Power System Reliability Evaluation Considering Protection Miscoordination due to Topology Change

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Abstract
Protection system operation has a vital role in power system reliability. The protection system failure and incorrect operation may cause cascading outages. In case of fault, one of the effective causes of protection system mal-operation is the change in network topology. Network topology changes due to scheduled and unscheduled outages of power system components and dynamic changes in topology cause a change in the short circuit current of the network. The change in short circuit current affects protection relay operation and can lead to protection miscoordination which results in an outage of some loads and degradation of power system reliability indices. This paper proposes a novel Markov model including the miscoordination of the protection system due to component outages. In addition, a new index is proposed for protection miscoordination. A sequential Monte Carlo simulation approach is used to implement the proposed Markov model on a 24-bus IEEE reliability test system. The reliability indices, such as loss of load probability (LOLP), loss of load expectation (LOLE), expected frequency of load curtailment (EFLC), and expected energy not supplied (EENS), are obtained for four scenarios with different miscoordination levels and compared to show how the protection miscoordination degrades the reliability indices.

Keywords
Power system reliability, Markov chain Monte Carlo, protection failure, protection miscoordination.

Nomenclature

C	components such as lines and transformers.
X	the adjacent component connected to component C
P1, P2	protection system on two sides of a component.
U_P	item (component or protection system) in a good state.
D_n	item in a failed state.
ISO	item isolated and not available.
M_C	item in a miscoordination state.
U_t	item in the undesired trip state.
λ_c, μ_c	failure and repair rate of component.
λ'_c, μ'_c	undesired trip and repair rate of protection system.
λ_{Pi}, μ_{Pi}	failure to operate and repair rate of protection system i.
λ_{PiMC}, μ_{PiMC}	miscoordination and repair rate of protection system i.
Ψ_{Mi}	switching rate.
P_{MC}	miscoordination probability.
FOR	force outage rate
t_p, t_b	primary and backup operating times.
N_b	total number of network buses.
Down	item in a failed state.

1. Introduction

Power systems must be able to deliver electricity to the customer under faulty network conditions. Protection systems are used to isolate faults and failures in the power system. In case of fault, protection systems identify and disconnect the faulty part from the network. Some features of a protection system are reliability, selectivity, sensitivity, and speed [1]. The protection system reliability is assessed in terms of dependability and security. Dependability is the ability to trip when required, and security is the ability to avoid undesired trips. There are two major failure modes in the protection system: “failure to operate” and “undesired tripping”. If the protection system fails to clear the fault in a network, a large part of the network is isolated from the network resulting in an outage. Moreover, an undesired trip of the protection system in the absence of a fault or faults outside the protection zone may cause the isolation of a healthy part of the network and an outage of some loads. Therefore, protection failures have a crucial effect on the power system reliability. Ref [2] introduced a new Markov model for both single and double-main protection systems, considering hidden failures and the function of the protection system under Condition-Based Maintenance (CBM) conditions. Moreover, the probability of a hidden failure state in the protection system is computed. A generalized analytical methodology in the paper [3] proposed to identify breaker active failure events in power distribution networks by introducing an active breaker incidence (ABI) matrix. This matrix is utilized to evaluate the reliability indices. In a study [4], the Bayesian Network (BN)-based analytical methodology has been introduced to assess the bulk power system reliability considering failure protection and interactions among components caused by protection failure and operation. The Dynamic Fault Trees (DFTs) were proposed in the research [5] to extend standard fault trees and enable the modeling of complex system components' behaviors and interactions for assessing cascading failure risk. Failure and operation of the protection system inside terminal stations affect contingencies in the composite power system [6]. This study [6] investigated this topic. Ref [7] proposed a novel analytical model that uses the information of distance relays such as starters, trip signals, and relay resets for direct identification of multiple hidden failures. The new Markov model of fuse cutout containing hidden failure was introduced in a study [8] to allocate fuse cutouts in MV overhead lines. In reference [9], a new method based on stochastic analysis has been suggested to evaluate reliability by taking into account indirect cyber-power interdependencies (ICPIs) such as failures in protection and monitoring systems. New concepts of self-down state and induced-down state are introduced in references [10], and a new Markov model of failure protection is proposed for evaluating system reliability. Unreadiness probability is introduced in [11] for the evaluation of the protection system reliability. Additionally, other reliability indices such as “abnormal unavailability” and “protective system unavailability” have been developed for reliability protection system analysis [12–13]. In a study [14], a new model for failure protection is developed to illustrate its impact on the reliability of the power system, and vulnerability analysis is performed. In reference [15], a Markov model was introduced that included routine test inspections, monitoring and self-checking tests, common-cause failure, temporary and permanent faults and their associated clearing times, operation of backup protection, and relay mal-trips. This model was used to determine the optimum intervals for routine tests and self-checking. In [16], a systematic methodology is proposed to include the effect of cyber-malfunctions in substations on the power system reliability. Power system reliability is evaluated considering the protection system failures. The protection system failure modes have substantial effects on reliability indices [17]. Protection system failure and miscoordination both affect the reliability of the power system. Different methods have been proposed to properly coordinate primary and backup protection systems [18–20]. The common objective of these methods is to clear faults in less time and isolate the smallest faulty part of the network as possible. In ref [21], a new adaptive characteristic has been suggested to address this undesired effect, where coordination constraints related to the presence or absence of distribution generations must be taken into account in the overcurrent relay coordination problem.The authors in the paper [22] introduce a new approach to determine the best settings for the instantaneous unit and delay unit of a combined overcurrent relay. They employ probabilistic modeling of uncertainties, such as measurement error, operating conditions, and fault conditions, to calculate the range of fault current that passes through the relays. The impact of various coordination methods is assessed in [23] by considering the impact of protection system failures on power system reliability. Relay miscoordination causes the hidden failure of the protection system components, such as circuit breakers

(CBs), and affects power system reliability [24]. Authors in ref [25] propose a framework for assessing the impact of operational uncertainties, such as communication link and circuit breaker failures, on the reliability of centralized adaptive microgrid protection schemes. The framework utilizes Markov chain models and a Monte Carlo algorithm to evaluate reliability indices.

The effect of protection failure on power system reliability has been studied in previous research. Protection miscoordination is another factor affecting power system reliability that has received less attention. Any change in the network that affects the fault current can lead to protection miscoordination. Topology change leads to short circuit current variation and consequently miscoordination of the primary/backup relay. Generally, topology change can result in the outage of lines or generator units as well as dynamic change in topology. Of course, the simultaneous occurrence of these cases can significantly affect protection coordination. Line outage and dynamic change in topology are considered in the problem of protective relay coordination in [26] and [27], respectively. This paper considers the impact of the miscoordination due to topology changes to evaluate the power system reliability, while in references [24,25], the effect of protection failures is modeled in the Markov model, but this paper considers the effect of protection miscoordination. The miscoordination created in the protection system is not due to protection failures, but rather due to changes in network topology, which is the most important innovation and difference of our manuscript compared to references [24,25].

Also, the probability miscoordination index and the Markov model are proposed. In this paper, the probability of protection miscoordination due to topology change is modeled using an index. Moreover, a new Markov Chain Monte Carlo scheme is proposed for the evaluation of power system reliability. Accordingly, protection failure ("failure to operate" and "undesired tripping") and miscoordination are used separately in the Markov model. Sequential Monte Carlo simulation is applied to a 24-bus IEEE reliability test system (RTS) to obtain reliability indices. The main innovation and difference of this paper compared to previous references is considering the effect of protection miscoordination on the assessment of system reliability. This miscoordination is modeled separately from protection failures in the Markov model, which was not considered in previous references.

Next, the problem statement is presented, and the Markov model is developed. Then, the protection miscoordination probability model is explained. Sections 5 and 6 present the problem-solving algorithm and results, respectively. Finally, the paper is concluded in Section 7.

2. Problem statement

There are two modes of protection failure: "failure to operate" and "undesired tripping". In case of fault, the failure to operate leads to the operation of the backup protection instead of the primary protection. Therefore, the healthy and faulty lines are isolated from the network, leading to load outages. The undesired tripping of the protection system may lead to the isolation of the network lines and the outage of some loads. Previous studies have evaluated the effect of both protection failures on power system reliability.

When there is protection miscoordination, a fault may lead to the operation of the backup relay before the primary relay and cause a load outage. The reasons for protection miscoordination can be improper relay setting, protection failure, and change in network topology. The changes in network configuration can be divided into two categories: 1) outage of line, transformer, or generator unit, and 2) dynamic change in the network topology [27].

In the first category, the isolation of the components, such as the line, transformer, and generator, may cause changes in the short-circuit current seen by the relays. A change in the relay fault current leads to primary/backup relay miscoordination. Therefore, in this situation, some loads are out of service, the reliability indices increase and the network reliability degrades.

To explain the second category (dynamic change in network topology), the test system in Fig. 1 is used [27].

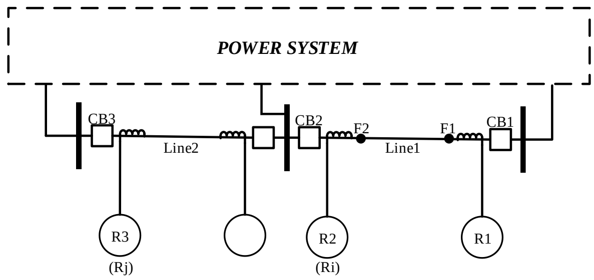

Fig. 1. Test system [27]

In the test system in Fig. 1, if a fault occurs on Line 1, relays R1 and R2 should trip in the shortest time. However, for a fault at F1, the relay R1 may operate before R2, i.e., CB1 opens, while CB2 is still closed. Therefore, the network topology changes during a short period. In this case, the current seen by the primary/backup relays R2/R3 may be higher than that seen in the original configuration. This dynamic change in network topology can cause miscoordination resulting in load outage.

The distinction between the first and second categories lies in the assumption made regarding the occurrence of outages: the first category assumes outages on other lines, whereas the second category assumes an outage specifically on the fault line. Each of the categories of topology change causes relay miscoordination. However, both categories may occur simultaneously, and in this case, the probability of relay miscoordination increases.

To assess the impact of the protection system on power system reliability, a Markov model including 16 states is proposed. In the proposed Markov Model, the protection failures and miscoordination are considered separately.

3. Proposed Markov model

In this paper, the proposed Markov model includes 16 states.The Markov model describes the states of a line and primary/backup protection on both sides of the line, so this model is composed of three parts. The first part is related to the failure to operate the protection system. The second and the third parts contain undesired trips and miscoordination of the protection system, respectively. For an explanation of the Markov model, a sample network (Fig. 2) is considered. Fig.2 shows line C with two primary protections P1 and P2 on two sides of the line. Additionally, X1 and X2 are the adjacent components connected to line C.

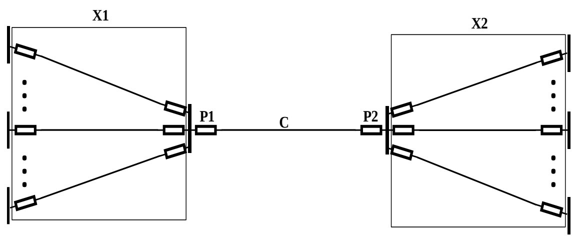

Fig. 2. Line with primary protections and adjacent connected components

The proposed Markov model is illustrated in Fig. 3. In this model, it is assumed that the backup protections operate correctly.

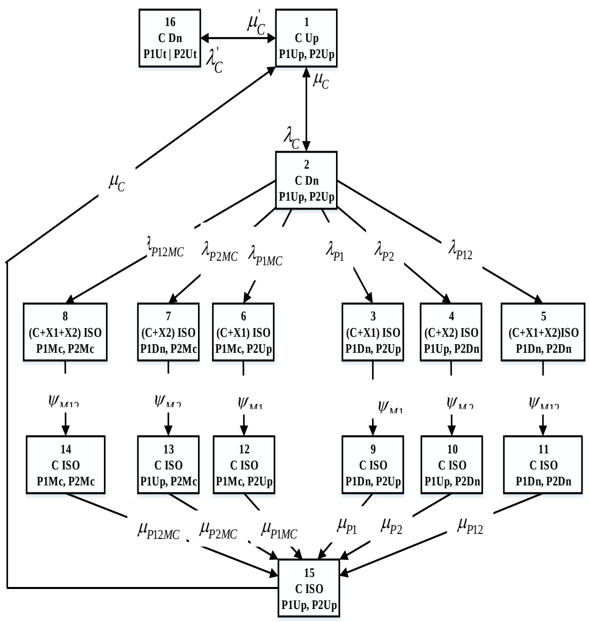

Fig. 3. Markov model of a component and its

corresponding protections

State 1: Line C and primary protections P1 and P2 are good.
State 2: Line C is faulted, while P1 and P2 are good.
State 3: Line C and the adjacent connected component X1 are isolated because of the failure to operate P1.
State 4: Line C and the adjacent connected component X2 are isolated because of the failure to operate P2.
State 5: Line C and the adjacent connected components X1 and X2 are isolated because of the failure to operate P1 and P2.
State 6: Line C and X1 are isolated because of the miscoordination of primary/backup protection P1/X1.
State 7: Line C and X2 are isolated because of the miscoordination of P2/X2.
State 8: Line C and the adjacent connected components X1 and X2 are isolated because of the miscoordination of P1/X1 and P2/X2.
State 9: Line C is isolated and X1 is restored to service, while P1 is still in the failure-to-operate mode.
State 10: Line C is isolated and X2 is restored to service, while P2 is still in the failure-to-operate mode.
State 11: Line C is isolated and the adjacent connected components X1 and X2 are restored to service, while P1 and P2 are still in the failure-to-operate mode.
State 12: Line C is isolated and X1 is restored to service, while P1/X1 is still in the miscoordination mode.
State 13: Line C is isolated and X2 is restored to service, while P2/X2 is still in the miscoordination mode.
State 14: Line C is isolated and the adjacent connected components X1 and X2 are restored to service, while P1/X1 and P2/X2 are still in the miscoordination mode.
State 15: Line C is isolated, while P1 and P2 are repaired or reset.
State 16: Line C fails because P1 or P2 is under an undesired trip.

4. Protection system miscoordination probability

Previous studies have not considered the impact of protection miscoordination on power system reliability. The operating time interval of primary/backup relay pairs should be less than the Coordination Time Interval (CTI) in the relay coordination problem. Thus, the miscoordination probability is higher if the operating time interval between primary/backup relays is less than CTI. If the difference between the performance time of the main and backup relays (tb-tp) falls within the range of CTI-0.1 to CTI, then there is a possibility of miscoordination. So miscoordination is considered a linear probability. If (t_b-t_p) is greater than CTI, then there is no miscoordination, so the probability of miscoordination is considered to be zero and if (t_b-t_p) is less than CTI-0.1, then there is definitely miscoordination, so the probability of miscoordination is considered to be one.
As mentioned in Section 2, the topology changes may cause miscoordination. This paper models the miscoordination probability as a linear function of the operating time interval between primary/backup relays, and Fig. 4 shows this model.

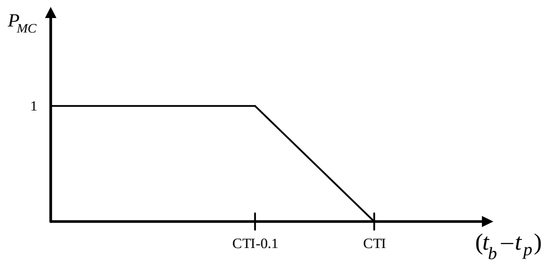

Fig. 4. Miscoordination probability of primary/backup

relay pair

In Fig. 4, the horizontal axis represents the operating time interval of primary/backup relays, and the vertical axis shows miscoordination probability P_{MC}. The probability formulation is given in Eq. (1):

$$P_{MC}=\begin{cases}1 & (t_b-t_p)\le CTI-0.1\\ -10\times(t_b-t_p)+10\times CTI & CTI-0.1<(t_b-t_p)<CTI\\ 0 & (t_b-t_p)\ge CTI\end{cases} \quad (1)$$

In Eq. (1), the miscoordination probability is higher for a shorter operating time interval of primary/backup relays. Since a primary relay can have several backup relays, the smallest difference in the operating time interval between the primary and backup relay pair can be used as a measure of miscoordination probability. The operating time of the relays depends on the fault current seen by the relays and the setting of the relays.

The present paper aims to investigate the effect of fault currents on reliability indices while the fault currents depend on the network topology. Moreover, the changes in network topology are divided into two categories including the outage of line/ transformer/generator and dynamic change in network topology. In the proposed algorithm, the miscoordination probability is calculated for each relay pair before the Monte Carlo simulation. When a fault occurs on a line, the operating times of the primary/backup relay pairs on the line are calculated, so the miscoordination probability can be obtained. Meanwhile, another line may be isolated from the network. Therefore, miscoordination probability can be expressed as in Eq. (2):

$$P^i_{MCt}=\sum_{\substack{j=1\\ j\neq i}}^{Nb} P^i_{MCj}\times FOR_j \quad (2)$$

$$FOR_j=\frac{\lambda_j}{\mu_j+\lambda_j}$$

Where FOR_j denotes the force outage rate of component j, P^i_{MCj} is the miscoordination probability of component i with the outage of line j, and P^i_{MCt} is the total miscoordination probability of component i. Since each component is protected by two protection systems on both sides, the miscoordination probability is calculated for both sides. The flowchart of miscoordination probability calculation is shown in Fig. 5.

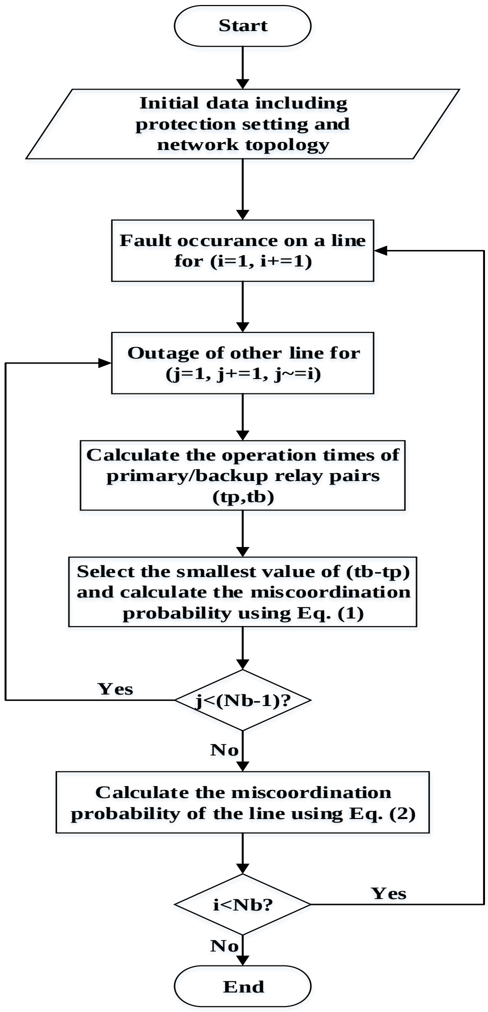

Fig. 5. Flowchart for calculating miscoordination probability

In the flowchart of Fig. 5, the initial data including the original topology network, the protection system parameters (such as TDS [1] and Iset [2]), and the failure/repair rate of lines are inputted. The force outage rate of all lines is defined. Therefore, for fault occurrence on line i while another line j is out of service, the short circuit currents and the operating times of primary/backup relays of line i are calculated. Since a line can have several backup relays, the smallest difference in operating times of the primary/backup relay pair is selected. Therefore, P^i_{MCt} can be found according to Eq. (1). Moreover, the miscoordination probability of components can be obtained using Eq. (2). This new index is used to calculate miscoordination rates in the proposed Markov model.

5. Proposed algorithm for problem-solving

To implement the Markov model, input data, such as failure and repair rates, are needed. The protection failure rates are known, but the miscoordination rates should be determined. According to the data and new index of miscoordination protection, the miscoordination rates

[1] Time Dialing Setting

[2] Current Setting

can be obtained by Eqs (3). The transient rate matrix, denoted as R, represents the rates at which the system

$$
R=\begin{bmatrix}
-\lambda_c-\lambda_c^{'} & \lambda_c & 0 & 0 & 0 & 0 & 0 & 0 & 0 & 0 & 0 & 0 & 0 & 0 & 0 & \lambda_c^{'} \\
\mu_c & -\mu_c-\lambda_{p1}-\lambda_{p2}-\lambda_{p12}-\lambda_{p1Mc}-\lambda_{p2Mc}-\lambda_{p12Mc} & \lambda_{p1} & \lambda_{p2} & \lambda_{p12} & \lambda_{p1Mc} & \lambda_{p2Mc} & \lambda_{p12Mc} & 0 & 0 & 0 & 0 & 0 & 0 & 0 & 0 \\
0 & 0 & -\psi_{M1} & 0 & 0 & 0 & 0 & 0 & \psi_{M1} & 0 & 0 & 0 & 0 & 0 & 0 & 0 \\
0 & 0 & 0 & -\psi_{M2} & 0 & 0 & 0 & 0 & 0 & \psi_{M2} & 0 & 0 & 0 & 0 & 0 & 0 \\
0 & 0 & 0 & 0 & -\psi_{M12} & 0 & 0 & 0 & 0 & 0 & \psi_{M12} & 0 & 0 & 0 & 0 & 0 \\
0 & 0 & 0 & 0 & 0 & -\psi_{M1} & 0 & 0 & 0 & 0 & 0 & \psi_{M1} & 0 & 0 & 0 & 0 \\
0 & 0 & 0 & 0 & 0 & 0 & -\psi_{M2} & 0 & 0 & 0 & 0 & 0 & \psi_{M2} & 0 & 0 & 0 \\
0 & 0 & 0 & 0 & 0 & 0 & 0 & -\psi_{M12} & 0 & 0 & 0 & 0 & 0 & \psi_{M12} & 0 & 0 \\
0 & 0 & 0 & 0 & 0 & 0 & 0 & 0 & -\mu_{P1} & 0 & 0 & 0 & 0 & 0 & \mu_{P1} & 0 \\
0 & 0 & 0 & 0 & 0 & 0 & 0 & 0 & 0 & -\mu_{P2} & 0 & 0 & 0 & 0 & \mu_{P2} & 0 \\
0 & 0 & 0 & 0 & 0 & 0 & 0 & 0 & 0 & 0 & -\mu_{P12} & 0 & 0 & 0 & \mu_{P12} & 0 \\
0 & 0 & 0 & 0 & 0 & 0 & 0 & 0 & 0 & 0 & 0 & -\mu_{P1Mc} & 0 & 0 & \mu_{P1Mc} & 0 \\
0 & 0 & 0 & 0 & 0 & 0 & 0 & 0 & 0 & 0 & 0 & 0 & -\mu_{P2Mc} & 0 & \mu_{P2Mc} & 0 \\
0 & 0 & 0 & 0 & 0 & 0 & 0 & 0 & 0 & 0 & 0 & 0 & 0 & -\mu_{P12Mc} & \mu_{P12Mc} & 0 \\
\mu_c & 0 & 0 & 0 & 0 & 0 & 0 & 0 & 0 & 0 & 0 & 0 & 0 & 0 & -\mu_c & 0 \\
\mu_c^{'} & 0 & 0 & 0 & 0 & 0 & 0 & 0 & 0 & 0 & 0 & 0 & 0 & 0 & 0 & -\mu_c^{'}
\end{bmatrix}
$$

$$
\begin{Bmatrix} pR=0 \\ \sum_{i=1}^{16} p_i=1 \end{Bmatrix} \tag{3}
$$

transitions between different states. These states can be characterized by the operating conditions of the power system. The probability vector, p, represents the probabilities of being in each state at a given time.

5.1. Implementing the Markov model using sequential Monte Carlo simulation

In this paper, sequential Monte Carlo simulation is used to evaluate the power system reliability. The basic steps of sequential Monte Carlo simulation are described as follows:

1- The initial states of each component (line, transformer, and generator unit) are given (all components are in normal state).

2- The residence time of state i, T_i, is obtained for all components using the inverse transform method as follows [28]:

$$T_i = -\frac{1}{\lambda_i}\ln(U_i) \tag{4}$$

where U_i denotes uniformly distributed random numbers over the interval (0,1), and λ_i is the transient rate. If there are several transitions from state i, the transition times are sampled for each possible transition from state i, according to Eq. (4). After calculating all the transition times, the smallest value is selected [29].

3- This process is repeated for a specific simulation period (one year), and the residence times of any state for all components are calculated. Therefore, based on the Markov model, a timing diagram of each component is obtained. Fig. 6 shows the Up and Down times of a component.

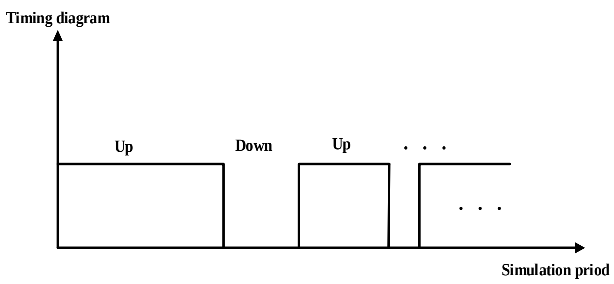

Fig. 6. Timing diagram of a component during the simulation period.

4- After determining the timing diagrams of all components, the diagrams are combined to find the system performance state. The hourly system state is assessed and power flow analysis is applied to obtain the reliability indices. Since the transition values are small, a large number of replications in Monte Carlo simulation are required for better results.

5.2. Flowchart for Reliability Index Calculation

The proposed Monte Carlo flowchart and the process of calculating the reliability indices are shown in Fig. 7.

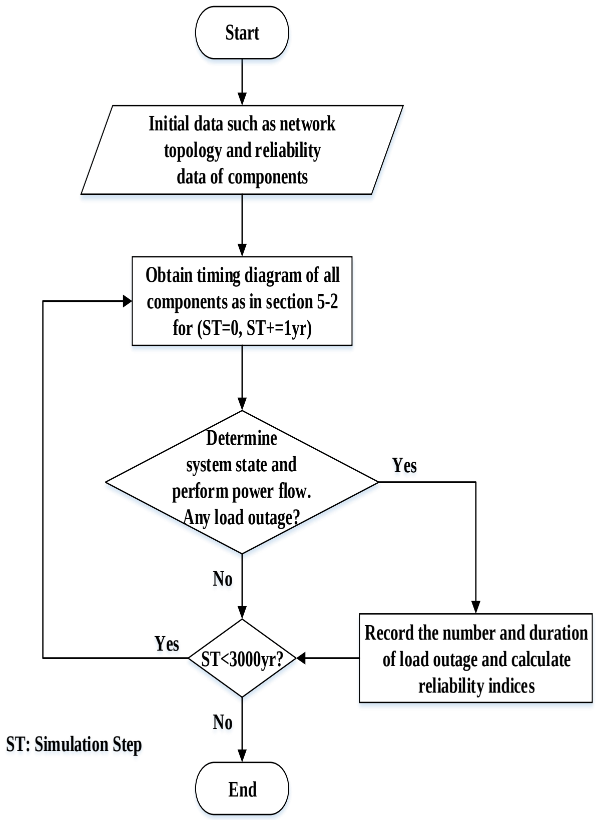

Fig 7. Flowchart of problem-solving algorithm

In the proposed flowchart, first, the initial data related to components and network topology are inputted. Then, the timing diagrams of all components are obtained as described in Subsection 5-2, and the outage of these components is assessed. If the outage of a component causes a load outage, the number of outages and the duration of each load outage are recorded. Next, the reliability indices are calculated. This process is replicated for 3000 simulation years.

In this paper, the reliability indices, such as loss of load probability (LOLP), loss of load expectation (LOLE), expected frequency of load curtailment (EFLC), expected energy not supplied (EENS), and are evaluated as follows [16]:

Loss of load probability (LOLP):

$$LOLP = \sum_{i=1}^{Ns} \frac{H_i t_i}{t_{total}} \tag{5}$$

where

N_s: Number of simulation iterations

H_i: Equal to 1 in case of loss of load in the i^{th} iteration, otherwise zero

t_i: Simulation time in the i^{th} iteration (1/yr)

t_{total}: Total simulation time (1/yr).

Loss of load expectation (LOLE):

$$LOLE = LOLP \times 8760 \quad (hr/yr) \tag{6}$$

Expected frequency of load curtailment (EFLC):

$$ELFC = \sum_{i=1}^{Ns} \frac{Z_i}{t_{total}} \quad (load/yr) \tag{7}$$

where Z_i is equal to one if there is a loss of load in the (i-1)th iteration and there is no loss of load in the ith iteration; otherwise, Z_i is equal to zero.

Expected energy not supplied (EENS):

$$EENS = \sum_{i=1}^{Ns} \frac{8760 R_i t_i}{t_{total}} \quad \left(MWhr / yr\right) \tag{8}$$

where R_i is the value of loss of load in the ith iteration.

6. Case study

6.1. Test system and data

The proposed method is implemented on a 24-bus IEEE RTS shown in Fig. 8 [30].

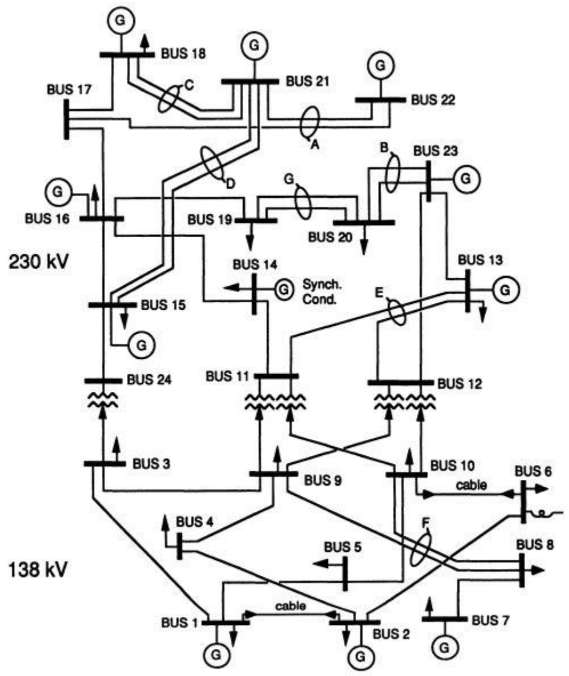

Fig. 8. 24-bus IEEE reliability test system [30]

This system consists of 24 buses and 38 lines and transformers. Directional overcurrent relays with inverse definite minimum time characteristics have been employed. The network information, as well as the failure and repair rates, are taken from reference [30] and also, the hourly load has been used to evaluate the system reliability. The coordination problem has been solved using two methods: linear programming as method 1 and a hybrid genetic algorithm as method 2 and results are shown by TDS1 and TDS2.

Since the probability of both protection devices failing simultaneously is very small, the failure rate for this state (states 2 to 5) has been considered to be small in the Markov model.

6.2. Simulation procedure

To assess the effect of the protection miscoordination and failure on power system reliability, three scenarios are proposed as follows:

Scenario 1. Protection system failures without miscoordination.

Scenario 2. Protection miscoordination (first category) is considered.

Scenario 3. Protection miscoordination (second category) is considered.

Scenario 4. Protection miscoordination (both categories) is considered. This scenario is the combination of scenarios 2 and 3.

6.3. Simulation results

MATLAB software has been used for simulation, and the hardware used is an Asus laptop with a core i5 processor and 4GB RAM. It took approximately one hour to simulate each scenario. According to the transition rates, the miscoordination probability of the system can be calculated as explained in Section 4. The Coordination Time Interval (CTI) is taken to be 0.2s. The miscoordination probabilities are calculated by using two different settings (TDS1 and TDS2) for scenarios 2, 3, and 4, and are shown in Table I.

Table I. Miscoordination probabilities of scenarios

Scenarios	Miscoordination Probability	
	TDS1	TDS2
Scenario 2	0.4547	0.3796
Scenario 3	0.4472	0.4035
Scenario 4	0.7482	0.6532

Scenario 1 has no miscoordination. So, the settings of various methods have no effect in scenario 1. The miscoordination probabilities obtained by using the first method (TDS1) are more than those of the second method (TDS2) in all scenarios. Therefore, the calculated settings from relay coordination methods may have different miscoordination probabilities in the system.

Also, the miscoordination probabilities considering line outage (scenario 2) and dynamic change in network topology (scenario 3) are almost equal and less than those of the combination of scenarios 2 and 3 (scenario 4). So, considering two categories together have a significant impact on miscoordination probability.

To investigate the impact of the protection system on power system reliability, four indices are calculated by using TDS1 and TDS2 in each scenario. The results are shown in Table II.

Table II. Reliability indices for TDS1 and TDS2

		LOLP	LOLE	EFLC	EENS
Scenario1	TDS1	0.0046	40.197	3.108	3079
	TDS2	0.0046	40.197	3.108	3079
Scenario2	TDS1	0.0048	41.922	3.129	3194
	TDS2	0.0047	40.693	3.055	3104
Scenario3	TDS1	0.0048	41.895	3.162	3200
	TDS2	0.0047	41.015	3.103	3117
Scenario4	TDS1	0.0050	43.510	3.194	3321
	TDS2	0.0048	42.235	3.128	3230

Table II shows that the system reliability in scenarios 2 and 3 has degraded more than that of Scenario 1 in the two methods. The EENS for the first method (TDS1) for scenario 1 is 3079 MWh/year, while scenarios 2 and 3 are 3194MWH/year and 3200 MWh/year of energy not supplied in a year, respectively. Also, the number of interruptions (LOLP) in the first method (TMS1) is larger in scenarios 2 and 3 (0.0048) than in scenario 1 (0.0046). This means that the network topology change that causes protection miscoordination affects the power system reliability. The values of reliability indices in TDS1 for both scenarios 2 and 3 are almost the same. Therefore, two categories of topology changes in the network equally affect system reliability. Moreover, the reliability level of the power system in scenario 4 is reduced more than that of other scenarios in TDS1. The values in the first method of LOLP and EENS in Scenario 4 are around 8.5% and 4.2% higher than those in Scenario 1 and Scenario 2 or 3, respectively. Hence, the protection miscoordination due to both categories of topology change degrades power system reliability indices. Since the miscoordination probability obtained by using the first method (TDS1) is less than that of the second method (TDS2), the reliability indices calculated by using TDS1 are better than those of TDS2 in scenarios 2, 3, and 4. So, the calculated settings of various relay coordination methods have different miscoordination probabilities and reliability levels of the power system.
The number of simulation years is selected such that the results converge. Additionally, Figs. 9 shows the EENS index for all cases of TDS1.

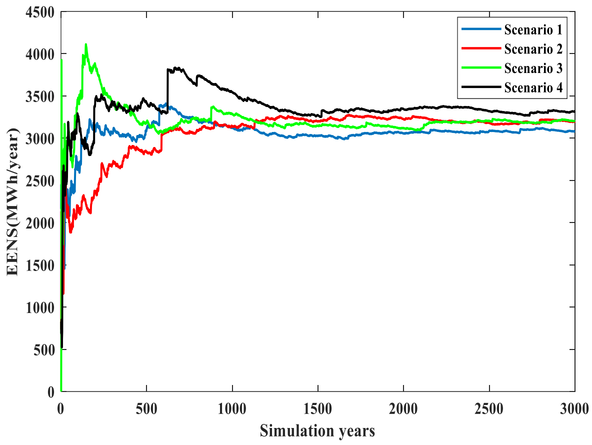

Fig. 10. EENS index for all scenarios of TDS1

It is clear from Fig. 9 that the results converge at 3000 years, so this value is selected for the simulations.
The probability of simultaneous failure of both protection devices is very low, so this state can be disregarded in the Markov model. In other words, the simultaneous failure rate of both protection systems in the Markov model has been considered zero and the reliability indices have been obtained. (eliminating states 2 to 5 in the Markov model). Table III compares the results obtained for the Markov model of Fig.3 (Case 1) and the Markov model without considering state 2 to state 5 (Case 2). The results are obtained for scenario 2 with TDS1.

Table III. Reliability indices of TDS1 for two Cases

Indices	Case 1	Case 2
LOLP	0.0046	0.0046
LOLE	40.197	40.185
EFLC	3.108	3.106
EENS	3079	3078

Table III shows the simultaneous failure of both protection systems in the Markov model is correct if this rate is considered negligible.
To evaluate the sensitivity of the reliability indices with respect to Coordination Time Interval (CTI) in the miscoordination probability model in Section 4, the two different values of CTI (0.2s and 0.3s) are considered. This analysis is performed for the first method (TDS1) and the reliability indices are shown in Table III.

Table IV. Reliability indices of TDS1 for various CTI

	Scenario2		Scenario3		Scenario4	
Indices	CTI=0.2	CTI=0.3	CTI=0.2	CTI=0.3	CTI=0.2	CTI=0.3
LOLP	0.0048	0.005	0.0048	0.005	0.005	0.0053
LOLE	41.92	43.89	41.89	43.54	43.51	46.66
EFLC	3.129	3.181	3.162	3.173	3.194	3.227
EENS	3194	3350	3200	3296	3321	3560

It can be seen from Table IV that the decrease of the CTI in the miscoordination probability model (Section 4) causes improvement in system reliability.

7. Conclusion

Protection failures and miscoordination significantly affect the reliability indices of power systems. Network topology change leads to protection miscoordination. Two reasons for topology change are line outage and dynamic topology change. In this paper, a 16-state Markov model was proposed to study miscoordination. Moreover, a new index was presented for the protection miscoordination. To evaluate the reliability of the power system, a sequential Monte Carlo simulation was performed to calculate the reliability indices. The simulation results were obtained for four scenarios, and the impact of each scenario on the power system reliability was explained. The sensitivity analysis of reliability indices under various relay coordination methods and different values of CTI is established. It can be concluded that the protection miscoordination due to the topology changes has a considerable effect on the reliability level of the power system. Also, the different relay coordination methods can affect power system reliability.

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