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Article

A Practical Protection Coordination Strategy Applied to Secondary and Facility Microgrids

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Abstract: In a conventional distribution system, protection algorithms are designed to operate on a unidirectional high fault-current level. In a microgrid, a fault current from distributed generation (DG) may bring about a relay malfunction because of the bidirectional and relatively small fault current. Therefore, the conventional protection scheme is not applicable to microgrids and a new protection method must be developed. In this paper, two protection coordination algorithms which can be applied for facility and secondary microgrids are proposed, respectively. The proposed protection algorithms eliminate faults not by the EMS signal but by directional relays. Moreover, this makes the algorithms flexible regardless of the types and numbers of DG. The proposed protection algorithms were simulated at the KEPCO RI Microgrid Demonstration Site.

Keywords: microgrid; protection coordination; protection device; distributed generation; fault current

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1. Introduction

With high oil prices and climate change causing serious environmental concerns, distributed generation (DG) using renewable energy is becoming necessary. Also, many countries have implemented regional energy businesses and pilot projects on diffusion of renewable energy as a national energy policy. Such conditions have led to the spread of microgrids. A microgrid is a small-scale power grid which includes various DGs and loads. It is usually connected to the utility grid at a point which is called a point of common coupling (PCC). To the utility grid, a microgrid behaves as a fully controllable load. A microgrid is usually operated in the grid connected mode, and it can be operated in island mode [1–4].

In relation to microgrids, technical issues on power and energy balance, power quality and protection have been studied [5–7]. The protection issue of microgrids is closely connected with control and operation problems. Conventional protection is designed to operate for unidirectional high fault-current levels in a radial grid. However, in a microgrid, high fault-current does not flow during island operation. In addition, DG in a microgrid can make bidirectional fault current flow through the system. This means that a relay can malfunction with the conventional protection algorithm in a microgrid. Therefore, the conventional protection model is not suitable for a microgrid [8].

The protection algorithm in CERTS eliminates faults by the detected differential current, zero sequence current, negative sequence current, and the operation time of the trip signal with respect to the types and location of the faults [4]. However, the algorithm might fail to remove faults with high line-impedance. In addition, the relay setting and the trip time have to be changed with microgrid components on a case by case basis. Hence, its application in microgrids is limited.

In the EU microgrid report, a proposed protection method for microgrids requires that a digital relay can communicate with the Energy Management System (EMS) and other digital relays. With the fault-information from a digital relay, the EMS compares the information with an event table, which is prepared in advance, to eliminate the fault and sends to CBs a signal to open [9]. Even though the protection algorithm in [9] is innovative and advanced, fault problems might not be solved quickly because of communication delays, and there could be numerous cases in which a diverse lineup of DGs are installed in a microgrid or the operation range of a microgrid is extended. Moreover, the algorithm in [9] requires a highly advanced protection device which is not currently economical. Therefore, the algorithm in [9] is difficult to apply in current microgrids.

This paper proposes a novel protection coordination algorithm for facility and secondary microgrids which is defined in the IEEE standards of distributed resource island systems with electric power systems [10]. In short, facility microgrid is an island system formed within a customer facility and secondary microgrid is an island system connected to the secondary side of a distribution transformer [10]. The proposed algorithm eliminates a fault by local relays and current-direction judged by protection devices, not by the signal from the EMS, thereby having a quick response for eliminating a fault and economic benefits. The proposed algorithm is also flexible for application in microgrids. The proposed algorithm was applied to the microgrid demonstration site of Korea Electric Power Corporation's Research Institute (KEPCO RI), where the site is being studied for the commercialization and expansion of environmentally-friendly small distributed generation systems. The remainder of this paper is divided into five sections. Section 2 presents a detailed description of the system configuration and control method of controllable DG. In Section 3, the proposed protection coordination algorithm for microgrids is introduced with the basic concept of the protection algorithm. Section 4 presents simulation results which demonstrate the performance of the proposed algorithm, and Section 5 contains concluding remarks.

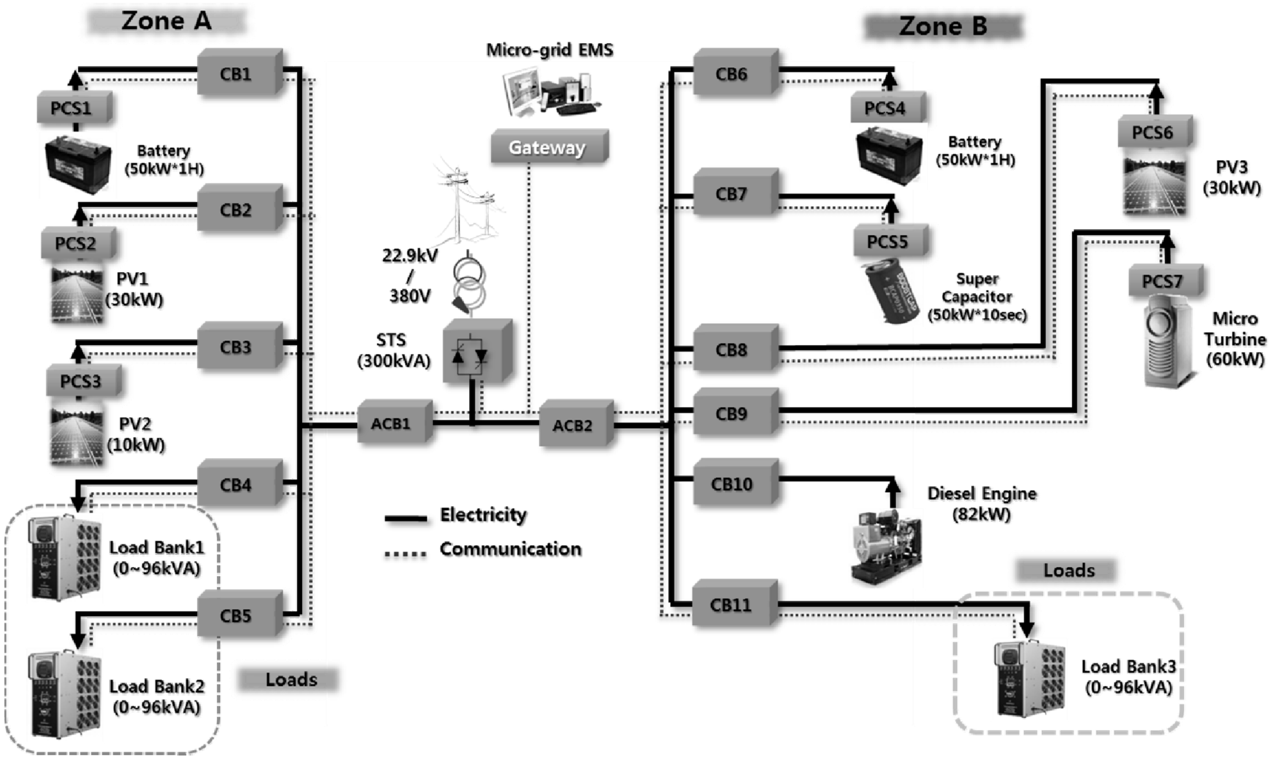
2. System Configuration

2.1. Components of the Demonstration Site at KEPCO RI

The system layout of the microgrid demonstration site is shown in Figure 1. To conduct various experiments for the proposed algorithm, the microgrid test system was divided into Zones A and B. Zone A contains three DGs [Battery Energy Storage System (BESS 50 kW), Photovoltaic (PV1 30 kW, PV2 10 kW) and two artificial loads (Load Bank1, Load Bank2)]. Zone B also has five DGs (BESS 50 kW, Super-capacitor (SC 50 kW), PV3 30 kW, Micro-Gas Turbine (MGT 60 kW), Diesel generation (DE 80 kW), and an artificial load (Load Bank 3).

In this test system, BESS and SC are controllable DGs, and PVs, MGT, and DE act as uncontrollable DGs. Basically, MGT and DE are controllable DGs; however, they are set up to a constant output power in this system.

Figure 1. System layout of the microgrid demonstration site.



2.2. Control Methods of BESS and SC

The control methods for DGs in a microgrid are divided into two modes, namely, unit power control (UPC) mode and feeder flow control (FFC) mode. UPC mode is used to fix the output power of the DG in a microgrid at a constant value when the microgrid is connected to the main grid. In UPC mode, extra power is compensated by the main grid when the load demand is changed anywhere in the microgrid. In island mode, DGs must follow the load demand accurately. With FFC mode, the change of load demand is taken over by DGs in a microgrid when the microgrid is connected to the main grid. However, with island mode, DG with FFC mode must follow the load demand like DG with UPC mode.

In this study, UPC mode was selected for microgrid operation in both grid-connected mode and island mode. The controllable DGs (BESS) in Zones A and B operate in UPC mode with droop control and restore function as shown in Figures 2 and 3. SC in Zone B has the same function as BESS except the restore function in which the DG changes its output power to restore voltage and frequency to the initial reference values.

Figure 2. P-f droop curve for UPC Mode of BESS and SC.

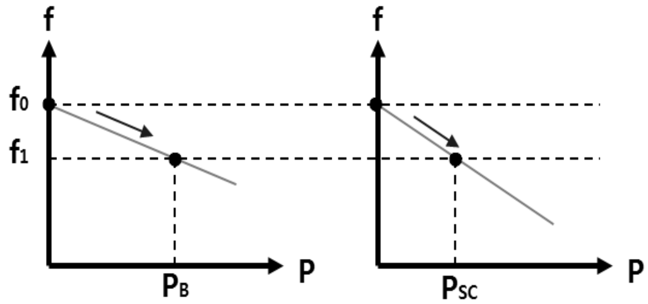
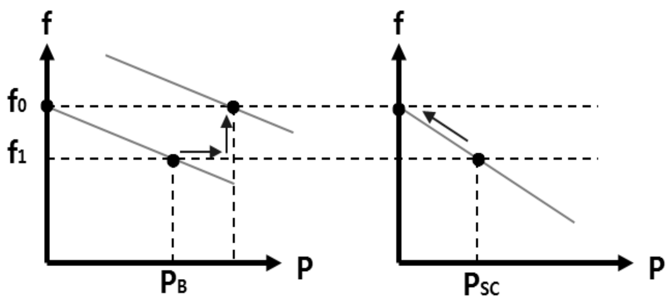


Figure 3. P-f droop curve for Restore Function of BESS.



3. Proposition of Protection Coordination Algorithm in Microgrid

3.1. Basic Concept for Protection Algorithm

Conventional protection coordination is designed to operate at high and unidirectional fault-current levels in a radial grid. When a fault occurs in a microgrid connected to the main grid, high fault-current flows from the main grid into the microgrid. In a microgrid with island mode, however, levels of fault-current are limited to 1.2 to 2.0 pu of the rated current since the DGs are mostly connected to the microgrid with an inverter. In addition, the direction of the fault-current is bidirectional with respect to fault-location due to the features of the microgrid. Hence, the conventional protection algorithm can cause malfunctions because of the fault-current from the DGs when faults occur in the microgrid [11–14]. This means that conventional protection coordination is no longer applicable to microgrids. Therefore, a new method of protection coordination must be developed for microgrids.

Above all, a new protection algorithm requires protection devices which have the ability to distinguish the direction of the fault current in a microgrid. In this study, directional relay by the use of sequence data in the transmission system and loop power distribution system was applied to the proposed protection algorithm for the protection device to distinguish the direction of the fault-current. Basically, directional relaying using sequence elements is divided into two ways. There are two protection devices; directional over-current relay (DOCR) and directional over-current ground relay (DOCGR). In the case of a directional relaying system with DOCR, comparing negative sequence components is suited for distinguishing an unbalanced fault, such as a single line-to-ground fault or a line-to-line fault. A balanced fault, such as a three-phase line-to line fault is distinguished by a positive sequence with DOCR. Zero sequence components are used to discriminate the direction of the grounding fault-current by using a directional relaying system with DOCGR.

In the case of a directional relaying system with DOCGR, a single line-to-ground fault might not be detected by the use of zero sequence elements because the values of the fault currents are small enough not to be distinguished in a microgrid. Therefore, the directional relaying system with DOCR using positive sequence and negative sequence was used to judge the direction of fault current in this study. Even though zero sequences of a line-to-line fault and a three line-to-ground fault are not used, DOCR can distinguish the direction of the faults by using positive sequence and negative sequence. Table 1 is the summary of sequence elements to detect various kinds of faults.

Table 1. Sequence elements used for detecting faults.

Sequence Elements	Three line-to-ground fault	Line-to-line fault	Single line-to-ground fault
V1	Yes	Yes	Yes
V2	Yes	Yes	Yes
V0	No	No	Yes
I1	Yes	Yes	Yes
I2	Yes	Yes	Yes
I0	No	No	Yes

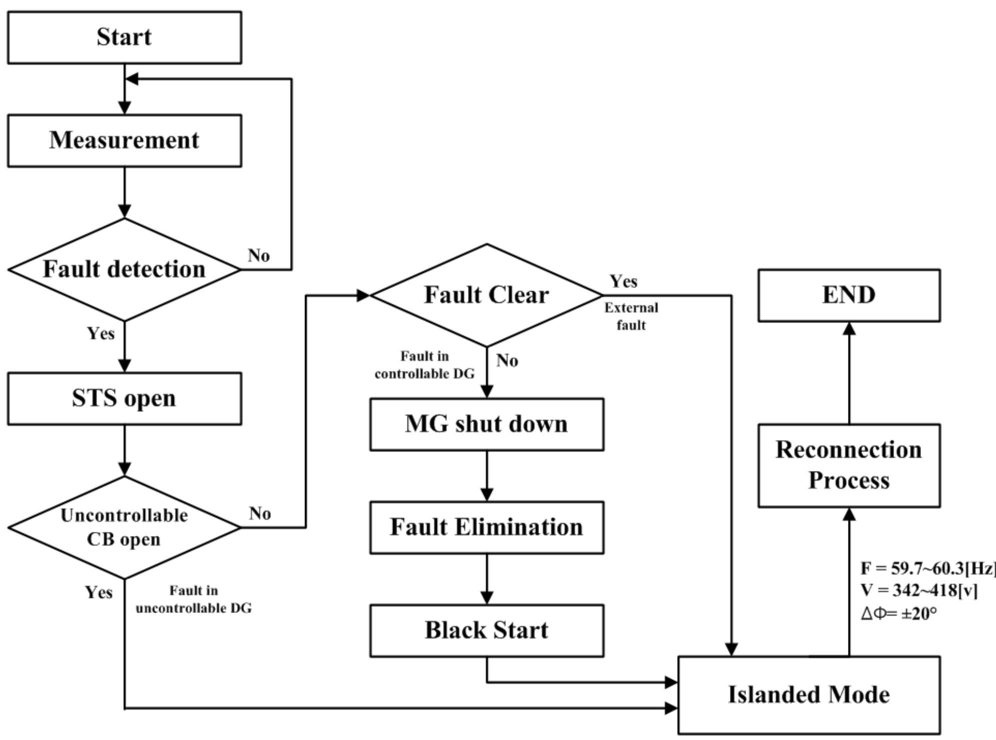
To apply the proposed algorithm to a microgrid, more assumptions are required. The EMS can communicate with all of the DG and protection devices in a microgrid. When a fault occurs, the EMS should identify the state of DGs quickly. All protection devices distinguish the direction of the fault current and communicate with the EMS so that the fault location is identified quickly. With the aforementioned presumptions, protection devices identify the direction of single line-to-ground faults and line-to-line faults by detected positive/negative sequence elements and the maximum torque angle (MTA). In addition, a static transfer switch (STS) is used to separate the microgrid and the main grid in the event of fault. The STS has two functions here. One is to isolate the microgrid from the main grid when a fault or power quality problem occurs. Another is that the microgrid can reconnect with the main grid after the elimination of faults. Since DGs are usually inverter-based in microgrids, the setting value of the positive sequence of protection relays is set to around 2.0 to 3.0 pu. The setting value of the negative sequence is set as the measured value from simulation because the negative sequence is undetected under normal conditions.

This paper presents a protection algorithm only to be applied to a facility microgrid (*i.e.*, Zone B), and the protection algorithm for a secondary microgrid (*i.e.*, Zones A and B). For verification of the proposed protection algorithm, faults were classified into three types of faults, namely, external faults, common line faults, and feeder faults. Note that common line faults are defined as faults that occur between STS and ACB1, ACB2. Feeder faults are the faults that occur between CBs and DG.

3.2. Protection Algorithm for a Facility Microgrid (Zone B)

A flowchart of the proposed algorithm only for Zone B is shown in Figure 4. Let us assume that an unknown fault occurs in the system. First of all, as the protection devices detect the fault current, STS is opened to isolate the microgrid from the main grid, and the operation mode of the microgrid is changed to island mode [15]. Since the STS separates the microgrid from the main grid, the external fault is eliminated at this step. Then, to check the fault of the uncontrollable DG, the EMS detects whether the circuit breaker (CB) is opened or not by signals from the CB of the uncontrollable DG in Zone B. If the CB of the uncontrollable DG is opened, it means the fault of the uncontrollable DG is cleared and the microgrid can continue operating in island mode. This is because the microgrid in island operation mode can be controlled by the controllable DG. After elimination of the fault, the microgrid changes from island mode to grid-connected mode following the distribution system interconnection standards of Korea (frequency: ±0.3 Hz, voltage: ±10%, phase angle: ±20°). If the CB of uncontrollable DG is still closed and the microgrid is abnormally operating in island mode, the EMS judges that the fault has occurred in the controllable DG. Therefore, the microgrid is shut down to eliminate the fault since the microgrid cannot operate in island mode without a controllable DG. Then, the microgrid resumes island operation by black start. Finally, the microgrid changes its mode to grid-connected mode following the standards.

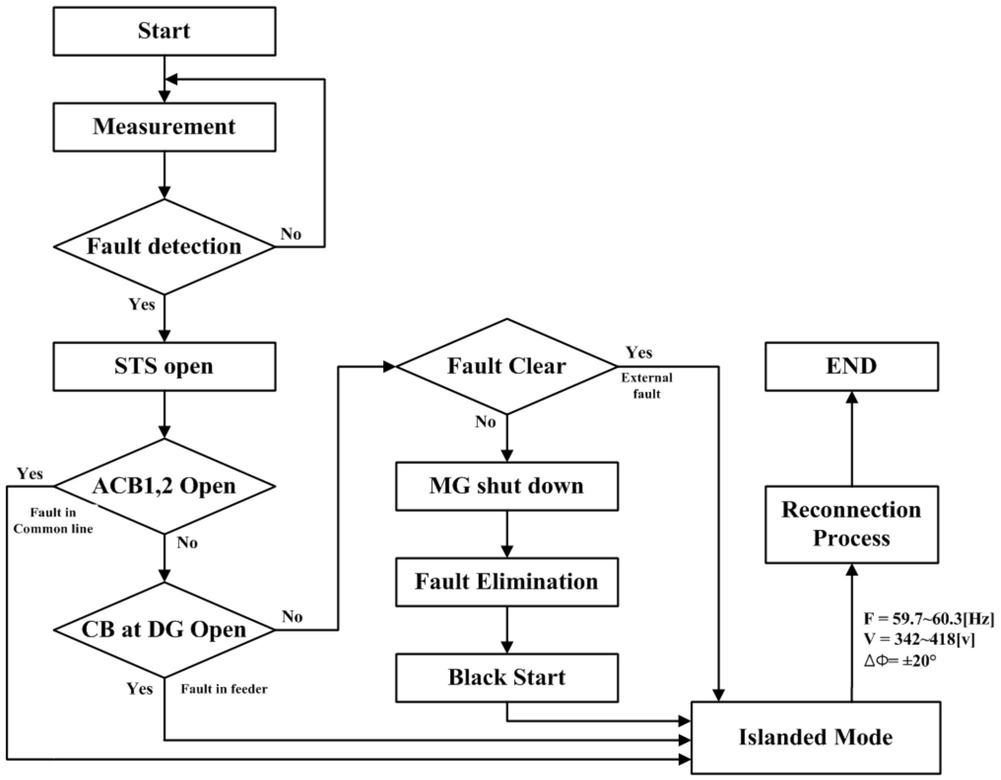
Figure 4. Flowchart of the protection algorithm for facility microgrid (Zone B).



3.3. Protection Algorithm for a Secondary Microgrid (Zones A and B)

A flowchart of the newly proposed protection coordination algorithm for Zones A and B is shown in Figure 5. As the proposed algorithm for Zone B, STS is first opened to isolate the microgrid from the main grid when an unknown fault occurs in the system. Then, the EMS checks on whether air circuit breakers ACB1 and ACB2 are opened to check whether it is a common line fault. When both ACB1 and ACB2 are opened, it means that the fault has occurred between STS and ACB1, 2, and it is eliminated. Hence, each of Zones A and B can operate in island mode respectively without receiving any signal from the EMS. This is because, if the fault occurs in Zones A or B, the CBs are opened before ACB1, 2 are opened because the fault current is higher near the fault location.

Figure 5. Flowchart of the protection algorithm for secondary microgrid (Zones A and B).



If both ACB1 and ACB2 are not opened and the CBs of the DGs are opened, the EMS sends a signal to operate in island mode to the DGs in Zones A and B. At this time, Zones A and B with island mode are connected in parallel. This means that a fault has occurred in DGs in Zones A and B, and it is eliminated by the CBs. In addition, unlike the proposed algorithm for Zone B, the type of DG is unimportant since each of Zones A and B has their own controllable DG. After checking the ACBs, if the CBs are still closed, the voltage and frequency of microgrid are judged by the EMS. If the voltage and frequency are in desired ranges, the microgrid continues operating in island mode with connection between Zones A and B. Finally, when the ACBs and CBs are still closed and the voltage and frequency are out of the required ranges in the microgrid, the EMS shuts down the microgrid and eliminates the unknown fault. Then the microgrid is restarted in island mode. After the black start, the microgrid changes its island mode to grid-connected mode following the distribution system interconnection standards of Korea (frequency: ±0.3 Hz, voltage: ±10%, phase angle: ±20°).

4. Simulation Results and Discussions

4.1. Simulation Scenarios

Simulations using PSCAD/EMTDC were conducted to test the effectiveness of the two proposed protection algorithms when a fault is created in both a microgrid and the main grid with respect to its location. The simulated microgrid was exactly modeled as shown in Figure 6. Also, the system parameters were selected to represent the demonstration site of KEPCO RI. The proposed protection algorithms were verified in the system with the scenario shown in Table 2. In this paper, only the single line-to-ground fault is presented to verify the proposed algorithm because the level of fault-current is the lowest when a single line-to-ground fault occurs.

Figure 6. Modeling of microgrids Zones A and B in PSCAD/EMTDC.

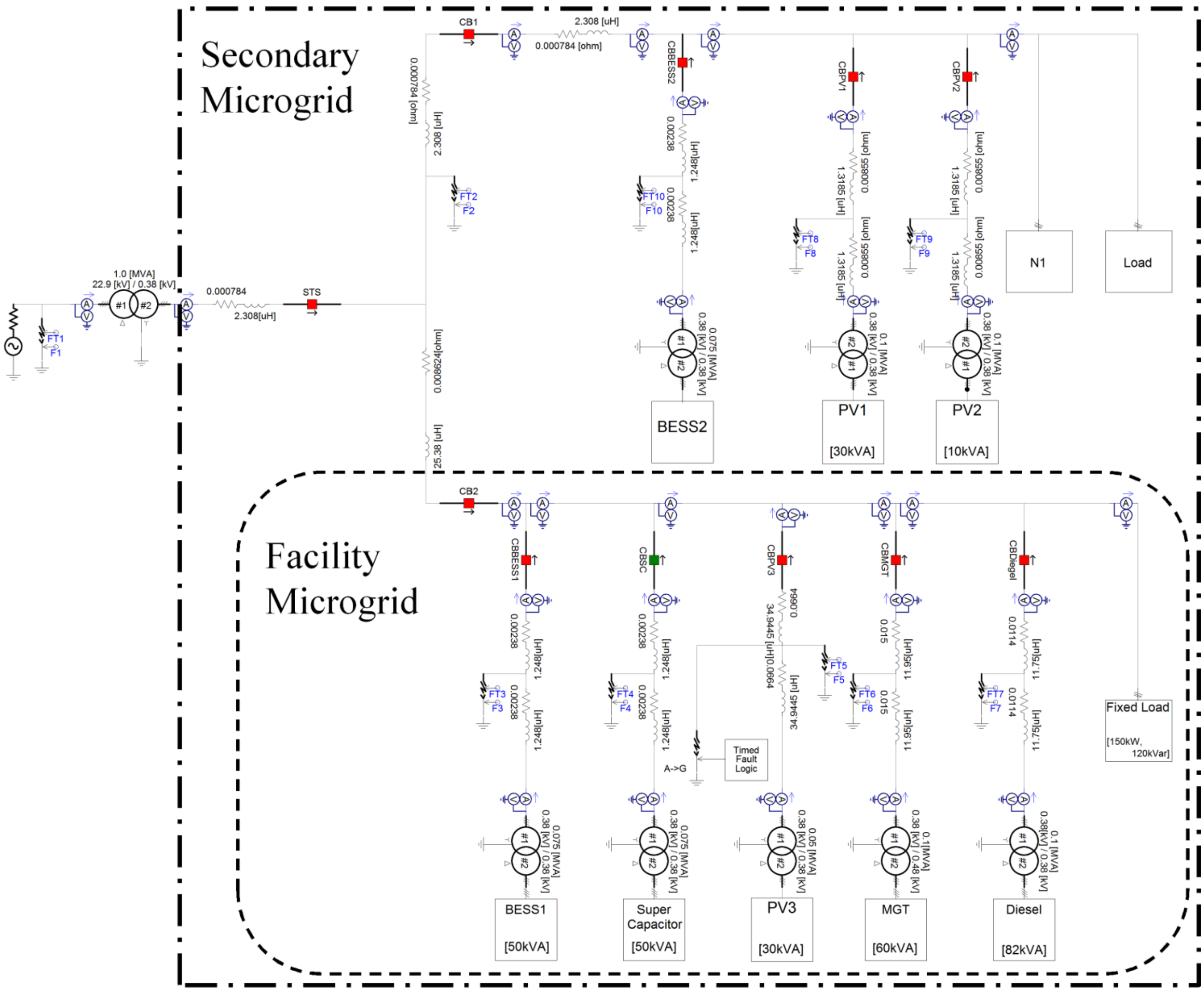


Table 2. Simulation scenarios.

Algorithm	Case	Fault Location
Protection Algorithm for Facility Microgrid (Zone B)	1	External Fault
	2	Feeder Fault with BESS in Zone B
	3	Feeder Fault with PV in Zone B
Protection Algorithm for Secondary Microgrid (Zones A and B)	4	External Fault
	5	Feeder Fault with BESS in Zone B
	6	Feeder Fault with PV in Zone A
Comparison of Relay Setting	7	Common Line Fault with Relay Setting: 2.0 ~ 3.0 pu
	8	Common Line Fault with Relay Setting: 1.0 ~ 1.1 pu
	9	Common Line Fault with Relay Setting: 7.0 ~ 8.0 pu

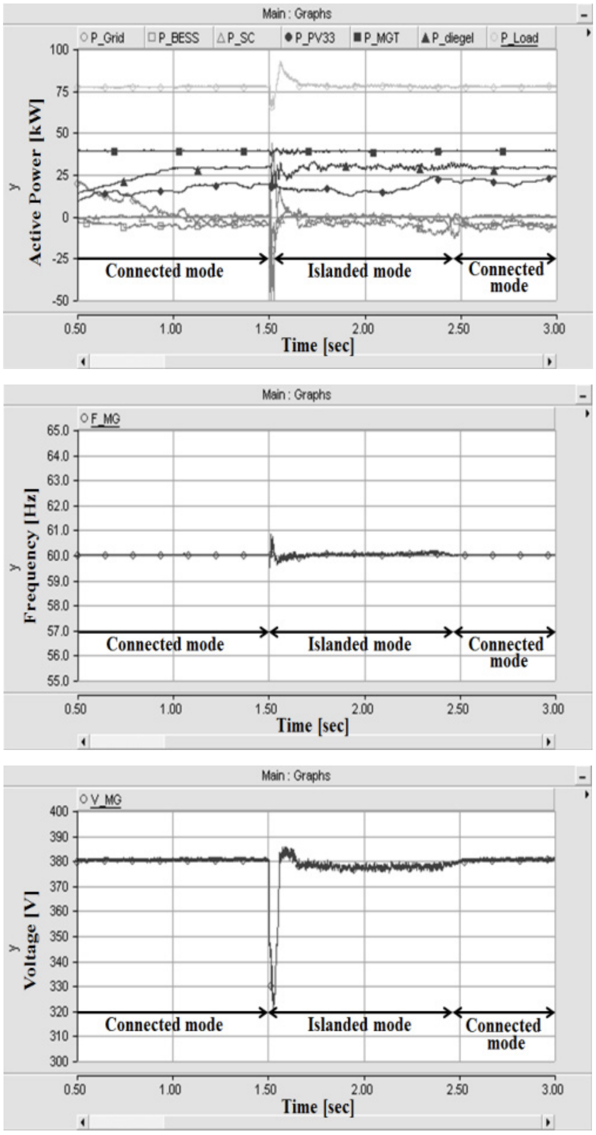
4.2. Simulation Results

In Cases 1, 2, and 3, the algorithm for Zone B was verified with respect to fault locations. To implement various experiments, the locations of three typical faults were chosen, namely, an external fault, a fault at the controllable DG, and a fault at the uncontrollable DG. Figure 7 shows the active power, frequency, and voltage in Zone B for Cases 1, 2, and 3, respectively. When a fault is created at 1.5 s, the STS is opened automatically by detection of the fault current. Then, Zone B changes its operation from grid-connected mode to island mode at 2.4 s. These processes are the same for all cases. However, the following processes depend on the fault locations. After opening the STS, the EMS determines the fault location by communication with the CBs. If the CB at the uncontrollable DG is opened, the microgrid continues operating in island mode because this means that the fault has occurred in the feeder at the uncontrollable DG, and it has been cleared by the CB. If not, the EMS identifies the system frequency and voltage to decide whether to shut down the microgrid or not. With abnormal frequency and voltage, the EMS sends a signal to shut down the microgrid because there is no controllable DG in Zone B. After the fault is eliminated, the microgrid is reconnected with the main grid under the required conditions.

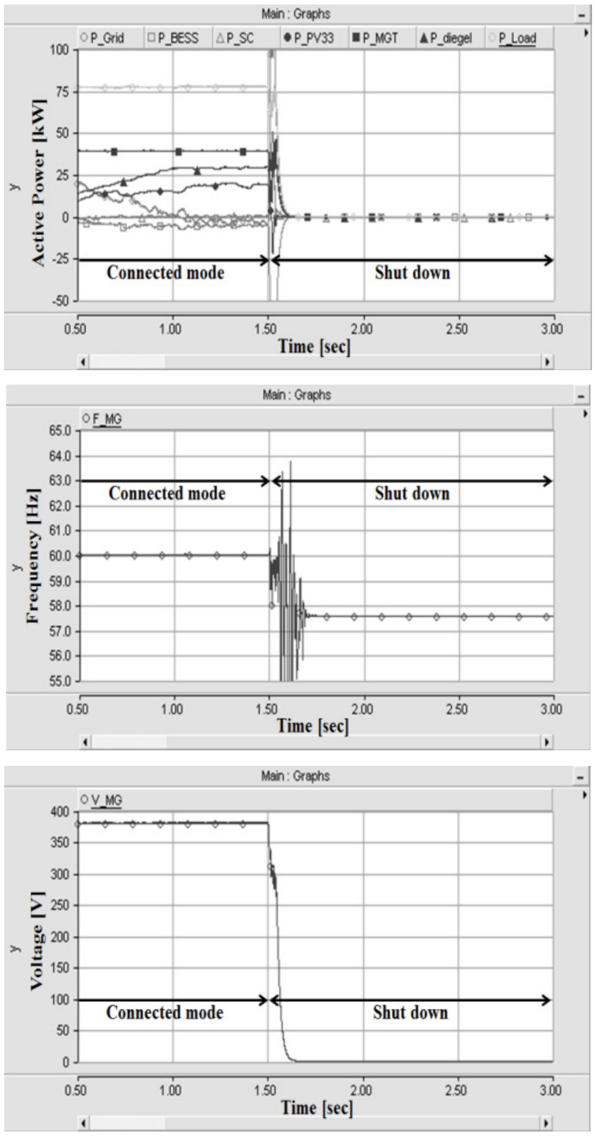
The algorithm applied to Zones A and B is verified by Cases 4, 5, and 6 with respect to fault locations like the algorithm for Zone B. In terms of an external fault and a fault at the feeder with uncontrollable DG, Figure 8 shows the same results as those in Figure 7. However, microgrids are able to operate in island mode in parallel after opening the STS because the frequency and voltage of a microgrid can be controlled by the controllable DG in Zone A. Therefore, two or more microgrids can operate in island mode when a fault occurs in the feeder at controllable DG.

One more type of fault, a common line fault, was implemented to verify the algorithm for two or more microgrids, here, Zones A and B. Also, it was compared to the conventional protection algorithm and other relay setting by Cases 7, 8, and 9. In Figure 9a, the relay setting is 2.0 to 3.0 pu of the rated current, which is in the proposed algorithm, and the microgrids are protected well from a fault. However, with the relay setting of 1.0 to 1.1 pu, all CBs in microgrids are opened after detecting the fault because the relay setting is unnecessarily low. As a result, both microgrids are shut down by opened CBs. Figure 9c shows the results of the conventional algorithm which has a relay setting of 7.0 to 8.0 pu of the rated current, and the algorithm is not capable of distinguishing the direction of the fault current. When a common line fault occurs, most CBs in microgrids are not opened. Consequently, the fault is not eliminated by the conventional algorithm; therefore, the results show that the conventional algorithm is not applicable to microgrids.

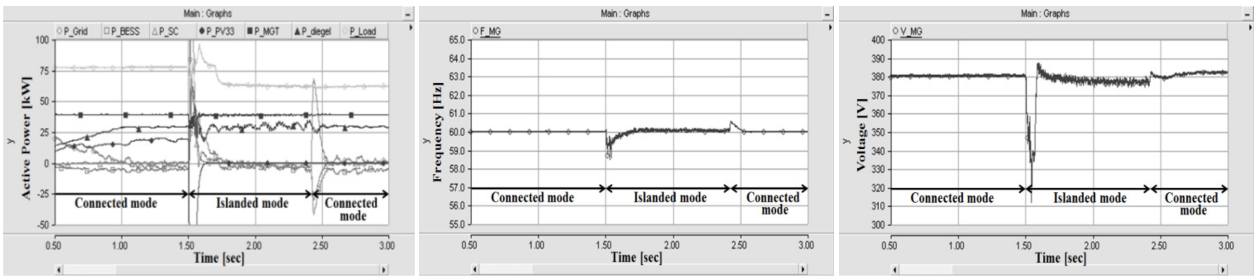
Figure 7. Active power, frequency and voltage in microgrid Zone B about Case 1, 2, and 3 respectively. (**a**) Case 1, External Fault; (**b**) Case 2, Feeder Fault with BESS in Zone B; (**c**) Case 3, Feeder Fault with PV in Zone B.



Zone B
(**a**)

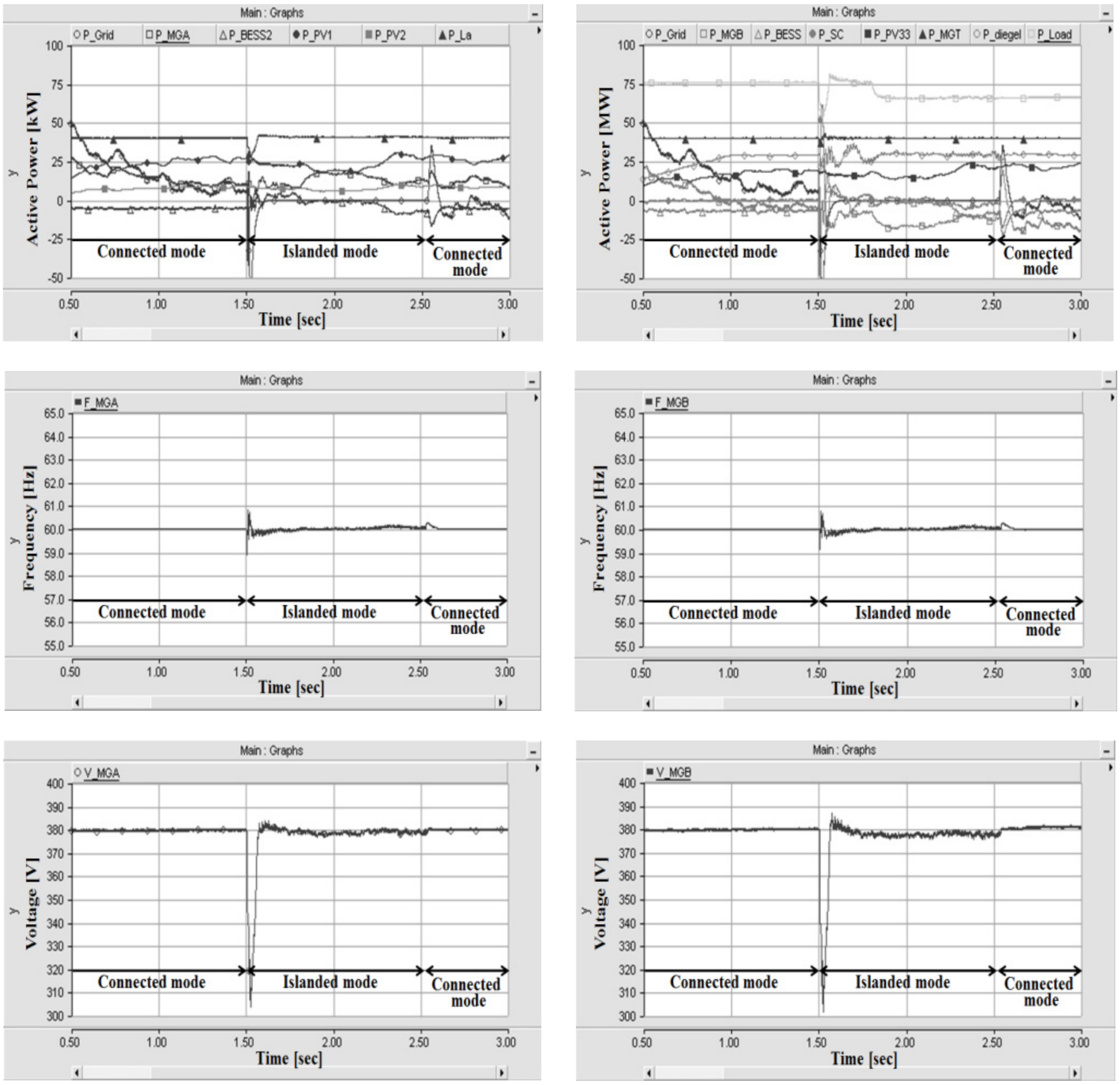


Zone B
(**b**)



Zone B
(**c**)

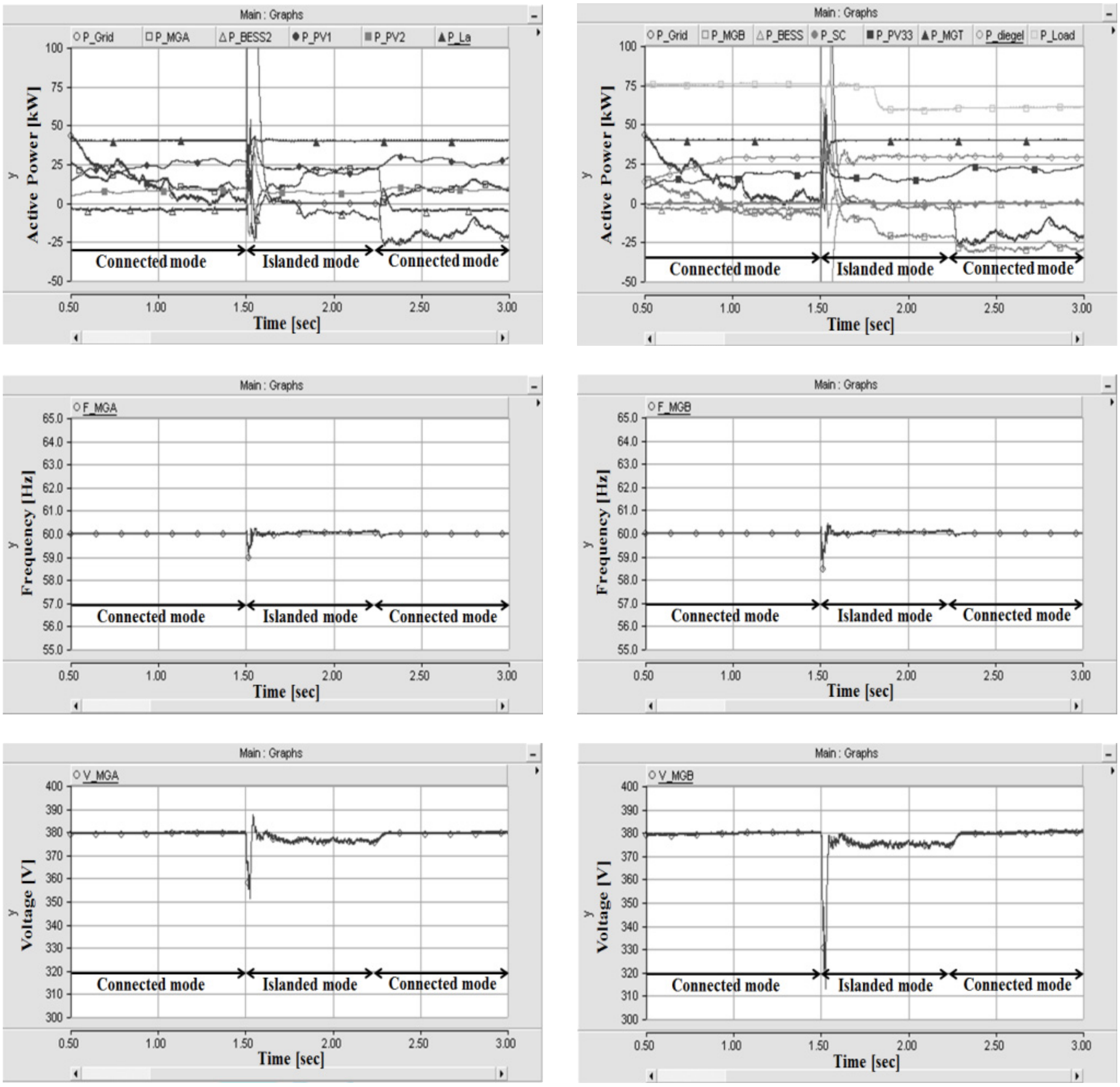
Figure 8. Active power, frequency and voltage in microgrid (Zones A and B) about Case 4, 5 and 6 respectively. (**a**) Case 4, External Fault; (**b**) Case 5, Feeder Fault with BESS in Zone B; (**c**) Case 6, Feeder Fault with PV in Zone A.



Zone A Zone B

(**a**)

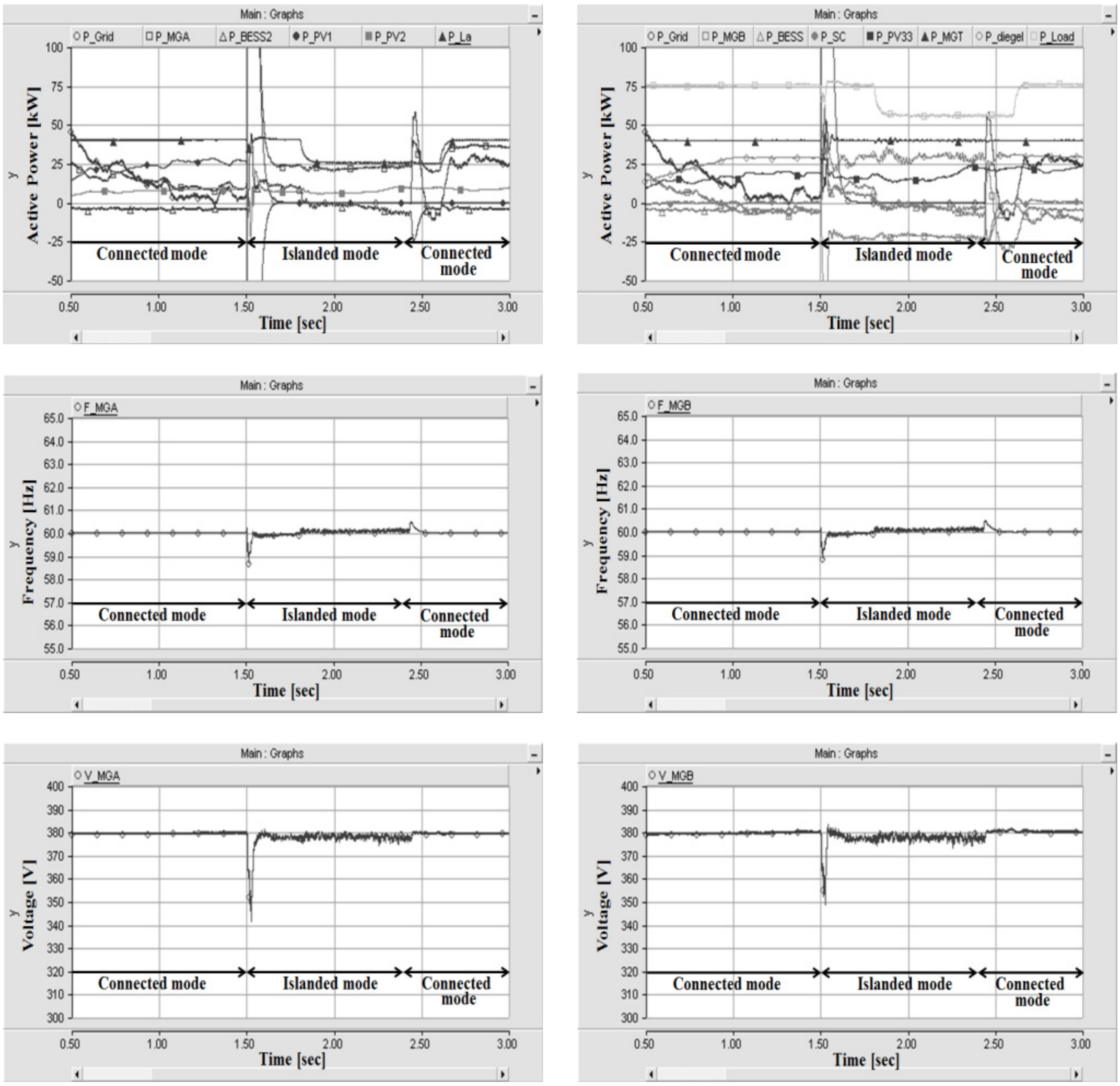
Figure 8. *Cont.*



Zone A   Zone B

(**b**)

Figure 8. *Cont.*

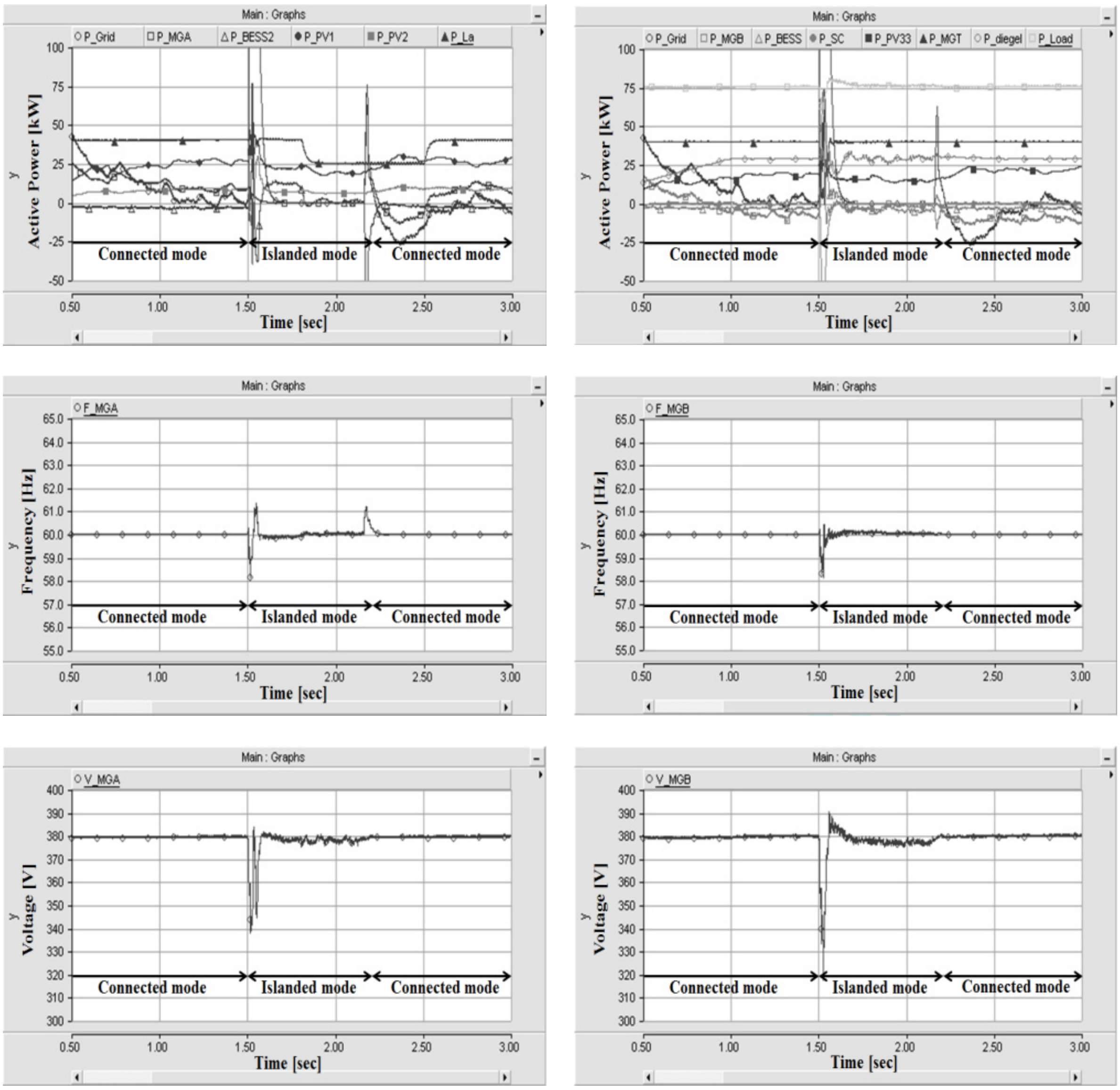


Zone A

Zone B

(**c**)

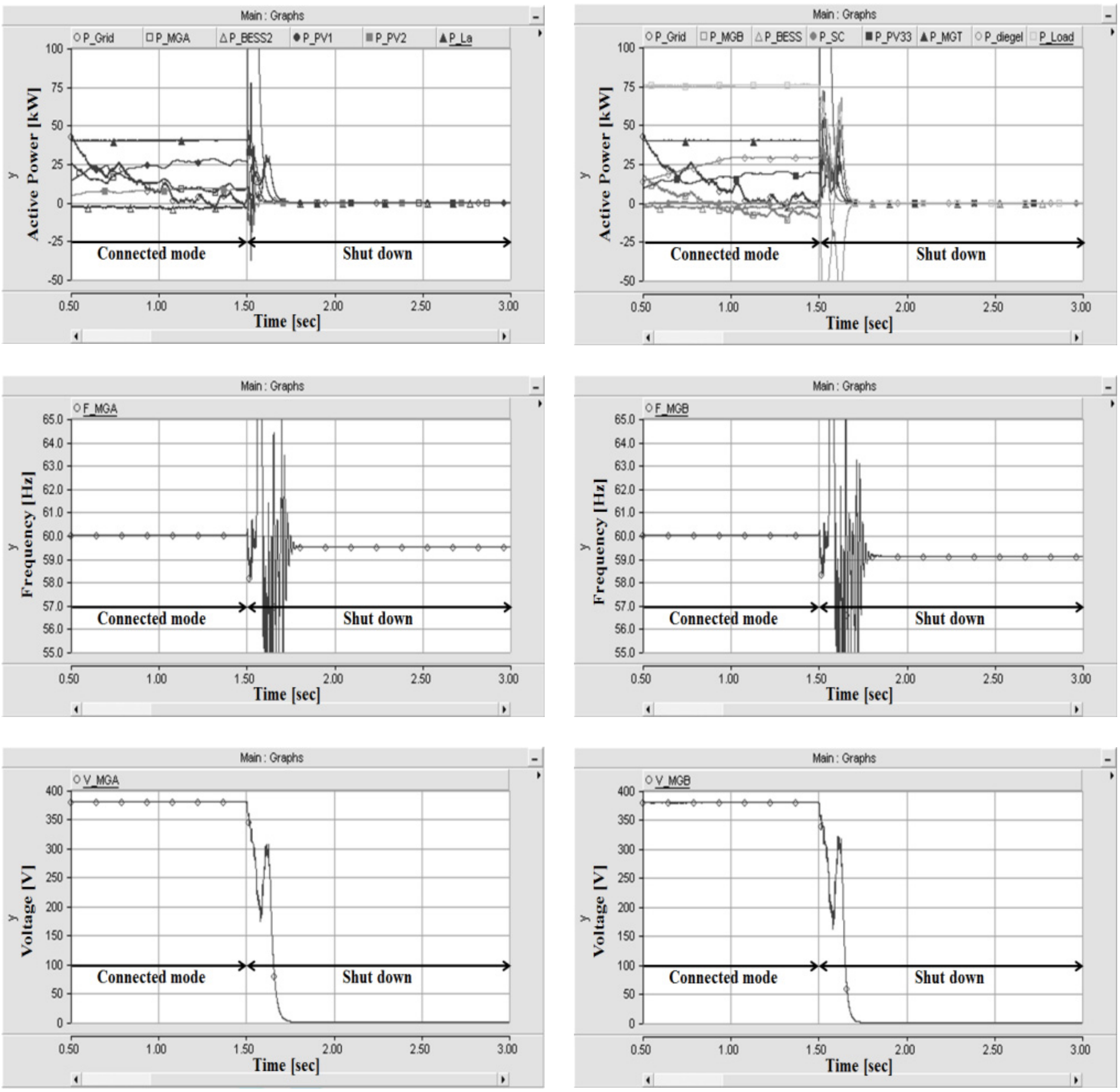
Figure 9. Active power, frequency and voltage in microgrid (Zones A and B) about Case 7, 8 and 9 respectively. (**a**) Case 7, Common Line Fault with Relay Setting: 2.0~3.0 pu (Adequate); (**b**) Case 8, Common Line Fault with Relay Setting: 1.0~1.1 pu (Low); (**c**) Case 9, Common Line Fault with Relay Setting: 7.0~8.0 pu (High).



Zone A Zone B

(**a**)

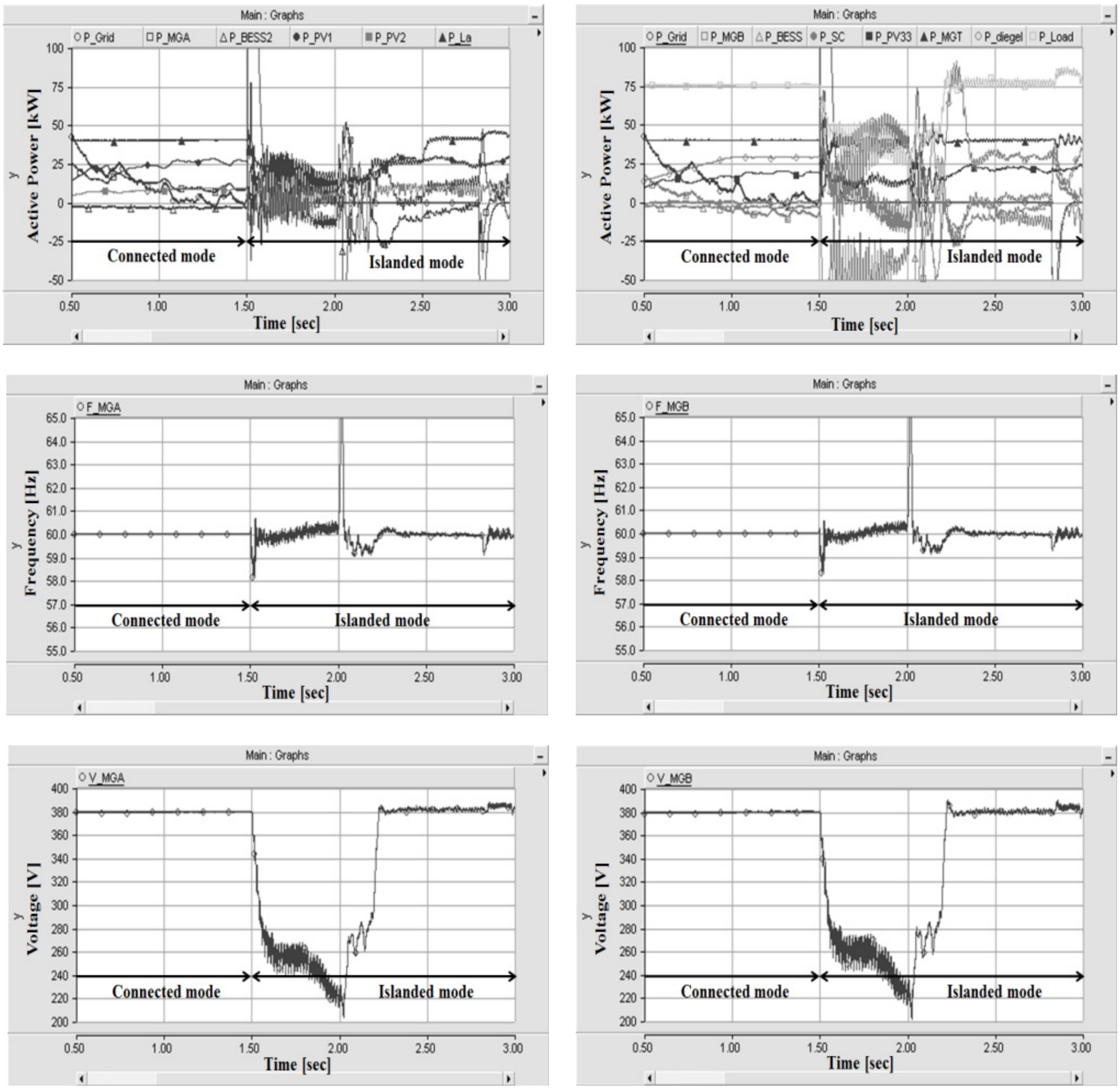
Figure 9. *Cont.*



Zone A Zone B

(**b**)

Figure 9. *Cont.*



Zone A Zone B

(**c**)

5. Conclusions

In this paper, a protection coordination algorithm applied to a facility microgrid (*i.e.*, Zone B) and a protection coordination algorithm applied to secondary microgrids (*i.e.*, Zones A and B) were proposed and verified. In the case of Zone A with the protection algorithm, the microgrid is shut down when a fault occurs at the feeder with a controllable DG. However, the microgrid can continue operating in island mode after eliminating a fault of the uncontrollable DG. In the case of Zones A and B with the proposed algorithm, unlike the proposed algorithm for Zone B, the microgrids can operate in island mode regardless of the type of DG since Zones A and B both have controllable DG.

Unlike the protection algorithm proposed in [9], the algorithm proposed here is economically feasible and applicable because faults are eliminated by local digital relays. Moreover, the relay setting of protection devices can be changed in accordance with the type and number of DGs in a microgrid. Therefore, the proposed algorithm can be applied through some changes of relay setting when a microgrid is expanded. In addition, the proposed algorithms can overcome the difficulty in the conventional protection, the CERTS's protection, and the EU's protection. The proposed protection algorithms are now being applied to the microgrid demonstration site of KEPCO RI. In the future, depending on the structure of microgrids and type of DG installed in microgrids, the proposed protection algorithms will be adapted and modified.

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