International Journal of Research and Technology in Electrical Industry

journal homepage: ijrtei.sbu.ac.ir

Shahid Beheshti University

Power Distribution Grid Reliability Assessment Considering Protection and Control Devices' Optimal Post-Fault Operation

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ARTICLEINFO

Article history:
Received 23 November 2021
Received in revised form 05 February 2022
Accepted 24 February 2022

Keywords:
Reliability indices
Service restoration
Protection devices
Isolating switches
Distribution system

ABSTRACT

The reliability level of the distribution network is a judgment tool of the grid and protection design quality, the effectiveness of the fault management unit, and customers' satisfaction. In this paper, a new approach is presented to evaluate common reliability indices namely ENS, SAIDI, SAIFI, MAIFIe, etc., while reliability improvement via optimal post-fault restoration describes the coordinated operation of various protection and control devices in temporary and permanent fault event conditions. Customers' outage times are calculated considering different switching operation times to capture manual operation issues, e.g., traffic level, geographical issues, fuse replacements, etc. The optimal service restoration scheme being formulated in a mixed-integer linear programming (MILP) fashion is constrained to network technical limitations, e.g., line thermal capacity, load points voltage level, DG units' parameters, and island operation. The performance of the proposed framework is verified in IEEE 33-bus test system.

Nomenclature

Sets

B	set for network buses
L	set for lines
D_b	set for buses downstream of the bus b

Parameters

CDF_b	customer outage costs
F_ℓ	sending node of the line ℓ
T_ℓ	receiving node of the line ℓ
M	sufficiently big value
T_ℓ^{sw-c}	required time for switching operation. This parameter is zero for closed switches and non-switchable lines.
T_ℓ^{sw-o}	required time for switching operation. This parameter is zero for opened switches and non-switchable lines.
R_ℓ^{line}	resistance of the network lines
X_ℓ^{line}	reactance of the network lines
$\underline{V}$	minimum allowable voltage level
$\overline{V}$	maximum allowable voltage level
$\overline{S}_\ell^{Line}$	line power capacity
$\underline{P}_b^G$	min. active power generation capacity

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http://dx.doi.org/10.52547/ijrtei.1.1.1

$\bar{P}_b^G$ max. active power generation capacity

$\underline{Q}_b^G$ min. reactive power generation capacity

$\bar{Q}_b^G$ max. reactive power generation capacity

λ_{Sc} annual rate for the fault scenario

N_b^c number of customers in each bus

N_{total}^c total number of customers

T^{p-min} minimum permanent fault duration

Variables

T_b^{out} bus outage duration

α_b^{ref} binary variable showing reference node

α_b^{Master} binary variable showing master DG node

α_b^{sub} binary value showing if a bus is a substation

β_ℓ^{Line} binary variable for line connection status

β_ℓ^{Nor} binary variable showing that the power flow direction of the line ℓ in new configuration is as normal, i.e., sending node is parent and receiving node is offspring.

β_ℓ^{Rev} binary variable showing reverse power flow direction

U_b square of the buses voltage level

P_ℓ^{Line} active power flow through each line

Q_ℓ^{Line} reactive power flow through each line

P_b^{load} load point active power demand

Q_b^{load} load point reactive power demand

P_b^G active power generation

Q_b^G reactive power generation

1. Introduction

Reliability assessment is an integral part of designing, planning, operation, and many other analyses of today's power systems, as it is able to quantify the quality of the energy which is being delivered to the costumers in terms of continuity or interruption. Monte Carlo Simulation (MCS) [1-4] is one of the most widely used method for evaluating the reliability of distribution systems. Studies like [5-7] propose an algorithmic way of estimating the reliability indices. In [7], the spanning tree search algorithm is used to generate optimal distribution system reconfiguration scheme for load restoration and finding minimum switching operations. However, this model has not considered network's technical limitations, and microgrids are modeled as separate modules with fixed load points and they don't contribute to island formation coordinated with switching actions. [6] proposes an optimal restoration sequence based on minimum costumers' interruption cost. A fault traversal algorithm has been used to trace the faulted area and the involved switches for fault-isolation and service restoration. This model also does not take into account network's technical constraints, and DGs' operation, and only circuit breaker and isolating switches are considered. In [5] a technique for reliability assessment of distribution systems, considering restoration sequence is presented. A parent-visit technique is used to determine the affected area after a failure, and a breadth-first search is used to divide the affected load points to different classes based on restoration times. The stated algorithmic models [5-7] lack a solid mathematical formulation to be modeled as a standard optimization problem. The numerous advantages, such as being globally optimum and easily solved by off-the-shelf software, of well-known optimization programming models like MILP, have captured the attention of many power system researchers for quite a long time [8, 9]. However, providing a standard mathematical model for reliability assessment of distribution systems seems to be overlooked until recently. Among the first attempts to address this issue is [10], where a multi-objective mixed-integer second-order conic programming model is introduced to simultaneously minimize power losses and improve network's reliability. [11] is another pioneer in establishing a non-simulation-based linear programming approach for reliability assessment of distribution networks. It develops a mathematical formulation for calculation of expected nodal repair-and-switching and switching-only rates and durations using a fictitious power flow optimization model. Some of the common reliability indices are then calculated. These analytical models aim to overcome the approximate techniques needed for solving reliability-constrained optimization models. These works rely on optimization-based methods for calculation of the shortest path between each load node and its connected substation. Later in [12], an algebraic approach was proposed to improve the time-consuming computational performance of the previous models, where a set of algebraic equations replaced the linear programming model used in [11, 12] to calculate reliability indices. However, these models lack several important features of a comprehensive reliability assessment framework.

An important issue in distribution feeders' restoration arises when facing complex structures. Some reliability assessment frameworks in literature consider only radially designed feeders [11]. In [13] mesh structured designs is considered but only when the maneuver points can connect the end buses of different feeders or laterals. thus, the presented model is not applicable to more complex structures in which maneuver points connect laterals from the same substation or two load points of a single lateral.

An analytical reliability assessment model is proposed in [13] to compensate some of the weaknesses of [10-12]. Here, the authors highlight the importance of a model-based method capable of evaluating the reliability of meshed-constructed networks. This paper aims to enhance the reliability by performing post-fault network reconfiguration as it has been proven in many cases [10, 14-20]. Although [13] offers a considerable improvement compared to [10-12] in terms of reliability enhancement, taking into account network's technical constraints and model scalability, it is not already able to deal with and take advantage of many active distribution networks' strategies, such as complex feeder structure, DG and microgrid operation and different protection devices. Also, several assumptions are made in [14] that are not practical in real distribution systems, e.g., placing switches on both sides of each feeder branches, only one circuit breaker on each feeder, etc. In their most recently published work [21], the authors try to cover some shortcomings of [13] by proposing another optimization model-based reliability assessment method that linearly characterize the placement of circuit breaker and switches and their actions. Despite being an obvious improvement over their previous model [13], the model in [21] has yet to be developed from different aspects to be applicable to real world distribution networks as a sound reliability assessment package.

Studies like [22] have attempted to face the reliability assessment problem from different angle and introduced a linear model for topology-variable-based distribution systems. This model focuses on providing a systematic way of calculating reliability indices, rather than reliability enhancement. It does not consider networks technical constraints, DGs and microgrids, and different protection devices. Like previous works, it does not take into account temporary faults.

Although temporary faults have a greater rate of occurrence, their impact in reliability indices calculation is forsaken in all the mentioned literature. A comprehensive assessment of the distribution reliability should consider temporary faults not only in temporary outage measures like Momentary Average Interruption Frequency Index (MAIFI) but also when they cause permanent outages. The latter condition happens when the protection does not have reclosing capability. In this paper, the MAIFIe index is preferred over MAIFI which is independent of how many reclosing cycles a temporary fault lasts. Furthermore, it better reflects the customers' experience in terms of power supply continuity.

As mentioned in earlier studies, e.g. [11, 22], and admitted by many others, a complete assessment of reliability of distribution network should consider: additional post-fault network reconfiguration to restore services for load nodes downstream of the fault, island operation capability, temporary faults, line overloading, etc. Thus, motivated by lack of a comprehensive reliability assessment framework for distribution systems, this paper proposes a novel analytical model-based reliability assessment method that covers several existing gaps.

The main contributions of this paper are as follows:

1) Proposing a novel reliability assessment framework using MILP. This model is able to not only evaluate network's reliability by various existing indices, but also adopts an active reliability assessment approach to minimize costumes' interruption duration, achieved by optimal fault-isolation, network reconfiguration and restoration that results in notable reliability enhancement compared to passive reliability calculations.

2) Compared to all previous works, this model is not limited to only radial or mesh-constructed networks, and can evaluate the reliability of any complex network design.

3) The proposed model takes into account one of the critical features of today's smart distribution grids, i.e. the integration of distributed generations and microgrids in the system, which has been overlooked in previous studies. Here, the model is capable of not only evaluating the reliability in the presence of grid-connected DGs and islanded-microgrid operations, but also harnessing this feature for further improvement of reliability indices.

4) This paper presents a model for a serious concern that has been addressed in pervious pioneer works, i.e. the impact of temporary faults on system's reliability. Besides the sustained faults and their impact on various common reliability indices, the proposed model evaluates the impact of temporary faults via some special quantitative reliability indices, such as MAIFIe.

5) The proposed model takes into account the network's technical constraints, such as power flow equations, nodal voltage magnitude, line's thermal capacity, and guarantees that these variables are within their specified limitations in each network configuration.

6) Unlike previous studies that only consider circuit breakers and typical sectionalizing switches, this model makes distinction between many protection devices, e.g. Circuit Breakers (CBs), Reclosers (Rs), Manual Switches (MSs), Remote Control Switch (RCSs), and Fuses (both fuse-saving and fuse-blowing settings), in terms of protection coordination and switching sequence.

Table I summarizes the proposed model's capabilities and features compared to some of the pioneer reliability assessment models in the literature.

Table I. Summarization of distribution network's reliability assessment model

Model	Assessment approach	Reliability enhancement	Post-fault restoration	DG and microgrid	Mesh-constructed grid	Complex feeder structure	Temporary faults	Diverse protection devices	Network Constraints
[6]	Algorithmic	✓	✓		✓				✓
[10]	Optimization-based	✓			✓				✓
[11]	Analytical								
[12]	Algebraic								
[13]	Analytical	✓	✓		✓				✓
[21]	Optimization-based	✓	✓		✓				✓
Proposed	Optimization-based	✓	✓	✓	✓	✓	✓	✓	✓

2. Proposed Framework

The proposed method for evaluating reliability indices can be described in three steps.

1- Gathering the required information - This information includes network parameters such as network structure, line parameters, control and protection devices locations, loading capacity, etc., information related to the load and DG such as power consumption or generation, customer counts, etc., as well as reliability parameters.

2- Data processing – Network configuration and devices location is used to determine the set of downstream nodes for each protection device as well as the protection of any temporary or permanent fault in the network.

3- Calculation of reliability indices - In this step, different scenarios of fault events in the network are generated. In each scenario, customers' outage duration based on the optimal restoration is calculated. Then, according to the obtained outage times and scenario rate, different reliability indices are calculated.

Data flow among different steps in the proposed algorithm is illustrated in Fig. 1.

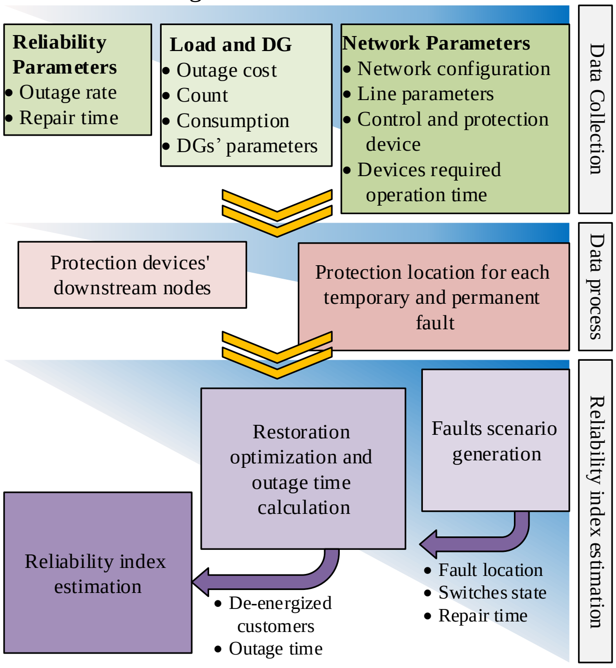


Fig. 1. Reliability estimation procedure data flow

3. Optimal Restoration

Restoration optimization in each fault scenario determines de-energized customers and their outage time.

3.1. Restoration Objective

The prime objective of restoration schemes in utilities may vary based on different policies toward critical loads, customers' vulnerability, reporting indices to higher authorities, or meeting a certain standard which in turn affects the post-fault correction actions and reliability indices. In this paper, the service restoration procedure aims to minimize the total customers' outage costs (1).

$$Min : \sum_{b\in \mathrm{B}} CDF_b\left(T_b^{out}\right) \quad (1)$$

Where, CDF_b determines customer outage costs as a function of outage duration. The description of customer costs could be linear or partially linear to hold MILP framework.

3.2. Restoration Constraints

The restoration optimization problem constraints include distribution network reconfiguration, outage times calculation, and network technical constraints.

3.2.1 Network Reconfiguration

Network graph connectivity and radiality entails each node to have exactly one parent as reference node to be supplied from, unless the node is a substation or hosts a master DG in island operation. In (2) and (3), this concept is mathematically stated.

$$\alpha_b^{ref} = \alpha_b^{sub} + \alpha_b^{Master};\forall b\in \mathrm{B} \quad (2)$$

$$\sum_{\substack{l\in L\\ \mathrm{T}_\ell=b}} \beta_\ell^{Nor} + \sum_{\substack{l\in L\\ \mathrm{F}_\ell=b}} \beta_\ell^{Rev} = 1-\alpha_b^{ref};\forall b\in \mathrm{B} \quad (3)$$

If the line is connected, energization direction is determined (4).

$$\beta_\ell^{Nor} + \beta_\ell^{Rev} = \beta_\ell^{Line};\forall \ell\in \mathrm{L} \quad (4)$$

3.2.2 Outage time

Due to the fact that each load point must somehow be connected to a reference bus, moving from reference nodes to end nodes through the path reconstructed in (2)-(4) and described by β_ℓ^{Nor} and β_ℓ^{Rev} variables, load points' outage time will increase.

$$T_b^{out} \ge T_{b'}^{out} - M\times\left(1-\beta_\ell^{Nor}\right);$$
$$\forall b,b'\in \mathrm{B},\ell\in \mathrm{L},b=\mathrm{T}_\ell,b'=\mathrm{F}_\ell \quad (5)$$

$$T_b^{out} \ge T_{b'}^{out} - M\times\left(1-\beta_\ell^{Rev}\right);$$
$$\forall b,b'\in \mathrm{B},\ell\in \mathrm{L},b'=\mathrm{T}_\ell,b=\mathrm{F}_\ell \quad (6)$$

Based on (5) and (6), outage time of each node is greater than its' parent.

If the reconfiguration process involves closing a switch, the downstream nodes should have outage time longer than the required switching time.

$$T_b^{out} \ge T_\ell^{sw-c}\times\beta_\ell^{Nor};\forall b\in \mathrm{B},\ell\in \mathrm{L},b=\mathrm{T}_\ell \quad (7)$$

$$T_b^{out} \ge T_\ell^{sw-c}\times\beta_\ell^{Rev};\forall b\in \mathrm{B},\ell\in \mathrm{L},b=\mathrm{F}_\ell \quad (8)$$

If a line is switched open during the network reconfiguration process, it means that the two sides of the switch could not be restored jointly. This may be due to a fault on either sides of the switch or for the matter that the restoration of both sides of the switch as a whole may result in a violation of system technical constraints such as the allowable line thermal or the voltage level limits. Accordingly, both sides of the switch cannot be energized before required switching time.

$$T_b^{out} \ge T_\ell^{sw-o}\times\left(1-\beta_\ell^{Line}\right);$$
$$\forall b\in \mathrm{B},\ell\in \mathrm{L},b=\mathrm{T}_\ell \; or \; b=\mathrm{F}_\ell \quad (9)$$

If the line between two buses is switchable and this line is initially closed and remains closed until the end of the process, both sides buses will have equal outage time. This situation is similar to the line that is not switchable.

Since according to (5) and (6), the restoration time of an offspring is longer than its parent, (10) and (11) that assure longer outage time for parent node, guarantee the equal outage times for parent and offspring.

$$T_b^{out} \geq T_{b'}^{out} - M \times \left(1-\beta_\ell^{Nor}\right); \quad \forall b,b' \in \mathrm{B}, \ell \in \mathrm{L}, b=\mathrm{F}_\ell, b'=\mathrm{T}_\ell, T_\ell^{sw-c}=0 \tag{10}$$

$$T_b^{out} \geq T_{b'}^{out} - M \times \left(1-\beta_\ell^{Rev}\right); \quad \forall b,b' \in \mathrm{B}, \ell \in \mathrm{L}, b=\mathrm{T}_\ell, b'=\mathrm{F}_\ell, T_\ell^{sw-c}=0 \tag{11}$$

Outage time of a node in a fault condition must be longer than the fault required repair time.

$$T_b^{out} \geq T_b^{Repair}; \forall b \in \mathrm{B} \tag{12}$$

Although in (12) the fault repair time is only considered in the related node, previous constraints also propagate the fault effect through connected lines to other nodes. As the result, any node connected to a fault cannot be restored before the repair time.

3.2.3 Network Operation

Since load restoration process is associated with network reconfiguration, it is necessary to consider the permitted ranges for load points voltage level and lines power flows in the mathematical model. For this purpose, it is necessary to add power flow equations to the mathematical model of the problem.

The voltage drop constraint across each line is given in (13). According to this constraint, if the line is connected, the voltage drop is calculated between its two end buses [23].

$$\pm\left| U_b - U_{b'} - 2\times \left(P_\ell^{Line} R_\ell^{line} + Q_\ell^{Line} X_\ell^{line}\right)\right| \leq \left(1-\beta_\ell^{Line}\right)\times M \tag{13}$$

$$\forall b,b' \in \mathrm{B}, \ell \in \mathrm{L}, b=\mathrm{F}_\ell, b'=\mathrm{T}_\ell$$

In each network bus, the sum of input power is equal to output. (14) and (15) show the constraints on the real and reactive power balance at the buses of the network, respectively.

$$\sum_{b\in \mathrm{F}_\ell} P_\ell^{Line} + P_b^{load} = \sum_{b\in \mathrm{T}_\ell} P_\ell^{Line} + P_b^G; \forall b \in \mathrm{B} \tag{14}$$

$$\sum_{b\in \mathrm{F}_\ell} Q_\ell^{Line} + Q_b^{load} = \sum_{b\in \mathrm{T}_\ell} Q_\ell^{Line} + Q_b^G; \forall b \in \mathrm{B} \tag{15}$$

Voltage level is constrained in permitted range through (16).

$$\underline{V}^2 \leq U_b \leq \overline{V}^2; \forall b \in \mathrm{B} \tag{16}$$

Line thermal capacity limitation can be modelled as in (17).

$$\left(P_\ell^{Line}\right)^2 + \left(Q_\ell^{Line}\right)^2 \leq \left(\overline{S}_\ell^{Line}\right)^2; \forall \ell \in \mathrm{L} \tag{17}$$

However, this formulation which describe the feasible solution area as a circle, is non-linear. Therefore, an octagonal approximation is used here through (18)-(19) to preserve the model in MILP format [24].

$$\pm P_\ell^{Line} \pm Q_\ell^{Line} \leq 1.3066\times \overline{S}_\ell^{Line}; \forall \ell \in \mathrm{L} \tag{18}$$

$$\pm P_\ell^{Line}, \pm Q_\ell^{Line} \leq 0.9239\times \overline{S}_\ell^{Line}; \forall \ell \in \mathrm{L} \tag{19}$$

DGs' output power limitation is also considered in (20) and (21) .

$$\underline{P}_b^G \leq P_b^G \leq \overline{P}_b^G; \forall b \in \mathrm{B} \tag{20}$$

$$\underline{Q}_b^G \leq Q_b^G \leq \overline{Q}_b^G; \forall b \in \mathrm{B} \tag{21}$$

4. Reliability Index Calculation Algorithm

Having an optimization-based decision-making system introduced in previous section, the calculation of reliability indices consists of scenario generation for events, outage time calculation for load points and finally calculating each index through a weighted sum of load point outages. The process of calculating reliability indices is shown in Fig. 2.

Outage scenarios consist of permanent and temporary faults. For each fault scenario, repair time, upstream switch ($T_\ell^{sw-o}=0$) with required closing operation time (T_ℓ^{sw-c}) at the beginning of the restoration process. If the protection type is a fuse, fuse replacement time is added to its close operation time. ENS and SAIDI indices calculation exclude momentary outages. So, T_b^{out} calculation for these faults is bypassed in Fig. 2.

Fig. 2. Reliability estimation process

For permanent faults cleared by fuse-saving fuses, nodes which are downstream to the upstream recloser, but not downstream to the fuse-saving fuse would experience temporary outage.

Once SAIFI and SAIDI values are available, other indices such as CAIDI and ASAI can readily be calculated.

$$CAIDI = SAIDI / SAIFI \tag{22}$$

$$ASAI = 1 - SAIDI / 8760 \tag{23}$$

5. Numerical Analysis and Results

5.1. Network Information and Assumptions

The 33-bus IEEE network is intended for numerical studies in this section. As shown in Fig. 3, this network consists of 33 buses, 32 lines and 5 manoeuvre points. This network is connected to the upstream network through bus #1. Network loading information and line parameters are available in [25]. To the purpose of this paper's studies, the network is equipped with a circuit breaker in the substation, a recloser, two fuse-blowing fuses, two fuse-saving fuses, three manual and five remotely controllable sectionalizers.

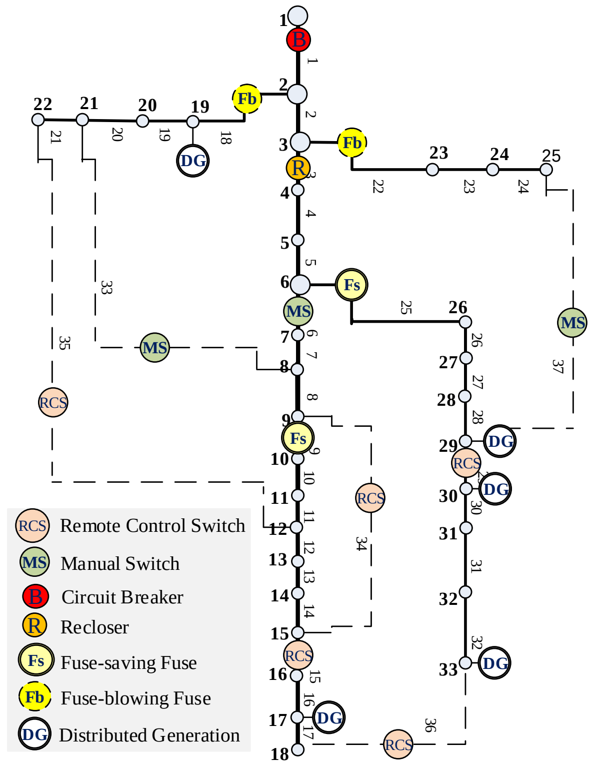
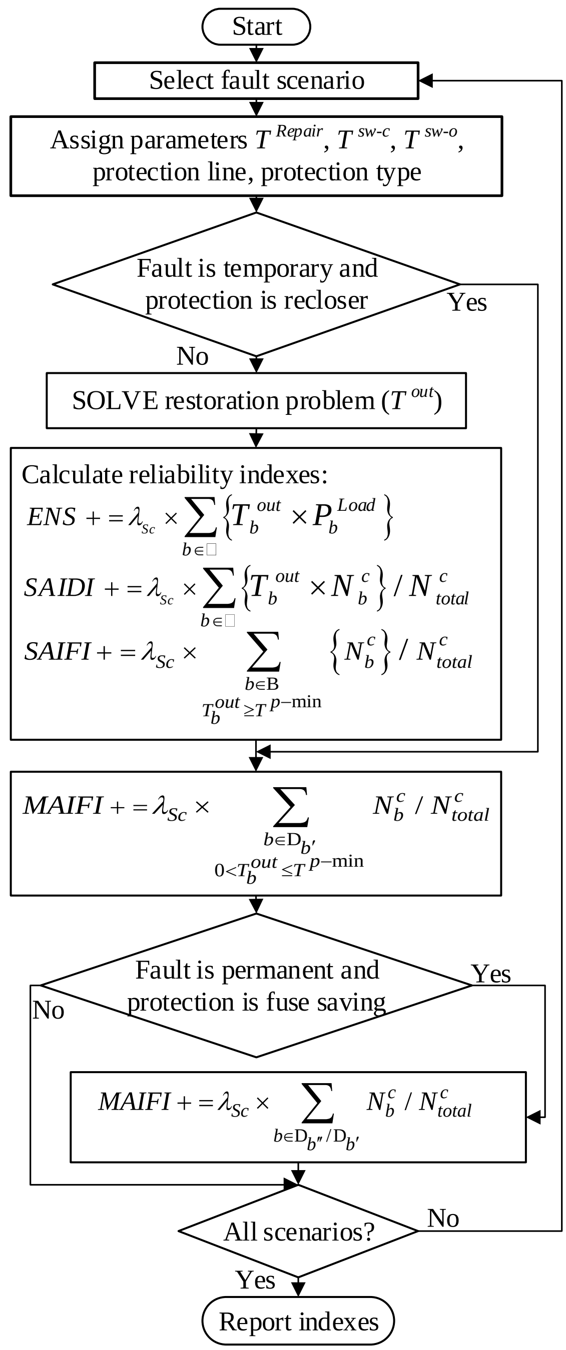


Fig. 3. Test feeder and switching devices

It is assumed that all switches involve in reconfiguration during load restoration process. The hypothetical times required for operation (opening or closing) of each switchable device or replacement of each fuse are given in Table II. One minute of operation time for remotely controllable switches is considered. It is also assumed that there are five distributed generation units in the network, information on which is given in Table III.

Network reliability information including the temporary



and permanent fault rates, expected required repair times of the faults and the number of customers per bus are also hypothetically selected. Thus, the following parameters are selected as random numbers, annual rate of permanent faults per bus between 0.05 and 0.25, annual failure rate of temporary faults per bus between 0.05 to 0.6, the expected time needed to repair each fault between 70 to 150 minutes selected.

Table II. Equipment required operation time.

Equipment	Installed line	Operation time (min.)
CB	1	1
Recloser	3	1
FB fuse	18	20
FB fuse	22	23
FS fuse	9	45

FS fuse	25	37
MS	6	35
MS	33	32
MS	37	36
RCS	15، 29، 34، 35، 36	1

Table III. DG parameters.

No.	Installed bus	$\underline{P}^G, \bar{P}^G$ (kW)	$\underline{Q}^G, \bar{Q}^G$ (kVar)
1	17	25 , 250	-175 , 175
2	19	40 , 400	-280 , 280
3	29	50 , 500	-350 , 350
4	30	50 , 500	-350 , 350
5	33	20 , 200	-140 , 140

The number of customers per bus is calculated using nominal bus power and based on the assumption that customers demand an average of 5 kW in all buses.
Outages lasting more than 3 minutes are considered permanent interruptions. The permitted range of voltage levels of different buses is considered between 0.9 to 1.05.

5.2. Numerical Results

The proposed method has been implemented on the 33-bus network with the assumptions introduced. The relevant results are collected in Table IV.
In Table IV the share of both temporary and permanent faults in each calculated index is also presented. According to these results, ENS, SAIDI, and SAIFI are mainly caused by permanent faults due to necessary repair actions and less caused by temporary faults due to recloser function. Temporary faults lead into sustained outages only where the protection has no reclosing capability, i.e., fuse-blowing fuses and CBs, as a result, restoration is subject to manual switching actions. Another observation is that ENS and SAIDI's shares from temporary and permanent faults are equal. This result is due to the assumption of similarity of customers. Because, number of customers without power is linearly dependent to power not supplied.
Depending on only outage counts, the SAIFI value relatively has a greater share from temporary faults. Because this index does not consider de-energized power and outage time. As mentioned in algorithm explanation, a permanent fault cleared by fuse-saving fuse causes momentary interruptions for loads between the fuse and its upstream recloser. Except for this condition, results regarding MAIFIe having greater value than SAIFI as well as the portion of MAIFIe caused by permanent faults show the prompt restoration which is the benefaction of the automation system, i.e., reclosing and remote switching. Expectedly, CAIDI values for temporary faults share are smaller due to restoration without repair actions. ASAI and SAIDI values being linearly dependent have similar shares from each kind of fault.

Table IV Results of reliability indices estimation

Reliability Index	Value	Temporary Fault	Permanent Fault
ENS	7236.322	6.51 (%)	93.49 (%)
SAIDI	1.94795	6.51 (%)	93.49 (%)
SAIFI	1.643	19.15 (%)	80.85 (%)
MAIFIe	4.574	83.40 (%)	16.60 (%)
CAIDI	1.1856	0.4029	1.3710
ASAI	0.9997776	0.999986	0.999792

ENS (kWh/y), SAIDI (hrs/customer/y), CAIDI (hrs/interruption), SAIFI (interruptions/customer/y), MAIFIe (interruptions/customer/y)

5.2.1 Load Points' Share in System Reliability Indices

Figure 4 shows the share of each load point in the unsupplied energy of the entire system. In this figure, as expected, load points with higher power consumption generally have a larger share of annual unsupplied energy. Because the load points that provide a large number of customers, will be de-energized all together in fault conditions.

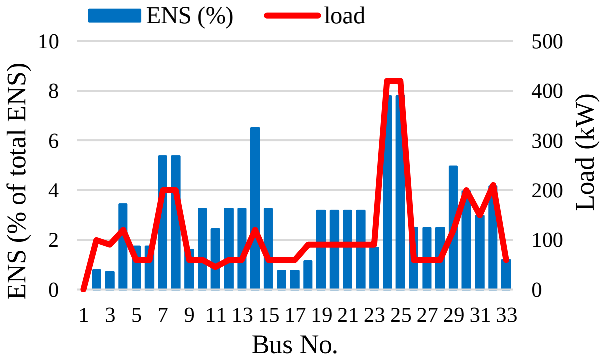


Fig. 4. Load points share in total ENS

In this regard, reliability considerations in the network planning stage can protect the distribution company from future power outage costs. Therefore, this figure can provide useful information about the weaknesses of the network in terms of unsupplied energy index. However, this figure does not provide useful information for evaluating system performance by comparing different load points. For example, looking at this figure, it cannot be concluded that the customers connected to bus #25 of the network are less satisfied with their power supply reliability than the customers connected to bus #26. To clarify this, consider Figure 5 showing the annual outage time of different load points in the network (known as the CID index). As can be seen in this figure, load point 25 experiences a shorter outage time per year than load point 26. Another noteworthy point in Figure 5 is that load points that cannot be separated by protective and control equipment have an equal outage time.

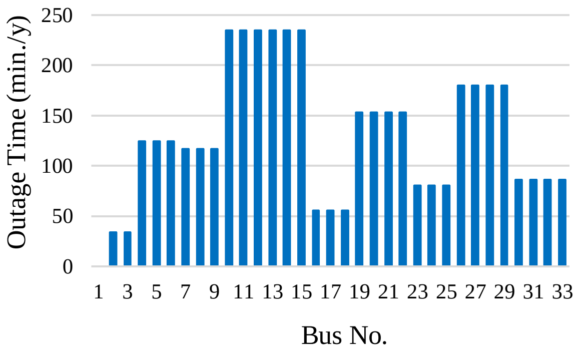


Fig. 5. Load points annual outage time

Since it is assumed that all network customers have the same power consumption, the number of customers at each load point is proportional to its power consumption, so the share of different network load points in the SAIDI index is exactly the same as energy not supplied.

In Figure 6, the share of each load point in the SAIFI and MAIFIe indices of the whole network is shown. In this figure, the effect of the number of customers on the two indices is evident. Since the temporary fault rate is higher than the permanent fault, the MAIFIe index always has larger values than the SAIFI index, except for the buses #19-#25.

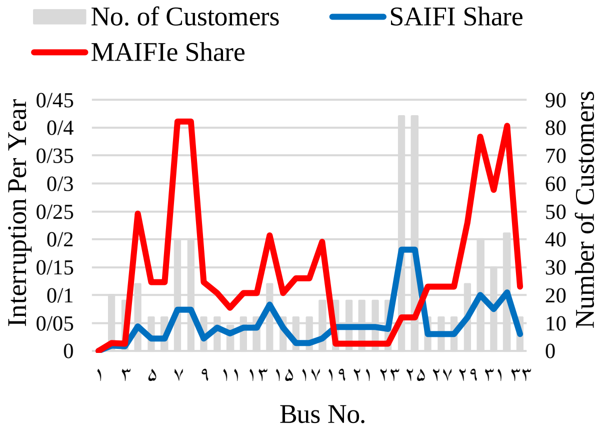


Fig. 6. Load points share in SAIFI and MAIFIe

In these buses, temporary fault due to fuse-blowing operation lead to permanent outage. Fuse-blowing fuses in these buses reduce the MAIFIe but increase the SAIFI.

5.2.2 The impacts of system's operational constraints on calculation of reliability indices

The load restoration process involves changing the normal configuration of the network and must be done in such a way that the network is in a safe operating condition. However, some authors have not considered the technical constraints of the system in their described load restoration process [11, 12, 22]. Figure 7 shows the error of indices estimation as the consequence of these constraints disregard.

The noticeable error occurred in the relaxed problem reveals that the restoration process in the absence of technical constraints suggests unacceptable configurations. This result is especially important where the estimated reliability measures are treated as a touchstone for network planning programs such as switch placement. Because, bad planning suggestions like installing switches where some switching combinations would lead to operational constraint violation, degrade system's functionality and reliability.

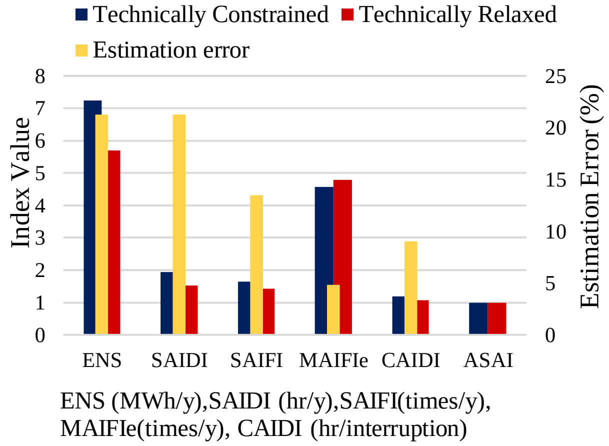


Fig. 7. Computational error in reliability indices in the absence of technical constraints

5.2.3 The Effect of DG Assisted Restoration on Outage Time

Load restoration through DGs' islanding operation is considered as an effective way to improve the reliability of local load points. In the 33-bus network described, the DG connected to bus #17 is very effective in accelerating the restoration of load points 16, 17 and 18. In order to evaluate the effect of the performance of this DG, the base problem investigated so far, has been compared with the case in which this DG is absent. Figure 8 compares annual outage time of different load points shown in Figure 5 with the new case. This figure introduces distributed generation resources as an efficient solution to reduce customers' outage times, especially for sensitive and crucial loads.

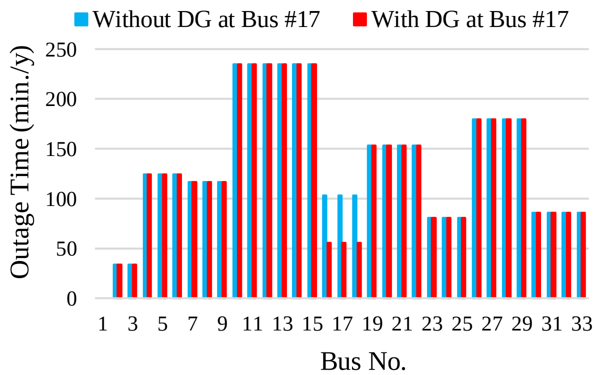


Fig. 8. DG effect on load points annual outage time

6. Conclusion

In this paper, a novel reliability assessment model was proposed to calculate common indices. As one of the main contributions, different protection and control devices function and post-fault optimal operation assessed. Applying the proposed model to 33-bus test network reveals the role of each device in system and load points reliability. Taking into account temporary and permanent faults, the model is able to calculate MAIFIe index. Results show that even for sustained interruption measures, temporary faults could have an undeniable share (6.5% in ENS and SAIDI and 19.15% in SAIFI). The optimal service restoration considers different switching operation times which could capture transportation system impacts and geographical issues. It also includes technical constraints to protect the evaluation framework from network unacceptable reconfigurations and erroneous results, especially when DGs contribute in island operation mode. Local restoration through island operation in the numerical example reduced annual outage time of three load points up to 46%.

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