Short Circuit Capacity: A Key to Design Reliable Protection Scheme for Power System with Distributed Generation

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***Abstract*—With the emerging issues about the ecological pollution and potential energy deficiency, many efforts are taken to initiate the renewable energy plans, established primarily with wind energy, solar panels and low capacity water power plants etc. These forms of power production are called Distributed Generation (DG), as they are installed near the load centers. Power utilities all over the world are welcoming DGs to increase their generation capacity. With the aim to cut electricity bills, DGs are brought into power networks in order to meet the increased load demands especially during peak hours. It is expected that in the future, more and more DGs will be taken into system. Therefore, with the increased number of DGs, the fault level issue becomes more complex. The interconnection of DG introduces somehow protection problems such as islanding, relay settings and increase of short circuit capacity. In this research, the influence of DG interconnection over the short circuit capacity in the radial distribution network was analyzed and the effective protection scheme for distribution network was proposed then. The effective method for setting the optimal Coordination Time Intervals (CTI) between the transformer and the feeder relays in real distribution systems was also discussed. A protection scheme based on over-current techniques was proposed for synchronous DGs, connected to utility feeder operating in grid-coupled mode, in order to make the most of DG benefits to customers. The proposed solutions were verified with MATLAB software simulations.**

***Index Terms*—Distributed Generators (DGs), network configuration, power loss, relay settings, Short Circuit Capacity (SCC)**

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I. Introduction

Recently, with the growing concerns about environmental pollution, the researchers all over the world are engaged in power generation which is environmental friendly to reduce the extensive CO_2 emissions. Renewable Energy Sources (RES) technically known as distribution generations are the most promising solutions in such regards. With more DGs' installations, the complexity of power system increases and more difficulties were observed in the process of designing protection and controlling schemes. The major problem arising due to DG interconnection is the increased fault level and the proper relay settings [1]. These problems may affect the economy of power system if not considered solemnly.

Installation of DGs alters the network properties. There are significant changes in the voltage profile, fault level and the power flows, when rating of incoming DG is comparable to the load demand, particularly during off - load periods [2]. It is of great concern for distribution companies that the installation of new DG affects adversely the security and reliability of power system. Distribution network especially radial feeders are designed to fulfill the requirements of reliable operation, faulty conditions and anomalous operation [3], especially during network reconfiguration or scheduled maintenance. When short circuit fault occurs in the distribution network, the fault current would flow towards the fault point. When the rotating loads like motors are connected, the load flow and the fault level of network would jump towards upstream or their magnitude rises due to the presence of DG into network [3]. It is now the responsibility of protection scheme designed earlier for

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network before the DG installation, to sense the new fault scenario. But unfortunately this protection scheme becomes unable to isolate such increased fault level. So it has become necessary to change a circuit breaker with high interrupting capacity, to achieve circuit interruption in the case of increased fault level. However it is not an easy task to replace the old circuit breaker with the new high rated one. This process requires reconditioning, decommissioning and reconfiguration of entire network. Therefore an easy approach to do so is to change the plug-in settings of existing relays installed at different sites of utility networks [4].

Fault current in the power networks is a key factor for calculating the ratings of interrupting and sensing protection devices. When the Circuit Breaker (CB) is asked to put into the operation and the relay settings were arranged, there would be roughly the functional improvements applied after the changes in the fault level. Before installing DG the load flow calculations should be performed for short circuit analysis. The protection scheme and the supplementary circuit disruptions are needed to be upgraded or substituted. Protection scheme design is a requisite parameter of electric power network planning. Analysis of the short circuit capacity and the pre-fault calculations are necessary for selecting the circuit breakers, the protective relays and their settings. [5]. Networks must be capable of withstanding a certain amount of fault current without violating its constraints. The increased short circuit capacity due to the DG installations mainly depends upon following factors [6]:

- The DG category: as various DGs produce various fault levels.
- The DG location: if a DG is located far away from the fault and source points, then the fault impedance would be high and the fault current would be minimized
- Presence of transformer: if a transformer is present in between a DG and the fault point and is grounded too, then the problem of voltage stability could be avoided.
- The network reconfiguration: if the part of radial feeder between the point of fault occurrence and the Point of Common Coupling (PCC) is required to be reconfigured then eventually the line impedance would change and thus this would cause changes into the fault levels of the rest of the network.
- The network DG coupling: if DGs are coupled directly to the network then they would generate the harmonics due to the use of various power electronic converters.

Since the utility networks are normally categorized by the severity of fault levels. For implementing a flexible protection design, the fault level should remain below the network designated value. Since the DGs are considered to be fast solutions for increasing the generation capacity of distribution companies (DISCOs) due to their quick operation. Therefore with the integration of DGs, the need for increasing the transmission circuit capacity would be eliminated [7], assuring the economy of power supply.

DG offers plenty of advantages so the researchers all over the globe are trying to enhance its benefits and elude any unwanted condition. Conti *et al* (2009) addressed various techniques for compensating the power losses in the utility network where distributed generation was embedded while looking for fault level changes. They discussed the Binary Particle Swarm Optimization (BPSO) method so as to reduce the power loss and eventually the fault level [2]. Gomez *et al.* (2013) evaluated the alterations in the short circuit currents for designing the network model. They analyzed that the pickup value of relay should be improvised post to DG installations. They also have recommended that the protection analysis of network should be carried out before connecting DG into system [4]. Girgis. *et al.* (2004) investigated the various sections of distribution feeder for protection scheme design with the DG installation and recommended the integration of directional protection schemes. They also have recommended that after DG installations the flow of short circuit currents changes, therefore the relay settings must be analyzed prior to DG installation via the Simulations [7]. Doyle. *et al.* (2002) investigated the various affects that a DG puts over the utility network concerning about the function and monitoring, alteration in fault level, stability and relay characteristics. They performed their analysis over a test system based on IEEE 30 bus and declared that the DG mitigates losses in power networks while contributes to increased fault currents which are dependent on the rating and position of DG and network in which it is installed [8]. The kla. *et al.* (2008) estimated the alteration in fault currents on the utility network when the DGs has been embedded into medium and low voltage utility networks. They used IEC 60909 norm as reference for the fault calculations and finally concluded that the utility power networks are operating at the verge of their designed fault level, with little margin left for incoming new DGs [9].

The DG's installation causes many protection problems but amongst all, the most important are the increase of fault level and the coordination of relays [8]. Variations in fault currents are related to the system configuration, rating and position of DG. This research focuses on the calculation of percentage increase of fault level due to the DG installation for designing an efficient and robust protection scheme for utility networks. MATLAB software is used for short circuit analysis which facilitates the simulations of real time utility networks to visualize the inverse impacts of DG over the fault level and coordinating the over current relays efficiently at the distribution levels.

II. Impact of DG on Radial Feeder Fault Current and Protection Coordination

In the distribution network, for calculating the symmetrical fault currents, the knowledge of system voltage and the impedance of line from source up to the point of fault inception are crucial. This technique defines that as the impedance from the source to the fault point increase, the fault current diminishes [9]. When DG was installed at the downstream of radial distribution system,

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it does not contribute sufficiently to the fault currents unlike the source which is the actual contributor to the fault current. With such changes, it has now become important to change the relay settings when DGs are installed at upstream of distribution network but not when installed at downstream sections of radial feeder.

When the DGs are installed at distribution networks, they unintentionally contribute to the fault currents and the short circuit current supplied by them can be calculated with the help of relation between the system voltage and the lumped impedance from DG to the fault point [9]. The fault current supplied by DGs is added up with the fault current supplied by the source thus increasing the total fault level of network. When several DGs are present in the distribution network, then fault current contribution by each DG unit would be calculated by using superposition principle [10]. The total fault current contributed by various DGs would be the sum of all separate contributions. This similar sort of technique can be used for calculating the fault currents in various branches of radial feeder network.

The settings of protective devices are devised according to the inverse behavior of current in radial feeders. The protection zone for each device is defined on the basis of maximum fault current flow. By declaring the pick-up value of each relay according to the maximum fault current of designated protection zone would assure that it will not operate outside the feeder zone [11]. Any fault occurring out of protection zone would have fault current less than the pickup value of designed relay and blocking operation of relay would be assured in such case. It is very much important for protection engineers to determine feeder impedance, source of errors, precision of pickup value for relays and the working voltage of system while working at the field so as to design efficient protection scheme [12]. In order to avoid the malfunctioning of protection equipment, a safety factor should be involved in the coordination assessment of protection equipment. The pickup is usually declared to be 80-90% of the designated value [12].

For designing the protection scheme of a radial distribution feeder, an over-current relays should be a directional in order to avoid back power flow from DG [13]. Although the fault current flows towards the fault point from the supply side and there is no need of direction discrimination for current flow from the supply side. The protection devices only sense the current amplitude and get activated if the threshold limits are surpassed. This specific condition of protection scheme for radial distribution feeder poses many limitations over DG installation. DG may contribute to the fault current opposite to that of one contributed by source. This fault current contribution by DG to the fault point may prompt the coordinated operation of devices located at the downstream causing a substantial weakness of the protection scheme [13].

III. Research Methodology

Fault in a distribution network is actually undesired situation that puts the network into more stressed condition. The result of fault is a very high current flow and it is necessary to block it before it damages any section of network. In order to disconnect the faulty section from rest of the healthy system, circuit breakers are invariably used. Relays and related equipment are applied, to sense an unwanted situations occurring after fault inception and then to activate the circuit breakers to detach the faulty section. The most dangerous fault is a three-phase fault which is a symmetrical fault, in which all three phases are bolted together and maximum destruction occurs to network accessories [14]. Symmetrical faults are examined on the basis of single phase. While in unsymmetrical faults, system components are no more symmetrical. Single phase to earth, phase to phase and double phase to earth faults fall under its umbrella [14].

Circuit breakers are designed on the basis of their interrupting current capacity to carry momentary short circuit current until threshold limit is being crossed by the relay. Circuit must be interrupted at the initial stages unless the current magnitude reaches to disastrous value and then even circuit breaker could be unable to break it, due to internal arc conduction. Interrupting capacity of circuit breaker is the product of peak symmetrical short circuit current and network declared voltage and it is rated in MVA. It is also known to be fault level/ short circuit MVA (SSC) [14], given by (1).

$$S_{SC} = \sqrt{3} * V_{PRE} * I_{SC} \qquad (1)$$

where

S_{SC}- short circuit power

V_{PRE}-pre-fault system voltage

I_{SC}- short circuit current

The capacity of bus bar is very much dependent on its fault level. In a traditional radial utility feeder, the fault level reduces as distance from source increases. When a DG is to be injected into the existing network, the state of feeder remains no longer the same.

Fig. 1 displays single line diagram of a simplex electrical network consisting of generating unit, power transformer and radial feeder. A DG in this test system is installed at bus C. Following assumptions assures that simpler calculations without disturbing the precision of fault level computations [15].

- Generating units work at designed voltage
- Power transformers work at settled tapings
- Parallel capacitances and series resistances of feeder are ignored

In this research, the fault was simulated on the feeder at its far end as shown in Fig. 1. For estimating the fault level, the base MVA and per unit methodologies are applied. The simpler calculations and relative measurements are the main reasons for using per unit methods. For uniform calculations, let 15 MVA be the base MVA. For the generator and high tension transformer sides, 33kV is rated as base kV. Over the low tension side of transformer T1, for feeder and High Tension (H.T) side of transformer TDG sections are rated with base of 11 kV. While on Low Tension (L.T) of TDG where actually DG is physically connected has a base kV of 0.690kV rated. Normally per unit impedances of network equipment are always declared at their base values. For transforming different per unit impedances of different equipment at different bases to a common selected base, equation (2) can be used [15].

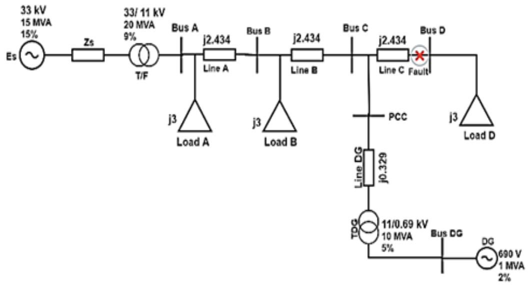


Figure 1. Single line diagram of test system.

$$Z_{NEW} = Z_{OLD} * \left(\frac{S_{New}}{S_{Old}}\right) * \left(\frac{V_{Old}}{V_{New}}\right)^2 \qquad (2)$$

where

Z_{NEW}- impedance on new selected base

Z_{OLD}- impedance on given old base

S_{New} and V_{New} – new selected base power and voltage

S_{Old} and V_{Old} – old given base power and voltage

Base impedance of any section of system can be found by (3)

$$Z_{BASE} = \frac{(V_{Base})^2}{S_{Base}} \qquad (3)$$

where

Z_{BASE} – base impedance in ohms

V_{Base}– base voltage in volts

S_{Base}= base power

For converting actual impedance to per unit impedance, expression (4) can be utilized

$$Z_{P.U} = Z_{\Omega} * \frac{S_{Base}}{(V_{Base})^2} \qquad (4)$$

where

$Z_{P.U}$ – per unit impedance

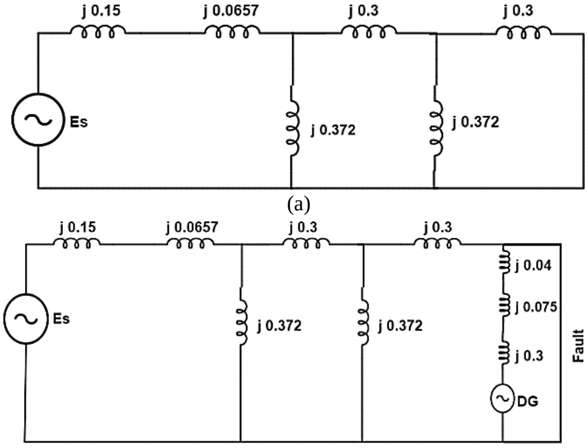
Z_{Ω}– given impedance in ohms

All the impedances of the test system components after converting to p.u values on the nominated base power and voltage are presented in Table I.

TABLE I. CALCULATION OF PER UNIT IMPEDANCES OF DIFFERENT SYSTEM COMPONENTS

Impedance	Equation Used	Calculation	Result
Feeder XF1, XF2, XF3	Eq. 4	j2.434 * (15) / (11)2	j 0.300
DG XDG	Eq. 2	j0.02* $(\frac{15}{1})$ * $(\frac{0.69}{0.69})$2	j 0.300
Transformer XTDG	Eq. 2	j0.05* $(\frac{15}{10})$ * $(\frac{11}{11})$2	j0.075
DG XLDG	Eq. 4	j0.329 * (15) / (11)2	j0.040
Transformer XT	Eq. 2	j0.09* $(\frac{15}{20})$ * $(\frac{33}{33})$2	j 0.067
Generator XG	Eq. 2	j0.15* $(\frac{15}{15})$ * $(\frac{33}{33})$2	j 0.150
Load XL1, XL2	Eq. 4	j3 * (15) / (11) 2	j0.372

By using reactance equivalents for all network components as presented in Fig. 2 (a-b) prior and post DG installation, we can easily calculate the impedance to fault point.



(a)

(b)

Figure 2. Reactance diagram of test system (a) without DG (b) with DG.

By using the Thevenin's theorem (Z_{Th}), the impedance up to fault point can be determined. Then fault level may be determined by (5)

$$S_{SC} = \frac{S_{Base}}{Z_{Th}} \qquad (5)$$

Short circuit current may be estimated by (6)

$$I_{SC} = \frac{S_{SC} * 10^6}{\sqrt{3} * V_{Base} * 10^3} \qquad (6)$$

The declared values of ISC, MVASC and ZTH prior and post DG interconnection are illustrated in Table II. Table II. also gives information about rise of fault levels and percentage alterations. It can been seen from Table II. That MVA fault level has beenincreased at the Point of Common Coupling (PCC) where DG is installed at bus C as shown in Fig. 1. Negative sign in change and percentage alteration for impedance in Table II. assures the reduction in total impedance to the fault point.

TABLE II. FAULT LEVEL CALCULATIONS AT DIFFERENT SECTIONS OF POWER TEST SYSTEM

System parameter	Without DG	With DG	Change in value	Percentage change
I_{SC}	1852	3468	1616.17	87.25%
Z_{TH}	j0.425	j0.22	-j0.198	46.58%
S_{SC}	35.29	66.08	0.64	87.27%

By using above described procedure fault level may be estimated at various sections of feeder. Theses assessments of system prior and post DG application are shown in Table III. As can be seen, there is agrowth in fault level oneach bus after DG installation. This issue has very much importance while designing protection schemes for power system involving interrupting capacity of breaker and pick up value setting of relay.

TABLE III. FAULT LEVEL COMPARISON AT VARIOUS SECTIONS OF POWER TEST SYSTEM

Bus section	Without DG	With DG	Change in value	Percentage change
B_A	109.17	145.34	36.17	33.13%
B_B	74.62	110.78	36.16	48.45%
B_C	29.94	66.08	36.14	120.70%

IV. OVERCURRENT RELAY SETTING

Various mathematical models for overcurrent relays have been proposed till but today our analyses are making the use of standard inverse type overcurrent relay. Mathematically the operating time for overcurrent relay can be defined by (7)

$$T_{opt} \equiv \frac{K \times TMS}{(I_{sc}/I_0)^n - 1} + L \qquad (7)$$

where I0 is the defined current setting, Isc is the short circuit current after fault, TMS is the time setting multiplier of relay whose value range between 0.05 and 1. L, K and n are the relay constants whose values depends upon type of overcurrent relays. According IEC data sheets, for standards inverse type relays, L=0, K=0.145, n=0.021.

When there is a fault on the feeder side, the relay feeder and feeder installed on low tension side of transformer measurevirtually the same amount of current as shown in Fig. 3. After fault inception, the protection zones of both feeder and transformer relay reduces and they start under reaching [16]. They only measures the portion of fault current which is contributed by source not by DG. Therefore their zones of protection must be increased and this will be efficiently done by pick up setting of relays. We should arrange their pick up setting in such a way that time of coordination between relays must assure fault disruption safely [17].

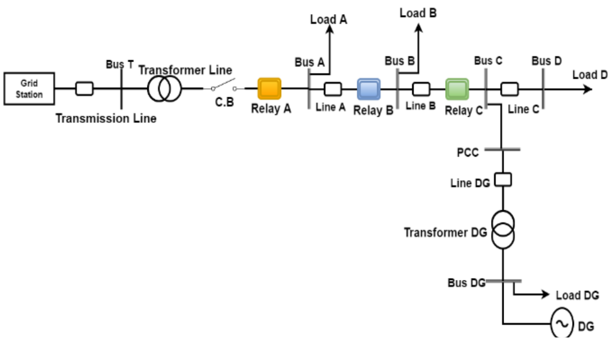
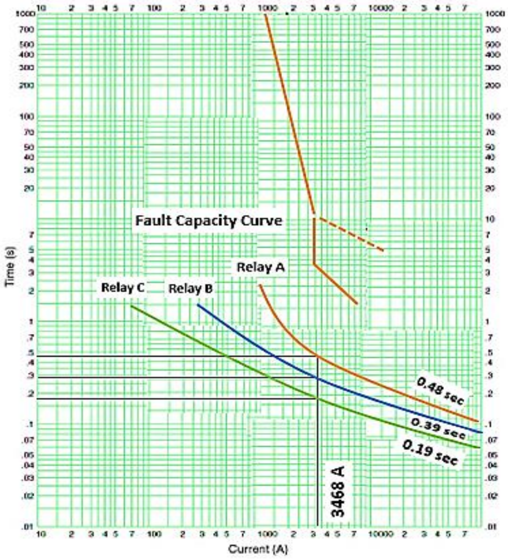


Figure 3. Relay coordination scheme for test system.

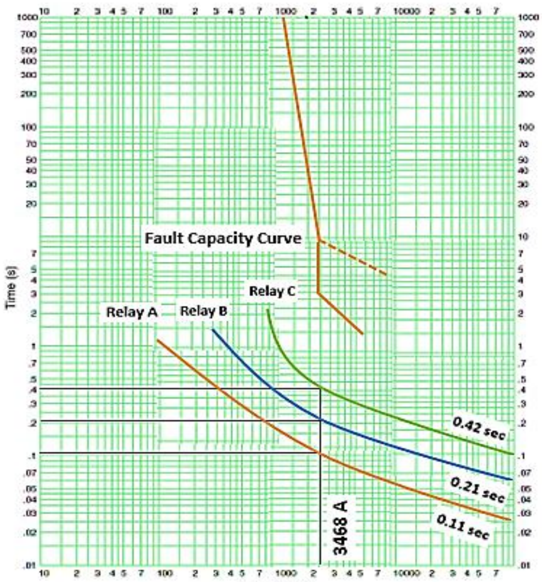
Fig. 4 shows coordination graph for over-current relays installed at both feeder and transformer. It is essential that when fault occurs at any part of feeder then over-current relays for transformer and feeder must coordinate to assure safer and efficient operation of designed protection scheme other it fails. The standard Coordination Time Interval (CTI) is 0.2 to 0.4 s [18].

When both relays have the similar characteristic curves, the smallest difference between the curves arises for the extreme short circuit current rate. Since the fault current in our study case after DG installation has become 3468 A, which was actually 1852 A before DG installation. As illustrated in Fig. 4. (a) that in the forward direction the relay settings are in the pattern that relay RA is set to operate in time instant of 0.48 s, while Relay RB has given time delay of 0.39 s and that for relay RC has been arranged at 0.19 s. It can be visualized from the graph given in Fig. 4. (b)that the functional time inverse-time overcurrent relay RA is 0.11 s and that for relay RB is 0.21 s in reverse direction. The functioning time of the inverse-time overcurrent relay RCis 0.42 s in reverse direction.

The functional timing difference between relays RB and RC is 0.2 and 0.21 s in forward and reverse direction respectively which is actually higher than minimal CTI margin required for efficient coordination. Since this operating margin is within the range ofstandard CTI, so the utility and feeder relays will coordinate more efficiently and respective circuit breaker will be tripped down accordingly.



(a)



(b)

Figure 4. Co-coordinating margin of relays for efficient fault elimination (a) forward (b) backward

V. Discussion and Results

Fig. 5 shows the Simulink model of radial distribution network, where DG is shown to be connected at Bus C through respective circuit breaker. In order to avoid reverse power flow and dis-coordination problems, different relay settings are needed in both reverse and forward directions, therefore directional overcurrent relays have been selected for this application. The relays R_A, R_B and R_C are located just before buses A, B and C respectively, such that DG supply fault current to upstream through these relays. It is necessary the rating of DGs installed at different buses, should have capacity equal to load demand. Based on system configuration, every DG has two controlling modes i.e. voltage control and current control mode. In grid-connected configuration when DG supplies nominal power to system then it is to be operated in current controlled mode. On the other hand, in voltage control mode the DG is required to supply power to system in order to maintain its voltage and frequency profile at standard limits. . In this case, fault conditions are detected by analyzing the amount of voltage drop in system after faults. The DG supplies fault current for a defined time period or until the fault has been removed. If the fault is cleared in the declared time span then DG will be recovered back and start supplying power to system. Otherwise, DG will be taken out of the system by its associated circuit breaker. It is worth a while to note that the DGs are disconnected either in un-cleared fault conditions in the system or in excessive load demand situations. The related information about system parameters is given in Table IV.

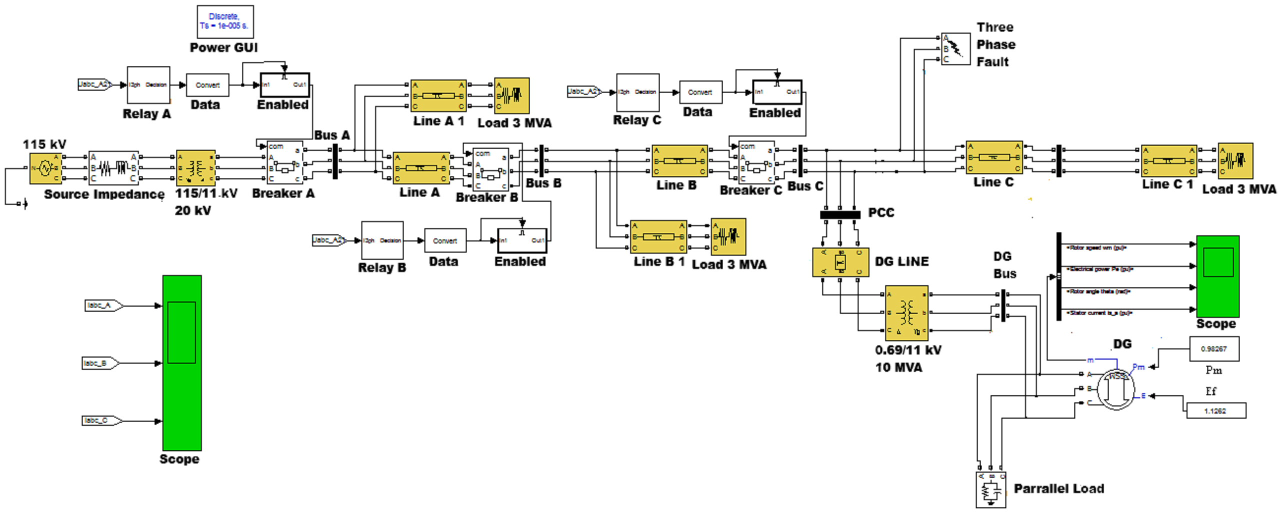


Figure 5. Simulink model for test distribution system with DG.

In this situation, the relay settings are decided by taking in view the effect of DG installation over fault level. Since the installed DGs inject twice the nominal current during the fault when operated in current mode. The relays installed at downstream isolate the fault by considering fault currents supplied by DG. Like, if fault occurs between buses B_B and B_C, the relay R_C at downstream will carry the fault current injected by DG. These relays should be graded separately for both forward and reverse directions. While considering forward direction, relays are graded by utilizing contributions of both utility and DG. For forward direction, inverse time over-current relay characteristics are specified and in order to achieve fast fault detection and isolation, instantaneous tripping element is also being connected. In this way, the functional time for higher fault levels would be reduced. Calculations are performed according to above explained procedure for fault levels at different buses. This information is necessary for setting pick up value and time coordination (inverse and instantaneous times) for different relays. It has been declared that minimum margin of 0.2 s should be maintained as time discrimination value between two relays of adjacent buses.

TABLE IV. System Specification

Parametric quantity	Value
Supply voltage	11 kV RMS
Source impedance (Z_S)	R_S = 0.4, L_S = 1.3 mH
System frequency	50 Hz
Feeder impedance ($Z_{AB} = Z_{BC} = Z_{CD}$) Positive sequence (Z_1) Zero sequence (Z_0) X_0/X_1	0.6449+ j2.4367 0.7673+ j3.6551 1.5000+j0.0000
Load demand (MVA)	0.8+j0.6
DGs capacity	1.0 MVA

Table V. shows the pick-up value and the time multiplier settings for different installed relays with appropriate current transformers' (CTs) ratios in the forward direction, calculated separately for all the inverse time relay elements. For backwards protection, the relays are graded on the basis of only the fault currents supplied by DG. In this case, the maximum load currents passing through relays during the normal operation are calculated in the backwards direction. However, if all the loads are disconnected from the feeder, then DG will start feeding power to the utility and that would be the maximum load current value passing through the relays in the backwards direction. Therefore, the pickup value for each relay should be fixed above the maximum load currents so that relays may not cause any malfunctioning and maintain the safety margin too.

TABLE V. RELAY SETTINGS IN FORWARD DIRECTION

Relay	CT ratio	Pick-up value	Time Multiplier Setting (TMS)
R_A	450/5	5.00	0.20
R_B	400/5	4.50	0.15
R_C	100/5	4.00	0.10

The maximum load current seen by R_B is 292.7 A. Therefore the relay R_B is set to detect the faults which have fault currents above the 439.05A by maintaining a safety margin of 1.5 times the maximum load current. Similarly, the maximum load current seen by R_C is 52.8A and this relay is set to detect the fault currents above 79.25 A. Time delay setting of R_B for definite time characteristic is selected as 0.1 s while it is 0.3 s for R_C, thereby allowing margin of 0.2 s for time discrimination between two relays. Note that the same CTs are used in both, forward and reverse directions. The selected relay settings in reverse direction are given in Table VI.

TABLE VI. DEFINITE TIME RELAY ELEMENT SETTINGS IN REVERSE DIRECTION

Relay	CT ratio	Pick-up value	Time Setting Multiplier (TMS)
R_B	400/5	5.48	0.15
R_C	100/5	3.96	0.35

Let consider a fault at point D in Fig. 5. The fault current is 230 A and the fault should be considered carefully by the relay R_C. Since the fault current is higher than the maximum fault current seen by R_c, therefore, R_c should isolate this fault from the upstream side. The standard inverse time relay element of R_c takes 0.286 s to clear this fault. But if the fault occurs at point B, then the fault current calculated is 1350 A and the relay R_A should isolate it from the utility supply. In this case, the relay R_A would take 0.453 s to clear the fault. This is the disadvantage of inverse time relay element's grading. The relay near to the source takes longer time to clear the faults which have higher fault current levels. In such cases, the problem is overcome by using the instantaneous relay element of R_c which will clear the fault instantly. The instantaneous settings for relays R_A, R_B and R_c can be determined according to principle explained in Section IV. Note that in the simulation, the elements are set to trip after a time delay of 120 ms.

The efficacy of deployed protection scheme has been assured through MATLAB software for the different fault scenarios at different fault locations. However, several results for three-phase fault are presented in this section. A three-phase fault was being created at the end of the line between the two buses with the fault resistance of 0.01 Ω and the relay response time can be visualized from Table VII. It can be seen that the relays deployed in the system have the ability to isolate the faulted section from the network. These results confirm that it is not essential to disconnect the DG from a network if and if the faulted section was isolated. If the fault was cleared before the faulted section isolation (i.e. temporary fault) the system could recover without disconnecting any DG, thereby maximizing the DG benefits. The fault ride through capability of DG played an important role to achieve the fault isolation.

TABLE VII. RELAYS RESPONSE FOR DIFFERENT FAULT LOCATION

Fault Location	Relay operating time (s)		
	R_A	R_B	R_C
B_A and B_B	0.072	0.104	0.312
B_B and B_C	0.785	0.479	0.278
B_C and B_D	0.974	0.562	0.254

VI. CONCLUSION

Due to extensive use of electrical power distribution system, the networks are operated at the edge of their short circuit capacity, with small margin left for incoming DG. Since the DG sources by their-selves contribute to the fault incepted into network. Therefore installation of DG is a risky task, because it badly affects the protection scheme of the utility network where it is installed. DG interconnection increases the short circuit capacity of power network. Due to change of fault level, the protection scheme designed for the network becomes ineffective. In this research, we analyzed a radial distribution feeder based on four buses, supplying power different load sections. Calculations were performed for short circuit capacity with and without the presence of DG into the network at different sections of radial feeder. According to such changes, over-current relay settings were then premeditated through the graphical analysis. Both the upstream and downstream defensive relays were coordinated to segregate the shortcomings of the system. An overcurrent relay protection scheme was proposed to seclude the faulty section contingent upon the DG status. The network restoration was then done by performing the auto reclosing. The proposed protection strategies amplified the DG advantages to the both utility and clients, keeping up the various numbers of DG associations, allowed in a high penetrative DG system.

VII. FUTURE RECOMMENDATIONS

Mitigating the impact of DG on the over-current protection coordination by a manual readjustment of overcurrent relay settings will not be effective when the change of maximum and minimum DG power into the system occurs quite often. Based on the short circuit analysis, network may also be reconfigured depends upon the new obtained values of fault current level. If not implemented, the consequences may be either false tripping or relay malfunctioning. One possible solution is to install switching reactor, which can be brought into service when the fault level of the system surpassed the designated limit. Detailed analysis for network reconfiguration with smart controlled reactors installed

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on radial utility feeder with DG installation is left for future task.

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