Indian J.Sci.Res. 17(2): 283 - 288, 2018
ISSN: 0976-2876 (Print)
ISSN: 2250-0138(Online)

OPTIMUM LOCATION OF OVER CURRENT RELAYS IN DISTRIBUTION NETWORKS FOR DISTRIBUTION GENERATION

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***Abstract* —** Conventional distribution networks are generally radial and are fed by Major sources located at the transmission level. The power flow direction in these networks is unilaterally from sources to load feeders. In recent years, to meet the growth of demand, there has been an upward trend in the integration of distributed generation (DG) units to distribution networks. Although, the connection of DG units to the distribution network has many advantages, there are some undesirable impacts on the network operation and protection. After the interconnection of DG unit, short circuit levels will change. In addition, the power flow in some parts of the system may no longer be unilateral, resulting in the loss of coordination between relays. In this paper, the effect of the size and location of DG unit on the coordination of overcurrent (OC) relays in distribution networks will be investigated. The magnitude and the direction of short circuit currents for a sample network will be analyzed with and without DG unit. By changing the size and the location of DG units, the operation of OC relays and the coordination between them for upstream and downstream faults will be evaluated.

***Keywords*—** Distributed Generation; Distribution Network; Protection Coordination; Over current Relay

I. Introduction

The integration of DG units to electrical networks has drawn more attention in recent years due to the many benefits they provide to grids. Two major reasons for increment in utilization of DG units are liberalization of markets, which opens the market to various kinds of participants, and the global trend of reduction in greenhouse gas emissions. Other benefits of DG including, but not limited to, improving system reliability, reducing losses and improving power quality are discussed in detail in [1].

According to IEEE standard 1547-2003, DG is a generation facility interconnected to an electrical grid through a Point of Common Coupling (PCC) [2]. DG's rating is small compared to conventional power plants.The size of a DG unit varies over a wide range, from less than a kW to 100 MW[2]-[4].

DG units, with respect to the existing technology, can be divided into two classes: renewable and nonrenewable. Renewable technologies include fuel cell, wind turbine, solar cell and geo thermal system whereas nonrenewable technologies encompass combined cycle power plant, combined heat and power (CHP) system, combustion turbine and diesel generator [1].

The interconnection of DG units to grids, although it adds benefits to the grids, raises some issues with the operation and protection of the grids. Fuses, reclosers and OC relays are used widely to protect distribution networks against faults. There is a lot of flexibility in the setting of an OC relay compared to a fuse due to different curves, several time settings and various current settings that can be applied to the OC relay. The protection coordination in traditional distribution networks is simple, and selectivity, as a key factor in protection systems, can be achieved effectively. By the means of time interval between operating times of main and backup protective devices, this purpose can be attained.

Investigating the impacts of DG units on the protection systems of distribution networks has been burgeoning in the last decade. Reverse power flow, false tripping, blinding of protection, unwanted islanding and unsynchronized reclosing have been reported as the nuisance effects of the interconnection of DG units to distribution networks. After integrating DG units, power flow in some parts of the network is no longer unilateral. Additionally, short circuit levels would drop or rise throughout the network when a DG unit is connected to the grid. This increment and decrement completely depends on the size and location of the DG unit [5]. Hence, the assessment of existing protection system is required.

In [6] false tripping, nuisance islanding and auto reclosing, as three undesirable effects of DG unit integration on the protection system, were analyzed and discussed.

Studies on the impacts of DG units have shown that the coordination of OC devices (e.g. OC relay, fuse and recloser) may no longer be maintained [7]-[11]. However, studies revealed that an inverter-based DG unit cannot aggravate the coordination between OC relays in medium voltage (MV) distribution networks since the contribution of the inverter-based DG unit to the fault is not significant enough to activate the OC relays [12]. Recently, the size of DG units, as the main key in maintaining the coordination, came to attention in a few research papers. In these studies,

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the maximum size of DG unitthat can be connected to the grid without deterioration of the protection coordination was determined [9]-[11].

Although, most of the papers have explored the impacts of the size and location of DG units on the coordination between fuse-fuse and fuse-reclose in the low voltage (LV) distribution networks, there are a few studies dedicated to the adverse effects of DG units on the OC relays in MV distribution networks [10], [13]-[14]. Blinding of protection and miscoordination between protective devices have been generally reported in these studies. Among these works only in [10] have the different DG capacities and several connection points been studied in a radial MV distribution network.

The objective of this paper is to investigate the effects of DG units on the coordination of OC relays in the MV distribution networks with respect to the location and size of the DG unit. Synchronous DG units are used in this study and several locations and different sizes are taken into consideration to figure out how the OC relays operate in the presence of the synchronous DG units. In addition to this, the DG units' impacts on the coordination between OC relays are assessed for forward and reverse faults and possible solutions are examined for each case.

II. System Model

A. Network Configuration

A simple radial network shown in Fig. 1 has been simulated in ETAP. The 63 kV network is connected to the 230 kV grid through a 40 MVA transformer. The 230 kV grid has X/R=6 and its short circuit capacity is 3000 MVA. Four 63/20 kV transformers with the capacity of 10 MVA interconnect the 63 kV network to the downstream 20 kV distribution systems. Transmission line length between substations is 8km. Four synchronous DG units, G1, G2, G3 and G4 are considered and would be connected and disconnected in different scenarios, as described further. To calculate the short circuit currents, impedances of generators and transformers are 12% for generators, 10% for 230/63 transformer and 8% for 63/20kV transformers. Constant loads, each one being 7MVA, are located on some busbars as shown in Fig. 1.

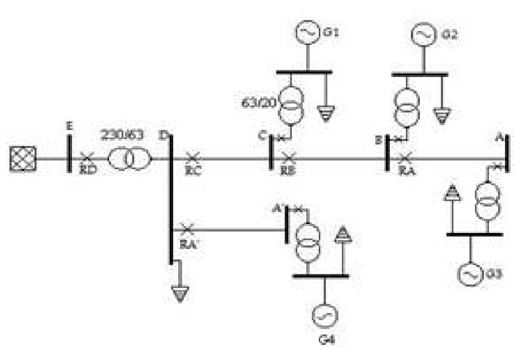

Fig. 1. Network under study

B. OC Relay Model

To simulate the operation of inverse-time OC relays, operating time of the OC relay should be represented as afunction of pick-up current and fault current as well as the time setting multiplier (TSM) or time dial setting (TDS). Several linear and non-linear methods have been suggested in order to approximate inverse-time curves [15]. Nowadays, with the widespread application of microprocessor relays across power systems, IEC and IEEE standards propose formulas for inverse-time curves [16]-[17]. The formula suggested by IEC for OC relay curves, which is defined by the following equation, is used in this paper [16].

$$t = \frac{A}{(PSM^{p} - 1)} \times TSM \tag{1}$$

Where PSM (plug setting multiplier) is the ratio of the

maximum short circuit current,I_F, to the relay current setting,

I_{SET}. Constant **A** and exponent **p** related to the

relay curves are given in Table I [16].

The OC relays are coordinated considering no DG is connected to the network. Normal Inverse curve is used for all OC relays and the coordination time interval (CTI) between the main and backup relays is 0.4 sec. Table II shows the current settings and TSMs of relays as well as the short circuit currents for the close-in fault.

Table I. Constants And Exponents For Iec Standard

Characteristics

Curve Type	A	P
Normally Inverse (C1)	0.14	0.02
Very Inverse (C2)	13.5	1
Extremely Inverse (C3)	80	2
Long-time Inverse (C4)	120	1

Table II. Relay Settings And Short Circuit Currents For Network

Under Study

Relay	Maximum Fault Current in Front of Relay (A)	Pick-up Current (A)	TSM
RA	2300	69	0.05
RA'	2900	71.4	0.05
RB	2600	149	0.2

RC	2900	218	0.35

III. Simulation And Investigation Of Different scenarios

Different scenarios are simulated with respect to the fault location, DG size and location of DGs. Eliminating the repetitive cases, three main cases are investigated in what follows.

A. Investigation of Relay Coordination for Forward Faults (From Grid to Loads)

In this case, it is supposed that the fault direction is forward, meaning that the fault current direction is from the transmission network to the distribution network. By changing the location of DGs, the three following scenarios would occur.

a)DG located before main and backup protection

In this case, DG1 with rated power of 4 MW is connected to the grid as indicated in Fig. 2. Table III represents the short circuit currents, with and without DG connection, in addition to the operating time of the main and backup relay According to Table III, the time interval between the main and backup relays is reduced to 0.387 sec, which is less than the permissible value of 0.4 sec. So, the coordination between two relays is missed. Fig. 3 depicts the curves of relays RA and RB plotted in the MATLAB. According to this figure, the coordination between relays RA and RB will no longer exist for short circuit currents more than 2300 A. Since the increment in fault current is directly related to the capacity of the interconnected DG unit, the coordination margin between two relays drops as the capacity of the DG unit increases.

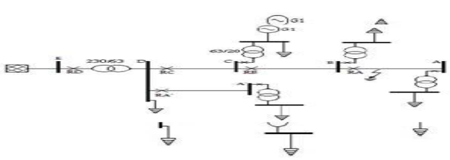

Fig. 2. DG unit connected before main and backup relay

Table III. Short Circuit Currents And Relay Operating Times For Case 1

Relay	without DG		with DG	
	Short CircuitCurrent (A)	OperatingTime(S)	Short CircuitCurrent (A)	OperatingTime(S)
RA (Main Relay)	2300	0.096	2500	0.094
RB (Backup Relay)	2300	0.498	2500	0.482

In the presence of the DG unit, the fault current rises and, therefore, the coordination between two relays will be lost. To solve this problem, all relays should be coordinated again considering the DG unit. With these new settings, coordination will be maintained even when no DG is in service.

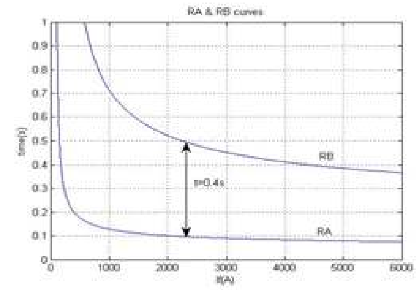

Fig. 3. Relay RA and RB curve

b)DG located between main and backup protection

This condition is depicted in Fig. 4. The simulation results are given in Table IV.

Considering the DG unit in this location, the current flowing through the main relay (RA) rises while the current seen by the backup relay (RB) drops. Thus, the time interval between two relays is still more than 0.4 sec (here it is 0.413 sec). In this case, the integration of the DG unit increases the operating time of the backup relay, and therefore the time interval between two relays goes up. Increasing the DG capacity will result in reducing the operating time of the main relay. On the other hand, the operating time of the backup relay rises. Hence, any changes in the capacity of the DG unit does not affect the coordination between relays RA and RB in this case.

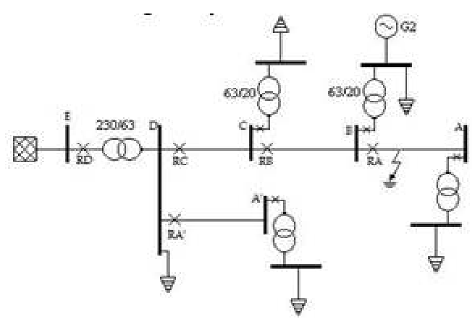

Fig. 4. DG unit located between main and backup protection

Table IV. Short Circuit Currents And Relay Operating Times For Case 2

Relay	without DG		with DG	
	Short CircuitCurrent(A)	OperatingTime(S)	Short CircuitCurrent(A)	OperatingTime(S)
RA (Main Relay)	2300	0.096	2600	0.093
RB (Backup	2300	0.498	2200	0.506

Relay)				

c)Considering two DG units in the network

This case shown in Fig. 5 is a combination of two former cases, case 1 and case 2.

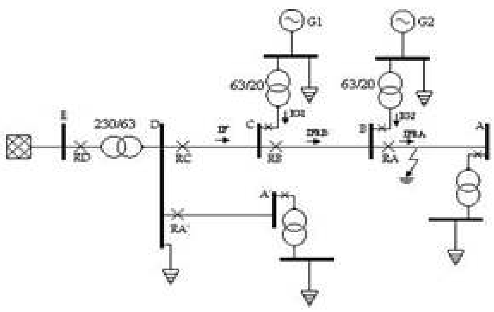

Fig. 5. Two DG units in the network

Based on case 1, the placement of DG units before main and backup relays causes the fault current seen by both relays to increase, resulting in missing the coordination between main and backup relays. On the other hand, as discussed in case 2, the connection of DG units between main and backup relays augments the coordination time margin between them. So, with two DG units, the contribution of each DG unit to the fault will determine whether the coordination will remain or not. The fault current seen by each relay can be obtained from equations

(2)-(3).

$$I_{FRA} = I_F + I_{G1} + I_{G2} \tag{2}$$

$$I_{FRB} = I_F + I_{G1} \tag{3}$$

Time difference between two relays can be shown as equation (4).

$$\frac{0.14 \times TSM_{RB}}{\left(\frac{I_{FRB}}{I_{setRB}}\right)^{0.02} - 1} - \frac{0.14 \times TSM_{RA}}{\left(\frac{I_{FRA}}{I_{setRA}}\right)^{0.02} - 1} \geq 0.4 \tag{4}$$

According to equations (2)-(4), a zone, where the coordination is still maintained, can be found. This zone is shown in Fig. 6.

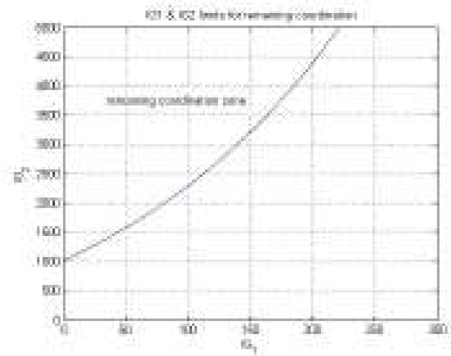

Fig. 6. Valid coordination zone with regard to the contribution of DG units to the fault current

Considering the impedances of generators, transformers and feeders, the size of generators, for which the coordination still remains, can be calculated. For instance, if DG1=1.5 MW, the size of DG2 should be more than 12MW so that the coordination will not be lost. Table V represents the operating time of relays RA and RB for above sizes of DG1 and DG2.

Table V. Short Circuit Currents And Relay Operating Times When Rated Powers Of DG1 IS 1.5 MW AND DG2 Is More Than 12 Mw

Relay	without DG		with DG	
	CircuitCurrent(A)	*OperatingTime(S)*	*CircuitCurrent(A)*	*OperatingTime(S)*
RA (Main Relay)	2300	0.096	3100	0.089
RB (Backup Relay)	2300	0.498	2400	0.489

In this case, if the coordination is missed, TSMs of relays RA and RB must be recalculated with respect to the new configuration of the network. Also, it is noteworthy that the connection of DG between two relays (i.e. connection of DG2) brings about the reduction in the load current seen by the relay RB. Therefore, the current setting of the relay RB should be calculated without considering DG2; otherwise RB may operate incorrectly in the absence of DG2. This modification improves the coordination between RA and RB as well.

B.Investigation of Protection Coordination for Reverse Fault Currents (from DG units to Grid)

In conventional distribution network, the fault current always flows in the forward direction. The interconnection of DG units will give rise to the flow of reverse fault current in the grid as well. In this section, the protection coordination regarding the reverse fault current will be investigated.

a) Reverse fault current with one DG

As shown in Fig. 7, for a fault on feeder CD, relays RA and RB sense the same reverse short circuit current when the DG unit is connected in front of both relays. The current seen by each relay and the operating times of relays are given in Table VI. The negative sign for the current in this table indicates that the fault current flows in the reverse direction. Relay RC measures the current from grid to the fault, and thus DG3 does not affect the direction and magnitude of the current seen by this relay.

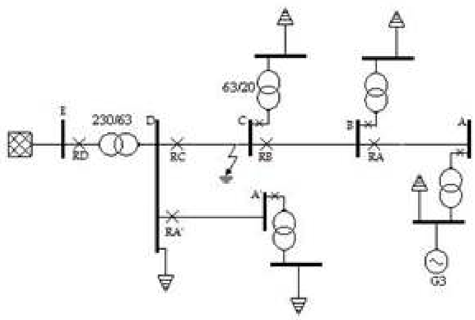

Fig. 7. Reverse fault current with one DG unit

Table VI. Short Circuit Currents And Relay Operating Times

Relay	With 4MW DG		with 10 MW DG	
	Short CircuitCurrent (A)	OperatingTime(S)	Short CircuitCurrent (A)	OperatingTime(S)
RA (Backup Relay)	-350	0.212	-841	0.137
RB (Main Relay)	-350	1.625	-841	0.795

It is obvious that relay RC must trip to clear the fault current injected from upstream. What is not evident is the fault current fed from the downstream DG units. Logically, in this case, if relay RB operates, the fault will be isolated. However, according to Table VI, the operating time of relay RA is less than relay RB. In other words, for the given fault, relay RA initiates trip sooner than relay RB resulting in unnecessary outage of healthy feeders (i.e. feeders AB and BC). Considering the fact that relay RB is the backup of relay RA for forward faults, according to the previous section, a conflict between relay coordination criteria for forward and reverse faults arises. In other words, the relays should be coordinated in a manner that, for forward fault currents, RB is the backup for RA whereas, for reverse fault currents, RB should clear the fault faster than relay RA, which is not feasible.

The installation of directional OC relays on the other end of all feeders could be a solution. Aside from the cost that the installation of the new OC relays will impose, coordination of these new directional OC relays in the presence of DG units will bring about more problems, as discussed in the previous sections.

Another possible solution would be to find the maximum capacity of DG units that can be connected to the network without deteriorating the coordination in case of reverse fault. In this solution, the relays will be coordinated for the forward fault and the limitation will be imposed to the capacity of connected DG units in order to maintain the coordination between OC relays for the reverse faults. The drawback of this solution is that the solution delimits DG capacity. However, it does not require any changes in the relays or installing new infrastructure and it is not costly.

B) Reverse fault current with two DG units

In this case, two DG units are connected: one to the after of both relays and the other one between relays RA and RB as indicated in Fig. 8.

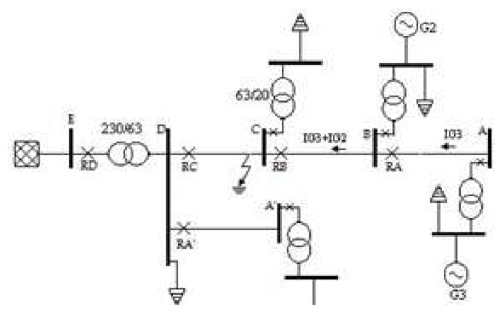

Fig. 8. Reverse fault current with two DG units

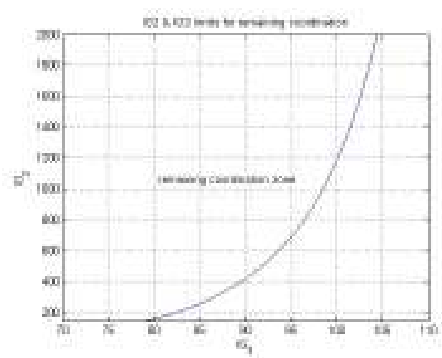

Fig. 9. Valid coordination zone for contribution of two DGs to reverse fault

For a fault occurring on feeder CD, RB is the main relay and RA is the backup relay. The relays RA and RB are still coordinated if the reverse fault currents measured by the relay RB is higher than the reverse fault current seen by the relay RA. Hence, a zone, where the coordination between two relays still remains, may exist.

To determine this zone, the amount of fault currents for each relay is defined as follows:

$$I_{FRA} = I_{G3} \tag{5}$$

$$I_{FRB} = I_{G2} + I_{G3} \tag{6}$$

The time difference between the operating times of two relays (i.e. between the main and the backup relays) is shown in equation (7).

$$\frac{0.14 \times TSM_{RA}}{\left(\frac{I_{FRA}}{I_{setRA}}\right)^{0.02} - 1} - \frac{0.14 \times TSM_{RB}}{\left(\frac{I_{FRB}}{I_{setRB}}\right)^{0.02} - 1} \geq 0.4 \tag{7}$$

The valid coordination zone, according to equations (5)-(7), is represented in Fig. 9.

For example, if DG3=1MW, then DG2 must be higher than 12MW for the protection coordination to remain. The operating times of the main and backup relays for aforementioned DG unit capacities are given in Table VII.

Table VII. Short Circuit Currents And Relay Operating Times When Rated Powers Of DG3 IS 1 MW AND DG2 IS More Than 12 MW

Relay	Short Circuit Current (A)	Operating Time (S)
RA (Backup Relay)	-90	1.314
RB (Main Relay)	-600	0.991

Limiting the generation and the size of the DG units based on the protection coordination criteria (e.g. criteria given in equations (5)-(7)) can eliminate the miscoordination between the OC relays. However, to determine the size of a DG unit in a distribution network, other criteria such as stability, load flow, voltage limitation and power losses must be considered as well.

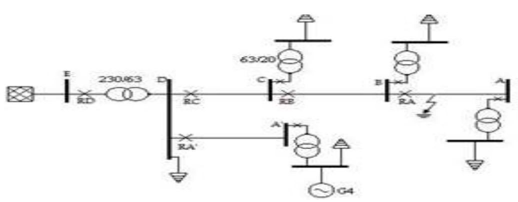

Fig. 10. DG unit in adjacent feeder of fault location

C)DG on Adjacent Feeder of Fault Location

According to Fig. 10, for a fault on feeder AB, relay RA is the main protection, and therefore RB will be its backup relay.

Nonetheless, with respect to Table VIII, if relay RA does not operate correctly or the circuit breaker corresponding to the relay RA does not get open, rela operates faster thanRB resulting in unnecessary isolation of healthy feeder. In this case, if DG4 on the bus cannot supply all the loads in the islanded part, DG4 will be shut down or otherwise some loads must be taken out of service. Neither situation is desirable.

To solve this problem, relay should be equipped with directional element to avoid any false tripping.

Table VIII. Short Circuit Currents And Relay Operating Times WHEN CAPACITY OF G4 IS 4MW

Relay	Short Circuit Current (A)	Operating Time (S)
RA (Main Relay)	2500	0.094
RB (Backup Relay)	2500	0.482
(Relay on the adjacent feeder)	264	0.264

D)Summary and Suggestions

According to the investigated scenarios and corresponding results, the following points can be suggested:

1. In cases of forward fault currents (from grid to loads), if DG is placed before main and backup relays, coordination will be lost. This problem can be solved by recalculating the time setting of the backup relay. With DG between main and backup relays, the fault current seen by the main relay increases, while the fault current through the backup relay diminishes. In this case, because only the operating time of the main relay rises, the coordination between the main and backup relays will still remain. In the situation when two DGs are integrated to the network, one before the backup protection and the other one between the main and the backup relays, a zone based on the size of DG units can be defined, in which the coordination between relays will still exist.
2. For reverse fault currents, in the presence of one DG unit, coordination will be lost. In case of two DG units, there is a zone, regarding the capacity of DG unit, in which the coordination will still remain. In this case, equipping the OC relays with the directional element is inevitable.
3. If DG unit is connected to a feeder and a fault occurs on the adjacent feeder, false tripping may cause undesirable isolation of the healthy parts of the grid.
4. After connecting DG units, the setting of protective relays must be examined and changed if required to maintain the coordination between relays. Therefore, the application of an adaptive protection system can improve the operation of the entire protection system. The adaptive protection system can clear faults as fast as possible, while the selectivity of the protection system is still retained.
5. Choosing the maximum size of DG units,

considering the coordination criteria, can maintain the coordination between OC relays. However, the selected size should meet other criteria such as stability, voltage limitation and reliability.

IV. Conclusion

In this paper, different scenarios for the protection system of a radial distribution network in the presence of DG units were

discussed. Results indicated that the size and the location of DG units would affect the coordination between relays. Recalculating OC relay TSMs, limiting the size of DG units with respect to the coordination criteria, and applying the directional OC relays can be considered as remedial actions in MV distribution networks with DG units. Using one or more of these solutions depends totally on the network configuration and location of DG units.

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