segment index
t, t'	Index of hours
w	Index of wind scenario
l	Index of transmission lines

B. Parameters:

MDT_i	Minimum down time of unit i
MUT_i	Minimum up time of unit i
N	Number of agents
P	Data of Generation Units
d	Demand
RU_i	Ramp up of unit i[MW/h]
RD_i	Ramp down of unit i[MW/h]
SUR_i	Start-up cost rate of unit i [$]
SDR_i	Shutdown cost rate of unit i [$]
$\rho_0(t)$	Initial electricity price [$/MW h]
ω_s	Probability of wind power scenario s

C. Variables:

$C_{EDRP}(t)$	Cost of customer's participation in EDRP [$]
F_{lwt}	Power flow through line l in hour t of wind scenario w [MW]
U_{it}	Binary status indicator of generating unit I in hour t
F_{lt}	Flow of transmission line L ,time T [MW]
$C_{i,t}^{G\_DC}$	Offered price of the down-reserve of unit i in hour t [MW]
$C_{i,t}^{G\_UC}$	Offered price of the Up-reserve of unit i in hour t [MW]
$P_{i,t,m}^{e}$	Power of segment m of unit i in hour t [MW]
$C_{i,t,m}^{G\_Eng}$	Slop of each segment of unit i in hour t
$C_{i,t}^{G\_UE}$	Offered price of up- employed reserves of unit i in hour t
$C_{i,t}^{G\_DE}$	Offered price of down- employed reserves of unit i in hour t
$r_{i,t,w}^{G\_up}$	Real-time up- used reserves of unit i in hour t [MW]
$r_{i,t,w}^{G\_dn}$	Real-time down- used reserves of unit i in hour t [MW]
$R_{i,t}^{G\_UC}$	scheduled amount of up- reserve of unit i in hour t [MW]
$R_{i,t}^{G\_DC}$	scheduled amount of down- reserve of unit i in hour t [MW]
δ_{bwt}	Voltage angle at bus b in hour t of wind scenario [rad]

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II. INTRODUCTION

Nowadays, necessity attention to environmental issues, fuel troubles, and economic points of view of applying the conventional sources extremely encouraged decision makers to replace thermal sources by Renewable Energy Sources (RESs) [1], [2].

To dealing with the intermittent nature of RESs, an effective management system associated with Demand Response Program (DRP) is required [3], [4]. DRPs can mitigate the risks of taking part in the energy markets for market players, furthermore improve the reliability and efficiency of the electrical system.

Although the participation of customers in DRPs is an advantageous option from system operator's points of view, it can significantly affect the strategic behavior of generations companies (Gencos), especially in oligopoly environments [5].

In [6], authors proposed the review paper and examined the latest Demand Response (DR) definition and classification which is used in this paper. The significant influences of intermittent wind units and DR on power system functioning and electricity market clearing are investigated in [7], [8].

Focusing on the incentive-based DR, peak demands can be shifted to off-peak, and the cost of system operation is minimized [9], [10]. In these studies, the responsive loads are moved from peak period to off-peak under the Independent System Operator (ISO) direct load controls considering the network limits and in the presence of wind generations.

In [11], a model is presented to operate both Gencos and demand side in power system considering the wind producers. The effects of both PBDR and IBDR are investigated to provide a flexible load pattern and facilitate the integration of wind generation.

In this paper, a model is proposed for short-term scheduling with demand side management. In fact, system uncertainties including an outage of wind generation sources and implementation of demand response programs are merged in a two-stage stochastic framework for the optimum operation of the network system. For increasing the network security and decreasing the operation cost, a demand response model is considered.

The paper is structured as follows. The different types of modeling the wind farms are introduced, and their mathematical model is developed in section II. In section III, the procedure of scenario generation is expressed, and two-stage stochastic model is formulated. Numerical results of the model are in section IV, and the conclusion is in the last section.

III. THE PROPOSED MODEL OF THE RESPONSIVE LOAD

Participants of the oligopoly markets are able to boost their profit through deciding on an effective strategy. Exploring such a strategy in the day-ahead market has captured the attention of the researchers recently.

In addition, the market structure and its fundamental rules might make an impact on this procedure, significantly [12]–[14]. Demand response programs sounds grabbed the attention of demand side through offering some incentives.

Recent modeling of the responsive loads is investigated. Ref [15] has proposed a game based on the linear method for retailer's scheduling. The uncertainty of market prices and customer's demands are exemplified as random variables. They are illustrated through a limited number of scenarios. The competitive market is modeled, and an attempt is made to discover the Nash-equilibrium of the system. Participant response to market prices is formulated employing the econometric model presented in [16], [17]. The presented model in [15] has been solved as an equilibrium problem. The diagonalization approach [18] is employed to solve the presented equilibrium formulation. Finally, the problem is solved by the use of the Lagrangian relaxation algorithm.

In this paper, both the priced- and incentive-based demand response strategies are formulated. From the operator system's point of view in two markets, day-ahead and real-time market, the objective function of the problem can be written as follows.

Minimize

$$\begin{aligned}&\sum_{t=1}^{NT}\sum_{i=1}^{NG}\left(SUC_{i,t}+MPC_iU_{i,t}+\sum_{m=1}^{NM}(P_{i,t,m}^{e}C_{i,t,m}^{G\_Eng})\right)+\\&\sum_{t=1}^{NT}\sum_{i=1}^{NG}C_{i,t}^{G\_UC}R_{i,t}^{G\_UC}+C_{i,t}^{G\_DC}R_{i,t}^{G\_DC}\\&+\sum_{t=1}^{NT}\sum_{w=1}^{NW}\rho_w\left(\sum_{i=1}^{NG}C_{i,t}^{G\_UE}r_{i,t,w}^{G\_up}-C_{i,t}^{G\_DE}r_{i,t,w}^{G\_dn}\right)+\sum_{t}C_{EDRP}(t)\end{aligned} \quad (1)$$

$P_{i,t,m}^{e}$ is the amount of generation of segment m in a linear cost function. $C_{i,t,m}^{G\_Eng}$ denotes the slope of each segment. $C_{i,t}^{G\_DC}$ and $C_{i,t}^{G\_UC}$ are the offered price of the down-reserve amount of power generation unit and up-reserves. To denote offered price of up- and down- employed reserves of each generation unit $C_{i,t}^{G\_UE}$ and $C_{i,t}^{G\_DE}$ are used. The scheduled amount of up- and down-reserve of each generation unit are presented respectively through $R_{i,t}^{G\_UC}$ and $R_{i,t}^{G\_DC}$. $r_{i,t,w}^{G\_up}$ and $r_{i,t,w}^{G\_dn}$ are the amount of real-time up- and down- used reserves of each generation unit. $SUC_{i,t}$ is the amount of start-up cost of each generation unit at T time. The minimum production cost is formulated as $MPC_iU_{i,t}$. The Equation (1) includes other types of costs such as the cost of the electricity of Gencos and so on.

The offer price of the Gencos up/down reserve is included in the second part of the objective function. To consider the scenarios the next term is addressed. Roulette wheel mechanism is employed to generate the scenarios of wind power which are described more fully in [19].

A. The equations of day-ahead market

Equation (2) represents the equilibrium between demand and supply. Equation (3) describes the DC load flow and models the linearized transmission lines limits. Moreover, to formulate the branch limitations Equation (4) is represented. Equation (5) illustrates that wind units are limited in the day-ahead term because of the uncertainty of the wind power generation. Equations (6)-(10) represent the electricity and capacity of conventional power plants.

The outage power of these kinds of units is restricted in Equations (7)-(8). Constraints of reserve up/down are explained in Equations (9)-(10). The start-up limit of thermal plants is explained through the inequality (11). The minimum up/down times of thermal units are formulated in (12) and (13), respectively [20].

$$\sum_{i\in G_b} P_{it} + \sum_{wf\in WF_b} P_{wf,t}^{WP,S} - \sum_{j\in J_b} L_{j,t}^{C} = \sum_{l\in L_b} F_{l,t}^{0} \quad \forall b,t \tag{2}$$

$$F_{l,t}^{0} = \left(\delta_{b,t}^{0} - \delta_{b',t}^{0}\right)/X_l \quad \forall l,t \tag{3}$$

$$-F_l^{\max} \le F_{l,t}^{0} \le F_l^{\max} \quad \forall l,t \tag{4}$$

$$0 \le P_{wf,t}^{WP,S} \le P_{wf,t}^{WP,\max} \quad \forall wf,t \tag{5}$$

$$P_{i,t} = \sum_{m=1}^{NM} P_{i,t,m}^{e}\ ,\ 0 \le P_{i,t,m}^{e} \le P_{i,m}^{\max} \quad \forall i,t \tag{6}$$

$$P_{i,t} + R_{i,t}^{G\_UC} \le P_i^{\max} \quad \forall i,t \tag{7}$$

$$P_{i,t} - R_{i,t}^{G\_DC} \ge 0 \quad \forall i,t \tag{8}$$

$$0 \le R_{i,t}^{G\_UC} \le RU_i\,\tau \quad \forall i,t \tag{9}$$

$$0 \le R_{i,t}^{G\_DC} \le RD_i\,\tau \quad \forall i,t \tag{10}$$

$$SUC_{i,t} \ge SC_i\,(U_{i,t} - U_{i,t-1}) \quad \forall i,t \tag{11}$$

$$\sum_{t'=t+2}^{t+MUT_i} \left(1-U_{i,t'}\right) + MUT_i\left(U_{i,t} - U_{i,t-1}\right) \le MUT_i \quad \forall i,t \tag{12}$$

$$\sum_{t'=t+2}^{t+MDT_i} U_{i,t'} + MDT_i\left(U_{i,t-1} - U_{i,t}\right) \le MDT_i \quad \forall i,t \tag{13}$$

B. The equations of real-time market

In this session facing the constraints is subjected in regards to all scenarios. The demand side and supply equilibrium are taken into account for all the scenarios in Equation (14) through considering the intermittent nature of wind power, which lead to unpredictable wind power outage.

Inequalities (15)-(16) are almost the same as (3)-(4) but with this difference that (15)-(16) are formulated for all the scenarios. Inequalities (17)-(18) denote that the amount of up/down reserve in all scenarios is necessary to be restricted to the planned reserve previously submitted to the markets. The equality (19) typifies the net electricity generation of thermal units in real-time.

The constraints of power plants are defined by (20). Inequalities (21)-(22) formulate Ramp up/down constraint.

$$\sum_{i\in G_b}\left(r_{i,w,t}^{G\_up} - r_{i,w,t}^{G\_dn}\right) + \sum_{wf\in WF_b}\left(P_{wf,w,t}^{W} - P_{wf,t}^{WP,S}\right) = \sum_{l\in L_b} F_{l,w,t} - F_{l,t}^{0} \quad \forall b,w,t \tag{14}$$

$$F_{l,w,t} = \left(\delta_{b,w,t} - \delta_{b',w,t}\right)/X_l \quad \forall l,w,t \tag{15}$$

$$-F_l^{\max} \le F_{l,w,t} \le F_l^{\max} \quad \forall l,w,t \tag{16}$$

$$0 \le r_{i,w,t}^{G\_up} \le R_{i,t}^{G\_UC} \quad \forall i,w,t \tag{17}$$

$$0 \le r_{i,w,t}^{G\_dn} \le R_{i,t}^{G\_DC} \quad \forall i,w,t \tag{18}$$

$$P_{i,w,t} = P_{i,t} + r_{i,w,t}^{G\_up} - r_{i,w,t}^{G\_dn} \quad \forall i,w,t \tag{19}$$

$$P_i^{\min} U_{i,t} \le P_{i,w,t} \le P_i^{\max} U_{i,t} \quad \forall i,w,t \tag{20}$$

$$P_{i,w,t} - P_{i,w,t-1} \le RU_i\,U_{it} + SUR_i\left(1-U_{i,t-1}\right)\ \forall i,w,t \tag{21}$$

$$P_{i,w,t-1} - P_{i,w,t} \le RD_i\,U_{i,t-1} + SDR_i\left(1-U_{i,t}\right)\ \forall i,w,t \tag{22}$$

IV. NUMERIC RESULTS OF THE MODEL

With regard to indicating the strong influence of DRPs in the presence of wind farms on oligopolistic behaviors of the energy market, the IEEE six-bus test system is employed [21]. In addition to EDRP, different types of TOU[22], CPP and RTP programs are studied. The influence of variant kinds of TOU programs on the behavior of Genco1, the total load of the system and many aspects of considering renewable energy simultaneously with the implementation of DRPs are discussed in this paper. Impacts of diverse kinds of DRPs on bidding of Genco1 in the presence of wind farm and without considering wind power is illustrated in Fig. 1.

It can show that renewable energy makes an impact on the behavior of Genco1specially at peak hours. Impacts of diverse kinds of TOU on the generation of Genco2 in the presence of wind farm and without considering wind power is illustrated in Fig. 2. Fig. 2 is presented to discuss the impact of different types of TOU programs on the behavior of market players. These figures depict the electricity generation output of Genco 2 without the presence of wind farm and in the presence of the wind units respectively. These results illustrate the different tariffs of TOU demand response in the presence of wind farm can more remarkably effect on shifting peak loads in peak hours.

Assuming that 20% of consumers have participated in programs, the RTP program prices are gained due to the simulation of the market without taking into account of the DRPs in Table II. Different types of program are illustrated in Table I, both the first and the second program of TOU have three levels of tariffs, while the third TOU has four levels. An incentive fee of amount of 30% of the tariff is considered as demand decrease, the tariffs of EDRP are the average of market prices. The self and cross elasticities are derived from [23].

TABLE I. TARIFFS/INCENTIVES OF CONSIDERED DRPS ($/MWH)

Case	**Valley (1 to 8)**	**Off-peak. (9-11,22-24)**	**Peak. (12-14 ,19-21)**	**Critical peak (15 to 18)**
TOU1	31.6	63.2	94.8	94.8
TOU2	15.8	63.2	126.4	126.4
TOU3	31.6	63.2	94.8	189.6
EDRP	63.2	63.2	63.2	63.2:tariff 18.9:incentive
CPP1	63.2	63.2	126.4	126.4

TABLE II. REAL TIME PRICES ($/MWH)

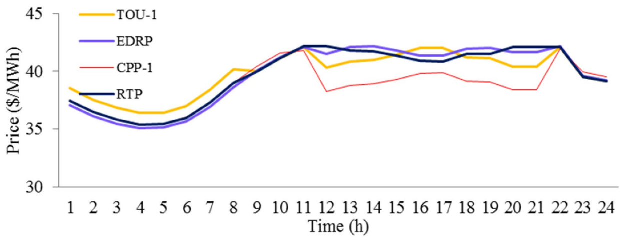
Hour	1	2	3	4	5	6
Price	54.7	52.8	51.2	50.1	50.2	51.7
Hour	7	8	9	10	11	12
price	54.4	57.7	60.7	63.0	65.2	66.7
Hour	13	14	15	16	17	18
price	67.9	69.2	74.7	82.1	82.4	72.5
Hour	19	20	21	22	23	24
price	71.6	66.9	66.9	64.9	59.8	59.0

V. DISCUSSION AND CONCLUSIONS

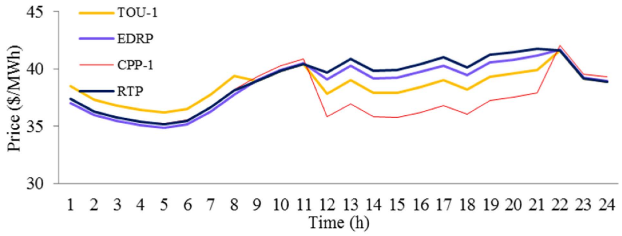
In the present paper, in addition to using a stochastic framework for economic dispatch and unit commitment, a demand response model has been applied for obtaining the helpful instruments for ISO along with a decrease in total operation cost.

A scenario-based contingencies analysis has been performed, and DR was modeled. A two-stage stochastic SCUC has been used in such a way that contingencies are analyzed in the second stage for security aspects and the final decision on units' commitment states and their optimal generation along with demand response program are made in the first stage through minimizing the total operation cost by MILP that is modeled in GAMS 24.0 and solved by CPLEX 12.0. Besides, DRPs were assumed for the demand side contracts of the company in the presence of wind power generation and also its effect on the gained profit was discussed thoroughly in this work.

The impact of DRPs on the function of the Gencos of the utility is considered and is included in the formulation. The derived numerical results demonstrated the efficiency and effectiveness of the presented approach. By applying the test system according to [21] and approximate real electricity market information, the power and intensity of the presented approach are judged and calculated, and it appears that, in all sample cases and items, the achieved results are more acceptable than the previous results.

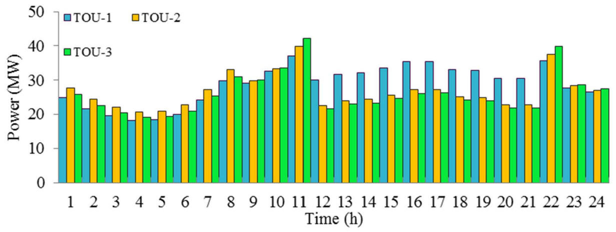


(a) Without considering wind power

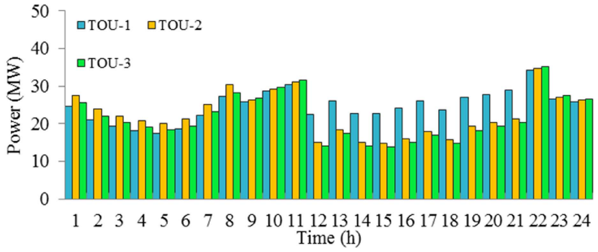


(b) In the presence of wind farm

Fig. 1. Impacts of variant kinds of DRPs on bidding of Genco1 in the presence of wind farm and without considering wind power.



(a) Without considering wind power



(b) In the presence of wind farm

Fig. 2. Impacts of variant kinds of TOU on power generation of Genco2 in the presence of wind farm and without considering wind power.

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