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An Inverse Time Admittance Relay for Fault Detection in Distribution Networks Containing DGs

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Abstract—Isolation of a faulted segment, from either side of a fault, in a radial feeder that has several converter interfaced DGs is a challenging task when current sensing protective devices are employed. The protective device, even if it senses a downstream fault, may not operate if fault current level is low due to the current limiting operation of converters. In this paper, a new inverse type relay is introduced based on line admittance measurement to protect a distribution network, which has several converter interfaced DGs. The basic operation of this relay, its grading and reach settings are explained. Moreover a method is proposed to compensate the fault resistance such that the relay operation under this condition is reliable. Then designed relay performances are evaluated in a radial distribution network. The results are validated through PSCAD/EMTDC simulation and MATLAB calculations.

Keywords- Normalised admittance, Relay grading, Relay reach setting, Unsymmetrical faults

I. INTRODUCTION

With the advanced technical development of power electronics, solid state converter based distributed generators (DGs) are rapidly being connected to the existing radial distribution networks. The renewable energy sources (e.g. photovoltaic) are usually connected to the grid through voltage source converters (VSCs). These converter connected DGs provide benefits for both utility and consumers. They reduce the amount of energy lost in transmission and distribution of electricity since electricity is generated by them is usually at the locations of electricity consumption. Therefore higher cost incurred due to the development of required infrastructure can be minimized.

As per IEEE Standard 1547, DGs have to be disconnected from the electric power system in the event of faults [1]. Therefore the DGs will be disconnected from a faulted network using an islanding detection method [2]. This may work effectively if the penetration of DGs in a distribution system is low. However, in case of high DG penetration, the disconnection of DGs will drastically decrease the reliability. Therefore DG benefits can be maximized by allowing the DGs to operate in both grid-connected and islanded modes of operation.

The existing distribution networks are radial due to the simplicity and low cost of overcurrent protection [3, 4]. Also, the coordination of protective devices based on the current is

relatively easy in the radial networks. Unfortunately the VSC connected DGs limit the output current to protect their power switches in the event of a fault [5]. As a result of this current limiting, the protection of a radial network with existing overcurrent relays will be a challenging task especially since such a protection is designed to operate for high fault current levels. As mentioned earlier, from reliability point of view, DGs should not be disconnected from the un-faulted segments during faults. This will be possible only when the protective devices, which are employed to protect the feeder, can isolate the faulted segment effectively. Under the normal operation, the DGs operate in parallel with the utility. In that case, the overcurrent relays that are located upstream to the fault will respond due potentially large fault current. However the overcurrent protective devices that are located downstream to the fault will not respond since current limited converters do not supply sufficient current. Therefore faulted segment can not be isolated using the overcurrent protective devices in a radial feeder. This is especially true in an islanded network since the overcurrent relays may not respond or take a long time to respond [6, 7].

A new inverse relay characteristic is proposed in this paper, which utilizes the measured admittance of the protected line. The relay has the ability to isolate the faulted segment of the distribution feeder effectively. The work described in this paper is mainly focused on the new relay fundamentals which cover the basic operation, grading and reach settings. A method to compensate the fault resistance is also described. Performance of the designed relay is evaluated in a radial distribution feeder, which has several converter connected DGs at different locations. The proposal is validated by PSCAD/EMTDC simulations and MATLAB calculations.

II. PROPOSED RELAY CHARACTERISTICS

A. New Relay Fundamentals

A new inverse time relay characteristic is proposed based on admittance measurement of the protected line. A radial distribution feeder as shown in Fig. 1 is considered to explain the new relay characteristic. Let the relay be located at node R and let K be an arbitrary point on the feeder. The total admittance of the protected line segment is denoted by Y_i and measured admittance between the nodes R and K is denoted by

Y_m . Then the normalized admittance (Y_r) can be defined in terms of Y_t and Y_m as

$$Y_r = abs\left(\frac{Y_m}{Y_t}\right) \quad (1)$$

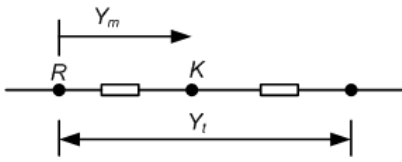


Fig. 1. Radial distribution feeder

This normalized admittance is used to obtain an inverse time tripping characteristic for the relay. The general form for the inverse time characteristic of the relay can be expressed as

$$t_p = \frac{A}{Y_r^\rho - 1} + k \quad (2)$$

where A , ρ and k are constants, while the tripping time is denoted by t_p . These values of the constants are chosen to tune a particular relay characteristic. For example, the relay tripping characteristic for $A = 0.0047$, $\rho = 0.08$ and $k = 0$ is shown in Fig. 2. The normalized admittance (i.e. Y_r) becomes higher as the fault point moves towards the relay location. As a result, the relay gives a lower tripping time for a fault near to the relay. On the other hand, higher fault clearing time will ensue when the fault is further away from the relay location.

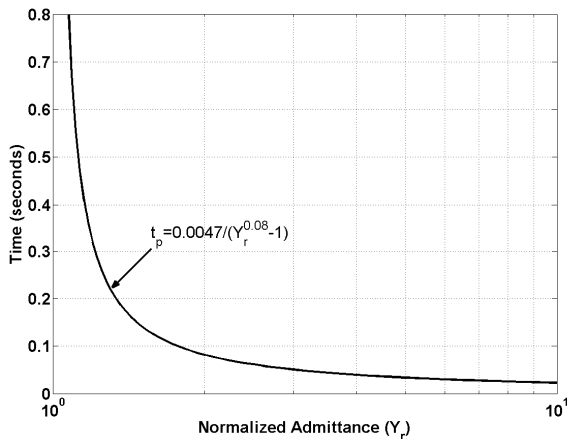


Fig. 2. Relay tripping characteristic curve

It is to be noted that the normalized admittance should be greater than one for relay tripping. It implies that the measured admittance is greater than the total admittance as given below.

$$Y_r > 1 \Rightarrow abs\left(\frac{Y_m}{Y_t}\right) > 1 \Rightarrow abs(Y_m) > abs(Y_t) \quad (3)$$

The relay reach setting can be implemented by choosing a suitable value for the Y_t . This is totally dependent on the protection requirements such as primary and backup protections. For a particular relay, different values for Y_t can be assigned to generate a number of required zones of protection. In each zone, the relay has a unique tripping

characteristic. It checks whether the measured admittance is greater than the total admittance of that particular zone before starting the relay tripping time calculation. A large coverage and minimum tripping time can be achieved by increasing the number of zones. It also leads to good coordination amongst the relays in the feeder. Any upstream relay always provides the back up protection for the immediate downstream relay. For example, let us assume that the relay has two zones of protection. Let us now consider two adjacent relays in a radial feeder. The relay coordination and zone assignment can be performed as illustrated in Fig. 3. Zone-1 of each relay covers the whole line segment between two adjacent relays, while Zone-2 covers twice of the first line segment. Each zone has a different values for the constants in (2) resulting different relay tripping characteristic curves. The locations of two adjacent relays R_1 and R_2 (R_1 being upstream) and tripping characteristic curves are shown against the distance of the fault from the relay locations. As can be seen from Fig. 3, Zone-2 of R_1 will provide a backup for the relay R_2 . Another zone can be assigned with a different tripping characteristic, if required.

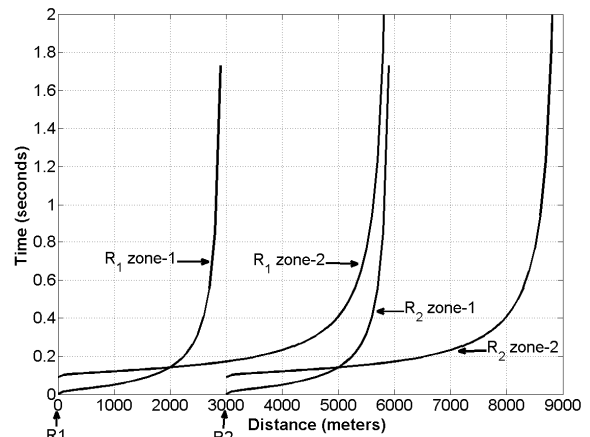


Fig. 3. Relay protection zones and relay coordination

B. New Relay Grading

To illustrate the grading of proposed inverse time relays, a radial system in Fig. 4, is considered. The relays are located at BUS-1, BUS-2, and BUS-3. We assume that each relay has two zones of protection. We assume that Zone-1 of all the relays have identical tripping characteristic. Also the tripping characteristic of Zone-2 of the relays is assumed to be identical. The tripping characteristics of graded admittance relays for this radial system are shown in Fig. 5. The combined tripping characteristic of Zone-1 and Zone-2 is shown. Coordination time intervals are denoted by t_{12} and t_{23} .

Overcurrent relay and distance relay grading are considered to identify the advantages of grading of these new relays. In the case of overcurrent protection, the relay near to the source takes longer time to operate due to the relay coordination settings, since time dial setting (TDS) of relays is increased towards the source. This is a disadvantage of an overcurrent protection, because faults which have higher fault currents cannot be cleared quickly. But the proposed inverse time

admittance relays will make the tripping decision based on the measured admittance to the fault location. Therefore faults are cleared quickly irrespective of the relay location, where they are R_1 , R_2 or R_3 . All of them will take the same amount of time that depends only on the distance between the fault and the relay location. This is an advantage of proposed inverse time admittance relay over an overcurrent relay. In the case of distance relays, the relay will take the same time period to issue the trip command, if the fault is within a particular zone. Moreover the relay does not consider the distance to the fault within the particular zone. On the other hand these newly designed relay have the inverse time characteristic in a particular zone. This is its advantage over the conventional distance relays.

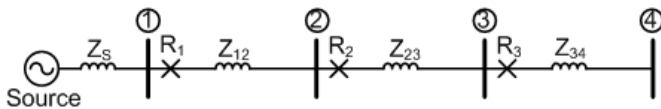


Fig. 4. A radial distribution feeder with relays

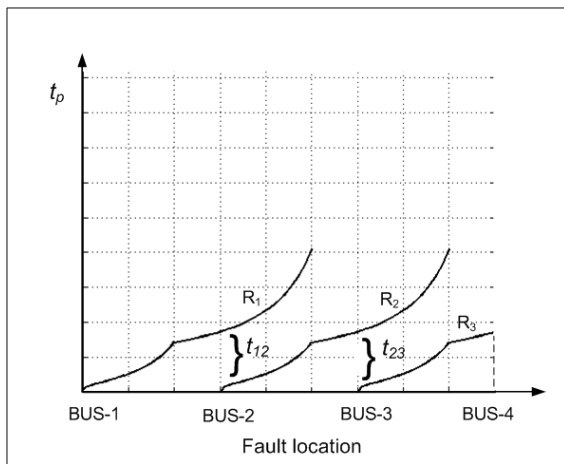


Fig. 5. Inverse time admittance relay grading

C. New Relay Reach Settings

To explain the faulted segment isolation and relay reach settings, a radial feeder with DGs connected at different locations is considered as shown in Fig. 6. The proposed new relay does have the ability to isolate the faults occurring at either side of the relay in a radial feeder. This is because absolute value is taken into the consideration in admittance normalizing process. However for the relay to operate for reverse faults there must be an infeed from a DG that is located downstream from the relay. For example, R_2 and R_3 operate for the faults between BUS-2 and BUS-3. The relay R_2 sees the fault as forward, while R_3 sees it as reverse.

If the distribution network consists of these relays located at equal distances, the same forward and reverse reach can be used to isolate forward and reverse faults. The value for the reach of a particular zone should be selected according to the requirement. For example, reach of the Zone-1 of each relay can be set as 120% of positive sequence admittance of a line

segment. For Zone-2, twice the positive sequence admittance of a line segment can be chosen.

However the reach setting should be different for forward and reverse faults, when the relays are not placed equidistant from one another. In this case, each relay has the capability such that the forward and reverse reach settings can be set appropriately. For example, the reach setting of Zone-1 of the relay R_3 in Fig. 6 is considered. We assume that the lengths of the line segments 2-3 and 3-4 are not equal. The forward reach of R_3 is selected as 100% of line 3-4 and 20% of line 4-5. Similarly, the reverse reach of R_3 is chosen as 100% of line 2-3 and 20% of line 1-2. In this case, both the reverse and the forward reach should have different values since line length between relays are not equal. To accomplish forward and reverse reach in relays, the relay should sense the fault direction. Moreover, the relay has the capability to identify whether the fault is forward or backward. Any method which will determine the fault direction can be used for this purpose. One possibility is to identify the direction of current flow. According to the current flowing direction, relay can select the appropriate reach settings for the tripping time calculations. Another possibility is to calculate the negative sequence impedance seen by the relay. It has been shown in [8] that the reactive part of the negative sequence impedance is always positive for the reverse faults and it is negative for the forward faults. After identifying the fault direction, the process of tripping time calculation can be implemented as shown in Fig. 7.

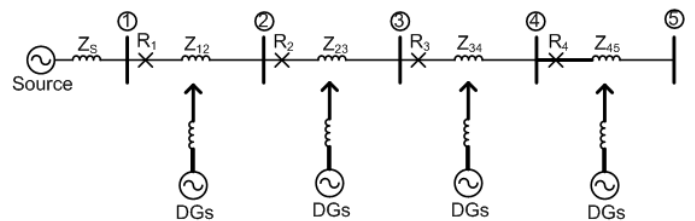


Fig. 6. A radial feeder with DGs

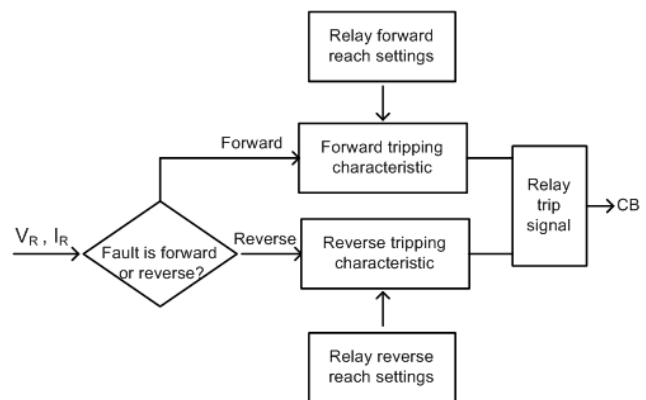


Fig. 7. Relay implementation based on different forward and reverse reach

D. Physical Connection of Relays to the Network

The basic connection diagram of the relay is shown in Fig. 8. Voltage and current at the relay location are obtained using a voltage transformer (VT) and a current transformer (CT)

respectively. The relay output is linked to the tripping coil of the circuit breaker (CB). The relay continuously monitors the input parameters and executes the relay logic to identify a faulted condition in the network. The process of making the tripping decision is shown in the Fig. 9. Fundamental extraction such as Fast Fourier Transform (FFT) can be used to obtain the fundamental magnitudes and angles of the voltages and the currents in the network. Alternatively, the fundamental extraction method proposed in [9] can also be used since it has a faster settling time. Based on the fundamental voltage and current, the admittance is calculated, which is the measured admittance of the relay point at a given time. The measured admittance and values for the relay reach settings are the inputs to the relay logic. This logic consists of normalized admittance calculation, relay characteristics equations, relay tripping time calculations, and defined relay constraints and conditions, etc. If a fault occurs, the tripping time is fed through an integrator to obtain the tripping signal for the CB.

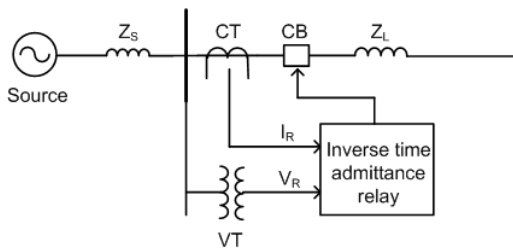


Fig. 8. Relay connection diagram to the system

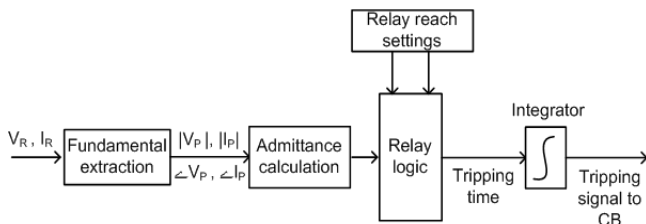


Fig. 9. Process of relay tripping decision making

E. Settings of relays to operate under Fault Resistance

High fault resistance can affect the operation of proposed admittance relays. Therefore a method of relay settings is described to achieve successful relay operation under the fault resistance. To generate the trip signal, relay carefully looks for the constraint in (3), which is the comparison between the measured admittance (Y_m) and the total admittance (Y_t) setting of a particular zone – Y_m should be greater than the Y_t for tripping. Within a particular zone, Y_m is always greater than Y_t , if fault resistance is zero. However with the increase of fault resistance, Y_m can become less than Y_t . Also the maximum fault resistance which allows the relay to operate depends on the fault location of the line. For example, the relay can operate for a higher resistive fault, if the fault is near to the relay than when it is further away from the relay since a higher value of fault resistance can be compensated by each zone for near faults.

To achieve the tripping operation of the relays under resistive faults, we introduce another zone. Maximum fault resistance which can be tolerated by the relay is decided based on the loads of the feeder. In this case, we can obtain the relay operation up to a predefined value of fault resistance. This method will not work for high resistive faults, where fault currents are in same levels as load currents. Since we know the system parameters, maximum equivalent admittance of loads (i.e. the maximum load condition in the system) can be found under normal operation. That will be the corresponding maximum fault resistance which can be tolerated by the relay under the fault condition. If the relay reach settings are below the maximum equivalent admittance of the loads, the relay may trip under normal operation as identifying the load as a high resistive fault. However a safety factor is introduced to avoid unnecessary relay operations. For example, effect of cold load inrush can be considered.

A relay, if it has two zones, has two tripping characteristic curves. In this case, total admittance, Y_t should be set separately for each zone depending on protection requirements. Instead of these two zone characteristics another characteristic will be introduced to discriminate the high resistive faults. Hereafter we will call this zone as Zone-3. Y_t should be appropriately set for this zone considering the loading condition as mentioned. In this case Y_t consists of line admittance and the maximum fault admittance value. A coordination time interval should be kept between adjacent two Zone-3 zones of relays to obtain the correct relay grading as in overcurrent relays. Otherwise relay characteristic of fault resistance zones in each relay will not show a considerable time difference for the faults with low fault resistance. Also the tripping time is set to a higher value than the settings in the normal zone operations, since there is no requirement to isolate the faults with lower fault currents faster than the higher fault current faults. To illustrate the relay settings, consider the radial network as shown in Fig.6. Relay reach setting can be illustrated as below.

R_1 reach setting can be described as,

- ✓ Zone-1 – Y_t is set equal to the value $[1/(1.2 \times Z_{12})]$ assuming that Zone-1 will protect 120% of the first line.

$$Y_{t_Zone1} = \frac{1}{(1.2 \times Z_{12})} \quad (4)$$

Tripping characteristics for Zone-1 can be given by,

$$t = \frac{0.0037}{Y_r^{0.08} - 1} + 0.05 \quad (5)$$

- ✓ Zone-2 – Y_t is set equal to the value $[1/(2 \times Z_{12})]$ assuming that Zone-2 will protect 200% of the line.

$$Y_{t_Zone2} = \frac{1}{(2 \times Z_{12})} \quad (6)$$

Tripping characteristics for Zone-2 can be given by,

$$t = \frac{0.0037}{Y_r^{0.1} - 1} + 0.15 \quad (7)$$

- ✓ Zone-3 - This represents the zone for fault resistance adaptation. Y_t value of this zone can be set using the

allowable maximum resistance value taken while considering the loads (i.e., for maximum loading condition). Let us assume that maximum allowable value is denoted by Z_f after keeping the safety margin. It should be noted that Z_f is the maximum fault resistance that can be handled by the relay when fault occurs in the far end of the protected zone. It is not the fault resistance in a particular fault condition. In this case, Y_t for the Zone-3 can be set as,

$$Y_{t_Zone3} = \frac{1}{(2 \times Z_{12} + Z_f)} \quad (8)$$

Zone-1 and Zone-2 tripping characteristics are same for all the relays. But setting of Zone-3 will be different for different relays since we need to introduce a coordination time margin between each relay. Otherwise relays generate the trip signal in Zone-3 approximately at the same time for zero resistive faults. Also as each relay needs to operate for both forward and reverse faults, it has two tripping characteristics for Zone-3. We name them as forward Zone-3 (tripping characteristic is given by t_{Zone3F}) and reverse Zone-3 (tripping characteristic is given by t_{Zone3R}). When a relay sees the fault direction as forward, t_{Zone3F} is selected as the tripping curve. Otherwise, t_{Zone3R} is selected as the tripping curve. Therefore tripping characteristics for Zone-3 can be given by assigning different values for K in (2). For t_{Zone3F} of relays, the minimum value of K should be assigned to the furthest downstream relay and then it can be increased according to the discrimination requirement. This setting is similar to the TDS setting of an overcurrent relay in a radial feeder. On the other hand the minimum value of K is assigned to the t_{Zone3R} of furthest upstream relay. Settings of Zone-3 for the relays R_1 , R_2 , R_3 and R_4 in the radial feeder of Fig. 6 can be shown from (9) to (12) respectively as,

$$t_{Zone3F_R1} = \frac{0.0037}{Y_r^{0.1-1}} + 1.45 \quad t_{Zone3R_R1} = \frac{0.0037}{Y_r^{0.1-1}} + 0.45 \quad (9)$$

$$t_{Zone3F_R2} = \frac{0.0037}{Y_r^{0.1-1}} + 1.15 \quad t_{Zone3R_R2} = \frac{0.0037}{Y_r^{0.1-1}} + 0.75 \quad (10)$$

$$t_{Zone3F_R3} = \frac{0.0037}{Y_r^{0.1-1}} + 0.85 \quad t_{Zone3R_R3} = \frac{0.0037}{Y_r^{0.1-1}} + 1.05 \quad (11)$$

$$t_{Zone3F_R4} = \frac{0.0037}{Y_r^{0.1-1}} + 0.55 \quad t_{Zone3R_R4} = \frac{0.0037}{Y_r^{0.1-1}} + 1.35 \quad (12)$$

To illustrate the operation of the relays in Zone-3, the tripping characteristic curves of R_2 and R_3 for the system of Fig. 6 are shown in Fig. 10. Only two relays are considered for clear illustration. Zone-3 tripping characteristics of R_3 and R_2 are calculated using (10) and (11) respectively. The figure also shows the forward combined characteristics of Zone-1 and Zone-2 of the relays. It can be seen that forward Zone-3 as well as reverse Zone-3 characteristics of each relay have been graded appropriately to achieve the backup protection. For example, let us assume that a fault between BUS-1 and BUS-2 in the system can not be detected by the primary zones (i.e., Zone-1 and Zone-2) of R_1 and R_2 . Then, in this case, R_2 detects the fault in reverse Zone-3 to isolate the fault from

downstream side while R_3 provides the backup protection as shown in Fig. 10.

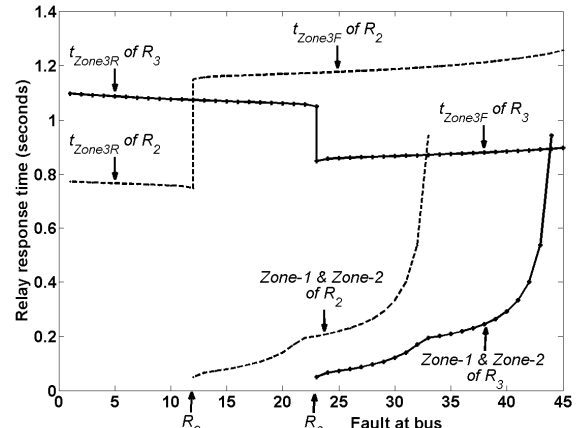


Fig. 10. Relay tripping characteristics of different zones

III. SYSTEM SIMULATION RESULTS

A radial distribution system with converter interfaced DGs connected at different locations is considered as shown in Fig. 11. The system has 5 buses with 4 DGs and 4 loads. All the buses are equidistant. The system parameters are shown in Table I. In this case DG penetration level is 100%.

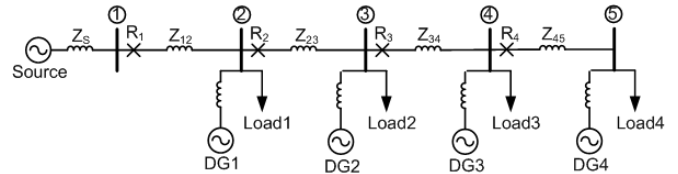


Fig. 11. Schematic diagram of the study system

TABLE-I: SYSTEM DATA.

System data	Value
System frequency	50 Hz
Source voltage (V_s)	11 kV rms (L-L)
Source impedance	$Z_s = 0.078 + j 0.7854 \Omega$
Feeder impedance	$0.585 + j 2.9217 \Omega$
Each load power	0.5 MW
Each DG power output	0.5 MW

It has been assumed that the DGs operate in constant current limiting mode, where a DG limits its output current to a peak value that is twice that of the rated current in the event of a fault. Four inverse time admittance relays are located in equal distance at BUS-1, BUS-2, BUS-3 and BUS-4. The relays have three zones of protection which comprise with Zone-1, Zone-2 and Zone-3. The Zone-1 and Zone-2 settings and tripping characteristics of each relay are same as given in (4)-(7). Zone-3 is set by determining a value to fault resistance (Z_f) as given in (8). In this case Z_f is taken as 10Ω . The tripping characteristics of Zone-3 are different for the relays – they are given by (9)-(12). The relay response is observed with these relay settings by generating single-line-to-ground (SLG) faults at exactly the mid point between two buses. The relay

response time is listed in Table II for the faults which have small fault resistance (0.01Ω), while Table III gives the relay tripping time for the fault resistance of 5Ω , which is equal to the half of the Z_f . Shaded portion of each table indicates the relay tripping time for reverse faults. From the results, it can be concluded that both the relays that are located either side of the fault operate to isolate the faults. Also the relay, which sees the forward fault, operates first, followed by the downstream relay to isolate the faulted segment completely. Adjacent upstream or downstream relay will provide backup protection for each relay. Backup operating time for each relay has been obtained assuming the primary protection has failed to operate during the fault.

TABLE-II: RELAY TRIPPING TIME

Fault Location	Relay tripping time with fault resistance of 0.01Ω (seconds)			
	R ₁	R ₂	R ₃	R ₄
Bus-1 & Bus-2	0.076	0.223	1.123	N.O.
Bus-2 & Bus-3	0.226	0.101	0.133	1.424
Bus-3 & Bus-4	0.862	0.227	0.101	0.170
Bus-3 & Bus-4	1.515	0.892	0.227	0.102

N.O. = No Operation

TABLE-III: RELAY TRIPPING TIME

Fault Location	Relay tripping time with fault resistance of 5Ω (seconds)			
	R ₁	R ₂	R ₃	R ₄
Bus-1 & Bus-2	0.262	1.078	1.461	N.O.
Bus-2 & Bus-3	1.499	0.283	1.400	N.O.
Bus-3 & Bus-4	1.516	1.190	0.283	1.717
Bus-3 & Bus-4	1.673	1.278	0.942	0.623

N.O. = No Operation

According to the relay operating time in Table III, it can be seen that relays operate for high fault resistance faults as well. But the operating time is considerably high since the relays decide the tripping time based on Zone-3. In this case, the error on the measured admittance due to the fault resistance is compensated by Zone-3. However relays still isolate the faulted segment. The relay operating time in Zone-3 can be changed by changing the tripping characteristic according to the system requirements. The relay response, which has been obtained from PSCAD simulation, for a SLG fault between BUS-2 and BUS-3 is shown in Fig. 12. The fault is generated at 0.1 s. Relays operates in the time as given in Table II. In this case operating time of R₁ and R₄ has been obtained assuming that R₁ and R₂ have failed to response for the fault (i.e. the backup protection). R₄ response time is comparably high due to the infeed effect of DGs. Relay R₄ only measures the current of one DG but there are three DGs feeding the fault current from the downstream side. Therefore measured admittance calculated by R₄ is not accurate and it causes a higher tripping time.

IV. CONCLUSION

A new inverse time relay characteristic based on measured admittance at relay location is discussed in this paper. This proposed relay has various advantages over the existing

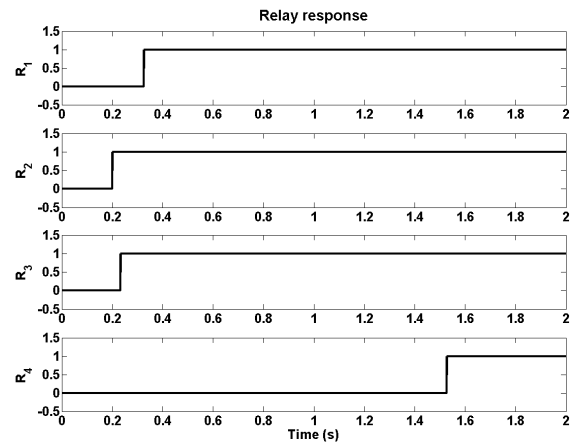


Fig. 12. Relay response for a fault between BUS-2 and BUS-3

overcurrent and distance relays. The relay has the ability to isolate the faulted segment of the feeder form upstream and downstream side of the fault. Moreover these relays operate to isolate the faults under low fault current level environment having an inverse time characteristic nature. This will facilitate the network to operate in islanding operation increasing the reliability, if there is enough generation from DGs. Furthermore the relays ensure the protection in the islanding system conditions as well. Fault resistance may affect the operation of the relays. Therefore a method has been proposed to compensate the fault resistance up to a predefined value. To illustrate the effectiveness of the proposal, the new inverse time admittance relay performances are evaluated in a radial distribution network consisting converter connected DGs. Investigations have revealed that these relays have the ability to isolate both forward and reverse faults satisfactorily based on measured admittance at the relay location.

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