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Security Based Congestion Management Considering Transmission Network Contingencies in a Competitive Environment

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***Abstract*— Open access to transmission networks, and the growing of electricity consumption have increased the presence of transmission congestion. To ensure system security in competitive electricity markets, a major task of the system operator is congestion management. This paper addresses a new framework for congestion management. The framework utilizes network distribution shift factors for congestion management. Within this framework, a new security based congestion management (SBCM) scheme has been developed. This framework considers security in congestion management (CM) so that, network security is included in the objective function of congestion management problem. In our proposed SBCM algorithm, the network security is considered in congestion management process so that economic advantages are preserved in managing network congestion. Appropriate functioning of the proposed SBCM algorithm has been evaluated by applying it to IEEE 9-bus and 30-bus test systems. Simulation results confirm that our proposed method compared with conventional congestion management methods is more efficient in managing network congestions.**

Keywords*— *Congestion management, security, line contingency, network distribution factors.

I. INTRODUCTION

Open access to transmission networks, and the growing of electricity consumption have increased the presence of transmission congestion. Transferring electrical energy between two buses or zones in a power system may result in the occurrence of congestion in one or more transmission lines in the network. Congestion is, essentially, a resultant of physical, operational or policy constraints imposed on the network. Both vertically integrated and unbundled power systems have experienced such problems [1], [2]. Congestion arises from two main resources: the occurrence of system contingencies and ignoring generation locations in market clearing mechanism [3]. Congestion may occur in day-ahead, hour-ahead and real-time dispatch. If congestion does happen, system operator is responsible for necessary preventive actions to relieve congestion. The set of the remedial activities performed for relieving violated limits is called congestion management. Managing network congestions may impose some additional cost on the operation of system. This is due to the fact that, to alleviate network congestion, the output of cheaper generators may become substituted by the output of more expensive ones. Transmission congestion may threaten system stability, damaging and outage of system components resulting in market power for some participants [4]. Therefore, preventive or corrective actions are necessary to relieve congestion and decrease system risk.

Much research has been focused on congestion management techniques and algorithms. These studies are categorized in two main groups. The first group is referred as cost-free methods and the second one is known as non-cost-free algorithms [5].

Cost-free methods include network reconfiguration and using network utilities to relieve congestion. In [6], a line switching algorithm for overload alleviation or rotation under contingency condition has been proposed. In this algorithm, Line outage distribution factors (LODF) have been used for simulating line flows after a switching pattern. In [7], the optimal topological configuration has been found to help independent system operator (ISO) to manage line overloads. In this algorithm, large-scale mixed-integer programming has been used to determine the optimum solution. Employing FACTS devices in congestion management may also been considered as another cost-free approach [8, 9].

Non cost-free methods basically include generation re-dispatch and load curtailment. A. Kumara et al. have presented a new zonal-based congestion management approach [10], [11]. Transmission zones are defined based on line flow sensitivity indexes referred to as transmission congestion distribution factors (TCDF). Reference [12] demonstrates an appropriate model for load interruption in reliving transmission congestion. An auction model has been presented for real-time selection of interruptible loads while it satisfies congestion management objectives and taking into account N-1 contingency criterion. In [3], by considering both generation rescheduling and load shedding, a compatible method for congestion management has been described. The sensitivities of congested line flows to bus injection and cost of changing market schedule are considered to rank generation and load buses. To select the most effective and desirable strategies in congestion management, a new method based on the utilization of a simple and transparent performance index has been proposed in [13]. The sensitivity of the flow in a congested line to variations of a particular load, electricity price at the customer location and acceptance level of the amount of the load to be curtailed constitute the main parameters of the proposed index.

Security analysis is an essential step in power system operation, especially whenever network is congested. Congestion management process may change day-ahead market schedule to alleviate violated network constraints. The main challenge here is network security assessment after performing congestion management activities. Indeed, the effects of relieving activities on the network security level must be considered during congestion management.

Some references investigate congestion management scheme taking into account the network security. In [14], a multi-objective framework for congestion management has been developed, which simultaneously optimizes objective functions for management cost, voltage security and dynamic security. Fuzzy decision-making has been employed to derive the most efficient solution among Pareto-optimal solutions of the proposed multi-objective problem. In [4], a congestion management problem has been formulated considering interactions between intra-zonal and inter-zonal flows. In this paper, considering contingency-constrained limits, the authors have proposed a procedure to minimize the number of adjustments of preferred schedule to alleviate congestion. Congestion management approach ensuring voltage stability has been proposed by A. Conejo et al. [15]. This method relaxes offline transmission capacity limits (static limits) which are replaced by optimal power flow-related constraints and ensures an appropriate level of security, especially voltage instabilities.

The purpose of this paper is to develop a new framework for congestion management algorithm considering network security by emphasizing on the viewpoint of transmission line loading level. In the proposed algorithm, to ensure that the proposed strategy reliably manages system congestion, system security level has been included in congestion management objective function. Quantifying the network security level is a major contribution of this paper that has been considered in the objective function of congestion management. This feature will result in a special optimal solution because it preserves both network security and re-dispatch costs simultaneously. Effectiveness of the proposed algorithm has been evaluated by applying the method on IEEE 9-bus and 30-bus test systems.

II. MATHEMATICAL FORMULATION

In this paper, day-ahead pool based electricity market has been used as the framework for implementation of congestion management algorithm. In this market, suppliers and consumers submit their bids to market operator, who is responsible for clearing procedure [16]. Time framework for market clearing procedure is 24 hours. On the other hand, congestion management will be performed hour by hour if necessary. In this section, to develop the mathematical formulation of the proposed model, conventional congestion management will be explained at first. Then using the conventional model, the proposed algorithm will be developed. In this paper, DC power flow has been used in market clearing and congestion management algorithms.

A. Conventional Congestion Management Model

System operators are responsible to operate network in a safe and optimal mode. To successfully do this task, congestion management is considered as an essential activity that ISO should perform to prevent violating transmission constraints and to avoid congestion in the power system.

Generators and loads may submit their adjustment bids to contribute to congestion management programs. The most common objective in congestion management is generation rescheduling and load interruption with the minimum cost. Generation Shift Distribution Factors (GSDF) [17], [18] have been used to select the most effective generators and loads in relieving congestion [10], [11]. Now, the conventional congestion management problem can be formulated as follows:

$$Minimize \quad f_{\text{cost}} \tag{1}$$

$$P_{Gi}^{\min} \le P_{Gi}^{o} + \Delta P_{Gi}^{up} - \Delta P_{Gi}^{down} \le P_{Gi}^{\max} \quad \text{i}=1,\cdots,\text{N}_{\text{gen.}} \tag{2}$$

$$P_{Lj}^{\min} \le P_{Lj}^{o} + \Delta P_{Lj}^{up} - \Delta P_{Lj}^{down} \le P_{Lj}^{\max} \quad \text{j}=1,\cdots,\text{N}_{\text{load}} \tag{3}$$

$$\sum_{i \in \text{N}_{\text{gen.}}} \left(\Delta P_{Gi}^{up} - \Delta P_{Gi}^{down} \right) = \sum_{j \in \text{N}_{\text{load}}} \left(\Delta P_{Lj}^{up} - \Delta P_{Lj}^{down} \right) \tag{4}$$

$$P_{line_k} \le P_{line_k}^{\max} \qquad \text{k}=1,\cdots,\text{N}_{\text{line}} \tag{5}$$

Where,

$$\begin{aligned} f_{\text{cost}} = & \sum_{i \in \text{N}_{\text{gen.}}} \left[C_i^{up} (\Delta P_{Gi}^{up}) + C_i^{down} (\Delta P_{Gi}^{down}) \right] \\ & + \sum_{j \in \text{N}_{\text{load}}} \left[C_j^{up} (\Delta P_{Lj}^{up}) + C_j^{down} (\Delta P_{Lj}^{down}) \right] \end{aligned} \tag{6}$$

ΔP_{Gi}^{up} and ΔP_{Gi}^{down} are the active power increment and decrement in output power of generator *i*, as well as ΔP_{Lj}^{up} and ΔP_{Lj}^{down} which are the active power increment and decrement in demand *j*. Also, P_{line_k} refers to as flow of line *k*. $N_{gen.}$, N_{load} and N_{line} are set of generators, loads and lines. f_{cost} is the total cost for re-dispatch of generators and loads. The constraints

(2) and (3) show the allowable range of changes for power injections. The equations (4) and (5) express the constraint associated with active power balance and the maximum allowed loading level for transmission lines, respectively.

Transmission line flows will change due to changing in power injection of any bus in the network. To calculate line flows, after power injections have changed, GSDFs may be used instead of performing power flow equations [19]. Using GSDFs, new values of line flows can be calculated as follows:

$$P_{line_k} = P^{o}_{line_k} + \sum_{i \in \mathrm{N_{gen.}}} \left[a_{k,i} \times (\Delta P^{up}_{Gi} - \Delta P^{down}_{Gi}) \right] + \sum_{j \in \mathrm{N_{load}}} \left[a_{k,j} \times (\Delta P^{down}_{Lj} - \Delta P^{up}_{Lj}) \right] \tag{7}$$

Where, $a_{k,i}$ is the change in flow of line k due to unit increment in power injection at bus i [18], [19].

$$a_{k,i} = \frac{\Delta P_{line_k}}{\Delta P_{Gi}} \tag{8}$$

The second term of (7), which is related to load changes, is multiplied by a minus because $a_{k,j}$ has been calculated due to unit increment in power injection at bus j.

The objective of congestion management is to decrease flows of congested lines so that they will be within their allowed range by varying power injections. The basis for selecting a participant in relieving congestion is the related distribution factors which explain the sensitivity of line flow to the power injected by such a participant. Now, the lagrangian function for the optimization problem in (1)-(6) can be formulated as follows:

$$\begin{aligned} L = f_{\text{cost}} + \text{ª} \times \left\{ \sum_{i \in \mathrm{N_{gen.}}} \left[\Delta P^{up}_{Gi} - \Delta P^{down}_{Gi} \right] - \sum_{j \in \mathrm{N_{load}}} \left[\Delta P^{up}_{Lj} - \Delta P^{down}_{Lj} \right] \right\} \\ + \sum_{k \in \mathrm{N_{line}}} \left\{ \text{«}_k \times (P^{o}_{line_k} + \sum_{i \in \mathrm{N_{gen.}}} \left[a_{k,i} \times (\Delta P^{up}_{Gi} - \Delta P^{down}_{Gi}) \right] \right. \\ \left. + \sum_{j \in \mathrm{N_{load}}} \left[a_{k,j} \times (\Delta P^{down}_{Lj} - \Delta P^{up}_{Lj}) \right] - P^{\max}_{line_k}) \right\} \end{aligned} \tag{9}$$

ª and «_k are the lagrange multipliers corresponding to equality and inequality constraints, respectively. The optimal solution can be achieved by applying Karush–Kuhn–Tucker (KKT) conditions.

To ensure reliable operation of the system, after performing congestion management activities, considering security analysis in congestion management is very useful. However, in the above mentioned congestion management process such as most conventional approaches, mainly, satisfaction of constraints has been considered. It should be mentioned that, increasing network security levels results in additional cost. Though, this will result in reducing contingency costs and harmful impacts.

In [15], a congestion management algorithm ensuring voltage stability has been proposed but the optimum level for system security has not been identified. In [20], expected security cost, which determines possible contingency costs in system operation, has been considered in optimal power flow problem.

An important question in congestion management is the amount of the cost that system operator should spend on increasing network security. To answer this question, Security Based Congestion Management is introduced. Our proposed algorithm determines the optimal security level that should be reached in congestion management process.

B. *Security Based Congestion Management (SBCM) Model*

A power system is said to be secure if it has the ability to withstand expected or probable contingencies so that it can continue its operation safely [21]. For a system to be secure, it should be operated so that all constraints are satisfied and the variables lie within their specified ranges. As a result, the security level will seriously depend on how far from their margins these variables are. On the other hand, congestion management may affect security level of the network. As a consequent, relieving congestion may result in the reduction of system security margins. Therefore, attention should be paid to network security in relieving network congestion.

It is obvious that operating the system in a more reliable state is costly. As a result, the amount of money allocated to preserving system security has always been a challenging question. This paper proposes a new approach to find the optimal strategy that should be adopted to preserve security level in congestion management.

The necessary condition to attain optimum security is that the marginal cost for security be smaller than or utmost equal with incremental value attained [21]. Marginal cost of security is the costs imposed on the system to raise network security level. Incremental value of security is the expected value of avoided loads interruption. It can be concluded that considering security costs together with re-dispatch costs in the objective function that should be minimized in congestion management, will result in modification of market schedule in SBCM process and guarantees the optimality of network security level. Therefore, the modified objective function that should be minimized can be written as follows:

$$Minimize \quad \mu_1 \times f_{\text{cost}} + \mu_2 \times f_{\text{interr.}} \tag{10}$$

where,

$$f_{\text{cost}} = \left\{ \sum_{i \in \mathrm{N_{gen.}}} \left[C^{up}_{i} (\Delta P^{up}_{Gi}) + C^{down}_{i} (\Delta P^{down}_{Gi}) \right] + \sum_{j \in \mathrm{N_{load}}} \left[C^{up}_{j} (\Delta P^{up}_{Lj}) + C^{down}_{j} (\Delta P^{down}_{Lj}) \right] \right\} \tag{11}$$

$$f_{\text{interr.}} = \sum_{l \in \mathrm{N_{cont.}}} \left[\Pr_l \times \sum_{j \in \mathrm{N_{load}}} \left(\quad_{Lj} \times \Delta P^{down}_{LCj-l} \right) \right] \tag{12}$$

$$\Pr_o = 1 - \sum_{l \in \mathrm{N_{cont.}}} \Pr_l \tag{13}$$

$\Pr_o$ is the probability of operating in normal state, while $\Pr_l$ stands for probability of contingency l. Also, in (12), $\,_{Lj}$ is the interruption cost coefficients for demand j and ΔP_{LCj-l}^{down} active power interruption in demand j in case of contingency l. The constraints for this optimization problem are same as constraints in (2)-(4). However, in this case for line flow constraints, we have:

$$P_{line_{k-l}} \le P_{line_k}^{\max} \qquad \mathrm{k}=1,\cdots,\mathrm{N_{line}},\ \mathrm{l}=1,\cdots,\mathrm{N_{line}},\ \mathrm{l} \ne k \tag{14}$$

$P_{line_{k-l}}$ shows the active power flow through line k in case of contingency l. In fact, line flows must be within their limits due to all of the other line contingencies. The objective function of this optimization problem includes two main parts; the first expresses the costs of management strategies to relieve congestion and the second refers to the load shedding costs imposed on the system due to probable network contingencies. In the objective function, $f_{interr.}$ stands for the total expected costs of load interruption for each state of system, while f_{cost} stands for the total expected costs to relieve congestion. μ_1 and μ_2 are the weighting factors in SBCM problem. These factors indicate the importance degree of each part of the objective function as decided by the system operator. Considering the weighting factors, the system operator can easily obtain the significance of the total expected costs of load interruption in comparison with the total expected costs to relieve congestion. It should be mentioned that the sum of μ_1 and μ_2 equals to 1. Both f_{cost} and $f_{interr.}$ are in *\$/h* unit and consequently, the objective function of the proposed SBCM, which is the total expected cost, has the same dimension. f_{cost} and $f_{interr.}$ follow reverse trends with respect to changes in power injections. Therefore, solving the optimization problem in equations (10)-(14) ends to a solution with the minimum amount of total expected cost including f_{cost} and $f_{interr.}$.

ΔP_{LCj-l}^{down} is the amount of load interruptions for contingency l which is calculated to remove the line overloads in case of contingency l. It can be written as:

$$Min \sum_{j \in \mathrm{N_{load}}} \left(\Delta P_{LCj-l}^{down} \right) \tag{15}$$

$$0 \le \Delta P_{LCj-l}^{down} \le \Delta P_{LCj}^{\max} \quad \mathrm{j}=1,\cdots,\mathrm{N_{load}} \tag{16}$$

$$\Delta P_{line_{k-l}} = \max\left\{0, P_{line_{k-l}} - P_{line_k}^{\max}\right\} \quad \mathrm{k}=1,\cdots,\mathrm{N_{line}} \tag{17}$$

In (15)-(17), the minimum amount of load interruptions to remove all line overloads caused by each contingency will be calculated. $\Delta P_{LCj}^{\max}$ is the maximum allowed power interruption in demand j in case of contingencies and $\Delta P_{line_{k-l}}$ shows the active power change in flow of line k in case of contingency l.

In the proposed SBCM algorithm, the sensitivity and variations of line flows due to both variations of power injection at different buses and unexpected outages of other lines are considered in optimization process. To model the security level and its value, line outage contingencies and line outage distribution factors (LODF) have been utilized. The effect of line outages on congested lines can be obtained by using contingency analysis and the utilization of line outage distribution factors. In this way, equation (7) will be modified like equation (18). The new term in line flow identifies the cost of loads interruption with respect to possible contingencies in the managed network.

In the above equations, DC power flow has been adopted to solve the problem. Therefore, considering this linearity, we can use the superposition theorem to calculate line flows in the post outage state [19]. Then, the post outage value of line flow for contingency l can be written as:

$$\begin{aligned} P_{line_{k-l}} = &\left\{ P_{line_k}^{o} + \sum_{i \in \mathrm{N_{gen.}}} \left[a_{k,i} \times (\Delta P_{Gi}^{up} + \Delta P_{Gi}^{down}) \right] \right. \\ &\left. + \sum_{j \in \mathrm{N_{load}}} \left[a_{k,j} \times (\Delta P_{Lj}^{down} - \Delta P_{Lj}^{up}) \right] \right\} \\ &+ d_{k,l} \times \left\{ P_{line_l}^{o} + \sum_{i \in \mathrm{N_{gen.}}} \left[a_{k,i-l} \times (\Delta P_{Gi}^{up} + \Delta P_{Gi}^{down}) \right] \right. \\ &\left. + \sum_{j \in \mathrm{N_{load}}} \left[a_{k,j-l} \times (\Delta P_{LCj-l}^{down} + \Delta P_{Lj}^{down} - \Delta P_{Lj}^{up}) \right] \right\} \end{aligned} \tag{18}$$

In (18), $d_{k,l}$ (LODF) is the change in flow of line k due to 1 MW change in flow of line l [19] while, $a_{k,i-l}$ and $a_{k,j-l}$ stand for the generation shift distribution factor in case of contingency l. While in conventional algorithms, only $\mathrm{N_{line}}$ inequality constraints mentioning transmission lines limitations are considered, the proposed SBCM considers all line flows to be within their limitation in post contingency states. In our problem, it is assumed that the system should be secure for outage of one line. Therefore, if the network contains $\mathrm{N_{line}}$ transmission lines, the total number of inequality constraints that should be considered in optimization will be increased to $\mathrm{N_{line}} \times \mathrm{N_{line}}$-1 inequalities. It means that all line flows must remain within their limits for all contingencies of other lines. Then, Lagrangian function for the SBCM problem can be written as follows:

$$\begin{aligned} L = &\ \mu_1 \times f_{\mathrm{cost}} + \mu_2 \times f_{\mathrm{interr.}} \\ &+ \text{ª} \times \left\{ \sum_{i \in \mathrm{N_{gen.}}} \left[\Delta P_{Gi}^{up} - \Delta P_{Gi}^{down} \right] - \sum_{j \in \mathrm{N_{load}}} \left[\Delta P_{Lj}^{up} - \Delta P_{Lj}^{down} \right] \right\} \\ &+ \sum_{k \in \mathrm{N_{line}}} \left\{ \sum_{\substack{l \in \mathrm{N_{line}} \\ l \ne k}} \left[\text{«}_{k,l} \times (P_{line_{k-l}} - P_{line_k}^{\max}) \right] \right\} \end{aligned} \tag{19}$$

The expected load not served (ELNS) is a reliability metric which can be used to evaluate the efficiency of the proposed method. It is expected that the amount of shed loads, when a contingency happens, declines in case of SBCM method compared with the conventional method. ELNS is formulated below [22].

$$ELNS = \sum_{l \in N_{cont.}} \left[\Pr_l \times \sum_{j \in N_{load}} \left(\Delta P_{LCj-l}^{down} \right) \right] \quad (20)$$

By solving the new optimization problem, an optimally reliable strategy to manage system congestions may be found. In this paper, the SBCM problem is solved by using a sequential quadratic programming (SQP) method.

III. SIMULATION RESULTS

To evaluate the proposed security based congestion management (SBCM) method, both congestion management and SBCM algorithms have been applied to 9-bus and 30-bus IEEE test systems. To compare the performances of these two methods, sensitivity analysis for parameters of SBCM has been carried out. For simplification, in this paper, only generation re-dispatch has been used to manage congestion and load interruption has been avoided. On the other hand, in case of system contingencies, load interruption has been employed to manage overloads in transmission lines.

A. Case (1)

In this case, CM and SBCM algorithms have been applied to a modified version of IEEE 9-bus system [23], as shown in Fig. 1. Tables VI and VII in appendix show the price bids by generators and loads to alter their output and consumption powers assigned in the day-ahead market.

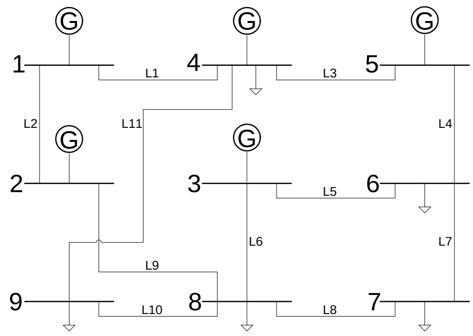

Fig. 1. Modified IEEE 9-bus system

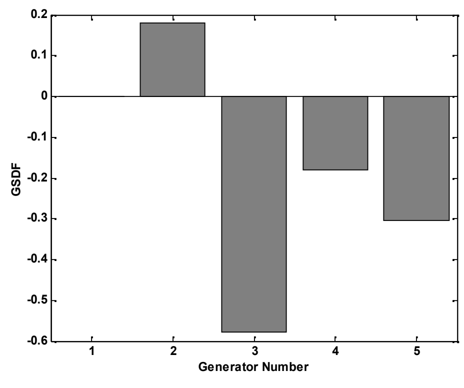

Fig. 2. GSDFs for line 9 in IEEE 9-bus test system

In this case study, it is assumed that applying the primary dispatch obtained by market clearing will result in congestion of line 9 (connecting bus 2 to bus 8). Fig. 2 shows the GSDFs for line 9 related to generation buses. To alleviate congestion in line 9, based on calculated GSDFs, ISO may decrease active power generation of unit 2 or increase active power generation of units 3, 4 and 5.

In this case, it is assumed that the weighting factors (μ_1, μ_2) are both equal to 0.5 and the probability of each contingency ($\Pr_l$) is equal to 0.05. Table I shows the results of generation re-dispatch for both CM and SBCM algorithms. It can be observed that pattern of generation re-dispatch for SBCM differs from CM. This is because of considering system security in managing congestion. In SBCM, while the output power of unit 2 almost remains without change, the output power of unit 3 is increased. The change in output power of unit 3 for CM and SBCM will be 25 MW and 32 MW, respectively. P_{base} is the base output of generators which is calculated in market clearing process.

TABLE I. CHANGE IN OUTPUT POWERS OF GENERATORS IMPOSED BY CM AND SBCM

Generator	**P_{base}**	**ΔP_G (MW)**	
		Conventional CM Method	***SBCM Method***
1	77.134	-0.128	-32.986
2	122.174	-25.037	-0.035
3	85.589	25.166	32.975
4	101.803	0.000	0.037
5	128.300	0.000	0.010

Moreover, as shown in table II, using the proposed strategy by SBCM, the amount of total re-dispatched power has been increased. However, the amount of load curtailment decreases in cases of contingencies. As a result, as shown in table III, the total expected cost of system operation for SBCM will become lower than that for CM.

TABLE II. CONGESTION MANAGEMENT RESULTS WITH CONVENTIONAL (CM) AND SECURITY BASED (SBCM) APPROACHES

	CM Method	**SBCM Method**		
		Pr_l=0.03	***Pr_l=0.05***	***Pr_l=0.07***
Sum of ΔP_G (MW)	50.331	65.526	66.043	74.486
ELNS (MWh)	211.26	192.47	191.84	172.56
F_{cost} ($/h)	273.38	284.34	284.82	320.90
$F_{interr.}$ ($/h)	6118.2	5576	5558	5004
Flow of line 9 (MW)	130	130	130	127.6

TABLE III. TOTAL EXPECTED COST ($/H) OF CM AND SBCM

	CM Method	**SBCM Method**
Pr_l=0.03	448.7	443.10
Pr_l=0.05	565.6	548.48
Pr_l=0.07	682.5	648.77

ELNS refers to the amount of load not supplied in each market arrangement which determined by CM and SBCM algorithms. N-1 contingency analysis has been performed on the transmission network to calculate ELNS in each suggested state by both CM and SBCM approaches. Load interruption has been executed to remove the line overloads in N-1 contingency studies. Based on this criterion, $f_{interr.}$ is the total cost of load interruption which results from contingency analysis in each network topology. Moreover, total expected cost is calculated to compare the efficiency of each method. It should be mentioned that, although CM is a deterministic approach, N-1 contingency analysis is considered on the suggested re-dispatch scheme by this approach. In this way, it is possible to have a thorough comparison between these methods. It can be clearly seen, although the re-dispatch cost (f_{cost}) in SBCM method is greater than CM method, the total expected cost of the former, with each probability of contingency, is smaller than that of the latter because the total cost of load interruption ($f_{interr.}$) in the SBCM method is lower than that in the CM approach. For example, if the probability of contingency is supposed to be 0.05, the total expected cost of SBCM approach (548.48 $/h) is smaller than that of CM method (565.6 $/h). This consequence is true for the two other cases which are simulated here. Fig. 3 illustrates the re-dispatch patterns of CM and SBCM algorithms for IEEE 9-bus test system.

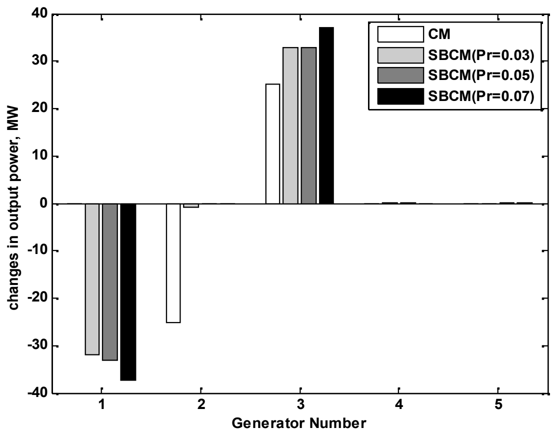

Fig. 3. Changes in output power of generators for different probabilities of contingency

This figure shows the output powers for five generation units in cases of conventional and SBCM methods. If the probability of line outage increases, re-dispatch pattern may also change to preserve network security level. The total amount of re-dispatched power in SBCM depends on the probability of transmission line contingencies (Pr). The component included in the objective function to preserve security adjusts the re-dispatch pattern in a manner that preserves the level of security as high as possible.

B. Case (2)

The second case is IEEE 30-bus test system with six generators and 41 transmission lines [24]. In this case, based on different weighting factors in SBCM problem, four scenarios, as reported in table IV, have been defined. In the first scenario, the relative importance factors of f_{cost} and $f_{interr.}$ are 0.7 and 0.3 respectively, while in the last scenario, these figures refer to 0.1 and 0.9.

Simulation results for these scenarios of SBCM are compared with that of conventional CM method. In this study, the power transfer limit for all lines is assumed to be 200 MW. Line 14 (connecting buses 9 and 10) transfers 218 MW, which implies that the line is overloaded. The weighting factor associated with the component included in the objective function to preserve security corresponds to the degree of attention paid to system security in congestion management problem. In the fourth scenario, the most attention has been paid to system security. Therefore, scenario 4 is expected to have the lowest interruption cost.

TABLE IV. WEIGHTING FACTORS OF THE OBJECTIVE FUNCTION AND THE PROBABILITY OF EACH CONTINGENCY FOR DIFFERENT SCENARIOS

SBCM	μ_1	μ_2	Pr_l
Scenario 1	0.7	0.3	0.02
Scenario 2	0.5	0.5	0.02
Scenario 3	0.3	0.7	0.02
Scenario 4	0.1	0.9	0.02

Table V shows the simulation results with more details. It can be observed that to preserve higher levels of system security, the total expected costs will be increased. The optimum solution is attained in scenario 2 in which both weighting factors are equal (0.5).

As can be observed in table V, the loading level of line 14 is decreased in SBCM algorithm as compared with that in CM. Therefore, the total amount of network interruption in contingency states will decrease in SBCM algorithm. For example, as mentioned above, the total expected cost of interruption for the fourth scenario, with a higher level of security, is the least.

TABLE V. CONGESTION MANAGEMENT RESULTS FOR CONVENTIONAL AND SECURITY BASED APPROACHES

	CM	**SBCM Scen. 1**	**SBCM Scen. 2**	**SBCM Secn. 3**	**SBCM Scen. 4**
Sum of ΔP_G (MW)	59.620	63.676	107.088	171.504	363.43
ELNS (MWh)	788.18	734.14	422.93	237.06	7.83
F_{cost} ($/h)	178.76	191.03	321.27	514.51	1257.12
$F_{interr.}$ ($/h)	23645.4	22024.3	12688	7111.9	234.6
Total Exp. Cost ($/h)	648.19	627.69	568.56	646.46	1236.67
$P_{line}(14)$	200	198.77	185.63	166.14	145.24

Simulation results in this case approve the efficiency of the proposed SBCM method. It can be inferred that the SBCM increases the re-dispatch costs but it reduces the cost of load interruption; as a result, the total expected cost of SBCM (scenario 2) is smaller than that of CM.

Fig. 4 illustrates the total expected and re-dispatches costs for different scenarios.

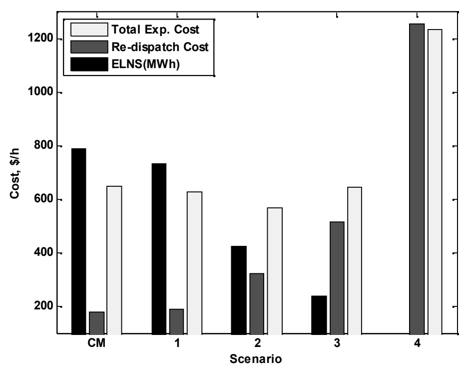

Fig. 4. Re-dispatch and total expected costs in different scenarios

ELNS is also shown in this figure. The best solution, which has the minimum total expected costs, is attained in the second scenario. In this scenario, the weighting factors for both parts of the objective function are equal to 0.5.

IV. CONCLUDING REMARKS

Congestion management is one of the essential tasks of system operator in the operation of power systems. The power system must be operated in a secure and optimal manner so that the network security is preserved for different operation regimes. In this paper, a new framework for congestion management based on shift factors has been developed. Security assessment is one of the most important issues that should be considered in managing network congestion. This framework considers security in congestion management so that, network security is included in the objective function of congestion management problem.

The appropriate functioning of the proposed SBCM problem has been demonstrated by using both IEEE 9-bus and 30-bus test systems. Simulation results indicate that considering network security in SBCM problem usually imposes more operation costs on market re-dispatch. However, the amount of load interruptions in the system for contingencies decreases saliently so that the total amount of expected costs in SBCM is less than the total amount of expected costs in CM problem.

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V. APPENDIX

TABLE VI. GENERATORS DATA FOR IEEE 9-BUS SYSTEM

Bus No.	Cost coefficients		Output limits	
	C^{up} ($/MWh)	C^{down} ($/MWh)	P_{min}	P_{max}
1	3.600	3.150	10	250
2	6.000	5.400	10	250
3	5.475	0.900	10	250
4	4.275	3.000	10	250
5	2.475	0.600	10	250

TABLE VII. LOADS DATA FOR IEEE 9-BUS SYSTEM

Bus No.	Load quantity (MW)	C_{down} ($/MWh)	$\Delta P_{LCj}^{\max}$ (MW)
4	90	10	90
6	80	20	80
7	100	25	100
8	120	30	120
9	125	20	125