Islanded Operation and System Restoration with Converter Interfaced Distributed Generation

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***Abstract*--The current practice of distributed generation disconnection for every fault in a distribution network drastically reduces the reliability when the penetration level of distributed generators (DGs) is high. Fault isolation, islanded operation, arc extinction and system restoration after a fault are the major protection barriers which will prevent DGs from maintaining connection during a fault. In this paper, a protection scheme and an intelligent control strategy for converter interfaced DGs are proposed for a distribution network containing higher DG penetration level. The proposals can be used to maximize the DG benefits by maintaining as many DG connections as possible either in grid connected or islanded mode. The protection scheme is proposed using overcurrent relays with the aid of communication to isolate the faults in the network. The intelligent control strategy for a converter interfaced DG will enable fault detection of relays, self extinction of arc faults and automatic restoration of the network after a fault. These proposed strategies will prevent immediate DG disconnections from the network. The results are validated using MATLAB calculations and PSCAD simulations.**

***Index Terms*—Distributed power generation, Fault detection, Relays, Power system restoration**

I. Introduction

THE penetration level of distributed generators (DGs) into distribution network is increasing rapidly. The environmental concerns and rapid load growth are two of the major reasons for this higher DG deployment. However, the higher level of DG penetration can cause considerable impact on operational, control and protection of the existing network [1]. The overcurrent (OC) protection has been usually employed to protect a radial distribution network due to its simplicity and low cost [2, 3]. However, after the DG connections into the network, several protection issues can be identified and they are well documented [4-8].

As according to current practice, all the DGs will be disconnected for a fault in the utility grid [9]. This automatic disconnection of DGs during loss of main grid supply drastically reduces the DG benefits [1]. The DG benefits can be maximized if as many DGs as possible are allowed to maintain the connection for temporary faults [10]. Also, the islanded operation with DGs is usually not allowed since restoration by reclosing is difficult and power quality within the islanded section cannot be guaranteed [6]. However, if the employed protection scheme is able to isolate the faulted segment and allow intentional power islands to operate with adequate protection, the reliability of the system can be increased [11].

In this paper, a control and protection solution is proposed with the aid of communication to enhance the benefits of converter interfaced DGs in a network containing high level of DG penetration. The proposed solution includes isolating the faulted segment from both upstream and downstream side of a radial feeder using overcurrent (OC) relays, a converter control strategy for a DG to achieve fault isolation, self extinction of arc, islanded and grid-connected operation without disconnecting DGs from unfaulted segments, and a method to perform system restoration in the presence of DGs using auto reclosers in a network. The proposed protection and control strategies help to maintain as many DG connections as possible thereby increasing the system reliability.

II. Proposed Protection Scheme for Fault Isolation

One of the main aims of the proposed protection scheme is to isolate the faulted segment from a radial feeder allowing DGs to supply the loads in unfaulted segments either in grid-connected or islanded mode. The upstream relay to a fault will see both utility current and current coming from any DG connected further upstream to the relay. However, the downstream relay will only see the fault current coming from DGs located further downstream from the relay. If the DGs are intermittent or not connected all the time to a network, the fault current level in the network cannot be predicted in advance. In this circumstance, the existing settings of OC relays will not work to isolate the faulted segment. Therefore, it is proposed to change the relay settings according to the present system configuration. The digital type OC relays, which have the communication capability, are necessary to accomplish the proposed strategy. The relay acquires the each DG circuit breaker states to work out the present system configuration. Based on the number of DG connections, the relay selects the most appropriate setting for fault detection.

III. Proposed Converter Control Strategy for a DG

A control strategy for a voltage source converter (VSC) is proposed based on the fold back current control characteristic

The authors acknowledge CSIRO Cluster on Intelligent Grid for the financial support to conduct this research.

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to help in successful fault isolation and fast system restoration with converter interfaced DGs. During a fault in the network, the VSC control maintains a sufficient fault current level for a defined time period. This results in effective fault detection by OC relays which are located downstream from the fault point. Also, the VSC control helps to self extinction of an arc fault without disconnecting the DG from a network. Moreover, the system restoration and coordination between network reclosers and DGs are achieved with the aid of proposed VSC control strategy. The VSC operates either in current control or voltage control mode. The proposed VSC control for a converter interfaced DG is explained below.

A. During grid connected and islanded operation

In grid connected mode, the VSC operates in current control mode injecting rated power. The converter injects current in phase with the point of connection (PC) voltage to supply only real power to the utility grid. On the other hand, in islanded mode, the VSC operates in voltage control mode maintaining the standard voltage and frequency in the islanded section while sharing both real and reactive power requirements of the loads.

B. During a fault

A fault can occur when the DGs are operating either in grid connected or islanded mode. In both cases, each VSC limits its output current to twice the rated current and operates in current control mode. It is to be noted that the VSC identifies a faulted condition in both grid connected and islanded mode by monitoring the PC voltage. The PC voltage reduces during a fault and this change of voltage triggers to apply the limit to the output current. The VSC maintains the current limiting for a defined time period (t_{cc}), if the fault exists. The time period (t_{cc}) allows OC relays which are located downstream from the fault to detect and isolate the fault. This time period (t_{cc}) can be adjusted depending on the relay characteristics selected. Also, the maximum allowable time given in IEEE 1547 [9] to disconnect a DG during a low voltage condition can be considered when selecting the t_{cc}. The VSC can recover if the fault is cleared before t_{cc} elapses depending on the system configuration exists after the fault isolation.

If the DG is still connected to the faulted segment after the time period t_{cc}, the VSC folds back the output current to a very small value for another defined time period t_{sm}. The operating mode of VSC in current control mode during this time is called as *sleep mode*. During the sleep mode, the DG injects a small current without disconnecting from the network. The sleep mode operation of VSC results in self extinction of any temporary arc fault which is not cleared by relays successfully during the time t_{cc}. Therefore the sleep mode operation enables the arc extinction without DG disconnection. The sleep mode time duration can be set based on the arc deionisation time which can be calculated using the equation given in [12].

The behaviour of a VSC during a fault is shown in Fig. 1 assuming the fault is not cleared by protective relays. The VSC injects the current (I_o) in pre-fault mode. The fault occurs at point *A*. The VSC limits the output current to twice the rated current for the time period of t_{cc} as shown in the figure. The VSC then rapidly reduces its output current to a very small value given by nI_r where n ia a small number and remains in the sleep mode for the time period of t_{sm}. The restoration process starts after this period and it is explained in the next sub-section.

C. System restoration

The system restoration is started once sleep mode time period elapses. During this process, each VSC tries to restore the system either in grid connected or islanded mode depending on the system configuration exists after the fault. The recovery characteristic of the VSC is shown in Fig. 2 by assuming the DG capacity is sufficient to supply the load demand and the fault has cleared when restoration begins. The line DEF represents the restoration boundary in current control mode. In sleep mode, the VSC starts at point *D* and calculate the PC voltage which is given by point *K* on the load line. Then VSC calculates the corresponding current on the line *DE*. After that VSC injects the calculated current which will result to move the operating point to *M* on the load line. Again, the VSC controller calculates the required current which is the rated current at point *N*. The injection of rated current increase the voltage above the rated value and thus operating point moves to *O* on the load line by successfully recovering the system.

It is to be noted that during the restoration process the VSC is not allowed to inject beyond the rated current to make sure the DG capacity is sufficient to restore the system. The restoration process is continued for a defined time period t_{res}. If the DG is not recovered during the t_{res} due to the higher load demand or faulted condition, the DG is then disconnected using its own circuit breaker. For the illustration purposes, a constant impedance type load is considered. However, the restoration characteristic of different types of loads may be different. Many constant power type loads such as motors and electronic devices change their characteristic below some voltage level to constant impedance type or tripping of load occurs below a specified voltage [13]. The proposed intelligent control algorithm for the VSC is shown in Fig. 3.

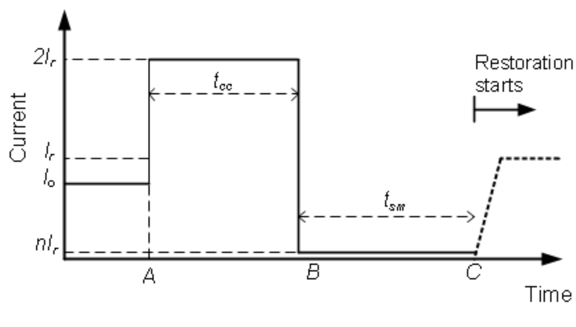

Fig. 1. DG behaviour during a fault

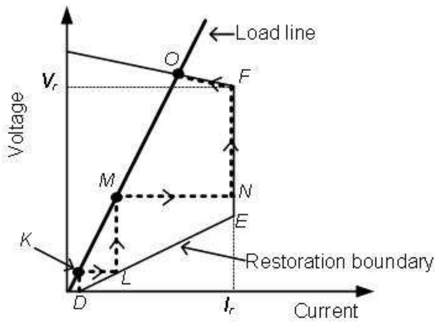

Fig. 2. Restoration characteristic

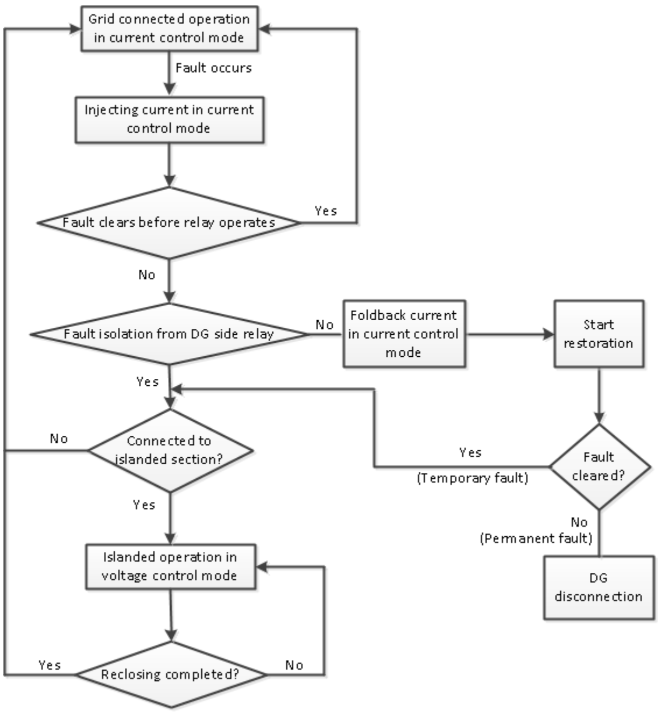

Fig. 3. The proposed VSC control algorithm

IV. DG Coordination with Network Reclosers

Reclosing can be considered as a major protection issue when several DGs are connected to a distribution network. In this paper, an effective method is proposed to coordinate network reclosers with converter interfaced DGs in a distribution feeder. The total time (defined as t_{dg} which includes t_{cc} +t_{sm} + t_{res}) associated with proposed DG control during a fault is used to coordinate the network reclosers with DGs. Two methods are introduced to coordinate a recloser with a DG. In the first proposed method, the DG takes the opportunity to restore the system before the operation of any auto recloser. This method is advantageous, if DG penetration level is significant and DGs have the ability to supply the load demand in islanded mode. As mentioned in VSC control strategy, elapsing t_{dg} after a fault, the DGs either supply power (i.e., in grid connected or islanded mode) to the network due to successful restoration or they are disconnected from the network due to unsuccessful restoration (i.e., uncleared fault or higher load demand). Then, the recloser which sees the fault as forward takes the first opportunity to perform the reclosing and it can result in a live to live or live to dead reclosing depending on the result of DG restoration. The recloser which sees the fault as reverse will always wait until the upstream side is restored.

In the second method, an opportunity is given to the recloser to restore the system before DG starts to restore the system. This method can be used for a system when DG capacity is not sufficient to supply the load demand in an islanded section. In this case, the DGs are kept in sleep mode until reclosing finishes. The recloser may restore the system depending on the fault status. If the system is successfully restored, then DG can start the restoration process which will be successful. This results in maximizing the DG benefits to the customer by connecting DGs quickly. On the other hand, if the reclosing fails to restore the system, DGs will be disconnected automatically after the defined time period of restoration.

A synchronism check element is used in each recloser to make sure whether two sides of a breaker is in exact synchronism when performing the live to live reclosing. The DGs maintained the original phases since they are not disconnected during a fault. Also, they maintain the standard voltage and frequency during the operation in islanded mode. However, there may be a slight phase angle mismatch due to frequency deviations in grid side. In that case, the recloser waits until phase angle on the both side becomes closer to join the two systems. However, the DG itself has the protection to withstand for contingency conditions and it is discussed in next section.

V. DG Protection

It is important to consider the consequences of out of phase reclosing when DGs are not disconnected during the auto recloser open time. The risk of DG damage due to the out of phase reclosing is lower, if DG is connected through a converter [14]. In the proposed reclosing scheme, the recloser is capable of checking the synchronisation which ensures there is no phase mismatch when it performs live to live reclosing.

From the point of DG protection, the DG should be protected itself. To achieve basic DG protection requirements, in the proposed method, a DG is employed with several protective elements: fold back current control, reverse power flow, over voltage and synchronism check. The proposed current limiting and fold back current control protect the DG from excessive current injection and unsuccessful system restoration. The reverse power flow protection is activated to trip the DG when current flows towards the DG. The over voltage element responds, when the terminal voltage of the DG rises above a predefined limit. However, under voltage protection is incorporated with the proposed fold back current control since DG is allowed to operate under the rated voltage in current control mode for a defined time interval. The synchronism check element ensures a trouble free connection to the feeder when it is being reconnected after any disconnection. These protection schemes will minimize the

DG safety risks associated with reclosing.

VI. The Need of Communication for the Protection

To achieve the proposed protection and control strategies, communication between relays and each DG controller is required. The each DG operates in voltage control mode in grid connected operation while current control mode is selected in islanded operation. Each relay-breaker status is available for all the DGs to determine the mode of operations (i.e. either grid connected or islanded).

Also, each DG circuit breaker status is available for all the relays in the feeder. The proposed protection scheme is employed to isolate the faulted segment from both the upstream and downstream side of a fault. In this study, the converter interfaced DGs are only considered and they are intermittent and limiting output currents during a fault. Therefore the fault current level changes depending on the DG connections and the fault current seen by downstream relay is low. Under this circumstance, isolating the faulted segment using the existing OC relays will be difficult. Thus the OC relay settings are changed with the aid of communication according to the number of DG connections.

In the case of communication failure, each relay selects its default setting which has been set during the initial relay settings. Also, the DGs switch into current control mode assuming they are connected to grid connected mode. However, if they are not connected to grid, they can sense that the standard voltage and frequency are not within the defined limits which will lead to disconnect all the DGs from the network.

VII. Simulation Studies

Consider the radial distribution feeder shown in Fig. 4 to validate the proposed protection and control strategies. Three converter interfaced DGs, DG1, DG2 and DG3 are connected at BUS-2, BUS-3 and BUS-4 respectively. It is assumed that the DGs are controlled in angle droop to share the load power in islanded mode according to a predefined ratio [15, 16]. However, different converter structures and controls can be used to achieve the proposed converter control strategy. The DG circuit breakers CB_{DG1}, CB_{DG2} and CB_{DG3} provide the protection for each DG. The feeder is protected by OC relays R_1, R_2 and R_3 which are located at BUS-1, BUS2 and BUS3 respectively. It is assumed that all the circuit breakers associated with these relays have the reclosing capability since one of the main objectives of this study is to show the system restoration performing auto reclosing in the presence of DGs. The system parameters of the study system are given in Table I.

The directional feature is added to the OC relays, since different relay settings are required in forward and reverse directions. In the forward direction, relays R_1, R_2 and R_3 are graded with IEC standard inverse time OC characteristic [17] with a 0.3 s discrimination time margin. Also, instantaneous tripping time element is added for each relay to isolate the faults fast which have higher fault currents. The calculated maximum and minimum fault current levels for different fault locations are given in Table II. Based on these values, the relay settings are calculated and they are given in Table III. The tripping time of each relay for different fault currents in forward direction is shown in Fig. 5. It can be seen that each upstream relay provides the backup protection for the immediate downstream relay.

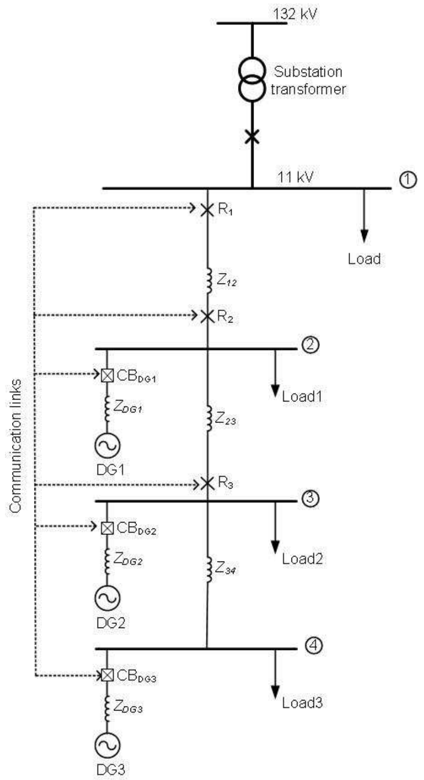

Fig. 4. Simulated radial feeder with DGs

TABLE I SYSTEM PARAMETERS

System data	Value
System frequency	50 Hz
Source voltage	11 kV rms (L-L)
Source impedance (Z_s)	0.078 + j 0.7854 Ω
Feeder impedance (Z_{12}=Z_{23} =Z_{34})	0.52 + j 2.60 Ω
Each load impedance	190 + j 142
DG data	
DG1 source impedance	0.9375 + j 15.708 Ω
DG2 source impedance	0.75 + j 12.566 Ω
DG3 source impedance	1.2503 + j 20.954 Ω
DG1 output power	0.5 MVA
DG2 output power	0.625 MVA
DG3 output power	0.375 MVA

TABLE II FAULT CURRENTS IN FORWARD DIRECTION

	Fault current (A)			
	BUS-1	BUS-2	BUS-3	BUS-4
Maximum	8054	1843	1040	724
Minimum	6967	1596	901	627

TABLE III RELAY SETTINGS IN FORWARD DIRECTION

Relay	CT ratio	Pickup current (A)	Time multiplier setting
R1	300/5	5	0.25
R2	250/5	4.0	0.15
R3	250/5	4.0	0.05

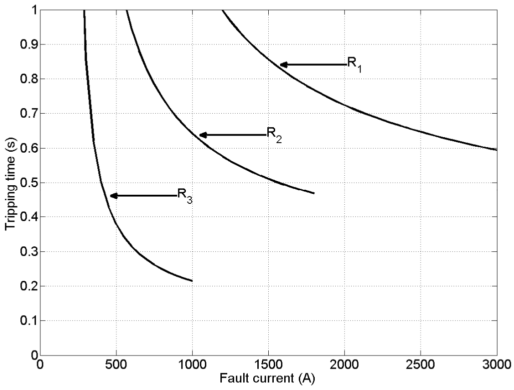

Fig. 5. Relay tripping times in forward direction

In the reverse direction, relays R_2 and R_3 are graded with definite time OC relay characteristic. The definite time element is selected due to lower fault current level in the reverse direction since the current limited DGs supply the fault current during a fault. However, the setting of definite time element should be changed according to the available number of DG connections. The maximum load current seen by each relay is taken into consideration when selecting the relay settings in the reverse direction. For example, with the absence of Load1, Load2 and Load3, the DGs connected to the network will inject current back into the utility grid. Therefore the relay pickup current is selected calculating the maximum load current and allowing a safety margin of 1.5 times the maximum load current. The calculated relay settings in the reverse direction are given in Table IV. The rated currents of DG1, DG2 and DG3 are calculated as 26.2 A, 32.8 A and 19.7 A respectively according to their power ratings for this calculation.

A number of simulation studies are carried out by creating different types of faults at different locations in PSCAD to evaluate the performance of proposed protection and control strategies. However, few results are presented here.

TABLE IV OC RELAY SETTINGS IN REVERSE DIRECTION

DG1	DG2	DG3	R_2		R_3	
			I_{Lmax} (A)	I_p (A)	I_{Lmax} (A)	I_p (A)
0	0	0	0.0	Blocked	0.0	Blocked
0	0	1	19.7	29.9	19.7	29.9
0	1	0	32.8	49.2	32.8	49.2
0	1	1	52.5	78.7	52.5	78.7
1	0	0	26.2	39.3	0.0	Blocked
1	0	1	45.9	68.8	19.7	29.9
1	1	0	59	88.5	32.8	49.2
1	1	1	78.7	118	52.5	78.7

0= not connected, 1= connected, I_{Lmax}= Maximum load current, I_p= pickup

A. A fault between BUS-1 and BUS-2 in grid connected mode

It is assumed that all the DGs and loads are connected to the feeder shown in Fig. 4. A three phase to ground fault is created between BUS-1 and BUS-2 at 0.2 s. The relays R_1 and R_2 respond to isolate the fault at 0.267 s and 0.312 s respectively. After successful faulted segment isolation, the DGs restore the system beyond BUS-2 supplying the load power requirement in the islanded mode. The response of DG1 is shown in Fig. 6. It can be seen that the DG limits its output current once fault occurs helping the downstream relay R_2 to detect the fault. However, once R_2 isolates the fault from downstream side, the DG terminal voltage rises to rated voltage and it causes DG to switch over to voltage control mode.

The real and reactive power variations of DGs are shown in Fig. 7. The DGs supply only the real power to the utility before the fault in grid connected operation. However, after the system is restored in islanded mode, the DGs supply both real and reactive power requirement of the loads.

The relay R_1 which sees the fault as forward starts the reclosing first at 1.012 s. However, the downstream relay R_2 waits until the upstream side is restored. In this simulation, it is assumed that the fault is temporary and it is cleared after the faulted segment is isolated. Therefore the first reclosing of R_1 (i.e., live to dead) is successful. The relay R_2 then starts the reclosing process by sensing the voltage of the upstream side. In this study, it is assumed that the grid side frequency has increased to 50.5 Hz from the nominal 50 Hz when the reclosing process of R_2 begins. Due to the frequency mismatch, the reclosing cannot be performed soon after starting the process. Thus R_2 waits until the phase angle get matched in both sides and so it performs the reclosing successfully at 2.4 s. The voltage of both grid side and islanded side of the reclosing breaker is shown in Fig. 8(a). The reclosing is performed when phase angles of grid and islanded sides are equal. The voltage and current of DG1 during the reclosing are shown in Figs. 8(b) and 8(c) respectively. The smooth transition from islanded mode to grid connected operation validates the suitability of the proposal control strategy. It is to be noted that if the fault is permanent, R_1 reclosing will be unsuccessful and islanded section operates in autonomous mode until fault is cleared and restore the upstream system.

The variation of DG power during the transition from islanded mode to grid connected is shown in Fig. 9. It can be seen that the DGs start to inject rated power in grid connected mode.

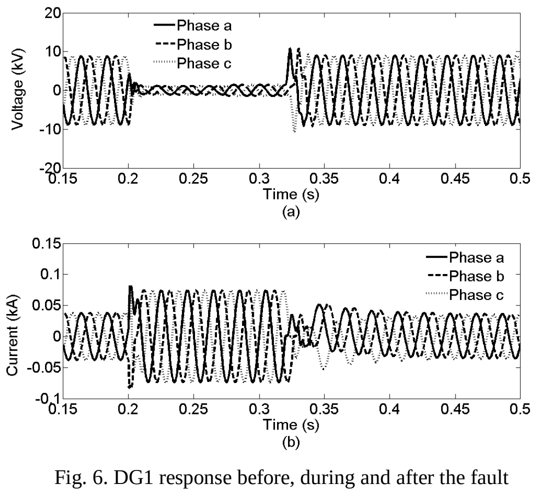

Fig. 6. DG1 response before, during and after the fault

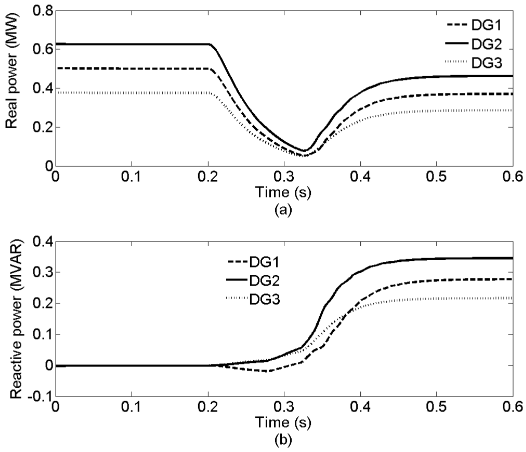

Fig. 7. The real and reactive power variation of DGs

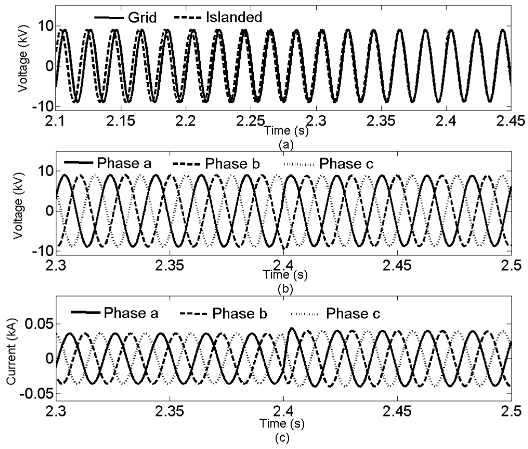

Fig. 8. System parameters during reclosing

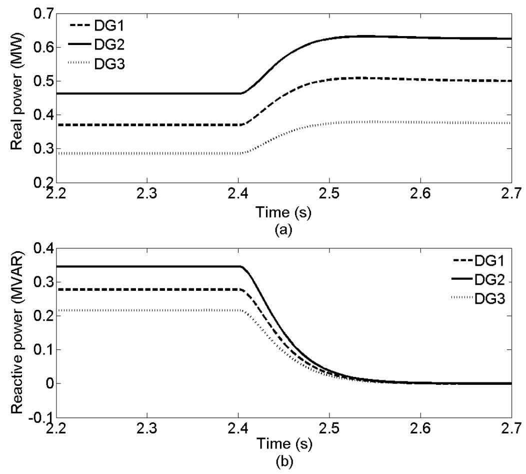

Fig. 9. Real and reactive power variation during transition

B. A fault between BUS-2 and BUS-3

It is assumed that a permanent fault occurs between BUS-2 and BUS-3 at 0.2 s. The relays R_2 and R_3 isolate the faulted segment at 0.265 s and 0.507 s respectively. The fault isolation from downstream side relay leads to restore the islanded system containing DG2 and DG3 with Load2 and Load3 beyond BUS-3. The current limiting of DG1 during the fault is shown in Fig. 10(a). However, the DG1 switches into sleep mode as shown in Fig. 10(b) at 0.56 s since it is still connected to the faulted segment. After the sleep mode time duration, the DG1 starts the restoration at 0.755 s. The restoration process of DG1 will be unsuccessful due to the fault. Therefore it is disconnected from the network at 0.82 s. The DG1 output current during the restoration process is shown in Fig. 10(c). It can be seen that DG1 output current is very small and the current will not rise due to the lower terminal voltage appears during the fault.

The relay R_1 starts the reclosing after DG1 has been disconnected. The attempt of reclosing will also be unsuccessful due to the permanent fault. The variation of output real and reactive power of DGs during and after the fault is shown in Fig. 11. It can be seen that DG2 and DG3 supply the power requirement in islanded mode while DG1 has been disconnected due to unsuccessful restoration.

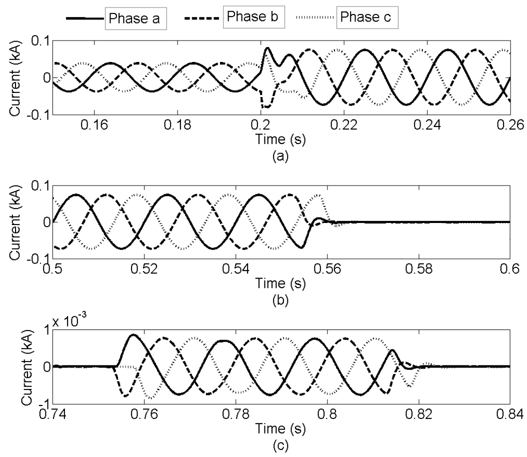

Fig. 10. The output current variation of DG1

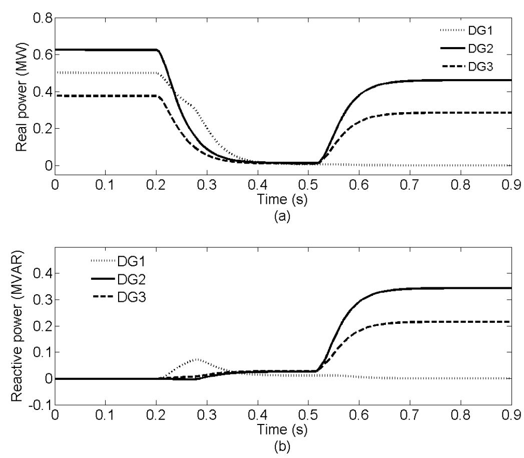

Fig. 11. The variation of DG real and reactive power

C. System restoration with induction type loads

The system restoration with induction motor type loads is investigated in study. It is assumed that two induction motors are connected at buses 3 and 4 respectively. The power rating of each motor is selected as (0.128+ j 0.075) MVA. A half of the constant impedance load given in Table 1 is assumed to be connected to buses 3 and 4. Thus, each load at buses 3 and 4 consists of induction motor and constant impedance type load. A fault is created at 0.2 s between BUS-2 and BUS-3. Once the downstream relay R_3 responds to isolate the fault at 0.507 s, the islanded system beyond BUS-3 is recovered with two induction motors. The real and reactive power variation of DG2, DG3 and one of the induction motor is shown in Fig. 12. According to the figure, the induction motor draws higher reactive power initially and the reactive power requirement is supplied by DG2 and DG3.

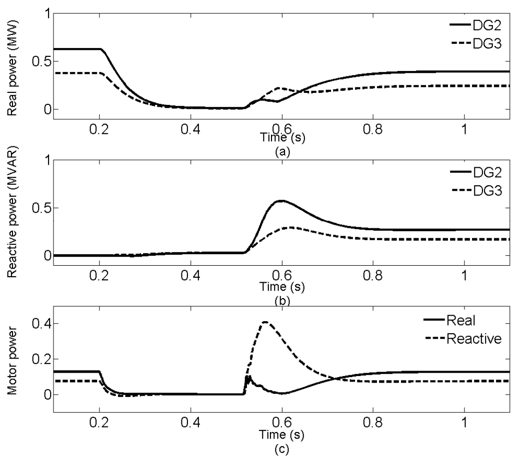

Fig.12. The variation of DG and induction motor power

If large induction motors are present in the network during the constant current and sleep mode time duration, these induction motors located near to a fault will be automatically disconnected due to its own protection. Therefore when DGs start the restoration, the restoration will be easier and quicker with the absence of induction generators.

VIII. Conclusions

The current practice of immediate DG disconnection for every fault drastically reduces the benefits of DGs to both utility and customers. In this paper, the identified protection and control issues which lead to immediate DG disconnections are addressed. The protection scheme has been proposed to isolate the faulted segment allowing DGs to operate either in grid connected or islanded mode. Furthermore, the proposed control strategy for a converter interfaced DG helps in fault detection, arc extinction and system restoration in a DG connected distribution network. It has been shown that if these proposed protection and control strategies are incorporated to DG connected networks, DG benefits can be maximized maintaining as many DG connections as possible during and after a fault.

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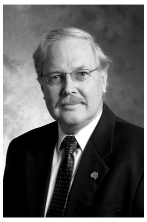
X. Biographies

Manjula Dewadasa (S'08, M'10) is working as a research associate at Queensland University of Technology, Australia. He received the Ph.D in Electrical Engineering from Queensland University of Technology, Australia in 2010 and B.Sc. (Hons) in Electrical Engineering from the University of Peradeniya, Sri Lanka in 2005. He worked as an Electrical Engineer for two years in a leading manufacturing company before starting the PhD studies at QUT in 2007. His interests are in fault analysis, power system protection and distributed generation.

Arindam Ghosh (S'80, M'83, SM'93, F'06) is the Professor of Power Engineering at Queensland University of Technology, Brisbane, Australia. He has obtained a Ph.D. in EE from University of Calgary, Canada in 1983. Prior to joining the QUT in 2006, he was with the Dept. of Electrical Engineering at IIT Kanpur, India, for 21 years. He is a fellow of Indian National Academy of Engineering (INAE) and IEEE. His interests are in Control of Power Systems and Power Electronic devices.



Gerard Ledwich (M'73, SM'92) received the Ph.D. in electrical engineering from the University of Newcastle, Australia, in 1976. He has been Chair Professor in Power Engineering at Queensland University of Technology, Australia since 2006. Previously he was the Chair in Electrical Asset Management from 1998 to 2005 at the same university. He was Head of Electrical Engineering at the University of Newcastle from 1997 to 1998. Previously he was associated with the University of Queensland from 1976 to 1994. His interests are in the areas of power systems, power electronics, and controls. He is a Fellow of I.E.Aust.