Influence of Distributed Generation on Protection Schemes of Medium Voltage Grids

Nguyen Hong Viet Phuong, Ioanna Xyngi, Marjan Popov and Lou van der Sluis

Abstract**-- This paper deals with the impact of the distributed generation (DG) interconnection to closed-loop medium voltage (MV) networks on the grid protection. A 10 kV underground cable test network with DG connection is modeled in Matlab/Simulink. Fault simulations at various locations are investigated while the network is operated in ring configuration. For the studied cases, the operation of directional overcurrent protection schemes is observed. The transient stability of DG units is also taken into account in order to validate the protection scheme coordination. It is concluded that the traditional protection schemes for a close-loop grid are not operating properly anymore with the presence of DG units. New adaptive protection principles should be used to keep the DG units availability during the fault.**

Keywords**: distributed generation, protection scheme, transient stability, directional relay, medium voltage.**

I. Introduction

NOWADAYS, the existing grid structure is changing from vertical to horizontal configuration. The main driving factor for this change is the availability of renewable energy sources at end-user locations. They are mostly in low and medium voltage (MV) levels. The presence of distributed generators will obviously affect the way that the power system is operated. As a result, the interest of producing electricity by applying distributed generating units is increasing. Distribution networks are mostly operated in radial configuration, though they are normally constructed with an alternate route of power supply to ensure backup connections. This construction is to increase the network reliability and minimize the impact of permanent faults. Radial operation of MV feeders offers simple operation, especially in the protection coordination of the feeders. However, the demand of high power quality and reliability is a need of closed loop operation of the network. Thus, the existing protection schemes in distribution networks should be also adjusted in such an adaptive way to guarantee the fault clearing selectivity, particularly in the case that distributed generation (DG) units are connected.

This paper mainly focuses on the effects of DG units on the protection schemes of a closed-loop MV network. The study is conducted for a simulated system that consists of a distribution grid with DG units using SimPowerSystems toolbox. DG units in the test network are represented by three different scenario cases, namely scenario case 1 including microturbines, scenario case 2 containing Combined Heat Power (CHP) plants and scenario case 3 including Diesel generators. Simulations are performed for various three-phase faults at different locations. For each scenario case, a specific protection scheme is applied to the grid in order to evaluate the protection devices' coordination with the presence of DG units. Finally, the results obtained from several case studies are presented and discussed.

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II. Modeling MV network in Matlab/Simulink

A 10kV underground cable network is used for this investigation. The one-line schematic diagram of the network is shown in Fig. 1. The network is supplied from 150 kV grid through a 150/10 kV transformer. This system has two feeders: feeder 1 and feeder 2 which have 4 and 3 sections respectively. Each section has its own protection devices. For meshed operation, directional relays are applied at both ends of each section. In addition, 6 DG units are connected to the network at bus B13, bus B15 and bus B23. DG units used in the test network are three different types, namely diesel generator, microturbine and CHP plants. Modeling and simulations have been performed in Simulink with the help of SimPowerSystems toolbox. Table I describes the type and the power rating of the DG units.

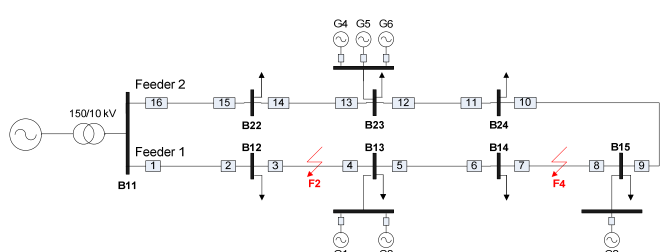


Fig. 1. Schematic diagram of the investigated network with DG

TABLE I
DG Power Ratings

DG Type	Snom [MVA]
Microturbine	0.25
CHP Plant	2.5
Diesel Generator	3.125

Details of the system parameters can be found in appendix

A. The model parameters of the microturbine and its detailed description can be found in [1]. Since the electromechanical behavior is of main interest, the recuperator and the heat exchanger are not included in the model. Both the real power control system model and the mircroturbine model are presented in Fig. 2 and Fig. 3. The CHP plant model is an aggregated model consisting of 10 microturbines as in [2]. The synchronous generator model, the excitation model and the governor model are taken from [3] they represent the operation of the diesel generator. It is a salient pole type that includes the effects of armature windings. Both the excitation system and the governor models are characterized in Fig. 4 and Fig. 5. All generators are connected to the distribution network through transformers. The loads are represented by constant impedances. The external system, to which the distribution network is connected, is assumed to behave as an ideal voltage source.

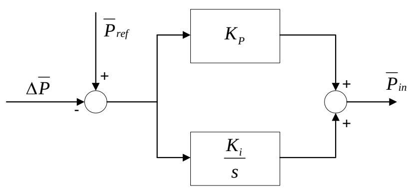


Fig. 2. Microturbine real power control system model.

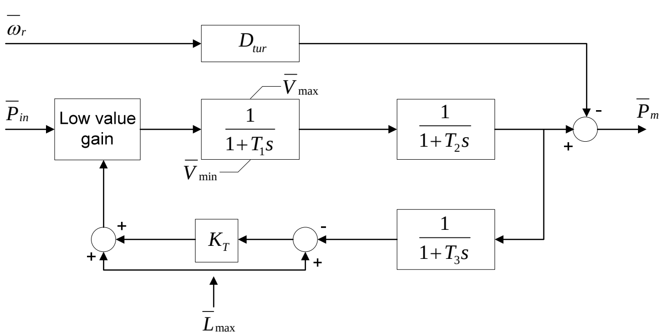


Fig. 3. Microturbine model.

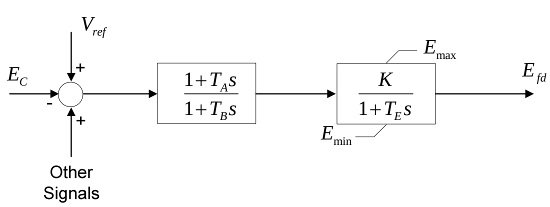


Fig. 4. Excitation system model of a diesel generator

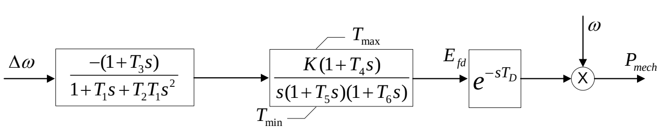


Fig. 5. Governor model of a diesel generator

III. Review of Overcurrent protection

A. Overcurrent relay coordination

Overcurrent relays are common protection devices that are used as a part of primary protection in distribution networks. Overcurrent relays can be instantaneous, definite-time and inverse-time based on tripping time. They will react when the current exceeds the predetermined minimum current value.

In this paper, the investigation mainly focuses on a ring network, thus the protection devices for this ring network are concentrated. It is well known that the protection devices in a multi sources system or a ring system have to be direction sensitive. The directional overcurrent relay is a normal overcurrent relay that has an additional part for detecting the power flow direction. The overcurrent relay needs a current signal to determine if a fault has occurred or not. Since the current measurement does not give the power flow direction, a reference signal is required to determine whether or not the relay should operate. Generally, the reference signal is a voltage.

The protection coordination of ring systems or multisource systems will be explained with the aid of Fig. 6. In this figure, a two-source system including protection relays is depicted. During a fault, both sources contribute to the fault current. To ensure the selectivity, all relays are divided in two groups. The arrows in Fig. 6 indicate the direction of operation. The first relay group which consists of relays 1a, 2a and 3a is set according to the contribution of source 1 while the rest relays are set when only source 2 is considered. Discrimination time t_{dcr} is used to guarantee the relay operation selectivity. Relay 1a time setting t_{1a} in Fig. 6(a) will be:

$$t_{1a} = t_{2a} + t_{dcr} = (t_{3a} + t_{dcr}) + t_{dcr} \tag{1}$$

Similarly, relay 3b time setting t_{3b} will be:

$$t_{3b} = t_{2b} + t_{dcr} = (t_{1b} + t_{dcr}) + t_{dcr} \tag{2}$$

Inverse-time directional relay used in ring system are configured by the same procedure above. The operation time t of this kind of relay is defined by the following expression in IEC 60255 standard:

$$t = \frac{k.\beta}{\left(\frac{I}{I_s}\right)^{\alpha} - 1} \tag{3}$$

Where I and I_s are the fault current and pick-up current respectively, while k is the time multiplier setting. The constants α and β determine the slope of the relay characteristics. For the three standard inverse-time overcurrent relay types, their values are given in table II.

TABLE II
Constants for standard inverse-time overcurrent relays

Relay Type	α	β
Inverse	0.02	0.14
Very inverse	1.00	13.50
Extremely inverse	2.00	80.00

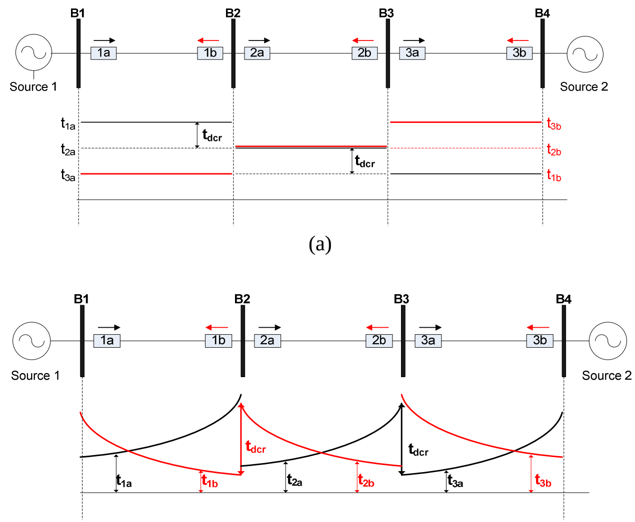


Fig. 6. Relay time coordination for multisource system: (a) directional definite-time relays and (b) directional inverse-time relays.

B. Modeling overcurrent protection

Both definite-time and inverse-time overcurrent relay with a directional unit are model in Simulink. For simplicity, the saturation in current and voltage transformers is ignored. The signals that relays receive come from the primary measurements. Fig. 7 shows the complete block diagram of these relays.

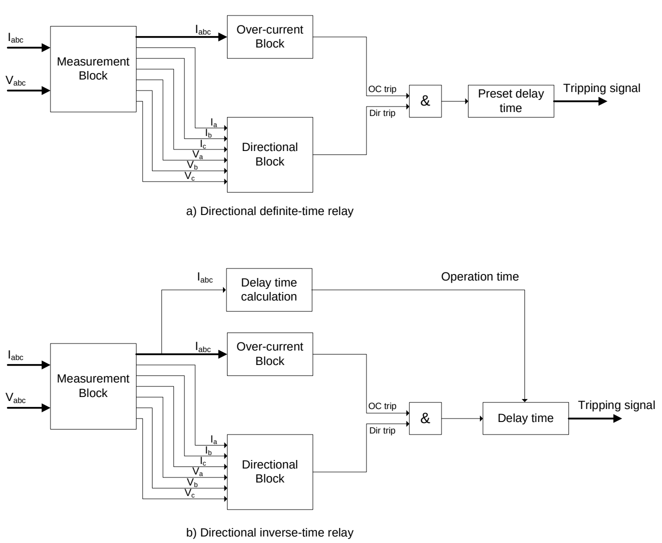


Fig. 7. Directional relay block diagram.

The measurement block not only provides current signal to over-current block but also sends voltage and current signals to the directional block. The directional block detects whether the direction of the energy belonging to the fault current is in forward or reverse direction. If the relay is set in forward direction, the directional trip signal is generated when the fault is in forward direction. Otherwise, the directional trip signal is not generated. The over-current block detects the fault condition and sends tripping signal after a certain time. This operation time depends on what type of the relay is used. If definite-time relay is utilized, the operation time will be set in advance as in Fig. 7(a). In case of an inverse-time relay, the operation time is determined by the delay time calculation block according to (3) as shown in Fig. 7(b). A logical AND-function block is used to combine the trip signals of over-current block and directional block. This AND-function generates the trip signal which trips the circuit breaker.

IV. Simulation Results

The test network which has been introduced above is used as a subject of investigation. Directional relays are applied at both ends of each section as can be seen in Fig. 1. Setting of these relays are followed the guideline mentioned in section III. For convenience, the presence of DG units is ignored when the setting is carried out. The pick-up current of each relay is 50% two-phase fault current end-of-section-line as in [4].

According to IEEE Std. 1547, all DG units should be disconnected by its own protection when the fault occurs after 0.2s [5]. This standard assures that the conventional protection schemes operate properly when there is any fault happened in distribution network. To see the impact of the DG on protection schemes, DG protection is assumed to be omitted. Thus, DG units are always connected to the grid when the fault occurs. This assumption gives us the opportunity to observe the dynamic response of the diverse type of DG units which are connected to the network.

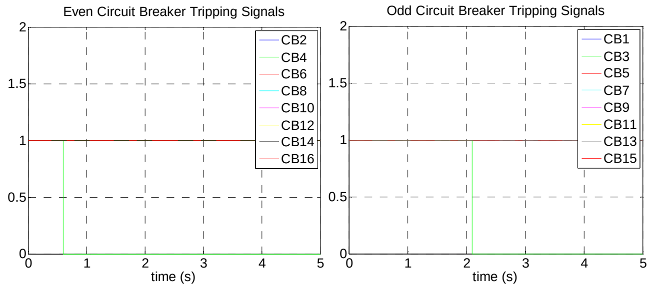
A. Directional definite-time overcurrent protection scheme with traditional time grading

Initially, the directional definite-time overcurrent protection scheme with traditional time grading is applied to the system. The operation time t_{op} setting coordination of each relay is shown in table III. The discrimination time t_{dcr} of 0.3s is used for relay setting.

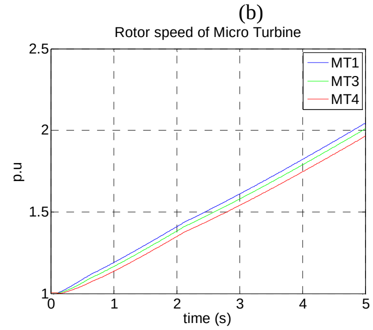
TABLE III
Details of Relay Operation Time Coordination

Relay	# 15	# 13	# 11	# 9	# 7	# 5	# 3	# 1
t_{op} [s]	0.2	0.5	0.8	1.1	1.4	1.7	2.0	2.3
Relay	# 2	# 4	# 6	# 8	# 10	# 12	# 14	# 16
t_{op} [s]	0.2	0.5	0.8	1.1	1.4	1.7	2.0	2.3

The system is subjected to various faults at different locations. All faults are three-phase faults because they are the most dangerous ones for both grid and DG units [6]. In scenario 1, a three-phase fault is applied at 0.1s at location F2 in the case of 20% microturbine penetration level. The protection devices operate correctly. Relay 3 and 4 detect the fault and trip their circuit breakers at 0.6s ant 2.1s respectively as it can be seen in Fig. 8(a,b). The fault duration is 2 seconds, which is higher than the critical clearing time (CCT) of the microtubine units. Hence, all microturbine units become unstable as shown in Fig. 8(c).



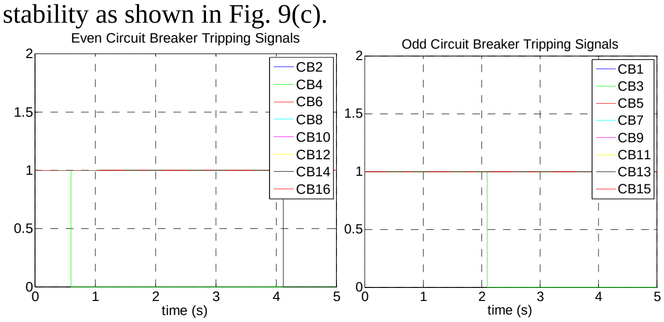
(a) (b)



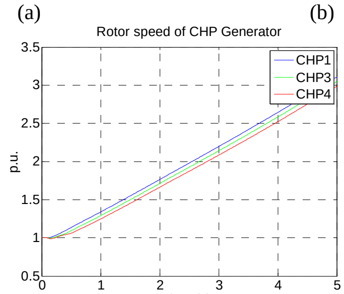
(c)

Fig. 8. (a,b) Circuit breakers tripping signals, (c) rotor speed of microturbine due to fault F2.

In scenario 2, all microturbine units are replaced by CHP plants. The penetration level of 20% is used. A three-phase fault is applied at 0.1s at location F2. The protection scheme performs incorrectly. Relays 3 and 4 detected the fault and tripped their circuit breakers (CB) at 0.6s and 2.1s respectively as it can be seen in Fig. 9(a,b). The fault is cleared and grid configuration is converted to radial. However, normal load current value exceeded the pick-up current of relay 14. Thus, CB 14 was tripped at 4.1s and a part of the grid was isolated. Therefore, all CHP plants lose their stability as shown in Fig. 9(c).



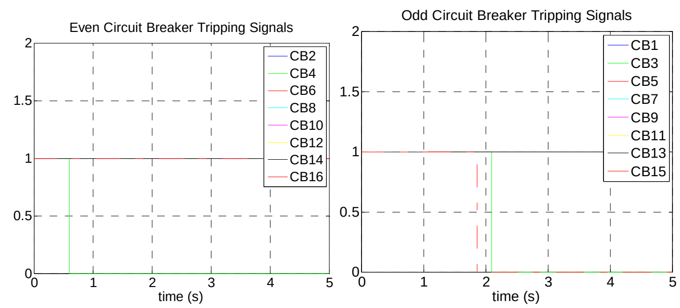
(a) (b)



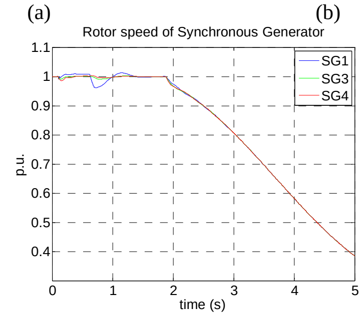
(c)

Fig. 9. (a,b) Circuit breakers tripping signals, (c) rotor speed of CHP plants due to fault F2.

In scenario 3, the test has been repeated when 20 % diesel generator penetration level is considered. From the simulations shown in Fig. 10(a,b) it can be seen that there is a relay giving a false tripping signal . Circuit breaker 4 is opened at 0.6s when it gets the tripping signal from relay 4. At this moment, the network is changed to radial configuration and the fault still exists. Fault currents contributed by all DG units flow to the fault point through the feeder 2. Consequently, the current flowing in feeder 2 is increased and rises beyond the pick-up current of relay 15. Thus, relay 15 sends a signal to trip its circuit breaker at 1.85s. From now on, a part of the network is isolated from the grid. At 2.1s, circuit breaker 3 is tripped. The fault is cleared entirely. Since the isolated part of the network includes all DGs, they are changed to islanding operation condition. It is obvious that total power delivered by all DG units does not meet the load demand. As a result, all diesel generators lose their stability at 1.85s, as in Fig. 10(c).



(a) (b)



(c)

Fig. 10. (a,b) Circuit breakers tripping signals, (c) rotor speed of diesel generators due to fault F2.

The scenario 3 takes place again for a three-phase fault at location F4. It is clear to notice that two expected circuit breakers, CB 7 and CB 8 are opened properly as it can be seen in Fig. 11(a,b). CB 7 and CB 8 are tripped at 1.5s and 1.2s when they get the tripping signals from relay 7 and 8, correspondingly. There are no unexpected tripping signals from other relays. The protection scheme operates correctly in this case. The fault that occurs in section 4 between bus B14 and bus B15 is cleared, and feeder 1 and feeder 2 are switched to radial operation. The fault duration is 1.4s which is lower than the CCT of diesel generators. Therefore, all DG units do not lose their stability during the fault period as in Fig. 11(c).

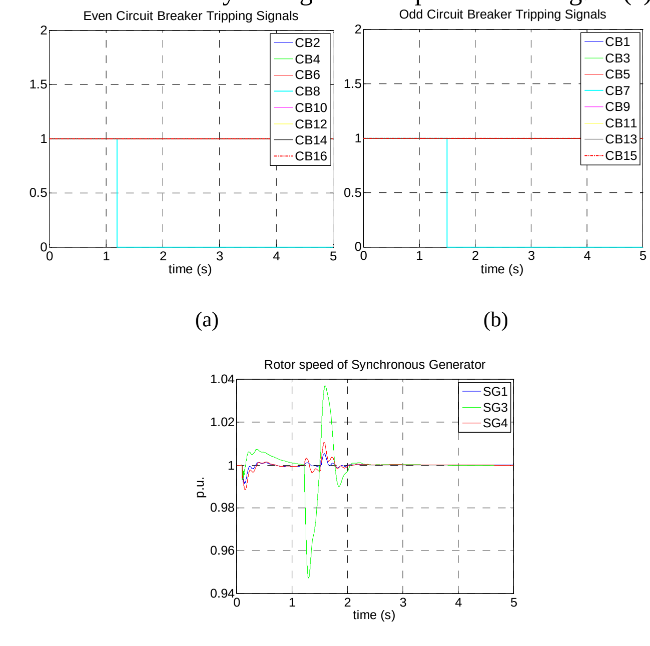


Fig. 11. (a,b) Circuit breakers tripping signals, (c) rotor speed of diesel generators due to fault F4.

B. Directional inverse-time overcurrent protection scheme

The definite-time overcurrent relay coordination shows that the operating time of the relay which is closer to the source is significantly large. The use of inverse-time relay could overcome this disadvantage. Thus, directional inverse-time overcurrent protection scheme are used to replace the previous protection scheme. A very inverse characteristic has been chosen for all relays in order to achieve short operation time when the fault occurs near the source. The relay settings are realized by applying the instruction in [7] with discrimination time of 0.3s. The coordination characteristic of the odd relay group and even relay group are shown in Fig. 12.

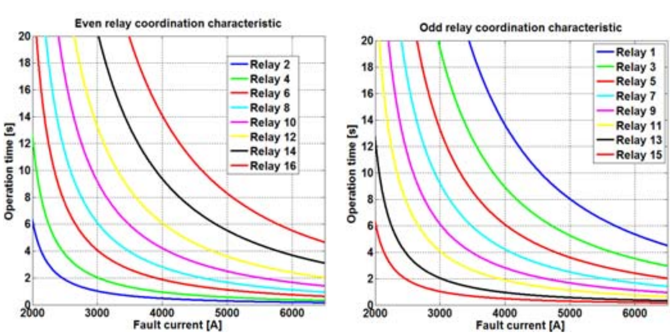


Fig. 12. Relay coordination characteristics of even relay group (a) and odd relay group (b).

A three-phase fault is applied at 0.1s at location F2 in the case of 20% diesel generator penetration level. The protection scheme functions properly. Relay 3 and 4 sense the fault and trip their circuit breaker at 0.86s and 0.88s correspondingly as seen in Fig. 13(a,b). The fault disappears after a duration of 0.78s which is lower than the CCT of all diesel generators. As a result, all DG units still remain in stable condition as seen Fig. 13(c). Compared with the previous test with definite-time protection scheme, the inverse-time relays operates correctly while definite-time relays do not in case of the fault happened at F2 location.

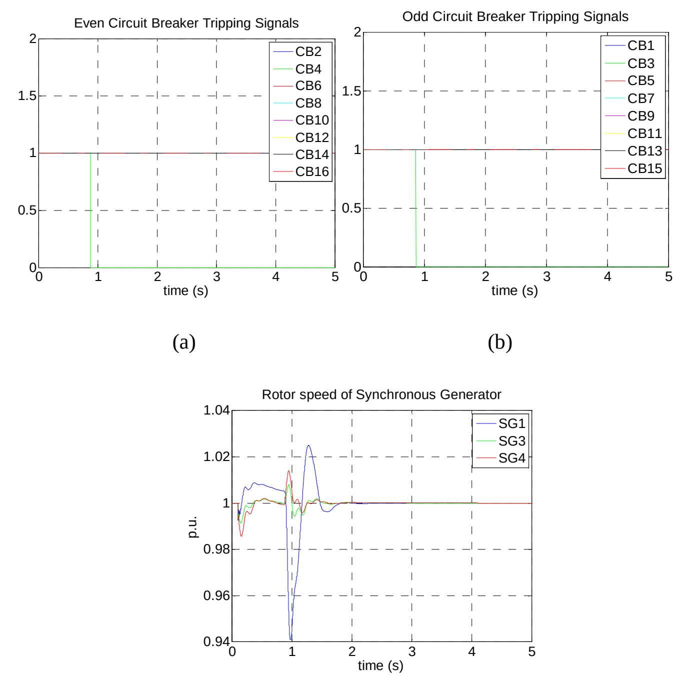


Fig. 13. (a,b) Circuit breakers tripping signals, (c) rotor speed of diesel generators due to fault F2 in case of directional inverse-time protection scheme

The simulation results which are mentioned above describe the impact of DG units on the directional overcurrent protection schemes. It can be said that the definite-time directional protection scheme takes a long time to clear the fault, especially when the fault occurs close to the source. As a result, microturbines and CHP plants are unable to keep their stability when the fault duration is very long. Conventional directional definite-time protection scheme may cause unintentional islanding operation of DG units which is an unexpected situation. Moreover, this protection scheme may perform properly depending on the fault location. It can be inferred that conventional definite-time protection scheme is no longer valid with the existence of DG units in the system. The inverse-time relay can make the protection scheme to operate properly in some situations in which definite-time relay cannot perform correctly. It is obvious that the inverse-time relay employment reduces the speed of protection scheme significantly. However, the fault clearing time is still quite large when compared with the CCT of generators.

V. Conclusions

Several scenarios have been considered to study the influence of DGs on protection schemes of MV network. Simulation results obtained from the study cases are presented and discussed. The results reveal two main problems. The first problem is long relay tripping time for the closed-loop system with DG units connected. Fault clearing time is higher than the CCT of the DG units in most cases. This implies that the protection scheme should be speeded up if we would like to prevent regular DG unit disconnection. The second problem observed is the protective devices' weakness to preserve the relay time coordination with the presence of DG units. When the DG units are not disconnected during the fault, traditional relay time coordination is not valid anymore and thus malfunctioning occurs. Although inverse-time relays may operate correctly in some cases in which definite-time relays perform incorrectly, the fault clearing time of protection scheme is quite large which may cause DG units unstable. It is recommended to do further study about the CCT of DG units and its impact on MV network protection schemes. It can result in coordinating overcurrent relays correctly in order to maintain DG stability. In addition, other protection schemes of distribution grids should be judged precisely in order to get fast response of protection speed. It is the fact that the number of DG units connected to the MV systems is increasing. Thus, it implies that protection schemes should be adaptive in such a way that all DG units connected to the grid do not lose their stability during the fault duration.

VI. Appendix

A. System specifications

- Grid: S_F = 7000 MVA, x/r = 10.

- Distribution cables: r = 0.125 Ω/km, x_L = 0.248 mH/km, x_C = 0.5 μF/km. The distances between two subsequent buses are 1.5 km and 1.25 km for feeder 1 and feeder 2, respectively.

- Transformer: 150/10 kV, 47 MVA.

- Loads: Lumped loads, $P_{L\text{-feeder } 2} = 1.5xP_{L\text{-feeder } 1}$, power factor of 0.9.

VII. References

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