Preventive Control for Transient Security with Generation Rescheduling Based on Rotor Trajectory Index

Kusum Verma[†] and K. R. Niazi*

Abstract - The increasing need to improve transient security assessment of existing or forecasted operating conditions of networks by power system operators is major concern of the power system security monitoring problem at the Energy Management Systems. This paper proposes a preventive control of transient stability with generation rescheduling based on rotor trajectory index obtained using time domain simulations. This index may help power engineers in making operational decision and to obtain a generation configuration with better transient security dispatch. The effectiveness of the proposed methodology is demonstrated on IEEE 39-bus New England system for a three phase fault at different loading conditions with single and multiple line outage cases.

Keywords: Generation rescheduling, Preventive control, Rotor trajectory index, Transient security

1. Introduction

Security control is one of the prime concerns for planning and operation of modern power systems. The increase in size and complexity of modern interconnected power systems and the present trend towards deregulation has forced the electric utilities to operate their systems under stressed operating conditions closer to their security limits [1]. With this growing stress on present day power systems, they are increasingly facing the threat of transient stability problems. Transient stability or large disturbance rotor angle stability is concerned with the ability of the power system to maintain synchronism when subjected to a severe disturbance, such as a short circuit on a transmission line. Instability that may result occurs in the form of increasing angular swings of some generators leading to their loss of synchronism with other generators ([2, 3]). When the transient security level falls below an acceptable level, preventive control actions can restore the system back to secure state of operation [4].

Preventive control aims at modifying the operating conditions of a power system so as to make it able to withstand severe contingencies that would drive it to instability, whenever they occur. The types of preventive control actions include: generation rescheduling; network switching; reactive compensation; and load curtailment. Preventive control is summoned up when the power system is still in normal status [5]. In the past many utilities have relied on preventive control in order to maintain system security at an acceptable level. This is due to the fact that with preventive control time is available for decision making. Also, for the uncertain disturbances, the state of system is known in this control; therefore, it becomes easier to study dynamic behavior of the system. The core of power system operation is to maintain a balance between supply and demand of electric power. Since reactive power can be locally compensated, active power balance is the most important issue for power system operation.

Preventive control is mainly dominated by generation rescheduling as reported in the literature survey. Various generator rescheduling techniques [6-23] have been proposed for transient security control. In [6], the transient energy function (TEF) method is used to check the dynamic security of the system and the coherent behavior of generators is used to find a new generation configuration. In [7], a coherency based sensitivity method is proposed for generation rescheduling. In [8], a coherency based generator rescheduling for preventive control of transient stability in power systems is proposed. In [9], dynamic security assessment and generation rescheduling method utilizing genetic algorithms (GAs) integrated with probabilistic neural networks (PNNs) and adaptive neuro-fuzzy inference systems (ANFISs) is proposed for the preventive control power systems against transient instabilities. A generation rescheduling approach for preventive control of power system is presented in [10] to reallocate power generation for multiple unstable contingencies based on graph theory. In [11], proposed a transient stability preventive control design that takes series compensation into account. A heuristic stability performance index (PI) was proposed to evaluate the gradient of the PI and determine the preventive control accordingly [12]. In [13], rescheduling of power systems constrained with transient stability limits in restructured power systems based on TEF is proposed. An optimal generation rescheduling with trajectory sensitivity-based

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transient stability constraints is presented in [14]. Generation rescheduling based upon the optimal result of multi-contingency transient stability constrained optimal power flow is suggested as preventive control of power systems in [15]. A real time preventive action for transient stability enhancement with a hybrid neural network-optimization approach using derivatives of transient energy margin value is proposed in [16]. A technique using trajectory sensitivities to provide a preventive rescheduling scheme in dynamic security constrained power systems taking into account the economic aspect is proposed in [17]. In [18], trajectory sensitivities are used for multi-contingency preventive control. Iterative solution methodology and computer package for generation rescheduling is suggested in [19]. The proposed approach in [20] considers generator shedding as the most effective discrete supplementary control for improving the dynamic performance of faulted power systems and preventing instabilities considering the sensitivity of the TEF with respect to changes in the amount of dropped generation which is used during the training phase of ANNs to assess the critical amount of generator shedding required to prevent the loss of synchronism. Decision tree (DT)-based preventive and corrective control methods are proposed in [21] to enhance the dynamic security of power systems against the credible contingencies causing transient instabilities. A radial basis function (RBF) neural network to assess the dynamic security status of the power system and to estimate the effect of a corrective control action applied in the event of a disturbance is proposed in [22] with optimal control action using particle swarm optimization (PSO). In [23], an optimal power flow model with transient stability constraints is proposed for both dispatching and re-dispatching.

The individual machine synchronism state for a given operating condition needs to be monitored to decide the participating generators for rescheduling to ensure security of power systems under all operating conditions. There is need for thorough investigation to obtain secure pre-contingency generating schedules so that system remains transiently secure in the event of large disturbances. For any approach using the energy margin and sensitivity analysis, computation time is a concern and a somewhat different approach is required for determining the proper preventive control action for transient security improvement. Therefore, there is an urgent need to improve and develop more robust and efficient preventive control method for transient security control. The objective of this paper is to analyze the role of preventive control from a transient security perspective and to develop alternative approach for active power rescheduling of generators to improve power system preventive control plans. The proposed approach is based on transient security index for preventive control of power system with multiple unstable contingencies. The method also determines the individual machine synchronism state for a given operating condition.

The method have been tested on IEEE 39-bus, 10-generator system and the transiently insecure cases for certain contingencies are made secure by rescheduling the generation according to the proposed method. Application results show that proposed method is able to provide near-optimal control solutions meeting steady-state and transient stability constraints.

2. Power System Swing Equation

The transient security assessment (TSA) requires dynamic simulation of power system to determine whether synchronism is preserved following a disturbance. This is judged by observing the variations of rotor angles following a disturbance over a period of time. If the rotor angle δ of a machine or a group of machines continues to increase without bound with respect to rest of the system, the system is called unstable. On the other hand if all rotor angles remain bounded within limit around their post disturbance steady state values, then the system is called stable system. The dynamic behavior of an n-generator power system can be described using the following swing equations ([2, 8]):

$$\frac{d\delta_i}{dt} = \Delta\omega_i \tag{1}$$

$$\frac{d\Delta\omega_i}{dt} = \frac{1}{M_i}(P_{m\,i} - P_{ei} - D_i\Delta\omega_i) \tag{2}$$

$$P_{ei} = G_{ii}E_i^2 + \sum_{j=1, j\neq i}^{n} E_i E_j\{G_{ii}\cos(\delta_i - \delta_j) + B_{ij}\sin(\delta_i - \delta_j)\} \tag{3}$$

where, for i^{th} machines δ_i is rotor angle, $\Delta\omega_i$ is rotor speed deviation, P_{mi} is mechanical power input, P_{ei} is electrical power output, M_i is moment of inertia, D_i is damping coefficient, δ_j is rotor angle of jth machine, $G_{ij} + jB_{ij}$ is transfer admittance between the ith and j^{th} machines. In describing the transient behavior of the system, it is convenient to use inertial center as a reference frame. The generators' angles with respect to centre of inertia (COI) [18] are used to indicate whether or not the system is stable. For an N_G-generator system with rotor angles δ_i and inertia constant M_i, the position of the inertial center δ_{COI} is defined as

$$\delta_{COI} = \frac{\sum_{i=1}^{NG} \delta_i M_i}{\sum_{i=1}^{NG} M_i} \tag{4}$$

In this paper, swing equation is solved by numerical integration techniques such as Runge-Kutta method. By observing the swing curves, the relative rotor angle of each generator with respect to COI are obtained to assess the transient security status. The criterion for transient instability is given as

$$\Delta\delta_{i,COI} = |\delta_i - \delta_{COI}| \leq \delta_{max} \text{ for i=1 to } N_G \tag{5}$$

Here, δ_i is the rotor angle of ith generator and δ_{max} is maximum allowable relative rotor angle difference for secure operation. If there is no relative rotor angles violations of any generator with respect to COI, $\Delta\delta_{i,COI}$ ($\leq \delta_{max}$) after fault clearing, the system is said to be secure (1), else insecure (0). For this study δ_{max} is taken as 120° ([22, 23]).

2.1 Rotor Trajectory Index (*RTI*)

The rotor trajectory index (*RTI*) can be used to measure the synchronism state of a generating unit and hence stability of the system for given severity of the contingency. In this paper, an angle based stability index *RTI* ([6-8]), is used in order to assess the severity of a contingency and the system's trajectory following a disturbance, defined as

$$RTI = 1 - \frac{360° - (\Delta\delta_{i,COI})_{max}}{360° + (\Delta\delta_{i,COI})_{max}} \qquad (6)$$

where $(\Delta\delta_{i,COI})_{max}$ is the maximum relative rotor angle difference of any generator with respect to COI in the post-fault response, obtained using (5). Here, $RTI > \varepsilon$ and $RTI \leq \varepsilon$ correspond to unstable and stable conditions, respectively and the generating machines can be grouped into critical machines, *CMs* and non-critical machines, *NMs* respectively. For a given post-fault condition, if any generating unit have $RTI > \varepsilon$, it indicates that this machine will lose synchronism with rest of the system making it insecure. The severity of the machines in order of their losing synchronism can be obtained by their RTI value that gives their ranking. Thus severity of machines can be analyzed on basis of the value of this index and accordingly significant units can be determined to apply preventive control for a given contingent case.

3. Proposed Methodology for Generation Rescheduling

Generation rescheduling has long been recognized as an efficient and cost effective means to alleviate system transient insecurity [14]. Generation rescheduling aims at shifting generation from selected machines. The proposed method utilizes the information of the rotor trajectory index values to determine the significant units to be considered for rescheduling. The pre-contingent power flow on the line is also distributed among the candidate machines for a given operating condition so as to maintain the power balance between supply and demand. The slack generator is not included in the rescheduling process as the active power generation of this generator is not controllable. This generator is used to provide system losses and to balance the active and reactive power in the system.

3.1 Selection of generating units for rescheduling

After the determination of critical contingencies, the generating units to be rescheduled are determined by their generating capabilities and their effects on restoring the security for the specified contingencies. In order to assess the severity of a contingency, the system's trajectory following a disturbance and hence the severity of machines in terms of their synchronism can be analyzed on basis of the value of this index. The machines having $RTI > \varepsilon$ are the "critical machines" (*CMs*) and the machines having $RTI \leq \varepsilon$ are the "non-critical machines" (*NMs*). Accordingly significant units can be determined for a given insecure contingent case and preventive control may be applied to these units to restore system security. The flowchart for proposed preventive control method based on rotor trajectory index, *RTI* is shown in Fig.1.

The procedure for proposed preventive control based on *RTI* values is summarized as follows:

1) For the insecure contingency, all the machines are divided into groups based on their *RTI* as the *CMs* and *NMs*.
2) All the critical machines having $RTI > \varepsilon$, form a group known as Generation Decrease (*GD*) group. All the non-critical machines having $RTI \leq \varepsilon$, form a group known as Generation Increase (*GI*) group.
3) The non-critical machine having lowest value of *RTI* is first considered to take up the increase in active power generation. The machines of *GI* group are the candidate generating units that are available and controllable for re-dispatch.
4) Synchronous generators running in parallel and delivering active power to the load depends on the rotor angle of the generators. This shows that any change in relative rotor angles will affect the active power output of the generating units. Rotor angle stability must be maintained for inter-connected synchronous machines running in the power system to remain in the state of synchronism. In this paper an index is developed to find the amount of generation decrease / increase for the generating units to regain synchronism in the event of insecure contingencies. Based on *RTI* values, a *Generation Shift Factor*, GSF_i is proposed for all insecure generators / critical machines having $RTI > \varepsilon$. For each ith critical machine, GSF_i is defined as

$$GSF_i = \frac{\delta RTI_i}{\delta P_{Gi}} = \frac{\Delta RTI_i}{\Delta P_{Gi}} = \left| \frac{RTI_i^{post} - RTI_i^{pre}}{P_{Gi}^{post} - P_{Gi}^{pre}} \right|$$
where, $i \in GD$ \qquad (7)

where, RTI_i^{post} = post-contingent value of rotor trajectory index for i^{th} critical machine
RTI_i^{pre} = pre-contingent value of rotor trajectory index for i^{th} critical machine

P_{Gi}^{post} = post-contingent real power output of ith critical machine

P_{Gi}^{pre} = pre-contingent real power output of ith critical machine

The amount of real power shift, ΔP_{Gi}^{shift} from these critical machines of *GD* group is then determined using the following equation:

$$\Delta P_{Gi}^{shift} = GSF_i \times P_{Gi}^{pre} \qquad (8)$$

5) The real power generation of the most stressed *CMs* is decreased as per Eq. (8) and their new schedules, P_{Gi}^{new} are calculated using

$$P_{Gi}^{new} = P_{Gi}^{pre} - \Delta P_{Gi}^{shift} \qquad (9)$$

For each case, the decrease of generation in *CMs* is done first for the most severe unit with rank 1 as per *RTI*.
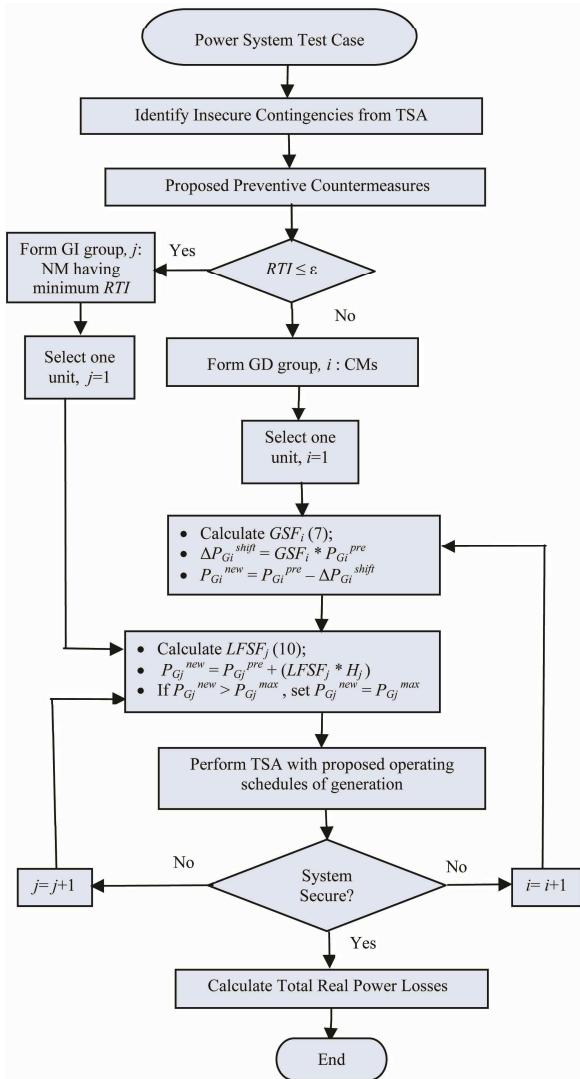

Fig. 1. Flowchart of proposed preventive control method based on rotor trajectory index

6) Pre-fault transmission line power flows may be modified to *remove* contingency problems. In an operational context this requires working with the existing electric grid, typically involving re-dispatch of generation so that power balance may be maintained. Therefore, the pre-contingent real power flow on the outaged line may be carried by the non-critical machines.

7) Real power rescheduling of each jth candidate non-critical *machine* is done by increasing their generation to adjust the decrease done for *CMs* and to carry additional pre-contingent real power flow on the outaged line. This is determined according to the proposed *Line Flow Shift Factor*, $LFSF_j$, defined as

$$LFSF_j = \frac{\Sigma \Delta P_{Gi}^{shift} + \Sigma P_{Gj}^{pre} + \Sigma P_{LO}^{pre}}{\Sigma(P_{Gj}^{pre} * H_j)}$$

where, $\qquad\qquad j \in GI \qquad (10)$

where, ΔP_{Gi}^{shift} = Real power decrease of each ith critical machine

P_{Gj}^{pre} = Pre-contingent real power output of jth non-critical machine

P_{LO}^{pre} = Pre-contingent real power flow on the outaged line

H_j = Inertia constant of jth non-critical machine

8) In order to *make* the system secure, the real power generation of the *NMs* is increased as per Eq. (10) and their new schedules, P_{Gj}^{new} are calculated using

$$P_{Gj}^{new} = P_{Gj}^{pre} + (LFSF_j \times H_j) \qquad (11)$$

The amount of generation increment is distributed in each unit of *GI* group in proportion to their machine inertias.

9) For *obtaining* secure operation, the active power generation constraint for candidate *NMs* must be satisfied as: $P_{Gj}^{new} <= P_{Gj}^{max}$, where, P_{Gj}^{max} is the maximum limit of active power generation of jth non-critical generating machine.

10) To obtain a transiently secure post-contingent scenario, the pre-contingent operating point is obtained by *rescheduling* the generating units according to these new active power schedules.

11) If the system is found to secure after applying the proposed reschedule, the rescheduling is complete; *otherwise*, the decrease of generation in *CMs* is done for other units in decreasing order of their ranks as per *RTI*. For generation increase, one more non-critical machine with next lowest value of *RTI* is included in the rescheduling process.

12) The *process* is continued till a secure state of the system is obtained.

13) After obtaining transient secure state with the proposed *rescheduling*, the total real power losses for the system are calculated and the process terminates.

4. Simulation and Results

The proposed method is tested on the IEEE-39 bus 10-generator New England system. The system has 10 generators, 12 transformers, 46 transmission lines shown in Fig. 2. Bus no. 39 is taken as slack bus [24]. It is 345 kV dynamic test system. The bus voltage magnitude limits are V^{min} = 0.94 p.u. and V^{max} = 1.06 p.u. All the simulations are carried out using MATLAB 7.7 [25], PST v3[26] with Intel Core i5, 2.50 GHz, 6GB RAM.

Three sample cases are illustrated in this section for IEEE 39-bus, 10-generator system for different contingent scenarios to demonstrate the effectiveness of the proposed methods. The three phase short circuit to ground fault is applied at 0.01s and is cleared by opening the line 26-28. The fault duration is 80ms and time domain simulation (TDS) is performed for 1sec. with frequency 60Hz to find whether the system is secure or insecure after a fault is
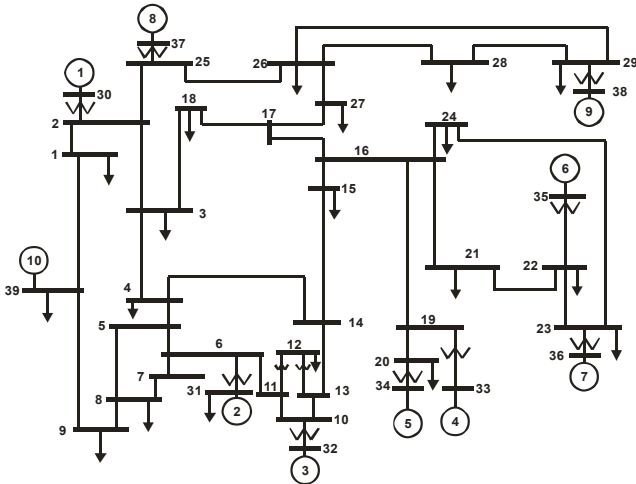
cleared.

For each case, a new pre-contingent operating point is determined, which is based on the results of proposed rescheduling. The TDS is carried out with the proposed generation schedules to establish post-contingent transient secure system and the performance analysis is carried out by determining the security status and total real power losses of the system. The proposed method reschedules the active generation of the units using Eqs. (7) - (11). The generation is decreased for *GD* units according to GSF_i (7) and new active power schedules for these units are obtained using (8) and (9). The generation is increased for *GI* units according to $LFSF_j$ (10) and new active power schedules for these units are obtained using (11). The obtained results of the proposed rescheduling for each case are verified by observing the transient stability/instability scenario, before and after rescheduling, for each case on the basis of the relative rotor angle swings with respect to COI obtained by the numerical routines for 1sec.

Case I: N-1 Topology Variation; 97.5% of Base Case

This case study is shown for 97.5% of base case with random load variation and N-1 contingency selection. Single line outage of line 2-25 is considered with three-phase fault at bus-26. As shown in Table 1, for line outage of line 2-25, TDS results show that generator no. 2, 5, 9 goes out-of-step with respect to COI and the system becomes transiently insecure. For each generating unit, $RTI > \varepsilon$ indicates that the machine lose synchronism making the system insecure. As seen from the post-contingent value of RTI^{post}, the generator no. 5, 2 and 9 loses synchronism, in the order of their severity ranking with rest of the system. Therefore, these generating units make the system transiently insecure. To bring back system to secure state, generation rescheduling is required. The generation may be shifted from these insecure *GD* units (*CMs*) to the candidate secure *GI* units (*NMs*).

Fig. 2. Single line diagram of IEEE 39-bus, 10-generator new england system

Table 1. Results obtained from time domain simulations for IEEE 39-bus system at 97.5% of base case with N-1 topology variation (insecure case)

Generator Number	Bus Number	P_G^{max} (p.u.)	P_G^{pre} (p.u.)	P_G^{post} (p.u.)	RTI^{pre}	RTI^{post}	Severity Rank	H (sec)
1	30	10.4	6.563	6.8977	0.160	0.362	-	4.2
2	31	6.46	6.460	7.0256	0.321	0.505	2	3.03
3	32	7.25	6.556	7.1892	0.252	0.449	-	3.58
4	33	6.52	6.393	7.1160	0.299	0.493	-	2.86
5	34	5.08	5.080	5.7537	0.331	0.533	1	2.6
6	35	6.87	6.452	6.9164	0.259	0.459	-	3.48
7	36	5.80	5.800	6.4612	0.301	0.482	-	2.64
8	37	5.64	5.640	5.6698	0.311	0.473	-	2.43
9	38	8.65	6.384	5.9789	0.302	0.501	3	3.45

Table 2. Active power rescheduling results for IEEE 39-bus system for Case-I obtained from proposed method

GD unit (i)	ΔP_{Gi}^{shift} (p.u.)	P_{Gi}^{new} (p.u.)	Line Outage	P_{LO}^{pre} (p.u.)	GI unit (j)	P_{Gj}^{new} (p.u.)
2	2.1016	4.3584	2-25	1.6657	1	8.8469
5	1.5232	3.5568				
9	3.1361	3.2479				

Table 2 show the proposed rescheduling of the active power generations among *CMs* and *NMs* to bring the current insecure operating state to a secure state. It is found that the *GI* group consists of only one unit, which is generator no.1 having lowest value of RTI^{post}. The generation decrease is required for all three critical machines while generation increase for only one non-critical generating unit is sufficient to bring the system back to secure state. As seen from Fig. 3, relative rotor angle of generator no. 2, 5 and 9 increases beyond the threshold value, ε and goes out of step before rescheduling. These machines lose synchronism with rest of the generators making system transiently insecure. As shown in Fig. 4, after proposed rescheduling, the relative rotor angle of all the generating units is below ε and the system becomes secure.

Case II: N-2 Topology Variation; Base Case

This case study is shown for base case with random load variation and N-2 contingency selection. Single line outage of line 2-3 and line 14-15 is considered with three-phase fault at bus-26. Table 3 shows the results obtained from

time domain simulations for this case. As seen from the post-contingent value of RTI^{post}, the generator no. 5 loses synchronism with rest of the system.

Table 4 shows the proposed rescheduling of the active power generations among *CMs* and *NMs* to bring the current insecure operating state to a secure state. It is found that the *GI* group consists of only one unit, which is generator no.1 having lowest value of RTI^{post}. It is found that the *GI* group consists of only one unit, which is generator no.1 having lowest value of RTI^{post}. The generation decrease is required for one critical machine while generation increase is required for one non-critical generating unit to bring the system back to secure state.

As seen from Fig. 5, relative rotor angle of generator no. 5 increases beyond the threshold value, ε and goes out of step before rescheduling. This machine loses synchronism with rest of the generators making system transiently insecure. To make the system secure for this case, the proposed rescheduling is applied to the generating units. As shown in Fig. 6, after proposed rescheduling, the relative rotor angle of all the generating units is below ε and the system becomes secure.
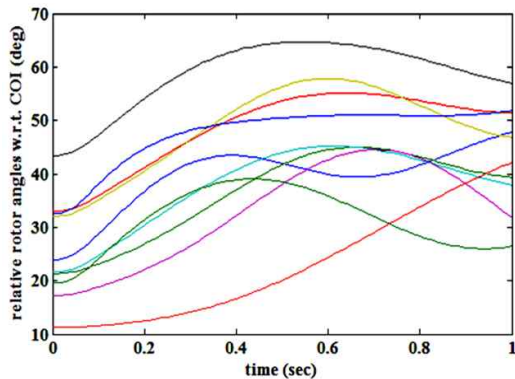

Fig. 3. Relative rotor angle trajectories of all generators of IEEE 39-bus system before rescheduling for Case I (insecure case)
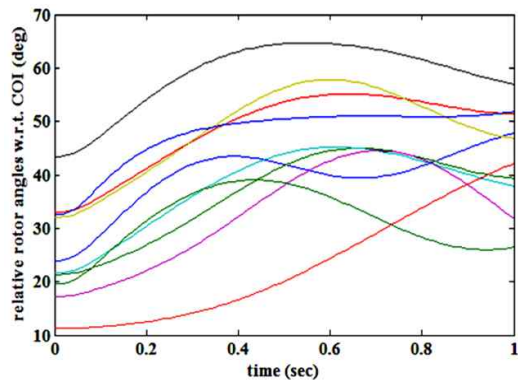

Fig. 4. Relative rotor angle trajectories of all generators of IEEE 39-bus system after proposed rescheduling for Case I (secure case)

Table 3. Results obtained from time domain simulations for IEEE 39-bus system at base case with N-2 topology variation (insecure case)

Generator Number	Bus Number	P_G^{max} (p.u.)	P_G^{pre} (p.u.)	P_G^{post} (p.u.)	RTI^{pre}	RTI^{post}	Severity Rank	H (sec)
1	30	10.4	6.819	6.4306	0.164	0.350	-	4.2
2	31	6.46	6.460	6.9024	0.318	0.437	-	3.03
3	32	7.25	6.814	7.3239	0.255	0.382	-	3.58
4	33	6.52	6.520	7.3148	0.297	0.463	-	2.86
5	34	5.08	5.080	5.7985	0.324	0.501	1	2.6
6	35	6.87	6.713	7.0500	0.261	0.429	-	3.48
7	36	5.80	5.800	6.4333	0.298	0.452	-	2.64
8	37	5.64	5.640	5.9895	0.309	0.449	-	2.43
9	38	8.65	6.628	5.5028	0.307	0.460	-	3.45

Table 4. Active power rescheduling results for IEEE 39-bus system for Case-II obtained from proposed method

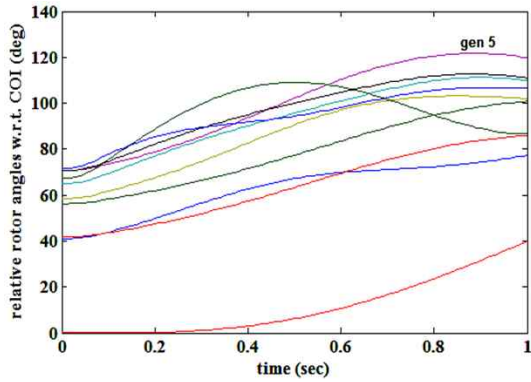| GD unit (*i*)	ΔP_{Gi}^{shift} (p.u.)	P_{Gi}^{new} (p.u.)	Line Outage	P_{LO}^{pre} (p.u.)	GI unit (*j*)	P_{LO}^{pre} (p.u.)
5	1.2514	3.8286	2-3	4.4659	1	8.3603
			14-15	0.1117	3	7.2500

Fig. 5. Relative rotor angle trajectories of all generators of IEEE 39- bus system before rescheduling for Case II (insecure case)

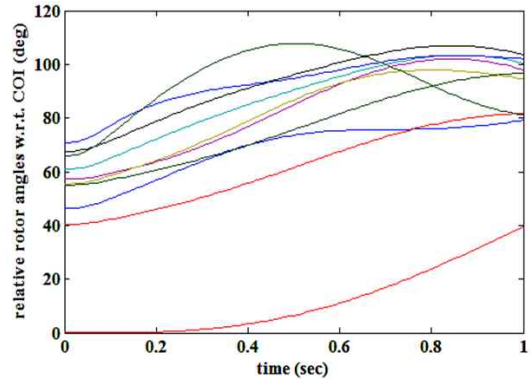**Fig. 6.** Relative rotor angle trajectories of all generators of IEEE 39-bus system after proposed rescheduling for Case II (secure case)

Table 5. Results obtained from time domain simulations for IEEE 39-bus system at 105% of base case with N-1 topology variation (insecure case)

Generator Number	Bus Number	P_G^{max} (p.u.)	P_G^{pre} (p.u.)	P_G^{post} (p.u.)	RTI^{pre}	RTI^{post}	Severity Rank	H (sec)
1	30	10.4	6.410	6.7141	0.147	0.392	-	4.2
2	31	6.46	6.460	6.8385	0.306	0.514	3	3.03
3	32	7.25	7.250	7.7259	0.253	0.476	-	3.58
4	33	6.52	6.520	7.2550	0.281	0.505	4	2.86
5	34	5.08	5.080	5.5803	0.305	0.532	2	2.6
6	35	6.87	6.870	7.1672	0.250	0.479	-	3.48
7	36	5.80	5.800	6.4001	0.285	0.496	-	2.64
8	37	5.64	5.640	6.3973	0.302	0.504	5	2.43
9	38	8.65	8.315	8.7561	0.331	0.555	1	3.45

Table 6. Active power rescheduling results for IEEE 39-bus system for Case-III obtained from proposed method

GD unit (i)	ΔP_{Gi}^{shift} (p.u.)	P_{Gi}^{new} (p.u.)	Line Outage	P_{LO}^{pre} (p.u.)	GI unit (j)	P_{Gj}^{new} (p.u.)
2	3.5500	2.9100	5-8	4.016	1	10.152
4	1.9782	4.5418				
5	2.3049	2.7751				
8	1.5044	4.1356				
9	4.2225	4.0925				

Table 7. Performance results of proposed rescheduling method for IEEE 39-bus system

Case	Particulars	Total Generation (MW)	Total Load (MW)	Total power loss (MW)	System security
Case I	Before Rescheduling (pre-contingent)	6207.03	6163	44.03	Insecure
	After Rescheduling (post-contingent)	6198.26	6163	35.26	Secure
Case II	Before Rescheduling (pre-contingent)	6348.28	6303.8	44.48	Insecure
	After Rescheduling (post-contingent)	6372.88	6303.8	69.08	Secure
Case III	Before Rescheduling (pre-contingent)	6687.89	6640.1	47.79	Insecure
	After Rescheduling (post-contingent)	6690.58	6640.1	50.48	Secure

Case III: N-1 Topology Variation; 105% of Base Case

This case study is shown for N-1 topology variation with randomly changing load at 105% of base case. Single line outage of line 5-8 is considered with three-phase fault at bus-26. As shown in Table 5, the results obtained from TDS indicate that the post-contingent value RTI^{post} for the generator no. 9, 5, 2 4, and 8 exceeds ε (in the order of their severity ranking) and hence they lose synchronism with rest of the system. Table 6 show the proposed active power rescheduling among *CMs* and *NMs* to bring the

current insecure operating state to a secure state. It is found that the *GI* group consists of only one unit, which is generator no.1 having lowest value of RTI^{post}.

The generation decrease is required for all five critical machines while generation increase for only one non-critical generating unit is sufficient to bring the system back to secure state. As seen from Fig. 7, relative rotor angle of generator no. 2, 4, 5, 8 and 9 increases beyond the threshold value, ε and goes out of step before rescheduling. These machines lose synchronism with rest of the generators making system transiently insecure. As shown
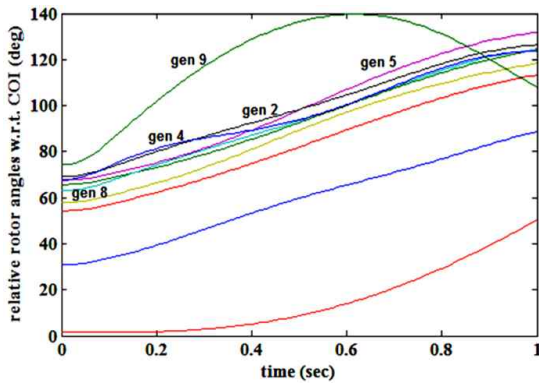
Fig. 7. Relative rotor angle trajectories of all generators of IEEE 39-bus system before rescheduling for Case III (insecure case)
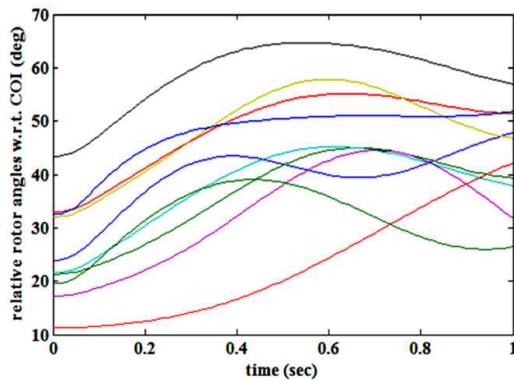

Fig. 8. Relative rotor angle trajectories of all generators of IEEE 39-bus system after proposed rescheduling for Case III (secure case)

in Fig. 8, after proposed rescheduling, the relative rotor angle of all the generating units is below ε and the system becomes secure.

The performance analysis and the effectiveness of proposed method is validated for all the cases as shown in Table 7 indicating the transient security status and total system real power losses. With the pre-contingent schedules if there is 3-phase fault on the system, it becomes transiently insecure.

5. Conclusions

In modern large and interconnected power systems, system security is paramount. Under normal operating conditions, power systems operate in economic mode with minimum possible operating cost. However, if any operating state is found to be insecure, then system security takes over system economy and the preventive action may be taken to bring the state in secure operating state even if it causes slight loss in economy. In this paper, generator rescheduling based on rotor trajectory index (*RTI*) is proposed. The application results are investigated on IEEE

39-bus, 10-generator system under different operating conditions. The proposed method of generators rescheduling is capable of converting insecure operating into secure operating state by modifying the generators' dispatch. The information about ranking obtained from *RTI* of each generating unit is important for selecting the units for generation decrease. The proposed method can be suitably employed for preventive control of power systems even under multiple contingency conditions.

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