PREVENTIVE AND CORRECTIVE SECURITY MARKET MODEL

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Abstract – Previous large blackouts in North America and Europe demonstrated that power system security issues have been neglected in favor of more financial concerns. While making decisions on generating unit scheduling by minimizing in the energy resource cost, the system operators also must provide adequate amount of reserve to keep up power system security in case of unforeseen events. Traditionally, security control was performed by preventive and corrective control actions. In this paper, we define preventive and corrective security markets corresponding to these two security actions. Making a trade-off between these two markets for reserve resource provision is deemed to be necessary. A new SCUC problem is proposed to model the relation between preventive and corrective security market. Benders decomposition is employed to solve the proposed model. By solving the SCUC problem, the optimal reserve resources required under pre-contingency and post-contingency state are determined. Three-bus test case is used to demonstrate the performance of the presented method.

Keywords: Security constraint unit commitment (SCUC), preventive security market (PSM), corrective security market (CSM), Spinning reserve (SR)

NOMENCLATURE

A. Variables

$P_{g,it}$ Power output of generator unit i at time t.
I_{it} Binary variable where 1 means unit i is online at time t, otherwise 0.
I_{itk}^{up} Binary variable; 1 means unit i is accepted as up-going reserve in CSM, 0 otherwise.
I_{itk}^{dn} Binary variable; 1 means unit i is accepted as down-going reserve in CSM, 0 otherwise.
$r_{g,it}^{p,up}$ Up-going SR provided by unit i at time t in PSM.
$r_{g,it}^{p,dn}$ Down SR provided by unit i at time t in PSM.
$r_{d,jt}^{p,up}$ Up SR provided by demand j at time t in PSM.
$r_{d,jt}^{p,dn}$ DownSR provided by demand j at time t in PSM.
$r_{g,itk}^{p,up}$ Up-going reserve provided by unit i at time t during contingency k in CSM.
$r_{g,itk}^{p,dn}$ Down-going reserve provided by unit i at time t during contingency k in CSM.
$r_{d,jtk}^{p,up}$ Up-going reserve provided by demand j at time t during contingency k in CSM.
$r_{d,jtk}^{p,dn}$ Down-going reserve provided by demand j at time t during contingency k in CSM.

B. Functions

$F_i(\ )$ Cost of energy production of generator i.

C. Constants

$L_{d,jt}$ Load of demand j at time t.
P_i^{min} Minimum capacity of generator unit i.
$\overline{r}_{g,it}^{p,up}$ Maximum up-going SR that generator i can provide at time t in PSM.
$\overline{r}_{g,it}^{p,dn}$ Maximum down-going SR that generator i can provide at time t in PSM.
$\overline{r}_{d,jt}^{p,up}$ Maximum up-going SR that demand j can provide at time t in PSM.
$\overline{r}_{d,jt}^{p,dn}$ Maximum down-going SR that demand j can provide at time t in PSM.
$\overline{r}_{g,it}^{c,up}$ Maximum up-going reserve that generator i can provide at time t in CSM.
$\overline{r}_{d,jt}^{c,up}$ Maximum up-going reserve that demand j can provide at time t in CSM.
SD_{it} Shut down cost of generator i at time t.
SU_{it} Start up cost of generator i at time t.
T_i^{on} Minimum up time of generator i.
T_i^{off} Minimum down time of generator i.
$\pi_{g,it}^{p,up}$ Bid of unit i for up SR at time t in PSM.
$\pi_{g,it}^{p,dn}$ Bid of unit i for down SR at time t in PSM.
$\pi_{d,jt}^{p,up}$ Offer of demand j for up SR at time t in PSM.
$\pi_{d,jt}^{p,dn}$ Offer of demand j for down SR at time t in PSM.
$\pi_{g,it}^{c,up}$ Bid of unit i for up reserve at time t in CSM.
$\pi_{g,it}^{c,dn}$ Bid of unit i for down reserve at time t in CSM.
$\pi_{d,jt}^{c,up}$ Demand j offer for up reserve at time t in CSM.
$\pi_{d,jt}^{c,dn}$ Demand j offer for down reserve at time t in CSM.

D. Indices

b Index of buses from 1 to NB.
i Index of generators from 1 to NG.
j Index of demands from 1 to ND.
k Index of contingencies running from 1 to K.
t Index of time periods from 1 to NT.

1 INTRODUCTION

Security can be defined as the ability of an electric power system to withstand sudden disturbances such as unanticipated loss of system components. Power system security is more and more in conflict with economic and environmental requirements. Security control aims at making decisions in different time horizons so as to prevent the system from undesired situations, and in particular to avoid large catastrophic outages. Traditionally, security control has been divided in two main categories: preventive and corrective control actions [1].

Therefore, two security markets can be defined corresponding to two security actions named preventive security market and corrective security market. In preventive security market, the objective is to prepare the system when it is still in normal operation in order to make it able to face future (uncertain) events in a satisfactory way. But, in corrective security market, the disturbing events have already occurred, and thus the objective becomes to control the system in such a way the consequences are minimized.

Generation rescheduling, sometimes load curtailment as interruptible loads, reactive compensation, and etc are considered as a preventive control actions and should be determined in preventive security market. On the other hand, the system operator use the involuntary load demand and generation shedding, calling some fast generating units, shunt capacitor or reactor switching, network splitting, and etc as a corrective control actions.

The reserve services are considered as important resources that the power system operators employ to keep up the system security in the case of unforeseen disturbances. There are two main strategies for reserve service provision. The first is the provision in a preventive security market. In this case, the power system operators should maintain some spinning reserve resources in advance to reschedule the system in order to restore a normal state when a contingency occurs. The second is the reserve provision in a corrective security market that got more attention in the new competition environment. In this strategy, the power system operators provide fast reserve resources in the real-time when they are actually needed in order to transfer quickly the system state to a new secure operating point. The reason why corrective security market is used for reserve provision can be either the reserve resources provided in the preventive security market are not sufficient or the preventive security market is not defined in the market model.

Note that the capitalized preventive provision can be expensive and even infeasible for considering all potential contingencies. In contrast, although the provision of reserve resource only in corrective security market can be economical; it might threaten the system security. Therefore, making a trade-off between these two markets for reserve provision is deemed to be necessary [2].

Security constrained unit commitment (SCUC) tool is one of the key components of standard market design (SMD) that can be used for market-clearing and reserve services provision problem. Considerable researches have been carried out to solve the SCUC in order to procure the required reserve resource, in the last years. Unlike the deterministic SCUC problem, the major parts of these studies have been recently focused mainly on the risk-based SCUC problem. For instance, references [3-4] incorporate the risk of the system, scheduled in normal state, as inequality constraint into the SCUC problem. The solution tries to satisfy this constraint in order to assess the required reserve resource that the system operator should maintain in advance. Moreover, references [5-8] simulate a cost-benefit analysis for evaluation of reserve resources by penalizing the risk index into the SCUC objective function. However, the close relations between preventive and corrective security markets are not well indicated in these literatures.

This paper presents a new SCUC problem to model the relation between preventive and corrective security market. By solving this SCUC problem, we can compute the optimal reserve resources required under pre-contingency and post-contingency state. The objective of the problem is to minimize the cost of operating the system in the normal state and the expected cost associated with each of post contingency operating states. In other words, the objective of this problem is to minimize the production costs coming from the energy market and the reserve costs coming from the preventive and corrective security market in an integrated optimization problem. The proposed model is based on effective coordination strategy. Benders decomposition is employed to solve the problem while taking into consideration this coordination in an iterative process.

2 PROPOSED MODEL FORMULATION AND METHODOLOGY

A proper coordination between the preventive security market and corrective security market is very imperative. One of the reasons for this coordination is, by accepting some expenses in the pre-contingency state, i.e., preventive market; the system operator may save more during the operation under post-contingency state. This coordination is obvious if the initial pre-disturbance operation set-points carried over into the real time operation are determined by the preventive security market. Here, a new SCUC is employed to take into account this coordination.

In what follow the complete problem formulation of SCUC problem including all constraints are first provided.

2.1 Complete problem formulation

The formulation is as follows,

$$\min f(x_0, u_0) + e(x_k, u_k, u_0) \quad (1)$$

Subject to

$$g_0(x_0, u_0) = 0 \quad (2)$$

$$h_0(x_0, u_0) \le h_0^{\max} \quad (3)$$

$$g_k(x_k, u_k, u_0) = 0, \quad k = 1, 2, ..., K \quad (4)$$

$$h_k(x_k, u_k, u_0) \le h_k^{\max}, \quad k = 1, 2, ..., K \quad (5)$$

$$(u_0, u_k) \in \varsigma, \quad k = 1, 2, ..., K \quad (6)$$

$f(x_0,u_0)$ models the SCUC objective function in normal state (pre-contingency) of power system. In fact, this function includes energy market and preventive security market objective functions. $e(x_k,u_k,u_0)$ models the expected cost of security corrective actions under post-contingency condition. A single entity named independent system operator (ISO) is responsible for management of energy market as well as both preventive and corrective security markets. x_0 is a vector of state variables denoting the voltage angles under pre-contingency conditions. Also, u_0 is a vector of control variables denoting the status (on/off) and the amount of power and reserve production of generating units under pre-contingency conditions. On the other hand, x_k and u_k indicate the vectors of state and control variables under post contingency condition, respectively. $g_0(x_0,u_0)$ and $g_k(x_k,u_k,u_0)$ represent the power flow equations (DC load flow) and $h_0(x_0,u_0)$ and $h_k(x_k,u_k,u_0)$ represent the line flow constraints under pre- and post-contingency condition, respectively. ς is feasible operating region of control variables under pre- and post-contingencies.

2.2 Problem Formulation in Benders Decomposition

Benders decomposition [9-10] is a popular optimization technique. In applying the benders decomposition algorithm, the original large-scale optimization problem will be decomposed into a master problem and sub-problem, which defines an iterative procedure between both levels in order to reach the optimal solution.

At the first stage, the master problem, MIP-based UC determining the commitment and energy and reserve dispatch of generating units, is solved under normal condition as represented below.

$$\min f(x_0,u_0)+\alpha^{(\upsilon)} \tag{7}$$

$$g_0(x_0,u_0)=0 \tag{8}$$

$$h_0(x_0,u_0)\le h_0^{\max} \tag{9}$$

$$\hat{\alpha}(x_0,u_0)\ge \alpha^{down} \tag{10}$$

where α^v is a continuous variable which approximates expected corrective cost in benders master problem at iteration v. α^{down} is a bound that can be determined from physical or economical considerations pertaining to the problem under study.

It is clear that the master problem depends on the optimal value of the sub-problem objective function, and subsequently, the sub-problem depends on the optimal solution of the master problem. Hence, using the solution $\hat{u}_0$ obtained in the master problem (first stage), the sub-problem is solved in the second stage and a new value for its objective function is obtained.

Here, the corresponding sub-problem is a combination of feasibility check and optimality check problems as follows. In order to check the master problem feasibility in the case of a contingency, control slack vectors are introduced and the summation of the components of these control slack vectors are minimized. The optimality checking part of the sub-problem minimizes the expected cost of the corrective security market.

$$\min Z^{(\upsilon)}=M.(s_k^1+s_k^2)+e(x_k,u_k,u_0) \tag{11}$$

$$g_k(x_k,u_k,u_0)+s_k^1-s_k^2=0,\quad k=1,2,...,K \tag{12}$$

$$h_k(x_k,u_k,u_0)\le h_k^{\max},\quad k=1,2,...,K \tag{13}$$

$$u_0=\hat{u}_0^{(\upsilon-1)}:\mu^{(\upsilon)},\quad \upsilon=1,2,...,S \tag{14}$$

where M is a large enough positive constant. The last constraint which enforces the preventive market scheduling, fixed in the master problem, deserves special mention. The dual variable $\mu^{(v)}$ associated with this constraint provide the master problem with relevant dual information to improve the current schedule.

The stopping criterion for the proposed problem is as (15). ε is convergence tolerance parameter.

$$\frac{\left|\alpha^{(\upsilon)}-Z^{(\upsilon)}\right|}{Z^{(\upsilon)}}\le\varepsilon \tag{15}$$

Equations (16) and (17) present the feasibility and the optimality benders cuts, respectively, that are generated from the subproblem.. The feasibility bender cut is used to mitigate the violations of equality constraints (12), and the optimality bender cut is used to guide the whole system toward the optimal solution.

$$Z^{(\upsilon)}+\mu^{(\upsilon)}(u_0-\hat{u}_0^{(\upsilon)})\le 0 \tag{16}$$

$$\alpha^{(\upsilon)}\ge Z^{(\upsilon)}+\mu^{(\upsilon)}(u_0-\hat{u}_0^{(\upsilon)}) \tag{17}$$

2.3 Solution Procedure

The step-by-step procedure of the problem solution is introduced here.

1) Solve the master problem. The system state, x_0, and the control variables, u_0, in the normal state are determined. Designate the solution as $\hat{u}_0$.
   - Initial solution: Start the solution procedure by solving the master problem with respect to the sub-problem by giving a guess to α^{down}.
   - Successive solutions: As the iterations proceed, the master problem is solved with respect to some constraints which are generated from the sub problem.
2) Solve the sub-problem according to the information obtained from the master problem. Then a new value for the sub-problem objective function, $Z^{(v)}$ and the dual variable of bundle constraint, $\mu^{(v)}$, associated with iteration v are obtained.
   - Benders feasibility cut: If the sub-problem is infeasible, an infeasibility benders cut is generated using (16) and is returned to the master problem.
   - Benders optimality cut: As the iterations proceed, the benders optimality cut is generated using (17) and is returned to the master problem.
3) Check the stopping criteria (15). If this condition is not met, add the benders cuts to the master problem and solve it again (go to step 1).

2.4 Pre-contingency Objective Function

The pre-contingency objective function, $f(x_0,u_0)$, includes the cost of energy production (energy market), and the cost of providing the reserve services in the preventive security market. This objective function is formulated in detail as (18).

$$\begin{aligned} f(x_0,u_0)=\sum_{t=1}^{NT}\Bigg\{&\sum_{i=1}^{NG}(F_i(P_{g,it})+SU_{it}+SD_{it})*I_{it}\\ &+\sum_{i=1}^{NG}(\pi_{g,it}^{p,up}r_{g,it}^{p,up}+\pi_{g,it}^{p,dn}r_{g,it}^{p,dn})\\ &+\sum_{j=1}^{ND}(\pi_{d,jt}^{p,up}r_{d,jt}^{p,up}+\pi_{d,jt}^{p,dn}r_{d,jt}^{p,dn})\Bigg\}\end{aligned} \tag{18}$$

The first line of (18) represents the energy production cost of generating units as well as the start-up and the shut-down costs. The energy production is restricted by a typical set of constraints including power balance constraint, minimum and maximum capacity of the generating units, ramping up/down rates constraints, startup/shutdown ramp limit of generators, minimum up/down time constraints and etc [11].

For the sake of conciseness, the mathematical formulation of these constraints is omitted here.

The second line of (18) is the cost of generation side spinning reserve scheduling, up-going and down-going spinning reserves, in the preventive security market. These two terms are restricted by the upper limits on the up- and down- spinning reserve as follows.

$$0 \le r_{g,it}^{p,up} \le \overline{r}_{g,it}^{p,up} * I_{it}, \ \forall i, \forall t \quad (19)$$

$$0 \le r_{g,it}^{p,dn} \le \overline{r}_{g,it}^{p,dn} * I_{it}, \ \forall i, \forall t \quad (20)$$

The third line of (18) is the cost of providing the demand side up-going and down-going spinning reserve in the preventive security market. In this respect it implies being ready to voluntarily decrease or increase the level of consumption if required. Similarly, these terms are restricted by the limits on demands which are willing to increase or decrease their consumption.

$$0 \le r_{d,jt}^{p,up} \le \overline{r}_{d,jt}^{p,up}, \ \forall j, \forall t \quad (21)$$

$$0 \le r_{d,jt}^{p,dn} \le \overline{r}_{d,jt}^{p,dn}, \ \forall j, \forall t \quad (22)$$

In addition, the power balance constraint at each bus and the DC network security constraint at normal state are listed as (23) - (25).

$$\sum_{i \in J_b} P_{g,it} - \sum_{j \in D_b} L_{d,jt} - \sum_{l \in H_b} PL_{lt} = 0, \ \forall b, \forall t \quad (23)$$

$$PL_{lt} = \frac{\delta_{mt} - \delta_{nt}}{X_{mn}}, \ (m,n \in l), \forall l \quad (24)$$

$$-PL_l^{\max} \le PL_{lt} \le PL_l^{\max}, \ \forall l, \forall \mathrm{t} \quad (25)$$

J_b is the set of generating units connected to bus b, and D_b is the set of load demands connected to bus b. Set H_b includes the lines connected to bus b which are labeled as either the "to bus" or the "from bus" in the set.

2.5 Post-contingency Objective Function

The post-contingency objective function, $e(x_k,u_k,u_0)$ is the expected cost of deploying the corrective actions which are specified in the corrective security market. This objective function is formulated in detail as follows.

$$\begin{aligned} e(x_k,u_k,u_0) = \sum_{t=1}^{NT} \Bigg\{ & \sum_{k=1}^{K} \rho_k(\tau) \sum_{i=1}^{NG} (\pi_{g,it}^{c,up} r_{g,itk}^{c,up} + SU_{it} * I_{itk}^{up}) + \\ & \sum_{k=1}^{K} \rho_k(\tau) \sum_{i=1}^{NG} (\pi_{g,it}^{c,dn} r_{g,itk}^{c,dn} + SD_{it} * I_{itk}^{dn}) \\ & \sum_{k=1}^{K} \rho_k(\tau) \sum_{j=1}^{ND} (\pi_{d,jt}^{c,up} r_{d,jtk}^{c,up} + \pi_{d,jt}^{c,dn} r_{d,jtk}^{c,dn}) + \Bigg\} \end{aligned} \quad (26)$$

$\rho_k(\tau)$ is the probability of the contingency k (including generating units and transmission lines) occurring during the time interval τ. As shown in the Appendix, under small time interval, this can be well approximated by equation (27).

$$\rho_k(\tau) = \lambda_k \tau \quad (27)$$

The first line of (26) represents the expected cost of calling the quick generating units to be turned on and to pick up the load in the case of contingency k. This quick start generating unit is limited by ramping-up constraint as listed below in addition of their feasible operating region limitations.

$$P_i^{\min} * I_{itk}^{up} \le r_{g,itk}^{c,up} \le \overline{r}_{g,it}^{c,up} * I_{itk}^{up}, \ \forall i, \forall t, \forall k \quad (28)$$

The relationship between unit status indicator in normal state and unit status indicator when contingency k occurs is

$$I_{itk}^{up} + \hat{I}_{it} \le 1, \ \forall i, \forall t, \forall k \quad (29)$$

Equation (29) enforces that this service can be provided only by off line generators, $\hat{I}_{it}=0$. They should be capable of being turned on when the system operators call them during the contingency k.

The second line of (26) is the cost applied to a generating units, already online ($\hat{I}_{it}=1$) and generating $\hat{g}_{it}$, when the system operator asks for them to be quickly turned off within the contingency occurrence duration. Hence, the down-going reserve that provided by these generating units in the corrective security market is restricted by the following constraints.

$$\hat{P}_{g,it} * I_{itk}^{dn} \le r_{g,itk}^{c,dn} \le \hat{P}_{g,it} * I_{itk}^{dn}, \ \forall i, \forall t, \forall k \quad (30)$$

$$I_{it,k}^{dn} - \hat{I}_{it} \le 0, \ \forall i, \forall t, \forall k \quad (31)$$

The last line of (26) is the involuntary load adding and load shedding costs, respectively. They are, in fact, the costs imposed to the load demands when the system operator asks them to abruptly increase or decrease their consumption level within the occurrence of contingency k. The up-going and down-going reserves provided by the load demands in the corrective security market are constrained by the following inequalities.

$$0 \le r_{d,jtk}^{c,up} \le \overline{r}_{d,jt}^{c,up}, \ \forall d, \forall t, \forall k \quad (32)$$

$$0 \le r_{d,jtk}^{c,dn} \le \overline{r}_{d,jt}^{c,dn}, \ \forall d, \forall t, \forall k \quad (33)$$

In addition, the equality constraint associated with nodal power balance using DC load flow in case of contingency k is as (34).

$$\sum_{i \in J_b} P_{g,itk} - \sum_{j \in D_b} L_{d,jtk} - \sum_{l \in H_b} PL_{ltk} = 0, \ \forall b, \forall t, \forall k \quad (34)$$

$$P_{g,itk} = \overline{P}_{g,it} + r_{g,itk}^{p,up} - r_{g,itk}^{p,dn} + r_{g,itk}^{c,up} - r_{g,itk}^{c,dn} \quad (35)$$

$$L_{d,jtk} = L_{d,jt} + r_{d,jtk}^{p,up} - r_{d,jtk}^{p,dn} + r_{d,jtk}^{c,up} - r_{d,jtk}^{c,dn} \quad (36)$$

$$PL_{ltk} = \frac{\delta_{mtk} - \delta_{ntk}}{X_{mn}}, \ (m,n \in l), \forall l, \forall t, \forall k \quad (37)$$

Equation (35) states the power outputs of generating units result from the power productions settled in the energy market plus the different types of reserves in preventive and corrective security markets deployed to accommodate system in contingency k. An analogous interpretation can be carried out for the power consumed by each load demand as addressed in (36).

The amount of reserve services, which were provided in the preventive security market, as a response to the contingency k must be under the following limits.

$$0 \le r_{g,itk}^{p,up} \le \hat{r}_{g,it}^{p,up}, \quad 0 \le r_{g,itk}^{p,dn} \le \hat{r}_{g,it}^{p,dn}, \ \forall i, \forall t, \forall k \quad (38)$$

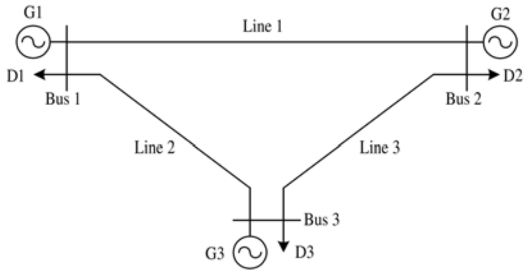

Figure 1: Three-bus test system.

$$0 \le r_{d,jtk}^{p,up} \le \hat{r}_{d,jt}^{p,up}, \quad 0 \le r_{d,jtk}^{p,dn} \le \hat{r}_{d,jt}^{p,dn}, \ \forall j, \forall t, \forall k \quad (39)$$

The transmission line limit in the case of contingency k is as

$$-PL_l^{\max} \le PL_{ltk} \le PL_l^{\max}, \ \forall l, \forall t, \forall k \quad (40)$$

Note that if under contingency k, a particular generating unit is out of service, then the corresponding status (I_{it}), the dispatch of this generating unit ($P_{g,it}$) and all the reserve service limits are set to zero. Moreover, if a particular line is out of service under contingency k, then the corresponding line flow limit (PL_l^{max}) is set to zero.

3 NUMERICAL EXAMPLE

The proposed model is applied to a three-bus test system over a five-hour horizon to illustrate the performance of the new SCUC with the preventive and corrective security markets. As depicted in fig.1, this case has three generation units, three transmission lines and three demands. This case is simple enough so that the correctness of the results can be readily verified. The line reactances are all 0.3 p.u on a base of 100 MVA and 138 kV. The capacities of lines are 100 MVA. Also, failure rate (λ) of lines is 1/500 (f/hr).

Three demands are allocated at each bus and vary hourly according to the given pattern in table 1. In addition, each consumer offers up to 40% of its hourly load as an interruptible load to the preventive security market. Besides, each consumer participates in the corrective security market while offer the value of lost load associated with involuntary curtailment of its load. The generating units' data are given in table 2. It is assumed that generator i, produce energy with startup cost SD_i and incremental cost a_i in the range of [g_i^{min}, g_i^{max}]. Here, the upper bounds on ramp up and down rate are the same for preventive and corrective security markets.

In this example for the sake of simplicity, it is assumed that: a) all the given load and generator data remain unchanged over all hours of the scheduled horizon, b) demand don't offer in up-going reserve in preventive and corrective security market, c) generating unit don't participates in corrective security market as down-going reserve, d) all the generating units, except generating unit 3, were off for three hours at the time t=0 and generating unit 3 was turned on for three hours at the time t=0.

The proposed model is in a linear form, and it is solved using CPLEX 12 under GAMS [13].

	Time t (hr)						
	1 (MW)	2 (MW)	3 (MW)	4 (MW)	5 (MW)	$\pi_{dt}^{p,dn}$ ($/MWh)	$\pi_{dt}^{c,dn}$ ($/MWh)
D_{11}	13.2	19.8	33	26.4	10.2	20	6000
D_{21}	13.2	19.8	33	26.4	10.2	25	5000
D_{31}	13.6	20.4	34	27.2	10.6	15	4000

Table 1: Load data.

	Generator i		
	1	2	3
$g_i^{\min}$ (MW)	10	10	10
$g_i^{\max}$ (MW)	120	120	120
a_i ($/MWh)	30	40	20
SD_i ($/h)	100	100	100
$\overline{r}_{it}^{up}$ (MW)	50	50	50
$\overline{r}_{it}^{dn}$ (MW)	50	50	50
T_i^{on} (hr)	2	1	3
T_i^{off} (hr)	2	1	3
$\pi_{it}^{p,up}$ ($/MWh)	10	12	8
$\pi_{it}^{p,dn}$ ($/MWh)	10	12	8
$\pi_{it}^{c,up}$ ($/MWh)	2500	2000	3000
λ (f/hr)	500^{-1}	500^{-1}	250^{-1}

Table 2: Generation data.

Note that up to second order contingencies are considered, here, and the analyses are carried out over five consecutive hours.

Three different scenarios are conducted to demonstrate the performance of the proposed models. The first scenario is characterized only with preventive security market. That is, the system operator has to schedule the system in the pre-contingency state in such a way that she is able to restore the system to the normal state only with the assistance of preventive actions (load and generation rescheduling) when a contingency happens. Consequently, the second and third scenarios consider both the preventive and corrective security markets. The second scenario takes into account the involuntary load curtailment as the corrective action, while in the third one both involuntary load curtailment and quick generating units are taken into consideration in the corrective security market. The results for the mentioned scenarios are summarized in tables 3-6.

Table 3 outlines the optimal generation and reserve schedule in energy and preventive security market associated with scenario 1. All generating units are committed at all the five hours in the result of security constraints and generating units' technical constraints such as ramp up/down rates and minimum up/down times. It is worthwhile to be mentioned that in the only preventive security market case, the system has to be prepositioned in such a way that all the possible contingencies would be covered by the preventive control actions. Since during the heavy loads periods the system is under more stress, the load demands are scheduled to participate in the preventive market as an interruptible load.

			Hour				
		unit	1	2	3	4	5
GD	$P_{g,it}$	G1	10	10	20	10	10
		G2	10	10	10	10	10
		G3	20	40	70	60	11
P	$r^{up}_{g,it}$	G1	30	50	50	50	21
		G2	30	50	50	50	21
		G3	20	20	30	20	20
	$r^{dn}_{g,it}$	G1	0	0	10	0	0
		G3	6.4	19.6	36	32.8	0.5
	$r^{dn}_{d,jt}$	D1	0	0	13.2	9.19	0
		D2	0	0	13.2	0	0
		D3	0	0	13.6	10.9	0

Table 3: Scenario 1 results. (*GD*, *P* and *C* are for generation dispatch in energy market, preventive market and corrective market, respectively.)

			Hour				
		unit	1	2	3	4	5
GD	$P_{g,it}$	G1	10	10	30	10	10
		G3	30	50	70	70	21
P	$r^{up}_{g,it}$	G1	30	50	50	50	21
		G3	10	10.4	30	10	10
	$r^{dn}_{g,it}$	G1	0	0	20	0	0
		G3	16.4	40	36	42.8	10.5
	$r^{dn}_{d,jt}$	D3	0	0	10.2	8.2	0
C	$LP^{c,dn}_{d,jt}$ $\times 10^{-4}$	D1	1.06	1.58	2.64	2.11	0.8
		D2	1.58	2.38	3.96	3.2	1.22
		D3	1.09	1.63	397	478	0.8

Table 4: Scenario 2 results.

Table 4 summarizes the results for scenario 2 in which the preventive and corrective security markets are employed for system prepositioning. As it can be seen from this table, the generating unit *G2*, being incrementally the most expensive one, is not committed in this case. Moreover, only the load demand *D3* provides the reserve during peak hour for the preventive market. Likewise, as seen in the last three rows of this table, the optimum market scheduling call for the load demand participation for all the periods in the corrective security market.

We measure the expected amount of participation associated with each load demand during the period t in the corrective security market using the following index.

$$LP^{c,dn}_{d,jt} = \sum_{k=1}^{K} \rho_k(t).r^{c,dn}_{d,jtk} \quad (41)$$

The values of this index for each load demand in different time periods are presented in the table 4.

As mentioned earlier, besides the load demands providing the reserve in corrective security market, the quick generating units can effectively participate in this market and improve the market efficiency. Table 5 shows the market scheduling in the case where both quick generating units and load demands are called for to act as a corrective action. It is obvious that the role of each load demand in corrective security market is reduced rather than scenario 2. The reason is the less expensive corrective action is provided by quick start generation unit *G2*. So, this generation unit effectively participates in corrective security market in all the periods as shown in the last row of table 5.

			Hour				
		unit	1	2	3	4	5
GD	$P_{g,it}$	G1	10	10	16	10	10
		G3	30	50	84	70	21
P	$r^{up}_{g,it}$	G1	30	50	50	50	21
		G3	10	10.4	16	10	10
	$r^{dn}_{g,it}$	G1	0	0	6	0	0
		G3	20	40	50	42.8	11
C	$LP^{c,dn}_{d,jt}$ $\times 10^{-4}$	D1	0	0	1.28	2.24	0
		D3	0	0.8	8.2	3.8	0
	$GP^{c,up}_{g,it}$ $\times 10^{-4}$	G2	3.73	4.8	1000	809	2.9

Table 5: Scenario 3 results.

	Scenario [$]		
	1	2	3
Running Cost	9681.7	7808.5	7670.5
Preventive Cost	7204.8	2963.6	2702.2
Corrective Cost	-	363.3	444.3
Total Cost	16886.5	11135.7	10817

Table 6: Comparison between each cost for each scenario.

The expected amount of generation unit participation during the period *t* in the corrective security market is evaluated using the following equation:

$$GP^{c,up}_{g,it} = \sum_{k=1}^{K} \rho_k(t).r^{c,up}_{g,itk} \quad (42)$$

Now, we show how this two security markets interact together to restore the system to the normal state when a contingency occurs. It is assumed that the outages of lines 1 and 3 occur simultaneously at peak hour (time *t*=3), such that the bus 2 is isolated from the whole system. With regard to the information in table 3, in scenario 1 the system operator deploys 23 *MW* up-going spinning reserve in bus 2, 10 *MW* and 13 MW down-going spinning reserve in bus 1 and bus 3, respectively, in order to deal with this contingency. While, in scenario 2, system operator deploys 20 *MW* and 13 *MW* down-going reserve from the preventive security market in bus 1 and bus 3, respectively to supply load demands in these two buses. Additionally, he asks for the load demand in bus 2 to shed 33 *MW* loads, as corrective action, to overcome the contingency. In the third scenario, the system operator dominates this contingency by using the following pre-specified reserves in preventive and corrective markets: deploying 6 *MW* and 27 *MW* down-going spinning reserve in bus 1 and bus 3, respectively, which are provided in preventive security market as well as calling 33 *MW* up-going reserves which is provided by fast generating unit *G2* in corrective security market.

What makes the results of this model interesting is the 36% reduction of the system total cost in scenario 1, by sacrificing only 2% of this cost in the corrective security market in scenario 2 (34% net benefit). These results are demonstrated in table 6. Moreover, it can be deduced from the comparison between scenario 2 and 3 in this table that if the number of services in corrective security market increase, the system scheduling cost in normal state would be efficiently decreased (from 10772.1$ in scenario 2 to 10372.7$ in scenario 3). Hence, the market efficiency is improved.

4 CONCLUSION

The preventive and corrective control actions are the main tools with which the system operator keeps the system security in its allowed boundary. This paper presents a preventive and corrective security market model corresponding to these two routine control actions. A new SCUC problem is formulated to model the relation between preventive and corrective security market. The objective of this integrated optimization problem is to minimize the production costs coming from the energy market and the reserve costs coming from the preventive and corrective security market. Here, up-going and down-going spinning reserve provided by synchronized generating units (generating units accepted in energy market) and load demands can be considered as reserve resources in the preventive security market. Moreover, calling the quick generating units to be turned on, asking some synchronized generating units to be turned off, adding some loads, and shedding some involuntary load in the case of contingency can be considered as reserve resources in corrective security market. Bender decomposition algorithm is applied to solve the proposed SCUC problem. The proposed approach is applied to a three-bus test system and the results show that system operator can manage the system more efficiently using both security markets rather than using one of them.

APENDIX
CONTINGENCY PROBABILITY

Consider that the interval of time $(0,\tau)$ is divided into n very small intervals of increment $\Delta\tau$. If λ_k is assumed to be the mean rate of occurrence contingency k, then the expected of occurrence in interval $\Delta\tau$ is given by $\lambda_k\Delta\tau$. Let denote the probability of having zero occurrences in $(0,\tau)$ by $\rho_0(\tau)$. In expressing $\rho_0(\tau+\Delta\tau)$, we note that 0 event may occur during $(0, \tau+\Delta\tau)$ in only one way: 0 event occur in $(0,\tau)$ and 0 events occur in $(\tau, \tau+\Delta\tau)$.

$$\rho_0(\tau+\Delta\tau)=\rho_0(\tau)*(1-\lambda_k\Delta\tau)\Rightarrow\frac{\rho_0(\tau+\Delta\tau)-\rho_0(\tau)}{\Delta\tau}=-\lambda_k\rho_0(\tau) \quad (43)$$

If $\Delta\tau$ is small, i.e., it goes to zero then:

$$\rho_0'(\tau)=-\lambda_k\rho_0(\tau) \quad (44)$$

By integrating, we have

$$\ln\rho_0(\tau)=-\lambda_k\tau+C \quad (45)$$

If at τ=0, we assume that no event has occurred (i.e., the device is operable), then $\rho_0\ (\tau=0)\ =1$, which forces $C=0$, so that

$$\rho_0(\tau)=e^{-\lambda_k\tau} \quad (46)$$

Therefore, probability of having an occurrence, named k, in the interval $(0,\tau)$ is

$$\rho_k(\tau)=1-e^{-\lambda_k\tau} \quad (47)$$

If $\lambda_k\tau <<1$, which is generally true for the operation period (up to several hours), then

$$\rho_k(\tau)=\lambda_k\tau \quad (48)$$

It can be easily shown using the Poisson distribution [14] that the occurrence of having more than one contingency k in the short time interval τ is nearly the same of having one contingency in this interval. That means the time for repairing the components in this contingency is so short and it is neglected. Therefore, equation (48) represents the probability that contingency k occurs and the failed elements are not replaced during the intervalτ. Some references [12] named this interval as lead time.

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