Optimal Protection Coordination of Directional Overcurrent Relays in Microgrids considering Grid-Connected and Islanded Modes based on User defined Characteristics and Fault Current Limiters

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Abstract- The introduction of distributed generation (DG) in the distribution system paved the way to the microgrids concept as a solution to the increased demand for energy. Microgrids can operate while grid connected or act as a standalone network in case of the main grid outage. However, this changeable conditions and configurations of microgrids: Grid-connected and Islanded modes significantly affect the short circuit levels. In this paper, a protection coordination strategy that relies on the capability of using user-defined characteristic curves of digital inverse overcurrent relays in microgrid utilizing fault current limiter (FCL) at point of common coupling. The main objective is to obtain the optimal setting for FCL, and the conventional relay setting parameters: time multiplier setting (TDS) and pick up current (Ip) along with (A) and (B) as variable setting to be chosen optimally while considering both modes of operation of the microgrid. The optimal coordination problem is formulated as a constrained non-linear programming problem and solved using MATLAB minimum-constrained nonlinear multivariable function. The proposed approach is tested on the IEEE 30-bus meshed distribution system equipped with DG units. The outcome of this study shows that utilizing user-defined characteristic curves for DOCRs achieves notable reduction in total relays' operating time over the conventional characteristic along with a reduction in FCL values which makes the proposed protection strategy as an attractive option for microgrids with dual configuration.

Keywords Directional Overcurrent Relays, User-defined Relay Characteristics, Distributed Generations, Fault Current Limiters, Optimal Protection Coordination.

1. Introduction

Energy demand is rising due to economic growth driving the electrical power system to expand. However, this expansion is constrained by financial aspects considering the construction of extensive infrastructure. Depending on distributed generation (DG) units appears to be applicable concept to satisfy the growing energy demand without extensive investments in infrastructure. DGs are small-scaled electric power generation units that vary between 1 kW to 50 MW and generally installed at the distribution level near the loads. They can be connected at customer level or at the distribution feeder, which support independence, facilitate sustainability, and deliver effective cost-saving solutions in the long term [1]–[4].

The advent of DG units has changed the traditional power distribution system topology from radial single source with unidirectional power flow into meshed multi-source looped structure in which power flow is bidirectional[3], [5], [6].

Despite the merits of utilizing DGs in distribution networks; grid reinforcement, reducing power losses and on-peak operating costs, and improving voltage profiles and load factors [7]; it raises challenges to the network if not well managed, including harmonics, voltage regulation, and voltage flicker besides its impact on protection scheme [5], [6].

Distribution networks with high penetration of distributed generation are subject to changes in short circuit levels and bidirectional power flow that may led to false tripping, blinding or failure operations of protection relays that are designed for the original system without DGs. The new bidirectional power flow in distribution systems with DGs leads to the change of the conventional fuses and reclosers protection scheme to dependence on directional overcurrent relays (DOCRs). This also increases the complexity of the coordination in distribution systems and optimization techniques appear to be an efficient tool to optimally choose the settings as to ensure protection coordination [8], [9]. Generally, an efficient protection coordination must assure reliability achieved by two aspects: dependability and security. It should also keep the proper speed of operation and selectivity to guarantee power continuity to the healthy areas of the system. When a fault occurs, the exact part of the system should be disconnected through the primary protective devices then backed-up with the backup protection devices as a second line of protection in case of primary devices fails to clear the fault [3].

With the increased use of DGs in the distribution networks, the concept of the microgrid was established, which is a controllable power system with local generation, loads, and energy storage to form a smaller model of the main grid that reduces power losses and increases the reliability of the energy supply. A microgrid can operate in two modes of operations: grid-connected mode and islanded mode, which give the capability to this small network to provide backup power during a main grid outage and reduce system losses [3], [9], [10]. In [11] a study had been conducted to define the optimal sizing and location of the power plant in a microgrid interconnecting several rural community along with defining power flow and energy management strategy.

Different computational intelligence-based approaches had been deployed to determine the optimized setting of DOCRs to achieve coordination. A wide range of optimization techniques has been used in the literature to solve DOCRs coordination problems and overcome the challenges of conventional approaches like trial-and-error technique or topological analysis such as functional or graph theory [11]. Evolutionary algorithms such as genetic algorithm is proposed in [3], [12]. In addition, nature-inspired algorithms using swarm intelligence is used to solve the optimization problem of DOCRs due to their flexibility and effectiveness such as particle swarm optimization in [13], Honey Bee Algorithm in [14], firefly algorithm in [15], and whale optimization algorithm in [16]. In [17] improved fire fly algorithm had been used to improve the optimal solution for the problem of directional overcurrent relays (DOCRs).these optimizers tend to find global solution to the optimization problem.

Utilizing digital processing relays in the distribution systems drives the researchers to develop new protection schemes to tackle protection issues that stablished on the capability of numerical relays to alter the standard characteristics of DOCRs. Several non-standard characteristics of DOCRs had been reported in the literature to achieve protection coordination. Standard relay operating time equation’s constants A and B were considered as an optimization variables in [8] and [16] to achieve protection coordination. In [19] value of voltage measured by the relay was inserted in the standard characteristic equation to formulate a new non-standard equation for determining the relay operating current . Moreover , in [20] the characteristic equation is dependable on the admittance instead of the current while excluding TDS from the equation to avoid high operating times. In [21] two user-defined characteristics one for primary operation and another for backup operation in looped networks utilizing the capabilities available in modern digital DOCRs to minimize their total operating time

Protection of microgrids requires new protection schemes to adapt to the changeable conditions and configuration since microgrid mode of operation, either grid-connected or islanded, has significant effects on the short-circuit currents [22]. Fault Current Limiter (FCL) had been proposed as an effective way to suppress fault currents considering the aggregated contribution of the DG units, especially conventional synchronous type generators which have much more effect on the short circuit than inverter-based DG units. In[23], the paper proposed utilizing FCL in series with DG in looped network to suppress the DG contribution in the fault current locally and restore original relay coordination without changing relay setting or disconnecting DG from the network. Authors in [6] had proposed an approach to reduce the value of FCL while selecting one relay to be an adaptive one. In [3], FCL had been used in series with the utility and determined FCL optimal value in addition to optimal DOCRs setting, taking into account dual mode of operation of the microgrid.

This paper proposes utilizing FCL in series with the utility while considering using user-defined characteristic curves of digital inverse overcurrent relays to achieve the protection coordination between DOCRs in interconnected systems with synchronous based DGs. The size of FCL and the settings of DOCRs are optimally selected for both operation modes of the microgrid: grid connected and islanded modes. The same settings and FCL sizing are used to achieve proper coordination for both modes of operation without the need of any changes when switching between them. The problem is formulated as a constrained nonlinear programming (NLP) problem and solved using the MATLAB fmincon function, which uses the reduced gradient approach (first-order optimality) for solving constrained nonlinear optimization problems [24]. The proposed approach was tested on the IEEE 30-bus looped distribution system equipped with synchronous based distributed generation.

2. Conventional Formulation of Protection Coordination Problem

Generally, the overcurrent relay (OCR) operation time is determined by an inverse function of the fault current passing through it. The characteristic equation controlling the relay operating time differs according to IEC 60255-3. The operating time of DOCR can be expressed as an inverse function of the short circuit current passing through it and is determined as shown in Eq. (1).

$$t = \frac{\text{TDS} * \text{A}}{({}^{I_{sc}}/_{I_p})^B - 1} \quad (1)$$

Where I_{SC} is the short circuit current magnitude seen by the relay, TDS is a tuning parameter, refers to Time-Dial Setting, A and B are constant-coefficient for the relay characteristic and inverse time type respectively, which define the relay characteristic curve. The most common relay time/current characteristic curve is the standard inverse-definite minimum time (IDMT) DOCR where A and B are 0.14 and 0.02 respectively.

Table 1 shows the different values of the DOCRs characteristics curves constants A and B standard that varies between four fixed standard values according to the tripping time required per IEC 60255-3.

Table 1. Standard relay characteristic

Relay Characteristic	IEC 60255 Characteristics curves constants	
	A	B
Standard Inverse (SI)	0.14	0.02
Very Inverse (VI)	13.5	1
Extremely Inverse (EI)	80	2

The key objective of protection coordination problem optimization is to minimize the total operating times of all relays, including primary and backup relays achieved by determining TDS and Ip values of each DOCR, while satisfying coordination protection conditions that eliminate the mis-coordination between relays. The objective function is expressed as the sum, T, of the operating times of all relays that required to be minimized as follows:

$$Minimize \quad T = \sum_{c=1}^{C}\sum_{i=1}^{N}\sum_{j=1}^{M} (t_{cij}^{p} + \sum t_{cij}^{b}) \quad (2)$$

Where:

T is the total operating time of relays

c is the system configuration identifier

C is the number of configurations considered, which is 2 in the case of microgrid (islanded mode and grid-connected mode)

N is the total number of fault locations investigated

i is the fault location identifier

M is the total number of relays

j is the relay identifier

t is the relay operating time

p is referred to primary relays

b is referred to backup relay

The boundary constraints of relays settings must be satisfied while solving the optimized coordination problem and can be formulated as follows:

$$Ip_{i\,min} \leq Ip_i \leq Ip_{i\,max} \quad (3)$$

$$TDS_{i\,min} \leq TDS_i \leq TDS_{i\,max} \quad (4)$$

Where Ip_i is the pickup current setting of the relay R_i, its limits are chosen between 1.25 and 2 times the maximum load current seen by that relay. $TDS_{i\,min}$, $TDS_{i\,max}$ are the minimum and maximum TDS values of relay R_i, respectively, which are assumed to be 0.1 and 1 sec.

Efficient protection coordination between primary and assigned backup relays must satisfy a coordination time interval (CTI) which depends on the number of factors, including circuit breaker opening time, the safety factor for CT saturation and setting errors, and overshoot time of the relay. The protection coordination time constraint usually takes values between 0.2 sec and 0.5 sec according to IEEE Std-242:2001. In this paper, CTI is chosen to be 0.2 sec and can be expressed as follows:

$$t_{ij}^{b} - t_{ij}^{p} \geq CTI \qquad \forall\, i, j \tag{5}$$

A lower limit of 50ms shall constrain minimum primary relays operating times for all fault locations

$$t_{ij}^{p}, t_{ij}^{b} \geq t_{ij-min} \qquad \forall\, i, j \tag{6}$$

3. Proposed Formulation of Protection Coordination Problem

Authors in [6] have proposed an approach of considering A and B as variable setting to utilize the capability of microprocessor based DOCRs units of defining the characteristic operating curve by user besides conventional setting parameters TDS and Ip to the make the most of digital relays by permit operating within a wider range of characteristics not limited to the standard ones.

This study will test the methodology of user-defined characteristic curves of DOCRs in a microgrid while utilizing FCL in series with the grid at the point of common coupling considering both modes of microgrid operation: grid connected and islanded modes. The main target is to reduce the short-circuit current drawn from the utility by providing high impedance under fault conditions and offering a very low impedance and power loss under normal operating conditions. FCLs can be classified by impedance: resistive or inductive. In this work, inductive type FCLs will be used, and they will be modeled by an impedance as shown in Eq.7. Therefore, additional constraints must be considered as shown in Eq. (7-9):

$$0 \leq X_{FCL} \leq X_{FCL\,max} \tag{7}$$

$$A_{i\,min} \leq A_i \leq A_{i\,max} \tag{8}$$

$$B_{i\,min} \leq B_i \leq B_{i\,max} \tag{9}$$

Since the constants A and B will be considered variables in this work, it will add boundaries constraints to the optimization problem and have been chosen to have a minimum value of 0.14 and 0.02 and a maximum value of 1 and 13.5, respectively as per IEC-60255.

4. System Details and Simulation Setup

This section describes the test system under study. The proposed coordination strategy is applied to the distribution part

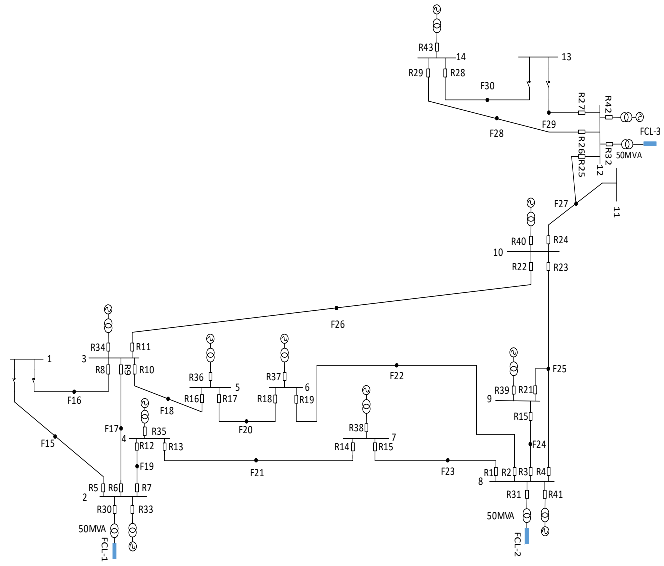

Fig. 1. Distribution Part of IEEE 30-Bus System

of the IEEE 30-bus test system. Fig. 1 shows the single line diagram of it [20]. This system is fed through three 50 MVA 132 kV/33 kV utility transformers connected at buses 2, 8, and 12. Moreover, Fault current limiter is connected in series with the utility. The base selected for the system is 100MVA and 33KV. DGs are connected at various buses in the system, as shown in Fig.1. the DG units utilized in this study are rated at 10MVA, synchronous type with 9.67% transient reactance. They are connected to the system through a step-up transformer 480V /33KV with 5% transient reactance. Conventional synchronous type generators were chosen in this study since it has much more effect on the short circuit than inverter-based DG units.

The system is equipped with 27 directional overcurrent relays on system lines, and the remaining 16 relays protect utility and DGs. Each relay should be capable of operating for within its zone. In this paper, three-phase faults that occur midway along the line and near/far end faults are considered. Each fault location is associated with up to two primary relays, one from each side. But the number of backup relays depends on the fault location. Case in point: considering a fault at node 21, relays R13 and R14 are primary relays, and in case of primary relays failure to clear the fault within the permissible time, Relay R13 has two backup relays, which are R7 and R35, and regarding Relay R14, two backup relays can be defined, namely R1, R38.

Protection coordination optimization problem is formulated as a constrained non-linear multivariable problem using Matlab developed m-files. Then it is solved using Matlab optimization toolbox through built-in function fmincon solver (finding the minimum of constrained non-linear multivariable function), which relies on the gradient-based method and is executed on a Core i7 2.20-GHz CPU with 12 GB RAM.

5. Results and Analysis

The distribution section of the IEEE 30-Bus system, as shown in Fig.1, is chosen as the test system for the proposed approach. Continuous TDS & I_P values are allowed in this study, and the optimal coordination will be achieved for both modes of operation in grid-connected and islanded mode with the same relays' settings. The coordination study is conducted considering midway three-phase fault locations (F15-F30) and conducted for close-in and far-end faults to verify the results.

The protection coordination optimization problem is solved considering conventional two settings (TDS & I_P) and results are compared with the proposed four-setting approach in the presence of fault current limiters. Intensive simulations are carried out with different fault current limiter's upper boundary, which presents the maximum allowable value of fault current limiters.

5.1 Conventional Characteristics of DOCRs Coordination in Presence of FCLS

The conventional two settings (TDS &I_P) strategy is conducted to assess the effectiveness of the study, and all relays in the system will be set following the standardized time/current characteristics. Inverse-definite minimum time (IDMT) overcurrent relays characteristics are chosen to be used; Hence, the constants A and B values are 0.14 and 0.02, respectively. The protection system is modeled and solved optimally.

Optimum values of TDS, I_P as well as X_{FCL} for faults at the midpoint, nodes are presented in Table 2. All constraints are satisfied and find the optimum setting with total relays operating time equals 184.36 Sec. for both modes of operations which is very close to results reported in [3] utilizing a genetic algorithm. However, optimum values of X_{FCL} obtained in our work which are 1.5, 1.56 and 0.53 p.u for X_{FCL-1}, X_{FCL-2}, and X_{FCL-3} respectively are lower than the counterpart in [3], which are 5.85, 7.1, and 1.6 p.u for X_{FCL-1}, X_{FCL-2}, and X_{FCL-3} respectively.

5.2 User-Defined Characteristics DOCRs Coordination in Presence of FCLs

The protection coordination optimization problem will be solved for the same system and four optimal settings for all relays which including TDS and I_P along with A and B as the adjustable setting is achieved while maintaining protection coordination constraints shown in Eq. [3:9] considering user-defined characteristics.

Optimum values of TDS, I_P , A and B as well as X_{FCL} for faults at the midpoint, nodes are presented in Table 3. All constraints are satisfied with total optimum relays operating time equals 89.8 Secs.

Table 2. Optimal TDS, I_P and X_{FCL} For IEEE 30-Bus System Using Conventional Coordination Strategy

Relay	TDS	I_P	Relay	TDS	I_P
R1	0.1045	0.6559	R23	0.1669	0.2349
R2	0.1067	0.5177	R24	0.1038	0.1686
R3	0.1005	0.7180	R25	0.1098	0.2644
R4	0.1417	0.0432	R26	0.1080	0.0699
R5	0.1312	0.0451	R27	0.1136	0.0296
R6	0.1627	0.1847	R28	0.1106	0.0108
R7	0.1025	0.5025	R29	0.2305	0.0346
R8	0.1097	0.1716	R30	0.1060	0.1795
R9	0.1039	0.4242	R31	0.1041	0.1750
R10	0.1025	0.4986	R32	0.1210	0.2111
R11	0.1085	0.1731	R33	0.1123	0.2024
R12	0.1030	0.4233	R34	0.1110	0.1793
R13	0.1027	0.5023	R35	0.1087	0.2330
R14	0.1035	0.4896	R36	0.1172	0.1879
R15	0.1607	0.2835	R37	0.1111	0.2117
R16	0.1247	0.2659	R38	0.1135	0.2491
R17	0.1045	0.4232	R39	0.1156	0.2765
R18	0.1044	0.4288	R40	0.1180	0.1893
R19	0.1037	0.3393	R41	0.1114	0.2098
R20	0.1539	0.2072	R42	0.1175	0.1929
R21	0.3125	0.0617	R43	0.1053	0.2190
R22	0.1102	0.2385			
FCL1		1.4979 pu			
FCL2		1.5562 pu			
FCL3		0.5300 pu			
T		184.36 Sec.			

The feasible solution was achieved over 4500 iterations to find the optimized value considering 175 variables utilizing user-defined methodology. In contrast, the optimum solution for the conventional optimization problem with 89 variables was achieved through 650 iterations that reflects the complexity and high dimensionality of the optimization problem utilizing the proposed approach compared to the conventional approach.

Table 4. shows relays operating times for all fault locations at midpoints, including primary and backup relays in grid-connected mode. The same table could be done for islanded mode by the same concept. For a fault, at F28 relays R26 and R29 are the primary relays and isolate the fault in 0.0713 and 0.3475 sec, respectively. Moreover, in case of primary relays fail to clear the fault, backup relays R24, R32, and R42 will operate in 0.4977, 0.432, and 0.6821 sec for R26 which satisfy the coordination time interval CTI of 0.2 sec, and R43 will operate in 0.5705 sec in case of R29 failed to clear the fault.

Table 3. Optimal TDS, Ip, and X_{FCL} for IEEE 30-Bus System Using User-Defined Strategy

Relay	TDS	I_P	A	B	Relay	TDS	I_P	A	B
R1	1.0000	0.6559	1.0000	3.6539	R23	1.0000	0.2349	1.0000	2.1605
R2	0.9538	0.5177	0.9588	2.9268	R24	1.0000	0.1686	1.0000	1.1427
R3	0.5662	0.7180	0.8581	0.6115	R25	1.0000	0.2644	1.0000	1.0474
R4	0.1005	0.0432	0.1402	0.0414	R26	0.1000	0.0699	0.1400	0.0434
R5	1.0000	0.0451	1.0000	0.9422	R27	0.1001	0.0296	0.1407	0.1148
R6	0.6911	0.1847	0.4961	2.0534	R28	0.1206	0.0108	0.1818	0.0200
R7	0.1006	0.5025	0.1406	0.1639	R29	0.1000	0.0346	0.1400	0.1014
R8	1.0000	0.1716	1.0000	1.6221	R30	0.1000	0.1795	0.1400	0.0782
R9	1.0000	0.4242	1.0000	2.7888	R31	0.1000	0.1750	0.1400	0.0257
R10	0.1000	0.4986	0.1400	0.1405	R32	0.1000	0.2111	0.1400	0.0237
R11	1.0000	0.1731	1.0000	2.2834	R33	0.1000	0.2024	0.1400	0.0283
R12	1.0000	0.4233	1.0000	4.4975	R34	0.1171	0.1793	0.9572	0.9534
R13	1.0000	0.5023	1.0000	2.5394	R35	0.1200	0.2330	0.9999	1.2667
R14	0.1000	0.4896	0.1401	0.0285	R36	0.1013	0.1879	0.1401	0.0299
R15	0.9902	0.2835	0.9988	0.8604	R37	0.1009	0.2117	0.1620	0.0200
R16	1.0000	0.2659	1.0000	3.7092	R38	0.1152	0.2491	0.4552	0.3707
R17	1.0000	0.4232	1.0000	3.3422	R39	0.1044	0.2765	0.1965	0.0200
R18	1.0000	0.4288	1.0000	2.0354	R40	0.1000	0.1893	0.1400	0.0279
R19	0.6607	0.3393	0.6164	0.3364	R41	0.1002	0.2098	0.1832	0.0200
R20	0.1197	0.2072	0.1484	0.0200	R42	0.1181	0.1929	0.1623	0.0200
R21	0.7479	0.0617	0.7203	0.7190	R43	1.0000	0.2190	1.0000	3.6539
R22	0.2753	0.2385	0.9938	0.2346					
FCL1					2.83 pu				
FCL2					2.41 pu				
FCL3					0.536 pu				
T					89.8 Sec				

5.3 User-Defined Characteristics Methodology Simulation Results Considering Near/Far Ends Faults

In [25], the levels of coordination criteria for faults to be simulated is classified into three categories: enhanced criteria, minimal criteria, and desired design criteria. Coordination of relay operations in cases of high fault currents, very close to a relay is accomplished by means of the near-end fault level (i.e., at the beginning of line). The far-end fault level coordinates for the minimum fault current at the end of the line. One of the simplest ways to identify crucial coordination issues is to achieve coordination considering near/far ends faults. In the previous section "minimum" criteria had been covered and for validating the proposed strategy and for a more accurate coordination study "desired" design criteria will be considered in which coordination is achieved by considering two classes of faults such as near end faults and far end faults.

Simple two bus system shown in Fig.2 clarifies the concept of far and near end faults that will be tested. For relay R3, the point A represents the near end point at distance equal to 1% of the line length and point B represents the far end point for the same relay at distance equal to 99% of the line length.

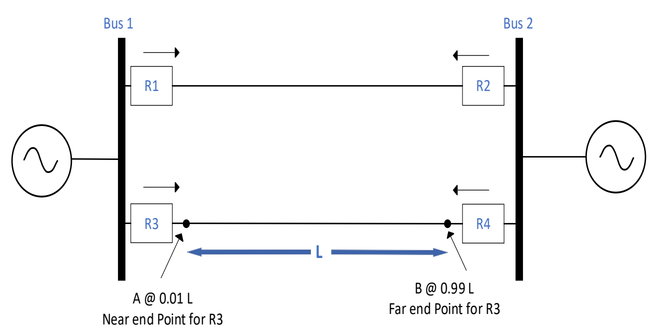

Fig. 2 Near and Far Ends Faults for R3

Table 4. Optimal Primary and Backup Relays Operating Times Using User-Defined Strategy for Grid-Connected Mode

Fault Location	P	b1	b2	b3	b4	b5	b6	P	b1	b2	b3	b4
F15	R5	R9	R12	R30	R33							
	0.0500	0.9594	0.5565	0.6417	0.3771							
F16	R8	R6	R16	R22	R34							
	0.0500	0.7001	0.3282	0.3276	0.3137							
F17	R6	R12	R30	R33				R9	R16	R22	R34	
	0.1080	0.3080	0.3080	0.3281				0.0705	0.2705	0.2705	0.2773	
F18	R10	R6	R22	R34				R16	R18	R36		
	0.0500	0.2500	0.3377	0.3021				0.1581	0.3581	0.3818		
F19	R7	R9	R30	R33				R12	R14	R35		
	0.0500	0.2633	0.4170	0.3509				0.0831	0.2831	0.3038		
F20	R17	R10	R36					R18	R2	R37		
	0.0500	0.2500	0.2679					0.0500	0.2500	0.2610		
F21	R13	R7	R35					R14	R1	R38		
	0.0500	0.2500	0.2802					0.0500	0.2500	0.4925		
F22	R2	R15	R20	R21	R23	R31	R41	R19	R17	R37		
	0.0500	0.4671	0.5967	0.6351	0.9593	0.8080	0.3769	0.0500	0.2500	0.2614		
F23	R1	R19	R20	R21	R23	R31	R41	R15	R13	R38		
	0.0500	0.3079	0.3862	0.3969	0.5306	0.2598	0.2784	0.2311	0.4311	0.4367		
F24	R3	R15	R19	R21	R23	R31	R41	R20	R4	R23	R39	
	0.0500	0.2682	0.2618	0.2627	0.4538	0.2500	0.2743	0.2538	0.9339	0.4538	0.4742	
F25	R4	R15	R19	R20	R31	R41		R21	R3	R39		
	0.0759	0.2865	0.3657	0.2759	0.2828	0.2873		0.2241	0.4241	0.4372		
	R23	R11	R25	R40								
	0.4085	0.6085	0.6085	0.6506								
F26	R11	R6	R16	R34				R22	R4	R21	R25	R40
	0.0500	0.3489	0.4784	0.3526				0.1370	0.3370	0.3804	1.0300	0.7818
F27	R24	R4	R11	R21	R40			R25	R29	R32	R42	
	0.0500	0.2500	0.3325	0.3688	0.9471			0.1761	0.5882	0.3761	0.5990	
F28	R26	R24	R32	R42				R29	R43			
	0.0713	0.4977	0.4322	0.6821				0.3475	0.5705			
F29	R27	R24	R29	R32	R42							
	0.0500	0.3592	2.1026	0.3976	0.6310							
F30	R28	R26	R43									
	0.0500	0.2500	0.5728									

The objective function of the protection coordination problem that supposed to be minimized will be reformulated to consider far/near end fault points. As shown in Eq. 10, the objective function T will represent the entire total working time of all system relays, considering both faults (near and far ends) for each relay and both configurations (grid-connected and islanded mode).

$$T = \sum_{c=1}^{C}\sum_{i=1}^{NR}\sum_{j=1}^{M}\left(t_{cij}^{p} + \sum t_{cij}^{b}\right) + \sum_{c=1}^{C}\sum_{i=1}^{FR}\sum_{j=1}^{M}\left(t_{cij}^{p} + \sum t_{cij}^{b}\right) \tag{10}$$

conventional and user-defined characteristics coordination approaches will be tested using the same distribution part of IEEE 30 bus system and each relay in the network will be supposed to satisfy two constrains considering a CTI = 0.2, one for the near end faults and the other for the far end faults besides other constraints considering microgrid's mode of operation.

One set of relays setting that accomplish protection coordination in the tested system was achieved considering near and far end faults and both microgrid's mode of operation. Table-5 summarizes the findings of both methods used, conventional and user-defined, to achieve protection coordination.

Optimum values of TDS, I_P as well as X_{FCL} for near and far end faults using conventional two setting directional overcurrent relays with standard inverse time/current characteristics. All constraints are satisfied with total operating times equals 636.31 Sec for both modes of operations with respect to far and near end faults and optimum values of X_{FCL} obtained in this case are 2.3, 1.9 and 2.1 for X_{FCL-1}, X_{FCL-2}, and X_{FCL-3} respectively while the counterpart using four relays settings minimized the total relays operating time to 446.75 Sec with reduction percentage of 29.75%. It is worth mentioning that there are some relays endure an increase regarding the relay operating time in islanded mode while solving with conventional approach or user-defined approach.

5.4 Different DGs Capacities Impact on the Proposed Methodology

The effectiveness of the user-defined methodology is tested under different DGs capacities, as shown in Fig.3. In each step, all DG generation capacities had been decreased by 5% to create 5 cases and solved to achieve new optimal settings and values for the relays and FCL, respectively. Figure 3 shows a common trend that the total operating time of relays had decreased with generation reduction in the system. A possible explanation for this is that FCL is used to balance the difference in short circuit level between island mode and grid-connected mode. At the same time, the summation of FCL values utilized is increased.

Island mode short circuit level is decreased with the decrease in generation capacities which increase the short circuit gap between the two modes of operation. The FCL value is increased accordingly to compensate the gap. For instance, For DG capacities are each rated at 9 MVA, the total relays operating time in both modes of operation is 88.6 sec.

The cumulative value of FCLs is 7.1 p.u. While for DG capacities 8 MVA, the total relays operating time in both modes of operation is 85 sec and the cumulative value of FCLs is 12.7 p.u.

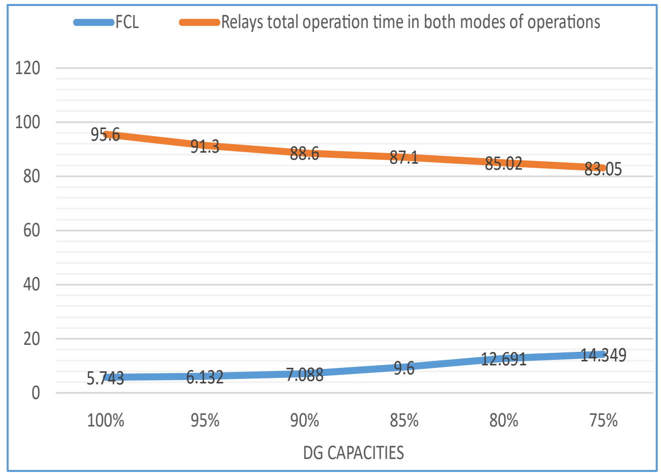

Fig. 3 Effect of DG capacities on total relays operation time and FCL value

6. Conclusion

This paper proposed the application of user-defined characteristics of directional overcurrent relays to benefit from utilizing digital relays along with the assist of FCL in point of common coupling in highly looped microgrid with intensive use of DG units. The proposed coordination strategy aims to achieve one group of optimal settings and FCL values that achieve the coordination in both microgrid modes of operation: grid connected and islanded modes.

Optimal FCL value together with optimal four relay settings reduce the overall relays operating time for both modes compared to the conventional characteristics. A reduction, in the overall relay operating time, of approximately 51% can be achieved with the proposed strategy . The problem is formulated as constrained non-linear programming (NLP) and is solved using a gradient-based method through MATLAB fmincon function.

The proposed strategy is tested on the distribution part of the IEEE 30-bus with synchronous based DGs of different capacities. The coordination study is conducted considering midpoint fault location as well as near/far end fault locations. The reduction in the total relays operating time is achieved in all the case studies, considering different fault locations as well as different DG capacities.

Table 5. Summarized Results for Conventional and User-Defined Coordination approach in presence of FCL Considering Far/Near End Faults

Method	Mode Of Operation	Fault Type	Total Relays Operating Time Top(s)	FCL Values	Method	Mode Of Operation
Conventional Approach	Grid-Connected	Far end Faults	152.69 Sec	636.01 Sec	FCL-1	2.31
		Near end Faults	168.12 Sec		FCL-2	1.96
	Islanded Mode	Far end Faults	153.8 Sec		FCL-3	2.10
		Near end Faults	161.4 Sec		Sum	6.36
User-Defined Approach	Grid-Connected	Far end Faults	104.85 Sec	446.75 Sec	FCL-1	2.92
		Near end Faults	118.29 Sec		FCL-2	2.05
	Islanded Mode	Far end Faults	107.7 Sec		FCL-3	2.69
		Near end Faults	115.91 Sec		Sum	7.66

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