UACEE International Journal of Advancements in Electronics and Electrical Engineering – IJAEEE
Volume 2 : Issue 3 [ISSN 2319 – 7498]
Publication Date : 09 September 2013

Reliability Analysis of Distribution System with Distributed Generator

Impact of Protection MisCo-ordination

A. Anil Kumar, Prof.G.N.Sreenivas

Abstract— **Distributed Generation (DG) is used to improve the system reliability. However, DG Contribution in fault current may cause the loss of the existing protection coordination. This problem can drastically deteriorate the system reliability and it is more serious and complicated when there are several DG Sources in the System. Hence, the above conflict in reliability aspect unavoidably needs a detailed investigation before the installation or enhancement of DG is done. In this Research work it is proposed to model of composite DG fault current to find the threshold that existing protection coordination is lost. Cases of protection misco-ordination are to be described, together with their consequences. And attempt will be made to prevent reliability degradation from recloser fuse misco-ordination due to Distributed Generation.**

Keywords— **Distributed generator, distribution network, protection equipment coordination, DG capacity**

I. Introduction

Connection of distributed generators directly to distribution systems has become a common practice worldwide. The connection of DGs brings a great change to configuration of the utility distribution network. As a result, this leads to a big challenge for its control and protection system. Capacity and location of DG in the network have much influence on the protection system. Some of the often-quoted benefits of DG include the following:

1) Emergency backup during sustained utility outages
2) Reduced voltage sags
3) Increased reliability
4) Potential utility capacity addition deferrals

At present standards for interconnecting DG to network, mostly are based on the principle that DG shouldn't bring influence upon the normal operation performance for the utility protection and control system.

A. Anil Kumar, Vice-Principal & HOD EEE,
Gyana Saraswathi College Engineering & Technology/JNTUH, India,
anilkumargscet@gmail.com
Prof.G.N.Sreenivas, Professor, Dept of EEE, JNTUH.

When a DG is connected into the network then levels of short circuit changed, so relay settings should be changed and if DG is disconnected relay setting should back to previous state, for doing these a lot of communication links require that usually not available in distributed network. This paper presents an analysis to the protection for the radial distribution system with DG. A method for determining the distributed generators capacity has been suggested that these units do not cause loss of coordination of relays.

II. Relay Coordination of Conventional Protection

Fig. 1 shows a simple radial distribution power system, where GS is the grid system, A, B, C, D, E are the nodes of system and their corresponding loads are load1, load2, load3, load4, load5 respectively. When a fault occurs at the network, inverse over-current protection is adopted.

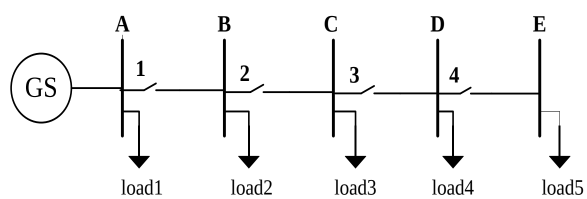

Fig.1. Simple radial distribution power system

The general operational characteristics of relays correspond to IEC standard which is expressed by the following equation:

UACEE International Journal of Advancements in Electronics and Electrical Engineering – IJAEEE
Volume 2 : Issue 3 [ISSN 2319 – 7498]
Publication Date : 09 September 2013

$$\frac{0.14TMS_i}{\left\{ [I_{fi}/(I_{pickup\ i})]^{0.02}-1 \right\}} \qquad \text{------------ (1)}$$

where

TMS_i = Time multiplier setting of relay i

I_{fi} = Fault current seen by relay i

$I_{pickup\ i}$= Pickup current of relay i

For coordination of relays at first the pickup currents are set. The user can select pickup current in a range that the minimum value is the largest between the current corresponding to the minimum available tap and the product of the maximum load current by a security factor (usually 1.1 until 1.3 for phase protection) and the maximum value is the least value between the current corresponding to the maximum available tap and the product of the minimum fault current by a security factor(usually 0.8). In this network, relay 3 is backup of relay 4, relay 2 is backup of relay 3, and relay 1 is backup relay 2. Minimum difference required for the operation time of any pair of primary/back up relays for a given fault named coordination time interval (CTI). CTI depends on some factors such as the circuit breaker operation time, delay and return time of the measuring element, etc. After determining pickup current, the time multiplier settings are set. Relay 4 give the lowest TMS, for relay 3 with a fault occurred at node D, the time of operation of relay 3 should larger than that of relay 4 at least by CTI and for other relays we act similarly.

III. Effect of DG at The Traditional Protection

The coordination of relays has changed, due to the number, location and capacity of DG interconnected. The following cases are analyzed in this paper.

A. Single DG interconnected

Fig. 2 shows DG1 located at bus A. Let's consider first at the network without DG1. A three phase fault occurs in section DE, relay 1, 2, 3 and 4 will sense downstream fault and relay 4 should operate. Relay 3 is backup of relay 4. If the relay 4 for any reason does not operate, after CTI relay 3 should operate. While DG1 injected, for a fault at downstream, e.g., a fault in section DE, relay 1, 2, 3 and 4 will see the downstream fault current, which is greater than that without DG1. Then, relay 4 will clear the fault and the sensitivity will be improved because of the larger fault current. But if fault current is greater than allowable current limit coordination between relay 3 and relay 4 not hold.

Allowable current limit is margin that if fault current be higher than this range, difference between operating time of main and backup relay will lower than CTI and interference in the operation of the relay is a probable. The situation will be similar for a given fault in section AB, BC or CD [7].

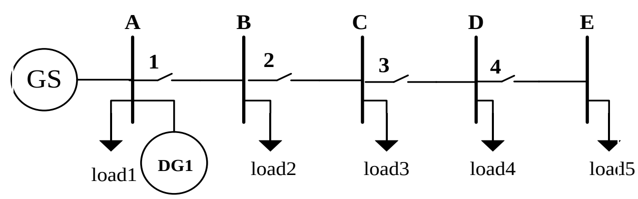

Fig. 2. Distribution system with DG1 located at bus A

Fig. 3 shows DG2 located at bus B, for a downstream fault, condition of relays are the same as before but for a fault in section AB, relay 2, 3, 4 will never see the upstream fault current, while relay 1 will sense a downstream fault current and if the fault current value is more than the set value relay 1 operates. Meanwhile, DG2 and the downstream loads will form an island.

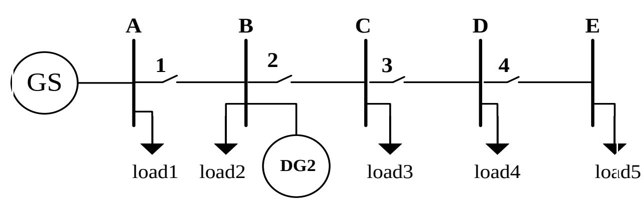

Fig. 3. Distribution system with DG2 located at bus B

B. Multiple DGs interconnected

Fig. 4 shows DG1 and DG2 which are located at bus B and C respectively. For a downstream fault of DG3, condition of relays is the same as previous section. Relay 1 is backup of relay 2. For a fault at section BC relay 2 operates before relay 1 and for a fault at section AB, relay 1 should be operate before relay 2 and here relay 2 is backup relay 1 so correct operation of relays depends on the amount of fault current. Fault current magnitude depends on the sizes of DG2 and DG3 [7]. Based on the above explanation it can be concluded that the number, location and capacity of DG interconnected to network can affect on relay coordination. In this paper determination of capacity of DG is investigated.

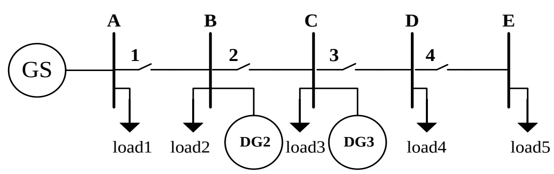

Fig. 4. Distribution system with DG2 and DG3 located at bus B and C

IV. DETERMINATION OF DG CAPACITY

The aim of this section is to determine the maximum and minimum capacity of DG connected to each node such that the mis-coordination of over-current relays do not happen, e.g., DG1 located at bus C and a three phase fault occurs in front of relay 4. Fig. 5 shows network in this position. Relay 4 is required to operate before relay 3 and if relay 4 doesn't operate, relay 3 eliminating fault after CTI. With presence of DG for downstream fault if current is greater than allowable current limit, coordination between relays 3 and 4 will be lost. Thus, the capacity of DG should be determined as the fault current will be lower than allowable current limit. To solve this problem the maximum DG capacity that can be placed in the bus C is determined.

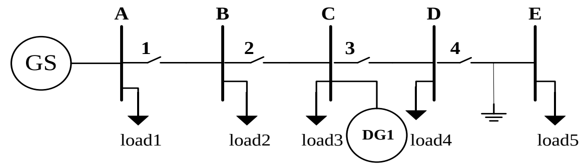

Fig. 5. Distribution system with DG1 located at bus C and a three phase fault occurs in front of relay 4

For determining the maximum capacity of DG at bus C, at first a DG with a predetermine capacity is connected to bus C. Then the three-phase fault is considered in front of relay 4. Now fault currents flow through the relays 3 and 4 are recorded. Change the capacity of DG1 and repeat the above section. Using the fault current recorded and equation 1, the operation time of relays 3 and 4 are calculated, for fault at bus C. In order to keep the coordination, the operation time interval between relays 3 and 4 should be greater than or equal to CTI. Therefore, maximum capacity that provide above limitation is selected as maximum capacity of the DG at bus C. If the DG capacity located at bus C is bigger than determined capacity, coordination between relays 3 and 4 will be lost. For a downstream fault, DG with determined capacity can keep the coordination between relays 3 and 4. After determining the maximum capacity of DG at bus C, the maximum capacity of DG at bus A and B are determined similarly.

For determining the maximum capacity of DG at bus A, three phase fault is considered in front of relays 2, 3 and 4. For each fault the maximum capacity of DG at bus A is found. The lowest values will be the maximum capacity of DG at bus A. After determining the maximum capacity of DG in the each bus, the minimum capacity of DG should be determined.

For this purpose, DG located at bus B, and it is assumed that the phase-to-phase fault at upstream bus is occurred (for example, bus A). DG capacity should be have a quantity that relay 1 senses the fault current and operates. For determining the minimum capacity of DG at bus B, first definite capacity DG located at bus B. phase-to-phase fault occurs at node A. Now fault current flow through the relays 1 recorded. Change the capacity of DG and repeat the above section. Using the fault current recorded and equation

UACEE International Journal of Advancements in Electronics and Electrical Engineering – IJAEEE
Volume 2 : Issue 3 [ISSN 2319 – 7498]
Publication Date : 09 September 2013

1, the operation time of relay 1 are calculated, for fault at bus A. Therefore, The lowest values selected as minimum capacity of the DG at bus B. Fig. 6 shows DG located at bus B and a phase-to-phase fault occurs at node A.

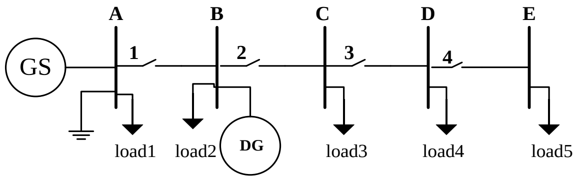

Fig. 6. Distribution system with DG located at bus B and a phase-to-phase fault occurs at bus A

Minimum capacity of DG at other bus determined similarly. After determining minimum and maximum capacity of DG for each bus, several DGs interconnected is investigated, e.g., DG2 and DG3 located at bus B, C respectively. Three phase fault occurs at bus A. Fig. 7 shows network in this position. Relay 1 should sense the fault current and operate before relay 2 and in order to keep the coordination, the operation time interval between relays 1 and 2 should be greater than or equal to CTI.

At first definite capacities of DG2 and DG3 are located at bus B and C respectively. Three phase fault occurs at node A. Now fault current flow through the relays 1 and 2 are recorded. Change the capacity of DG2 and DG3 and repeat the above section. Capacity of DG2 and DG3 are between maximum and minimum capacity that determined from previous section. Using the fault current recorded and equation 1, the operation time of relays 1 and 2 are calculated, for fault at bus A. The capacity of DGs that relay 1 operates before relay 2 and the operation time interval between relays 1 and 2 greater than or equal to CTI are selected.

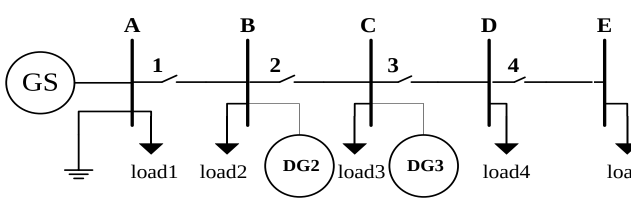

Fig. 7. Distribution system with DG2 and DG3 located at bus B, C and a three phase fault occurs at bus A

Fig. 8 shows DG2 and DG3 located at buses B and C respectively. Three phase fault occurs in front of relay 4. Fault current flow through the relays 3 and 4 are recorded. Change the capacity of DG2 and DG3 and repeat the above section. Capacities of DG2 and DG3 are capacity that determined from previous section. Using the fault current recorded and equation 1, the operation time of relays 3 and 4 are calculated, for fault at bus D. The capacity of DG is selected in a manner that the difference between operation times of relays 3 and 4 is greater than or equal to CTI.

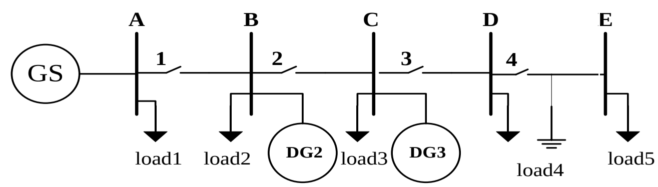

Fig. 8. Distribution system with DG2 and DG3 located at bus B and C and a three phase fault occurs in front of relay 4.

V. Conclusion

Cause loss of coordination of relays. e.g., in distribution network with DG for downstream fault operation of relay may be interface and for upstream fault miss operation of relay for fault current is possible. To solve this problem, in this paper a method for determining the distributed generators capacity has been suggested that these units do not cause loss of coordination of relays. The capacities of DGs are determined as follows:

(1) Various capacity of DG located at mentioned bus. For downstream fault operation of relays may be interface.

For any downstream fault determining maximum capacity of DG, the minimum of these maximums determine maximum capacity of DG for that bus.

(2) Various capacity of DG located at mentioned bus. For upstream fault miss operation of relay for fault current is possible. For any upstream fault determining minimum capacity of DG, the maximum of these minimums determine minimum capacity of DG for that bus.

(3) Several DG located at bus together. In this state investigate operation of relays.

REFERENCE

1) S. Brahma and A. Girgis, "Development of Adaptive Protection Scheme for Distribution Systems with High Penetration of Distributed Generation", IEEE Trans. Power Delivery, pp. 56-63, Jan. 2004.
2) P.P. Barker and R.W. de Mello, "Determining the Impact of Distributed Generation on Power Systems: Part 1-Radial Distribution Systems", IEEE Trans. Power Delivery, Vol. 15, pp. 486-193, Apr. 2000.
3). R. C. Dugan and T. E. McDermott, "Operating Conflicts for Distributed Generation Inter Connected with Utility Distribution Systems", IEEE Industry Applications Magazines, pp. 19-25, Apr. 2002.
4). IEEE Standard for Inter Connecting Distributed Resources With Electric Power System, IEEE Std. 1547.
5). UK Electricity Association, Engineering Recommendation G.59/1, Recommendations for the Connection of Embedded Generation Plant to the Regional Electricity Companies.
6). Y. Xin and L. Yuping, "Islanding Algorithm of Networks with Distributed Distribution Generators Power System Technology", pp. 50-54, 2006.
7) Y. Lu, L. Hua, J. Wu, G. Wu & G. Xu, " A Study on Effect of Dispersed Generator Capacity on Power System Protection", Engineering Society General Meeting, pp.1-6, 24-28, Jun. 2007.
8). T.M. de Britto, D.R. Morais, M.A. Marin, J.G. Roim, H.H. Ziirn and R.F. Buendgens, "Distributed Generation Impacts on the Coordination of Protection Systems in Distribution Networks", Transmission and Distribution Conference, IEEE/PES, pp. 623- 628, 8-11, Nov. 2004.
9).Girgis and S. Brahma, "Effect of Distributed Generation on Protective Device Coordination in Distribution System", Power Engineering, pp.115-119, 2001.
10).M.T. Doyle, "Reviewing the Impacts of Distributed Generation on Distribution System¬¬¬¬ Protection", ¬IEEE Power Engineering Society Summer Meeting, Vol. 1, pp. 103-105, 2002.
11).F.A. Viawan and M. Reza, "The Impact of Synchronous Distributed Generation on Voltage Dip and Overcurrent Protection Coordination", International Conference on Future Power Systems, IEEE, 2005.

About Author (s):

I am A.Anil Kumar, Working as HOD, Dept of of EEE,GSCET. I have completed my B.Tech& & M.Tech from JNTU Anantapur. Presently pursuing Ph.D