# Automated Review of Distance Relay Settings Adequacy After the Network Topology Changes

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***Abstract*—A challenge raised in today's power system is assessing the system protection security and dependability after the topology has been changed due to relay operation upon the occurrence of cascading faults or intentional operator switching action. This paper proposes an automated setting calculation module which could be used to review the adequacy of the distance relay settings following network topology changes. The calculation procedure is broken down into blocks which could be processed in parallel in order to improve the computation speed. A new concept called distance of impact is proposed to reduce the computational burden by conducting the calculations on a limited portion of the network affected by the topology change. The module performance is tested on a synthetic IEEE 118-bus and real-life Alberta transmission operator systems. A sensitivity analysis in the form of N-2 contingency impact on the network relay settings coordination is conducted on the test systems.**

***Index Terms*—Distance-of-impact (DoI), N-2 contingency, phase distance settings, power system protection security and dependability, relay ranking, topology control, vulnerability.**

## NOMENCLATURE

| | |
|---|---|
| Nbu | Number of buses in the network. |
| Nbr | Number of branches in the network. |
| $V_{\text{LL}}$ | Rated line-to-line voltage. |
| $I_{\text{rating}}$ | The line current rating. |
| $Z_{\text{relay}}^{30}$ | Relay reach in primary ohms at a power factor angle of 30 degrees. |
| $Z_1$ | Zone 1 phase reach in primary ohms. |
| $Z_2$ | Zone 2 phase reach in primary ohms. |
| $Z_3$ | Zone 3 phase reach in primary ohms. |
| $Z_2^l$ | Zone 2 phase reach based on line ohms only. |
| $Z_2^{\text{app}}$ | Zone 2 phase reach based on the remote bus fault apparent impedance. |
| $Z_3^l$ | Zone 3 phase reach based on line ohms only. |
| $Z_3^{\text{app}_{\text{bus}}}$ | Zone 3 phase reach based on apparent impedance of next adjacent bus faults. |
| $Z_3^{\text{app}_{\text{end}}}$ | Zone 3 phase reach based on apparent impedance of next adjacent line-end faults. |
| $z_l$ | Impedance of the line. |
| $z_{l_i}^{\text{adj}}$ | Impedance magnitude of the next adjacent line $i$. |
| $z_{p_i}^{\text{adj}}$ | Line ohms path magnitude to the next adjacent bus $i$. |
| $z_{\text{rem}}$ | Apparent impedance for three phase fault on remote bus. |
| $z_i^{\text{adj}}$ | Apparent impedance for three phase fault on next adjacent bus $i$. |
| $z_{\text{end}_i}^{\text{adj}}$ | Apparent impedance for three phase line-end fault on next adjacent line $i$. |
| $N^{\text{adj}}$ | Number of next adjacent buses. |
| $Z^{\text{col}}$ | Required updated column of $Z_{\text{bus}}$ corresponding to a line-end fault implementation. |
| $V_n^{\text{post}}$ | Post-fault voltage of bus $n$. |
| $V_n^{\text{pre}}$ | Pre-fault voltage of bus $n$. |
| $R_{i-j}$ | Distance relay looking from bus $i$ to bus $j$. |
| $Y_{\text{ij}}$ | The admittance of the line between buses $i$ and $j$. |
| $Y_{\text{sh}}$ | Shunt capacitance in pi model of the line. |

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## I. INTRODUCTION

OPERATIONAL schemes are being changed in today's restructured power systems. As an example, deploying the renewable distributed generation is changing the traditional way of operation [1]. Other examples include the transmission line switching mostly aimed towards reducing the system operational cost in real time [2]–[5] or the load shedding following a contingency [6]–[8]. Multiple switching actions may also be associated with cascading line tripping [9]–[11] as well as transmission line taken out of service due to maintenance purposes. As a result, setting coordination of the distance relays may be affected due to the change of the network short circuit values following a topology change [1]. The tool to review the adequacy of the protection coordination of the distance relays neither before the planned topology change, e.g. for corrective purposes, nor after the topology change, e.g. due to maintenance purposes, is available. Hence an assessment whether a change in relay settings is needed to maintain the security and dependability of the power system protection at such times is typically not performed.

There are several reported studies which investigated the transmission line relay operation under abnormal conditions especially power swings [12]–[17]. Several relay ranking schemes have been proposed to identify vulnerable relays in a network. Singh *et al.* [12] have ranked the relays based on Lyapunov stability criterion related to the power swing severity. Relay margin concept has been used in [13] to measure the closeness of a relay from issuing a trip signal. Reference [14] has proposed a new approach to locate all the electrical centers following an unstable swing and simplify the visual monitoring of all the R-X plots. For stable swings, the concepts of the branch norm, fault norm, and system norm are defined to rank the power swings, faults or contingencies, and detect an out-of-step condition respectively. Seethalekshami *et al.* [15] have used the branch loss sensitivity measure presented in [16] to propose a relay ranking index (RRI). This index is defined as the ratio of normalized apparent impedance seen by the relay to the corresponding branch loss sensitivity. The less the RRI value, the more the relay is probable to miss-operate under power swing and voltage instability conditions. The performance of various conventional power swing detection algorithms for the relays on the series compensated lines are compared in [17].

Overloaded lines, as a result of a line-tripping contingency, could also lead to relay miss-operation which is known as "load encroachment" into the relay operating characteristic. This happens when the load apparent impedance gets so small that it falls into the protection zone of a relay. Calculating the relay apparent impedance from a load flow analysis could be used to detect such a case [18], [19].

The above mentioned efforts have studied the miss-operation of distance relays under cases such as power swing, voltage instability, and load encroachment. The focus of this study is to investigate the adequacy of the network relay settings for a new (evolving) network topology and identify the consequent vulnerable relays at selected locations in the transmission system. The proposed automated approach for adequacy checking of distance relay settings is able to improve the transmission system operators (TSOs) actions by providing them with a decision making tool to assess the adequacy of distance settings for an evolving network topology, especially the long-term ones, so that a proper action can be taken either before or after the topology change as needed. For example, in the scenario that the operator is provided with a list of switching actions for corrective purposes, e.g. load shedding or cost reduction, he/she is able to assess the switching candidates in regards to their impact on the protection security and dependability when selecting the best option. If the topology has already changed due to maintenance purposes or cascading tripping as a consequence of relay mal-operation, the operator could assess the protection security and dependability for the current topology and take proper action. Previous study [20] proposed the general framework for the approach and briefly discussed the impacts of switching actions on distance relay settings coordination, which was tested on rather small-sized systems. The new contributions reported here relate to:

1) The concept of distance of impact (DoI), which is proposed and implemented with comprehensive simulations.
2) The results of parallelization using supercomputing facilities.
3) The results from the Alberta transmission operator system that demonstrate the effectiveness and robustness of the approach in realistic user setting.
4) Discussion of how the computational burden can be reduced for implementation on real sized systems.

The rest of the paper is organized as follows. Section II describes the creation of short circuit databases necessary for the phase distance setting calculations. The basic rules for calculating zones 1, 2 and 3 of a distance relay are discussed in this Section. The general procedure for the proposed setting calculation, as well as the distance-of-impact measure to asses relay setting adequacy are presented in Section III. Section IV illustrates simulation results along with sensitivity analysis. Concluding remarks and the main contributions are summarized in Section V.

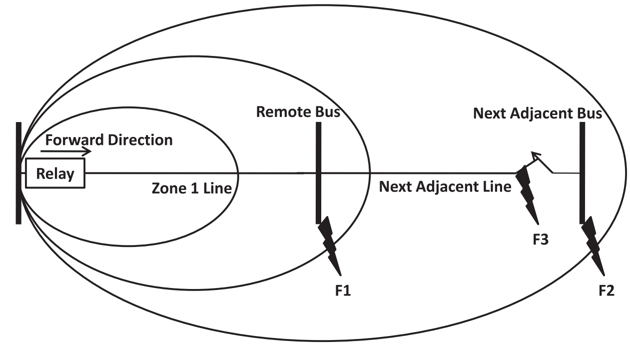



Fig. 1. Fault types used for phase distance setting calculation: remote bus fault (F1), next adjacent bus fault (F2), and line-end fault (F3).

## II. Phase Distance Setting Rules

Utilities, all over the world, follow different rules in setting calculation of the distance relays depending on their approach to operating the network. The setting procedure followed in this study is the same as the default procedure in CAPE [21]. A modern distance relay has several elements which provide many protection functions in a single package. In this study, the focus is on the phase distance elements and mho settings of different zones. There are two ways to calculate the zone settings: one is based on the line ohms only, which is not so practical, and the other, which is used here, is to consider both the line ohms and the apparent impedance of different fault types seen by the relay [22]–[23], Fig. 1.

To obtain the initial mho settings, in regards to the apparent impedances, three types of fault calculation, as shown in Fig. 1, are implemented: a) three-phase fault on remote bus, b) three-phase fault on the next adjacent bus, and c) three-phase line-end fault on the next adjacent line. The maximum torque angle (MTA) is considered the same as the zone 1 line angle, i.e., $\mathrm{MTA} = \angle Z_l$.

The apparent impedances are checked as follows to make sure they are valid during the setting procedure:

$$z_{\text{rem}} = \begin{cases} z_{\text{rem}} & |z_{\text{rem}}| \leq 10 \times |Z_l| \, \& \\ & |\angle z_{\text{rem}} - \mathrm{MTA}| \leq \frac{\pi}{4} \\ 0 & \text{otherwise} \end{cases} \quad (1)$$

$$z_i^{\text{adj}}\Big|_{i \in N^{\text{adj}}} = \begin{cases} z_i^{\text{adj}} & \left|z_i^{\text{adj}}\right| \leq 10 \times |Z_l| \, \& \\ & \left|\angle z_i^{\text{adj}} - \mathrm{MTA}\right| \leq \frac{\pi}{4} \\ 0 & \text{otherwise} \end{cases} \quad (2)$$

$$z_{\mathrm{end}_i}^{\mathrm{adj}}\Big|_{i\in N^{\mathrm{adj}}} = \begin{cases} z_{\mathrm{end}_i}^{\mathrm{adj}} & \left|z_{\mathrm{end}_i}^{\mathrm{adj}}\right| \le 10\times|Z_l| \,\& \\ & \left|\angle z_{\mathrm{end}_i}^{\mathrm{adj}} - \mathrm{MTA}\right| \le \frac{\pi}{4} \\ 0 & \text{otherwise} \end{cases} \tag{3}$$

The phase distance setting rules are as follow:

### A. Zone 1 Setting Rule

$$Z_1 = 0.8\times Z_l \tag{4}$$

### B. Zone 2 Setting Rule

$$Z_2^l = \max\left\{1.2\times|Z_l|\,,|Z_l| + 0.2\times\left|\min\left(z_{l_i}^{\mathrm{adj}}\right)\right|_{i\in N^{\mathrm{adj}}}\right\} \tag{5}$$

$$Z_2^{\mathrm{app}} = 1.2\times|z_{\mathrm{rem}}| \tag{6}$$

$$Z_2 = \max\left\{Z_2^l, Z_2^{\mathrm{app}}\right\}\angle\mathrm{MTA} \tag{7}$$

### C. Zone 3 Setting Rule

$$Z_3^l = 1.2\times\max\left(z_{p_i}^{\mathrm{adj}}\right)_{i\in N^{\mathrm{adj}}} \tag{8}$$

$$Z_3^{\mathrm{app_{bus}}} = 1.1\times\left|\max\left(z_i^{\mathrm{adj}}\right)\right|_{i\in N^{\mathrm{adj}}} \tag{9}$$

$$Z_3^{\mathrm{app_{end}}} = 1.1\times\left|\max\left(z_{\mathrm{end}_i}^{\mathrm{adj}}\right)\right|_{i\in N^{\mathrm{adj}}} \tag{10}$$

$$Z_3 = \max\left\{Z_3^l, Z_3^{\mathrm{app_{bus}}}, Z_3^{\mathrm{app_{end}}}\right\}\angle\mathrm{MTA} \tag{11}$$

Then, the load encroachment is evaluated for all zones to prevent phase protective relay settings from limiting the transmission system loading capacity while maintaining dependability of the network protection. According to NERC [24], the relay performance should be checked for 150% of the highest seasonal rating of the lines at 0.85 per unit voltage and a power factor angle of 30 degrees:

$$Z_{\mathrm{relay}}^{30} = \frac{0.85\times V_{\mathrm{LL}}}{\sqrt{3}\times 1.5\times I_{\mathrm{rating}}} \tag{12}$$

Furthermore, according to setting rules followed by CAPE [21], the zone settings are checked not to over-reach 20% of the transformer impedance in order not to interfere with the distance relay settings on the lines located after the transformer.

## III. Relay Setting Calculation and Adequacy Check

The proposed module contains algorithms which check the adequacy of the existing relay settings for the new system topology after switching. It performs fast relay setting calculation for the new topology and compares the new setting values with the current settings. Fig. 2 shows a general flowchart of the proposed setting calculation module.

The critical challenge for actual implementation of this methodology is that the setting coordination check of distance relays in a transmission operator (TOP) sized system is a significantly time consuming task and should be automated [21]–[23]. Identifying the relays whose settings get affected due to a change of the network short circuit values following a network topology change could be considered as an initial step in conducting automated settings coordination check. Performing the setting coordination check on the affected relays should also be fast enough. As a result, the focus of this study is also to make the setting calculation process faster by investigating how to reduce the problem size and calculation burden. This paper illustrates the methodology and demonstrates its effectiveness using a real-life network example.

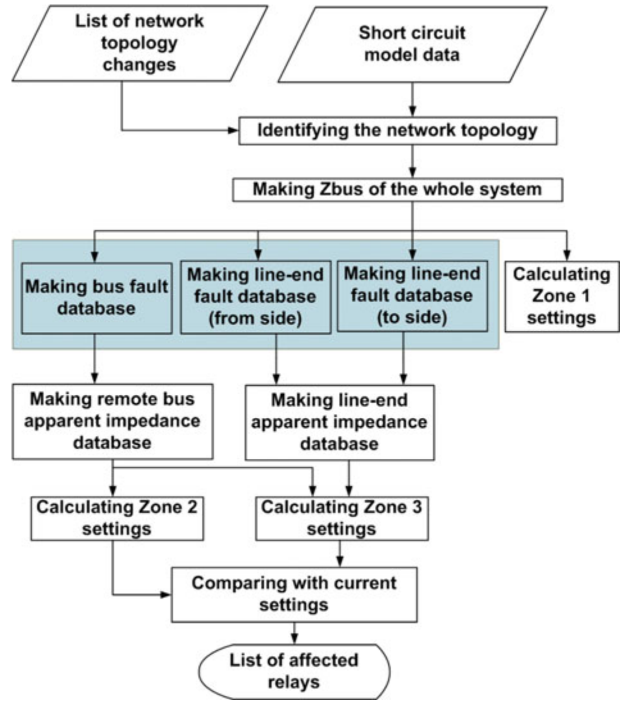



Fig. 2. General flowchart of the relay setting calculation module.

### A. Short-Circuit Model Data Preparation

The input for the relay setting calculation module is: 1) short-circuit model data for buses, branches, generators, 2) power flow data, and default relay settings and 3) list of network topology changes. Having recognized the network topology, the module builds up the $Z_{\mathrm{bus}}$ for the whole network which is used in fault calculations. Furthermore, a list of network distance relays and their adjacent buses and branches is obtained from the network topology. For each relay the buses and branches on which the bus fault and line-end fault should be implemented respectively to obtain the relay settings are determined. Having identified the required fault calculations for the setting procedure of each distance relay in a network, this method could be implemented on a system with different types of relays without causing an interference with setting calculation of the distance relays in that network. The module could be run for the identified distance relays in the network to assess their settings. Moreover, any exclusive condition such as the type of the relay used at specific points in the network or specific setting procedures (rules) followed by a network operator could be predefined in the module so the relays are set accordingly.

### *B. Fault Databases Preparation*

During the fault calculations several updates to $Z_{\text{bus}}$ are required depending on the fault type. This prevents repetitive and excessive $Z_{\text{bus}}$ calculation if not necessary. The sparsity oriented compensation methods are used to perform updates to $Z_{\text{bus}}$ [25]. $Z_{\text{bus}}$ should specifically be modified by updating the required column when implementing a line-end fault as assumedly another bus is added to the network. The process of calculating the voltages of all the buses for the case of a line-end fault implemented on the $j$ side of the line from bus $i$ to bus $j$, are formulated as follows using branch-oriented compensation method [25]:

$$U_{\text{Nbu}\times 1} = \left[0 \ldots \overset{i}{-Y_{\text{ij}}} \ldots 0\right]^{T} \tag{13}$$

$$V_{\text{Nbu}\times 2} = \begin{bmatrix} 0 \cdots & 0 & \overset{i}{1} & \overset{j}{0} \cdots \cdots \cdots & 0 \\ 0 \cdots \cdots \cdots & 0 & 1 & 0 \cdots & 0 \end{bmatrix}^{T} \tag{14}$$

$$\Delta = \begin{bmatrix} 0 & Y_{\text{ij}} \\ Y_{\text{ij}} & -(Y_{\text{ij}} + Y_{\text{sh}}) \end{bmatrix} \tag{15}$$

$$W = \left(I_{2\times 2} + \Delta \times V^{T} \times Z_{\text{bus}} \times V\right)^{-1} \times \Delta$$

$$X = Z_{\text{bus}} \times V \times W \times V^{T} \times Z_{\text{bus}}$$

$$Z = (Z_{\text{bus}} - X) \times U \tag{16}$$

$$Z^{\text{col}} = \frac{1}{Y_{\text{ij}} + Y_{\text{sh}} - U^{T} \times Z} \begin{bmatrix} Z \\ -1 \end{bmatrix}_{(\text{Nbu}+1)\times 1} \tag{17}$$

$$V_n^{\text{post}} = V_n^{\text{pre}} \left(1 - \frac{Z_{n1}^{\text{col}}}{Z_{(\text{Nbu}+1)1}^{\text{col}}}\right) \quad n \in \{1, \ldots, \text{Nbu}\} \tag{18}$$

### *C. Implementation of Parallel Computation*

The algorithm computation burden mostly relates to the creation of different fault type databases, as shown in the three blocks highlighted in Fig. 2. Specifically, line-end fault database preparation for two ends of the line is a very time consuming task. This is because the power system $Z_{\text{bus}}$ is a big order sparse matrix for which operations such as inversion and multiplication shown in (16)–(17), require more computation efforts from the processor. Each of the fault databases contains the bus voltage and branch current values for the corresponding type of fault. The voltage and current values are then used to calculate the associate apparent impedances. To improve the calculation speed, parallel computation could be performed on the three fault type calculation independently. Fig. 3 shows the general flowchart of implementing parallel computation for N tasks each of which might contain several sub-tasks. For the parallel computation to be implemented the tasks should be independent from each other, i.e., there should be no flow of data required between the tasks for each of them to be completed. In that case, all the tasks could be submitted to a group of workers (computing nodes) called pool of workers. Each worker might include several processing cores. The access to input data is provided for all the workers so they can use the same input data. However, the worker does not need any data obtained by other tasks.

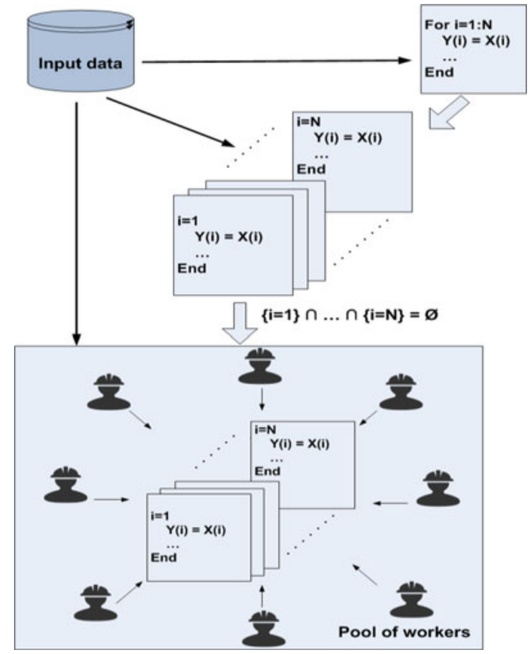



Fig. 3. General implementation of parallel computation for N tasks.

Now, as an example, let's discuss how the line-end fault database preparation could be parallelized. Considering to-end of the lines, the goal is to obtain the voltages of all the buses for the faults implemented on all the to-ends of the lines. In other words, (13) to (17) should be calculated for $i = 1 : \text{Nbr}$. As it could be understood from these equations, they could be conducted for branch $n$ completely independent from those of branch $m$. For each implemented fault, the voltage of all the buses could be calculated and stored separately. This allows implementation of the parallel computation. The same process could be implemented for the from-end of the lines and also for the remote bus fault calculations. The latter could be conducted much faster as no change to $Z_{\text{bus}}$ is required to implement it. For a fault implemented on bus $n$, $Z^{\text{col}}$ is simply the $n$th column of $Z_{\text{bus}}$ and there is no need to conduct (16)–(17). The network $Z_{\text{bus}}$ is the only common data fed into the three blocks. Having the voltages at both ends of the branches corresponding to each fault case together with their impedances, the branches currents could be easily calculated.

### *D. Distance-of-Impact (DoI) Concept*

For the algorithm to be practical for real-time applications in TOP-sized networks, the calculation burden and corresponding time should be reduced further. For this purpose, we have investigated the distance-of-impact (DoI) concept, which determines how far from the line that experiences a switching action we could expect the relay settings to be affected. This has been verified from conducting numerous simulations on both the 118-bus and Alberta transmission operator systems. In the case that the switching actions impact on the relay settings is limited to a certain electrical distance from the switching location, the calculations are then focused on the portion of the network within

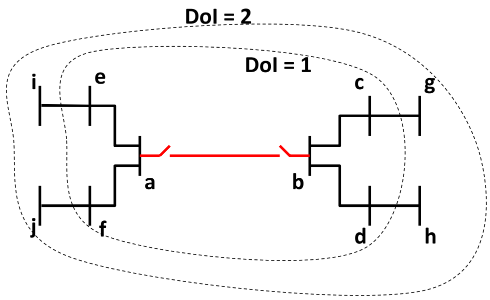



Fig. 4. Illustrating the concept of DoI.

that distance. Fig. 4 illustrates an example to clarify the DoI concept. For the switched transmission line a-b, the DoI of one includes the buses c to f with their corresponding branches and relays, and DoI of two includes those of the buses c to j.

The proposed module could be used in practice to assess multiple switching impacts on the network relay settings. The settings are calculated for the new system topology and compared with the previous ones to identify the affected relays. The module's output contains the list of the relays whose settings have changed beyond an acceptable margin. It provides the network operator with an extra decision making tool to deal with the impact of switching actions on the security and dependability of power system protection.

## IV. Simulation Results

The performance of the proposed module is tested on the synthetic IEEE 118-bus [26] and real-life Alberta transmission operator system [27]. The actual calculated relay setting values are verified by comparing them with the output of CAPE commercial package used in the project reports submitted to ARPA-E, U.S. Department of Energy [28]. The relays are assumed to be set only in the forward direction as shown in Fig. 1. The transmission lines do not have mutual coupling and transformer protection is neglected for the sake of simplicity. In general, the impact of mutual coupling is limited to the relays on the lines with such feature and could be modeled by proper changes to the network $Z_{\text{bus}}$ so it does not harm the effectiveness and generality of the proposed approach and it does not introduce a significant additional computational burden. The distance protection is not the best option for transformer protection and it is assumed that transformers are normally protected by differential relays.

### A. Sensitivity Analysis

In the first step of the simulations, a sensitivity analysis to investigate the impact on the network relay settings by N-2 contingencies with 2 lines switched out has been done using IEEE 118-bus test system. The N-2 contingencies are chosen to be studied because of two reasons: 1) the number of cases to be investigated and 2) they are practical switching scenarios in today's power systems. Conducting each case is significantly fast as the size of the system is rather small. All N-2 contingencies for which the power flow solution converges have been considered (13945 cases in total). A sensitivity analysis is used to detect and rank the probable system protection vulnerabilities following a network topology change leading to N-2 contingency.

Multiple results from the sensitivity analysis conducted on IEEE 118-bus system could be seen in Table I. The relays whose settings change for a greater number of N-2 contingencies are identified as vulnerable points in the network protection. A relay is considered being affected if its zone 2 or zone 3 experiences a change beyond 5% of the base network settings. Zone 1 is not a concern as it is only based on the line impedance. Top 10 vulnerable points (critical relays) in the network protection following N-2 contingency cases are ranked in Table I based on the number of N-2 contingency cases which affect them. The participation ratio for a relay means the ratio of the number of N-2 contingency cases which have affected the relay to the total number of contingency cases. Top 10 N-2 contingency cases according to their impacts on the network relay settings, and number of affected relays, are also shown in Table I. The lines participating in the majority of the N-2 contingency cases with significant impacts on the relay settings could also be identified from the sensitivity analysis. Table I shows top 10 of such critical lines.

In the second step of the simulations, the same sensitivity analysis was conducted for 1000 N-2 contingency cases on Alberta transmission operator system. The top 10 N-2 contingency cases with major impact on the relay settings are shown in Table II. The size of this system is rather big (2585 buses and 2970 branches) and the relay setting calculation process is time-consuming, specifically the process of creating and updating the line-end fault databases. The parallel computation and supercomputing facilities have been deployed to conduct the contingency cases as will be discussed in the next section.

### B. Role of Parallelization

Parallel computation technique is implemented to increase the calculation speed. For this purpose, Texas A&M University supercomputing facility [29] with the access to the maximum of 32 workers (nodes) of the facility to conduct the simulations has been employed.

The simulation time to run the setting module for each N-2 contingency case of 118-bus system is insignificant already (less than a second) when using only one processing node of supercomputing facilities even without employing parallel computation. Therefore, to show the effectiveness of the parallel computation technique in improving the calculation speed on IEEE 118-bus test system, it is deployed in conducting all the contingency cases (13945 cases) together when having access to different numbers of workers. On the other hand, running the setting calculation module for each contingency case of the real sized Alberta transmission operator system is significantly time consuming. The improvements from parallel computation could be seen when implemented on even one contingency case. For Alberta system, the setting module is run for the case ranked first in Table II having access to different numbers of workers. Fig. 5(a) and (b) show how parallel computation could significantly improve the module calculation speed based on the available numbers of workers for IEEE 118-bus system and Alberta

TABLE I
RESULTS OF SENSITIVITY ANALYSIS ON THE IEEE 118 BUS TEST SYSTEM

| | Critical Relays | | Critical N-2 Contingency Cases | | Critical Lines | |
|---|---|---|---|---|---|---|
| Rank | Relay | Participation Ratio (%) | Lines (from-to) | No. of Affected Relays | Lines (from-to) | Participation Ratio (%) |
| 1 | $R_{98-80}$ | 18.32 | 60–61 & 82–83 | 21 | 82–83 | 35.74 |
| 2 | $R_{57-56}$ | 16.9 | 60–61 & 82–96 | 18 | 94–100 | 27.58 |
| 3 | $R_{58-56}$ | 12.35 | 54–56 & 82–83 | 18 | 82–96 | 26.45 |
| 4 | $R_{16-17}$ | 10.24 | 49–51 & 82–83 | 18 | 60–61 | 23.13 |
| 5 | $R_{70-24}$ | 10.2 | 31–32 & 82–83 | 18 | 11–12 | 19.42 |
| 6 | $R_{62-60}$ | 10.13 | 15–19 & 82–83 | 18 | 31–32 | 19.34 |
| 7 | $R_{54-55}$ | 10.06 | 11–12 & 82–83 | 18 | 49–51 | 18.54 |
| 8 | $R_{105-106}$ | 9.98 | 82–83 & 100–106 | 17 | 54–56 | 18.25 |
| 9 | $R_{59-54}$ | 9.76 | 82–83 & 100–104 | 17 | 100–103 | 17.56 |
| 10 | $R_{17-15}$ | 9.72 | 60–61 & 94–100 | 17 | 100–104 | 17.52 |

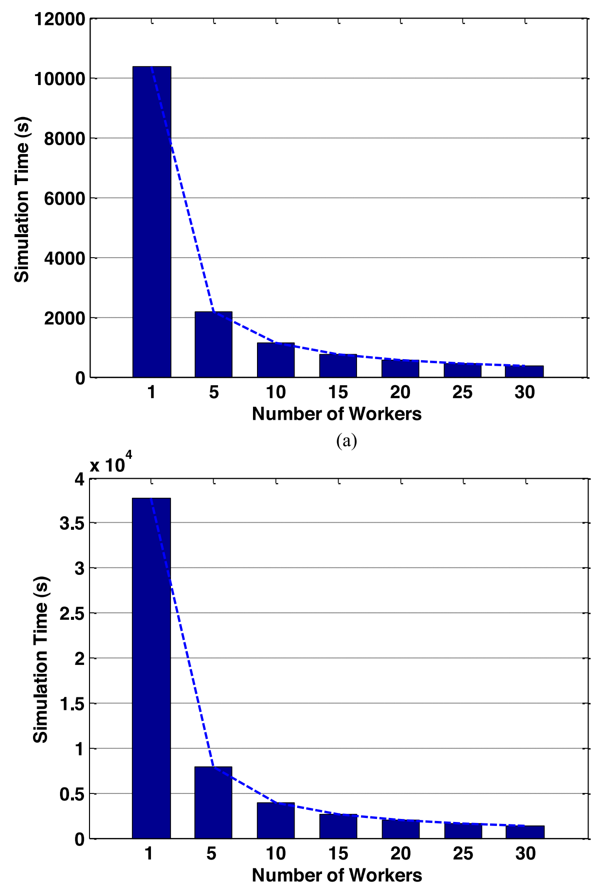
TABLE II
N-2 CONTINGENCY CASES AFFECTING MAJOR RELAY SETTINGS

| Rank | Lines (from-to) | No. of Affected Relays |
|---|---|---|
| 1 | 89–91 & 579–585 | 29 |
| 2 | 420–865 & 666–1691 | 29 |
| 3 | 420–865 & 1318–1344 | 25 |
| 4 | 207–590 & 666–1200 | 23 |
| 5 | 208–581 & 242–253 | 23 |
| 6 | 35–331 & 167–737 | 22 |
| 7 | 297–483 & 669–677 | 22 |
| 8 | 35–331 & 666–1670 | 22 |
| 9 | 152–988 & 1431–1484 | 22 |
| 10 | 63–821 & 136–514 | 21 |

system respectively. In Fig. 5, one worker represents running the module without parallelization. These results provide a perspective how parallel computation benefits escalate especially when the module is conducted on a TOP-sized network. While the cost of supercomputing facility may be prohibitive for the control room setting today, the simulation time could be improved to a desired level just using the ordinary high-end control room computers. With the pace of the technology development, the use of the supercomputers in the control room may be feasible in the near future.

### C. Role of Distance-of-Impact

Another focus of the sensitivity analysis was to search for the DoI of the switching actions. For this purpose, a search space of the branches starting from the ones adjacent to both ends of the line participating in the switching action is created. The search space grows based on the network connectivity graph till it covers all the affected relays on the network branches. For IEEE 118-bus test system, it was observed that the impact of N-2 contingency cases is limited to the relays on the branches within DoI $= 3$ of the switching action as it could be seen for the top 10 cases in Table III. Fig. 6 shows one-line diagram of IEEE 118-bus test system for which the switching actions 60–61 and 82–83, the contingency case ranked first in Table I, are highlighted in red. The neighboring branches up to DoI of three are highlighted in blue and as it could be seen the affected relays, which are shown by red arrows, are within the DoI. By the use of




(a)

(b)

Fig. 5. Simulation time based on the number of workers; (a) Running the module for all the N-2 contingency cases together in IEEE 118-bus system; (b) Running the module for the contingency case ranked 1st in Table II for Alberta system.

TABLE III
DISTANCE OF IMPACT FOR TOP 10 CASES IN BOTH SYSTEMS

| | Rank | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 |
|---|---|---|---|---|---|---|---|---|---|---|---|
| DoI | IEEE 118-bus system | 3 | 2 | 3 | 3 | 3 | 3 | 3 | 2 | 2 | 2 |
| | Alberta TOP system | 5 | 5 | 5 | 3 | 4 | 5 | 5 | 5 | 4 | 4 |

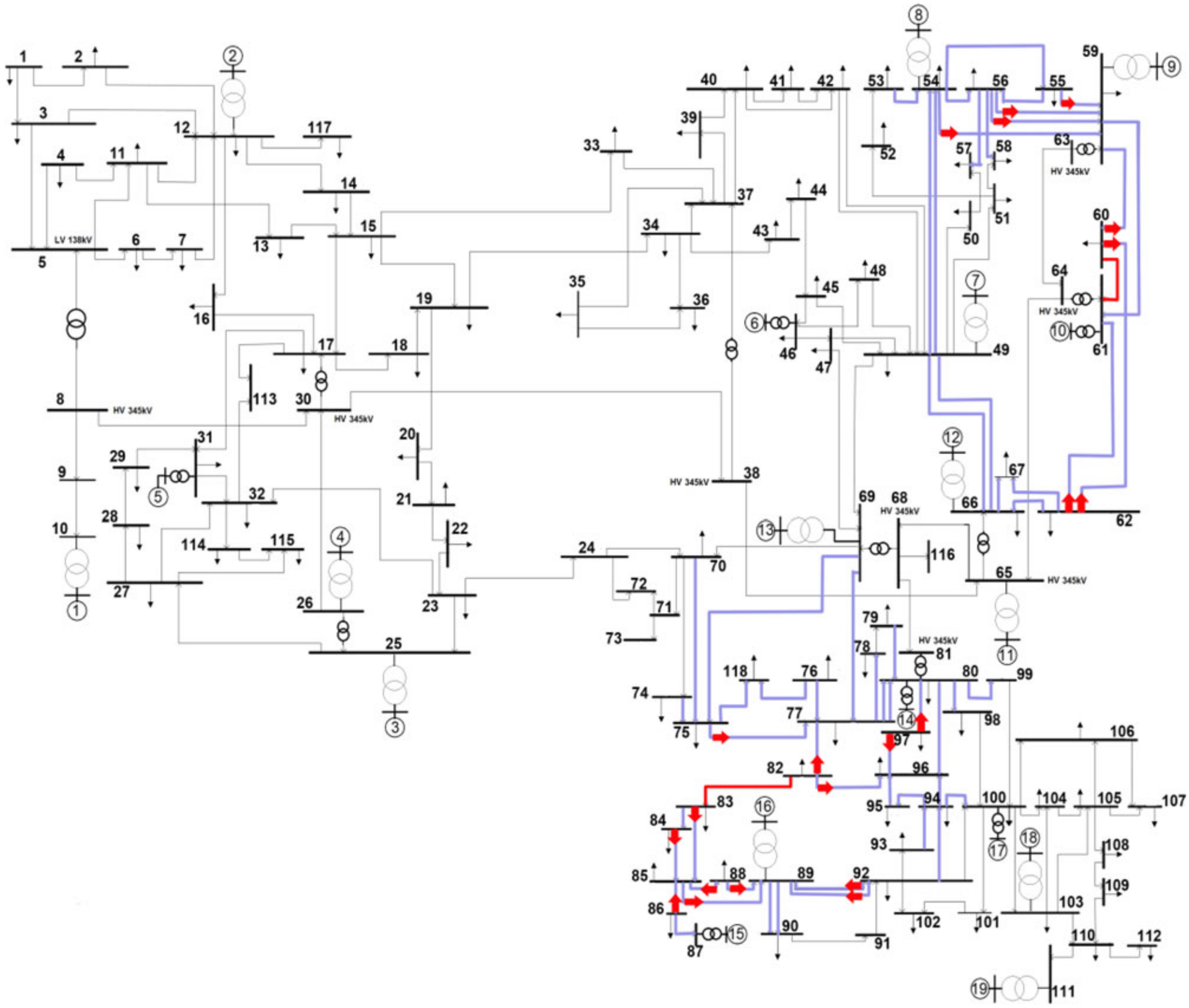



Fig. 6. One-line diagram of IEEE 118-bus test system.

DoI concept, the relays for which the short circuit values should be updated are the ones within the DoI of the switching action leading to a significant reduction in computational burden.

The sensitivity analysis for the contingency cases in Alberta transmission operator system points the maximum of DoI to be 5 as shown in Table III for the previously obtained top 10 contingency cases. The number of buses and branches within $\mathrm{DoI} = 3$ and $\mathrm{DoI} = 5$ for the top 10 cases in IEEE 118-bus and Alberta transmission operator systems respectively are shown in Table IV. The number of relays which settings are to be checked is two times the number of branches in DoI. As mentioned before, creating and updating the line-end fault database is the most time consuming part of the setting calculation process. Following the network topology change, the line-end fault values for the relays within DoI should be updated. Fig. 7(a) and (b) shows the simulation time for the cases ranked first in Tables I and II respectively based on different number of implemented line-end faults to obtain the updated values. Different numbers of line-end faults are obtained based on the number of relays within the DoI as it increases from the switching action location.

TABLE IV
PORTION OF THE NETWORK WITHIN DOI FOR BOTH SYSTEMS

| | IEEE 118-bus (DoI = 3) | | Alberta (DoI = 5) | |
|---|---|---|---|---|
| Rank | No. of Buses | No. of Branches | No. of Buses | No. of Branches |
| 1 | 56 | 113 | 239 | 420 |
| 2 | 60 | 120 | 310 | 569 |
| 3 | 65 | 122 | 242 | 467 |
| 4 | 73 | 133 | 303 | 542 |
| 5 | 64 | 131 | 168 | 325 |
| 6 | 72 | 142 | 236 | 447 |
| 7 | 59 | 120 | 198 | 348 |
| 8 | 50 | 94 | 176 | 305 |
| 9 | 50 | 94 | 364 | 660 |
| 10 | 59 | 114 | 229 | 407 |

These simulations are conducted while deploying 1 worker for IEEE 118-bus system and 30 workers for Alberta system.

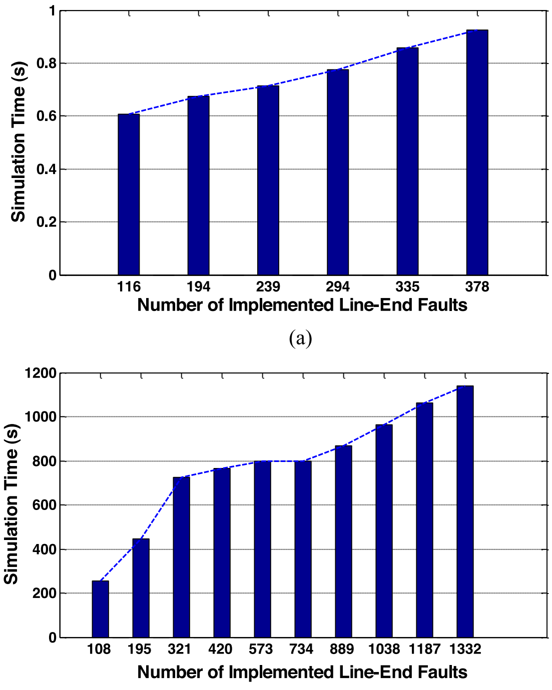



Fig. 7. Simulation time based on the required number of line-end faults; (a) Case ranked 1st in Table I in IEEE 118-bus system; (b) Case ranked 1st in Table I in Alberta transmission operator system.

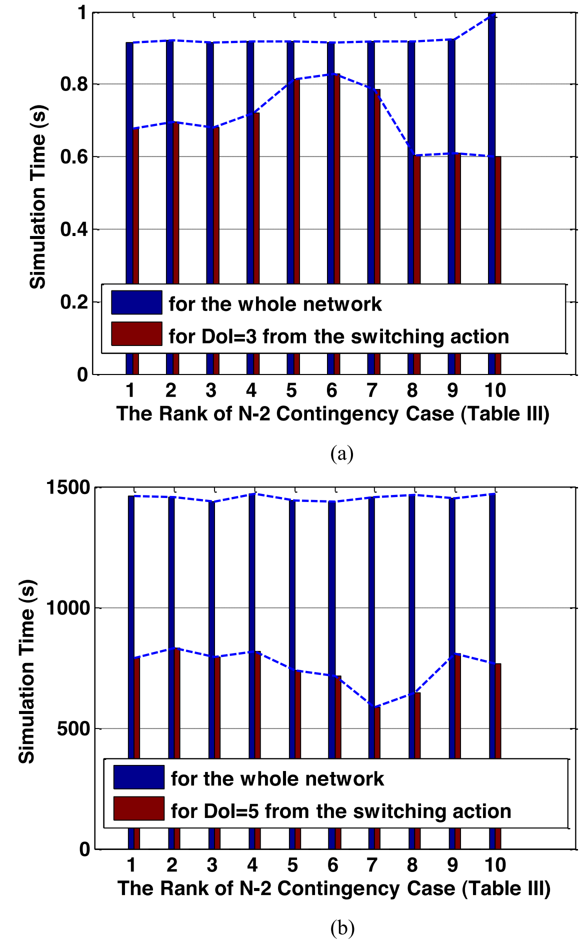



Fig. 8. Simulation time comparison between with and without implementing DoI; (a) Top 10 cases of IEEE 118-bus system; (b) Top 10 cases of Alberta transmission operator system.

As it could be seen from Fig. 7, simulation time could be significantly reduced depending on the required number of line-end fault simulations especially in a real sized system.

Considering the DoI, the calculations could be done exclusively for the relays in the portion of the network within the distance. This leads to significant time savings in simulations as shown in Fig. 8(a) and (b). The calculation time for 10 cases of Tables I and II could be compared respectively between 2 scenarios: 1) running the setting calculation module for the whole system and 2) doing it for the portion of the system within $\text{DoI} = 3$ for 118-bus system and $\text{DoI} = 5$ for Alberta transmission operator system. The parallel computation has been deployed in both scenarios for Alberta system. In the first scenario, the simulation time for all cases is almost the same while in the second scenario it changes based on the network connectivity graph. As it could be seen from Fig. 8, the calculation time has been reduced significantly and real-time identification of vulnerable relays following a network topology change becomes more practical.

## V. Conclusion

The contributions of this work are:

1) The proposed algorithm allows a novel way of setting calculation and evaluation under changing network topology.
2) The proposed parallel computation technique significantly reduces the computation time and makes the approach applicable for real-time analysis.
3) The proposed calculation module follows the same relay setting procedure as CAPE commercial package and is tested and verified on real-sized Alberta transmission operator systems.
4) The proposed distance of impact (DoI) metric is realized to handle numerous cases of network topology changes in the form of N-2 contingencies, which significantly reduces the computation burden.

The proposed decision making tool can allow the utility staff to assess the impact of multiple switching actions and network topology changes on network protection security and dependability leading to a proper setting coordination action.

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