

Application of a Fault Current Limiter To Minimize Distributed Generation Impact on Coordinated Relay Protection

G. Tang, *Member, IEEE*, and M. R. Iravani, *Fellow, IEEE*,

Abstract—Radial power distribution systems, common in North America, typically use coordinated relay protection for fault protection. However, the rising interest in distributed generation (DG) poses a problem, as DG causes such systems to lose their radial nature, disrupting the coordinated relay protection.

The use of a fault current limiter (FCL) is proposed to limit the effect of the DG on the coordinated relay protection scheme in a radial system during a fault. This paper shows that the FCL enhances the stability of and limits the transient stresses on the DG. Such a device is only recently more plausible with the ongoing developments of a new hybrid mechanical/electrical fault current limiter.

To determine the effectiveness of the FCL for the proposed application, test systems are introduced, the effects of DG on the relay protection system are examined, and the effectiveness of FCL to mitigate these effects are determined.

Index Terms—Relay protection, power distribution system, distributed generation, fault current limiter, reclosers, power electronics, GTO.

I. INTRODUCTION

THE majority of distribution systems in North America are operated in a radial configuration, predominant because of the simplicity of their operation and the economy of the overcurrent protection [1], [2]. Both of these advantages are due to the fact that in any branch of a radial system, power only flows in one direction.

In such distribution systems, the protection equipment needs only to sense current, with no need to detect direction [2]. Commonly used for protection are inverse time overcurrent relays [3], set up for relay coordination [2], [4], [5]. The purpose of relay coordination is to provide a reliable and redundant protection scheme, while minimizing the disruption to customers [1].

Distributed Generation, DG, is defined as an electric power source connected directly to the distribution network of a power system [6]. It is estimated that by the year 2010, 20-30% of all new installed power generation will be introduced in the form of distributed generation [7]–[9].

A. Protection Problem Caused by Introduction of DG to Radial System

With the introduction of DG into a radial distribution system, the radial power flow nature is lost [10]. Depending on the loading conditions, it may not be possible to re-coordinate the relays [4]. It is well known that protection devices in a multisource system need to be direction-sensitive [2], [3], and the relays must be coordinated for faults where the current may flow in either direction [9]. Even if the loading is such that the current will still only flow in one direction, DG may reduce the reach of the relays and disturb their coordination [1]. Another problem introduced by adding DG is an increase in fault current levels [11], causing problems as the inverse overcurrent relays are coordinated based on the prospective fault currents.

B. Existing Proposed Solutions

Several ideas have been introduced as possible solutions to the problem of relay overcurrent protection in systems with DG, including microprocessor based reclosers [12] and adaptive protection [3]. While these solutions may technically work, they involve very high initial equipment costs: to replace the existing relays with microprocessor based relays in [12] and to implement special breakers and a substation computer to control these breakers in [4].

Furthermore, technical complications of these solutions include the necessity of altering the relay curves when DG is removed from service or placed into service in [12] and ensuring the security of communication lines between a substation computer and protection relays in [4]. Because of these complications and the high cost of these solutions, they are not viable for existing distribution systems today.

C. New Approach - Fault Current Limiter

Most of the proposed solutions for the described problem involve modifying the existing protection scheme to accommodate the DG. Such solutions tend to be expensive to implement because of equipment costs, which reduces the benefit of adding DG.

An alternative approach would be to consider the idea to negate or, at the very least, minimize the contribution of the DG during a fault, while adding no adverse effects to the network during normal steady state non-fault operation. Thus, a proposed solution is to implement a fault current limiter that

G. Tang is with the Department of Electrical and Computer Engineering, University of Toronto, CANADA. (email: glen@ele.utoronto.ca)

M. R. Iravani is with the Department of Electrical and Computer Engineering, University of Toronto, CANADA. (email: iravani@ecf.utoronto.ca)

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would limit the current of the DG during a fault, and would otherwise allow the unimpeded flow of power from the DG into the system. The advantage of this solution over others is that it does not require the existing relay protection scheme in a distribution system to be changed.

II. FAULT CURRENT LIMITERS

Before technologies can be considered for the application of limiting a distributed generator's fault current contribution, the operating conditions and requirements of such a limiter must first be established. The existing technologies can then be evaluated for their suitability for such an application by ensuring that any proposed device meets the requirements.

The first requirement for the FCL is that it must operate at the distribution voltage level. According to a utility survey in [13] in which utilities were asked to describe their present distribution systems and predicted future system, utilities responded that the most prevalent voltage class is at 15kV. A typical radial distribution system is shown in Figure 1.

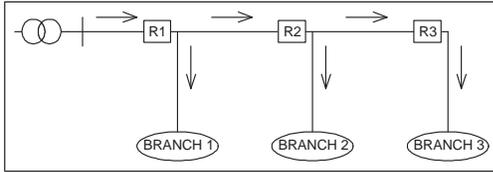


Fig. 1. Typical radial distribution system with relay protection

The distribution system shown in Figure 2 is an example in which the addition of DG to the system in Figure 1 would impact the existing relay coordination. If a fault were to occur in *Branch 1* or *Branch 3*, the DG would likely contribute to the fault current, with the current flowing from the DG back onto the main feeder, towards the fault. The current that flows through relay *R2* would then be different than if the DG had not been added, so that the coordination between the 3 relays, *R1*, *R2*, and *R3*, would be affected.

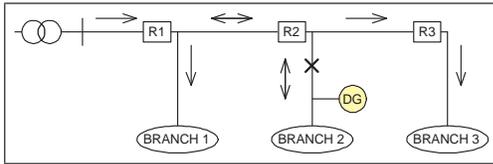


Fig. 2. Radial distribution system with added DG.

To prevent the DG from supplying fault current onto the main feeder, the FCL should be placed between the DG and the main feeder, along the distribution line off of the main feeder leading to the DG and *Branch 2* as shown by the **X** in Figure 2. The fault current limiter's operation must follow specific guidelines in such a placement. When there is no fault in the system, the FCL must not affect the system. If a fault occurs in the system outside of *Branch 2*, the FCL must limit the current that will flow from the DG to the fault. In the last mode of operation, for faults inside *Branch 2*, the FCL must not operate, preserving the fault current seen by the relay, *R2*.

To be able to operate in the manner described, limiting the fault current in one direction while having no effect on

the other, the fault current limiter needs the ability to be selectively turned on and off based on the direction of the sensed current. Finally, for the FCL to be viable, it will need to introduce almost no losses during the steady-state operation of the system, and be able to sustain repeated operations with low maintenance.

A. Passive Limiters

Traditionally, fault current limiters implemented in practice and researched have been of the passive type: devices that are permanently connected to the power system and do not need to be "turned on" or controlled by an external signal. When a fault occurs, the nature of these devices is such that the overcurrent is automatically reduced or limited. Passive devices include series inductors [14], and superconducting fault current limiters [15], [16].

While series inductors are inexpensive and require low maintenance, they cause a voltage drop during steady state operation and have poor limiting performance compared to newer FCL topologies. Superconducting fault current limiters have no resistive or ohmic losses during steady state operation, and can effectively limit a fault current, but uncertainties regarding cooling losses, regular maintenance, and the ongoing research to develop more economically cooled high temperature superconductor devices reduce the viability of such devices. Additionally, passive limiters will limit fault currents in both directions natively, which is not the desired operation for use in the application described in this paper.

B. Solid State Limiters

With advances in switch technology that have made them suitable for the voltage and power levels necessary for power applications, power electronic switches can be used to build devices that could sustain repeated operations with high reliability and without wearing out [17]. There are 2 main types of solid state current limiters: resonance based devices and impedance switch-in limiters.

Resonance based limiters include devices proposed in [18]–[20]. The basis for their operation is that because power is transmitted at a fixed AC sinusoidal frequency, the impedance of a LC-resonant circuit can be tuned such that the impedance of the device during steady state operation is nearly zero. During a fault, power electronic switches isolate a capacitor or inductor from the device, introducing a large impedance into the system. The limitations of resonance based limiters are that they can cause voltage sags during faults, current limitation effectiveness declines as distance from substation increases, large infrastructure for capacitors is required, and tuning of devices is necessary to ensure low impedance.

Impedance switched bypass limiters include devices proposed in [21]–[24]. The basis for their operation is that an impedance is placed in series with the distribution line. A pair of Gate-Turn-Off (GTO) thyristor switches are placed in shunt with this impedance, and operated during alternate half-cycles of the voltage waveform to present a low impedance path. In the event of a fault, the gating signals to the GTO switches are blocked, resulting in a large impedance being

introduced into the system, limiting the current. However these limiters introduce switching losses as the power flows through the power electronic switches during steady state operation and the long term reliability of these devices is questionable because of the continuous switching.

Recently, in 2004, Meyer, Koellensperger, and De Doncker proposed several new topologies of switched current limiters in [24], but came to the conclusion that the high operation expenses for losses made all other costs (i.e. initial cost, maintenance) negligible.

C. Solid-State Switch/Mechanical Switch Hybrid Current Limiter

While solid-state fault current limiters offer many advantages to the passive limiters, the switching losses are a major drawback. Mechanical breakers and switches exist that have virtually no closed circuit losses, but they cannot operate quickly and so are unable to commutate the voltage across their contacts.

A novel idea is to use a power electronic switch path as a commutation aid for a mechanical switch to open. With a power electronic switch path providing an alternate low impedance current path, the mechanical switch should be able to open without the arcing problems typically associated with mechanical switches opening at high voltage. In [25], Steurer et al. proposes such a hybrid fault current limiter (and circuit breaker) based around a new fast mechanical switch designed by the same authors. The device is capable of operating in a system with a single phase voltage of 12kV rms and a steady state current of 1kA. Figure 3 shows the Hybrid FCL/Circuit Breaker proposed in [25].

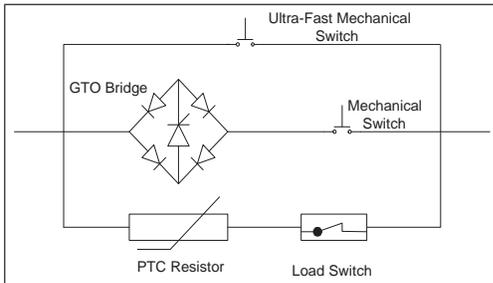


Fig. 3. Novel hybrid fault current limiter/circuit breaker.

During the steady state operation of the system, all three mechanical switches are closed and the GTO in the bridge is gated on. When a fault occurs, the Ultra-Fast Mechanical Switch opens within several hundred microseconds [25]. After the complete commutation of the current to the GTO bridge, the GTO is gated off, forcing the current through the positive temperature coefficient (PTC) resistor, whose resistance increases as its temperature rises. The mechanical switch in series with the GTO bridge disconnects shortly thereafter to prevent a high voltage across the GTO bridge. The load switch interrupts the limited current for circuit breaker operation.

This hybrid fault current limiter meets the original application requirements as described in Section II. However, the circuit breaker operation of the proposed device is not needed

in use in the application described in this paper, so the fault current limiter in Figure 3 can be modified to omit the load switch. Additionally, for the simulations, the PTC resistor in the device is replaced by a fixed value resistor, a feasible implementation given the energy dissipation capabilities of high voltage resistors currently available.

III. SIMULATIONS

The impact of the FCL on a test system will be determined by its effect on the DG currents, transient stability, and transient torques during and subsequent to a fault. The effect of the DGs and the FCL on the coordinated relay protection will be examined by observing the relay timing following faults at various locations. Specifically, it is of interest to determine if DGs have a negative impact on the relay timing in a radial system, and whether the FCL can mitigate that impact or not.

A. Test System

The test system chosen is a radial distribution system connected to the infinite bus through a step-down transformer. There is a single three-phase 2.4MW resistive load at the very end of the feeder. Fault protection in the system is provided by three coordinated relays, one at the beginning of the feeder (BRK1), one at one-third of the length of the line (BRK2), and one at two-thirds of the length of the line (BRK3). The relays are inverse time overcurrent breakers coordinated to protect this system.

Two new loads are added to the radial system at intermediate points along the long feeder. In addition, a DG at each of the two new load sites is installed, to locally provide the power used by the new loads. The DG augmented system is shown in Figure 4.

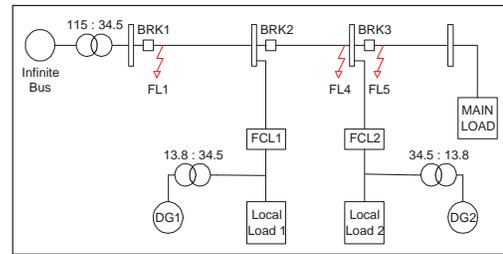


Fig. 4. Radial test system with DG and local loads.

Each of the new loads is rated at 5.9MW and 1.6MVar, and the distributed generation units are 6MVA synchronous machines. The DG and local load are connected to the bus on the main feeder through the FCL.

1) *Test Scenarios:* To determine the impact of the DG generators on the relay protection, three fault scenarios are used. The fault imposed on the system is a three-phase-to-ground fault and the fault locations are shown in Figure 4. The first scenario to be tested is the fault at FL1 (fault location 1) with the relay that should trip being BRK1. The second scenario to be tested is the fault at FL4 (fault location 4), and the relay that should trip is BRK2. The third scenario to be tested is the fault at FL5 (fault location 5), almost identical to the second scenario except that the relay that should trip is BRK3.

B. Fault Location 1 - FL1

Three cases are tested in this fault scenario. The first case is the test system without the DG units and local loads being in service. The second and third cases incorporate the DG units and the local loads, but in the former, the current limiters are not activated.

1) *Test System without DG and Local Loads:* Without the DG subsystems, the fault current supplied by the infinite bus reaches a peak of 10kA. The relay, BRK1 trips at about 90.5 cycles after fault inception.

2) *Test System with DG Subsystems:* With the addition of the DG subsystems, BRK1 trips as before, at 90.5 cycles after the fault starts. The operation of the FCL does not affect the timing of breaker trip, nor the Breaker 1 current.

Though the BRK1 breaker current is not affected in this scenario by the DGs and loads or the FCLs, the FCLs do have major impacts on the DG currents. Figure 5(a) shows the current contribution of DG1 to the main feeder without FCL, and Figure 5(b) shows the same current with FCL.

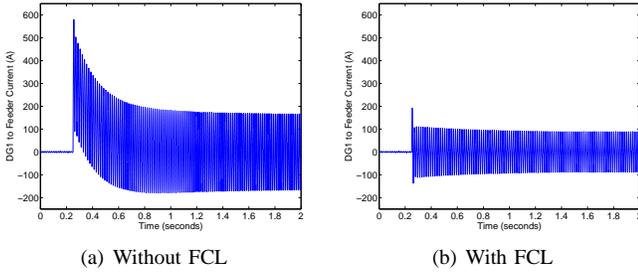


Fig. 5. DG1-to-main-feeder current for fault at location 1.

Without the FCL in operation, the DG1 fault current peaks at 600A before settling down to 370A peak-to-peak. With the FCL, the fault contribution from DG1 is reduced to 190A peak to peak. Prior to the instant of fault inception, DG1 supplies Local Load 1, and its current exchange with the main feeder is insignificant, as seen in Figure 5(a) and (b). The currents for DG2 shows a similar trend to the DG1 currents.

Another effect of the FCL on the system is on DG stability. To demonstrate DG stability, the electrical torques of the generators are examined. Without the FCL, DG1 becomes unstable (torque reaches zero) and its electrical torque oscillates. With the FCL, the torque does not show the same large oscillations. Figure 6(a) shows the electrical torque of DG2 without FCL, and 6(b) shows the same torque with the FCL in operation.

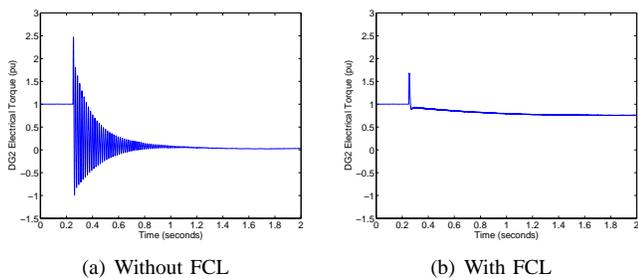


Fig. 6. DG2 electrical torque for fault at location 1.

DG2 is unstable without the FCL in operation as the torque oscillates from -1 to 2.5 per unit, reaching zero per unit. With the FCL, the torque does not exhibit the same large oscillations.

Lastly, the torsional torque between the turbine and generator is examined. Figure 7(a) shows the torsional torque of DG1 without FCL, and 7(b) shows the same torque with FCL.

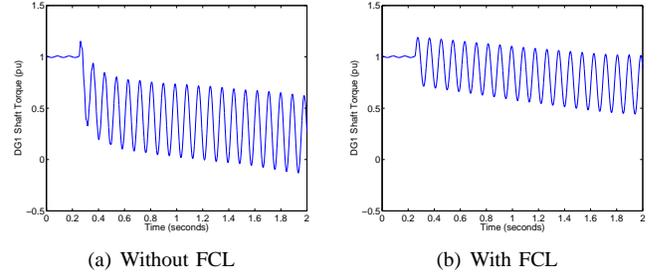


Fig. 7. DG1 torsional torque for fault at location 1.

The torsional torque of DG1 oscillates with a peak-to-peak value of 0.7 per unit. However, with the FCL in operation, this oscillation is reduced to 0.45 per unit. The results for DG2, for both with and without FCL are similar to those for DG1.

C. Fault Location 4 - FL4

As with the simulations with a fault at FL1, three cases are tested: one case without DGs, a second case with DGs but no FCLs, and a third case with DGs and FCLs.

1) *Test System without DG Subsystems:* For a fault at location FL4, the fault current seen by BRK2 reaches a peak of 2.2kA. The relay, BRK2, trips 39.1 cycles after the fault inception.

2) *Test System with DG Subsystems:* With the DGs in service, the current supplied by the infinite bus is the main component, but the DG units have a significant contribution to the fault current. BRK2 trips 20ms earlier than without the DG subsystems in service, at 37.9 cycles after the fault first starts.

With the FCL, BRK2 trips at 38.9 cycles after the fault starts, only one-fifth cycle earlier than the scenario without the DG subsystems. Figure 8(a) shows the BRK2 breaker current for the DG augmented system with no FCL, and Figure 8(b) shows the current with FCL.

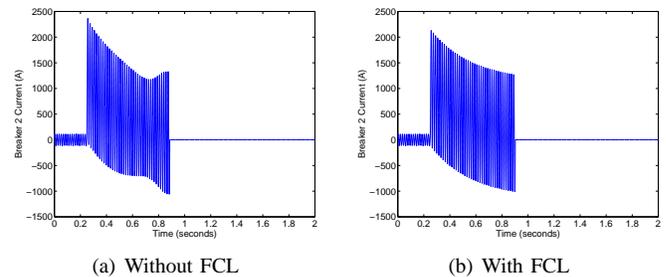


Fig. 8. BRK2 breaker current for fault at location 4 with DG subsystems.

With the FCL, the BRK2 breaker current, Figure 8(b), is almost identical to the case with no DG. Figure 9(a) shows

the current of DG1 to the main feeder without FCL, and Figure 9(b) shows the same current with the FCL.

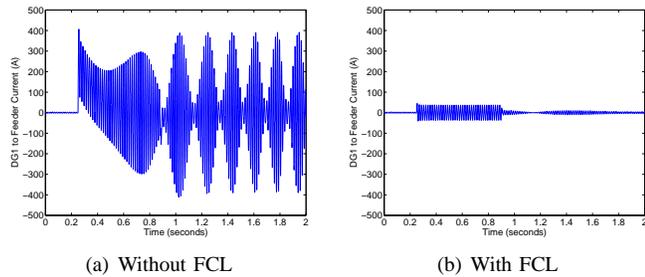


Fig. 9. DG1-to-main-feeder current for fault at location 4.

Without FCL, the DG1 fault current peaks at 400A and the generator becomes unstable, experiencing large current oscillations. With the FCL, the generator remains stable and DG1 fault current is reduced to 100A peak-to-peak. Without the FCL, the DG2 fault current contribution peaks at about 750A before settling down to 400A peak-to-peak. With the FCL, this current is reduced to 190A peak-to-peak.

As with the fault scenario at FL1, the next step is to examine the machine torques. Figure 10(a) shows the electrical torque of DG1 without FCL, and 10(b) shows the same torque with the FCL in operation.

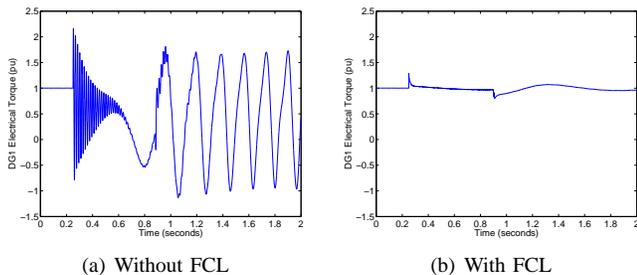


Fig. 10. DG1 electrical torque for fault at location 4.

Without FCL, the electrical torque of DG1 oscillates, the DG becomes unstable and large oscillations continue after the fault is cleared. With the FCL, the torque oscillations are prevented.

For DG2 in the scenario without the FCL, the electrical torque oscillates and the DG becomes unstable (zero torque). With the FCL, the DG remains stable. Figure 11(a) shows the torsional torque of DG1 in this fault scenario without FCL, and 11(b) shows the same torque with the FCL.

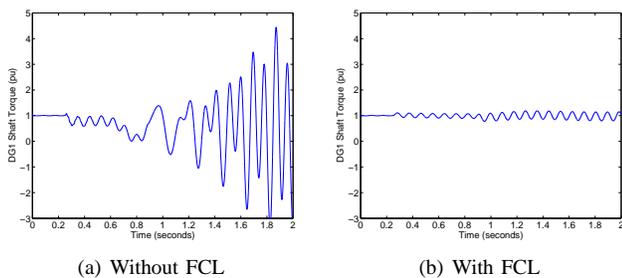


Fig. 11. DG1 torsional torque for fault at location 4.

The torsional torque of DG1 shows that the generator is unstable, with large oscillations in the range of -3.0 to 4.5 per unit. With the FCL in operation, the fault is almost unnoticed, showing only a brief transient peak before returning to around 1 per unit.

For DG2, without the FCL, the torsional torque shows large amplitude oscillations. With the FCL in place, the oscillations are reduced.

D. Fault Location 5 - FL5

This fault location is almost the same as for FL4, with the difference being that FL5 is in the reach of a faster breaker, which prevents DG1 from becoming unstable.

E. Relay Timings

To determine the effect of the DGs and the FCL on the relay coordination, the relay timings are examined. Table I shows the impact of the FCL on the timing of fault removal for the case studies in the previous sections. The presence of DGs results in a maximum of 8.69% change in the breaker operation time. The use of FCL reduces this maximum change to 4.09%.

Fault Loc.	Breaker	Scenario	Trip Time (cycles)	Diff. in Cycles	Time Diff (%)
FL1	BRK1	No DG	90.46	—	—
FL1	BRK1	DG, no FCL	90.46	0	0
FL1	BRK1	DG, with FCL	90.46	0	0
FL4	BRK2	No DG	39.09	—	—
FL4	BRK2	DG, no FCL	37.90	1.19	3.04
FL4	BRK2	DG, with FCL	38.90	0.19	0.49
FL5	BRK3	No DG	9.78	—	—
FL5	BRK3	DG, no FCL	8.93	0.85	8.69
FL5	BRK3	DG, with FCL	9.38	0.4	4.09

TABLE I
RELAY TIMINGS IN TEST SYSTEM.

Although the use of FCLs reduced the impact of the DGs on the coordination of the relay protection (breakers BRK1, BRK2, and BRK3), the impact of the DGs on the system even without the FCLs is not significant.

Table II shows the impact of the DGs and the FCLs on the same study system (Figure 4) for the same fault locations, with the exception that Local Load 2 is not in service, and DG2 supplies its rated power to the system. Therefore, the contribution of DG2 to the fault current is significantly higher. In this case, the presence of the DG units (without FCLs) can result in a maximum reduction of 36.30% in the tripping time (occurring with a fault at FL5, breaker BRK3 tripping). However, the use of the fault current limiters can limit this maximum reduction to 6.54%, which is a vast improvement and is potentially acceptable, without a need to change the relay protection settings of the breakers on the main feeder.

Table III shows the impact of the DGs and the FCLs on the study system (Figure 4) with faster relay settings and Local Load 1 disconnected from service such that DG1 supplies its rated power to the system. Without FCL, the impact of the DGs on the tripping times of both BRK2 for a fault at FL4

Fault Loc.	Breaker	Scenario	Trip Time (cycles)	Diff. in Cycles	Time Diff (%)
FL1	BRK1	No DG	90.46	—	—
FL1	BRK1	DG, no FCL	90.46	0	0
FL1	BRK1	DG, with FCL	90.46	0	0
FL4	BRK2	No DG	39.09	—	—
FL4	BRK2	DG, no FCL	35.6	3.49	8.93
FL4	BRK2	DG, with FCL	37.1	1.99	5.09
FL5	BRK3	No DG	9.78	—	—
FL5	BRK3	DG, no FCL	6.23	3.55	36.30
FL5	BRK3	DG, with FCL	9.14	0.64	6.54

TABLE II

RELAY TIMINGS IN TEST SYSTEM, LOCAL LOAD 2 DISCONNECTED.

and BRK3 for a fault at FL5 (59.90% and 40.00% respectively) is significant and unacceptable. With the FCLs, however, the impact of the DGs on the BRK2 and BRK3 tripping times are effectively limited to 14.85% and 8.00% respectively.

Fault Loc.	Breaker	Scenario	Trip Time (cycles)	Diff. in Cycles	Time Diff (%)
FL1	BRK1	No DG	50.00	—	—
FL1	BRK1	DG, no FCL	45.16	4.84	9.68
FL1	BRK1	DG, with FCL	48.92	1.08	2.16
FL4	BRK2	No DG	20.00	—	—
FL4	BRK2	DG, no FCL	8.20	11.80	59.90
FL4	BRK2	DG, with FCL	17.03	2.97	14.85
FL5	BRK3	No DG	5.00	—	—
FL5	BRK3	DG, no FCL	3.00	2.00	40.00
FL5	BRK3	DG, with FCL	4.60	0.40	8.00

TABLE III

RELAY TIMINGS IN TEST SYSTEM, FASTER RELAY SETTINGS, LOCAL LOAD 1 DISCONNECTED.

IV. CONCLUSION

In this paper, a novel hybrid mechanical/electrical fault current limiter is shown to be able to reduce the impact of a DG on the existing coordinated relay protection in a distribution system to tolerable levels (within 10 to 15% of original tripping times). Additionally, it is shown that the FCL can maintain the stability of and reduce the stresses on a DG during a ground fault.

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Glen Tang received his B.Sc degree in electrical engineering in 2003 from the University of Calgary and M.A.Sc in electrical engineering from the University of Toronto in 2005. He has previously worked with ABB Switzerland and the University of British Columbia.

M. Reza Iravani (M85, SM00, F03) received his B.Sc. degree in electrical engineering in 1976 from Tehran Polytechnique University and M.Sc. and Ph.D degrees also in electrical engineering from the University of Manitoba in 1981 and 1985 respectively. Currently he is a professor at the University of Toronto. His research interests include power system dynamics and power electronics.