An adaptive protection infrastructure for modern distribution grids with distributed generation

Vasileios A. Papaspiliotopoulos, George N. Korres* and Nikos D. Hatziargyriou
National Technical University of Athens, Greece

Abstract
The presence of renewable energy resources and conventional distributed generation (DG) in modern distribution networks challenges the traditional protection schemes, since the radial single-fed concept is no longer adopted. In this paper, a new adaptive protection system, which takes advantage of multiple relay setting groups (SGs) and optimisation techniques, is introduced. Moreover, a hardware-in-the-loop (HIL) configuration appropriate for testing adaptive protection systems is presented. A distribution test system with large DG penetration is used to demonstrate the efficacy of the proposed solution, and simulation results are thoroughly discussed.

1. Introduction
These days, the global demand for more “green” energy resources has led to large integration of distributed generation (DG) into distribution systems, and the concept of “smart grid” has introduced new sophisticated network configurations. However, this evolution of distribution systems has posed new challenges to long-established protection schemes, including feeder protection blinding, sympathetic tripping of adjacent feeder relays, miscoordination between reclosers and downstream fuses, failed auto-reclosing, and unintentional islanding. Therefore, the development of advanced protection solutions is of great importance, since distribution systems reliability and service continuity are inextricably linked with the performance of protection schemes.

So far, non-directional overcurrent protective devices were successfully employed in distribution networks operating with single-source radial topology. Nevertheless, the growing DG penetration in distribution grids, combined with the variable grid operating mode, has caused significant change in short circuit levels and bidirectional fault current flows. To address this paradigm shift in distribution systems operation, new protection strategies are mainly orientated to the implementation of adaptive protection schemes, utilising directional overcurrent relays (DOCRs) with communication capabilities and multiple setting groups (SGs).

Several methods have been used by protection engineers to derive proper relay setting values, satisfying also the so-called coordination constraints between primary and backup protective devices. Worldwide, distribution utilities were using expert rules to determine appropriate pickup current and time dial values for the inverse-time characteristics of feeder relays, achieving also sufficient coordination with downstream reclosers and fuses. On the other hand, various optimisation methods have been proposed in the literature for the problem of optimal setting and coordination of the relays, which has been stated and successfully solved as linear programming (LP), nonlinear programming (NLP), and mixed-integer nonlinear programming (MINLP) problem.

In this paper, the impact of DG presence on conventional distribution protection schemes is thoroughly discussed. Then, a hardware-in-the-loop (HIL) infrastructure is proposed, which can be used as a complete testbed for adaptive protection schemes. Moreover, the integration of optimisation techniques in the adaptive procedure is proposed. This novel concept can lead to great enhancement of adaptive protection schemes developed so far, since it combines the flexibility of automatic relay SG adjustment with the determination of optimal relay setting parameters.

The remainder of the paper is structured as follows. In Section 2, protection blinding, sympathetic tripping,
which frequently follows an out-of-zone fault, or due to DG backfeed to a fault on an adjacent feeder [1], [2]. This phenomenon is also called false tripping, and belongs to the wide class of nuisance tripping problems due to various root causes (e.g. motor starting, magnetising inrush current during transformer energisation, cold-load pickup, voltage sag or swell etc.). In this paper, we focus on the sympathetic tripping scenario caused by the contribution of DG for faults beyond its feeder protection zone.

As has been discussed in recent literature, DG units can cause false tripping and undesirable disconnection of an adjacent healthy feeder. The basic principle of sympathetic tripping can be explained in Fig. 2, where a fault occurs at Feeder 2 and the DG unit connected to Feeder 1 feeds the short-circuit through the substation bus. If the DG contribution is particularly large, relay R1 may operate before relay R2 takes action and clears the fault. This is possible when non-directional overcurrent relays are used for feeder protection, which cannot discriminate the change of fault current direction (reverse fault). The utilisation of non-directional overcurrent relays is a long-established protection practice for most distribution utilities owing to their single-fed radial networks, unlike modern multi-source distribution systems with bi-directional current flow.

2. Impact of distributed generation on feeder protection

2.1. Protection Blinding

Traditional distribution systems had only one source contributing to a fault incident, that is the main substation, and protective relays were set to see a certain distance down the radial feeder. This distance is usually referred to as the reach of the protective device, which is actually determined by the minimum fault current that the device can detect. However, the connection of DG units to modern distribution networks introduces additional fault current sources, which may increase the total short-circuit level within the network, while altering the magnitude and direction of fault currents sensed by installed protective devices.

When the DG plant is located between the utility substation and the fault location, the total fault current is increased due to the partial contribution of DG, as illustrated in Fig. 1. On the other hand, the fault current seen by feeder relay R1 is actually decreased for the same fault, owing to fault current division between the sources, which may not exceed the pickup current setting of R1. This undesirable protection performance is widely known as protection blinding [1], [2]. The blinding effect results in delayed protection operation or even total desensitisation in case of weak upstream system and large DG penetration. This phenomenon is also called protection under-reach, since the actual reach of the feeder relay is decreased due to DG fault current contribution, as also shown in Fig. 1.

2.2. Sympathetic Tripping

Sympathetic tripping refers to the undesirable operation of the feeder relay due to unbalanced or high-load condition, which frequently follows an out-of-zone fault, or due to DG backfeed to a fault on an adjacent feeder [1], [2]. This phenomenon is also called false tripping, and belongs to the wide class of nuisance tripping problems due to various root causes (e.g. motor starting, magnetising inrush current during transformer energisation, cold-load pickup, voltage sag or swell etc.). In this paper, we focus on the sympathetic tripping scenario caused by the contribution of DG for faults beyond its feeder protection zone.

As has been discussed in recent literature, DG units can cause false tripping and undesirable disconnection of an adjacent healthy feeder. The basic principle of sympathetic tripping can be explained in Fig. 2, where a fault occurs at Feeder 2 and the DG unit connected to Feeder 1 feeds the short-circuit through the substation bus. If the DG contribution is particularly large, relay R1 may operate before relay R2 takes action and clears the fault. This is possible when non-directional overcurrent relays are used for feeder protection, which cannot discriminate the change of fault current direction (reverse fault). The utilisation of non-directional overcurrent relays is a long-established protection practice for most distribution utilities owing to their single-fed radial networks, unlike modern multi-source distribution systems with bi-directional current flow.

2.3. Failed Reclosing

Protection problems in distribution networks may be caused by the automatic reconnection of the utility in

Fig. 1. Change in flowing fault currents due to DG presence (protection blinding case).

Fig. 2. DG contribution to fault incident on adjacent feeder (sympathetic tripping case)
case of DG presence. A reclosing attempt is deemed to be successful when there is sufficient time margin between shots for the fault arc to dissipate and clear, which means that each DG unit must detect the presence of a fault and disconnect early in the reclose interval, as illustrated in Fig. 3. Otherwise, the DG unit will continue to feed the fault hindering the arc extinction, and the fault that would have been temporary becomes permanent.

A potential reclosing failure to clear the fault means that some customers will suffer a sustained outage, whereas they should be subjected to only momentary interruptions. Thus, the reliability of the power delivery system is slightly degraded. Furthermore, the active power unbalance during the dead time of the reclosing sequence can lead to frequency variation in the islanded part of the distribution grid, and generators may drift away from the synchronism with respect to the main system [1], [2]. In this scenario, a reclosing attempt would couple two asynchronously operating systems. Moreover, conventional reclosers are designed to reconnect the circuit only if the substation side is energised and the opposite side is de-energised. In case of DG integration, there would be active sources on both sides of the recloser, hampering proper operation of the reclosers.

In addition to the aforementioned protection challenges, the constantly increasing presence of DG units in distribution systems deteriorates the coordinated operation of feeder reclosers with downstream lateral fuses. Fuses are the most common overcurrent protective means in distribution networks, characterised by low cost and high reliability, while reclosers are overcurrent protective devices most often used to “give every fault a chance to be temporary” [3]. The vast majority of distribution utilities have successfully employed fuse-saving schemes so far, aiming at the highest level of service availability for their end-customers.

In a fuse-saving scheme, the recloser operates with its fast curve (an instantaneous overcurrent element 50P/N is usually used), and trips the feeder breaker for any downstream phase or ground fault. The breaker is tripped before the downstream fuse begins to melt, and the instantaneous protection element is deactivated temporarily. The breaker re-closes its poles after a sufficient time delay, to allow transient faults to extinguish and re-establish cold non-ionised air at the fault point. In case of a permanent fault, the recloser should operate with its slow curve, using a time-delayed overcurrent element 51P/N and allowing the load-side fuse to clear the fault. Fuse-saving schemes are based on the premise that both recloser and downstream fuse sense the same current. However, the DG presence in distribution networks increases the total fault current, and thus the branch fuse will always see more current than the upstream recloser (Fig. 4). As a result, the fast curve will be shifted to the right on the time-current characteristic (TCC) diagram, and the fuse may blow before the fast operation of the recloser, as depicted in Fig. 5.
3. Proposed adaptive protection infrastructure

In recent years, several protection solutions for the previous challenges have been suggested; however adaptive protection concept has dominated over its antagonists. Adaptive protection has been defined in [4] as “a protection philosophy which adjusts the settings of various protection functions in order to make them more attuned to prevailing power system conditions”. Characteristic implementations of adaptive protection in distribution systems and microgrids have been presented in [5]–[7].

Adaptive protection schemes require off-the-shelf digital or numerical DOCRs with several SGs, which can be configured either locally or remotely. The element parameter values of available SGs are calculated and stored offline in relays. In addition, adaptive protection schemes require communication between each protection device and a central control unit. The central controller monitors constantly the grid configuration by collecting operational data (e.g. circuit breakers status), and updates appropriately the SGs of the relays when necessary.

Current adaptive protection technology can be developed further, making use of powerful optimisation algorithms. These algorithms can determine optimal relay SGs, which minimise the operating time of feeder DOCRs, either acting as primary or backup protection, optimising thus the overall protection performance. Optimal SGs can be either pre-calculated offline when the system operating scenarios are pre-specified or calculated online when the system operates under numerous configurations and the number of available relay SGs is not sufficient.

3.1. Description of HIL Laboratory Infrastructure

An innovative HIL infrastructure has been developed in the Electric Energy Systems Laboratory (EESL) of the National Technical University of Athens (NTUA), Greece, for testing and evaluating the performance of adaptive protection schemes. HIL simulation is a very promising validation technology, constituting a closed-loop procedure where a hardware device is tested through bidirectional interaction with a simulator. HIL process provides the capability of identifying hidden defects of the tested equipment before applied to the real system, and reveals features not visible in pure simulations.

The set-up of the proposed infrastructure, illustrated in Fig. 6, consists of a Real Time Digital Simulator (RTDS), digital multifunction protection relays with multiple SGs, as well as a programmable logic controller (PLC), which plays the role of the centralised controller. The examined distribution network is simulated on the RTDS, while the digital relays provide supervision and protection of the distribution feeders. The PLC is firstly responsible for gathering the circuit breaker (CB) statuses, and secondly for transition of the relays to the proper SG whenever a major change in the network operation takes place (e.g. DG on/off, grid reconfiguration, tie breaker closed/open).

The optimal determination of feeder relay SGs in the proposed adaptive protection system is based on the generic DOCR setting and coordination problem for each possible network configuration. The objective function aims at minimising the aggregate operating time of both primary and backup DOCRs installed at the distribution network, subject to operation and coordination constraints which are imposed by distribution network operators.
systems was verified. The main feeders were protected only by the non-directional relays R3 and R7, according to the traditional protection practice. The obtained HIL test results revealed the inadequacy of existing protection settings, which were determined considering single-fed radial configuration for the distribution system.

More specifically, when the simulated network was operating without DG presence and a three-phase fault was conducted at Bus 1.2, relay R3 operated properly after 0.554 s, seeing the total fault current (2.12 kA) supplied solely by the upstream external grid. Then, the same short-circuit test was conducted with DG1 connected. The total fault current was increased due to DG presence, however the partial contribution from the external grid was reduced to 932 A, resulting in a greatly delayed tripping time of relay R3 (2.23 s). In addition, a symmetrical fault was applied at Bus 2.1, causing faster operation of R3 than R7. Stated another way, R3 was tripped sympathetically to R7 for an out-of-zone fault, disrupting the service continuity of the healthy line L1. The previous description is made clear in Fig. 8, where the TCCs of R3 and R7 relays are plotted for each test case, showing also the sensed fault currents and the corresponding tripping times.

4. Test results

To evaluate the performance of the proposed adaptive protection scheme, a 5-bus distribution network with variable operating mode was simulated, representing a simplified two-feeder portion of the Hellenic Distribution System (Fig. 7). The phase overcurrent elements (51P) of feeder relays were enabled and tested during the evaluation procedure, operating with the IEC C1 standard inverse characteristic. Detailed system and protection data are given in [11].

The evaluation procedure was actually composed of three stages. In the first stage, the adaptive logic was inactive, while the likelihood of protection blinding and sympathetic tripping occurrence in DG-penetrated distribution systems was verified. The main feeders were protected only by the non-directional relays R3 and R7, according to the traditional protection practice. The obtained HIL test results revealed the inadequacy of existing protection settings, which were determined considering single-fed radial configuration for the distribution system.

More specifically, when the simulated network was operating without DG presence and a three-phase fault was conducted at Bus 1.2, relay R3 operated properly after 0.554 s, seeing the total fault current (2.12 kA) supplied solely by the upstream external grid. Then, the same short-circuit test was conducted with DG1 connected. The total fault current was increased due to DG presence, however the partial contribution from the external grid was reduced to 932 A, resulting in a greatly delayed tripping time of relay R3 (2.23 s). In addition, a symmetrical fault was applied at Bus 2.1, causing faster operation of R3 than R7. Stated another way, R3 was tripped sympathetically to R7 for an out-of-zone fault, disrupting the service continuity of the healthy line L1. The previous description is made clear in Fig. 8, where the TCCs of R3 and R7 relays are plotted for each test case, showing also the sensed fault currents and the corresponding tripping times.
In the second stage of the evaluation procedure, the adaptive protection logic was activated. The connection status (on/off) of the installed DGs was being changed on the RTDS, while the PLC was updating appropriately the binary signals to relays. Each variation of relay input values was followed by successful transition of the active SG to the appropriate one, adjusting properly the feeder protection.

In the third and final stage, the proposed infrastructure was put into effect in combination with the optimal determination of relays’ SG, whereas several HIL tests were carried out to demonstrate its efficacy, as well as the treatment of protection blinding and sympathetic tripping problems. It was considered that DOCRs were installed at both ends of the line segments, and their nominal current was 1 A. Various operating modes for the simulated distribution network were taken into account, and protection performance was assessed for several short-circuit scenarios.

Simulation results for two configuration cases, covered by two different SGs, are given in Tables I, II. Specifically, all primary-backup protection pairs with the corresponding current transformer ratios (CTRs), the close-in fault currents seen by primary and backup DOCRs, the optimal and settings of each DOCR, and the achieved tripping times for each protection pair are presented. The lower and upper bounds for and settings were taken equal to 1.5÷5 A and 0.1÷1.0, respectively, the desired tripping times were restricted between 0.1 s and 1.5 s, and the required coordination time interval was assumed equal to 0.3 s as per common practice. It is evident that the optimal protection settings ensure not only fast tripping times, but also complete coordination between each primary-backup relay pair. Moreover, it should be noted that the employed optimisation solvers spent less than 1 s to converge and find the optimum solution, demonstrating the robustness of the developed NLP model.

### Table I. Simulation results for the 5-bus test system with DG1 connected (SG1 active)

<table>
<thead>
<tr>
<th>Primary DOCRs</th>
<th>Backup DOCRs</th>
</tr>
</thead>
<tbody>
<tr>
<td>Relay ID (CTR)</td>
<td>Fault Current (A)</td>
</tr>
<tr>
<td>R1 (100/1)</td>
<td>11547</td>
</tr>
<tr>
<td>R2 (300/1)</td>
<td>4212</td>
</tr>
<tr>
<td>R3 (300/1)</td>
<td>8614</td>
</tr>
<tr>
<td>R4 (300/1)</td>
<td>10642</td>
</tr>
<tr>
<td>R5 (200/1)</td>
<td>13630</td>
</tr>
<tr>
<td>R7 (300/1)</td>
<td>12012</td>
</tr>
<tr>
<td>R9 (200/1)</td>
<td>4213</td>
</tr>
</tbody>
</table>

### Table II. Simulation results for the 5-bus test system with DG1 & DG2 connected (SG2 active)

<table>
<thead>
<tr>
<th>Primary DOCRs</th>
<th>Backup DOCRs</th>
</tr>
</thead>
<tbody>
<tr>
<td>Relay ID (CTR)</td>
<td>Fault Current (A)</td>
</tr>
<tr>
<td>R1 (100/1)</td>
<td>11547</td>
</tr>
<tr>
<td>R2 (300/1)</td>
<td>9145</td>
</tr>
<tr>
<td>R3 (300/1)</td>
<td>10203</td>
</tr>
<tr>
<td>R4 (300/1)</td>
<td>10642</td>
</tr>
<tr>
<td>R5 (200/1)</td>
<td>13793</td>
</tr>
<tr>
<td>R7 (300/1)</td>
<td>12012</td>
</tr>
<tr>
<td>R8 (300/1)</td>
<td>2512</td>
</tr>
<tr>
<td>R9 (200/1)</td>
<td>6469</td>
</tr>
<tr>
<td></td>
<td></td>
</tr>
</tbody>
</table>
5. Conclusion
In this paper, an adaptive protection system with optimally calculated relay setting values was presented. This innovative concept constitutes a versatile protection solution for modern distribution systems which face large DG penetration. First of all, it was stressed that the proposed scheme can completely resolve the new protection problems arisen due to DG presence. Furthermore, optimal determination of setting groups for the protection relays was achieved by means of NLP techniques. The efficacy, as well as the high rate of convergence, of the developed optimisation model was verified by a series of simulations. As a next step, the proposed protection scheme can be further evolved by using optimisation algorithms to recalculate the protection setting parameters in real time, thus leading to significant improvement in the operation of power distribution networks.

6. Acknowledgement
This work was supported in part by the European Community’s Seventh Framework Programme (FP7/2007-2013) under grant agreement number 308755 – the SuSTAINABLE project, funded under the EC call “ENERGY.2012.7.1.1”.

7. References

8. Biographies
Vasileios A. Papaspiliotopoulos received the diploma in electrical and computer engineering from the National Technical University of Athens (NTUA), Athens, Greece, in 2012, where he is currently pursuing the Ph.D. degree in adaptive protection systems. His research field includes power system protection, optimisation techniques, and industrial automation. He is a member of the Technical Chamber of Greece.

George N. Korres received the diploma and Ph.D. degrees in electrical and computer engineering from the National Technical University of Athens (NTUA), Athens, Greece, in 1984 and 1988, respectively. He has been involved in the development and installation of the Hellenic emergency-management system by ESCA in the early 1990s. Currently, he is Professor with the School of Electrical and Computer Engineering at NTUA. His current fields of interest include power system state estimation, power system protection, substation automation, and supervisory control and data-acquisition systems. Prof. Korres is a member of the Technical Chamber of Greece and a Greek member of the International Council on Large Electric Systems (CIGRE) Study Committee D2 “Information systems and telecommunication.”

Nikos D. Hatzigiargyriou is Chairman and CEO of the Hellenic Distribution Network Operator (HEDNO). Since 1984 he is with the Power Division of the Electrical and Computer Engineering Department of the National
Technical University of Athens (NTUA), and since 1995 he is professor in Power Systems. From February 2007 to September 2012, he was Deputy CEO of the Public Power Corporation (PPC) of Greece, responsible for Transmission and Distribution Networks, island DNO and the Center of Testing, Research and Prototyping. He is Fellow Member of IEEE, past Chair of the Power System Dynamic Performance Committee, Distinguished member of CIGRE and past Chair of CIGRE SC C6 “Distribution Systems and Distributed Generation”. He is chair of the Advisory Council of the EU Technology Platform on SmartGrids. He is member of the Energy Committee of the Athens Academy of Science. He has participated in more than 60 R&D Projects funded by the EC and the industry.