Adaptive protection for distribution systems with multiple distributed generations

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Connections of Distributed Generations (DGs) powered by renewable energy resources on power system start to show benefits but cause new concerns in system operation and protection. This paper proposes a new strategy for network-integrated adaptive protection for distribution systems connected to multiple DGs. The scheme relies on directional protection to allocate the faulted feeder. Results show that the direction of the fault can be determined by finding the difference in angle of positive-sequence current phasors from fault and pre-fault data. The method uses only pre and post fault current signals, without the need for a voltage signal, hence eliminating their cost. The adaptive algorithm proposed in this paper identifies the faulted line and minimizes the area to be tripped. Simulation results show the ability of the protection algorithm to identify and isolate the fault, leaving most of the system functioning in a normal way.

أدت الزيادة فى عدد المولدات بالشبكة التى تتبع الطاقة المتجددة الى وجود بعض التحفظات على الوقاية الخاصة بشبكات التوزيع. يقدم البحث طريقة جديدة للوقاية فى الشبكات التى تحتوى على أعداد متفرقة من هذه المولدات، حيث يعتمد البحث على الوقاية المهيئة الإتجاهية فى تحديد مكان العطل على خطوط الشبكة، ويحدد إتجاه التيار فى حالة حدوث عطل عن طريق حساب زاوية التيار قبل وبعد حدوث العطل. وتتميز هذه الطريقة المقترحة بالإعتماد على التيارات فقط دون الفولتيات، وبالتالى تقل تكلفة الوقاية. كما أن إستخدام الوقاية المهيئة تساعد على فصل أقل عدد من الخطوط عند حدوث العطل. وتوضح النتائج فاعلية الطريقة فى تحديد الأعطال وفصلها.

Keywords: Adaptive network protection, Directional digital relay, Distributed generation

1. Introduction

By definition, Distributed Generation (DG) is an electric generation facility of limited size connected to an electric power system at distribution level [1]. Many technologies are available to generate electricity at distribution level, like internal combustion engine, photovoltaic cell, wind turbine, gas turbine, ..etc. It has been more economical to generate electricity at customer's premises than to generate it at remote location and then transmit it over a long distance [2]. Added to this is the advantage of increased supply reliability as multiple sources have become available to meet the load requirements [3]. All these factors have led to a rapid increase in trend of embedding DGs into existing distribution system which mostly are radial in nature. DG penetration of such a high level surely calls for investigating the impacts on protective device coordination (as a result of disruption of radial nature of network) and protective device ratings (as a result of increased fault level) [4].

Traditional distribution system has been radial i.e. characterized by single source and hence the time-coordination between protective devices is designed on basic assumption of system to be radial [1, 2]. However, with the increased penetration of DG into the distribution system, its radial nature will no longer hold. Hence, the system will be regarded as a multi source system. Traditional protection of radial distribution system consists mainly of a single over-current relay at the substation and section reclosers coordinated with fuses (both upstream and downstream). This typical kind of protection is not sufficient to adequately protect a distribution system with several DGs. It is a well-established fact that protection devices in a multi-source system have to be direction sensitive [5, 6]. Fuses and conventional reclosers do not have directional features, whereas relays can be easily made direction sensitive.

In [3] a detailed analysis is carried out to identify exactly the problems in fuse-fuse and fuse-recloser coordination due to high penetration of DG. This analysis concluded with the suggestion that, in general, if the protection scheme is not changed, the only way to maintain coordination in presence of arbitrary DG penetration is to disconnect all DG instantaneously in case of a fault. This would enable the system to regain its radial nature and coordination would withhold. A similar study is carried out in [1]. The authors in [1] proposed a fast scheme for disconnecting DGs instantly from the system in case of short circuit by using Gate Turn-Off thyristors.

Adaptive protection has emerged as an effective tool when considering multi-source systems. It provides improved selectivity and speed of fault detection under varying distribution system conditions. A network integrated adaptive protection scheme for feeders with DGs is developed in [7]. The scheme adapts the settings of the relays in response to the changes in the system conditions and the feeding from the available DGs.

In this paper an adaptive protection scheme for a distribution system network with several DGs is presented. The scheme relies on directional protection to allocate the faulted feeder or line. Results show that the direction of the fault can be determined by finding the difference in angle of positive-sequence current phasors from fault and pre-fault data. Unlike other directional relay algorithms, the method uses only pre and post fault current signals, without the need for a voltage signal at the relay point. Hence the cost of a voltage sensor can be eliminated and there is no major upgrade of existing protection systems. After applying adaptive directional protection to identify the faulted line, only those DGs involved with the fault will be tripped. In doing so the system will maintain its radial nature, as the relay that will trip is the relay that is responsible to trip in case of feed from one source in addition to the involved DGs. This method improves the reliability of the system by avoiding the unnecessary tripping of other relays, which is a common problem in systems with multiple DGs. Also, not all the DGs will be tripped as suggested in [1], but only those associated with the fault. Hence, the remaining DGs will remain feeding the system in addition to the utility supply. It will be shown that the suggested protection algorithm also offers other tripping alternatives depending on the fault location.

2. Power system simulation

The power system model shown in fig. 1 represents a typical distribution system with a single feed from the utility (short circuit level 1 GVA) in addition to multiple feeds from three DGs. This power system will be used as an example to demonstrate the proposed adaptive protection algorithm. It should be noted that the protection algorithm proposed in this paper is generic and can be applied to any distribution system fed from DGs.

The single line diagram shown in fig. 1 shows an 11 kV 3 phase supply from the utility feeding a network of 11 kV distribution Transmission Lines (TL) with various 3 phase loads in addition to three 11 kV, 3 phase DGs. The load data is as shown in fig. 1 and DG1 is 2.5 MVA, DG2 is 4.5 MVA and DG3 is 3 MVA. The power system under study is simulated using PSCAD [8], which is used to study various loading and fault conditions.

The ideal situation for any protection scheme is to isolate only the faulted section from the system. Proper isolation of the fault is impossible in case of in feed from multiple DGs as has been explained in section 1 of this paper and also in [2]. Hence feeder protection using relays is proposed. fig. 1 shows the location of the feeder relays (R_{aa}, R_{bb}, R_{cc}.... and R_{gg}) in addition to a relay for each DG (R_{DG1}, R_{DG2}, R_{DG3}).

3. Proposed protection algorithm

3.1. Directional protection principle

The fault direction estimation method adopted in this paper is based on a phase change in current during the fault. This method is explained thoroughly in [9] for single phase radial system and three phase radial systems for all types of faults. In this section a brief explanation of this method is presented. Also the adaptation of this system to fit a typical distribution system with multiple feeding from several DGs is given.

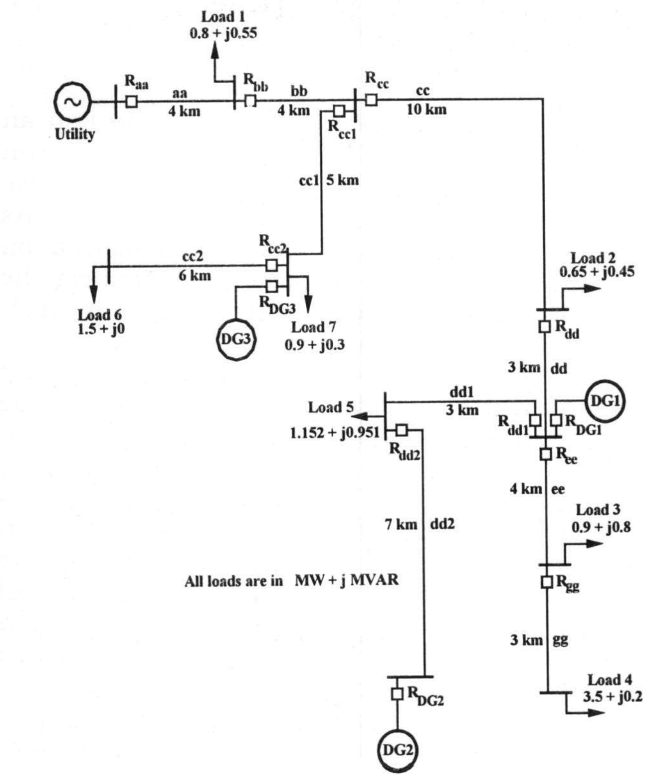

Fig. 1. Power system model.

The basis of the approach is first set for a single-phase radial system and the idea is then extended to the three-phase system. For this purpose, a single-phase 11 kV simple radial distribution system as shown in fig. 2 is considered where a DG source at bus A is connected to the distribution system at C through a line [9]. The source at A feeds power to the system and the power-flow direction is always from A to B in this case. At the common coupling point B, the relay is located where direction estimation is required for protection. The upstream and downstream areas in the system correspond to points *F1* and *F2* in the diagram. Faults are created at 0.4s on both sides of the relay (*F1* and *F2*) and the current waveforms are plotted in fig. 3. The figure depicts that the fault currents change differently in phase, with reference to the expected normal current. It should be noted that fault current in this paper is understood as current observed in a phase during a fault (i.e., including load current).

Explanation: The prefault current in the line can be expressed as:

$$I_{pre} = (V_A - V_C)/Z\,. \tag{1}$$

Where V_A and V_B are the bus voltages and Z is the total line impedance.

For the fault at *F*1, the fault component of current (without load current) at bus B will be

$$I_{F1} = V_C/Z1\,, \tag{2}$$

where V_C is the bus voltage and *Z*1 corresponds to the associated impedance from C to *F*1.

Likewise, the fault component of current at bus B for fault at *F*2 will be

$$I_{F2} = V_A/Z2\,, \tag{3}$$

where *Z2* is the associated impedance from A to *F2*.

During the fault at *F1* and *F2*, the currents at bus B will be

$$\begin{aligned} I_1 &= I_{pre}\text{-}I_{F1} \\ &= \frac{V_A\text{-}V_C}{Z} - \frac{V_C}{Z1}\,, \end{aligned} \tag{4}$$

and

$$\begin{aligned} I_2 &= I_{pre} + I_{F2} \\ &= \frac{V_A\text{-}V_C}{Z} + \frac{V_A}{Z2}\,, \end{aligned} \tag{5}$$

respectively.

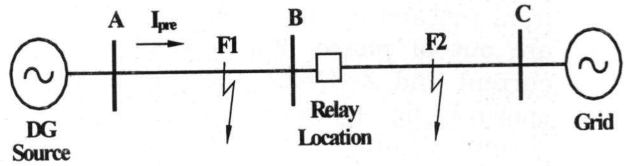

Fig. 2. Single phase 11 kV system.

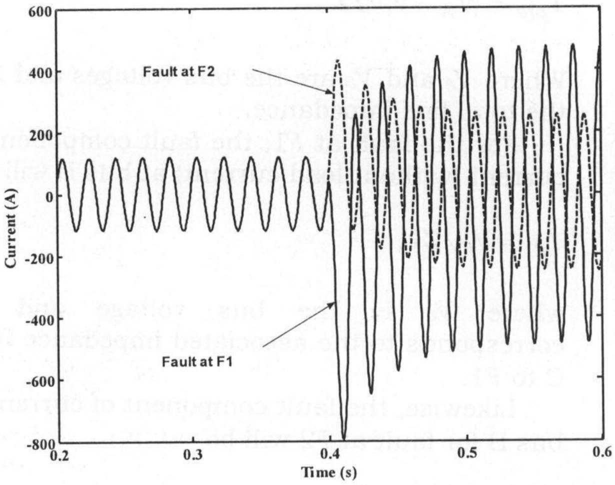

Fig. 3. Different current waveforms for faults at *F1* and *F2*.

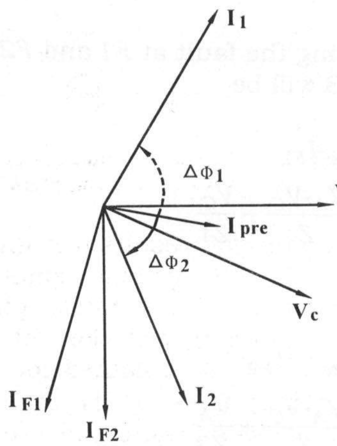

Fig. 4. Single phase system phasor diagram.

With V_A and V_C, phasors of the same magnitude and phase (no prefault current) and faults are at bus A and bus C $Z=Z1=Z2$ from the above equations infer that I_1 and I_2 are out of phase. For a case with prefault current and $Z=Z1=Z2$, the phasor diagram is shown in fig. 4 where it is observed that fault currents I_1 and I_2 remain in different regions with respect to the prefault current I_{pre} .Thus, the direction of fault can be identified from the fault phasor position with respect to the prefault phasor. The angle difference of fault and prefault current phasors for the upstream case (*F1*) is positive ($\Delta\phi_1$) and for downstream (*F2*), it is negative ($\Delta\phi_2$) as observed from the phasor diagram.

3.2. The concept of the proposed protection scheme

It is the purpose of this paper to find an adaptive protection scheme that can successfully isolate only the faulty part in case of a power system fed from multiple DGs. As explained earlier the system will depend on relays and circuit breakers to disconnect the faulty part instead of fuses that can mal-operate in the presence of multiple DGs [2].

The protection scheme suggested implements directional protection using current signals only and using prefault and fault data. Each relay in the system, shown in fig. 1 will be able to know if the fault is upstream (behind the relay) or downstream (in front of the relay) to it. A central processing unit will gather the information from all relays, through proper communication channels. The central processing unit will be able to identify the faulty line. The faulty line will be the one identified by two adjacent relays; one relay will indicate that the fault is downstream to it, while the other relay will identify the fault as upstream to it.

3.3. Implementation of directional adaptive scheme in multiple DG system

The discussion in section A reveals that the prefault and fault current phasors are indicative of the fault direction for single-phase radial systems. To extend the idea to three-phase systems and for all types of faults, positive-sequence component current is selected. This is because the previously discussed analysis (or rule) for the single-phase system is not valid for the three-phase system and, second, positive sequence is available for all types of faults.

The power system model shown in fig. 1 is used to explain the implementation of the proposed method in a three phase system. The method proposed requires knowledge of the current positive sequence component phase-angle prior and after the fault occurrence. As indicated earlier that PSCAD is used to simulate the power system under study. Discrete Fourier transform is used to process the prefault and fault data to obtain the prefault and fault positive-sequence phase-angles. The sampling frequency used is 3200 Hz (64 samples per cycle).

Fig. 5 shows the load flow current directions, magnitudes and phase angles prior to fault occurrence. The default current direction is always assumed from the utility towards the loads. It is understood that currents that have phase angles higher than ±90° are actually in a direction opposite to that assumed, as for example in line dd1 and dd2. However in order to implement the directional protection proposed in this paper, the current direction will be from the utility towards the loads as indicated in fig. 5.

A phase-to-phase (ab) fault is now simulated on line cc. Table 1 shows the prefault phase angle, fault positive-sequence phase angle and the difference (fault angle-prefault angle). It is noticed, as shown in table 1, that the phase angle difference is negative for TL cc and is positive for TL dd indicating a reversal of current in dd. By applying the fault direction criterion explained in part A of this section, it can be concluded that this fault is downstream to relay R_{cc} and is upstream to relay R_{dd}.

Once this information is fed to the central processing unit the faulty line (in this case cc) will be exactly identified and the proper tripping criterion will be applied as explained below.

In this method the phase angle difference of fault and prefault phasors is limited to ±180°. In some cases, this angle difference calculated this way will exceed the above limit. In that case, 360 should be subtracted from or added to the difference if it exceeds 180 or -180 limit, respectively. This is performed as the approach is based on the principle of whether the fault phasor leads or lags the prefault phasor.

Table 1
Positive-sequence current phasors for line-to-line fault (ab) on TL cc

Relay	Fault angle (degrees)	Prefault angle (degrees)	Angle difference ($\Delta\phi$)
R_{cc}	-70	-39	-31
R_{dd}	128	-49	177

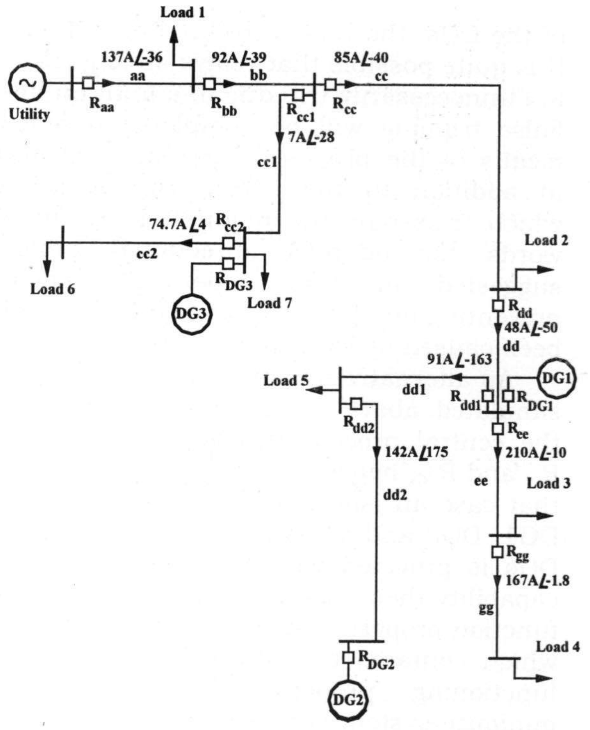

Fig. 5. Power system model showing prefault current directions, magnitudes and phase angles.

The simulation results performed on the 3-phase multi DG system confirm with the earlier results of the single phase system. Hence the tripping criterion for three phase system will be as explained for single phase system. Given that $\Delta\phi$ is the phase angle difference between fault and prefault current phasors for a certain line; in case that $\Delta\phi$ is positive, the fault is upstream to the relay and in case that $\Delta\phi$ is negative the fault is downstream to the relay. When two adjacent relays see the fault differently (one as downstream and the other as upstream), then the relay seeing the fault in its downstream will be given a signal to trip (in the simulated case R_{cc}) together with the relays of the DGs associated with the fault (in the simulated case R_{DG1} and R_{DG2}).

By applying the tripping criterion suggested above the protection system would have reacted as in a radial system fed from the utility, even though the system is fed from DGs. It should be noted that the relays in a normal radial system are coordinated with reference to the fault being fed from the utility. However, because of the fault feeding tendency of the DGs, the relay coordination will be lost. It is quite possible that relays as R_{dd1}, R_{dd2} and R_{dd} unnecessarily trip due to a fault on line cc False tripping will be completely avoided by means of the proposed directional protection in addition to the central processing unit which trips only the required relay. In other words the adaptive directional protection suggested in this paper succeeded in preventing any false tripping which could have been caused by DGs feeding the fault.

An alternative tripping scheme for the fault simulated above could also be implemented; the central processing unit could trip relays R_{cc} and R_{dd}, hence isolating the faulted line. In that case an island will be formed containing DG1, DG2 and loads 3, 4 and 5. If one of the DGs is provided with load frequency control capability then such an island can continue to function properly. The other part of the system which contains the utility will also continue functioning properly. This scheme will minimize system outage and most of the loads will continue to be fed.

4. Protection scheme flow chart

The proposed protection algorithm is implemented in a Matlab environment and receives data from the power system, simulated using the PSCAD program, fig. 1. The flow chart shown in fig. 6 is for the operation performed by the central processing unit which receives from the relays in the system, through proper communication channels, the currents positive phase-sequence magnitudes and phase angles. The program keeps record of the pre-fault data for future comparisons with incoming fault data. For each relay; the phase angle difference, $\Delta\phi$, is calculated as follows:

$$\Delta\phi = \textit{received phase angle (possible fault angle)} - \textit{stored phase angle (prefault phase angle)}. \quad (6)$$

Based on the simulation results obtained, it has been decided to give the calculated phase angle difference a tolerance of $\delta=\pm10°$, i.e. relays with phase angle difference less than δ will be regarded either as fault free relays or are located away from the fault location. It should be noted that to eliminate triggering the algorithm during normal switching operations, the algorithm will not be activated unless the current magnitudes exceed their pick-up values. In that way false tripping during switching operations will be eliminated. The scheme will then compare each two adjacent relays to allocate the fault location. The detection criterion is to find one relay with a negative phase angle difference and an adjacent relay with a positive phase angle difference. As explained previously in section 3 that this criterion will identify the faulted line. Depending on the fault location, a more thorough check might be needed in order to decide on the best tripping criterion. As for example a fault identified on line bb, fig. 5, requires more attention to its tripping criterion. Tripping relay R_{bb} and all associated DGs will result in a major shut down of the system with only one load (load 1) kept in operation. On the other hand tripping relays R_{bb} and R_{cc} only will not isolate the fault, fig. 5. In that case the best tripping criterion will be tripping R_{bb}, R_{cc} and R_{cc1}, while leaving the rest of the system operating in form of islands. This example leads to the conclusion that each fault location has a specific characteristic and hence a more in-depth analysis is required to decide on optimum tripping philosophy, fig. 6.

There are few faults in the system, in which no two adjacent relays will have opposite signs for phase angle difference. This is true for faults on lines ee, gg and cc2, for example, as the fault direction will not be reversed as there are no DGs that will back-feed the fault, fig. 5. In this situation the fault location will not be identified by the method explained earlier. For such faults, the faulted line will have the highest magnitude among all other lines, as the fault is fed from the utility and all DGs in the system. Hence, this line will be identified and instantaneously tripped. The central processing unit will restrain any other relay from tripping, and the only isolated part will be the fault part. The DGs will not be tripped in that case, fig. 6.

5. Simulation results

This section presents four typical case studies of the network enabled adaptive protection strategy for feeders in the distribution system with DGs. These case studies are done using the distribution system shown in fig.1. Each case shows a different tripping strategy depending on the fault location.

The first case shows faults on line aa. Tables 2, 3 show the pre-fault and fault angles for the relays in the fault vicinity. It can be seen that relay R_{aa} did not experience a phase reversal ($\Delta\phi$ is negative) hence fault is downstream to R_{aa}. The other relays R_{bb}, R_{cc} and R_{cc1} all experienced a phase reversal ($\Delta\phi$ is positive). The central processing unit based on the flow chart shown in fig. 6, will identify line aa as the faulty line. Tripping relay R_{aa} and all DGs (as they all feed the fault) will result in a complete shut down of the system. Hence, it will be better to trip relays R_{aa} and R_{bb}. In that case the distribution system will depend on the DGs only as the utility is disconnected.

The second case is for faults on line bb. Table 4, 5 show the pre-fault and fault angles for relays in the fault vicinity. It can be seen that relays R_{cc}, R_{dd} and R_{cc1} experienced a phase reversal while the adjacent relay R_{bb} did not experience a reversal. This information indicates a possible fault on line bb or somewhere else on line cc1. Hence, in order to exactly identify the faulted section a more in-depth analysis should be made. This analysis will focus mainly on the pre-fault current direction in line cc1. In case that the pre-fault phase angle for line cc1 is less than ±90° (pre-fault angle is -27° table 4, 5) this indicates that the pre-fault current direction was from the utility towards line cc1 and cc2. Hence, a phase reversal in relay cc1 indicates that the fault is upstream of relay cc1.

Based on this analysis the central processing unit will identify the fault on line bb. The optimum tripping strategy in that case is to trip relays R_{bb}, R_{cc} and R_{cc1} and leave the rest of the system to operate as separate islands, provided that the DGs can have sufficient power to feed the required loads.

The third case is for faults on TL dd1 (ag, bc). Tables 6, 7 show the pre-fault and fault angles for the relays in the fault vicinity. Relay R_{ee} did not have a significant change in $\Delta\phi$ as $\Delta\phi < \delta$. Running this information by the central processing unit will indicate that there is a possible fault on lines dd, dd1 or dd2. A more thorough check should be made to exactly identify the faulted line. For Relays R_{dd1} and R_{dd2} the prefault current direction was from DG2 to busbar dd1, as the prefault phase angles are > ±90° as explained earlier.

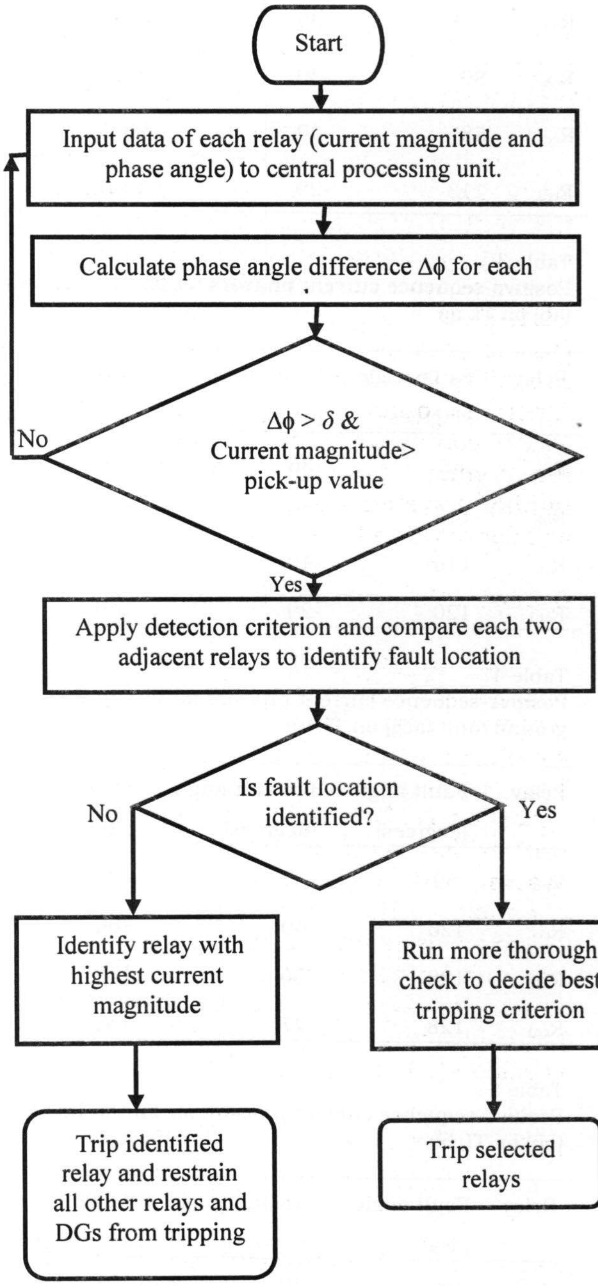

Fig. 6. Protection algorithm flow chart.

Table 2
Positive-sequence current phasors for line-to-ground fault (cg) on TL aa

Relay	Fault angle (degrees)	Prefault angle (degrees)	Angle difference ($\Delta\phi$)
R_{aa}	-64	-36	-28
R_{bb}	89	-39	128
R_{cc}	58	-40	98
R_{cc1}	113	-29	142

Table 3
Positive-sequence current phasors for line-to-line fault (ab) on TL aa

Relay	Fault angle (degrees)	Prefault angle (degrees)	Angle difference ($\Delta\phi$)
R_{aa}	-65	-36	-29
R_{bb}	118	-39	157
R_{cc}	116	-40	156
R_{cc1}	120	-29	149

Table 4
Positive-sequence current phasors for line-to-line- to-ground fault (acg) on TL bb

Relay	Fault angle (degrees)	Prefault angle (degrees)	Angle difference ($\Delta\phi$)
R_{bb}	-69	-39	-30
R_{cc}	126	-40	166
R_{dd}	128	-50	178
R_{cc1}	128	-27	155

Table 5
Positive-sequence current phasors for line-to-line fault (ab) on TL bb

Relay	Fault angle (degrees)	Prefault angle (degrees)	Angle difference ($\Delta\phi$)
R_{bb}	-68	-39	-29
R_{cc}	119	-40	159
R_{dd}	122	-50	172
R_{cc1}	124	-27	151

Table 6
positive-sequence current phasors for line-to-ground fault (ag) on TL dd1

Relay	Fault angle (degrees)	Prefault angle (degrees)	Angle difference ($\Delta\phi$)
R_{dd}	-72	-50	-22
R_{dd1}	-81	-163	82
R_{dd2}	140	175	-35
R_{ee}	-9	-10	$\Delta\phi < \delta$

Table 7
Positive-sequence current phasors for line-to-line fault (bc) on TL dd1

Relay	Fault angle (degrees)	Prefault angle (degrees)	Angle difference ($\Delta\phi$)
R_{dd}	-74	-50	-24
R_{dd1}	-73	-163	90
R_{dd2}	138	175	-37
R_{ee}	-5	-10	$\Delta\phi < \delta$

It can be seen that relay R_{dd1} experienced a phase reversal while the adjacent relays R_{dd} and R_{dd2} did not experience a phase reversal. This result indicates that the fault is on line dd1 as the current in line dd1 changed its direction to feed the fault while the current in line dd2 did not change its direction. Hence, the central processing unit will issue a trip signal to relay R_{dd1} in addition to R_{DG2}, thereby isolating the faulted section while the rest of the system will remain in operation. In this case the system tripped while maintaining its radial nature and only the DG involved with the fault is tripped.

The forth case is for two faults on line ee (ag, acg). Tables 8, 9 show the pre-fault and fault phase angles for relays in the fault vicinity. It should be noted that 360° is subtracted (sub) from $\Delta\phi$ for line dd1 as it exceeded 360° as explained previously in section 3. It can be seen from the table that none of the relays experienced a phase reversal. Also it is noticed that, the phase difference in line gg did not exceed the tolerance specified in the flow chart shown in fig. 6. Also on examining the magnitude of the

Table 8
Positive-sequence current phasors for line-to-ground fault (ag) on TL ee

Relay	Fault angle (degrees)	Prefault angle (degrees)	Angle difference ($\Delta\phi$)
R_{dd}	-63	-50	-13
R_{ee}	-49	-10	-39
R_{gg}	-3	-2	$\Delta\phi < \delta$
R_{dd1}	148	-163	-49(sub 360)

Table 9
Positive-sequence current phasors for line-to-line-to-ground fault (acg) on TL ee

Relay	Fault angle (degrees)	Prefault angle (degrees)	Angle difference ($\Delta\phi$)
R_{dd}	-72	-50	-22
R_{ee}	-60	-10	-50
R_{gg}	2	-2	$\Delta\phi < \delta$
R_{dd1}	134	-163	-63(sub 360)

fault current in line gg (120 A for ag fault 72A for acg fault), it is found that it did not exceed its pick-up value, as the normal load current is 167A. Hence, line gg is not faulted. For line ee the magnitude of the fault current is highest among all relays (549.9A for ag fault and 1387A for acg). Hence, the central processing unit will decide to trip relay R_{ee} and all other relays in the system will be restrained from tripping.

6. Conclusions

This paper has proposed a new central-based adaptive directional protection for distribution system with feeders connected to DGs. The proposed strategy provides intelligent-enabled protection and overcomes DGs imposed challenges such as increase in fault level, change of prescribed fault flow paths and un-coordinated tripping. The protection algorithm proposed in this paper makes use of the positive-sequence phase angle difference and also the current magnitudes in exactly identifying the faulted line. The tripping criterion is adaptive and depends on the fault location. The protection algorithm trips the minimum part of the system to isolate the fault. Simulation results have shown that the algorithm responds well to faults occurring in different places in the system, tripping and isolating only the faulted area while the remaining parts of the system are still functioning properly and feeding the loads.

The presented scheme is generic and can be applied to any distribution system fed from multi DGs. However, each system has its own special tripping requirements that should be incorporated in the protection algorithm to achieve the best performance.

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