5

EFFECT ON PROTECTION SCHEME BY DG IN ETAP

Preyansh Sharma[1], Kashyap Mehta[2], R. Venkata Rama Raju[3]

1 B.Tech, Department of Electrical Engineering, Pandit Deendayal Petroleum University, Gandhinagar
2 B.Tech, Department of Electrical Engineering, Pandit Deendayal Petroleum University, Gandhinagar
3 Assistant Professor, Department of Electrical Engineering, Pandit Deendayal Petroleum University, Gandhinagar

ABSTRACT: This paper discusses the analysis and coordination of protection equipment's in a power system when Distributed Generations (DG) are incorporated in it. The study of the problems faced and its various protection techniques are conducted on IEEE 30 bus test system in Electrical Transient Analyzer Program (ETAP) simulation software. An IEEE 30 bus test system without any DG source is considered, and its protection analysis is carried out with Over-Current (OC), and Directional Over-Current (DOC) relays. This ensures the system is working normally. Further, the DGs are then incorporated and the changes, as well as problems faced by the protection system, are studied, and the respective solution is presented for this scenario in IEEE 30 bus test system. Short circuit fault current contribution, blinding of protection and sympathetic tripping are addressed in this paper.

KEYWORDS

IEEE 30 Bus system, Protection Coordination, ETAP, Distribution Generation

Introduction

The power system network is increasing with the increasing load demand. This leads to an increase in the frequency of faults. Therefore, protection relaying plays a vital role to isolate the fault within any power system. Moreover, relay coordination must ensure fast, selective and reliable relay operation to isolate the faulted section of the power system (Zeineldin et al., 2015; Oza et al., 2010). For the protection of interconnected sub-transmission systems, DOC relays are an attractive choice economically (Zeineldin, et al., 2015; Coster & Kling, 2010).

Electric power systems were until now known by their system of centralized production units, i.e., a huge generating station, a high voltage transmission grid, medium or low voltage distribution grid (Moore, 2008). However, this trend has changed significantly in the past decade. Nowadays to reduce the CO2emission, renewable sources such as wind turbines, micro-turbines, and photovoltaic panels are used as small generation sources in the distribution grid (Coster & Kling, 2010). Moreover, by generating the power locally in the distribution system, the transmission line losses are reduced (Vijeta & Sarma, 2012) and the voltage profile is improved. Due to increasing penetration of DG, distribution systems are transforming from the commonly radial structure toward a meshed and looped structure (Zeineldin et al., 2015). However, the negative impact of DG is to increase the fault current level and multiple current flow paths during the fault condition. These conditions decrease the capability and reliability of the existing design of power system protection for the radial distribution network.

The protection issues by introducing DGs are faulted current contribution, reverse power flow, single phase connection and reduction in reach of impedance relays. The major concerns of the protection system are fault current contribution, sympathetic tripping, blinding and islanding (Deuse et al., 2007; Driesen & Belmans, 2006; Hadjsaid et al., 1999). Sympathetic under-voltage tripping occurs with more penetration of DGs into the power system (Jennett et al., 2011).To avoid such problems into the power system protection, generally, DGs are disconnected rapidly during the fault in order to have the normal operation of conventional protective devices. Disconnecting DGs would lead to under-utilization of the benefits for both utility and DG owners as well as mal-operation of the protective system. Solutions are discussed in (Moreno et al., 2012) based on fault detection and directional comparison scheme which works on high-frequency transient signals by applying wavelet transform. In (Bernardo et al., 2012), a model was proposed for improving the selectivity of protection relays by performing dynamic tuning of protection settings. One of the solutions for limiting the fault current by DG is to limit the inverter short circuit current contribution (Bhattacharya, 2014).

The connection of DG to distribution feeders changes the fault current in the faulted feeder. With the introduction of DG into the system, the fault current seen by circuit breaker gets increased, and hence the circuit breaker has to be replaced (Coster & Kling, 2010).

Sympathetic tripping is possible when a generator which is installed on a feeder, starts contributing to the fault in a nearby feeder connected to the same bus.The DG contributes to the thefault current which will exceed the pick-up value of the OC relay and ultimately it will cause tripping of the healthy feeder even before the fault is cleared. The solutions to this are discussed in (Kauhaniemi & Kumpulainen, 2004) and can be avoided by finding a relay setting or by changing the fault clearing time. In (Xu & Jiao, 2014) it is discussed that sympathetic tripping can be prevented by reducing the fault level which can be reduced by the use of current limiting reactors.

During the fault, contribution by utility gets reduced due to penetration of DG into the grid. Due to this decrement of current levels, the fault stays undetected as the utility fault current contribution never reaches the pick-up level current of the feeder relay (Coster & Kling, 2010). This phenomenon is called blinding of the relay, or the relay is blind to detect the fault. Solution to this is given in (Chilvers et al., 2010) which is done by changing the X/R ratio of distance protection with the change in fault current.

In this paper, we have first of all considered IEEE 30 bus system for study and then carried out load flow in order to determine and verify the system parameters like voltage, active power, reactive power, etc. Then we further study the short circuit analysis which helps find out the minimum and maximum short circuit current. The relay coordination is studied &protection of the entire system of IEEE 30 bus is then carried out and ensured that it is working normally.

Further, DGs are introduced in the system, and the system behavior in terms of protection analysis is studied, and some key problems are addressed in the study. Also, the solutions to their respective problems are found and been verified using the ETAP software.

System Description

An IEEE 30 bus distribution system is considered for the study. Fig. 1 shows the single line diagram of the IEEE 30 bus system (IEEE). It consists of 30 buses, 6 generators, 41 branches, 24 loads and 4 transformers. Generator 1 is considered as swing bus, Generator 2 as a voltage control bus and the rest four are synchronous condensers. The parameters of the system are given in Appendix 1. The DGs are connected at bus numbers 14, 15, 16 & 24 with a respective interconnecting transformer. The rating of DGs is also given in Appendix 1.

Load Flow Analysis

In order to study the power flows in the system, a load flow study is carried out. The advantage in studying the power flow analysis is in planning the future expansion of power systems as well asin determining the best operation of existing systems. In ETAP software load flow analysis is carried out using Newton-Raphson keeping 0.0001 as the precision of solution. Using load flow study the unknown parameters such as activepower, reactive power, voltage, and phase angle are determined. Results of the load flow analysis are shown in Table. 1.

Bus Data						
	Bus		Initial Voltage		Power	
Sr. No.	Bus ID	kV	%Mag	Ang.	MW	Mvar
1	Blaine 13_7	132	100.217	-12.3	22.899	10.947
2	Bus 15 3_15	33	103.316	-14.2	8.753	2.669
3	Bus 14 3_14	33	103.874	-12.3	6.690	1.726
4	Bus 16 3_16	33	103.779	-12.9		
5	Bus 17 3_17	33	103.379	-14.1	9.619	6.199
6	Bus 18 3_18	33	102.252	-15.0	3.346	0.941
7	Bus 19 3_19	33	101.954	-15.2	9.875	3.534
8	Bus 20 3_20	33	102.361	-15.1	2.305	0.733
9	Bus21	33	103.484	-13.1	3.748	1.928
10	Bus 21 3_21	33	102.625	-14.7	18.431	11.796
11	Bus 22	0.400	100.000	0.00	15.719	-3.050
12	Bus 22 3_22	33	102.687	-14.7		
13	Bus23	0.690	98.872	-12.0	2.000	-1.239
14	Bus 23 3_23	33	102.186	-14.7	3.341	1.671
15	Bus 24	33	100.353	-14.8	8.762	6.747
16	Bus 24 3_24	33	101.563	-14.9	0	-4.435
17	Bus 25	0.690	104.204	-11.5	2.000	0
18	Bus 25 3_25	33	101.277	-14.8		
19	Bus 26 3_26	33	99.519	-15.3	3.466	2.278
20	Bus 27	0.690	103.696	-11.0	2.500	0
21	Bus 29 3_29	33	100.000	-15.7	2.400	0.900
22	Bus 30 3_30	33	98.881	-16.6	10.364	1.858
23	Clayton 13_2	132	104.318	-5.1	23.615	23.615
24	Cloverdale 3_27	33	101.960	-14.5		
25	Cloverdle13_28	132	100.684	-11.0		
26	Fieldale 13_5	132	100.920	-13.8	95.941	19.351
27	Glen Lyn 13_1	132	106.000	0.0	247.835	-14.788
28	Hancock 1_13	11	107.1	-13.3		13.953
29	Hancock 3_12	33	105.276	-13.3	12.413	8.312
30	Hancock 13_4	132	101.254	-8.7	7.792	1.640
31	Kumis 13_3	132	102.150	-7.0	2.504	1.252
32	Reusens 13_8	132	101.000	-11.1	30.603	30.603
33	Roanoke 1_9	33	104.826	-12.9		
34	Roanoke 1_11	11	108.2	-13.0		17.552
35	Roanoke 3_10	33	103.920	-14.3	6.266	-18.359
36	Roanoke 13_6	132	101.053	-10.4		

TABLE 1. Load flow analysis of IEEE 30 bus distribution system with DGs

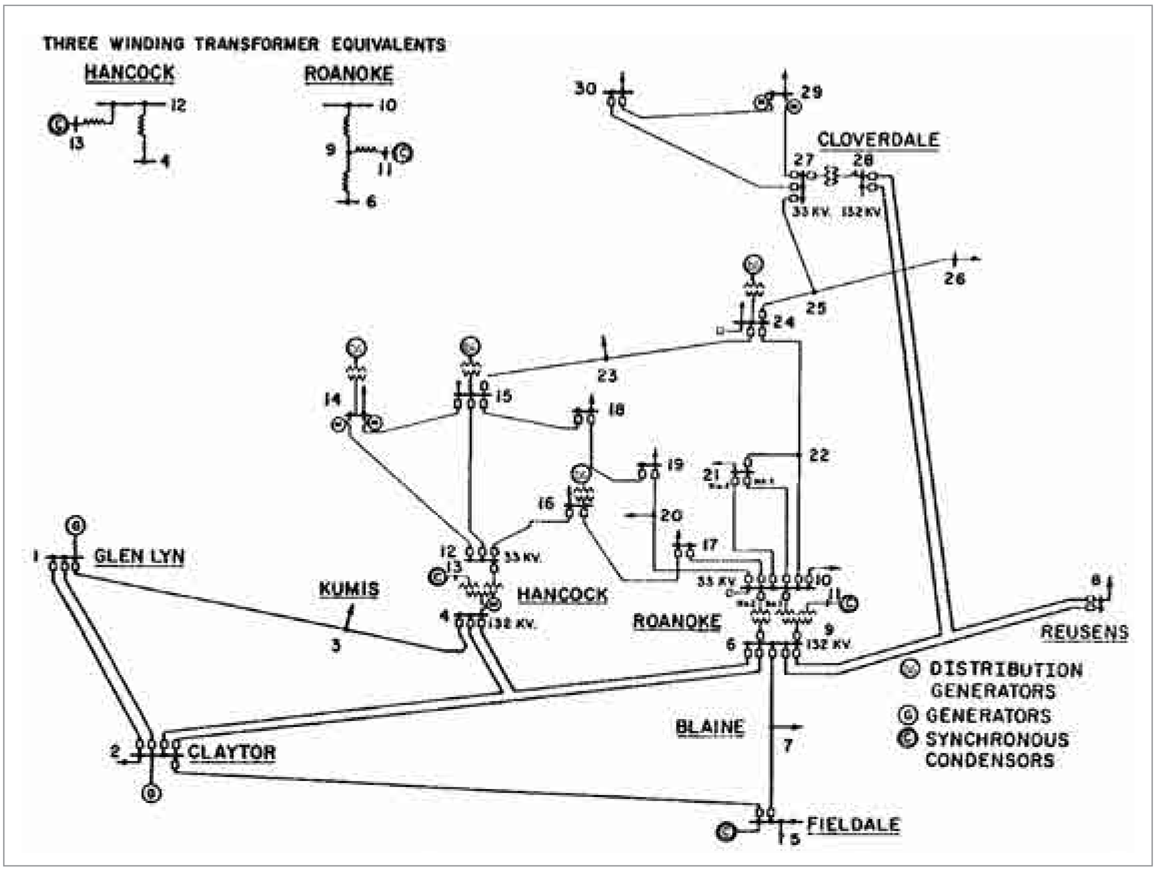


FIGURE 1. Single line diagram of IEEE 30 bus distribution system with DGs

Receiving end active and reactive power flows are given by (Stevenson, 1985):

$$P_R = \frac{|V_S| \times |V_R|}{|B|}\cos(\beta-\delta) - \frac{|A| \times |V_R|^2}{|B|}\cos(\beta-\alpha) \quad (1)$$

$$Q_R = \frac{|V_S| \times |V_R|}{|B|}\sin(\beta-\delta) - \frac{|A| \times |V_R|^2}{|B|}\sin(\beta-\alpha) \quad (2)$$

Where V_S is the sending voltage, V_R is the receiving end voltage, A & B are ABCD parameters while α & β are the phase angle of A &B respectively, and δ is the load angle.

Short Circuit Analysis

All the electrical equipment should be able to withstand the fault current for a specified time. Protecting equipment shall clear the fault within the withstand time of the device to be protected. Mostly, Short Circuit Calculation (SCC) is performed to find the maximum available fault current and minimum available fault current in the system. The maximum available fault current is used for selecting the short circuit withstanding capacity of all electrical equipment. The minimum available fault current is used for selecting the pick-up setting of the instantaneous OC relay (Prabhu et al. 2016). Using short circuit analysis in ETAP, Plug Setting Multiplier (PSM) and Time Dial setting of the relay are decided. PSM is given as:

$$PSM = \frac{I_F}{T I_p} \quad (3)$$

Where, I_F is the fault current, T is the Current Transformer (CT) ratio, and I_p is the primary current of the CT.

The fault current for different faults is calculated as:

Line to Ground fault: $$I_F = \frac{3E}{Z_1 + Z_2 + Z_0} \quad (4)$$

Line to Line fault: $$I_F = \frac{\sqrt{3}E}{Z_1 + Z_2} \quad (5)$$

Line to Line to Ground Fault: $$I_F = \frac{3E}{Z_1 + (Z_2 \parallel Z_0)} \quad (6)$$

Three phase fault: $$I_F = \frac{E}{Z_1} \quad (7)$$

Where E is the pre-fault voltage, Z0, Z1& Z2 are the zero, positive & negative sequence impedances respectively.

Relay Coordination

For OC relay coordination, time dial and pick-up value settings are necessary. These two settings decide the time of operation of OC relay for a particular fault current (Patel et al., 2015).

Pick-up value setting

The pick-up value setting of OC relay is different for the transformer and transmission line. The pickup value for transformer is given as

$$I_k = \frac{S}{\sqrt{3}V_L T} \tag{8}$$

Where, I_k is the pickup current, S is the rated VA of transformer, V_L is line to line rms voltage.

The pickup value for the transmission line is given as

$$I_k = 1.25\ I_{max} \tag{9}$$

Where I_{max} is the maximum current that the transmission line could withstand.

Time Dial

Time Dial setting depends on the time of operation and is calculated as

$$T_{op} = \frac{\gamma}{(PSM)^{\zeta} - 1} \times T_D \tag{10}$$

Where, T_{op} is the time of operation of the relay, γ and ζ are constants (Jennett et al., 2011) given in Table. 2, T_D is the time dial setting.

Over-current Curves	ζ	γ
Normal Inverse Relay	0.02	0.14
Very Inverse Relay	1.00	13.5
Extremely Inverse Relay	2.0	80.0

TABLE 2. Values of ζ & γ for different relay characteristics.

Relay Coordination with DG

While interconnecting the DGs into the power system, an interconnecting transformer is used (Arritt & Dugan, 2008). In general Delta (Utility) – Grounded-Wye (DG) (Fig. 2) interconnection transformer is used due to the advantages such as isolation from voltage sags for single line-ground faults at utility-side and allowing the DG to better ride through voltage sags. DGs are connected in Grounded-Wye as they are at the load end which requires neutral. Delta connection suppresses the harmonics to the utility and reduces the fault current contribution by the DG. The advantage is that it will not contribute to the fault current.

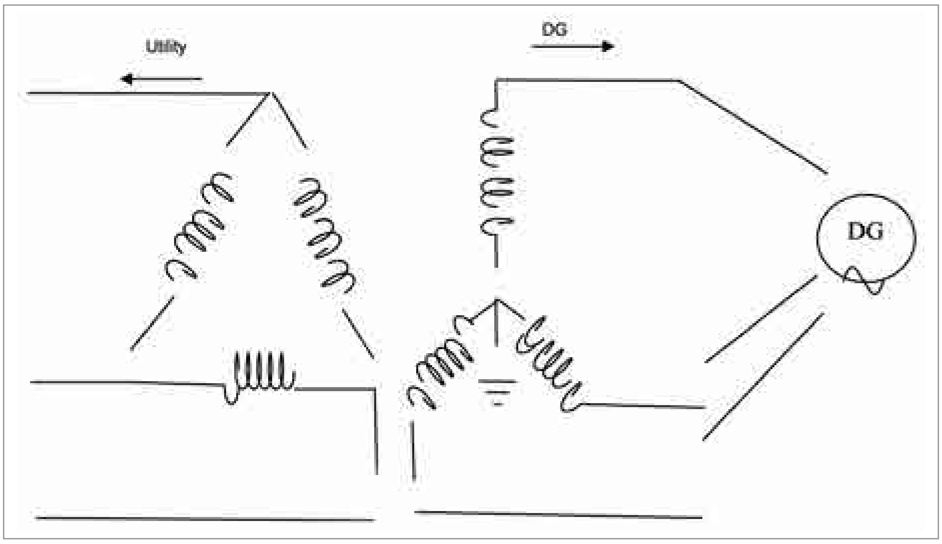


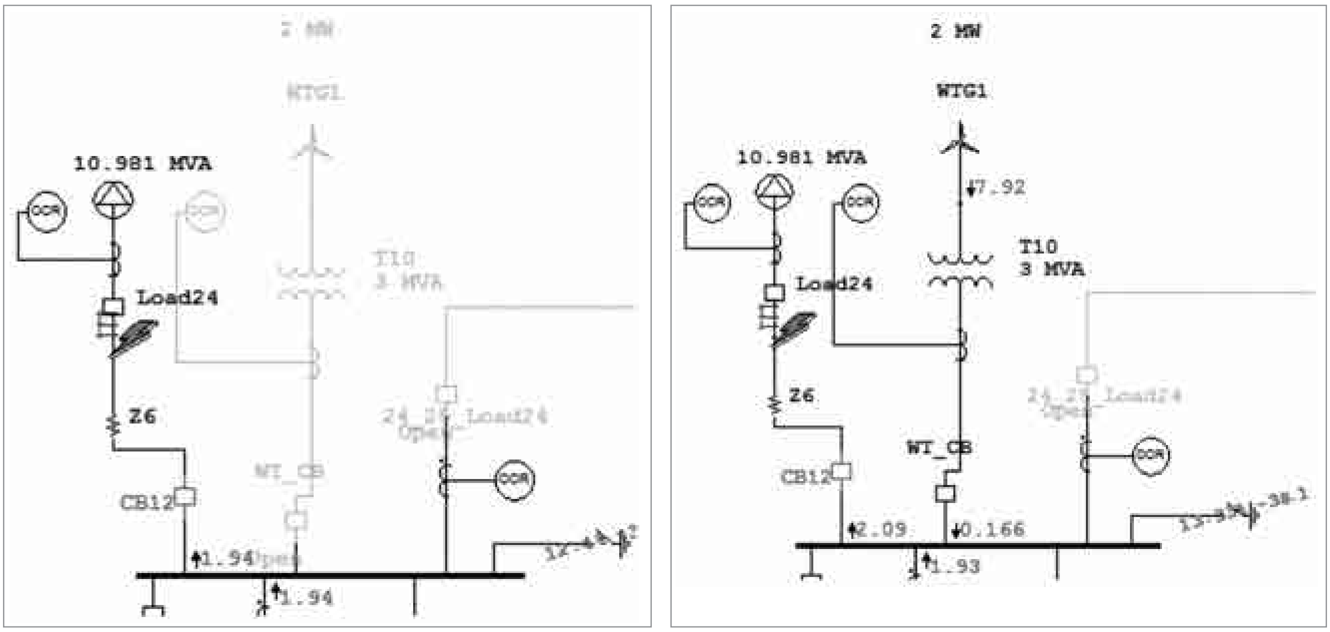
FIGURE 2. Interconnection transformer

Simulation Results

Simulation results are presented for fault current contribution, blinding, and sympathetic tripping cases. The solutions for each case are tested in ETAP software.

Fault current contribution

The connection of DG to distribution feeder changes the fault current in the faulted feeder. The rate of change of the fault current strongly depends on the ability of the DG to contribute to the fault (Zeineldin, et al., 2015). Whenever there is only one way to feed the load, then this kind of case may occur. For a 3-Φ fault at the terminals of CB 15_23_Load15 (circuit breaker connected between bus 15 and bus 23 at load 15) the fault current seen by the relay 15_23-Load15 is 5.96A. But now if a DG is connected to the bus 24 and the same fault occurs at the same location, then the fault current seen by the relay does not increase. But if the fault occurs at the terminals of Load24 and DG is disconnected then the fault current seen by CB12 is 1.94 kA as shown in Fig.3 (a). Now DG is connected to the bus 24, and the same fault occurs at Load24 then the fault current seen by CB12 is 2.09 kA (Fig. 3(b)). Hence the current seen by CB12 has increased due to the introduction of DG into the system. As before connecting DG, the CB had designed hence the short circuit current capability was designed was less but now as DGs are introduced the short circuit current capability should be increased by replacing the CB with the new one. Else a control strategy can be used to stop firing to the inverter of DG whenever it senses a fault. If DG connected is operating using an inverter or active networks like thyristors then the fault current could be limited, short circuit contribution or k-factor of an inverter is used to limit the fault current.



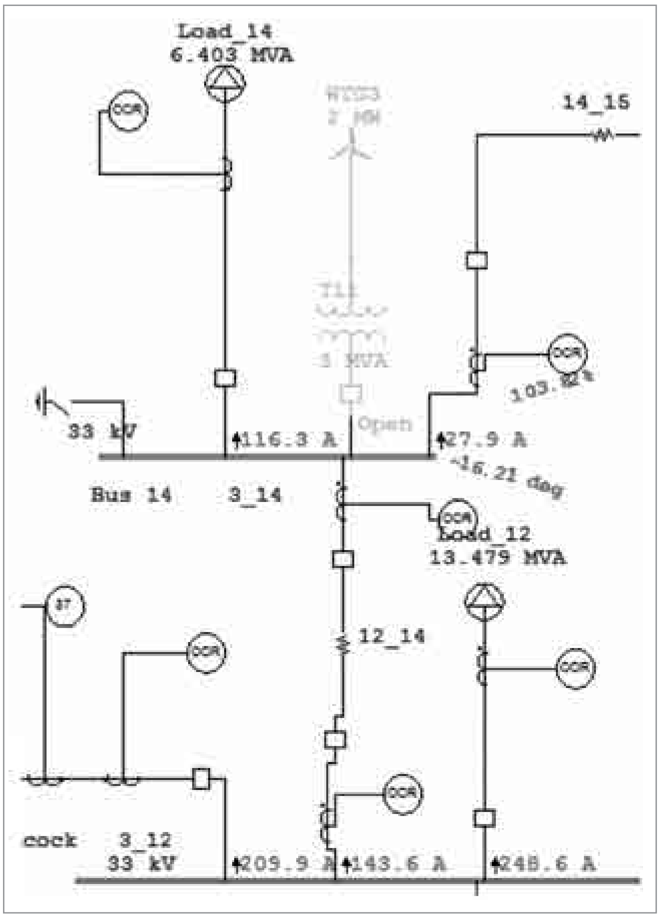
(a) (b)

FIGURE 3. Fault level contribution (a) without DG & (b) with DG

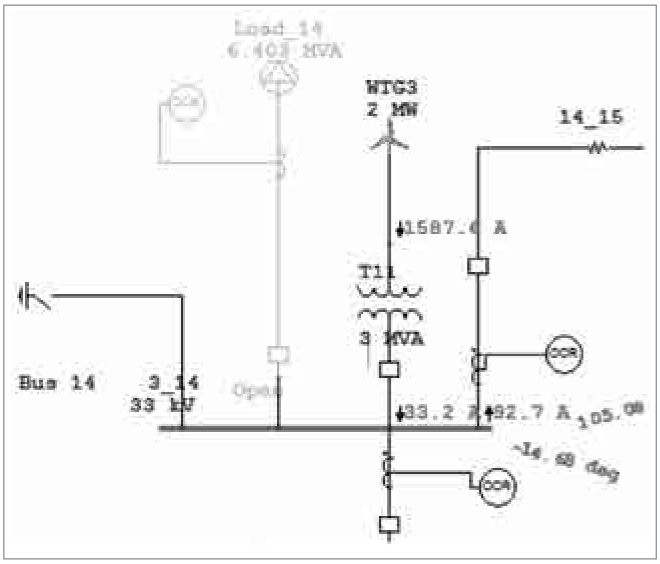
Sympathetic Tripping

The generator has a major contribution to the fault current when the generator and/or the fault are located near the substation. Especially in weak grids, false tripping can occur with long feeder length which is protected by definite OC relays. The settings of the protection relays have to ensure that fault at the end of the feeder is also detected which leads to a relatively small pick-up current. Here DG affects the security of the protective system.

Fig. 4 shows the load flow analysis of the section of Bus 14 of IEEE 30 bus system. Here the nominal current for the transmission line between bus 14 & bus 15 is 27.9 A (Fig. 4 (a)) and under worst scenario, the maximum nominal current is 70 A. Hence the pickup value is 85 A. Now, DG is connected to Bus 14 and load is removed. Under this condition, the nominal current flowing through the transmission line between bus 14 & bus 15 is 92.7 A as shown in Fig. 4 (b). Under the normal condition also the relay would give the trip signal as the nominal current is higher than the pickup value of DOC relay at bus 14 & bus 15.



(a)



(b)

FIGURE 4. Sympathetic tripping (a) without DG & (b) with DG

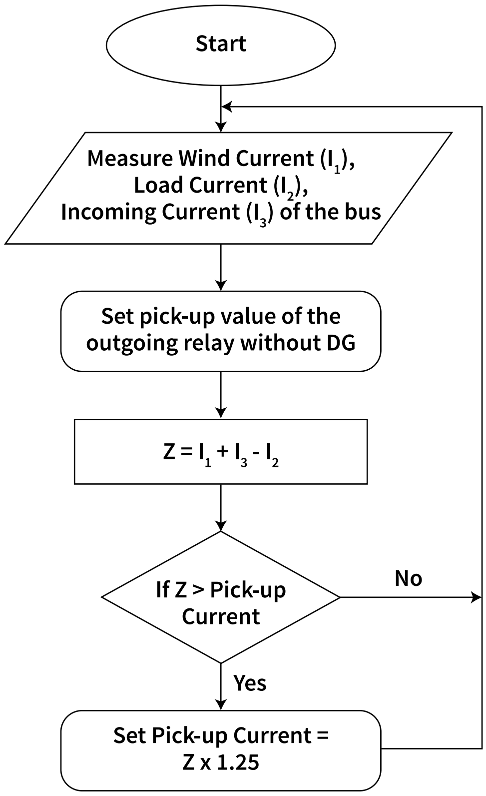
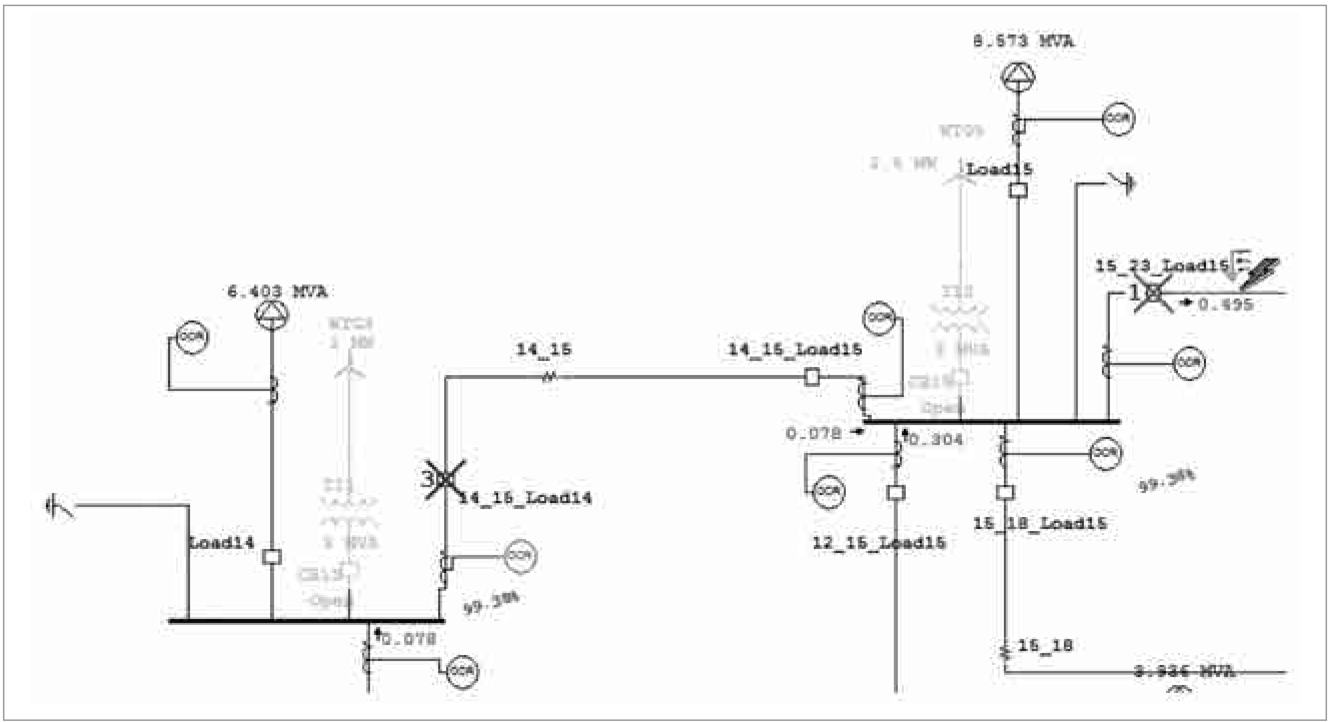


FIGURE 5. Flow chart to overcome sympathetic tripping

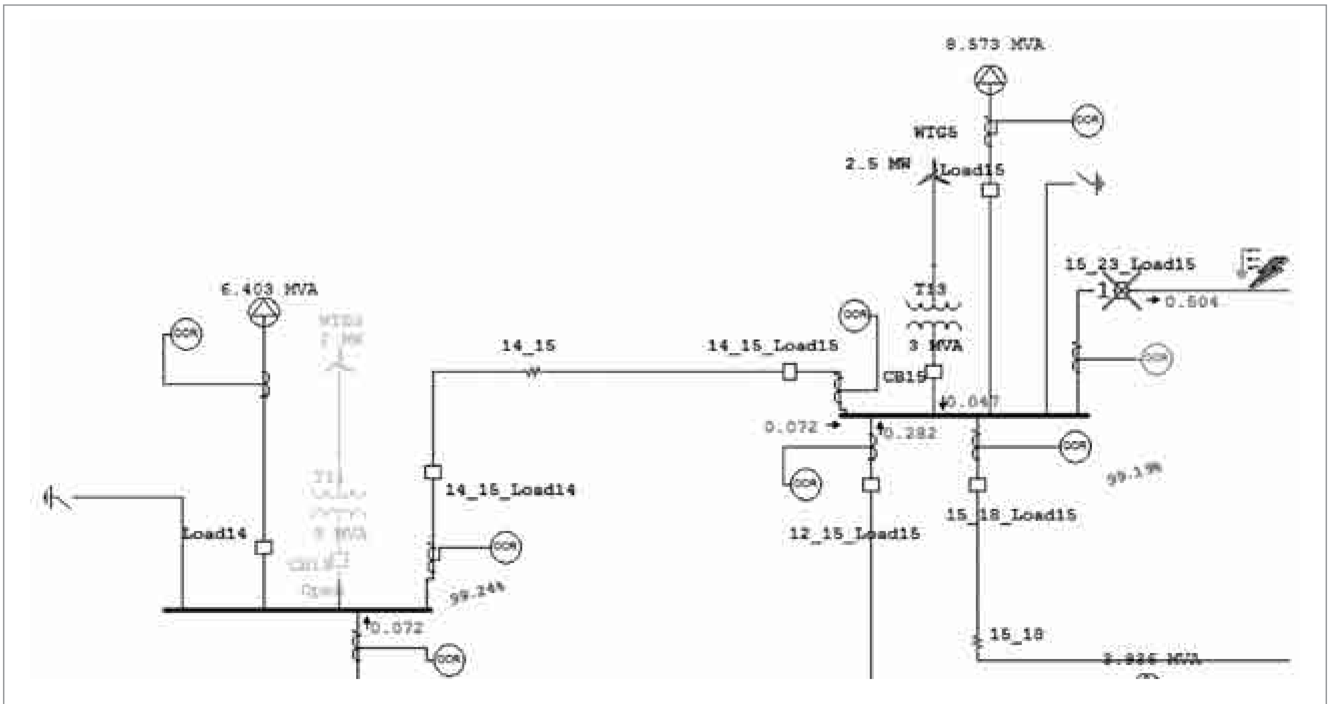
The solution is to increase the pick-up value of relay. However, the problem is DGs are renewable in nature and are not always available. If we increase the pickup value of relay and DGs are not supplying any power, then under some circumstances relay will not pick up. Another solution to this problem is to use a loop wherein we measure the incoming and outgoing currents of the bus and based on that we decide the relay pickup value. Fig. 5 shows the flowchart for this solution. First of all, we have to measure all the incoming currents using CTs, i.e. here it is transmission line between bus 12 & bus 14 which is 143.6A as shown in Fig. 4(a). Now measure the load current from the bus which is 116.3 A. Hence subtract the load current from current through transmission line between bus 12 & bus 14 which will give the current of a transmission line between bus 14 & bus 15 and that is 27.9 A. Thereupon increase the relay pickup setting based on value obtained using numerical relays or by SCADA system if the relay is connected to remote locations. Here, in this case, the relay pick-up setting would be 35 A (27.9 * 1.25). Now if DG is connected then the current in the transmission line between bus 14 & bus 15 is 92.7 A. Therefore, the relay pick-up current value would be 116 A (92.7 * 1.25). Now with the change in DG generation also the pick-up value will change. As in substation ammeters are available to measure the incoming currents and outgoing currents from the substation. Hence using these values in digital relay logic can be performed. First set the pick-up value of the relay without DG as in this case is 78 A. Now measure the value of Z (flow chart) and if its value is greater than pick-up value of the relay then set new pick-up value else same pick-up value will be retained. In this way, with a change in the DG generation, the pick-up value is set, and the problem of sympathetic tripping is overcome.

Blinding

Fig. 6 shows that the single line to a ground fault has occurred at the terminals of CB 15_23_Load15 with fault impedance 30 Ω. Now, as DG is not connected (Fig. 6(a)) the current seen by the relay 14_15_Load14 during the fault is 78 A. As seen in Fig. 6(a) relay 14_15_Load14 has pickup value of 78 A, and hence it will operate. Table. 3 shows the sequence of operations when DG is not connected. Now DG is introduced at the Bus 15 with 2.5 MW of Wind Turbine Type 4 system (Camm, 2009). LG fault is created at the terminals of CB 15_23_Load15 as shown in Fig. 6(b). The fault current seen by relay 14_15_Load14 is 72 A, and it will not operate as the pickup value is 78 A. This phenomenon is called as blinding or the relay is blind to operate with the incorporation of DG into the system. Table. 4 shows the sequence of operations with incorporating DG at Bus 15, and it clearly indicates that relay 14_15_Load14 is blind to operate.



(a)



(b)

FIGURE 5. Blinding (a) without DG & (b) with DG

Line-to-Ground Fault between 15_23_Load15 and 15_23. Adjacent to Bus 15 3_15				
Total Time (ms)	**ID**	**If (kA)**	**T1 (ms)**	**Condition**
1237	15_23-Load15	0.501	1237	Phase - OC1 - 51 - Reverse
1320	15_23_Load15		83.3	Tripped by 15_23-Load15 Phase - OC1 - 51 - Reverse
11185	23_24-Load24	0.120	11185	Phase - OC1 - 51 - Forward
11268	23_24_Load24		83.3	Tripped by 23_24-Load24 Phase - OC1 - 51 - Forward
81100	14_15-Load14	0.080	>81100	Phase - OC1 - 51 - Reverse
81183	14_15_Load14		83.3	Tripped by 14_15-Load14 Phase - OC1 - 51 - Reverse

TABLE 3. The sequence of operations without DG

Total Time (ms)	ID	If (kA)	T1 (ms)	Condition
1225	15_23-Load15	0.504	1225	Phase - OC1 - 51 - Reverse
1308	15_23_Load15		83.3	Tripped by 15_23-Load15 Phase - OC1 - 51 - Reverse
12100	23_24-Load24	0.117	12100	Phase - OC1 - 51 - Forward
12183	23_24_Load24		83.3	Tripped by 23_24-Load24 Phase - OC1 - 51 - Forward

TABLE 4. The sequence of operations with DG

Conclusion

In this paper, the protection coordination analysis of the system is performed with and without DGs to understand the effects of distributed generation on the protection system. The complete analysis is carried out on a modified IEEE 30 bus test system in ETAP software. Following were the main problems and conclusions derived from the study:

1. Protection System maloperates due to the introduction of DGs in the system, it is observed that false tripping of the breakers takes place due to change in system parameters.
2. Also, the protection system is seen to become resistant to the preset pickup parameters and gets blinded due to the incorporation of DGs in the system.
3. It is also concluded that the short circuit fault current level of the system increases with the introduction of DGs in the system.

To overcome the above mentioned problems in the system, various solutions for the same are presented and verified in ETAP simulation software. For sympathetic tripping, either the pick-up currents for the relaysshould be increased, or a control loop can be used wherein the input and output currents of the bus having DGs are measured. If DGs are active, then pick-up current of relay near DG is increased and vice versa.

For solving the problem of blinding of the protection system, one of the solutions could be to use Delta-Wye transformer as an interconnecting transformer between DG and utility with delta is on the utility side. This would prevent any fault current contribution from DGs during faulty conditions. Also, the control loop used for sympathetic tripping could be used to overcome blinding as well.

To avoid the effect of increased short circuit fault current level, either the rating of the circuit breakers can be increased or the inverter short circuit current limiting factor (k factor) value could be set as a percentage of rated current. Also, one of the methods could be to isolate the DG from the system before it contributes to the fault current by controlling or commuting the firing pulses of the inverter.

References

Arritt, R. F., & Dugan, R. C. (2008, July). Distributed generation interconnection transformer and grounding selection. In 2008 IEEE Power and Energy Society General Meeting-Conversion and Delivery of Electrical Energy in the 21st Century (pp. 1-7). IEEE.

Bernardo, A., Silva, N., Delgado, N., Jorge, R., & Carrapatoso, A. (2012, May). DG behaviour and protection schemes in case of disturbances within the concept of distribution grid area. In CIRED 2012 Workshop: Integration of Renewables into the Distribution Grid (pp. 1-4). IET.

Bhattacharya, S. (2014). Power system protection problems caused by grid connected PV systems.

Camm, E. H., Behnke, M. R., Bolado, O., Bollen, M., Bradt, M., Brooks, C., ... & Klein, S. (2009, July). Characteristics of wind turbine generators for wind power plants. In 2009 IEEE Power & Energy Society General Meeting (pp. 1-5). IEEE.

Coster, E., Myrzik, J., & Kling, W. (2010). Effect of DG on distribution grid protection. In Distributed generation. IntechOpen.

Chilvers, I. M., Jenkins, N., & Crossley, P. A. (2004). The use of 11 kV distance protection to increase generation connected to the distribution network.

Deuse, J., Grenard, S., Bollen, M., Häger, M., & Sollerkvist, F. (2007). Effective impact of DER on distribution system protection. In International Conference on Electricity Distribution: 21/05/2007-24/05/2007. AIM.

Driesen, J., & Belmans, R. (2006, June). Distributed generation: challenges and possible solutions. In 2006 IEEE power engineering society general meeting (pp. 8-pp). IEEE.

Hadjsaid, N., Canard, J. F., & Dumas, F. (1999). Dispersed generation impact on distribution networks. IEEE Computer Applications in power, 12(2), 22-28.

Patel, H. A., Sharma, V. M., & Deshpande, A. (2015). Relay Coordination Using ETAP. International Journal of Scientific & Engineering Research, 6(5), 1583-1588.

Prabhu, J. A. X., Nande, K. S., Shukla, S., & Ade, C. N. (2016, March). Design of electrical system based on Short Circuit study using ETAP for IEC projects. In 2016 IEEE 6th International Conference on Power Systems (ICPS) (pp. 1-6). IEEE.

IEEE 30 bus data retrieved from http://www2.ee.washington.edu/research/pstca/pf30/pg tca30bus.html

Jennett, K., Booth, C., & Lee, M. (2011, October). Analysis of the sympathetic tripping problem for networks with high penetrations of distributed generation. In 2011 International Conference on Advanced Power System Automation and Protection (Vol. 1, pp. 384-389). IEEE.

Kauhaniemi, K., & Kumpulainen, L. (2004). Impact of distributed generation on the protection of distribution networks.

Moore, A. T. (2008). Distributed generation (DG) protection overview. University of Western Ontario, London, Canada.

Moreno, J. G., Perez, F. E., & Orduna, E. A. (2012, September). Protection functions for distribution networks with distributed generation applying wavelet transform. In 2012 Sixth IEEE/PES Transmission and Distribution: Latin America Conference and Exposition (T&D-LA) (pp. 1-5). IEEE.

Oza Bhuvanesh, Nair Nirmalkumar, Mehta Rashesh, Vijay Makwana, Power System Protection & Switchgear, New Delhi:Tata McGraw Hill Education Private limited, 2010.

Stevenson, W. D. (1985). “Elements of power system analysis.” Fourth Edition, McGraw-Hill International Book Company.

Vijeta, K., & Sarma, D. S. (2012, August). Protection of distributed generation connected distribution system. In 2012 International Conference on Advances in Power Conversion and Energy Technologies (APCET) (pp. 1-6). IEEE.

Xu, C. X., & Jiao, Y. J. (2014). Protection Scheme for Distribution Network with Distributed Generation. In Advanced Materials Research (Vol. 960, pp. 1376-1380). Trans Tech Publications.

Zeineldin, H. H., Sharaf, H. M., Ibrahim, D. K., & El-Zahab, E. E. D. A. (2014). Optimal protection coordination for meshed distribution systems with DG using dual setting directional over-current relays. IEEE Transactions on Smart Grid, 6(1), 115-123.

Appendix1

DG No.	Bus No.	Operation Mode	Type	Power rating	Voltage	Power-factor	Efficiency	Rpm	FLA
WTG3	Bus 14	Voltage Control	Type4, WECC	2MW	0.69kV	0.85	95%	1800Rpm	1969
WTG1	Bus 24	Induction Generator	Type1, WECC	2MW	0.69kV	0.85	95%	1800Rpm	1969
WTG5	Bus 15	Voltage Control	Type4, WECC	2.5MW	0.69kV	0.85	95%	1800Rpm	2461

TABLE A1. Wind turbine generation data

DG No.	X_{SC}	X_0	X_2	X/R	Inverter SC contribution (k factor)	I_{SC} = k * FLA
WTG3	16.667 (1/2 cycles)	16.667	16.667	40.333	150%	2954
WTG1	16.667 (1/2 cycles)	16.667	16.667	40.333	-	-
WTG5	16.667 (1/2 cycles)	16.667	16.667	45.094	150%	3692

TABLE A2. Wind Turbine impedance data

DG No.	V_{oc}	I_{SC}	Power (Watt/ Panel)	Irradiance	Temp	No. of panels in series	No. of panels in parallel	Total no. of panels in array	DC Voltage (V)	Power (kW)	Current (A)
PVA6 at Bus 16	46.3	9.32	340	1000 W/m^2	25°C	160	120	19200	6160	6527	1059.6

TABLE A3. PV panel data

Inv I_d	Bus No.	Operation Mode	DC load	DC volts	DC FLA	Efficiency	AC KVA	PF	kV	FLA	Inverter SC Contribution (k factor)	I_{SC} = k * FLA
Inv8	Dc bus1, AC bus 22	Swing	6250	6160	1015	90%	7031	80%	0.4	10149	150%	15223

TABLE A4. PV-inverter data

Preyansh Sharma
B.Tech, Department of Electrical Engineering,
Pandit Deendayal Petroleum University, Gandhinagar, India
Email: preyansh96@outlook.com

Kashyap Mehta
B.Tech, Department of Electrical Engineering,
Pandit Deendayal Petroleum University, Gandhinagar, India
Email: kashyap.mehta123@gmail.com

R. Venkata Rama Raju
Assistant Professor, Department of Electrical Engineering,
Pandit Deendayal Petroleum University, Gandhinagar, India
Email: ramaraju1010@gmail.com