Restoration of Directional Overcurrent Relay Coordination in Distributed Generation Systems Utilizing Fault Current Limiter

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***Abstract*—A new approach is proposed to solve the directional overcurrent relay coordination problem, which arises from installing distributed generation (DG) in looped power delivery systems (PDS). This approach involves the implementation of a fault current limiter (FCL) to locally limit the DG fault current, and thus restore the original relay coordination. The proposed restoration approach is carried out without altering the original relay settings or disconnecting DGs from PDSs during fault. Therefore, it is applicable to both the current practice of disconnecting DGs from PDSs, and the emergent trend of keeping DGs in PDSs during fault. The process of selecting FCL impedance type (inductive or resistive) and its minimum value is illustrated. Three scenarios are discussed: no DG, the implementation of DG with FCL and without FCL. Various simulations are carried out for both single- and multi-DG existence, and different DG and fault locations. The obtained results are reported and discussed.**

***Index Terms*—Directional overcurrent relay coordination, distributed generation (DG), fault current limiter (FCL), looped power delivery system (PDS), short-circuit analysis.**

NOMENCLATURE

A, B, C	Relay characteristic constants.
$CDGL$	Number of candidate DG locations.
CTI_j, i	Coordination time interval for backup-primary relay pair (j, i) (in seconds).
fl	Fault location.
i, j	Relay indices.
I_{fi}	ith relay near-end-fault current (in amps).
$I_{fj,i}$	jth relay fault current for near-end fault at the ith relay (in amps).
I_{pi}	ith relay pickup current (in amps).
IFCL	Inductive reactance FCL (in per unit).
J	The objective function (in seconds).
LDC	Local distribution company.
M_i	ith relay multiple of pickup current.
$M_{j,i}$	jth relay multiple of pickup current for the ith relay near-end fault.
N	Total number of system directional overcurrent relays in the system.
NDG	Total number of DGs in the system.
PDS	Power delivery system.
$RCTI\_j, i$	Revised coordination time interval for the backup-primary relay pair (j, i) (in seconds).
Ri	Relay unit i.
RFCL	Resistive FCL (in per unit).
SDG	Individual DG capacity.
t_i	Operating time of the ith primary relay for near-end fault at i (in seconds).
$t_{j,i}$	Operating time of the backup jth relay for a near-end fault at the ith relay (in seconds).
TDS_i	Time delay setting for the ith relay.
Z_FCL_i	ith DG associated FCL impedance (in per unit).

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I. INTRODUCTION

LOOPED power delivery systems (PDS) (subtransmission and primary distribution systems) are typically used to ensure power continuity and a system's reliability. In such PDS, the commonly used protection devices are inverse time overcurrent relays [1], which sense both fault current values and directions [2]. These relays are coordinated to provide a reliable redundant protection scheme while minimizing load interruption [2] and [3]. However, introducing distributed generation (DG) into the PDS territories alters the existing protection practice.

DGs are defined as electric power generating units that are: small size (few kilowatts to megawatts), mostly compact, and utilize new and modified technologies. DGs are installed at/near an electrical load and owned by customers, independent power producers, and/or electric utilities [4]. Introducing DG into the PDS has both positive [5]–[9] and negative impacts on system design and operation. One of the negative effects of DGs is system protection, especially the disturbance caused to the existing relay coordination [1], [3], and [10]. This disturbance is caused by the change in value and direction of both the system's power flow (under normal operation) and short-circuit current (under fault conditions) [6] due to DG implementation. The severity of DG impact is affected by DGs: size, location, technology type, and method of interconnection with the existing PDS [1].

Therefore, researchers venture to implement possible solutions to overcome the overcurrent relay coordination problem for PDS with and without DGs. In case of PDS without DG, a lot of literature has proposed solving the relay coordination problem. In [11], the author reported an approach to break all system loops and started to coordinate the breakpoint for both directions. In [12], a linear graph theory approach was used to determine a set of breakpoints, which was extended in [13]. Furthermore, optimization approaches were used to minimize the relay operating times. In [14], linear programming implementing simplex and generalized reduced gradient methods were introduced to optimize the relay time multiplier settings and pickup currents. A simplex two-phase method is proposed to determine the optimal directional overcurrent relay settings for online adaptive protection in [2]. This proposed adaptive method requires all relays in the system to be microprocessor based. Other optimization techniques used dual simplex [15], [16] and genetic algorithms [17].

On the other hand, for PDS with DG, solving the identified relay coordination problem is still under development. In [7], the impact of DG on the system short-circuit current level is examined. The authors suggested checking the required protection selectivity, each time a new DG is installed, which may need revising some relays settings. In [3], the authors illustrated the possibility of maintaining the required coordination in radial systems, if there is enough margin between relay curves. Otherwise, the relay parameters have to be reset to achieve revised relay curves. Developing the discussion in [3], the authors suggested the use of microprocessor-based reclosers to solve the fuse-recloser coordination problem in [18]. Furthermore, to prevent DG reconnection without synchronism, the authors introduced disconnecting all DGs downstream of the recloser before a recloser action. To solve the problem of disconnecting all downstream DGs, a system-independent adaptive protection scheme is presented to achieve the fuse-relay coordination in [1]. It is based on using a main substation locating relays to isolate the faulty zone and its DGs, which require remote communication capabilities. Furthermore, the authors indicated that this scheme is not suitable for low DG penetration. The illustrated discussion and methods in [1], [3], and [18] are practically valuable for systems with microprocessor-based relays. In [19], the paper introduces the use of FCL in a radial distribution system to eliminate the control complexity and high capital costs. However, the authors did not tackle the problem mathematically, validate its application in looped systems, or provide a value for FCL impedance.

In general, FCL is a series device that is considered to be hidden for the PDS (zero/low impedance) in normal operation, but takes fast action to limit the instantaneous magnitude of the short-circuit current during fault situations to a preset value by inserting a predesigned high impedance value [20]. Several FCL technologies and applications are reported in [21]–[22] and [27].

This paper proposes a new approach, based on implementing FCL as an attractive option, for solving the directional overcurrent relay coordination problem associated with DG-looped PDS. It introduces the use of an FCL connected in series with DG, as shown in Fig. 1, to locally limit the DG drawn current at its interconnection bus to a looped PDS only during fault. Therefore, the proposed approach is presented to restore the original relay coordination in case of DG existence, without either altering the original relay settings or disconnecting DG from the PDS, which is the current practice during fault [23].

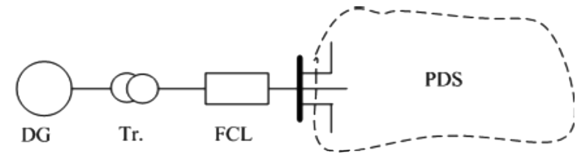

Fig. 1. FCL–DG system interconnection.

Furthermore, the existing protection devices and schemes are used without a need for new breaker installations, relay technology replacement, or complicated communication systems. A solid-state FCL [inductive reactance FCL (IFCL) or resistive FCL (RFCL)] is assumed. A developed integrated optimization model/MatLab code is used to validate the proposed approach. The optimization model is formulated with modified constraints to include the local distribution company (LDC) engineer's experience. The most optimal relay settings are obtained by minimizing the total primary relays operating time in the original PDS without DGs in a two-phase process. The developed MatLab code performs: the load flow and short-circuit calculations taking into consideration system loading and providing relay operating times. By integrating the obtained results and an LDC engineer's experience, the FCL's impedance (Z_FCL) type and its minimum feasible value, required to restore the original PDS relay coordination, are provided with new revised coordination time intervals $(RCTI)$ between relays. In Section II, the proposed approach for relay coordination restoration and the mathematical model formulation are discussed. In Section III, the PDS understudy and several operating scenarios are illustrated. In Section IV, these scenarios are carried out and results are discussed to cover different possibilities that can exist in a looped PDS. Finally, in Section V, the conclusions are summarized.

II. Proposed Relay Coordination Restoration Approach

Due to the presence of DG in PDSs, the original relay coordination is lost. The current LDC's practice is to disconnect all DGs during the fault to restore the original relay coordination. However, this will lead to the loss of DG power even for temporary faults; and synchronization problems for reconnecting those DGs into the PDS after clearing the fault. The other LDC option is to replace the existing relays with microprocessor-based relays and communication systems for adaptive control to obtain new relay settings. However, this option is considered to be economically expensive and highly dependable on a complex control.

Therefore, the proposed approach restores the original relay setting by locally installing FCL to DGs in series to limit their fault currents. Thus, by suppressing the DG impact during fault, the PDS can be pushed toward its original situation as if there is no DG existing. Based on the mentioned suppression, the existing relay settings can be used without disconnecting DGs. The proposed approach is explained as follows:

A. Determination of the Original Relay Coordination

The operating time of overcurrent relay for a looped PDS is a function of fault location and short-circuit current level. As it is impossible to satisfy the backup relays coordinated during individual minimum primary relay operating time, therefore as an acceptable assumption, a sum of all primary relays operating time is minimized [2] and [24]. The two-phase proposed optimization model is mathematically formulated and described in detail in (1)–(4). In Phase I, the model is formulated as nonlinear programming, followed by Phase II where the model is formulated as linear programming.

The total time objective function in (1), for N primary relay near-end-fault is minimized, subject to various constraints (2)–(4). These constraints are relay setting constraints and backup-primary relay constraints.

$$\text{Minimize..}\quad J=\sum_{i=1}^{N} t_i. \tag{1}$$

The coordination constraints are:

1) Relay Setting: Each relay pickup current (I_p) has minimum and maximum values. These values are chosen based on the value of the maximum load current flowing in the relay and the available relay tap setting. Similarly, the relay time delay setting (TDS) has minimum and maximum limits based on the relay current-time characteristic. Two sets of constraints are introduced for each optimization model's phase.

For Phase I

$$\left.\begin{array}{c} I_{pi\,\min.} \le I_{pi} \le I_{pi\,\max.} \\ TDS_{i\,\min.} \le TDS_i \le TDS_{i\,\max.} \end{array}\right\} \quad \forall i \in N. \tag{2a}$$

For Phase II

$$\left.\begin{array}{r} I_{pi} = I_{piFixed} \\ TDS_{i\,\min.} \le TDS_i \le TDS_{i\,\max.} \end{array}\right\} \quad \forall i \in N. \tag{2b}$$

2) Relay Operating Time: If the primary relay near-end-fault current and the backup relay current for the same fault are known, all relay operating times can be calculated based on their pickup current and TDS from the following constraints for both phases:

$$\begin{aligned} t_i &= TDS_i\left\{\frac{A}{M_i^C-1}+B\right\}, \quad M_i=\frac{I_{fi}}{I_{pi}} \\ t_{j,i} &= TDS_j\left\{\frac{A}{M_{j,i}^C-1}+B\right\}, \quad M_{j,i}=\frac{I_{fj,i}}{I_{pj}}. \end{aligned} \tag{3}$$

3) Backup-Primary Relays Coordination Time Interval: To ensure relay coordination, the operating time of the backup relay has to be greater than that of the primary relay for the same fault location by a coordination time interval (CTI). The value of the CTI is chosen based on the LDC practice, which consists of: relay overtravel time, the breaker operating time, and safety margin for relay error. Similar to constraints (2), two sets of CTI constraints are illustrated.

For Phase I

$$t_{j,i}-t_i \ge CTI\_j,i \quad \forall i,j \in N. \tag{4a}$$

For Phase II

$$t_{j,i}-t_i \ge RCTI\_j,i \quad \forall i,j \in N. \tag{4b}$$

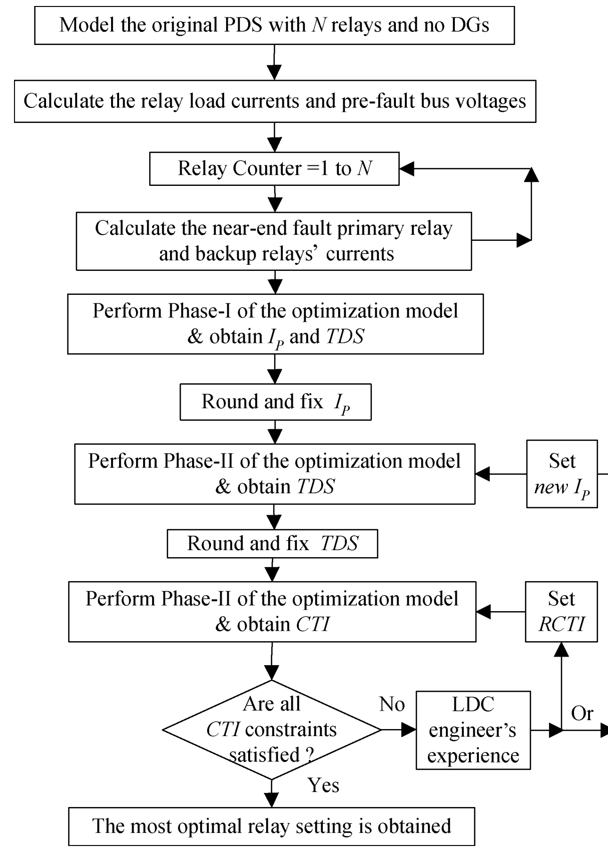

Fig. 2. Determination of the original relay coordination.

Following Fig. 2, the most optimal relay settings (I_p and TDS) are obtained by engaging the solution obtained from the optimization model, with the LDC engineer's experience.

B. Restoration of the Original Relay Coordination

The proposed approach introduces the use of FCL to restore the original relay coordination. The process of determining the FCL type and calculating its minimum impedance will be discussed below. In general, the value of individual Z_FCL is a function of its associated individual DG capacity (SDG), number of DGs (NDG), candidate DG location $(CDGL)$, and fault location (fl) in the PDS as shown in (5)

$$\begin{aligned} Z\_FCL_i &= f(SDG,NDG,CDGL,fl) \\ &\qquad \forall i \in NDG, NDG \in CDGL. \end{aligned} \tag{5}$$

Following Fig. 3, the step-by-step process for determining the FCL type and its minimum impedance value is shown. By knowing the NDG existing in the PDS at the same time and their SDG and $CDGL$, (3) and (4) can be used to calculate the relays operating times and identify backup-primary relay pairs that have CTI less than a preset $RCTI$, while maintaining the original relay settings unaltered. The $RCTI$ value is chosen based on the LDC engineer's experience and the feasible cost of commercially available Z_FCL.

The process of selecting Z_FCL value is iterative, starting from a zero value or a low value based on the commercially available Z_FCL. This value is increased until the lowest

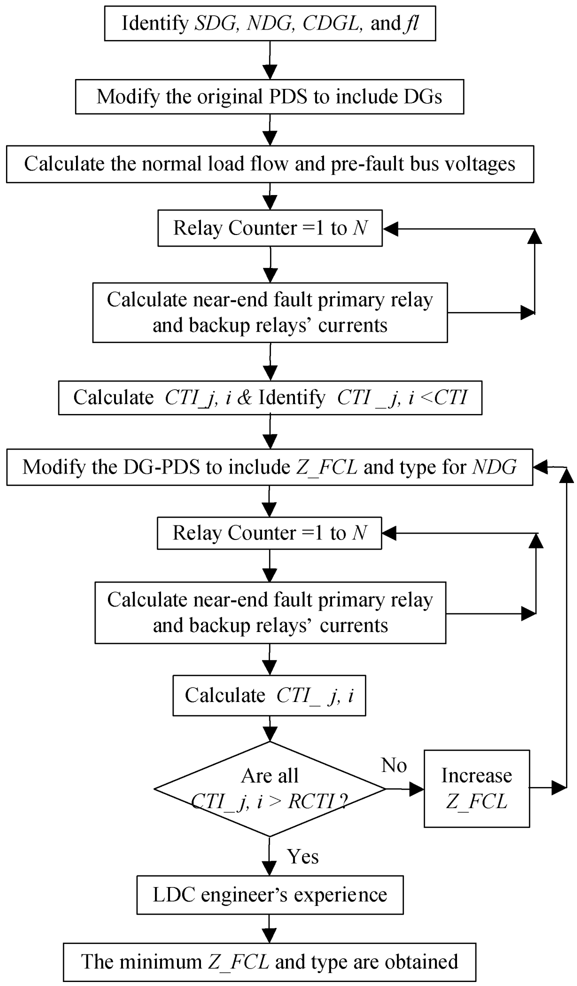

Fig. 3. Restoration of the original relay coordination.

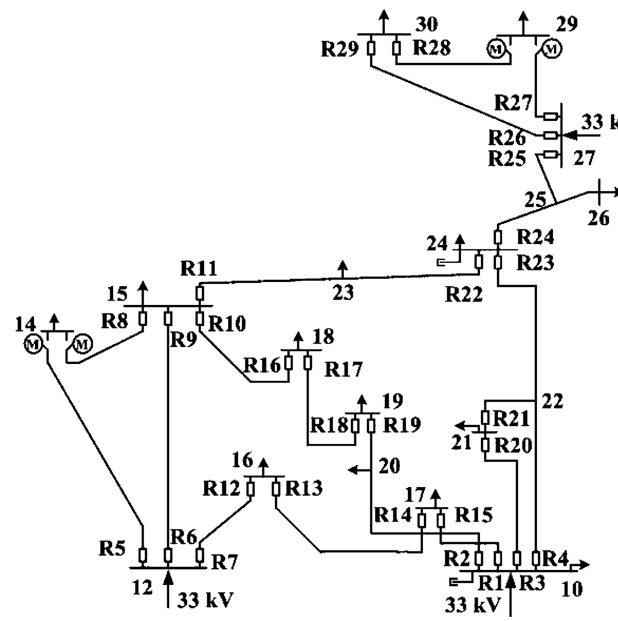

Fig. 4. PDS of the 30-bus IEEE system under study.

CTI_j, i in the PDS is greater or equal to chosen $RCTI$. Each time, the Z_FCL value changes, the PDS has to be modified taking into consideration the new value of Z_FCL only during fault calculation. However, it has no effect in the normal power flow due to FCL operating characteristics. After obtaining the minimum Z_FCL for either IFCL or RFCL, the most economical one will be chosen.

Finally, to select the feasible minimum Z_FCL for a multi-DG PDS, the proposed iterative process has to be carried out for all possible DGs operating combinations.

1) Each individual DG assumes that it is working alone.
2) Each DG pair works at the same time.
3) Finally, all DGs work at the same time.

Based on the obtained minimum Z_FCL value from each DG possible operation combination, the feasible minimum Z_FCL will be the highest one.

III. Applications

A. PDS Under Study

The complete system under study is the 30-bus IEEE system [25]. The system is modeled with all of its detailed parameters (synchronous condensers with their generation limits, shunt reactors, distribution transformers taking into consideration their turn's ratio, and aggregated loads represented by constant power models). The PDS under study, shown in Fig. 4, is fed from three primary distribution substations (132/33 kV) at buses 10, 12, and 27. Each primary distribution feeder is protected by two directional overcurrent relays, one relay at each end. The PDS is assumed to have 29 existing directional overcurrent relays and the system is originally well coordinated. It is assumed that all relays are identical and have the standard IEEE moderately inverse relay curves with the following constants 0.0515, 0.114, and 0.02 for A, B, and C, respectively [24]. The CTI is assumed to be 0.3 s for each backup-primary relay pair.

Eleven $CDGL$s are assumed which include: PDS substation buses 10, 12, and 27, and PDS load buses 15 to 19, 21, 24, and 30. $CDGL$ is chosen based on environmental and fuel availability restrictions. The chosen DG technology is a synchronous type, 10 MVA capacity, operating nominally at 0.9 lagging power factor, and 0.15 p.u. transient reactance based on its capacity [6]. The DG is practically connected to the PDS bus through a transformer which is assumed to have 10 MVA capacity and 0.05 p.u. reactance based on its capacity. The DG is simulated with its required active power and constrained by the minimum and maximum reactive power that can be generated in normal operating conditions. The allowable DG penetration level is considered as a percentage of the total load to be served in the 33 kV area and is based on system historical data and LDC practice. In this study, the maximum individual DG capacity is assumed to be around 10% of the maximum PDS active power loading (115 MVA at 0.9 lagging power factor). This DG capacity limit is used to keep the concept of DG.

B. Scenarios Under Study

Three scenarios are examined to evaluate the effectiveness of utilizing FCL to restore the original directional overcurrent relay coordination for a PDS with DGs.

1) Scenario A: It is thought-out as the base case with well established relay coordination, where there is no DG presented in the PDS.
2) Scenario B: DG as a power source within the PDS territories is presented. It is considered to be the worst case as there is relay miscoordination.
3) Scenario C: It illustrates the proposed approach of installing FCL in series with DG as an alternative candidate option to solve the relay coordination problem locally. The restoration of relay coordination can be done by pushing the system toward the Scenario-A condition. This is done without the need for changing the relays' settings or disconnecting DGs during a fault. Furthermore, this scenario is divided into two cases, each one is evaluating different Z_FCL types (inductive or resistive).

Based on (5), the analysis carried out in Section IV assumes identical 10 MVA SDG, however, different SDG can be used. First, a single-DG operation is evaluated for all $CDGL$ and fl. Then, the analysis is extended to include a multi-DG operation with all of their possible combination. For each operating case, the feasible minimum Z_FCL value and type is calculated.

IV. Analysis and Results

A. Scenario A: Relay Coordination for the Original PDS

This scenario is considered as a base PDS case without DGs. As shown in Fig. 2, to evaluate the most optimal relay settings, a two-phase process is carried out using GAMS software [26] as follows.

1) In Phase I: The optimization model is formulated as nonlinear programming where both the relay's I_P and TDS are considered continuous variables. The minimum and maximum I_P limits are chosen to be 1.25 and 2 times the maximum load current seen by each relay, respectively. On the other hand, the minimum TDS is assumed to be 0.1 in all studies. The obtained relays I_P are rounded and kept fixed at the nearest available relay's pickup current setting.

2) In Phase II: The linear programming formulated optimization model is carried out to provide the optimal relay TDS, which will be also rounded to the nearest available TDS characteristic. If the CTI constraints are violated, an $RCTI$ can be set. Two possibilities are evaluated, which affect the rounding relay settings process (a PDS equipped either by numerical relays or electromechanical relays). In this study, numerical relays allow two decimal places for TDS. However, electromechanical relays discrete TDS are: 0.1, 0.15, 0.2, 0.3, 0.4, 0.5, 0.6, 0.7, 0.8, 0.9, 1.0, 1.1, 1.2, and 1.3. For a system equipped with both relay types, the same proposed process (Fig. 2) is applicable.

Based on rounding the results obtained in Phase II, 10 out of 50 CTI constraints (4) are violated. The $RCTI$ is chosen based on the LDC engineer's experience. The chosen minimum $RCTI$ values in our study are 0.285 s and 0.27 s in case of a PDS equipped with numerical or electromechanical relays respectively, which are only 5% and 10% less than the original 0.3 s CTI value. Finally, the obtained rounded relays I_P and TDS settings are found to satisfy the optimization model (1) and its constraints (2)–(4) for the chosen $RCTI$ values.

TABLE I
Scenario A: Relay Coordination for PDS Without DG

Relay Unit	Load Current (Amp.)	Fault Current (Amp.)	CT	Numerical Relays		Electro-mechanical Relays	
				Relay Setting	TDS	Relay Setting	TDS
R1	115.9	6314.4	200/5	6.0	1.30	6.0	1.3
R5	136	7092.0	300/5	4.5	0.56	4.5	0.6
R6	316.8	6368.1	600/5	5.5	0.75	5.5	0.8
R7	132.2	6160.6	300/5	4.5	1.22	5.0	1.2
R8	28.7	5209.1	50/5	5.5	0.80	5.5	0.8
R9	316.8	2745.0	600/5	5.5	0.19	5.5	0.2
R10	105	5017.0	200/5	5.0	1.09	5.0	1.1
R11	98.1	5015.2	200/5	5.0	0.84	5.0	0.9
R18	48.5	2657.7	100/5	5.0	1.11	5.0	1.2
R19	124.2	1817.8	200/5	6.0	0.49	6.0	0.5

TABLE II
Scenario A: Relay Current and Operating Time in PDS Without DG

Relay Unit	Relay Current (Amp.)	Numerical Relays		Electro-mechanical Relays	
		Operating Time (sec.)	CTI (sec.)	Operating Time (sec.)	CTI (sec.)
R1 (Primary)	6314.4	1.139	-	1.139	-
R19,1 (Backup)	598.6	1.424	0.285	1.453	0.314
R23,1 (Backup)	864.1	1.439	0.300	1.576	0.437
R15_1 (Far-end)	1066.5	1.270	-	1.339	-

The value of the optimal total operating time obtained from Phase I is 20.645 s, which is increased to 20.686 s after rounding the relay I_P. The final most optimal total times obtained from Phase II are found to be 20.702 and 21.656 s for numerical or electromechanical relays, respectively. The final total primary relay operating times are only 0.3% (for numerical relays) and 4.9% (for electromechanical relays) greater than their corresponding optimal total times. Therefore, rounding the relay setting is acceptable.

Table I shows some of the results obtained from normal maximum load flow, near-end-fault currents, and the most optimal relay settings for both possibilities (a PDS equipped with numerical or electromechanical relays).

Table II shows a sample of backup-primary relay pair short-circuit currents, operating times, and the far-end relay operating time for a fault at bus 10.

B. Scenario B: Relay Coordination in Presence of DG

In this scenario, the LDC experiences DG operation in its territories. The presence of DG will change the normal power flow as well as the short-circuit current all over the PDS, which is not restricted to the DG connected bus. As discussed in Fig. 2, the fixed relay settings are used to calculate the relays' operating times and backup-primary relay pairs CTI_j, i. The reported results in this section are shown only for numerical relays; however, the same proposed approach shown in Fig. 2 is applicable for electromechanical relays.

TABLE III
SCENARIO B: CURRENTS OF PDS WITH DG FOR DIFFERENT FAULT LOCATIONS

Relay Unit	Fault Bus	Current (Amp.) (DG at bus 12)			Current (Amp.) (DG at bus 19)		
		Load	Fault	DG Fault	Load	Fault	DG Fault
R1	10	103.4	6895.0	585.5	118.3	6897.8	710.1
R5	12	140.5	7737.9	901.0	128.5	7530.2	623.5
R6		336.1	6965.2		284.2	6617.1	
R7		154.1	6741.9		128.6	6549.4	
R8	15	33	5574.0	669.6	23.8	5692.3	624.9
R9		336.1	2929.6		284.2	3167.6	
R10		117.3	5375.2		66.2	5180.7	
R11		108.5	5383.7		104.8	5463.4	
R18	19	61.2	2801.3	437.9	40.3	3524.6	851.2
R19		114.3	1913.7		84	2683.8	

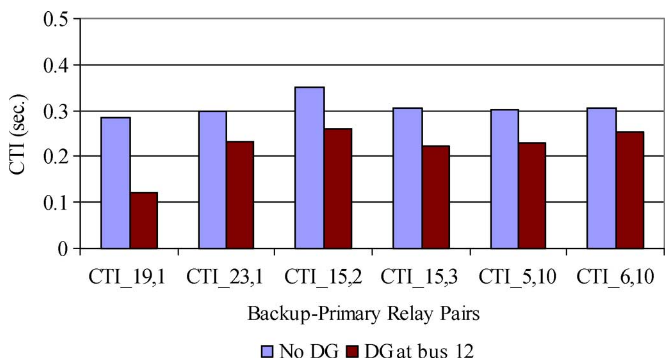

Fig. 5. Scenario B: backup-primary relay pair miscoordination for DG at bus 12.

Table III reports samples of relay normal load and near-end-fault currents, DG drawn current at different fl for single-DG operation at buses 12 and 19 (each at a time). As the value of the DG current depends on the fault location, the maximum DG contribution current during fault occurs if the fault takes place at the same DG interconnected bus. In case of a DG connected at bus 12, the value of the drawn DG current varies from 135% (for fault at bus 30) to 590% (for a fault at bus 12) relative to the DG load current (153.3 A). On the other hand, for a DG installed at bus 19, the drawn DG current varies from 126% (for fault at bus 30) to 516% (for a fault at bus 19) with respect to the DG load current (164.9 A). Based on the reported results shown in Table III, the PDS will face relay miscoordination.

For the DG at bus 12, six relay pair miscoordinations, based on a new $RCTI$ threshold (0.27 s), are reported for faults at buses 10 and 15. Fig. 5 compares these relay pairs CTI with and without DG. It is clear that the CTI is reduced in case of the presence of DG. The new $RCTI$ threshold (0.27 s) is chosen with a minimum of 90% of the original CTI, based on economical and electrical constraints which will be discussed in Scenario C.

Similarly, in Fig. 6, eight relay pair miscoordinations are reported for a DG installed at bus 19 and different fault locations. Five relay pairs (23,1 & 12,6 & 8,7 & 16,11 & 3,21) have lower CTI than $RCTI$, and three pairs (19,1 & 19,3 & 9,7) have a backup relay operation before the primary one.

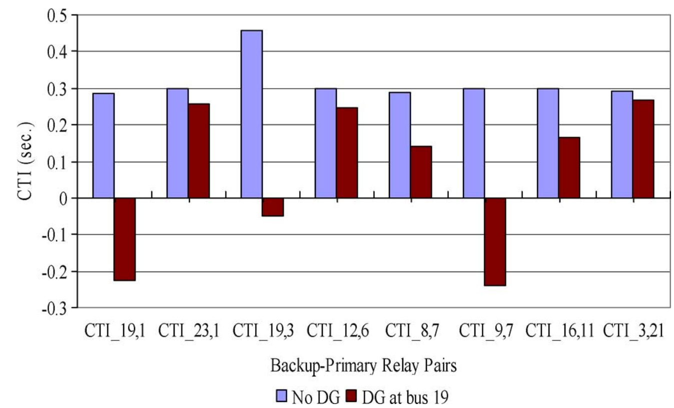

Fig. 6. Scenario B: backup-primary relay pair miscoordination for DG at bus 19.

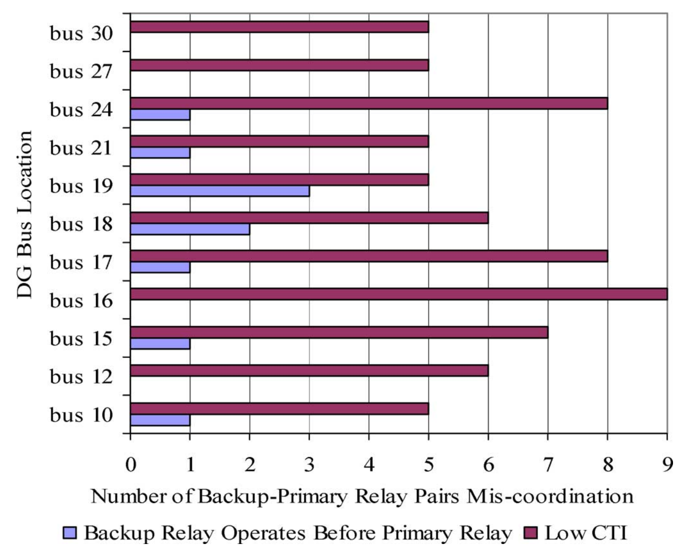

Fig. 7. Scenario B: summary of miscoordination relay pairs.

As a summary, Fig. 7 shows the number of miscoordination relay pairs for individual single-DG operation at each location of $CDGL$ and all fl (29 relay near-end faults) for each DG, due to either low CTI or backup operation before primary relays. These relay pair miscoordinations will be tackled in Scenario C to evaluate the effectiveness of using FCL to restore the original system coordination stated in Scenario A.

C. Scenario C: Relay Coordination in Presence of FCL–DG

In this scenario, the authors propose the use of FCL as an attractive option for alleviating the DG impact on the existing protection system coordination without altering the relay settings or disconnecting DG during fault. Single-DG and multi-DG operating possibilities are discussed. For each DG operating possibility, two Z_FCL types [inductive (Case 1) and resistive (Case 2)] are evaluated and the obtained results are compared with those obtained from both Scenarios A and B. The minimum Z_FCL value and type that restore the original relay settings are obtained. The proposed restoration approach (Fig. 3) is applicable for a PDS equipped with numerical, electromechanical, or both relay types. The reported results in this section are for

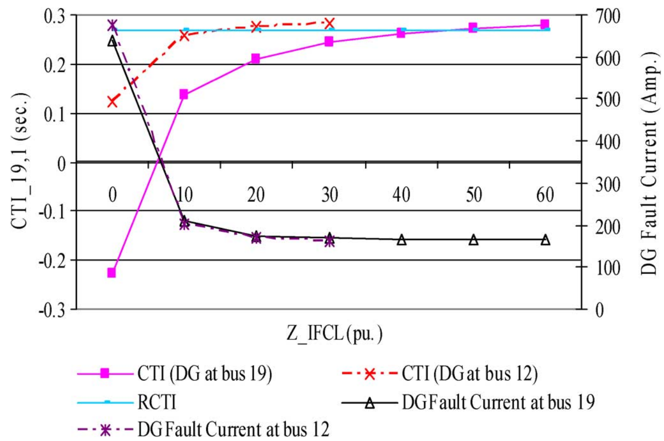

Fig. 8. Scenario C: restoration of miscoordination relay pairs using IFCL.

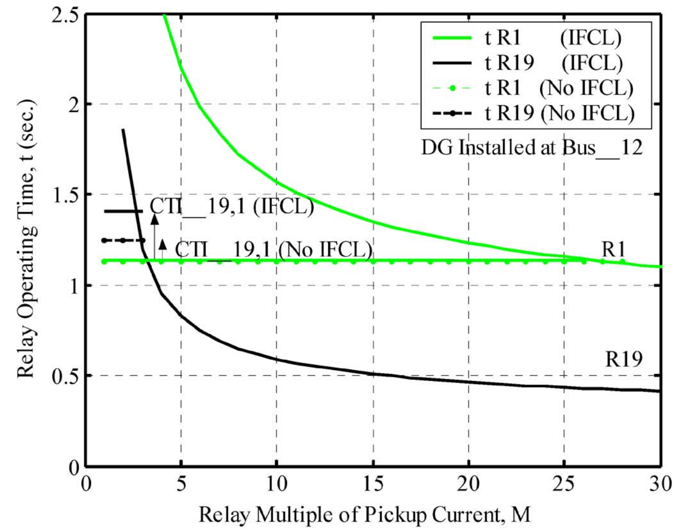

Fig. 9. Scenario C: restoration of relay miscoordination using IFCL.

TABLE IV
SCENARIO C, SINGLE-DG: IFCL-DG AT BUS 12

Z_IFCL (pu.)	*CTI_19,1* (sec.)	*CTI_19,1* (%)	*CTI_19,1* Imp. (%)
0	0.1227	41	-
10	0.258	86	-
20	0.2752	92	6
30	0.2814	94	8
Min. value of 16	0.2709	90.3	4

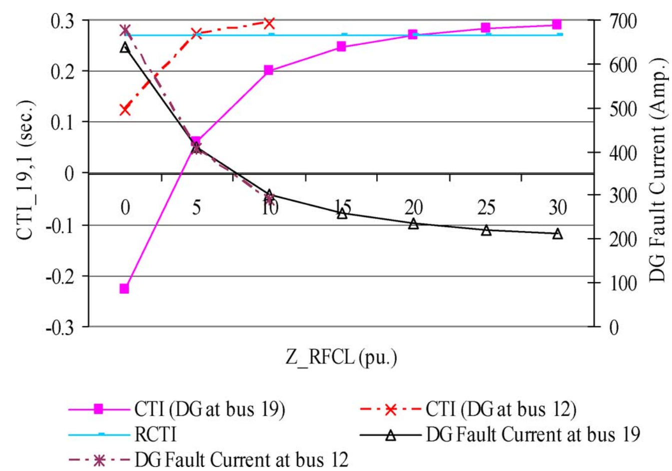

Fig. 10. Scenario C: restoration of miscoordination relay pairs using RFCL.

numerical relays. However, some results for electromechanical relays will be presented for comparative purposes.

1) Single-DG Scenarios Under Study:

a) Case 1: IFCL-DG: By equipping DG with series IFCL, the DG drawn current during fault will be reduced depending on the inductive reactance value. Fig. 8 shows the $CTI\_19,1$ values (also, see Table IV) and the DG drawn currents during a fault at bus 10 for two individual DGs at buses 12 and 19 (each at a time) and different increasing values of their associated Z_IFCL.

For a DG installed at bus 12 without IFCL and a fault at bus 10 (near-end fault of R1), Fig. 8 shows a backup-primary relay pair miscoordination for $CTI\_19,1$. Fig. 8 and Table IV show that as the Z_IFCL increases, the $CTI\_19,1$ value and percentage with respect to the original CTI (0.3 s) increases. This rate of increase starts high then almost saturates. From these values, it is clear that to increase the $CTI\_19,1$ from 86% to 94% (i.e., 8% improvement), the IFCL reactance has to be tripled (from 10 p.u. to 30 p.u.), which is economically unacceptable. The authors proposed to choose the minimum IFCL reactance to be installed to meet a $RCTI$ of 0.27 s (90% of the original CTI). The $RCTI$ is to be chosen based on the LDC engineer's experience (types of protected equipment used in the PDS and their errors) and IFCL reactance's cost. Based on this discussion, the minimum value of the IFCL reactance is calculated to be 16 p.u., which provides a $CTI\_19,1$ of 0.2709 s. Furthermore, Fig. 8 shows that the DG drawn current drastically reduces as the IFCL reactance increases and its value beyond the chosen minimum IFCL reactance (16 p.u.) has a minor or low rate of change. On the other hand, for electromechanical relays, the minimum value of Z_IFCL is 5 p.u. based on $RCTI$ of 0.26 s.

Similarly, for a DG connected at bus 19 and a fault at bus 10, the backup-primary relay pair has a miscoordination due to backup relay operation (R19) before its primary relay (R1). Similar to the previous case, using IFCL will restore the relay pair coordination (i.e., $CTI\_19,1$ of 0.27 s) with an inductance reactance of 48 p.u. In case of electromechanical relays, the minimum value of Z_IFCL is 26 p.u. based on $RCTI$ of 0.26 s.

Fig. 9 shows the restoration of R19 and R1 coordination on their time–current characteristics by utilizing the minimum IFCL reactance (16 p.u.) for the DG installed at bus 12.

2) Case 2: RFCL-DG: In this case, the same procedure carried out in Case 1 is repeated by using RFCL as an alternative Z_FCL type. Fig. 10 shows that to restore the backup-primary relay pair coordination $(CTI\_19,1)$ for a fault at bus 10, only an RFCL resistance of 5 p.u. (provides $CTI\_19,1$ of 0.275 s) is needed for a DG installed at bus 12. Similarly, for a DG at bus 19, the minimum RFCL resistance required is 20 p.u.

The process of selecting the minimum RFCL value is given in Table V. Also, it is shown that it is not economically acceptable to increase the RFCL resistance by 50% of its value to gain an improvement of 6.9% with respect to the selected minimum

TABLE V
SCENARIO C, SINGLE-DG: RFCL-DG AT BUS 19

Z_RFCL (pu.)	*CTI_19,1* (sec.)	*CTI_19,1* (%)	*CTI_19,1* Imp. (%)
0	-0.2262	-75.4	-
5	0.0600	20.0	-
10	0.1989	66.3	-
15	0.2482	82.7	-
20	0.2710	90.3	-
25	0.2837	94.6	4.2
30	0.2917	97.2	6.9
Min. value of 20	0.2710	90.3	0

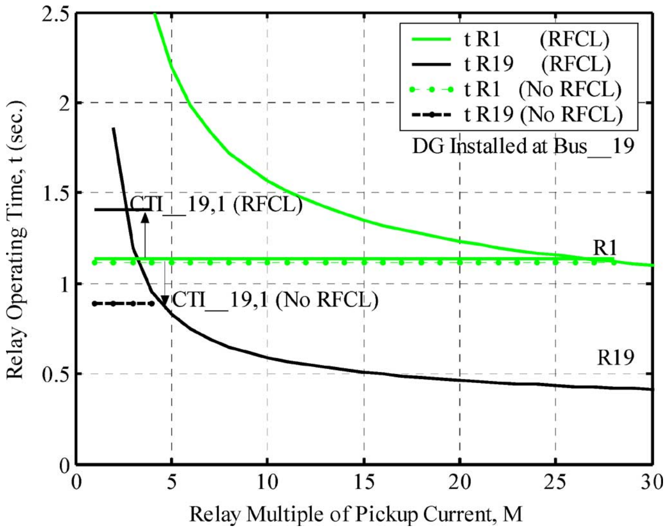

Fig. 11. Scenario C: restoration of relay miscoordination using RFCL.

resistance value (20 p.u.). Also, as noted earlier, the DG drawn current during a fault in the PDS changes based on the value of the RFCL resistance. Fig. 11 shows the obtained restoration coordination between R19 and R1 and the result gained from utilizing RFCL for a DG installed at bus 19.

As a summary, Figs. 12 (DG at bus 12) and 13 (DG at bus 19) are provided to show a comparison between the normal loading and current drawn from DG with and without both Z_FCL types at different fault locations. It is observed that using IFCL will limit the current drawn from DG during fault in the PDS to a value near to its maximum loading to satisfy the relay coordination $RCTI$. However, using RFCL will obtain the required coordination without much limiting of DG fault current.

To validate the proposed approach, all $CDGL$ are examined for all possible faults (29 relay near-end faults). For each $CDGL$, Fig. 14 shows the minimum Z_FCL value and type required to satisfy the preset $RCTI$ (0.27 s) for the worst backup-primary relay pair and all possible fault locations. It is shown that the RFCL type will result in restoring the original relay coordination with lower per unit impedance, than using that of IFCL.

The proposed implementation of FCL adds an economical benefit to the electrical ones. Having DGs in the PDS increases the short-circuit current at its connected bus. Thus, FCL can assist limiting the short-circuit current to a preset value which allows circuit breakers and/or other lower rated protective devices to isolate faults within their design capabilities. Fig. 15 shows a comparison of PDS buses short-circuit megavolt-ampere capacity with or without the DG connected to it. Also, it shows the impact of using IFCL and RFCL to limit the bus short-circuit MVA capacity to a value near to that when there is no DG connected to this bus. This limitation will help to defer bus equipment upgrading.

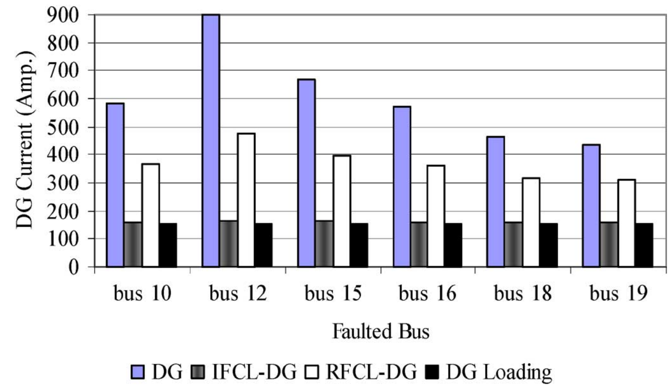

Fig. 12. Scenario C: currents of FCL-DG installed at bus 12.

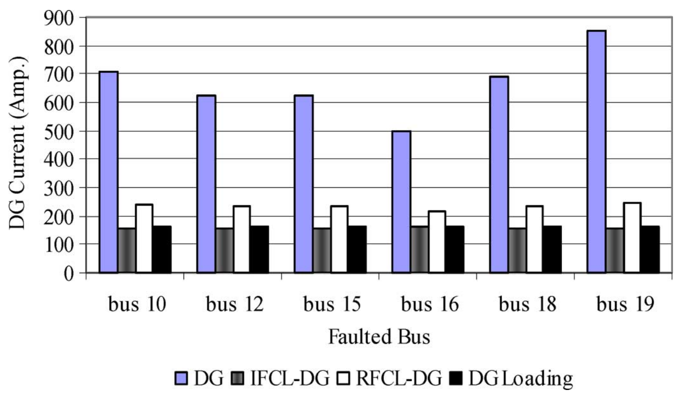

Fig. 13. Scenario C: currents of FCL-DG installed at bus 19.

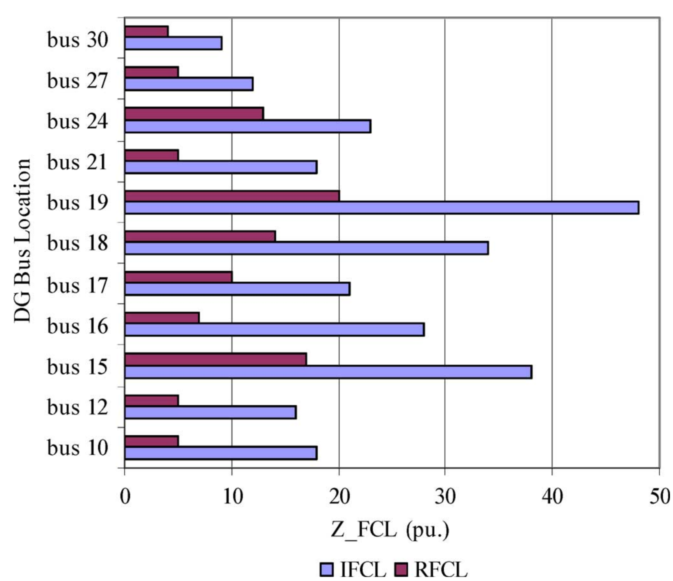

Fig. 14. Scenario C, single-DG: FCL impedances for various DG locations.

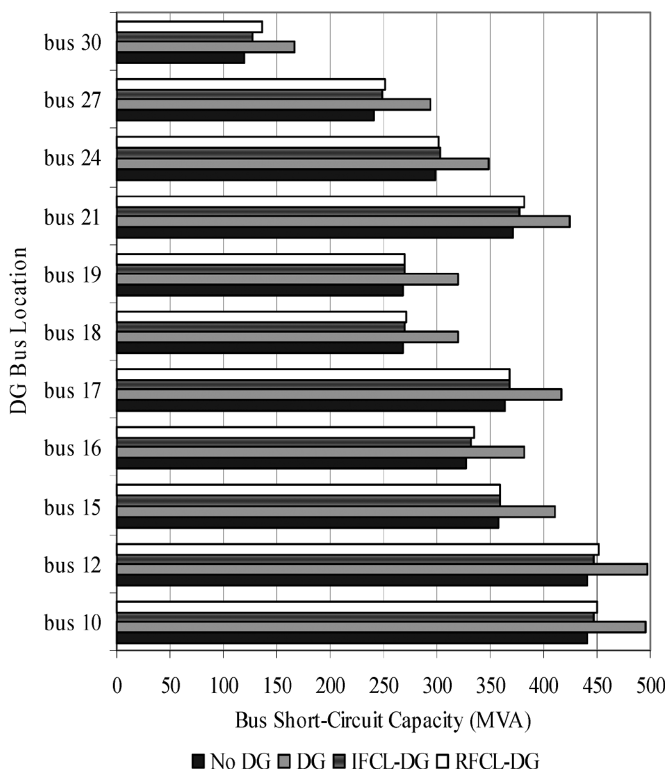

Fig. 15. PDS buses short-circuit megavolt-ampere capacities.

3) *Multi-DG Scenarios Under Study:* The proposed approach was implemented to have two DGs located at different buses in the PDS working at the same time. For two 10 MVA-DG units connected to buses 12 and 19 in the PDS, Table VI shows the minimum Z_FCL required to restore the relay coordination of the worst relay pair CTI to the preset $RCTI$ value. The minimum inductive and resistive Z_FCL obtained are 56 and 22 p.u., respectively. Even though the minimum value of Z_FCL for each DG operating alone at buses 12 or 19 is less than that in case of multi-DG operation, the larger value has to be chosen. This value will satisfy all DG operating possibilities (Figs. 8 and 10). Therefore, for any DG possibility to be out of service, the calculated Z_FCL is capable of restoring the original PDS relay coordination.

Similarly, for two DGs operating at buses 10 and 12 at the same time, Table VI shows that the minimum Z_FCL is 53 and 6 p.u.. for inductive and resistive Z_FCL, respectively.

For further examining the proposed approach, three 10 MVA-DG are installed, operated and evaluated at buses 10, 12, and 19. Table VII shows the minimum value of Z_FCL for all DG operating possibilities. As mentioned earlier, the largest value of the calculated minimum Z_IFCL (56 p.u.) is chosen, even though only 42 p.u. reactance is required for three DGs operating at the same time. Similarly, the minimum Z_RFCL chosen is 22 p.u. Finally, the choice of the proper Z_FCL type is based on the LDC engineer's experience and Z_FCL type cost.

Table VII provides the validation of the proposed approach for three DGs (30% of the total PDS loading). Although the proposed approach is applicable for more DGs operating at the same time in the PDS, the authors did not carry out more DGs so as to keep the concept of dispersed generation.

In this study, the simulation carried out for selecting the minimum value of Z_FCL is based on equal DG capacities. Therefore, upon starting with a zero initial value of Z_FCL in Fig. 3, the final value of Z_FCL for all DGs will be equal. However, the proposed approach (Figs. 2 and 3) is also applicable for different DG capacities. In case of multi-DG operation with different DG capacities, the iteration is started with different Z_FCL values obtained for each single-DG operation. Thus, the final value of each DG's Z_FCL will be different and based on its associated individual DG capacity.

TABLE VI
MULTI-DG SCENARIO: TWO DGs

	DG Operating Possibility					
	12	19	12 & 19	10	12	10 & 12
***Z_IFCL*(pu.)**	16	48	56	18	16	53
***CTI* (sec.)**	0.2709	0.2701	0.2702	0.2714	0.2709	0.2700
***Z_RFCL*(pu.)**	5	20	22	5	5	6
***CTI* (sec.)**	0.2749	0.2710	0.2711	0.2772	0.2749	0.2792

TABLE VII
MULTI-DG SCENARIO: THREE DGs

DG Operating Possibility	10	12	19	10 & 12	10 & 19	12 & 19	10, 12 & 19
***Z_IFCL*(pu.)**	18	16	48	53	39	56	42
***CTI* (sec.)**	0.2714	0.2709	0.2701	0.2700	0.2700	0.2702	0.2709
***Z_RFCL*(pu.)**	5	5	20	6	17	22	18
***CTI* (sec.)**	0.2772	0.2749	0.2710	0.2792	0.2720	0.2711	0.2746

V. CONCLUSION

This paper introduces an attractive approach for restoring the original relay coordination in looped PDS, utilizing DGs by implementing FCL. Inductive and resistive FCLs are examined to limit the DG drawn current during a fault anywhere in the PDS. An integrated optimization model with a comprehensive MatLab code is used to calculate the minimum FCL impedance value and its proper type for various PDS operating scenarios. The results show the effectiveness of the proposed approach in restoring the original relay coordination for both single and multi-DG operations. This approach has the privilege of restoring the relay coordination without altering the existing relay settings (technology replacement) or disconnecting DGs from the PDS. Therefore, it makes use of the existing relay devices and protective scheme; and avoids the synchronization problems associated with reconnecting DG into the PDS. Hence, the proposed approach is valid under the current practice of disconnecting DG and in the emerging trend of maintaining DG in the PDS during fault. Furthermore, implementing FCL adds an economic opportunity to limit the buses' short-circuit currents without the need for the buses' equipment upgrading.

The results show that resistive FCL is found to achieve the required relay coordination with lower impedance value than that of the inductive FCL. The results of the proposed approach are valid for the parameters portrayed in the paper, which can vary based on system construction and available relay technology in the PDS under study.

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