ABSTRACT

HOOSHYAR, HOSSEIN. System Protection for High PV-Penetrated Residential Distribution Systems (Green Hubs). (Under the direction of Dr Mesut E. Baran).

This study investigates the protection issues on distribution systems with high penetration of residential Photovoltaic (PV) systems. The investigation is done on both conventional and Solid State Transformer (SST) based distribution systems. Then, new fault analysis method suitable for Green Hubs is proposed and solutions are developed to handle the protection issues in these distribution systems.

System Protection for High PV-Penetrated Residential Distribution Systems (Green Hubs)

by
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BIOGRAPHY

Hossein Hooshyar was born in 1981. He received his B.Sc., M.Sc., and Ph.D. from University of Tehran, Iran University of Science and Technology, and North Carolina State University all in electrical engineering in 2004, 2007, and 2012, respectively. His research interests include renewable energy systems, protection systems, real time simulation of power systems, and applied superconductivity.

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All praise is due to God for making this possible.

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To my advisor, Dr Mesut Baran, who has supported me throughout my thesis with his patience and knowledge whilst allowing me the room to work in my own way.

To my parents for the love and support they have given me during my entire life, and for providing me the opportunity to study and succeed.

And lastly and foremost, to my wife, for her support, encouragement, patience, understanding and endless love, through the duration of my studies.

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CHAPTER 1

INTRODUCTION

Electric power distribution systems have traditionally been designed assuming that the primary substation is the sole source of power and short-circuit capacity. Distributed Energy Resources (DER) invalidates this assumption by placing power sources onto the distribution system. As a result, DER interconnection results in operating conditions that do not occur in a conventional system [1].

DER IMPACTS ON DISTRIBUTION SYSTEM PROTECTION

One of the main impacts of the DERs is on the protection system. This impact brings up the following issues:

- Change in reach and operating time of protective devices.
- Loss of Coordination between Protective Devices.
- Sympathetic Tripping, which is incorrect tripping of the protective device for faults elsewhere in the system.
- Reclosing Problems
    - Unsuccessful Clearance of Temporary Faults.
    - Out-of-Phase Reclosing, between the utility and the DERs.
- Unintentional Islanding, including DERs and loads.

These issues will be discussed in detail in chapter 3.

LITERATURE SURVEY

Several papers have investigated the negative impacts of DERs on conventional protection systems and have proposed some solutions. Walling et al. investigated the issues as fuse coordination, feeding faults after utility protection opens, faults on adjacent feeders, fault detection, and recloser coordination [1]. Lu et al. focused on the coordination loss and have proposed a faulty line selection approach based on the negative sequence current [2]. Driesen and Belmans explained more about the loss of speed in protective devices, sympathetic tripping, and unintentional islanding. They have suggested the use of a communication system in order to avoid the mentioned issues [3]. Cheung et al. also addressed the issues such as sympathetic tripping, failure of fuse saving practice, mis-protection due to feeder-network reconfiguration, reduction-of-reach protection, unintentional islanding operation, and mis-coordination [4]. They have also proposed solutions mostly based on readjusting of the protection settings. However, most of the relays they discussed are distance relays which are rarely used in distribution systems. Maki et al. also emphasized the need for readjusting the protection settings while adding new DERs by addressing the issues of sensitivity and selectivity loss, autoreclosing problems, and unintentional islanding problems [5]. By reviewing the published literatures, it is concluded that the issues can be categorized as the five issues mentioned in the previous section of this document.

Beside these papers, IEEE has also developed Standards on criteria and requirements for DER interconnection with the electric power system. IEEE 1547 is one of them and consists of 8 sections. Section 7 of this standard talks on engineering studies of the DER impacts on the electric power system which we follow in order to perform our system studies [6].

The mentioned documents are about all types of DERs. However as the PV systems are going to be more common at residential level [7,8], this study focuses on distribution systems with high penetration of PV systems.

One of the other standards developed by IEEE is IEEE 929 which applies to utility-interconnected PV systems operating in parallel with the utility and utilizing static inverters for the conversion of direct current (dc) to alternating current (ac) [9]. This document recommends the protection settings for PV systems and we are going to follow it in our studies.

CHAPTER 2

GREEN HUBS

GREEN HUB

The most common type of distribution system for serving residential loads is the radial-type. Therefore, our focus in this study is radial-type distribution systems where the protection scheme is implemented by breakers, reclosers, and fuses which work based on non-directional overcurrent protection. Figure 1 shows the overcurrent protection scheme for a typical distribution feeder. As shown in the figure, a recloser or a circuit breaker with reclosing relays is located at the substation to protect the three-phase feeder and to provide a back-up protection for the laterals. For long feeders, a second recloser might be required to increase the system reliability. It is a common practice to install a fuse at the head of each lateral. Also, each distribution transformer is protected by a fuse [10].

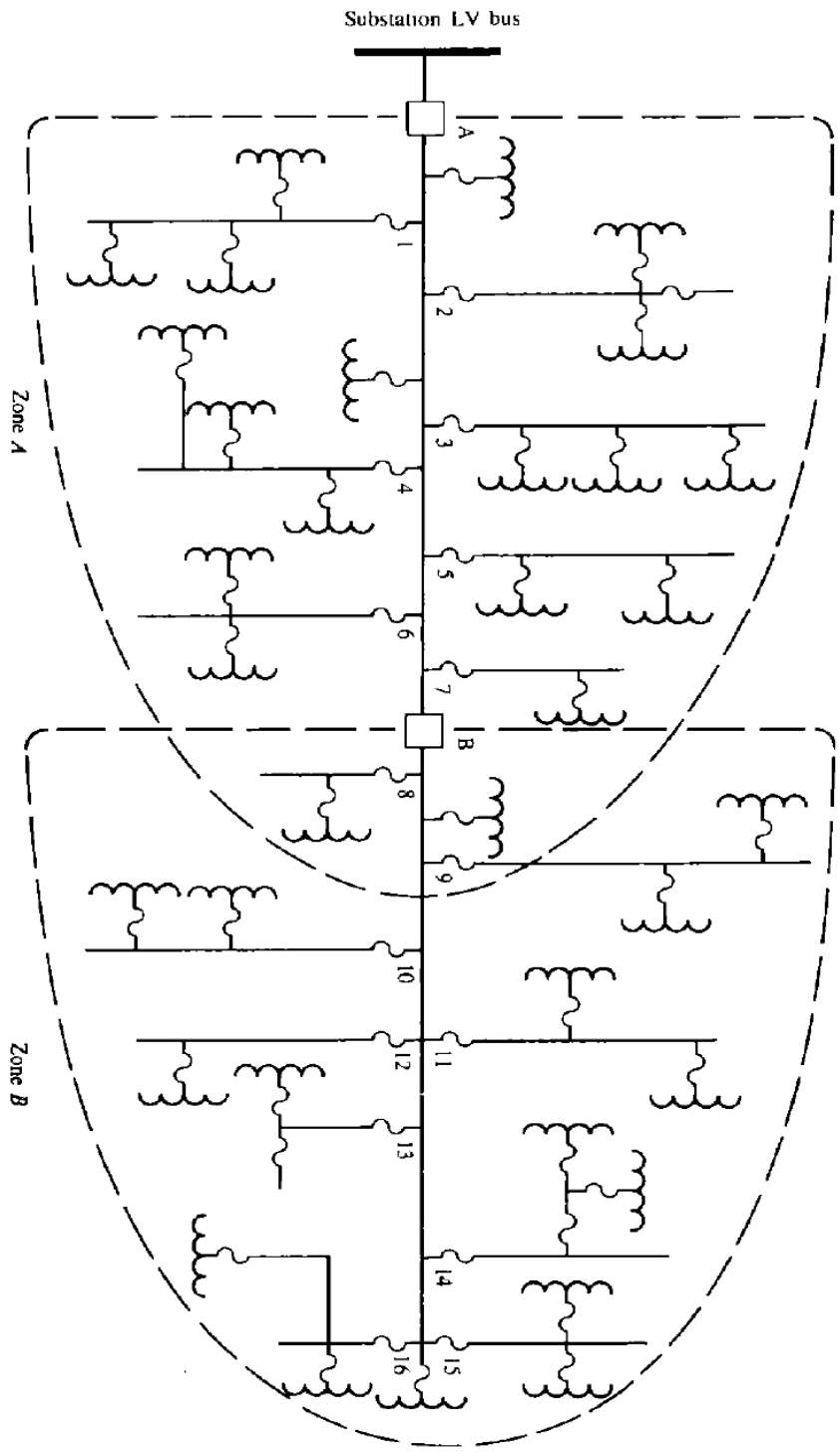


Figure 1: Overcurrent protection scheme for a typical distribution feeder

What we define as “Green Hub” is a residential distribution system where each costumer has roof-top photovoltaic system. It is assumed that each PV system can generate up to maximum load of the residential unit. Since the SST technology takes time to become a commercial product, the Green Hub has been defined in three versions in order to consider the migration timing from a conventional distribution system to a FREEDM system:

1. Green Hub I: The substation and distribution transformers are all conventional magnetic transformers. The feeders are radial.

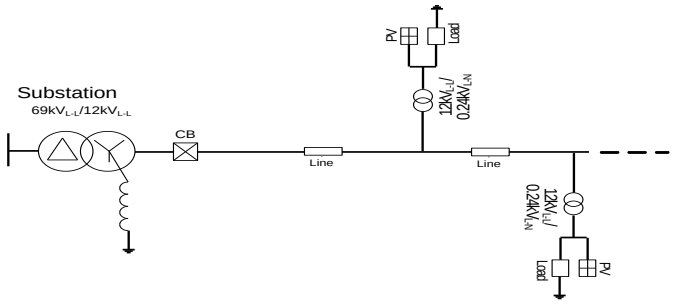


Figure 2: Green Hub I

2. Green Hub II: The substation transformer is a conventional magnetic transformer but the distribution transformers are all replaced by Solid State Transformers. The feeders are radial.

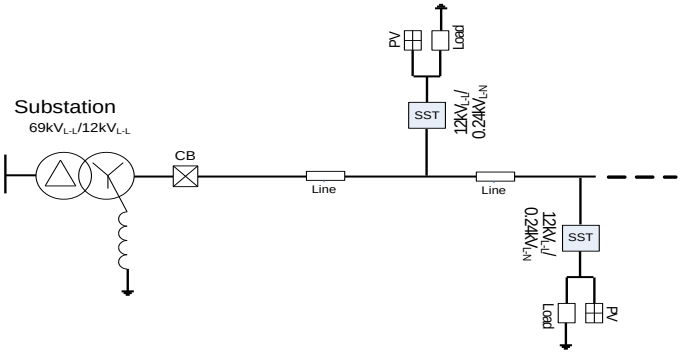


Figure 3: Green Hub II

3. Green Hub III: The substation and distribution transformers are all Solid State Transformers (FREEDM System). The feeders are looped.

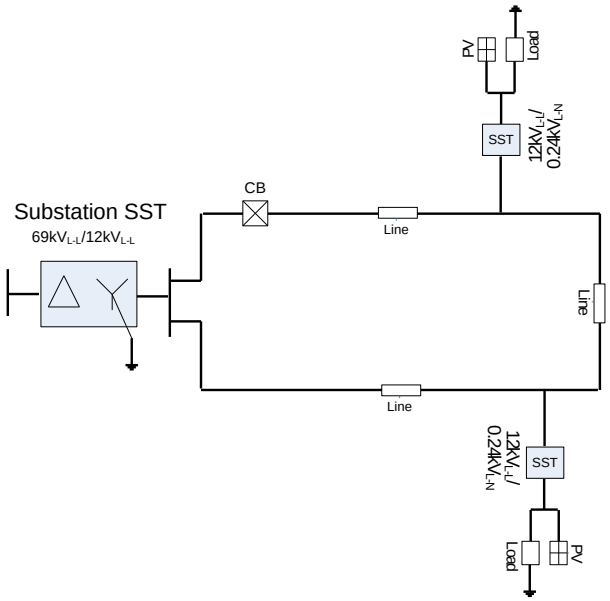


Figure 4: Green Hub III (FREEDM System)

In this study, the focus will be on Green Hubs I and II.

TEST CASE

In order to simulate a set of Green Hubs and investigate the issues being brought up by high penetration of PV systems, an actual 230kV/22.86kV substation along with its two 22.86kV distribution feeders being fed from this substation in the Raleigh area, have been selected and implemented in PSCAD. Figure 5 shows the single line diagram of the implemented system.

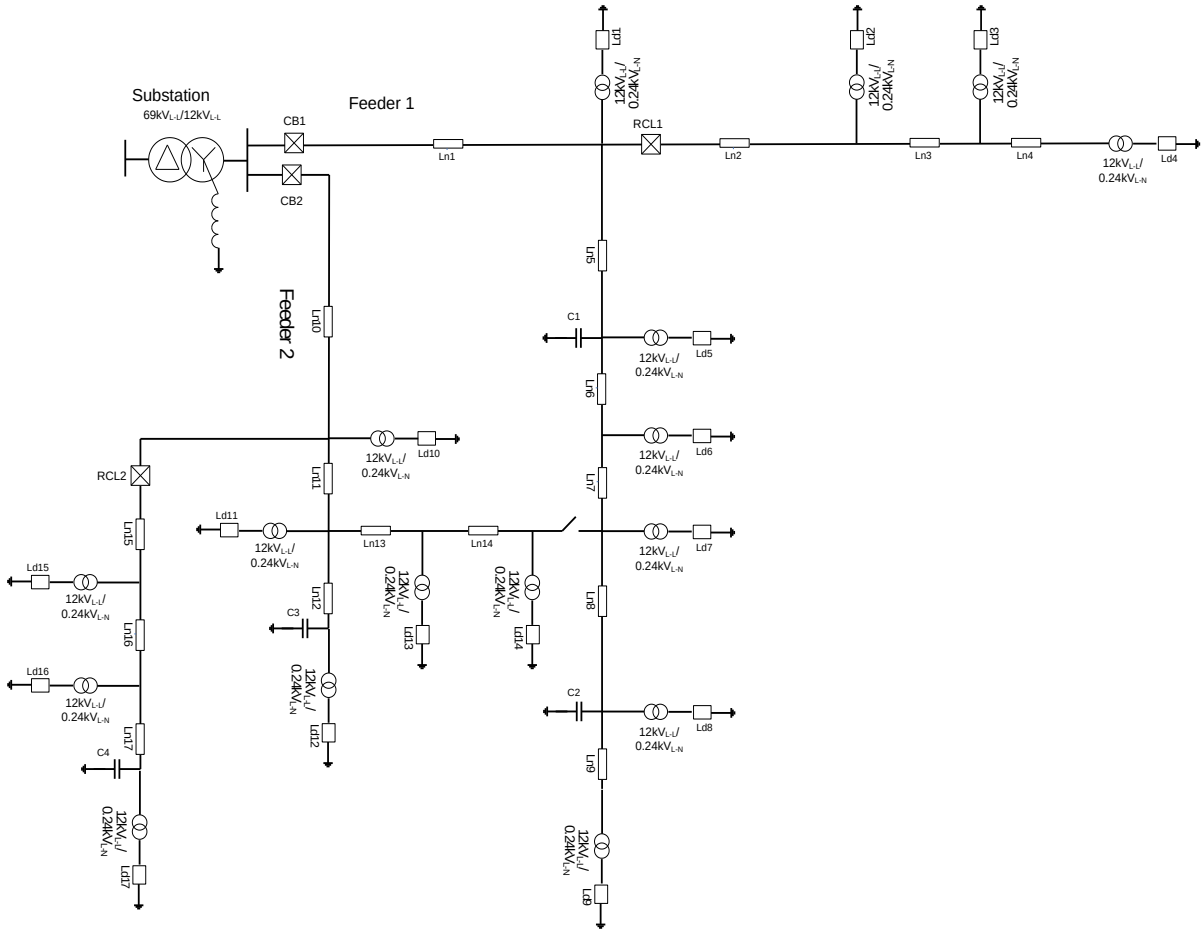


Figure 5: Single line diagram of the implemented distribution system

To simulate a common 12kV system, we reduced the substation voltage to 69kV/12kV and increased the substation transformer reactance and the neutral reactor to keep the fault current levels the same as what they were with the original voltage.

The feeders are three-phase with numerous laterals. Several single-phase underground laterals tap off from the main three-phase feeders to feed the costumers within the same neighborhood. However since it was not possible to simulate all the loads separately, the loads on the single-phase laterals of each three-phase line section have been aggregated and implemented by one load model.

As shown in figure 5, each feeder is protected by a circuit breaker located at the substation. Also, to increases the system reliability, the horizontal branch of feeder 1 and the leftmost branch of the feeder 2, that are geographically located in woody areas, have been equipped with reclosers.

All protective devices have been modeled using the real settings. Details on the implemented system can be found in appendix I.

PV SYSTEM

The PV system considered has a maximum power point tracker (MPPT) and relevant power electronics to convert the PV generated DC power to grid utilizable AC power. This model has been adopted from the PV model simulated in MATLAB/Simulink by the ECEE department at the University of Colorado at Boulder [11]. Figure 6 shows the main components of the prototype simulated PV system.

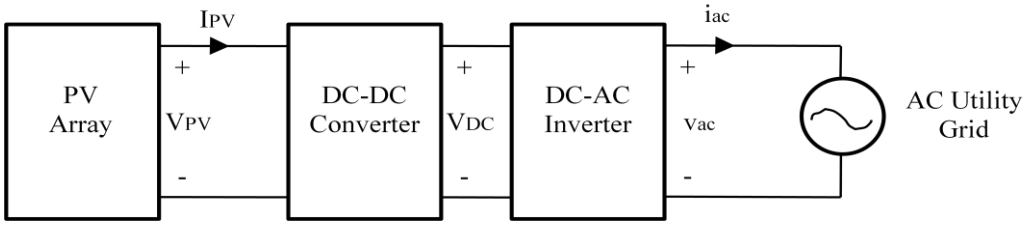


Figure 6: Prototype simulated PV system

The PV system is equipped with U/O voltage, U/O frequency, and anti-islanding protection as determined by IEEE 929. Table 1 summarizes the PV self-protection scheme [9].

Table 1: Protection system of PVs

		trip time
anti-islanding		immediately
grid voltage	V < 0.5pu	6 cycles
	0.5pu ≤ V < 0.88pu	120 cycles
	0.88pu ≤ V < 1.1pu	normal operation
	1.1pu ≤ V < 1.37pu	120 cycles
	1.37pu ≤ V	2 cycles
grid freq.	f < 59.3	6 cycles
	59.3 ≤ f ≤ 60.5	normal operation
	60.5 < f	6 cycles

Details of the simulated model can be found in appendix II.

The inverter is equipped with dq control and limits the fault current to two per unit. Figure 7 shows the instantaneous and RMS profiles of the PV output current for a fault occurring at the inverter terminals. As shown, the RMS value of the current can be approximated to 2 pu during the fault. Also, the PV shuts down after 0.1s due to undervoltage protection.

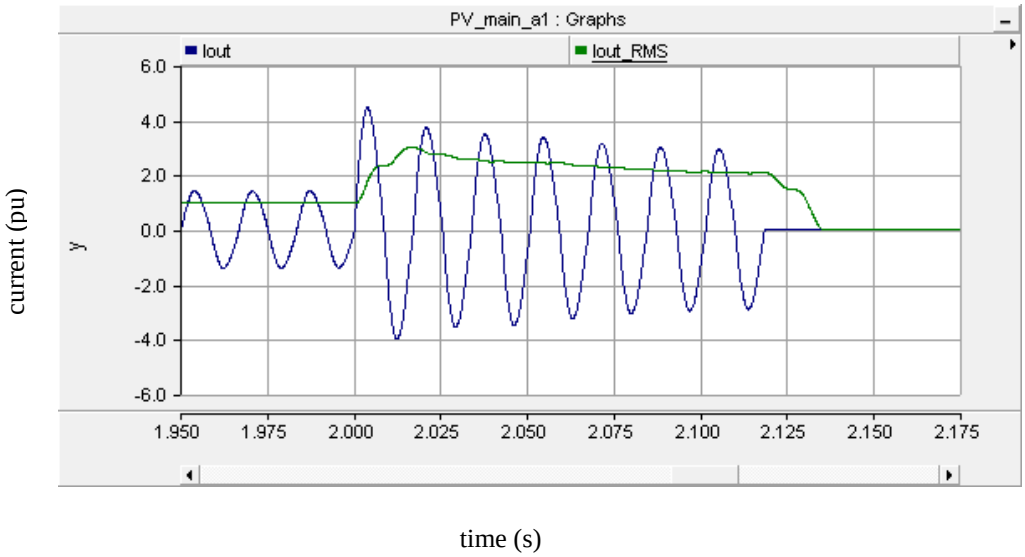


Figure 7: PV system terminal current when a fault occurs

Figure 8 shows the voltage-current (V-I) curve of the PV system. As shown, for low voltages the PV current is limited to two per unit as the inverter operates under constant current mode, whereas for higher voltages the inverter operates under constant power mode.

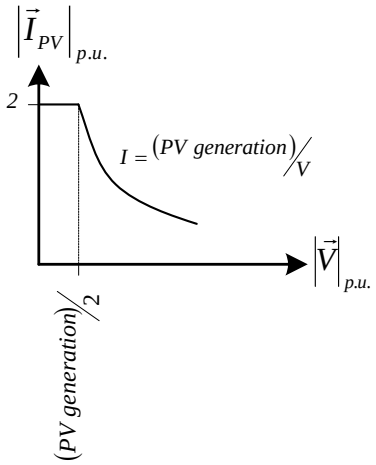


Figure 8: V-I curve of a PV system

SOLID STATE TRANSFORMER (SST)

To facilitate integration of DERs (Distributed Energy Resources) into a distribution system, FREEDM Systems Center is developing a SST [12]. In this study, an average model of this SST has been adopted for system simulations. The SST is assumed to have under/Over voltage protection which uses the DC bus voltage as its input. Therefore, in case of a fault occurrence on the primary side of the SST, it stays online as long as it can provide the active power demanded by the load; if it can't provide the demanded active power, the DC bus voltage drops and the protection trips and the SST shuts down. Figure 9 shows the main of the SST.

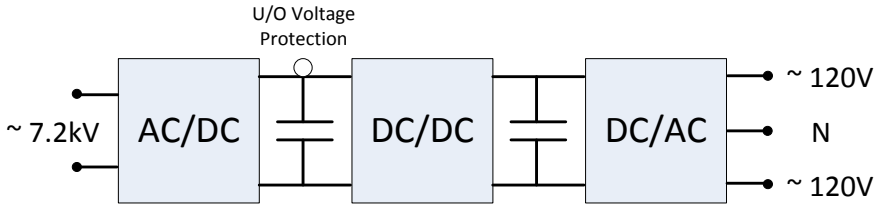


Figure 9: Main topology of the SST

Figures 10, 11, and 12 show the SST current on the primary side while a fault happens at the primary side for different directions of power flows in SST. In all cases the SST current is limited by the rectifier stage controllers to about two per unit. The SST shuts down in the first two cases due to U/O voltage protection.

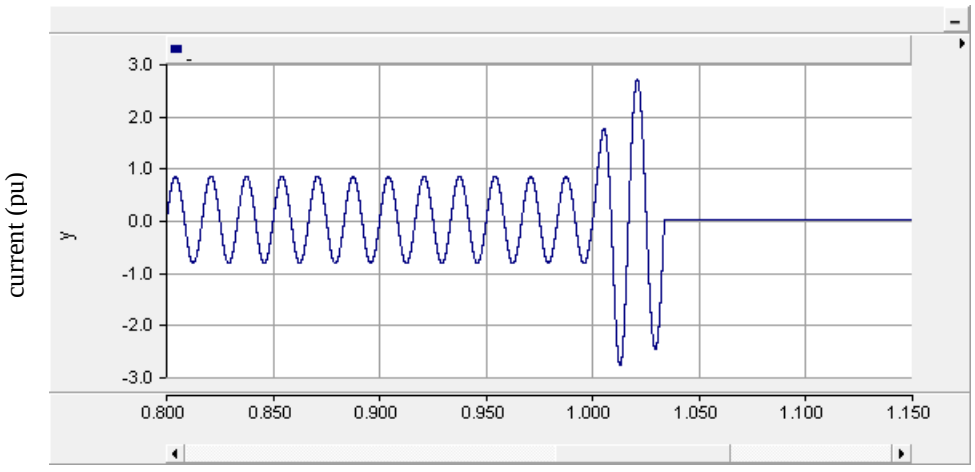


Figure 10: SST primary side current when the power flows from the primary side to the secondary side

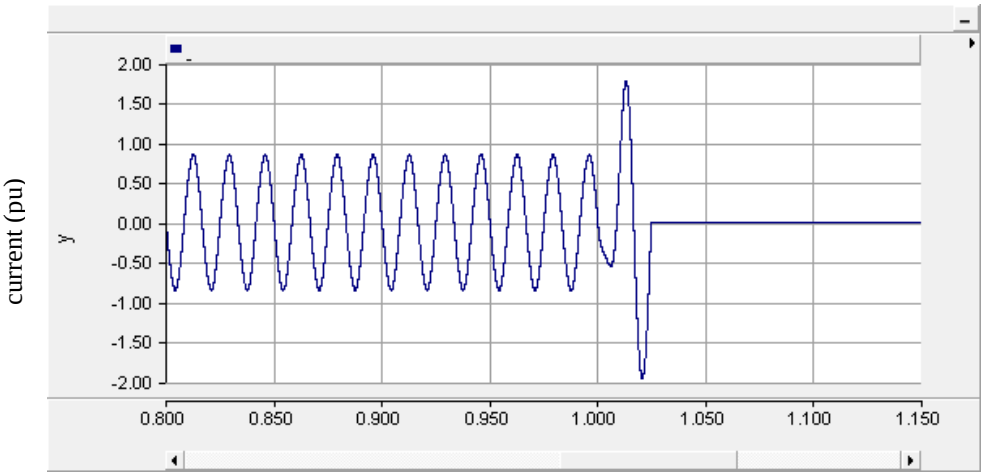


Figure 11: SST primary side current when the power flows from the secondary side to the primary side

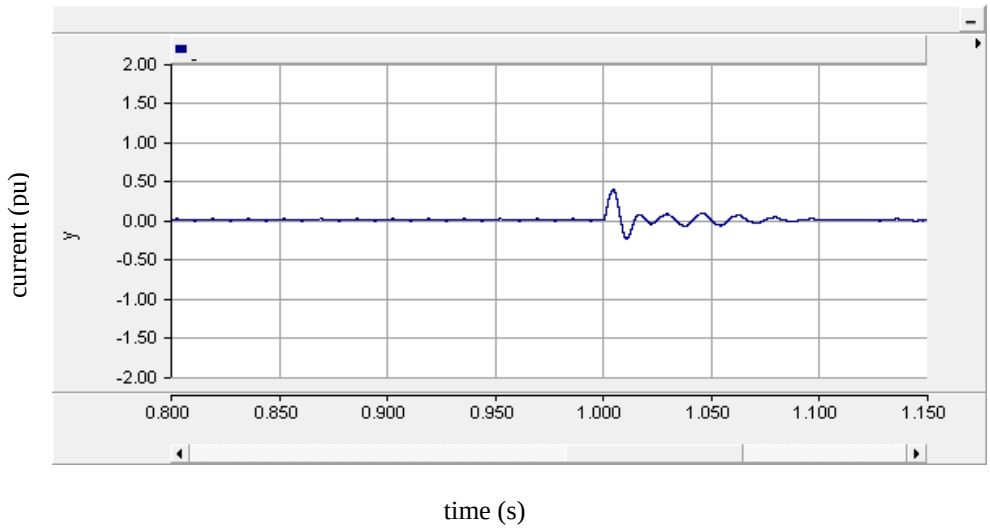


Figure 12: SST primary side current when no power flows through SST (PV/load balance)

Figure 13 shows the voltage-current (V-I) characteristic observed from the primary side of the SST. As shown, for low voltages the SST current is limited to two per unit as the SST rectifier stage operates under constant current mode, whereas for higher voltages it operates under constant power mode. The PV/Load unbalancy determines at what voltage the inverter should change the operation mode from constant power to constant current or vice versa. The unbalancy is per-united based on the rating of the SST.

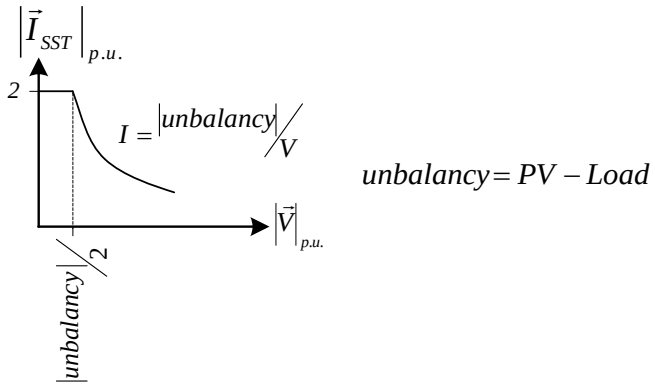


Figure 13: V-I curve of a SST

Figure 14 shows the SST primary current while a fault occurs at the primary side terminal for different PV/load balances. As shown in the figure, although the fault current flowing through the SST is limited by the rectifier stage controllers, however the time period between the fault occurance and SST's shuting down is directly dependant on the PV/load balance on the secondary side of the SST. This is because the O/U voltage protection is based on the DC bus voltage. The more balanced the PV and load are, the longer it takes for the DC capacitor discharges or overcharges, resulting in a longer trip time.

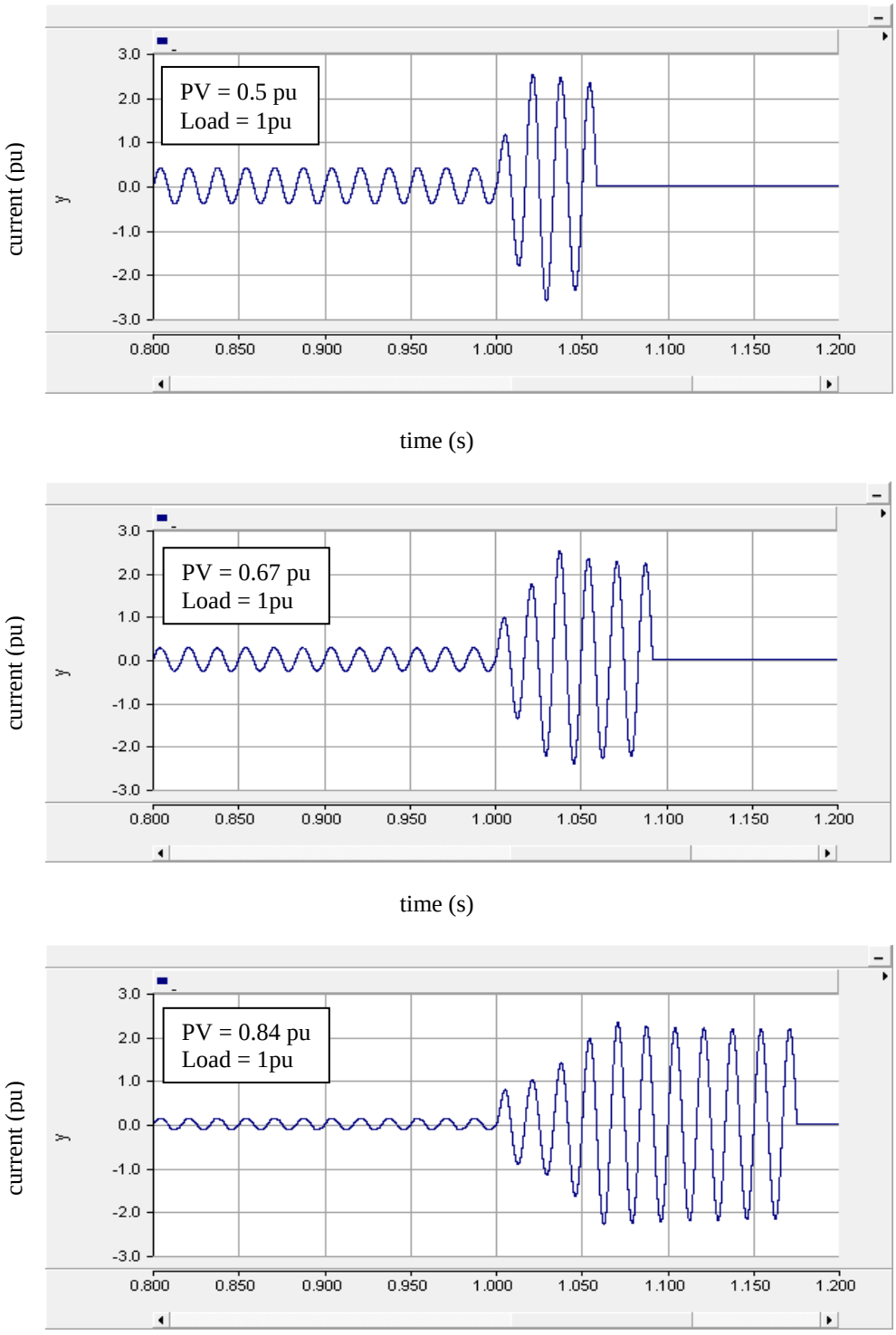


Figure 14: SST primary side fault current for difference PV/load balances

The followings are a number of different tests on the SST model to demonstrate the behavior of the model under fault conditions:

SST'S CURRENT DIRECTION VS MAGNETIC TRANSFORMER'S CURRENT UNDER FAULT

Figure 15 shows the two test cases that have been set up for this test. Figure 16 shows the primary currents of the SST and the magnetic transformer for two different scenarios, when PV > Load and when Load < PV. In case 1 where PV > Load, both SST and the magnetic transformer keep injecting current to the system after the fault occurs. But in case 2 where PV < Load, the SST draws current and the magnetic transformer again injects current to the system after the fault occurs. This is because the SST regulates the load voltage and draws more current from the system to provide the power requested by the load.

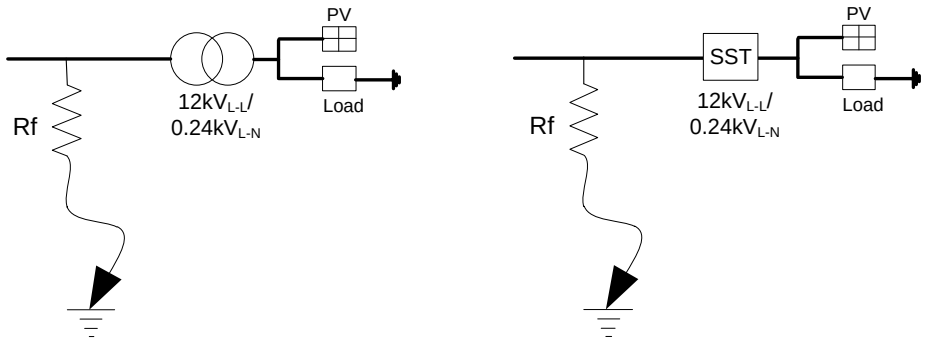
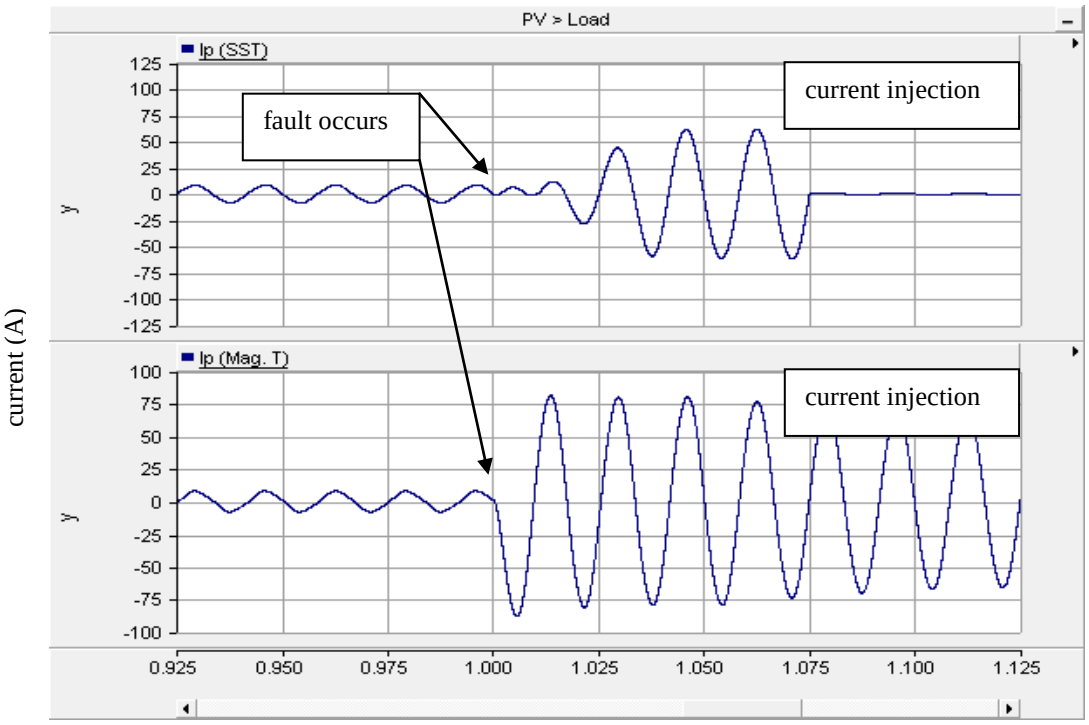


Figure 15: Test cases



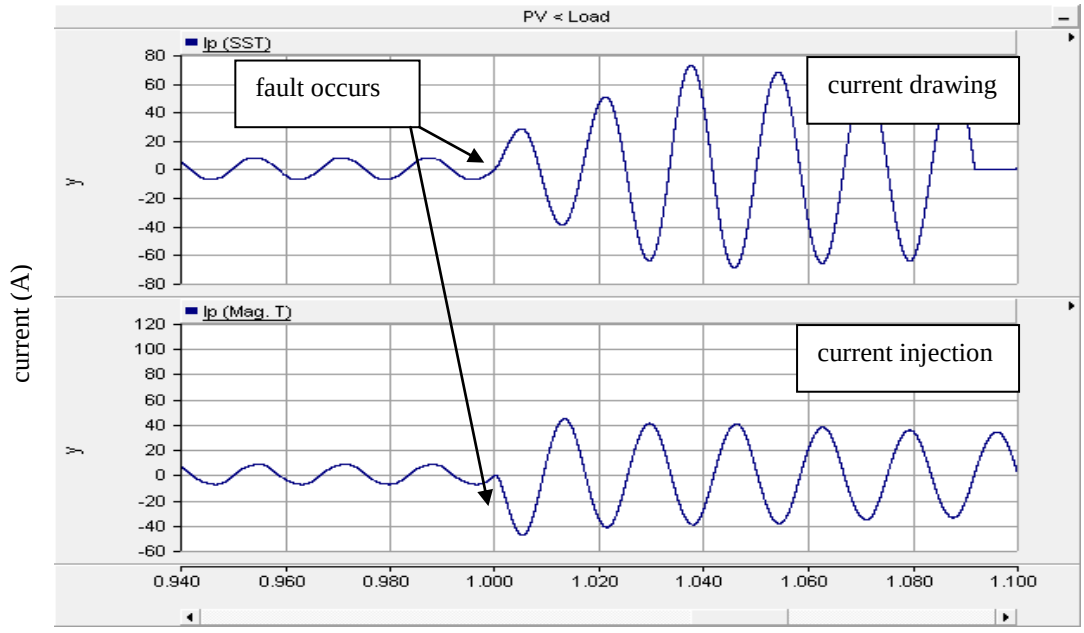


Figure 16: SST's and magnetic transformer's primary currents

EFFECT OF FAULT IMPEDANCE ON SST'S PRIMARY CURRENT

Figure 17 and 18 show the test case and the voltages/currents on the primary side of the SST for different $\frac{R_f}{Z_S}$ ratio, respectively. As shown, as this ratio increases, the SST stays online for a longer period of time after the fault. This is due to higher post fault voltage which enables the SST to draw/sink the power demanded/generated on its secondary side.

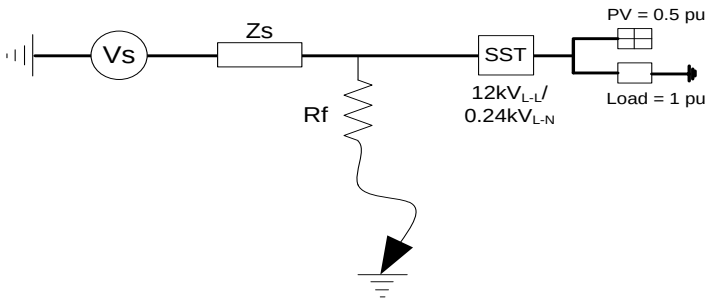
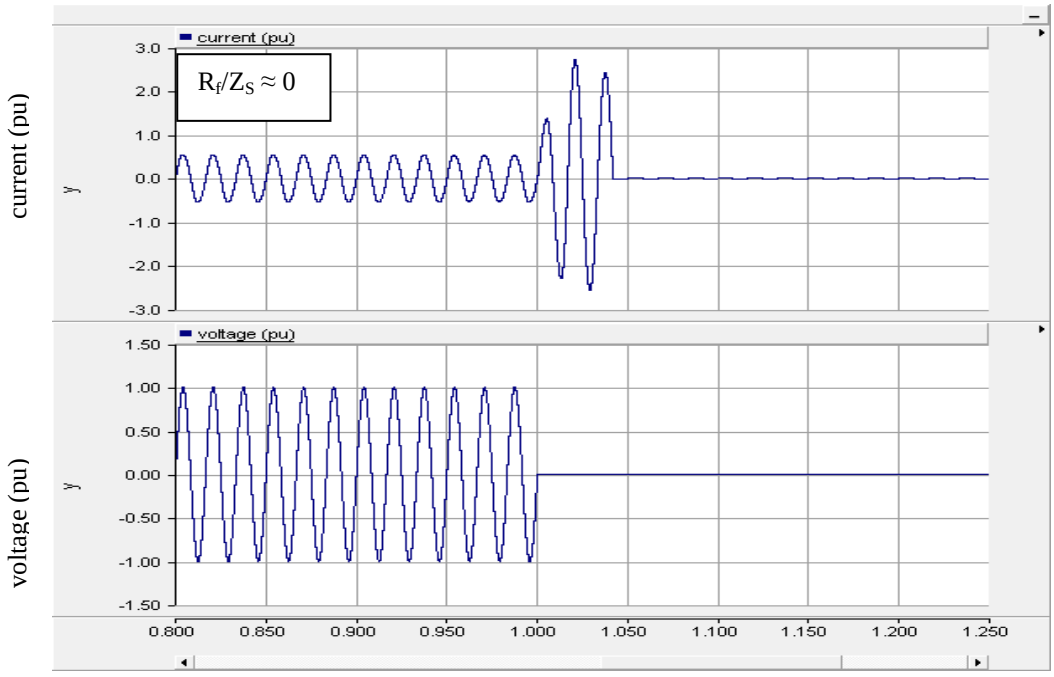
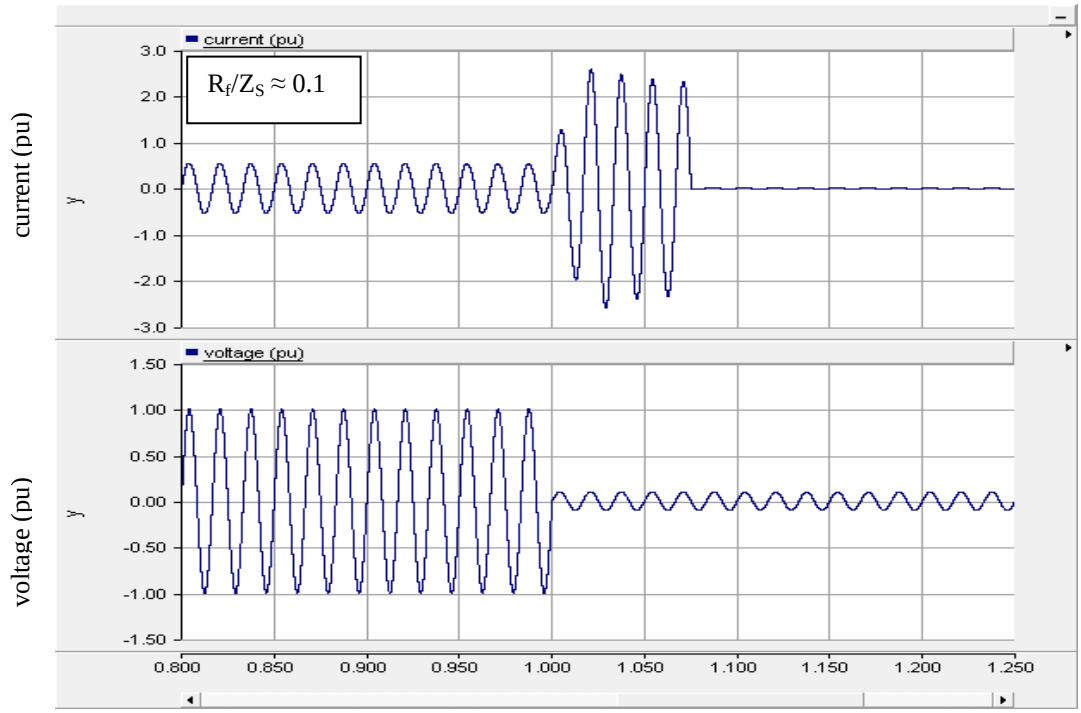
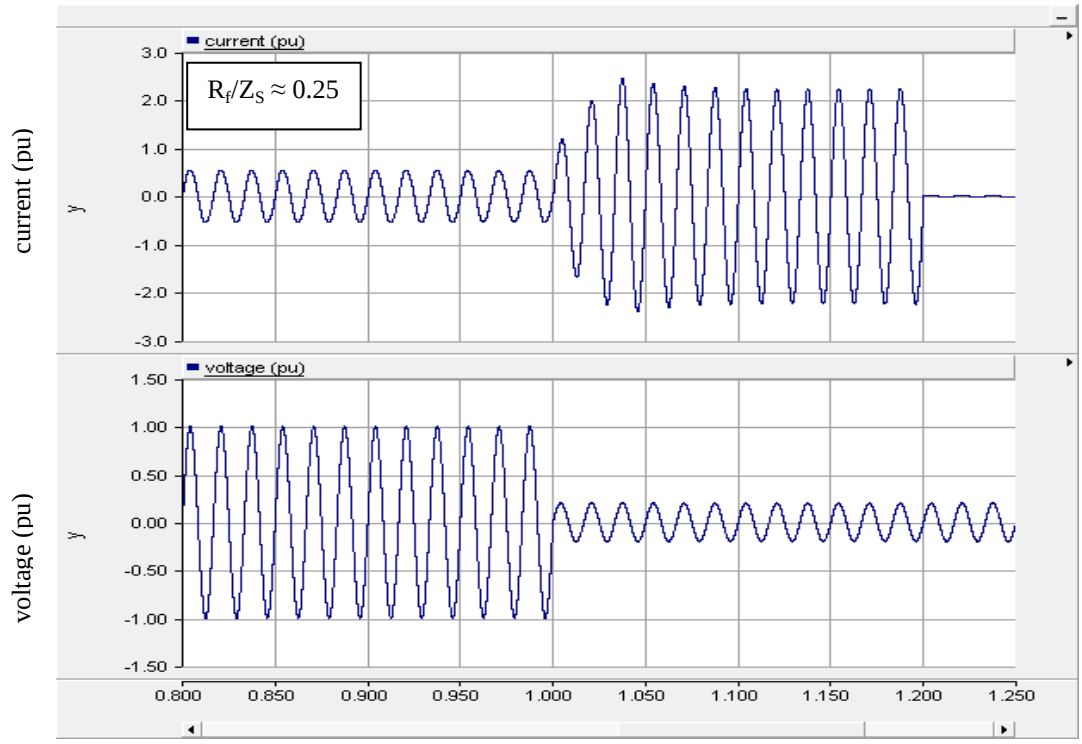


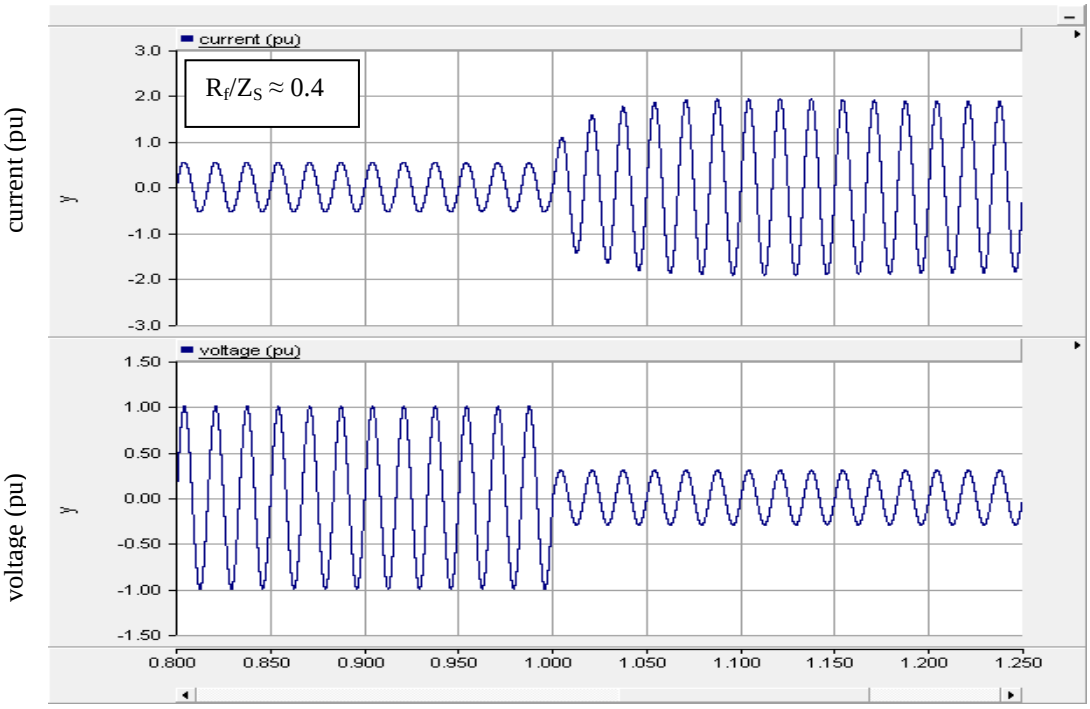
Figure 17: Test case

Figure 18: SST primary voltage/current


current (pu)
$R_f/Z_S \approx 0$
voltage (pu)
current (pu)
3.0
2.0
1.0
0.0
-1.0
-2.0
-3.0
y
voltage (pu)
1.50
1.00
0.50
0.00
-0.50
-1.00
-1.50
y
0.800
0.850
0.900
0.950
1.000
1.050
1.100
1.150
1.200
1.250
time (s)

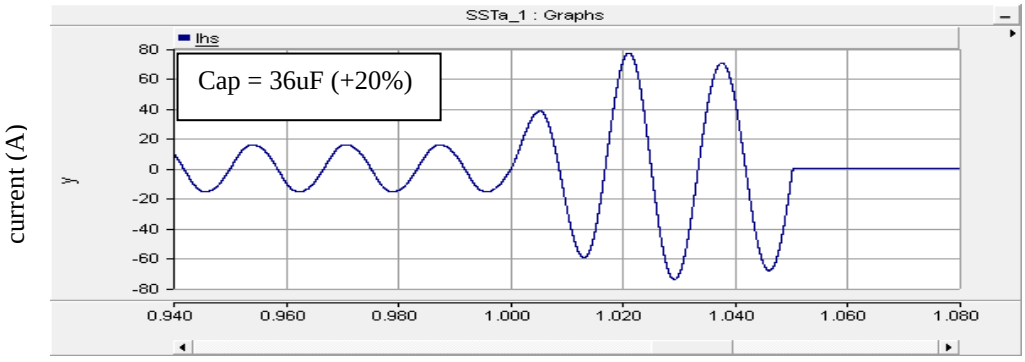

current (pu)
$R_f/Z_S \approx 0.1$
voltage (pu)
current (pu)
3.0
2.0
1.0
0.0
-1.0
-2.0
-3.0
y
voltage (pu)
1.50
1.00
0.50
0.00
-0.50
-1.00
-1.50
y
0.800
0.850
0.900
0.950
1.000
1.050
1.100
1.150
1.200
1.250
time (s)

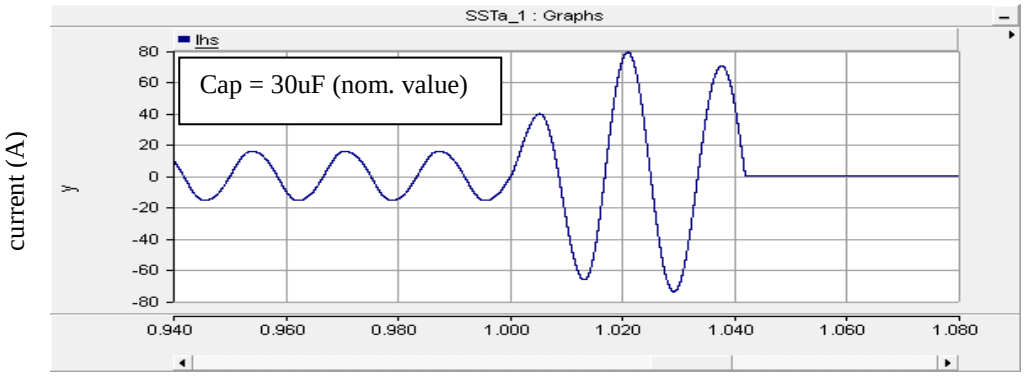

current (pu)
$R_f/Z_S \approx 0.25$
voltage (pu)
current (pu)
voltage (pu)
time (s)


current (pu)
$R_f/Z_S \approx 0.4$
voltage (pu)
current (pu)
voltage (pu)
time (s)

RELATION OF HV CAP AND INPUT INDUCTANCE WITH SST'S PRIMARY CURRENT

A simple test case as shown in figure 17 has been set up for a SST to investigate the effect of change in HV cap and input inductance ratings on the SST's primary current. As shown in figure 19, the higher the cap capacity, the longer the SST stays online after the fault. This is because the cap with higher capacity takes more time to discharge as shown in figure 20. Similar test has been done by changing the rating of the input inductance; however, as shown in figure 21, change in input inductance does not have noticeable effect on the primary current.





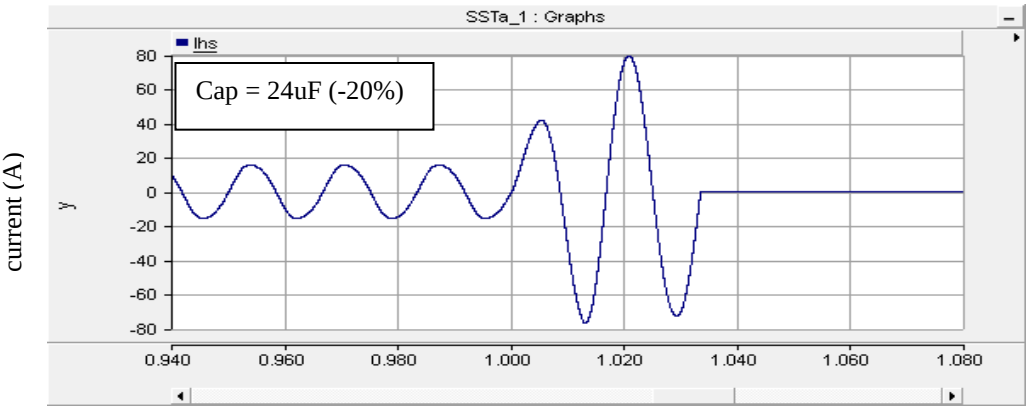


Figure 19: SST primary current

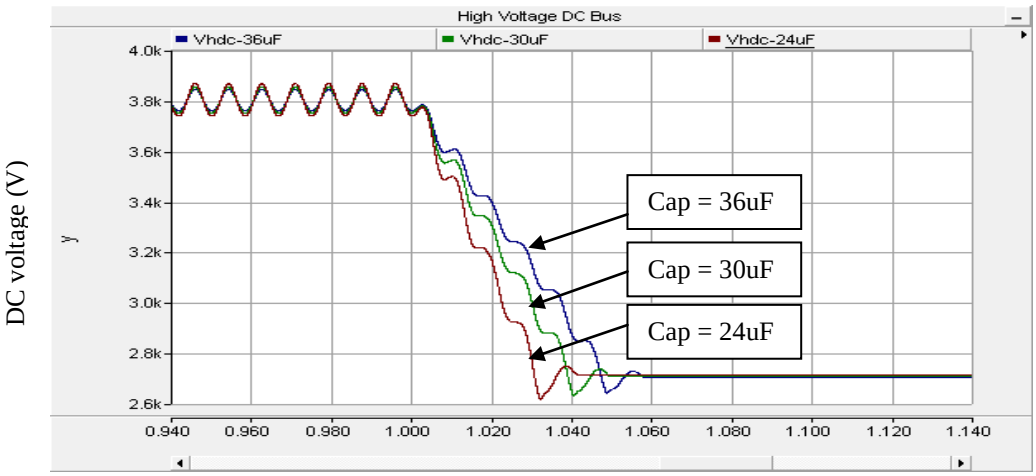
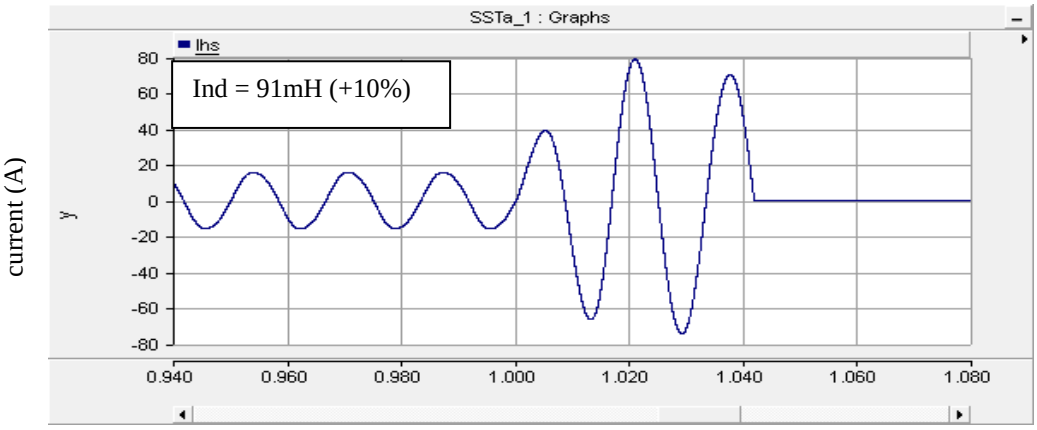
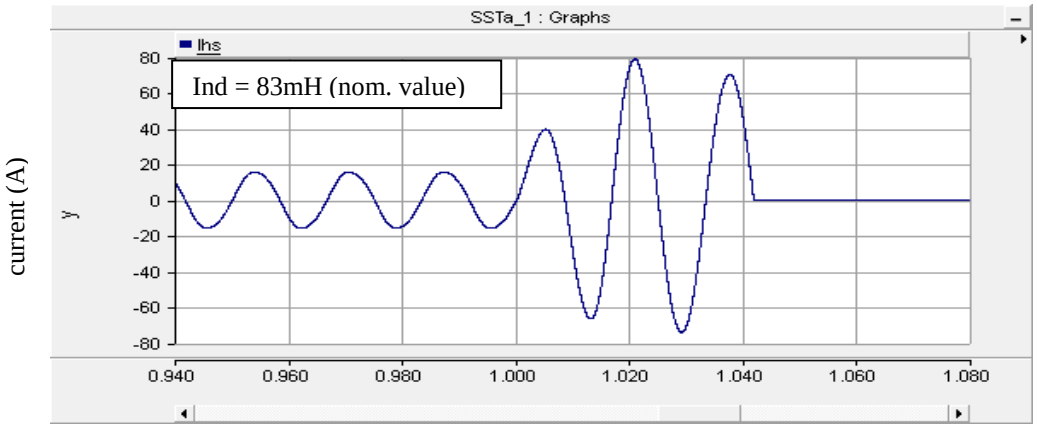


Figure 20: SST DC cap voltage





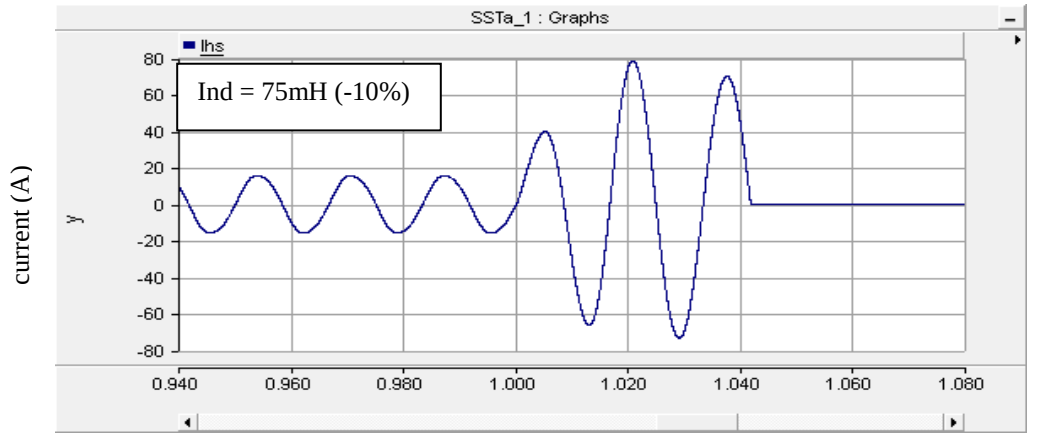


Figure 21: SST primary current

In order to have a three-phase 69/12kV substation SST, three single-phase SST models have been used in delta/wye connection as shown in figure 22. These single-phase SST models are basically the same models as the original SST model except that the voltages measured at the power stage have been scaled down from 69/12kV to 12/7.2kV and the voltage signals calculated by the controllers have been scaled up from 12/7.2kV to 69/12kV in order to make the original design utilizable.

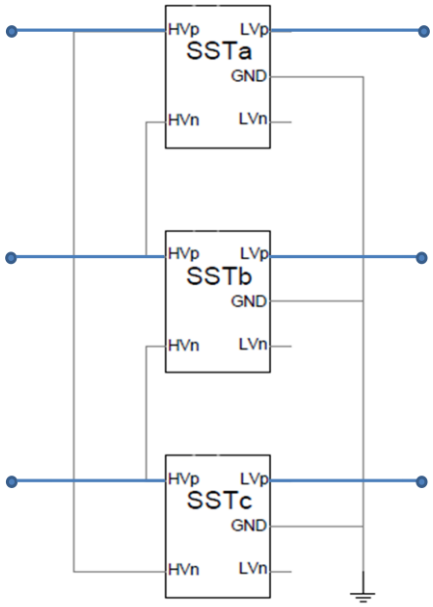


Figure 22: Three-phase substation SST

CHAPTER 3

PROTECTION ISSUES IN GREEN HUBS

GREEN HUB I

In this section, impact of high level PV penetration on the protection of the feeder has been investigated by using the prototype system and simulations.

CHANGE IN REACH AND OPERATING TIME OF PROTECTIVE DEVICES

PROBLEM STATEMENT

DERs change the fault current flowing through the protective devices (PD). Figure 23 shows two cases where in the first part, the DER decrease the PD's current and in the second part, it increases the PD's current. As a result, the change in the current changes the operating time of the PD.

One of the potential problems known as protection underreach is the same as what happens in the first part of the figure 23 where the DER could potentially source enough of the fault current so that the upstream of the protective device would not see the fault [1,13,14].

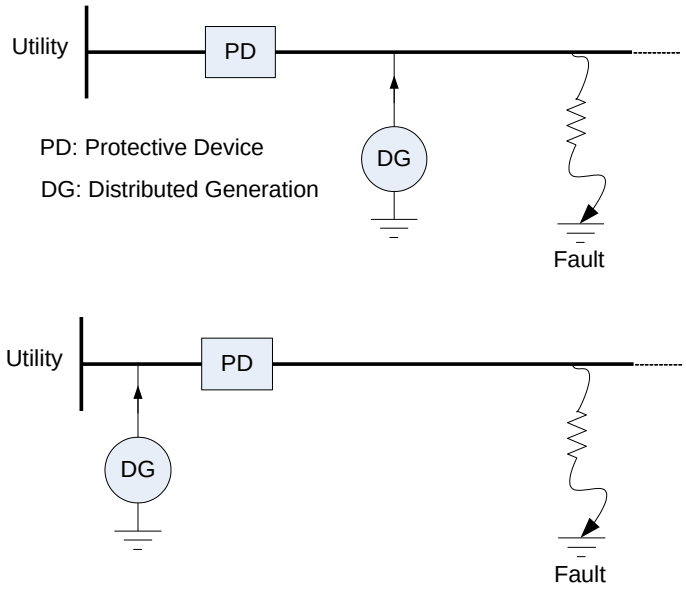


Figure 23: Change in PDs' currents in presence of a DER

SIMULATION AND RESULTS

Figure 24 shows a generic case where three groups of PVs are connected to the system in different locations: I_1 which represents all the generation from adjacent feeders and the branches upstream of the PD, I_2 which represents all the generation between the PD and the fault, and I_3 which represents all the generation after the fault. As implied in the figure, the amount of PVs' effect on the operating time of the PD is determined by the following variables:

1. Amount of PV generation
2. PVs' locations
3. Fault resistance
4. Fault location

In this section, we want to find what combination of values for the above-mentioned variables construct the worst case where the PVs' effects on the PD's operating time is maximized. The ultimate goal of this study is to propose new procedures for system protection which will be presented in Chapter 5.

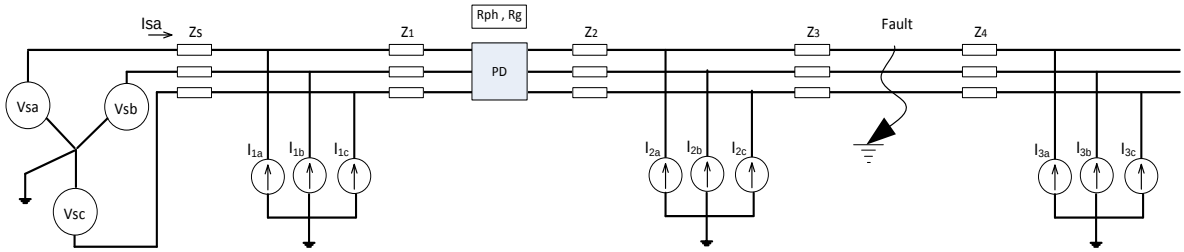


Figure 24: A generic three-phase case showing the PVs in different locations

In this section different three-phase and single-phase faults with varying resistances and in different locations have been applied to the prototype system to see how the PVs affect the operating time of the protective devices (PD).

For each of the PDs, faults are placed at the closest and the farthest points in the primary zone of protection. The fault resistances are zero, the typical fault resistance at each location based on the Warrington expression [15], and higher resistances up to the maximum resistance that can be picked up by the PD.

$$R_{arc} = \frac{2.9\times10^{4} L}{I^{1.4}} \qquad \text{(Warrington expression)} \qquad (1)$$

where L is the conductor spacing, I is fault current, and R_{arc} is the approximate value of the fault arc resistance.

This set of tests has been done on the breaker and the recloser of the feeder 1. The faults are shown in figure 25 on the single-line diagram of the system. Figure 26 shows the PSCAD implementation of Green Hub I.

PV output has been expressed as a percentage of the system load in the simulation results. For example, PV = 50% means each PVs' output is equal to 50% of its corresponding load. In all cases, the loads are set to their nominal ratings (100%). However, since the system voltage collapses after the fault, the loads do not have noticeable impact on fault current levels.

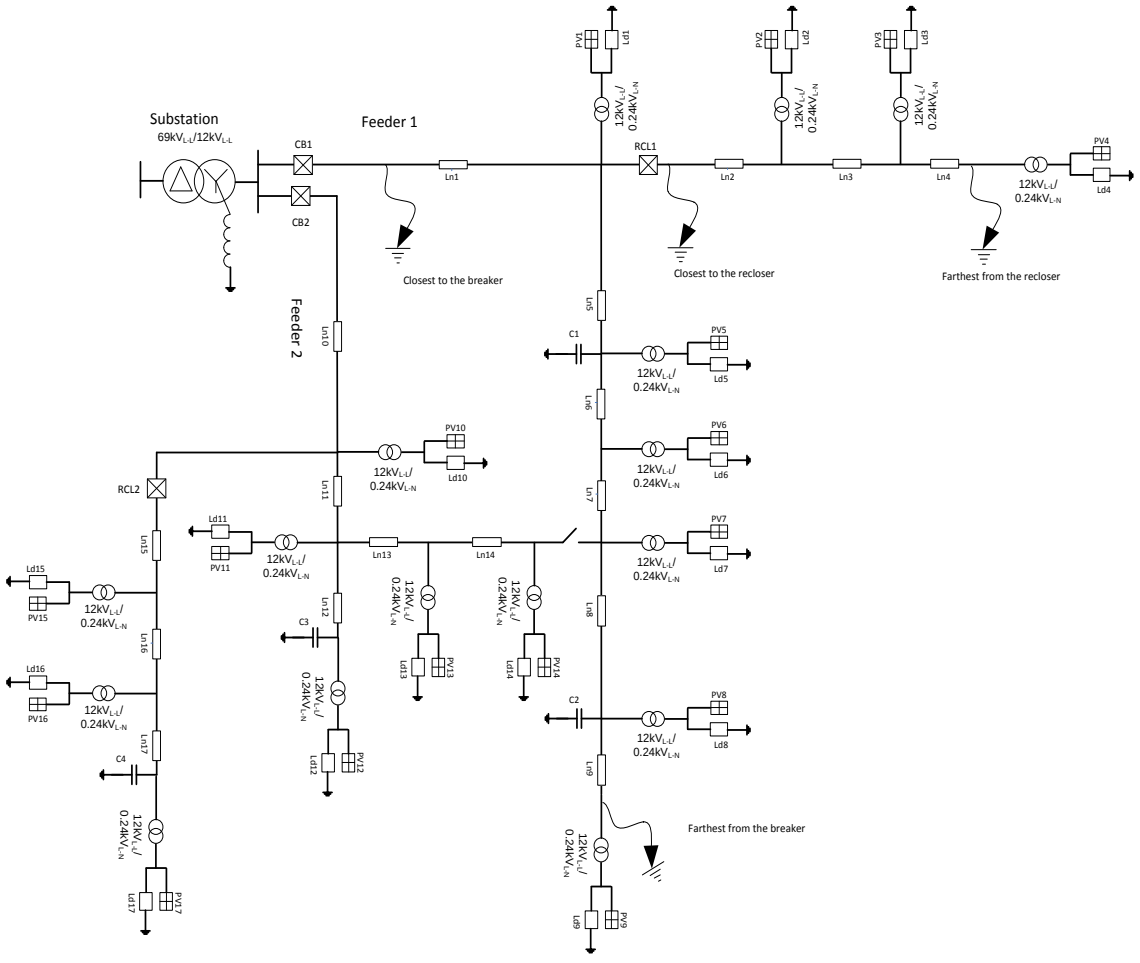


Figure 25: Fault locations on Green Hub I

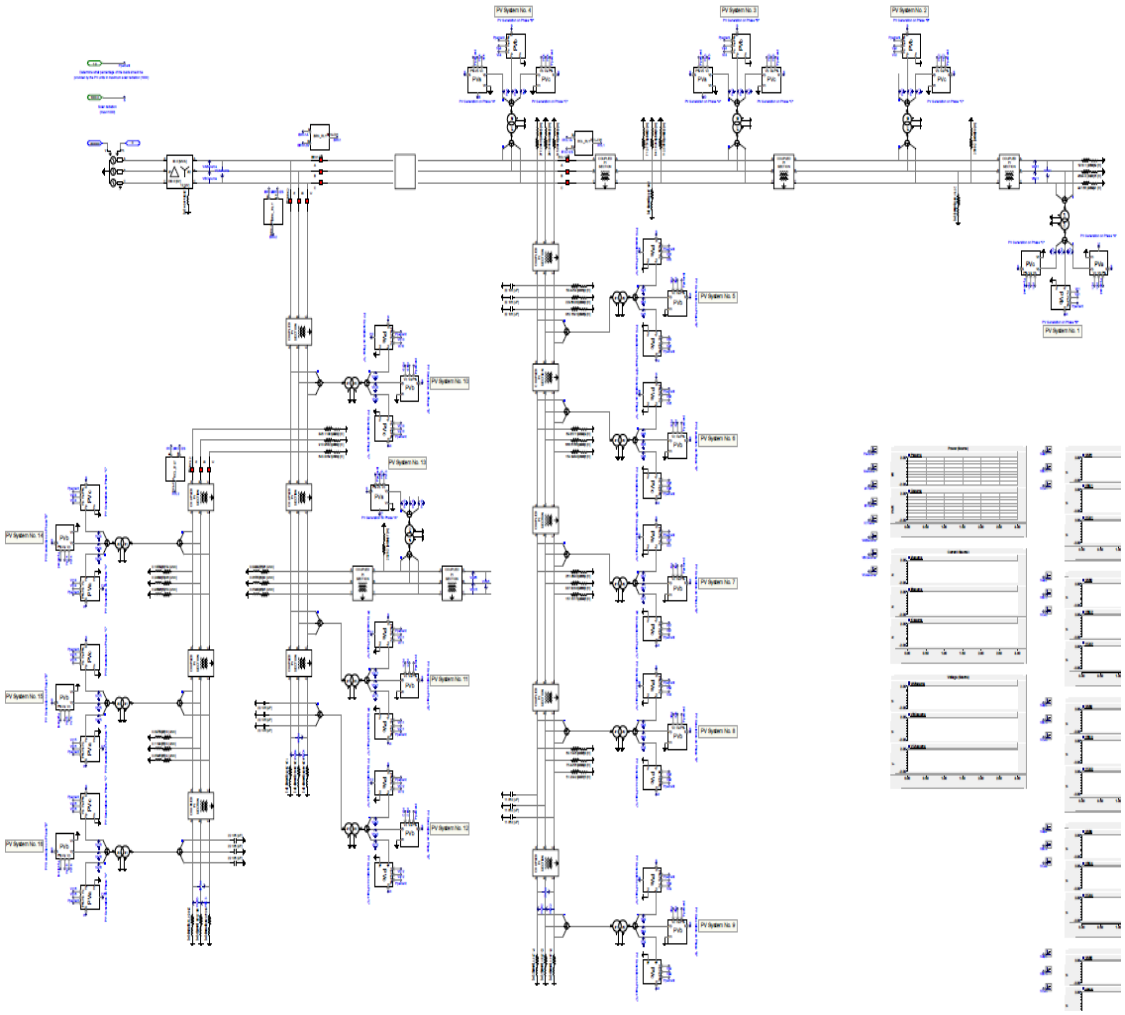


Figure 26: PSCAD implementation of Green Hub I

PVs have been divided into two groups based on their locations: PVs downstream the PDs and PVs upstream the PDs. The effect of these two groups of PVs will be investigated separately.

PVs downstream a protective device

In this section, it has been assumed that the adjacent feeder in our test case in covered by clouds. Figures 27 and 28 show the single line diagram of the whole system and the generic electrical circuit showing the PV set that is covered by the clouds. The fault has been placed at the closest and farthest points with regard to the breaker to see how the PVs affect the reach and operating times.

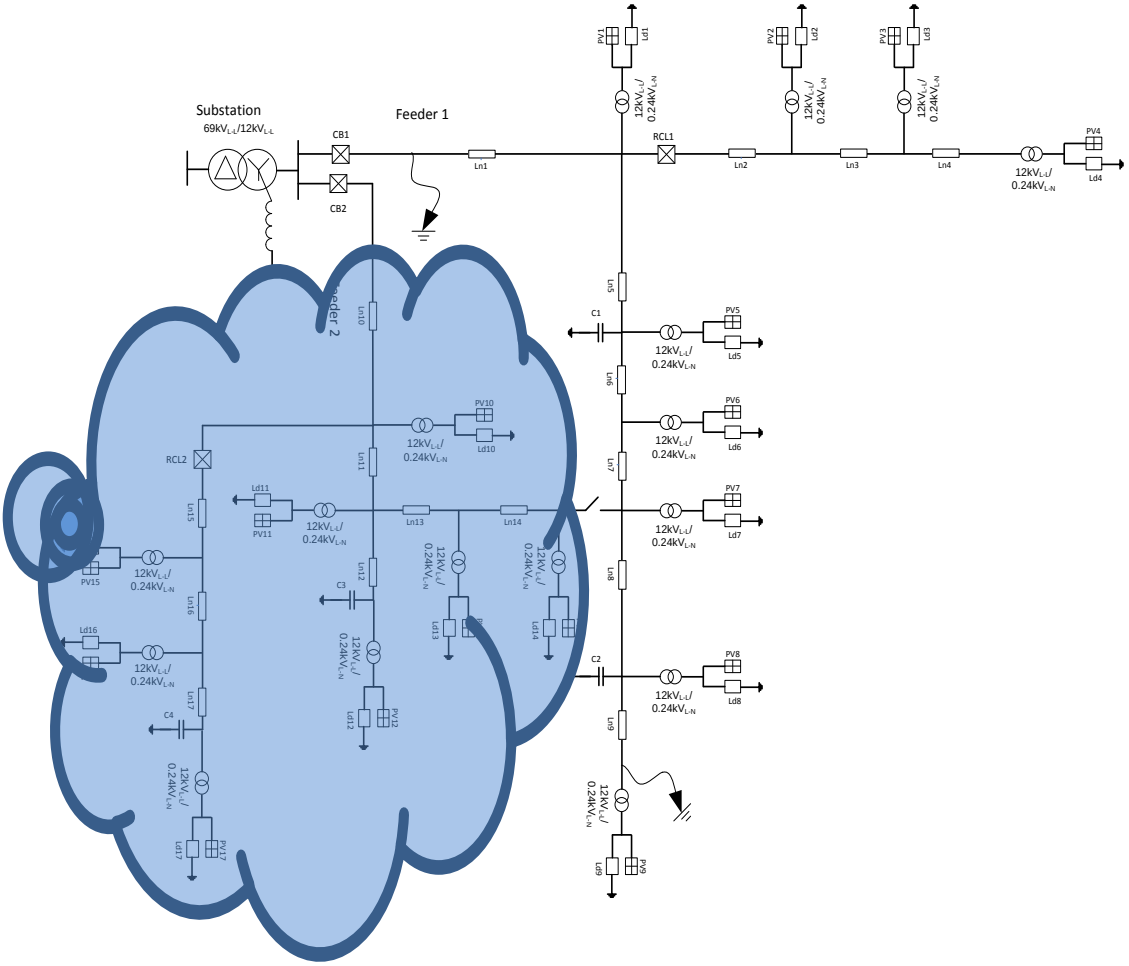


Figure 27: Green Hub I while the PVs, upstream the breaker, are under cloud

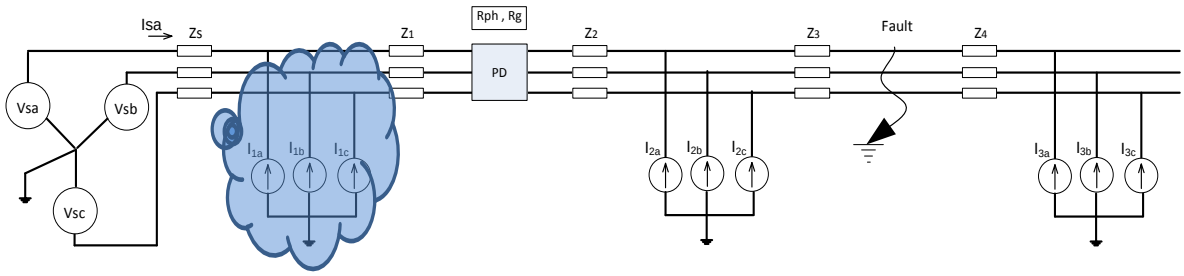
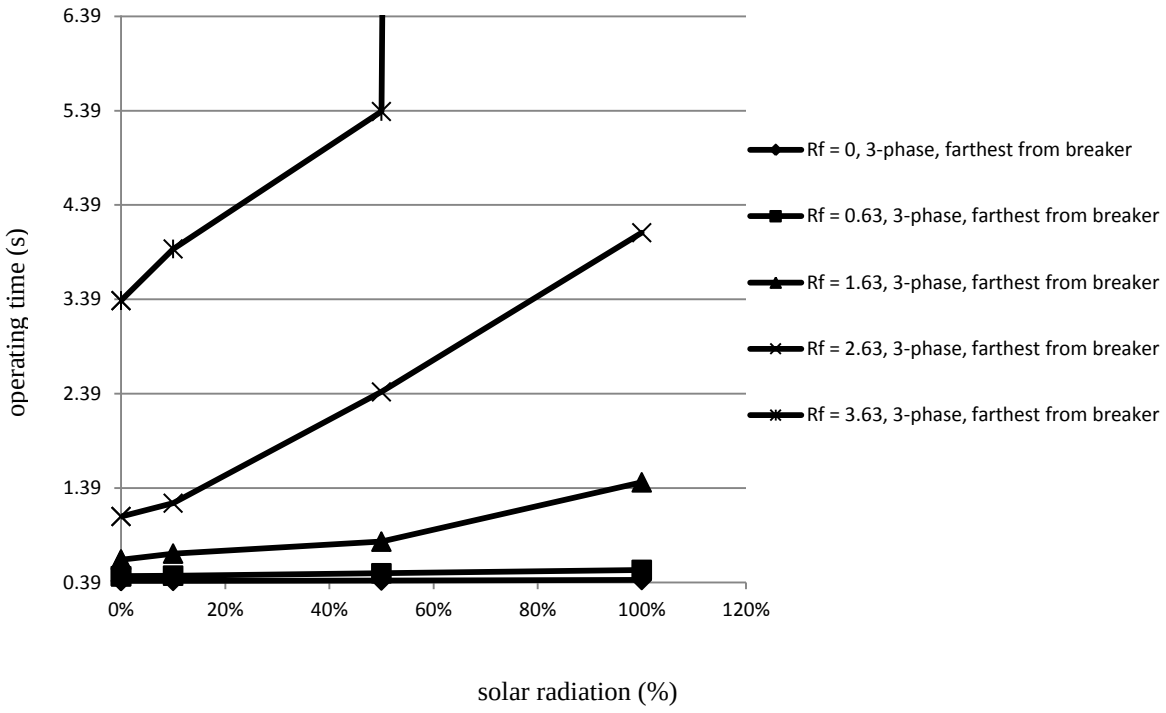
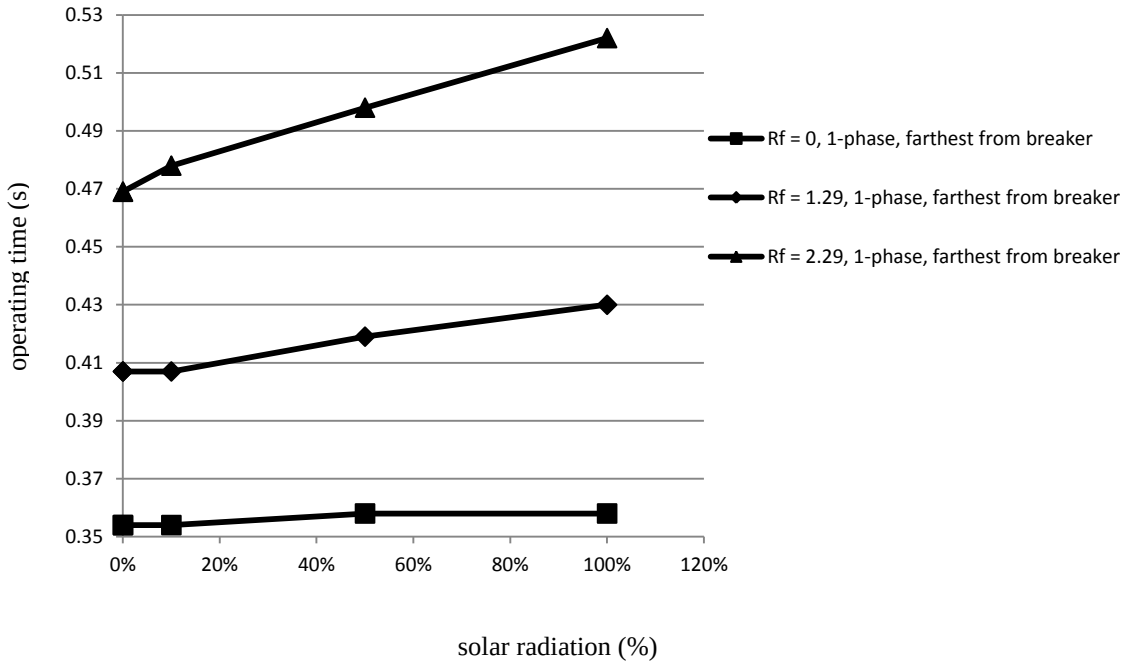


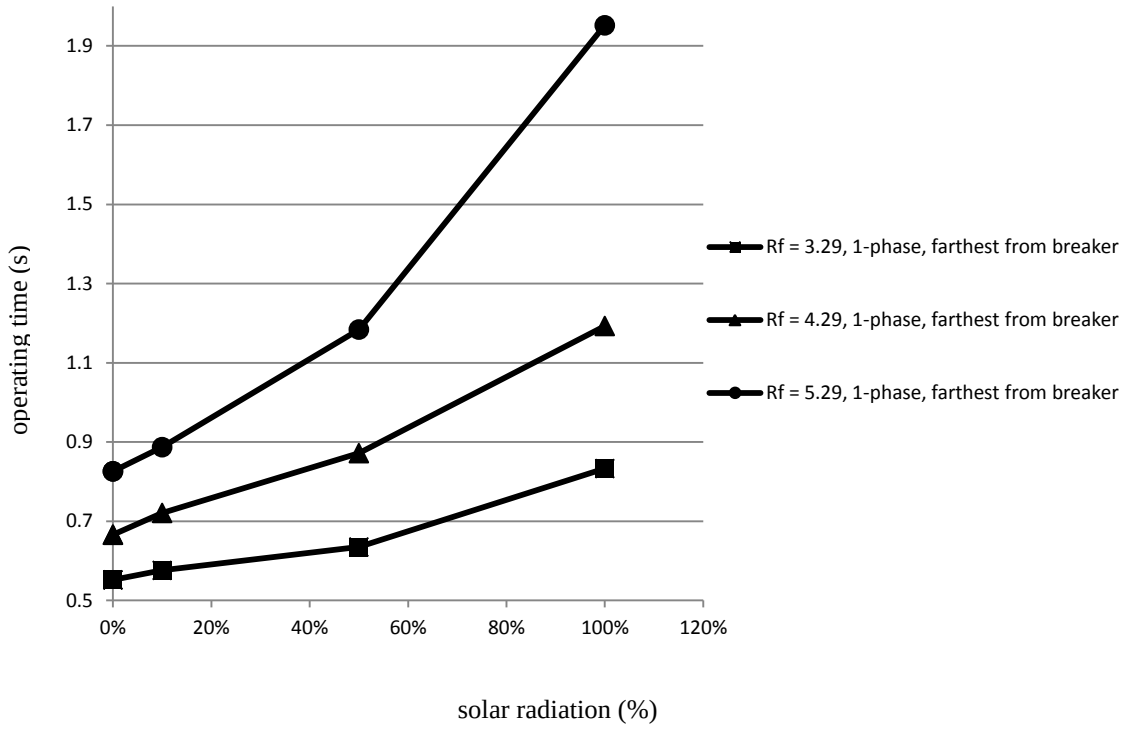
Figure 28: Generic electrical circuit showing that the PVs, upstream the breaker, are under cloud

Figures 29 and 30 summarize the effect of the PVs on the operating time of the breaker of the feeder 1.

Figure 29: Breaker operating time vs. PV generation while the fault is at the farthest point from the breaker


6.39
5.39
4.39
3.39
2.39
1.39
0.39
operating time (s)
0%
20%
40%
60%
80%
100%
120%
solar radiation (%)
Rf = 0, 3-phase, farthest from breaker
Rf = 0.63, 3-phase, farthest from breaker
Rf = 1.63, 3-phase, farthest from breaker
Rf = 2.63, 3-phase, farthest from breaker
Rf = 3.63, 3-phase, farthest from breaker


0.53
0.51
0.49
0.47
0.45
0.43
0.41
0.39
0.37
0.35
operating time (s)
0%
20%
40%
60%
80%
100%
120%
solar radiation (%)
Rf = 0, 1-phase, farthest from breaker
Rf = 1.29, 1-phase, farthest from breaker
Rf = 2.29, 1-phase, farthest from breaker


operating time (s)
1.9
1.7
1.5
1.3
1.1
0.9
0.7
0.5
0%
20%
40%
60%
80%
100%
120%
Rf = 3.29, 1-phase, farthest from breaker
Rf = 4.29, 1-phase, farthest from breaker
Rf = 5.29, 1-phase, farthest from breaker
solar radiation (%)

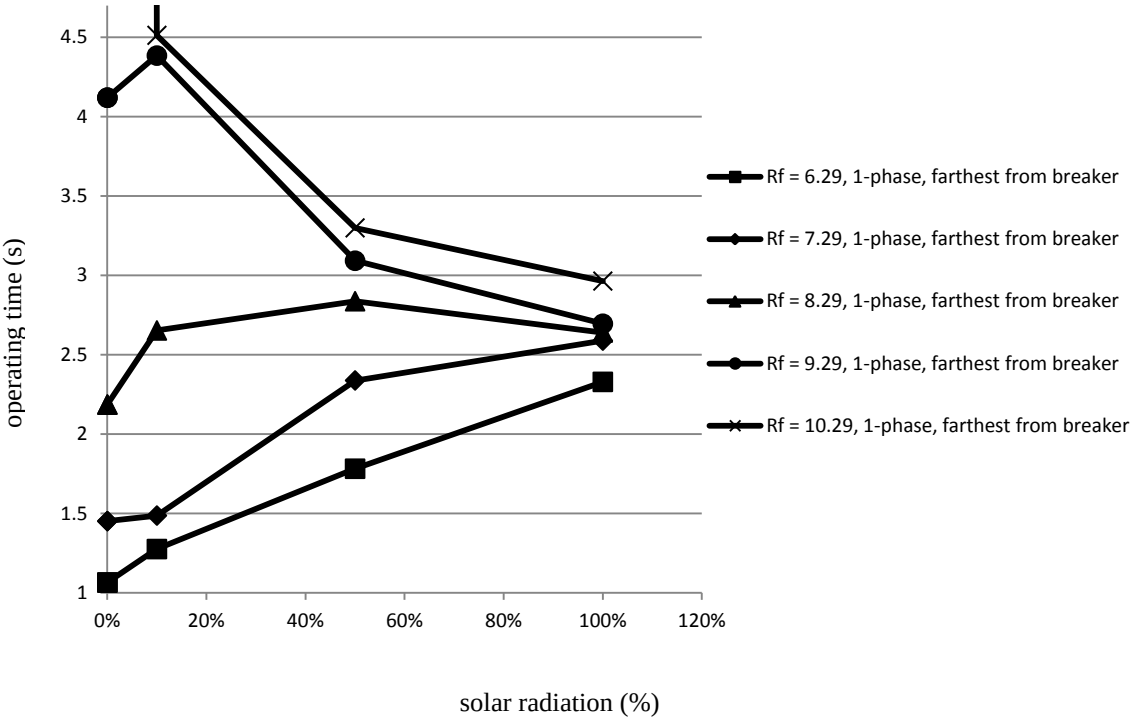
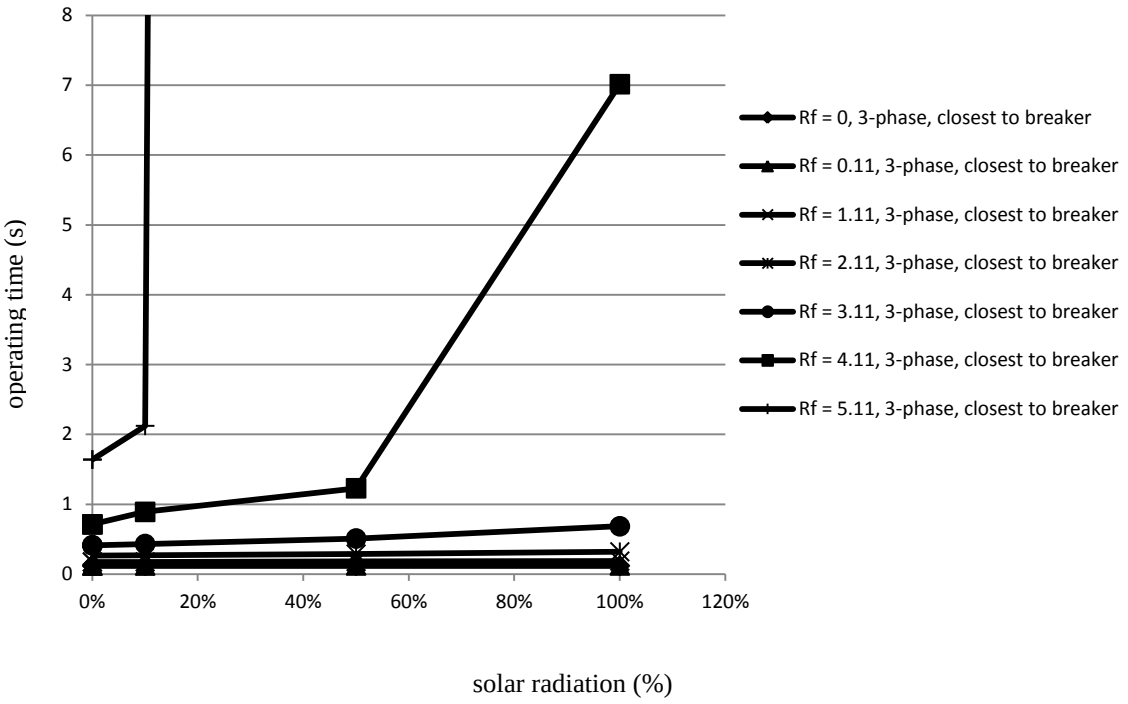
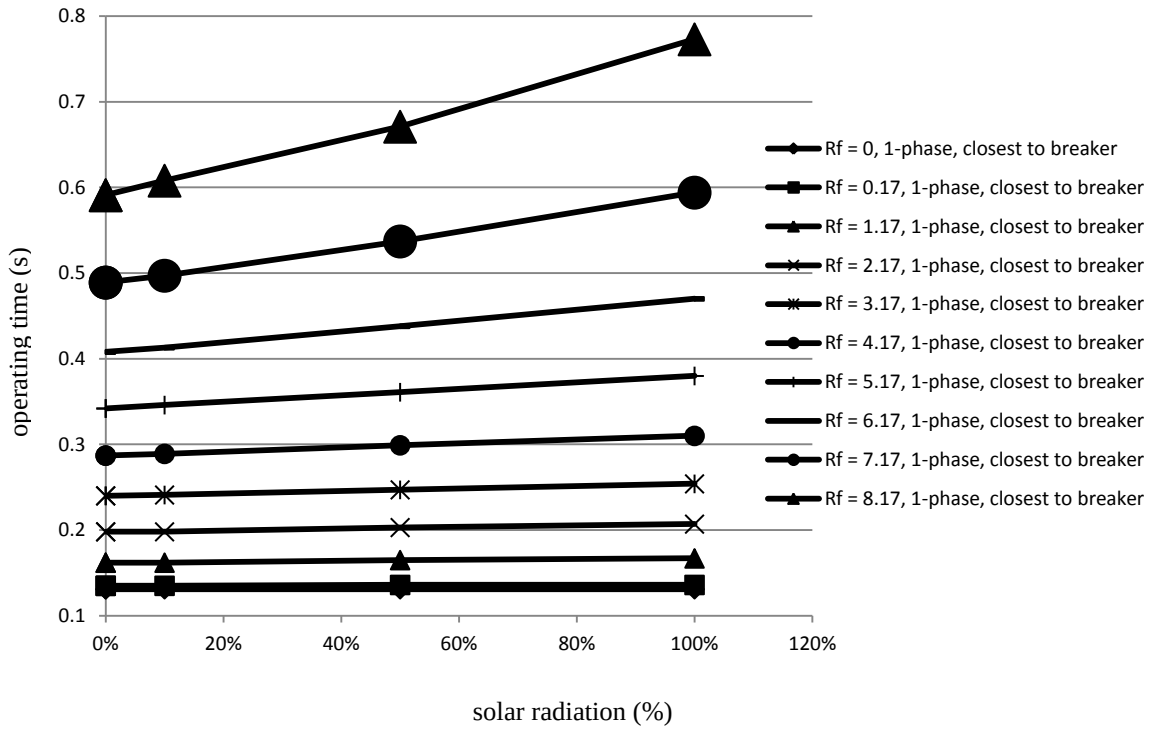
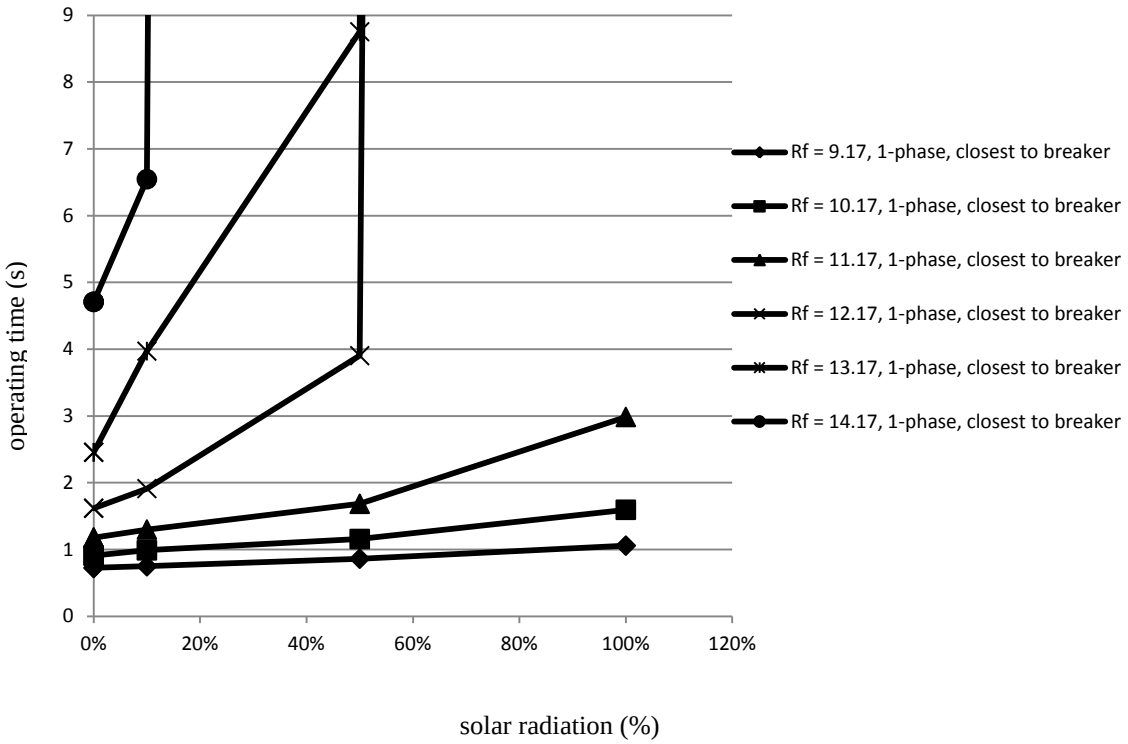

operating time (s)
4.5
4
3.5
3
2.5
2
1.5
1
0%
20%
40%
60%
80%
100%
120%
Rf = 6.29, 1-phase, farthest from breaker
Rf = 7.29, 1-phase, farthest from breaker
Rf = 8.29, 1-phase, farthest from breaker
Rf = 9.29, 1-phase, farthest from breaker
Rf = 10.29, 1-phase, farthest from breaker
solar radiation (%)

Figure 30: Breaker operating time vs. PV generation while the fault is at the closest point to the breaker

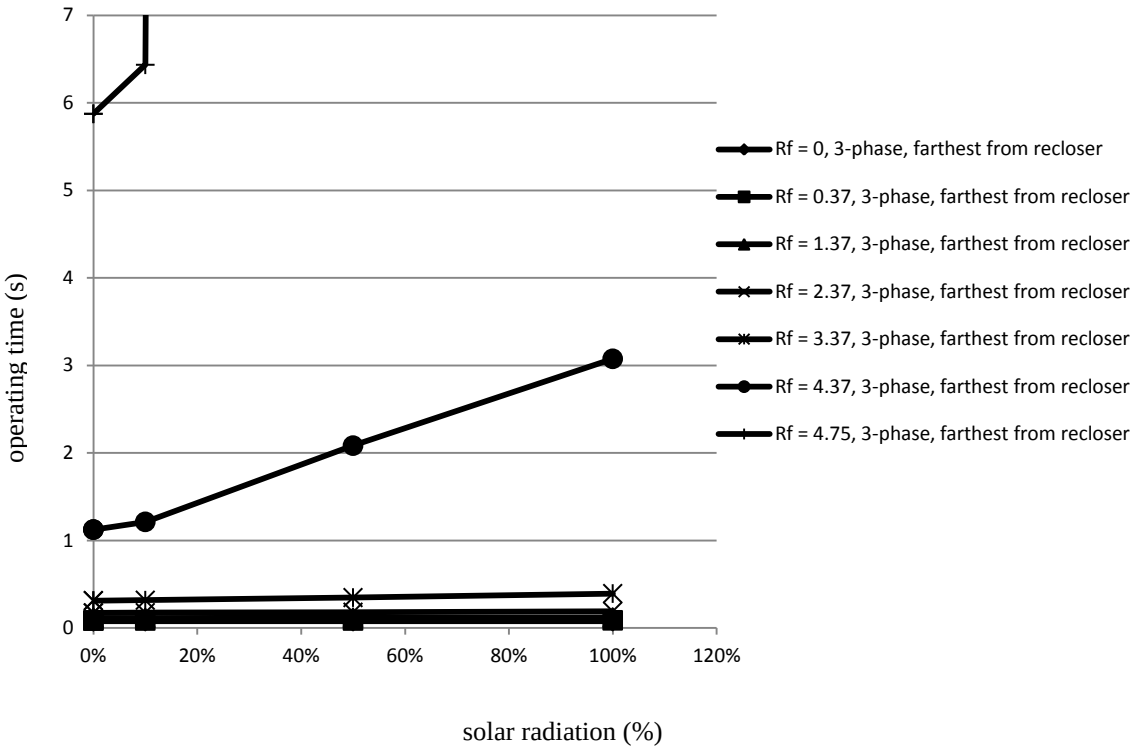

operating time (s)
8
7
6
5
4
3
2
1
0
0%
20%
40%
60%
80%
100%
120%
solar radiation (%)
Rf = 0, 3-phase, closest to breaker
Rf = 0.11, 3-phase, closest to breaker
Rf = 1.11, 3-phase, closest to breaker
Rf = 2.11, 3-phase, closest to breaker
Rf = 3.11, 3-phase, closest to breaker
Rf = 4.11, 3-phase, closest to breaker
Rf = 5.11, 3-phase, closest to breaker

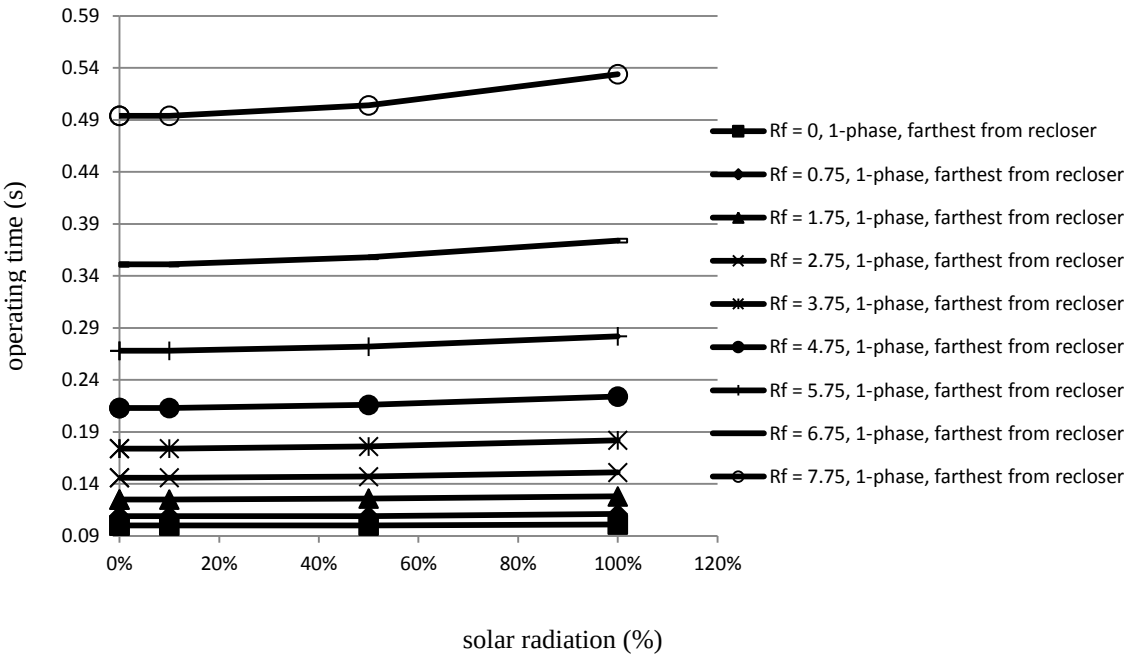

operating time (s)
0.8
0.7
0.6
0.5
0.4
0.3
0.2
0.1
0%
20%
40%
60%
80%
100%
120%
solar radiation (%)
Rf = 0, 1-phase, closest to breaker
Rf = 0.17, 1-phase, closest to breaker
Rf = 1.17, 1-phase, closest to breaker
Rf = 2.17, 1-phase, closest to breaker
Rf = 3.17, 1-phase, closest to breaker
Rf = 4.17, 1-phase, closest to breaker
Rf = 5.17, 1-phase, closest to breaker
Rf = 6.17, 1-phase, closest to breaker
Rf = 7.17, 1-phase, closest to breaker
Rf = 8.17, 1-phase, closest to breaker



The same simulations have been done for the recloser of the feeder 1 assuming that all PVs upstream the recloser are covered by clouds. Figures 31 and 32 summarize the effect of the PVs on the operating time of the recloser.

Figure 31: Recloser operating time vs. PV generation while the fault is at the farthest point from the recloser


operating time (s)
7
6
5
4
3
2
1
0
0%
20%
40%
60%
80%
100%
120%
solar radiation (%)
Rf = 0, 3-phase, farthest from recloser
Rf = 0.37, 3-phase, farthest from recloser
Rf = 1.37, 3-phase, farthest from recloser
Rf = 2.37, 3-phase, farthest from recloser
Rf = 3.37, 3-phase, farthest from recloser
Rf = 4.37, 3-phase, farthest from recloser
Rf = 4.75, 3-phase, farthest from recloser


operating time (s)
0.59
0.54
0.49
0.44
0.39
0.34
0.29
0.24
0.19
0.14
0.09
0%
20%
40%
60%
80%
100%
120%
solar radiation (%)
Rf = 0, 1-phase, farthest from recloser
Rf = 0.75, 1-phase, farthest from recloser
Rf = 1.75, 1-phase, farthest from recloser
Rf = 2.75, 1-phase, farthest from recloser
Rf = 3.75, 1-phase, farthest from recloser
Rf = 4.75, 1-phase, farthest from recloser
Rf = 5.75, 1-phase, farthest from recloser
Rf = 6.75, 1-phase, farthest from recloser
Rf = 7.75, 1-phase, farthest from recloser

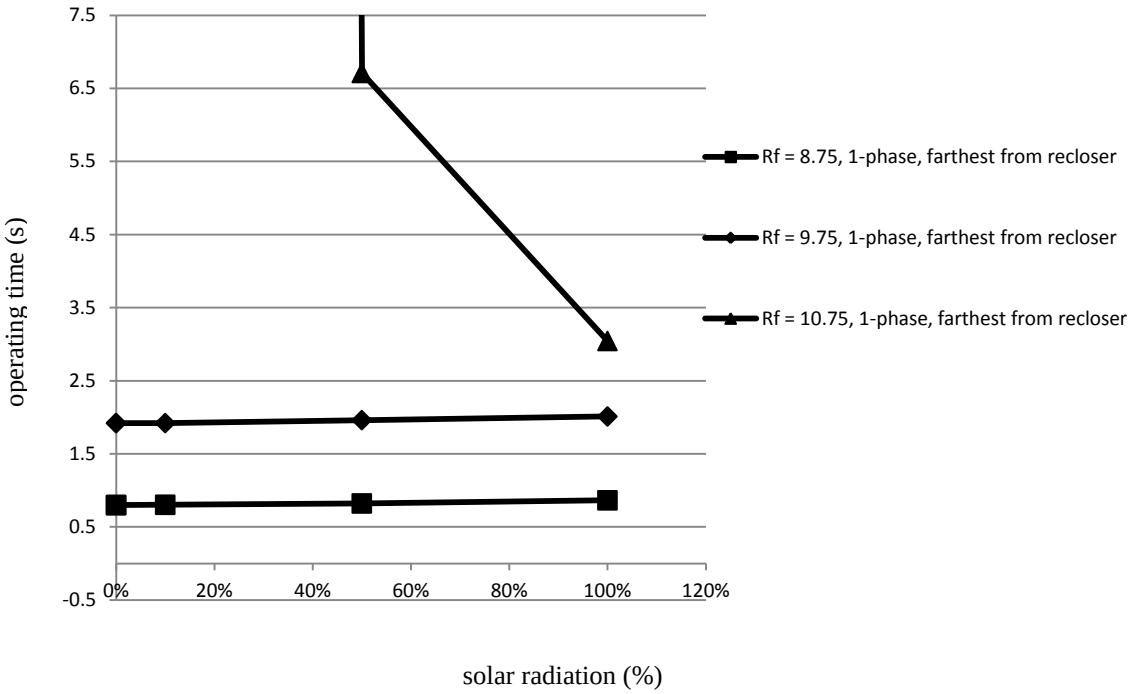
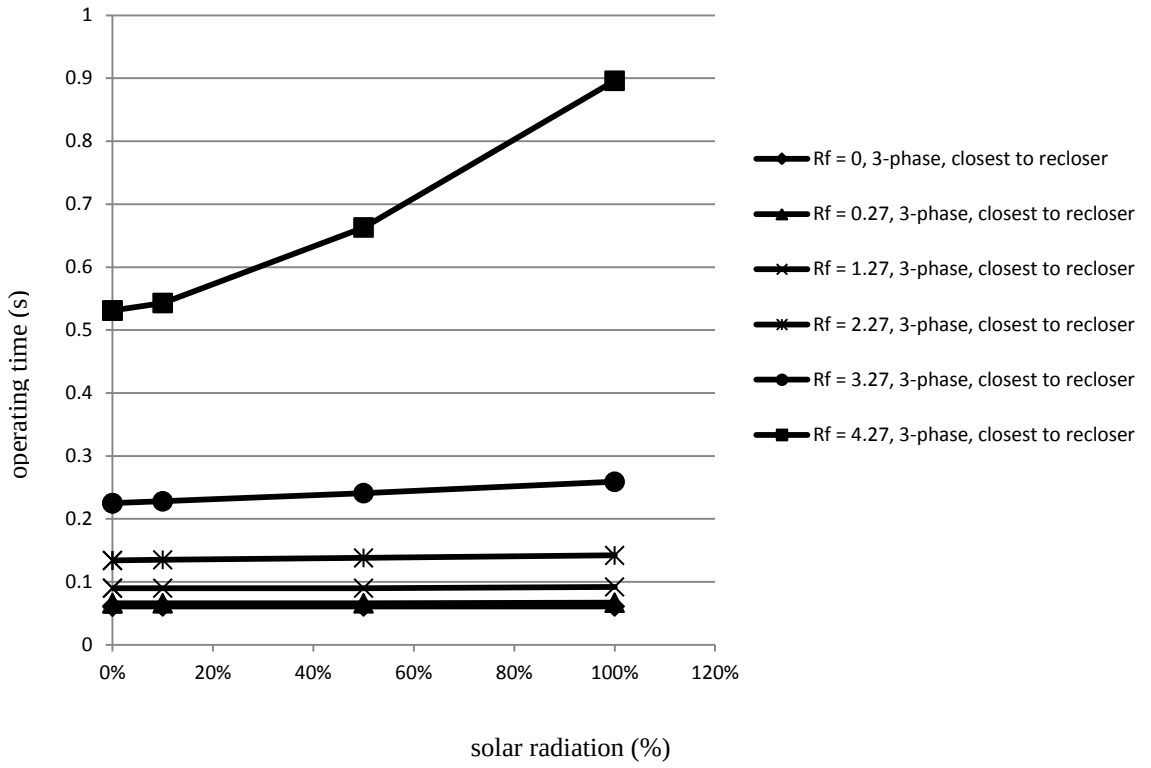
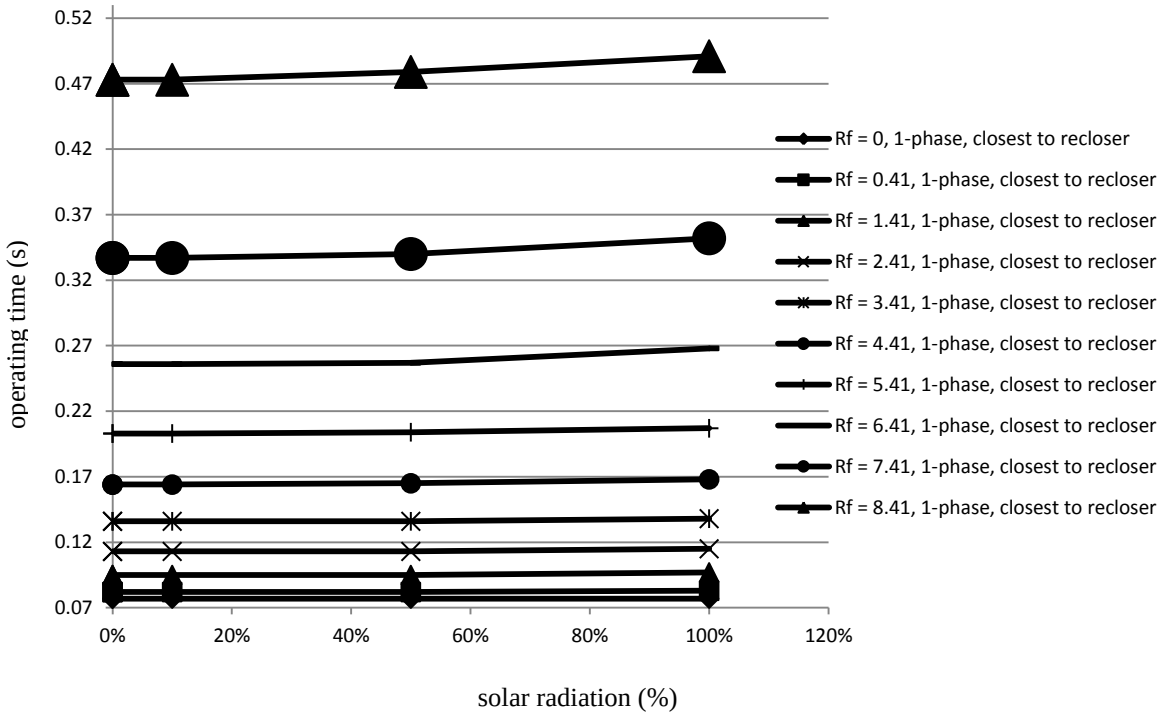
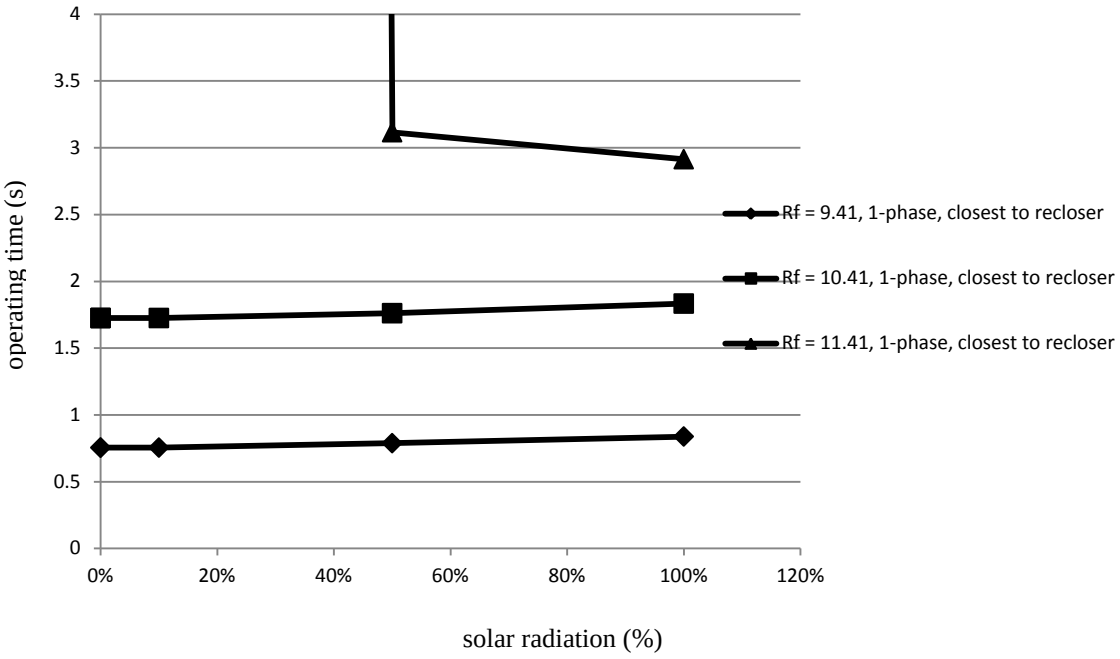

7.5
6.5
5.5
4.5
3.5
2.5
1.5
0.5
-0.5
operating time (s)
0%
20%
40%
60%
80%
100%
120%
solar radiation (%)
Rf = 8.75, 1-phase, farthest from recloser
Rf = 9.75, 1-phase, farthest from recloser
Rf = 10.75, 1-phase, farthest from recloser

Figure 32: Recloser operating time vs. PV generation while the fault is at the closest point to the recloser


operating time (s)
1
0.9
0.8
0.7
0.6
0.5
0.4
0.3
0.2
0.1
0
0%
20%
40%
60%
80%
100%
120%
solar radiation (%)
Rf = 0, 3-phase, closest to recloser
Rf = 0.27, 3-phase, closest to recloser
Rf = 1.27, 3-phase, closest to recloser
Rf = 2.27, 3-phase, closest to recloser
Rf = 3.27, 3-phase, closest to recloser
Rf = 4.27, 3-phase, closest to recloser


operating time (s)
0.52
0.47
0.42
0.37
0.32
0.27
0.22
0.17
0.12
0.07
0%
20%
40%
60%
80%
100%
120%
solar radiation (%)
Rf = 0, 1-phase, closest to recloser
Rf = 0.41, 1-phase, closest to recloser
Rf = 1.41, 1-phase, closest to recloser
Rf = 2.41, 1-phase, closest to recloser
Rf = 3.41, 1-phase, closest to recloser
Rf = 4.41, 1-phase, closest to recloser
Rf = 5.41, 1-phase, closest to recloser
Rf = 6.41, 1-phase, closest to recloser
Rf = 7.41, 1-phase, closest to recloser
Rf = 8.41, 1-phase, closest to recloser



The following observations can be derived from the simulation results on figures 29 to 32 which will be discussed in the next section:

- Three-phase faults: As shown in the figures 29 to 32, the PV generation increases the operating times of the PDs when the fault if of the three-phase type. This means that the PV generation reduces both reach and speed of the PDs.
- Single-phase faults: The last part of the figure 30 shows that the PV generation increases the operating time of the breaker hence reduces both its reach and its speed when the fault is close to the substation. However when the fault is distant from the substation, as shown in the last parts of the figures 29, 31 and 32, the PV generation decreases the operating times of the PDs hence increases both their reach and their speed.

PVs upstream a protective device

In this section, it has been assumed that the main feeder (Feeder 1) in our test case in covered by clouds. Figures 33 and 34 show the single line diagram of the whole system and the generic electrical circuit showing the PV set that is covered by the clouds. The fault has been placed at the closest and farthest points with regard to the breaker to see how the PVs affect the reach and operating times.

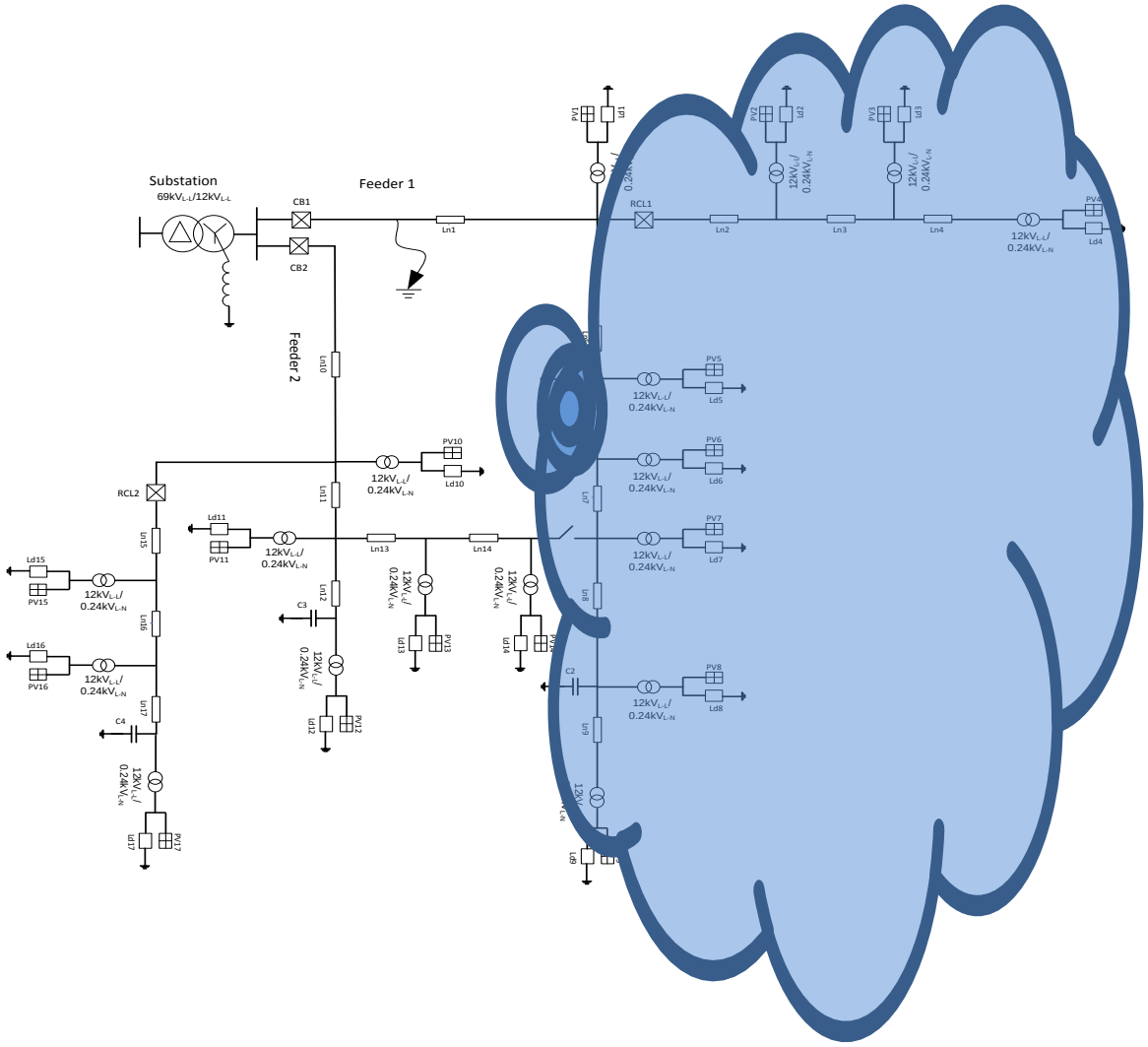


Figure 33: Green Hub I while the PVs, downstream the breaker, are under cloud

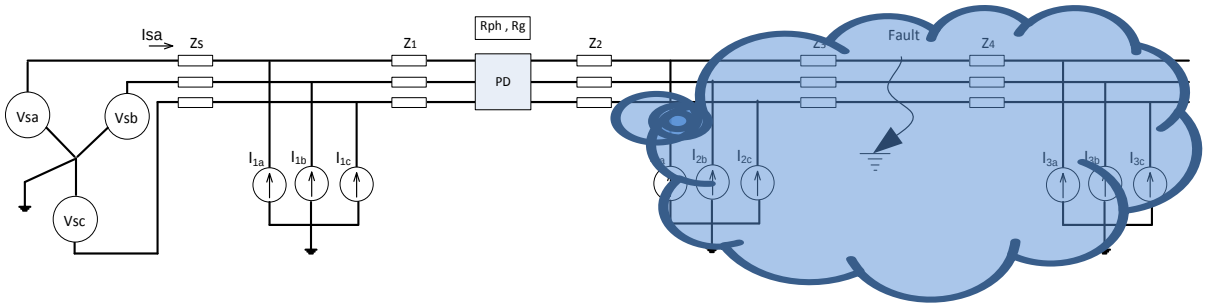
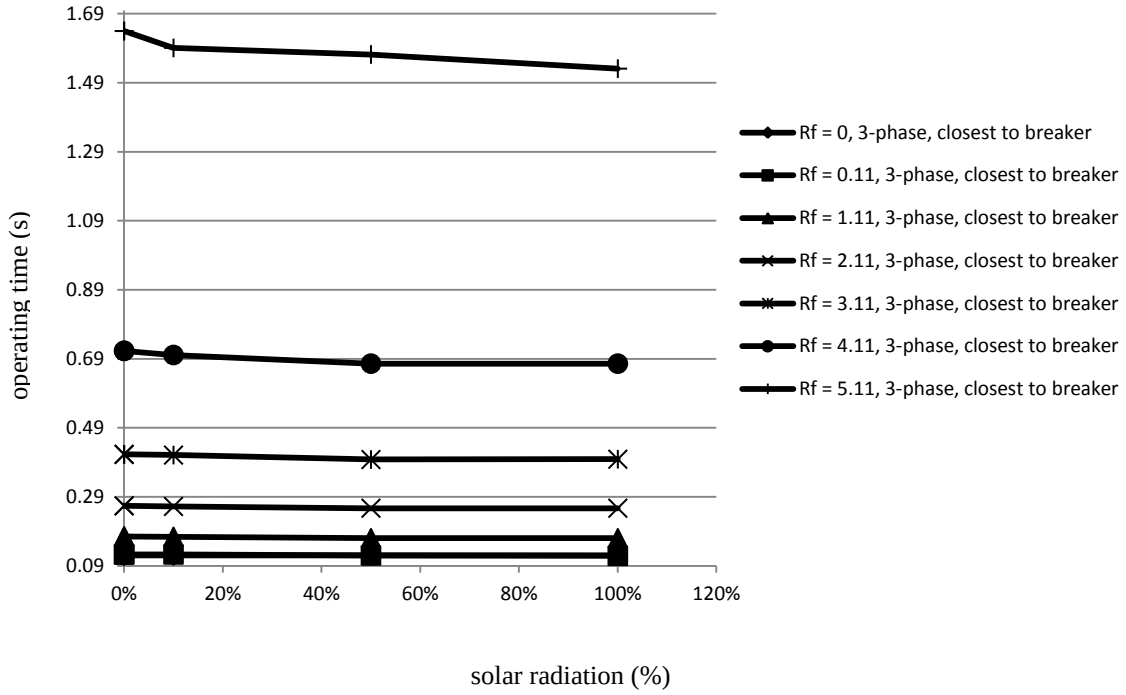
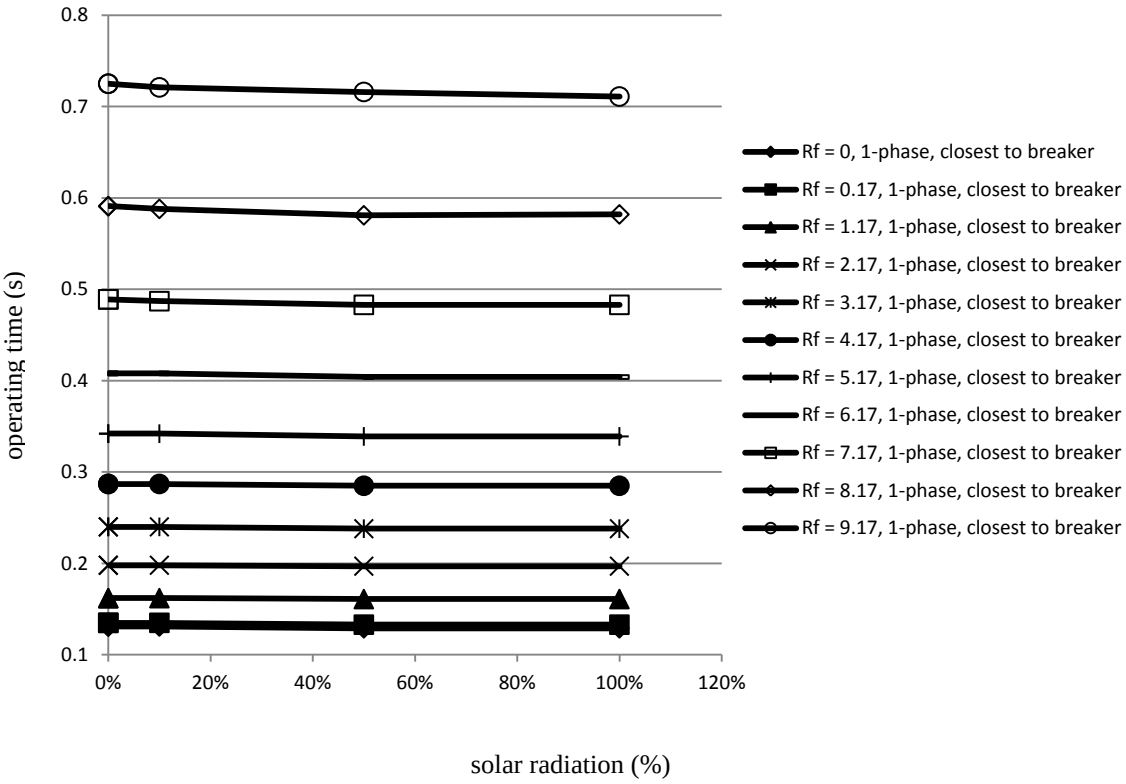


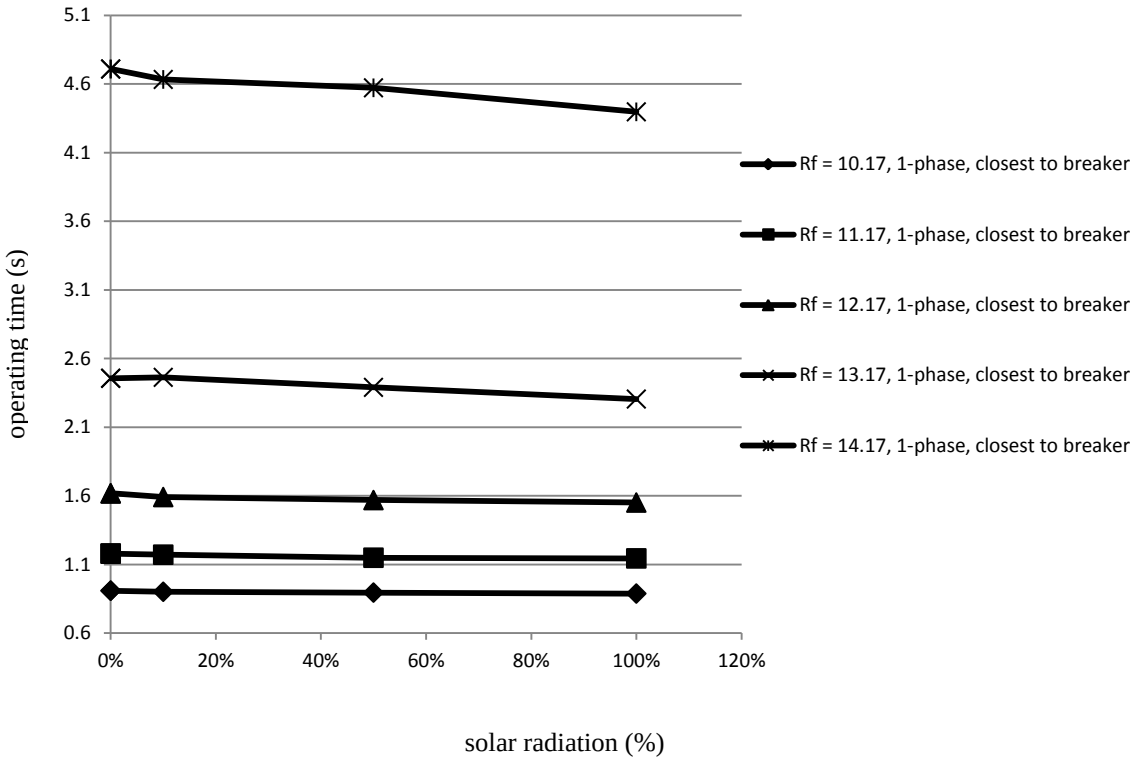
Figure 34: Generic electrical circuit showing that the PVs, downstream the breaker, are under cloud

Figures 35 and 36 shows the effect of the PVs on the operating time of the breaker of the feeder 1.

Figure 35: Breaker operating time vs. PV generation while the fault is at the closest point to the breaker


1.69
1.49
1.29
1.09
0.89
0.69
0.49
0.29
0.09
operating time (s)
0%
20%
40%
60%
80%
100%
120%
solar radiation (%)
Rf = 0, 3-phase, closest to breaker
Rf = 0.11, 3-phase, closest to breaker
Rf = 1.11, 3-phase, closest to breaker
Rf = 2.11, 3-phase, closest to breaker
Rf = 3.11, 3-phase, closest to breaker
Rf = 4.11, 3-phase, closest to breaker
Rf = 5.11, 3-phase, closest to breaker


0.8
0.7
0.6
0.5
0.4
0.3
0.2
0.1
operating time (s)
0%
20%
40%
60%
80%
100%
120%
solar radiation (%)
Rf = 0, 1-phase, closest to breaker
Rf = 0.17, 1-phase, closest to breaker
Rf = 1.17, 1-phase, closest to breaker
Rf = 2.17, 1-phase, closest to breaker
Rf = 3.17, 1-phase, closest to breaker
Rf = 4.17, 1-phase, closest to breaker
Rf = 5.17, 1-phase, closest to breaker
Rf = 6.17, 1-phase, closest to breaker
Rf = 7.17, 1-phase, closest to breaker
Rf = 8.17, 1-phase, closest to breaker
Rf = 9.17, 1-phase, closest to breaker


5.1
4.6
4.1
3.6
3.1
2.6
2.1
1.6
1.1
0.6
operating time (s)
0%
20%
40%
60%
80%
100%
120%
solar radiation (%)
Rf = 10.17, 1-phase, closest to breaker
Rf = 11.17, 1-phase, closest to breaker
Rf = 12.17, 1-phase, closest to breaker
Rf = 13.17, 1-phase, closest to breaker
Rf = 14.17, 1-phase, closest to breaker

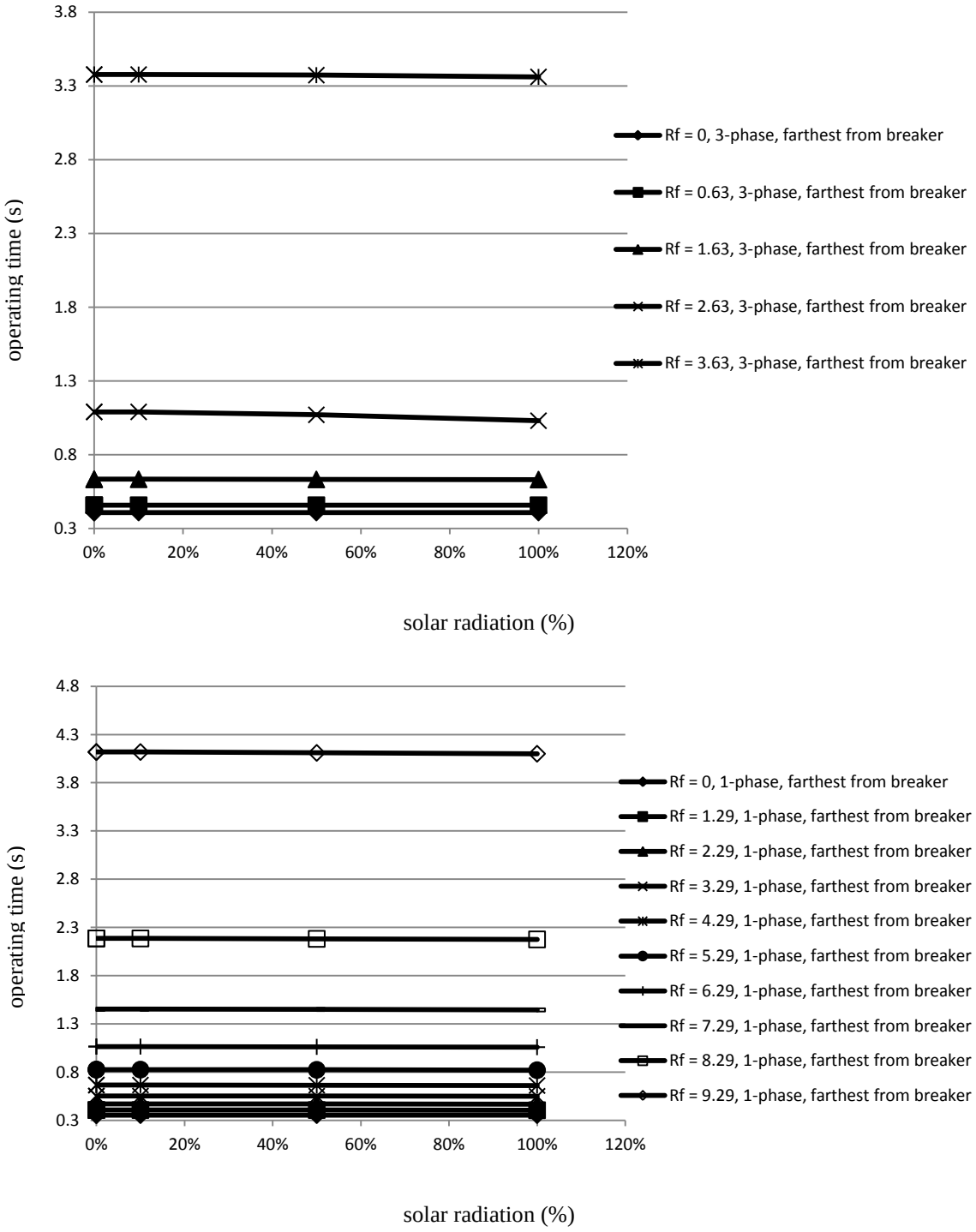
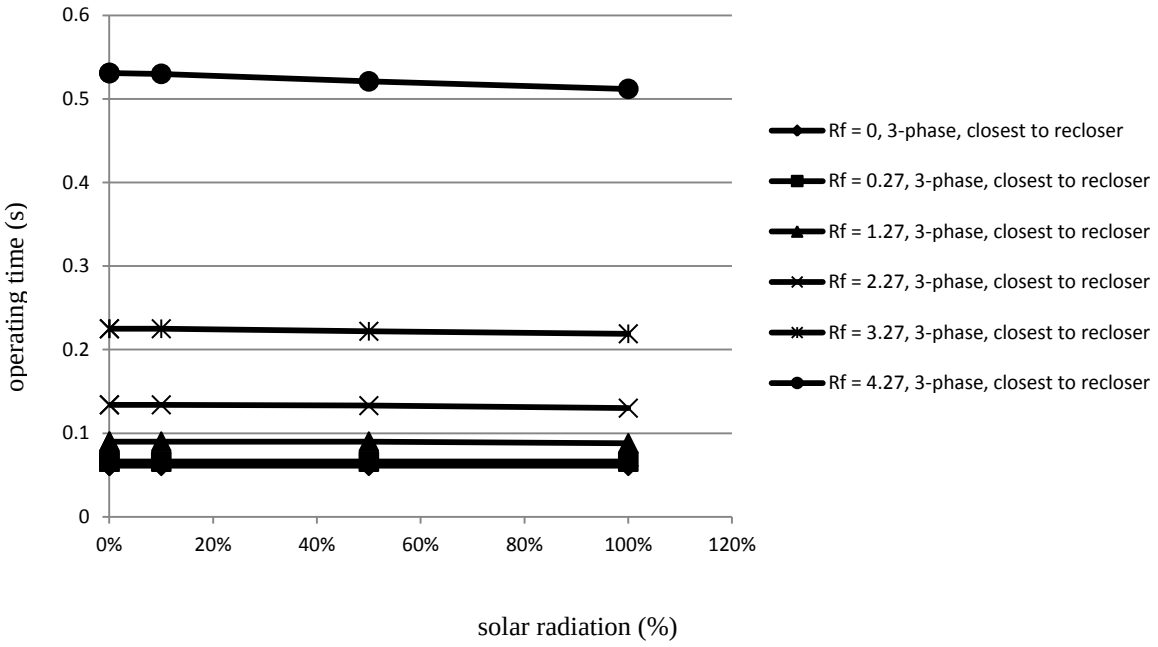
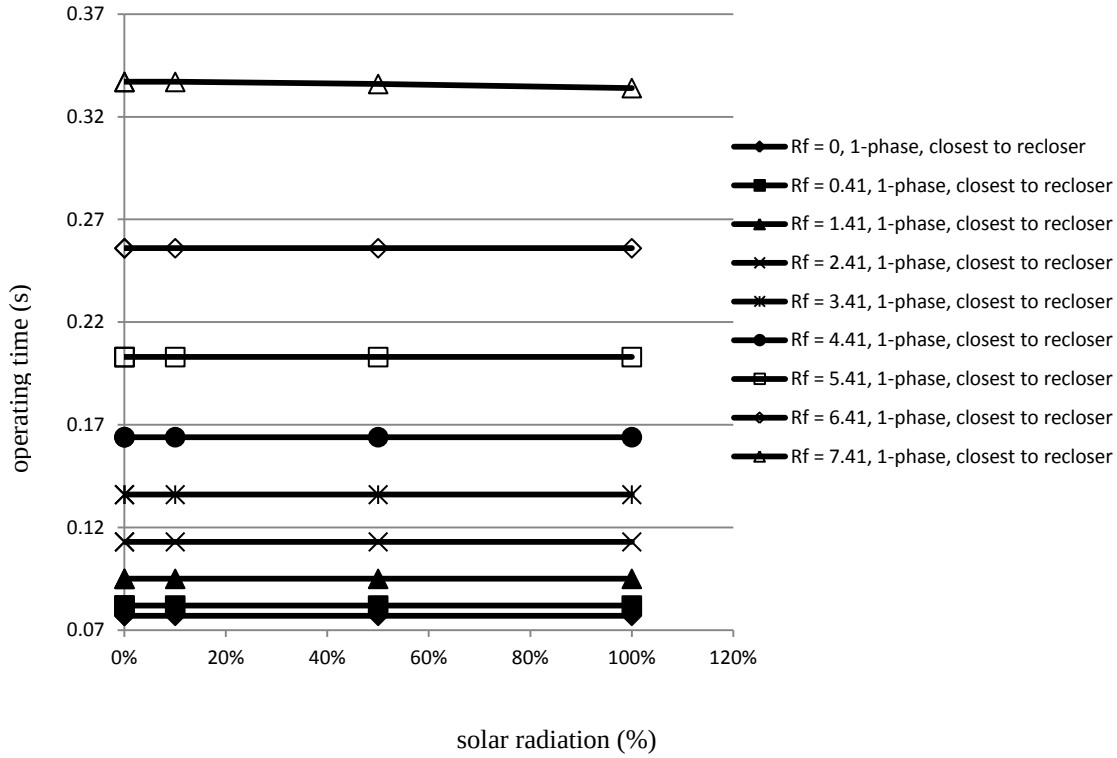


Figure 36: Breaker operating time vs. PV generation while the fault is at the farthest point from the breaker

The same test has been done on the recloser of the feeder 1 assuming that all PVs downstream the recloser are covered by clouds. Figures 37 and 38 summarize the effect of the PVs on the operating time of the recloser.

Figure 37: Recloser operating time vs. PV generation while the fault is at the closest point to the recloser


0.6
0.5
0.4
0.3
0.2
0.1
0
operating time (s)
0%
20%
40%
60%
80%
100%
120%
solar radiation (%)
Rf = 0, 3-phase, closest to recloser
Rf = 0.27, 3-phase, closest to recloser
Rf = 1.27, 3-phase, closest to recloser
Rf = 2.27, 3-phase, closest to recloser
Rf = 3.27, 3-phase, closest to recloser
Rf = 4.27, 3-phase, closest to recloser


0.37
0.32
0.27
0.22
0.17
0.12
0.07
operating time (s)
0%
20%
40%
60%
80%
100%
120%
solar radiation (%)
Rf = 0, 1-phase, closest to recloser
Rf = 0.41, 1-phase, closest to recloser
Rf = 1.41, 1-phase, closest to recloser
Rf = 2.41, 1-phase, closest to recloser
Rf = 3.41, 1-phase, closest to recloser
Rf = 4.41, 1-phase, closest to recloser
Rf = 5.41, 1-phase, closest to recloser
Rf = 6.41, 1-phase, closest to recloser
Rf = 7.41, 1-phase, closest to recloser

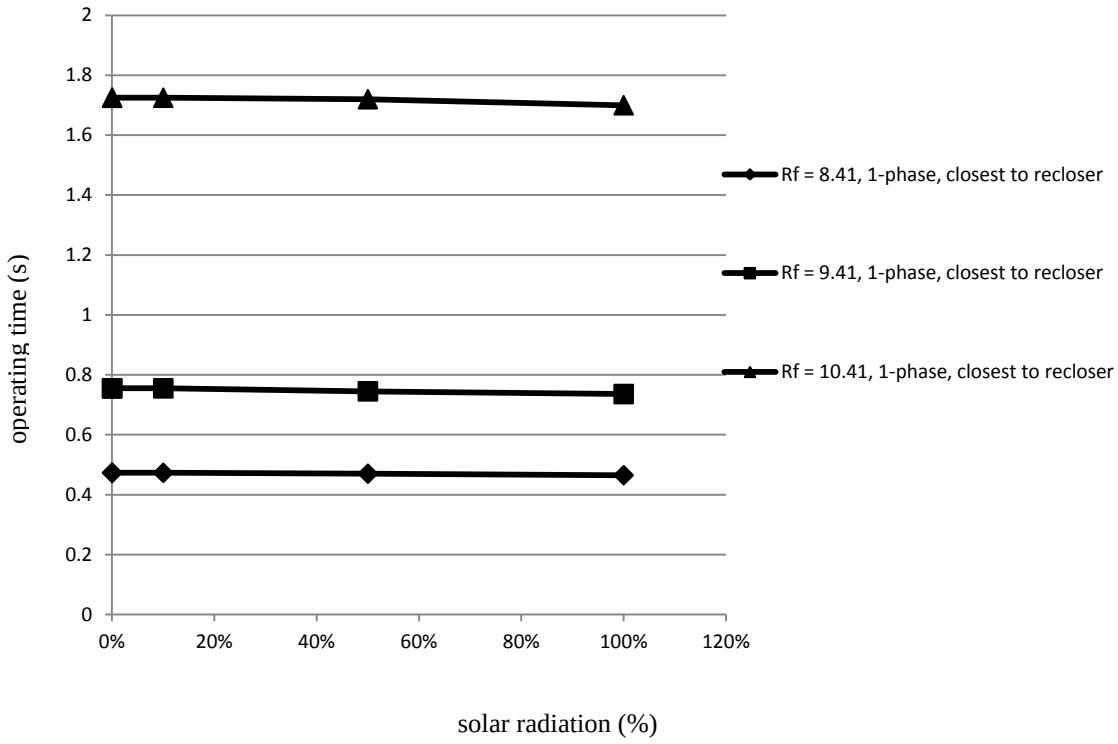
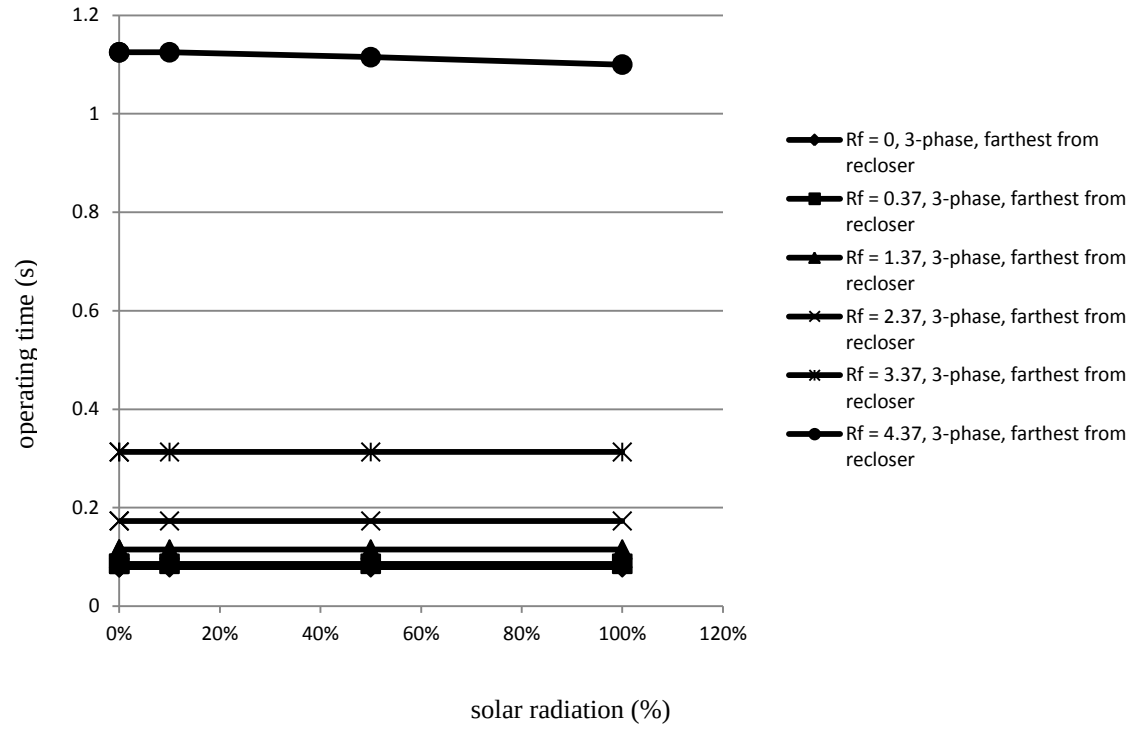
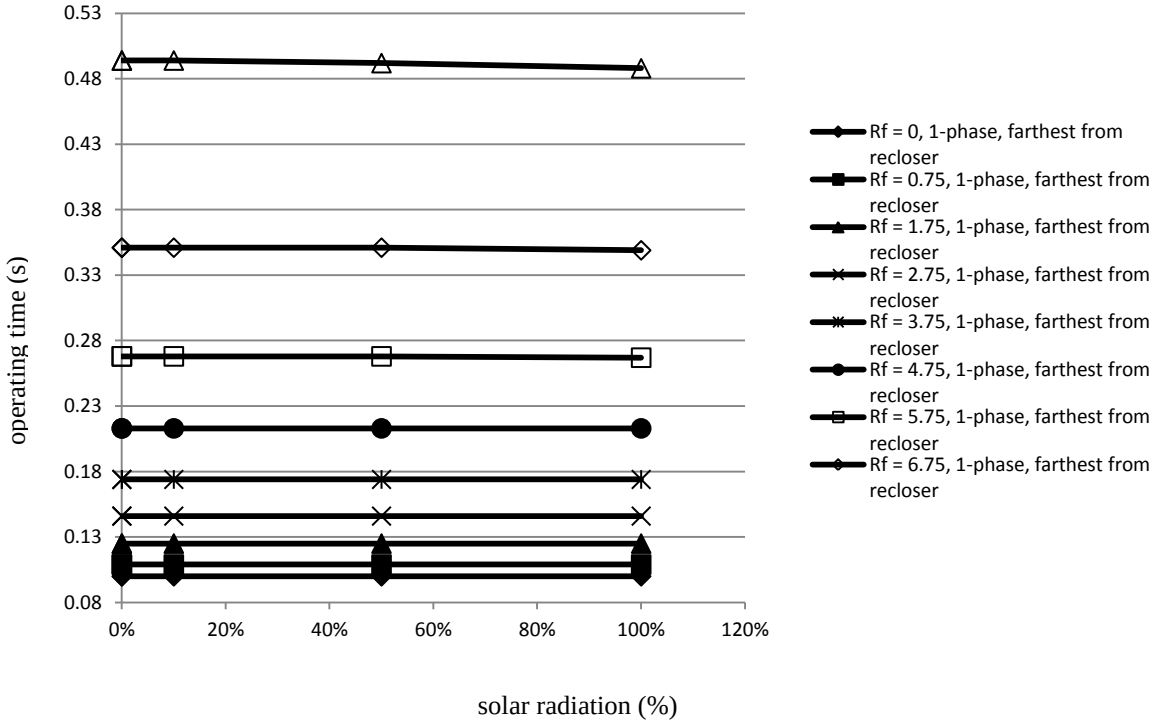
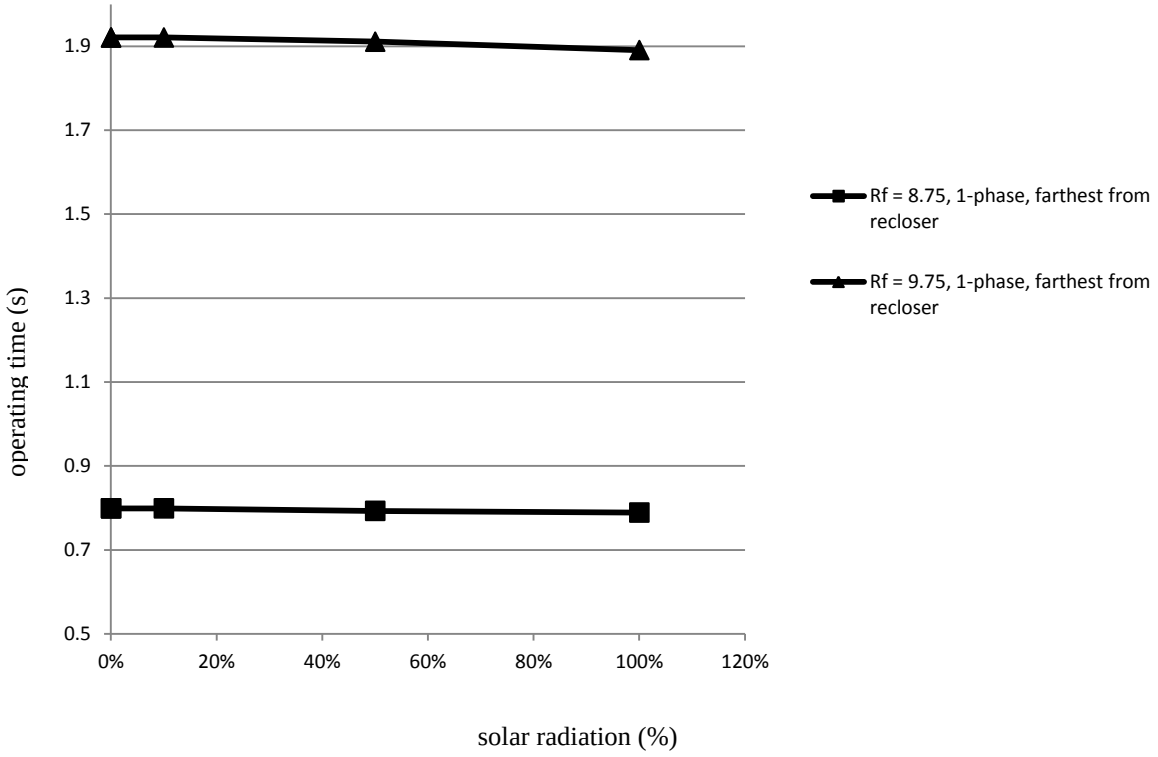

2
1.8
1.6
1.4
1.2
1
0.8
0.6
0.4
0.2
0
operating time (s)
0%
20%
40%
60%
80%
100%
120%
solar radiation (%)
Rf = 8.41, 1-phase, closest to recloser
Rf = 9.41, 1-phase, closest to recloser
Rf = 10.41, 1-phase, closest to recloser

Figure 38: Recloser operating time vs. PV generation while the fault is at the closest point to the recloser


1.2
1
0.8
0.6
0.4
0.2
0
operating time (s)
0%
20%
40%
60%
80%
100%
120%
solar radiation (%)
Rf = 0, 3-phase, farthest from recloser
Rf = 0.37, 3-phase, farthest from recloser
Rf = 1.37, 3-phase, farthest from recloser
Rf = 2.37, 3-phase, farthest from recloser
Rf = 3.37, 3-phase, farthest from recloser
Rf = 4.37, 3-phase, farthest from recloser


0.53
0.48
0.43
0.38
0.33
0.28
0.23
0.18
0.13
0.08
operating time (s)
0%
20%
40%
60%
80%
100%
120%
solar radiation (%)
Rf = 0, 1-phase, farthest from recloser
Rf = 0.75, 1-phase, farthest from recloser
Rf = 1.75, 1-phase, farthest from recloser
Rf = 2.75, 1-phase, farthest from recloser
Rf = 3.75, 1-phase, farthest from recloser
Rf = 4.75, 1-phase, farthest from recloser
Rf = 5.75, 1-phase, farthest from recloser
Rf = 6.75, 1-phase, farthest from recloser



Figures 35 to 38 clearly shows that the PVs upstream of a protective device do not have noticeable effect on both reach and speed. This effect will be discussed in detail in the next section.

DISCUSSIONS

In order to have a better understanding of the results and generalize them, it is required to review the following points to see how each of the PVs affects the current flowing through the PDs.

First of all, it has to be considered that the PVs' contributions to the fault current are small compared to the contribution of the power grid as the PVs' inverters limit the output current

to two per rated current. Therefore, as these results confirm, the PVs do not have considerable effect on the protective device while the fault resistance is low. Table 2 shows the typical values for SCC (Short Circuit Capacity) and nominal S (rating) of Substation transformers [17]. The ratio between I_{SC} and $2*I_n$ (which represents maximum PVs' contributions to the fault current) is calculated and shown in this table.

Table 2: Sub-transmission level transformers

Distribution System Voltage (kV)	Power Rating (kVA)		Short Circuit Capacity (MVA)	$2*I_n / I_{SC}$ (%)	
	From	To		From	To
7.2	500	630	500	0.20%	0.25%
12	500	630	500	0.20%	0.25%
17.5	500	630	500	0.20%	0.25%
24	500	630	500	0.20%	0.25%
36	630	1250	1000	0.13%	0.25%
52	1250	3150	3000	0.08%	0.21%
72.5	1250	3150	3000	0.08%	0.21%

Secondly, let's do an approximate fault analysis on the generic case shown in figure 24 based on the type of the fault:

- Three-phase fault: If the fault is a three-phase fault, then we can replace the whole system with its single-line diagram presentation. Equation 2 demonstrates the current flowing through the PD.

$$I_{Rph} = I_S + C_1 I_1 + C_2 I_2 + C_3 I_3 \quad (2)$$

where $C_1 = \frac{Z_S}{Z_S + Z_1 + Z_2 + Z_3 + R_f}, C_2 = \frac{-(Z_3 + R_f)}{Z_S + Z_1 + Z_2 + Z_3 + R_f}, C_3 = \frac{-R_f}{Z_S + Z_1 + Z_2 + Z_3 + R_f},$

and $I_1, I_2, I_3 = 1 - 2\,pu$.

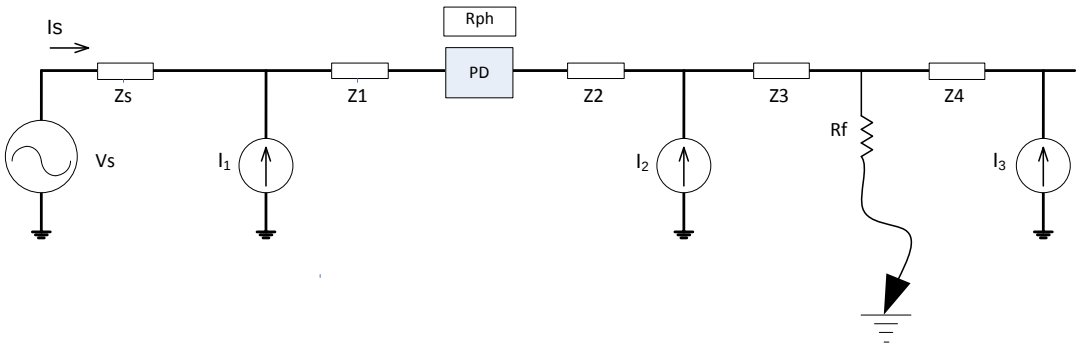


Figure 39: Single-line diagram presentation of the generic case

It's clear that I_1 increases the PD's current while I_2 and I_3 have decreasing effect. Also, when the PVs shut down due to their under voltage protections, the PD's current becomes equal to I_S as it is in the conventional system.

- Single-phase fault: If the fault is a single-phase fault, then we can replace the whole system the following sequence diagram. Equation 3 demonstrates the ground current (three times the PDs' zero sequence current) flowing through the PD.

$$I_{Rg} = \left(3I_S^+\right) + \left[C_1^+\left(3I_1^+\right) + C_1^-\left(3I_1^-\right) + C_1^0\left(3I_1^0\right)\right] + \left[C_2^+\left(3I_2^+\right) + C_2^-\left(3I_2^-\right) + C_2^0\left(3I_2^0\right)\right] + \left[C_3^+\left(3I_3^+\right) + C_3^-\left(3I_3^-\right) + C_3^0\left(3I_3^0\right)\right] \quad (3)$$

where

$$C_1^+ = C_1^- = \frac{Z_S^+}{Z_S + Z_1 + Z_2 + Z_3 + 3R_f}, C_1^0 = \frac{Z_S^0}{Z_S + Z_1 + Z_2 + Z_3 + 3R_f}$$

$$C_2^+ = C_2^- = \frac{Z_S^+ + Z_1^+ + Z_2^+}{Z_S + Z_1 + Z_2 + Z_3 + 3R_f}, C_2^0 = \frac{-\left(2Z_S^+ + 2Z_1^+ + 2Z_2^+ + Z_3 + 3R_f\right)}{Z_S + Z_1 + Z_2 + Z_3 + 3R_f}$$

$$C_3^+ = C_3^- = \frac{Z_S^+ + Z_1^+ + Z_2^+ + Z_3^+}{Z_S + Z_1 + Z_2 + Z_3 + 3R_f}, C_3^0 = \frac{-\left(2Z_S^+ + 2Z_1^+ + 2Z_2^+ + 2Z_3^+ + 3R_f\right)}{Z_S + Z_1 + Z_2 + Z_3 + 3R_f}$$

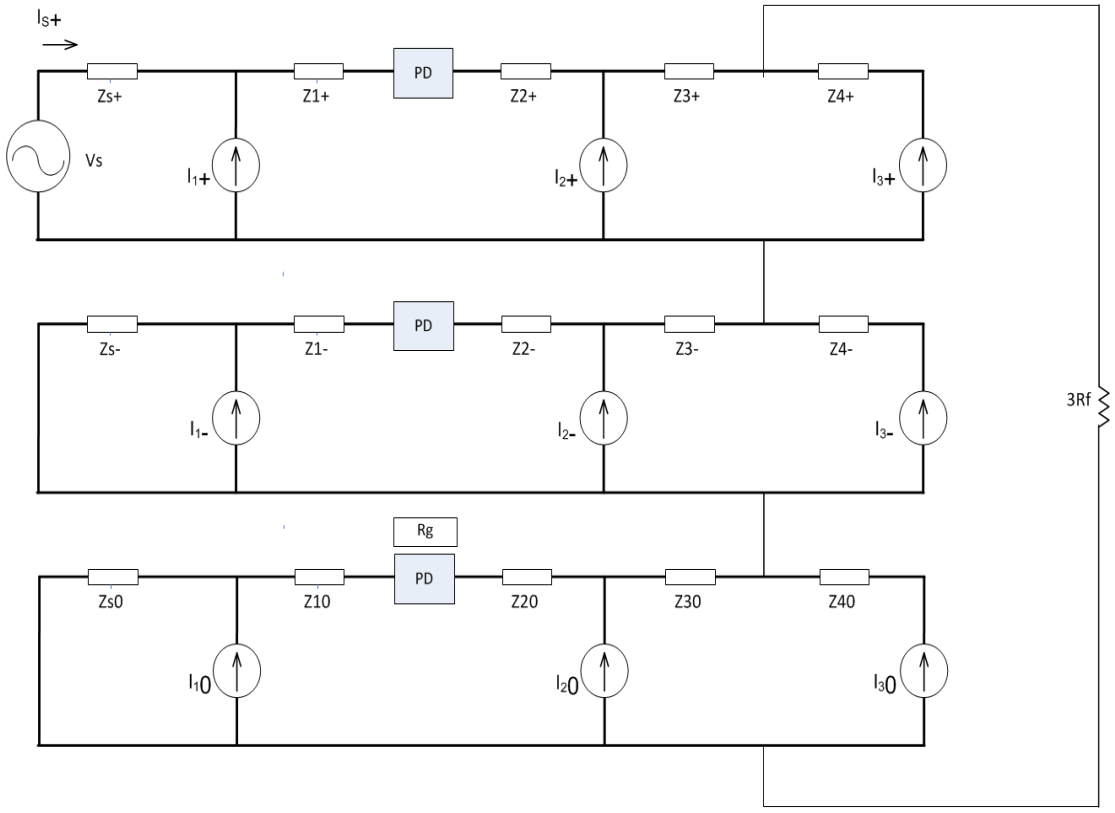
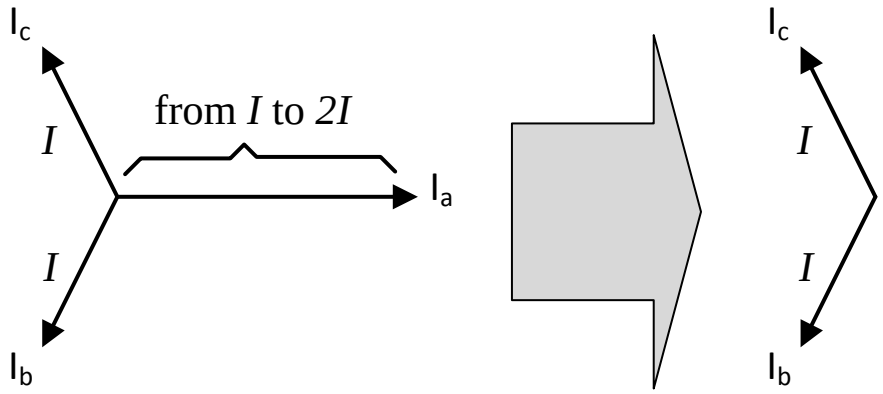


Figure 40: Sequence diagram presentation of the generic case with a single-phase fault

The challenging part is the sequence values of the PVs' currents that change when the PVs' protections react against the fault on the faulty phase. Figure 41 shows the sequence values of a set of PVs on three phases before and after the reaction of the PV's protection on the faulty phase.



$$\begin{cases} I^{+} = \frac{4}{3} I \; to \; I \\ I^{-} = \frac{1}{3} I \; to \; 0 \\ I^{0} = \frac{1}{3} I \; to \; 0 \end{cases} \qquad \begin{cases} I^{+} = \frac{2}{3} I \\ I^{-} = -\frac{\sqrt{2}}{3} I \\ I^{0} = -\frac{\sqrt{2}}{3} I \end{cases}$$

Figure 41: Sequence values of PVs on three phases before and after the reaction of PV's protection on the faulty phase

As shown, the negative and zero sequence values become negative after the PV's protection system trips on the faulty phase. As it will be explained later, the terms corresponding to I_2^0 and I_3^0 are dominant in equation 3; therefore when they become negative, the I_{Rg} increases and reduces the operating time of the relay.

Having these points in mind, the simulation results shown in the previous section can be discussed as follows.

PVs downstream a protective device

As discussed, the PVs do not have noticeable effect when the fault resistance is low as the current contribution from the power grid is relatively higher. The following explains the PVs' effect when the fault resistance is high:

- Three-phase faults: Since the upstream PVs are covered by clouds, I_1 in equation 2 is zero. Also, as shown in this equation, the PVs downstream a PD decrease the current flowing through it so they cause reduction in both REACH and SPEED; however since C_2 is greater than C_1, the maximum reduction occurs when the fault is at the end of the feeder.
- Single-phase faults: Similar to the three-phase case, all terms related to I_1 in equation 3 are zero as the upstream PVs are covered by clouds. Also, only the terms with the coefficient of C_2^0 and C_3^0, I_2^0 and I_3^0, are dominant for high resistance faults. The reason is that all other coefficients have the term $3R_f$ only in their denominators except C_2^0 and C_3^0 that have this term both in their denominators and numerators. In order to interpret the difference between the results for faults close to the substation and the results for faults far from the substation, let's take a look at figure 42 that shows a three-phase system with a single-phase fault at an arbitrary distance from the substation. The impedance Z shown in this figure includes the impedance of the transmission system plus the transformer impedance plus the power grid impedance. Figure 43 shows the equivalent sequence network presentation of this system.

Equation 4 demonstrates the post-fault voltage of the faulty phase at the fault location. For simplicity, it has assumed that the PVs do not affect the voltage.

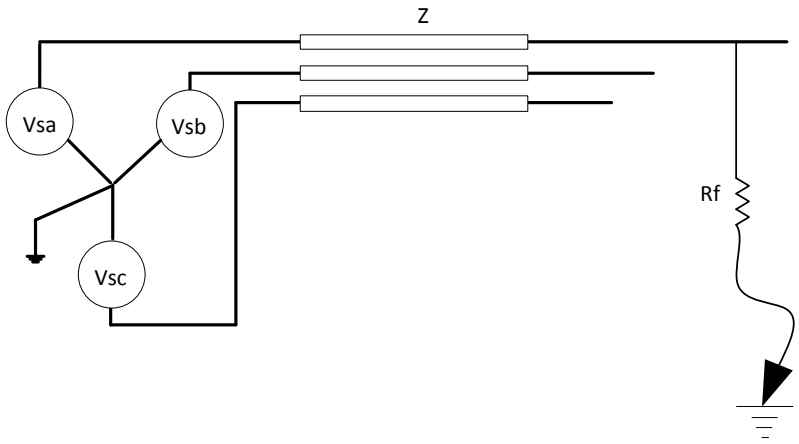


Figure 42: A three-phase system with a single-phase fault

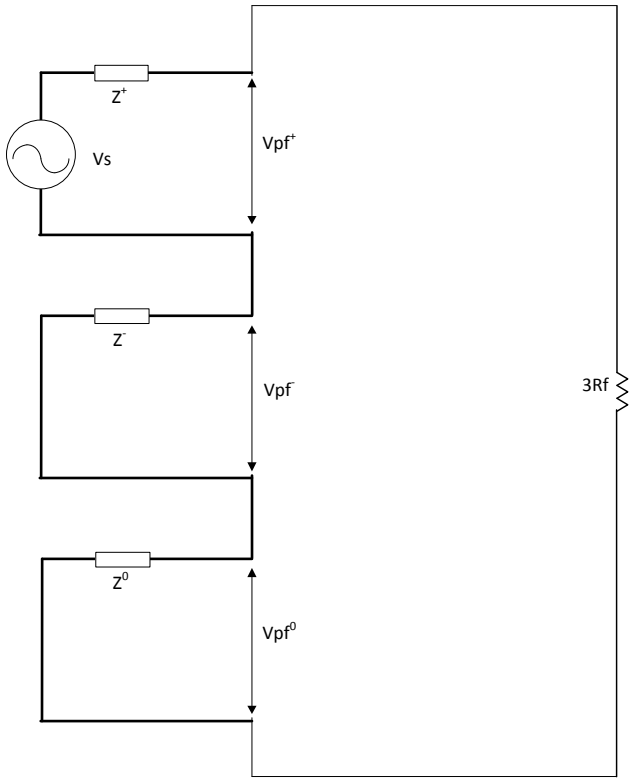


Figure 43: Equivalent sequence network presentation of the system in figure 42

$$V_{PFa} = V_{pf}^{+} + V_{pf}^{-} + V_{pf}^{0} = \frac{3R_f}{3R_f + Z} V_S \quad (4)$$

Figure 44 is a plot of the equation 4 for different values of Z. As shown, for high fault resistances, if the fault location is close to the substation, V_{PFa} is above 0.88pu. This means that the PVs' voltage terminals are equal or greater than 0.88pu as V_{PFa} is the minimum voltage along feeder. So, none of them shut down after the fault; therefore I_2^0 and I_3^0 in equation 3 will have positive values and will reduce the ground current flowing through the PD, so the PVs will cause reduction in both REACH and SPEED. However, if the fault location is far from the substation, V_{PFa} is less than 0.88pu which means that PVs on the faulty phase shut down after 2s; therefore I_2^0 and I_3^0 in equation 3 will have negative values and will increase the ground current flowing through the PD.

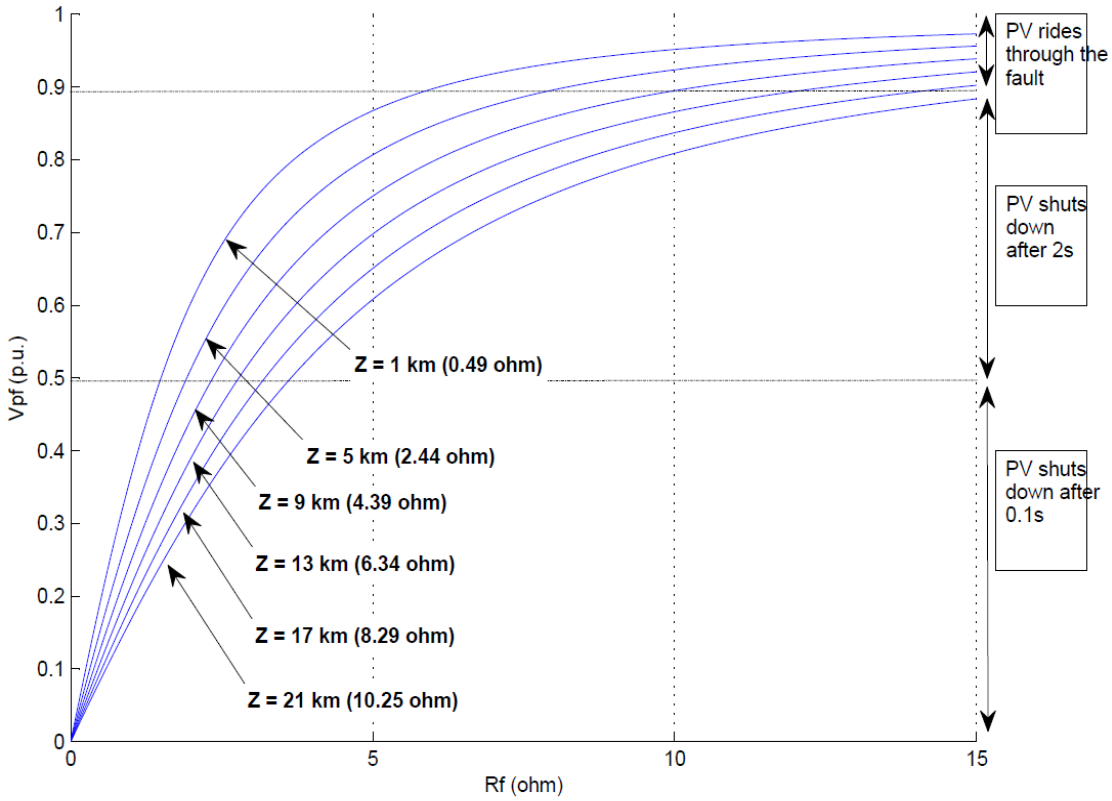


Figure 44: Plot of the equation 4 for different values of Z

As an example, figure 45 compares the RMS value of the ground current flowing through the breaker when PV = 0% with the same current when PV = 100%. The fault resistance is 9.29ohms and is located at the end of the feeder 1. When PV = 100%, for the first 2s after the fault, the relay doesn't even see the fault as the pick-up current is 480; but then after the PVs shut down on phase A at t = 3s, the PVs' on the other phases (B and C) causes negative values of I_2^0 and I_3^0, and this in turn makes the ground current to increase to about 800A; therefore the overall operating time of the relay becomes less than the operating time When PV = 0%.

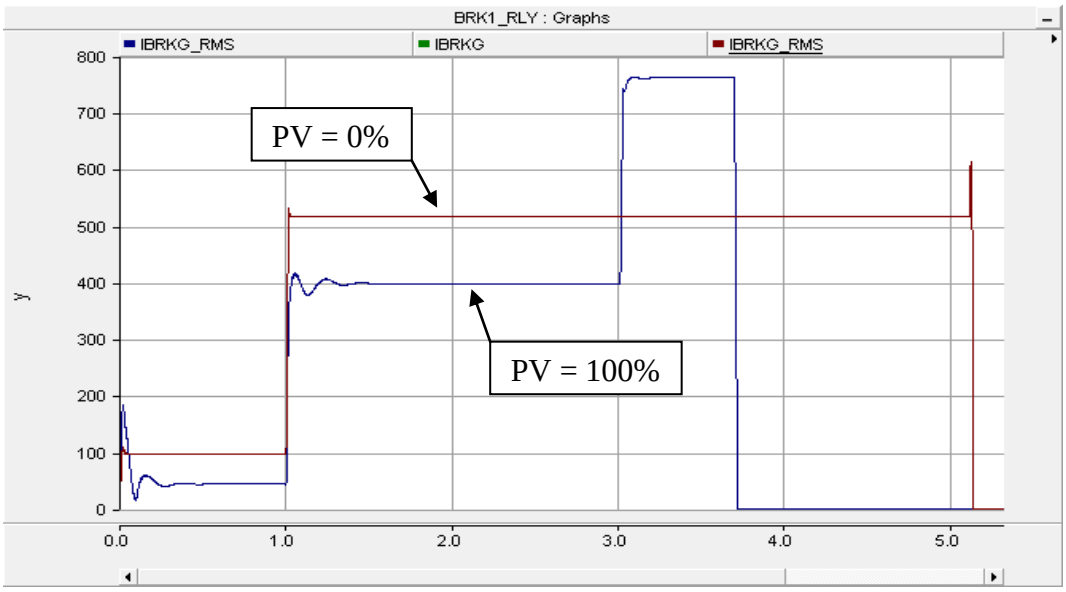


Figure 45: RMS value of the ground current flowing through the breaker

PVs upstream a protective device

Again, we know that the PVs do not have noticeable effect when the fault resistance is low. The following explains the PVs' effect when the fault resistance is high. As it is assumed that the PVs downstream the PD is covered by clouds, all terms related to I_2 and I_3 are zero in equations 2 and 3. Also since the terms related to I_1 have coefficients with the term $3R_f$ only in their denominators, the PVs upstream the PD do not have noticeable effect on the speed and reach. That's why the curves showing the simulation results are flat.

CONCLUSIONS

As mentioned earlier, the goal in this section is to find the situation in which the worst case, where the PVs' effect on the PD's operating time is maximized, takes place. By using the simulation results and the discussions, we can conclude that the worst case occurs when:

- For three-phase faults:
    1. Amount of PV generation: Maximum (100%).
    2. PVs' locations: Downstream the PD.
    3. Fault resistance: Maximum (the fault resistance for which the fault current is equal to the pick-up current of the PD)
    4. Fault location: At the end of the feeder.
- For single-phase faults:
    1. Amount of PV generation: Maximum (100%).
    2. PVs' locations: Downstream the PD.
    3. Fault resistance: Maximum (the fault resistance for which the fault current is equal to the pick-up current of the PD)
    4. Fault location: At the beginning of the feeder.

Figure 46 shows the operating times of the breaker and the recloser in the worst case conditions considering all downstream and upstream PVs. As shown, the results are quite similar to the results shown in figures 29 to 32. This is because the upstream PVs do not have noticeable effect on the PDs' operating times. Also note that for three-phase faults the worst

case condition occurs when the fault is at the end of the feeder whereas for the single-phase faults the worst case condition occurs when the fault is at the beginning of the feeder.

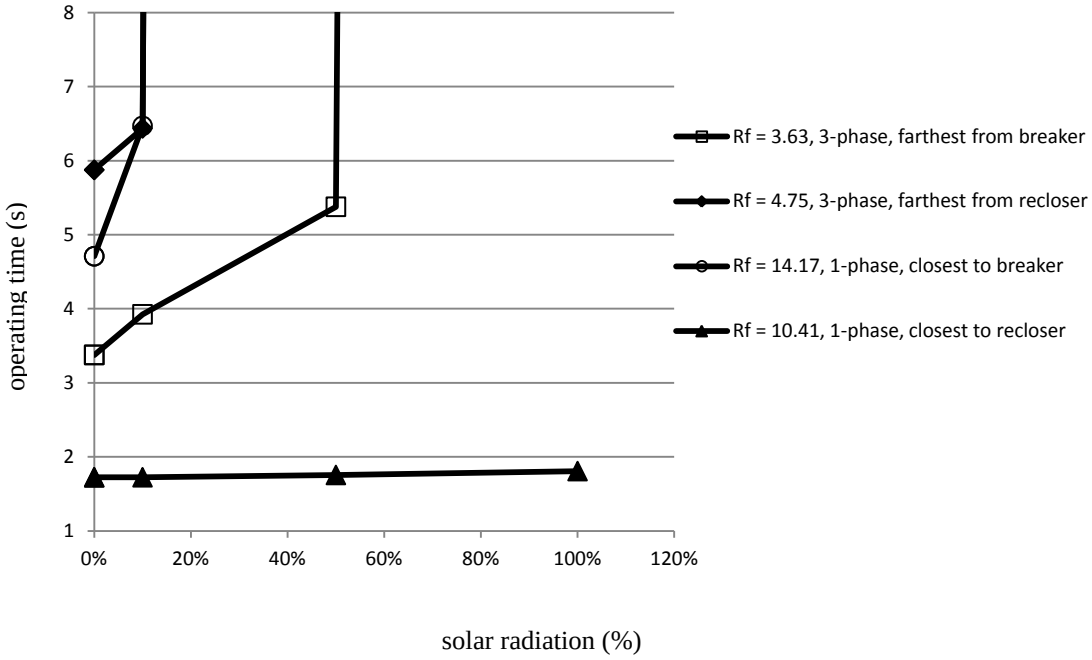


Figure 46: Breaker and recloser operating times in the worst case conditions while considering all PVs

LOSS OF COORDINATION

PROBLEM STATEMENT

Loss of coordination is a result of "change in operating time" discussed in the previous part. As shown in figure 47, the DER can change the operating time of PD1 and PD2 in different directions meaning making one faster and the other one slower. In this case, we may potentially lose the coordination between the protective devices.

Failure of fuse saving addressed in literatures as a potential problem is a kind of coordination loss. In this case PD2 is a fuse and PD1 is a recloser which is supposed to react faster than the fuse in the first operation, but the presence of the DER causes the fuse to react faster than the recloser [1,4,13].

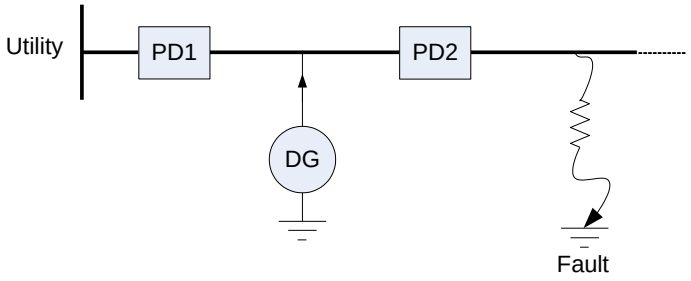


Figure 47: Loss of coordination in presence of a DER

DISCUSSIONS AND CONCLUSIONS

As known, the margin between the operating times of two consecutive devices is minimum when the maximum possible fault flows through both of them. The maximum possible fault current is associated with a bolted fault right after the downstream PD. In this case, the PVs do not have any effect as the current coming from the power grid is much higher than the PVs' contribution to the fault current. Therefore, PVs do not affect the coordination.

However, it's also essential to investigate the effect of PVs on the coordination when the fault resistance is high.

Figure 48 gives a better understanding of how the PVs change the marginal time. Similar to figure 24, I_1 represents all the generation from adjacent feeders and the branches upstream of the PD1, I_2 represents all the generation between the PD1 and the PD2, and I_3 represents all the generation downstream of the PD2.

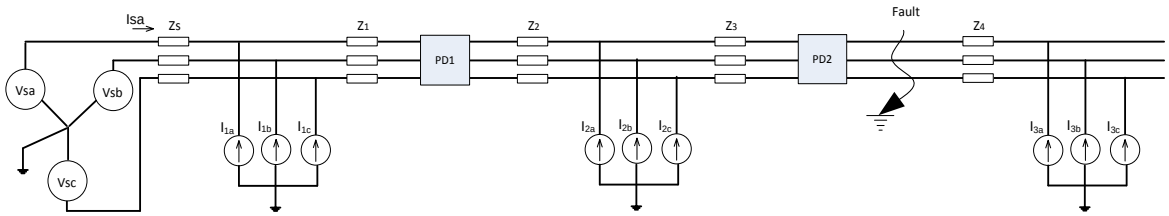


Figure 48: A generic case showing the PVs' effect the marginal timing

Figure 49 shows how the PVs represented by I_1 affect the operating times of the PDs. As shown in this figure, I_1 does not have any effect on the operating times of both PD1 and PD2 as it's located upstream of both PDs. So PVs represented by I_1 do not hinder the coordination.

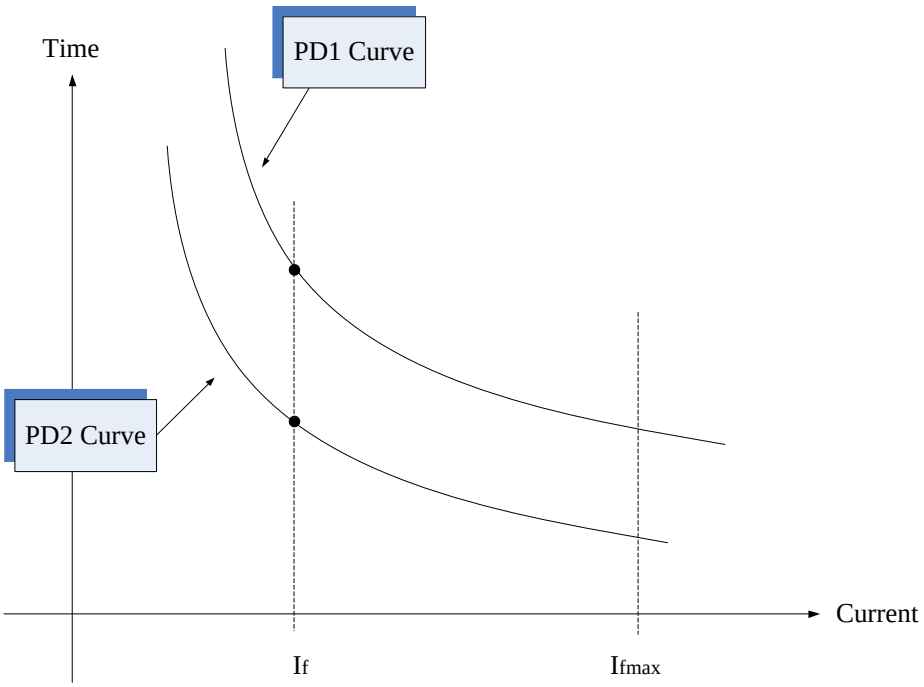


Figure 49: Effect of I_1 on the coordination

Figures 50 and 51 show the effects of the PVs represented by I_2 and I_3. As shown I_2 does not affect the operating time of PD2 but increases the operating time of PD1 which results in an increase in the difference of the operating times. Also, I_3 increases the operating times of both PD1 and PD2 which again results in an increase in the difference of the operating times. So PVs represented by I_2 and I_3 do not hinder the coordination.

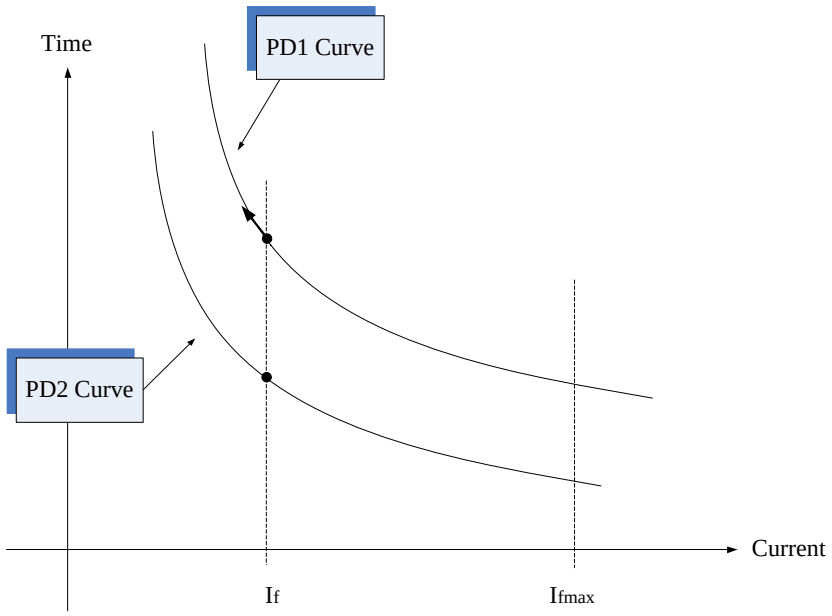


Figure 50: Effect of I_2 on the coordination

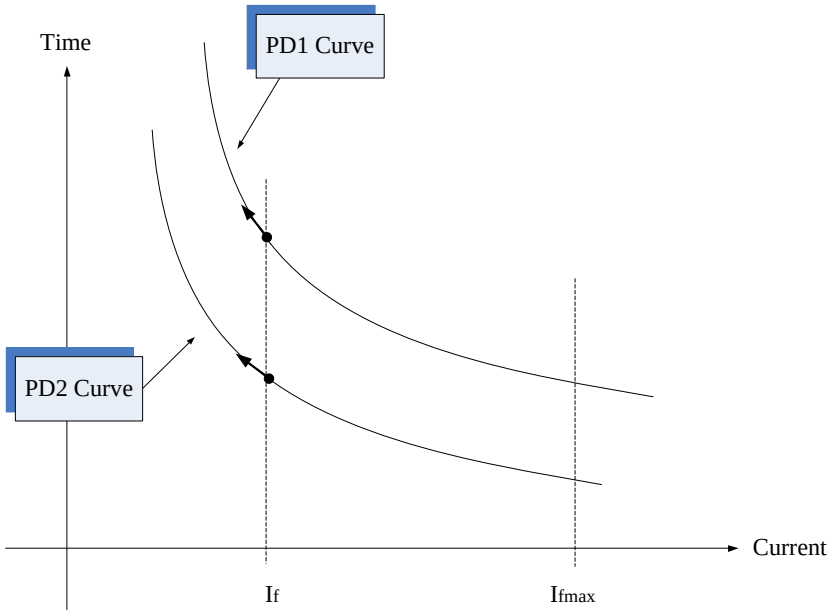


Figure 51: Effect of I_3 on the coordination

The above-mentioned investigation shows that the PVs do not hinder the coordination.

SIMULATION AND RESULTS

Figures 52 and 53 show the marginal time between the breaker and the recloser of feeder 1 for both phase and ground relays. The faults applied for these cases were of bolted type and were located right after the recloser. As shown, the marginal time is not affected by the PVs.

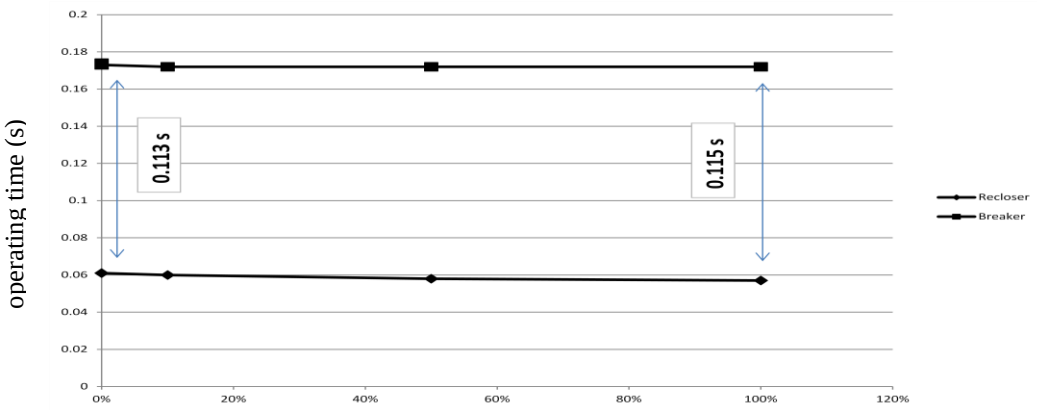


Figure 52: Marginal time between the operating times of the breaker and the recloser when the fault is a three-phase one with Rf=0

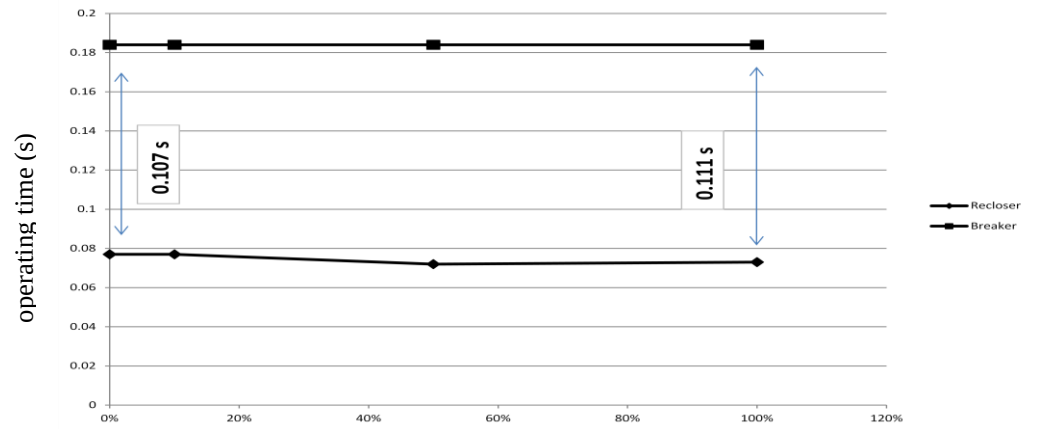


Figure 53: Marginal time between the operating times of the breaker and the recloser when the fault is a single-phase one with Rf=0

Figures 54 and 55 show the difference between the operating times of the breaker and the recloser of feeder 1 for faults with high resistances. The resistance of the three-phase fault is 4.27Ω and the resistance of the single-phase fault is 10.41Ω. As shown, the PVs increase the difference therefore they do not hinder the coordination.

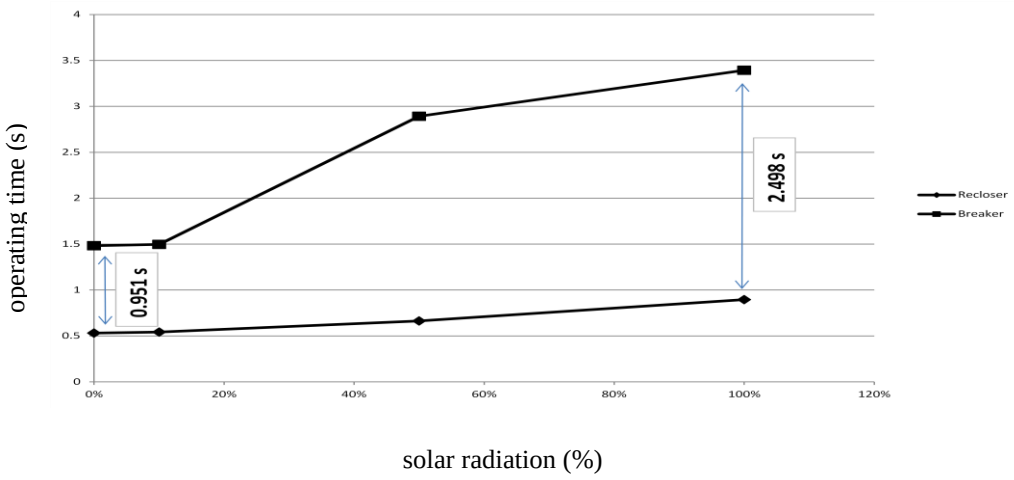


Figure 54: Difference between the operating times of the breaker and the recloser when the fault is a three-phase one with Rf=4.27Ω

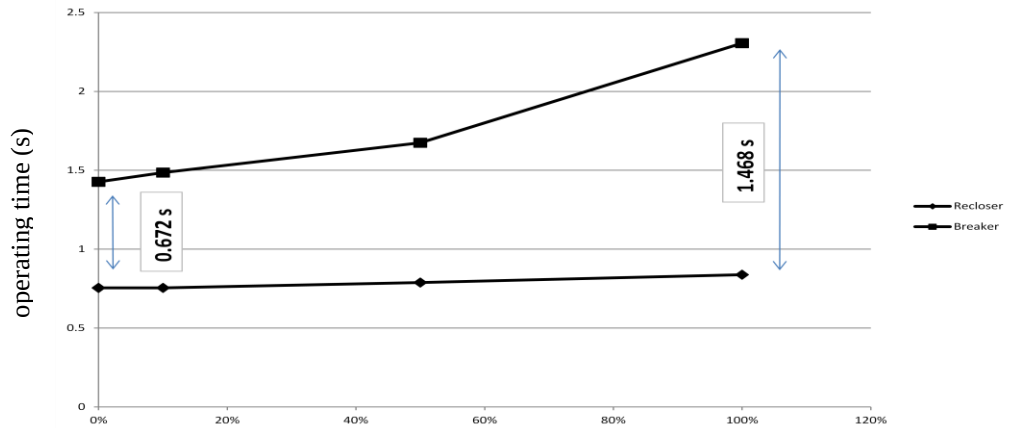


Figure 55: Difference between the operating times of the breaker and the recloser when the fault is a single-phase one with Rf=10.41Ω

SYMPATHETIC TRIPPING

PROBLEM STATEMENT

As shown in figure 56, the DER can feed the faults on adjacent feeders back through the upstream of the protective device. As most feeders do not have directional sensing on the protective devices, this can easily result in wrong tripping of the upstream of the protective device for faults elsewhere in the system [1,4].

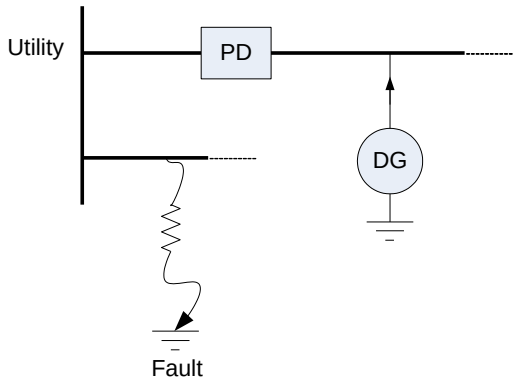


Figure 56: Sympathetic tripping in presence of a DER

SIMULATION AND RESULTS

A three-phase zero-resistance fault (the most severe fault) has been applied right after the breaker of the feeder 1 to see how much the PVs on the feeder 2 contribute to the fault and to see if this contribution can lead to a sympathetic tripping of the breaker of the feeder 2. In this study, the solar radiation had been set to 100% (maximum PV generation).

Figure 57 shows the current flowing through the breaker of the feeder 2. As shown, before the fault being applied at t = 2s, the current is almost zero due to PV/load balance. Then after the fault, the current becomes high to less than 1kA. The direction of the current changes at t = 2.1s when the PVs' undervoltage protections make them to shut down and the feeder 1

breaker trips. The figure clearly shows that the fault current, that the PVs on the feeder 2 provided, is about two times the nominal current of the feeder, so it never triggers the breaker since the relay pick-up current has been set to 1440A.

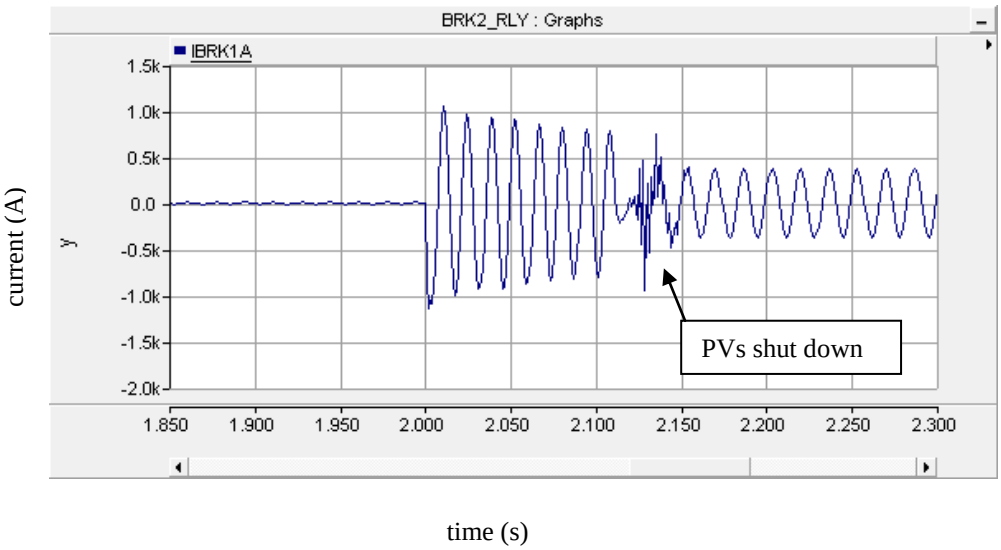


Figure 57: Fault current flowing through the breaker of feeder 2 while a fault occurs on feeder 1

DISCUSSIONS AND CONCLUSIONS

The sympathetic tripping is not likely on healthy feeder because the relay pick-up current is set to be more than two times the feeder nominal current. On the other hand, the total fault current contributions from the PVs are limited to two times the feeder nominal current which is not enough to trigger the feeder relay.

RECLOSING

PROBLEM STATEMENT

Reclosers are one of the most popular protective devices in feeder protection, however recloser installation is always along with this assumption that the feeders are only fed by the grid. The presence of DER in the feeder means that there are several sources of fault current which can potentially causes the following problems [5,14]:

Unsuccessful clearance of temporary fault: The reclosing operation may lose its effect with the presence of the DER. As shown in the figure 58, the DER may sustain feeding the fault current during the recloser open time prohibiting the intended arc extinction. The fault that would have been temporary may become permanent.

Out-of-phase reclosing: While the recloser is open, the DER may sustain feeding the fault and as a result its voltage may get out-of-phase in comparison to the grid voltage. This leads to an out-of-phase reclosing which can severely harm the DER.

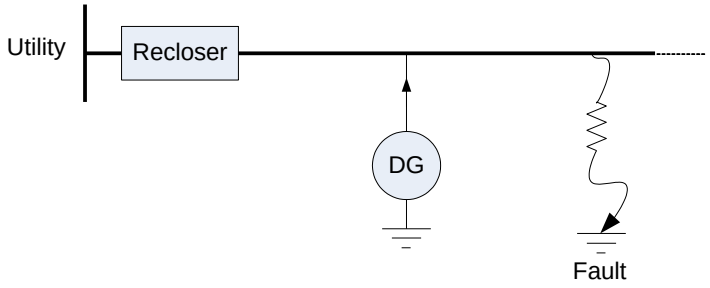


Figure 58: Reclosing problems in presence of a DER

SIMULATION AND RESULTS

Figures 59 and 60 show the terminal voltage and current of a PV in the protection zone of the feeder 1 recloser, respectively. In this case, the fault occurs at t=2s, then the recloser trips at

t=2.09s, then the PVs shut down at t=2.1s letting the fault clears, and finally the recloser recloses at t=2.29s. The figures show that the PVs stop feeding the fault, letting the recloser be successful, and do not cause any out-of-phase reclosing.

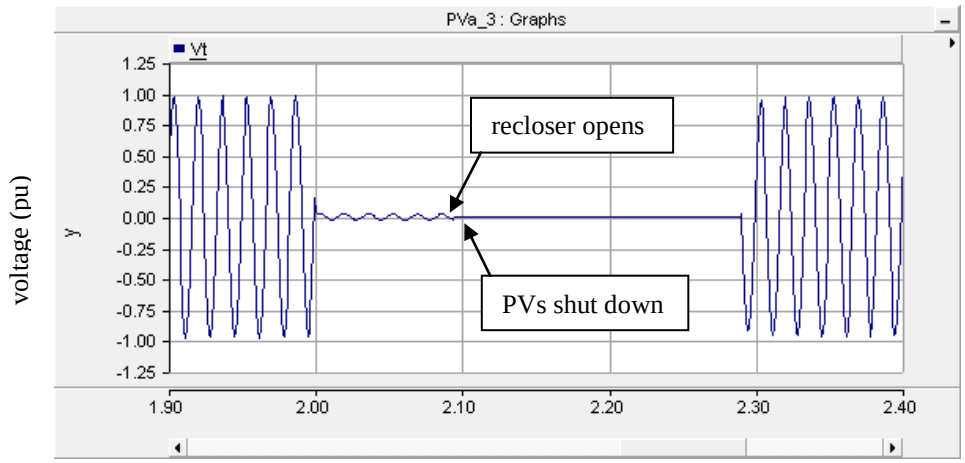


Figure 59: PV's terminal volatge

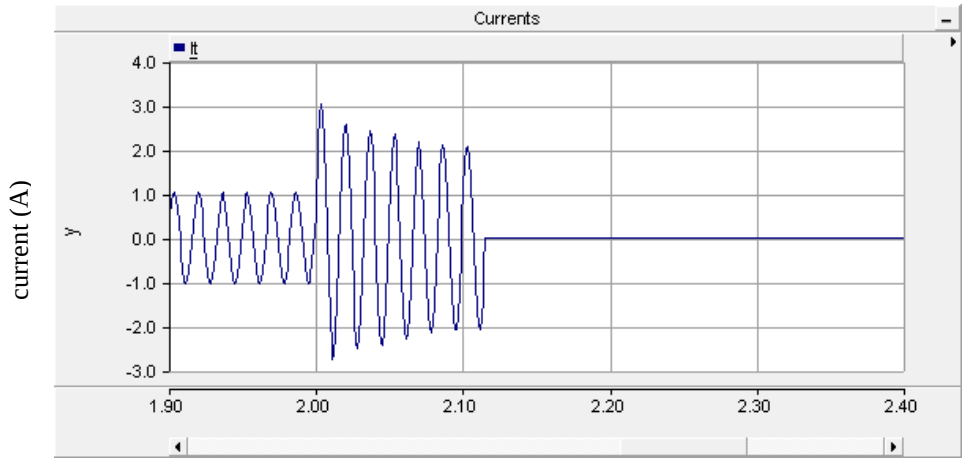


Figure 60: Current flowing through PV terminal

DISCUSSIONS AND CONCLUSIONS

The undervoltage protection of the PVs makes them to shut down after 0.1s after the fault occurrence. This ensures that the PVs are prevented from feeding the fault. In other words a temporary fault does not become permanent as a result of PVs' feeding because the PVs won't be online after 0.1s.

On the other hand, the open interval of the recloser is 0.2s which ensures that the PVs are off when the recloser recloses. In other words no out-of-phase reclosing can happen provided that the reclosing open interval is coordinated in time with the PVs' protection.

It should be noted that the PVs are assumed to have anti-islanding protection which works as a backup protection for preventing reclosing problems. However the reclosing open interval should be coordinated with the anti-islanding protection speed to make sure that it's long enough to let the anti-islanding work.

ISLANDING

PROBLEM STATEMENT

Figure 61 shows a case in which the DER triggers the PD for a fault occurring outside its protection zone similar to what mentioned for sympathetic tripping. In this case, the DER may stay online making up an island with the loads and feeding the loads with abnormal voltage and frequency which could be detrimental to the utility customers. Even if the voltage and frequency remains in a permissible range, the island voltage can easily get out-of-phase. Also, since the island is unintentional, it can be dangerous to the technical crew who has been sent to fix the problems on the feeder [16].

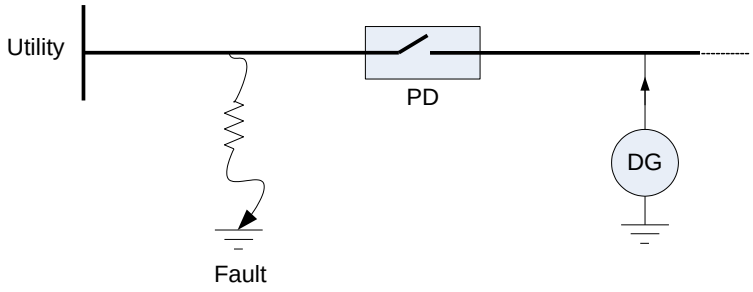


Figure 61: Unintentional islanding

DISCUSSIONS AND CONCLUSIONS

It has been assumed that all PVs are equipped with a reliable anti-islanding protection. So unintentional islanding can never happen.

However, if the feeder protective device happened to have reclosing function, then the reclosing open interval should be coordinated with the anti-islanding protection speed to make sure that the PVs are off when the protective device recloses.

GREEN HUB II

In this section, the same issues investigated on Green Hub I are investigated on Green Hub II. In order to upgrade the Green Hub I to Green Hub II, all distribution magnetic transformers have been replaced with SSTs.

CHANGE IN REACH AND OPERATING TIME OF PROTECTIVE DEVICES

SIMULATION AND RESULTS

Figure 62 and 63 show the single-line diagram of the system and the PSCAD implementation of Green Hub II, respectively. Similar simulations have been done on Green Hub II. In all simulation results, the operating times of the breaker and the recloser have been expressed versus the balance between PV and Load (PV%-Load%).

Also, there are two points corresponding to balance of -100%. The first one corresponds to pure conventional system (No PV and No SST) and the second one corresponds to the Green Hub II while PV = 0%. This is just to show the effect of SST presence in the system.

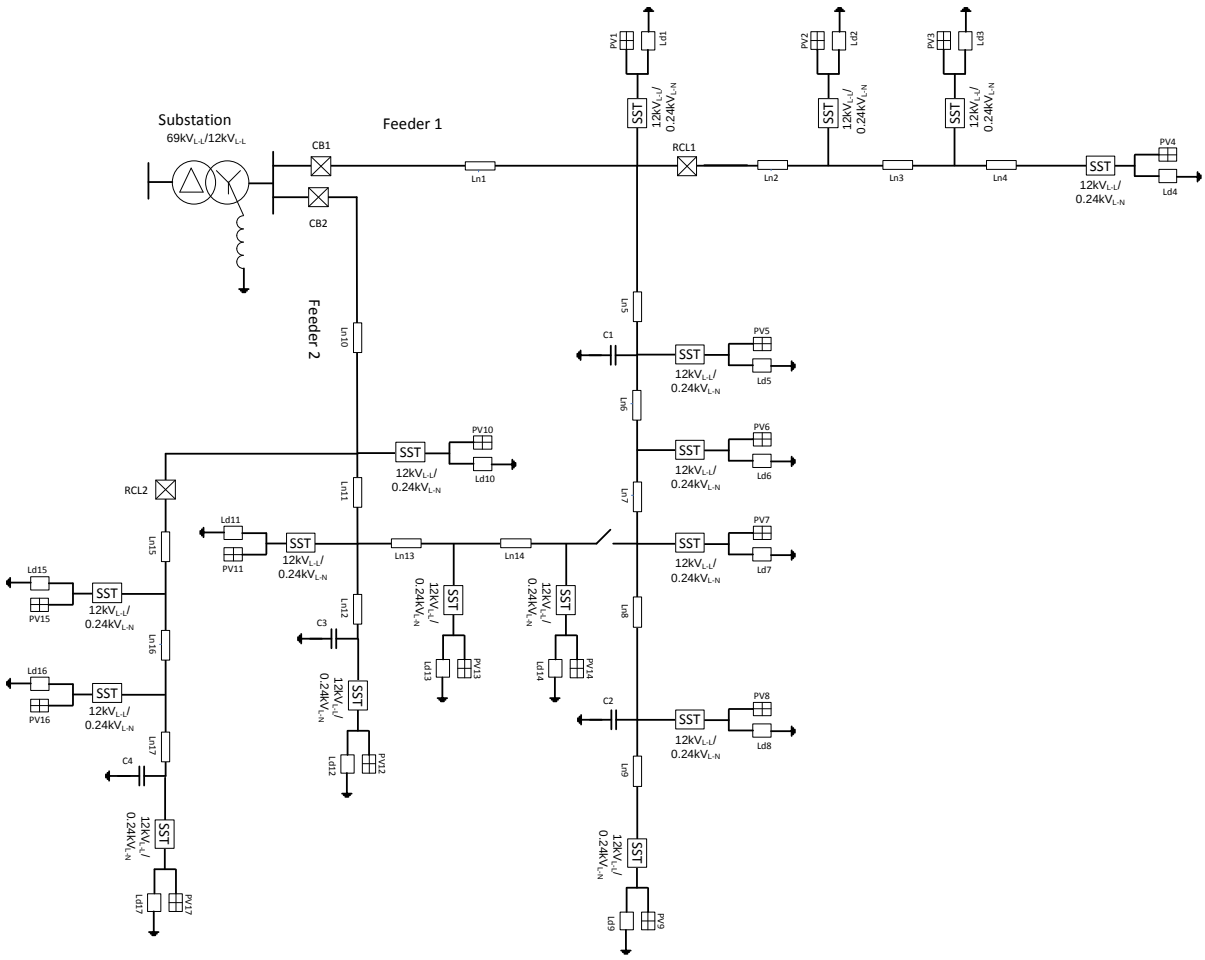


Figure 62: Single line diagram of Green Hub II

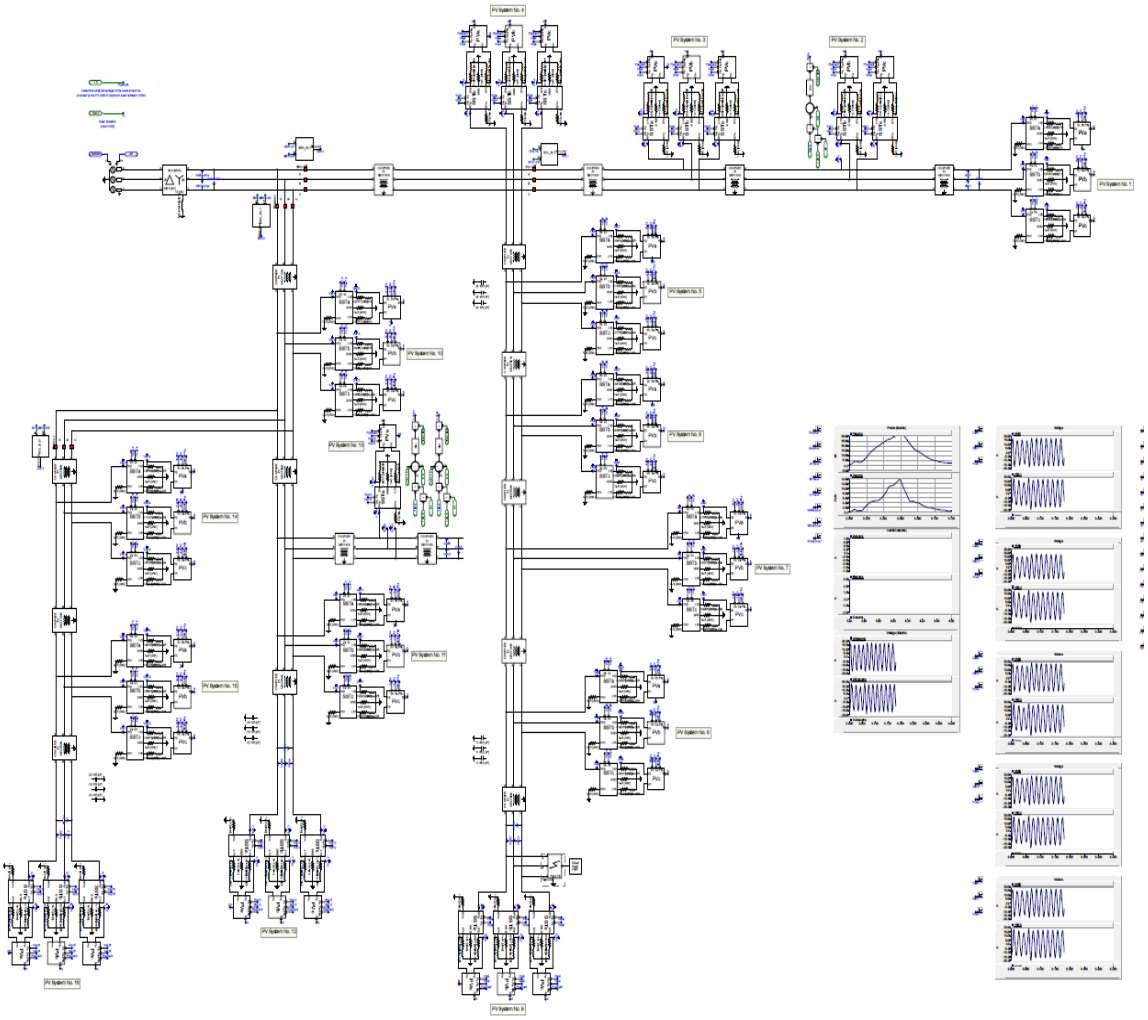


Figure 63: PSCAD implementation of Green Hub II

Similar to Green Hub I, PVs have been divided into two groups based on their locations: PVs downstream the PDs and PVs upstream the PDs. The effect of these two groups of PVs will be investigated separately.

PVs downstream a protective device

Figures 64 and 65 show the single line diagram of the whole system and the generic electrical circuit. Note that in contrast to Green Hub 1, when a group of PVs are covered by clouds, the corresponding SSTs draw current from the system. This is because, in absence of PVs, the SSTs try to draw the power demanded by the loads from the system. The fault has been placed at the closest and farthest points with regard to the breaker to see how PVs and SSTs affect the reach and operating times.

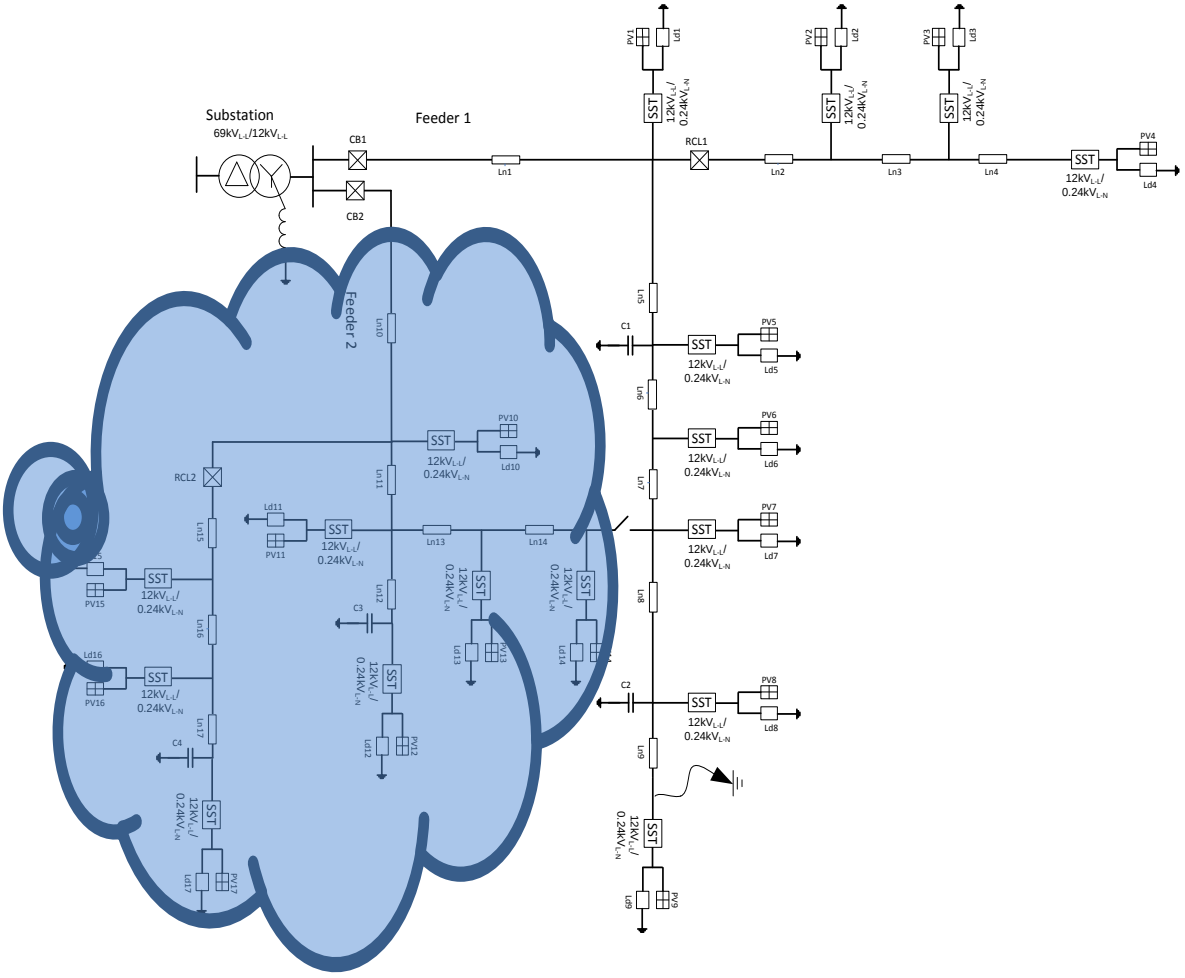


Figure 64: Green Hub II while the PVs, upstream the breaker, are under cloud

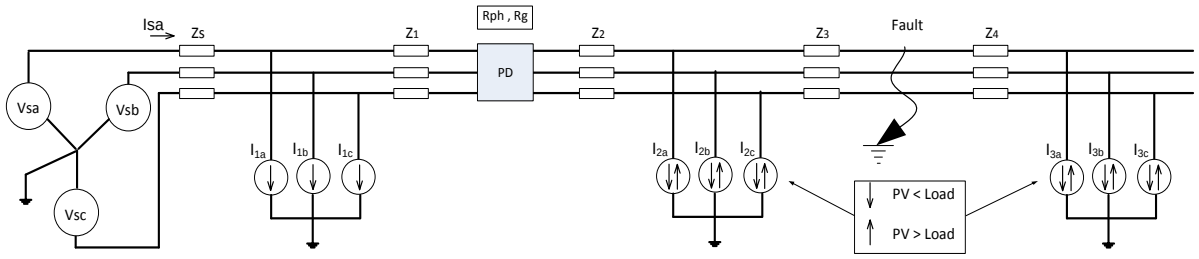
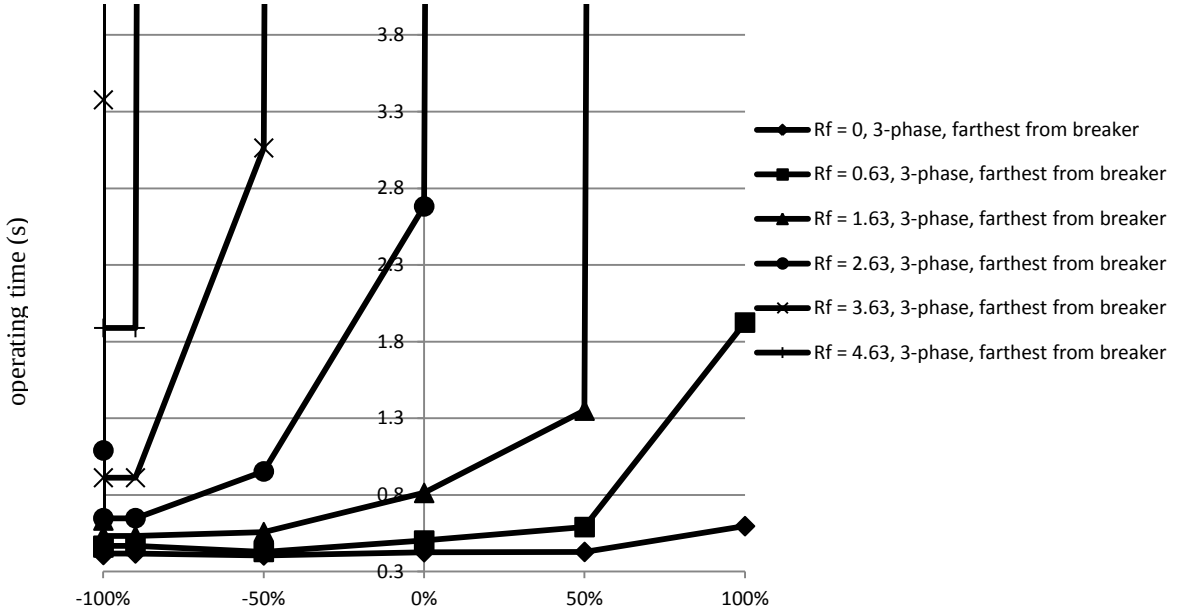


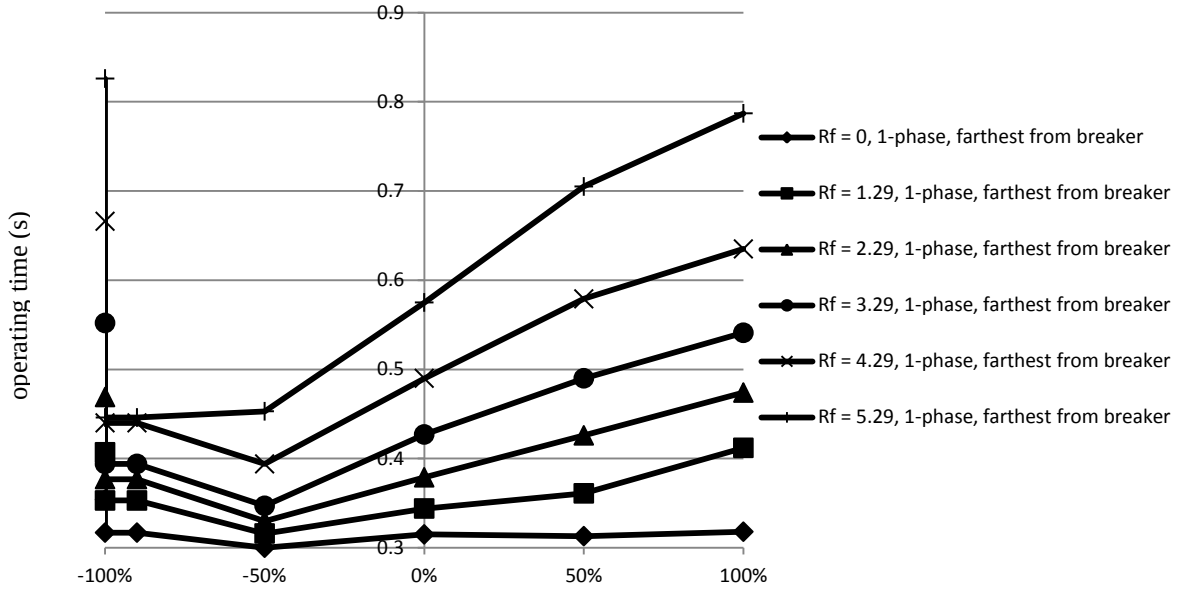
Figure 65: Generic electrical circuit showing that the PVs, upstream the breaker, are under cloud

Figures 66 and 67 summarize the effect of the PVs on the operating time of the breaker of the feeder 1.

Figure 66: Breaker operating time vs. PV/Load balance while the fault is at the farthest point from the breaker



PV% - Load%



PV% - Load%

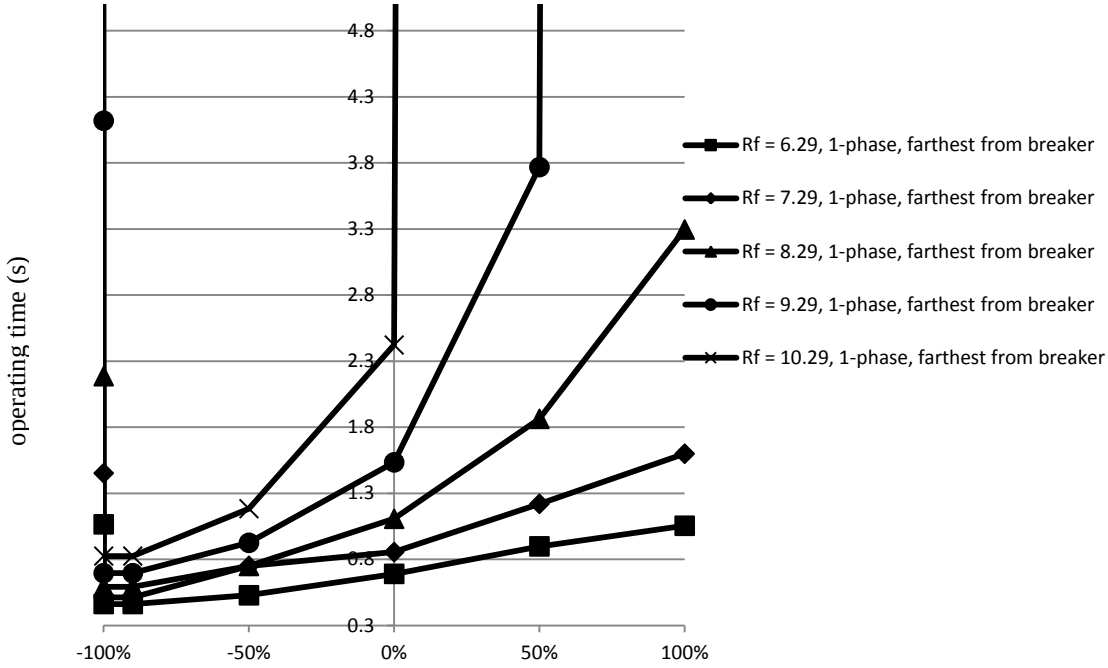
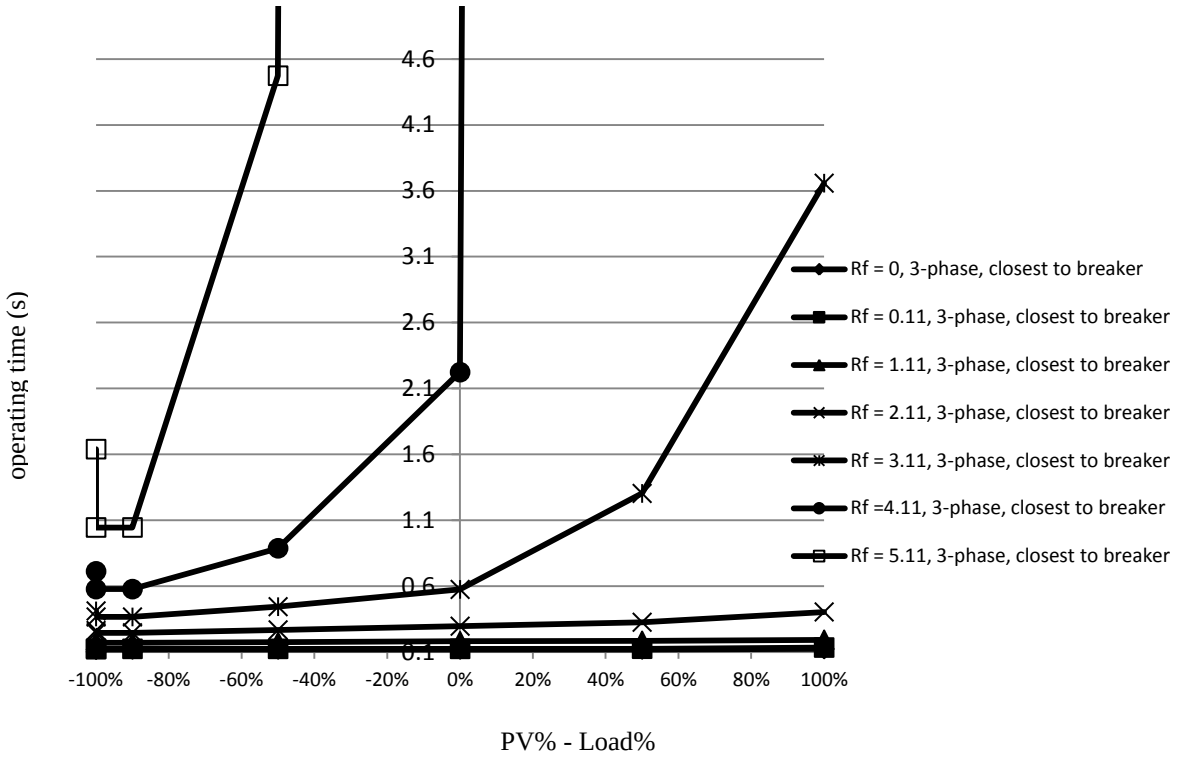
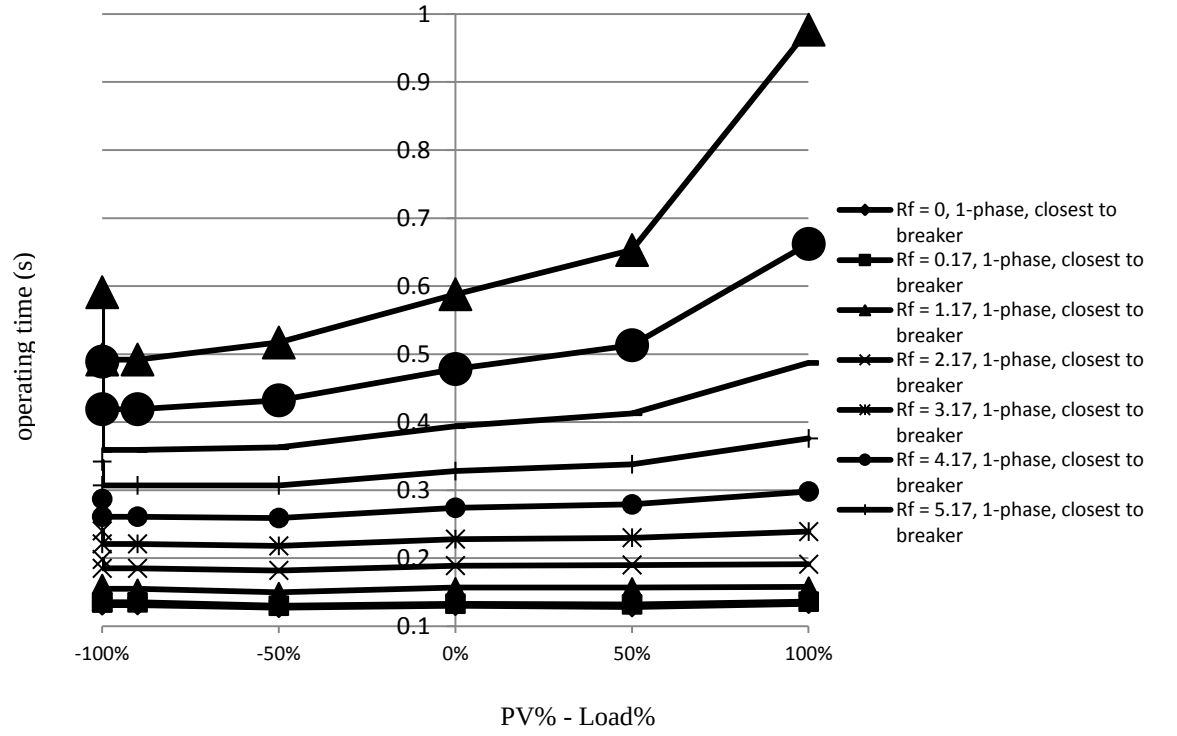
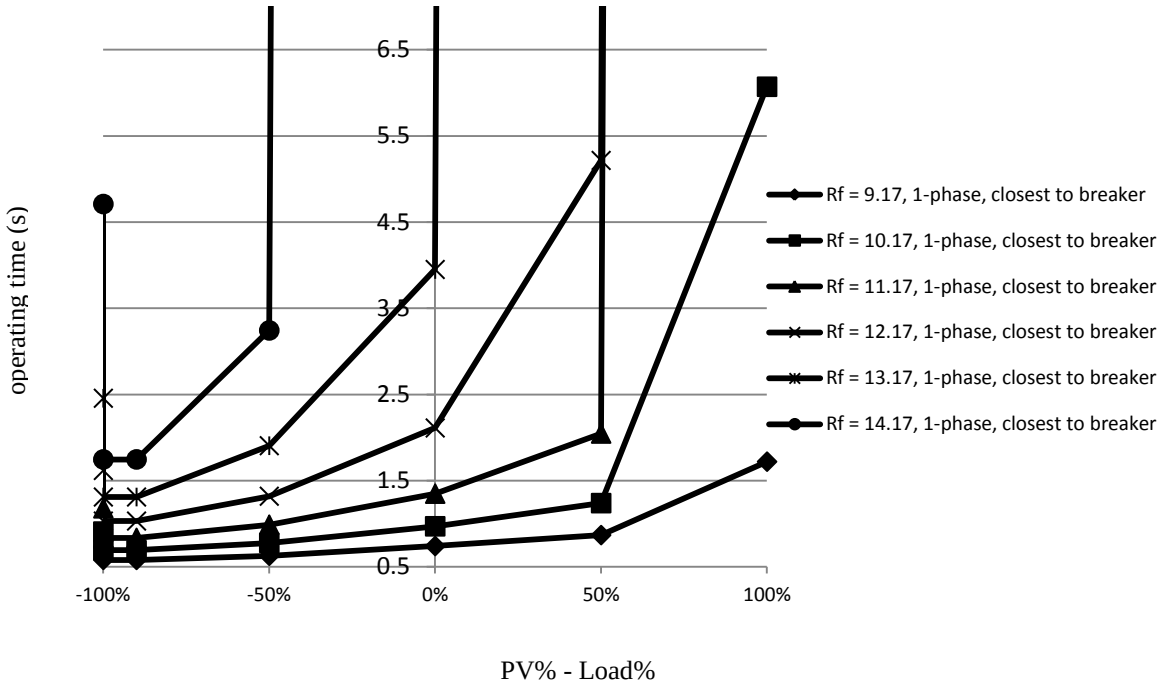

operating time (s)
4.8
4.3
3.8
3.3
2.8
2.3
1.8
1.3
0.8
0.3
-100%
-50%
0%
50%
100%
PV% - Load%
Rf = 6.29, 1-phase, farthest from breaker
Rf = 7.29, 1-phase, farthest from breaker
Rf = 8.29, 1-phase, farthest from breaker
Rf = 9.29, 1-phase, farthest from breaker
Rf = 10.29, 1-phase, farthest from breaker

Figure 67: Breaker operating time vs. PV/Load balance while the fault is at the closest point to the breaker


operating time (s)
4.6
4.1
3.6
3.1
2.6
2.1
1.6
1.1
0.6
0.1
-100%
-80%
-60%
-40%
-20%
0%
20%
40%
60%
80%
100%
PV% - Load%
Rf = 0, 3-phase, closest to breaker
Rf = 0.11, 3-phase, closest to breaker
Rf = 1.11, 3-phase, closest to breaker
Rf = 2.11, 3-phase, closest to breaker
Rf = 3.11, 3-phase, closest to breaker
Rf =4.11, 3-phase, closest to breaker
Rf = 5.11, 3-phase, closest to breaker


operating time (s)
1
0.9
0.8
0.7
0.6
0.5
0.4
0.3
0.2
0.1
-100%
-50%
0%
50%
100%
PV% - Load%
Rf = 0, 1-phase, closest to breaker
Rf = 0.17, 1-phase, closest to breaker
Rf = 1.17, 1-phase, closest to breaker
Rf = 2.17, 1-phase, closest to breaker
Rf = 3.17, 1-phase, closest to breaker
Rf = 4.17, 1-phase, closest to breaker
Rf = 5.17, 1-phase, closest to breaker



The following observations can be derived from the simulation results on figures 66 and 67 which will be discussed in the next section:

- As shown in the figures, for both three-phase and single-phase faults, replacing the magnetic transformers by the SSTs decreases the operating time of the relay when PV generation is zero. This fact can be seen by comparing the relay operating time from the conventional system with the relay operating time from Green Hub II when the PV/Load unbalance is -100%.
- For both three-phase and single-phase faults, as the PV generation increases, the relay operating time increases.
- In contrast to Green Hub I, there's no reduction in the operating time of the relay for high resistance single-phase faults with PV/Load unbalance of 100%.

PVs upstream a protective device

Figures 68 and 69 show the single line diagram of the whole system and the generic electrical circuit showing the PV set that is covered by the clouds. The fault has been placed at the closest and farthest points with regard to the breaker to see how the PVs affect the reach and operating times.

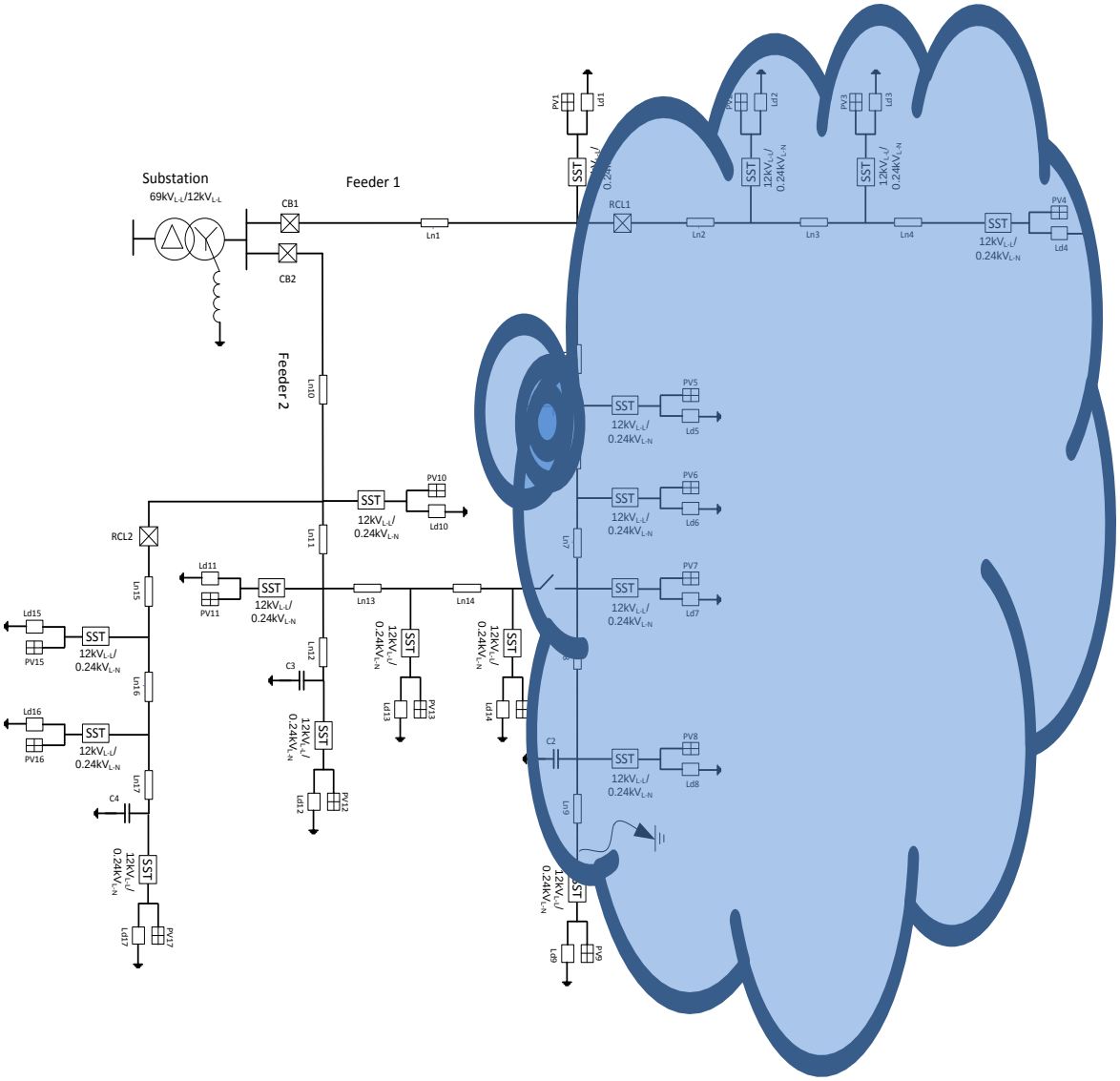


Figure 68: Green Hub II while the PVs, downstream the breaker, are under cloud

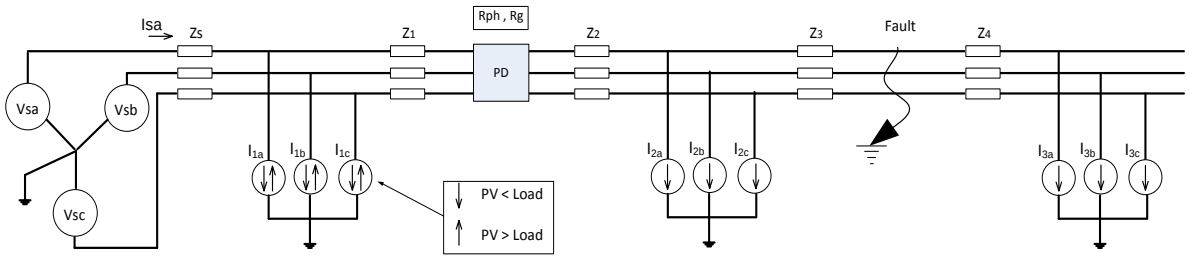
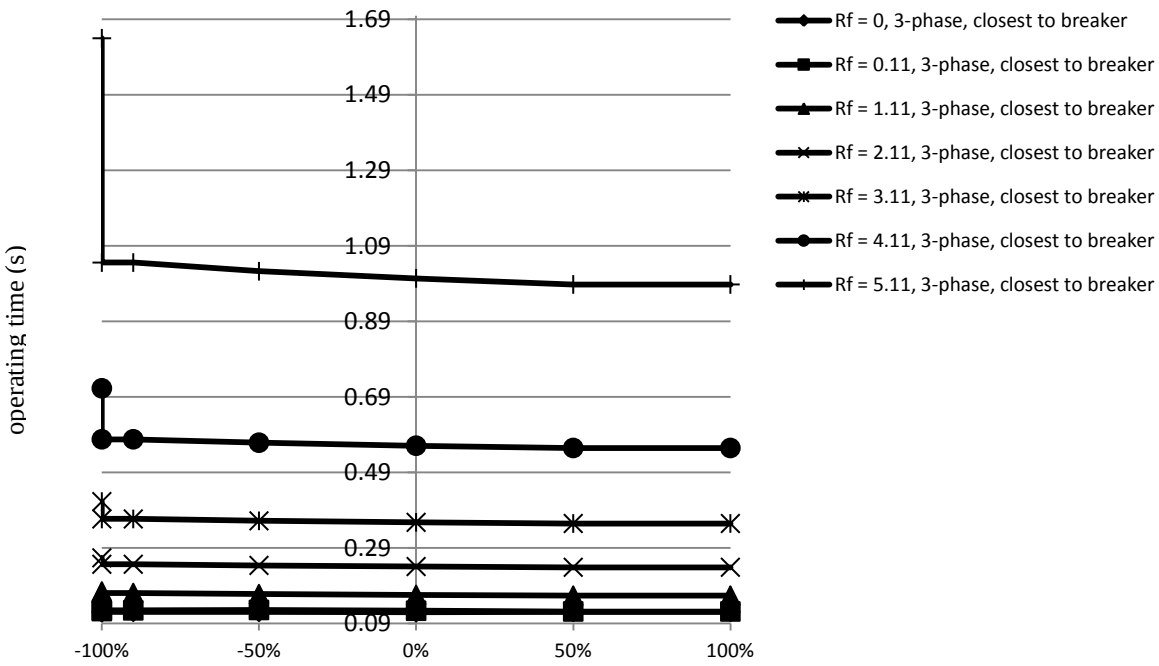
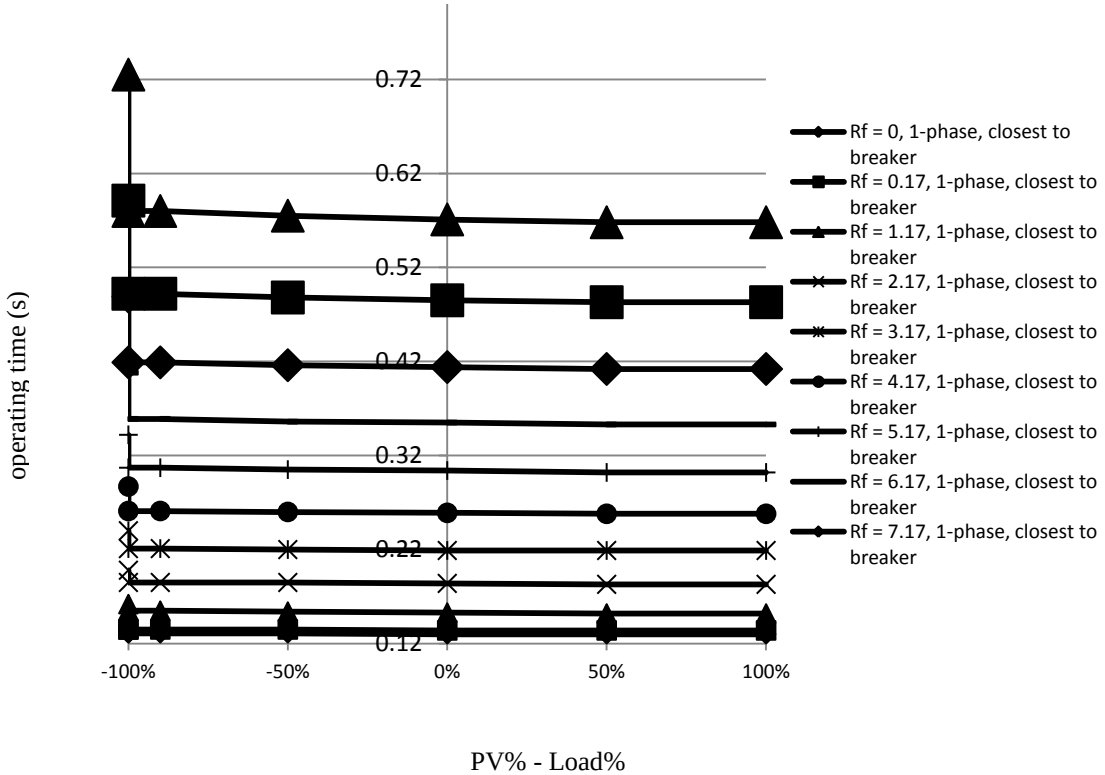


Figure 69: Generic electrical circuit showing that the PVs, downstream the breaker, are under cloud

Figures 70 and 71 summarize the effect of the PVs on the operating time of the breaker of the feeder 1.

Figure 70: Breaker operating time vs. PV generation while the fault is at the closest point to the breaker


operating time (s)
1.69
1.49
1.29
1.09
0.89
0.69
0.49
0.29
0.09
-100%
-50%
0%
50%
100%
PV% - Load%
Rf = 0, 3-phase, closest to breaker
Rf = 0.11, 3-phase, closest to breaker
Rf = 1.11, 3-phase, closest to breaker
Rf = 2.11, 3-phase, closest to breaker
Rf = 3.11, 3-phase, closest to breaker
Rf = 4.11, 3-phase, closest to breaker
Rf = 5.11, 3-phase, closest to breaker


operating time (s)
0.72
0.62
0.52
0.42
0.32
0.22
0.12
-100%
-50%
0%
50%
100%
PV% - Load%
Rf = 0, 1-phase, closest to breaker
Rf = 0.17, 1-phase, closest to breaker
Rf = 1.17, 1-phase, closest to breaker
Rf = 2.17, 1-phase, closest to breaker
Rf = 3.17, 1-phase, closest to breaker
Rf = 4.17, 1-phase, closest to breaker
Rf = 5.17, 1-phase, closest to breaker
Rf = 6.17, 1-phase, closest to breaker
Rf = 7.17, 1-phase, closest to breaker

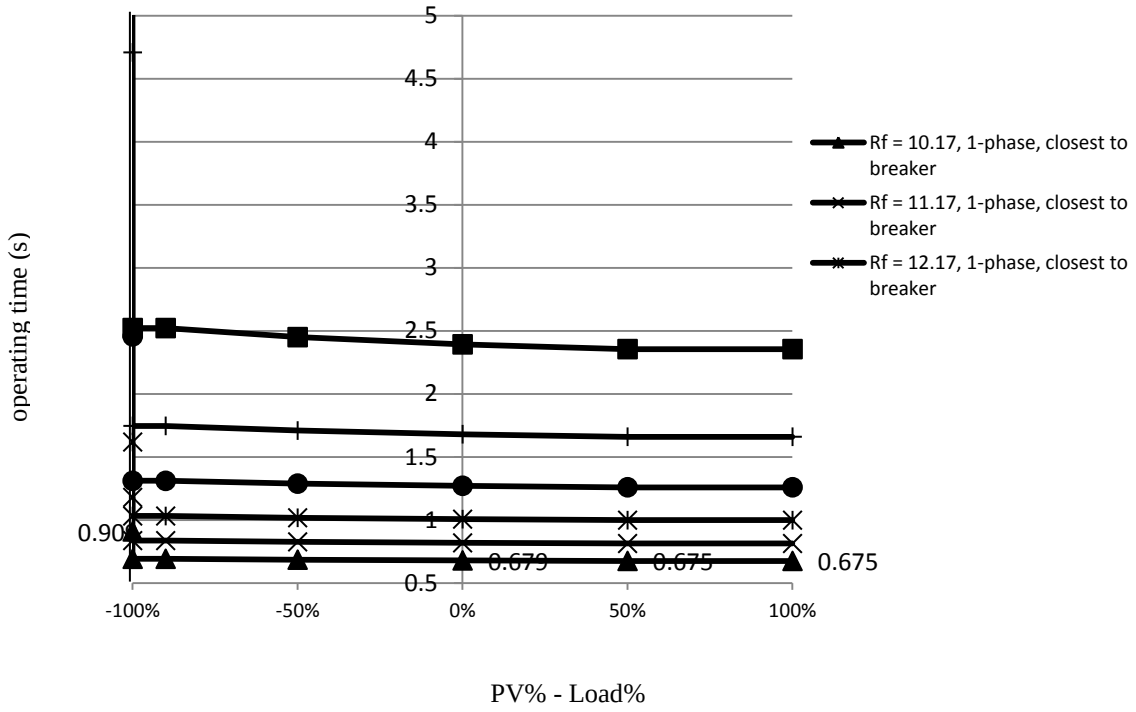
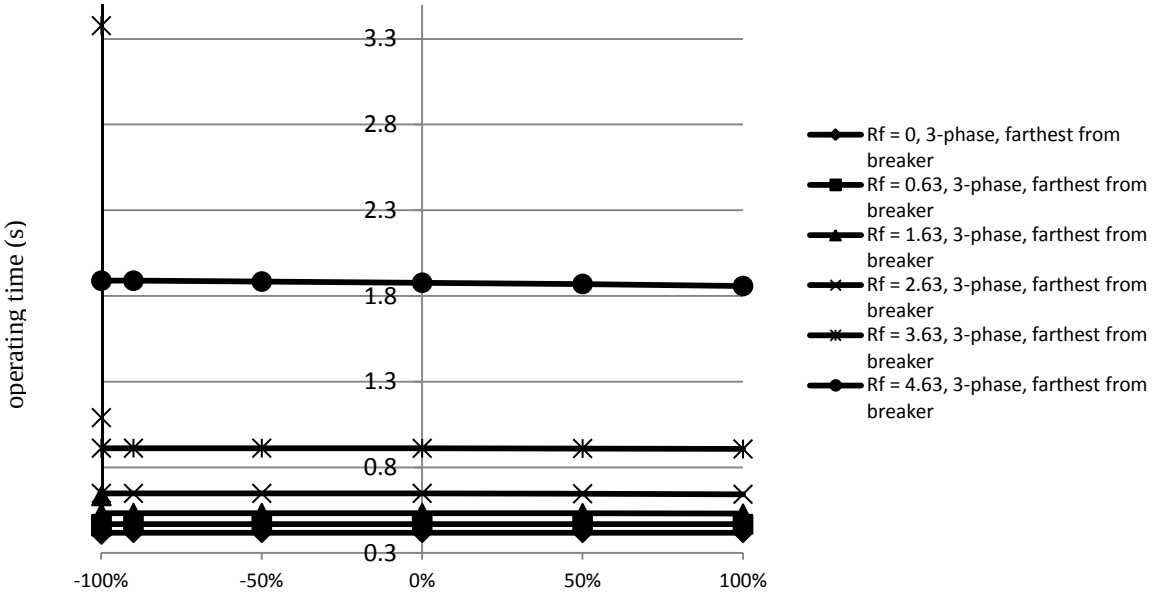
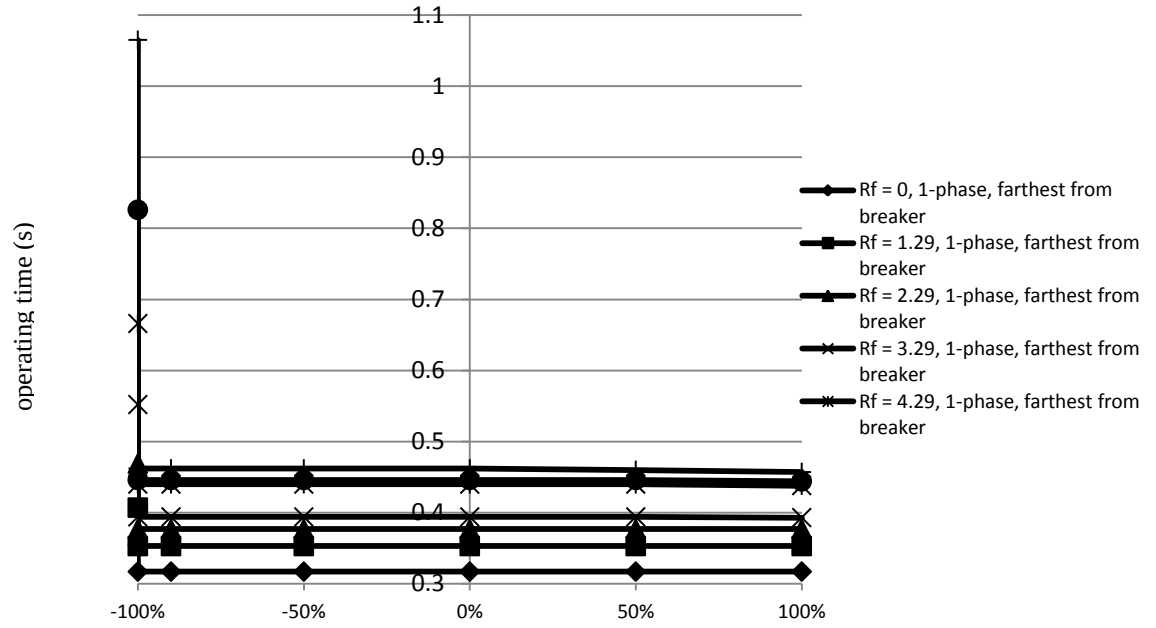
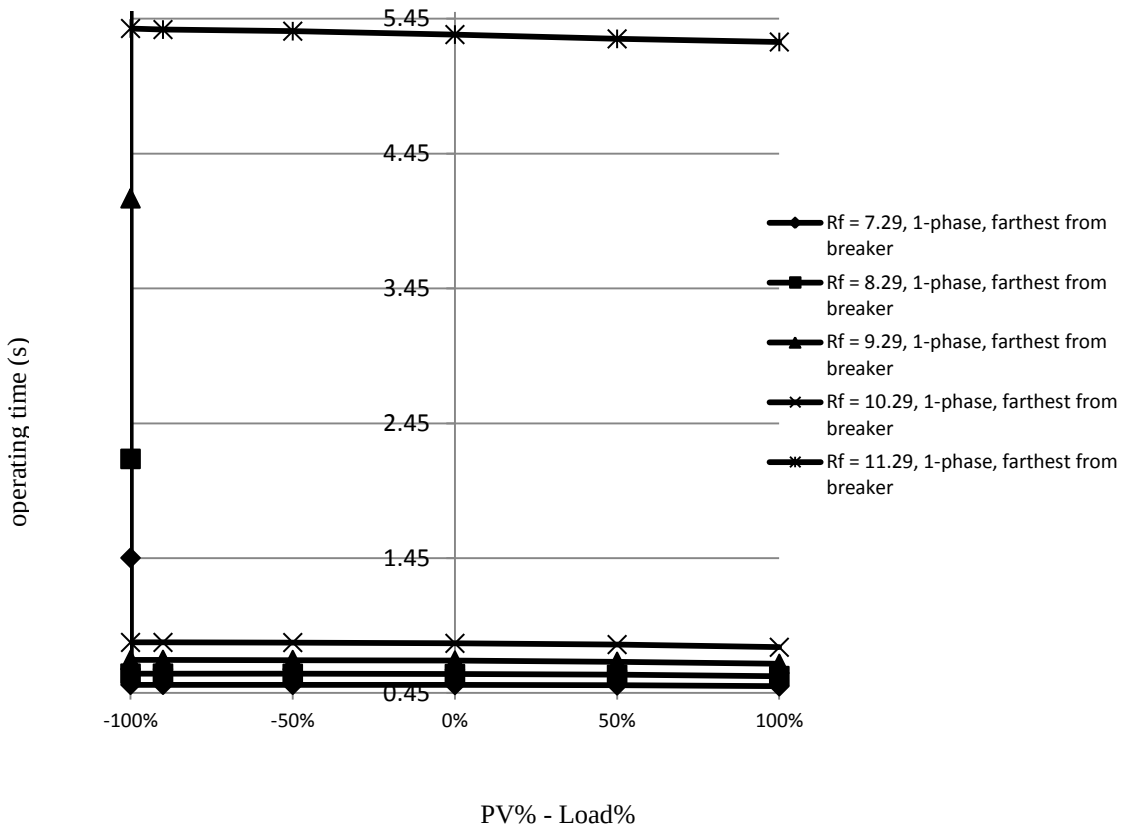

operating time (s)
5
4.5
4
3.5
3
2.5
2
1.5
1
0.5
0.90
0.679
0.675
0.675
-100%
-50%
0%
50%
100%
PV% - Load%
Rf = 10.17, 1-phase, closest to breaker
Rf = 11.17, 1-phase, closest to breaker
Rf = 12.17, 1-phase, closest to breaker

Figure 71: Breaker operating time vs. PV generation while the fault is at the farthest point from the breaker


operating time (s)
3.3
2.8
2.3
1.8
1.3
0.8
0.3
-100%
-50%
0%
50%
100%
PV% - Load%
Rf = 0, 3-phase, farthest from breaker
Rf = 0.63, 3-phase, farthest from breaker
Rf = 1.63, 3-phase, farthest from breaker
Rf = 2.63, 3-phase, farthest from breaker
Rf = 3.63, 3-phase, farthest from breaker
Rf = 4.63, 3-phase, farthest from breaker


operating time (s)
1.1
1
0.9
0.8
0.7
0.6
0.5
0.4
0.3
-100%
-50%
0%
50%
100%
PV% - Load%
Rf = 0, 1-phase, farthest from breaker
Rf = 1.29, 1-phase, farthest from breaker
Rf = 2.29, 1-phase, farthest from breaker
Rf = 3.29, 1-phase, farthest from breaker
Rf = 4.29, 1-phase, farthest from breaker



Figures 70 and 71 clearly showed that, similar to Green Hub I, the PVs upstream a protective device do not have noticeable effect on both reach and speed. Note that at the PV/Load unbalance of -100%, the relay operating time in Green Hub II is lower than the relay operating time in the conventional system. This effect will be discussed in detail in the next section.

DISCUSSIONS

Similar to the PVs, the SSTs' contribution to the fault current are small compared to the contribution of the power grid as the SSTs' rectifiers limit the output current to two per rated

current. Therefore, the SSTs' fault contributions do not have considerable effect on the protective device while the fault resistance is low.

Figure 72 shows a generic three-phase case where three groups of SSTs are connected to the system in different locations: I_1 which represents all the SSTs from adjacent feeders and the branches upstream of the PD, I_2 which represents all the SSTs between the PD and the fault, and I_3 which represents all the SSTs after the fault.

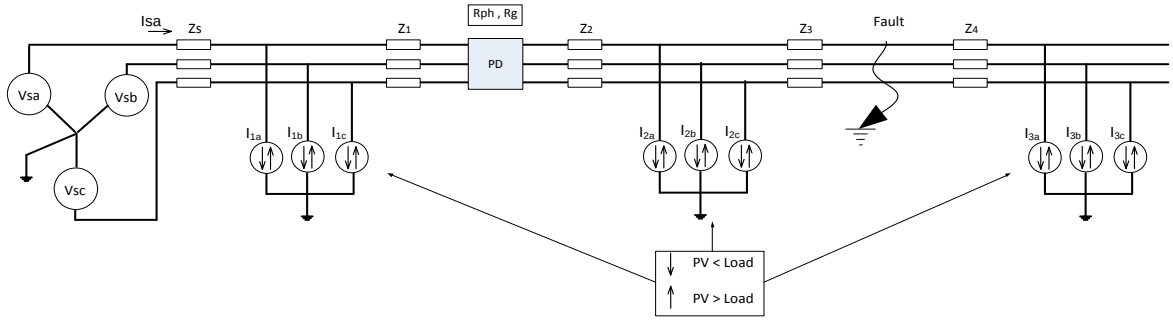


Figure 72: A generic three-phase case showing the SSTs in different locations

- Three-phase fault: If the fault is a three-phase fault, an approximate solution can be obtained by considering only one phase. Equation 5 demonstrates the current flowing through the PD. The '+' signs are for when the PVs' generations are greater than the loads and the '-' signs are for when the loads are greater than the PVs' generations.

$$I_{Rph} = I_S \pm C_1 I_1 \pm C_2 I_2 \pm C_3 I_3 \quad (5)$$

where $C_1 = \frac{Z_S}{Z_S + Z_1 + Z_2 + Z_3 + R_f}, C_2 = \frac{-(Z_3 + R_f)}{Z_S + Z_1 + Z_2 + Z_3 + R_f}, C_3 = \frac{-R_f}{Z_S + Z_1 + Z_2 + Z_3 + R_f},$

and $I_1, I_2, I_3 = 1 - 2\,pu$.

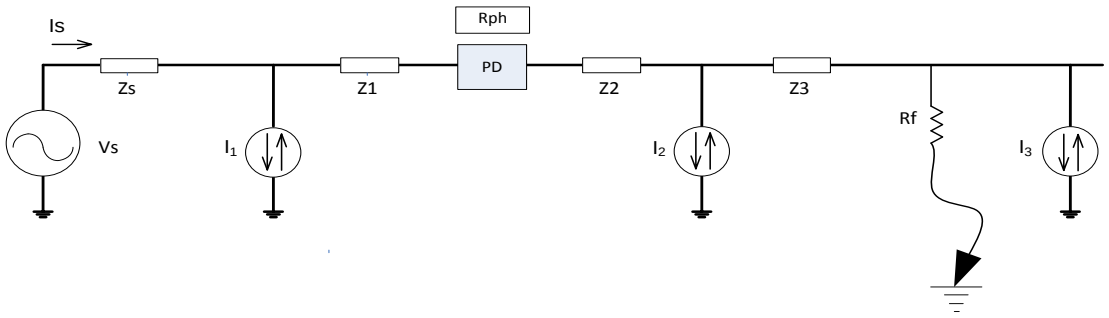


Figure 73: Single-line diagram presentation of the generic case

- Single-phase fault: If the fault is a single-phase fault, then we can approximate the fault current using the sequence complements approach as shown in the figure 74. Equation 6 demonstrates the ground current (three times the PDs' zero sequence current) flowing through the PD. Similar to the three-phase case, the '+' signs are for when the PVs' generations are greater than the loads and the '-' signs are for when the loads are greater than the PVs' generations.

$$I_{Rg} = (3I_{S0}) \pm \left[C_1^+(3I_1^+) + C_1^-(3I_1^-) + C_1^0(3I_1^0)\right] \pm \left[C_2^+(3I_2^+) + C_2^-(3I_2^-) + C_2^0(3I_2^0)\right] \pm \left[C_3^+(3I_3^+) + C_3^-(3I_3^-) + C_3^0(3I_3^0)\right]$$

where (6)

$$C_1^+ = C_1^- = \frac{Z_S^+}{Z_S + Z_1 + Z_2 + Z_3 + 3R_f}, C_1^0 = \frac{Z_S^0}{Z_S + Z_1 + Z_2 + Z_3 + 3R_f}$$

$$C_2^+ = C_2^- = \frac{Z_S^+ + Z_1^+ + Z_2^+}{Z_S + Z_1 + Z_2 + Z_3 + 3R_f}, C_2^0 = \frac{-\left(2Z_S^+ + 2Z_1^+ + 2Z_2^+ + Z_3 + 3R_f\right)}{Z_S + Z_1 + Z_2 + Z_3 + 3R_f}$$

$$C_3^+ = C_3^- = \frac{Z_S^+ + Z_1^+ + Z_2^+ + Z_3^+}{Z_S + Z_1 + Z_2 + Z_3 + 3R_f}, C_3^0 = \frac{-\left(2Z_S^+ + 2Z_1^+ + 2Z_2^+ + 2Z_3^+ + 3R_f\right)}{Z_S + Z_1 + Z_2 + Z_3 + 3R_f}$$

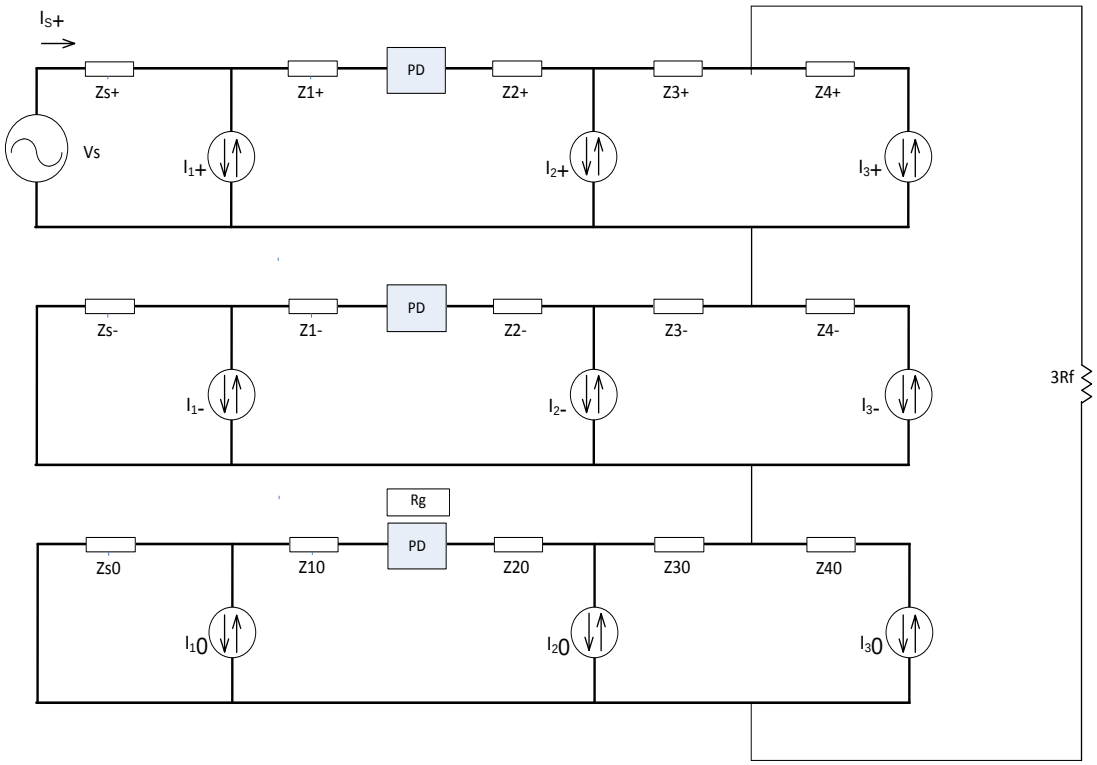


Figure 74: Sequence diagram presentation of the generic case with a single-phase fault

Having these points in mind, the simulation results shown in the previous section can be discussed as follows.

PVs downstream a protective device

Similar to Green Hub I, the PVs do not have noticeable effect when the fault resistance is low as the SSTs' current is also limited to two per unit and the current contribution from the power grid is relatively higher. The following explains the PVs' effect when the fault resistance is high:

- For both three-phase and single-phase faults, as shown in equation 5 and 6, the PVs downstream a PD decrease the current flowing through it if PV > Load so they cause

reduction in both REACH and SPEED. Also, if Load > PV, the current flowing through the PD increases, therefore the operating time of the relay decreases.

- For both three-phase and single-phase faults, the SSTs upstream the PD draw current from the system but do not have any effect on the relay operating time. This is because all terms related to I_1 in equation 5 and 6 have the term $3R_f$ or R_f only in their denominators.
- In contrast to Green Hub I, there's no increase in relay reach or speed for high resistance single-phase faults with PV/Load unbalance of 100%. This is because first, in worst case meaning when the PV/Load unbalance is 100% or -100%, the SSTs stay online with a minimum voltage of 0.5pu and, second, the post fault voltage is higher than 0.5pu for most of or all of the SSTs when the fault resistance is high. In our test case, for R=3.29Ω and more (when PV/Load unbalance = 100%), the terminal voltage of all SSTs are more than 0.5pu.

PVs upstream a protective device

Similar to Green Hub I and for the same reasons, the PVs, upstream the PD, do not affect the relay operating time. The SSTs' current drawing, downstream the PD, make the relay operating time in Green Hub II lower than the relay operating time in the conventional system.

CONCLUSIONS

Similar to what we concluded about Green Hub I, the goal in this section is to find the situation in which the worst case, where the effect of the combination of PVs and SSTs on the PD's operating time is maximized, takes place. By using the simulation results and the discussions, we can conclude that the worst case occurs when:

- For three-phase faults:
    1. Amount of PV generation: Maximum (100%).
    2. PVs' locations: Downstream the PD.
    3. Fault resistance: Maximum (the fault resistance for which the fault current is equal to the pick-up current of the PD)
    4. Fault location: At the end of the feeder.
- For single-phase faults:
    1. Amount of PV generation: Maximum (100%).
    2. PVs' locations: Downstream the PD.
    3. Fault resistance: Maximum (the fault resistance for which the fault current is equal to the pick-up current of the PD)
    4. Fault location: At the end of the feeder.

Figure 75 shows the operating times of the breaker and the recloser in the worst case conditions considering all downstream and upstream SSTs with different PV/Load balances. As shown, the results are quite similar to the results shown in figures 66 and 67. This is because the upstream SSTs do not have noticeable effect on the PDs' operating times. Also

note that for both three-phase and single-phase faults the worst case condition occurs when the fault is at the end of the feeder.

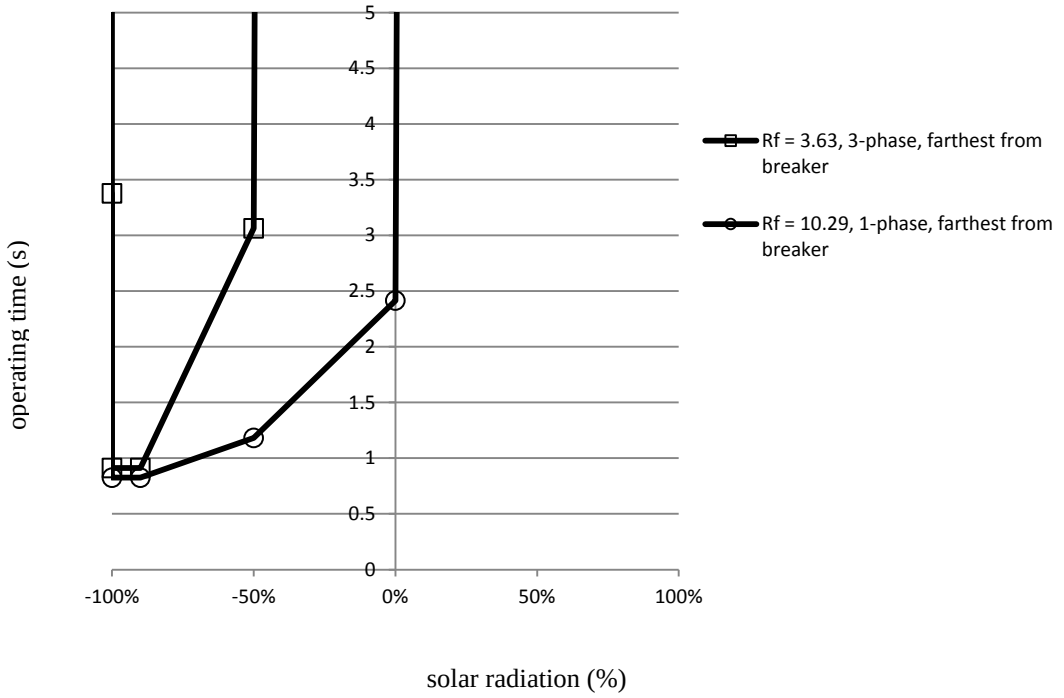


Figure 75: Breaker and recloser operating times in the worst case conditions while considering all PVs

LOSS OF COORDINATION

DISCUSSIONS AND CONCLUSIONS

Similar to Green Hub I, the PVs/SSTs do not have any effect on coordination as the current coming from the power grid is much higher than the SSTs' contribution to the fault current. In order to investigate the effect of PVs/SSTs on the coordination for high resistance faults, let's take a look at figure 76. As shown in the figure, I_1 represents all fault current contribution from SSTs on adjacent feeders and the branches upstream of the PD1, I_2 represents all fault current contribution from SSTs between the PD1 and the PD2, and I_3 represents all fault current contribution from SSTs downstream of the PD2.

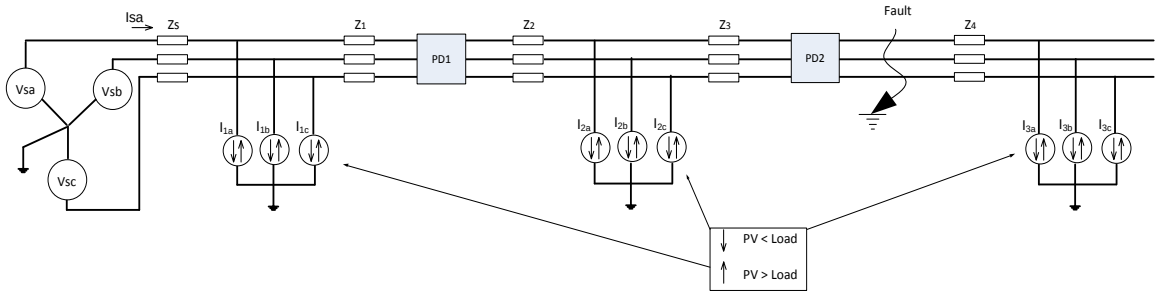


Figure 76: A generic case showing the PVs/SSTs' effect the marginal timing

Figure 77 shows how the PVs/SSTs represented by I_1 affect the operating times of the PDs. As shown in this figure, I_1 does not have any effect on the operating times of both PD1 and PD2 as it's located upstream of both PDs. So PVs/SSTs represented by I_1 do not hinder the coordination.

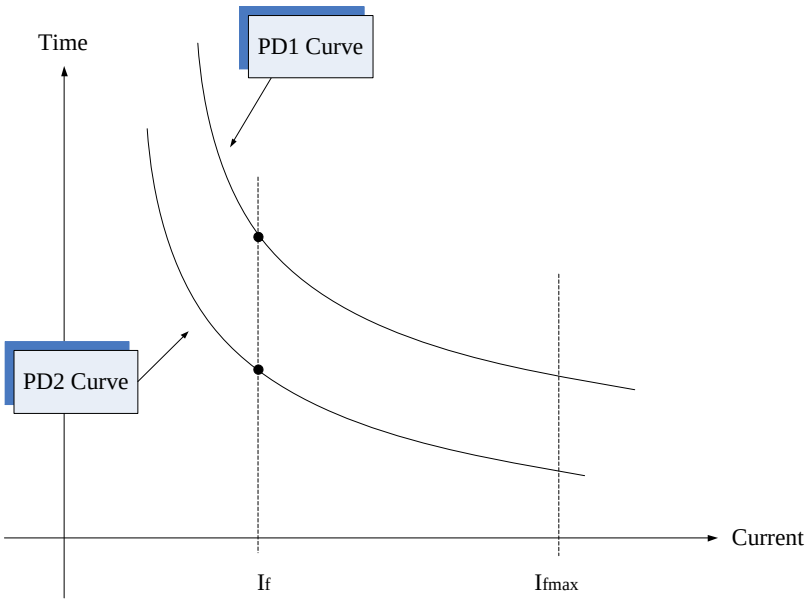


Figure 77: Effect of I_1 on the coordination

Figures 78 and 79 show the effects of the PVs represented by I_2 and I_3. As shown I_2 does not affect the operating time of PD2 but increases the operating time of PD1 if PV> Load which results in an increase in the difference of the operating times. However if PD<Load then I_2 decreases the operating time of PD1, which results in a reduction in the difference of the operating times. This reduction does not lead to loss of coordination as the time difference between the time-current curves is huge for low fault currents (high resistance faults). Also, I_3 increases the operating times of both PD1 and PD2 if PV> Load which results in an increase in the difference of the operating times. However if PD<Load then I_3 decreases the operating times of both PD1 and PD2, which results in a reduction in the difference of the operating times. Again, this reduction does not lead to loss of coordination as the fault current is lower than the I_{fmax} and therefore the time difference between the operating points

is greater than the marginal time. So PVs/SSTs represented by I_2 and I_3 do not hinder the coordination.

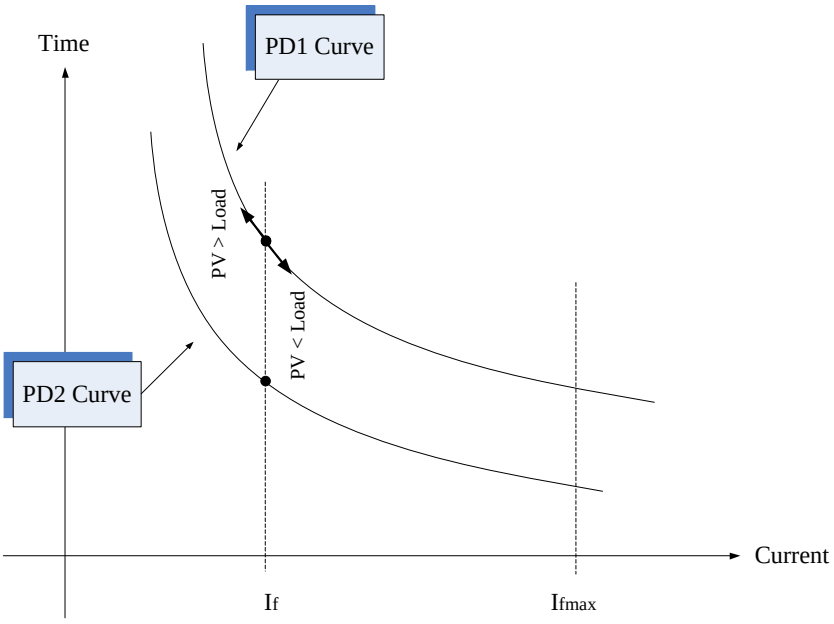


Figure 78: Effect of I_2 on the coordination

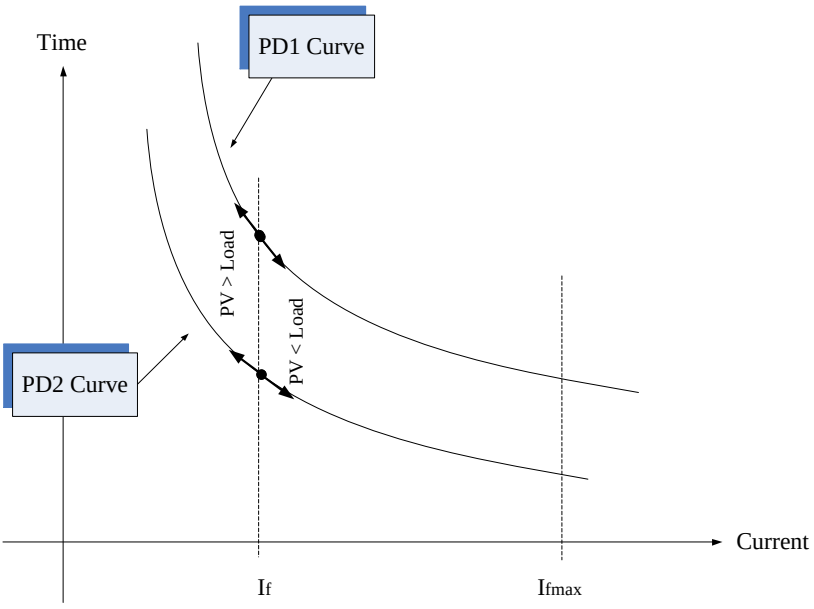


Figure 79: Effect of I_3 on the coordination

The above-mentioned investigation shows that the PVs/SSTs do not hinder the coordination.

SIMULATION AND RESULTS

Figures 80 and 81 show the marginal time between the breaker and the recloser of feeder 1 for both phase and ground relays. The faults applied for these cases were of bolted type and were located right after the recloser. As shown, the marginal time is not affected by the PVs/SSTs.

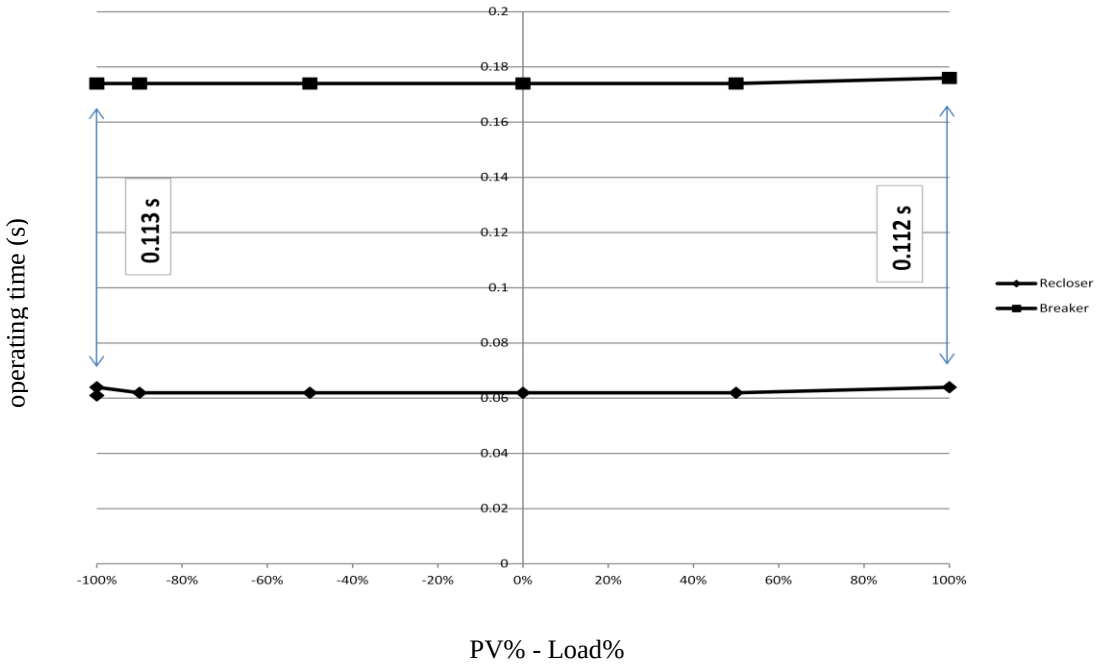


Figure 80: Marginal time between the operating times of the breaker and the recloser when the fault is a three-phase one

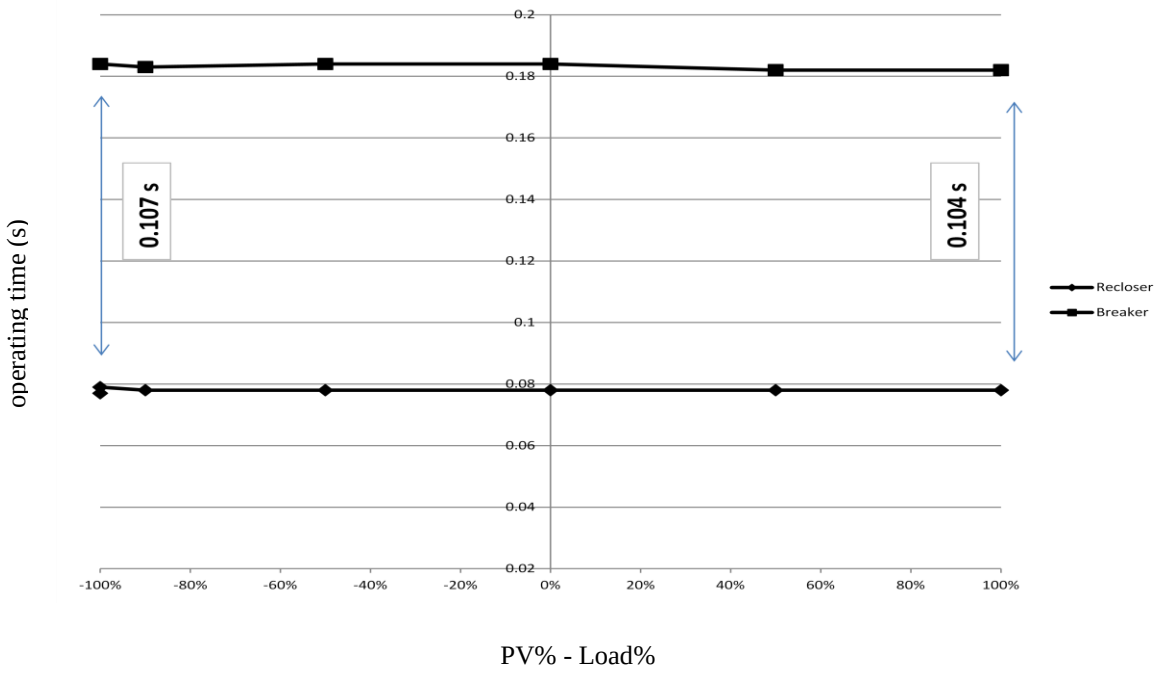


Figure 81: Marginal time between the operating times of the breaker and the recloser when the fault is a single-phase one

Figures 82 and 83 show the difference between the operating times of the breaker and the recloser of feeder 1 for faults with high resistances. The resistance of the three-phase fault is 4.27Ω and the resistance of the single-phase fault is 10.41Ω. As shown, for both cases the minimum difference between the operating times of the breaker and the recloser occurs when PV/Load balance is -100%; however these values are higher than the marginal times shown in figures 65 and 66; therefore no loss of coordination occurs.

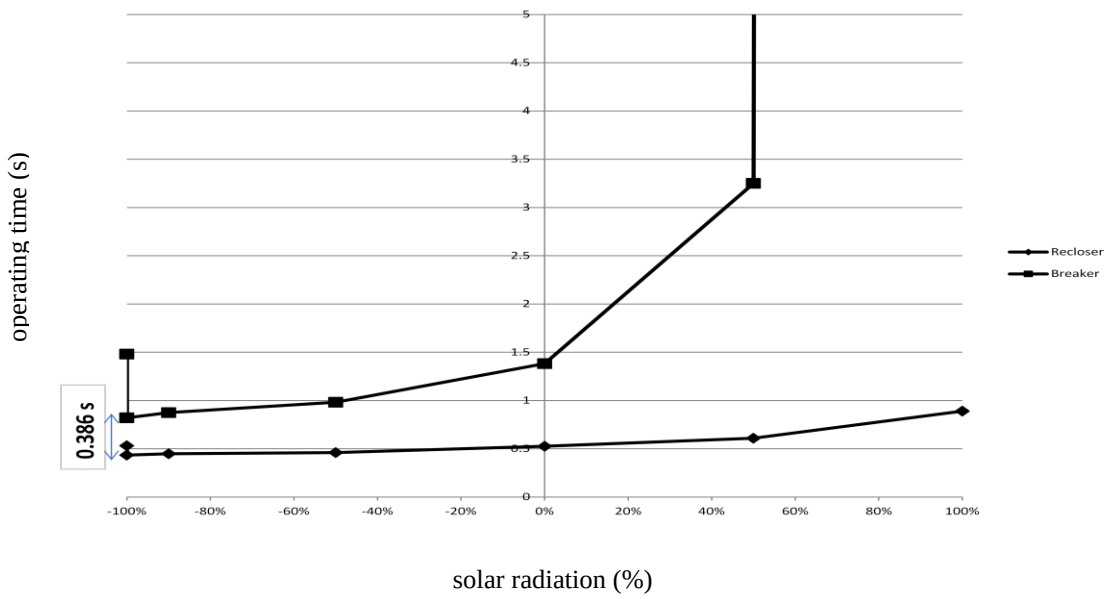


Figure 82: Difference between the operating times of the breaker and the recloser when the fault is a three-phase one with Rf=4.27Ω

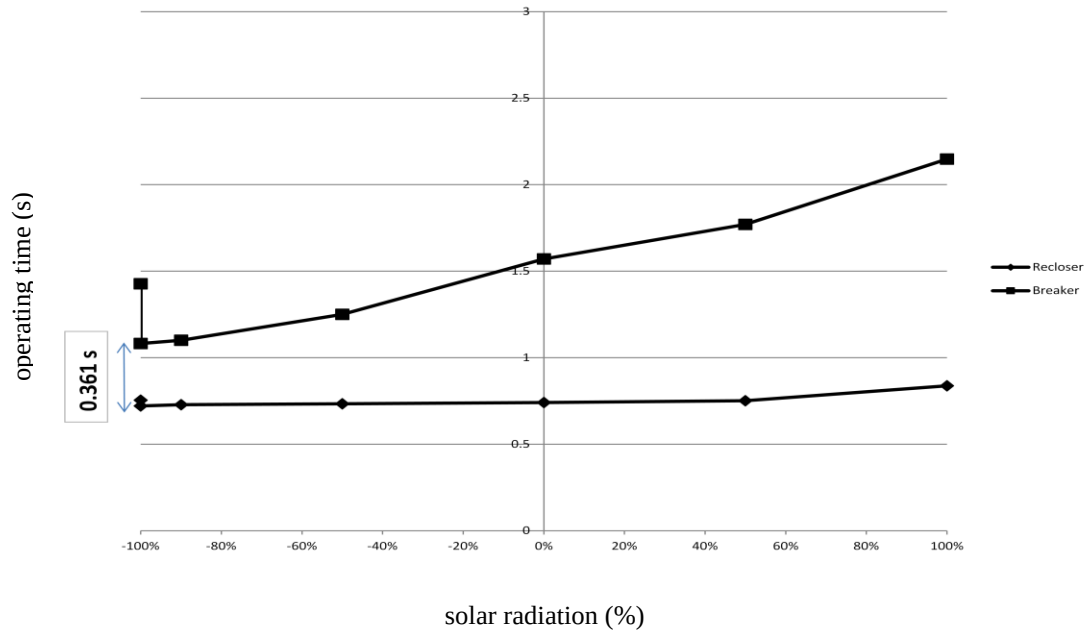


Figure 83: Difference between the operating times of the breaker and the recloser when the fault is a single-phase one with Rf=10.41Ω

SIMULATION AND RESULTS

A three-phase zero-resistance fault (the most severe fault) has been applied right after the breaker of the feeder 1 to see how much the SSTs on the feeder 2 contribute to the fault and to see if this contribution can lead to a sympathetic tripping of the breaker of the feeder 2. In this study, the PV/Load unbalance is set to be -100% so that the SSTs on feeder 2 draw the maximum current. It should be noted that since the feeder overcurrent protection is non-directional, this study could also have been done with the PV/Load unbalance of 100%, which would have resulted in the same current profile but in the opposite direction.

Figure 84 shows the current flowing through the breaker of the feeder 2. As shown, after the fault occurrence at t = 0.5s, the current becomes high to less than 1kA. The figure clearly shows that the fault current, that the SSTs on the feeder 2 provided, is about two times the nominal current of the feeder, so it never triggers the breaker since the relay pick-up current has been set to 1440A.

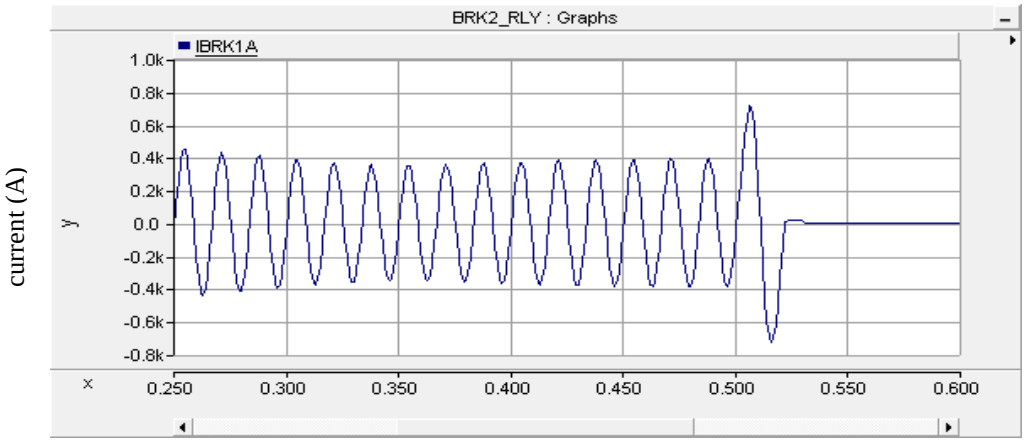


Figure 84: Fault current flowing through the breaker of feeder 2 while a fault occurs on feeder 1

DISCUSSIONS AND CONCLUSIONS

The sympathetic tripping can never happen in these feeders because the relay pick-up current is always set to be more than two times the feeder nominal current but the fault current the SSTs provide is limited to two times the nominal current which is not enough to trigger the feeder breaker.

SIMULATION AND RESULTS

In this part, two different simulations have been done. In the first one which focuses on unsuccessful reclosing issue, a permanent fault has been applied at t = 0.5s in the protection zone of the feeder 1 recloser. The PV /Load unbalance has been set to be 0% which means there is a good balance between the loads and PVs. Figures 85 shows the terminal voltage and current of a SST in this zone. The recloser trips at t=0.58s, however as shown, the SSTs remain online continuing feeding the fault and making the reclosing unsuccessful.

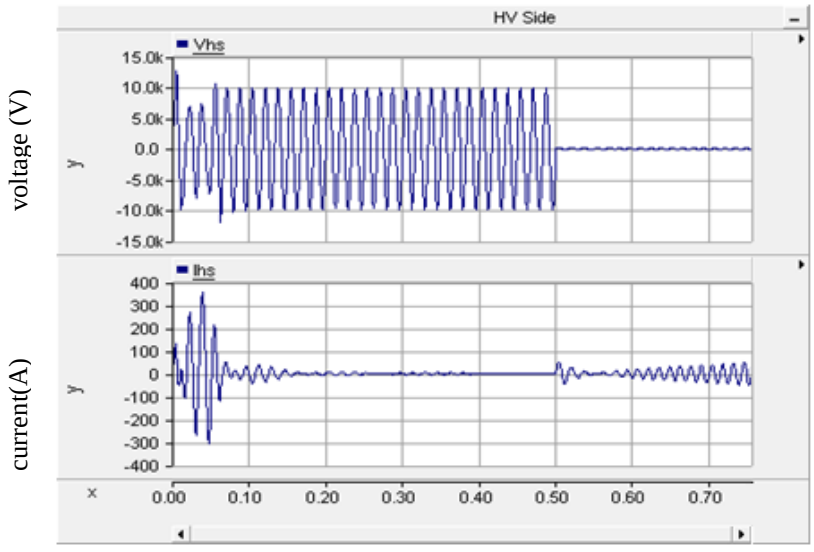


Figure 85: Terminal voltage and current of a SST in the faulty zone

The second simulation focuses on out-of-reclosing issue. In this case, all the conditions were the same as the conditions in the first simulation except that the fault has been assumed to be temporary (although the SSTs feed it). So what happens is that the recloser trips at t = 0.58s

and the fault clears at t = 0.6s so that when the recloser recloses, the load side of the recloser is a healthy island with online SSTs. Figure 86 shows the voltages on both system side (grid voltage) and load side (SST voltage) of the recloser. As shown, there is no noticeable phase difference between these two voltages.

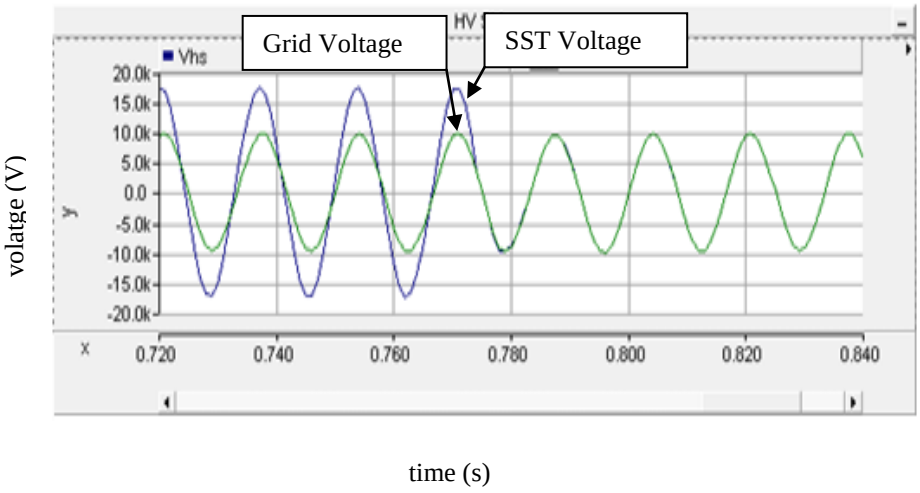


Figure 86: Power grid and SST voltage

DISCUSSIONS AND CONCLUSIONS

SSTs are likely to stay online while there's a good balance between load and PV generation. The results from the first simulation show that, with a good PV/load balance, the SST can feed the fault and still stay online and make the reclosing unsuccessful. So the SSTs need to be equipped with a reliable anti-islanding protection to detect this kind of situation and to disconnect from the grid as soon as the recloser opens. However the reclosing open interval should be coordinated with the anti-islanding protection speed to make sure that it's long enough to let the anti-islanding work.

The results from the second simulation show that there's no noticeable phase difference between the voltages of the grid side and the load side of the recloser. This is because the SSTs are static devices with no rotating parts. So out-of-phase reclosing can never occur in these systems.

DISCUSSIONS AND CONCLUSIONS

It has been assumed that all SSTs are equipped with a reliable anti-islanding protection. So unintentional islanding can never happen.

However, if the feeder protective device happened to have reclosing function, then the reclosing open interval should be coordinated with the anti-islanding protection speed to make sure that the SSTs are disconnected when the protective device recloses.

CHAPTER 4

FAULT ANALYSIS METHOD FOR GREEN HUBS

INTRODUCTION

Fault analysis is a prerequisite for setting the protective relays. However, fault analysis in power systems like Green Hubs are inherently different from other systems. The followings are some major differences between the conventional distribution systems and the Green Hubs:

1. In conventional distribution systems, fault current is only supplied by the power grid; whereas, in Green Hubs, PVs and SSTs contribute to the fault current as well.
2. In Green Hubs, PVs and SSTs are single-phase sources with special characteristics such as limited fault current and unity power factor current injection.
3. In conventional distribution systems, the fault current flowing through the PDs has constant RMS value until it's interrupted; however, in Green Hubs, the RMS value of the fault current varies as some of the PVs/SSTs shut down before the PDs trip.
4. Since the RMS value of the fault current varies in the Green Hubs, it's not possible to estimate the relay operating time using the inverse time-current curves; therefore some method is required to estimate the relay operating time in the Green Hubs.

Although the effect of DER penetration on the fault current has been investigated in many references, only a few papers have proposed fault analysis method for the DER-penetrated distribution systems. Wang et al. proposed a fault analysis method based on the regular load flow method being used by the utilities; however this method only considers the distributed

synchronous generators [18]. Baran and El-Markaby developed a fault analysis method for the distribution systems penetrated by inverter-interfaced DERs. This method is based on modeling the DERs by their Thevenin equivalent. However, as mentioned in this paper, the proposed method is suitable for the DERs with inverters under voltage control schemes and not current control schemes (on which the inverters of the PV systems under consideration are based) [19].

Reviewing the published literatures showed that none of them have focused on the DER-penetrated distribution systems resulting in a need for developing a fault analysis method which can capture the special characteristics of the PVs and SSTs.

FAULT ANALYSIS METHOD FOR GREEN HUB I

Consider the distribution system shown in figure 87 where each bus has a PV injecting $\vec{I}_{PV}$ to the bus and a load drawing $\vec{I}_{Load}$ from the bus and $\vec{V}$ is the bus voltage.

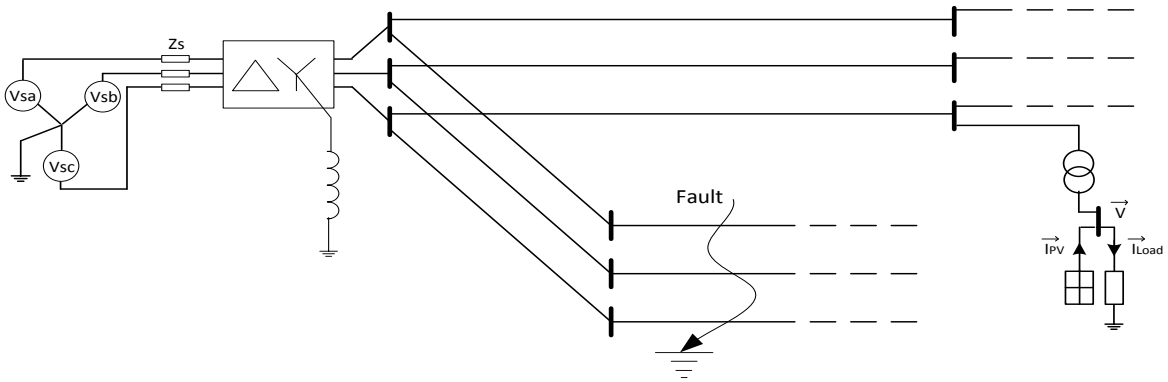


Figure 87: Green Hub I

As explained in the Chapter 2, on pages 11 and 12, the PV V-I characteristic follows the curve shown in figure 88. The PV is a current source and its magnitude and angle are functions of the terminal voltage. If the solar radiation equals to 100%, the PV current magnitude will be limited to 2pu for voltages under 0.5pu and follows a constant power curve for voltages above 0.5pu. Also, the PV current angle is always equal to the terminal voltage angle to ensure operation with unity power factor. Figure 89 shows the PV current versus PV voltage obtained from simulation.

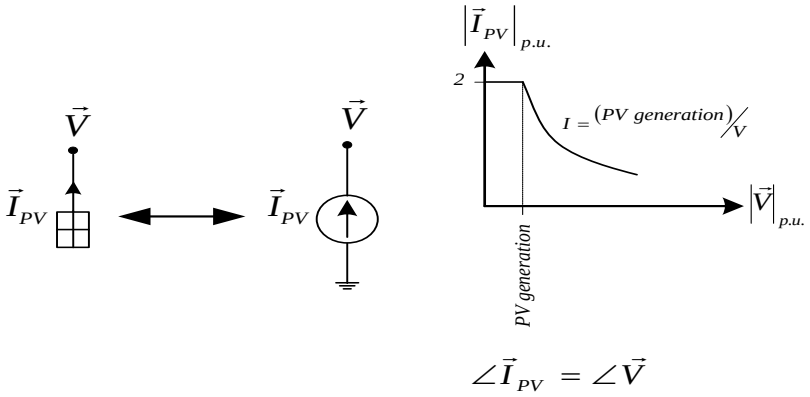


Figure 88: PV model for fault analysis

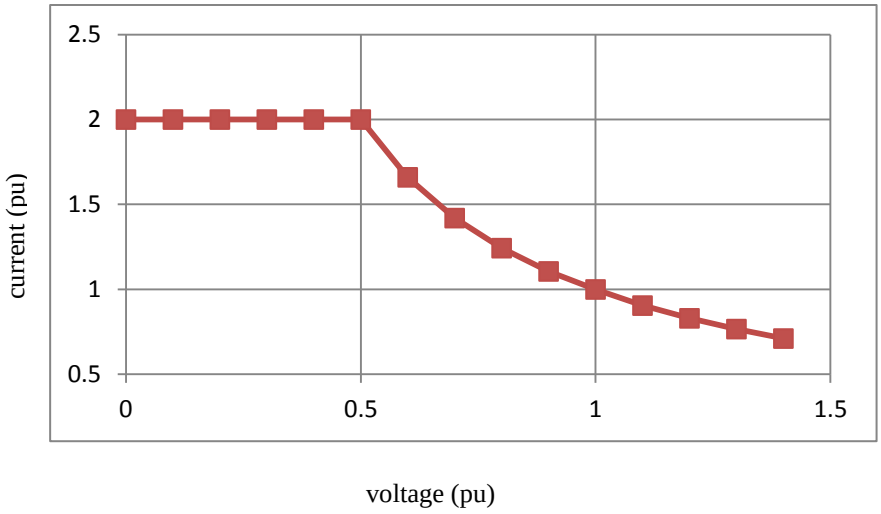


Figure 89: PV current versus PV voltage

Figure 90 shows the model for the load current.

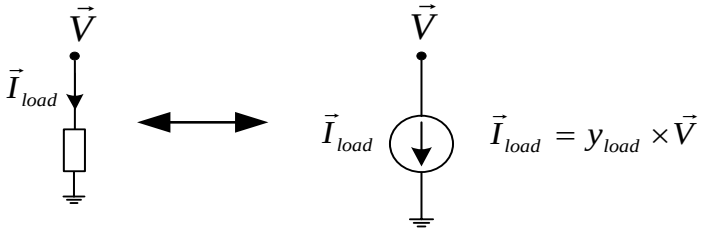


Figure 90: Load model for fault analysis

By having the models for PV and load currents, we can replace the PV and load connected to each bus by two current sources as shown in figure 91:

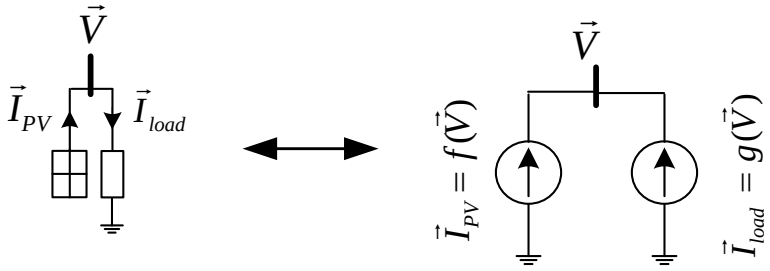
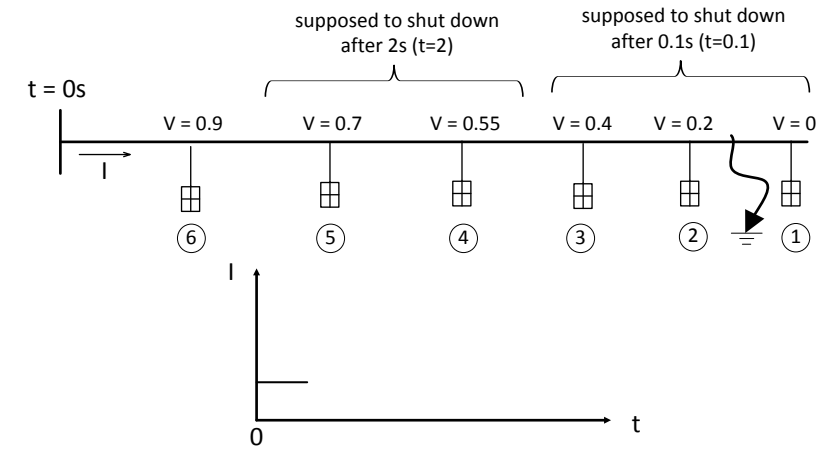
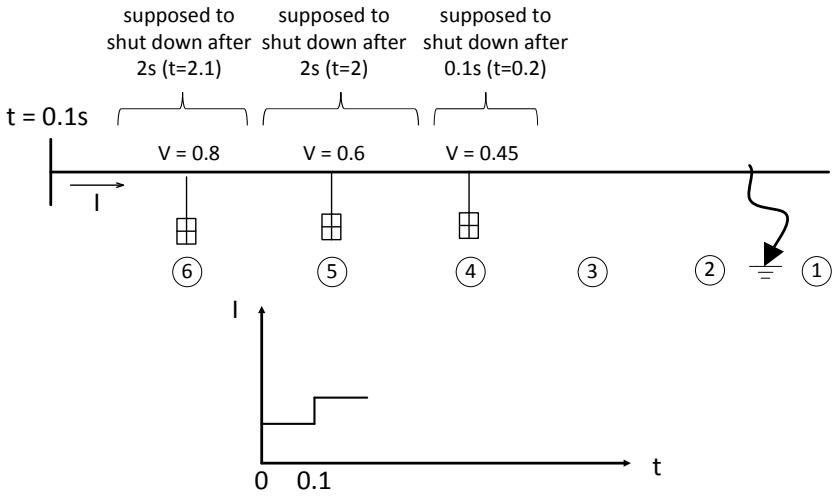


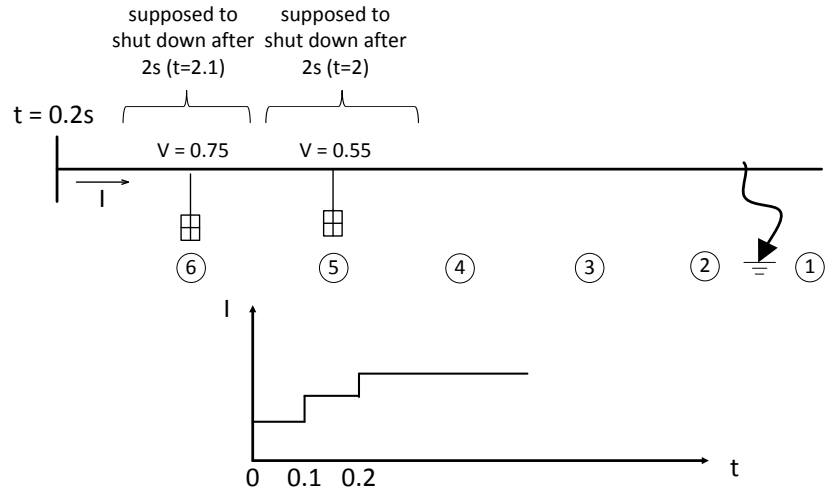
Figure 91: PV/Load model for fault analysis

Since the PVs have under/over voltage protection as described in the IEEE Standard 929, our algorithm should include the PVs' protection and also their system interaction. Figure 92 shows the interaction of PVs in a system. As shown in this figure, at t=0s, the disconnection time of PV4 is set to be 2s and PV6 is set to ride through the fault. However after the PVs 1, 2, and 3 disconnect at t=0.1s, the system voltage decreases and the disconnection times of PVs 4 and 6 change to 0.1s and 2s, respectively. Therefore PV4 disconnects at t=0.2s and PV6 disconnects at t=2.1s.

Figure 92: PVs’ interactions in the system


supposed to shut down after 2s (t=2)
supposed to shut down after 0.1s (t=0.1)
t = 0s
V = 0.9
V = 0.7
V = 0.55
V = 0.4
V = 0.2
V = 0
I
6
5
4
3
2
1
I
0
t


supposed to shut down after 2s (t=2.1)
supposed to shut down after 2s (t=2)
supposed to shut down after 0.1s (t=0.2)
t = 0.1s
V = 0.8
V = 0.6
V = 0.45
I
6
5
4
3
2
1
I
0
0.1
t


supposed to shut down after 2s (t=2.1)
supposed to shut down after 2s (t=2)
t = 0.2s
V = 0.75
V = 0.55
I
6
5
4
3
2
1
I
0
0.1
0.2
t

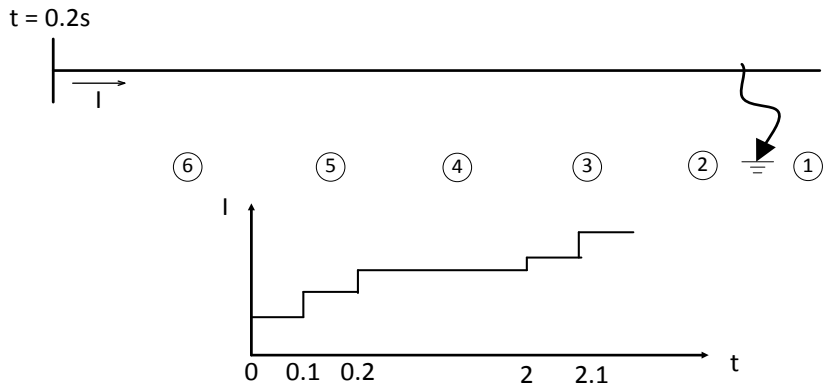


Figure 93 shows the proposed algorithm for the fault analysis method of Green Hub I. As shown in this figure, the algorithm starts calculating the PVs' fault current contributions (*I*) and system bus voltages (*V*) by using an iterative method at t=0 (right after the fault). Then it emulates the PVs' protections to find which group of PVs and at what time should get disconnected. From there, it obtains Δt. The algorithm applies the PVs' protections by making the current injections of the intended PVs zero. In the next step, the algorithm re-calculates the system bus voltages and the PVs' fault current contributions at t=t2=t1+ Δt. This loop will be repeated until all PVs, which are supposed to shut down, are disconnected. The MATLAB implementation of the proposed algorithm can be found in appendix IV.

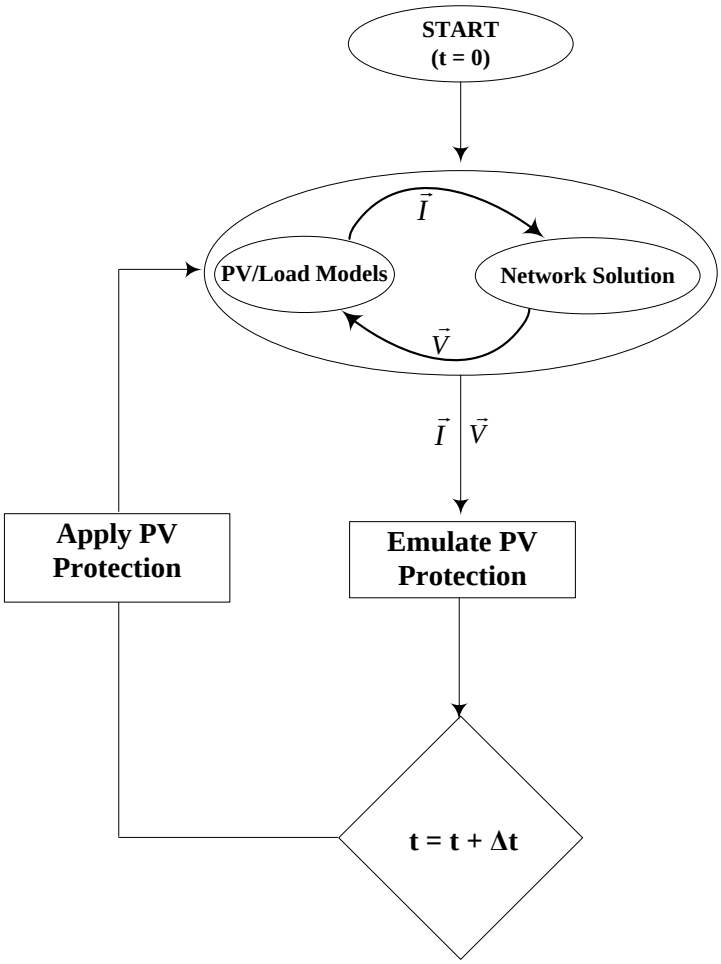


Figure 93: Proposed fault analysis algorithm for Green Hub I

Figures 95 and 96 compare the results from the implemented algorithm in MATLAB with the results from simulation for the breaker current for single-phase and three-phase faults, respectively. Figure 94 shows the single line diagram of the Green Hub I and the bus numbers which have been selected for the fault locations.

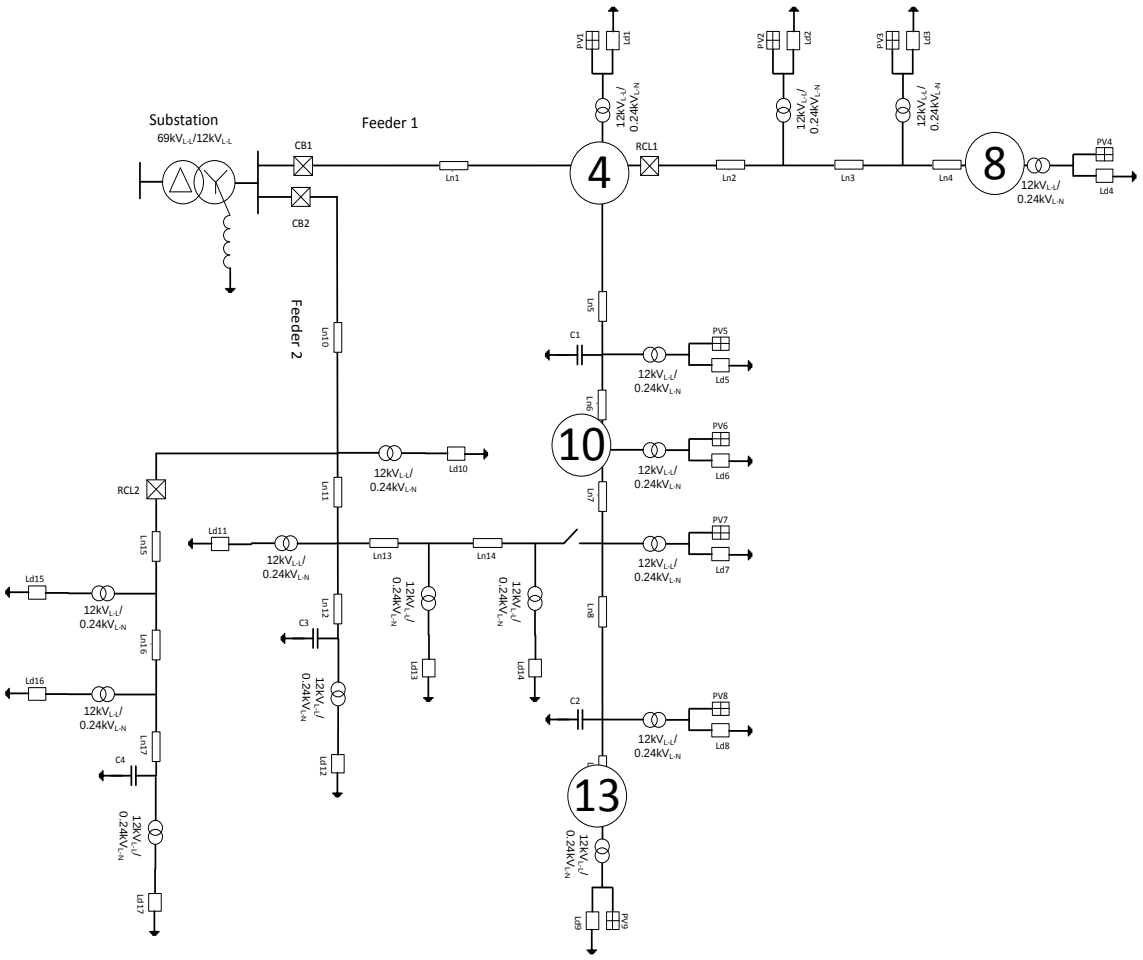
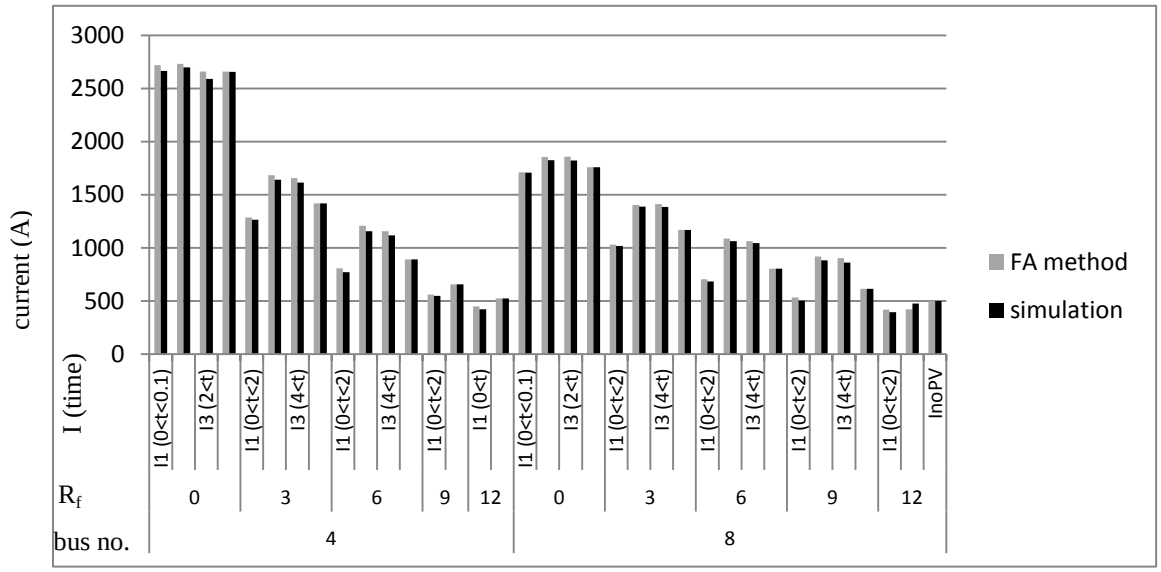


Figure 94: Fault locations on Green Hub I



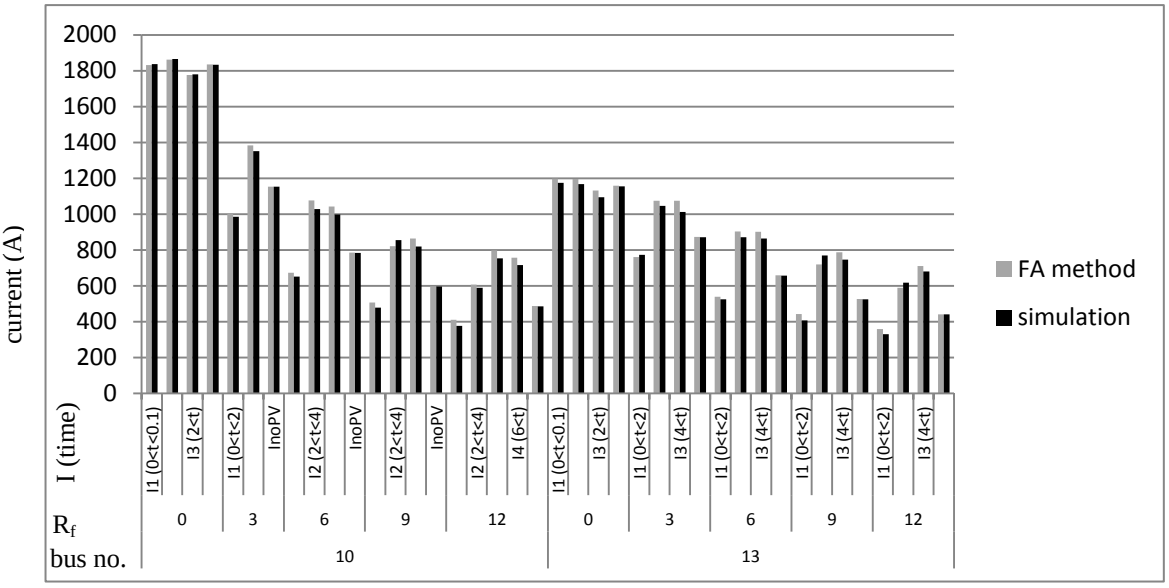


Figure 95: Breaker current for single phase faults

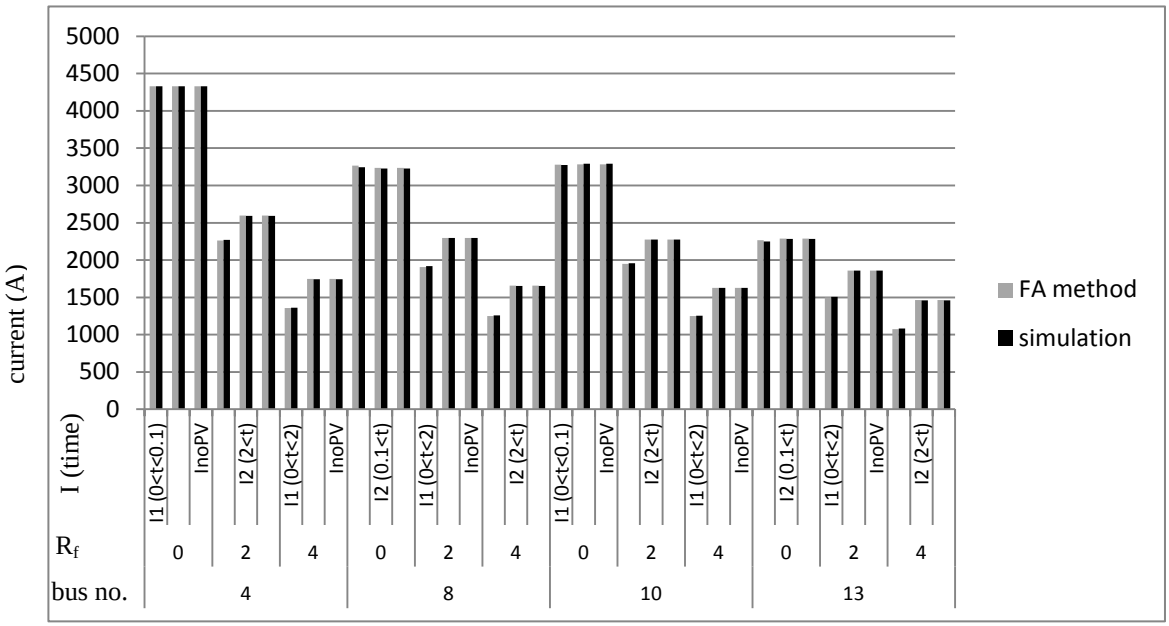


Figure 96: Breaker current for three phase faults

The maximum difference between the current magnitudes calculated by the proposed method and obtained from the simulations is 6.16%. As shown in figures 95 and 96, the output of the algorithm is the values of the current levels and the time instants at which the current level changes.

FAULT ANALYSIS METHOD FOR GREEN HUB II

Consider the distribution system shown in figure 97 where each bus has a SST either injecting or drawing $\vec{I}_{SST}$ to/from the bus and $\vec{V}$ is the bus voltage.

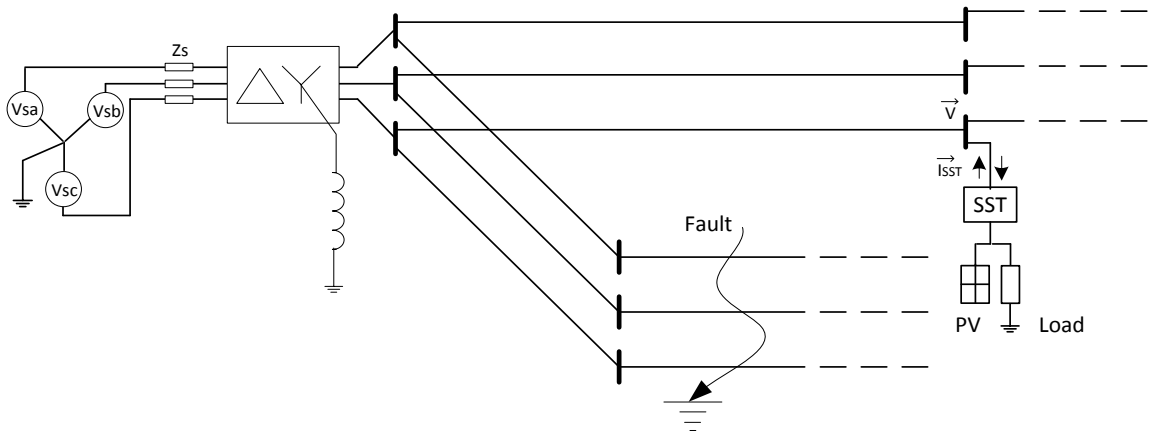
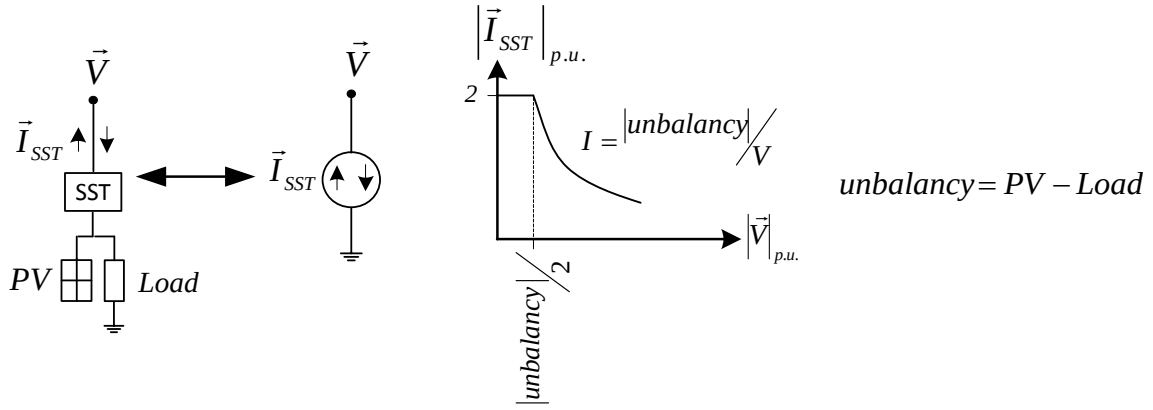


Figure 97: Green Hub II

Similar to the PV, the SST in combination with its corresponding PV and load can be modeled as shown in figure 98.



if unbalancy > 0: $\angle \vec{I}_{SST} = \angle \vec{V}$

if unbalancy < 0: $\angle \vec{I}_{SST} = -\angle \vec{V}$

Figure 98: SST model for fault analysis

By having this model, we can replace each SST with its corresponding PV and load connected to each bus by one current source as shown in figure 99:

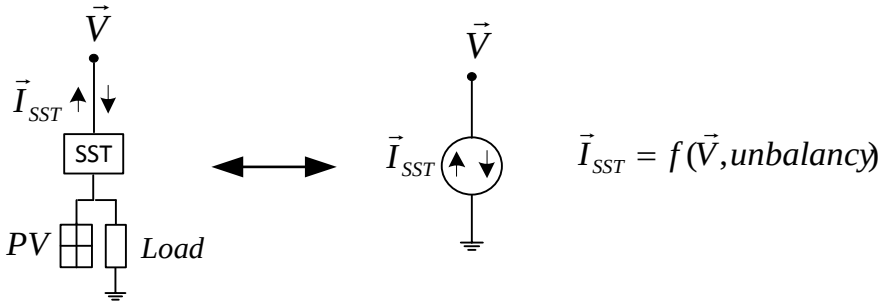


Figure 99: SST model for fault analysis

As known, the SSTs have under/over voltage protection on the high voltage DC cap. So we need to include this protection in our models. Figure 100 shows the power flow to/from the DC cap. P_1 is the power drawn from the power grid, P_2 is the power demanded by the load, and P_{dis} is the power discharged from the cap. So:

$$P_{dis} = P_2 - P_1 \qquad (7)$$

It is assumed that the controller of the SST rectifier stage is fast enough to react so that if the system voltage varies, the SST primary current settles to a new value within a cycle; therefore, we don't need to consider the transients of P_1 as they last for a few milliseconds. This will be more discussed on page 137.

$\Rightarrow W_{dis} = P_{dis} \times \Delta t$ where Δt is the passed time (8)

$\Rightarrow W_{new} = W_{old} - W_{dis}$ where W_{new} is the cap stored energy after the time Δt, and W_{old} is the cap stored energy before the time Δt (9)

W_{old} can initially be $W_{init} = \frac{1}{2}C(3800)^2$. If $W_{cap} < W_{Ulmt}$ or $W_{cap} > W_{Olmt}$, then SST shuts down.

W_{Ulmt} is $\frac{1}{2}C(2660)^2$ where 2660 is 70% of 3800 and W_{Olmt} is $\frac{1}{2}C(4560)^2$ where 4560 is 120% of 3800.

So this means that for a given period of time like Δt we can determine the new value of the stored energy in the DC cap and see if the SST should shut down or not.

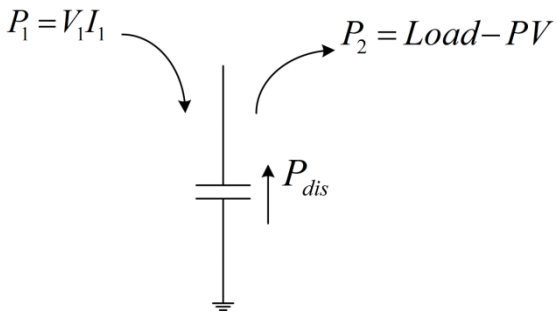


Figure 100: Power flow to/from the DC cap

The other formula that we need to know in our algorithm is the time at which the next SST will shut down assuming that the stored energy for all SSTs at the current time.

if $PV<Load$ *then* $W_{dis} = W_{cap} - W_{2660}$

if $PV>Load$ *then* $W_{dis} = W_{4560} - W_{cap}$

Since $P_{dis} = |P_2 - P_1|$, $t_{sd} = \frac{W_{dis}}{P_{dis}}$ where t_{sd} is the time takes for the SST to shut down. This calculation should be done for all SSTs and the minimum of them is the time at which the next SST will shut down.

Figure 101 shows the proposed algorithm for the fault analysis method of Green Hub II. As shown in this figure, similar to the proposed algorithm for Green Hub I, the algorithm starts calculating the SSTs' fault current contributions (I) and system bus voltages (V) by using an iterative method at t=0 (right after the fault). Then it emulates the SSTs' protections to find which SST at what time should disconnect. From there, it obtains Δt by finding the minimum of t_{sd}s calculated for all SSTs. The algorithm applies the SSTs' protections by making the current injections of the intended SST equal to zero. In the next step, the algorithm re-calculates the system bus voltages and the SSTs' fault current contributions at t=t2=t1+ Δt. This loop will be repeated until all SSTs, which are supposed to shut down, get disconnected. The MATLAB implementation of the proposed algorithm can be found in appendix IV.

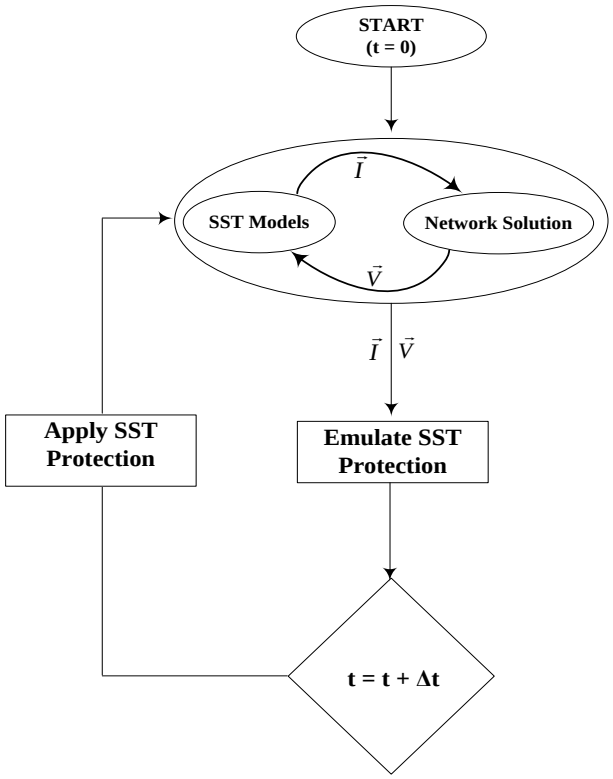


Figure 101: Proposed fault analysis algorithm for Green Hub II

It should be noted that SST's rectifier controller is designed to be fast enough to react within a cycle. Figure 102 shows the voltage and the current at the primary side of a SST. As shown in the figure, occurrence of a fault at t=1s decreases the voltage to 0.5pu. It takes less than a cycle for the rectifier stage to change the current to its new value. This means that we don't need to consider the transients while calculating the new operating points for SSTs.

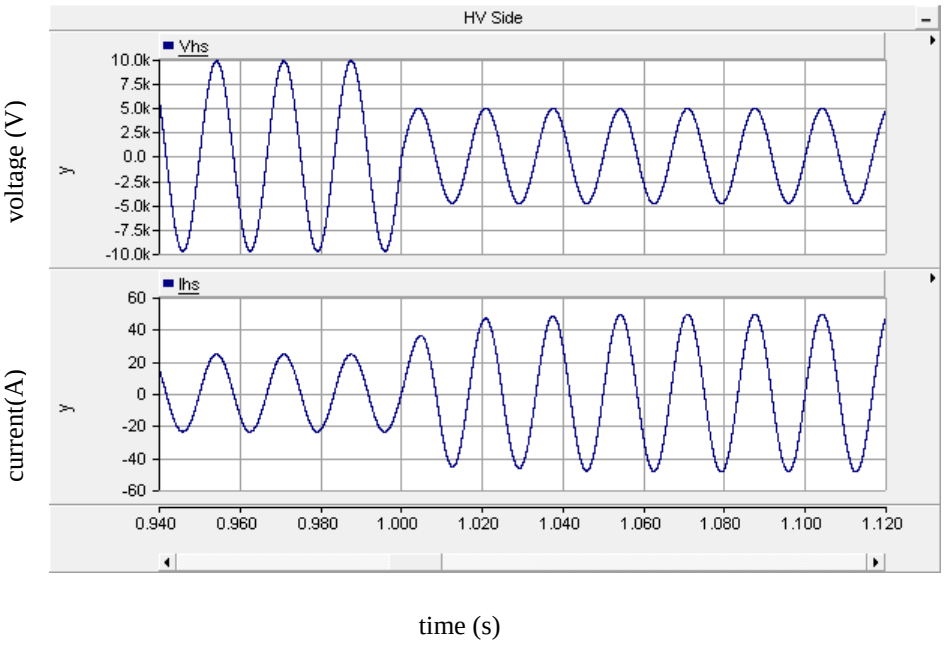


Figure 102: Primary voltage and current of a SST

Figures 103 to 106 compare the results from the implemented algorithm in MATLAB with the results from simulation for the breaker current while the fault is single-phase and three-phase.

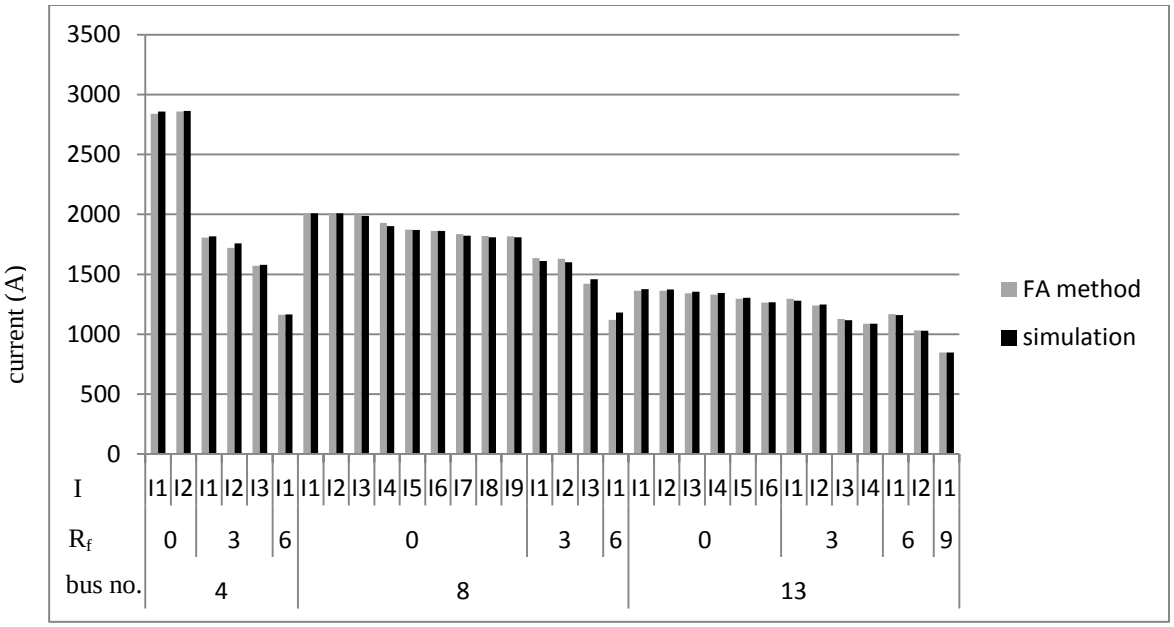


Figure 103: Breaker current levels for single phase faults

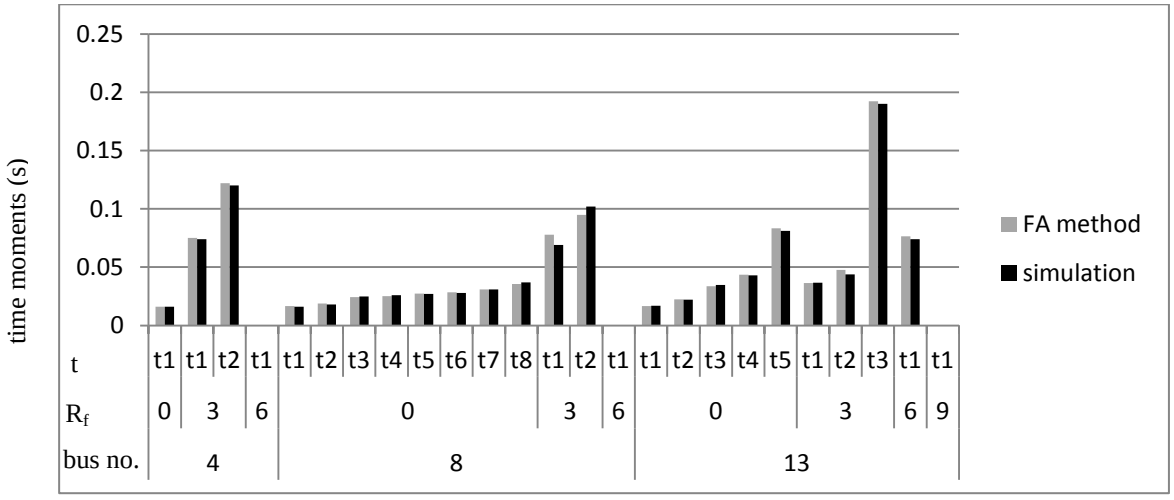


Figure 104: Time instants at which the breaker current changes level

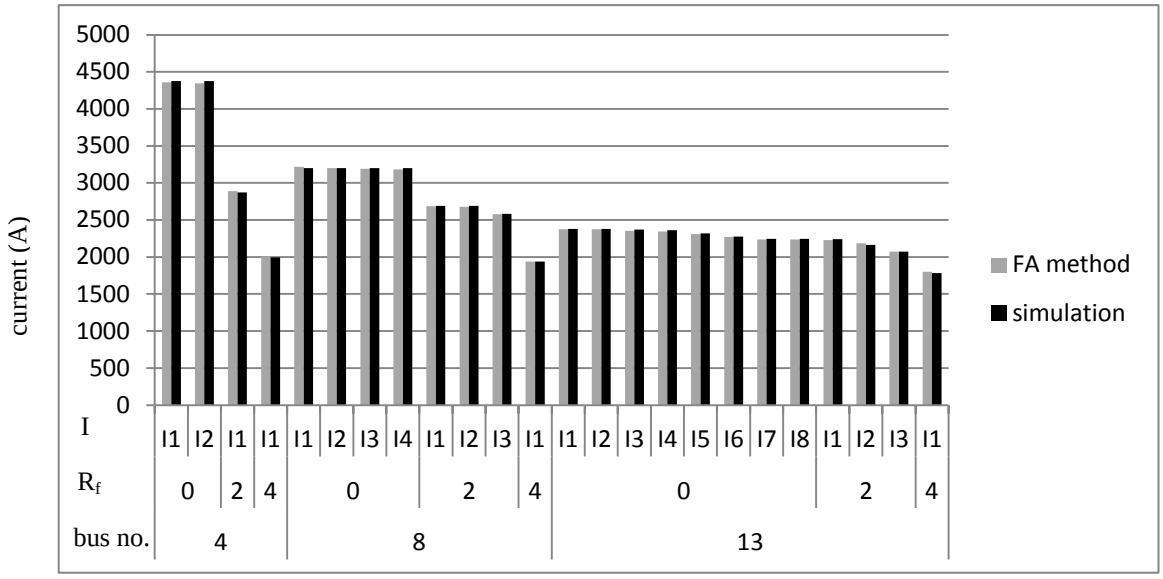


Figure 105: Breaker current levels for three phase faults

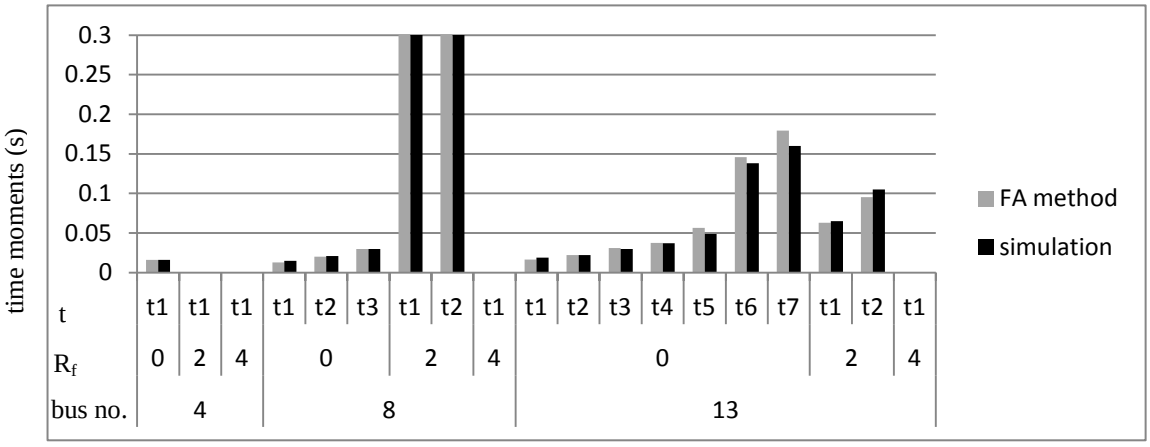


Figure 106: Time moments at which the breaker current changes level

For Green Hub II, the maximum error for the current levels is 5.88% and for the separation time moments is 7.25%. As shown in figures 103 to 106, the output of the algorithm is the values of the current levels and the time moments at which the current changes level.

ESTIMATION OF RELAY TRIP TIME IN GREEN HUBS

As discussed in the introduction, as the RMS value of the fault current varies in the Green Hubs, it's not possible to estimate the relay operating time by just using the inverse time-current curves; therefore it is required to develop a method to estimate the relay operating time in the Green Hubs.

Since the method that we are going to develop is dependent on the type of the relay, the method will be developed separately for electromechanical relays and digital relays.

ELECTROMECHANICAL RELAYS

Figure 107 shows the contacts of an electromechanical relay. The moving contact rotates the angular distance of φ in t_{trip} seconds which is unknown. Also, it has been assumed that the current changes from I_1 to I_2 at t_1 seconds. φ_1 and φ_2 are the angular distances that have been swept by I_1 and I_2, respectively. The φ follows the following equation [20]:

$$\varphi = k\left(M^2 - 1\right)t^2 \quad where \quad M = \frac{I}{I_{pickup}} \tag{10}$$

$$\Rightarrow \ \varphi = \varphi_1 + \varphi_2 = k\left(M_1^2 - 1\right)t_1^2 + k\left(M_2^2 - 1\right)\left(t_{trip} - t_1\right)^2 \tag{11}$$

On the other hand if we assume that whole φ has been swept by constant I_1 we can get to the following equation:

$\varphi = k\left(M_1^2 - 1\right)t_{trip1}^2$ where t_{trip1} can be obtained from the relay time-current curve (12)

Now by equating equation 11 with equation 12, we will have the followings:

$$k\left(M_1^2 - 1\right)t_{trip1}^2 = k\left(M_1^2 - 1\right)t_1^2 + k\left(M_2^2 - 1\right)\left(t_{trip} - t_1\right)^2 \ \Rightarrow \ t_{trip} = t_1 + \sqrt{\frac{\left(M_1^2 - 1\right)}{\left(M_2^2 - 1\right)}\left(t_{trip1}^2 - t_1^2\right)} \tag{13}$$

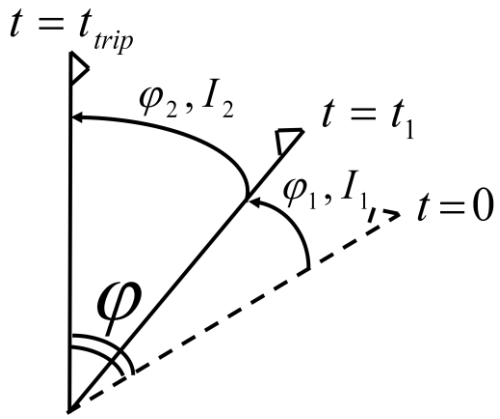


Figure 107: Contacts of an electromechanical relay

Following the same logic, equation 14 gets the relay trip time if the fault current changes *n* times from I_1 to I_n at t_1 to t_{n-1}.

$$t_{trip} = t_{n-1} + \sqrt{\frac{\left(M_1^2 - 1\right)\left(t_{trip1}^2 - t_1^2\right) - \sum_{k=2}^{n-1}\left[\left(M_k^2 - 1\right)\left(t_k - t_{k-1}\right)^2\right]}{\left(M_n^2 - 1\right)}} \tag{14}$$

DIGITAL RELAYS

Figure 108 shows the principles of a digital relay operation [21]. As shown, for a given fault current, the digital relay obtains the value of t_{trip} from the time-current curve. Then it construct a function with the value of $1/t_{trip}$. This function is integrated until the output of the integral becomes 1. This is the time when the relay sends the trip signal to the interrupting device.

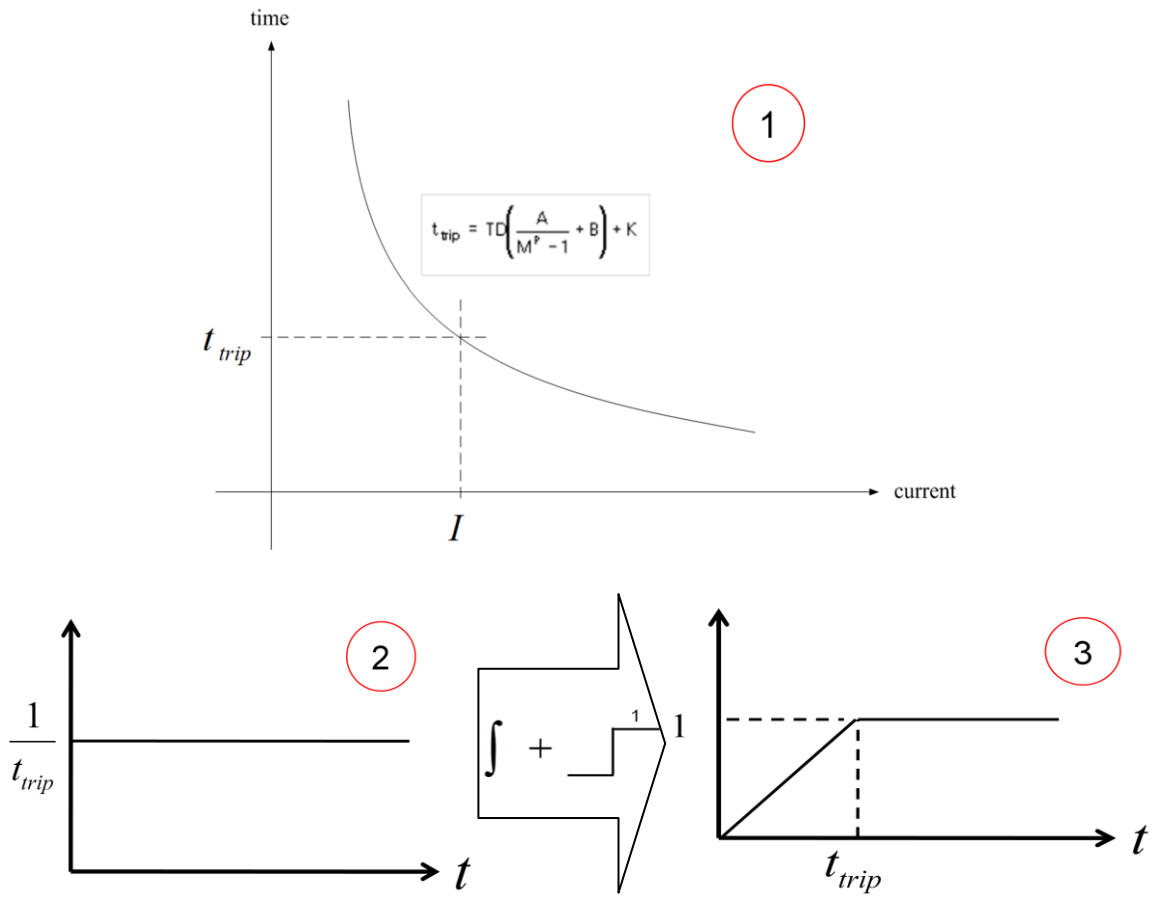


Figure 108: Principles of a digital relay operation

Following the same procedure, if the current changes from I_1 to I_2 at t_1, the relay constructs the function shown in figure 109.

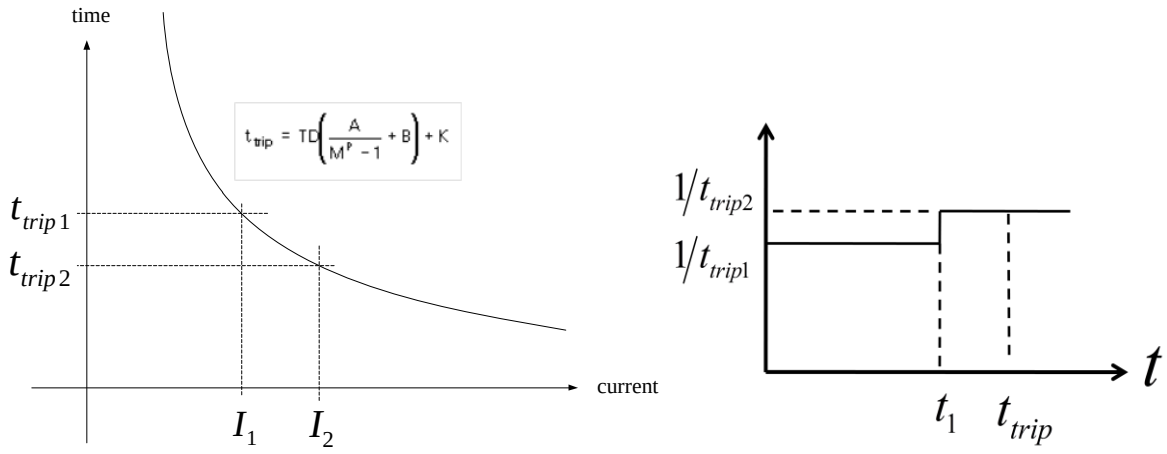


Figure 109: Digital relay operation when the fault current changes

By getting integral from the function shown in figure 109 and equating it to 1, we can obtain t_{trip}, as follows:

$$\frac{t_1}{t_{trip1}} + \frac{t_{trip} - t_1}{t_{trip2}} = 1 \Rightarrow t_{trip} = t_1 + t_{trip2} - t_1 \frac{t_{trip2}}{t_{trip1}} \quad (15)$$

Following the same logic, equation 14 gives the relay trip time if the fault current changes n times from I_1 to I_n at t_1 to t_{n-1}.

$$t_{trip} = t_{n-1} + t_{trip(n)} - \sum_{k=1}^{n-1}\left[t_{trip(n)} \frac{t_k - t_{k-1}}{t_{trip(k)}} \right] \quad , \quad t_0 = 0 \quad (16)$$

HOW TO USE THE OBTAINED EQUATIONS

Assuming that the fault current changes n times from I_1 to I_n at t_1 to t_{n-1}, we cannot simply use the equation 14 or 16, because the relay trip time is unknown. For example, the relay might trip on the second level of the fault current, so the rest of the information about the fault current levels or the separation time instants shall not be used. Figure 110 shows the

proposed algorithm. The MATLAB implementation of the proposed algorithm can be found in appendix IV.

Figures 111 to 114 compare the results from the implemented algorithm in MATLAB with the results from simulation for the breaker relay while the fault is single-phase and three-phase in both Green Hubs. The maximum error is 5.97%.

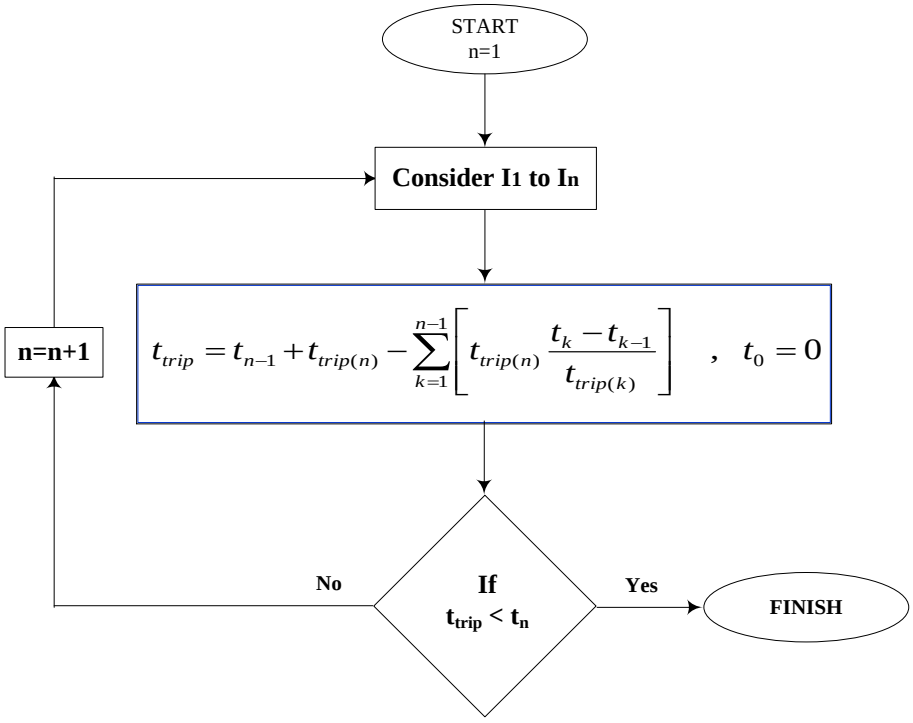


Figure 110: Method to calculate the relay trip time in Green Hubs

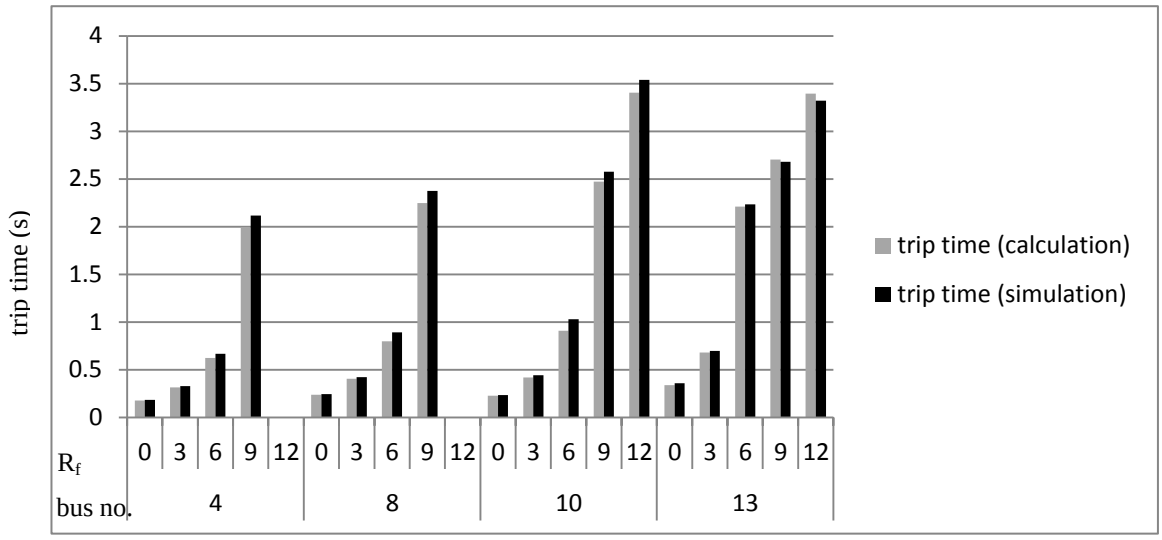


Figure 111: Breaker relay trip times for single-phase faults in Green Hub I

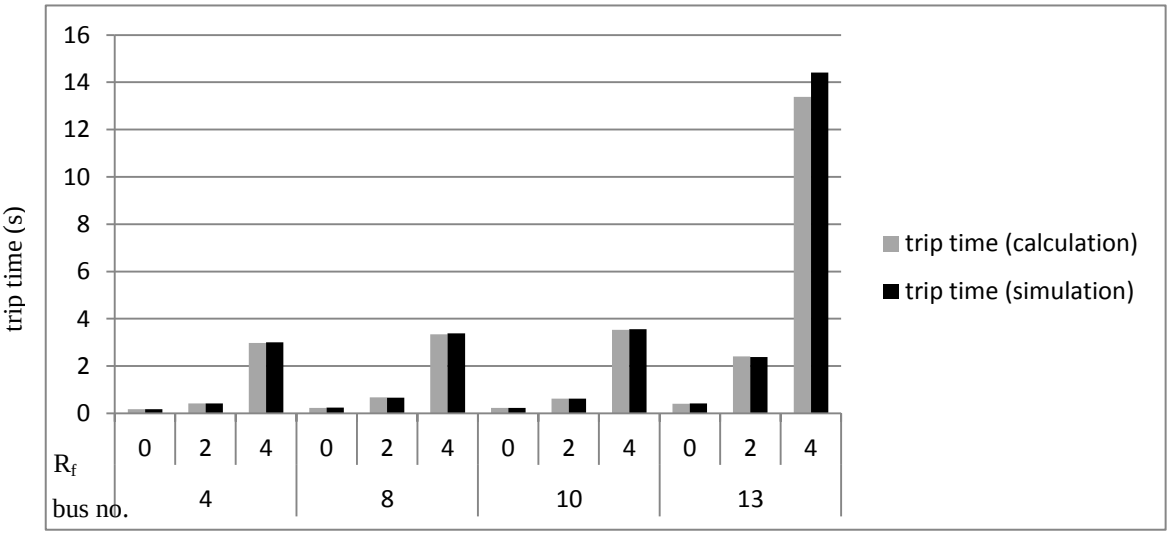


Figure 112: Breaker relay trip times for three-phase faults in Green Hub I

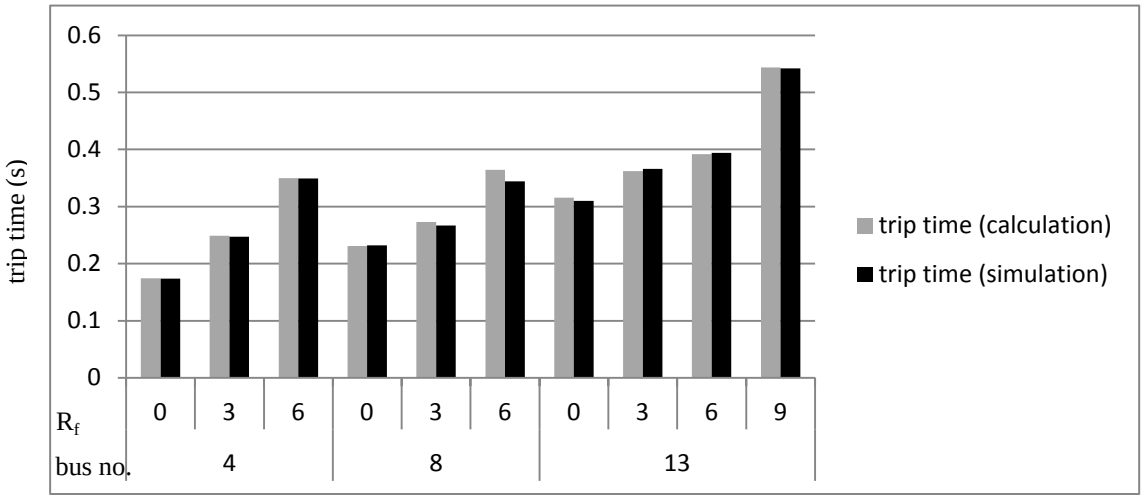


Figure 113: Breaker relay trip times for single-phase faults in Green Hub II

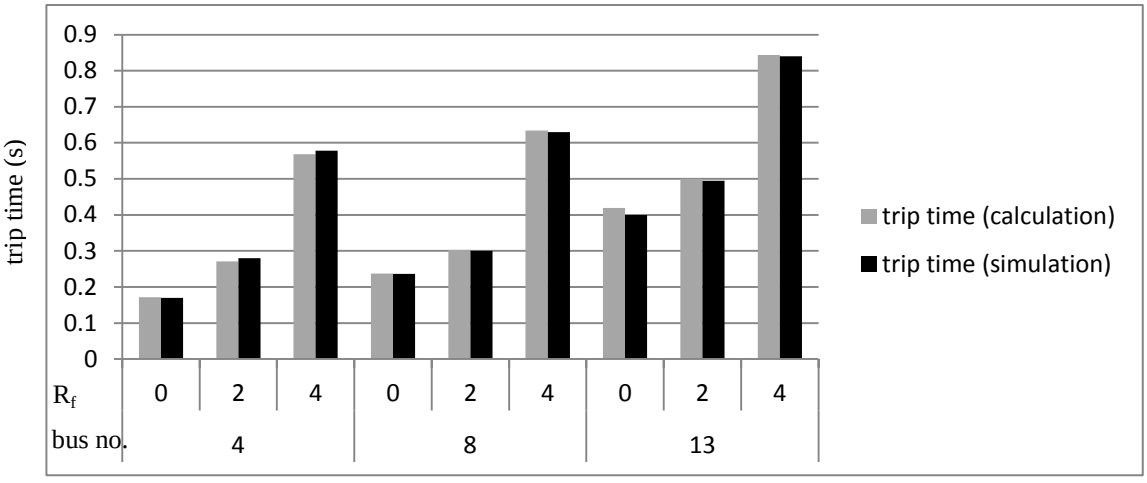


Figure 114: Breaker relay trip times for three-phase faults in Green Hub II

CHAPTER 5

GUIDELINES FOR DESIGN OF PROTECTION SCHEMES FOR GREEN HUBS

INTRODUCTION

As shown in chapter 3, PVs and SSTs have impacts on the reach and speed of the system protection. In this chapter, a set of guidelines is introduced to improve the conventional overcurrent protection so that it considers the mentioned impacts and works properly in the Green Hubs.

Since the maximum generation of each PV in the Green Hubs is equal to its corresponding maximum load, the feeders' currents at normal operation do not exceed the rated current of the devices. In other words, there won't be any impact on the rated current of the devices. Also, there won't be any impact on the rated voltage level of the devices. Therefore, in this chapter only the parameters that are related to fault interrupting such as fuse interrupting current, recloser pick-up current, recloser time dial settings, etc will be discussed. Other than those, the parameters such as nominal voltage, nominal current, etc will be the same as the conventional distribution system and won't be discussed in these solutions.

It is worth noting here that the traditional design for overcurrent protection can still be followed for the Green Hubs considering the presence of PVs and SSTs by using the proposed fault analysis method; however it is not recommended to follow the traditional design as it will not guarantee any specific reach or speed.

PROTECTION SCHEME FOR GREEN HUB I

BASICS

In this solution, it is assumed that our only degree of freedom is the settings of the relays and no other infra structure such as communication system is available.

For example, for a feeder like the feeder shown in figure 115, the pick-up current of the relay is set such that it is higher than twice the normal current and less than one third of the minimum fault current that flows through the protective device. Since according to the traditional guidelines, the minimum fault current is obtained by applying a bolted fault at the end of the feeder, the relay picks the faults with zero resistances as well as the faults with non-zero resistances. The R_{fmax} is the maximum fault resistance the relay can pick up and is associated with $I_{pick\text{-}up}$. In other words the feeder is protected against the faults up to R_{fmax} with a speed determined by the time-dial of the relay time-current curve. We want to improve the protection system so that the feeder is protected up to the same resistance with the same speed. So two issues have to be taken care of, reduction in reach and reduction in speed. Basically, reduction in reach occurs because the presence of PVs downstream of a PD makes the PD's R_{fmax}-associated current less than the I_{pickup}. In other words, $I_{withPVs}^{Rf\ \max} < I_{pickup}\left(I_{withoutPVs}^{Rf\ \max}\right)$. So if we know the value of $I_{withPVs}^{Rf\ \max}$ (by using our fault analysis method) then we can set the relay's new pick-up current equal to $I_{withPVs}^{Rf\ \max}$ so it picks up the fault with R_{fmax}.

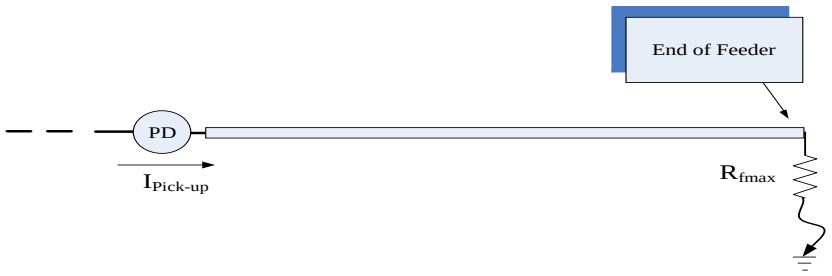


Figure 115: A feeder protected by the overcurrent protection scheme

This has to be done for all relays along the feeder by applying a fault with R_{fmax} considering the downstream PVs. As concluded in Chapter 3, on page 70:

- For the phase relays, the fault has to be at the end of the feeder as the PVs' effect is greater when the fault is at the farthest point from the PD.
- For the ground relays the fault should be applied at the beginning of the feeder as the PVs' effect is greater when the fault is at the closest point to the PD. Also if the PVs cause an increase in reach at the end of the feeder, then the PVs' reducing effect on reach can only be observed at the beginning of the feeder. However, it might happen that PVs cause an increase in reach even at the beginning of the feeder; then there's no need to calculate $I_{withPVs}^{Rf\ max}$. Such feeders can be recognized by calculating the value of the last level of the fault current flowing through the PD. If it is higher than the pick-up current, it means that the PVs cause an increase in reach; if not, it implies that the PVs cause a reduction in reach. Note that for ground relays R_{fmax} has to be translated to Rb_{fmax}. The definition of Rb_{fmax} has been described in figure 116.

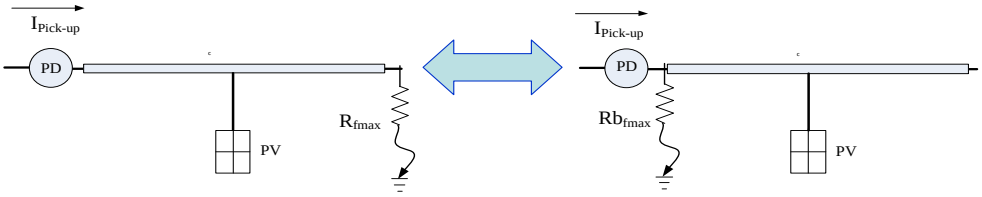


Figure 116: Definition of Rb_{fmax}

PROPOSED GUIDELINES

The following procedure has to be followed for phase relays:

1. Calculate $I_{withPVs}^{Rf\ max}$ for each PD considering the downstream PVs as shown in figure 117.

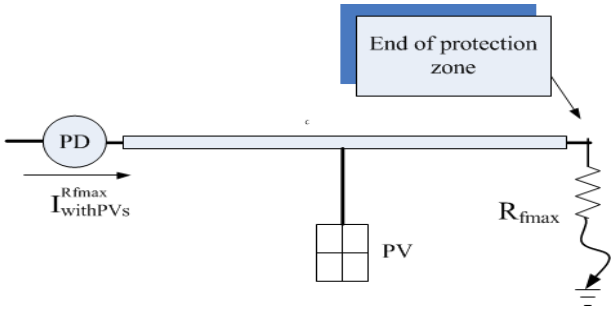


Figure 117: Calculation of new pick-up current for phase relays

2. Consider all limitations such as 2 times the PD's nominal current, etc.
3. If $IB_{withPVs}^{Rf\ max} < IR_{withPVs}^{Rf\ max}$ then $IB_{pickup}^{new} = IR_{pickup}^{new} = IB_{withPVs}^{Rf\ max}$ else

   $IB_{pickup}^{new} = IB_{withPVs}^{Rf\ max}$, $IR_{pickup}^{new} = IR_{withPVs}^{Rf\ max}$ (This is to ensure that the downstream PD is more sensitive than the upstream PD)

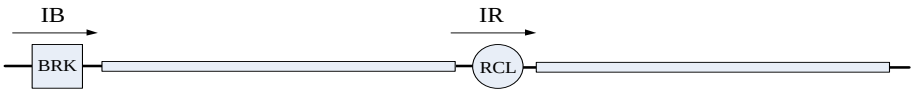


Figure 118: Protective devices on a feeder

4. Readjust the time-dials following the traditional method. There is no need to consider PVs at this step (As shown in Chapter 3, on pages 72 to 77, the PVs don't have any noticeable effect on the marginal time).

The following procedure has to be followed for ground relays:

1. For each PD, determine if the PVs cause a reduction in reach at the beginning of the feeder or not (as instructed on page 149). If yes, calculate $I_{withPVs}^{Rf\ \max}$ considering the downstream PVs as shown in figure 119; if not, keep the old pickup current as a candidate for the new one.

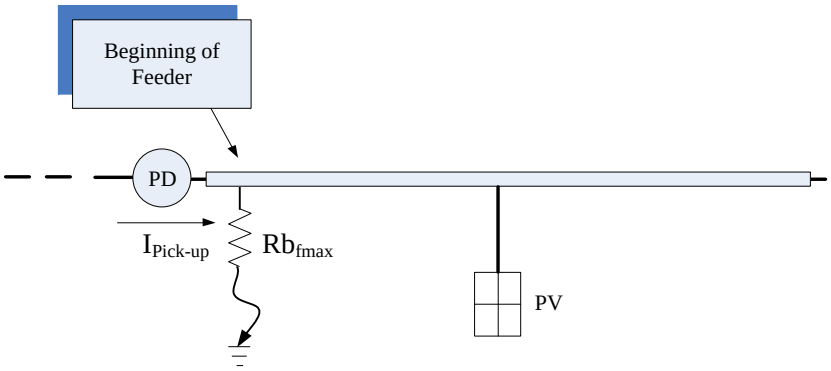


Figure 119: Calculation of new pick-up current for ground relays

2. Consider all limitations such as 2 times the PD's nominal current, etc.
3. If $IB_{withPVs}^{Rf\ \max} < IR_{withPVs}^{Rf\ \max}$ then $IB_{pickup}^{new} = IR_{pickup}^{new} = IB_{withPVs}^{Rf\ \max}$ else

   $IB_{pickup}^{new} = IB_{withPVs}^{Rf\ \max}$, $IR_{pickup}^{new} = IR_{withPVs}^{Rf\ \max}$
4. Readjust the time-dials following the traditional method. There is no need to consider PVs at this step. Note that the recloser ground relay should be coordinated with fuses.

APPLICATION TO OUR TEST CASE

Phase relays: We start from the recloser. The original I_{pickup} of the recloser is 1200A and the corresponding R_{fmax} is 4.75Ω located at the end of the feeder. $I_{withPVs}^{Rf\ max}$ of the recloser is 1126A which is higher than 2 times the feeder nominal current (83A).

The original I_{pickup} of the breaker relay is 1440A and the corresponding R_{fmax} is 4.15Ω located at the end of the branch which is not protected by the recloser. $I_{withPVs}^{Rf\ max}$ of the breaker is 1052A which is higher than 2 times the feeder nominal current (430A).

Since the $I_{withPVs}^{Rf\ max}$ of the breaker is lower than the $I_{withPVs}^{Rf\ max}$ of the recloser, the new pickup current for both devices is set to 1052A.

The time-dial of the breaker relay is changed from 1.1 to 1.4, so that it has the same marginal time with respect to the recloser as it had with the original settings at the maximum fault current flowing through both of them simultaneously (4329A).

Figure 120 compares the new time-current curves of the breaker and the recloser with the old ones. Figures 121 and 122 show the improvement index $\frac{(t_{GH} - t_{Con})}{t_{Con}}\%$ versus the fault resistance for the recloser and the breaker, respectively. As shown, the recloser has an increase in reach because the new pick-up current is lower than its $I_{withPVs}^{Rf\ max}$. Also, the breaker has the desired reach. The breaker reduction in speed is due to the increase in its time-dial to become coordinated with the breaker.

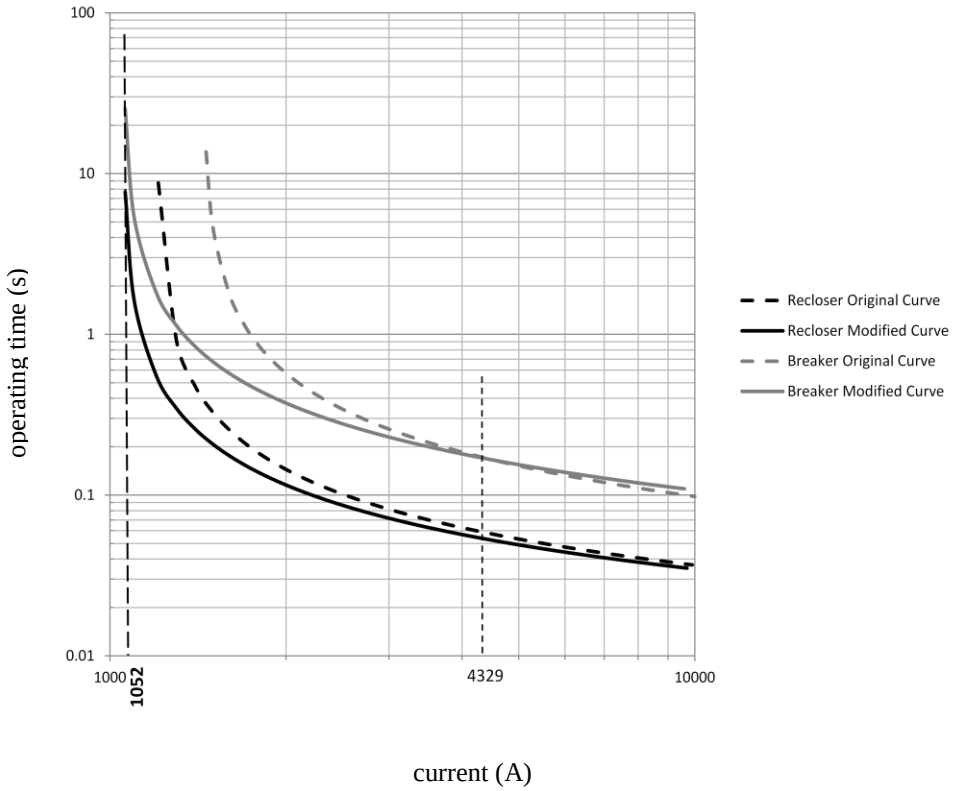


Figure 120: Time-current curves of the breaker and the recloser

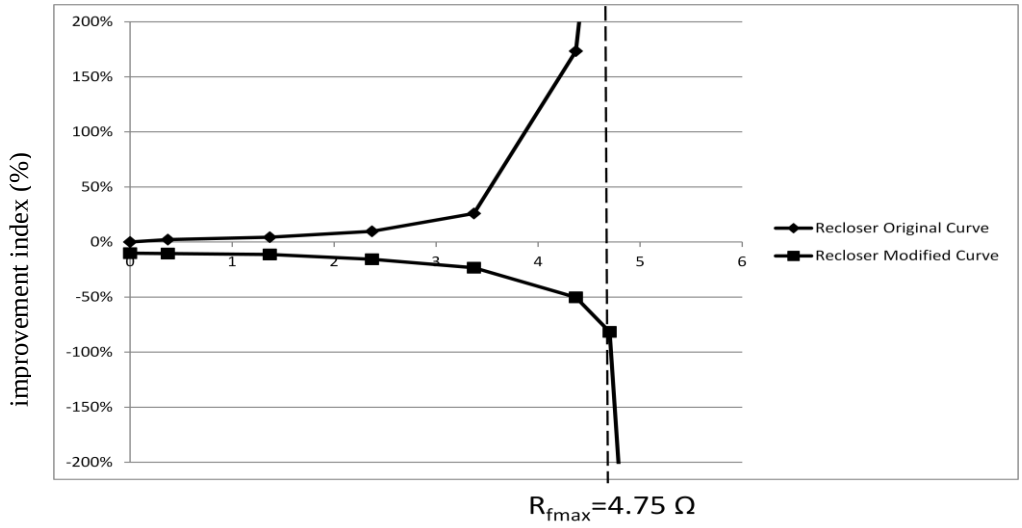


Figure 121: Recloser improvement with new settings

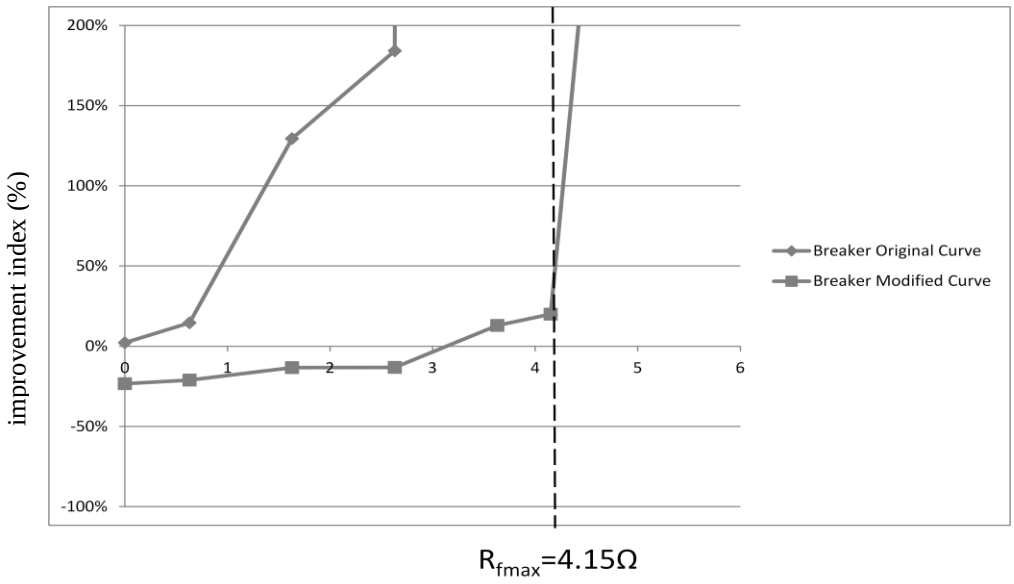


Figure 122: Breaker improvement with new settings

Ground relays: Again we start from the recloser. The original I_{pickup} of the recloser is 480A and the corresponding Rb_{fmax} is 11.2Ω located at the beginning of the feeder. Last level of the fault current flowing through the recloser for Rb_{fmax} is 514A, so the PVs do not cause any reduction in reach for the recloser.

The original I_{pickup} of the breaker relay is 480A and the corresponding Rb_{fmax} is 15.3Ω located at the beginning of the feeder. Last level of the fault current flowing through the recloser for Rb_{fmax} is 399A, so the PVs cause a reduction in reach for the breaker. $I_{withPVs}^{Rf\ max}$ of the breaker is 399A, however the pickup current should be higher than the maximum unbalance while one phase is disconnected (400A), so an appropriate candidate for the breaker new pickup can be 420A.

From what discussed, the new pickup current for both devices is set to 420A.

The time-dials of the recloser and the breaker relay is changed from 1.3 to 1.4 and from 1.8 to 2, respectively, to maintain the fuse-recloser-breaker coordination.

Figure 123 compares the new time-current curves of the breaker and the recloser with the old ones. Figures 124 and 125 show the improvement index $\frac{(t_{GH} - t_{Con})}{t_{Con}}\%$ versus the fault resistance for the recloser and the breaker, respectively. As shown, the recloser has an increase in both speed and reach, which is due to lowering the pickup current. Although the breaker reach is improved, it is still less than what it is supposed to be, which is because the breaker new pick-up current is higher than its $I_{withPVs}^{Rf\ \max}$.

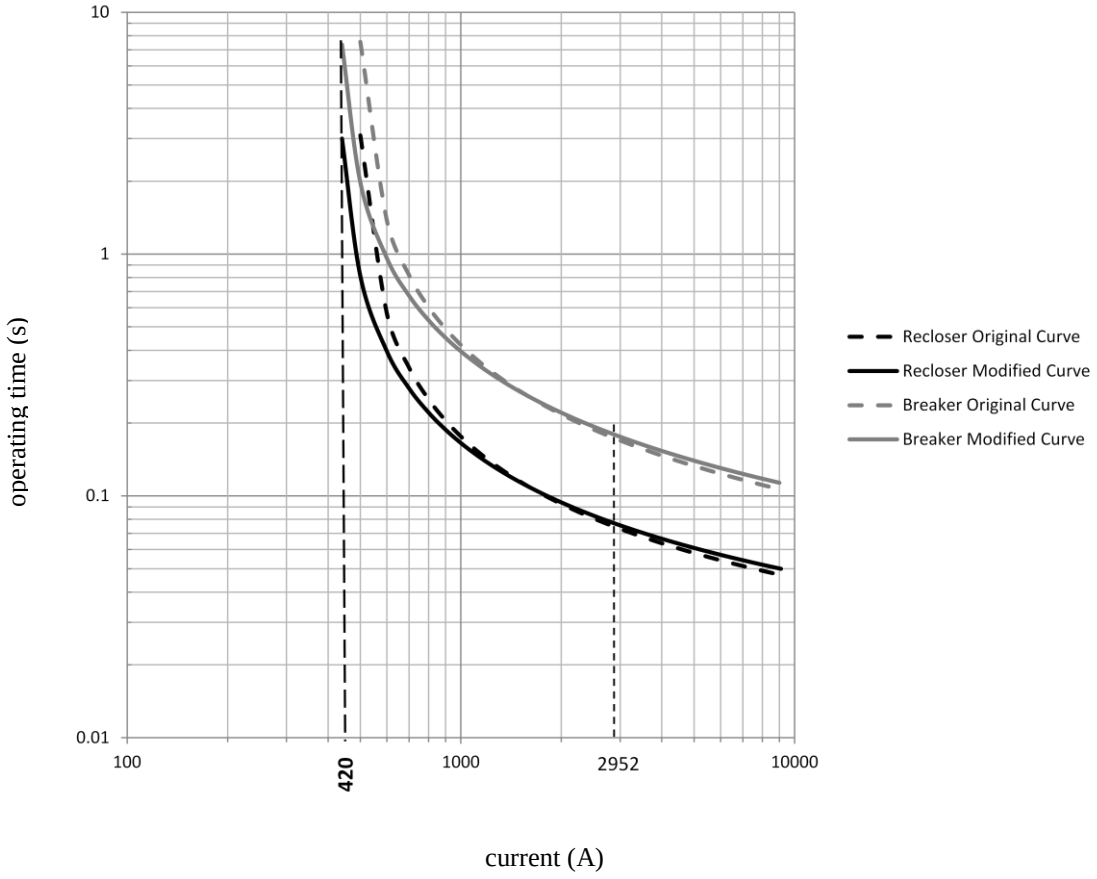


Figure 123: Time-current curves of the breaker and the recloser

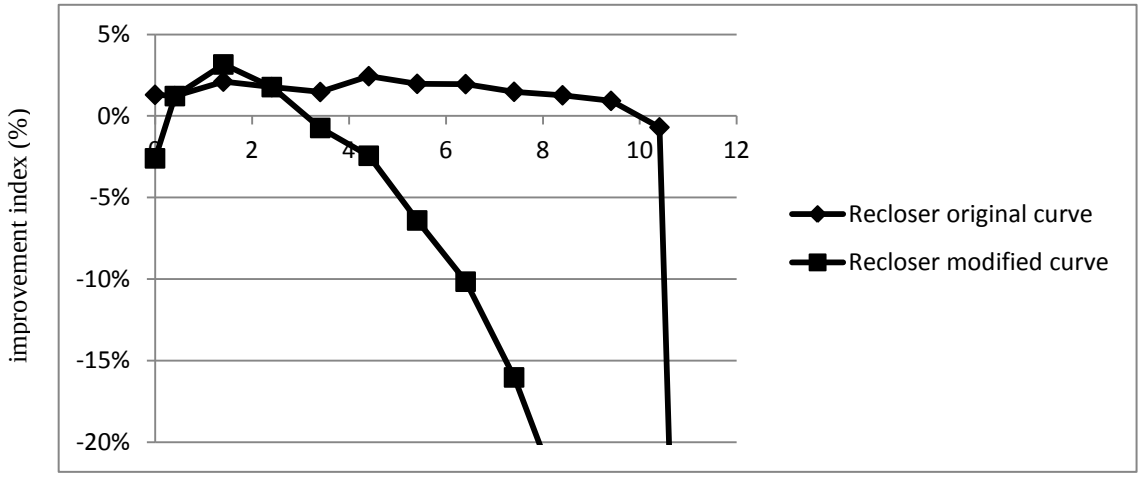


Figure 124: Recloser improvement with new settings

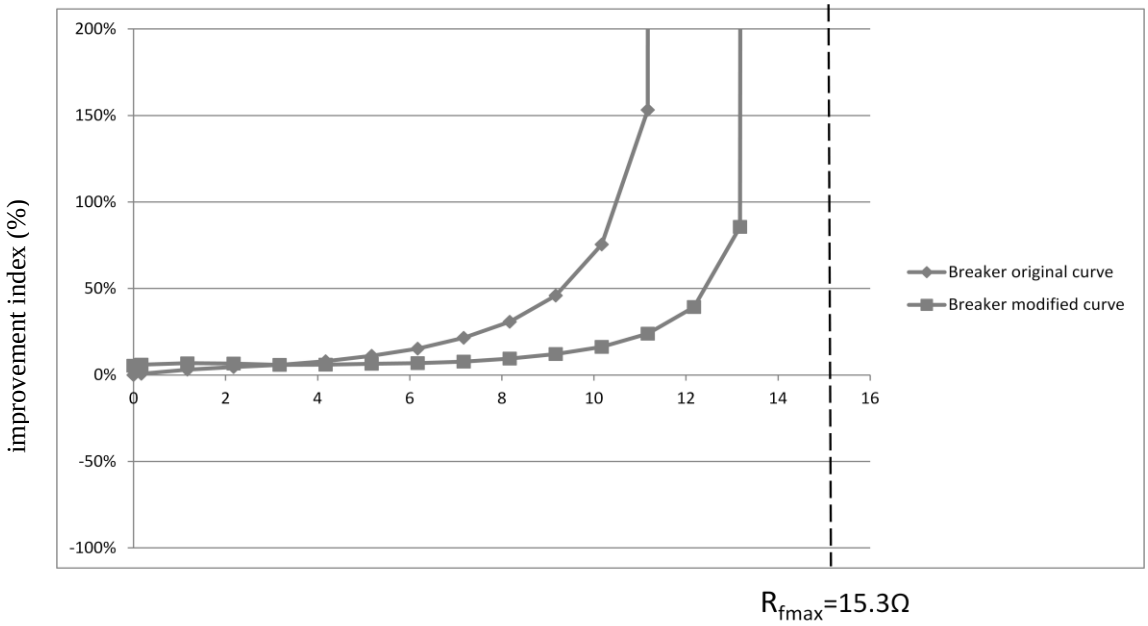


Figure 125: Breaker improvement with new settings

PROTECTION SCHEME I FOR GREEN HUB II

BASICS AND PROPOSED GUIDELINES

The same basics and solution adopted for Green Hub I have to be followed for Green Hub II; except that there is no need to check if the SSTs cause an increase in reach for single-phase faults at the beginning of the feeder or not, as this does not happen in Green Hub II.

APPLICATION TO OUR TEST CASE

Phase relays: Similar to Green Hub I, we start from the recloser. The original I_{pickup} of the recloser is 1200A and the corresponding R_{fmax} is 4.75Ω located at the end of the feeder. $I_{withPVs}^{Rf\ max}$ of the recloser is 1169A which is higher than 2 times the feeder nominal current (74A).

The original I_{pickup} of the breaker relay is 1440A and the corresponding R_{fmax} is 4.15Ω located at the end of the branch which is not protected by the recloser. $I_{withPVs}^{Rf\ max}$ of the breaker is 840A which is higher than 2 times the feeder nominal current (408A).

Since the $I_{withPVs}^{Rf\ max}$ of the breaker is lower than the $I_{withPVs}^{Rf\ max}$ of the recloser, the new pickup current for both devices is set to 840A.

The time-dial of the breaker relay is changed from 1.1 to 1.6, so that it has the same marginal time with respect to the recloser as it had with the original settings at the maximum fault current flowing through both of them simultaneously (4329A).

Figure 126 compares the new time-current curves of the breaker and the recloser with the old ones. Figures 127 and 128 show the improvement index $\frac{(t_{GH} - t_{Con})}{t_{Con}}\%$ versus the fault resistance for the recloser and the breaker, respectively. As shown, the recloser has an increase in reach because the new pick-up current is lower than its $I_{withPVs}^{Rf\ \max}$. Also, the breaker has the desired reach. The breaker reduction in speed is due to the increase in its time-dial to become coordinated with the breaker.

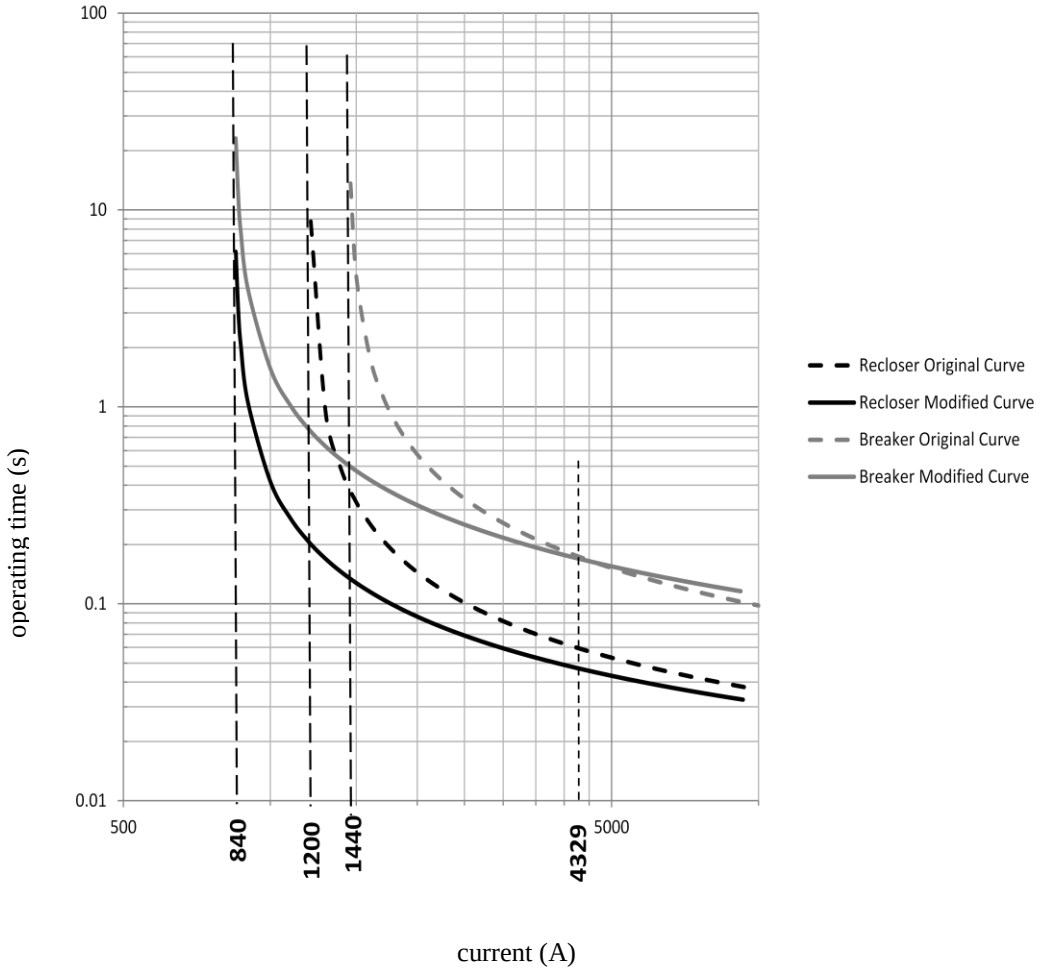


Figure 126: Time-current curves of the breaker and the recloser

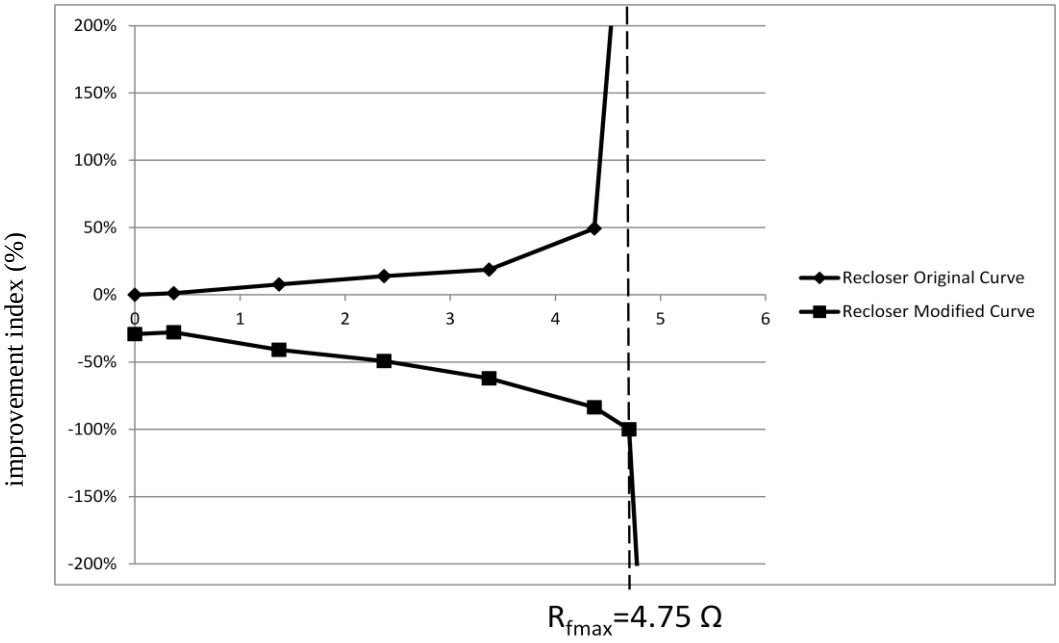


Figure 127: Recloser improvement with new settings

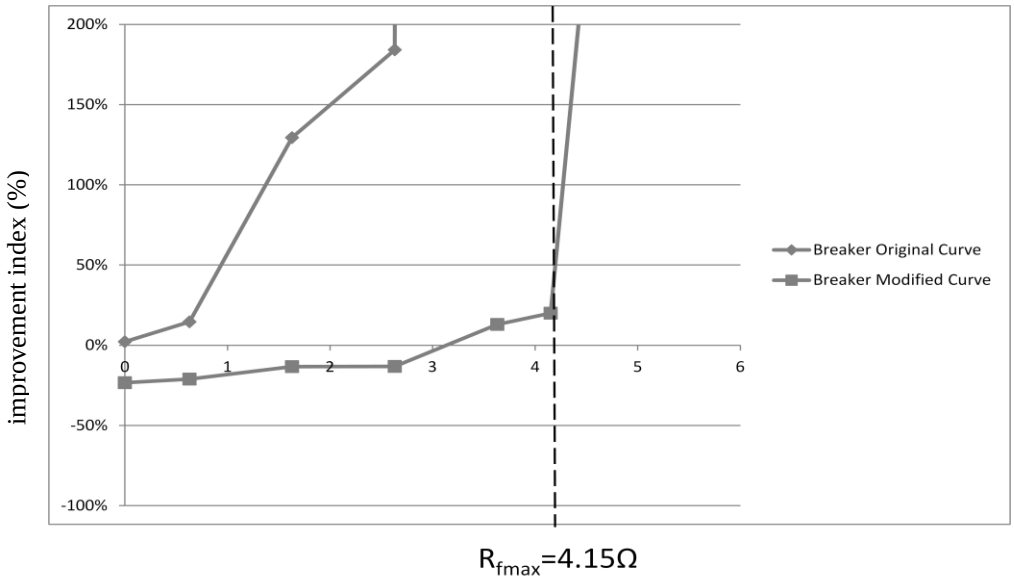


Figure 128: Breaker improvement with new settings

Ground relays: Again we start from the recloser. The original I_{pickup} of the recloser is 480A and the corresponding R_{fmax} is 11.2Ω located at the beginning of the feeder. $I_{withPVs}^{Rf\ max}$ of the recloser is 477A which is almost the same as the original pick-up current.

The original I_{pickup} of the breaker relay is 480A and the corresponding Rb_{fmax} is 15.3Ω located at the beginning of the feeder. $I_{withPVs}^{Rf\ max}$ of the breaker is 354A, however the pickup current should be higher than the maximum unbalance while one phase is disconnected (400A), so an appropriate candidate for the breaker new pickup can be 420A.

From what discussed, the new pickup current for both devices is set to 420A.

The time-dials of the recloser and the breaker relay is changed from 1.3 to 1.4 and from 1.8 to 2, respectively, to maintain the fuse-recloser-breaker coordination.

Figure 129 compares the new time-current curves of the breaker and the recloser with the old ones. Figures 130 and 131 show the improvement index $\frac{(t_{GH} - t_{Con})}{t_{Con}}\%$ versus the fault resistance for the recloser and the breaker, respectively. As shown, the recloser has an increase in reach because the new pick-up current is lower than its $I_{withPVs}^{Rf\ max}$. Although the breaker reach is improved, it is still less than what it is supposed to be, which is because the breaker new pick-up current is higher than its $I_{withPVs}^{Rf\ max}$.

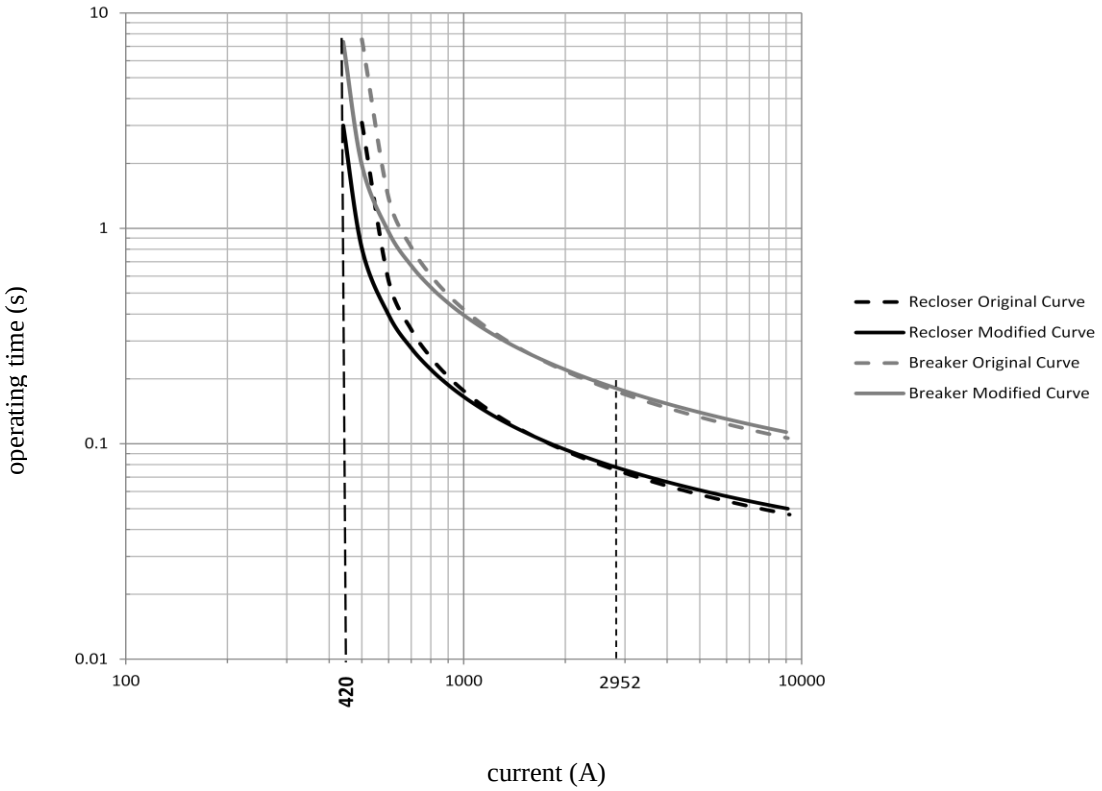


Figure 129: Time-current curves of the breaker and the recloser

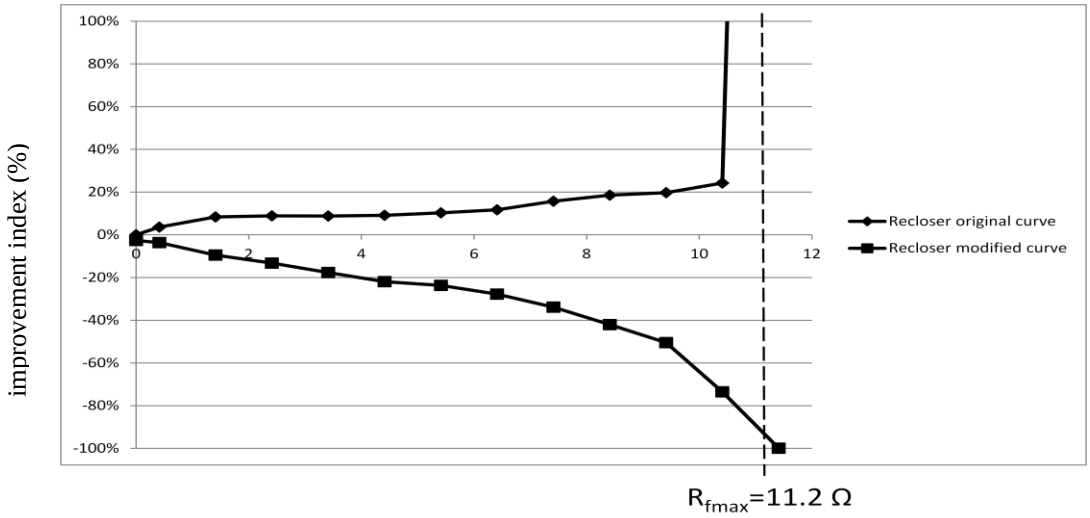


Figure 130: Recloser improvement with new settings

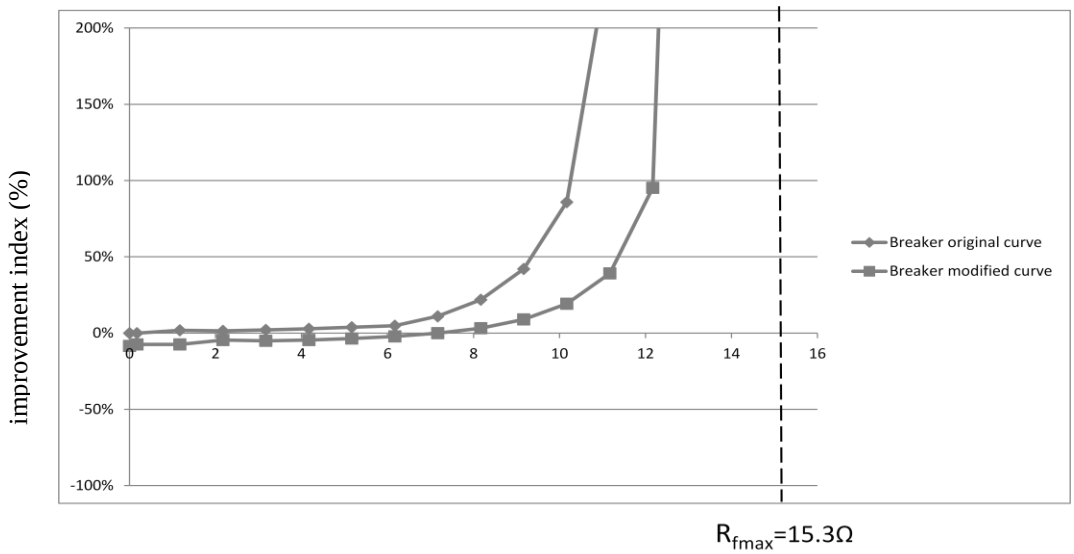


Figure 131: Breaker improvement with new settings

PROTECTION SCHEME II FOR GREEN HUB II

BASICS AND PROPOSED GUIDELINES

The most upstream PD is the most affected PD in the Green Hubs. This is because as the PD becomes closer to the substation, it will see more SSTs installed downstream of it. On the other hand, the highest nominal current belongs to the most upstream PD as it feeds all the consumers on the feeder. That's why in the previous solution, it was impossible to set the new pickup current equal to the $I_{withPVs}^{Rf\ \max}$.

Figure 132 describes a method to improve the solution I. As shown, the basic idea is to input $i_{BRK} - i_{RCL}$ to the breaker relay instead of i_{BRK}. As a result, if a fault occurs between the breaker and the recloser, the fault current seen by the relay is affected by only the SSTs located between the recloser and breaker. In other words, the effects of the SSTs, downstream of the recloser, are eliminated as shown below:

$$\vec{I}_{RLY} = \vec{I}_{BRK} = \vec{I}_f - \vec{I}_1 - \ldots - \vec{I}_n$$

$$\vec{I}_{RLY} = \vec{I}_{BRK} - \vec{I}_{RCL} = \vec{I}_f - \vec{I}_1 - \ldots - \vec{I}_n - \left(-\vec{I}_{m+1} - \ldots - \vec{I}_n\right) = \vec{I}_f - \vec{I}_1 - \ldots - \vec{I}_m$$

This will improve the reach and speed of the breaker. However, if a fault occurs in the recloser protection zone, the relay won't be able to sense the fault and act as a backup for the recloser; therefore the logic mentioned below has to be added before the breaker relay in order to select the relay input properly.

$$if \quad I_{RCL} > I_{Pickup} \quad i_{RLY} = i_{BRK} \quad else \quad i_{RLY} = i_{BRK} - i_{RCL}$$

It should be noted that this solution is a continuation of the solution I assuming that a communication link is available between the PDs.

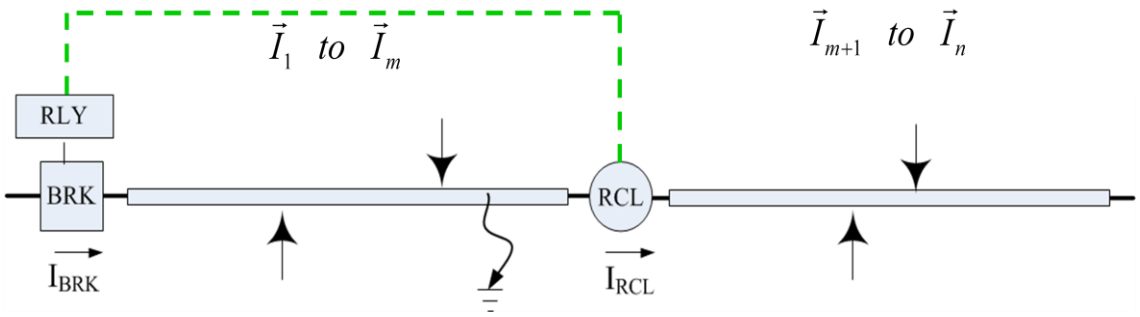


Figure 132: Solution II for Green Hub II

APPLICATION TO OUR TEST CASE

Figure 133 shows the breaker improvement on the speed and the reach of its ground relay with the communication link.

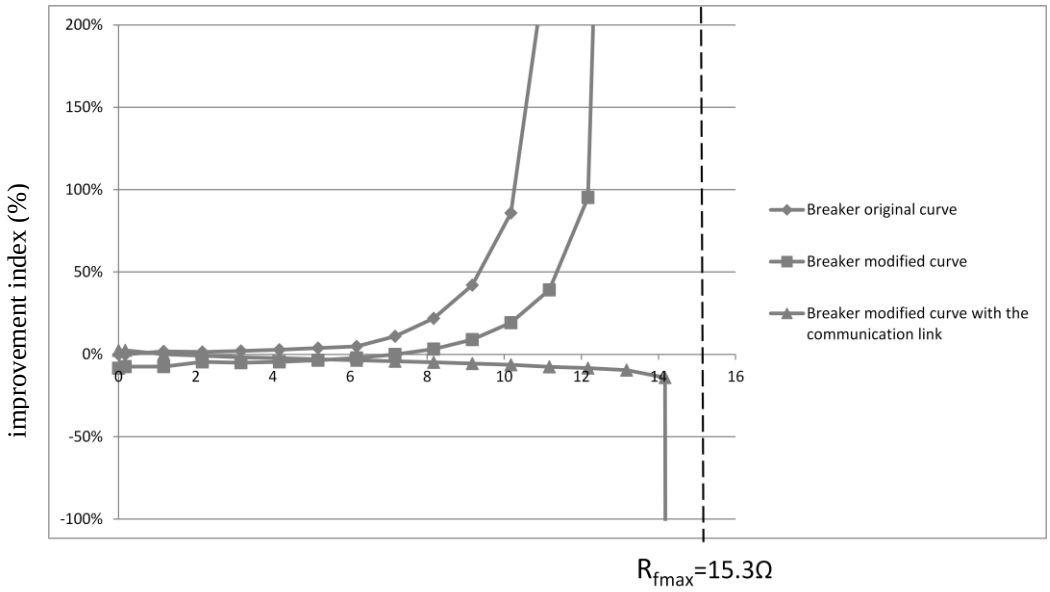


Figure 133: Breaker improvement with the communication link

PROTECTION SCHEME III FOR GREEN HUB II

BASICS AND PROPOSED GUIDELINES

This solution relies on a communication system which is capable of collecting instantaneous information on the SSTs' primary currents and transferring them to the PDs. Figure 134 describes the basic idea. By summing up the instantaneous information on the SSTs' primary currents, we can input the actual fault current into the PD's relay. It should be noted that in this solution, there's no need to change the original settings of the PDs' relays. Also, since all PDs' relays see the same i_f, the coordination is maintained.

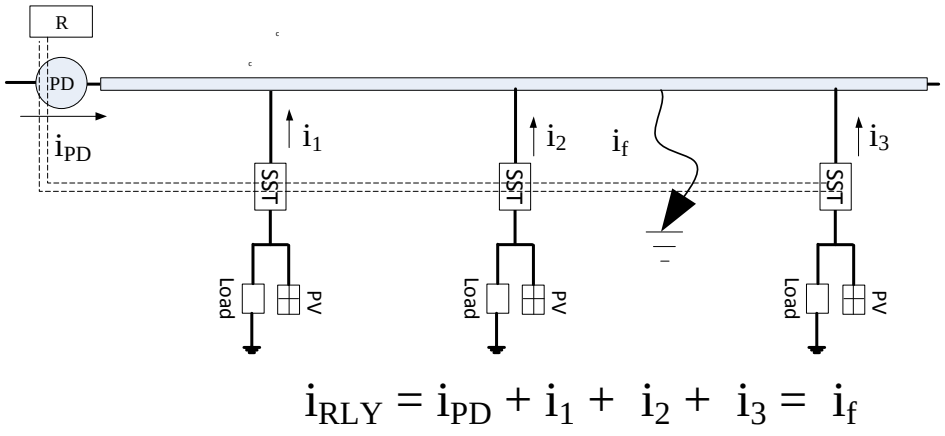


Figure 134: Basic idea of solution III for Green Hub II

Another issue to be addressed is that we don't want the proposed solution to occupy the communication system capacity all the time. Also, it should be coordinated with the fuses which protect the lateral; therefore it should run under the logic shown in figure 135. By using the proposed logic, the SSTs' current information is required for a short period of time starting from the moment when a fault occurs until the moment when the relay trips. Also,

the solution is coordinated with the fuses as it still uses the overcurrent scheme with the original settings.

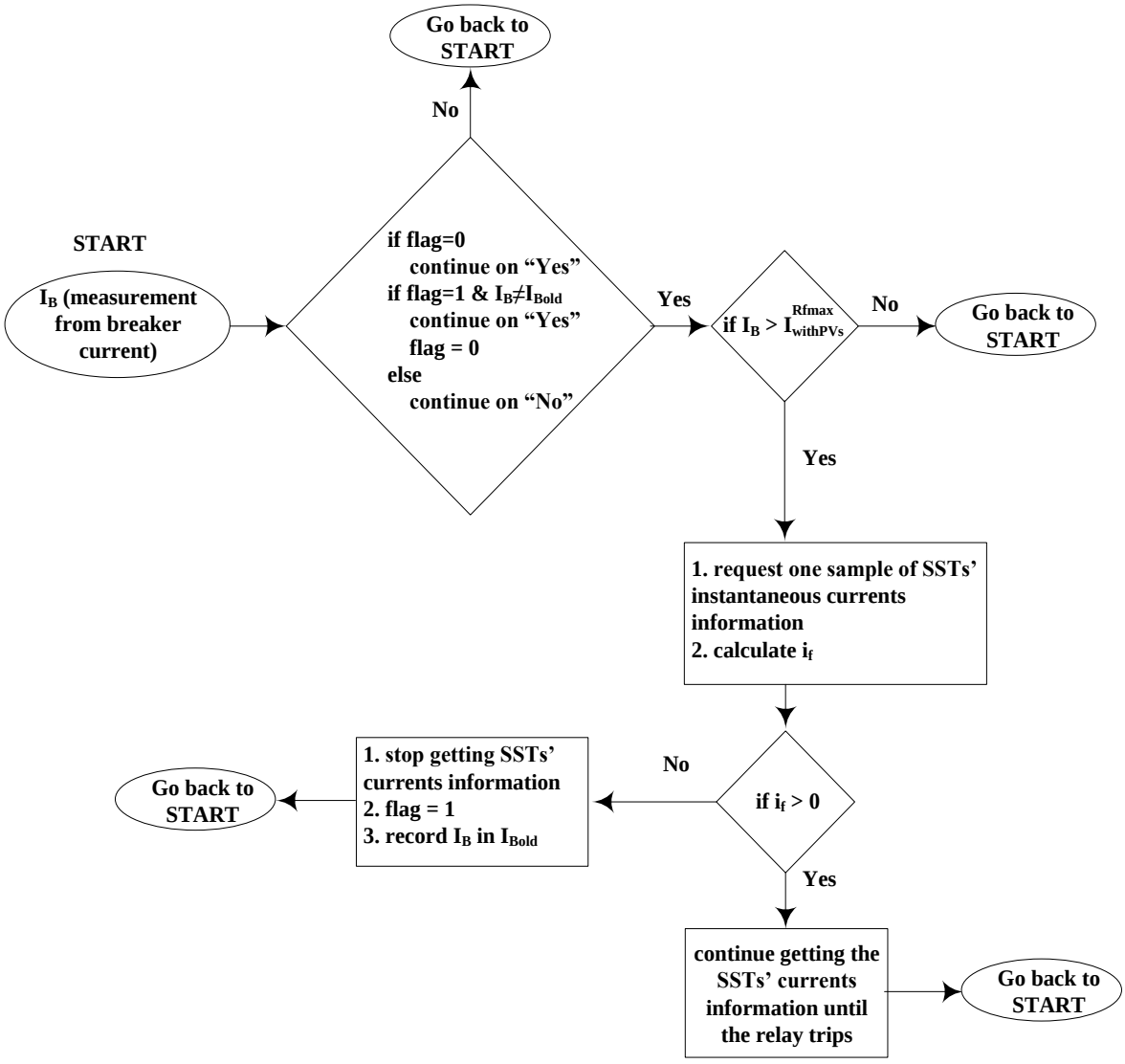


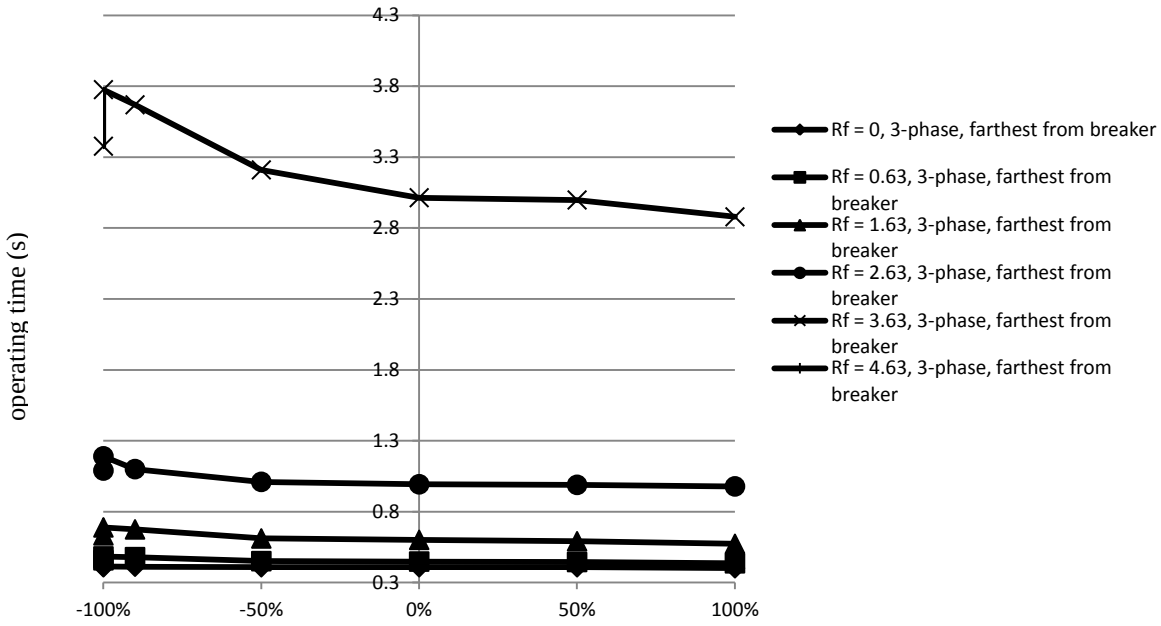
Figure 135: Flowchart of solution III for Green Hub II

APPLICATION TO OUR TEST CASE

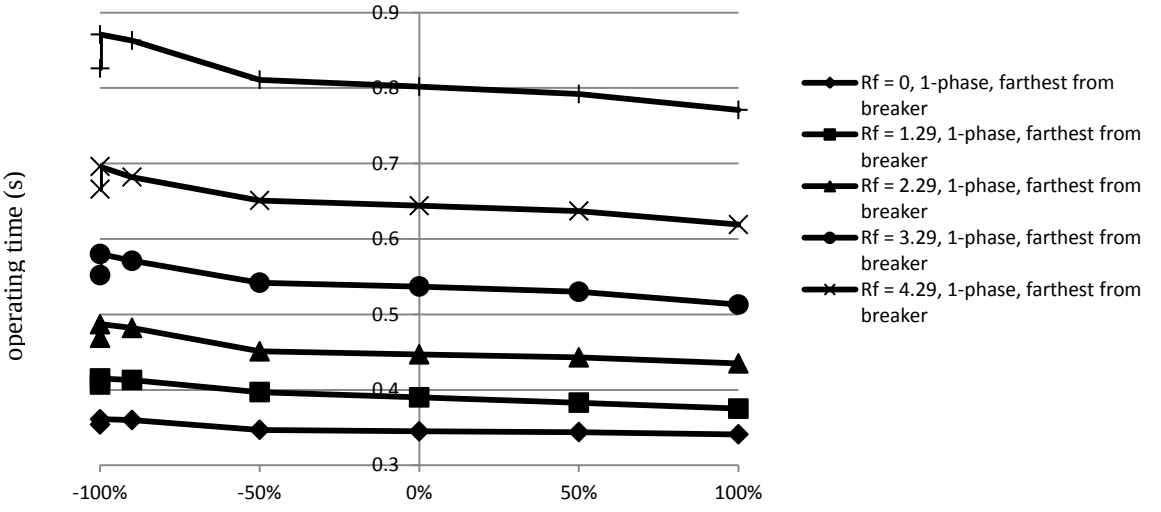
Figure 136 shows the operating time of the breaker for different values of PV/Load unbalance. As shown, the operating time for all PV/Load unbalance in the Green Hub II is

almost the same as the operating time in the conventional system. The small difference is due to the effect of the SSTs on the system voltage. SSTs' current drawing, which occurs for negative PV/Load unbalancies, decreases the system voltage and the fault current; therefore causing the PD to be a bit slower. On the other hand, SSTs' current injection, which occurs for positive PV/Load unbalancies, increases the system voltage and the fault current; thereby causing the PD to be a bit faster.

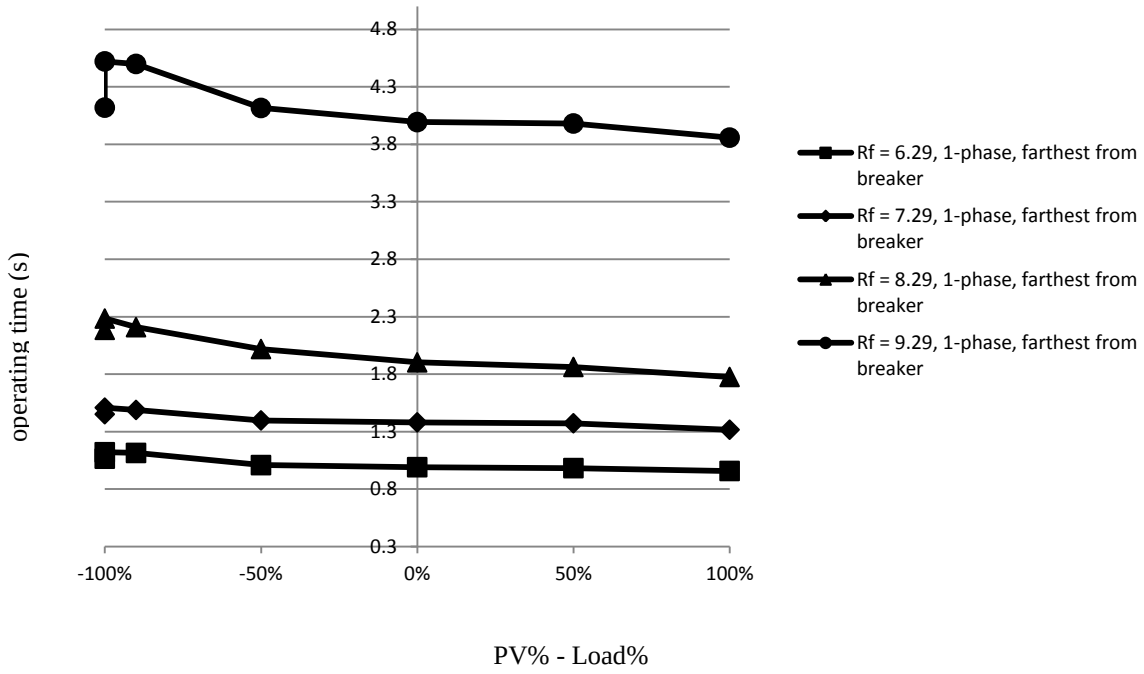
Figure 136: Breaker operating time vs. PV generation while the fault is at the farthest point from the breaker



PV% - Load%



PV% - Load%


operating time (s)
4.8
4.3
3.8
3.3
2.8
2.3
1.8
1.3
0.8
0.3
-100%
-50%
0%
50%
100%
PV% - Load%
Rf = 6.29, 1-phase, farthest from breaker
Rf = 7.29, 1-phase, farthest from breaker
Rf = 8.29, 1-phase, farthest from breaker
Rf = 9.29, 1-phase, farthest from breaker

CHAPTER 6

CONCLUSIONS AND FUTURE WORK

In this study, the protection issues on distribution systems with high penetration of residential Photovoltaic (PV) systems have been investigated. The protection issues and their significance in both conventional and SST-based distribution systems (Green Hubs) have been identified and explained with simulation results and analytical methods. It has been concluded that, in Green Hub I, the PVs downstream a protective device reduce its reach and speed; however, the upstream PVs do not have any noticeable effect. In Green Hub II, the SSTs downstream a protective device reduce/increase its reach and speed if PV>Load/PV<Load; however, similar to Green Hub II, the upstream SSTs do not have any noticeable effect. Also it has been shown that the PVs/SSTs do not hinder the coordination between protective devices. Reclosing and islanding issues have also been discussed and it has been shown that the PVs do not cause such problems; however, the SSTs should have reliable anti-islanding protection as, with a good PV/load balance, the SSTs stay online when the recloser opens.

It has been shown that traditional fault analysis methods do not work properly on these kind of distribution systems due to the current contributions from PVs/SSTs to the fault current. Also, the self-protection of PVs/SSTs cause the fault currents (flowing through the protective devices) to have a varying RMS value. Therefore, a new fault analysis method has been developed to calculate the current profile flowing through the PV/SST-penetrated distribution feeders in case of a fault occurrence. Also, a method has been developed to estimate the trip time of the overcurrent relays against the varying RMS fault currents.

To conclude the study, new guidelines for design of protection schemes for Green Hubs have been proposed. The basis of all the proposed schemes is the overcurrent protection scheme as we wanted to make use of the current relays and fuses as much as possible to make our schemes economically justified. The schemes were divided into two groups: non-communication-assisted and communication assisted. It has been shown that adjusting the setting of the existing relays, as instructed in the non-communication-assisted schemes, can improve the performance of the protection system; however, the improvement is limited on the performance of protective devices located at the beginning of the feeders as the amount of PV/SST installation downstream of them is too high to be handled by adjusting the relay settings. Therefore, communication-assisted schemes have been proposed to fully handle the effects of PVs/SSTs on all protective devices.

This study showed that the 100% PV penetration can still be handled.

For future work, more investigation needs to be performed in order to find cases in which the proposed fault analysis method might be unable to converge. Also, additional research needs to be done in order to enhance the SST control methods so that they can improve the performance of these protection schemes.

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APPENDICES

APPENDIX I – TEST CASE DISTRIBUTION SYSTEM

Tables 3 to 7 show the lengths of the line sections, the load ratings, the per length impedance of the feeders, and the substation specifications, the cap bank ratings, respectively.

Table 3: Lengths of the line sections

line section number	**line length (km)**	**line section number**	**line length (km)**
Ln1	7.141	Ln10	3.378
Ln2	4.37	Ln11	2.261
Ln3	0.356	Ln12	5.6913
Ln4	1.239	Ln13	0.239
Ln5	2.939	Ln14	2.089
Ln6	2.596	Ln15	2.819
Ln7	1.739	Ln16	0.883
Ln8	4.047	Ln17	3.17
Ln9	4.647		

Table 4: Load ratings

	phase A		**phase B**		**phase C**	
load number	**kW**	**kVAR**	**kW**	**kVAR**	**kW**	**kVAR**
Ld1	57.75	81.62	165.55	110.11	112.42	66.99
Ld2	532.07	273.35	734.83	364.99	338.8	173.25
Ld3	0	0	141	68	14.63	7.7
Ld4	20.02	10.01	10.01	1.54	85.47	43.12
Ld5	651.42	332.64	171.71	80.08	100.1	56.98
Ld6	544.39	278.74	56.98	29.26	254.1	120.12
Ld7	145.53	74.69	112.42	57.75	245.63	120.12
Ld8	597.52	304.92	510.51	253.33	733.81	386.54
Ld9	535.15	272.58	530.53	261.8	520.52	264.88
Ld10	32.725	28.028	25.564	26.334	50.743	34.804
Ld11	455.84	189.651	715.176	325.094	841.841	353.661
Ld12	235.081	112.959	207.438	98.945	196.119	93.709
Ld13	319.396	145.222	317.856	141.603	95.326	39.578
Ld14	15.862	8.701	0	0	0	0
Ld15	357.665	168.553	207.207	105.798	59.598	35.266
Ld16	499.576	232.617	424.424	187.957	846.461	364.133
Ld17	168.938	55.363	608.839	271.887	227.227	87.549

Table 5: Per length impedance of the feeders

R_0 (ohm/km)	0.112
R_1 (ohm/km)	0.021
L_0 (H/km)	0.0009
L_1 (H/km)	0.0002

Table 6: Substation specification

substation voltage	69kV/12kV
transformer capacity	30MVA
transformer winding type	delta/wye
transformer impedance	19%
neutral reactor	0.315 Ω

Table 7: Cap bank ratings

cap bank number	**kVAR/phase**
C1	400
C2	200
C3	400
C4	400

The breakers on both feeder 1 and 2 are equipped with Schweitzer relays. The following phrases summarize the specifications of the relays:

- Phase relaying, first operation: pickup current = 1440A, Schweitzer “U5” curve, time dial 1.1
- Phase relaying, last three operations: pickup current = 720A, Schweitzer “U3” curve, time dial 2.3
- Ground relaying, first operation: pickup current = 480A, Schweitzer “U5” curve, time dial 1.8

- Ground relaying, last three operations: pickup current = 360A, Schweitzer “U3” curve, time dial 4.0

The relays are programmed to have reclosing operations. Reclosing open intervals are set at 0.25s, 15s, 35s.

The reclosers are three phase ABB reclosers with the following specifications:

- Phase first operation: pickup current = 1200A, ABB PCD 2000 Short Time Inverse, time dial 0.9
- Phase last three operations: pickup current = 600A, ABB PCD 2000 Extremely Inverse, time dial 1.0
- Ground first operation: pickup current = 480A, ABB PCD 2000 Short Time Inverse, time dial 1.3
- Ground last three operations: pickup current = 240A, ABB PCD 2000 Extremely Inverse, time dial 3.0

Reclosers’ open intervals are 0.2s, 10s, 13s.

APPENDIX II – PV SYSTEM

The PV system has the following main modules:

a) PV array module: This module is composed of PV cell modules which are modeled based on the single-diode model [9]. The input of the module is the array output current value determined by the MPPT, and a specific solar insolation. It outputs the array output voltage and the corresponding DC power.

b) MPPT module: This module is a simple perturb and operate module which sets the PV array output current so that the maximum DC power can be derived from the array.

c) DC-DC boost converter module: This module increases the output voltage of the PV array to a certain voltage.

d) DC-AC inverter module: This module converts the DC power provided by the DC-DC converter into the grid utilizable AC power.

e) Protection module: This module disconnects the whole system from the grid if it detects grid abnormal voltage/frequency or being islanded. Table 8 summarizes the protection scheme [9].

Table 8: Protection system of PVs

		trip time
anti-islanding		immediately
grid voltage	V < 0.5pu	6 cycles
	0.5pu ≤ V < 0.88pu	120 cycles
	0.88pu ≤ V < 1.1pu	normal operation
	1.1pu ≤ V < 1.37pu	120 cycles
	1.37pu ≤ V	2 cycles
grid freq.	f < 59.3	6 cycles
	59.3 ≤ f ≤ 60.5	normal operation
	60.5 < f	6 cycles

Figure 137 shows the PV system implementation in PSCAD:

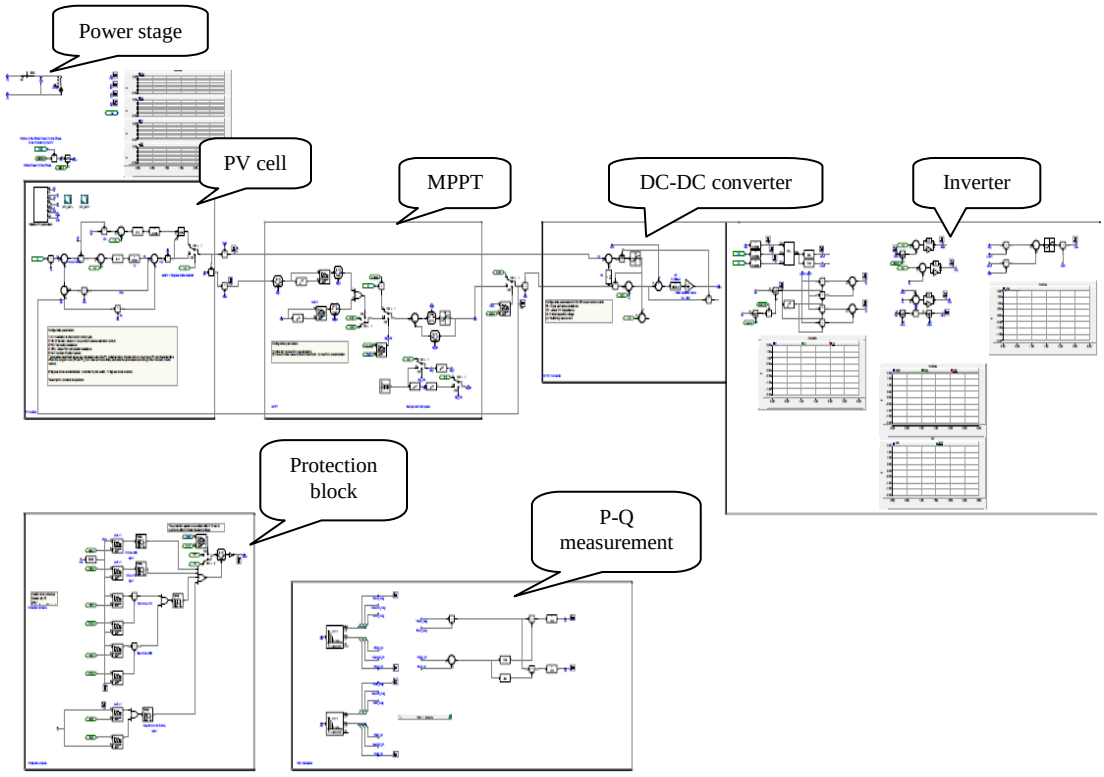

Figure 137: PV system implementation in PSCAD

APPENDIX III – SOLID STATE TRANSFORMER

Figures 138 and 139 show the SST topology and its implementation in PSCAD, respectively[12].

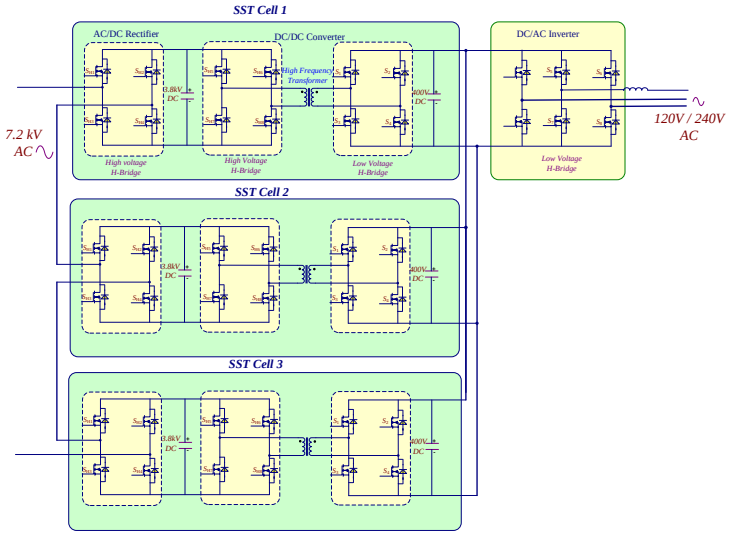

Figure 138: SST topology

The protection block shuts down the SST when the HVDC bus voltage become higher than 1.2 pu or less than 0.7 pu. The SST returns back online when the voltage on the primary side become within 0.8 – 1 pu for at least one cycle.

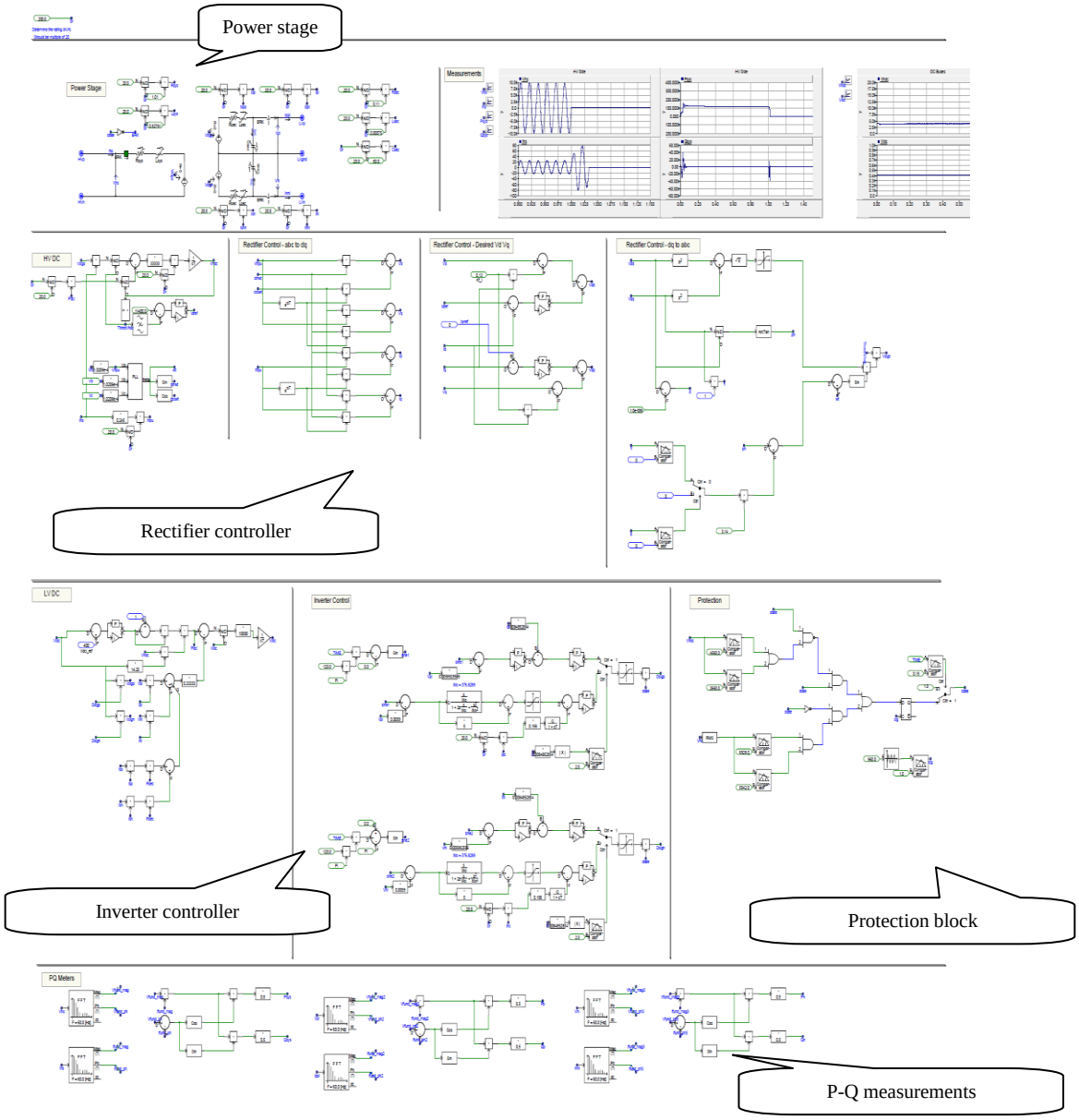

Figure 139: SST PSCAD implementation

APPENDIX IV – MATLAB IMPLEMENTATION OF FAULT ANALYSIS METHOD

GREEN HUB I – THREE PHASE FAULTS

INPUT

```
Sb = 100;

econv = 1e-3;

mxitr = 20;

% Bus no. 0 is located between the system voltage source and system
% impedance and will not be considered in the YBus matrix. The system
% voltage source and impedance will be converted to their Norton equivelant
% circuit.
%       Bus        PVa(MW)    PVb(MW)    PVc(MW)        Loada(MW)    Loadb(MW)    Loadc(MW)
Loada(MVAR)    Loadb(MVAR)    Loadc(MVAR)        kV(nom.)          kV(reg.)
bus =    [
        0          0          0          0             0            0            0                0
0              0                  230              230;
        1          0          0          0             0            0            0                0
0              0                  230              0;
        2          0          0          0             0            0            0                0
0              0                  12               0;
        3          0          0          0             0            0            0                0
0              0                  12               0;
        4          0.05775    0.16555    0.11242       0.05775      0.16555      0.11242
0.08162        0.11011        0.06699            12                0;
        5          0          0          0             0            0            0                0
0              0                  12               0;
        6          0.53207    0.73483    0.3388        0.53207      0.73483      0.3388
0.27335        0.36499        0.17325            12                0;
        7          0          0.141      0.01463       0            0.141        0.01463          0
0.068          0.0077             12               0;
        8          0.02002    0.01001    0.08547       0.02002      0.01001      0.08547
0.01001        0.00154        0.04312            12                0;
        9          0.65142    0.17171    0.1001        0.65142      0.17171      0.1001           -
0.06736       -0.31992       -0.34302           12                0;           % Cap bank at this
node each phase 0.4MVAR
        10         0.54439    0.05698    0.2541        0.54439      0.05698      0.2541
0.27874        0.02926        0.12012            12                0;
        11         0.14553    0.11242    0.24563       0.14553      0.11242      0.24563
0.07469        0.05775        0.12012            12                0;
        12         0.59752    0.51051    0.73381       0.59752      0.51051      0.73381
0.10492        0.05333        0.18654            12                0;           % Cap bank at this
node each phase 0.2MVAR
        13         0.53515    0.53053    0.52052       0.53515      0.53053      0.52052
0.27258        0.2618         0.26488            12                0;
        14         0.032725   0.025564   0.050743      0.032725     0.025564     0.050743
0.028028       0.026334       0.034804           12                0;
        15         0.45584    0.715176   0.841841      0.45584      0.715176     0.841841
0.189651       0.325094       0.353661           12                0;
        16         0.319396   0.317856   0.095326      0.319396     0.317856     0.095326         -
0.254778      -0.258397      -0.360422           12                0;           % Cap bank at this
node each phase 0.4MVAR
        17         0.015862   0          0             0.015862     0            0
0.008701       0              0                  12                0;
```

```
        18        0         0         0             0           0           0               0
0             0                12               0;
        19        0.357665  0.207207  0.059598      0.357665    0.207207    0.059598
0.168553      0.105798      0.035266          12               0;
        20        0.499576  0.424424  0.846461      0.499576    0.424424    0.846461
0.232617      0.187957      0.364133          12               0;
        21        0.168938  0.608839  0.227227      0.168938    0.608839    0.227227        -
0.344637     -0.128113     -0.312451         12              0;          % Cap bank at this
node each phase 0.4MVAR
        ];

% IsPD is 1 if the branch represents a protective device and 0 if not.
%       Fr        To        r1(p.u./km)   x1(p.u./km)   r0(p.u./km)   x0(p.u./km)
length(km)   IsPD
brnch = [
        0         1         7.7996e-4     0.010618      7.7996e-4     0.010618      1
0;       % Zs
        1         2         0.0863334     0.6553334     0.0863334     0.6553334     1
0;       % transformer
        2         3         6.9444e-4     0             6.9444e-4     0             1
1;       % breaker
        3         4         1.4738e-2     5.9408e-2     5.4123e-2     2.0972e-1     7.141
0;
        4         5         6.9444e-4     0             6.9444e-4     0             1
1;       % recloser
        5         6         1.4616e-2     6.1453e-2     9.0933e-2     2.6508e-1     4.37
0;
        6         7         1.4271e-2     6.1163e-2     9.0726e-2     2.6504e-1     0.356
0;
        7         8         1.4645e-2     6.4731e-2     8.3183e-2     2.3520e-1     1.239
0;
        4         9         1.4570e-2     6.1369e-2     7.9149e-2     2.4313e-1     2.939
0;
        9         10        1.4678e-2     6.1509e-2     7.8843e-2     2.4338e-1     2.596
0;
        10        11        1.4608e-2     6.1353e-2     7.7840e-2     2.4416e-1     1.739
0;
        11        12        1.4527e-2     6.2053e-2     7.3442e-2     2.3718e-1     4.047
0;
        12        13        1.4604e-2     6.1460e-2     6.3490e-2     2.3085e-1     4.647
0;
        2         14        2.9037e-2     8.4174e-2     8.7871e-2     2.8265e-1     3.378
0;
        14        15        2.9408e-2     8.4976e-2     1.1812e-1     2.9863e-1     2.261
0;
        15        16        2.5045e-2     6.9389e-2     1.0283e-1     2.5542e-1     5.6913
0;
        15        17        1.1989e-1     1.6754e-1     8.8843e-1     3.0895e-1     0.239
0;
        17        18        2.8313e-2     7.7376e-2     1.1835e-1     2.9139e-1     2.089
0;
        14        19        2.8645e-2     8.3402e-2     8.3272e-2     2.7862e-1     2.819
0;
        19        20        2.8707e-2     8.3208e-2     8.7784e-2     2.8041e-1     0.883
0;
        20        21        2.8742e-2     8.2511e-2     1.1577e-1     2.9261e-1     3.17
0;
        ];

% The type information will not be used in the calculations.
% The resistance cannot be zero but can be close to zero.
% type=3 for three-phase faults, type=1 for single-phase faults
%       Bus       resistance(ohm)   type
fault = [
        13         1                3;
        ];
```

```
% The neutral reactor connected to the neutral of the Y side of the transformer.
ntrlReactor = 120 * pi * 8.3556e-4;

% Time at which the current is calculated.
tSim = 3;
```

METHOD IMPLEMENTATION

```
%% Version 1.11:
    % - This version is based on nodal analysis.
    % - Works for three-phase faults with arbitrary resistance.
    % - The distribution system is Green Hub I.
    % - The PVs can be unbalanced three-phase sources. (PVa~=PVb~=PVc)
    % - The PVs are works at their rating (maximum generation = maximum solar radiation).
    % - The calculated values of currents and voltages are associated with the moments right
after the fault before the PVs' protections trip.
    % - This version considers the load effects on the fault currents.
    % - This version can calculate currents in times other than 0.


%% Input Area
clc;
clear;

a = -0.5 + (sqrt(3)/2)*1i;

FAinputV1_11;    % Read the input file

%% Seperate the bus data into columns
BusNo = bus(:, 1);
PVa = 0*bus((2:end), 2) ./ (Sb/3);  % Per unit values of PVs' powers on phase A, row 1 is
assossiated with bus 0 and should be eliminated.
PVb = 0*bus((2:end), 3) ./ (Sb/3);  % Per unit values of PVs' powers on phase B, row 1 is
assossiated with bus 0 and should be eliminated.
PVc = 0*bus((2:end), 4) ./ (Sb/3);  % Per unit values of PVs' powers on phase C, row 1 is
assossiated with bus 0 and should be eliminated.
LoadaP = bus((2:end), 5) ./ (Sb/3);  % Per unit values of Loads' active powers on phase A,
row 1 is assossiated with bus 0 and should be eliminated.
LoadbP = bus((2:end), 6) ./ (Sb/3);  % Per unit values of Loads' active powers on phase B,
row 1 is assossiated with bus 0 and should be eliminated.
LoadcP = bus((2:end), 7) ./ (Sb/3);  % Per unit values of Loads' active powers on phase C,
row 1 is assossiated with bus 0 and should be eliminated.
LoadaQ = bus((2:end), 8) ./ (Sb/3);  % Per unit values of Loads' reactive powers on phase A,
row 1 is assossiated with bus 0 and should be eliminated.
LoadbQ = bus((2:end), 9) ./ (Sb/3);  % Per unit values of Loads' reactive powers on phase B,
row 1 is assossiated with bus 0 and should be eliminated.
LoadcQ = bus((2:end), 10) ./ (Sb/3);  % Per unit values of Loads' reactive powers on phase C,
row 1 is assossiated with bus 0 and should be eliminated.
PVa = [PVa(1:13); zeros(8,1)];
PVb = [PVb(1:13); zeros(8,1)];
PVc = [PVc(1:13); zeros(8,1)];
kVNom = bus(:, 11);
kVReg = bus(:, 12);

%% Seperate the branch data in columns
From = brnch(:, 1);
To = brnch(:, 2);
r1OfBranches = brnch(:, 3) .* brnch(:, 7);  % Per unit values of r1s of branches
x1OfBranches = brnch(:, 4) .* brnch(:, 7);  % Per unit values of x1s of branches
r0OfBranches = brnch(:, 5) .* brnch(:, 7);  % Per unit values of r0s of branches
x0OfBranches = brnch(:, 6) .* brnch(:, 7);  % Per unit values of x0s of branches
ntrlReactor = ntrlReactor /(kVNom(3)*kVNom(3)/Sb);  % Neutral reactor should be per-united.
IsPD = brnch(:, 8);
```

```
%% Seperate the fault data into columns
FBusNo = fault(:, 1);
FRes = fault(:, 2)/(kVNom(FBusNo+1)*kVNom(FBusNo+1)/Sb);  % FRes should be per-united.
FType = fault(:, 3);

%% Figure out the number of branches and buses excluding bus 0.
NoOfBuses = size(BusNo, 1) - 1;
NoOfBranches = size(From, 1);


%% Iterations

% Step 0

% Add the neutral reactor and a branch for the fault resistance
NoOfBranches = NoOfBranches + 1;
From = [From ; FBusNo];
To = [To ; 0];
r1OfBranches = [r1OfBranches ; FRes];
x1OfBranches = [x1OfBranches ; 0];
r0OfBranches = [r0OfBranches ; FRes];
x0OfBranches = [x0OfBranches ; 0];
x0OfBranches(2) = x0OfBranches(2) + 3 * ntrlReactor;

% Calculate admittance of loads
yofLoada = LoadaP - LoadaQ * 1i;
yofLoadb = LoadbP - LoadbQ * 1i;
yofLoadc = LoadcP - LoadcQ * 1i;

% Calculate admittance of branches
z1OfBranches = r1OfBranches + x1OfBranches * 1i;
y1OfBranches = 1./z1OfBranches;
z0OfBranches = r0OfBranches + x0OfBranches * 1i;
y0OfBranches = 1./z0OfBranches;

% Calculate Y1 bus and Y0 bus
Y1Bus = zeros(NoOfBuses);
Y0Bus = zeros(NoOfBuses-1);
for k = 1 : 1 : NoOfBuses
    for h = 1 : 1 : NoOfBuses
        if k == h
            for w = 1 : 1 : NoOfBranches
                if ((From(w) == k) || (To(w) == k))
                    Y1Bus(k, h) = Y1Bus(k, h) + y1OfBranches(w);
                end
            end
        else
            for w = 1 : 1 : NoOfBranches
                if ((From(w) == k) && (To(w) == h)) || ((From(w) == h) && (To(w) == k))
                    Y1Bus(k, h) = Y1Bus(k, h) - y1OfBranches(w);
                end
            end
        end
    end
end
for k = 1 : 1 : NoOfBuses
    for h = 1 : 1 : NoOfBuses
        if k == h
            for w = 1 : 1 : NoOfBranches
                if ((From(w) == (k+1)) || (To(w) == (k+1)))
                    Y0Bus(k, h) = Y0Bus(k, h) + y0OfBranches(w);
                end
            end
        else
            for w = 1 : 1 : NoOfBranches
```

```
                if ((From(w) == (k+1)) && (To(w) == (h+1))) || ((From(w) == (h+1)) && (To(w)
== (k+1)))
                    Y0Bus(k, h) = Y0Bus(k, h) - y0OfBranches(w);
                end
            end
        end
    end
end

% Initialization
Vs = 1;  % The system source voltage
IPVa = PVa;  % Per unit values of PVs' currents on phase A
IPVb = a*a*PVb;  % Per unit values of PVs' currents on phase B
IPVc = a*PVc;  % Per unit values of PVs' currents on phase C
Va = zeros(NoOfBuses, 1);  % The final bus voltages on phase A
Va(1) = Vs;
Vb = zeros(NoOfBuses, 1);  % The final bus voltages on phase B
Vb(1) = a*a*Vs;
Vc = zeros(NoOfBuses, 1);  % The final bus voltages on phase C
Vc(1) = a*Vs;
Vaold = Va;  % Is used to check convergence
Vbold = Vb;  % Is used to check convergence
Vcold = Vc;  % Is used to check convergence
IPVaold = IPVa;  % Is used to check convergence
IPVbold = IPVb;  % Is used to check convergence
IPVcold = IPVc;  % Is used to check convergence
Valast = Va;  % Is used to check convergence
Vblast = Vb;  % Is used to check convergence
Vclast = Vc;  % Is used to check convergence
IPValast = IPVa;  % Is used to check convergence
IPVblast = IPVb;  % Is used to check convergence
IPVclast = IPVc;  % Is used to check convergence

tPast = 0;  % Time steps at which the PV protection is checked
pZonea = zeros(NoOfBuses, 1);  % The protection status at which each PV works (0 = "V>0.88",
1 = "V<=0.5", 2 = "0.5<V<=0.88", 3 = "disconnected")
sClocka = zeros(NoOfBuses, 1);  % The time at which the PV enters a new protection status
pZoneb = zeros(NoOfBuses, 1);
sClockb = zeros(NoOfBuses, 1);
pZonec = zeros(NoOfBuses, 1);
sClockc = zeros(NoOfBuses, 1);

flag = 0;  % "1" when a PV disconnects, "0" when no changes happen

disTimea = 1000 * ones(NoOfBuses, 1);
disTimeb = 1000 * ones(NoOfBuses, 1);
disTimec = 1000 * ones(NoOfBuses, 1);



while (1)   % This "while" is to apply PVs' protections

    % Counter of number of iteration to = 0
    ItrNo = 0;

    % This "while" continues working unless one of the ifs in STEP 2 becomes true
    while (1)
        % STEP 1

        % Total current injection to each node: (PVs'  currents - Loads' currents)
        Ia = IPVa - Va .* yofLoada;
        Ib = IPVb - Vb .* yofLoadb;
        Ic = IPVc - Vc .* yofLoadc;

        % From abc to +-0 (pnz)
        Iz = (Ia + Ib + Ic) / 3;
```

```
        Ip = (Ia + a*Ib + a*a*Ic) / 3;
        In = (Ia + a*a*Ib + a*Ic) / 3;
        Ip(1) = Ip(1) + Vs/z1OfBranches(1);
        Iz = Iz(2:end);  % Since the transformer is of delta-wye type, we don't consider the
bus 1 in the zero sequence network.

        % Calculate V
        Vp = Y1Bus \ Ip;
        Vn = Y1Bus \ In;
        Vz = [0 ; Y0Bus \ Iz];

        % From +-0 (pnz) to abc
        Va = Vz + Vp + Vn;
        Vb = Vz + a*a*Vp + a*Vn;
        Vc = Vz + a*Vp + a*a*Vn;


        % STEP 2

        % Check if deltaV and deltaIPVa gets less than "econv" or not. If yes,
        % the program terminates
        if ((max(abs([Va(1:(FBusNo-1));Vb(1:(FBusNo-1));Vc(1:(FBusNo-1))]-[Vaold(1:(FBusNo-
1));Vbold(1:(FBusNo-1));Vcold(1:(FBusNo-1))])) < econv) && (max(abs([IPVa(1:(FBusNo-
1));IPVb(1:(FBusNo-1));IPVc(1:(FBusNo-1))]-[IPVaold(1:(FBusNo-1));IPVbold(1:(FBusNo-
1));IPVcold(1:(FBusNo-1))])) < econv))
            break;
        end

        % Check if number of iteration exceeds the limit or not. If yes, the
        % program terminates
        if ItrNo > mxitr
            break;
        end
        ItrNo = ItrNo + 1;

        Vaold = Va;
        Vbold = Vb;
        Vcold = Vc;
        IPVaold = IPVa;
        IPVbold = IPVb;
        IPVcold = IPVc;


        % STEP 3

        % Update PVs' currents based on the bus voltages
        for k = 1 : 1 : NoOfBuses
            if (abs(Va(k)) < 0.5)
                IPVa(k) = 2 * PVa(k) * (cos(angle(Va(k))) + sin(angle(Va(k)))*1i);
            elseif (abs(Va(k)) >= 0.5)
                IPVa(k) = (1/abs(Va(k))) * PVa(k) * (cos(angle(Va(k))) +
sin(angle(Va(k)))*1i);
            end
            if (abs(Vb(k)) < 0.5)
                IPVb(k) = 2 * PVb(k) * (cos(angle(Vb(k))) + sin(angle(Vb(k)))*1i);
            elseif (abs(Vb(k)) >= 0.5)
                IPVb(k) = (1/abs(Vb(k))) * PVb(k) * (cos(angle(Vb(k))) +
sin(angle(Vb(k)))*1i);
            end
            if (abs(Vc(k)) < 0.5)
                IPVc(k) = 2 * PVc(k) * (cos(angle(Vc(k))) + sin(angle(Vc(k)))*1i);
            elseif (abs(Vc(k)) >= 0.5)
                IPVc(k) = (1/abs(Vc(k))) * PVc(k) * (cos(angle(Vc(k))) +
sin(angle(Vc(k)))*1i);
            end
        end
```

```
    end


    % Apply PVs' protections

    if tSim <= tPast
        break;
    else
        for k = 1 : 1 : NoOfBuses
            if (abs(Va(k)) <= 0.5)
                if (pZonea(k) == 0) || (pZonea(k) == 2)  % Checks if the PV protection status
should be set to "1"
                    sClocka(k) = tPast;
                    pZonea(k) = 1;
                elseif pZonea(k) == 1                    % Disconnects the PVs with status
"1" which has already been in "1" for 0.1s
                    if (tPast-sClocka(k)) >= 0.1
                        IPVa(k) = 0;
                        PVa(k) = 0;
                        pZonea(k) = 3;
                        disTimea(k) = tPast;
                        flag = 1;
                    end
                end
            elseif (abs(Va(k)) <= 0.88) || (abs(Va(k)) >= 1.1)  % Checks if the PV protection
status should be set to "2"
                if (pZonea(k) == 0) || (pZonea(k) == 1)
                    sClocka(k) = tPast;
                    pZonea(k) = 2;
                elseif pZonea(k) == 2                        % Disconnects the PVs with
status "2" which has already been in "2" for 2s
                    if (tPast-sClocka(k)) >= 2
                        IPVa(k) = 0;
                        PVa(k) = 0;
                        pZonea(k) = 3;
                        disTimea(k) = tPast;
                        flag = 1;
                    end
                end
            end
            if (abs(Vb(k)) <= 0.5)
                if (pZoneb(k) == 0) || (pZoneb(k) == 2)
                    sClockb(k) = tPast;
                    pZoneb(k) = 1;
                elseif pZoneb(k) == 1
                    if (tPast-sClockb(k)) >= 0.1
                        IPVb(k) = 0;
                        PVb(k) = 0;
                        pZoneb(k) = 3;
                        disTimeb(k) = tPast;
                        flag = 1;
                    end
                end
            elseif (abs(Vb(k)) <= 0.88) || (abs(Vb(k)) >= 1.1)
                if (pZoneb(k) == 0) || (pZoneb(k) == 1)
                    sClockb(k) = tPast;
                    pZoneb(k) = 2;
                elseif pZoneb(k) == 2
                    if (tPast-sClockb(k)) >= 2
                        IPVb(k) = 0;
                        PVb(k) = 0;
                        pZoneb(k) = 3;
                        disTimeb(k) = tPast;
                        flag = 1;
                    end
                end
```

```
            end
            if (abs(Vc(k)) <= 0.5)
                if (pZonec(k) == 0) || (pZonec(k) == 2)
                    sClockc(k) = tPast;
                    pZonec(k) = 1;
                elseif pZonec(k) == 1
                    if (tPast-sClockc(k)) >= 0.1
                        IPVc(k) = 0;
                        PVc(k) = 0;
                        pZonec(k) = 3;
                        disTimec(k) = tPast;
                        flag = 1;
                    end
                end
            elseif (abs(Vc(k)) <= 0.88) || (abs(Vc(k)) >= 1.1)
                if (pZonec(k) == 0) || (pZonec(k) == 1)
                    sClockc(k) = tPast;
                    pZonec(k) = 2;
                elseif pZonec(k) == 2
                    if (tPast-sClockc(k)) >= 2
                        IPVc(k) = 0;
                        PVc(k) = 0;
                        pZonec(k) = 3;
                        disTimec(k) = tPast;
                        flag = 1;
                    end
                end
            end
        end
        if flag == 0        % Freezes the time if flag is "1" to check if any PV has changed
protection status due to other PVs' disconnection
            tPast = tPast + 0.1;
        end
        flag = 0;
    end

end

%% Results

if ItrNo <= mxitr
    disp(['   Fault at Bus:  ', num2str(FBusNo)])
    disp(' ')
    disp('   Bus        Va(pu)    PVa Current(pu rating)')
    disp([BusNo((2:end),:) abs(Va) abs(IPVa)./PVa])
    disp('   PDs Currents:')
    for k = 1 : 1 : (NoOfBranches-1)  % An extra branch had been added to model the Rf which
has to be removed here.
        if IsPD(k) == 1
        disp(['   PD Between ', num2str(From(k)), ' and ', num2str(To(k)), ', Phase A Fault
Current (kA):  ', num2str(abs((Vp(From(k))-Vp(To(k)))/z1OfBranches(k) + (Vn(From(k))-
Vn(To(k)))/z1OfBranches(k) + (Vz(From(k))-
Vz(To(k)))/z0OfBranches(k))*Sb/(sqrt(3)*kVNom(FBusNo+1)))])  % Ia = Ip + In + Iz
        end
    end
else
    disp('NOT CONVERGENT!')
end
```

GREEN HUB I – SINGLE PHASE FAULTS

INPUT

```
Sb = 100;

econv = 1e-4;

mxitr = 200;


% Bus no. 0 is located between the system voltage source and system
% impedance and will not be considered in the YBus matrix. The system
% voltage source and impedance will be converted to their Norton equivelant
% circuit.
%       Bus        PVa(MW)    PVb(MW)    PVc(MW)        Loada(MW)    Loadb(MW)    Loadc(MW)
Loada(MVAR)    Loadb(MVAR)    Loadc(MVAR)        kV(nom.)          kV(reg.)
bus =    [
        0          0          0          0             0            0            0                0
0              0                   230              230;
        1          0          0          0             0            0            0                0
0              0                   230              0;
        2          0          0          0             0            0            0                0
0              0                   12               0;
        3          0          0          0             0            0            0                0
0              0                   12               0;
        4          0.05775    0.16555    0.11242       0.05775      0.16555      0.11242
0.08162        0.11011        0.06699           12                0;
        5          0          0          0             0            0            0                0
0              0                   12               0;
        6          0.53207    0.73483    0.3388        0.53207      0.73483      0.3388
0.27335        0.36499        0.17325           12                0;
        7          0          0.141      0.01463       0            0.141        0.01463          0
0.068          0.0077              12               0;
        8          0.02002    0.01001    0.08547       0.02002      0.01001      0.08547
0.01001        0.00154        0.04312           12                0;
        9          0.65142    0.17171    0.1001        0.65142      0.17171      0.1001           -
0.06736       -0.31992       -0.34302          12                0;           % Cap bank at this
node each phase 0.4MVAR
        10         0.54439    0.05698    0.2541        0.54439      0.05698      0.2541
0.27874        0.02926        0.12012           12                0;
        11         0.14553    0.11242    0.24563       0.14553      0.11242      0.24563
0.07469        0.05775        0.12012           12                0;
        12         0.59752    0.51051    0.73381       0.59752      0.51051      0.73381
0.10492        0.05333        0.18654           12                0;           % Cap bank at this
node each phase 0.2MVAR
        13         0.53515    0.53053    0.52052       0.53515      0.53053      0.52052
0.27258        0.2618         0.26488           12                0;
        14         0.032725   0.025564   0.050743      0.032725     0.025564     0.050743
0.028028       0.026334       0.034804          12                0;
        15         0.45584    0.715176   0.841841      0.45584      0.715176     0.841841
0.189651       0.325094       0.353661          12                0;
        16         0.319396   0.317856   0.095326      0.319396     0.317856     0.095326         -
0.254778      -0.258397      -0.360422          12                0;           % Cap bank at this
node each phase 0.4MVAR
        17         0.015862   0          0             0.015862     0            0
0.008701       0              0                 12                0;
        18         0          0          0             0            0            0                0
0              0                   12               0;
        19         0.357665   0.207207   0.059598      0.357665     0.207207     0.059598
0.168553       0.105798       0.035266          12                0;
        20         0.499576   0.424424   0.846461      0.499576     0.424424     0.846461
0.232617       0.187957       0.364133          12                0;
```

```
        21        0.168938  0.608839  0.227227      0.168938    0.608839    0.227227        -
0.344637     -0.128113     -0.312451         12               0;          % Cap bank at this
node each phase 0.4MVAR
        ];

% IsPD is 1 if the branch represents a protective device and 0 if not.
%       Fr        To        r1(p.u./km)   x1(p.u./km)   r0(p.u./km)   x0(p.u./km)
length(km)   IsPD
brnch = [
        0         1         7.7996e-4     0.010618      7.7996e-4     0.010618      1
0;       % Zs
        1         2         0.0863334     0.6553334     0.0863334     0.6553334     1
0;       % transformer
        2         3         6.9444e-4     0             6.9444e-4     0             1
1;       % breaker
        3         4         1.4738e-2     5.9408e-2     5.4123e-2     2.0972e-1     7.141
0;
        4         5         6.9444e-4     0             6.9444e-4     0             1
1;       % recloser
        5         6         1.4616e-2     6.1453e-2     9.0933e-2     2.6508e-1     4.37
0;
        6         7         1.4271e-2     6.1163e-2     9.0726e-2     2.6504e-1     0.356
0;
        7         8         1.4645e-2     6.4731e-2     8.3183e-2     2.3520e-1     1.239
0;
        4         9         1.4570e-2     6.1369e-2     7.9149e-2     2.4313e-1     2.939
0;
        9         10        1.4678e-2     6.1509e-2     7.8843e-2     2.4338e-1     2.596
0;
        10        11        1.4608e-2     6.1353e-2     7.7840e-2     2.4416e-1     1.739
0;
        11        12        1.4527e-2     6.2053e-2     7.3442e-2     2.3718e-1     4.047
0;
        12        13        1.4604e-2     6.1460e-2     6.3490e-2     2.3085e-1     4.647
0;
        2         14        2.9037e-2     8.4174e-2     8.7871e-2     2.8265e-1     3.378
0;
        14        15        2.9408e-2     8.4976e-2     1.1812e-1     2.9863e-1     2.261
0;
        15        16        2.5045e-2     6.9389e-2     1.0283e-1     2.5542e-1     5.6913
0;
        15        17        1.1989e-1     1.6754e-1     8.8843e-1     3.0895e-1     0.239
0;
        17        18        2.8313e-2     7.7376e-2     1.1835e-1     2.9139e-1     2.089
0;
        14        19        2.8645e-2     8.3402e-2     8.3272e-2     2.7862e-1     2.819
0;
        19        20        2.8707e-2     8.3208e-2     8.7784e-2     2.8041e-1     0.883
0;
        20        21        2.8742e-2     8.2511e-2     1.1577e-1     2.9261e-1     3.17
0;
        ];

% The type information will not be used in the calculations.
% The resistance cannot be zero but can be close to zero.
% type=3 for three-phase faults, type=1 for single-phase faults
%       Bus       resistance(ohm)   type
fault = [
        3         15.3                  1;
        ];

% The neutral reactor connected to the neutral of the Y side of the transformer.
ntrlReactor = 120 * pi * 8.3556e-4;

% Time at which the current is calculated.
tSim = 0;
```

METHOD IMPLEMENTATION

```
% Version 1.10:
    % - This version is based on nodal analysis.
    % - Works for 1-phase faults with arbitrary resistance.
    % - The distribution system is Green Hub I.
    % - The PVs can be unbalanced three-phase sources. (PVa~=PVb~=PVc)
    % - The PVs works at their rating (maximum generation = maximum solar radiation).
    % - The calculated values of currents and voltages are associated with the moments right
after the fault before the PVs' protections trip.
    % - This version considers the load effects on the fault currents.
    % - This version can calculate currents in times other than 0.


% Input Area
clc;
clear;

a = -0.5 + (sqrt(3)/2)*1i;

FAinputV1_10;    % Read the input file

% Seperate the bus data into columns
BusNo = bus(:, 1);
PVa = bus((2:end), 2) ./ (Sb/3);  % Per unit values of PVs' powers on phase A, row 1 is
assossiated with bus 0 and should be eliminated.
PVb = bus((2:end), 3) ./ (Sb/3);  % Per unit values of PVs' powers on phase B, row 1 is
assossiated with bus 0 and should be eliminated.
PVc = bus((2:end), 4) ./ (Sb/3);  % Per unit values of PVs' powers on phase C, row 1 is
assossiated with bus 0 and should be eliminated.
LoadaP = bus((2:end), 5) ./ (Sb/3);  % Per unit values of Loads' active powers on phase A,
row 1 is assossiated with bus 0 and should be eliminated.
LoadbP = bus((2:end), 6) ./ (Sb/3);  % Per unit values of Loads' active powers on phase B,
row 1 is assossiated with bus 0 and should be eliminated.
LoadcP = bus((2:end), 7) ./ (Sb/3);  % Per unit values of Loads' active powers on phase C,
row 1 is assossiated with bus 0 and should be eliminated.
LoadaQ = bus((2:end), 8) ./ (Sb/3);  % Per unit values of Loads' reactive powers on phase A,
row 1 is assossiated with bus 0 and should be eliminated.
LoadbQ = bus((2:end), 9) ./ (Sb/3);  % Per unit values of Loads' reactive powers on phase B,
row 1 is assossiated with bus 0 and should be eliminated.
LoadcQ = bus((2:end), 10) ./ (Sb/3);  % Per unit values of Loads' reactive powers on phase C,
row 1 is assossiated with bus 0 and should be eliminated.
PVa = [PVa(1:13);0;0;0;0;0;0;0;0];
PVb = [PVb(1:13);0;0;0;0;0;0;0;0];
PVc = [PVc(1:13);0;0;0;0;0;0;0;0];
kVNom = bus(:, 11);
kVReg = bus(:, 12);

% Seperate the branch data in columns
From = brnch(:, 1);
To = brnch(:, 2);
r1OfBranches = brnch(:, 3) .* brnch(:, 7);  % Per unit values of r1s of branches
x1OfBranches = brnch(:, 4) .* brnch(:, 7);  % Per unit values of x1s of branches
r0OfBranches = brnch(:, 5) .* brnch(:, 7);  % Per unit values of r0s of branches
x0OfBranches = brnch(:, 6) .* brnch(:, 7);  % Per unit values of x0s of branches
ntrlReactor = ntrlReactor /(kVNom(3)*kVNom(3)/Sb);  % Neutral reactor should be per-united.
IsPD = brnch(:, 8);

% Seperate the fault data into columns
FBusNo = fault(:, 1);
FRes = fault(:, 2)/(kVNom(FBusNo+1)*kVNom(FBusNo+1)/Sb);  % FRes should be per-united.
FType = fault(:, 3);

% Figure out the number of branches and buses excluding bus 0.
NoOfBuses = size(BusNo, 1) - 1;
```

```
NoOfBranches = size(From, 1);


% Step 0

% Add the neutral reactor
x0OfBranches(2) = x0OfBranches(2) + 3 * ntrlReactor;

% Calculate admittance of loads
yofLoada = LoadaP - LoadaQ * 1i;
yofLoadb = LoadbP - LoadbQ * 1i;
yofLoadc = LoadcP - LoadcQ * 1i;

% Calculate admittance of branches
z1OfBranches = r1OfBranches + x1OfBranches * 1i;
y1OfBranches = 1./z1OfBranches;
z0OfBranches = r0OfBranches + x0OfBranches * 1i;
y0OfBranches = 1./z0OfBranches;

% Calculate Y1 bus and Y0 bus
Y1Bus = zeros(NoOfBuses);
Y0Bus = zeros(NoOfBuses-1);
for k = 1 : 1 : NoOfBuses
    for h = 1 : 1 : NoOfBuses
        if k == h
            for w = 1 : 1 : NoOfBranches
                if ((From(w) == k) || (To(w) == k))
                    Y1Bus(k, h) = Y1Bus(k, h) + y1OfBranches(w);
                end
            end
        else
            for w = 1 : 1 : NoOfBranches
                if ((From(w) == k) && (To(w) == h)) || ((From(w) == h) && (To(w) == k))
                    Y1Bus(k, h) = Y1Bus(k, h) - y1OfBranches(w);
                end
            end
        end
    end
end
for k = 1 : 1 : NoOfBuses
    for h = 1 : 1 : NoOfBuses
        if k == h
            for w = 1 : 1 : NoOfBranches
                if ((From(w) == (k+1)) || (To(w) == (k+1)))
                    Y0Bus(k, h) = Y0Bus(k, h) + y0OfBranches(w);
                end
            end
        else
            for w = 1 : 1 : NoOfBranches
                if ((From(w) == (k+1)) && (To(w) == (h+1))) || ((From(w) == (h+1)) && (To(w)
== (k+1)))
                    Y0Bus(k, h) = Y0Bus(k, h) - y0OfBranches(w);
                end
            end
        end
    end
end

% Calculate the Z buses
Z1Bus = inv(Y1Bus);
Z0Bus = inv(Y0Bus);

% Initialization
Vs = 1;  % The system source voltage
IPVa = PVa;  % Per unit values of PVs' currents on phase A
IPVb = a*a*PVb;  % Per unit values of PVs' currents on phase B
```

```
IPVc = a*PVc;  % Per unit values of PVs' currents on phase C
Va = zeros(NoOfBuses, 1);  % The final bus voltages on phase A
Va(1) = Vs;
Vb = ones(NoOfBuses, 1);  % The final bus voltages on phase B
Vc = ones(NoOfBuses, 1);  % The final bus voltages on phase C
Vaold = Va;  % Is used to check convergence
Vbold = Vb;  % Is used to check convergence
Vcold = Vc;  % Is used to check convergence
IPVaold = IPVa;  % Is used to check convergence
IPVbold = IPVb;  % Is used to check convergence
IPVcold = IPVc;  % Is used to check convergence
Valast = Va;  % Is used to check convergence
Vblast = Vb;  % Is used to check convergence
Vclast = Vc;  % Is used to check convergence
IPValast = IPVa;  % Is used to check convergence
IPVblast = IPVb;  % Is used to check convergence
IPVclast = IPVc;  % Is used to check convergence

tPast = 0;  % Time steps at which the PV protection is checked
pZonea = zeros(NoOfBuses, 1);  % The protection status at which each PV works (0 = "V>0.88",
1 = "V<=0.5", 2 = "0.5<V<=0.88", 3 = "disconnected")
sClocka = zeros(NoOfBuses, 1);  % The time at which the PV enters a new protection status
pZoneb = zeros(NoOfBuses, 1);
sClockb = zeros(NoOfBuses, 1);
pZonec = zeros(NoOfBuses, 1);
sClockc = zeros(NoOfBuses, 1);

flag = 0;  % "1" when a PV disconnects, "0" when no changes happen

disTimea = 1000 * ones(NoOfBuses, 1);
disTimeb = 1000 * ones(NoOfBuses, 1);
disTimec = 1000 * ones(NoOfBuses, 1);


while (1)   % This "while" is to apply PVs' protections

    % Counter of number of iteration to = 0
    ItrNo = 0;

    while (1)    % This "while" is to calculate voltages and currents and continues working
unless one of the ifs in STEP 2 becomes true
        % STEP 1

        % Total current injection to each node: (PVs'  currents - Loads' currents)
        Ia = IPVa - Va .* yofLoada;
        Ib = IPVb - Vb .* yofLoadb;
        Ic = IPVc - Vc .* yofLoadc;

        % From abc to +-0 (pnz)
        Iz = (Ia + Ib + Ic) / 3;
        Ip = (Ia + a*Ib + a*a*Ic) / 3;
        In = (Ia + a*a*Ib + a*Ic) / 3;

        % Calculate If (Fault current in the sequential network)
        If = 0;
        for k = 1 : 1 : NoOfBuses
            If = If + Z1Bus(FBusNo, k) * Ip(k) + Z1Bus(FBusNo, k) * In(k);
        end
        for k = 2 : 1 : NoOfBuses
            If = If + Z0Bus(FBusNo-1, k-1) * Iz(k);
        end
        If = (If + Z1Bus(FBusNo, 1) * Vs/z1OfBranches(1)) / (3 * FRes + Z1Bus(FBusNo, FBusNo)
+ Z1Bus(FBusNo, FBusNo) + Z0Bus(FBusNo-1, FBusNo-1));

        % Calculate I
        Ip(1) = Ip(1) + Vs/z1OfBranches(1);
```

```
        Ip(FBusNo) = Ip(FBusNo) - If;
        In(FBusNo) = In(FBusNo) - If;
        Iz = Iz(2:end);  % Since the transformer is of delta-wye type, we don't consider the
bus 1 in the zero sequence network.
        Iz(FBusNo-1) = Iz(FBusNo-1) - If;

        % Calculate V
        Vp = Y1Bus \ Ip;  % The positive sequence bus voltages
        Vn = Y1Bus \ In;  % The negative sequence bus voltages
        Vz = [0 ; Y0Bus\Iz];  % The zero sequence bus voltages

        % From +-0 (pnz) to abc
        Va = Vz + Vp + Vn;
        Vb = Vz + a*a*Vp + a*Vn;
        Vc = Vz + a*Vp + a*a*Vn;


        % STEP 2

        % Check if deltaV and deltaIPVa gets less than "econv" or not. If yes,
        % the program terminates
        if ((max(abs([Va(1:(FBusNo-1));Vb(1:(FBusNo-1));Vc(1:(FBusNo-1))]-[Vaold(1:(FBusNo-
1));Vbold(1:(FBusNo-1));Vcold(1:(FBusNo-1))])) < econv) && (max(abs([IPVa(1:(FBusNo-
1));IPVb(1:(FBusNo-1));IPVc(1:(FBusNo-1))]-[IPVaold(1:(FBusNo-1));IPVbold(1:(FBusNo-
1));IPVcold(1:(FBusNo-1))])) < econv))
            break;
        end

        % Check if number of iteration exceeds the limit or not. If yes, the
        % program terminates
        if ItrNo > mxitr
            break;
        end
        ItrNo = ItrNo + 1;

        Vaold = Va;
        Vbold = Vb;
        Vcold = Vc;
        IPVaold = IPVa;
        IPVbold = IPVb;
        IPVcold = IPVc;


        % STEP 3

        % Update PVs' currents based on the bus voltages
        for k = 1 : 1 : NoOfBuses
            if (abs(Va(k)) < 0.5)
                IPVa(k) = 2 * PVa(k) * (cos(angle(Va(k))) + sin(angle(Va(k)))*1i);
            elseif (abs(Va(k)) >= 0.5)
                IPVa(k) = (1/abs(Va(k))) * PVa(k) * (cos(angle(Va(k))) +
sin(angle(Va(k)))*1i);
            end
            if (abs(Vb(k)) < 0.5)
                IPVb(k) = 2 * PVb(k) * (cos(angle(Vb(k))) + sin(angle(Vb(k)))*1i);
            elseif (abs(Vb(k)) >= 0.5)
                IPVb(k) = (1/abs(Vb(k))) * PVb(k) * (cos(angle(Vb(k))) +
sin(angle(Vb(k)))*1i);
            end
            if (abs(Vc(k)) < 0.5)
                IPVc(k) = 2 * PVc(k) * (cos(angle(Vc(k))) + sin(angle(Vc(k)))*1i);
            elseif (abs(Vc(k)) >= 0.5)
                IPVc(k) = (1/abs(Vc(k))) * PVc(k) * (cos(angle(Vc(k))) +
sin(angle(Vc(k)))*1i);
            end
        end
```

```
    end

    % Apply PVs' protections

    if tSim <= tPast
        break;
    else
        for k = 1 : 1 : NoOfBuses
            if (abs(Va(k)) <= 0.5)
                if (pZonea(k) == 0) || (pZonea(k) == 2)  % Checks if the PV protection status
should be set to "1"
                    sClocka(k) = tPast;
                    pZonea(k) = 1;
                elseif pZonea(k) == 1                    % Disconnects the PVs with status
"1" which has already been in "1" for 0.1s
                    if (tPast-sClocka(k)) >= 0.1
                        IPVa(k) = 0;
                        PVa(k) = 0;
                        pZonea(k) = 3;
                        disTimea(k) = tPast;
                        flag = 1;
                    end
                end
            elseif (abs(Va(k)) <= 0.88) || (abs(Va(k)) >= 1.1)  % Checks if the PV protection
status should be set to "2"
                if (pZonea(k) == 0) || (pZonea(k) == 1)
                    sClocka(k) = tPast;
                    pZonea(k) = 2;
                elseif pZonea(k) == 2                        % Disconnects the PVs with
status "2" which has already been in "2" for 2s
                    if (tPast-sClocka(k)) >= 2
                        IPVa(k) = 0;
                        PVa(k) = 0;
                        pZonea(k) = 3;
                        disTimea(k) = tPast;
                        flag = 1;
                    end
                end
            end
            if (abs(Vb(k)) <= 0.5)
                if (pZoneb(k) == 0) || (pZoneb(k) == 2)
                    sClockb(k) = tPast;
                    pZoneb(k) = 1;
                elseif pZoneb(k) == 1
                    if (tPast-sClockb(k)) >= 0.1
                        IPVb(k) = 0;
                        PVb(k) = 0;
                        pZoneb(k) = 3;
                        disTimeb(k) = tPast;
                        flag = 1;
                    end
                end
            elseif (abs(Vb(k)) <= 0.88) || (abs(Vb(k)) >= 1.1)
                if (pZoneb(k) == 0) || (pZoneb(k) == 1)
                    sClockb(k) = tPast;
                    pZoneb(k) = 2;
                elseif pZoneb(k) == 2
                    if (tPast-sClockb(k)) >= 2
                        IPVb(k) = 0;
                        PVb(k) = 0;
                        pZoneb(k) = 3;
                        disTimeb(k) = tPast;
                        flag = 1;
                    end
                end
            end
```

```
            if (abs(Vc(k)) <= 0.5)
                if (pZonec(k) == 0) || (pZonec(k) == 2)
                    sClockc(k) = tPast;
                    pZonec(k) = 1;
                elseif pZonec(k) == 1
                    if (tPast-sClockc(k)) >= 0.1
                        IPVc(k) = 0;
                        PVc(k) = 0;
                        pZonec(k) = 3;
                        disTimec(k) = tPast;
                        flag = 1;
                    end
                end
            elseif (abs(Vc(k)) <= 0.88) || (abs(Vc(k)) >= 1.1)
                if (pZonec(k) == 0) || (pZonec(k) == 1)
                    sClockc(k) = tPast;
                    pZonec(k) = 2;
                elseif pZonec(k) == 2
                    if (tPast-sClockc(k)) >= 2
                        IPVc(k) = 0;
                        PVc(k) = 0;
                        pZonec(k) = 3;
                        disTimec(k) = tPast;
                        flag = 1;
                    end
                end
            end
        end
        if flag == 0        % Freezes the time if flag is "1" to check if any PV has changed
protection status due to other PVs' disconnection
            tPast = tPast + 0.1;
        end
        flag = 0;
    end
end


% Results

if ItrNo <= mxitr
    disp(['   Fault at Bus:  ', num2str(FBusNo)])
    disp(' ')
    disp('   Bus        Va(pu)     PVa(puR)  Vb(pu)     PVb(puR)  Vc(pu)     PVc(puR)')
    disp([BusNo((2:end),:) abs(Va) abs(IPVa)./PVa abs(Vb) abs(IPVb)./PVb abs(Vc)
abs(IPVc)./PVc])
    disp('   PDs Currents:')
    for k = 1 : 1 : (NoOfBranches-1)  % An extra branch had been added to model the Rf which
has to be removed here.
        if IsPD(k) == 1
        disp(['   PD Between ', num2str(From(k)), ' and ', num2str(To(k)), ', (3I0) Fault
Current (kA):  ', num2str(abs(3*(Vz(From(k))-
Vz(To(k)))/z0OfBranches(k))*Sb/(sqrt(3)*kVNom(To(k))))])  % IPD = 3 * Iz
        end
    end
else
    disp('NOT CONVERGENT!')
end
```

GREEN HUB II – THREE PHASE FAULTS

INPUT

```
Sb = 100;

econv = 1e-4;

mxitr = 200;


% Bus no. 0 is located between the system voltage source and system
% impedance and will not be considered in the YBus matrix. The system
% voltage source and impedance will be converted to their Norton equivelant
% circuit.
%       Bus       SSTa(MW)  SSTb(MW)  SSTc(MW)       Loada(MW)   Loadb(MW)   Loadc(MW)
kV(nom.)         kV(reg.)
bus =   [
        0         0         0         0              0           0           0
230              230       ;
        1         0         0         0              0           0           0
230              0;
        2         0         0         0              0           0           0
12               0;
        3         0         0         0              0           0           0
12               0;
        4         0.1       0.2       0.14           0.05775     0.16555     0.11242
12               0;
        5         0         0         0              0           0           0
12               0;
        6         0.6       0.84      0.4            0.53207     0.73483     0.3388
12               0;
        7         0         0.16      0.02           0           0.141       0.01463
12               0;
        8         0.04      0.02      0.1            0.02002     0.01001     0.08547
12               0;
        9         0.74      0.2       0.12           0.65142     0.17171     0.1001
12               0;
        10        0.62      0.08      0.3            0.54439     0.05698     0.2541
12               0;
        11        0.18      0.14      0.28           0.14553     0.11242     0.24563
12               0;
        12        0.68      0.58      0.84           0.59752     0.51051     0.73381
12               0;
        13        0.62      0.6       0.6            0.53515     0.53053     0.52052
12               0;
        14        0.06      0.04      0.08           0.032725    0.025564    0.050743
12               0;
        15        0.5       0.8       0.92           0.45584     0.715176    0.841841
12               0;
        16        0.36      0.36      0.12           0.319396    0.317856    0.095326
12               0;
        17        0.02      0         0              0.015862    0           0
12               0;
        18        0         0         0              0           0           0
12               0;
        19        0.4       0.24      0.08           0.357665    0.207207    0.059598
12               0;
        20        0.56      0.48      0.94           0.499576    0.424424    0.846461
12               0;
        21        0.18      0.68      0.26           0.168938    0.608839    0.227227
12               0;
        ];
```

```
% IsPD is 1 if the branch represents a protective device and 0 if not.
%       Fr        To        r1(p.u./km)   x1(p.u./km)   r0(p.u./km)   x0(p.u./km)
length(km)   IsPD
brnch = [
        0         1         7.7996e-4     0.010618      7.7996e-4     0.010618      1
0;       % Zs
        1         2         0.0863334     0.6553334     0.0863334     0.6553334     1
0;       % transformer
        2         3         6.9444e-4     0             6.9444e-4     0             1
1;       % breaker
        3         4         1.4738e-2     5.9408e-2     5.4123e-2     2.0972e-1     7.141
0;
        4         5         6.9444e-4     0             6.9444e-4     0             1
1;       % recloser
        5         6         1.4616e-2     6.1453e-2     9.0933e-2     2.6508e-1     4.37
0;
        6         7         1.4271e-2     6.1163e-2     9.0726e-2     2.6504e-1     0.356
0;
        7         8         1.4645e-2     6.4731e-2     8.3183e-2     2.3520e-1     1.239
0;
        4         9         1.4570e-2     6.1369e-2     7.9149e-2     2.4313e-1     2.939
0;
        9         10        1.4678e-2     6.1509e-2     7.8843e-2     2.4338e-1     2.596
0;
        10        11        1.4608e-2     6.1353e-2     7.7840e-2     2.4416e-1     1.739
0;
        11        12        1.4527e-2     6.2053e-2     7.3442e-2     2.3718e-1     4.047
0;
        12        13        1.4604e-2     6.1460e-2     6.3490e-2     2.3085e-1     4.647
0;
        2         14        2.9037e-2     8.4174e-2     8.7871e-2     2.8265e-1     3.378
0;
        14        15        2.9408e-2     8.4976e-2     1.1812e-1     2.9863e-1     2.261
0;
        15        16        2.5045e-2     6.9389e-2     1.0283e-1     2.5542e-1     5.6913
0;
        15        17        1.1989e-1     1.6754e-1     8.8843e-1     3.0895e-1     0.239
0;
        17        18        2.8313e-2     7.7376e-2     1.1835e-1     2.9139e-1     2.089
0;
        14        19        2.8645e-2     8.3402e-2     8.3272e-2     2.7862e-1     2.819
0;
        19        20        2.8707e-2     8.3208e-2     8.7784e-2     2.8041e-1     0.883
0;
        20        21        2.8742e-2     8.2511e-2     1.1577e-1     2.9261e-1     3.17
0;
        ];

% The unbalancy between PV and load in p.u. based on the load MW (PV-Load)
unblnc = 1;

% The type information will not be used in the calculations.
% The resistance cannot be zero but can be close to zero.
% type=3 for three-phase faults, type=1 for single-phase faults
%       Bus       resistance(ohm)   type
fault = [
        5        4.27               3;
        ];

% The neutral reactor connected to the neutral of the Y side of the transformer.
ntrlReactor = 120 * pi * 8.3556e-4;

% Time at which the current is calculated.
tSim = 10;
```

```
% Version 1.14:
    % - This version is based on nodal analysis.
    % - Works for three-phase faults with arbitrary resistance.
    % - The distribution system is Green Hub II.
    % - The SSTs can be unbalanced three-phase sources. (SSTa~=SSTb~=SSTc)
    % - This version calculates the currents and voltages at any times.
    % - This version records the current levels in "IBfault" and "IRfault" and the changing
times in "tSepa".
    % - This version differentiates between SSTs' ratings and loads'ratings.

% Note: The unbalancy is different for SSTs (1-13) and SSTs (14-21). This will effect P2,
RSST, and sign of SSTs' currents in the display results section.


% Input Area
clc;
clear;

a = -0.5 + (sqrt(3)/2)*1i;

FAinputV1_14;    % Read the input file

% Seperate the bus data into columns
BusNo = bus(:, 1);
SSTa = bus((2:end), 2) ./ (Sb/3);  % Per unit values of SSTs' ratings on phase A, row 1 is
assossiated with bus 0 and should be eliminated.
SSTb = bus((2:end), 3) ./ (Sb/3);  % Per unit values of SSTs' ratings on phase B, row 1 is
assossiated with bus 0 and should be eliminated.
SSTc = bus((2:end), 4) ./ (Sb/3);  % Per unit values of SSTs' ratings on phase C, row 1 is
assossiated with bus 0 and should be eliminated.
SSTa = [SSTa(1:13);zeros(8,1)];
SSTb = [SSTb(1:13);zeros(8,1)];
SSTc = [SSTc(1:13);zeros(8,1)];
LoadaP = bus((2:end), 5) ./ (Sb/3);  % Per unit values of PVs' powers on phase A
LoadbP = bus((2:end), 6) ./ (Sb/3);  % Per unit values of PVs' powers on phase B
LoadcP = bus((2:end), 7) ./ (Sb/3);  % Per unit values of PVs' powers on phase C
kVNom = bus(:, 8);
kVReg = bus(:, 9);

% Seperate the branch data in columns
From = brnch(:, 1);
To = brnch(:, 2);
r1OfBranches = brnch(:, 3) .* brnch(:, 7);  % Per unit values of r1s of branches
x1OfBranches = brnch(:, 4) .* brnch(:, 7);  % Per unit values of x1s of branches
r0OfBranches = brnch(:, 5) .* brnch(:, 7);  % Per unit values of r0s of branches
x0OfBranches = brnch(:, 6) .* brnch(:, 7);  % Per unit values of x0s of branches
ntrlReactor = ntrlReactor /(kVNom(3)*kVNom(3)/Sb);  % Neutral reactor should be per-united.
IsPD = brnch(:, 8);

% Seperate the fault data into columns
FBusNo = fault(:, 1);
FRes = fault(:, 2)/(kVNom(FBusNo+1)*kVNom(FBusNo+1)/Sb);  % FRes should be per-united.
FType = fault(:, 3);

% Figure out the number of branches and buses excluding bus 0.
NoOfBuses = size(BusNo, 1) - 1;
NoOfBranches = size(From, 1);

% Unbalancies
unblnca = zeros(NoOfBuses, 1);
unblncb = zeros(NoOfBuses, 1);
unblncc = zeros(NoOfBuses, 1);
for k = 1 : 1 : NoOfBuses
```

```
    if SSTa(k) ~= 0
        unblnca(k) = unblnc * LoadaP(k) ./ SSTa(k);  % Unbalancy based on the corresponding
SST's rating
    end
    if SSTb(k) ~= 0
        unblncb(k) = unblnc * LoadbP(k) ./ SSTb(k);  % Unbalancy based on the corresponding
SST's rating
    end
    if SSTc(k) ~= 0
        unblncc(k) = unblnc * LoadcP(k) ./ SSTc(k);  % Unbalancy based on the corresponding
SST's rating
    end
end


% Step 0

% Add the neutral reactor and a branch for the fault resistance
NoOfBranches = NoOfBranches + 1;
From = [From ; FBusNo];
To = [To ; 0];
r1OfBranches = [r1OfBranches ; FRes];
x1OfBranches = [x1OfBranches ; 0];
r0OfBranches = [r0OfBranches ; FRes];
x0OfBranches = [x0OfBranches ; 0];
x0OfBranches(2) = x0OfBranches(2) + 3 * ntrlReactor;

% Calculate admittance of branches
z1OfBranches = r1OfBranches + x1OfBranches * 1i;
y1OfBranches = 1./z1OfBranches;
z0OfBranches = r0OfBranches + x0OfBranches * 1i;
y0OfBranches = 1./z0OfBranches;

% Calculate Y1 bus and Y0 bus
Y1Bus = zeros(NoOfBuses);
Y0Bus = zeros(NoOfBuses-1);
for k = 1 : 1 : NoOfBuses
    for h = 1 : 1 : NoOfBuses
        if k == h
            for w = 1 : 1 : NoOfBranches
                if ((From(w) == k) || (To(w) == k))
                    Y1Bus(k, h) = Y1Bus(k, h) + y1OfBranches(w);
                end
            end
        else
            for w = 1 : 1 : NoOfBranches
                if ((From(w) == k) && (To(w) == h)) || ((From(w) == h) && (To(w) == k))
                    Y1Bus(k, h) = Y1Bus(k, h) - y1OfBranches(w);
                end
            end
        end
    end
end
for k = 1 : 1 : NoOfBuses
    for h = 1 : 1 : NoOfBuses
        if k == h
            for w = 1 : 1 : NoOfBranches
                if ((From(w) == (k+1)) || (To(w) == (k+1)))
                    Y0Bus(k, h) = Y0Bus(k, h) + y0OfBranches(w);
                end
            end
        else
            for w = 1 : 1 : NoOfBranches
                if ((From(w) == (k+1)) && (To(w) == (h+1))) || ((From(w) == (h+1)) && (To(w)
== (k+1)))
                    Y0Bus(k, h) = Y0Bus(k, h) - y0OfBranches(w);
```

```
                end
            end
        end
    end
end

% Initialization
Vs = 1;  % The system source voltage
RSSTa = unblnca .* SSTa;  % Applicable SST rating on phase A
RSSTb = unblncb .* SSTb;  % Applicable SST rating on phase B
RSSTc = unblncc .* SSTc;  % Applicable SST rating on phase C
RSSTa = [RSSTa(1:13);((-1).*SSTa(14:21))];  % No PVs after 13
RSSTb = [RSSTb(1:13);((-1).*SSTb(14:21))];  % No PVs after 13
RSSTc = [RSSTc(1:13);((-1).*SSTc(14:21))];  % No PVs after 13

ISSTa = RSSTa;  % Per unit values of SSTs' currents on phase A
ISSTb = a*a*RSSTb;  % Per unit values of SSTs' currents on phase B
ISSTc = a*RSSTc;  % Per unit values of SSTs' currents on phase C
Va = zeros(NoOfBuses, 1);  % The final bus voltages on phase A
Va(1) = Vs;
Vb = zeros(NoOfBuses, 1);  % The final bus voltages on phase B
Vb(1) = a*a*Vs;
Vc = zeros(NoOfBuses, 1);  % The final bus voltages on phase C
Vc(1) = a*Vs;
Vaold = Va;  % Is used to check convergence
Vbold = Vb;  % Is used to check convergence
Vcold = Vc;  % Is used to check convergence
ISSTaold = ISSTa;  % Is used to check convergence
ISSTbold = ISSTb;  % Is used to check convergence
ISSTcold = ISSTc;  % Is used to check convergence

pTamin = zeros(NoOfBuses, 1);  % "Tmin" determines the next "t" at which one of the SSTs
shuts down
pTbmin = zeros(NoOfBuses, 1);
pTcmin = zeros(NoOfBuses, 1);
disSSTNoa = 1;  % No of SSTs to shut down
disSSTNob = 1;
disSSTNoc = 1;
Wcapa = 0.5*(30e-6)*3800*3800*ones(NoOfBuses,1);  % Initial value for cap energy
Wcapb = 0.5*(30e-6)*3800*3800*ones(NoOfBuses,1);
Wcapc = 0.5*(30e-6)*3800*3800*ones(NoOfBuses,1);

Wdisa = zeros(NoOfBuses,1);
Wdisb = zeros(NoOfBuses,1);
Wdisc = zeros(NoOfBuses,1);

disTimea = 1000 * ones(NoOfBuses, 1);
disTimeb = 1000 * ones(NoOfBuses, 1);
disTimec = 1000 * ones(NoOfBuses, 1);

tPasta = 0;  % Total time passed
tPastb = 0;
tPastc = 0;

cLevel = 1;
IBfault = zeros(NoOfBuses, 1);  % Breaker current levels
IRfault = zeros(NoOfBuses, 1);  % Recloser current levels
tSepa = zeros(NoOfBuses, 1);  % Moments seperating the current levels

disSSTNoaOld = 0;


ItrNo2 = 0;
while (1)   % This "while" is to apply PVs' protections

    % Counter of number of iteration to = 0
```

```
    ItrNo = 0;

    % This "while" continues working unless one of the ifs in STEP 2 becomes true
    while (1)
        % STEP 1

        % From abc to +-0 (pnz)
        ISSTz = (ISSTa + ISSTb + ISSTc) / 3;
        ISSTp = (ISSTa + a*ISSTb + a*a*ISSTc) / 3;
        ISSTn = (ISSTa + a*a*ISSTb + a*ISSTc) / 3;

        % Calculate I
        Ip = ISSTp;
        Ip(1) = Ip(1) + Vs/z1OfBranches(1);
        In = ISSTn;
        Iz = ISSTz(2:end);  % Since the transformer is of delta-wye type, we don't consider
the bus 1 in the zero sequence network.

        % Calculate V1
        Vp = Y1Bus \ Ip;
        Vn = Y1Bus \ In;
        Vz = [0 ; Y0Bus \ Iz];

        % From +-0 (pnz) to abc
        Va = Vz + Vp + Vn;
        Vb = Vz + a*a*Vp + a*Vn;
        Vc = Vz + a*Vp + a*a*Vn;


        % STEP 2

        % Check if deltaV and deltaISSTa gets less than "econv" or not. If yes,
        % the program terminates
        if ((max(abs([Va(1:(FBusNo-1));Vb(1:(FBusNo-1));Vc(1:(FBusNo-1))]-[Vaold(1:(FBusNo-
1));Vbold(1:(FBusNo-1));Vcold(1:(FBusNo-1))])) < econv) && (max(abs([ISSTa(1:(FBusNo-
1));ISSTb(1:(FBusNo-1));ISSTc(1:(FBusNo-1))]-[ISSTaold(1:(FBusNo-1));ISSTbold(1:(FBusNo-
1));ISSTcold(1:(FBusNo-1))])) < econv))
            break;
        end

        % Check if number of iteration exceeds the limit or not. If yes, the
        % program terminates
        if ItrNo > mxitr
            break;
        end
        ItrNo = ItrNo + 1;

        Vaold = Va;
        Vbold = Vb;
        Vcold = Vc;
        ISSTaold = ISSTa;
        ISSTbold = ISSTb;
        ISSTcold = ISSTc;


        % STEP 3

        % Update SSTs' currents based on the bus voltages
        for k = 1 : 1 : NoOfBuses
            if (abs(Va(k)) < (abs(unblnca(k))/2))
                ISSTa(k) = 2 * unblnca(k)/abs(unblnca(k)) * SSTa(k) * (cos(angle(Va(k))) +
sin(angle(Va(k)))*1i);
            elseif (abs(Va(k)) >= (abs(unblnca(k))/2))
                ISSTa(k) = (1/abs(Va(k))) * RSSTa(k) * (cos(angle(Va(k))) +
sin(angle(Va(k)))*1i);
            end
```

```
            if (abs(Vb(k)) < (abs(unblncb(k))/2))
                ISSTb(k) = 2 * unblncb(k)/abs(unblncb(k)) * SSTb(k) * (cos(angle(Vb(k))) +
sin(angle(Vb(k)))*1i);
            elseif (abs(Vb(k)) >= (abs(unblncb(k))/2))
                ISSTb(k) = (1/abs(Vb(k))) * RSSTb(k) * (cos(angle(Vb(k))) +
sin(angle(Vb(k)))*1i);
            end
            if (abs(Vc(k)) < (abs(unblncc(k))/2))
                ISSTc(k) = 2 * unblncc(k)/abs(unblncc(k)) * SSTc(k) * (cos(angle(Vc(k))) +
sin(angle(Vc(k)))*1i);
            elseif (abs(Vc(k)) >= (abs(unblncc(k))/2))
                ISSTc(k) = (1/abs(Vc(k))) * RSSTc(k) * (cos(angle(Vc(k))) +
sin(angle(Vc(k)))*1i);
            end
        end
        for k = 14 : 1 : NoOfBuses  % the unblnc for the adjacent feeder is (-1)
            if (abs(Va(k)) < (1/2))
                ISSTa(k) = 2 * RSSTa(k) * (cos(angle(Va(k))) + sin(angle(Va(k)))*1i);
            elseif (abs(Va(k)) >= (1/2))
                ISSTa(k) = (1/abs(Va(k))) * RSSTa(k) * (cos(angle(Va(k))) +
sin(angle(Va(k)))*1i);
            end
            if (abs(Vb(k)) < (1/2))
                ISSTb(k) = 2 * RSSTb(k) * (cos(angle(Vb(k))) + sin(angle(Vb(k)))*1i);
            elseif (abs(Vb(k)) >= (1/2))
                ISSTb(k) = (1/abs(Vb(k))) * RSSTb(k) * (cos(angle(Vb(k))) +
sin(angle(Vb(k)))*1i);
            end
            if (abs(Vc(k)) < (1/2))
                ISSTc(k) = 2 * RSSTc(k) * (cos(angle(Vc(k))) + sin(angle(Vc(k)))*1i);
            elseif (abs(Vc(k)) >= (1/2))
                ISSTc(k) = (1/abs(Vc(k))) * RSSTc(k) * (cos(angle(Vc(k))) +
sin(angle(Vc(k)))*1i);
            end
        end
    end


    % Apply SSTs' protections
    % Very important note!: In contrast to the network solution, in the
    % protection logic the current injection to the system has "-" sign and
    % current drawing from the system has "+" sign.
    P1a = (-1)*real(Va .* conj(ISSTa./SSTa));
    P1b = (-1)*real(Vb .* conj(ISSTb./SSTb));
    P1c = (-1)*real(Vc .* conj(ISSTc./SSTc));
    P2a = (-1) * [unblnca(1:13);(-1)*ones(8,1)];  % All P2s are defined as Load-PV, No PVs
after 13
    P2b = (-1) * [unblncb(1:13);(-1)*ones(8,1)];
    P2c = (-1) * [unblncc(1:13);(-1)*ones(8,1)];
    Pcapa = P2a - P1a;
    Pcapb = P2b - P1b;
    Pcapc = P2c - P1c;
    for k = 1 : 1 : NoOfBuses
        if Pcapa(k) >= 0
            Wdisa(k) = Wcapa(k) - 0.5*(30e-6)*2660*2660; % Energy that has to be dissipated
so that the cap voltage reduces to 2660
        else
            Wdisa(k) = 0.5*(30e-6)*4560*4560 - Wcapa(k); % Energy that has to be absorbed so
that the cap voltage increases to 4560
        end
        if Pcapb(k) >= 0
            Wdisb(k) = Wcapb(k) - 0.5*(30e-6)*2660*2660; % Energy that has to be dissipated
so that the cap voltage reduces to 2660
        else
            Wdisb(k) = 0.5*(30e-6)*4560*4560 - Wcapb(k); % Energy that has to be absorbed so
that the cap voltage increases to 4560
```

```
        end
        if Pcapc(k) >= 0
            Wdisc(k) = Wcapc(k) - 0.5*(30e-6)*2660*2660; % Energy that has to be dissipated
so that the cap voltage reduces to 2660
        else
            Wdisc(k) = 0.5*(30e-6)*4560*4560 - Wcapc(k); % Energy that has to be absorbed so
that the cap voltage increases to 4560
        end
    end
    pTimea = abs(Wdisa ./ (Pcapa*20000/3));  % The time it takes for the cap voltage to
reduce to 2660 or increase to 4560
    pTimeb = abs(Wdisb ./ (Pcapb*20000/3));
    pTimec = abs(Wdisc ./ (Pcapc*20000/3));
    [pTamin(disSSTNoa), pka] = min(pTimea);  % The SST whose turn is to shut down with the
time it takes to shut down
    [pTbmin(disSSTNob), pkb] = min(pTimeb);
    [pTcmin(disSSTNoc), pkc] = min(pTimec);


    for k = 1 : 1 : (disSSTNoa-1)
        tPasta = pTamin(k) + tPasta;
    end
    for k = 1 : 1 : (disSSTNob-1)
        tPastb = pTbmin(k) + tPastb;
    end
    for k = 1 : 1 : (disSSTNoc-1)
        tPastc = pTcmin(k) + tPastc;
    end

    %  Applying the voltage protection
    if (tSim <= (pTamin(disSSTNoa)+tPasta)) && (tSim <= (pTbmin(disSSTNob)+tPastb)) && (tSim
<= (pTcmin(disSSTNoc)+tPastc))
        break;
    else
        if tSim > (pTamin(disSSTNoa)+tPasta)
            ISSTa(pka) = 0;
            RSSTa(pka) = 0;
            SSTa(pka) = 0;
            disTimea(pka) = pTamin(disSSTNoa)+tPasta;
            Wcapa = Wcapa - pTamin(disSSTNoa)*Pcapa*20000/3;  % Update all Ws
            tSepa(cLevel) = tPasta + pTamin(disSSTNoa);  % Record the moments at which the
current changes levels
            IBfault(cLevel) = abs((Vp(From(3))-Vp(To(3)))/z1OfBranches(3) + (Vn(From(3))-
Vn(To(3)))/z1OfBranches(3) + (Vz(From(3))-Vz(To(3)))/z0OfBranches(3))* Sb /
(sqrt(3)*kVNom(FBusNo+1));  % Record the breaker current levels
            IRfault(cLevel) = abs((Vp(From(5))-Vp(To(5)))/z1OfBranches(5) + (Vn(From(5))-
Vn(To(5)))/z1OfBranches(5) + (Vz(From(5))-Vz(To(5)))/z0OfBranches(5))* Sb /
(sqrt(3)*kVNom(FBusNo+1));  % Record the recloser current levels
            cLevel = cLevel + 1;
            disSSTNoa = disSSTNoa + 1;
        end
        if tSim > (pTbmin(disSSTNob)+tPastb)
            ISSTb(pkb) = 0;
            RSSTb(pkb) = 0;
            SSTb(pkb) = 0;
            disTimeb(pkb) = pTbmin(disSSTNob)+tPastb;
            Wcapb = Wcapb - pTbmin(disSSTNob)*Pcapb*20000/3;  % Update all Ws
            disSSTNob = disSSTNob + 1;
        end
        if tSim > (pTcmin(disSSTNoc)+tPastc)
            ISSTc(pkc) = 0;
            RSSTc(pkc) = 0;
            SSTc(pkc) = 0;
            disTimec(pkc) = pTcmin(disSSTNoc)+tPastc;
            Wcapc = Wcapc - pTcmin(disSSTNoc)*Pcapc*20000/3;  % Update all Ws
            disSSTNoc = disSSTNoc + 1;
```

```
        end
    end

    if disSSTNoa == disSSTNoaOld
        break;
    end
    disSSTNoaOld = disSSTNoa;
end

IBfault(cLevel) = abs((Vp(From(3))-Vp(To(3)))/z1OfBranches(3) + (Vn(From(3))-
Vn(To(3)))/z1OfBranches(3) + (Vz(From(3))-Vz(To(3)))/z0OfBranches(3))* Sb /
(sqrt(3)*kVNom(FBusNo+1));  % Record the last level of the breaker current
IRfault(cLevel) = abs((Vp(From(5))-Vp(To(5)))/z1OfBranches(5) + (Vn(From(5))-
Vn(To(5)))/z1OfBranches(5) + (Vz(From(5))-Vz(To(5)))/z0OfBranches(5))* Sb /
(sqrt(3)*kVNom(FBusNo+1));  % Record the last level of the recloser current

Vcapa = sqrt(2*Wcapa/(30e-6));
Vcapb = sqrt(2*Wcapb/(30e-6));
Vcapc = sqrt(2*Wcapc/(30e-6));


% Results

if ItrNo <= mxitr
    disp(['   Fault at Bus:  ', num2str(FBusNo)])
    disp(' ')
    disp('   Bus        Va(pu)    SSTa Current(pu rating)')
    disp([BusNo((2:end),:) abs(Va) [sign(unblnca(1:13));(-1)*ones(8,1)].*abs(ISSTa)./SSTa])
    disp('   PDs Final Currents:')
    for k = 1 : 1 : (NoOfBranches-1)  % An extra branch had been added to model the Rf which
has to be removed here.
        if IsPD(k) == 1
        disp(['   PD Between ', num2str(From(k)), ' and ', num2str(To(k)), ', Phase A Fault
Current (kA):  ', num2str(abs((Vp(From(k))-Vp(To(k)))/z1OfBranches(k) + (Vn(From(k))-
Vn(To(k)))/z1OfBranches(k) + (Vz(From(k))-
Vz(To(k)))/z0OfBranches(k))*Sb/(sqrt(3)*kVNom(FBusNo+1)))])  % Ia = Ip + In + Iz
        end
    end
    disp(' ')
    disp('   Breaker and Recloser current levels and change times')
    disp('    Brk(kA)   Rcl(kA)   Change times(s)')
    disp([IBfault ; IRfault ; tSepa])

else
    disp('NOT CONVERGENT!')
end
```

GREEN HUB II – SINGLE PHASE FAULTS

INPUT

```
Sb = 100;

econv = 1e-5;

mxitr = 200;


% Bus no. 0 is located between the system voltage source and system
% impedance and will not be considered in the YBus matrix. The system
% voltage source and impedance will be converted to their Norton equivelant
% circuit.
%       Bus       SSTa(MW)  SSTb(MW)  SSTc(MW)       Loada(MW)   Loadb(MW)   Loadc(MW)
kV(nom.)         kV(reg.)
bus =   [
        0         0         0         0              0           0           0
230              230       ;
        1         0         0         0              0           0           0
230              0;
        2         0         0         0              0           0           0
12               0;
        3         0         0         0              0           0           0
12               0;
        4         0.1       0.2       0.14           0.05775     0.16555     0.11242
12               0;
        5         0         0         0              0           0           0
12               0;
        6         0.6       0.84      0.4            0.53207     0.73483     0.3388
12               0;
        7         0         0.16      0.02           0           0.141       0.01463
12               0;
        8         0.04      0.02      0.1            0.02002     0.01001     0.08547
12               0;
        9         0.74      0.2       0.12           0.65142     0.17171     0.1001
12               0;
        10        0.62      0.08      0.3            0.54439     0.05698     0.2541
12               0;
        11        0.18      0.14      0.28           0.14553     0.11242     0.24563
12               0;
        12        0.68      0.58      0.84           0.59752     0.51051     0.73381
12               0;
        13        0.62      0.6       0.6            0.53515     0.53053     0.52052
12               0;
        14        0.06      0.04      0.08           0.032725    0.025564    0.050743
12               0;
        15        0.5       0.8       0.92           0.45584     0.715176    0.841841
12               0;
        16        0.36      0.36      0.12           0.319396    0.317856    0.095326
12               0;
        17        0.02      0         0              0.015862    0           0
12               0;
        18        0         0         0              0           0           0
12               0;
        19        0.4       0.24      0.08           0.357665    0.207207    0.059598
12               0;
        20        0.56      0.48      0.94           0.499576    0.424424    0.846461
12               0;
        21        0.18      0.68      0.26           0.168938    0.608839    0.227227
12               0;
        ];
```

```
% IsPD is 1 if the branch represents a protective device and 0 if not.
%       Fr        To        r1(p.u./km)   x1(p.u./km)   r0(p.u./km)   x0(p.u./km)
length(km)   IsPD
brnch = [
        0         1         7.7996e-4     0.010618      7.7996e-4     0.010618      1
0;       % Zs
        1         2         0.0863334     0.6553334     0.0863334     0.6553334     1
0;       % transformer
        2         3         6.9444e-4     0             6.9444e-4     0             1
1;       % breaker
        3         4         1.4738e-2     5.9408e-2     5.4123e-2     2.0972e-1     7.141
0;
        4         5         6.9444e-4     0             6.9444e-4     0             1
1;       % recloser
        5         6         1.4616e-2     6.1453e-2     9.0933e-2     2.6508e-1     4.37
0;
        6         7         1.4271e-2     6.1163e-2     9.0726e-2     2.6504e-1     0.356
0;
        7         8         1.4645e-2     6.4731e-2     8.3183e-2     2.3520e-1     1.239
0;
        4         9         1.4570e-2     6.1369e-2     7.9149e-2     2.4313e-1     2.939
0;
        9         10        1.4678e-2     6.1509e-2     7.8843e-2     2.4338e-1     2.596
0;
        10        11        1.4608e-2     6.1353e-2     7.7840e-2     2.4416e-1     1.739
0;
        11        12        1.4527e-2     6.2053e-2     7.3442e-2     2.3718e-1     4.047
0;
        12        13        1.4604e-2     6.1460e-2     6.3490e-2     2.3085e-1     4.647
0;
        2         14        2.9037e-2     8.4174e-2     8.7871e-2     2.8265e-1     3.378
0;
        14        15        2.9408e-2     8.4976e-2     1.1812e-1     2.9863e-1     2.261
0;
        15        16        2.5045e-2     6.9389e-2     1.0283e-1     2.5542e-1     5.6913
0;
        15        17        1.1989e-1     1.6754e-1     8.8843e-1     3.0895e-1     0.239
0;
        17        18        2.8313e-2     7.7376e-2     1.1835e-1     2.9139e-1     2.089
0;
        14        19        2.8645e-2     8.3402e-2     8.3272e-2     2.7862e-1     2.819
0;
        19        20        2.8707e-2     8.3208e-2     8.7784e-2     2.8041e-1     0.883
0;
        20        21        2.8742e-2     8.2511e-2     1.1577e-1     2.9261e-1     3.17
0;
        ];

% The unbalancy between PV and load in p.u. based on the load MW (PV-Load)
unblnc = -1;

% The type information will not be used in the calculations.
% The resistance cannot be zero but can be close to zero.
% type=3 for three-phase faults, type=1 for single-phase faults
%       Bus       resistance(ohm)   type
fault = [
        5         10.41             1;
        ];

% The neutral reactor connected to the neutral of the Y side of the transformer.
ntrlReactor = 120 * pi * 8.3556e-4;

% Time at which the current is calculated.
tSim = 10;
```

```
% Version 1.15:
    % - This version is based on nodal analysis.
    % - Works for 1-phase faults with arbitrary resistance.
    % - The distribution system is Green Hub II.
    % - The SSTs can be unbalanced three-phase sources. (SSTa~=SSTb~=SSTc)
    % - This version calculates the currents and voltages at any times.
    % - This version records the current levels in "IBfault" and "IRfault" and the changing
times in "tSepa".
    % - This version differentiates between SSTs' ratings and loads'ratings.

% Note: The unbalancy is different for SSTs (1-13) and SSTs (14-21). This will effect P2 and
RSST.


% Input Area
clc;
clear;

a = -0.5 + (sqrt(3)/2)*1i;

FAinputV1_15;    % Read the input file

% Seperate the bus data into columns
BusNo = bus(:, 1);
SSTa = bus((2:end), 2) ./ (Sb/3);  % Per unit values of SSTs' ratings on phase A, row 1 is
assossiated with bus 0 and should be eliminated.
SSTb = bus((2:end), 3) ./ (Sb/3);  % Per unit values of SSTs' ratings on phase B, row 1 is
assossiated with bus 0 and should be eliminated.
SSTc = bus((2:end), 4) ./ (Sb/3);  % Per unit values of SSTs' ratings on phase C, row 1 is
assossiated with bus 0 and should be eliminated.
SSTa = [SSTa(1:13);zeros(8,1)];
SSTb = [SSTb(1:13);zeros(8,1)];
SSTc = [SSTc(1:13);zeros(8,1)];
% SSTa = [zeros(4,1);SSTa(5:8);zeros(13,1)];
% SSTb = [zeros(4,1);SSTb(5:8);zeros(13,1)];
% SSTc = [zeros(4,1);SSTc(5:8);zeros(13,1)];
LoadaP = bus((2:end), 5) ./ (Sb/3);  % Per unit values of PVs' powers on phase A
LoadbP = bus((2:end), 6) ./ (Sb/3);  % Per unit values of PVs' powers on phase B
LoadcP = bus((2:end), 7) ./ (Sb/3);  % Per unit values of PVs' powers on phase C
kVNom = bus(:, 8);
kVReg = bus(:, 9);

% Seperate the branch data in columns
From = brnch(:, 1);
To = brnch(:, 2);
r1OfBranches = brnch(:, 3) .* brnch(:, 7);  % Per unit values of r1s of branches
x1OfBranches = brnch(:, 4) .* brnch(:, 7);  % Per unit values of x1s of branches
r0OfBranches = brnch(:, 5) .* brnch(:, 7);  % Per unit values of r0s of branches
x0OfBranches = brnch(:, 6) .* brnch(:, 7);  % Per unit values of x0s of branches
ntrlReactor = ntrlReactor /(kVNom(3)*kVNom(3)/Sb);  % Neutral reactor should be per-united.
IsPD = brnch(:, 8);

% Seperate the fault data into columns
FBusNo = fault(:, 1);
FRes = fault(:, 2)/(kVNom(FBusNo+1)*kVNom(FBusNo+1)/Sb);  % FRes should be per-united.
FType = fault(:, 3);

% Figure out the number of branches and buses excluding bus 0.
NoOfBuses = size(BusNo, 1) - 1;
NoOfBranches = size(From, 1);

% Unbalancies
unblnca = zeros(NoOfBuses, 1);
```

```
unblncb = zeros(NoOfBuses, 1);
unblncc = zeros(NoOfBuses, 1);
for k = 1 : 1 : NoOfBuses
    if SSTa(k) ~= 0
        unblnca(k) = unblnc * LoadaP(k) ./ SSTa(k);  % Unbalancy based on the corresponding
SST's rating
    end
    if SSTb(k) ~= 0
        unblncb(k) = unblnc * LoadbP(k) ./ SSTb(k);  % Unbalancy based on the corresponding
SST's rating
    end
    if SSTc(k) ~= 0
        unblncc(k) = unblnc * LoadcP(k) ./ SSTc(k);  % Unbalancy based on the corresponding
SST's rating
    end
end


% Step 0

% Add the neutral reactor
x0OfBranches(2) = x0OfBranches(2) + 3 * ntrlReactor;

% Calculate admittance of branches
z1OfBranches = r1OfBranches + x1OfBranches * 1i;
y1OfBranches = 1./z1OfBranches;
z0OfBranches = r0OfBranches + x0OfBranches * 1i;
y0OfBranches = 1./z0OfBranches;

% Calculate Y1 bus and Y0 bus
Y1Bus = zeros(NoOfBuses);
Y0Bus = zeros(NoOfBuses-1);
for k = 1 : 1 : NoOfBuses
    for h = 1 : 1 : NoOfBuses
        if k == h
            for w = 1 : 1 : NoOfBranches
                if ((From(w) == k) || (To(w) == k))
                    Y1Bus(k, h) = Y1Bus(k, h) + y1OfBranches(w);
                end
            end
        else
            for w = 1 : 1 : NoOfBranches
                if ((From(w) == k) && (To(w) == h)) || ((From(w) == h) && (To(w) == k))
                    Y1Bus(k, h) = Y1Bus(k, h) - y1OfBranches(w);
                end
            end
        end
    end
end
for k = 1 : 1 : NoOfBuses
    for h = 1 : 1 : NoOfBuses
        if k == h
            for w = 1 : 1 : NoOfBranches
                if ((From(w) == (k+1)) || (To(w) == (k+1)))
                    Y0Bus(k, h) = Y0Bus(k, h) + y0OfBranches(w);
                end
            end
        else
            for w = 1 : 1 : NoOfBranches
                if ((From(w) == (k+1)) && (To(w) == (h+1))) || ((From(w) == (h+1)) && (To(w)
== (k+1)))
                    Y0Bus(k, h) = Y0Bus(k, h) - y0OfBranches(w);
                end
            end
        end
    end
```

```
end

% Calculate the Z buses
Z1Bus = inv(Y1Bus);
Z0Bus = inv(Y0Bus);

% Initialization
Vs = 1;  % The system source voltage
RSSTa = unblnca .* SSTa;  % Applicable SST rating on phase A
RSSTb = unblncb .* SSTb;  % Applicable SST rating on phase B
RSSTc = unblncc .* SSTc;  % Applicable SST rating on phase C
RSSTa = [RSSTa(1:13);((-1).*SSTa(14:21))];  % No PVs after 13
RSSTb = [RSSTb(1:13);((-1).*SSTb(14:21))];  % No PVs after 13
RSSTc = [RSSTc(1:13);((-1).*SSTc(14:21))];  % No PVs after 13

ISSTa = RSSTa;  % Per unit values of SSTs' currents on phase A
ISSTb = a*a*RSSTb;  % Per unit values of SSTs' currents on phase B
ISSTc = a*RSSTc;  % Per unit values of SSTs' currents on phase C
Va = zeros(NoOfBuses, 1);  % The final bus voltages on phase A
Va(1) = Vs;
Vb = ones(NoOfBuses, 1);  % The final bus voltages on phase B
Vc = ones(NoOfBuses, 1);  % The final bus voltages on phase C
Vaold = Va;  % Is used to check convergence
Vbold = Vb;  % Is used to check convergence
Vcold = Vc;  % Is used to check convergence
ISSTaold = ISSTa;  % Is used to check convergence
ISSTbold = ISSTb;  % Is used to check convergence
ISSTcold = ISSTc;  % Is used to check convergence

pTamin = zeros(NoOfBuses, 1);  % "Tmin" determines the next "t" at which one of the SSTs
shuts down
pTbmin = zeros(NoOfBuses, 1);
pTcmin = zeros(NoOfBuses, 1);
disSSTNoa = 1;  % No of SSTs to shut down
disSSTNob = 1;
disSSTNoc = 1;
Wcapa = 0.5*(30e-6)*3800*3800*ones(NoOfBuses,1);  % Initial value for cap energy
Wcapb = 0.5*(30e-6)*3800*3800*ones(NoOfBuses,1);
Wcapc = 0.5*(30e-6)*3800*3800*ones(NoOfBuses,1);

Wdisa = zeros(NoOfBuses,1);
Wdisb = zeros(NoOfBuses,1);
Wdisc = zeros(NoOfBuses,1);

disTimea = 1000 * ones(NoOfBuses, 1);
disTimeb = 1000 * ones(NoOfBuses, 1);
disTimec = 1000 * ones(NoOfBuses, 1);

tPasta = 0;  % Total time passed
tPastb = 0;
tPastc = 0;

cLevel = 1;
IBfault = zeros(3*NoOfBuses, 1);  % Breaker current levels
IRfault = zeros(3*NoOfBuses, 1);  % Recloser current levels
tSep = zeros(3*NoOfBuses, 1);  % Moments seperating the current levels

disSSTNoaOld = 0;
disSSTNobOld = 0;
disSSTNocOld = 0;


ItrNo2 = 0;
while (1)   % This "while" is to apply PVs' protections

    % Counter of number of iteration to = 0
```

```
    ItrNo = 0;

    % This "while" continues working unless one of the ifs in STEP 2 becomes true
    while (1)
        % STEP 1

        % From abc to +-0 (pnz)
        ISSTz = (ISSTa + ISSTb + ISSTc) / 3;
        ISSTp = (ISSTa + a*ISSTb + a*a*ISSTc) / 3;
        ISSTn = (ISSTa + a*a*ISSTb + a*ISSTc) / 3;

        % Calculate If (Fault current in the sequential network)
        If = 0;
        for k = 1 : 1 : NoOfBuses
            If = If + Z1Bus(FBusNo, k) * ISSTp(k) + Z1Bus(FBusNo, k) * ISSTn(k);
        end
        for k = 2 : 1 : NoOfBuses
            If = If + Z0Bus(FBusNo-1, k-1) * ISSTz(k);
        end
        If = (If + Z1Bus(FBusNo, 1) * Vs/z1OfBranches(1)) / (3 * FRes + Z1Bus(FBusNo, FBusNo)
+ Z1Bus(FBusNo, FBusNo) + Z0Bus(FBusNo-1, FBusNo-1));

        % Calculate I
        Ip = ISSTp;
        Ip(1) = Ip(1) + Vs/z1OfBranches(1);
        Ip(FBusNo) = Ip(FBusNo) - If;
        In = ISSTn;
        In(FBusNo) = In(FBusNo) - If;
        Iz = ISSTz(2:end);  % Since the transformer is of delta-wye type, we don't consider
the bus 1 in the zero sequence network.
        Iz(FBusNo-1) = Iz(FBusNo-1) - If;

        % Calculate V1
        Vp = Y1Bus \ Ip;  % The positive sequence bus voltages
        Vn = Y1Bus \ In;  % The negative sequence bus voltages
        Vz = [0 ; Y0Bus\Iz];  % The zero sequence bus voltages

        % From +-0 (pnz) to abc
        Va = Vz + Vp + Vn;
        Vb = Vz + a*a*Vp + a*Vn;
        Vc = Vz + a*Vp + a*a*Vn;


        % STEP 2

        % Check if deltaV and deltaISSTa gets less than "econv" or not. If yes,
        % the program terminates
        if ((max(abs([Va(1:(FBusNo-1));Vb(1:(FBusNo-1));Vc(1:(FBusNo-1))]-[Vaold(1:(FBusNo-
1));Vbold(1:(FBusNo-1));Vcold(1:(FBusNo-1))])) < econv) && (max(abs([ISSTa(1:(FBusNo-
1));ISSTb(1:(FBusNo-1));ISSTc(1:(FBusNo-1))]-[ISSTaold(1:(FBusNo-1));ISSTbold(1:(FBusNo-
1));ISSTcold(1:(FBusNo-1))])) < econv))
            break;
        end

        % Check if number of iteration exceeds the limit or not. If yes, the
        % program terminates
        if ItrNo > mxitr
            break;
        end
        ItrNo = ItrNo + 1;

        Vaold = Va;
        Vbold = Vb;
        Vcold = Vc;
        ISSTaold = ISSTa;
        ISSTbold = ISSTb;
```

```
        ISSTcold = ISSTc;


        % STEP 3

        % Update SSTs' currents based on the bus voltages
        for k = 1 : 1 : NoOfBuses
            if (abs(Va(k)) < (abs(unblnca(k))/2))
                ISSTa(k) = 2 * unblnca(k)/abs(unblnca(k)) * SSTa(k) * (cos(angle(Va(k))) +
sin(angle(Va(k)))*1i);
            elseif (abs(Va(k)) >= (abs(unblnca(k))/2))
                ISSTa(k) = (1/abs(Va(k))) * RSSTa(k) * (cos(angle(Va(k))) +
sin(angle(Va(k)))*1i);
            end
            if (abs(Vb(k)) < (abs(unblncb(k))/2))
                ISSTb(k) = 2 * unblncb(k)/abs(unblncb(k)) * SSTb(k) * (cos(angle(Vb(k))) +
sin(angle(Vb(k)))*1i);
            elseif (abs(Vb(k)) >= (abs(unblncb(k))/2))
                ISSTb(k) = (1/abs(Vb(k))) * RSSTb(k) * (cos(angle(Vb(k))) +
sin(angle(Vb(k)))*1i);
            end
            if (abs(Vc(k)) < (abs(unblncc(k))/2))
                ISSTc(k) = 2 * unblncc(k)/abs(unblncc(k)) * SSTc(k) * (cos(angle(Vc(k))) +
sin(angle(Vc(k)))*1i);
            elseif (abs(Vc(k)) >= (abs(unblncc(k))/2))
                ISSTc(k) = (1/abs(Vc(k))) * RSSTc(k) * (cos(angle(Vc(k))) +
sin(angle(Vc(k)))*1i);
            end
        end
        for k = 14 : 1 : NoOfBuses  % the unblnc for the adjacent feeder is (-1)
            if (abs(Va(k)) < (1/2))
                ISSTa(k) = 2 * RSSTa(k) * (cos(angle(Va(k))) + sin(angle(Va(k)))*1i);
            elseif (abs(Va(k)) >= (1/2))
                ISSTa(k) = (1/abs(Va(k))) * RSSTa(k) * (cos(angle(Va(k))) +
sin(angle(Va(k)))*1i);
            end
            if (abs(Vb(k)) < (1/2))
                ISSTb(k) = 2 * RSSTb(k) * (cos(angle(Vb(k))) + sin(angle(Vb(k)))*1i);
            elseif (abs(Vb(k)) >= (1/2))
                ISSTb(k) = (1/abs(Vb(k))) * RSSTb(k) * (cos(angle(Vb(k))) +
sin(angle(Vb(k)))*1i);
            end
            if (abs(Vc(k)) < (1/2))
                ISSTc(k) = 2 * RSSTc(k) * (cos(angle(Vc(k))) + sin(angle(Vc(k)))*1i);
            elseif (abs(Vc(k)) >= (1/2))
                ISSTc(k) = (1/abs(Vc(k))) * RSSTc(k) * (cos(angle(Vc(k))) +
sin(angle(Vc(k)))*1i);
            end
        end
    end


    % Apply SSTs' protections
    % Very important note!: In contrast to the network solution, in the
    % protection logic the current injection to the system has "-" sign and
    % current drawing from the system has "+" sign.
    P1a = (-1)*real(Va .* conj(ISSTa./SSTa));
    P1b = (-1)*real(Vb .* conj(ISSTb./SSTb));
    P1c = (-1)*real(Vc .* conj(ISSTc./SSTc));
    P2a = (-1) * [unblnca(1:13);(-1)*ones(8,1)];  % All P2s are defined as Load-PV, No PVs
after 13
    P2b = (-1) * [unblncb(1:13);(-1)*ones(8,1)];
    P2c = (-1) * [unblncc(1:13);(-1)*ones(8,1)];
    Pcapa = P2a - P1a;
    Pcapb = P2b - P1b;
    Pcapc = P2c - P1c;
```

```
    for k = 1 : 1 : NoOfBuses
        if Pcapa(k) >= 0
            Wdisa(k) = Wcapa(k) - 0.5*(30e-6)*2660*2660; % Energy that has to be dissipated
so that the cap voltage reduces to 2660
        else
            Wdisa(k) = 0.5*(30e-6)*4560*4560 - Wcapa(k); % Energy that has to be absorbed so
that the cap voltage increases to 4560
        end
        if Pcapb(k) >= 0
            Wdisb(k) = Wcapb(k) - 0.5*(30e-6)*2660*2660; % Energy that has to be dissipated
so that the cap voltage reduces to 2660
        else
            Wdisb(k) = 0.5*(30e-6)*4560*4560 - Wcapb(k); % Energy that has to be absorbed so
that the cap voltage increases to 4560
        end
        if Pcapc(k) >= 0
            Wdisc(k) = Wcapc(k) - 0.5*(30e-6)*2660*2660; % Energy that has to be dissipated
so that the cap voltage reduces to 2660
        else
            Wdisc(k) = 0.5*(30e-6)*4560*4560 - Wcapc(k); % Energy that has to be absorbed so
that the cap voltage increases to 4560
        end
    end
    pTimea = abs(Wdisa ./ (Pcapa*20000/3));  % The time it takes for the cap voltage to
reduce to 2660 or increase to 4560
    pTimeb = abs(Wdisb ./ (Pcapb*20000/3));
    pTimec = abs(Wdisc ./ (Pcapc*20000/3));
    [pTamin(disSSTNoa), pka] = min(pTimea);  % The SST whose turn is to shut down with the
time it takes to shut down
    [pTbmin(disSSTNob), pkb] = min(pTimeb);
    [pTcmin(disSSTNoc), pkc] = min(pTimec);

    tPasta = 0;  % Total time passed
    tPastb = 0;
    tPastc = 0;
    for k = 1 : 1 : (disSSTNoa-1)
        tPasta = pTamin(k) + tPasta;
    end
    for k = 1 : 1 : (disSSTNob-1)
        tPastb = pTbmin(k) + tPastb;
    end
    for k = 1 : 1 : (disSSTNoc-1)
        tPastc = pTcmin(k) + tPastc;
    end

    %  Applying the voltage protection
    if (tSim <= (pTamin(disSSTNoa)+tPasta)) && (tSim <= (pTbmin(disSSTNob)+tPastb)) && (tSim
<= (pTcmin(disSSTNoc)+tPastc))
        break;
    else
        if tSim > (pTamin(disSSTNoa)+tPasta)
            ISSTa(pka) = 0;
            RSSTa(pka) = 0;
            SSTa(pka) = 0;
            disTimea(pka) = pTamin(disSSTNoa)+tPasta;
            Wcapa = Wcapa - pTamin(disSSTNoa)*Pcapa*20000/3;  % Update all Ws
            tSep(cLevel) = tPasta + pTamin(disSSTNoa);  % Record the moments at which the
current changes levels
            IBfault(cLevel) = abs(3*(Vz(From(3))-
Vz(To(3)))/z0OfBranches(3))*Sb/(sqrt(3)*kVNom(FBusNo+1));  % Record the breaker current
levels
            IRfault(cLevel) = abs(3*(Vz(From(5))-
Vz(To(5)))/z0OfBranches(5))*Sb/(sqrt(3)*kVNom(FBusNo+1));  % Record the recloser current
levels
            cLevel = cLevel + 1;
            disSSTNoa = disSSTNoa + 1;
```

```
        end
        if tSim > (pTbmin(disSSTNob)+tPastb)
            ISSTb(pkb) = 0;
            RSSTb(pkb) = 0;
            SSTb(pkb) = 0;
            disTimeb(pkb) = pTbmin(disSSTNob)+tPastb;
            Wcapb = Wcapb + pTbmin(disSSTNob)*Pcapb*20000/3;  % Update all Ws
            tSep(cLevel) = tPastb + pTbmin(disSSTNob);  % Record the moments at which the
current changes levels
            IBfault(cLevel) = abs(3*(Vz(From(3))-
Vz(To(3)))/z0OfBranches(3))*Sb/(sqrt(3)*kVNom(FBusNo+1));  % Record the breaker current
levels
            IRfault(cLevel) = abs(3*(Vz(From(5))-
Vz(To(5)))/z0OfBranches(5))*Sb/(sqrt(3)*kVNom(FBusNo+1));  % Record the recloser current
levels
            cLevel = cLevel + 1;
            disSSTNob = disSSTNob + 1;
        end
        if tSim > (pTcmin(disSSTNoc)+tPastc)
            ISSTc(pkc) = 0;
            RSSTc(pkc) = 0;
            SSTc(pkc) = 0;
            disTimec(pkc) = pTcmin(disSSTNoc)+tPastc;
            Wcapc = Wcapc + pTcmin(disSSTNoc)*Pcapc*20000/3;  % Update all Ws
            tSep(cLevel) = tPastc + pTcmin(disSSTNoc);  % Record the moments at which the
current changes levels
            IBfault(cLevel) = abs(3*(Vz(From(3))-
Vz(To(3)))/z0OfBranches(3))*Sb/(sqrt(3)*kVNom(FBusNo+1));  % Record the breaker current
levels
            IRfault(cLevel) = abs(3*(Vz(From(5))-
Vz(To(5)))/z0OfBranches(5))*Sb/(sqrt(3)*kVNom(FBusNo+1));  % Record the recloser current
levels
            cLevel = cLevel + 1;
            disSSTNoc = disSSTNoc + 1;
        end
    end

    if (disSSTNoa == disSSTNoaOld) && (disSSTNob == disSSTNobOld) && (disSSTNoc ==
disSSTNocOld)
        break;
    end
    disSSTNoaOld = disSSTNoa;
    disSSTNobOld = disSSTNob;
    disSSTNocOld = disSSTNoc;
end

IBfault(cLevel) = abs(3*(Vz(From(3))-
Vz(To(3)))/z0OfBranches(3))*Sb/(sqrt(3)*kVNom(FBusNo+1));  % Record the breaker current
levels
IRfault(cLevel) = abs(3*(Vz(From(5))-
Vz(To(5)))/z0OfBranches(5))*Sb/(sqrt(3)*kVNom(FBusNo+1));  % Record the recloser current
levels

Vcapa = sqrt(2*Wcapa/(30e-6));
Vcapb = sqrt(2*Wcapb/(30e-6));
Vcapc = sqrt(2*Wcapc/(30e-6));


% Results

if ItrNo <= mxitr
    disp(['   Fault at Bus:  ', num2str(FBusNo)])
    disp(' ')
    disp('   Bus        Va(pu)    SSTa(puR)  Vb(pu)    SSTb(puR)  Vc(pu)    SSTc(puR)')
```

```
    disp([BusNo((2:end),:) abs(Va) [sign(unblnca(1:13));(-1)*ones(8,1)].*abs(ISSTa)./SSTa
abs(Vb) [sign(unblncb(1:13));(-1)*ones(8,1)].*abs(ISSTb)./SSTb abs(Vc)
[sign(unblncc(1:13));(-1)*ones(8,1)].*abs(ISSTc)./SSTc])
    disp('   PDs Currents:')
    for k = 1 : 1 : (NoOfBranches-1)  % An extra branch had been added to model the Rf which
has to be removed here.
        if IsPD(k) == 1
        disp(['   PD Between ', num2str(From(k)), ' and ', num2str(To(k)), ', (3I0) Fault
Current (kA):  ', num2str(abs(3*(Vz(From(k))-
Vz(To(k)))/z0OfBranches(k))*Sb/(sqrt(3)*kVNom(FBusNo+1)))])  % IPD = 3 * Iz
        end
    end
    disp(' ')
    disp('   Breaker and Recloser current levels and change times')
    disp('    Brk(kA)   Rcl(kA)   Change times(s)')
    disp([IBfault  IRfault  tSep])
else
    disp('NOT CONVERGENT!')
end
```

ESTIMATION OF RELAY TRIP TIME

```
clc;
clear;

%% Input
I = [1552;1660;1740];  % current levels
T = [0.2;0.5];  % time moments at which the current changes level

%% Ttrip calculation based on time-current curve
% Breaker
TD = 1.1;  % time dial setting
Ipick = 1440;  % pickup current

sI = size(I);  % number of current levels

Ttrip = zeros(sI(1),1);  % Ttrip calculation
for k = 1 : 1 : sI
    Ttrip(k) = TD*(0.00262+0.00342/(power(I(k)/Ipick,0.02)-1));
end

% Recloser
% TD = 1.3;  % time dial setting
% Ipick = 480;  % pickup current
%
% sI = size(I);  % number of current levels
%
% Ttrip = zeros(sI(1),1);  % Ttrip calculation
% for k = 1 : 1 : sI
%     Ttrip(k) = (0.00172/(power(I(k)/Ipick,0.02)-1)+0.0037)*((14*TD-5)/9);
% end
%

%% Seperating the current levels lower than the pickup current
T0 = 0;  % the moment at which the first current level above the pickup current occurs
indexIlow = 1;  % the number of the first current level above the pickup current

for k = 1 : 1 : sI(1)
    if I(k) > Ipick
        if k == 1
            T0 = 0;
        else
            T0 = T(k-1);
        end
        indexIlow = k;
        break;
    end
end

%% Final trip time calculation
for h = indexIlow : 1 : sI(1)  % this "for" is to determine at which current level the relay
trips. the current level at which the relay trips is NOT necessarily the last level
    if h == indexIlow  % to see if the relay trip in the first level of current (which is
obviously higher than the pickup)
        TFtrip = T0 + Ttrip(h);
    else                % checking other levels
        TFtrip = T0 + (T(h-1)-T0) + Ttrip(h);
        TFtrip = TFtrip - Ttrip(h) * (T(indexIlow)-T0) / Ttrip(indexIlow);
        for k = (indexIlow+1) : 1 : (h-1)
            TFtrip = TFtrip - Ttrip(h) * (T(k)-T(k-1)) / Ttrip(k);
        end
    end

    if (h < sI(1)) && (TFtrip <= T(h))  % if the relay trip time gets higher than the next
seperating time, the "for" loop should break
```

```
        break;
    end
end
TFtrip
```