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RESEARCH ARTICLE

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Search space reduction–based new approach for transmission branch outage identification using minimum PMU

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Summary

This study presents a search space reduction–based new approach for branch outage identification in the transmission network employing the minimum number of phasor measurement units (PMUs). Two innovative logical terms, namely normalized generator bus current variation (NGBCV) and branch power distribution factor (BPDF), are introduced. The search space is reduced by selecting a single generator bus named as critical generator bus (CGB) based on proposed NGBCV. Thereafter, a single branch named as critical transmission branch (CTB) connected to the CGB is chosen. The identification of branch outage is performed by comparing the calculated power flow through the CTB using BPDF, and PMU provided monitored power flow through CTB. Moreover, the measurement error is also incorporated in mathematical modeling in order to make the developed model practically viable. Furthermore, the capability of the proposed model to identify parallel branches (PBs) is also tested. Extensive case studies on IEEE 6-bus, 14-bus, 57-bus, and 118-bus networks are conducted through simulation on the MATLAB environment. The identification rate and implementation cost of the

List of Symbols and Abbreviations: ACMEL, AC model excluding losses; ACMIL, AC model including losses; ACPF, AC power flow; BOI, branch outage identification; BPDF, branch power distribution factor; BWCS, blockwise compressive sensing; CEO, cross entropy optimization; CGB, critical generator bus; CTB, critical transmission branch; DBO, double branch outage; DCM, DC model; DCPF, DC power flow; EDA, estimation of distribution algorithm; ETR, expected tripped region; FDLF, fast decoupled load flow; GIM, gain in momentum; IRENCC, identification rate including nonconverging cases; IRINCC, identification rate including nonconverging cases; LASSO, least square absolute shrinkage and selection operator; MBOI, multiple branch outage identification (MBOI); MLR, multinomial logistic regression; MVOF, minimum value of the objective function; NGBCV, normalized generator bus current variation; OS, outage scenario; PBs, parallel branches; PMU, phasor measurement unit; PSSA, power system situational awareness; SBO, single branch outage; SCADA, supervisory control and data acquisition; SG, smart grid; SVM, support vector machine; VOF, value of the objective function; $\mathcal{N}$, set representing the all buses; $\mathcal{B}$, set representing all branches; B, total number of branches; N, total number of nodes or buses; $I_{N,\text{nor}}$, current at Nth bus during normal condition; $I_{N,k}$, current at Nth bus during kth outage scenario; I_k, bus current vector considering kth outage scenario; $\mathcal{N}_{\text{gen}}$, set representing all generator buses; N_{gen}, number of generator buses; NGBCV(i,k), normalized generator bus current variation at ith bus considering kth outage scenario; BPDF(b,k), branch power distribution factor for bth branch considering kth outage scenario; $P_{b,k}$, power flow through bth branch during kth outage scenario; $P_{b,\text{nor}}$, power flow through bth branch during normal condition; ΔP_b, change in power flow through bth branch; $P_{\text{CTB,cal}(k)}$, calculated power flow through CTB considering kth outage scenario; $P_{\text{CTB,mon}}$, monitored power through CTB; ρ, measurement error; N_{correct}, number of correctly identified scenarios; $N_{\text{attempt,exc\_NCC}}$, total attempts made excluding non-converging cases; $\overline{V_p}, \overline{V_q}$, complex voltage phasor of pth and qth bus, respectively; Z_{b_1}, Z_{b_2}, impedance of the parallel branches b_1 and b_2, respectively; $\overline{I_{b_1,\text{nor}}}, \overline{I_{b_2,\text{nor}}}$, complex current flowing through parallel branches b_1 and b_2 respectively during normal condition; BPDF(b,b_1), BPDF(b,b_2), branch power distribution factor of bth branch considering outage of branch b_1 and b_2 respectively; VOF(k), value of the objective function for kth outage scenario.

proposed method are also compared with several existing methods to confirm the applicability and effectiveness of the developed algorithm.

KEYWORDS

branch outage identification, identification rate, load flow, measurement error, outage scenarios

1 | INTRODUCTION

The gradual increase in electricity demand and expansion of power grid network combinedly poses a great challenge to the power system operators and planners for maintaining the reliability and security of modern smart grid (SG). Over the years, researchers have made significant efforts to transform the conventional grid into SG, which has several attracting features like resiliency, reliability, sustainability, etc. Therefore, new emerging and promising technologies are adopted by the researchers to achieve the objective of SG network. One of such cutting edge technology is phasor measurement unit (PMU), which provides real-time synchronized measurements of voltage and current phasors.[1] It has been observed that past few blackouts such as North American Blackout [2] and Indian Blackout[3] happened due to the lack of situational awareness and the deficiency of the system monitoring. In this context, the real-time monitoring the status of generators, transmission branches, and transformers is urgently needed to improve the power system situational awareness (PSSA). The branch outage identification (BOI) is an important aspect to improve PSSA.

Several studies highlighted the issue of BOI topic in transmission network, and different schemes have been proposed in the literature.[4-23] Tate and Overbye presented a method using phasor angle measurements to identify single branch outage (SBO)[4] and double branch outages (DBO).[5] The BOI problem is solved using least square absolute shrinkage and selection operator (LASSO),[6] cross entropy optimization (CEO),[7] considering multiple contingencies. Wu et al[8] address two issues, that is, limited number of PMUs and high complexity by proposing an efficient algorithm based on the ambiguity group theory. Multiple branch outage identification (MBOI) is addressed using estimation of distribution algorithm (EDA),[9] and premature convergence is avoided via an efficient thresholding routine. The performance of the EDA-based algorithm is compared with other population-based techniques. The transient state of power system is taken into account while developing the BOI models in References 10 and 11. The distinctive signatures resulting from various branch outages are classified through multinomial logistic regression (MLR).[12] Utilizing the 24 hours load profile, the MLR-based approach[12] is implemented on different IEEE benchmark systems. A sparse sensing-based model is reported in Reference 13 where the PMUs are placed at the subset of total buses. In Reference 13, the binary integer programming tool is adopted for placing the PMUs while formulating the BOI model. A block-wise compressive sensing (BWCS)-based method is presented in Reference 14, which shows the better accuracy compared to traditional compressive sensing (CS)-based method.[15] The authors presented a graph-based model utilizing the variation of the correlation matrix.[16] The assessment of transient stability[17] is carried out by identifying the branch outage via normalized kinetic energy of the generators. Jena et al[18] detected the tripped line by identifying the expected tripped region (ETR) through maximum gain in momentum (GIM) of the generator, but the methodology is tested only for single contingency. Authors adopted support vector machine (SVM)-based approach[19] to classify the different single contingencies with various loading conditions. Arabali et al[20] developed three different models, that is, DC model (DCM), AC model excluding loss (ACMEL), and AC model including loss (ACMIL) for identifying multiple branch outages (MBO). It is observed that ACMIL has shown better performance compared to other methods, that is, DCM and ACEL. The machine learning–based Hidden Markov Model is applied in Reference 21 for dynamic detection of branch outage. The authors developed a DC model–based approach considering bad data to address the MBOI issue. Li et al[22] presented a methodology and discussed the results considering the presence as well as the absence of bad data. Recently, a new AC model is developed employing the sensitivity theory[23] in order to solve MBOI problem. The MBOI issue resolved by adopting sequential uncovering[23] of SBO, and the PMUs are installed optimally. The various uncertainties of PMU are extensively highlighted in Reference 24, and the effect of uncertainty is quantified through multi-hypothesis testing. The authors suggested machine learning framework for locating line outages in Reference 25 using the phasor angle data of PMU. Three different machine learning techniques such as random forest (RF), logistic regression (LR), and graphical convolutional network (GCN) are considered for classification of line outages in Reference 25, and the performance is also tested under different level of noise and missingness. Nie et al,[26] proposed multiple line outage detection algorithm using the concept of adaptive observer. The transient dynamics of the power network along with load perturbations are considered in Reference 26. Very recently, a modified sparse signal recovery algorithm is presented in Reference 27 for improving the detection accuracy. The authors also proposed an accumulation-based mechanism to reduce the noise interference in Reference 27. Further, the computation burden is also reduced by introducing an event trigger mechanism in Reference 27. The authors proposed a new "Learning to infer" method[28] for finding the line status, and the training data were generated rapidly with minimum cost. Line failure detection considering cyber physical attack is reported in Reference 29 where two types of attack models are considered. One model considers the disconnection of line in attack area, and another model blocks the measurements coming from attack area to control center.[29] A linearized incremental small signal model is developed in Reference 30 utilizing the phasor angle of PMU. The authors in Reference 30 identify the outage by exploiting the quickest change detection (QCD) theory and statistical property of phasor angle. Recently, the rank correlation coefficient is utilized to develop a new model in Reference 31 to identify the outage. A brief review on different cascading failure is presented in Reference 32 where the several features related to cascading failure and comparison between different models are highlighted. The authors used the current phasors in Reference 33 for identification of outage using L-2 norm minimization technique. The anomaly in the power grid is detected by collecting the measurements sequentially and update the decision gradually about anomaly location.[34] The process of updating is continued until anomaly location is identified with reasonable reliability. The effect of line failure in power grid is analyzed in Reference 35 considering AC and DC model. The metric "yield"[35] (ratio of demand supplied at the end of cascade to the ratio of initial demand) is used to evaluate the effect of line failure. The authors in Reference 36 present a new cyber physical attack strategy for masking the line outage, and the presented method is found to mislead the control center effectively.

Through a comprehensive literature survey, it has been investigated that existing articles have the following limitations:

- Most of the available articles[4-7,9,13-16,19,21,22] rely on the DC power flow (DCPF) model due to which the exact behavior of power network is not reflected.
- The DCPF model based approaches utilize the voltage phasor of the PMU, while both the measurements, that is, voltage phasors and current phasors are available at the observable buses. Therefore, the PMU data are partially exploited.
- The voltage phasor based models face a serious challenge while identifying the outage of parallel branches (PBs) due to ambiguity problem. Hence, the PBs are not identified in References 4-23, and the PBs are modeled as single branch in References 4-7,12, and 22. Therefore, the identification of PBs outage needs to the addressed.
- The authors implicitly assume the requirement of the PMUs at all buses mentioned in References 6,7, and 22. On the contrary, it is not possible to install the PMUs at all buses due to financial restriction. However, considering economic viability, the reduction of the required number of PMUs is mandatory.
- Most of the published articles have not considered the measurement error while formulating the BOI model.

In light of the aforementioned limitations, a new cost-competitive BOI algorithm is developed in this article. The major technical contributions of this study are mentioned below,

- The proposed model is based on the AC power flow (ACPF) model which will overcome the limitation of the DCPF-based models
- Two new innovative indices, namely NGBCV and BPDF, are introduced in this study. The NGBCV is used to select a single bus among the generator buses, and this assists to reduce the search space. Further, BPDF used to calculate the power through the branch due to various contingency scenarios.
- The developed objective function is completely new from that available in literature.
- The proposed objective function considers the measurement noises as well as errors due to the malfunctioning of PMU.
- The modelling of PBs outage is developed and the capability to identify the PBs is also verified.
- To make the proposed model cost-effective, a new approach of PMU installation is suggested in this study that will make the algorithm economically viable. The cost competitiveness of the suggested model is also analyzed in terms of PMU requirements.

The rest of the article is structured as follows. In section 2, the proposed BOI framework is developed by suggesting two new indices. The implementation procedure of the proposed scheme is described in section 3. Section 4 illustrates the case studies and numerical results of various IEEE test systems. The extensive analysis on the test results covering various aspects is highlighted in section 5. Finally, the concluding remarks are drawn in last section.

2 | PROPOSED BOI FRAMEWORK

The suggested method is fundamentally based on the following factors:

- Bus current variation
- Branch power variation

To develop the BOI framework, the following assumptions are considered:

- The postevent network reaches quasi-steady-state[4-7,20,22] operating condition so that the transient oscillations are damped out.
- The branch outage will not lead to the islanding or unstable[4-7,20] operation of the network. It is assumed that the power flow solution of the post event network will be available. Otherwise, the postoutage parameters will not be available to the system operators. The unstable and islanded operation is beyond the scope of this study as mentioned in References 4-7, and 20.

2.1 | Proposed index related to bus current variation

To formulate the mathematical model, we consider a transmission system with total N buses and total B number of transmission branches. Therefore, set of all buses ($\mathcal{N}$) and set of all branches ($\mathcal{B}$) can be written by,

$$\mathcal{N} = \{1, 2, \ldots N\}; \mathcal{B} = \{1, 2, \ldots B\} \tag{1}$$

It is worth noting that line outage causes the alteration of currents flow through each lines. On the other hand, the bus current is the algebraic summation of currents through the lines connected to the corresponding bus. In view of this, it is inferred that the current at each buses will be different for different outage scenarios (OSs). Therefore, different OSs will yield different variation of bus current with reference to bus current during normal condition. Moreover, the bus current at any particular bus during normal condition will be different from the bus current considering various OSs. In view of this, we can write for the bus-N current

$$I_{N,\text{nor}} \neq I_{N,1} \neq I_{N,2} \ldots \neq I_{N,n} \tag{2}$$

where, $I_{N,\text{nor}}$ represents the bus-N current during normal condition. Similarly, $I_{N,1}, I_{N,2}$, and $I_{N,n}$ represent the bus-N current during outage scenario (OS)-1, OS-2, and OS-n, respectively. Here, n denotes the total number of feasible OSs.

Now, the bus current considering kth OS can be written as,

$$I_k = [I_{1,k}, I_{2,k}, \ldots, I_{N,k}]^T \tag{3}$$

where, $I_{1,k}, I_{2,k}$, and $I_{N,k}$ represent the bus-1 current, bus-2 current, and bus-N current, respectively, considering kth OS. Here, we express the OS $k = 1, 2, \ldots, n$. In this study, we only focus on the current variation of the generator buses. Therefore, considering the generator buses only, we propose a new index namely normalized generator bus current variation (NGBCV), which indicates the variation of bus current for different OSs. The NGBCV for ith bus considering kth OS is defined by,

$$\text{NGBCV}(i,k) = \left|\frac{I_{i,k} - I_{i,\text{nor}}}{I_{i,\text{nor}}}\right|; i \in \mathcal{N}_{\text{gen}} \tag{4}$$

where, $I_{i,k}$ and $I_{i,\text{nor}}$ denote the current at ith bus during kth OS and during normal condition, respectively. The set of generator buses is represented by $\mathcal{N}_{\text{gen}}$. This index will help to monitor the variation of the current at generator buses. Among these generator buses, single bus will be selected to reduce the search area. This strategy reduces the computational burden of the proposed algorithm significantly.

It is worth noting that NGBCV for various OSs will be different. Moreover, for a specific OS, the NGBCV associated with any of the generator buses will have highest value. In view of this, the generator bus with highest NGBCV is chosen in this study. The chosen bus is named as critical generator bus (CGB), which is used to reduce the search space.

2.2 | Proposed index related to branch power variation

It is worth noting that the different OSs are associated with different bus voltage and branch current signatures. Therefore, for each OSs, the power flow through each branches of the network is altered. In other word, the power flow through entire network is redistributed following branch outage. In view of this, we propose a new term, that is, branch power distribution factor (BPDF), which is expressed by,

$$\text{BPDF}(b,k) = \frac{\Delta P_b}{P_{b,\text{nor}}} \tag{5}$$

where, the BPDF for bth branch considering kth OS is denoted by $\text{BPDF}(b,k)$. The change in power flow through bth branch is represented by ΔP_b. The power flow through bth branch during normal condition is denoted by $P_{b,\text{nor}}$. The value of b will be from $1,2,\ldots,B$; B is the total number of branches. Therefore, the dimension of BPDF for each OS will be $B \times 1$ and the dimension of BPDF matrix will be $B \times n$.

Now, the change in power flow through bth branch can be written as,

$$\Delta P_b = P_{b,k} - P_{b,\text{nor}} \tag{6}$$

where $P_{b,k}$ and $P_{b,\text{nor}}$ represent the power flow through bth branch during kth OS and normal condition, respectively.

It is worth noting that the BPDF can be utilized to find the power flow through the branches for several OSs. However, the power flow through the branches during normal condition can be found from supervisory control and data acquisition (SCADA) system. Therefore, the procedure of finding the branch power for several OSs is demonstrated by IEEE 6-bus network, which constitutes 11 lines. The power through branch-1 during kth OS can be expressed as,

$$P_{1,k} = \text{BPDF}(1,k)P_{b,\text{nor}} + P_{b,\text{nor}} \tag{7}$$

Similarly, the power through branch-2 during kth OS can be written as,

$$P_{2,k} = \text{BPDF}(2,k)P_{b,\text{nor}} + P_{b,\text{nor}} \tag{8}$$

In general, the power through branch-b during kth OS can be written as,

$$P_{b,k} = \text{BPDF}(b,k)P_{b,\text{nor}} + P_{b,\text{nor}}; b = 1,2,\ldots,B \tag{9}$$

2.3 | Proposed approach of PMU installation

The existing schemes reported in Reference 6,7, and 22 consider the full observability of the network by installing the PMUs at all buses. Considering the investment cost, the installation of PMUs at all buses is not acceptable in today's cost competitive market. Therefore, a suitable strategy of PMU installation is required, which incur the low investment cost. For execution of the developed model, it is sufficient to observe the generator buses only. Therefore, we suggest to install PMUs at only generator buses. It is interesting to note that the suggested model is capable to provide competitive performance with the observable generator buses.

2.4 | Formulation of objective function

As mentioned earlier, the PMUs are installed at generator buses. Therefore, the power flow through the branches connected to the generator buses are available through PMU measurements. Based on the maximum value of NGBCV, the CGB is selected. Thereafter, any branch connected with the CGB is selected, and this selected branch is termed as critical transmission branch (CTB). As soon as CGB and CTB are identified, the power flow through CTB is to be monitored using PMU. Let, $P_{\mathrm{CTB,mon}}$ represents the monitored power through CTB. We aim to compare the postoutage monitored power flow through CTB and calculated power flow through CTB using BPDF. Now, the power flow through CTB can be computed with the help of BPDF and base case power flow. In view of this, the calculated power flow through CTB considering kth OS can be written as,

$$P_{\mathrm{CTB,cal}(k)} = \mathrm{BPDF}(\mathrm{CTB},k)P_{\mathrm{CTB,nor}} + P_{\mathrm{CTB,nor}} \tag{10}$$

where, $P_{\mathrm{CTB,nor}}$ represents the power flow through CTB during normal condition, and $\mathrm{BPDF}(\mathrm{CTB},k)$ represents the BPDF of the CTB considering kth OS. In a general way, the difference between the monitored power flow and calculated power flow through CTB during kth OS can be expressed by,

$$\mathrm{P}_{\mathrm{CTB,mon}} - \mathrm{P}_{\mathrm{CTB,cal(k)}} = P_{\mathrm{CTB,mon}} - \left(\mathrm{BPDF}(\mathrm{CTB},k)P_{\mathrm{CTB,nor}} + P_{\mathrm{CTB,nor}}\right) \tag{11}$$

It is worth mentioning that the monitored power through CTB will be approximately matching with the calculated power through CTB for a particular OS. In order to find that particular OS, comparison of monitored power and calculated power through CTB is to be carried out for all possible OSs. In view of this, the value of the objective function (VOF) to identify the kth OS is defined as,

$$\mathrm{VOF}(k) = \left|P_{\mathrm{CTB,mon}} - P_{\mathrm{CTB,cal}(k)}\right| \tag{12}$$

It is to be noted that the criteria mentioned (12) is applicable only for ideal situation, that is, when the PMUs are free from any error, which is not feasible in a practical power system.

Further, the measurements are also subjected to noise. In this study, Gaussian noise is added to the measurements as per the IEEE standard C.37.118-118.[37] Additionally, the PMU error arises due to several reasons like communication error, calibration error, malfunctioning of the associated devices, etc. In this article, we assume the Gaussian distribution of error. The assumption of Gaussian distribution is reasonable according to the central limit theorem.[24]

Therefore, considering the error, the VOF can be expressed by,

$$\mathrm{VOF}(k) = \left|P_{\mathrm{CTB,mon}} - P_{\mathrm{CTB,cal}(k)}\right| + \rho \tag{13}$$

where, ρ denotes the measurement error, which follows the Gaussian distribution. Now, the minimum value of the objective function (MVOF) is related to the actual outage which is written as

$$\mathrm{MVOF} = \min\left(\left|P_{\mathrm{CTB,mon}} - P_{\mathrm{CTB,cal}(k)}\right| + \rho\right) \tag{14}$$

Finally, the actual OS can be identified through the index related to MVOF which can be expressed as

$$k = \mathrm{index}(\mathrm{MVOF}) \tag{15}$$

3 | IMPLEMENTATION OF THE PROPOSED BOI MODEL

The proposed BOI scheme is implemented through four stages which are described below:

- Stage-1: Data base formation.
- Stage-2: Calculation of NGBCV.
- Stage-3: Selection of a single bus and single branch.
- Stage-4: Evaluation of objective function.

3.1 | Database formation

During normal condition, the power flow through the branches is known to the system operators from supervisory control and SCADA information. Now, the BPDF for different OSs is calculated using load flow simulation. Therefore, the simulation of each OSs is conducted one by one to build the BPDF matrix. This BPDF matrix is now stored, and this database will guide the system planners and engineers to analyze the postoutage behavior of the network. Furthermore, the postoutage power flow through branches can be obtained using BPDF matrix and base case power flow.

3.2 | Calculation of NGBCV

As mentioned earlier, the PMUs at generator buses facilitates the direct monitoring of the generator buses. It is well known that PMU installed at any bus is able to provide the complex voltage phasor of that bus and current phasor of the lines connected to that bus. Therefore, the generator bus currents are monitored continuously through the installed PMUs. In view of this, on the occurrence of outage, the NGBCV can be computed easily using (4).

3.3 | Selection of a single bus and single branch

Now, the bus having maximum NGBCV is selected as CGB. Thereafter, identify the branches connected with the CGB, and among these branches, any one branch is selected as CTB. During selection of CTB, the following rules are to be followed:

Rule 1: The CTB should be connected with CGB.

Rule 2: The CTB must be observable through PMU.

Now, the power flow through CTB is monitored continuously through PMU. The idea of CGB and CTB is incorporated to reduce the computational burden of the proposed scheme.

3.4 | Evaluation of objective function

After the selection of CGB and CTB, compute the VOF using (13). Now, the MVOF is to be found using (14) and the actual OS is detected based on (15).The flowchart describing detail procedure of proposed BOI scheme is illustrated in Figure 1.

4 | SIMULATION STUDIES AND NUMERICAL RESULTS

Simulation studies are performed on MATLAB 7.10.0 (R2013a) version loaded in a PC having Intel i-3 processor @2.4 GHz and 4 GB RAM. The well-known and popular fast decoupled load flow (FDLF)[38] technique is used for load flow simulation. Different benchmark IEEE systems[39] are considered to check the effectiveness and scalability of the proposed scheme. The measurement error is set to vary upto 10% to check the consistency and reliability of the algorithm. The sampling frequency of the PMU is considered 50.

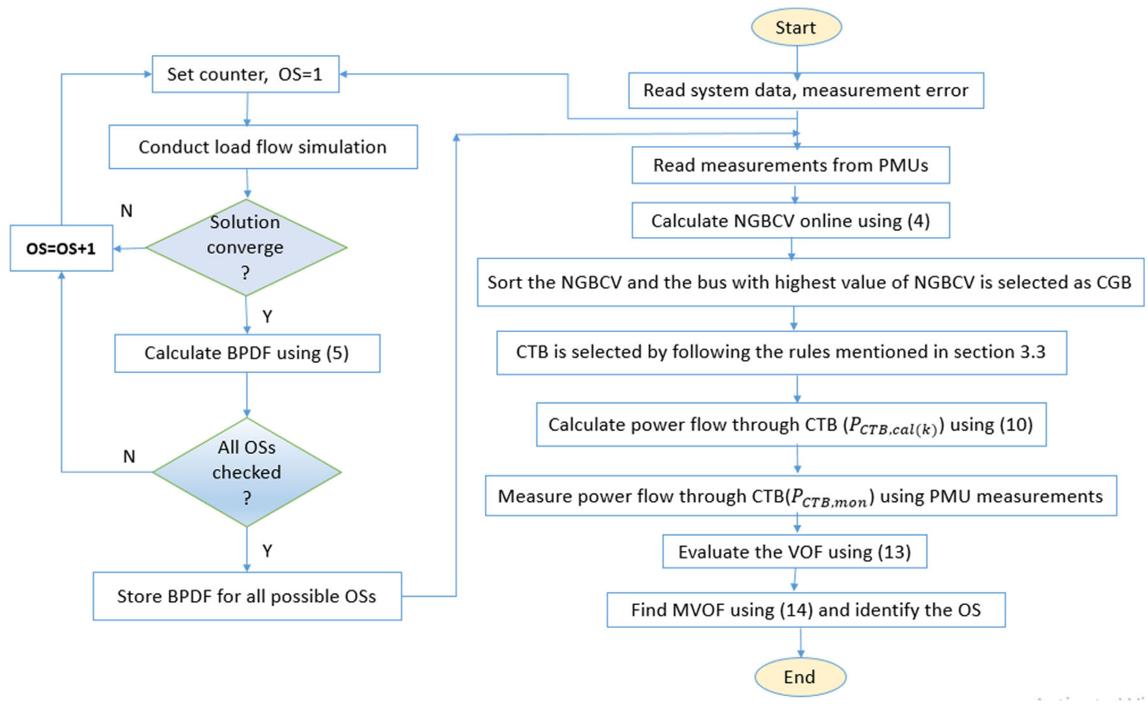

FIGURE 1 Flowchart of the proposed branch outage identification (BOI) framework

TABLE 1 Nonconverging cases for different networks

IEEE network	SBO	DBO
6 bus	Nil	{2;5},{7;9}
14 bus	14	{8;14},{17;20}
57 bus	45;48	{29;30},{38;39},{40;45}
118 bus	15;19;110; 120;144;177;178	{15;20},{110;115},{128;144},{132;159}

Abbreviations: DBO, double branch outage; SBO, single branch outage.

4.1 | Nonconverging cases

We have tested total of 600 OSs considering 280 SBO and 320 DBO scenarios. It is worth noting that during simulation study, power flow solution for some OSs do not yield results, and the MATLAB provides output "NaN." This happens due to the nonconvergence of load flow program. For these cases, the postevent measurements are not available, and these cases are termed as *nonconverging cases*. In this study, we exclude these cases from BOI simulation. In this context, it is to be noted that the OSs for which the system becomes unstable or islanded are not considered in this study like other methods reported in literature.[4-7,20] The *nonconverging cases* for different test networks considering all SBO and few DBO are listed in Table 1. For these cases mentioned in Table 1, the postcontingency results are not available. Therefore, these cases are excluded from our study. In case of SBO, it is seen from Table 1 that 1, 2, and 7 number of *nonconverging cases* are found for IEEE 14-, 57-, and 118-bus system, respectively. In case of DBO, two *nonconverging cases* are found for IEEE 6-bus system. For other systems, few *nonconverging cases* considering DBO are shown in Table 1.

4.2 | IEEE 6-bus case study

In order to better grasp of the proposed scheme, the detailed results of the IEEE 6-bus network (Figure 2) is illustrated here. The NGBCV for different OSs is displayed in Figure 3 from which it can be implied that NGBCV is more for generator 1 compared to generator 2 in case of OS 1,2,3,4,5,6,9,10, and 11. Further, it is also noticed from Figure 3 that the NGBCV is more for generator 2 compared to generator 1 in case of OS 7 and 8. For this network, let consider OS-11, that is, outage of branch 11 for which the maximum NGBCV (0.015) occurs at generator 1, that is, bus 2. The branches 1, 4, 5, and 6 are connected with bus 2. Therefore, bus 2 is selected as CGB. Now, let $\mathcal{B}_{CGB}$ denotes the set of branches connected with CGB. Therefore, $\mathcal{B}_{\mathrm{CGB}} = \{1,4,5,6,7\}$ and the branch 4 is selected as CTB. Now, considering the branch 4 as CTB and 5% error, the VOF for several OSs is presented in Figure 4. It is observed from Figure 4 that 11 values of VOF are found for 11 OSs. Among the 11 VOF, the MVOF is found 0.013, which corresponds to the actual OS-11, and this can be easily understood from Figure 4. Hence, the identification of branch outage is accomplished successfully. The simulation results considering other few OSs of IEEE 6-bus network with 10% error are summarized in Table 2. The each column of Table 2 presents the VOF for different OSs considering a particular branch outage. The branch outage is indicated in bracket, and the chosen CTB is mentioned at first of the each column. For instance, considering the outage of branch 1 and taking branch 5 as CTB, the obtained VOF is in the first column of Table 2. For this case, the MVOF is 0.0029 which corresponds to the actual OS-1, that is, branch 1 outage. From Table 2, it can be seen that the MVOF are found to be 0.0024, 0.0033, 0.0551, 0.0156, 0.1061, and 0.0556 considering the outage of branch 2, 3,

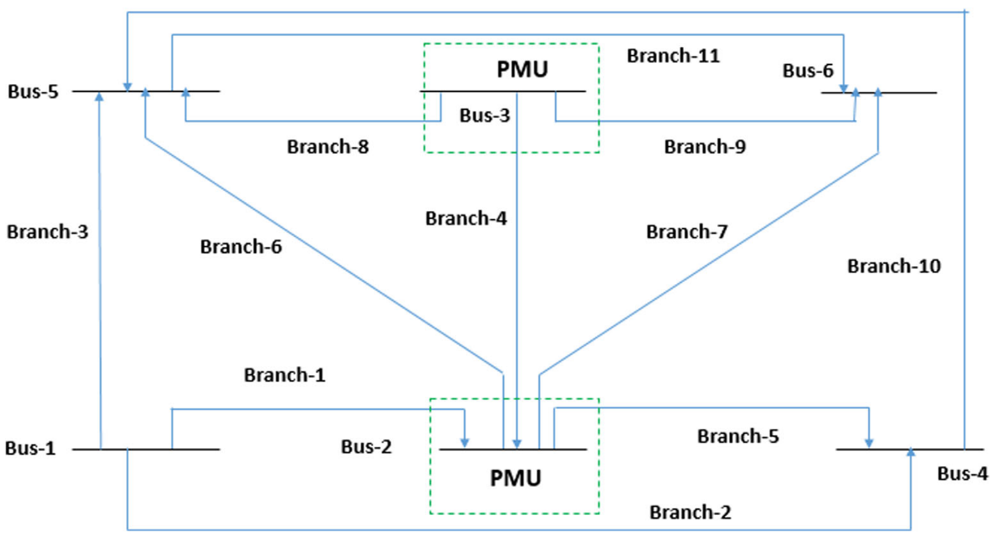

FIGURE 2 Diagram of IEEE 6-bus network

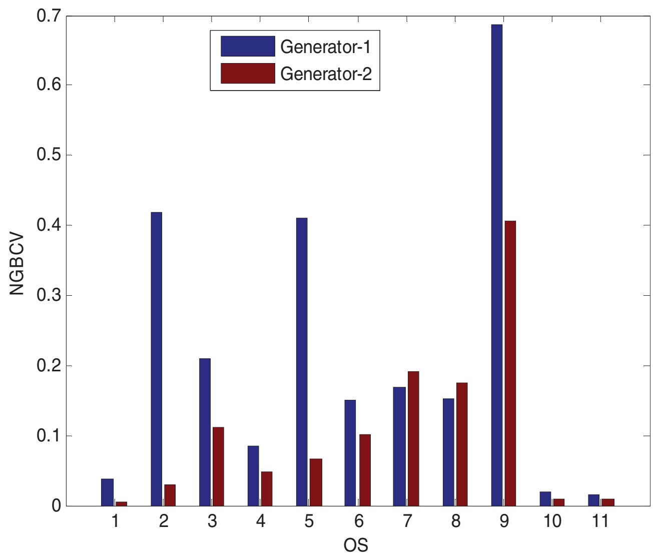

FIGURE 3 Normalized generator bus current variation (NGBCV) for different single branch outage (SBO) scenarios of IEEE 6-bus network

5, 7, 8, and 10, respectively. The branches 5, 6, 7, 8, 9, and 1 are chosen as CTB while considering outage of branch 2, 3, 5, 7, 8, and 10, respectively. It is also observed from Table 2 that for each OS, we found 11 VOF among which the lowest value indicates the actual branch outage. Therefore, the size of each column of Table 2 is 11×1.

For this network, total $\binom{11}{2}$, that is, 55 combinations of DBO cases can be found. Among 55 OSs, load flow diverges for two OSs as seen from Table 1. Therefore, remaining 53 OSs are considered in our study. The OSs and the corresponding branch outage are summarized in Table 3. It can be seen from Table 3 that the outage of branch 1, 2 is designated as OS-1, and the outage of branch 10, 11 is designated as OS-53. All other OSs are designated in a similar way and listed in Table 3. For DBO cases, the NGBCV in connection with different 53 OSs are presented in Figure 5. For each OS, the maximum NGBCV can be found either for generator 1 or generator 2. Therefore, the information contains in this Figure 5 is used in determining the CGB while considering the DBO simulation. Now, let consider OS-50, that is, outage of branch 8 and 10. In this case, the maximum NGBCV found to be 0.2466 (see Figure 5) at generator 2 (bus 3). Therefore, CGB is bus 3, which is connected with branches 4, 8, and 9. Considering 10% error and branch 4 as CTB, the VOF obtained for several OSs is shown in Figure 6. It is observed from Figure 6 that 53 values of VOF are found for 53 OSs during DBO simulation. Among the 53 values, the MVOF (lowest value) is found to be 0.0085, which represents the OS-50. Therefore, the identification of DBO is also verified.

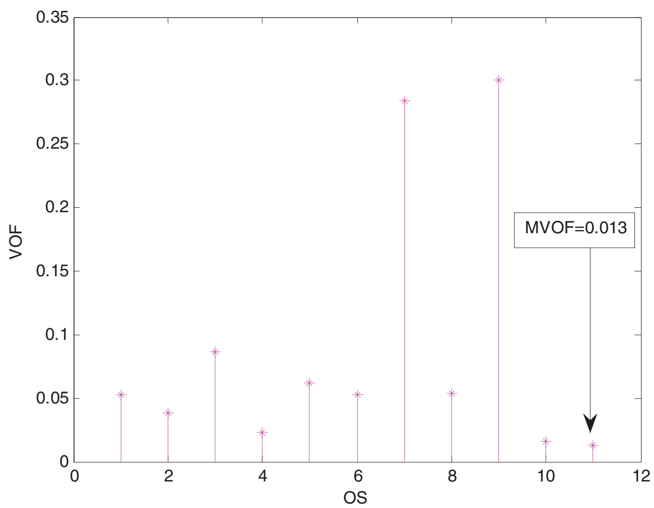

FIGURE 4 Value of the objective function (VOF) for different outage scenarios (OSs) of IEEE 6-bus network considering 5% error

TABLE 2 Value of the objective function (VOF) for different single branch outage (SBO) of IEEE 6-bus network with 10% error

	CTB (actual branch outage)						
OS	5(1)	5(2)	6(3)	7(5)	8(7)	9(8)	1(10)
1	**0.0029**	0.5198	0.175	0.1441	0.0192	0.2157	0.3491
2	0.5203	**0.0024**	0.1538	0.1295	0.0346	0.2177	0.3679
3	0.0914	0.4313	**0.0033**	0.0792	0.1364	0.2281	0.2685
4	0.1699	0.3528	0.1144	0.0946	0.0428	0.2373	0.0613
5	0.173	0.6899	0.0379	**0.0551**	0.1108	0.2247	0.2079
6	0.2106	0.3121	0.2759	0.0648	0.102	0.2252	0.0816
7	0.2047	0.318	0.0592	0.3748	**0.0156**	0.1685	0.0845
8	0.2079	0.3148	0.0661	0.1445	0.1714	**0.1061**	0.0772
9	0.1528	0.3699	0.1259	0.2935	0.2454	0.6543	0.0898
10	0.1377	0.385	0.1078	0.1018	0.0622	0.2192	**0.0556**
11	0.1639	0.3588	0.1255	0.1042	0.0483	0.2091	0.058

Note: Bold value represents the minimum value of the objective function(MVOF) which basically determines the line outage. Therefore, in order to emphasize on the MVOF and better understanding, the minimum value of each column.

Abbreviations: CTB, critical transmission branch; OS, outage scenarios.

TABLE 3 Different double branch outage (DBO) scenarios and corresponding branch outage of IEEE 6-bus network

Branch outage	OS
{1;2}, {1;3}, {1;4}, {1;5}, {1;6}, {1;7}, {1;8}, {1;9}, {1;10}, {1;11}, {2;3}, {2;4}, {2;6}, {2;7}, {2;8}, {2;9}, {2;10}, {2;11}, {3;4}, {3;5}, {3;6}, {3;7}, {3;8}, {3;9}, {3;10}, {3;11}, {4;5}, {4;6}, {4;7}, {4;8}, {4;9}, {4;10}, {4;11}, {5;6}, {5;7}, {5;8}, {5;9}, {5;10}, {5;11}, {6;7}, {6;8}, {6;9}, {6;10},{6;11},{7;8},{7;10},{7;11}, {8;9}, {8;10}, {8;11}, {9;10}, {9;11},{10;11}	1,2,3,4,5,6,7,8,9,10,11,12,13,14,15,16,17,18, 19,20,21,22,23,24,25,26,27,28,29,30,31,32, 33,34,35,36,37,38,39,40,41,42, 43,44,45,46,47,48,49,50,51,52,53

Abbreviation: OS, outage scenario.

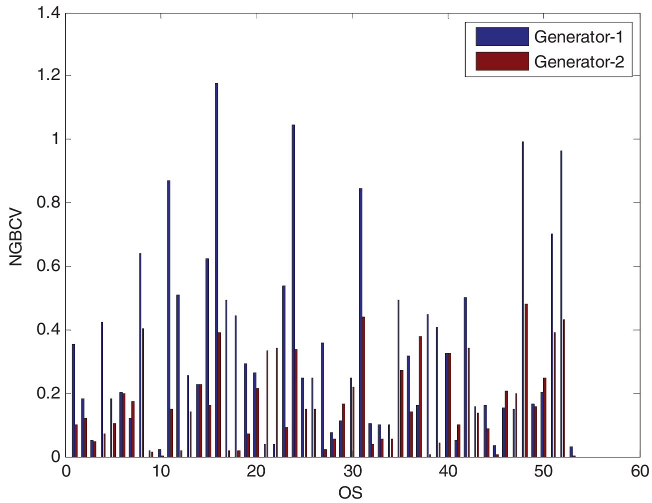

FIGURE 5 Normalized generator bus current variation (NGBCV) for different double branch outage (DBO) scenarios of IEEE 6-bus network

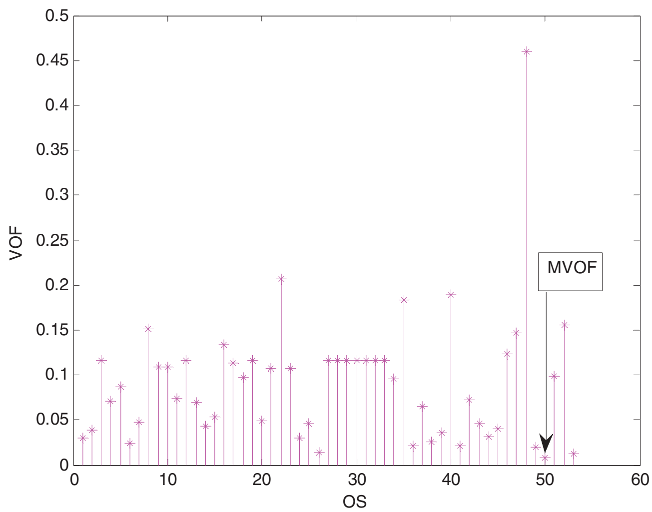

FIGURE 6 Value of the objective function (VOF) for different double branch outage (DBO) scenarios of IEEE 6-bus network considering 10% error

4.3 | IEEE 14- and 118-bus case study

For IEEE 14-bus network, let's take an example of OS-7. The maximum NGBCV (0.2832) is found at bus 2 (generator 1), which is connected with branches 1, 3, 4, and 5. Here, we can write $\mathcal{B}_{\mathrm{CGB}} = \{1, 3, 4, 5\}$. The obtained VOF for

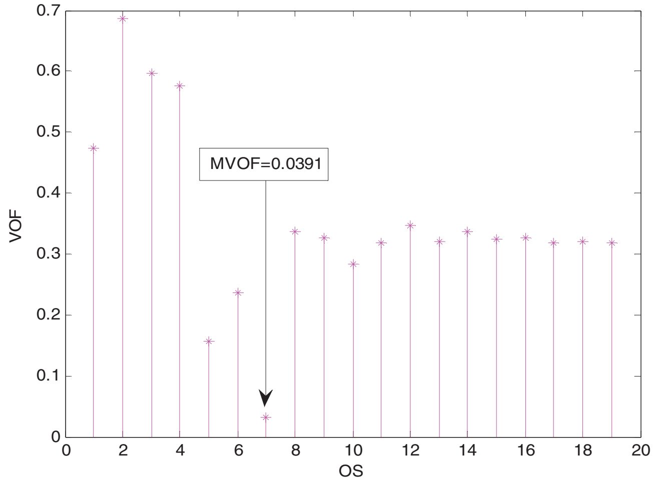

FIGURE 7 Value of the objective function (VOF) for different outage scenarios (OSs) of IEEE 14-bus network considering 10% error

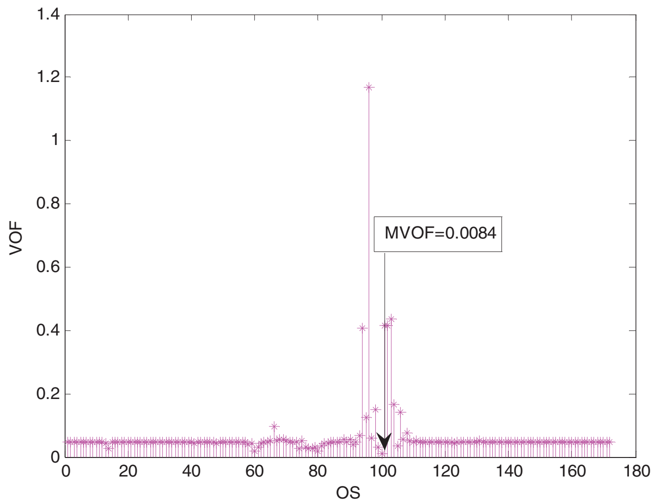

FIGURE 8 Value of the objective function (VOF) for different outage scenarios (OSs) of IEEE 118-bus network considering 5% error

different OSs considering 10% error and branch 5 as CTB is presented in Figure 7. It is seen from Figure 7 that MVOF is 0.0391, which corresponds to the OS-7. For IEEE 14-bus, one OS (branch 14 outage) is excluded from our experiment. Therefore, we found 19 VOF during execution of the algorithm, and the Figure 7 represents the 19 VOF for different OSs.

The OS-100 is considered as example for IEEE 118-bus network. We found the maximum NGBCV at bus 62 (generator 23), which is selected as CGB. For this case, we can express $\mathcal{B}_{\mathrm{CGB}} = \{97, 98, 106\}$. The VOF for different OSs is displayed in Figure 8 considering 5% error and branch 98 (connected with bus 62) as CTB. The MVOF is found 0.0084, which basically related to the OS-100. It is to be noted that seven SBO cases are not considered for IEEE 118-bus network, which has 179 branches. Therefore, we found 172 VOF during simulation, and the Figure 8 represents the 172 VOF for different OSs.

5 | DISCUSSIONS

5.1 | Identification rate

In order to check the accuracy of the proposed model, two new indices, that is, identification rate excluding nonconverging cases (IRENCC) and identification rate including nonconverging cases (IRINCC) are introduced in this article. The first index, that is, IRENCC is defined as

TABLE 4 Comparison of identification rate for different test networks

Method	IEEE systems 6 bus	14 bus	57 bus	118 bus
ACMIL[20]	—	—	93.5%	94%
ACMEL[20]	—	—	91%	92.5%
DCM[20]			89%	90.5%
40% PMU coverage[23]	—	85.17%	72.85	68.23%
30% PMU coverage[8]	—	80%	65%	75%
Reference 6	—	—	—	95.5%
Proposed scheme (IRENCC)	100%	100%	100%	100%
Proposed scheme (IRINCC)	96.97%	95.65%	97.26%	96.36%

Abbreviations: ACMEL, AC model excluding losses; ACMIL, AC model including losses; DCM, DC model; PMU, phasor measurement unit; IRENCC, identification rate including nonconverging cases.

TABLE 5 Comparison of maximum identification rate for IEEE 118-bus network with 1% noise

Method	SBO	DBO
Reference 6	93%	91.7%
Reference 7	98.6%	97.9%
Reference 20	95.5%	93%
Proposed	100%	99.17% (considering 120 random scenarios)

$$\mathrm{IRENCC} = \frac{N_{\text{correct}}}{N_{\text{attempt,exc\_NCC}}} \tag{16}$$

where, N_{correct} denotes the total number of scenarios identified correctly and $N_{\text{attempt,exc\_NCC}}$ denotes the total number of attempts made excluding nonconverging cases.

Similarly, the IRINCC can be defined by,

$$\mathrm{IRINCC} = \frac{N_{\text{correct}}}{N_{\text{attempt,inc\_NCC}}} \tag{17}$$

where $N_{\text{attempt,inc\_NCC}}$ denotes the total number of attempts made including nonconverging cases. To illustrate, let consider IEEE 6-bus system which has 2 number of nonconverging cases considering DBO. For this system, 11 SBO and 53 DBO cases have been identified correctly. Therefore, the IRENCC can be calculated as $(11+53)/64 = 100\%$ and IRINCC will be $(11+53)/66 = 96.97\%$. The comparative performance of the proposed method with some existing methods is listed in Table 4. The results of the Table 4 infer that the proposed method yields competitive results in terms of identification rate. Further, considering the 1% noise, the comparison of the maximum identification rate of the proposed scheme with other methods is demonstrated in Table 5. Both the Tables 4 and 5 confirm the superiority of the proposed method with respect to identification rate.

5.2 | Modeling of PBs outage

Although a lot of approaches related to BOI have been proposed by the researchers, most of the approaches rely on the DCPF model and utilize the phasor angle measurements only. In view of this, it is to be noted that voltage phasor–based schemes are unable to identify the outage of PBs due to identical phasor angle of the terminating buses of PBs.

Therefore, PBs are modeled as single branch as reported in References 4-7,12, and 22 where the inability of identifying the outage of PBs is highlighted. In this study, a good effort has been made to develop the modeling of PBs outage, which addresses the shortcomings the existing voltage phasor–based algorithms.

To develop the modeling of PBs, let consider a system, which constitutes two number of PBs, that is, b_1 and b_2 terminated between pth bus and qth bus. Let the impedance of the branch b_1 and b_2 is denoted by Z_{b_1} and Z_{b_2}, respectively. Further, the complex voltage phasor of pth bus and qth bus be denoted by $\overline{V_p}$ and $\overline{V_q}$, respectively.

During the normal situation, the complex current flow through branch b_1 can be written as,

$$\overline{I_{b_1,\text{nor}}} = \frac{\overline{V_p} - \overline{V_q}}{Z_{b_1}} \tag{18}$$

Similarly, during normal situation, the complex current flow through branch b_2 can be expressed as,

$$\overline{I_{b_2,\text{nor}}} = \frac{\overline{V_p} - \overline{V_q}}{Z_{b_2}} \tag{19}$$

Now, the power through branch b_1 during normal condition can be written as,

$$P_{b_1,\text{nor}} = Re\left(\overline{V_p I_{b_1,\text{nor}}}^*\right) \tag{20}$$

$$P_{b_2,\text{nor}} = Re\left(\overline{V_p I_{b_2,\text{nor}}}^*\right) \tag{21}$$

Now, considering branch b_1 outage the BPDF for any branch b can be written by,

$$\text{BPDF}(b, b_1) = \frac{P_{b,b_1} - P_{b,\text{nor}}}{P_{b,\text{nor}}} \tag{22}$$

where, $P_{b,\text{nor}}$ and P_{b,b_1} denote the power flow through branch b during normal condition and branch b_1 outage respectively.

Similarly, considering branch b_2 outage the BPDF for any branch b can be expressed by,

$$\text{BPDF}(b, b_2) = \frac{P_{b,b_2} - P_{b,\text{nor}}}{P_{b,nor}} \tag{23}$$

where, P_{b,b_2} represents the power flow through branch b during branch b_2 outage. It is also to be noted that $P_{b,b_1} \neq P_{b,b_2}$.

From (18) and (19), it can be written that $\overline{I_{b_1,nor}} \neq \overline{I_{b_2,nor}}$. Now, considering the equality mentioned in (20) and (21), it can be inferred that the power flow through PBs will be different that is, $P_{b_1,\text{nor}} \neq P_{b_2,\text{nor}}$. Therefore, based on this fact, it can be concluded that the proposed algorithm is able to identify the outage of PBs. It has been observed that IEEE 57-bus network has two PBs, that is, branch 35 and 36. Now, let consider the outage of branch 35 of IEEE 57-bus network. For this case, we found highest NGBCV at generator 2, that is, bus 3, which is connected with branches 2, 3, and 18. Now, considering 10% error and branch 18 as CTB, we have calculated the VOF. The VOF for different OSs is represented in Figure 9. It can be implied from Figure 9 that we found 78 values of VOF during consideration of outage of branch 35 or branch 36. Among the 78 values, the MVOF (lowest value) is found 0.0434 which represents the OS-35 that is, branch outage is identified accurately. Similarly, during consideration of branch 36 outage, among 78 values the MVOF is found 0.0186, which represents the OS-36. The VOF for different OSs are represented by red color and blue color during consideration of outage of branch 35 and branch 36, respectively, in Figure 9.

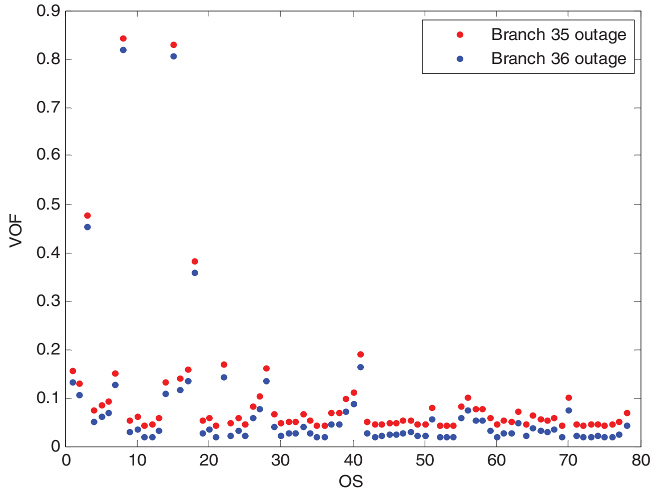

FIGURE 9 Value of the objective function (VOF) for different outage scenarios (OSs) of IEEE 57-bus network considering outage of branch 35 and branch 36

TABLE 6 Comparison of phasor measurement unit (PMU) requirement with other schemes

	IEEE systems			
Method	**6 bus**	**14 bus**	**57 bus**	**118 bus**
Reference 6	—	—	—	118
Reference 7	—	—	—	118
Reference 13	—	6	34	56
Reference 22	—	—	—	118
Proposed	2	4	6	54

TABLE 7 Comparison of computation time in seconds

	IEEE systems			
Method	**6 bus**	**14 bus**	**57 bus**	**118 bus**
ACMIL20	—	—	0.068817	0.10792
ACMEL20	—	—	0.06556	0.103782
DCM20	—	—	0.064599	0.098627
Proposed	0.000019	0.000212	0.002798	0.056397

Abbreviations: ACMEL, AC model excluding losses; ACMIL, AC model including losses; DCM, DC model.

5.3 | Implementation cost and search space reduction

Any suggested methodology must be cost-competitive so that the planners can easily adopt the scheme. It is clear that the number of generator buses is a fraction of total number of buses. In this context, it can be inferred that the set of generator buses $(\mathcal{N}_{\text{gen}})$ is a subset of all buses, that is, $\mathcal{N}_{\text{gen}} \subset \mathcal{N}$. Therefore, the suggested method requires less number of PMUs in comparison with the methods mentioned in References 6, 7, 13, and 22. The comparison of number of required PMUs with some existing established methods is demonstrated in Table 6. From Table 6, it can be seen that the proposed method is cost-effective and can be adopted by the power system planners for the execution of BOI.

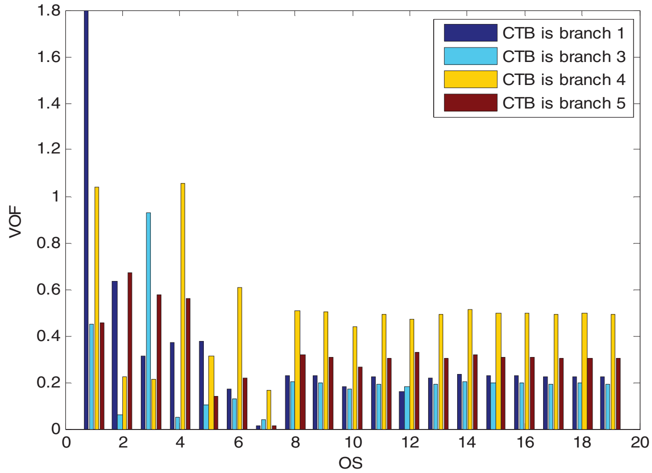

FIGURE 10 Value of the objective function (VOF) considering different selection of critical transmission branch (CTB) for IEEE 14-bus network

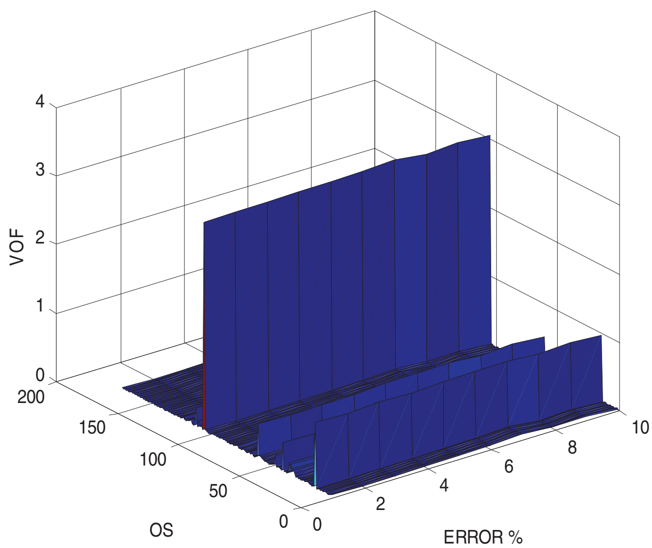

FIGURE 11 Value of the objective function (VOF) considering error variation up to 10% for IEEE 118-bus network

The search space is significantly reduced in case of our suggested scheme. In general, search space considering all buses and only generator buses will be 2^N and $2^{N_{\text{gen}}}$, respectively (N and N_{gen} denote the number of all buses and generator buses, respectively). Therefore, the reduction of search space will be order of $2^{N-N_{\text{gen}}}$. The computation time of the proposed algorithm for different networks is presented in Table 7. The Table 7 also highlights the comparative analysis of the proposed scheme with the three methods described in Reference 20 with respect to computation time. From Table 7, it can be inferred that the computation time of the proposed scheme is competitive with respect to the three methods presented in Reference 20.

5.4 | Independency on CTB

In the proposed algorithm, power flow through CTB is compared. Hence, the choice of CTB is very important and needs to be discussed. It is worth noting that our developed algorithm is not dependent on the selection of CTB. In other words, it can be inferred that any one branch connected to CGB can be selected as CTB, and this will no way affect the identification of the branch outage. To verify this fact, an example considering the selection of different CTB is illustrated here. For example, we consider the outage of branch 7 for IEEE 14 bus. Recalling from section II.C, we can see the maximum NGBCV at bus 2, that is, generator 1. The branches 1, 3, 4, and 5 are connected with bus 2. So, bus 2 is chosen as CGB and connected branches (1, 3, 4, 5) are chosen one by one as CTB. Now, considering the branches 1, 3, 4, and 5 as CTB, the VOF is calculated for each cases, which is presented in Figure 10. It is clearly seen from Figure 10 that for each case of chosing different CTB, the lowest VOF is found for OS-7, which indicates the branch 7 outage. Therefore, for all the four cases, the branch outages are detected correctly. It is to be noted that during consideration of different CTB, we found 19 VOF among which MVOF is always found for OS-7. Note that MVOF found 0.0146, 0.037, 0.1663, and 0.0147 during selection of branch 1, 3, 4, and 5, respectively, considering 10% error. Therefore, the selection of different CTB has no impact on the identification of branch outage. Hence, the independency of the proposed model on the choice of CTB is proved.

5.5 | Error variation

The proposed BOI model also considers the measurement error, which is varied upto 10%. The variation of error is conducted to check the effectiveness of the algorithm in presence of large error. For illustration purpose, let consider OS-40, that is, branch 42 outage (two preceding outages, that is, branch 15 and branch 19 are excluded from simulation due to nonconvergence of load flow) for IEEE 118-bus network. In this case, maximum NGBCV (0.0959) is found at bus-25 (generator-11), which is selected as the CGB and branch 37 (connected with bus 25) is selected as CTB. The simulation results considering the error from 1% to 10% is displayed in Figure 11. It is noticed from Figure 11 that with the variation of error level, the MVOF changes, but for each error level, the MVOF is always found for the actual OS-40. The MVOF are found to be 0.0098, 0.0026, 0.0131, 0.0149, 0.0355, 0.0403, 0.0611, 0.0196, 0.0459, and 0.0111 considering error of 1%, 2%, 3%, 4%, 5%, 6%, 7%,8%, 9%, and 10%, respectively. It can be implied from Figure 11 that for each case, we found 172 VOF among which the lowest values (0.0098, 0.0026, 0.0131, 0.0149, 0.0355, 0.0403, 0.0611, 0.0196, 0.0459, 0.0111) are found for OS-40. Therefore, the validation of the proposed model with the error variation up to 10% is established.

5.6 | Impact of partial observability

Partial observability of the network may lead to performance degradation, which has been observed in References 8 and 23. With the decrease of the PMU coverage, the degradation of the performance of the methods[8,23] has been reported in literature. In this context, it is to be noted that our suggested method performs well, even if some of the generator buses are not observable due to outage of PMU at any buses. At that condition, the NGBCV of the remaining generator buses are to be considered to find out the CGB and CTB. Recalling from section 4.3, let us assume OS-7 of IEEE 14 bus. During normal condition (ie, all data from all PMUs are available), the generator 1 is chosen as CGB. Now, consider the outage of PMU at generator 1. At this condition, the data from the remaining generator buses are to be considered except generator 1. It is seen that generator 4 has the highest NGBCV among generators 2, 3, and 4. Now, generator 4 is chosen as CGB, and the outage is also identified correctly. Therefore, the developed model is able to provide consistent performance in case of any PMU outage or partial observability of the network.

6 | CONCLUSION

In this study, a new approach is suggested to identify the outage of transmission branches. The suggested approach is based on the PMUs installed at generator buses. A new logical index, that is, NGBCV is introduced to measure the variation of bus current due to various OSs. Furthermore, another index that is, BPDF is also introduced to calculate the postevent power flow through the branches. The introduction of the concept of CGB and CTB helps to reduce the search space, which is utmost important in large power network. Based on the proposed indices, a new and unique objective function is developed in this study, which is completely different from existing literature. Moreover, the proposed scheme is also able to identify the outage of PBs, and it is also proved with an example of the IEEE 57-bus network. Additionally, the suggested approach is proven to be cost-effective compared to several existing methods reported in literature. Further, considering the practical aspect of the real power network, the measurement error is also included in the proposed model. The developed model is implemented on different IEEE benchmark systems to confirm the applicability and viability of the algorithm.

PEER REVIEW

The peer review history for this article is available at https://publons.com/publon/10.1002/2050-7038.13069.

DATA AVAILABILITY STATEMENT

The data that support the findings of this study are available from the corresponding author upon reasonable request.

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