



Risk-based maintenance scheduling of generating units in the deregulated environment considering transmission network congestion

Hessam GOLMOHAMADI (✉), Maryam RAMEZANI,
Amir BASHIAN, Hamid FALAGHI

Abstract In restructured power systems, the traditional approaches of unit maintenance scheduling (UMS) need to undergo major changes in order to be compatible with new competitive structures. Performing the maintenance on generating units may decrease the security level of transmission network and result in electricity shortage in power system; as a result, it can impose a kind of cost on transmission network as called security cost. Moreover, taking off line a generating unit for performing maintenance can change power flow in some transmission lines, and may lead to network congestion. In this study, generating unit maintenance is scheduled considering security and congestion cost with N-1 examination for transmission lines random failures. The proposed UMS approach would lead to optimum operation of power system in terms of economy and security. To achieve this goal, the optimal power flow (OPF) compatible with market mechanism is implemented. Moreover, the electricity price discovery mechanism as locational marginal pricing (LMP) is restated to analyze the impacts of UMS on nodal electricity price. Considering security and congestion cost simultaneously, this novel approach can reveal some new costs which are imposed to transmission network on behalf of generation units; as a result, it provides a great opportunity to perform maintenance in a fair environment for both generating companies (GenCo) and transmission companies (TransCo). At the

end, simulation results on nine-bus test power system demonstrate that by using this method, the proposed UMS can guarantee fairness among market participants including GenCos and TransCo and ensure power system security.

Keywords Congestion, Security, Transmission network, Unit maintenance scheduling

1 Introduction

In the traditional vertical bundled power systems, unit maintenance scheduling (UMS) is currently dispatched based on the system security and economy [1]. As electric power systems move towards a more deregulated market structure, decision-making tools must be prepared to evaluate the effect of competition [2]. Deregulation in power systems has resulted in unbundling of electricity utilities including generating companies (GenCo), transmission companies (TransCo), distribution companies (DisCo), independent system operator (ISO) and other important service providers. Therefore, additional competition and growing complexity in power generating systems, as well as a need for high service of reliability and low production cost, are provoking additional interests in maintenance scheduling, capable of providing least cost maintenance schedule [3].

Many studies have been focused on the problem of maintenance scheduling in power market [1–8]. Reference [1] has modeled the transmission network and adopted concept of congestion rate (CR) to evaluate the probability of unacceptable dispatching ways for the ISO. In [2], transportation model is considered to represent system operation and line capacity limits. In this paper, in order to avoid over-optimistic planning, generation and transmission outages are also taken into account. In [3],

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H. GOLMOHAMADI, M. RAMEZANI, H. FALAGHI, Faculty of Electrical and Computer Engineering, The University of Birjand, Birjand, Iran
(✉) e-mail: hessam.golmohammadi@gmail.com
A. BASHIAN, Department of Power Electrical Engineering, Ferdowsi University of Mashhad, Mashhad, Iran

transmission line capacity limits are considered as probabilistic problems and Benders decomposition method is employed to solve them. Reference [4] proposed a model while provides hourly schedules for maintenance outages, generation unit commitment, and transmission flows based on hourly load curves to reduce the chance of blackouts in aging power systems. Reference [5] considered maintenance and interruption cost of transmission network in objective function. In this reference, interruption cost is divided into dominant loss and recessive loss. Reference [6] presents a global generation and transmission maintenance scheduling considering security and economical efficiency of power system and fairness of power market and has used hybrid genetic algorithm (GA) and particle swarm optimization (PSO) to solve them. Reference [7] describes a new approach for establishing power systems scheduled generators outages for short-term maintenance purposes. The main contribution of this paper is focused on modeling grid operational constraints, which are dealt with by a DC optimal power flow and is solved by mixed-integer programming techniques aided by Benders decomposition strategy. Reference [8] classified some coordination mechanisms which were suggested in recent years in the ground of UMS in competitive markets:

- 1) The ISO coordinated UMS based on both GenCo's interest and the system security.
- 2) The ISO negotiated UMS with GenCos on behalf of customers and obtained the improved system security through paying for GenCos who would adjust their plans, and the cost burden would go to customers.
- 3) The ISO coordinated UMS according to some forms of expression about maintenance desire announced by GenCos.

Table 1 shows a set of various studies which have focused on the problem of generating unit maintenance scheduling considering transmission constraints.

In this paper, a novel approach to unit maintenance scheduling is presented. This approach considers two kinds of cost, including security and congestion cost, which have not been taken into account in UMS in the other studies. This novel approach devises a comprehensive method to UMS which can minimize the operation cost of transmission network when maintenance actions is performing on the GenCos of power system. In the other words, this approach considers two kinds of cost which are imposed by one market participant—GenCo to another private participant—TransCo. Similarly, considering new costs, proposed method can prevent financial loss of TransCos during maintenance performing on GenCos. In addition, a set of random failures for transmission lines are considered during the GenCos' maintenance scheduling to evaluate the

imposed risk on power system during the generators maintenance. The UMS approach of this paper is applied according to a market-based optimal power flow (OPF) by locational marginal pricing (LMP) concept [11], and has the applicability of performing in practical power markets. Finally, the UMS approach can guarantee fairness among two main participants and ensure power system security.

This paper is organized as follows. In first section, a comprehensive illustration about proposed UMS approach is presented. Moreover, this section formulates the whole UMS approach mathematically and analyses the influences of UMS on transmission lines in term of security and economy. Congestion and security cost are proposed in detail considering N-1 examination of lines. Numerical example and simulation results on a nine-bus test power system are provided in the section. At the end, conclusion and some proposed research for future in the ground of UMS are presented.

2 Distribution factor method

The problem of studying thousands of possible outages becomes very difficult to solve if it is desired to present the results quickly. One of the easiest ways to provide a quick calculation of possible overloads is to use linear sensitivity factors. These factors show the approximate change in line flows for changes in generation on the network configuration and are derived from the DC load flow. These factors can be derived in a variety of ways and basically come down to two types [12]: ① Generation shift distribution factors; ② Line outage distribution factors.

In this paper, the mentioned linear sensitivity factors are used to evaluate the power system security. These sensitivity factors are described in the next part.

2.1 Generation shift distribution factors

Generation shift distribution factors (GSDF) indicate proportion of transmission line power variations and active power generation variations. *GSDF* or *A* multipliers are expressed as [13]:

$$\begin{cases} \Delta F_{l-k} = A_{l-k,i} \Delta G_i \\ \Delta G_r = -\Delta G_i \end{cases} \quad (1)$$

where ΔF_{l-k} is change in total transmission flow between buses l and k ; $A_{l-k,i}$ is generation shift distribution factor (GSDF) related to line connecting buses l and k caused by generation changes in bus i ; ΔG_i is change in total generation in bus i ; r is index of reference bus.

$A_{l-k,i}$ is obtained from reactance matrix and DC load flow relaxation. This factor, measures increasing use of transmission network by generators and consumers.



Table 1 A set of different studies on UMS problem

Ref.	Maintenance		Reliability criteria	Transmission constraints	Solution method
	Generator	Transmission			
[1]	×		Surplus generation capacity	Congestion rate (CR)	No discuss
[2]	×	×	Unserved power	Transmission capacity limit	Benders decomposition
[4]	×	×	Transmission flow limit	Line capacity-maintenance duration	Benders cuts lagrangian
[5]	×	×	EENS	Interruption cost of network	Mathematical model's Solution
[9]	×	×	LOLP	Power flow and voltage	Hierarchical optimization Annealing algorithm
[6]	×	×	Generation reserve rate	Available transfer capacity (ATC)	Genetic algorithm Particle swarm optimization
[10]	×	×	ELNS	Line flow limits-line maintenance cost	Benders decomposition Lagrangian relaxation

A multiplier can be calculated by the use of reactance matrix which is presented in [12, 13].

2.2 Generalized load distribution factors

Generalized load distribution factors (GLDF) indicate the contribution of each load in transmission line power. *GLDF* or *C* factors formulated as [13]

$$\begin{cases} C_{l-k,r} = \left\{ F_{l-k}^0 + \sum_{\substack{j=1 \\ j \neq r}}^N A_{i-k,j} L_j \right\} / \sum_{j=1}^N L_j \\ C_{l-k,j} = C_{l-k,r} - A_{l-k,j} \end{cases} \quad (2)$$

where $C_{l-k,r}$ is GLDF factor related to line between buses l and k caused by demand in bus r ; F_{l-k}^0 is transmission flow between buses l and k obtained in previous iteration; L_j is total demand in bus j ; $C_{l-k,j}$ is GLDF factor related to line between buses l and k caused by generation variation in reference bus.

Note that these factors are obtained from reactance matrix and DC load flow relaxation.

3 Proposed method formulation

The congestion cost considered is allocated to the generation units whose UMS contributes in congestion occurrence. Distribution factors are used to allocate this cost to different buses. Moreover, the security cost related to UMS is allocated to its parties in proportion to their contribution in network security reduction. In the proposed method, the Pool-Bilateral model is assumed for electricity market model. After setting the amount for power system including generators and loads,

an OPF will be performed in the network. Therefore, the generation and consumption of buses, power transmitted in each line, transmission losses, bus voltage and the LMP in network buses is calculated. In this paper, the nonlinear optimization is solved based on Lagrange method. The Lagrange factor is involved with an economic concept. It can show the LMP in each bus in power systems.

4 Congestion cost

When one or more generators are taken off line to perform maintenance, the generation point deviates from optimum one, and congestion may occur in some weak transmission lines. Deviation from optimum generation point and congestion occurrence in transmission lines increases the operation cost of power system. Moreover, congestion occurrence may cause to lose revenue for some generators. Therefore, congestion occurrence can increase the power system operation cost considerably.

In a practical competitive electricity market, an electricity market participant that has a contract with delivery and compensation in different locations under market rules is subject to congestion risk and hence, for the same capacity and time duration, should have its exposure reduced.

When there is no congestion, the OPF program yields the same optimal equilibrium condition for different buses. However, in the presence of congestion, a set of new cost is imposed on power system for relieving the congestion. In this situation, CR increases in transmission lines and it may cause the overloads in some weak lines. Computing flows on transmission lines after OPF and fitting the flows against unacceptable security level yield cumulative probability of transmission network usage as [14]:

$$Prob\{F_{ij} \leq F_{ij}^{max}\} \tag{3}$$

where F_{ij} is transmission power flow between buses i and j and F_{ij}^{max} is the maximum allowable transmission flow between buses i and j . Therefore, the congestion will occur in transmission lines, when the unacceptable dispatching ways of power flow appear in power system. If we represent the network congestion rate by following probability calculation, the CR will appear in power system when σ has a positive value:

$$\sigma = Prob\{F_{ij} \geq F_{ij}^{max}\} \tag{4}$$

In power system studies, a predefined critical value is defined for σ such as $\sigma_{critical}$, which means if σ is bigger than the critical value of CR, the network congestion will occur in some transmission lines and hence, the congestion management is essential.

As a result, the imposed cost on power system must be considered as an indirect cost of unit maintenance scheduling. This cost is generated by private GenCos and is imposed on another private company, TransCo, hence, consideration of them is essential and inevitable. Therefore, two steps are considered to calculate the congestion cost of transmission lines:

- 1) First, all generators are considered in service with no maintenance. OPF is run and network operation cost is calculated, healthy mode (C_h).
- 2) In second step, unit maintenance is performed on target generators. In this situation, congestion may occur in some weak lines, OPF is run and network operation cost is calculated again, maintenance mode (C_m).

Occurrence of congestion changes amount of buses' LMP obviously. Generally, LMP depends on two objects:

- 1) Congestion rate in transmission lines
- 2) Power loss in transmission lines

In other words, if no congestion occurs in transmission lines and no power loss exists, the LMP will be same in all power system buses. Therefore, congestion occurrence would alter the LMP amounts in power system nodes and finally increase the power system operation cost considerably ($C_m > C_h$).

Actually, the congestion cost due to taking off line of generator i is calculates as:

$$C_{cong} = C_m^i|_{(\sigma > \sigma_{critical})} - C_h^i|_{(\sigma < \sigma_{critical})} \tag{5}$$

where C_{cong} is congestion cost \$; C_m^i power system operation cost in the presence of congestion when GenCo i is

offline for maintenance; and C_h power system operation cost when all GenCos are in service and no congestion occurs.

Considering congestion cost, the proposed method gets the benefit of following points:

- 1) Minimization of congestion rate in transmission network
- 2) Reduction in imposed cost on transmission network (produced by GenCos)

5 Security cost

Considering the appropriate index for security analysis is one of the main contributions of the UMS studies. The oldest reliability criteria is loss of load probability (LOLP) [15], but nowadays, the most common approach is to utilize the loss of load expectation (LOLE) method [16]. There is, however, a considerable appeal in utilizing deterministic technique rather than more complicated probabilistic methodologies, some new techniques have been developed recently which embed an accepted deterministic criterion within a probabilistic framework [17].

In fact, in addition to power system security, cost arising from stochastic failure may also be incorporated with which is called security cost. In order to calculate the security cost, N-1 examination of lines is considered in this paper. In fact, in order to avoid over-optimistic planning, transmission outage should be taken into account. Therefore, target GenCo is taken off line to perform maintenance, and random failure occurs in transmission line simultaneously. Finally, objective function is minimization of outage cost (load shedding cost) as [18]

$$\text{Min} \left\{ \sum_{k=1}^{N_L} \pi^k C^k \right\} \tag{6}$$

C^k is defined as

$$C^k = \sum_{i=1}^{N_D} B_{i,i} [P_{L,i}^0 - P_{L,i}^k] \tag{7}$$

where C^k is outage cost (load shedding cost) for line k (\$/h); π^k the failure probability for transmission lines k ; N_L the number of transmission lines; $B_{i,i}$ the predefined outage cost for bus i (as power market contracts) (\$/MWh); $P_{L,i}^0$ the load value for bus i before failure occurrence (before load shedding) in line k (MW); $P_{L,i}^k$ the load value for bus i after failure occurrence (after load shedding) in line k (MW); and N_D the number of buses that are exposed to load shedding.

To minimize C^k , firstly, we should determine 'which buses should be selected for load shedding'. For this reason, factor A must be calculated to determine load shedding



plans. These factors show the approximate change in line flows for changes in generation (or bus' load) on the network configuration and are derived from the DC load flow. The generation shift factor A is a linear sensitivity factor which indicates the contribution of loads' and generations' power to transmission lines capacity, as following:

$$A_{l,i} = \frac{\Delta f_l}{\Delta P_i} \quad (8)$$

where $A_{l,i}$ is generation shift factor for line l because of change in generation at bus i ; Δf_l the change in power flow on line l when a change in generation, ΔP_i , occurs at bus i ; and ΔP_i the change in generation at bus i .

It is most evident that A may be a negative or positive number (for generation, $\Delta P_i > 0$, and for load, $\Delta P_i < 0$). Now, in order to relieve the network congestion, load shedding must be done at some buses. For minimizing the load shedding cost, two following objects are intended:

- 1) Select the load with the most impact on the congested lines, which means a load with the highest generation shift factor (A_{\max}), maximum security level.
- 2) Select the load with the minimum outage cost ($B_{l,i}^{\min}$), minimum cost.

Finally, the division of A_{\max} and $B_{l,i}^{\min}$ determines the load which has the minimum load shedding cost and the most impact on network congestion relieving (high-reliable state). This approach does load shedding which leads to a cost-effective load shedding management and high security level for maintenance time durations. Therefore, we determine the proportion as:

$$\mu_{L,i} = \frac{A_{l,i}^{\max}}{B_{l,i}^{\min}} \quad (9)$$

where $\mu_{L,i}$ is load shedding priority factor; $A_{l,i}^{\max}$ the maximum generation shift factor; and $B_{l,i}^{\min}$ the minimum outage cost.

Therefore, the load with minimum outage cost and maximum generation shift factor are selected for load shedding. Priority list for load shedding is arranged according to incremental rate of "load shedding priority factor ($\mu_{L,i}$)".

Now, according to probability of random failures on transmission lines (π^k), the security cost (SC) is calculated. Thereupon, in each state according to transmission line outages, the security cost is calculated and total cost indicates the final security cost of power system as

$$SC = \sum_{k=1}^{N_L} \pi^k C^k \quad (10)$$

Mathematically, considering (5) and (10), UMS objective cost function can be formulated as

$$C_{network}^i = \text{Min} \sum_t \left[\sum_{k=1}^{N_L} \pi_t^k C_t^k + \sum_{k=1}^{N_c} C_{C,t}^k \right] \quad (11)$$

where $C_{network}^i$ is the power system operation cost arising from OPF at time t when GenCo i is on maintenance (\$); C_t^k the outage cost (load shedding cost) for line k at time t (\$/h); π_t^k the failure probability for transmission lines k at time t ; $C_{C,t}^k$ the congestion cost at time t when line k is congested; N_L the number of transmission lines; and N_c the number of congested lines.

The first term ($\sum_{k=1}^{N_L} \pi^k C_t^k$) in (11) is security cost, and the second ($\sum_{k=1}^{N_c} C_{C,t}^k$) is the congestion cost.

Considering two mentioned costs, this approach can prevent some financial losses of TransCos during maintenance performing on GenCos. Moreover, the security analysis enables us to minimize the rate of failures in power system. Finally, this unit maintenance scheduling can strike a right balance between fair environment and reliable operation with market mechanisms.

Fig. 1 shows the power system's generators and transmission lines in proposed UMS approach.

The proposed UMS approach can be summarized in steps which are summarized in Fig. 2.

6 Numerical example and analysis

6.1 Test power system

A nine-bus test power system shown in Fig. 3 is considered to show the applicability of proposed method on a practical power system. It is assumed that the test system has three private GenCos, 12 transmission lines and 9 buses [19]. Maintenance horizon of UMS is considered as 6 weeks. Tables 2, 3 and 4 show the load, GenCos and transmission lines data of test power system respectively.

6.2 Security cost analysis

Different scenarios for unit maintenance plans are applied to examine test power system in order to investigate an optimum maintenance strategy. As illustrated above, the system generators are taken offline individually and a set of random failure on transmission lines are considered as N-1 examination of lines. In each scenario, if load shedding is necessary to be done, the cost of load shedding management is considered as the security cost which is formulated in (6)-(10).

Fig. 4 plots the profile of LMP, and it shows that the power market's electricity price has been affected by the

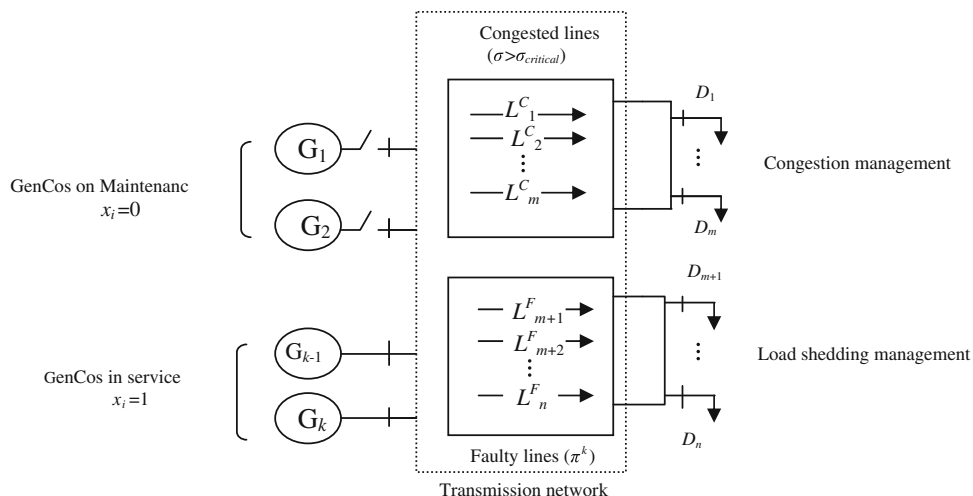


Fig. 1 Generators and transmission lines in UMS approach

generators maintenance. Accordingly, performing the maintenance on generators has increased the nodal electricity price in power market. In fact, the generating unit maintenance has led to more expensive operation of power system. Moreover, different GenCos does not have the same effect on power system operation cost. It may depend on generating unit capacity, generator’s cost function as bid cost function, GenCo’s location in power system configuration and other parameters. Fig. 4 shows that GenCos 1, 2, 3 have the most effects on operation cost of power system respectively. And Fig. 4 shows average amount of different buses’ LMP as a function of maintenance horizon. Healthy mode in this figure indicates the normal operation of power system with no maintenance on generating units and no failure on transmission lines.

All GenCos are taken off line individually to perform maintenance, and operation costs considering forced outage on transmission lines are calculated. In each scenario, if transmission line power flow exceeds the predefined line capacity, load shedding is performed and related costs are considered as the security cost; as a result, this cost increases the power system operation cost.

Fig. 5 plots the performed load shedding in different buses associated with maintenance on GenCo 1, 2, 3 respectively. It can be concluded that:

- 1) For performing maintenance on GenCo 1, maximum load shedding is done on bus 4 at weeks 1, 2, 3.
- 2) For performing maintenance on GenCo 2, maximum load shedding is done on bus 4 at weeks 1, 2, 4.
- 3) For performing maintenance on GenCo 3, maximum load shedding is done on buses 4, 3 at weeks 6, 4, 2.

Fig. 5 shows that UMS has the most impacts on overloads on buses 4 at weeks 1 and 2. In the other words, the bus 4 and

connected loads are more subject to load shedding during maintenance in comparison to other buses and loads.

Table 5 shows the outage cost of different consumers, which are specified in the electricity sell contract in power market.

Security analysis according to (6)-(10) is done and respective results of them, including security cost for maintenance strategy (GenCo’s maintenance and transmission lines’ failure) are obtained individually. Table 6, as a sample, describes the security cost for maintenance on GenCo 1. Moreover, the security cost for maintenance on GenCo 2 and 3 is shown in Tables 11 and 12 in the appendix.

Tables 6, 11 and 12 describe the security cost of power system in maintenance horizon as a function of forced outage on transmission lines and GenCos’ maintenance on different weeks. In fact, through these tables, we can obtain the security level and imposed security cost of each GenCo’s maintenance strategy considering forced outage on each transmission lines individually. Moreover, different maintenance strategies have various effects on power system security and economy. Therefore, the proposed method can investigate the maintenance plans with optimum point of lowest cost and highest security level. It can ensure power system security be compatible with electricity market structure; similarly, the proposed method can guarantee fair competition among market participants.

6.3 Congestion cost analysis

According to (5), the difference between operation costs in two operation states indicates the network congestion cost. Table 7 describes the power system cost in normal

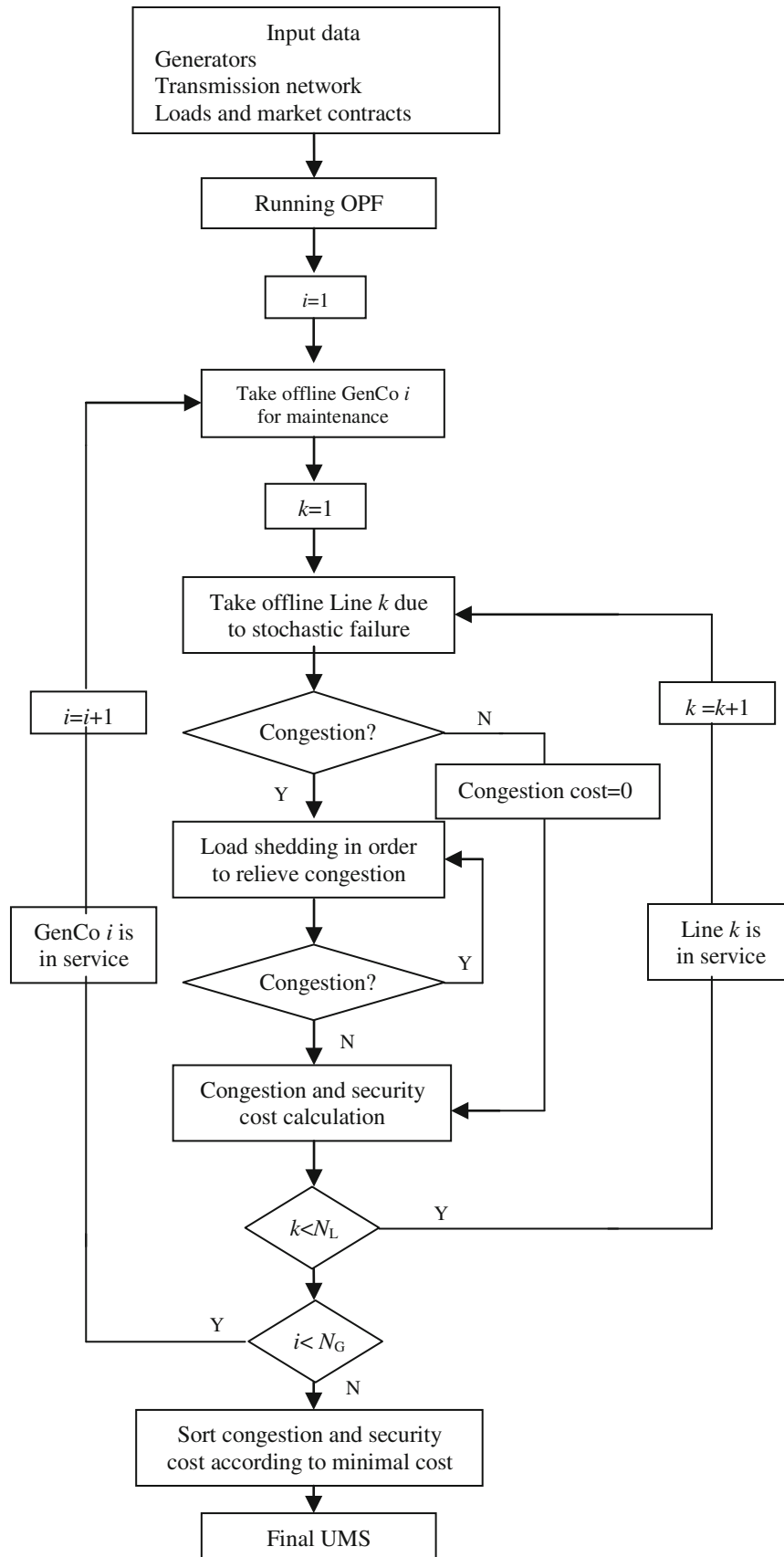


Fig. 2 UMS using congestion risk approach and advanced security analysis

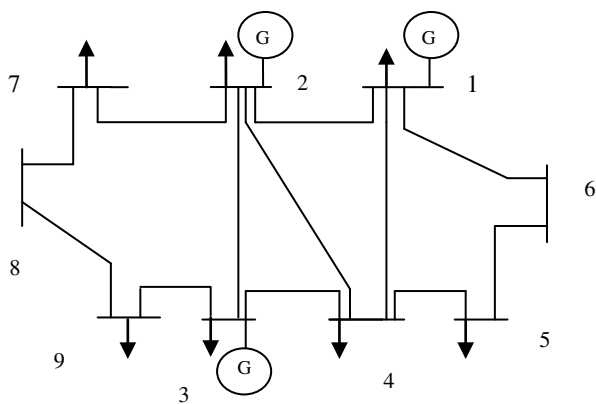


Fig. 3 Nine-bus test power system

Table 2 Load value (MW) in maintenance horizon, 6 weeks

Week	Bus number								
	1	2	3	4	5	6	7	8	9
1	77	74	75	120	118	0	68	0	56
2	73	79	76	119	117	0	67	0	57
3	75	78	72	116	118	0	70	0	58
4	78	78	77	118	117	0	62	0	58
5	78	75	76	117	114	0	66	0	60
6	78	76	76	112	120	0	67	0	59

operation state, while no maintenance on generators and no outage on transmission lines are considered. Table 8 shows the congestion cost for performing different maintenance strategy on power system generators individually.

It is anticipated that the operation cost of power system during maintenance on generators are more than the cost of normal operation state (healthy mode). Table 10 shows that maintenance of GenCos 1, 2, 3 have the most effects on congestion cost respectively. It may depend on generation capacity of under maintenance GenCo, network configuration, line power flow limitation and other electrical and

Table 3 Generators' data of test power system

GenCo	$C(P_g) = A \cdot P_g^2 + B \cdot P_g + C$ (\$/hr)			Q_{gmax} (MVar)	Q_{gmin} (MVar)	P_{gmax} (MW)	V (pu)
	A	B	C				
1	0.00150	7.92	561	800	-800	1000	1.060
2	0.00194	7.85	310	100	-90	400	1.045
3	0.00482	7.97	78	100	-90	400	1.010

$C(P_g)$ is the cost of power produced by generator; P_g is amount of power generated; A , B and C is constant factors

Table 4 Transmission lines data of test power system

Transmission line	Connected buses	R (pu)	X (pu)	Y (pu)
1	1-2	0.042	0.1680	0.041
2	1-4	0.031	0.1210	0.031
3	1-6	0.053	0.2100	0.051
4	2-3	0.031	0.1260	0.031
5	2-4	0.084	0.3360	0.082
6	2-7	0.053	0.2100	0.051
7	3-4	0.053	0.2100	0.051
8	3-9	0.053	0.1260	0.051
9	4-5	0.030	0.1260	0.031
10	5-6	0.031	0.1260	0.031
11	7-8	0.03	0.1260	0.031
12	8-9	0.015	0.0513	0.015

economical characteristics. In this study, GenCo 1 has imposed the most congestion cost to power system.

6.4 Final UMS

Table 9 shows the final unit maintenance scheduling for three GenCos of power system. As mentioned above, the purpose of UMS is to minimize the operation cost under severe security constraints and making a fair environment by using two kinds of new cost, security and congestion cost. In order to achieve the minimum operation cost, an advanced analysis of security studies is performed on the test power system. Because of simultaneous study on power system's security and economy, the obtained result will show the optimum operation point in order cost and reliability. As shown in Table 9, the maintenance of GenCos 1, 2, 3 has imposed the most additional operation cost (congestion /security cost) to power system respectively.

Maintenance on GenCos 3 and 1 has the minimum and maximum congestion cost as 197.7 \$ and 522.2 \$ respectively. As regards security cost, GenCo 1 has the minimum security cost as 574.98 \$ and GenCo 3 has the maximum



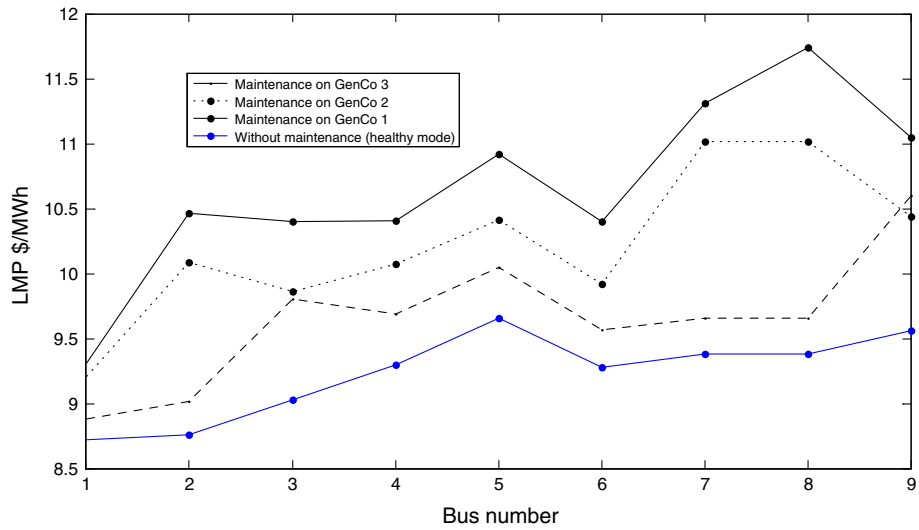


Fig. 4 Effect of GenCo’s maintenance on nodal electricity price, LMP

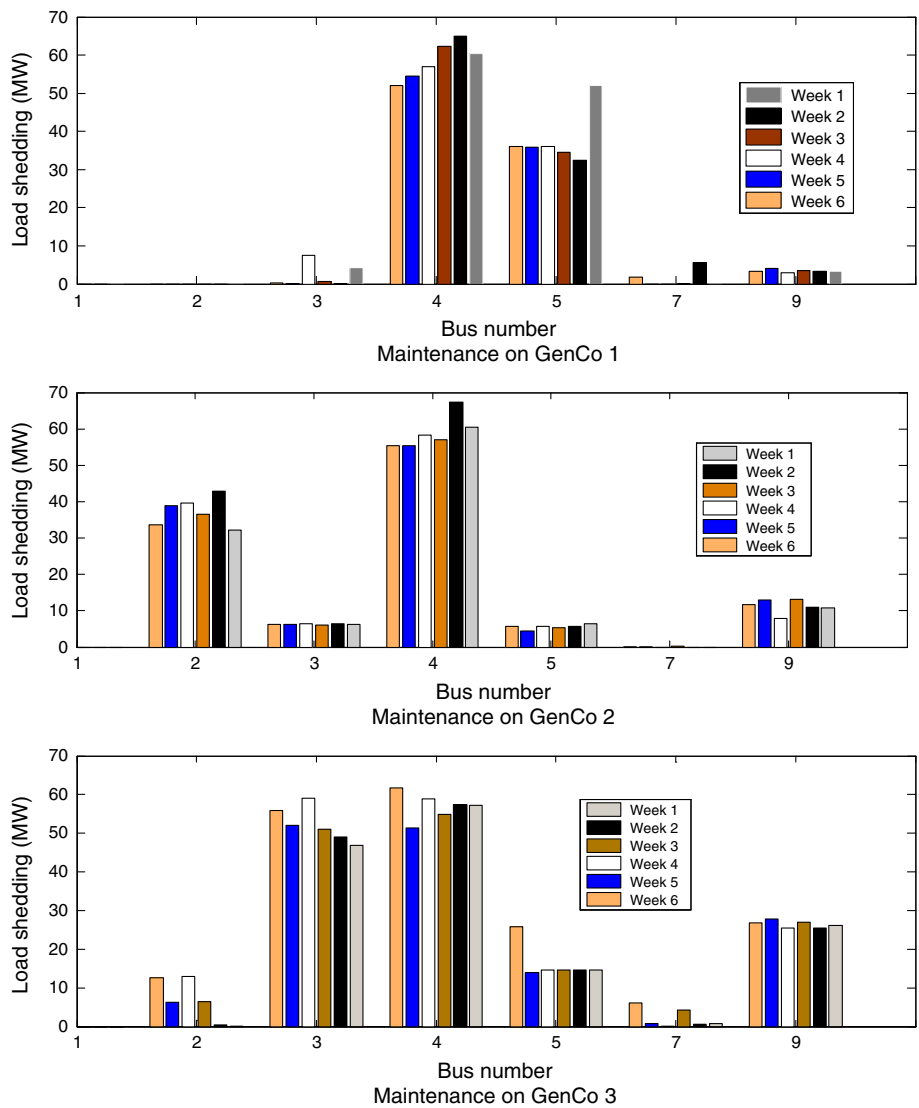


Fig. 5 Load Shedding in maintenance scenarios for GenCo 1,2,3

Table 5 Outage cost of power system’s buses

Bus number	B_l (\$/MWh)
1	16.60
2	18.32
3	19.52
4	25.88
5	25.05
7	19.61
9	19.91

Table 6 Security cost for maintenance on GenCo 1

Failure on line	Week 1	Week 2	Week 3	Week 4	Week 5	Week 6
1–2	2.58	0.440	0.17	6.58	0.78	0.90
1–4	74.20	69.590	70.06	73.39	71.03	71.34
1–6	37.16	0.210	3.01	0.89	14.51	11.12
2–3	107.70	101.100	100.84	105.09	101.00	101.14
2–4	34.41	0.347	5.35	4.68	0.14	0
2–7	114.58	109.110	110.60	111.51	110.32	110.88
3–4	9.62	0.479	0.56	0.82	3.20	1.53
3–9	98.55	92.510	93.27	96.06	95.90	93.64
4–5	59.11	90.460	47.16	0.18	0.59	0
5–6	0	0.021	7.27	36.77	1.11	0.30
7–8	92.95	87.770	87.79	91.41	88.28	88.02
8–9	92.78	87.640	87.63	91.24	88.12	87.86
Total cost (\$)	723.64	639.677	613.71	618.62	574.98	566.73

Table 7 Power system operation cost in healthy mode, no congestion ($\sigma < \sigma_0$)

Week	Operation cost (\$)
1	5.3309×10^3
2	5.3299×10^3
3	5.3214×10^3
4	5.3260×10^3
5	5.3074×10^3
6	5.3303×10^3

security cost as 792.1 \$. Table 10 shows that weeks 5, 6 and 1 is allocated to GenCos 1, 2 and 3 respectively. These scheduled weeks are representative of following characteristics in UMS: 1) minimum operation cost by use of OPF; 2) minimum load shedding management in power system by considering security cost; 3) minimum rate of failure on transmission lines by considering N-1 examination of random failures; 4) minimum congestion rate in transmission line by considering congestion analysis.

Table 8 Power system operation cost in congested network mode ($\sigma > \sigma_0$)

GenCo	Week	Operation cost (\$)	Congestion cost (\$)
GenCo 1	1	5.8678×10^3	536.9
	2	5.8693×10^3	539.4
	3	5.8620×10^3	540.6
	4	5.8552×10^3	529.2
	5	5.8296×10^3	522.2
	6	5.8656×10^3	535.3
GenCo 2	1	5.8059×10^3	475.0
	2	5.8096×10^3	479.7
	3	5.8022×10^3	480.8
	4	5.7955×10^3	469.5
	5	5.7776×10^3	470.2
	6	5.8056×10^3	475.3
GenCo 3	1	5.5288×10^3	197.7
	2	5.5229×10^3	200.0
	3	5.5185×10^3	197.1
	4	5.5270×10^3	201.0
	5	5.5085×10^3	201.1
	6	5.5316×10^3	201.3

Considering both of costs simultaneously, this approach enables us to minimize the kinds of cost which are imposed by GenCos to TransCo during maintenance, which can strike a right balance between security and cost; moreover, the market-based mechanism helps to make a fair competitive environment for all market participants. Finally, the proposed method can ensure fairness among different market participants (GenCo and TransCo) and guarantee power system security.

Table 10 describes the effect of different GenCos’ maintenance on power system parameters. These results investigate the relation between capacity of maintenance and transmission network parameters variations in order security and imposed cost.

In spite of the fact that the GenCo 1 has the most generation capacity in the test power system, but outage of it does not have the most effect on network parameters. For example, outage of GenCo 1 has led to minimum load shedding in power system. This results show the important role of transmission network modeling in generating unit maintenance studies. Therefore, considering the transmission network in UMS can lead to secure and cost effective operation of power system. To sum up, this novel approach proposes a framework for UMS to prevent additional cost in transmission lines; in the same way, it can ensure power system security and guarantee fairness among all market participants.



Table 9 Unit maintenance schedule, relevant economic values and load shedding management

GenCo	Start of outage week	Impose cost on power system		Total congestion and security cost (\$)	Load shedding on bus number
		Congestion cost (\$)	Security cost (\$)		
1	5	522.2	574.98	1097.18	4, 5, 9, 3
2	6	475.3	611.26	1086.56	2, 3, 4, 5, 9
3	1	197.7	792.10	989.80	3, 4, 5, 7, 9

Table 10 GenCos' maintenance effects on power system's and market's characteristics

Maintenance on GenCo	Generation capacity (MW)	Effect on network parameters				
		LMP	Load shedding	Congestion cost	Security cost	Total imposed cost
1	1,000	Maximum	Minimum	Maximum	Minimum	Maximum
2	400	Average	Average	Average	Average	Average
3	400	Minimum	Maximum	Minimum	Maximum	Minimum

7 Conclusions

In this paper, a new market-based framework for UMS problem is proposed in order to minimize the operational cost of power system and maximize the power system security, emphasizing the risk associated with random line outage. The proposed framework enables us to explicitly consider the interaction of competing GenCos and TransCos which are the crucial concerns in the competitive restructured power systems. In this method, the GenCos' maintenance is scheduled considering two kinds of cost in TransCo imposed by GenCos. The market equations are characterized by the LMP and can be obtained by OPF scheme based on power market structure. The numerical illustration for nine-bus power system is provided to demonstrate the basic idea of the proposed method. The final purpose is the UMS with minimum imposed cost on transmission network and highest security level for power system. In addition, when the impact of UMS on power system security is investigated, the random line outages were also taken into account with N-1 examination of lines.

For each GenCo's maintenance strategy, congestion and load shedding management are done in order to relieve congestion and reliable operation of power system.

In order to a reliable operation of power system, a probabilistic approach of network congestion for reliability analysis is used in this paper, which embeds the deterministic framework within a probabilistic approach. The reliability analysis method can guarantee the power system security during the maintenance horizon.

The novelty of this paper is that it considers two kinds of cost which impose by generation units to transmission

system. This approach has not been considered in the past studies about UMS; therefore, the proposed approach suggests an advanced plan for UMS with no additional cost which normally imposed to transmission network. This paper provides a new framework for UMS problem in competitive markets and a lot of realistic problem to be solved are still remained. To overcome the limitations of this paper, inclusion of wide spread transmission network constraints and analysis on the impact of reliability requirement on the solution should be further investigated. Although the proposed approach requires more investigations for transmission network analysis, we expect the proposed framework can provide a comprehensive approach with useful information on determining optimal maintenance strategy for power system generators, which can strike a right balance between fair competition among GenCo, TransCo and power system operational cost. Based on the results of this paper, one can investigate to obtain more precise presentations as well as more efficient UMS procedure in the future.

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Appendix

The result of security cost analysis for all GenCos of test power system reveals the fact that the final UMS suggests the maintenance strategy with highest possible security and least operation and congestion cost. Here, some information about the security analysis of GenCo 2 and 3 are shown in Tables 11 and 12.

Table 11 Security cost for maintenance on GenCo 2

Failure on line	Week 1	Week 2	Week 3	Week 4	Week 5	Week 6
1–2	27.48	30.32	31.46	26.50	27.05	27.74
1–4	71.75	79.12	78.79	73.32	71.81	71.25
1–6	111.59	111.26	109.86	109.35	102.76	107.84
2–3	56.64	58.39	57.45	55.91	55.13	55.31
2–4	53.39	54.84	53.50	52.68	51.92	51.89
2–7	15.79	15.42	16.99	23.09	16.11	16.15
3–4	58.41	59.63	58.43	57.33	56.49	56.52
3–9	3.08	8.75	1.19	15.82	2.20	0.92
4–5	10.29	74.54	2.97	1.17	34.54	1.80
5–6	111.20	111.15	109.87	108.40	102.20	107.69
7–8	58.61	60.33	59.07	57.59	56.97	57.07
8–9	58.63	60.35	59.08	57.61	56.99	57.08
Total cost (\$)	636.86	724.10	638.66	638.77	634.17	611.26

Table 12 Security cost for maintenance on GenCo 3

Failure on line	Week 1	Week 2	Week 3	Week 4	Week 5	Week 6
1–2	172.81	172.58	170.36	172.85	171.24	171.26
1–4	106.63	105.59	101.81	101.11	97.68	101.43
1–6	105.36	104.42	104.77	102.97	101.39	105.48
2–3	0	2.77	0	4.20	45.31	31.77
2–4	87.71	87.19	84.62	86.22	86.11	85.45
2–7	0.47	7.12	78.27	102.6	1.55	201.90
3–4	46.93	47.09	45.19	46.18	45.62	45.27
3–9	2.19	0.05	0.17	28.67	3.40	12.84
4–5	32.95	35.99	29.22	28.44	25.56	21.76
5–6	105.53	104.59	104.94	103.09	101.57	105.65
7–8	65.76	66.35	63.23	66.72	65.62	64.79
8–9	65.76	66.36	63.24	66.72	65.63	64.80
Total cost (\$)	792.10	800.10	845.82	909.77	810.68	1012.4

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Hessam GOLMOHAMADI received the B.S. degree from Department of Electrical Engineering, Ferdowsi University of Mashhad, Iran in 2008 and M.S. degree from faculty of Computer and Electrical Engineering, the University of Birjand, Iran in 2012. Currently, he is with the Electricity distribution and transmission center, Mashhad, Iran. His research interests include control, operation, planning and economics of electric energy systems.



Maryam RAMEZANI received the B.S. degree in electrical engineering from Ferdowsi University of Mashhad, Mashhad, Iran, and the M.S. and Ph.D. degrees from Tarbiat Modares University, Tehran, Iran, in 2003 and 2008, respectively. In 2007, she was a Visiting Research Scholar with the Department of Electrical and Computer Engineering, Texas A&M University, College Station. Currently, she is an Assistant Professor with the Department of Electrical Engineering, The University of Birjand, Birjand, Iran. Her current research interests include transmission network management, wind power generation, and power system reliability.

Amir BASHIAN was born in Mashhad, Iran on 1986. He received the B.Sc. degree from the Department of Electrical Engineering, Ferdowsi university of mashhad, mashhad, Iran in 2008 and the M.Sc. degree from the Department of Electrical Engineering, Ferdowsi

University of Mashhad in 2011. He is currently working on renewable energies at Sun & Air Research Institute in Ferdowsi University of Mashhad. His research interests include power systems economics, power quality and electricity markets.

Hamid FALAGHI received the B.S. degree from Shahid Abbaspour University, Tehran, Iran, in 2000, and the M.S. and Ph.D. degrees from Tarbiat Modares University, Tehran, in 2002 and 2008, respectively, all in electrical engineering. In 2007, he was a Visiting Scholar with the Department of Electrical and Computer Engineering, Texas A&M University, College Station. Currently, he is an Assistant Professor with the Department of Electrical Engineering, The University of Birjand, Birjand, Iran. His current research interests include transmission and distribution networks planning, distributed power generation, and power system reliability and operation.