Investigation of Market-Based Demand Response Impacts on Security-Constrained Preventive Maintenance Scheduling

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***Abstract*—In recent years, load management (LM) programs have been contemplated as a crucial option in all energy policy decisions. Under deregulation, the scope of LM programs has been considerably expanded to include demand response (DR) programs. Here, the market-based DR programs are regarded as a virtual resource for reserve provision. Basically, demand-side reserve affects handling and controlling of power systems ranging from short-term to long-term scheduling. Preventive maintenance scheduling (PMS) of generating units is addressed as a long-term scheduling in power system studies, which is affected by DR programs. In this paper, a new structure for security-constrained PMS associated with DR programs is suggested. In order to scrutinize the economic- and environmental-driven measures of DR programs, a new linearized formulation of cost-and-emission-based preventive maintenance problem is presented. Here, the proposed framework is structured as a mixed-integer programming problem and solved using a CPLEX solver. This model would schedule reserves provided by DR providers, maintenance scheme, and commitment status of generating units. Values of energy and reserves over the scheduling time horizon are also simultaneously determined in this paper. The IEEE Reliability Test System is utilized to demonstrate the effectiveness of the proposed structure.**

***Index Terms*—Economic and environmental driven, energy and reserve scheduling, market-based demand response (DR) programs, mixed-integer programming (MIP), security-constrained preventive maintenance scheduling (PMS).**

NOMENCLATURE

$a(\cdot), b(\cdot), c(\cdot)$	Fuel cost coefficient.
$A_{\rm PF}$	Active power flow vector.
b	Bus index.
$b_m(\cdot)$	Slope of mth segment in linearized fuel cost curve.
$C_C(\cdot)$	Capacity cost in a point of a demand response provider (DRP) in a period.
$C_{\rm Total}^{\rm DRP}(\cdot)$	Capacity cost of reserve provided by a DRP in a period.
d	DRP index.
$\mathrm{DRR}(\cdot)$	Scheduled reserve of a DRP in a period.
$\mathrm{Em}(\cdot)$	Emission function of a unit.
$\underline{\mathrm{Em}}(\cdot)$	Lower limit on the emission of a unit.
$e_m(\cdot)$	Slope of mth segment in linearized emission curve.
$F(\cdot)$	Unit fuel cost function.
$\underline{F}(\cdot)$	Lower limit on the fuel cost of a unit.
i	Unit index.
I_M	Node branch incidence matrix.
$\mathrm{loss}(\cdot)$	System losses in a period.
l	Transmission line index.
$L(\cdot)$	Demand vector in a period.
$L_{\rm Cur}(\cdot)$	Load curtailment vector due to participating in demand response (DR) programs in a period.
$L_{\rm DR}(\cdot)$	DR level in a point of a DRP in a period.
m	Segment index for linearized fuel cost and emission curves.
$M_C(\cdot)$	Maintenance cost of a unit.
N_B	Number of buses.
N_G	Number of generating units.
$N_{\rm DRP}$	Number of DRPs.
$N_{\rm SDR}$	Number of discrete points in offer package of a DRP.
$N_{\rm SF}$	Number of segment for the piecewise linearized fuel cost curve.
$N_{\rm SE}$	Number of segment for the piecewise linearized emission curve.
$P(\cdot)$	Output power of a unit in a period.
$P_D(\cdot)$	Load demand of a bus in a period.
P_g	Vector of generated power.
$\overline{P}(\cdot)/\underline{P}(\cdot)$	Maximum/minimum generating capacity of a unit.
$\mathrm{PL}(\cdot)$	Power flow of a line in a period.
$\overline{\mathrm{PL}}(\cdot)$	Capacity of a line.
$P_m(\cdot)$	Generated power in mth segment of linearized fuel cost curve.
$\overline{P}_m(\cdot)$	Maximum generated power in mth segment.
r	Dummy units vector associated with the unsupplied energy in a period.
$\mathrm{SRR}(\cdot)$	System reserve requirement in a period.
t	Period index.
T	Scheduling time horizon.
$u(\cdot)$	Commitment status of a unit in a period.
$\mathrm{url}(\cdot)$	Unit reservation level in reserve acquisition in a period.

Manuscript received August 12, 2013; revised October 17, 2013; accepted October 21, 2013.

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Digital Object Identifier 10.1109/JSYST.2013.2287603

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w_c, w_e	Weighting coefficient for generating cost/emission in objective function.
$\overline{Y_{\mathrm{LC}}}(\cdot)$	Maximum yearly load curtailment in a DRP.
$z(\cdot)$	Maintenance status of a unit.
$\alpha(\cdot), \beta(\cdot), \gamma(\cdot)$	Emission coefficient of a unit.
$\Upsilon_m(\cdot)$	Generation of mth segment in linearized emission curve.
$\vartheta(\cdot)$	Binary variable associated with a point of a DRP in a period.
$\varpi(\cdot)$	Maintenance starting time.
$\Gamma(\cdot)$	Offered capacity cost of a unit for providing system reserve.
$\zeta(\cdot)$	Maintenance duration of a unit.
$\upsilon(\cdot)$	Maximum number of under inspection units in a period.
$\eta(\cdot)$	The potential of DRPs' implementation.
ε	Accepted level of expected unserved energy.

I. Introduction

THE International Energy Agency (IEA) introduces demand-side activities as the first option in all energy policy decisions because they affect operation, economic, and emission levels [1]. Under restructured power systems, the scope of demand-side management is developed to demand response (DR) programs. DR is a program that is established to change electric use by demand-side resources from their normal consumption patterns in response to changes in the price of electricity, or to incentive payments designed to induce lower electricity use at times of high wholesale market prices or when system reliability is jeopardized [2]. DR programs provide many potential benefits such as cost and emission reduction, decline of overseas fuel dependence, power system reliability improvement, and increase in revenues due to differing commitment of units [3]. According to the Federal Energy Regulatory Commission (FERC), DR programs had been classified into two major categories, namely, time-based rate (TBR) and incentive-based programs (IBPs), in 2006. However, it is worth noting that the number of program classifications was expanded from 12 in 2008 to 15 in 2010 [2]. More detailed explanations of DR programs are provided in Section II.

In order to scrutinize the economic and environmental benefits of demand-side programs, the cost-and-emission-based preventive maintenance scheduling (PMS) associated with market-based DR programs is addressed in this paper.

Preventive maintenance can be defined as an undertaken activity at preselected intervals to operate satisfactorily and reduce the deterioration of the equipment [4]. In power system research studies, optimal outage scheduling of generating units is introduced as a PMS. Maintenance schedule of generating units is extremely crucial because it affects short-term generation scheduling. Furthermore, regular preventive maintenance of generating units can defer capital expenditures for new power plants because it increases the generator lifetime [5]. Several deterministic, heuristic, and hybrid methods have been utilized in the last decades for solving the PMS problem as a large-scale, nonconvex, and mixed-integer combinatorial optimization problem. Deterministic methods in general are unable to seek a solution within the available time, when the problem is of medium or large size [6]–[8]. These restrictions have been redounded to introduce the heuristic methods. Heuristic optimization algorithms may have some advantages to solve such a complicated optimization problem, whereas the main drawback of heuristic methods is that they cannot guarantee the optimal solution [5], [9]–[15]. Tabu search algorithm has been used in [11] to determine the maintenance scheme while the operation cost is minimized over the scheduling time horizon. Reference [12] suggested the ant colony optimization technique to find the maintenance schedule, which aims to improve the system economy and increase the system reliability. Reference [15] expressed a method based on simulated annealing to seek the optimum maintenance scheme while the operating cost is minimized. Since there exists a need for more improvement to the existing preventive maintenance solution techniques, hybrid methods have been experienced [16]–[19]. Reference [17] proposed a fuzzy model based on an evolutionary programming technique to handle the security-constrained PMS considering uncertainties in the load and fuel. Currently, in most cases, the commercial solvers are utilized to solve such complicated problems [7], [20], [21]. In [21], general algebraic modeling system (GAMS) is employed to solve security-constrained PMS to minimize the operation cost while fuel constraint and energy purchased from outside are also contemplated.

In PMS, system reserve procurement is addressed as an essential constraint, which improves system reliability against sudden increase in demand and generating unit unexpected outages. In previous studies of PMS, reserve provision cost is not considered during the scheduling horizon. The required demand is supplied with the most economical units, whereas the system reserve is provided with the most expensive units to merely decrease the operation cost without considering the reserve expenditures. In recent research studies, although the operation cost has been minimized, the total cost, including operation, maintenance, and reserve expenditures, has been increased due to the improper reserve assessment. This paper regards the reserve provision cost during the security-constrained PMS problem. Therefore, the unit contribution level in reserve procurement and the demand satisfaction are simultaneously determined to handle the security-constrained preventive maintenance cost at its minimum possible level.

Moreover, the environmental issues have been addressed as a crucial society concern in the last decades, which affect management of the power system ranging from long-term planning activities to short-term generation scheduling. In previous studies of PMS [7], [22], the environmental impacts are merely contemplated as permissible generated power of multifarious generating units over the scheduling time horizon to handle the environmental measures. In this paper, the amount of emitted contaminants is also considered in the objective function of security-constrained PMS, which is minimized, and system total expenditure, simultaneously, during the study time horizon.

This paper also investigates the impacts of market-based DR programs on PMS. Referring to the FERC report, demand

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resources are capable of providing the functions assessed in a planning process and should be permitted to participate in that process on a comparable basis [23]. Here, DR programs are contemplated as virtual resources to procure system reserve necessity in PMS problems. Therefore, a new cost-and-emission-based structure for security-constrained PMS associated with market-based DR programs is presented. In addition, the prevailing constraints of security-constrained PMS, maximum load curtailment per year, and the potential of implementing DR program per period are also considered as DR limits. The proposed framework determines maintenance scheme and commitment status of generating units, energy and reserve scheduling, and demand-side reserve scheduling so that the system total cost and emission are both minimized over the scheduling time horizon. The suggested framework is developed as a combinatorial optimization problem, which is linearized and structured as a mixed-integer programming (MIP) problem. The advantages of an MIP method include global optimality, direct measure of the optimality of a solution, and more flexible and accurate modeling capabilities. Here, CPLEX as a sophisticated and computationally efficient MIP solver is applied for solving the proposed model [24].

The rest of this paper is organized as follows. Section II provides a primer on DR programs. The hierarchy of investigating DR programs on security-constrained PMS from Independent System Operator (ISO) perspective is presented in Section III. The structure of the market-based DR programs and the proposed MIP-based formulation for the security-constrained PMS associated with the market-based DR programs are also elaborated in Section III. Section IV presents the numerical simulations, and finally, the concluding remarks are given in Section V.

II. Primer on DR

Investigation on DR programs was assigned to the United States by strategic plan of the IEA demand-side management program [1]. According to the FERC report, DR programs are introduced as changing in electric use by demand-side resources from their normal consumption patterns in response to changes in the price of electricity, or to incentive payments designed to induce lower electricity use at times of high wholesale market prices or when system reliability is jeopardized [2]. In the FERC 2006 report, DR programs are classified into two basic clusters, namely, TBR and IBPs. In TBR programs, the electricity price changes for different periods and is divided into three categories, namely, time of use (TOU), real-time pricing (RTP), and critical peak pricing (CPP) programs. No penalty or incentive is considered for customer response in time-based rate programs. IBPs are organized in such a way to reduce the power consumption in peak periods or when the system is jeopardized, which improve the system reliability. IBPs are categorized into three main clusters, namely, voluntary, mandatory, and market-based programs. In voluntary programs, including emergency DR program and direct load control (DLC), customers are not penalized if they do not curtail demand. Consumers are penalized if they do not reduce their consumption in mandatory programs, including capacity market program and interruptible/curtailable service. Market-based programs include demand bidding (DB) and ancillary service (A/S) programs. The DB program encourages large customers to provide load reductions at a price at which they are willing to be curtailed or to specify 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 [25]. In the FERC 2008 report, the CPP program is categorized into four clusters: fixed-period CPP, variable-period CPP, variable peak pricing, and peak time rebates [26]. In the FERC 2010 report, the number of program classifications was expanded from 12 in 2008 to 15 in 2010. The classification of DR programs in the FERC 2010 report is presented as follows: DLC, interruptible load, CPP with control, load as capacity resource, spinning reserves, nonspinning reserves, emergency DR, regulation service, DB and buyback, TOU pricing, CPP, RTP, peak time rebate, system peak response transmission tariff, and other programs [27], [28]. More explanations about each cluster of the DR programs are provided in [2].

III. Model Description and Formulation

The hierarchy of investigating DR programs' impact on the security-constrained PMS from ISO perspective is depicted in Fig. 1.

The crucial point is to link demand- and supply-side resources to the security-constrained maintenance scheduling in a way that the economic and environmental benefits of DR programs be observable. In the proposed framework, the characteristics of demand-side resources and signed contracts to participate in DR programs are submitted to the ISO. Demand response providers (DRPs) act as a medium between the independent system operator and the customers, which possess the responsibility of aggregating and managing customers' response. The ISO runs the security-constrained PMS to seek the optimal outage time of generating units and energy and reserve scheduling over the scheduling time horizon while the system total cost and emission are both minimized. The optimum participation level of consumers in system reserve procurement in each period is also determined. Moreover, the ISO determines the load curtailment level by the security-constrained PMS, which can be utilized in short-term scheduling of power system. In the following subsections, more explanations are elaborated about Fig. 1.

A. Market-Based DR Model

Here, the utilized framework of market-based DR programs is illustrated. Here, DR program is contemplated as a virtual resource to procure system reserve necessity. Each customer submits his/her offer to DRPs to procure portion of the system reserve requirement. Indeed, DRPs aggregate discrete customer responses and serve as a medium between the ISO and the consumers. A bid-quantity offer package submitted by DRPs to the ISO is shown in Fig. 2. Moreover, demand-side reserve increases as prices increase and is constrained to increase monotonically [29]. The minimum customers' participation at dth DRP, i.e., $\underline{L}_{\mathrm{DR}}(d,t)$, should be greater than the minimum

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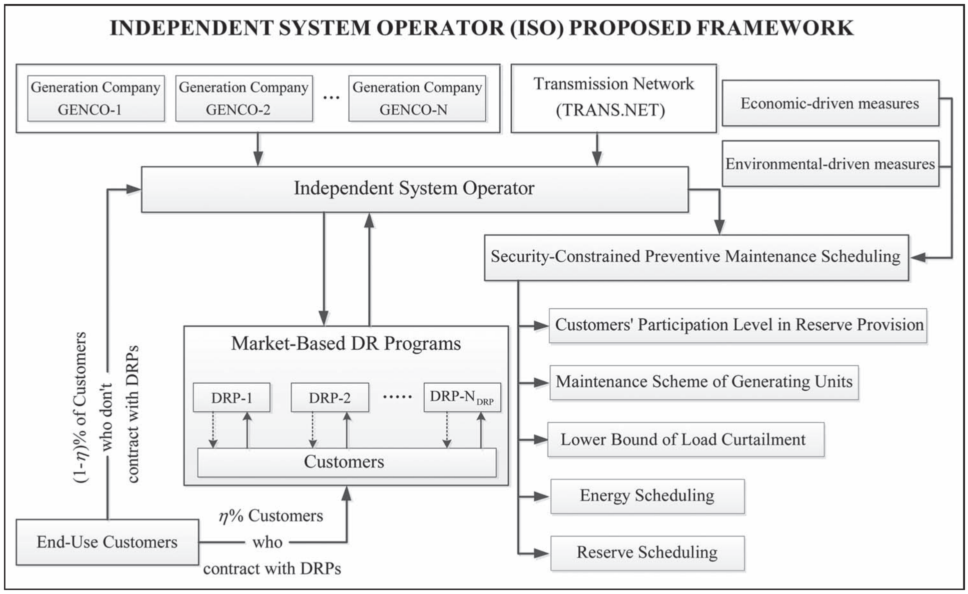

Fig. 1. Proposed hierarchy for security-constrained PMS associated with DR programs from ISO perspective.

curtailment level of the DR programs, which is specified by the ISO. A mixed-integer model of the DR program bid-quantity is presented by [30]

$$\mathrm{DRR}(d,t) = \left[\underline{L}_{\mathrm{DR}}(d,t)\underline{\vartheta}(d,t) + \sum_{\nu=1}^{N_{\mathrm{SDR}}} L_{\mathrm{DR}}(\nu,d,t)\vartheta(\nu,d,t)\right] \quad \forall d, \forall t. \tag{1}$$

$$C_{\mathrm{DRP}}^{\mathrm{Total}}(d,t) = \left[\underline{C}_{C}(d,t)\underline{L}_{\mathrm{DR}}(d,t)\underline{\vartheta}(d,t) + \sum_{\nu=1}^{N_{\mathrm{SDR}}} L_{\mathrm{DR}}(\nu,d,t)C_{C}(\nu,d,t)\vartheta(\nu,d,t)\right] \quad \forall d, \forall t. \tag{2}$$

$$\Delta L_{\mathrm{DR}}(\nu,d,t) = L_{\mathrm{DR}}(\nu,d,t) - L_{\mathrm{DR}}(\nu-1,d,t) \quad \forall d, \forall t. \tag{3}$$

In (1) and (2), the status of dth DRP's offer package at point ν is labeled as $\vartheta(\nu,d,t)$, which is one when the point is scheduled by the ISO and otherwise takes zero. The discrete DR reserve levels are symbolized by $L_{\mathrm{DR}}(\nu,d,t)$ with the associated cost of $C_{C}(\nu,d,t)$, as displayed in Fig. 2.

B. Security-Constrained PMS Associated With Market-Based DR

Security-constrained PMS is addressed as one of the crucial issues in power system studies, whereas the system reserve

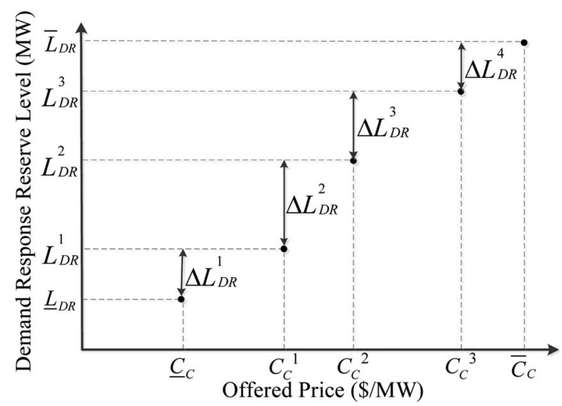

Fig. 2. Sample bid-quantity offer in a DRP.

acquisition is considered as a challenging concern. In this paper, the economic and environmental impacts of demand-side reserve on the maintenance problem are scrutinized. Here, a cost-and-emission-based model for the security-constrained PMS associated with market-based DR programs is presented. The objective of the proposed model is to minimize the system total cost, including operating, maintenance, reserve, and demand-side reserve expenditures, and the generating units emission is also minimized over the scheduling time horizon. The suggested framework determines the maintenance scheme and the commitment status of generating units, energy and reserve scheduling, and offers of DR programs participants to procure system reserve simultaneously. Here, an alternative MIP formulation, which is suitable for available MIP software, is presented for the suggested structure. One of the main features of the MIP method includes direct measure of the optimality of a solution and more flexible and accurate modeling capabilities. The employed optimization software is GAMS, and CPLEX as a commercial and computationally efficient MIP solver is used for solving the problem [24], [31].

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The linearized objective function for the proposed framework is presented as

$$\text{Min}: \sum_{t=1}^{T}\left[w_c \sum_{i=1}^{N_G}\left\{\left(\underline{F}(i)u(i,t)+\sum_{m=1}^{N_{\text{SF}}(i)} P_m(i,t)b_m(i)\right) +z(i,t)M_C(i)+\text{url}(i,t)\Gamma(i)\right\} +w_c \sum_{d=1}^{N_{\text{DRP}}}\left(\underline{C}_C(d,t)\underline{L}_{\text{DR}}(d,t)\underline{\vartheta}(d,t) +\sum_{\nu=1}^{N_{\text{SDR}}} L_{\text{DR}}(\nu,d,t) \times C_C(\nu,d,t)\vartheta(\nu,d,t)\right) +w_e\sum_{i=1}^{N_G}\left\{\underline{\text{Em}}(i)u(i,t)+\sum_{m=1}^{N_{\text{SE}}(i)}\Upsilon_m(i,t)e_m(i)\right\}\right]. \quad (4)$$

In (4), w_c and w_e are considered to include or exclude cost and emission in the objective function. More explanations about each parameter of the objective function are outlined in the following.

1) Fuel cost: The quadratic fuel cost function typically utilized in scheduling problems is formulated as

$$F(i,t) = a(i) + b(i)P(i,t) + c(i)P^2(i,t). \quad (5)$$

Equation (5) can be correctly approximated by a set of piecewise blocks, which cannot be recognizable from the nonlinear model if enough segments are utilized. An analytic representation of the piecewise linear function is provided by

$$\underline{F}(i)u(i,t) + \sum_{m=1}^{N_{\text{SF}}(i)} P_m(i,t)b_m(i). \quad (6)$$

2) Maintenance cost: Maintenance cost is constant for each generating unit and is modeled using a maintenance indicator, i.e., $z(i,t)$, in such a way to minimize the system total expenditure, as shown in (4).
3) Reserve cost: The reserve provision expenditure in ith unit is symbolized by $\Gamma(i)$. Each unit participation level in reserve provision is determined so that the system total expenditure and emission are both minimized.
4) DR financial burden: Customers' participation level to procure portion of system reserve requirement in each period is specified in such a way that the system total expenditure over the scheduling time horizon is minimized. Regarding Fig. 2, the cost, which is paid to customers by the ISO, is structured as a bid-quantity offer.
5) Emission: Emission effects as the last term of the objective function is taken into consideration for environmental-friendly power production. Typically, emissions produced by generating units are presented as a polynomial function of their power production. In this paper, a quadratic function is considered for the emission curve [32] as follows:

$$\text{Em}(i,t) = \alpha(i) + \beta(i)P(i,t) + \gamma(i)P^2(i,t). \quad (7)$$

Emission function can be also accurately approximated by a set of piecewise blocks. The analytic representation of this linear approximation is similar to (6) and formulated as

$$\underline{\text{Em}}(i)u(i,t) + \sum_{m=1}^{N_{\text{SE}}(i)} \Upsilon_m(i,t)e_m(i). \quad (8)$$

The objective function is subjected to the following constraints.

a) Economic unit commitment constraints: Generated power from committed units must satisfy the required demand and system losses. $\text{DRR}(d,t)$ is considered as the customers' participation level in market-based DR programs, i.e.,

$$\sum_{i=1}^{N_G} P(i,t) = \sum_{b=1}^{N_B} P_D(b,t) - \sum_{d=1}^{N_{\text{DRP}}} \text{DRR}(d,t) + \text{loss}(t) \quad \forall t. \quad (9)$$

To encounter any unanticipated operating conditions such as unexpected outage of generating units or sudden increase in demand, the specified reservation amount must be considered. System reserve is usually a prespecified amount that is equal to either the largest unit or a given percentage of the forecasted load. Mathematically, $\text{SRR}(t)$ is the total amount of maximum capacity of all synchronized units minus the total generating output, which can be given by

$$\sum_{i=1}^{N_G} u(i,t)\overline{P}(i,t) \geq \left[\sum_{b=1}^{N_B} P_D(b,t) - \sum_{d=1}^{N_{\text{DRP}}} \text{DRR}(d,t) + \text{loss}(t) + \text{SRR}(t)\right] \quad \forall t. \quad (10)$$

$$0 \leq \text{url}(i,t) \leq \left(\overline{P}(i,t) - \underline{P}(i,t)\right) u(i,t) \quad \forall i, \forall t. \quad (11)$$

$$\sum_{i=1}^{N_G} \text{url}(i,t) + \sum_{d=1}^{N_{\text{DRP}}} \text{DRR}(d,t) \geq \text{SRR}(t) \quad \forall t. \quad (12)$$

In (10), the ith unit on/off status is symbolized by $u(i,t)$, which is one when the generator is on, and otherwise, it takes zero. The unit reservation level in each period is symbolized as $\text{url}(i,t)$, which should be placed between the allowable limits, as shown in (11). The required system reserve can be procured via generating units and demand-side participations, as presented in (12).

Power generation constraint is expressed as

$$\underline{P}(i,t)u(i,t) + \sum_{m=1}^{N_{\text{SF}}(i)} P_m(i,t) \leq \left[\overline{P}(i,t)u(i,t) - \text{url}(i,t)\right], \quad \forall i, \forall t$$

$$0 \leq P_m(i,t) \leq \bar{P}_m(i,t), \quad \forall i, \forall t, \forall m. \quad (13)$$

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DR limits are modeled by (14) and (15). The customers' participation level per year in each DRP, i.e., $\overline{Y}_{\mathrm{LC}}(d)$, is restricted as (14). Moreover, the amount of load curtailment in each DRP at period t must be lower than the prespecified level. Thus

$$\sum_{t=1}^{T} \mathrm{DRR}(d,t) \leq \overline{Y}_{\mathrm{LC}}(d) \quad \forall d \tag{14}$$

$$\mathrm{DRR}(d,t) \leq \eta(d,t) \quad \forall d, \forall t. \tag{15}$$

b) Maintenance constraints: Each unit must be maintained for a specified time as follows:

$$\sum_{t=1}^{T} z(i,t) = \zeta(i) \quad \forall i. \tag{16}$$

Each unit is taken under maintenance only once during the time horizon. $\varpi(i,t)$ is a maintenance starting variable that is considered equal to one if ith generator inspection starts at the beginning of period t and otherwise takes zero, i.e.,

$$\sum_{t=1}^{T} \varpi(i,t) = 1 \quad \forall i. \tag{17}$$

The maintenance of each unit must be performed in successive periods, i.e.,

$$z(i,t) - z(i,t-1) \leq \varpi(i,t) \quad \forall i, \forall t. \tag{18}$$

Connection constraint represents the relation between the maintenance status and the commitment state of the generating unit, i.e.,

$$z(i,t) + u(i,t) \leq 1 \quad \forall i, \forall t. \tag{19}$$

Exclusive constraint represents that ith and jth generating units cannot be taken under maintenance at the same time, i.e.,

$$z(i,t) + z(j,t) \leq 1 \quad \forall t. \tag{20}$$

The total available technical staffs and the required manpower for the specified unit inspection in each period are definite. Hence, the number of the generating units, which can be simultaneously maintained, is limited, i.e.,

$$\sum_{i=1}^{N_G} z(i,t) \leq \upsilon(t) \quad \forall t. \tag{21}$$

c) Transmission network constraints: Transmission security constraint in PMS can be handled either by a transportation model (TM) or other power flow models. Since a TM is a linear model, it is easier to be solved and may lead to feasible solutions but not necessarily an optimal one, which is modeled by (22)–(24). The power balance in each node is structured by (22). In (22), $L(t)$ is the vector of load in a period, and $L_{\mathrm{Cur}}(t)$ is the vector of customers' participation level in DR programs. The power that flows through transmission lines must be lower than the maximum capacity of the line, which is represented by (23). In (24), ε is the allowable unserved energy, which is determined by the ISO. Although an increase in the maximum unserved energy level decreases the operating cost and the system total cost, it causes attenuation of system reliability level [20], i.e.,

$$I_M A_{\mathrm{PF}}(t) + P_g(t) + r(t) = L(t) - L_{\mathrm{Cur}}(t) \quad \forall t \tag{22}$$

$$-\overline{\mathrm{PL}}_L \leq \mathrm{PL}(l,t) \leq \overline{\mathrm{PL}}_L \quad \forall t, \forall l \tag{23}$$

$$\sum_{b=1}^{N_B} r(b,t) \leq \varepsilon \quad \forall t. \tag{24}$$

IV. Simulation Results and Discussions

In this paper, the IEEE Reliability Test System (RTS) has been utilized for simulation studies with a scheduling time horizon of 52 weeks, as shown in Fig. 3. This system includes 26 generating units (15 oil with 1031 MW, i.e., $\mathrm{OF}_1-\mathrm{OF}_{15}$; 9 coal with 1274 MW, so-called $\mathrm{CF}_{16}-\mathrm{CF}_{24}$; and 2 nuclear with 800 MW as $\mathrm{N}_{25}-\mathrm{N}_{26}$), 24 buses, and 38 transmission lines.

The peak load is 2100 MW, and the weekly load profile of the IEEE RTS is used to obtain the annual load curve [33]. The fuel cost curves for generating units given as a quadratic function are approximated by 20 linear segments between the minimum and maximum generating units' capacities [34]. More required data, including operating and maintenance insights of the generating units and transmission lines' characteristics, are provided in [35]. System reserve requirement, i.e., $\mathrm{SRR}(t)$, is considered as 400 MW, which is equal to the largest unit capacity [36]. Furthermore, the generating units' emission function is considered similar to the fuel cost curve with conversion factors of 0.2 and 0.5 for SO_2 and NO_x, respectively [37]. The emission curves are also approximated by 20 linear segments between the minimum and maximum generating units' capacities. In this paper, it is assumed that three generators can be simultaneously repaired due to the technical limitation. Here, the network losses are disregarded during the scheduling period. Moreover, the load must be completely satisfied in each period, which means that no unserved energy is allowed by the ISO, and ε is considered equal to zero in (23).

DR programs are also performed in each load bus. Therefore, DRPs aggregate discrete retail customer responses and submit bid-quantity offers to procure system reserve. The potential of implementing DR programs, i.e., $\eta(d,t)$, is considered as 10% of the total load in each bus. The yearly load curtailment is assumed equal to 5% of the total yearly load in each bus. The offer packages with the format depicted in Fig. 2 are presented in Table I. DRPs data are composed of three discrete points, namely, 33%, 66%, and 100% of the total response of the customers [38]. Two sample DRPs have been depicted in buses 3 and 13 in Fig. 3.

The following case studies are conducted to investigate the impacts of DR programs and reserve provision cost on security-constrained PMS. A tradeoff between cost and emission minimization is considered. Multifarious weighting factors can be assigned for cost and emission, which depend on the system operator demand. Here, w_e and w_c are both considered equal to 0.5 in (4).

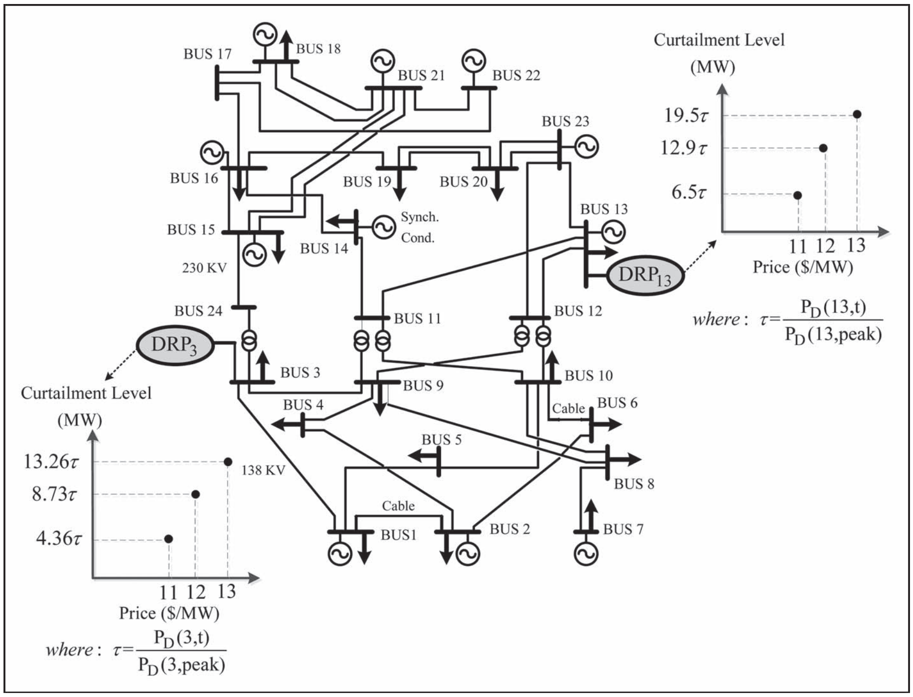

Fig. 3. IEEE 24-bus RTS considering DRPs.

TABLE I
DRPs' OFFERS FOR LOAD REDUCTION

ν	$L_{DR}(\nu,d,t)$: (MW)	$C_C(\nu,d,t)$: ($/MW)
0	33% of total Response	11
1	66% of total Response	12
2	100% of total Response	13

TABLE II
COMPARISON OF THE COST AND EMISSION IN CASES I AND II

	Case #I	Case #II	$\frac{\text{Case \#II - Case \#I}}{\text{Case \#I}}$ (%)
Operation & Maintenance cost (million $)	177.435	184.475	3.96
Reserve scheduling cost (million $)	63.512	50.762	-20.07
System total cost (million $)	240.948	235.238	-2.37
NO_x emission (million lbs)	87.982	91.502	4.01
SO_2 emission (million lbs)	35.193	36.601	4.01

In case I, the security-constrained PMS is addressed without considering the reserve expenditure and DR programs. In the second case, i.e., case II, the reserve provision cost is contemplated while DR programs are disregarded. Finally, both the reserve provision cost and the market-based DR programs are evaluated in case III.

Applying CPLEX 12.4.0 [24], the system total costs in cases I and II are computed equal to $240.94 and $235.23 million/year, respectively. The operation and reserve cost and SO_2 and NO_x emissions in the aforementioned cases are presented in Table II. As shown in Table II, although environmental pollution in case II has been increased by 4.01% in comparison with case I, the system total expenditure has been considerably decreased, which is about $5.7 million.

Generated power percentage of committed units in terms of their available capacities is presented in Table III. For example, N_{26} is the lowest cost unit in IEEE RTS, which is committed with its maximum capacity in case I, whereas in the next case, due to cooperating in system reserve procurement, the aforementioned unit does not participate in demand satisfaction with its marginal capacity. The total power generation of N_{26} is 18 400 and 16 147.97 MW in cases I and II, respectively, over the time horizon. Since this unit is committed for 46 periods, its available capacity is computed equal to $400 \times 46 = 18\,400$ MW. Therefore, the aforementioned unit generated power percentage in terms of the available capacity is equal to $(18\,400/18\,400 =)100\%$ in case I and $(16\,147.97/18\,400 =)$ 87.76% in case II. It is concluded that most economical units' generation levels are decreased in case II, whereas produced power of more expensive units, i.e., $OF_{10}-OF_{12}$, is increased, which raises the operation cost. Moreover, considering the reserve provision cost also affects the commitment status of generating units, as shown in Table III. The participation percentage of committed units to procure system reserve requirement in terms of their available capacities is reported in Table IV. It is deduced that, without considering the reserve assessment expenditure in the objective function, the most expensive units merely committed with the minimum capacity to provide system reserve, whereas in case II, all committed units can partake in reserve acquisition to minimize the system total cost. Therefore, the reservation level of expensive units is lessened in case II, whereas the cooperation amount of economical unit in reserve provision is increased in comparison with case I.

In the second case, the economic benefits of considering the reserve expenditure have been demonstrated. In the following, case III is addressed to investigate the economic and environmental measures of DR programs on security-constrained PMS.

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

TABLE III
PARTICIPATION PERCENTAGE OF COMMITTED UNITS FOR DEMAND SATISFACTION IN CASES I AND II

Unit NO	Committed periods		Produced power (%)		Unit NO	Committed periods		Produced power (%)	
	Case #I	Case #II	Case #I	Case #II		Case #I	Case #II	Case #I	Case #II
OF_1	34	21	20	20	CF_{16}	49	49	26	22.95
OF_2	26	13	20	20	CF_{17}	49	49	34.23	37.26
OF_3	22	5	20	20	CF_{18}	49	49	32.8	34.06
OF_4	11	1	20	20	CF_{19}	49	49	29.17	29.58
OF_5	3	0	20	0	CF_{20}	48	48	95.05	96.8
OF_7	2	0	20	0	CF_{21}	48	48	97.2	98.4
OF_{10}	47	48	25	70.7	CF_{22}	48	48	95.8	96.5
OF_{11}	22	16	25	27.57	CF_{23}	48	48	94.9	94.3
OF_{12}	45	41	25	64.25	CF_{24}	47	47	99.67	100
OF_{13}	1	10	35	35	N_{25}	46	46	100	88
OF_{14}	0	1	0	35	N_{26}	46	46	100	87.76

Available Capacity : 47×100 = 4700
Generated Power during Committed Periods : 1175 MW
⇓
Produced Power (%) = (1175/4700)×100= 25%

Available Capacity : 46×400 = 18400
Generated Power during Committed Periods : 16191.021 MW
⇓
Produced Power (%) = (16191.021/18400)×100= 88%

TABLE IV
PARTICIPATION PERCENTAGE OF COMMITTED UNITS FOR RESERVE PROVISION IN CASES I AND II

Unit NO	Reservation Level (%)		Unit NO	Reservation Level (%)		Unit NO	Reservation level (%)	
	Case #I	Case #II		Case #I	Case #II		Case #I	Case #II
OF_1	53.88	40.23	OF_{12}	72.03	30.21	CF_{21}	2.8	1.6
OF_2	62.6	68.33	OF_{13}	65	65	CF_{22}	4.2	3.5
OF_3	68.03	78	OF_{14}	0	65	CF_{23}	5.1	5.7
OF_4	72.65	80	CF_{16}	74	77.05	CF_{24}	0.33	0
OF_5	66.5	0	CF_{17}	65.77	62.74	N_{25}	0	12
OF_7	57.5	0	CF_{18}	67.2	65.94	N_{26}	0	12.24
OF_{10}	72.63	21.79	CF_{19}	70.83	70.42			
OF_{11}	73.3	65.67	CF_{20}	4.95	3.2			

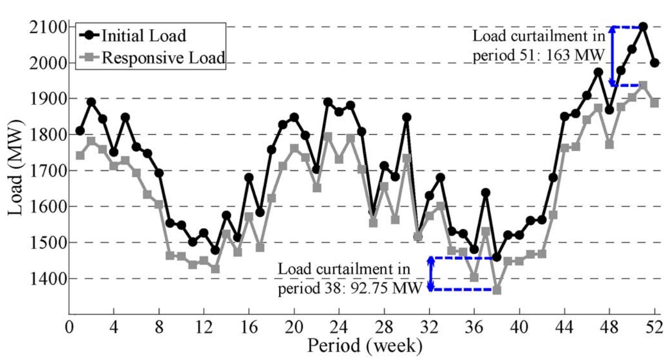

Fig. 4. Impact of market-based DR programs on load profile.

Utilizing DR programs, consumers' consumption is altered during the time. The load curve of the IEEE RTS before and after implementing DR programs is displayed in Fig. 4. As shown in Fig. 4, the participation of customers in peak periods is more in comparison with the other periods in order to decline the system total cost more tangibly.

TABLE V
MAINTENANCE SCHEME

Unit No	Maintenance periods			Unit No	Maintenance periods		
	Case #I	Case #II	Case #III		Case #I	Case #II	Case #III
OF_1	14-15	9-10	29-30	OF_{14}	32-35	14-17	2-5
OF_2	47-48	3-4	9-10	OF_{15}	49-52	22-25	9-12
OF_3	21-22	39-40	23-24	CF_{16}	1-3	20-22	22-24
OF_4	43-44	11-12	14-15	CF_{17}	21-23	27-29	17-19
OF_5	36-37	46-47	1-2	CF_{18}	18-20	1-3	25-27
OF_6	26-27	32-33	19-20	CF_{19}	10-12	39-41	27-29
OF_7	28-29	47-48	40-41	CF_{20}	4-7	40-43	15-18
OF_8	6-7	13-14	21-22	CF_{21}	15-18	31-34	15-18
OF_9	50-51	30-31	3-4	CF_{22}	27-30	15-18	29-32
OF_{10}	15-17	27-29	19-21	CF_{23}	42-45	17-20	5-8
OF_{11}	19-21	24-26	49-51	CF_{24}	31-35	11-15	33-37
OF_{12}	25-27	42-44	39-41	N_{25}	9-14	6-11	9-14
OF_{13}	1-4	23-26	2-5	N_{26}	36-41	34-39	38-43

By applying CPLEX 12.4.0, the system total cost, including operation, maintenance, reserve expenditure, and DR financial burden, is obtained equal to \$209.09 million/year in case III, which decreases $(235.23-209.09=)$ \$26.14 million/year in comparison with case II. The amounts of SO_2 and NO_x are equal to 32.9 and 82.26 million lbs/year, respectively. The maintenance scheme of cases I–III is provided in Table V.

As shown in Table V, DR programs and reserve procurement cost affect the maintenance scheme of generating units. Therefore, it is beneficial to consider DR programs in the PMS of generating units to determine the more proper maintenance scheme. Moreover, the optimization information of cases I–III, including the number of variables and equations, is presented in Table VI.

Different terms of the objective function in case III are provided in Table VII. It can be observed from Table VII that, although DR programs impose an additional financial

TABLE VI
GAMS MODEL STATISTICS OF CASES I–III

Optimization information	Case #I	Case #II	Case #III
Blocks of equations	38	41	45
Blocks of variables	7	8	11
Single equations	38793	41549	45934
Single variables	34217	35569	39105
Nonzero elements	167935	176047	190607
Discrete variables	4056	4056	4940

TABLE VII
SECURITY-CONSTRAINED PMS ASSOCIATED WITH DR

	Case #III	(Case #III - Case #I) / Case #I (%)	(Case #III - Case #II) / Case #II (%)
Operation & Maintenance cost (million $)	166.008	-6.44	-10.01
Reserve scheduling cost (million $)	34.547	-45.6	-31.94
DR cost (million $)	8.543	---	---
Total reserve cost (million $)	43.091	-32.15	-15.11
System total cost (million $)	209.0986	-13.21	-11.11
NO_x emission (million lbs)	82.268	-6.49	-10.09
SO_2 emission (million lbs)	32.907	-6.49	-10.09

burden, they cause a reduction in both the operation and reserve scheduling costs of the system. Moreover, the greenhouse gas emissions also declined due to deferring commitment of polluted units.

In case III, generating units are differently committed during the scheduling time horizon in comparison with case II. More expensive units are only committed to procure system reserve in case II, whereas due to participating customers in reserve acquisition in case III, the number of committed units is lessened. This issue has been represented for a sample unit, i.e., OF_{10}, during the scheduling time in Table VIII. The shaded boxes display the difference between the commitment status of OF_{10} in cases II and III.

According to the total yearly load curtailment in each DRP, potential of implementing DR programs, and availability of generating units in each period, the percentage of customer participation in system reserve acquisition is determined in such a way to minimize the system total cost and the generating units' emission over the scheduling time horizon. As an example, the ISO curtails 163 MW of the demand in period 51, which is shown in Fig. 4. Therefore, $(163/400 =)$ 40.75% of the system reserve requirement is provided with the customers' cooperation. System reserve share, which is scheduled with demand-side resources, is presented in Table IX. Moreover, the amount of system reserve, which is procured via generating units, is also presented in Table IX.

TABLE VIII
COMMITMENT STATUS OF OF_{10} IN CASES II AND III

Period	Case #II	Case #III	Period	Case #II	Case #III	Period	Case #II	Case #III
1	1	0	19	1	0	37	1	1
2	1	0	20	1	0	38	1	0
3	1	0	21	1	0	39	1	1
4	1	0	22	1	0	40	1	1
5	1	0	23	1	1	41	1	1
6	1	1	24	1	0	42	1	1
7	1	0	25	1	1	43	1	1
8	1	0	26	1	0	44	1	0
9	1	1	27	0	0	45	1	0
10	1	1	28	0	0	46	1	1
11	1	1	29	0	0	47	1	1
12	1	1	30	1	1	48	1	0
13	1	1	31	0	0	49	1	1
14	1	1	32	1	0	50	1	1
15	1	1	33	1	1	51	1	1
16	1	1	34	1	1	52	1	1
17	1	1	35	1	1			
18	1	1	36	1	0			

TABLE IX
DISTRIBUTION OF SYSTEM RESERVE REQUIREMENT BETWEEN DEMAND-SIDE AND SUPPLY-SIDE RESOURCES

Period	Units (MW)	DR (%)	Period	Units (MW)	DR (%)
1	331.9	17.02	27	368.24	7.94
2	292	27	28	342.2	14.45
3	315.1	21.22	29	280.45	29.89
4	361.3	9.67	30	285.5	28.62
5	280.4	29.88	31	400	0
6	326.4	18.38	32	344.7	13.82
7	285.9	28.52	33	322	19.5
8	313.2	21.7	34	346.55	13.36
9	310	22.5	35	349.68	12.58
10	313.1	21.71	36	321.75	19.56
11	336.2	15.94	37	293	26.75
12	323.6	19.09	38	307.25	23.19
13	347.8	13.05	39	326.8	18.3
14	349.3	12.67	40	326.8	18.3
15	358.28	10.43	41	306.85	23.29
16	292	27	42	305.8	23.55
17	302.3	24.42	43	297	25.75
18	265.15	33.71	44	311.95	22.01
19	285.5	28.62	45	307.75	23.06
20	313	21.75	46	332.55	16.86
21	338.2	15.45	47	300	25
22	347.45	13.14	48	302.5	24.37
23	304	24	49	297.9	25.52
24	267.65	33.09	50	265.56	33.61
25	308.2	22.95	51	237	40.75
26	294.95	26.26	52	287.4	28.15

The level of load curtailment in bus 5 with minimum loading and bus 18 with maximum loading is depicted in Fig. 5. As shown in Fig. 5, the customers' participation level in DR programs depends on the amount of load in each bus and is increased during the peak periods.

In the following, the generation pattern and reserve scheduling of generating units for the minimum and maximum levels of demand, i.e., weeks 38 and 51, are precisely examined. In Table X, the commitment status of generating units for periods 38 and 51 is presented in cases II and III. The shaded boxes show the difference in the commitment status of generating units between the two cases.

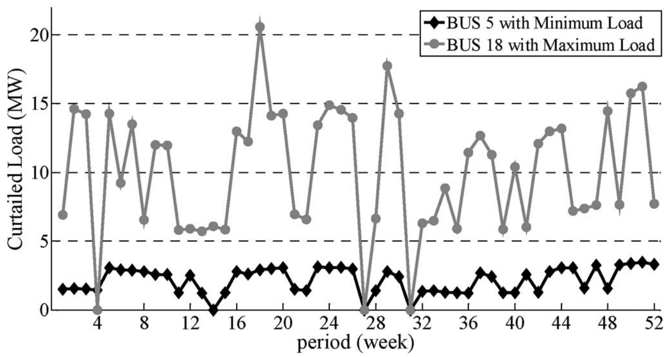

Fig. 5. Load curtailment level of two sample buses in case III.

TABLE X
COMMITMENT STATUS OF GENERATING UNITS IN PERIODS 38 AND 51

Unit NO	Period 38 Cases		Period 51 Cases		Unit NO	Period 38 Cases		Period 51 Cases	
	#II	#III	#II	#III		#II	#III	#II	#III
OF_1	Off	Off	On	Off	OF_{14}	Off	Off	Off	Off
OF_2	Off	Off	On	Off	OF_{15}	Off	Off	Off	Off
OF_3	Off	Off	On	Off	CF_{16}	On	On	On	On
OF_4	Off	Off	Off	Off	CF_{17}	On	On	On	On
OF_5	Off	Off	Off	Off	CF_{18}	On	On	On	On
OF_6	Off	Off	Off	Off	CF_{19}	On	On	On	On
OF_7	Off	Off	Off	Off	CF_{20}	On	On	On	On
OF_8	Off	Off	Off	Off	CF_{21}	On	On	On	On
OF_9	Off	Off	Off	Off	CF_{22}	On	On	On	On
OF_{10}	On	Off	On	On	CF_{23}	On	On	On	On
OF_{11}	Off	Off	Off	Off	CF_{24}	On	On	On	On
OF_{12}	On	Off	On	Off	N_{25}	On	On	On	On
OF_{13}	Off	Off	On	Off	N_{26}	Off	Off	On	On

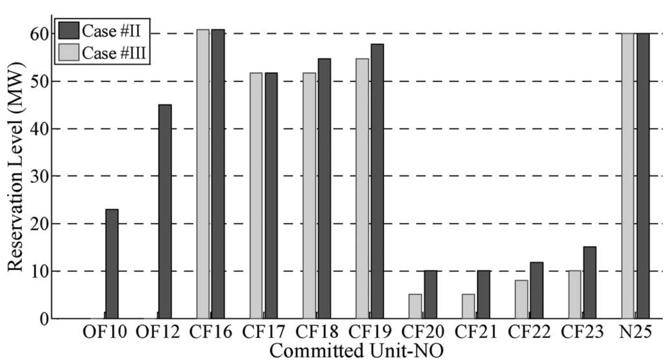

Fig. 6. Procured reserve via generating units in period 38.

Referring to Table X and due to unavailability of N_{26} in period 38, two 100-MW units, i.e., OF_{10} and OF_{12}, are committed to satisfy the demand and reserve procurement in case II. By participating customers in reserve provision in case III, the committed units and the reservation level in generating units are both decreased in comparison with case II, which is shown in Fig. 6.

In week 51, without considering the impacts of DR programs, three 12-MW units (OF_1-OF_3) and one of the 197-MW units (OF_{13}) are just committed with their minimum capacity to provide system reserve necessity. As represented in Fig. 7, although some units' reservation capacity is increased in case III, e.g., CF_{19}, the total reservation capacity in generating units has been lessened.

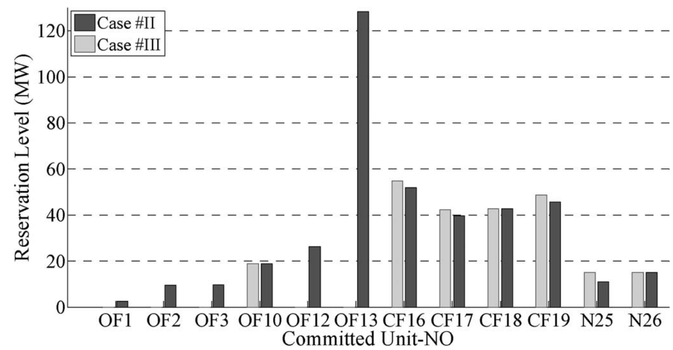

Fig. 7. Procured reserve via generating units in period 51.

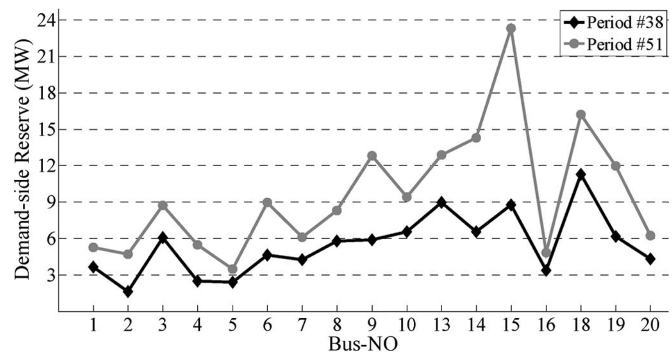

Fig. 8. Customers' participation level in reserve procurement in weeks 38 and 51.

The customers' participation level in the reserve provision for the aforementioned periods is shown in Fig. 8. As represented in Fig. 8, the cooperation level of customers in reserve procurement is diminished when the system is loading less due to inexpensive units' commitment in off-peak periods. Therefore, the ISO prefers to curtail load in peak periods more to decline the system expenditures more tangibly.

V. CONCLUDING REMARKS

In this paper, demand-side resources have been introduced as a virtual resource to provide system reserve requirement. Here, the security-constrained PMS is addressed as a long-term scheduling in power system research studies. In order to investigate the economic- and environmental-driven measures of DR programs, a new MIP-based structure for cost-and-emission-based maintenance scheduling associated with DR programs has been suggested. Utilizing the proposed framework, maintenance scheme and commitment status of generating units, energy and spinning reserve scheduling, and scheduled reserve of DRPs are simultaneously determined over the scheduling horizon. The applicability of the proposed model has been illustrated using the IEEE RTS. It is concluded that implementing market-based DR programs reduces the system total cost and produced emission considerably. DR resources also affect the maintenance scheme and commitment status of generating units due to deferring commitment of power plants. Future research is needed to develop the proposed structure considering load and price uncertainties, as well as more complementary constraints.

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