

Integrating commercial demand response resources with unit commitment



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ABSTRACT

This paper investigates the impact of demand response resources (DRRs) as the consequence of implementing demand response programs (DRPs) on power markets. Indeed, this paper incorporates commercial concept of DRPs with unit commitment (UC) to solve “unit and DR commitment” problem. This mixed problem will decrease the network operation cost by using of DRPs’ potential to mitigate some UC constraints and avoiding some highly priced generation of units. Here, employing the proposed DRPs model is considered as a new concept in electricity market. In this paper, a dynamic approach is proposed for participating DR service providers in power markets in order to maximize their profits. This paper also aims to concurrently consider the aforementioned commercial DRPs supply model with the generators supply curves in the unit commitment problem, which is solved to minimize operational costs considering multifarious constraints. Performance of the proposed approach is investigated through numerical studies using a standard IEEE 10-unit test system. The results show the efficiency and advantage of the proposed methodology.

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1. Introduction

In the strategic plan of International Energy Agency (IEA), demand side activities are introduced as the first choice in all energy policy decisions, because of their potential benefits both at operation and economic levels [1]. Demand response programs are short-term activities taken by customers to adjust their electricity consumption in order to mitigate the volatility of electricity market’s prices; or reliability problems on the electricity network [2]. Cost and emission reduction, decrease of fuel dependency, increase in power system reliability, and an increase in revenues are some of the benefits resulting by implementing demand side management (DSM) programs [1,3,4]. There are three types of demand side management measures based on the overall purpose of the load management (LM) program [5]:

- *Environmental-driven programs*: Achieves environmental and/or social goals by reducing energy usage, deferring commitment of polluted units, leading to increased energy efficiency, and/or reduced greenhouse gas emissions.

- *Network-driven programs*: Deals with challenges in the electricity network by reducing demand in ways that maintain the system reliability in the immediate term and over the longer term, deferring or avoiding the need for distribution and transmission infrastructure enforcements and upgrades.
- *Economic/Market-driven programs*: Provides short term responses to electricity market conditions to reduce the overall costs of energy supply, increase the reserve margin and mitigate the price volatility.

Demand response is established to motivate changes in electricity consumption by end-users. Dramatic increases in electricity demand have made the use of DRPs more attractive to both customers and system operators [2,6–8].

DRPs are divided into three basic categories so-called, Time-Based Rate Programs (TBRPs), Incentive-Based Programs (IBPs) and Market-Based Programs (MBPs) as depicted in Fig. 1.

Each of these categories is consisted of several programs. Time-based programs include: Time of Use (TOU), Real Time Pricing (RTP), Critical Peak Pricing (CPP). These programs expose customers to varying levels of price exposure; the least with TOU and the most with RTP [2]. In TBRPs, the electricity price changes for different periods, so customers should adjust their consumption according to the time and associated tariffs.

IBPs consist of Direct Load Control (DLC), Emergency Demand Response Program (EDRP), Interruptible/Curtailable service (I/C), Capacity market Program (CAP). DLC and EDRP are voluntary programs, and if customers do not curtail consumption, they are not

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Nomenclature	
Indices	
j	number of generators
i	index of demand response service providers
k	index of generators prohibited zones
t	time index
Constants	
Ω_i	customer type
RD	amount of required demand response (MW)
$SUC_{i,t}$	start-up cost of j th unit at time t (\$/each switching)
$SDC_{i,t}$	shut-down cost of j th unit at time t (\$/each switching)
N	number of generators
T	time horizon of unit commitment
N^{DRSP}	number of demand response service providers
HSC_j	hot start-up cost (\$/each hot start-up)
CSC_j	cold start-up cost (\$/each cold start-up)
MDT_j	minimum down-time of j th unit (h)
MUT_j	minimum up-time of j th unit (h)
CST_j	cold start time of j th unit (h)
D_t	demand during hour t (MW)
$\underline{p}_{j,t}$	minimum generation of j th unit (MW)
$\overline{p}_{j,t}$	maximum generation of j th unit (MW)
$DR_{i,t}^{max}$	maximum value for DR service providers enabled DR (MW)
SR_t	amount of spinning reserve in hour t (MW)
RUR_j	ramp up rate limit of j th unit (MW/h)
RDR_j	ramp down rate limit of j th unit (MW/h)
PZ_j	number of prohibited zones of j th unit
$p_{j,k}^{lower}$	lower bound of the k th prohibited zone of j th unit (MW)
$p_{j,k}^{upper}$	upper bound of the k th prohibited zone of j th unit (MW)
Variables	
DP	demand response clearing price (\$/MW h)
a_i, b_i	DR service providers' supply curve coefficients
$DR_{i,t}^0$	amount of sold DR by i th provider at hour t (MW)
$p_{j,t}^0$	power output of j th unit at hour t (MW)
$u_{j,t}$	on/off status indicator of unit j at hour t where 1 means on and 0 means off
T_j^U	time during which the j th unit is continuously on (h)
T_j^D	time during which the j th unit is continuously off (h)
SUI	start-up indicator
SDI	shut-down indicator
Functions	
$F_{j,t}$	j th generator supply function
$F_{i,t}^{DR}$	supply function of i th DR service provider
pf_i	i th DR service provider profit function

penalized. I/C and CAP are mandatory programs, and enrolled customers are subjected to penalties if they do not curtail when directed. In IBPs, customers are being encouraged with independent system operator (ISO) or local utility to moderate their consumption. Moreover, MBPs include: Demand Bidding (DB) and Ancillary Service (A/S) programs. DB programs encourage large customers to provide load reductions at a price at which they are willing to be curtailed, or to identify how much load they would be willing to curtail at posted prices. A/S programs allow customers to bid load curtailments in electricity markets as operating reserves. In the market-based approach, all players are categorized in two groups: DR Service Users (DRSUs) as well as DR Service Providers (DRSPs). DRSUs need demand response to improve their business and

system reliability while, DRSPs are aggregators and customers who provide DR to increase their benefit. This structure creates an efficient market for trading DR. As introduced in [9], DRPs is treated as a tradable commodity in the power market where, the demand response exchange operator (DRXO) collects both the aggregated demand and individualized supply curves. Then, it clears the supply and demand at a common price [9].

DR programs are faced with some important barriers to be successfully implemented in the network. Ref. [10] has raised some important barriers related to DR. One of these common failures of demand response is the inability of customers to continuously participate in DRPs so called “response fatigue”. Demand response service providers are considered in this paper as entities to manage

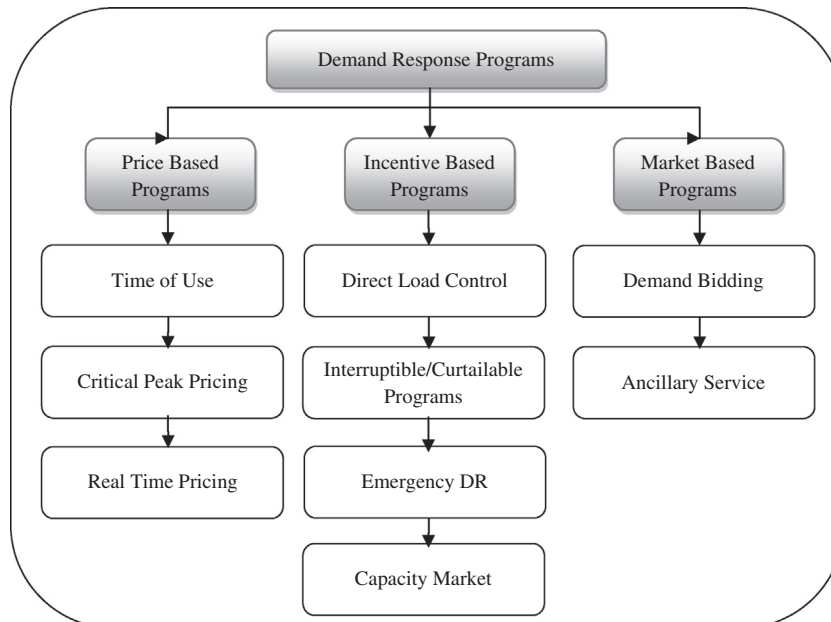


Fig. 1. Classification of DR programs.

the participation of end-users in DRPs. A dynamic approach is proposed to model the behavior of DR service providers in order to maximize their profit. At the same time, the ISO tries to operate the system with minimum possible cost. The idea of “Unit and DR commitment” problem is proposed in this paper that ISO should integrate generators’ supply curves as well as DRSPs’ DR supply curves and then solving the problem.

In fact, this paper considers both side of DR trading market, i.e. selling and purchasing. On the one hand, there are demand response service entities who are executors that manage customers’ DR capacities and provide DR resources in the network. As above mentioned, their main goal is to maximize their profit of providing DRPs. From this point of view, this paper introduces a dynamic method for DRSPs to participate in demand response programs. On the other hand, ISO caters all resources in the network to optimally provide network’s load. His optimal schedule is to minimize the operation cost of the network. Unit and DR commitment program will give more flexibility to ISO to manage systems’ constraints and needs to improve the system operational conditions. The results of solving the proposed problem will simultaneously determine the on/off status of generators as well as DRSPs and also the amount of power that they should provide during the pre-specified time horizon.

The time frame of DR trading must coincide with that of the system. Both time frames could be divided into different time scales such as day ahead, hour ahead, real time, etc. This paper addresses only the day ahead time scale.

As mentioned, in this study, DRSPs’ supply curve will concurrently be considered with generators supply curve in a unit commitment (UC) problem. Generation scheduling and UC problem have always been presented as important issues in power system researches. UC has a combinational nature with true multi period characteristics in the form of nonlinear and non-convex as well as mixed-integer problem. UC involves on/off status of generation units and generators production values to meet the forecasted demand for a given time horizon [11–13]. The optimal schedule should minimize the system production costs during the study period, while satisfying load demand, spinning reserve requirements, and the physical as well as operational constraints of each individual unit [14–17]. Several deterministic, heuristic, and hybrid methods have been proposed in the last decades for solving the UC as a large scale, nonconvex, and mixed-integer combinatorial optimization problem. In general deterministic methods are unable to find a solution within the available time frame, when the problem is medium or large size [18,19]. These limitations have been redounded to introduce the heuristic methods [20–22]. Heuristic optimization algorithms may have some advantages to solve such a complicated optimization problem, while the main drawback of heuristic methods is that they cannot guarantee the optimal solution. Since there exist a need for more improvement to the existing unit commitment solution techniques, hybrid methods have been experienced [23–25].

DRPs are useful tools for the independent system operator, which can be activated within a relatively short time in critical system conditions. In the authors’ previous work [26], an economic model of price/incentive responsive loads for DRPs has been developed based on the concept of “price elasticity of demand” and “customers’ benefit function”. The focus of [26] is on direct load control (DLC) and emergency demand response programs (EDRPs) which are categorized as voluntary incentive-based programs. In these programs, it is considered that ISO prizes the customers for load reduction, but does not penalize their violation. Furthermore, for investigating both economic- and environmental-driven measures of voluntary IBPs, a new formulation of cost-emission based unit commitment problem associated with DRRs (UCDR) is introduced in this authors’ work [26].

Providing the required amount of load and reserve is considered as a crucial issue of generation scheduling problems. Therefore,

demand response resources can also be called to satisfy the value of demand load and reserve. As previously mentioned, DRPs are useful tools for the ISO which can be activated within a relatively short time in critical system conditions. Therefore, employing of demand response programs can be considered to cover part of the concerns of load and reserve supply.

Ref. [27] has introduced indices for evaluating customer response. Then, scheduling of generation and demand response has discussed in this reference. Economic models of tbrps and ibps have been addressed in many researchers in recent years [28–33]. Valero et al. [28] have discussed methods for customer and demand response policies in new electricity markets. [29,30] have presented an economic model of price responsive loads based on the constant value of price elasticity. Market clearing programs are discussed in [31], which takes their economic benefits into account. In the authors’ previous studies [26,32–34], an economic model of responsive loads has been derived.

Nguyen et al. [9] have considered a typical linear structure for DRSPs’ supply curves with constant coefficient for MBPs. In this paper, a dynamic structure for the demand function is suggested. The proposed model is called dynamic, because the constant coefficients of DRSPs’ supply curves are determined for each hour of scheduling, separately. The dynamics of the markets are the results of players’ decisions [35]. In the proposed dynamic approach, each of DRSPs’ supply curves is achieved based upon other providers’ behavior in previous hours. It also depends on the amount of demand response, which is required for each hour. Furthermore, the aforementioned dynamic demand response supply curves will be considered beside the generators’ supply curves in a unit commitment problem. The optimum scheduling of generators and the DR penetration rate will also be attained as the result of this problem.

As above mentioned, the aim of DRSPs is to maximize their own profit by trading DR. However, reduction of operation cost is considered as the main aim of ISO. Furthermore, generators can have some strategies to maximize their own profit. However, their strategy is behind the scope of this paper.

The rest of the paper is organized as follows. The problem formulation is explained in details in Section 2. The procedure of investigating a dynamic approach for participating DRSPs’ in demand response programs is elaborated in this section. Section 3 conducts the numerical simulations. Finally, concluding remarks are drawn in section 4.

2. Problem formulation

Fig. 2 depicts the hierarchy of investigating DRRs impact on the unit commitment problem. The important point is to link the demand and supply-side resources to the generation scheduling problem in a way that the economic-driven measures of DRRs be observable. In the subsequent sections, the objective function and constraints of the problem are discussed.

2.1. DRSPs’ supply curve

This section emphasizes on supply side of the MBPs. DRSPs want to maximize their profits. In this section, a dynamic approach is developed for DRSPs’ supply function which is assumed to be a linear curve, as follows [9]:

$$DP = a_i \times DR_i + b_i(1 - \Omega_i), \quad i = 1, \dots, N^{\text{DRS}} \quad (1)$$

The coefficient Ω is the customer type and represents a customer’s willingness to participate in DR programs. It takes a value between 0 and 1. By increasing in the amount of Ω , the cost of DR decreases because the customer has more willingness to participate in DR. Also, a_i and b_i are common coefficients applied to all customers [9]. Eq. (1) can be presented as:

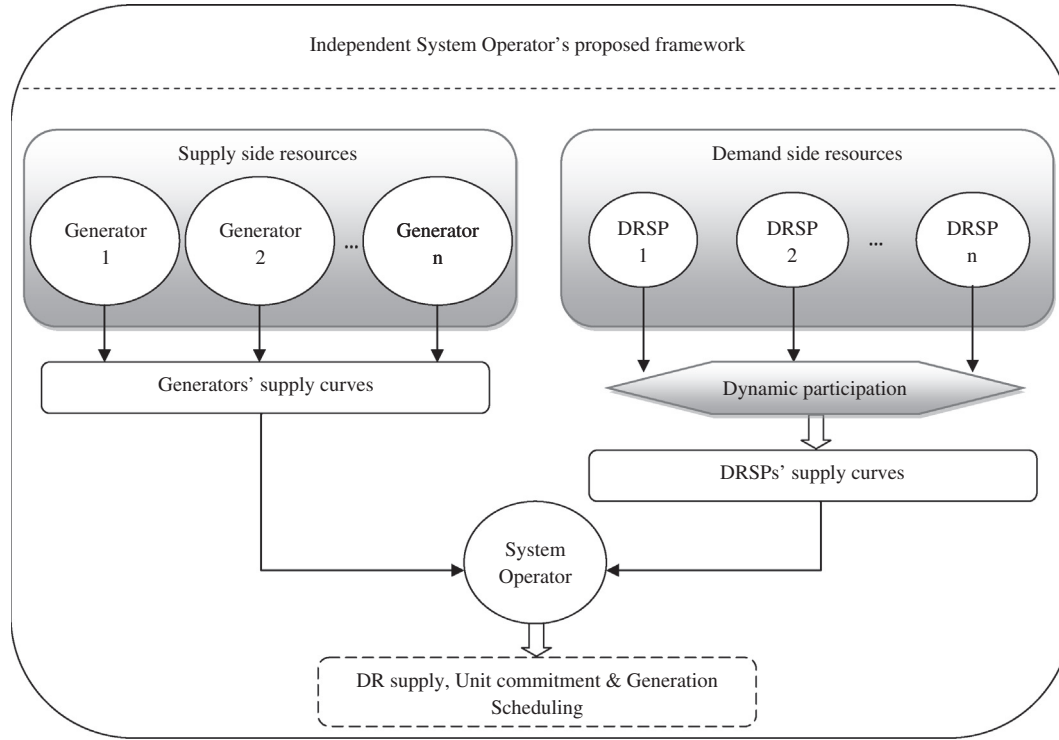


Fig. 2. General view of the proposed concept.

$$DP = a_i \times DR_i + b'_i, \quad i = 1, \dots, N^{\text{DRS}} \quad (2)$$

where

$$b'_i = b_i(1 - \Omega_i)$$

The amount of the traded DR can be considered as a function of DP:

$$DR_i = \frac{DP - b'_i}{a_i}, \quad i = 1, \dots, N^{\text{DRSP}} \quad (3)$$

A balance should exist between the amount of the sold and purchased DR. By considering this constraint, following equations will be obtained:

$$RD = \sum_{i=1}^{N^{\text{DRS}}} DR_i = \sum_{i=1}^{N^{\text{DRS}}} \frac{DP - b'_i}{a_i} \quad (4)$$

then

$$DP = \frac{RD + \sum_{i=1}^{N^{\text{DRS}}} \frac{b'_i}{a_i}}{\sum_{i=1}^{N^{\text{DRS}}} \left(\frac{1}{a_i}\right)} \quad (5)$$

DRSPs with high willingness for participating in DRPs have smaller b'_i coefficient in their demand response supply curve. With the order reversed, if DRSPs have less willingness, their associated b'_i coefficient will get higher. An approach for determining b'_i to maximize DRSPs' benefit is described as follows. In this approach, each aggregator should maximize its benefit, which can be defined as:

$$Pf_i = DP \times DR_i - \cos t_i(DR_i), \quad i = 1, \dots, N^{\text{DRS}} \quad (6)$$

In this paper, it is assumed that consumers' cost functions have quadratic form. Accurate estimation of consumers cost functions needs accurate investigation and data mining in various energy sectors. Ref. [36], investigates the utility function of end-users and proposes some related functions. As it has been described in [36], the utility function can be considered to be quadratic or etc. Participating in DRPs means that customers reduce their electricity

consumption and will lose corresponding utility. Considering this fact, if the revenue of providing DR be less than their pre-existed benefit of electricity consumption, customers will not be convinced to participate in DRPs. However, other functions can be considered as the customers' cost functions and they need accurate analysis on various energy sectors which is behind the scope of this paper. It should be noted that this assumption will not affect on the generality of this study.

Considering quadratic cost function for the consumers and combining Eqs. (3) and (6) will result in:

$$pf_i = DP \times \left(\frac{DP - b'_i}{a_i}\right) - \left[\frac{am_i}{2} \times \left(\frac{DP - b'_i}{a_i}\right)^2 + bm_i \times \left(\frac{DP - b'_i}{a_i}\right)\right], \quad i = 1, \dots, N^{\text{DRS}} \quad (7)$$

where coefficients am_i and bm_i are considered as the customers marginal cost. It is assumed that a_i is always equal to am_i and each DR service provider, changes its supply curve by changing b_i . Each DRSP can increase its profit by offering higher price offer or larger output amounts by lower price offer. The control variable for each customer is considered to be b_i . By taking the derivation of the profit function with respect to b_i for customer i , Eqs. (8), (9) will be obtained:

$$\begin{bmatrix} b'_1(k) \\ b'_2(k) \\ \vdots \\ b'_{N^{\text{DRS}}}(k) \end{bmatrix} = \begin{bmatrix} 0 & \frac{a_1}{a_2} \times \frac{1}{a_2^2 S^2 - 1} & \cdots & \frac{a_1}{a_{N^{\text{DRS}}}} \times \frac{1}{a_2^2 S^2 - 1} \\ \frac{a_2}{a_1} \times \frac{1}{a_2^2 S^2 - 1} & 0 & \cdots & \frac{a_2}{a_{N^{\text{DRS}}}} \times \frac{1}{a_2^2 S^2 - 1} \\ \vdots & \vdots & \ddots & \vdots \\ \frac{a_n}{a_1} \times \frac{1}{a_2^2 S^2 - 1} & \frac{a_{N^{\text{DRS}}}}{a_2} \times \frac{1}{a_2^2 S^2 - 1} & \cdots & 0 \end{bmatrix} \times \begin{bmatrix} b'_1(k) \\ b'_2(k) \\ \vdots \\ b'_{N^{\text{DRS}}}(k) \end{bmatrix} + \begin{bmatrix} \frac{a_1 S}{a_1 S + 1} & 0 & \cdots & 0 & \frac{a_1}{a_1^2 S^2 - 1} \\ 0 & \frac{a_2 S}{a_2 S + 1} & \cdots & 0 & \frac{a_2}{a_2^2 S^2 - 1} \\ \vdots & \vdots & \ddots & \vdots & \vdots \\ 0 & 0 & \cdots & \frac{a_{N^{\text{DRS}}}}{a_{N^{\text{DRS}}} S + 1} & \frac{a_{N^{\text{DRS}}}}{a_{N^{\text{DRS}}}^2 S^2 - 1} \end{bmatrix} \cdot \begin{bmatrix} bm_1(k) \\ bm_2(k) \\ \vdots \\ bm_{N^{\text{DRS}}}(k) \\ RD \end{bmatrix} \quad (8)$$

and,

$$DP = \begin{bmatrix} \frac{1}{a_1 S} & \frac{1}{a_2 S} & \cdots & \frac{1}{a_{N^{\text{DRS}}} S} \end{bmatrix} \cdot \begin{bmatrix} b'_1(k) \\ b'_2(k) \\ \vdots \\ b'_{N^{\text{DRS}}}(k) \end{bmatrix} + \left(\frac{1}{S} \times RD \right) \quad (9)$$

where

$$S = \sum_{i=1}^{N^{\text{DRS}}} \frac{1}{a_i}$$

While Section 2 is devoted to the problem formulation of this paper, Eqs. (8) and (9) are proved in the Appendix A.

It should be mentioned that, there are some upper and lower bands on the amounts of enabled DR. DRSPs will determine their desired supply curves' coefficients to reach to their aims. However, it is assumed that at first, DRSPs determine the DR supply curve coefficients by using of proposed method without considering the existed thresholds on their capacity. Then, they can change their supply curves for out of their capacity and choose higher coefficients in such a way that trading of DR be impossible in reality in higher ranges that are out of their DR capacity. Indeed, although DRSPs utilize dynamic method without considering DR capacity, they propose supply curves for their possible band according to their capacity and change it to very expensive ones in out of the acceptable threshold.

2.2. Generation scheduling & UC associated with DR exchange

2.2.1. Objective function

The outage cost as well as fuel cost of generation units should be considered in power system operation as an objective function of a UC problem. Also, in the proposed UC problem, the cost of enabled DR should be considered as a part of total operation cost. This approach will lead to the best combination of generated power and enabled DR.

The objective function is comprises the fuel costs of generating units, the start-up costs of the committed units, shut-down costs of decommitted units and also enabled DR costs. The start-up cost may include two schemes: hot start-up costs and cold start-up costs, while the shut-down cost is assumed to be fixed. In brief, the objective function in common form is expressed by following equation:

$$\begin{aligned} \text{Minimize } & \left\{ \sum_{t=1}^T \sum_{j=1}^N F_{j,t} (p_{j,t}^0) \times u_{j,t} \right\} \\ & + \left\{ \sum_{t=1}^T \sum_{j=1}^N SUC_{j,t} \times u_{j,t} \times (1 - u_{i,t-1}) \right\} \\ & + \left\{ \sum_{t=1}^T \sum_{j=1}^N SDC_{j,t} \times u_{j,t-1} \times (1 - u_{i,t}) \right\} \\ & + \left\{ \sum_{t=1}^T \sum_{i=1}^{N^{\text{DRS}}} F_{i,t}^{\text{DR}} (DR_{i,t}^0) \times u_{i,t} \right\} \end{aligned} \quad (10)$$

The fuel costs of generating units and the major component of the operating costs for thermal units are generally given in a quadratic form as it is shown by Eq. (11) [37].

$$F_{j,t}(p_{j,t}^0) = \alpha_j + \beta_j \times p_{j,t}^0 + \gamma_j \times (p_{j,t}^0)^2 \quad \text{for } j \in N, t \in T \quad (11)$$

where α_j , β_j and γ_j are fuel cost coefficients for unit j .

It should be noted that DRSPs' cost coefficients are calculated dynamically as describe in previous section.

The generators start-up cost is defined as following:

$$SUC_{j,t} = \begin{cases} HSC_j, & \text{if } MDT_j \leq T_j^D \leq MDT_j + CST_j \\ CSC_j, & \text{if } T_j^D \geq MDT_j + CST_j \end{cases} \quad (12)$$

2.2.2. Problem constraints

The minimization of the problem is subjected to some constraints as following.

2.2.2.1. Initial condition. Initial conditions of generating units include; the number of hours that a unit continuously been on-line or off-line, and its generation output power at an hour before the scheduling.

2.2.2.2. Power balance constraint. The total generated power and enabled DR must be equal to the network load in each hour.

$$\sum_{j=1}^N p_{j,t}^0 \times u_{j,t} + \sum_{i=1}^{N^{\text{DRS}}} DR_{i,t}^0 \times u_{i,t} = D_t \quad \text{for } 1 \leq t \leq T, j \in N, i \in N^{\text{DRS}} \quad (13)$$

2.2.2.3. Unit output limit. All units have certain amounts for their maximum and minimum generated power. Generation limits are defined as following:

$$\underline{p}_{j,t} \times u_{j,t} \leq p_{j,t}^0 \leq \overline{p}_{j,t} \times u_{j,t} \quad \text{for } 1 \leq t \leq T, j \in N \quad (14)$$

Similarly, constraints on DR are:

$$0 \leq DR_{i,t}^0 \leq DR_{i,t}^{\text{max}} \times u_{i,t} \quad \text{for } 1 \leq t \leq T, i \in N^{\text{DRS}} \quad (15)$$

2.2.2.4. Spinning reserve. Spinning reserve requirement must be sufficient enough to prevent any undesirable load shedding related to different events in power system or unexpected increasing of demand is usually a pre specified amount that is either equal to the largest unit or a given percentage of the forecasted load [38]. Mathematically, at each hour, it is the total amount of maximum capacity of all synchronized units minus the total generating output in that hour which can be given by the following equation:

$$\sum_{j=1}^N \overline{p}_{j,t} \times u_{j,t} + \sum_{i=1}^{N^{\text{DRS}}} DR_{i,t}^{\text{max}} \times u_{i,t} \geq D_t + SR_t \quad \text{for } 1 \leq t \leq T, j \in N, i \in N^{\text{DRS}} \quad (16)$$

2.2.2.5. Unit ramp-up/down constraint. Ramping up/down constraints are given by Eqs. (17) and (18), respectively:

$$\begin{cases} p_{j,t}^0 \leq \overline{p}_{j,t} \\ \overline{p}_{j,t} = \text{Min} \{ p_{j,t-1}^0 + RUR_j, \overline{p}_j \} \\ 1 \leq t \leq T, j \in N \end{cases} \quad (17)$$

$$\begin{cases} p_{j,t}^0 \geq \underline{p}_{j,t} \\ \underline{p}_{j,t} = \text{Max} \{ p_{j,t-1}^0 - RDR_j, \underline{p}_j \} \\ 1 \leq t \leq T, j \in N \end{cases} \quad (18)$$

2.2.2.6. Unit Start up and shut down constraint. A unit may not be started up and shut down at a given time, therefore [26]:

$$SUI(j,t) + SDI(j,t) \leq 1 \quad \text{for } j \in N, t \in T \quad (19)$$

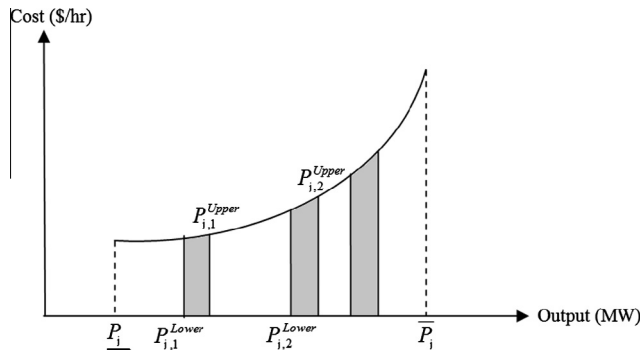


Fig. 3. Prohibited operating zones and output limit of a generator.

2.2.2.7. *Prohibited operating zone.* Some on-line generating units have their generation limit, which cannot be exceeded at any time [39]. Moreover, a typical thermal unit may have a steam valve in operation, or a vibration in a shaft bearing, which may result in interference and discontinue input–output performance–curve sections, called the prohibited operating zones, as shown in Fig. 3.

Therefore, in practical operation, adjusting the generation output of a unit must avoid all capacity limits and unit operations in prohibited operating zones. The feasible operating zones of a unit can be described as follows:

$$\begin{cases} p_j \leq p_j^0 \leq p_{j,1}^{Lower} \\ p_{j,k-1}^{Upper} \leq p_j^0 \leq p_{j,k}^{Lower}, \quad k = 2, \dots, PZ_j \\ p_{j,PZ_j}^{Upper} \leq p_j^0 \leq \bar{p}_j \end{cases} \quad (20)$$

2.2.2.8. *Minimum up/down time limit (MUT/MDT).* Once a unit is committed, it must remain “on” for a minimum number of hours. The minimum number of hours that a unit must be continuously on-line since it has been turned on is represented as:

$$MUT_j \leq T_j^U \quad (21)$$

The minimum down time constraint is the minimum number of hours that a unit must be continuously off-line since it has been turned off as represented by:

$$MDT_j \leq T_j^D \quad (22)$$

DR programs might have other constraints and costs such as minimum down or up time and any changes in their status will have extra costs for them. Since the focus of this paper is to model the participation of DRSPs in the network and also to show the effect of DR resources on the system flexibility and operation cost, extra costs which are related to DRRs such as shutting down costs are not considered in this study. This assumption will not affect the purpose and generality of this paper.

3. Numerical study

In this study, a conventional 10-unit test system has been used for our simulation studies with a scheduling time horizon of 24 h. The load data associated with the 10-unit test system are listed in Table 1 [26], and the operation constraints of the problem are represented in Table 2. In Table 2, SC and IC denote the startup cost and initial condition of units, respectively. Five different DRSPs are suggested here. Units 11–15 are considered as demand response service providers. As demonstrated in section 2, linear demand response supply curves are considered where, their coefficients are fluctuating during a scheduling period. Generating

Table 1 Load demands during a day.

Hour	Demand (MW)	Hour	Demand (MW)
1	700	13	1400
2	750	14	1300
3	850	15	1200
4	950	16	1050
5	1000	17	1000
6	1100	18	1100
7	1150	19	1200
8	1200	20	1400
9	1300	21	1300
10	1400	22	1100
11	1450	23	900
12	1500	24	800

Table 2 Generators and DRSPs' operation data.

Units	\bar{P} (MW)	$P_{i,t}$ (MW)	MUT (h)	MDT (h)	SC (\$)	IC (h)
Unit_01	455	150	8	8	4500	8
Unit_02	455	150	8	8	5000	8
Unit_03	130	20	5	5	550	-5
Unit_04	130	20	5	5	560	-5
Unit_05	162	25	6	6	900	-6
Unit_06	80	20	3	3	170	-3
Unit_07	85	25	3	3	260	-3
Unit_08	55	10	1	1	30	-1
Unit_09	55	10	1	1	30	-1
Unit_10	55	10	1	1	30	-1
Unit_11	60	0	1	1	0	-1
Unit_12	60	0	1	1	0	-1
Unit_13	60	0	1	1	0	-1
Unit_14	60	0	1	1	0	-1
Unit_15	60	0	1	1	0	-1

Table 3 Generators supply curves' coefficients.

Coefficients	Unit 1	Unit 2	Unit 3	Unit 4	Unit 5
a	0.00048	0.00031	0.002	0.00211	0.00398
b	16.19	17.26	16.6	16.5	19.7
c	1000	970	700	680	450
	Unit 6	Unit 7	Unit 8	Unit 9	Unit 10
a	0.00712	0.0079	0.00413	0.00222	0.00173
b	22.26	27.74	25.92	27.27	27.79
c	370	480	660	665	670

units' data associated with the 10-unit test system are listed in Table 3 [26].

According to Eqs. (8) and (9), DRSPs must estimate the approximate amount of required demand response. Here, 20% of load is assumed as the amount of required DR.

Table 4, shows the amounts of *b'* coefficients which are determined optimally through the dynamic approach by DRSPs. Here, the coefficient “a” for different DRSPs' supply curves are also considered equal to 20 as described in section 2. It should be mentioned that similar results are also taken into account in the subsequent section for different values of “a”.

The italicized hourly statuses in Table 5 present the status of units that are different from the base case without considering DRRs. Also, Fig. 4 shows the results of unit commitment optimization problem by concurrently consideration of commercial DR and generators' supply curve. In Fig. 4, the amount of enabled DR and generators supply power are simultaneously exposed for the simulated period. Note that the amounts of specified power for each

Table 4
 b'_i Coefficients for DRSPs during a day.

Hour	Beta 1	Beta 2	Beta 3	Beta 4	Beta 5
1	96	74.4	26.4	18	12
2	168.78	151.68	113.68	107.03	102.28
3	194.22	176.93	138.52	131.8	126.99
4	209.48	192.20	153.80	147.08	142.28
5	217.59	200.31	161.91	155.18	150.38
6	230.05	212.77	174.37	167.65	162.85
7	237.68	220.40	182	175.28	170.48
8	244.51	227.23	188.83	182.11	177.31
9	256.76	239.48	201.08	194.36	189.56
10	269.91	252.63	214.23	207.51	202.71
11	277.66	260.38	221.98	215.26	210.46
12	284.50	267.22	228.82	222.10	217.30
13	274.53	257.25	218.85	212.13	207.33
14	261.76	244.48	206.08	199.36	194.56
15	248.52	231.24	192.84	186.12	181.32
16	229.65	212.37	173.97	167.25	162.45
17	220.95	203.67	165.27	158.55	153.75
18	230.61	213.33	174.93	168.21	163.41
19	243.33	226.05	187.65	180.93	176.13
20	267.67	250.39	211.99	205.27	200.47
21	260.62	243.34	204.94	198.22	193.42
22	237.22	219.94	181.54	174.82	170.02
23	211.10	193.82	155.42	148.70	143.90
24	195.63	178.35	139.95	133.23	128.43

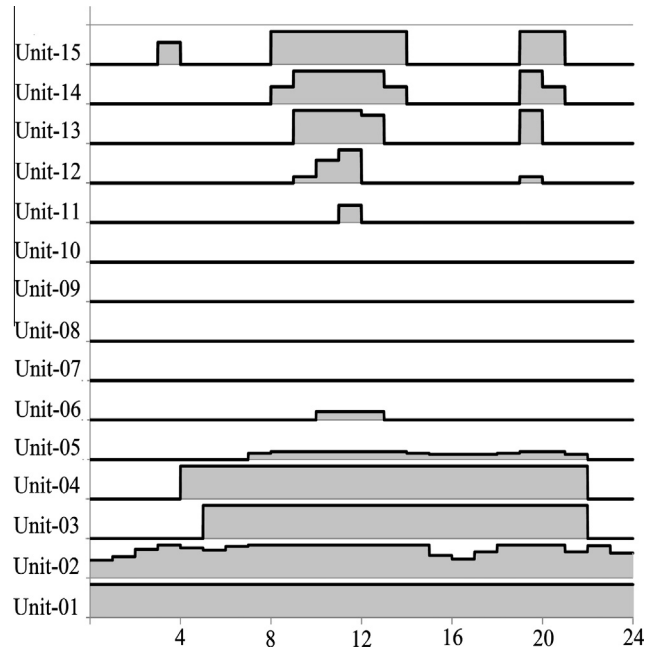


Fig. 4. The output data for all 15 units.

unit are normalized according to their maximum generation power during a day. The base values for each of these units are shown in Table 6. Each of DRSPs can enabled special amount of DR according to its willingness coefficient. As indicated in Fig. 4, DRSPs 11 and 12 participate in DRP only in peak times, while providers 13–15 are called in demand response programs in most hours. Using Fig. 4, it can be concluded that DRSPs have more penetration in DRPs in peak hours, which is directly due to the more capacity and need for demand response.

Here, the operation cost during the scheduling time horizon is obtained equal to 558180 (\$) without considering DR supply curves. By enrolling DRSPs' supply curves in UC problem, the operation cost is decreased to 453,511, 492,415, 531,070 and 551,664.072 (\$) for $\alpha = 5, 10, 15$ and 20, which causes 18.7%, 11.7%, 4.8% and 1.2% cost reduction, respectively. Therefore, the cost reduction due to net reduction in consumption and deferring commitment of expensive units emphasize the economic-driven measure of the proposed scheme.

As it is demonstrated in Fig. 4, units 6, 7 and 8 can be turned off during a scheduling time horizon when DRP is enrolled. In the conventional UC problem, the aforementioned units should be on in

some hours. Then, the minimum up time constraint of generators cause these units to be on in next hours. So, they are on with a low efficiency in these hours. All these situations have important effects on increasing operation costs. But, when DR is considered in UC problem, most of these unfavorable situations can be mitigated.

Network operation cost which is obtained by solving the proposed "unit and DR commitment" problem is shown in Fig. 5 versus b'_i coefficients of DRSPs' supply curve.

Furthermore, DRSPs' benefit by varying the amounts of b'_i coefficients is illustrated in Fig. 6. Increasing the amount of b'_i cause the operation costs to be greater. This is due to DRSPs' willingness to participate in DRPs. Small amounts of b'_i means more willingness of DRSPs. Increasing in b'_i value shows that demand response service providers have less willingness to participate in DRPs. If the coefficient b'_i get higher value, DRSPs cannot enroll for load procurement. In this condition, DRSPs' benefit tends to zero and the operation cost tends to the cost of conventional UC.

Changes in the amount of operation costs by varying the maximum amount of DR capacity in the network is shown in Fig. 7 for $\alpha = 5, 10, 15$ and 20. Also, Table 7 presents the changes in operation

Table 5
 Unit output power and enabled DR for the 10-unit test system.

Units	Hours (1–24)																							
1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
2	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
3	0	0	0	0	0	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	0	0	0
4	0	0	0	0	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	0	0	0
5	0	0	0	0	0	0	0	0	1	1	1	1	1	1	1	1	1	1	1	1	1	0	0	0
6	0	0	0	0	0	0	0	0	0	0	0	1	1	1	0	0	0	0	0	0	0	0	0	0
7	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
8	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
9	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
10	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
11	0	0	0	0	0	0	0	0	0	0	0	1	0	0	0	0	0	0	0	0	0	0	0	0
12	0	0	0	0	0	0	0	0	0	0	1	1	1	0	0	0	0	0	0	0	0	1	0	0
13	0	0	0	0	0	0	0	0	0	0	1	1	1	1	0	0	0	0	0	0	1	0	0	0
14	0	0	0	0	0	0	0	0	0	1	1	1	1	1	1	0	0	0	0	0	1	1	0	0
15	0	0	0	1	0	0	0	0	1	1	1	1	1	1	0	0	0	0	0	0	1	1	0	0

Table 6
The base value for units power.

Units	Base value	Units	Base value
Unit_01	455	Unit_09	55
Unit_02	455	Unit_10	55
Unit_03	130	Unit_11	60
Unit_04	130	Unit_12	60
Unit_05	162	Unit_13	60
Unit_06	80	Unit_14	60
Unit_07	85	Unit_15	60
Unit_08	55		

Table 7
Operation costs with various amount of maximum DR capacity.

Total amount of DR capacity (MW)	Percentage of peak load	The minimum amount of operation cost (\$)	Percentage of cost reduction comparing to the operation cost in the absence of DR
100	6.67	548257.54	1.8
200	13.33	537854.5	3.64
300	20	531070	4.86
400	26.67	530720.38	4.91

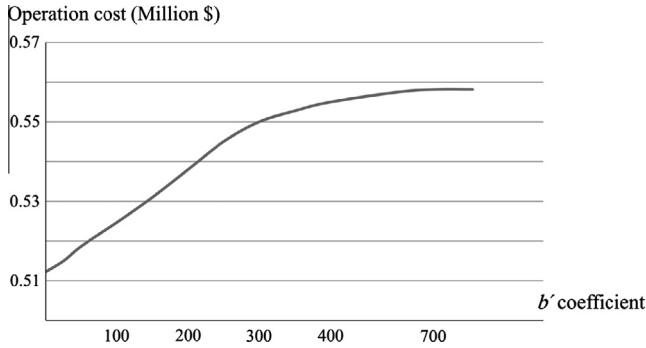


Fig. 5. Operation cost versus b' coefficient.

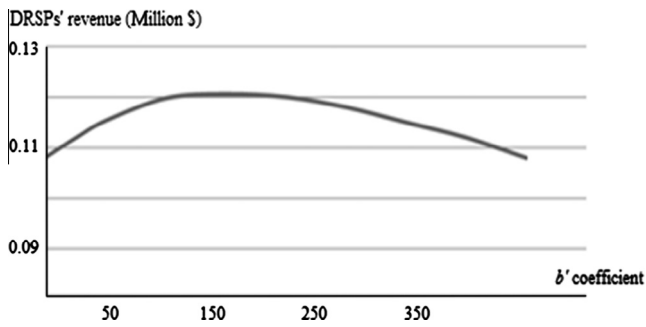


Fig. 6. DRSPs' revenue versus b' coefficient.

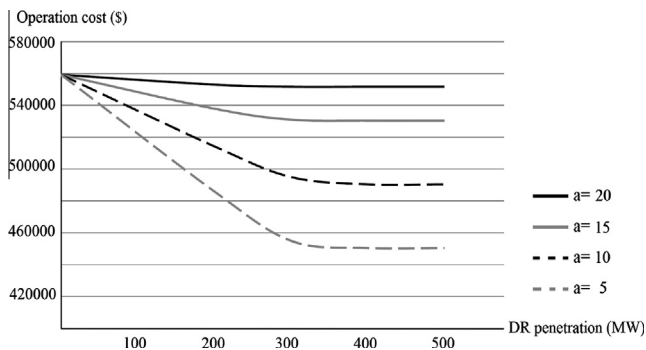


Fig. 7. Operation cost versus maximum capacity of DR.

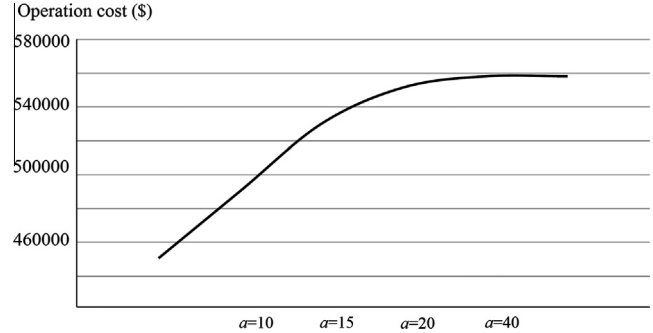


Fig. 8. Operation cost versus " α " coefficient value.

Fig. 8 shows the changes in operation cost for some different α values. Increasing in α , shows that DRSPs have less willingness to participate in DRPs. For this reason, increasing in the amount of α , cause more operation cost. If the coefficient α be extremely high, DRSPs cannot participate in DR and the operation cost will be equal to the cost of conventional UC problem.

4. Conclusion

In this paper, the commercial concept of DR is addressed. Based on this new concept, DR programs are modeled as a tradable commodity which can be considered concurrently with generators in unit commitment optimization problems. Simultaneous determination of generators power and amount of enabled DR for minimizing the operation costs is the main aim of the proposed UC problem. A dynamic approach is proposed for achieving to DRSPs' supply curves. Each DRSPs' supply curve depends on the behavior of other providers in the past times. It also depends on the amount of the required DR. Comparison between the results of the proposed UC, which contains the commercial DR curves beside the generators supply curves, by traditional UC, will clarify the advantage of the proposed method. As it is shown with numerical study, using of introduced approach decreases the operation costs dramatically. Sometimes, it is possible that some generators have to work with low efficiency only because of its MUT constraint. These similar situations will cause huge costs for operation. Considering commercial supply curves of DR simultaneously with generators supply curves, can eliminate some of these expensive situations. If it is possible for operators to supply a load demand without using of expensive generators in peak times, these generators can stay off and it is not necessary for these units to work with low efficiency in other hours. In addition, the startup costs of these units will be removed. All simulation results are verifying these claims and show the advantage and usefulness of the proposed method.

costs by varying the total amount for DR's maximum capacity in the network and the percentage of all changes.

Operation costs with various amount of maximum DR capacity for $\alpha = 15$.

Appendix A

Rewriting (7),

$$pfi = DP \times \left(\frac{DP - b'_i}{a_i} \right) - \left[\frac{am_i}{2} \times \left(\frac{DP - b'_i}{a_i} \right)^2 + bm_i \times \left(\frac{DP - b'_i}{a_i} \right) \right] \quad (A.1)$$

DP is a function of b'_i , and:

$$DP = \frac{RD + \sum_{i=1}^{NDRS} \frac{b'_i}{a_i}}{\sum_{i=1}^{NDRS} \left(\frac{1}{a_i} \right)} = \frac{RD + \frac{b'_i}{a_i} + \sum_{i \neq j}^{NDRS} \frac{b'_i}{a_i}}{\sum_{i=1}^{NDRS} \left(\frac{1}{a_i} \right)} \quad (A.2)$$

By taking the derivative of the DP with respect to b_i and putting the result in $\frac{\partial pfi}{\partial b_i}$, and by taking the result equal to zero, we conclude:

$$b'_i = \sum_{i \neq j}^l \left(\frac{a_i}{a_j} \times \frac{1}{a_i^2 \cdot S^2 - 1} \times b'_j \right) + \left(\frac{a_i}{a_i^2 \cdot S^2 - 1} \times RD \right) + \left(\frac{a_i \cdot S}{a_i \cdot S - 1} \times bm_i \right) \quad (A.3)$$

where

$$S = \sum_{i=1}^l \left(\frac{1}{a_i} \right).$$

So, Eqs. (8) and (9) are easily derived from (A.3).

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