High-Speed Falling Conductor Protection in Distribution Systems using Synchrophasor Data

Yujie Yin, Nathan Dunn, Hannes Kruger, Hasan Bayat and Matthew Leyba
GE Grid Solutions
Alfredo Marquez, Arturo Torres, Ignacio Sanchez, Kiet Tran, and Matthew Webster
Southern California Edison Company, USA

***Abstract*— An energized overhead power line may break and fall to the ground or other surrounding objects due to reasons such as severe weather conditions, conductor aging, natural disasters, hardware failures, and/or pole knock-over. When the falling conductor touches the earth or other grounded objects, it may cause a high-impedance (Hi-Z) fault which cannot be detected reliably by conventional overcurrent protection schemes. While current-based algorithms using negative-sequence components (e.g., the ratio of |I2/I1|) can detect most broken conductor faults in transmission systems, their efficiency is compromised in distribution systems. The performance of Falling Conductor Protection (FCP) schemes in distribution systems depends on several factors such as feeder topology, penetration level of Distributed Energy Resources (DERs), broken phase location, single-phase switching, and/or protection philosophy (e.g., type of protective devices).**

This paper proposes a synchrophasor-based algorithm to reliably detect and de-energize broken overhead lines in distribution systems using PMU data inside the substation and along the feeders. The effectiveness of the proposed FCP algorithm has been validated with Hardware-in-the-Loop (HIL) testing of realistic distribution feeders using a Real-Time Digital Simulator (RTDS). A comprehensive set of cases were tested including internal/external broken conductors, internal/external faults, various DER penetration, different load levels, and transient/switching incidents. The test results show that the proposed algorithm can detect and trip broken conductors reliably. Therefore, the proposed High-Speed Falling Conductor Protection (HFCP) scheme will be able to de-energize the affected circuit prior to the conductor hitting the ground, eliminating the risk of an arcing ground fault or energized circuits on the ground.

***Index Terms*— Falling Conductor Protection, RTDS, Synchrophasor, PMU, Broken Conductor Detection.**

I. Introduction

THE protection devices of over-head distribution lines have been primarily designed to detect high current short-circuit faults to avoid damages to equipment, isolate and minimize the faulted area, and continue service to the remaining unaffected circuits. The down conductor fault caused by a broken/falling conductor, as shown in Fig. 1, often results in very low fault current magnitudes due to the high fault impedance. In general, it is a challenging task to develop an effective method to detect high-impedance (Hi-Z) faults. While Hi-Z fault detection functions/elements have been developed and are commercially available in some digital relays [1][2], their effectiveness in complex distribution networks, especially network with high penetration of Distributed Energy Resources (DERs) is compromised. Failure to detect a falling conductor would cause a potential arcing ground fault and possibly an ignition point. Conventional technologies that uses current- or voltage-based methods such as phase voltage measurement, I2/I1 ratio, and capacitive current are not effective in distribution systems [3]-[5]. Recently, new algorithms such as 3rd harmonic power, rate of change of phase-voltage, negative-sequence voltage, zero-sequence voltage, voltage harmonic distortion, or a combination of them have been proposed [6]-[8]. However, the complexity of distribution systems and high penetration of DERs are not properly addressed in these methods. As a result, the sensitivity of these algorithms is significantly compromised under some operating conditions and feeder topologies.

A practical and scalable solution for detecting falling conductors in midair to avoid an arcing ground fault is necessary for power utilities. This paper proposes a new algorithm to effectively detect the falling conductor using rate of change of load impedance calculated using synchrophasor data, which is readily available from most modern protective relays. With one Phasor Measurement Unit (PMU) at the feeder source (substation), the algorithm provides an additional layer of protection for the main feeder and majority of branches with a high percentage of feeder load. Increased coverage can be realized by integration of additional PMUs to outlying branches that have smaller loads. The setpoints are also adapted based on the pre-fault load current to increase security of the detection algorithm for downstream branches. Further, the PMU integration criteria and methodology for proper system performance are explained in the paper. The considerations for an effective design, implementation, and testing are also discussed to help utility engineers deploy an effective protection system.

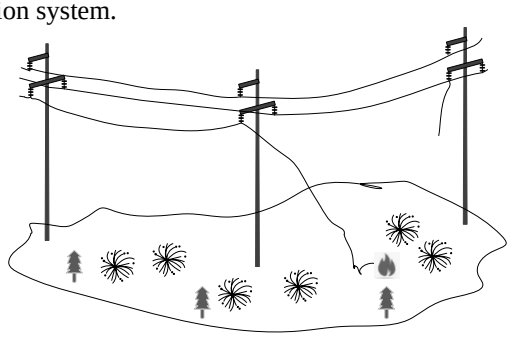

Fig. 1. An example of down conductor (Hi-Z fault) due to a broken/falling conductor

II. The Proposed Algorithm and Solution

This section analyzes the current-based methods for detecting a falling conductor in overhead lines as well as the

issues associated with those methods. Then, a new impedance-based algorithm using PMU data is proposed together with a solution architecture for a typical distribution substation.

A. Current-Based Methods

In a distribution system, a broken conductor can happen anywhere along the overhead line section of the feeder due to severe weather conditions, natural disasters, hardware failures, and/or pole knock-over. For a single-phase broken conductor, the I2/I1 ratio can be calculated from Z0/(Z1+Z0) when the current of the affected phase drops to zero. The assumption of zero load current on an open phase, due to a broken conductor of the overhead line is appropriate for two-terminal transmission lines. However, for three-terminal lines or distribution lines, this assumption does not usually hold true. Therefore, the network impedance, pre-fault load flow, and location of the break significantly impact the calculation of I2/I1 ratio in distribution system. Studies have shown that 50% of single-phase load has to be dropped for the element to pick up based on an I2/I1 ratio setting of 0.2 [4]. Fig. 2 shows a typical distribution feeder that has a recloser in the middle of the feeder as well as three load branches with possible DERs. Fig. 3 and Fig. 4 show simulation results for a close-in falling conductor on phase A (FC1) and a falling conductor behind L1 (FC2). As can be seen, the I2/I1 ratios are 0.63 and 0.2, respectively. Therefore, if a falling conductor happens at FC2 or downstream of the feeder, the probability of detecting it is very low. This significantly affects the coverage and compromises the dependability of the protection for a distribution line as it may have many branches for which load flow also varies.

There are some other methods proposed but none of them have been widely accepted and deployed. For example, the loss of single-phase voltage detection method cannot be reliably used for identifying the open phase in the distribution overhead lines due to the penetration of DERs. Setpoints for capacitive current and 3rd harmonic power methods are also hard to define due to the short length of distribution lines and the variation of load current for different fault locations.

B. Proposed Impedance-Based Algorithm

When a conductor breaks, the load impedance, can change significantly as compared with the pre-fault (healthy) condition. The phase-to-ground load and phase-to-phase load impedances can be calculated using the following equations:

$$Z_{ag} = \frac{V_a}{I_a} \quad Z_{bg} = \frac{V_b}{I_b} \quad Z_{cg} = \frac{V_c}{I_c} \tag{1}$$

$$Z_{ab} = \frac{V_a - V_b}{I_a - I_b} \quad Z_{bc} = \frac{V_b - V_c}{I_b - I_c} \quad Z_{ca} = \frac{V_c - V_a}{I_c - I_a} \tag{2}$$

The Impedance Change Ratio (ICR) δ_Z is calculated by subtracting the previous impedance Z' ($Z' = Z_{t0\text{-}n}$) from the current impedance Z (Z_{t0}) and then dividing by previous impedance Z', as follows:

$$\delta_Z = \frac{|Z|}{|Z'|} - 1 \tag{3}$$

where 'n' indicates the time window as shown in Fig. 6.

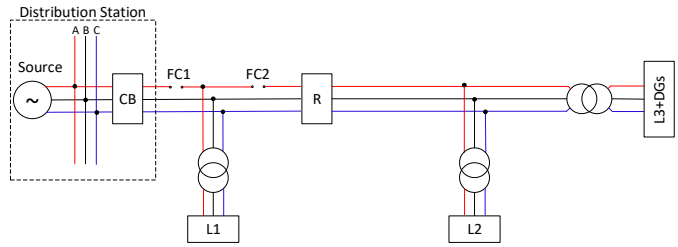

Fig. 2. A conductor break/open-phase fault on a simplified distribution feeder

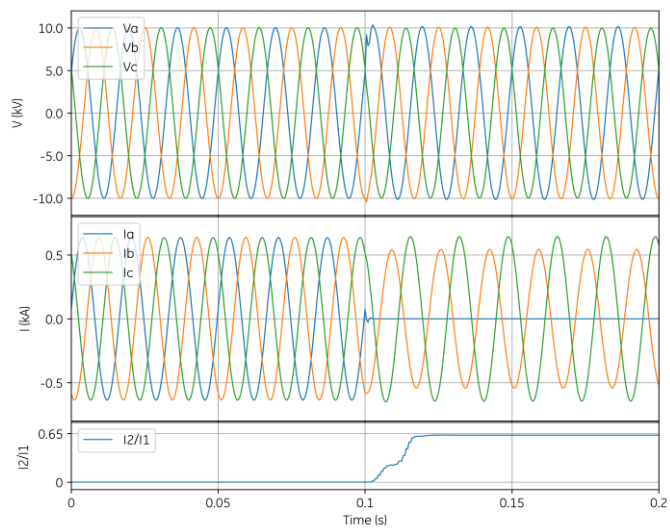

Fig. 3. A close-in conductor break/open-phase fault at FC1

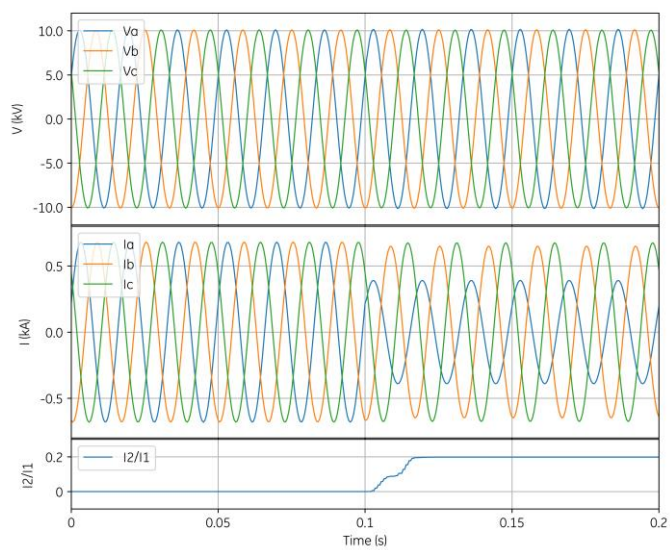

Fig. 4. A conductor break/open-phase fault behind the L1 (FC2)

Then, the ICR for phase-to-ground and phase-to-phase impedances can be calculated by Equations 4 and 5.

$$\begin{bmatrix} \delta_{Zag} \\ \delta_{Zbg} \\ \delta_{Zcg} \end{bmatrix} = \begin{bmatrix} \frac{|Z_{ag}|}{|Z'_{ag}|} - 1 \\ \frac{|Z_{bg}|}{|Z'_{bg}|} - 1 \\ \frac{|Z_{cg}|}{|Z'_{cg}|} - 1 \end{bmatrix} \tag{4}$$

$$\begin{bmatrix} \delta_{Zab} \\ \delta_{Zbc} \\ \delta_{Zca} \end{bmatrix} = \begin{bmatrix} \frac{|Z_{ab}|}{|Z'_{ab}|} - 1 \\ \frac{|Z_{bc}|}{|Z'_{bc}|} - 1 \\ \frac{|Z_{ca}|}{|Z'_{ca}|} - 1 \end{bmatrix} \quad (5)$$

The proposed FCP algorithm, as shown in the block diagram of Fig. 5, uses the ICRs calculated from synchrophasor measurements, which are streamed from feeder protective relays. The algorithm declares a falling conductor condition when certain ICRs for a distribution feeder exceed a threshold (an adjustable setpoint, defaulted at 0.18). Only single-phase falling conductors that create an open phase before falling to the ground or other objects can be detected with this algorithm. Multi-conductor per phase can be a challenge when only one of the sub-conductors breaks and falls. To prevent an incorrect alarm/trip when a fuse is blown, e.g., in one of the feeder laterals, the FCP function operates only when no fault is detected prior to the falling conductor condition (e.g., within an adjustable timer "in seconds" before the FCP operates). The FCP logic is blocked when any phase current is below or above a threshold, any phase voltage is beyond the defined healthy level, a single-phase fault condition is identified, PT secondary fuse is blown, and feeder power fuse is blown due to a short-circuit fault. A voltage-based detection scheme is also added for PMUs located along the feeder. It can detect open phases upstream of the PMU by measuring a low voltage and low current on one phase, and healthy voltages on the other two phases. This has the potential to improve the coverage of the overall solution and provides a rough estimate as to where the fault might be located for coordination with upstream PMUs, e.g., the PMU at the substation.

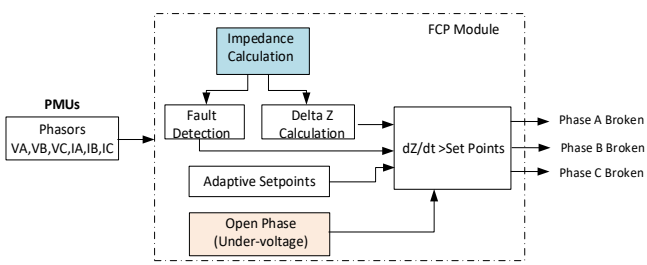

Fig. 5. Block Diagram of Proposed FCP Algorithm

Transient incidents (e.g., arcing) prior to the conductor starting to fall can affect the calculation of the impedance. To avoid this from happening, the program stores 10 previous phasors with a moving window as shown in Fig. 6. The number of phasors that is used to calculate the impedance Z is user adjustable (setting range:1-10). It is recommended to keep 4 samples between the current impedance Z and the previous impedance Z'; therefore, the default value will be 4 for PMU frame rate of 60 samples/s and 8 for 120 samples/s. Fig. 6 shows the concept of moving windows for reliable falling conductor detection.

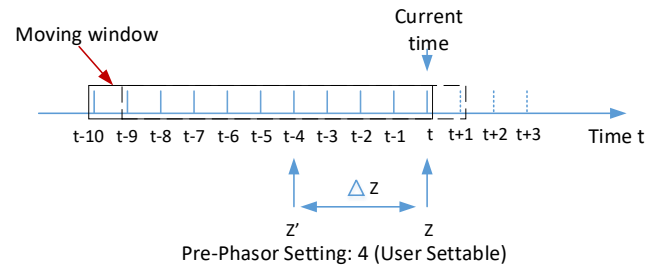

Fig. 6. Moving window of the ICR calculation

The setpoint/threshold for ratio of δ_Z in FCP logic can be adaptively adjusted based on the feeder loading (current) as indicated in Fig. 7. It can be observed from this figure that the setpoint is inversely related to the feeder load current. Thus, as the feeder load reduces, a higher ICR (ICR = δ_Z) is utilized to correctly detect a broken conductor condition. Assuming a fairly constant voltage at the substation, Fig. 8 shows the minimum approximate current (percentage of maximum load) that a branch needs to carry such that the proposed FCP logic can detect broken conductors on this branch/lateral reliably. The figure illustrates a feeder with the rating of 300A and ratio of delta_Z_setpoint (δ_{Z_Sp}) of 0.18 at the rated load. It is recommended that PMU placement and setpoints should be studied based on the load flow for each feeder and its branches to optimize the sensitivity and maximize the coverage.

Security features such as blown Potential Transformer (PT) or power fuse detection, PMU data integrity check, and Single-Line-to-Ground (SLG) fault detection are also implemented in the proposed algorithm. The fuse-blown detection blocks the operation of the FCP function when a fault is first detected, prior to the open-phase detection caused by the blown fuse (within a time frame defaulted at 1 second). A SLG fault is detected once the impedance enters the mho characteristic (setpoints) of the FCP logic. For this case, only single-phase fault can operate (combined with over-current disturbance detection – 50DD); thus, the SLG fault detection module blocks the FCP algorithm when a fault is first identified.

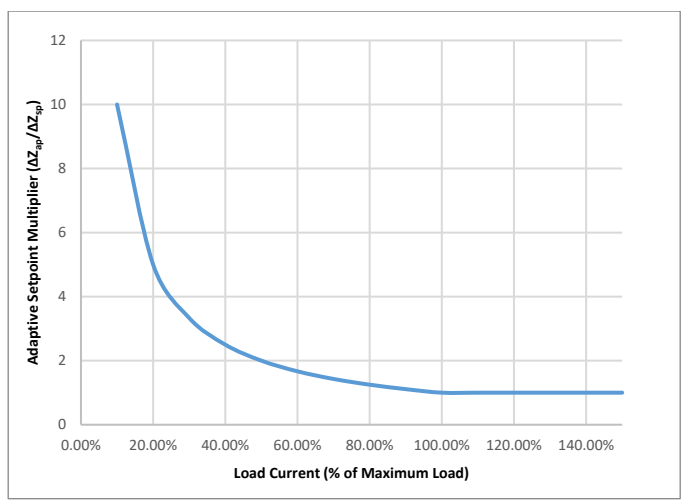

Fig. 7. Ratio of Delta_Z setpoint (setpoint at rated feeder load 300A is 0.18)

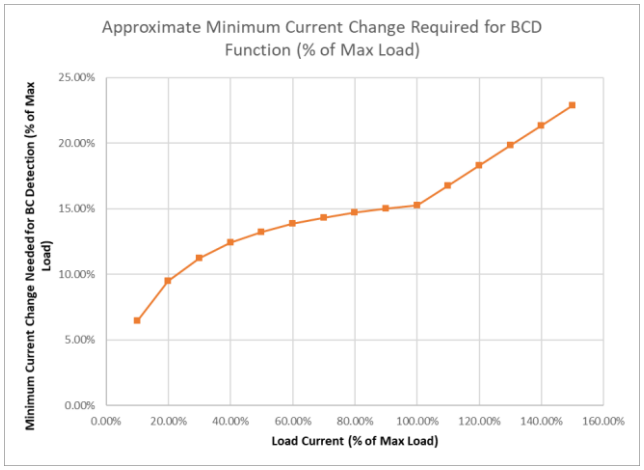

Fig. 8. Minimum branch current for successful FCP as a function of the feeder loading (rated load is 300A with ratio of delta_Z_setpoint = 0.18)

C. *High-Speed Falling Conductor Protection Solution*

Fig. 9 shows the proposed HFCP system architecture for a typical six-feeder distribution substation that embeds DERs. The PMU function of each feeder protection relay is enabled to stream out synchrophasor data (e.g., with 60 samples per second) to a Real-Time Controller (RTC) where the HFCP algorithm is implemented. These devices are all located within the substation and communicate with each other over Ethernet/Fiber on the substation's Local Area Network (LAN).

The Substation LAN forms the core of the HFCP solution and provides a good percentage of coverage for all the feeders. Additional PMUs can improve the coverage of the overall HFCP solution; they could be installed along the feeder and/or sourced from existing auto-recloser relays (only one feeder is shown in Fig. 9 as an example). The feeder PMU data is also streamed back to the RTC via a Field Area Network (FAN) and an Access Point (AP) located in the substation. Various technologies such as cellular communication and unlicensed/licensed radio can be used to implement this solution. The advantages and disadvantages of each technology are outside the scope of this paper. However, the main requirements from the HFCP solution would be that the network should provide sufficient bandwidth for the number of PMUs required at an acceptable latency to ensure that the algorithm has enough time to de-energize the line before the conductor reaches the ground. When a broken conductor occurs on one of the overhead lines, the RTC detects it and sends trip commands via IEC 61850 GOOSE messages to the relevant relay to trip the corresponding feeder and/or block the reclosing function. An engineering workstation can be installed for configuration of the HFCP system as well as the Human Machine Interface (HMI). When a broken conductor is detected, an indication of the affected feeder along with an approximate location of the falling conductor is displayed.

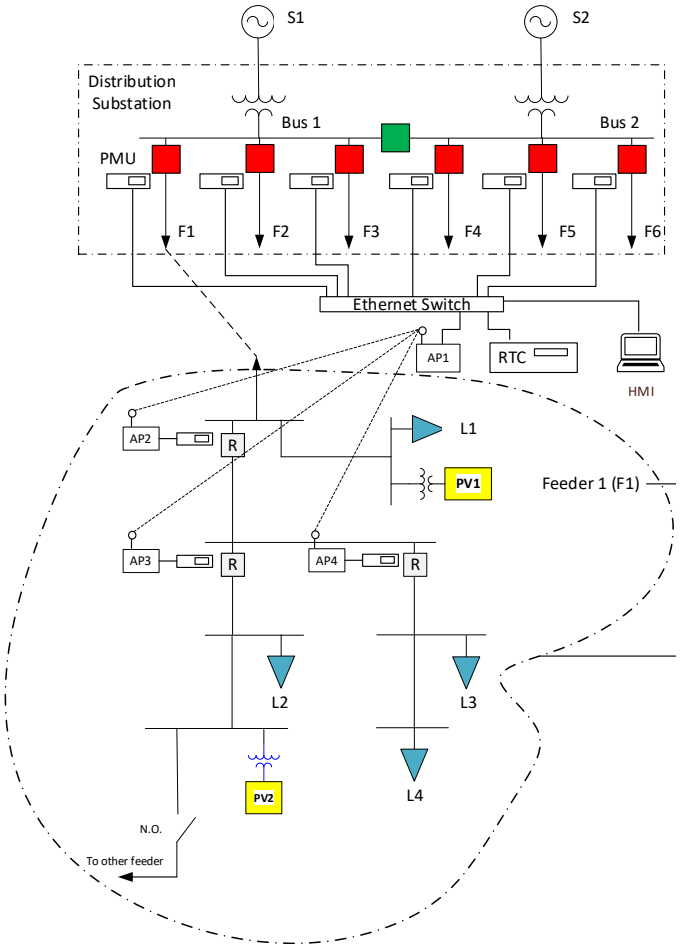

Fig. 9. An example of FCP system for a distribution substation with six radial feeders

III. System Design Considerations

The HFCP solution for detecting falling conductors in distribution systems can be deployed for any distribution substation regardless of the number of outgoing feeders. Taking Fig. 9 as an example, the HFCP system consists of an RTC, a workstation (optional), a managed Ethernet Switch for the LAN, PMU devices (e.g., from protective relays that have PMU capabilities), and FAN for distribution feeders.

A. *Hardware Requirements*

The RTC is a high-performance computing platform that supports real-time control logic engine and high-speed Ethernet communications with multiple protocols such as DNP, C37.118, IEC 61850. It also serves as a Phasor Data Concentrator (PDC) and buffers the incoming phasor data in a synchronized manner to ensure coordination between multiple PMUs. Current and voltage measurements that are used to calculate the ICRs can be synchrophasor data or IEC 61850 analogue GOOSE data.

The workstation (optional) is an industrial computer with required software such as HMI software, data archiving and visualization software, and HFCP configurator.

Typical bandwidth of the Ethernet LAN for the substation communication network is 100Mbps or higher. Since PMUs and the RTC shall be time synchronized, a GPS clock is required for the HFCP solution. The IEEE 1588 Precision Time Protocol and IRIG-B are supported to provide GPS clock

signals throughout the network. The PMU device (IEEE C37.118 protocol) can be stand-alone devices or protective relays with PMU capabilities.

The FAN is utilized for extending the HFCP solution beyond the substation to incorporate additional feeder PMUs into the solution. It should provide sufficient bandwidth at an acceptable latency to ensure that the solution can trip the breaker before the conductor reaches the ground. It should also support the protocols required by the solution (i.e., C37.118 and IE C61850 GOOSE) as well as relevant standard time synchronization protocols.

B. Time Constraints

The HFCP solution detects a falling conductor and trips the breaker before the conductor reaches the ground to evolve into a fault, as shown in Fig. 10. A conservative estimation can be made using the worst-case scenario of a sagging conductor free-falling from a height of midpoint (lowest sagging point). The height of the conductor depends on the voltage level and other factors (building, highway, bridges, hills). The minimum ground clearance requirements from NESC [9] have been used as a conservative estimation for the calculation of falling time. The minimum height for 11kV voltage level or higher is around 5.6m or 18 feet, which results in a falling time of 1.06 seconds (see Eq. (6)).

$$h = \frac{1}{2}(g.t^2) \rightarrow t = \sqrt{\frac{2h}{g}} = \sqrt{\frac{2x5.6}{9.8}} = 1.06s \qquad (6)$$

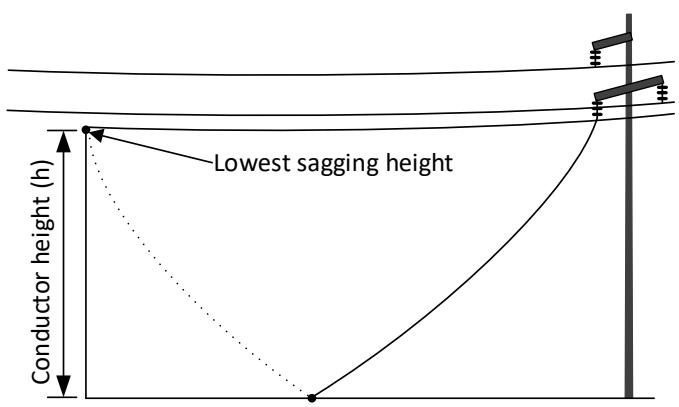

Fig. 10. An illustration of the relevant heights for a falling conductor in distribution system for estimating the time to trip

C. HFCP Configuration

The HFCP solution is adaptable and has certain setpoints that need to be configured; these settings give enough flexibility to the operator to adjust the overall sensitivity and security of the solution.

The Delta Z setpoint (δ_{Z_Sp}) is used by the algorithm as the threshold for detecting a fallen conductor. The setpoint is adapted based on the ratio of the maximum load current to the prevailing load current. At load currents below the maximum load current, the ICR is adapted and scaled up to increase security. At load currents above the maximum load current, the ICR required is kept constant. The effect of these setpoints can be observed in Fig. 11 with each curve corresponding to a different setpoint and indicating the minimum current change that would be needed to operate. Increasing δ_{Z_Sp} decreases overall sensitivity, while increasing the maximum load current would decrease sensitivity for currents below that level.

The number of phasors used by the algorithm to calculate the ICR is also adjustable and is dependent on the PMU frame rate. There is also an option to delay the operation of the HFCP logic for any given PMU for coordination purposes on feeders with multiple PMUs. The default is set at 300ms for the PMU located at the substation. This allows devices downstream to clear the falling conductor fault before the relay at the substation issues a trip command to de-energize the entire feeder. The voltage-based detection (loss of a single phase voltage) in downstream PMU devices can also be enabled, which improves the security of the overall solution; this allows the substation relays to trip immediately because it is a clear signal of a falling conductor between the substation PMU and the PMUs that detected the open phase based on single-phase voltage loss. Finally, the minimum fault current is used to block the HFCP operation and to identify fuse-blown conditions.

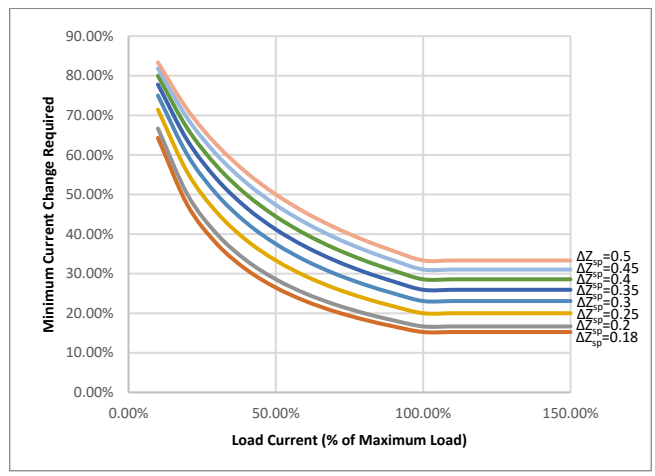

Fig. 11. Minimum current change needed for various setpoints of Delta_Z.

D. PMU Placement and Performance Evaluation

To increase the sensitivity and maximize the coverage for each feeder, studies must be performed to optimize the placement of additional PMUs along the feeder. A methodology is proposed in Fig. 12 on how to identify and select the optimal locations for the placement of the PMUs.

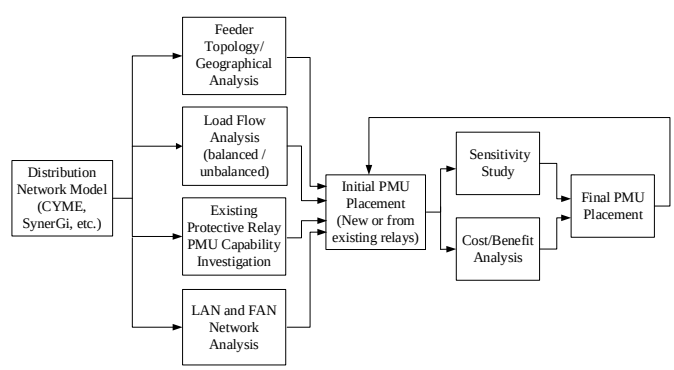

Fig. 12. PMU Placement Methodology

Firstly, the distribution network model is required to start the study and identify potential locations for additional PMUs. Utilities typically model their distribution systems with

substations, generators, feeders, and protective devices for power system studies such as power flow, short-circuit, protection coordination, arc-flash study, voltage analysis, etc. Geographic Information System (GIS) should also be used to analyze the feeder topology; the criteria for selection may include identification of the major laterals on the feeder considering locations where the feeder splits, prioritization of overhead lines sections over cables, availability of communication infrastructure (LAN or FAN), availability of primary plant infrastructure (e.g., current and voltage transformers for PMU, protective relays, and the potential impact of a falling conductor (e.g., areas with high risk of fire). The feeder geographical maps and distributed load can also be modeled in simulation software. The location of DERs should also be considered as it may have the effect of reducing the sensitivity of the solution. This is because DERs generally decrease the load current at the feeder head below the maximum load current for a significant period; as a result, the adaptive setpoint gets shifted higher. Installing a PMU beyond sections of the network with significant DER penetration could improve the overall sensitivity and coverage of the solution. With the above criteria, each feeder can be divided into sections to shortlist initial PMU locations for further analysis. Once all candidate locations have been identified, the exposure length of the feeder beyond each location needs to be noted.

Next, for each feeder, these sections for initial PMU placement can be evaluated by performing a sensitivity study and cost/benefit analysis. With the load-flow study results, the maximum load current and the largest single-phase load expected within each section should be recorded. The sensitivity study can then be performed to identify how much the sensitivity of the solution is improved with the installation of an additional PMU and determining the potential risk that will be reduced by using the exposure length as a metric. The minimum current needed for detecting a falling conductor can also be determined from Fig. 11. An example of the data required is shown below in Table 1 for the study system of Fig. 9.

Table 1. Data needed for PMU Placement Study

Potential PMU Locations	Max Current (A)	Largest 1φ Load (A)	Exposure Length (m)	Min Load Current Required
Sub PMU	214	7	13474	33
P1	67	7	6477	10
P2	127	5	2209	19
P3	51	5	3419	8
P4	12	5	2107	2
P5	52	7	834	8
P6	58	5	281	9

The data can then be represented visually as shown in Fig. 13 for each PMU location. The maximum load current observed at each location is indicated on the right side of the chart with a blue dot and denoted by the suffix "-Max". The required minimum current change that is detectable as a fallen conductor condition for each location is indicated on the left side of the chart with a green dot and denoted by the suffix "-FCP". These two points effectively indicate the range of detectable falling conductor currents during maximum load conditions.

The limit of the PMU located at the substation is also shown as a solid orange line to give an indication of how much the sensitivity of the scheme can be improved by placing a PMU at that location. Everything to the right of the line would be covered by the PMU at the substation, while locations to the left would not. Installing additional PMUs essentially allows the engineer to reduce the maximum load current for that section and increase the sensitivity of the overall solution. The exposure length provides an indication of the amount of risk that the PMU at that location would mitigate if the sensitivity is improved.

The largest single-phase load within the zone of each PMU is also shown as a red dot for consideration. The recommended default for this is calculated at 100kW, but if any larger single-phase loads are present, this needs to be considered. The largest single-phase load puts a practical limit on the improvements to sensitivity, because it is not possible to distinguish between a single-phase load trip and a falling-conductor condition.

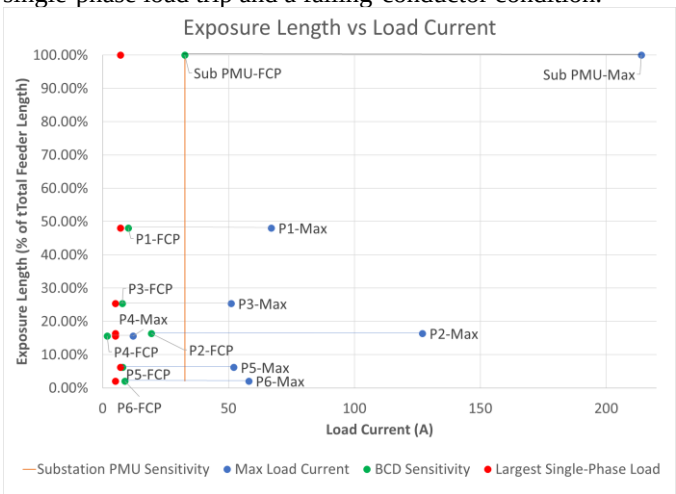

Fig. 13. Load Current and Exposure Length Analysis example.

Finally, the under-voltage detection method provides an option to install PMUs at remote locations on the feeder if there are no large DERs installed on the feeder that can keep the voltage healthy at the PMU's point of measurement. This method has the advantage that it can detect broken-conductor conditions upstream of the PMU, even during low load conditions where the impedance-based algorithm may miss a falling conductor on laterals. Installing a PMU at the end of the feeder effectively covers the section of the feeder in series from the substation to the PMU.

IV. Simulation Studies and Result Analysis

The RSCAD software was used to model a realistic distribution substation shown in Fig. 14 in Real-Time Digital Simulator (RTDS). The RTDS model includes two feeders where the feeder of interest is modelled in more detail including behind-the-meter rooftop Photovoltaic (PVs) systems. Moreover, to study the impact of high DER penetration on the performance of the HFCP algorithm, a 1MW utility-scale DER is added to the feeder under study. This DER provides the opportunity to study the performance of HFCP in the presence of a large DER on the feeder under various loading conditions.

As shown in Fig. 14, the modeled distribution feeder has three PMU devices on its branches (PMU1, PMU2, and PMU3) and one PMU device at the substation (PMU0). The PMU devices on feeder branches communicate measured currents and voltages to the real-time logic engine through a radio

channel. The PMU device at the substation communicates its measured values with the real-time logic engine using Ethernet cable or fiber optic (all in IEEE C37.118 protocol).

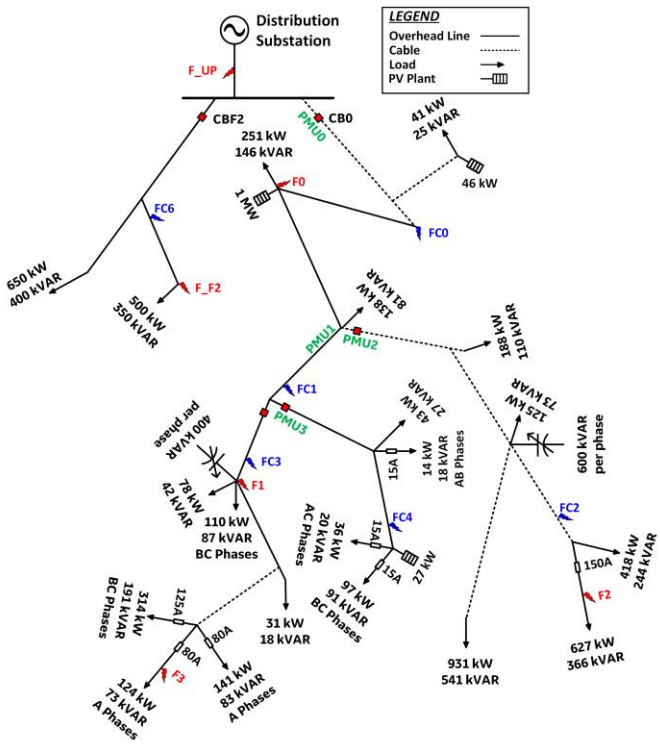

Fig. 14. A simplified one-line diagram of the distribution feeder model

The simulated system includes six different fault locations where F_UP is the upstream fault, and F_F2 is the fault on neighboring feeder. Fault locations F0 to F3 are located on the feeder of interest, while faults F2 and F3 would cause a fuse-blown condition because these faults are situated downstream of fuses. Moreover, the model of the system embeds five broken conductor locations on the feeder of interest which are identified as FC0 to FC4, while there is also a falling-conductor location on the neighboring feeder (FC6). FC6 is simulated to evaluate the impact of an out-of-zone falling conductor on the performance of the HFCP algorithm

The HFCP solution has been tested using the Hardware-In-the-Loop (HIL) technique, and all the devices such as PMUs, relays, and the RTC are integrated with the RTDS in a lab environment to test the HFCP performance. The HFCP solution has the capability to archive and visualize measured and calculated parameters of the system. The archiving and visualization provide detailed insight into the status of the feeder and performance of the solution.

Fig. 15 shows the communication architecture for the HFCP solution. The PMU devices located downstream of the substation send associated measurements to the radio master station using a wireless channel. These data are then sent to the RTC to be used by the HFCP algorithm. The internal variables of the HFCP algorithm including the impedances measured at the location of each PMU device is also sent to the workstation for monitoring and archiving. The solution can be accompanied by an HMI, which allows the user to interact with the HFCP system and monitor the status of the system.

To evaluate the performance of the HFCP solution, 188 broken conductor cases, 32 control cases, and 168 fault cases were tested. Seven possible fault types (AG, BG, CG, ABG, BCG, ACG, and ABC) at different loading levels with and without the utility-scale DER are included in the 168 fault scenarios. Single-phase falling conductor at different loading levels and different phases with and without the presence of the DER form the 188 broken conductor test cases. For control scenarios, 32 switching operations at all the breakers shown in Fig. 14 at different loading conditions and with and without the DER are conducted.

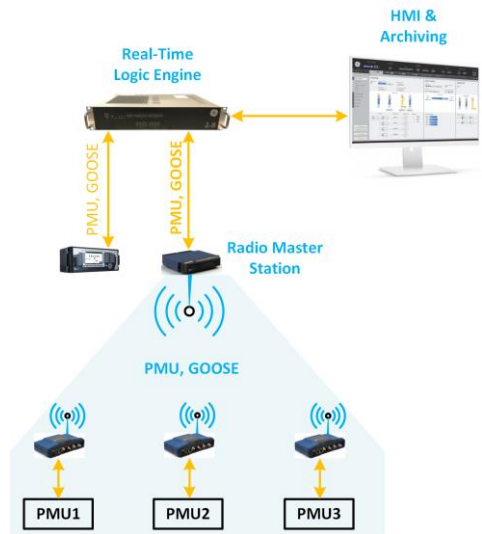

Fig. 15. Communication architecture used for HIL testing of HFCP solution

Table 2. HFCP test results and operation times

Case	Location	DER	Load	PMU0 BCD (s)	PMU1 BCD (s)	PMU2 BCD (s)	PMU3 BCD (s)	HFCP Op_Time (s)
1	FC0	OFF	MAX	0.13765				0.13765
2	FC1	OFF	MAX	0.13665	0.1207			0.1207
3	FC2	OFF	MAX	0.46068		0.13188		0.13188
4	FC3	OFF	MAX	0.44435	0.1311			0.13105
5	FC4	OFF	MAX				0.13843	0.13843
6	FC0	ON	MAX	0.14508				0.14508
7	FC1	ON	MAX	0.46205	0.1327			0.1327
8	FC2	ON	MAX	0.45575		0.14175		0.14175
9	FC3	ON	MAX	0.44638	0.1324		0.14803	0.14803
10	FC4	ON	MAX				0.14108	0.14108
11	FC0	OFF	MIN	0.14523				0.14523
12	FC1	OFF	MIN		0.1503			0.15025
13	FC2	OFF	MIN					
14	FC3	OFF	MIN		0.1429			0.14292
15	FC4	OFF	MIN					
16	FC0	ON	MIN	0.45445				0.45445
17	FC1	ON	MIN		0.1314			0.13135
18	FC2	ON	MIN			0.16007		0.16007
19	FC3	ON	MIN		0.1544			0.15443
20	FC4	ON	MIN					

Table 2 shows a selection of test results for HFCP HIL testing. The test results cover broken-conductor events at minimum and maximum loading of the feeder, which correspond to 20% and 100% feeder loading, respectively. The blank cells in the table indicate that the specific PMU was not located on the path to the broken conductor or it did not detect the fault. As an example, for Case 1 in Table 2, PMU1, PMU2 and PMU3 do

not see the impedance change caused by broken conductor at location 0 since they are not located in the path and are not expected to detect the falling-conductor event at this location.

Case 1 is a close-in falling conductor which happened at the main feeder; therefore, only PMU0 has detected the event. The detailed recording of this event is shown in Fig. 16. It can be observed that the impedance seen by PMU0 increased significantly after the broken conductor event and the ICR reached 92.6, which is significantly above the setpoint; thus, the RTC issued an FCP event in about 138ms. The calculated |I2/I1| ratio in this case increased to 0.5, and it will be able to detect this event as well.

For Case 5 in Table 2, the falling conductor happens at Location 4, downstream of PMU0, PMU1, and PMU3. However, since the current of the branch where the falling conductor has taken place is too small, only PMU3 (the closest PMU to the break point) can detect it. Fig. 17 shows the coordination example of the HFCP for a falling conductor downstream of PMU2 at FC2. As can be seen in this figure, the ICRs measured by both PMU0 and PMU2 data were above the setpoints. Therefore, the HFCP delayed the FCP signal of PMU0 by 300ms to allow downstream devices at PMU2 to trip the circuit. It can also be observed that the |I2/I1| ratios in this case for both PMU0 and PMU2 are less than 0.2 and, therefore, the |I2/I1| method fails to detect the broken conductor. The HFCP operating time (Op_Time) represents the overall performance of the solution, which corresponds to the minimum time required for the broken conductor to be detected by one or more of the PMU devices. Investigating this column in the table shows that there are 3 cases where the HFCP system was not able to detect a broken conductor. All three cases happened during the minimum loading condition of the feeder while the break location was on the lateral branches; this is because the load current is very small for these branches when the feeder loading is at minimum (0.8A for FC4 and 1.2A for FC2).

Further analysis of the HFCP operating time shows that all operations have happened within 150ms except case 16, which has operated in 454ms (see Table 2). The reason for the longer operation time in this case is that PMU0 coordinates with downstream devices with a 300ms Coordination Time Interval (CTI). If no loss of phase voltage confirmation is received within the CTI, then PMU0 operates based on its own ICR. The loading of the feeder is minimal in this case, hence, following a broken conductor incident, the downstream PMU devices do not see immediate loss of voltage because the utility-scale DER supports the system voltage beyond the break point. By comparison with Case 1, it can be observed that the DERs along the feeder may slow down or desensitize the proposed algorithm.

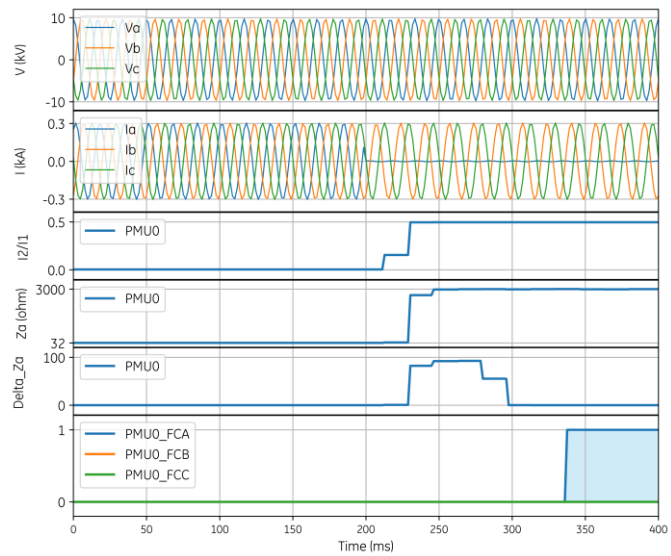

Fig. 16. Case 1: a close-in falling conductor at main feeder

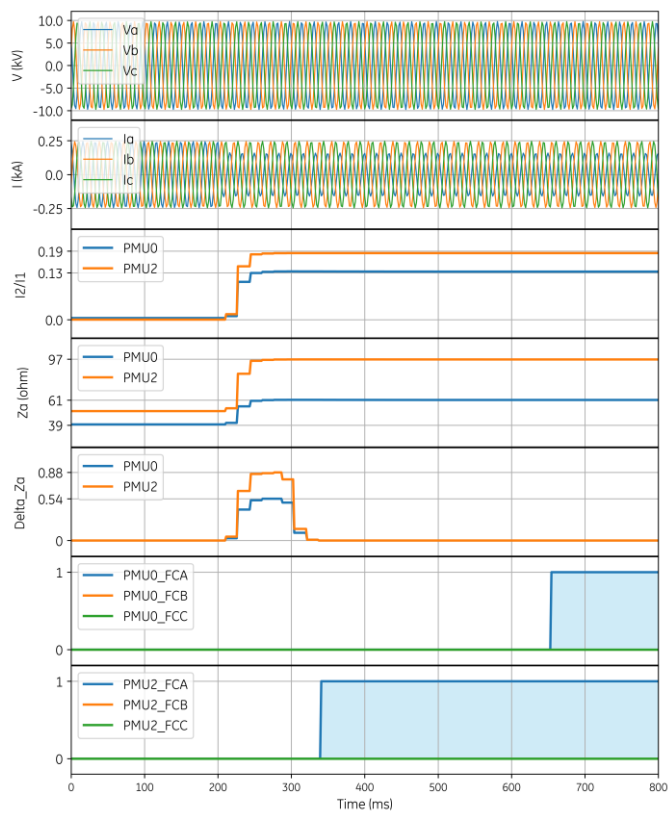

Fig. 17. Case 8: falling conductor at FC2 (one of the branches)

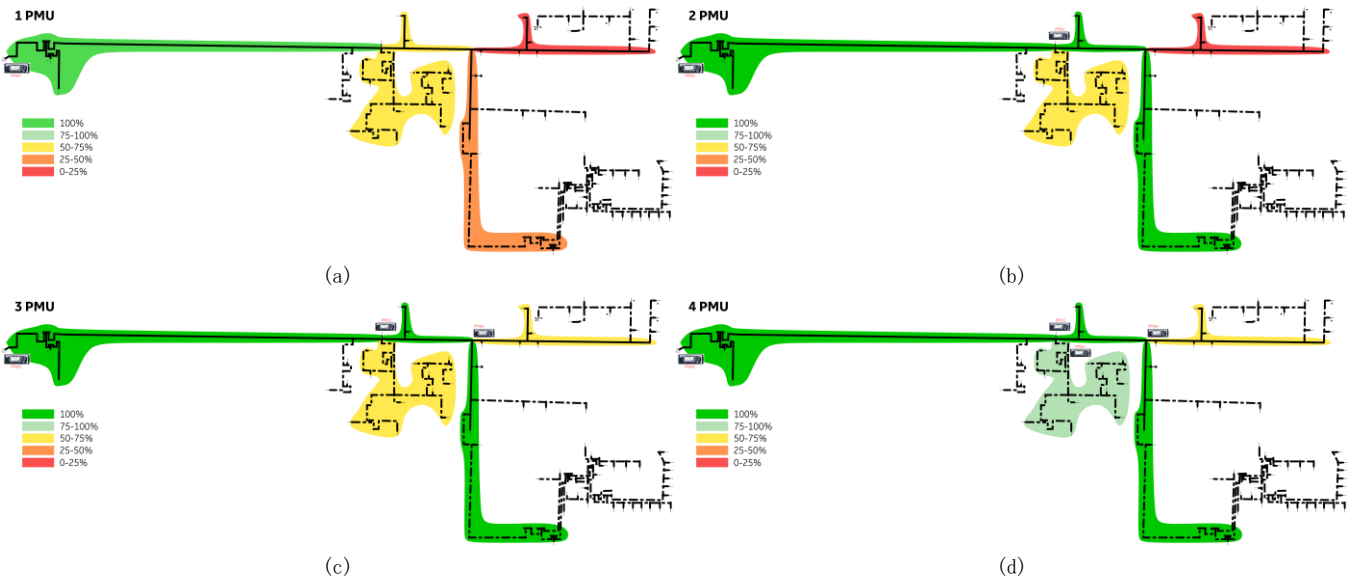

Fig. 18. Broken conductor coverage w.r.t the number of PMU devices

As mentioned earlier, the solution can work with only one PMU at the substation; however, more PMU devices on the feeder means higher falling conductor protection coverage and better visibility of the feeder's status. The RTDS model used for this study includes three downstream PMU devices and one PMU device located at the feeder head inside the substation. Fig. 18 shows the broken conductor protection coverage increase of the HFCP solution based on the number of PMU devices on the feeder. One PMU at the substation would provide coverage for the backbone portion of the feeder. However, if the break happens within the branches of the feeder, one PMU at the substation would not suffice for covering all cases. Strategic placement of more PMU devices on the distribution feeder and monitoring the ICR at different locations on the feeder increases the coverage significantly as shown in Fig. 18(a)-(d).

V. Conclusions

Detection of a falling/broken conductor on the distribution system is a challenging task with existing current- or voltage-based methods, especially when the distribution feeders embed a high penetration of DERs. This paper presented a new solution for detection of falling conductors using ICRs calculated from synchrophasor measurements at different locations along the over-head distribution lines. It is widely applicable to the utility's distribution systems and can trip the line breakers before the conductor hits the ground; therefore, it mitigates the risk of an arcing ground fault or energized circuits on the ground. Moreover, it prevents the possibility of any ignition point caused by the broken power lines.

The solution presented in this paper is flexible and easy to expand. Using a single PMU installed at the distribution substation for each feeder, a significant percentage of falling conductor conditions on the main feeder can be detected. Also, depending on the load distribution among laterals and allowable system imbalance, the proposed HFCP function can detect falling conductor events on laterals with adequate load current. Additional PMUs can be placed on the main branches as well to help increase the coverage. It is recommended to conduct a PMU placement study based on feeder load data, DER locations and type, and communication network availability and baud rate to optimize the deployment cost.

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