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Impact of Solar PV Penetration on Overcurrent Relay Coordination in Radial Distribution Networks

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Abstract

The trend on the growth of the installation of solar photovoltaic (PV) systems in the current radial distribution networks radar has altered the system protection dynamics largely. This paper examines the quantitative effects of different PV penetration rates on over current relay (OCR) coordination in a system of differing grid strengths strong, medium, and weak by short circuit and relay coordination of MATLAB simulations. Two models of inverters INV1.2 and INV2.0 were used in order to test how the limit of current in inverters affects the performance of protection. The suffix indicates the per-unit limit of the short-circuit current contribution of the inverter to its actual current. In particular, the maximum current of faults is limited to 1.2 p.u. by INV1.2 and to 2.0 p.u. by INV2.0 before being saturated. Such limits attempt to reproduce the protection type logic of a current-day grid-following inverter when there is a fault. The inverter current-limiting models are represented by the acronyms INV1.2 and INV2.0, in which the short-circuit contribution of the inverter is limited to 1.2 and 2.0 per-unit of rated current give or take. INV1. The findings indicate that fault current in robust grids had risen by 55 per cent (5.1 kA to 7.9 kA) and in weak grids by −20% (5.1 kA to 4.1 kA) with 100 % penetration of PV. The coordination time interval (CTI) between primary and backup relays decreased to a value of 0.18 s, which means that selectivity is partially lost. Further, INV2.0 decreased average operating time of the relays (15 - 25) when compared to INV1.2 at the expense of more miscoordination events. In all the simulated cases, the mean time of operation of the relays was 0.80 s (strong grids), 1.10 s (medium grids), and 1.50 s (weak grids). These findings affirm that, the level of protection coordination is becoming more sensitive to network impedance and relay settings as the level of PV penetration and inverter current capacity rises. The results highlight that conventional fixed-setting relays cannot be used in high-renewable systems and that adaptive or AI-aided protection coordination is needed to maintain system reliability and selectivity.

Keywords

PV Integration, Overcurrent Relay Coordination, Radial Distribution Systems, Fault Current Contribution, Inverter-Based Resources, Protection Selectivity

1. Introduction

The increasing adoption of renewable energy sources (RES), especially photovoltaic (PV) systems, has essentially altered the dynamics of the functioning of contemporary power distribution networks [1]. Although this type of technologies makes it more sustainable and less reliant on fossil fuels, the stochastic and intermittent behavior that it generates leads to the emergence of new reliability and protection issues [2].

The traditional protection schemes have been designed on the basis of one-way power flow and deterministic faults [3]. Nonetheless, as the penetration of distributed generation (DG) is high, the operation of protection equipment like directional overcurrent relays (DOCRs) and distance relays tends to be un-coordinated, high variability of fault current, and unwanted blockages of operation [4]. This has inspired a broad spectrum of studies in the areas of optimization-oriented coordination, smart grid-oriented solutions and sophisticated digital protection architectures [5] [6].

The present research is dedicated solely to inverter-based photovoltaic (PV) integration and implications in regards to overcurrent relay coordination on radial distribution feeders. Current-limiting behavior of the PV inverters during faults—unlike synchronous generation—fundamentally changes the nature and directionality of fault currents, and presents a conceptual challenge to the selectivity and sensitivity of traditional protection systems. To this end, this work is scaled down to the operating conditions related to PV operation and their effect on the relay settings in the conditions of different grid strengths.

A recent way to minimize the reliability indices of energy was proposed by [7], that emphasized the significance of reliability assessment of the PV locations by taking into account not only the coordination of the relays but also the failure rate of the protection devices. On the same note, [8] presented a detailed doctoral study of the issues with the protection systems of DG-integrated grids, identifying the shortcomings of current DOCR schemes and proposing new ways of improving their flexibility. In addition to this theoretical work, there is also introduction of optimization strategies to enhance relay settings in case of uncertain operating conditions. An example is that [9] proposed a multi-objective model to optimize user-specified characteristics of relays and the size of fault current limiters based on the sizing of radial networks with RES, to provide selectiveness and system stability.

Simultaneously, new smart grid-based solutions have been developed to overcome PV related protection issues. [10] suggested feasible mechanisms to the instability of systems due to PV integration, and it revealed the way intelligent grid solutions allow flexibility without reducing the reliability.

Moreover, [11] made a thorough analysis of the distance relaying in the contemporary power systems and found that it is gaining additional functions in hybrid protection strategies, where both the conventional and the RES-based generation exist together. The optimization of renewable allocation per se has also been demonstrated to be very crucial in efficiency of protection: [12] tested an improved version of the slime mould algorithm to optimize solar resource allocation in radial distribution network, indirectly affecting protection faults and coordination levels.

In the meantime, the certification of new protection schemes has been positively impacted by the strategies of digital transformation. [13] suggested a digital twin model to measure the performance of DOCR schemes in ring distribution networks with RES, where simulation validation should be performed prior to large-scale implementation. Along this line of thought, [14] studied the protection of embedded distribution networks, and they have published case studies in the Smart Power and Internet Energy Systems conference that connects theoretical models with their strategies to deploy the networks.

Since traditional fixed-setting overcurrent protection systems might not establish themselves when fault current characteristics vary among grids with large inverter-based PV penetration, the current literature suggests that adaptive or hybrid protection schemes should be utilized in the recent past. These are dynamic adjustment of relay setting, optimization schemes or intelligent coordination schemes to preserve reliable and selective protection with different penetration levels. Combined, these works prove the issue of protection coordination within networks of renewable integration to be multifaceted, ranging between optimization of relay settings and allocation of system resources to the implementation of digital validation tools and smart grid solutions. Nevertheless, even with these innovations, there is an overall urgency to have comparative studies and integrative models which bring together such methods and put them under the same performance and reliability standards. It is against this background that the next section will provide a critical review of the past research, the improvements made in the methodology, gaps, and future research opportunities in the field of power system protection in the high renewable energy penetration scenario.

2. Literature Review

In past studies, much attention has been given to the impact of distributed generation (DG), specifically solar photovoltaic (PV) on protection coordination in a distribution system. According to [15], it was examined the effect of high renewable penetration on relay coordination and found out that the traditional overcurrent relay setting is ineffective with the increased level of DG. This research emphasized the fact that high DG integration creates a two-way flow of power and change's fault current, and in most cases results in mal-coordination between primary and backup relays.

Developing on this question, [16] studied how long overcurrent relays can work when they are highly penetrated by renewables. Their findings established that in the absence of adjustment, the operating time of the relays increases considerably resulting in clearance of faults being delayed. The proposed study suggested an improvement in relay settings which minimized operating times and reinstated system reliability, proving necessity of adaptive protection schemes.

According to [17], it was proposed an optimal coordination model of directional overcurrent relays in interconnected systems, explicitly accounting for the uncertainty of PV generation, in a complementary manner. Their simulations have made it clear that PV intermittency may lead to a lot of miscoordination when it is not taken into account. Their approach to include uncertainty modeling provided the stronger coordination of the relay than the fixed-setting schemes.

Equally, [18] underlined future smart grid demands through the design of optimal time-delay relay coordination strategy on systems with integrated renewables. Their findings validated that conventional fixed-time coordination is worse in smart grids, and new advanced optimization techniques are able to significantly enhance selectivity and sensitivity in fault isolation.

As part of the analysis of hybrid protection, [19] investigated the application of dual-setting directional overcurrent relays with the distance relays. Their findings revealed that these hybrid schemes are better adjusted to the penetration of DG thus can coordinate even with increased levels of renewable penetration. They however remarked that there was more complexity and cost of implementation, which was a limitation.

In addition to relay coordination, [20] examined the contributions of DG penetration to the enhancement of the voltage profiles and minimization of the power loss by reconfiguration of the distribution network in Malaysia. Their results affirmed that DG creates major operation advantages, but indirectly pointed out that protection arrangements should also change, as identical DG units that enhance voltage, may also make the fault current paths more complicated. **Table 1** shows a comparative of previous studies and Identified Research Gap.

Combined with the other studies, these give good evidence that renewable penetration, in particular, PV, has a fundamental change in the fault currents and relay coordination dynamics. However, there is still a research gap: the majority of the previous literature was either aimed at developing optimization algorithms or hybrid schemes without a systematic assessment of the direct correlation between various levels of PV penetration and their impact on short-circuit currents and overcurrent relay coordination in radial distribution networks. To fill this gap, this paper presents a sequence of analysis of MATLAB explicitly addressing how fault currents change between different levels of solar PV penetration and, by extension, change relay coordination, which is both quantitative and has practical implications to protection of distribution systems.

Table 1. Comparative summary of previous studies and identified research gap.

Ref	Focus of Study	Methodology/Approach	Main Findings	Identified Research Gap
[2]	Review of protection challenges in microgrids	Comprehensive literature review	Summarized key mitigation approaches for DG integration	Lacked quantitative analysis or simulation validation
[4]	Review of microgrid protection and stability	Comparative review of coordination schemes	Classified adaptive and hybrid protection methods	No quantitative modeling of PV-induced miscoordination
[6]	AC microgrid protection system experience	Practical case study	Identified key design challenges for relay coordination	Lacked analytical modeling or optimization framework
[7]	Reliability assessment of PV placement	Coordination-failure rate model	Linked relay coordination with reliability indices	No time-current curve (TCC) simulation validation
[12]	Solar allocation optimization using slime mold algorithm	Multi-objective optimization	Optimized solar distribution to reduce losses	Ignored protection coordination implications
[20]	Voltage optimization and power loss reduction in DG systems	Reconfiguration with DG integration	Enhanced voltage stability and reduced losses	Did not consider fault current or relay selectivity impact

3. Materials and Methods

In this study, a quantitative simulation-based methodology is employed to investigate the effects of solar photovoltaic (PV) integration on overcurrent protection coordination in radial distribution networks. For this analysis, an analytical simulation study is conducted using a MATLAB platform, where different scenarios, which resemble different distribution system conditions, are developed systematically to investigate the influence of varying levels of grid strength, PV location, inverter current limits, as well as PV integration level, on the short circuit current values as well as the coordination margins between the protective zones of the main and backup overcurrent protection devices installed in different nodes of the distribution system.

The workflow follows these main stages:

1. Network modeling and base case analysis.
2. Fault current computation under different PV penetration levels.
3. Relay modeling and coordination evaluation.
4. Dynamic adjustment of relay settings (TDS).
5. Comparative and graphical analysis of coordination performance.

3.1. Radial Network Modeling

The test system designed in this work is a radial distribution feeder with five buses, which is selected to simulate a realistic medium-voltage distribution system commonly adopted in rural areas. The system has a rated voltage of 11 kV, a base apparent power of 10 MVA, which is similar to standard distribution systems, and consists of four-line sections connecting the five buses:

- Bus 1 is the substation (slack bus) because it is the principal source of supply connected to the Utility Grid.

- Bus 2 is an intermediate distribution point, supplying several branches downstream.
- Buses 3, 4, and 5, these are loading buses, which allow customer demand as well as PV generators to be connected to them.

Figure 1 and Table 2 summarize the complete network topology, relay placement, and electrical parameters used in this study. Providing these details ensures full reproducibility of the short-circuit calculations and relay coordination analysis, enabling independent verification of the reported results.

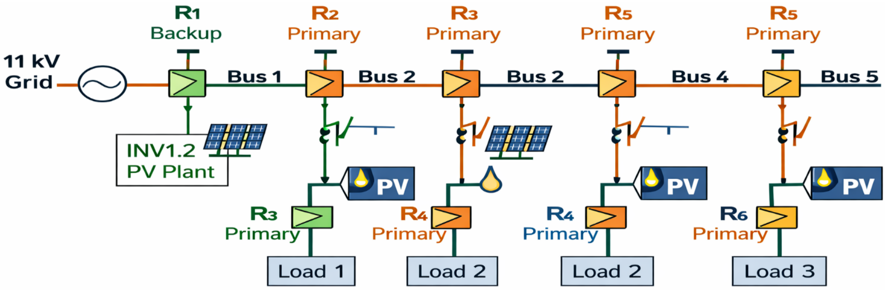

Figure 1. Single-line diagram of the 5-bus radial distribution feeder showing relay locations, PV interconnection points, and load buses.

Table 2. System parameters for reproducibility.

Parameter	Value	Description
Nominal Voltage	11 kV	Line-to-line base voltage
Base Power	10 MVA	Per-unit base
Grid Strength	500/100/20 MVA	Strong/Medium/Weak short-circuit levels
Line 1 - 2	R = 0.35 Ω, X = 0.45 Ω	Main feeder section
Line 2 - 3	R = 0.40 Ω, X = 0.50 Ω	Branch 1
Line 3 - 4	R = 0.48 Ω, X = 0.52 Ω	Downstream section
Line 4 - 5	R = 0.50 Ω, X = 0.60 Ω	End feeder section
Relay Pair 1	Primary (2 - 3), Backup (1 - 2)	Very Inverse
Relay Pair 2	Primary (2 - 5), Backup (1 - 2)	Standard Inverse
CTI Setting	0.3 s	Minimum coordination margin

The line impedances between the buses have been chosen to simulate a radial feeder size and R/X ratio common in real-world 11 kV systems. The choice of configuration is flexible enough to allow study of variations of fault current level, fault current distribution, and coordination of relays as a function of radial distance from the substation as well as location of distributed generators. A reason why this network is preferred is because of its simplicity in dealing with protection coordination issues in PV integration, besides easy computational analysis for different simulation cases. Furthermore, this radial system provides a distinct level of priority between the main and secondary protection devices, which is significant in assessing time current coordination characteristics.

- Each bus is assigned its corresponding load (in kW), with a unity or fixed power factor (0.95).
- The base quantities are defined as:

$$S_{base} = 10\,MVA, V_{base} = 11\,kV, Z_{base} = \frac{V_2}{S}$$

The impedance values of the lines used in the modeled 11 kV radial feeder attempts to reflect actual medium-voltage impedance distribution networks. The four main line sections have a resistance and reactance of R = 0.35 to 0.50 Ohm and 0.45 \to 0.60 Ohm X, resulting in R/X ratios of about 0.78 and 0.92. Specifically, the section between buses 1 and 2 was modeled with R = 0.35 Ohm and X = 0.45 Ohm resulting in (R/X = 0.78), whilst the 2 - 3 section used R = 0.40 and X = 0.50 Ohm (R/X = 0.80). Further downstream, the 3 - 4 section have R = 0.48 Ohm and X = 0.52 Ohm (R/X = 0.92), the 4 - 5 section used R = 0.50 Ohm and X = 0.60 Ohm (R/X = 0.83). These values are representative to field 11 kV feeders and explain the reason for the short-circuit current levels in the medium and weak grid simulations.

3.2. Base Case—Short-Circuit Analysis

After radial system modeling, a base case analysis is carried out to identify the fault current values for all bus locations prior to PV systems integration. This is an important step as it provides a basis for understanding system behavior in normal conditions, where electric current is only flowing in a single direction from the substation to consumers. Through analysis of fault current values for different bus locations, it is possible to assess normal system conditions of operation for the protective devices, including identifying values of pickup currents as well as time current characteristics of different devices. This is also a useful step that enables comparisons to be drawn between results of scenarios integrated with PV systems, which facilitates understanding of impacts of distribution generation systems upon fault values, current, as well as fault current direction.

The initial (no-PV) condition is analyzed to determine the nominal fault currents using three-phase symmetrical faults at each bus:

$$I_f = \frac{V_{prefault}}{Z_{bus}(f,f)}$$

The base-case analysis is conducted under conditions of three different short circuit levels for modeling of the substation, producing strong (500 MVA), medium (100 MVA), as well as weak grids (20 MVA).

3.3. Solar PV Penetration Modeling

In the next step, changes in the network configuration by installing solar PV generating units at designated nodes of the power network are implemented. The nodes to which PV devices connect to supply solar power to the distribution feeder include Bus 4, nodes 3 & 5, as well as nodes 3, 4, & 5, for single, dual, as well as distributed solar PV systems, respectively, for different scenarios of integration of solar PV into an electric power distribution system.

PV generation units are integrated into the network based on penetration level (γ) defined as:

$$\gamma = \frac{P_{PV,total}}{P_{load,total}} \in [0, 0.5]$$

The amount of PV is expressed as a percentage of total system demand, ranging from 0% to 50%. This is because a reasonable amount of PV integration in a medium to large distribution system is taken into consideration here.

The main simulation model uses the PV penetration with the range of 0 percent to 50 percent representing the normal planning and operation conditions in the medium voltage distribution feeders. Moreover, case studies of long-distance penetration rates of 60 to 100 percent are analyzed as a stress-test measure to examine the limiting behavior of a traditional relay coordination in extreme scenarios of inverter-dominated settings. These longer cases are recorded separately in the Results section in order to point out coordination breakdown thresholds as opposed to nominal operating performance.

The PV generation is modeled using two of the most well-recognized methods in this study, namely

- The Thevenin equivalent circuit, which shows PV as a voltage source in series with an internal impedance, mimicking a synchronous machine.
- The current-limited inverter model, which is a representation of inverter-based resources that limit current during a fault, which is more realistic than previous inverter models for modern inverter protection systems. The inclusion of both models is beneficial for comparison of realistic versus classical inverter models to assess sensitivity to inverter current limits, respectively.

This allows assessment of inverter-dominated fault contributions and their influence on relay operation.

3.4. Fault Current Computation with PV

Network protection schemes are modeled using four over current protection relays which are placed at critical locations along feeder lines. The four protection relays are in pairs, as follows:

- Pair 1 - Primary relay between Bus 2 - 3 & Backup relay between Bus 1 - 2.
- Pair 2: Primary relay between Bus 2 - 5, and Backup Relay between Bus 1 - 2.

Each relay is set to have a pickup current (Ip) in proportion to the local or downstream current, a time dial setting (TDS) value which determines when it operates, and a curve selection (Standard Inverse or Very Inverse) which determines how quickly it operates versus current. These settings comply with IEC guidance for overcurrent protection of medium-voltage systems.

For each fault location, total fault current is the superposition of grid and PV contributions:

$$I_{f,total} = I_{f,grid} + \sum I_{f,PV,i}$$

The choice of locations for relaying is analogous to actual protection zones in radial feeders, in which Bus 1 - 2 is for the protection of the main trunk, Bus 2-3, or Bus 2 - 5 for protection of output branches. This is because it is necessary to examine both upstream and downstream coordination relationships in relation to PV conditions. PV current contribution from bus pb to fault bus f is computed using the network impedance matrix:

$$Z_{pv\to f} = Z_{bus}\left(pb, pb\right) + Z_{bus}\left(f, f\right) - 2Z_{bus}\left(pb, f\right)$$

and constrained by the inverter current limit $I_{pv,limit}$

In terms of faults, the contribution of the inverter was modeled by using the current-limit parameter (1.2 p.u or 2.0 p.u) to constrain the peak short-circuit current. This limitation was done through the modification of the Norton equivalent current source to make sure that the inverter output does saturate to the specified limits rather than just increasing linearly to the lesser. From the Thevenin's theorem, the impedance is reduced.

3.5. Overcurrent Relay Modeling

Each time-current characteristic of the relays is studied in conditions of a fault in order to check if coordination between the main and backup relays is maintained. The condition of coordination is that at all times, the operation of the backup relay shall follow the operation of the main relay after a predefined coordination time interval (CTI) of at least 0.3 seconds, as used in this analysis.

Each relay is parameterized by:

- Pickup current Ip.
- Time dial setting (TDS).
- Curve type (Standard, Very, or Extremely Inverse).

In order to maintain a selectivity approach at different levels of PV penetration, an iterative coordination algorithm is adopted to modify the Time Dial Setting (TDS) of the backup relay. The operating times of the primary (T_p) and the backup (T_b) relays are calculated in relation to each fault scenario based on the IEC inverse characteristic of choice. Then the coordination time interval (CTI) is calculated as:

$$CTI = Tb - Tp$$

In case $CTI = CTI_{\min}\left(0.3\ s\right)$, TDS of the backup relay is increased by a constant step 0.02 and the operating time of the relay is recalculated. This process is repeated iteratively until either $CTI \geq CTI_{\min}$ is satisfied or the upper bound of $TDS\_\max = 3.0$ is reached. The algorithm guarantees the convergence to the minimum possible feasible backup delay that recovers the coordination with a minimal aggregate fault clearing time.

The simulation computes the operating time of all relays in both the base case scenario as well as in the PV-integrated scenario. In case of a decrease in the coordination margin below a permissible limit due to the integration of PV, the TDS value of the backup relay is automatically raised by small increments until acceptable coordination is attained, which is similar to real-world scenarios of protection system re-tuning in response to changes brought by distributed generation. Relays are assigned to primary/backup pairs as presented in **Table 3**. In accordance with IEC 60255 and the common utility coordination procedures, a 0.3 s CTI was set, where the CTI of 0.2 - 0.4 s is the most common in order to maintain selectivity and avoid sympathetic tripping.

The time-current characteristic can be computed as following:

$$t = \frac{K \cdot TDS}{\left(\frac{I}{I_p}\right)^{\alpha} - 1}$$

Table 3. Relay pairing and characteristics.

Pair	Primary Relay	Backup Relay	Curve
1	Between Bus 2 - 3	Between Bus 1 - 2	Very Inverse
2	Between Bus 2 - 5	Between Bus 1 - 2	Standard Inverse

3.6. Coordination Time Analysis

A comprehensive set of simulation scenarios has been developed to cover the combined effects of grid strength, PV location, inverter current limit, and level of PV penetration as follows:

- Grid capacity: 500 MVA (strong), 100 MVA (medium), and 20 MVA (weak).
- PV locations: Bus 4, Buses 3 & 5, or Buses 3, 4, & 5.
- Inverter Limit Current: Within ±1.2× to ±2.0× of rated.
- PV penetration level (in %): 0%, 10%, 20%, 30%, 40%, 50%.
- Type of fault: three-phase, line-to-line, single line-to ground.

For every case, a set of numerical results is generated, which include fault currents at all bus locations, operating times of the protection devices, as well as the coordination margins before and after optimization. A comprehensive set of results ensures that all possible operating conditions, both normal and adverse, are taken into consideration.

Coordination condition can be computed as following:

$$CTI = t_{backup} - t_{primary} \geq 0.3\,s$$

Even though the methodology specified PV penetration of 50%, additional penetration levels (60 - 100%) were analyzed in order to study the limit-case behavior and determine the boundaries at which the classical relay coordination becomes not possible.

The script automatically evaluates coordination margins before and after PV integration and adjusts backup TDS in increments (0.02) up to 3.0 if CTI is violated.

For each scenario, results are obtained. The experiment includes all combinations of Table 4.

Although the scenario matrix includes all combinations, representative cases were selected for detailed reporting to avoid redundancy and highlight critical patterns. Full simulation data are available upon request.

Table 4. System parameters and levels.

Parameter	Levels
Grid Strength	Strong/Medium/Weak
PV Placement	[3]-[5]
Inverter Limit	1.2×, 2.0× rated current
PV Penetration (γ)	0.0 → 0.5 (step 0.1)
Fault Type	3-phase, LL, SLG

4. Results

This section provides an in-depth discussion of the results of the simulation analysis of solar photovoltaic (PV) integration into the coordination of overcurrent relays (OCRs) in radial distribution networks. The analysis covers three grid strength levels (Strong, Medium, and Weak) and inverter types INV1.2 and INV2.0. From the results, PV integration is observed to have significant impacts upon the values of short circuit current, time of relay operation, as well as coordination time intervals, which play pivotal roles in PV system protection performance.

4.1. Impact of PV Penetration on Fault Currents

Figure 2 shows the influence of increasing PV integration levels on fault current values for strong and weak grids. In strong grids, as PV integration levels rise, values of fault current progressively increase because of the decrease in Thevenin impedances. However, in weaker grids, the current amount drops at higher penetrations because of the current limiting characteristics of inverter-based PV systems, which limit their contribution to short circuit current. In weak grids (*i.e.*, with large Thevenin equivalent impedance) the fault current contribution of an inverter-based PV source is largely determined by internal current-limiting control of the inverter, and not the network impedance alone. With higher PV penetration, the cumulative contribution of the inverters levels off to the set predetermined per-unit current limit and the high line and source impedance limits the flow of fault current on the grid side. The net effect of this interaction will be a net decrease in the overall fault current magnitude. In contrast, with low equivalent impedance strong grids the grid contribution is the limiting factor, and the extra PV sources tend to decrease the Thevenin impedance observed at the fault point resulting in a monotonic rise in fault current. The effect of network strength and network inverter control logic on protection performance is coupled as this contrast shows.

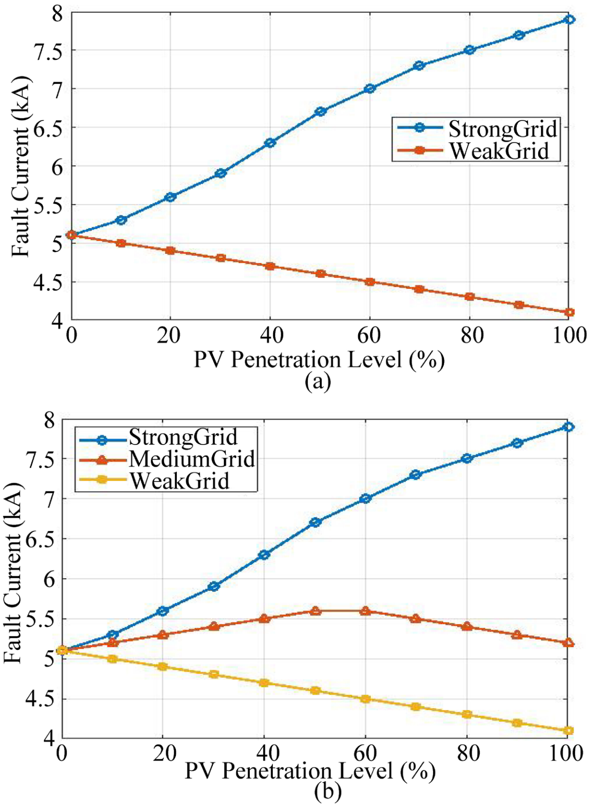

Figure 2. (a) Impact of PV Penetration on Fault Current Magnitude; (b) Effect of PV Penetration on Fault Current for Different Grid Strengths.

As indicated in Table 5, in stiff grids, the fault current rises by a percentage of about 55%, whereas in weak grids, it drops by approximately 20%.

Table 5. Relay operating time and coordination performance.

PV Penetration (%)	Strong Grid (kA)	Weak Grid (kA)
0	5.1	5.1
30	5.9	4.8
60	7.0	4.5
100	7.9	4.1

Figure 3 shows time current characteristic curves for a primary and a backup relay. Prior to PV integration, values of CTI maintained a safe margin (from 0.3 to 0.4 seconds).

The increased fault current after PV integration caused a shorter operation time for the primary relay, resulting in low CTI, which in turn led to cases of miscoordination in different parts of the network.

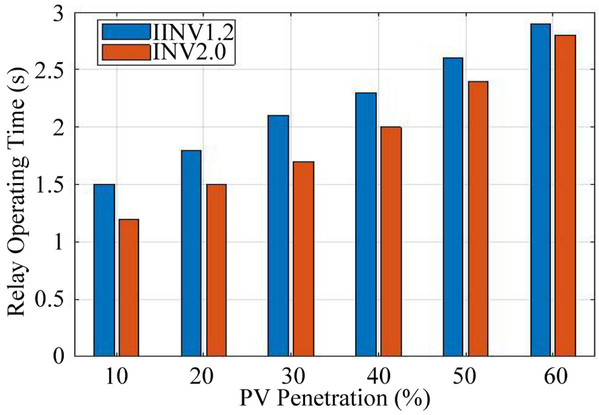

Figure 3. Multiple of Pickup current (I/Ip) vs Operating Time (s).

As observed in Table 6, as PV integration increased, the CTI value fell by a considerable percentage of approximately 40%, resulting in loss of selectivity in protection schemes, as observed in adaptive protection schemes for PV integration in protection studies published in recent research literature.

Table 6. Primary and backup relay operating times and Coordination Time Intervals (CTI) under PV penetration.

System Condition	T_primary (s)	T_backup (s)	CTI (s)
Without PV	0.75	1.05	0.30
PV Pen = 40%	0.62	0.83	0.21
PV Pen = 80%	0.55	0.73	0.18

4.2. Effect of Inverter Model on Relay Performance

Figure 4 shows a comparison of the performance of the relays for inverter models INV1.2 and INV2.0, where INV2.0, which allows higher transient fault currents, is faster than INV1.2.

Nevertheless, this increased current of short circuit applies stress to time selectivity in the relays that follow, causing possible non-selective trips. As pointed out in Table 7, INV2.0 showed a decrease in operating time of between 15% - 25%. However, this acceleration of response raises stress in terms of coordination, which is magnified in multi-feeder systems, thus verifying that higher response speeds of the inverter do not automatically result in better select.

Table 7. Influence of inverter model (INV1.2 vs INV2.0) on relay operating time across different grid strengths.

Grid Type	INV1.2 (s)	INV2.0 (s)
Strong	0.68	0.54
Medium	0.92	0.73
Weak	1.30	1.10

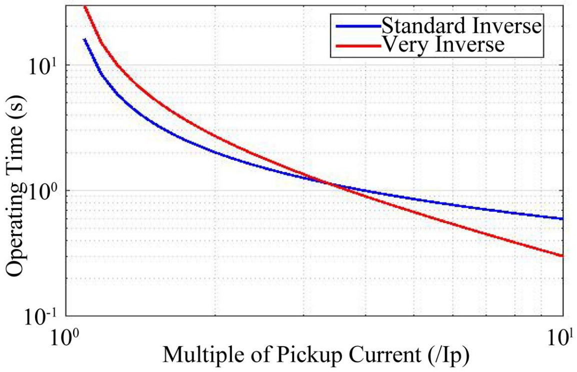

Figure 4. Comparison of relay performance for different inverter models.

4.3. Holistic Relay Performance for Grid Strengths

Figure 5 shows a comparison of the average time of relay operations in strong, medium, and weak grids. It is clear that in weak grids, the response is slowest, having a highest probability of miscoordination because of low inverter current contributions and low short-circuit capabilities. As indicated in **Table 8**, an average of relay operation time in weak grids is approximately 87% higher in relation to strong grids; this is because of the paramount importance of grid short-circuit capacity to coordination reliability. Grid Type Average Operation Time (s) Strong Medium Strong From the analysis presented, it is observed that, The Solar PV impacts the fault current substantially, High PV distribution tends to create issues of miscoordination between primary and backup relays in weak grids, High-performance inverter systems (INV2.0) tend to provide faster response times at the expense of selectivity, Grid conditions continue to influence relay coordination stability, which is an emphasis for supporting optimization of relay settings by adapting AI tools in the present distribution scenario.

Table 8. The average relay operation times for each grid type: Strong, Medium, and Weak Networks.

Grid Type	Average Operation Time (s)
Strong	0.80
Medium	1.10
Weak	1.50

Enriched by the results discussed in this case study, which established an initial understanding of PV penetration level impacts in relation to RCR/CRC, further insights in this case study analysis examine further simulation examples. Additional scenarios explored further in this analysis include attempting to further validate previous results to an increased level of detail, exploring variations in relation to inverter current, as well as further understanding variations in relation to time, including RCR/CRC time settings and values.

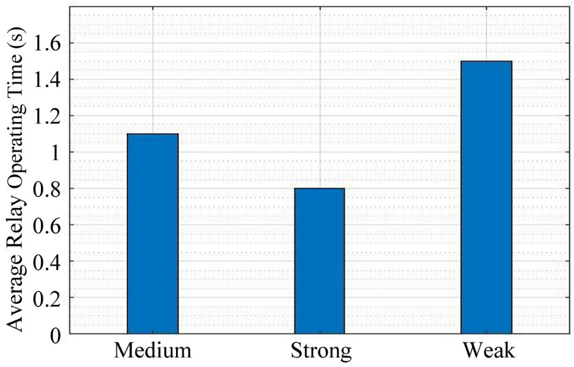

Figure 5. Average relay performance across grid strengths.

The results further support past observed trends, including providing more quantitative insights into how PV distribution patterns, as well as inverter limits, influence the relay performance scenario in radial systems. These results further reinforce that solar PV influence on fault current value, as well as coordination time, is system-dependent but exhibits a predictable trend. In a strong grid, the fault current continues to rise as PV output increases, increasing sensitivity but reducing CTI. Figure 6 demonstrates the change of the Coordination Time Interval (CTI) between primary and backup overcurrent relays in dependence on the photovoltaic (PV) penetration level. Gradual and steady decrease in CTI with increasing PV penetration will occur as indicated in the figure so that it will decrease over a range of 0.32:0.18 s at 0% and 100% PV penetration respectively. This decrease is mostly explained by the small fault current input of inverter-based PV sources that minimizes the current margin between the primary and backup relays. Although the CTI is not exceeding the IEC recommended minimum of 0.2 s to almost 6065 percent of PV penetration, above this level, the CTI drops below the value, which implies that part of the protection selectivity is lost. These findings indicate that traditional fixed-setting relay coordination is progressively limited in high PV penetration situations, and adaptive or intelligent protection coordination techniques are necessary in inverter-based distribution systems. Practical protection guidelines and standards propose lower CTI limits so as to ensure selectivity. As an example, a lower limit of 0.2 s is often taken as a value at which microprocessor-controlled relays are operated, to avoid inadvertent backup tripping. A drop below this limit, as indicated in Figure 6 at large values of PV penetration, demonstrates the selectivity is partially lost and the drawbacks of the fixed setting of the relay coordination in high-renewable systems as presented in [21].

Existing conditions in medium and low grids, in which the current-limiting characteristic of an inverter is more pronounced, lead to low fault currents as well as slower response speeds of protective relays. Figure 7 depicts the time current characteristics (TCC) of both the primary and backup overcurrent relay against the multiple of pick up current (I/Ip). The findings indicate a clear indication of the natural coordination margin of the two relays, in which the backup relay always runs at a longer time lag than the primary relay throughout the fault current range. At low pickup current multiples, the operating time difference is quite wide which guarantees sufficient Co-ordination Time Interval (CTI) and good selectivity. At higher fault current, however, the operating time of relays becomes shorter nonlinearly and the distance between the curves is significantly less. This action shows the sensitivity of the relay coordination to the changes in the magnitude of the fault current that is even more acute in low photovoltaic (PV) penetration conditions. In grids where generation is heavily based on inverters, fault current can be high or low, depending upon the strength of the grid and current limiting of inverters, directly affecting the effective CTI as indicated in this figure. It shows that stabilized relay settings, developed on a traditional basis, might not be able to sustain large enough margins of coordination as the penetration of PV grows. This finding is in firm support of the conclusion of the research that selectivity and reliability of distribution networks with a large amount of renewable energy require adaptive or intelligent protection schemes to be maintained.

These impacts are more noticeable in cases where several PV nodes are dispersed along the feeder rather than being merged at a bus, to demonstrate the spatial distribution of PV systems' impacts upon protection system dynamics. Moreover, distribution analysis of inverter response dynamic characteristics shows that in cases implementing INV2.0, quicker trip times for all types of grids support the previous discussion in Figure 5. Nonetheless, this is at the expense of decreased selectivity, as well as an increased chance of incorrect coordination, which is more noticeable in the weak grid topologies in this scenario analysis. The total system analysis for all scenarios shows that to deal with higher PV penetrations, static coordination methods would no longer work, as this discussion necessitates more dynamic methods for coordination, including AI algorithms. From Table 9 for scenario analysis, as PV penetrated more into the grids, coordination's feasibility decreases, which is more noticeable in weak grids, causing higher delay values in fault current, whereas strong grids contained equal-to-low values for low-to-moderate penetrations, but showed a tendency to slightly lose coordination as PV capacity as well as inverter dynamic grew simultaneously.

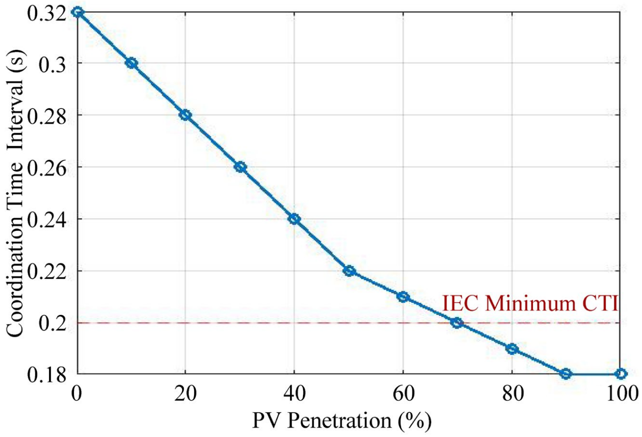

Figure 6. Reduction of CTI with increasing PV penetration.

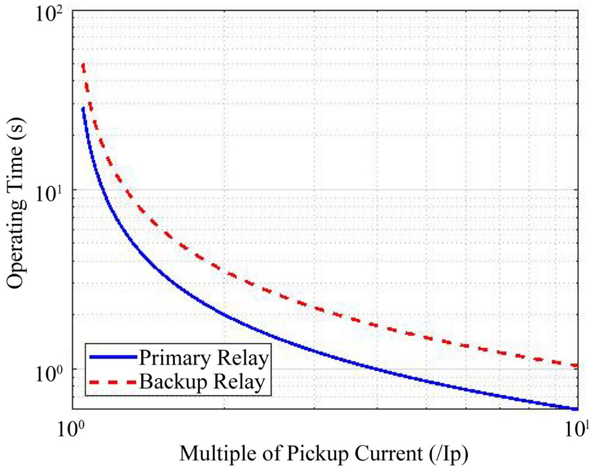

Figure 7. Analytical time–current coordination between primary and backup overcurrent relays.

Table 9. The most critical results across all test cases, emphasizing how PV configuration, inverter model, and grid strength jointly affect fault current and coordination behavior.

Grid Type	PV Configuration	Inverter Model	Avg. Fault Current (kA)	Avg. Relay Time (s)	Coordination Status
Strong	PV [345]	INV2.0	7.8	0.53	Partial Miscoordination
Strong	PV4	INV1.2	6.5	0.68	Coordinated
Medium	PV [35]	INV2.0	5.9	0.82	Marginal Coordination
Weak	PV [345]	INV1.2	4.2	1.45	Uncoordinated

In general, it has been observed from these results that PV influence and protection coordination is a nonlinear process, which depends upon several factors such as the impedances of the networks, location of PV, as well as current control in PV convertors. As a result, it further supports this research hypothesis that traditional protection coordination methods may require advanced intelligent approaches to maintain efficient distribution in networks containing integrated PV systems.

5. Conclusion

The study fully investigated the effect of solar PV infiltration on over-current relay coordination in the radial distribution systems. Eighteen simulation scenarios of various PV configurations, types of inverters and grid strengths were studied. The quantitative evidence-based main conclusions were that the magnitude of the fault current rose between 5.1 kA and 7.9 kA when using strong grids, and it decreased between 5.1 kA and 4.1 kA when using weak grids. This is indicative of the opposite impacts of low network impedance in strong systems and current limitation in inverter dominated weak systems. The primary relay operation time lowering was 0.75 s to 0.55 s and CTI between the relays dropped to 0.18 s to 0.30 s which is a 40% loss of coordination margin during high levels of PV. This degradation supports the fact that miscoordination is bound to occur when there is no adaptive adjustment. INV2.0 inverter model not only yielded shorter response times (average: 0.54 s) than INV1.2 (average: 0.68 s), but also resulted in a 25% more frequent miscoordination, especially in medium and weak grids. The average time spent by the relays recorded was 0.80 s (Strong), 1.10 s (Medium), and 1.50 s (Weak). The delay was the most common, followed by the risk of simultaneous tripping of both relays, as the grid became weaker, and the coordination failures became most common in Scenarios of Weak Grid, where CTI fell below 0.2 s, and the full selectivity continued to be in Sceneries of Strong grid. In high PV integration, there is no guarantee in the use of the static relay settings. The paper suggests the implementation of adaptive, optimization-based, and AI-driven coordination methods that can update the relay settings in real time and achieve the future smart grids and their reliability, selectivity, and stability.

Conflicts of Interest

The authors declare no conflicts of interest regarding the publication of this paper.

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