OPTIMAL AUTOMATION LEVEL IN MICROGRIDS

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ABSTRACT

In this paper a new methodology for determining the optimal level of automation in microgrids is proposed. In traditional distribution networks, automation is referred to the management of the fault in a more efficiently manner especially in medium voltage (MV) distribution network in order to improve the network reliability indices by reduction of average outage duration per consumer and meanwhile mitigation of the costs due to the energy not supplied. Microgrid as a subset of distribution network which is composed of a cluster of loads and paralleled DG systems in a common local area needs to inherit the concept of automation from traditional distribution. The problem of network automation in a microgrid is more complicated than conventional distribution systems, as in traditional distribution networks, the only way to restore supply is the loop automation, while in microgrids, there are so many options for load restoration by using different combinations of microsources other than the loop automation and utility grid. Hence the automation level in a microgrid is a complex, non-linear and discrete optimization problem of enormous dimensions that needs to be handled by sophisticated and heuristic optimization procedures. The proposed methodology is a scenario-based search method using local automation and remote control strategies in an individually and combinatory manner considering achievable benefits for each scenario. The proposed methodology is simulated on a sample microgrid; the results indicate the functionality of the proposed methodology for the determination of the optimal level of investments in the automation of microgrids.

INTRODUCTION

Microgrid is a newly evolved concept interpreting as systematically grouping a cluster of loads and paralleled Distributed Generation (DG) systems, powered by microsources such as fuel cells, photovoltaic cells, and microturbines in a common local area. Being a larger entity, a microgrid is anticipated to have a larger power capacity and more control flexibilities to fulfill system reliability and power-quality requirements, in addition to all inherited advantages of a single DG system. The formed microgrid can operate in two distinct modes; i.e., utility-grid (macrogrid) connected mode and autonomous (islanding) mode. In autonomous mode the DGs could serve the connected loads in full or partially by shedding the remaining ones [1].

Automation is a concept that is necessary to be inherited from traditional distribution network to the microgrid. In [2] and [3], different automation levels in traditional distribution systems is analyzed and described, hence, the explained methodology is extended to the microgrids in this paper. In other words, the commonly accepted and implemented methodology described in [2]-[3] is inherited to microgrids in this paper by considering the pros and cons of a microgrid automation with respect to conventional distribution systems. The differences can be summarized as follows:

1. Restoration of the supply of traditional distribution systems upon incidence of a fault is energizing from another feeder, which is referred to as loop automation in a remotely controlled automation system.
2. Microgrid has more options to restore the supply. In addition to the restoration methods commonly used in traditional distribution systems, its supply could be restored by using available DGs within the microgrid.
3. Dispatching the generation of the available DGs and importing/exporting power from/to the macrogrid is another point that influences the automation of the microgrid and increases the complexity of the microgrid's automation.

Local automation refers to distribution systems that benefit from automatic switching of devices such as circuit breakers with local protective relays, reclosers, autosectionalizers, changeovers, local fault passage indicators as described in [4]-[5]. Automation of distribution systems by using remote control is introduced in [6]-[8]. The determination of the optimal level of network automation as a complex, non-linear and discrete optimization problem of enormous dimensions is analyzed and reported in [2]-[3] and [9].

In this paper a new methodology for the determination of the optimal automation level in a microgrid is proposed based on searching different scenarios using local automation and remote control strategies in order to reduce the average outage duration per consumer, to decrease the costs due to the energy not supplied and to improve the network reliability. The proposed methodology is simulated on a sample microgrid with different loads and DGs. The results indicate the functionality of the proposed methodology for the determination of the optimal level of investments in the automation of microgrids.

PROPOSED METHODOLOGY

The proposed methodology is the extension of the method proposed in [2]-[3] to include the unique features of a microgrid.

Cost/benefit analysis is performed for each scenario for the planned period, i.e., investments in the network automation represents the cost, while the price of reduction the energy not supplied, cut-off power and maintenance represents the benefit. The foreseen scenarios are ranked in different subclasses and suboptimal scenarios are obtained. Scenarios can be ranked according to any appropriate criterion such as appropriate C/B ratio, total annual benefit or appropriate reliability index. The optimization problem is defined as a multi-objective function (maximizing benefit, meanwhile minimizing reliability indices and C/B ratio) with fulfilling the constraints such as reliability indices to be less than a limit, investment costs to be less than the planned budget, C/B ratio to be less than one.

SIMULATION RESULTS

Figure 1 shows the sample microgrid used for simulation. It is composed of three feeders with different combinations of loads (sensitive, industrial, commercial, residential, etc.) and different energy resources. The microgrid is connected to the utility-grid (macrogrid) through a transformer. CB1 to CB3 are equipped with protective relays to deal with the faults on the feeders. The loads are connected to the nodes (i) with incoming (Si-1) and outgoing switches (Si-2). These switches could be manually operated or remotely controlled. For simplicity, the calculation is presented with the following assumptions [3]:

- lengths of all sections of each feeder are 1 km,
- speed of movement of field crew during fault location and restoration is 1 km/min,
- duration of one manual switch operation is 2 min,
- duration of one remote switch operation is 0.1 min,
- duration of entry into distribution substation is 10 min,
- time of repairing faulted element is 5 h (300 min).

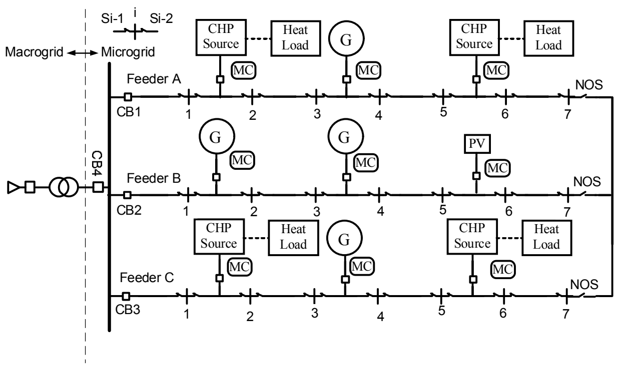

Figure 1: Sample microgrid

Scenario 1: No local automation or remote control

Figure 2 shows a fault on feeder B at point F with indication of fault currents from different resources. Upon occurrence of a fault on section 5, the protective relay associated with CB1 is activated and trips CB1, simultaneously the related CBs of the DGs disconnect the microsources, leaving all consumers on feeder B without supply.

Outage duration for this fault is calculated using bisectional search method as mentioned in [3]. It takes 3min for the field crew to reach distribution substation 3, i.e., (1+1+1) km/1 km/min=3min. Entering to the substation 3 needs 10 min. Then, manual switch S3-2 is being opened in 2min, to check whether the fault is located on the first or the second half of the feeder. Then CB1 is closed within 2min. Since CB1 does not trip, it means that the fault is on the second half of the feeder. CB1 is being opened within 2min to allow other operations of the manual switches. Switch S3-2 is closed manually in 2min. The field crew then moves from distribution substation 3 to substation 5 in 2min, entering substation 5 within 10 min; and opening switch S5-2 in 2min. CB1 is then closed within 2min, but it trips. The conclusion is that the fault is on feeder part between substation 3 and 5. Switch S5-2 is being closed in 2min. Then the field crew moves from distribution substation 5 to substation 4, with the duration of 1min, entering substation 4 in10 min and opens switch S4-2in 2 min. CB1 on feeder head is being closed in 2min. CB1remains closed. Conclusion is that the fault is on section 5 which is between substations 4 and 5. By closing CB1 the procedure of fault location, isolation and supply restoration of consumers in substations 1, 2, 3 and 4 is finished. Then outage duration of consumers in those substations is calculated as 54min. The associated DGs can also be connected to the healthy section of feeder B.

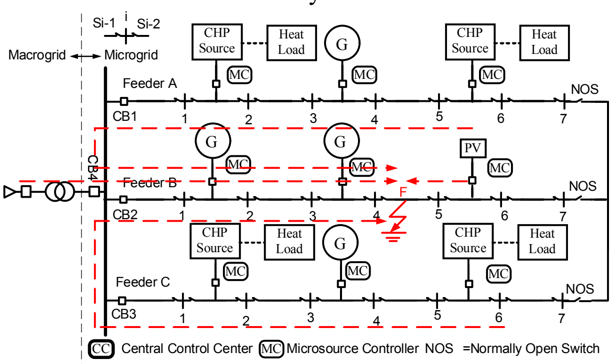

Figure 2: Scenario 1, no local/remote automation

Switch S4-2 remains opened, and field crew moves again to distribution substation 5 in 1 min, entering the substation in 10 min and opens switch S5-1 in 2 min. Now the faulty section is isolated and there are different options to restore supply to substations 5to7, i.e., by closing NOSs on feeder B and either feeder A or feeder C (or both of them if needed), or connection of PV microsource to the feeder. Moving time to the two NOSs (at least) is 3min and two 2min is required for closing them. In this case the outage duration time for these consumers is 54+20=74min; or 54+13+2=69min, if substations 5 to 7 are energized by the related DG.

Scenario 2: Remote control of CBs and NOSs

Figure 3 shows the sample microgrid with the central controller (CC) to dispatch generation on the DGs. The commands are received and deployed by microsource controllers (MC).

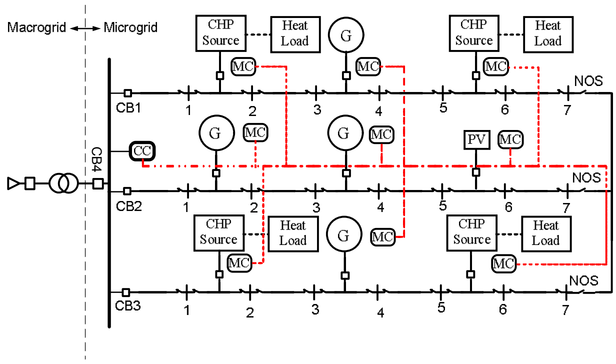

Figure 3: Sample microgrid with central controller for power dispatch of DGs

Figure 4 shows the sample system with the functionality of remotely operating CBs and NOSs by CC. The restoration time of substations 1 to 4for the shown fault is the same as previous, i.e., 54min, for substations 5 to 7 will be reduced due to the remote control of the NOSs, i.e., 54+13=67.

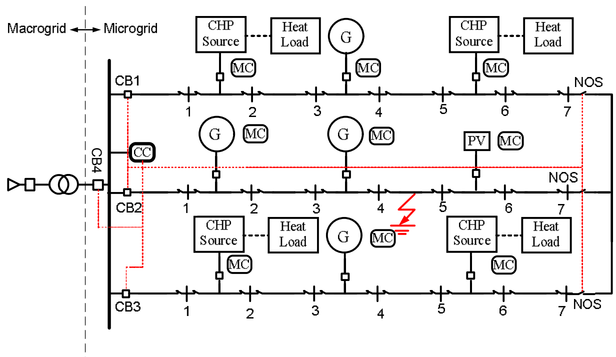

Figure 4: Scenario 2 remotely controlled of CBs (RCBs) and remotely controlled NOSs (RNOSs).

Scenario 3: Remote control of RCBs and RNOSs

Remote control of CBs does not effectively reduce the outage time, since the fault location is not fulfilled. Figure 5 shows the sample microgrid with RCBs on the feeder head and midpoint of the feeder plus RNOSs. If the same fault occurs, the outage duration time of substations 1 to 4 is the zero, but the restoration time of substations 5 to 7 will be 6min to move to substation 6, 10min to enter substation and 2min to open S6-2 and 0.1min to close CB5, but it trips and the conclusion is the fault is between substation 4 to 6, the field crew moves in 1min to substation 5, enter the substation in 10min, open S5-2 in 2min, close CB5 in 0.1min, it trips, so the field crew close S5-2 in 2min and open S5-1 in 2min, and closes RNOS in 0.2min; hence the total time is 35.4min.

Scenario 4: RCBs, RNOSs and RFIs

Figure 6 shows the sample microgrid with RCBs, RNOSs plus remotely monitored fault indicators (RFIs) on all circuits of substations. If the same fault occurs, the outage duration time of substations 1 to 4 is the zero, but the restoration time of substations 5 to 7 will be 17.2min. This configuration reduces the outage time of substations 5 to 7 from 35.4min to 17.2min, as the fault location is identified by RFIs.

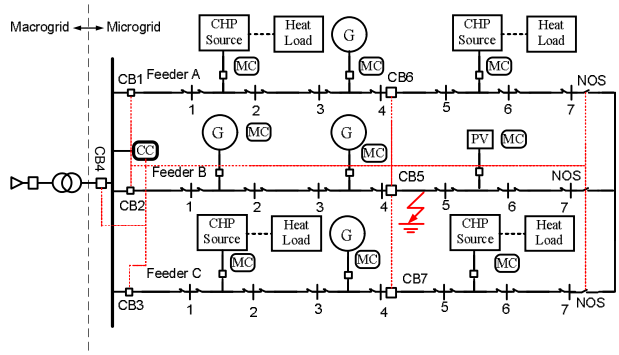

Figure 5: Scenario 3 RCBs on feeder head, feeder mid-point and RNOSs.

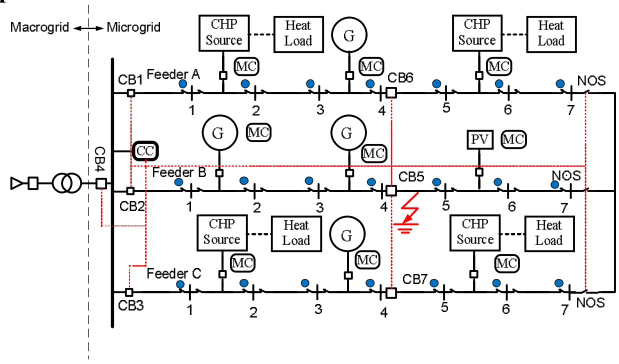

Figure 6: Scenario 4, RCBs, RNOSs and remotely controlled fault indicators (RFIs).

Scenario 5: Local automation with reclosers (RCLs) and local FIs (LFIs)

Figure 7 shows the sample microgrid with reclosers and local fault indicators (LFIs) on all circuits. For the same fault, the restoration time of substations 1 to 4 is 16min; and restoration time of substations 5 to 7 is 35min.

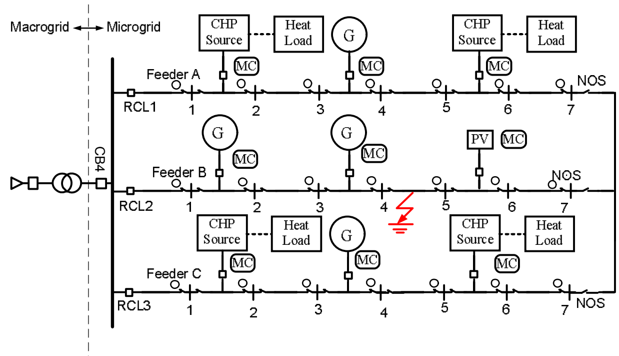

Figure 7: Scenario 5, local automation by RCLs LFIs

Scenario 6: Local automation with feeder head recloser, mid-point recloser and local FIs (LFIs)

Figure 8 shows the sample microgrid with the same configuration as scenario 5 but with midpoint reclosers. The restoration time for the same fault is zero for substations 1 to 4 and 23min for substations 4 to 7.

Scenario 7: Local automation with feeder head recloser, autosectionalizers (ASs), Changeover

Switches (COs) and local FIs (LFIs)

Figure 9 shows the sample system for the same fault with feeder head reclosers (RCLs), autosectionalizers (ASs) at feeder midpoint, changeovers (COs) at the location of NOSs. The restoration time for substations 1 to 4 is (20s+40s) = 1min, and restoration time for substations 5 to 7 is 1min+5min+ 10min+2min+0.1min=18.1min.

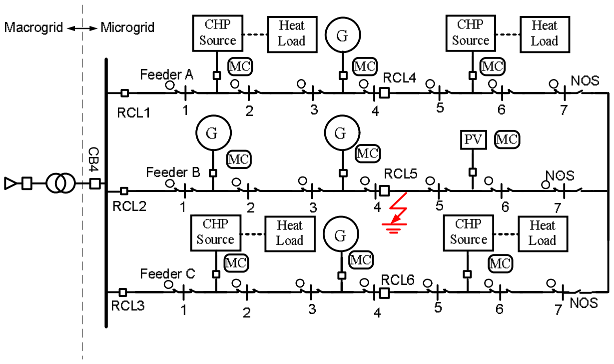

Figure 8: Scenario 6, local automation by using feeder reclosers, mid-point reclosers and LFIs.

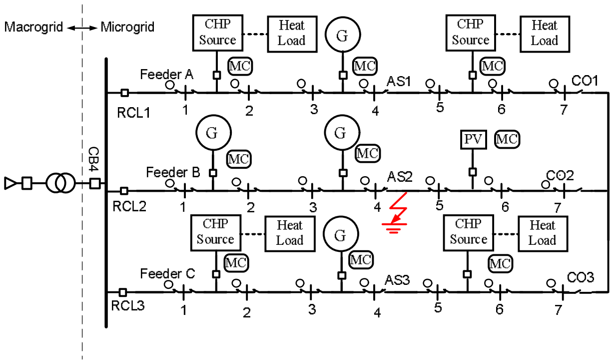

Figure 9: Scenario 7, local automation by using feeder head RCLs, midpoint ASs, Changeovers (COs) and LFIs.

Table 1 shows the optimization results for the sample network. If it is assumed that the budget is 12000€, then scenarios R3 and R6 are suboptimal solutions by different strategies. The optimal solution is a mixed one using remote controls on feeder head, feeder midpoint and local fault indicators on all substations. It is worth noting that the role of DGs in decreasing the outage duration time of consumers are also considered in the simulations.

Table 1: Comparison of different scenarios

Scen-ario		Type of device	Location	C_{inv} (€)	EENS (kWh/yr)	SAIDI (h/yr)	C/B
Remote Cont	R1	No Autom.	------	----	630.4	22.72	0.18
	R2	RCB+RNOS	Feeder Head	6400	185.63	6.68	0.45
	R3	RCB+RNOS	Feeder Head & Midpoint	11903	145.7	5.25	0.52
	R4	RCB+RNOS +RFI	Feeder Head & Midpoint +S/S	12914	114.66	4.25	0.68
Local	R5	RCL+LFI	Feeder Head +S/S	5900	212.73	8.65	0.39
	R6	RCL+LFI	Feeder Head & Midpoint +S/S	11296	158.45	5.95	0.54
	R7	RCL+AS+CO +LFI	Feeder Head & Midpoint	10694	189.66	6.46	0.44

CONCLUSION

In this paper a methodology for analyzing different automation levels in a microgrid is presented. Optimal level of microgrid automation is evaluated based on different scenarios that satisfy the allocated budget. The fulfilled scenarios are ranked based on solution of a multi-objective optimization problem (maximizing benefit, meanwhile minimizing reliability indices and C/B ratio) with fulfilling the constraints such as reliability indices to be less than a limit, investment costs to be less than the planned budget, C/B ratio to be less than one. It is worth noting that the DGs play a vital role in restoration process and could have an important effect on reduction of restoration time in comparison to the traditional process of restoration. As the DGs' capacities are limited, restoration by DGs needs special knowledge about the extent that they could participate in restoration and hence adds more complexity to the optimization problem.

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