Adaptive IEC 61850-Based Overcurrent Protection in Active Distribution Systems

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Abstract

Overcurrent relays (OCRs) with fixed setting parameters are the primary protection devices for distribution network feeders. The integration of inverter-based distributed generation (IBDG), such as photovoltaic (PV) systems, into active distribution networks (ADNs) introduces significant challenges, including blinding zones where a fault cannot be detected by the traditional OCR with fixed settings. In this paper, an adaptive protection scheme is proposed to address protection blinding by dynamically adjusting the IEC overcurrent curves, available in all relays, based on the IBDG level of generation. The operational status of the IBDG can be determined by the time of day (e.g., PV on or PV off) or through data received via the Advanced Metering Infrastructure (AMI) infrastructure. Accordingly, the adjustment can be either scenario-based or continuous. A case study and the use of real-time simulation and actual protection relay (employed as hardware-in-the-loop) utilizing the IEC 61850 standard demonstrates the method's effectiveness and practicality.

1 Introduction

The penetration of IBDGs in distribution networks, despite their undeniable advantages, can have significant impact on traditional protection systems. The presence of IBDGs presents various protection challenges, including the risk of loss of coordination, protection blinding, and false tripping of the protection [1]. These issues are worse by the increasing penetration of renewable energy sources (RES), making conventional ideal OCRs' fixed settings insufficient. making conventional OCRs' fixed settings insufficient. Adaptive protection schemes, capable of adjusting relay settings dynamically according to system conditions, offer a promising solution [2].

Protection blinding is a critical issue in distribution grids with high renewable penetration. It occurs when a circuit breaker fails to trip due to fault current contributions from distributed generation. This phenomenon has been studied in the literature [3-5]. A key finding is that protection blinding is not solely caused by the presence of distributed generation between a circuit breaker and a fault but is influenced by factors such as the location of the distributed generation within the grid, fault level, fault level distribution across generation units, and fault location. These studies raise the question of how to effectively protect the blinding zones of feeders with multiple IBDGs. Ref. [6] proposes activating thermal overload protection in the relay to prevent blinding. This method can mitigate the issue for a limited range of high-impedance faults.

In this paper, an adaptive protection scheme is proposed to address protection blinding. In the proposed algorithm, the appropriate IEC time-current characteristic type, pickup current and Time Multiplier Settings (TMS) are determined for varying levels of IBDG generation. The operational status of the IBDG can be determined by the time of day (e.g., PV on or PV off), through good estimation, or via data received from the AMI infrastructure. Depending on the situation, the adjustments can be either scenario-based or continuous. The adaptive strategy proposed is straightforward and does not require sophisticated tools nor real-time infrastructure for grid monitoring.

The paper is organized as follows: Section 2 describes the blinding zones of overcurrent relays in distribution networks. Section 3 presents the proposed adaptive protection scheme. Section 4 and section 5 discuss the simulation results, analysis and present the hardware in the loop (HIL) implementation. Finally, the conclusion is provided in Section 6.

2 Blinding zones of OCRs

Generally, the IBDG output current is limited by the inverter to a value close to its maximum nominal current (e.g., 1–1.2 pu), even in fault conditions.

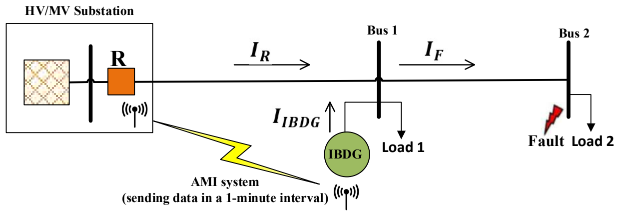

Fig. 1: Blinding of a single feeder protection

In most cases, a 1.2-pu fault contribution from IBDG should be negligible in relation to the conventional fault contribution fed from the transmission system. However, huge penetration of PV units along distribution feeders may cause the upstream protective relays to sense just a portion of the actual fault current, leading to the risk of protection blinding.

Fig. 1 shows a distribution feeder with a PV source that represents the aggregation of many small PV units. When a fault occurs at the downstream of main protection, the fault current through the feeder relay R is:

$$I_R^{PV\_off} = I_F \qquad (1)$$

However, with an increasing number of PV systems installed between the main substation and the fault location, according to the current division law, the fault current contribution from the upstream grid measured by relay R is decreased to:

$$I_R^{PV\_on}=I_F - k.I_{PV} \qquad (2)$$

Where k=1–1.2, depending on the control of the PV inverter. In this paper, we assumed that the PV inverter limits the output current to its nominal value (e.g., k=1).

Under fault conditions, depending on the importance of the contribution of the distributed generation to the downstream fault, two situations might arise:

a) Any moderate PV contribution to the fault current would lead to an increased tripping time of the feeder because of the inverse time-current characteristics of OC relays, exposing the cables downstream to thermal overload.

b) If the PV contributes more significantly to the fault current, the current sensed by the feeder relay might decrease below its pickup current threshold, resulting in a missed detection of the fault (blinding effect), leaving the faulted downstream line to inevitably fail.

3 Adaptive protection scheme

The proposed protection scheme relies on the possibility of selecting every minute the most appropriate setting group (SG) among (up to) six curves that have been previously determined offline, basing on the algorithm illustrated in Section 3.2. The input GOOSE message for the adaptation of the OC settings is received from a protection management unit that changes the

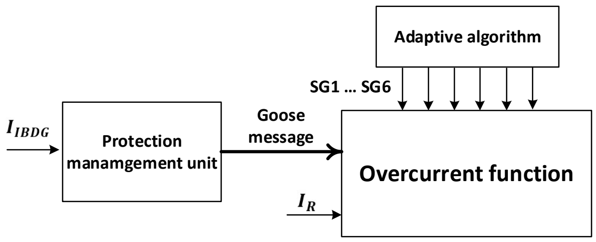

Fig. 2: Adaptive protection scheme

setting group based on the current level of the IBDG output, monitored by an AMI system, as is shown in Fig. 2.

The measured value of I_{IBDG} is sent from the IBDG to the substation at 1-minute intervals. PV generation typically exhibits minimal variation over short intervals, such as one minute, due to the gradual nature of solar irradiance changes, except during rapid cloud movement. If a fault occurs at t_F, between two successive transmission times t_1 and t_2, the fault current contribution of IBDG ($I_{F,IBDG}$) is estimated with the received current magnitude at t_1.

3.1 Fundamental concept of the IEC curve determination algorithm

To illustrate the operation of the proposed algorithm, the simple feeder shown in Fig. 1 is considered. Two distinct scenarios are defined based on the operating status of PV unit: no PV (which will lead to the setting group SG1) and PV at 100% of its capacity (which will identity the parameters of the setting group SG2). It must be noted that the number of possible scenarios to determine is limited by the number of setting groups that could be pre-charged in the protection relay (typically, equal to six) but only two have been considered here to explain the procedure.

To estimate the overcurrent settings for the relay in case of PV injecting at 100% of its capacity (SG2), the procedure begins with the assumption of PV Off. In this scenario, the inverse time overcurrent SG1 shown in Fig. 2 is adopted conventionally for the relay. SG1 includes two parts: the inverse-time part and the instantaneous one. A threshold I_{ins} is used to decide which part should work. The relay trips once the current exceeds I_{ins}. For fault currents lower than I_{ins}, the SG1 will calculate the operation time in accordance with the standard IEC 60255:

$$t^{SG} = TMS \times \frac{k}{(\frac{I_R}{I_p})^{\alpha} - 1} \qquad (3)$$

where I_R, I_p and TMS are fault current sensed by the relay, pick up current, and time multiplier setting; k and α are constant parameters determining the slope of the protection characteristic curve.

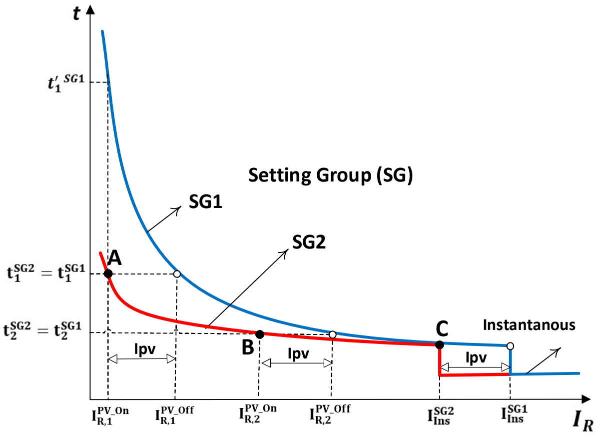

Fig. 3: Adaptive characteristic of overcurrent relay

For the same I_F, relay R senses different current levels depending on the PV production.
To eliminate the effect of PV current on relay performance, as shown in Fig. 3, the objective is to adjust the overcurrent relay settings for SG2 by changing the IEC curve and TMS value to achieve the same operating time as SG1.

$$t^{SG_2}\left(I_R^{PV\_On}\right) = t^{SG_1}\left(I_R^{PV\_Off}\right) \qquad (4)$$

By doing so, the relay can detect faults with the same sensitivity, regardless of the presence of PV generation.

3.2 *Steps of the algorithm*

The steps of the proposed algorithm are as follows:

Step 1: Design protection curve SG1 for no PV ($I_{PV} = 0$) in the feeder using an IEC curve with three characteristics: curve type extremely inverse (A), pick-up current (I_p^{SG1}), and time multiplier setting (T_{TMS}^A). Additionally, an instantaneous part.

Step 2: $\Delta I_{PV} = 1$

Step 3: $I_{PV} = I_{PV} + \Delta I_{PV}$

Step 4: Calculate I_p^{SG2} using following equation:

$$I_p^{SG2} = I_p^{SG1} \text{-} I_{PV} \qquad (5)$$

Step 5: Define I_1 as the sum of the PV current and the pick-up current.

$$I_1 = I_p^{SG1} + I_{PV} \qquad (6)$$

Step 6: Select N samples between I_p^{SG1} and I_1, forming the current set $\boldsymbol{I_A}$.

Step 7: For each element in $\boldsymbol{I_A}$, apply the photovoltaic current adjustment to form the current set $\boldsymbol{I_B}$.

$$\boldsymbol{I_B} = \boldsymbol{I_A} - I_{PV}.\boldsymbol{1_n} \qquad (7)$$

Where $\boldsymbol{1_n}$ denotes a vector of N ones and I_{PV} is the photovoltaic represents the photovoltaic current received by the relay through the AMI system.

Step 8: Calculate operation time set $\boldsymbol{T_A}$ for SG2:

$$\boldsymbol{T_A} = T_{TMS}^A \times \frac{k.\boldsymbol{1_n}}{\left(\frac{\boldsymbol{I_B}}{I_p^{SG1}.\boldsymbol{1_n}}\right)^{\alpha} - \boldsymbol{1_n}} \qquad (8)$$

Step 9**:** Set operation time set of SG2 to be equal to the operation time of curve SG1, $\boldsymbol{T_B} = \boldsymbol{T_A}$.

Step10**:** Consider different IEC curve types—extremely inverse, very inverse, and normal inverse. For each curve type, calculate the **TMS** set by using $\boldsymbol{I_B}$ and $\boldsymbol{T_B}$ in its respective formula.

Step11**:** For each TMS set, calculate the coefficient of variation (CV) of its elements. The CV quantifies the relative variability in the TMS set, normalized to the mean:

$$CV = \frac{\sigma_{TMS}}{\mu_{TMS}} \qquad (9)$$

A lower CV indicates a more stable estimate.

Step12**:** Select The curve type with the minimum corresponding CV as the desired SG2 curve.

Step 13**:** Take the mean value of the TMS vector as the TMS value for the selected curve type as the estimate curve for I_{PV}.

Step14: Repeat the steps from Step 3 to Step13 until I_{PV} reaches its nominal value.

Step15: Cluster the obtained settings into N clusters, where N is the number of setting groups in the relay (typically N=6).

4 Case study

In Fig. 4 a simple example test feeder is considered. The case comprises of a medium-voltage distribution network with nominal current of 200A and a PV generator of 5 MW connected into the network. The current injected by the PV generator varies from 0 to 150 A.

Four fault locations at different distances downstream from the PV were used in the calculations. A three-phase short-circuit fault was analysed for each location, resulting in fault currents of I_F = 800A, 600A, 400A and 300A at the locations F1, F2, F3, and F4, respectively.

Two protection scenarios are defined: first with the conventional protection and second with the adaptive protection proposed in this paper.

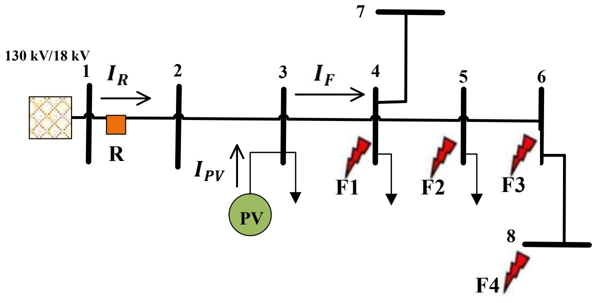

Fig. 4: Test feeder

Table 1: Tripping times of the relay for various scenarios

I_F (A)	I_{PV} (A)	Conventional relay tripping time (s)	Adaptive relay tripping time(s)
300	0	18.1	18.1
	50	Blinding	18.5
	100	Blinding	21.6
	150	Blinding	19.2
400	0	5.1	5.1
	50	8.3	5
	100	18.1	5.6
	150	Blinding	4.6
600	0	1.68	1.68
	50	2.0	1.58
	100	2.6	1.66
	150	3.5	1.42
800	0	0.8	0.8
	50	1	0.79
	100	1.1	0.8
	150	1.3	0.65

4.1 Conventional protection

The feeder is equipped with an overcurrent relay (R) consisting of two components: an IEC extremely inverse time component with TMS=0.2 and $I_p = 1.2 \times I_n$ where I_n is the nominal current of the feeder, and an instantaneous component that trips immediately when the fault current exceeds $I_{ins} = 5 \times I_n$.

As shown in the third column of Table 1, for the same fault current downstream of the PV unit, the tripping time of the conventional relay increases significantly due to the current contribution of the PV unit. Additionally, the relay is unable to detect faults within the blind zone of its coverage. Consequently, this can result in the burning of the affected lines.

4.2 Adaptive protection

It is assumed that the measured value of output current of PV is received to the protection unit via AMI system at 1-minute intervals or can be determined by the time of day (e.g., PV on or PV off).

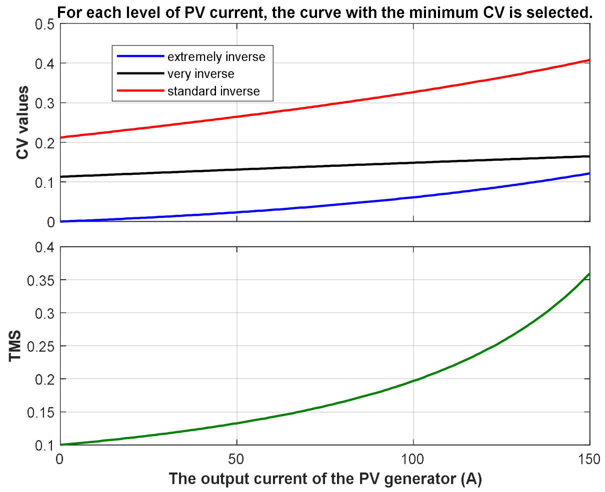

Fig. 5: Adaptive IEC curve characteristics

The proposed algorithm in Section 3 suggests the adaptivity of inverse time relay characteristics, as shown in Fig. 5, in relation to the output current of the PV system plus an instantaneous component that trips when the fault current exceeds $I_{ins} = 4 \times I_n$.

Typically, the relays are limited to six setting groups. Users are restricted to these six groups and cannot define additional groups. To address this limitation, we consider one cluster for instantaneous part, then we cluster the setting groups proposed in Fig. 5 into 5 major groups. For this purpose, the current range from 0 to 150 A is divided into 5 clusters, each with an equal range of 30 A. The curve type is always extremely inverse (corresponding to the minimum CV value), but the TMS value is the average of the TMS values within that current range. For example, for the current range of 0–30 A, the TMS value is set to 0.11.

When the protection unit receives the PV currents Ipv=0, 50A, 100A, and 150A via the AMI system, it activates the first, second, fourth, and fifth defined setting groups of OC relay, respectively, by sending GOOS messages.

As presented in the fourth column of Table 1, for the same fault current downstream of the PV unit, the tripping time shows negligible variation with increasing levels of PV current. This aligns with the objective specified in relation (4), which aims to eliminate the effect of PV current on relay performance. As a result, there is no blinding zone caused by the PV unit generation for the relay.

5 Real-time HIL implementation

In a laboratory environment, the methodology described can be implemented using a hardware-in-the-loop setup, as shown in Fig. 6, This approach leverages the IEC 61850-8-1 GOOSE protocol, which supports high-speed, peer-to-peer communication of status and control commands between devices in a substation automation system. OPAL-RT's support for GOOSE messaging enables seamless integration and real-time communication between simulation models and physical protection, monitoring, and control devices like the ABB REX640.

The REX640 is protection and control relay for advanced power generation and distribution applications developed by ABB, which is limited to six setting groups.

Here we ask OPAL-RT to adjust dynamically the setting group of the REX640 in response to varying PV production levels, thereby enhancing the adaptability and reliability of the protection system. for advanced power generation and distribution applications

REX640 has protection function block for setting group activation shown in Fig. 7. Setting group can be changed with binary inputs (BI_SG_2...BI_SG_6). The highest TRUE binary input defines the active setting group. By default, setting group 1 (SG1) is active.

Based on the level of PV production, the OPAL-RT unit sends the appropriate binary GOOSE message to activate the corresponding setting group. For instance, if the current is in the range of 30 to 60 A, it sends [1 0 0 0 0] to activate SG2. The REX640 receives this message and utilizes its protection function block to activate the specified setting group for this relay.

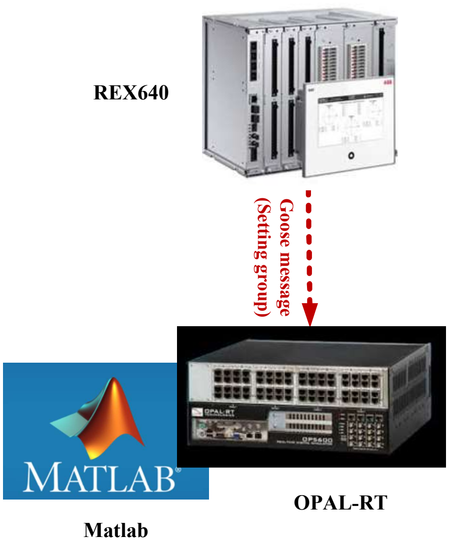

Fig. 6: HIL environment setup

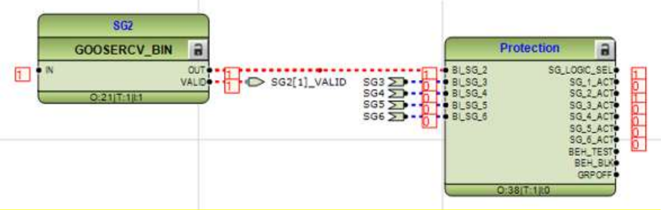

Fig. 7: GOOSE receiver and protection function blocks

6 Conclusion

In conclusion, the proposed adaptive protection scheme effectively addresses the challenges posed by protection blinding in ADNs with integrated IBDGs. By dynamically adjusting the IEC overcurrent curves based on generation levels and leveraging operational data from AMI, the scheme ensures reliable fault detection under varying conditions. The results from the case study, supported by real-time simulation and hardware-in-the-loop testing, validate the practicality and efficacy of the method, offering a robust solution to enhance the reliability and safety of modern distribution networks.

7 References

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