Enhancing the transient stability of distributed generators with adaptive time-overcurrent protection augmented with transient based unit protection

A. N. Pathirana and A. D. Rajapakse

***Abstract*-- This paper investigates the application of a transient based unit protection scheme to implement adaptive characteristics on time-overcurrent relays. Time overcurrent relays located upstream have longer operating times due to the coordination with the downstream relays. This makes the operating time of upstream time-overcurrent relays longer and opens up the possibility of small synchronous generators connected to the distribution grid becoming unstable. In order to prevent that and increase the system reliability, it is proposed to apply adaptive time-current curves depending on the location of the fault as indicated by a transient based unit protection scheme. The resulting lower fault clearing times enable distributed generators to operate stably in grid connected mode of operation or in an islanded microgrid formed by the generators.**

***Keywords*: Adaptive overcurrent protection, transient based unit protection, protection of micro grid**

I. Introduction

Traditional power distribution networks are being transformed into active distribution networks with the interconnection of distributed generation (DG). With worldwide efforts to increase of the utilization renewable energy, the penetration of DG into distribution networks is rapidly growing. Many of these DG units are expected to operate as microgrids in the near future [1][2]. With increasing penetration of DG, protection of active distribution grids with traditional methods becomes problematic [3]. A number of potential problems related to the protection of active distribution systems and micro grids have been discussed in literature [4][5][6].

Time-overcurrent relays are commonly used to provide protection to the distribution networks which are radial in nature. A feature of time overcurrent relay coordination is that the relays closer to the source have slower time current characteristics compared to the relays at far end of the distribution feeders [7]. In active distribution systems and microgrids, longer fault clearing times may cause some of the DG units to become unstable during the network faults. Several studies have shown that very short clearing times are needed to preserve the stability of DG units which generally have a low inertia [8][9]. In order to prevent DGs becoming transiently unstable during remote disturbances, protection systems need to be modified after proper studies. These modifications generally include adjustment of time-overcurrent relay settings. If the proper coordination is unable to be maintained, differential protection methods needs to be adopted [9].

This paper investigates a new hybrid approach where a transient based unit protection scheme is applied to implement adaptive characteristics on time-overcurrent relays which have longer operating times due to the coordination with the downstream relays. The transient based unit protection scheme utilizes Rogowski coils for measuring transients and determines the faulted section of the network by comparing the polarity of the measured transients. The time overcurrent relays employ adaptive settings depending on the location of the fault indicated by the unit protection scheme to minimize the fault clearing times.

Following sections of the paper will describe this hybrid adaptive protection principle and demonstrate its application through detailed simulations in PSCAD/EMTDC, as applicable to an active distribution system as well as for a microgrid situation.

II. Investigated Test Network

Test network shown in Figure 1 contains two 5.5 MVA diesel generators connected to a 13.2 kV distribution system. The DG units are designed to operate as a microgrid in case of loss of mains supply and provide power to critical loads connected to Bus 3 and Bus 2. Although the two generators are of the same capacity, DG2 has a higher inertia. Data of the generator and the network are given in Appendix-A. The loads connected to Bus 2 and Bus 3 draw 9 MW of active power and 2 Mvar of reactive power. A part of the loads amounting to 2 MW is considered to be non-critical and disconnected in the event of losing the grid supply. All the cases studied in this paper are simulated using PSCAD/EMTDC using 1 μs time-step. Primary intention of this paper is to present the methodology in which the use of transient based decision making process to reduce the tripping time of overcurrent relays. Reducing the tripping time of the breakers helps synchronous generators (DG units) to remain stable after a fault which would otherwise trip the DG. In order to clearly demonstrate that fact, a simple test network is used for the study.

Under normal mode of operation in parallel with the grid, both the DG units are operated as constant power generators.

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In case of loss of grid supply, control systems of the two diesel generators are changed. DG2 is switched to isochronous operation to control the frequency in the isolated microgrid. It is assumed that the overcurrent protection scheme of the network has been designed prior to the interconnection of DG units, as such, the protection settings have been determined without considering the two generators. Since the synchronous generators can provide sustained contribution to the fault currents for any type of fault, the coordination of original protection scheme may be affected.

The coordinated time-overcurrent relay curves of the breakers are shown in Figure 2. For faults downstream from the CB23, fault current path is CB23-CB25-CB12. Thus, CB25 should be delayed compared to CB23. The minimum delay between the CB23 and CB25 is 0.2s. A similar minimum delay exists between the curves of CB25 and CB12.

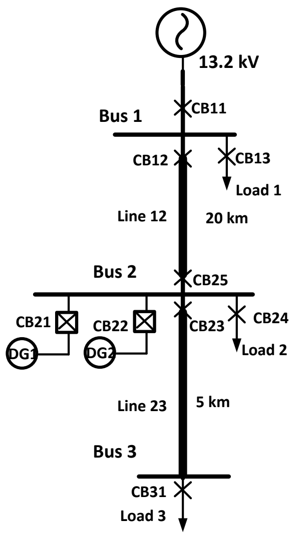


Fig. 1. Investigated distribution grid

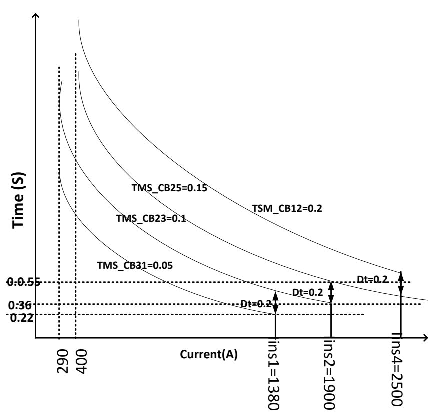


Fig. 2. Coordination of Time overcurrent Relays

III. Potential DG stability problems

A. Case I: Prolonged fault on Line 12

For a fault between Bus1 and Bus 2 in the network shown in Figure 1, the expected response is to remove Line 12 and supply the critical loads at Bus 2 and Bus 3 from the diesel generators. In order to maintain a stable microgrid, governor control of DG2 is changed to frequency control mode. The non-critical load is shed immediately to help stabilize the isolated microgrid.

However, during the fault, the grid power supply to the loads is disrupted and the synchronous generators start to accelerate as their electrical power output is restricted due to low terminal voltages during the fault. If the duration before the fault is cleared is too long, the generators become unable and form an unstable microgrid. The fault clearing time of CB12 and CB25 is dictated by the time-overcurrent protection coordination. On the other hand, operating time of CB25 would be long since the fault current contribution from the DG units is low.

Figure 3 shows the output power, speed and rotor angle of the two DG units after a three-phase to ground fault on Line 12. Following the fault, CB12 and CB25 were opened by the trip signals from the relevant time-overcurrent relays. The trip signal of CB25 is used to change the control modes of the DG units for enabling them to operate as a microgrid. Although the control mode was changed immediately after detection and clearing of the fault, the plots in Figure 3 indicate that the two synchronous generators eventually become unstable and will be tripped by generator protection, jeopardizing the microgrid operation.

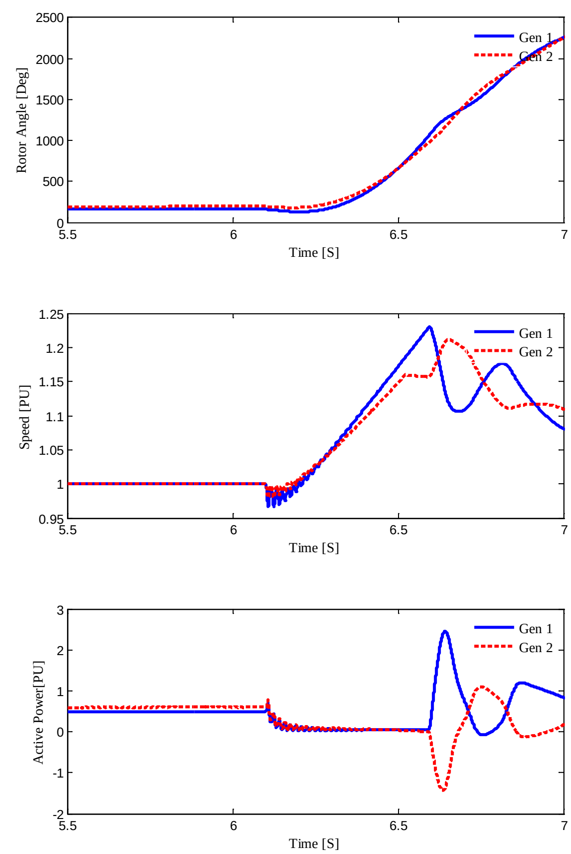


Fig. 3. Power output, speed and rotor angle after solid ground fault-Case I

Circuit breakers CB12 and CB25 operate after a certain delay that is required for the coordination with the downstream breakers. Although this delay is quite acceptable for the network without DG units, it is larger than the critical clearing time of the two generators that from a power island. Even though the fault is isolated and removed from the network, protection relays are unable to do it before the diesel generators become unstable.

B. Case II: Prolonged fault on Line 23

The second case considers a fault between Bus 2 and Bus 3. The fault needs to be cleared by removing Line 23 by opening the breaker CB23, and as a result the loads connected at Bus 3 cannot be supplied. After clearing the fault, the two DG units can continue to operate and supply the load connected to Bus 2 and export excess power to the grid. However, if the opening of relay CB23 is delayed due to coordination with downstream relays, DG units may become unstable and tripped by generator protection, especially if the fault is close to Bus 2.

Figure 4 shows the generator behavior after a three-phase to ground short circuit on Line 23 close to Bus 2. The plots in Figure 4 shows the variations of the output power, speed and the rotor angle of the two diesel generators. For this fault, the two diesel generators quickly become unstable and therefore will be disconnected from the grid by generator protection.

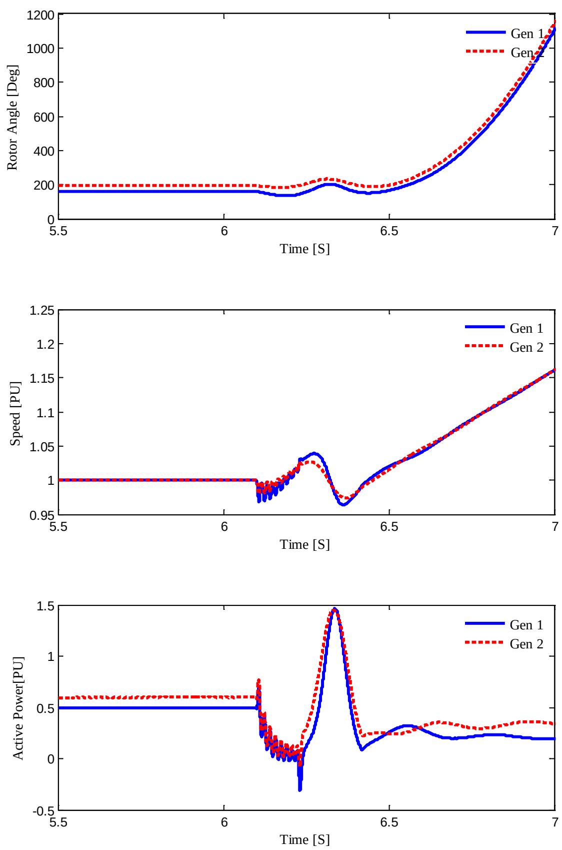


Fig.4. Power output, speed and rotor angle after solid ground fault-Case II

C. Case III: fault during the islanded operation

The third case considers a fault happening while the two DG units are operating as an autonomous microgrid encompassing the network downstream of CB25. In the microgrid, DG2 is operating in isochronous mode controlling the frequency while DG1 is operating with a constant power output. The simulation case considers a solid three-phase to ground fault on Line 23 close to Bus 2. The expected response for this fault is to remove Line 23 by opening CB23, and continue to supply the load connected to Bus 2. However, if the opening of CB23 is delayed due to coordination with downstream relays, the two diesel generators become unstable and tripped by the generator protection. This is demonstrated in the simulation results shown in Figure 5. The graphs show the variations of output power, speed and rotor angle of the two generators following a three-phase to ground fault on Line 23.

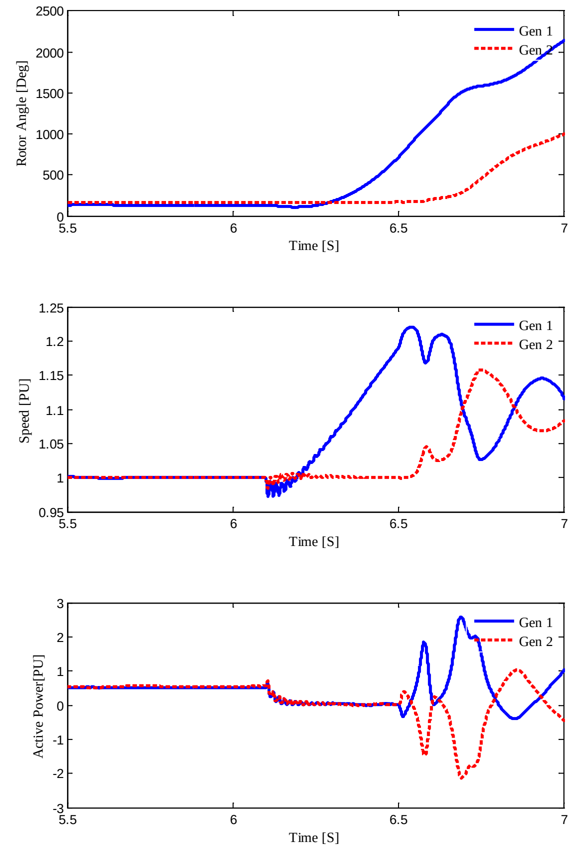


Fig. 5. Power output, speed and rotor angle after solid ground fault-Case III

The three simulation cases discussed above clearly show that the faults needed to be removed within certain critical clearing time (CCT) to maintain the stability of the generators and form a stable power island.

IV. FACTORS AFFECTING THE STABILITY OF GENERATORS

In this section, the sensitivity of critical clearing time for few factors under typical contingencies are briefly studied through simulations carried out in PSCAD/EMTDC. In these studies, DG units are assumed to be operating in the grid connected mode prior to the faults. The critical clearing time is considered as the maximum fault duration for which the generators can remain stable after clearing the fault. There is no control mode change in either of the generators since it was assumed that generator control mode is initiated by the trip signal of CB25. This study gives simple understanding of the typical values of the critical clearing time and the effects of inertia constant of the synchronous generators, location of the fault, and fault impedances on the critical clearing time. The results are summarized in Table I.

DG units are generally associated with low inertia constants and therefore prone to become unstable very quickly. The results show that low impedance faults on lines connected to the generator bus (at any distance from bus) are the worst type of disturbance. Such faults have the lowest critical clearing times. Faults closer to the generators have lower critical clearing times. Higher the distance to the fault from the generators, longer the critical clearing times as expected.

TABLE I
SYSTEM PARAMETER EFFECTS ON CCT

Inertia (S)		Fault Distance from Bus 2 (Km)	Fault Resistance (Ω)	CCT (S)
G1	G2			
1.0	1.0	10	0.01	0.52
1.0	1.0	10	10.0	1.00
1.0	1.0	0.1	0.01	0.34
1.0	1.0	0.1	10.0	0.40
0.6	0.5	10	0.01	0.36
0.6	0.5	10	10.0	0.52
0.6	0.5	0.1	0.01	0.30
0.6	0.5	0.1	10.0	0.42

V. USING ADAPTIVE SETTINGS FOR TIME OVERCURRENT RELAYS

With the existing settings of the overcurrent relays at CB23 and CB25, the CCT values given in Table I are difficult to achieve. In order to achieve faster fault clearing times, the settings of the overcurrent relays can be changed to a faster time-current characteristics curve. But this cannot be achieved without losing the coordination with the downstream relays. A possible solution is to use faster time-current curve for the faults that cause stability problems and a coordinated time-current curve for rest of the faults. For example, for faults between Bus 1 and Bus 2, a faster time-current setting can be selected for CB12 and CB25 in order to remove the fault within the CCT of the generators. For the faults downstream from Bus 2, normal time-current curve can be used to ensure the coordination with the downstream circuit breakers. However, in order to apply the correct time-current curve, relays need to know (very quickly) the segment in which the fault has occurred. For this purpose, use of a transient based unit protection scheme is proposed. The scheme is described in Section VI.

VI. TRANSIENT BASED UNIT PROTECTION SCHEME

Traditional protection principals use power frequency components of the voltages and currents to determine the operation of a relay. Transients are treated as unwanted signals and filtered out. In transient based protection focus is only on the transient signal and not the steady state signal. Transients generated due to faults can have a bandwidth of several hundred kilo hertz, and detectable transients are present even for faults occurring at small inception angles. The proposed transient based unit protection determines whether a fault is inside or outside the protected zone by comparing the polarity of the transients superimposed on the currents measured at two ends of the protected line segment. Although this appears similar to a line differential protection scheme, the actual measured signals are not exchanged between the two ends: only the polarities of the initial transients on each of the phase currents are sent to the other end via a telecommunication link. Thus the bandwidth requirement of the telecommunication link is minimal. The polarities are compared on phase by phase basis. The logic for determining the location of fault is shown in Table II.

TABLE II
LOGIC OF THE POLARITY COMPARISON

Polarity of initial transient at		Location of the fault
End-1	End-2	
Positive	Positive	Inside protected segment
Positive	Negative	Outside protected segment
Negative	Positive	Outside protected segment
Negative	Negative	Inside protected segment

In the proposed scheme, high frequency transients are measured using Rogowski coil sensors to avoid bandwidth limitations of the conventional current transformers. The Rogowski coil output voltage signals, which are proportional the rate of change of measured currents, are used for polarity comparison. Discriminating external and internal faults based on polarity comparison of initial current transients can be used in any power network, but is especially suitable for medium voltage distribution networks where voltage transducers are not commonly available. Some examples of the output signals from the Rogowski coil sensors, obtained through simulations of the test network, are shown in Figure 6. These waveforms were obtained by the sensors located at two ends of Line 12, on Phase-A conductor. The sensor locations and the respective protected zones are as indicated on Figure 7.

Output voltages from the Rogowski coils which are attached to each phase are initially filtered in order to remove the 60 Hz component. Remainder of the signal contains only the transients created by the fault. The filter used to remove the power frequency component is a high pass filter with a cut-off frequency of 1 kHz. Figure 8 (a) shows filtered transient signals for an internal fault (ABC-G), i.e. a fault on Line 12 and Figure 8 (b) shows those for an external fault, a fault on Line 23 (ABC-G). As seen in the figure, transients may not be arriving at the two ends at the same time, due to propagation delay. Polarity of the initial transient (positive/negative) is determined locally after a fault, and sent to the relay at the other end of the protected line segment. Once the polarity signal is received from the opposite end, a relay can use the logic shown in Table II to decide whether the fault is internal or external to the zone protected by the two relays. Polarity of the transient can be determined in less than 1 ms after the arrival of initial travelling wave, and thus the location of the fault (whether inside or outside the protected zone) can be determined very fast provided that a fast telecommunication is available between two relays.

Polarity detection of a transient signal can be affected by the noise level contained in the signal. The detection threshold should be set well above the noise level. Some test measurements carried out by the authors at an HVDC converter station switch yard showed that the magnitude of high frequency noise is comparatively smaller than the output generated by the fault current transients.

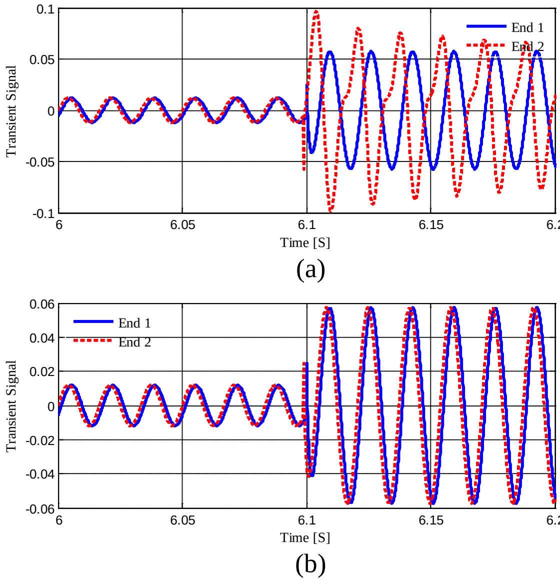


Fig. 6. (a) Rogowski coil voltage signals for Internal fault, and (b) Rogowski coil voltage signals for external fault

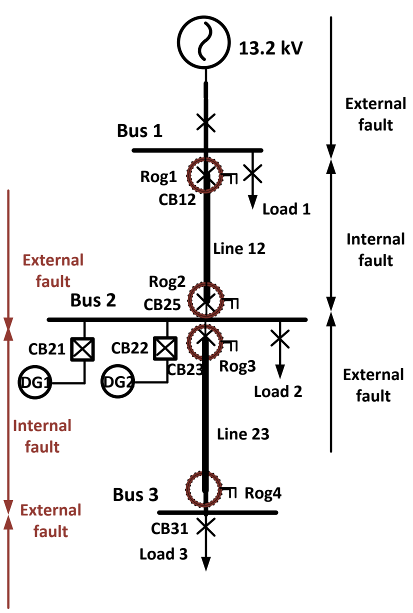


Fig. 7. Internal faults and external faults are determined relative to the measurement locations

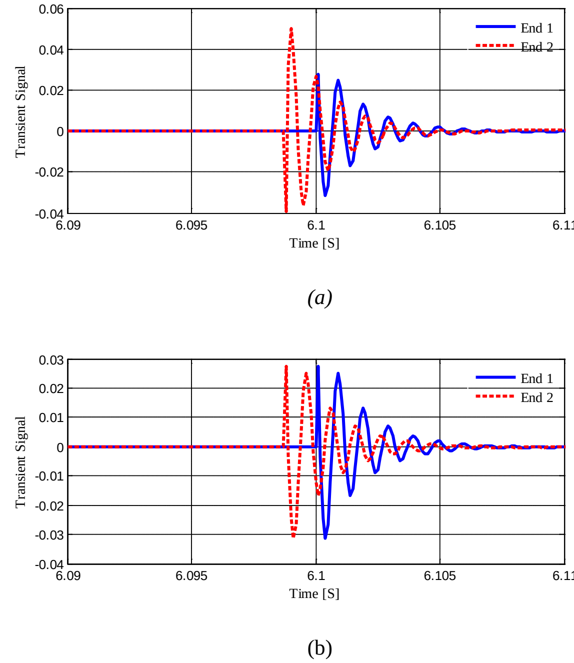


Fig. 8. (a) Filtered Rogowski coil voltage signals for Internal fault, and (b) Filtered Rogowski coil voltage signals for external fault

VII. Proposed Hybrid Protection Scheme

Transients can be generated by faults as well as by non-fault events, but these non-fault events could also be picked up by the transient based unit protection scheme described in Section VI. The breakers should not be tripped to isolate the line segment for the events like switching of loads or capacitor banks, switching of generators, and temporary faults. Line segments need to be tripped and isolated only in case of the permanent faults. Thus the transient based unit protection scheme cannot be used as a stand-alone system, without being supervised by a method for identification of fault generated transient events. In literature, knowledge based methods have been proposed for classification transient events [10], but they are too complicated for application at MV distribution systems that are often subjected to topology changes.

This paper proposes a simple approach to overcome the reliability issues with transient based unit protection method by combining it with time-overcurrent protection. In the proposed hybrid approach, the transient based unit protection is used as an adaptive mechanism for time-overcurrent protection. Based on the location of the fault (internal/external) determined by the transient based unit protection scheme, the overcurrent relays chose a faster or slower time-current curve. This helps to speed up the trip decisions for faults inside the protected zone. Because the actual trip signals are always issued by the overcurrent relays, malfunction of protection due to non-fault related transients is prevented.

The shorter fault clearing times achieved with the hybrid adaptive protection system help to preserve the stability of DG units during close up faults.

VIII. SIMULATION RESULTS

A. Case I: A fault on Line 12 during normal operation

In case I, response of the generators for a fault on Line 12 with the proposed hybrid protection scheme is investigated. Flow chart in Figure 9 shows the procedure for changing the relay settings for the overcurrent relays at CB12 and CB25.

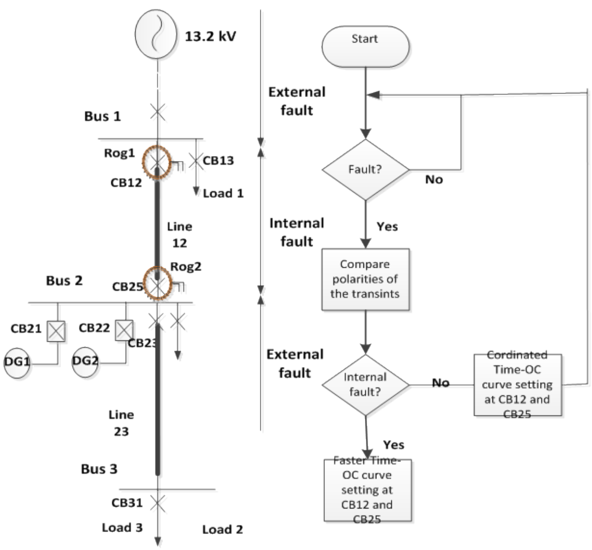
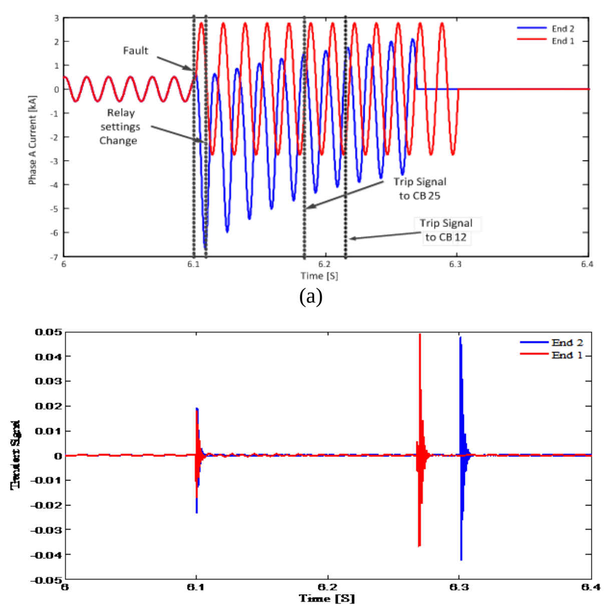


Fig. 9. Methodology for changing the relay settings



(a)

(b)

Fig. 10. (a) Fault currents at two ends and sequence of operations of the protection scheme (b) Transient signals at two ends

The current waveforms of Phase-A at two ends and the corresponding transient signals extracted by the transient sensors are shown in Figure 10. Based on the polarity of transients, the unit protection system determines that the fault is internal, and applies faster time-current curves (corresponding to TMS=0.05 in this example) for the relays at CB12 and CB25. The transient based unit protection only takes few tens of micro seconds to determine the polarity of the transients, and dispatch the information to the other end. Once the signal is received after the communication delay (assumed 10 ms in this study considering the shorter distances involved) a relay can determine whether the fault is inside Line12 or not. Based on the faster time-current curve, CB25 now opens faster compared to case shown in Section III. Note that transients generated at the time of opening the breakers will be seen by the unit protection sensors of Line 23. However, the unit protection of Line 23 will see them as an external event. Furthermore, since the actual trip signals are issued by the overcurrent relays, these transients have no adverse effect on the operation of the protection scheme.

Figure 11 shows the variation of the rotor angles, active power and speed of the two generators after the fault. Since CB25 was able to remove the fault sooner, DG units managed to form a stable power island.

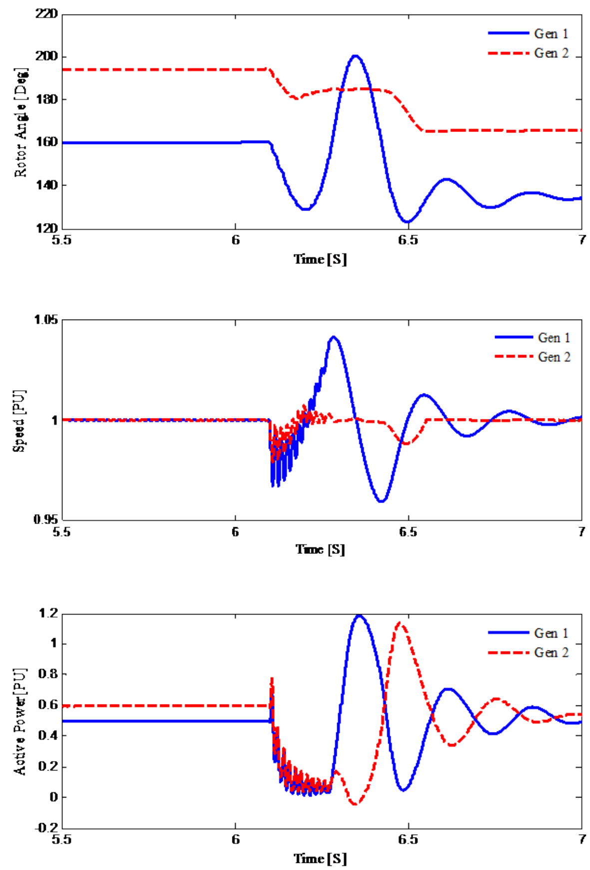


Fig. 11. Power output, speed and rotor angle after solid ground fault

B. Case II Fault on Line 23 under normal operation

This is the same scenario considered under Case II in Section III, but simulated with the new hybrid protection scheme. Following the fault, the transient based unit protection system quickly finds that the fault is within Line 23 and informs the relay at CB23 to switch to the faster time-current curve. With faster clearing of the fault by opening CB23, both DG units were able to remain stable as seen in Figure 12. Both DG units continued to operate in the constant power control mode and supply power to Load 2 and the utility grid.

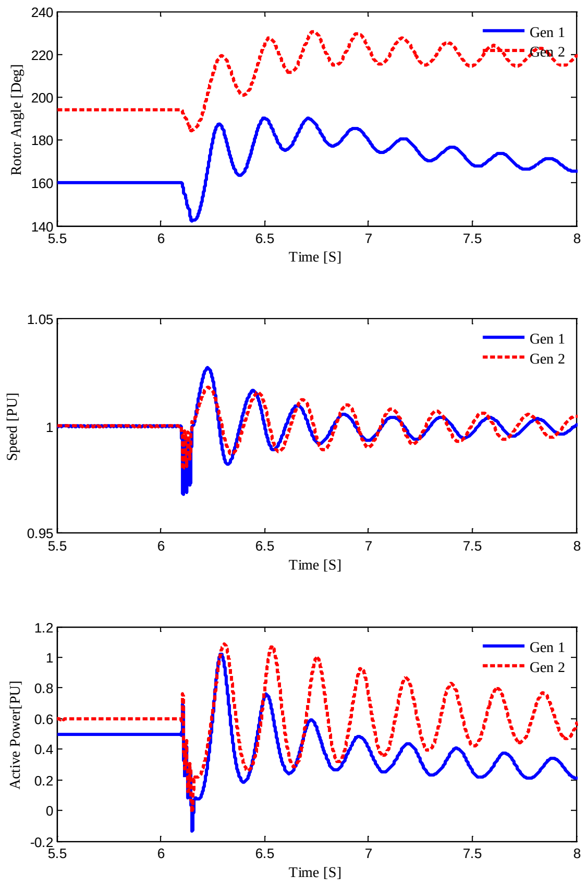


Figure 12: power output, speed and rotor angle after solid ground fault

C. Case III Fault during the islanded operation

In this case, the protection problems when operating as an islanded microgrid are considered. A three-phase to ground fault was simulated on Line 23 at a distance of 1km from Bus 2. As there is no grid connection, fault currents provided by the diesel generators are smaller. Based on the determination by the transient based unit protection that the fault is on Line 23, the relay at CB23 switches to faster time-current curve (TMS=0.05) and trips CB23 faster compared to Case III in Section III. This helps the two DG units to maintain the stability of the smaller island consisting of two generators and the load connected at Bus 2. Figure 13 shows Rotor angle, active power and speed of the two generators after the fault.

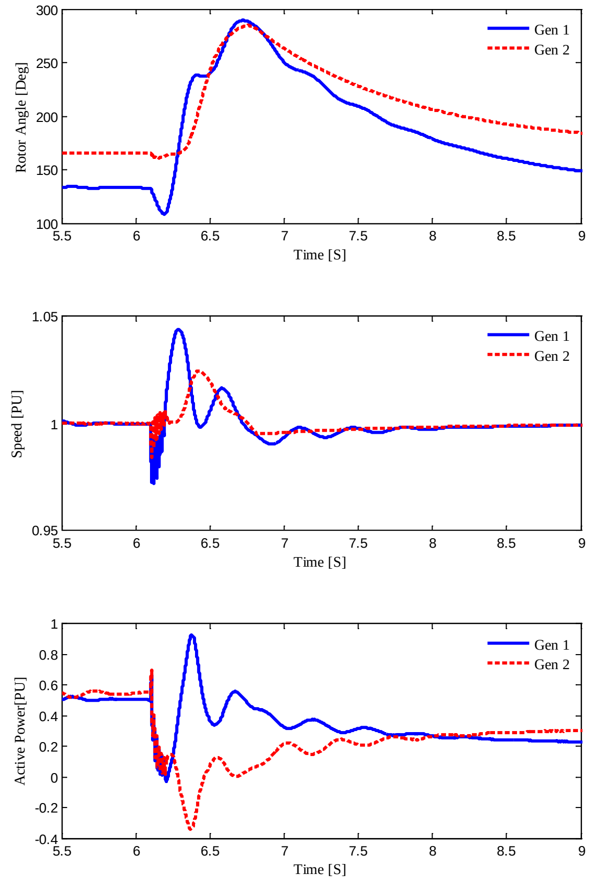


Figure 13: power output, speed and rotor angle after solid ground fault

IX. CONCLUSION

Considering a small test network, it was demonstrated that the conventional time-overcurrent protection may not be able to preserve the stability of small distributed generators after network faults. As a solution, a transient based hybrid protection scheme with adaptive time-overcurrent curves was proposed. It was shown through simulations that the faulted segment can be quickly identified by comparing the polarity of the current transients measured at two ends of the protected segment. The fault location information provided by the transient based unit protection is used to change the time-current curves used by the time-overcurrent relays. The simulation experiments showed that with the proposed new protection scheme, the stability of the distributed generators can be ensured under variety of fault scenarios. The proposed method will be tested for a more complex larger network in future research.

X. APPENDIX A

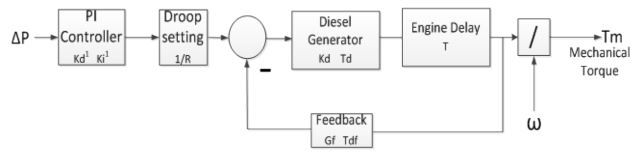
DIESEL GENERATOR PARAMETERS

Parameter	Value	Parameter	Value
Rated MVA	5.5	$X_q{}'$	0.228 pu
Power MW	3.0	$X_q{}''$	0.200 pu
Vrated	4.00 kV LL	R_a	0.002 pu
Frequency	60 Hz	$T_{do}{}'$	4.300 sec
X_a	0.130 pu	$T_{do}{}''$	0.032 sec
X_d	1.790 pu	$T_{qo}{}'$	0.850 sec
$X_d{}'$	0.169 pu	$T_{qo}{}''$	0.050 sec
$X_d{}''$	0.135 pu	H	DG1- 0.4 sec DG2- 0.6 sec
X_q	1.710 pu		

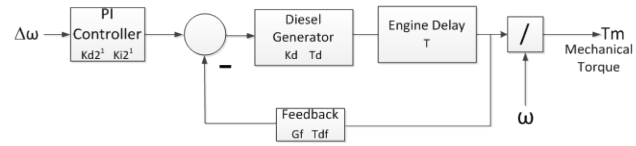
GOVERNOR SYSTEM PARAMETERS

Parameter	Value
Power controller proportional gain Kd[1]	0.001
Power controller integral gain Ki[1]	1
Droop Setting R	DG1 - 5% , DG2 - 10% (Grid mode)
Diesel engine dynamics gain Kd	10
Diesel engine dynamics time constant Td	0.1 (Sec)
Engine delay T	0.1 (Sec)
Feedback controller gain Gf	1
Feedback controller time constant Tdf	0.01 (Sec)
Limits	Tmax = 1(pu); Tmin = 0
Speed controller proportional gain Kd2[1]	1
Speed controller integral gain Ki2[1]	1

A. Grid connected operation



B. Frequency control mode



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