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Protection of AC Microgrids with Inverter Interfaced Renewable Energy Sources using Differential Relays:

A Case Study of the CIGRE Low Voltage Distribution Network

Master's Thesis in Electric Power Engineering

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CHALMERS UNIVERSITY OF TECHNOLOGY
Gothenburg, Sweden 2018

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Abstract

With the passing of time, it is expected that more renewable energy sources (RES) are going to be integrated into the power system. Further, power systems are most likely to shift to distributed generation and microgrids. Unfortunately, integrating distributed generators in a distribution network changes both the directions and magnitude of the fault currents, giving challenges in relay coordination. Microgrids connected to the grid (grid connected mode) have higher fault current levels than when operating independently (island mode) because of the increased amount of fault current contributing sources. Further, islanded mode fault current levels are even lower for inverter interfaced RES because of their limited fault current capabilities. Low fault currents in islanded mode give protection challenges for pre-set over current based protection schemes. Also, the intermittency of RES results in varying fault current levels in a microgrid. To protect these independent systems, there is a need for modified protection schemes that reliably protect microgrids with inverter interfaced RES in a low voltage distribution network, particularly when it switches between operation modes.

The aim of this thesis was to demonstrate the reliability of the differential current protection (DCP) scheme in protecting microgrids with inverter interfaced RES for low voltage distribution networks. To prove this reliability, the PSCAD/EMTDC simulation software was used to conduct simulations for the DCP scheme, while comparing it to the traditional Overcurrent protection (OCP) scheme. A model of the CIGRE low voltage distribution network was used to conduct the simulations. OCP was evaluated for grid connected mode with and without Photovoltaic (PV) generation, and in island mode. Results showed the OCP average relay tripping time for single phase faults in grid mode without PV was 0.131s, and that of 3phase faults was 0.121. The addition of PV generators resulted in the increase of the average relay tripping time to 0.199s and 0.135s respectively. This occurs as a result of the fault current contributed by PV generation integration, which limits the current that can be seen by the preset OC relays. Results also showed some OC relays failing to trip in island mode due to loss of coordination and reduction in fault currents. DCP was then applied as the solution and was evaluated on grid mode with PV generation, on grid mode without PV generation and on island mode. DCP proved to be unaffected by neither bidirectional current flow nor changes in fault levels, giving an average tripping time for single phase faults in grid mode without PV of 0.101s, and that of three phase faults was 0.100s. Addition of PV generation resulted in a negligible increase in relay operating time for both three phase and singe phase faults. These results also show that DCP is faster than that OCP. The system was further tested for different generation levels (15%, 57% and 81%) in island mode and gave a negligible difference in average tripping time for different generation levels. This clearly showcased the effectiveness of the DCP scheme. DCP is a reliable protection solution for microgrids with invertor interfaced RES operating in both grid connected and islanded mode. Further, it can operate in either of the modes without changing protection settings.

Key words: Renewable Energy Sources (RES), Photovoltaic (PVC), Microgrid, Protection Coordination, Protection Scheme, Overcurrent Protection (OCP), Differential Current Protection (DCP).

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SWITHUN CHAKWAKWAMA, Gothenburg, November 2018.

Abbreviations

AC	Alternating Current
BESS	Battery Energy Storage Systems
CB	Circuit Breaker
CT	Current Transformer
DCP	Differential Current Protection
DC	Direct Current
DERs	Distributed Energy Resources
DG	Distributed Generation
DCP	Differential Current Protection
EMTDC	Electro Magnetic Transient Design and Control
ES	Energy Storage
FFT	Fast Fourier Transform
GW	Gigawatts
IDMT	Inverse Definite Minimum Time
LAN	Local Area Network
MC	Master Controller
MPP	Maximum Power Point
MPPT	Maximum Power Point Tracker
OC	Over Current
OCP	Over Current Protection
PCC	Point of Common Coupling
PSCAD	Power Systems Computer Aided Design
PV	Photovoltaic
PVC	Photovoltaic Cell
RES	Renewable Energy Sources
SDH	Synchronous Digital Hierarchy
SONET	Synchronous Optical Network
SPWM	Sinusoidal Pulse Width Modulation
TOC	Time-Over Current
THD	Total Harmonics Distortion
UNFCCC	United Nations Framework Convention on Climate Change

VT	Voltage Transformer

Symbols

Emf	Electromotive force
G_0	Standard test conditions of irradiance
I	Current
I_{diff}	Differential current
I_{fl}	Full load current
I_{fmin}	Minimum fault current
I_l	Cell current component due to photons
I_0	Reverse saturation diode current
I_m	Maximum power point current
I_{sc}	Short circuit current
t_{trip}	Trip time
t_{reset}	Reset time/s
I_{input}	Input current
$I_{pick\ up}$	Relay pick-up current
M	Ratio of input current to pick-up current
P	Active Power
P_{max}	Maximum power
Q	Reactive Power
T	Temperature
V_{oc}	Open circuit voltage
V_m	Maximum power point voltage

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1
Introduction

This chapter covers the general background, objectives and tasks, scope of the master's thesis research and the structure of the report. The background unveils the motivation behind the conducting of this thesis. This then leads to the research objectives and corresponding tasks that were conducted in a bid to attain the set-out objectives. The scope guides on the exact extent to which this thesis was applied. The latter part of the chapter highlights the structure of the report, thus providing clarity on the flow of the thesis report so that there is easy navigation through the report.

1.1 Background

For many decades, environmental degradation has been a key policy issue around the world. As part of the solution to this global problem, renewable energy generation is being enhanced in order to adopt power generation methods that are more environmental friendly. The largest annual increase of renewable energy generation hit its highest mark in 2016, with an additional capacity of approximately 161 gigawatts (GW) [1]. This increased the overall global capacity to almost 2,017 GW by the end of 2015, i.e. a 9% increase [1]. Globally, there has been a continued addition of annual renewable energy capacity as compared to the net capacity addition from fossil fuels, mainly due to a continued reduction in renewable energy technology prices [1]. For instance, the year 2016 saw renewable energy sources accounting for approximately 62% of the global power generation net capacity additions [1]. Specifically, 2016 saw newly installed renewable energy capacity having Solar PV account for about 47%, while wind accounted for 34% and hydropower 15.5% [1].

Globally, the fastest growing electricity sources are solar PV and wind [2]. The additional annual generation of solar PV and wind met over 90% of the additional electricity demand in 2015 [2]. For policy makers to achieve energy policy objectives such as lowering pollution, lowering CO_2 emissions and diversifying supply so that energy security is improved, solar PV and wind power tend to be an increasingly attractive option because of their lower costs and technological maturity [2]. For instance, the average cost of solar PV reduced by almost 80% while that of land-based wind reduced by 35% between 2008 and 2015 [2].

In both developing and emerging countries, the contribution of renewable energy to power systems has seen a rapid move from marginal to mainstream, partly due to the anticipated critical contribution that renewable energy would make in meeting the aims set out in the Paris Agreement [2]. The United Nations Framework Convention on Climate Change (UNFCCC) in Paris placed a 20% renewable energy penetration target in electricity markets by the year 2022 [2]. The successful penetration of these Renewable Energy Sources (RES) is pushing for modifications in power systems worldwide [2].

The integration of RES changes the network topologies and leads to different and intermittent fault levels. These changes are a protection challenge for pre-set protection systems, as failure to operate when needed may occur. Hence, to reliably operate and control power systems integrated with RES, there is a crucial need to design new protection methods or modify the existing protection schemes [3]. Much research has been done on the protection of sub-transmission networks with RES integration, since wind generation is generally connected at this level. However, solar penetration is increasing at distribution level and few papers focus on the protection of distribution networks in this regard. For distribution networks, there seems to be no available literature on the protection of 0.4kV distribution networks with inverter interfaced RES, particularly when the microgrid switches between operation modes. What seems to be largely available in the literature is the protection of 11kV distribution networks. Consequently, this thesis tried to fill this research gap by analysing different protection systems suitable for 0.4kV distribution networks with inverter interfaced RES, and it sort to propose a protection system that could provide reliable protection in both modes of operation.

1.2 Objectives and Tasks

The main objective of this thesis was to investigate the protection challenges associated with grid connected and islanded AC Micro-grids with inverter interfaced RES and propose solutions to the challenges. The effectiveness of the proposed solution was demonstrated through simulations. The simulation software that was used in this thesis is PSCAD/EMTDC and the simulations were conducted on a model of the CIGRE low voltage distribution network. The specific objectives were twofold. The first specific objective was to explore and simulate the limitation of conventional overcurrent-based protection schemes due to change in network topology and fault current levels in AC Micro-grids with inverter interfaced RES, especially when the microgrid switches from grid connected to island mode. The second specific objective was to explore and simulate selected protection solutions that would complement conventional protection methods and critically analyse results from different simulations and draw concrete conclusions.

To achieve the above objectives, the specific tasks are as follows:

1. *Literature study*: Conducting a thorough research on all possible protection solutions for AC Micro-Grids with Inverter Interfaced RES, and an analysis of different methods and selection of the most effective protection method.

2. *Simulations:* Based on the findings from the literature study, to demonstrate the effectiveness of the proposed solutions, simulating the selected method using PSCAD/EMTDC and conducting the simulations on a model of the CIGRE low voltage distribution network.

3. *Analysis:* To analyse results from the simulation and draw up a solution and recommendation for future research based on the findings.

4. *Report Writing:* The literature study, simulations and analysis were then document into a thesis report.

1.3 Scope

The thesis investigated the limitation of traditional preset overcurrent relays on microgrids, especially when the mode of operation switches from grid connected to island mode. A simulation of OCP was conducted on the CIGRE distribution network in both grid connected and island mode. Results were analyzed, limitations observed, and a solution was drawn. A simulation of DCP was conducted on the same CIGRE distribution network in both grid connected and island mode. Results were again analyzed, improvements observed, and a conclusion was drawn. This study was limited only to low voltage distribution systems of 400 volts (0.4kV). Simulations were conducted down to busbar level, and the demonstration only covered distribution lines.

In this study, the PVC models were set to operate at constant temperature and irradiance, therefore the intermittency of PVC was not considered. Faults were studied at steady state, and the only RES type connected was the PVC. Protection schemes used multimeters for signal measuring instead of CTs, hence the effect of CT mismatch inaccuracy is not considered. Finally, communication channel is assumed to be available.

1.4 Report Structure

This report is structured as following;

- Chapter 2: Microgrids and Protection Systems - explores the literature around microgrids, PV systems, protection systems, microgrid protection challenges and different protection solutions.
- Chapter 3: Network Modelling in PSCAD - illustrates how the network was modelled in PSCAD.
- Chapter 4: Case Study and Results - demonstrates the inefficiency of overcurrent, and efficiency of differential current protection.
- Chapter 5: Conclusion - a conclusion is drawn in this chapter, including recommendations on future research.

2

Microgrids And Protection Systems

This chapter presents the literature review for the thesis and discusses the protection challenges in microgrids with inverter interfaced generation. For the former, the specific areas to be covered are microgrids, PV systems, Battery Energy Storage Systems and protection systems. The latter part provides a discussion of protection challenges and possible solutions from different authors, and then presents a seemingly suitable protection system that was used in this thesis.

2.1 Microgrids

A microgrid is an independent, controllable and single power system that comprises distributed generation (DG), control devices, energy storage (ES) and load. A microgrid can also be considered as a mini electric power system that includes generation, transmission, and distribution. It is capable of achieving optimal energy allocation and power balance in a specified area [4]. A microgrid is more flexible than conventional power transmission and distribution grid. The battery energy storage system (BESS) and the distributed generation is connected directly in parallel to the load. A microgrid's capability of autonomous management, control and protection, gives a microgrid the ability of operation either in grid connected or islanded mode [4]. When a microgrid is grid-connected, a microgrid connects to the utility grid through a point of common coupling (PCC), and power is exchanged with the utility grid's distribution or sub transmission system. When a microgrid is in islanded mode of operation, the microgrid is completely disconnected from the utility grid. If there is a major disturbance, the grid supply can be disconnected so that the microgrid operates independently (off grid/island mode), where the distributed generators (DGs) independently continue supplying to local loads. It can, however, be grid connected when the generation seems insufficient to meet the load [5].

Microgrids can be categorised into Alternating Current (AC) microgrid, Direct Current (DC) microgrid and AC/DC hybrid microgrid. A DC microgrid has DGs, Battery Energy Storage Systems (BESSs), and DC loads connected to a DC bus through a DC/DC converter. AC loads connect to the DC BUS through an inverter. The main advantage of DC microgrid is easy control, with the main disadvantage being that inverters are needed for supplying power to AC loads [6]. An AC microgrid has the distribution network connected to an AC bus. AC microgrids are more dominant, with the advantage that there are no inverters needed for supplying power to AC loads. The main disadvantage is that operation and control is not easy. An AC/DC hybrid microgrid is composed of both a DC bus and an AC bus. The DC bus directly supplies power to DC loads whereas AC loads are directly supplied by the AC bus as shown in Figure 1 [7].

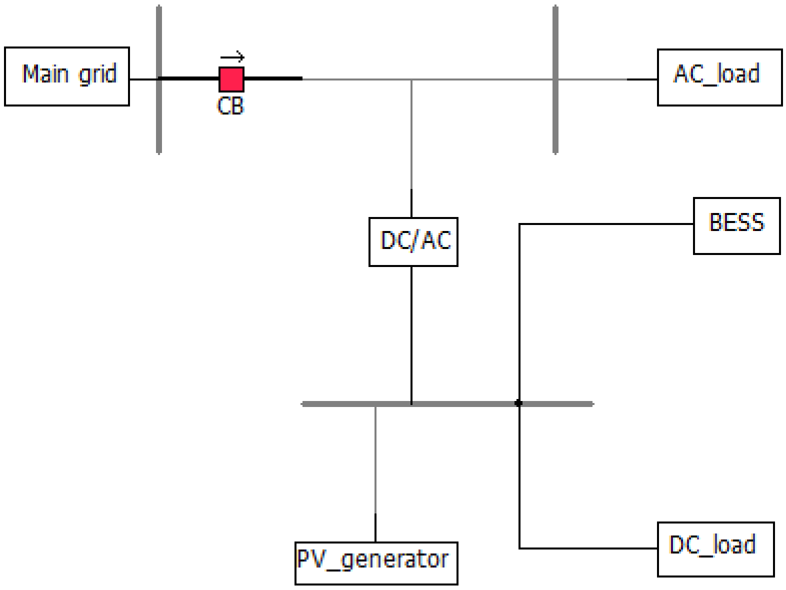

Figure 1: AC/DC Hybrid Grid Connected Microgrid

2.2 PV Systems

PV is a method of generating electricity by the conversion of solar energy into electrical energy. This phenomenon is performed by solar cells. Solar cells are the fundamental components in converting electrical energy from solar energy. Encapsulating solar cells forms a solar cell module and combining solar cell modules forms a solar cell array. Currently, the market is dominated by the crystalline silicon solar cell, and other solar cell types include; compound solar cells and amorphous silicon solar cell [8].

2.2.1 PV Cell

The PV cell is simply a pn junction specially designed barrier device. The operation of the PV cell is well described by the common diode equation. The PV cell produces electron-hole pairs when illuminated, due to the interaction of cell atoms and the incident photons. The electron-hole pairs generated by incident photons are then separated by the cell junction electric field, leading to holes moving towards the p region and electrons moving towards the n region [8]. The ideal PV cell I-V characteristic equation is given by;

$$I = I_l - I_0(e^{\frac{qV}{kT}} - 1) \tag{2.1}$$

where;
I_l = Cell current component due to photons
I_0 = Reverse saturation diode current
q = 1.6×10–19 coulombs
k = 1.38× 10–23 j/K
T = Temperature of the cell in K.

The PV cell short circuit current (I_{sc}) is determined by setting V to 0 in (2.1), giving $I_{sc} = I_l$. I_l is approximately, directly proportional to the irradiance to the cell. Thus, for a known I_l at standard test conditions of irradiance (G_0) = 1000 W/m^2, I_l at irradiance G, is given by;

$$I_l(G)=(G/G_0)\, I_l(G_0) \tag{2.2}$$

The PV cell open circuit voltage (V_{oc}) is determined by setting the cell current to zero in (2.1). solving for V_{oc}, yields;

$$V_{oc} = \frac{kT}{q} ln\left(\frac{I_l+I_0}{I_0}\right) \equiv \frac{kT}{q} ln(I_l/I_O) \tag{2.3}$$

$$I_l \gg I_0 \tag{2.4}$$

The PV cell power is obtained by Multiplication of the cell voltage with the cell current. To maximise the output from PV cell, the PV cell must be operated in such a way that it produces maximum power. Maximum power from a PV cell can only be obtained at one point on the I-V characteristic curve of the PV cell. The maximum power point voltage and current depend upon cell temperature, irradiance and load. The maximum power point (MPP) can be acquired by plotting the cell current vs voltage and observing where the MPP occurs [9]. The maximum power of a cell is given by;

$$P_{max} = I_m V_m \tag{2.5}$$

where V_m and I_m are the corresponding voltage and current values at maximum power point (MPP).

2.2.2 PV Module

PV modules are formed by connecting PV cells in series. This is done to increase the output voltage. Usually, PV systems connected to form 12 volts or higher multiples. The module design aim is to make a connection of adequate PV cells that can maintain the module V_m under average irradiance conditions conform with the BESS voltage. If this is done, the module output power can be kept at a level close to the maximum. [10]

2.2.3 PV Array

To obtain higher currents and voltages than produced by a single module, PV modules are connected to form PV arrays. Higher voltages are obtained from connecting PV modules in series, while higher currents are obtained from parallel connections. Different series parallel combinations can be done to obtain different voltage and current outputs. It is important to note that it is recommended for series connected modules to have their MPP occurring at the same current, also it is recommended for parallel connected modules to have their MPP occurring at the same voltage. And this information for each module must be available for the installer when mounting. [8]

2.2.4 Maximum Power Point Tracking

Operation at MPP is a challenge, since this needs the system to always use up all the PV output power. This means that the system load needs to adjust itself to meet the power output all the time. The ideal load I-V characteristic line intersects the PV array I-V characteristic curve at different points for varying irradiance levels. Figure 1 shows the IV characteristic curves for the PV array under different conditions, the ideal load for MPP operation and different types of loads.

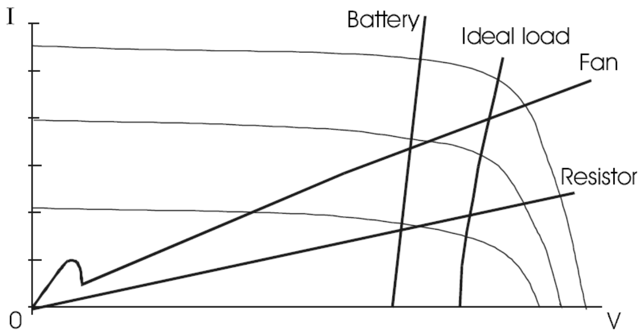

Figure 2: I-V Characteristics and MPP Operation
Source: *Messenger & Ventre [11]*

As observed from the above figure, the load I-V characteristic at some instance intersect the PV source I-V characteristic at a point significantly far from the MPP, in that event it is recommended to employ a maximum power point tracker (MPPT). A MPPT is placed between the load and the PV array. MPPTs normally use pulse-width modulation techniques, with a feedback loop to match the output voltage accordingly [11].

2.3 Battery Energy Storage Systems (BESSs)

Due to the uncertainty, dependence on solar light and intermittency nature of DGs. BESS technologies are provided to solve the demand and supply imbalance. Solar energy is only available when there is solar light, but power is needed around the clock. Therefore, for PV systems to able to provide energy around the clock, they must have energy storage systems. Also, an inverter must be connected to supply power to AC loads. BESS also has other purposes which include; control, stability, black start and power quality adjustment.

ES technologies are in different forms which include physical, electrochemical and electromagnetic. The physical form of ES technologies includes flywheel, compressed air and pumped storage. The electrochemical form of ES technologies includes batteries of all types, battery types include Lead-acid battery, Nickel-cadmium battery, Lithium-ion battery and Sodium sulfur battery. The electromagnetic ES technologies includes different types of capacitors [12]. BESS are generally installed with charge controllers. The role of a charge controller is to cut off the load in the event of an undesirable state of discharge and must also cut off the PV array supply when the BESS is fully charged [12].

2.4 Protection

Electrical power systems are there to supply electrical power to loads. Power systems should therefore supply this energy reliably and economically [13]. Protection systems are integral for detection of faults and disconnection of faulted power system parts [13]. A Protection System is described as "*a complete arrangement of protection equipment and other devices required to achieve a specified function based on a protection principal (IEC 60255-20)"* [13, p7]. A protection system must be designed to ensure sensitivity, selectivity, stability and speed of operation. That is a protection system must be sensitive enough to pick up low operating parameters. It should be selective enough to isolate only the faulted part and trip only required circuit breakers, and stable enough to refrain from operation for faults outside the zone of protection and fast in operation to minimize the possible damage that a fault can cause. Generally, a protection system must be fast to operate under all fault conditions, operating only required breakers, refraining from operating for external faults [13].

2.4.1 DC Supply

Since the protection system is supposed to remove all the faults from the system, this function must never be compromised during a fault. In the event that the substation supply has been cut out due to a close by fault and the AC power is unavailable, the AC power required by relays to trip the circuit breakers and for communication purposes is supplied by the substation DC supply. The battery is usually rated to supply and maintain enough power for 24 hours after a substation blackout. The battery is connected permanently to a charger and maintains a floating charge during normal operation. [14]

2.4.2 Measuring Transformers

The voltage and current values in a power system are so high that they cannot be directly connected to relays and measuring instruments. Therefore, the connection of these instruments is made through measuring transformers - that is, current and voltage transformers. Measuring transformers scales down the high values, producing an accurate replication. A Voltage transformer is almost like a small power transformer, differences are only in the accuracy design details. A current transformer transforms current from high values to low values, the primary windings of a current transformer is series connected with the power circuit [15].

2.4.3 Switch Gear

"Switchgear is the apparatus used for switching, controlling and protecting electrical circuits and equipment" [16, p388]. Switch gear equipment include switches, circuit breakers (CBs), fuses and relays. Switches are the equipment used to make and break the power circuit under normal operating conditions. Circuit breakers are equipment used to manually or remotely make and break power circuit, during normal and abnormal conditions. Circuit breakers basically comprise of a fixed and moving contact enclosed in an arc quenching medium [16]. A fuse is a device equipped with a current rated short wire, designed to melt when current above its rated capacity flows through it. A fuse is connected in series with equipment which is to be protected. A relay is a device that detects a fault condition and sends a trip signal to the circuit breaker. A typical relay circuit consist of a CT with a primary winding connected in series with equipment to be protected, and the secondary winding connected to the relay

operating coil. In the event of a fault, excessive current flows through the primary circuit leading to a rise in secondary emf [16]. This energises the relay operating coil and, depending on the delay settings, the relay sends a trip signal to the breaker operating coil [16]. Circuit breaker opening time increase the operating time of the relay. Different breaker types have different operating times. Typically, a low voltage CB is anticipated to operate in 1 to 3 cycles, that is 20ms to 60ms for a 50Hz system. While the medium voltage CB is expected to operate in 3 to 5 cycles, that is 60ms to 100ms for a 50Hz system [13].

2.4.4 Communication

Protection relays are distantly located from each other. Therefore, to effectuate protection services, communication between these elements is essential. There are different communication link types used for protection signalling. These include pilot wires, power line carrier channels, radio channels, optical fibre and ethernet [17]. A pilot wire is a continuous copper wire connecting two signalling stations. Power Line Carrier Communications technique involves the imbedding of a high frequency signal on an overhead power line. Radio channel communication provide a wide bandwidth, which could allow high data rate modem operation. An optical fibre is a fine glass strand, which guides light waves. Optic fibres can transmit light over a long distance, have very large information carrying capacity and immune to electromagnetic interference. Ethernet is a technology used for the connection of different local area networks (LAN), hence enabling communication amongst different devices. Factors such as resource availability, distance, terrain and cost are considered when choosing a communication link [17].

A reliable communication channel is crucial for DCP. The reliability of DCP is mainly dependent on the reliability of the communications channel. The measurements from both remote ends need to be accurately transferred for deferential comparison. The transferred signals should have accurate magnitude and angle, also being time coincident. Due to this requirement, DCP requires reliable communication [18]. Figure 3 shows a typical relay communication setup on a transmission line.

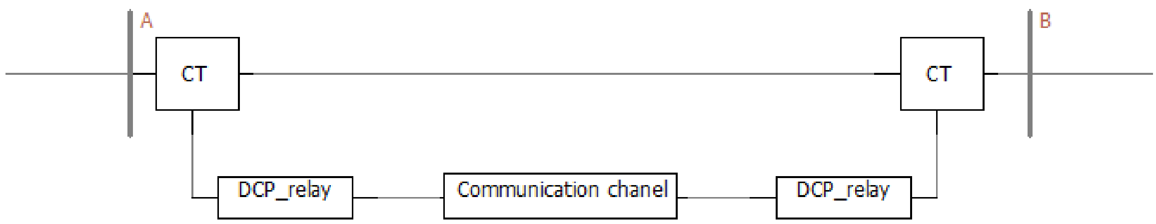

Figure 3: Communication assisted DCP Relaying Protection

Most DCP relays use 64 kbps communications interface, which is over a dedicated fiber or multiplexed network. However, some DCP relays use slower speed asynchronous serial communications. Currently, Ethernet communication application to DCP has been getting attention as it could provide an easy access to information at a reduced total system cost. Nevertheless, implementation is infrequent for DCP, but promising in forthcoming designs [19].

Depending on the protection distance, the dedicated fiber connection is implemented by LED or laser. Typically, the laser option can be used for a length of up to 100km, and repeaters may be needed for longer distances. When using multiplexed communications, the relay communications interface connects directly to the substation multiplexer [20]. For higher speed data transfer over optic fiber, synchronous optical network (SONET) and synchronous digital hierarchy (SDH) have been adopted. Currently, time-based SDH/SONET networks are steadily migrating to packet-based core networks [19].

The time delay required to transmit a signal from the remote end to the local end for differential comparison increases the total relay operating time. Therefore, there is a need for a fast communication channel [19]. Significant delays include delays by in-between devices that includes relay interfacing which is typically 1-5 ms, optic fiber propagation delay (5 microseconds/km) and SONET/SDH multiplexers (0.2 ms) [19].

Since DCP mainly relies on a protection channel, it is desirable for relay systems to be able to activate alternative communication channels or secondary protection upon failure of a communication channel. The relay should quickly detect and activate the alternative option, since failure to do so negatively affects the overall reliability of the DCP system. One of the best ways of implementing DCP with improved reliability is by using backup or redundant communications channels [19].

The deployment of smart grid technologies will see ready availability of communication channels. Hence, in this thesis a communication channel is assumed to be readily available and simulations do not include effects of communications systems.

2.4.5 Overcurrent Protection

Overcurrent protection is protection against excessive flow of current. This method was one of the earliest protection methods. From this principle, there was the development of discriminative fault protection and graded overcurrent protection system. Discrimination refers to the ability of a relay to disconnect only the faulted part and leaving the healthy part of the power system. This aspect can also be referred to as selectivity [21]. Discrimination can be performed by time, current or both. Discrimination by time is a method where a fixed time is set on each relay in the power system circuit, assuring that the relay controlling the breaker closest to the fault point operates first [21]. This method is simple but has a disadvantage that it takes more time to clear faults closer to a power source which in turn have higher fault currents - that is, more time is taken to clear more severe faults.

Due to the variation of impedance between the fault point and the source, a variation of fault current with the fault position is observed. Therefore, discrimination can be done by current. In this method, tapered current values are set on the relays in the power system, assuring that the relay controlling the breaker closest to the fault point operates first. This method is also simple but has a disadvantage that the method is only applicable where there is a considerable difference in impedance between two protection points. Due to the limitations of discrimination using only time or current, discrimination by a combination of both Time and Current evolved [21]. In this method, relay operating time is inversely proportional to the level fault current. The current/time tripping characteristics of an inverse definite minimum time (IDMT) relay is varied following the required tripping time and the network characteristics [21].

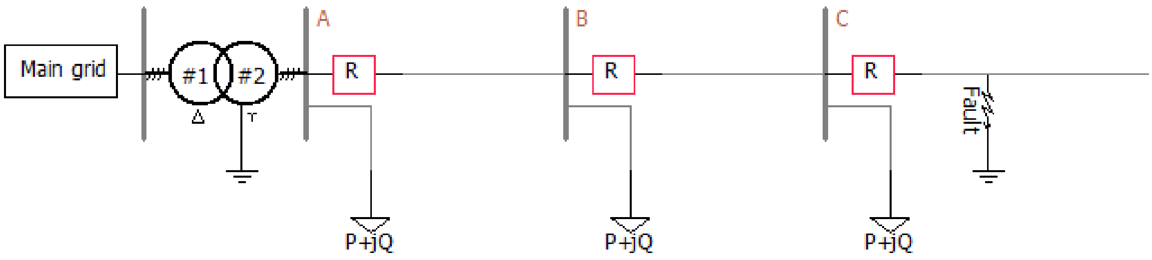

Figure 4: Overcurrent Protection Coordination

Figure 4 illustrates overcurrent protection coordination with a network diagram showing relays marked with 'R'. In a radial network, the OC relays need to provide both main protection to a specific line segment and backup protection for the downstream network. Upstream protection operates as back up protection for downstream faults when a downstream fault is unsuccessfully cleared by the corresponding main protection, this can be due to protection failure or inability. To achieve this, the overcurrent relay, is equipped with a Time Dial Setting (TDS) feature. Increase or decrease in TDS results in proportional increase or decrease of the relay operating time [14]. Primary protection must operate as fast as possible.

2.4.6 Differential Current Protection

As the power network gets more complex, overcurrent grading fails to produce satisfactory results. As a result, Unit Protection evolved. This involves individual protection of power system sections. Power system sections are individually protected as complete units. This is done without referring to other power system sections. Differential Current Protection (DCP) is one of the best forms of Unit Protection [22]. DCP principle of operation involves the sensing of the difference between the output and input current, of the protected unit [22]. CTs are placed at the input and output terminals of the protected unit. A communication link can be employed between these points. Under normal operation, the current that is entering from the first end (I_1), must always be equal to the current that is leaving the second end (I_2). This is not true, in the event of a fault occurring anywhere in between these two ends, I_1 and I_2 are unequal. When a fault occurs within the protected section, an imbalance in CT secondary currents occurs, and the difference in currents flows through the relay, thereby operating breakers at both ends [23]. The difference between the two currents is known as the differential current (I_{diff}). The DCP pickup current is defined as the difference between the two CT secondary phasor currents allowed, above which a trip signal is issued.

Basically, the protection philosophy to detect a fault is by sensing the differential current, since the presence of differential current signifies the presence of a fault [23]. Ideally I_{diff} must be equal to 0 but this is not true due to line charging and CT mismatch errors, so practically the DCP pickup current is set at a minimum of 0.25A [14]. In general, DCP can detect very low fault current levels [14]. Figure 5 illustrates how the DCP principle was applied in this thesis, two current meters were installed at both ends of the line. The two meters send their measurements to a DCP relay for differential comparison.

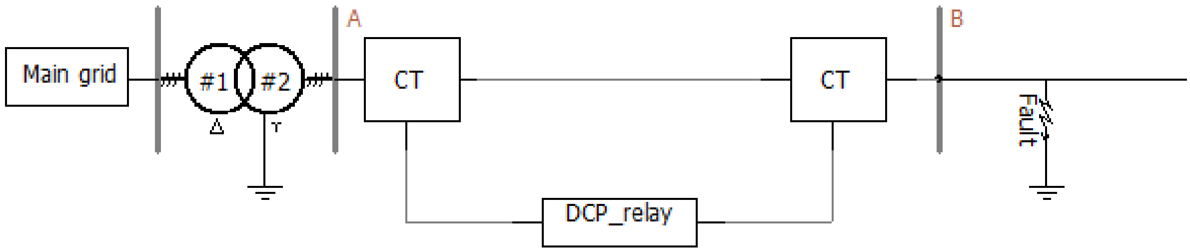

Figure 5: Differential Current Protection

2.5 Protection Challenges and Possible Solutions

2.5.1 Protection Challenges in Microgrids

Microgrids can operate independently or connected to the main grid. In the event of a major disturbance in the main grid, the grid supply can be disconnected from the micro grid. In this case the microgrid operates independently (off grid/ island mode), where the distributed generators (DGs) continue supplying to local loads [4]. It can, however, be grid connected when the generation seems insufficient to meet the load [4]. In grid connected mode, microgrids have higher fault current levels than in islanded mode, because of the amount of fault current contributing sources that are connected [3]. The islanded mode fault current levels are even lower for inverter interfaced renewable energy resource (RES) because of their limited fault current capabilities [3]. An inverter's output current is limited to an amount that is equivalent to double the inverter's power rating, because inverters are designed to protect themselves by limiting their output current [24]. The low fault currents in islanded mode give protection challenges for pre-set over current based protection schemes [24]. RES is intermittent, this results in varying fault current levels in the microgrid. The fault current level depends on connected active DGs, therefore making it further difficult to implement a fault current level-based protection scheme [25]. Loss of relay coordination due to bidirectional current flow, is another major protection challenge experienced by microgrids when they switch from grid mode to island mode.

Figure 6 illustrates one of the major challenges of grid connected microgrids. The fault current is supplied by both the grid and the PV generator. Depending on the PV generator rating, this contribution increases the fault current through R2 and decrease that of R1 accordingly. This results in overcurrent relay R1 under reach operation. This effect is known as relay blinding.

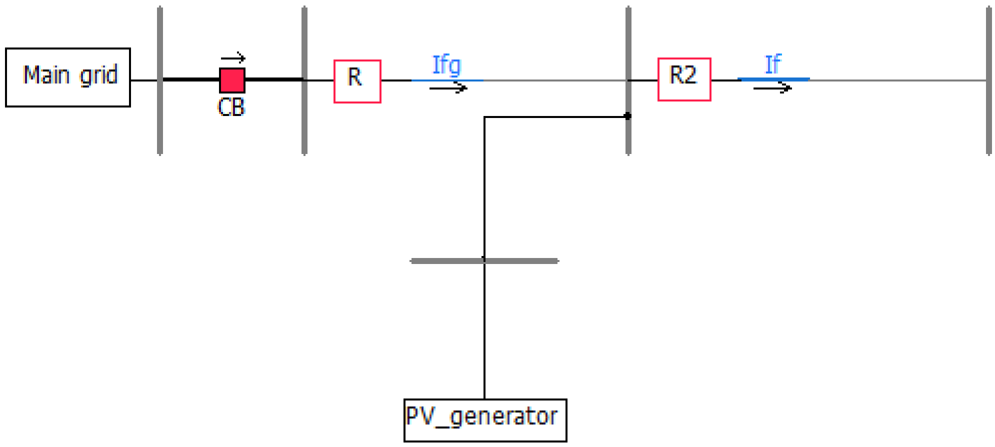

Figure 6: Relay Blinding Operation

Figure 7 illustrates another challenge as the microgrid switches from grid connected to island mode of operation. Due to poor fault contribution capabilities of PV generators, overcurrent relay R2 is not able to operate. In this situation, neither RI nor R2 can detect the fault.

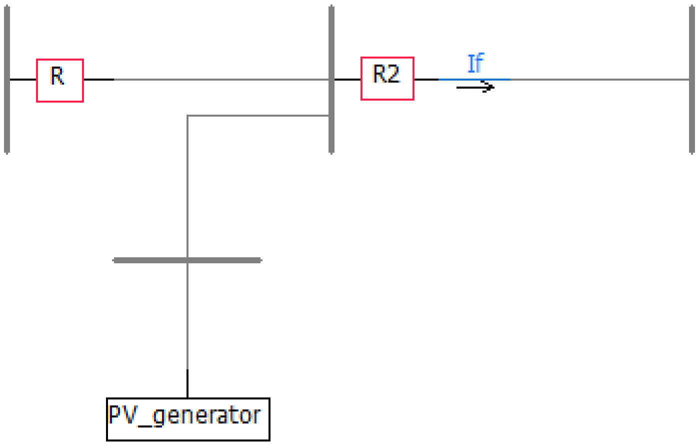

Figure 7: Limited Fault Current in Island Mode

Also, since the protection systems was initially designed for unidirectional power flow, false tripping and loss of coordination is observed for the power flow in the opposite direction as shown in Figure 8. In Figure 8, a non-directional overcurrent relay R2 may operate for reverse current due to RES infeed.

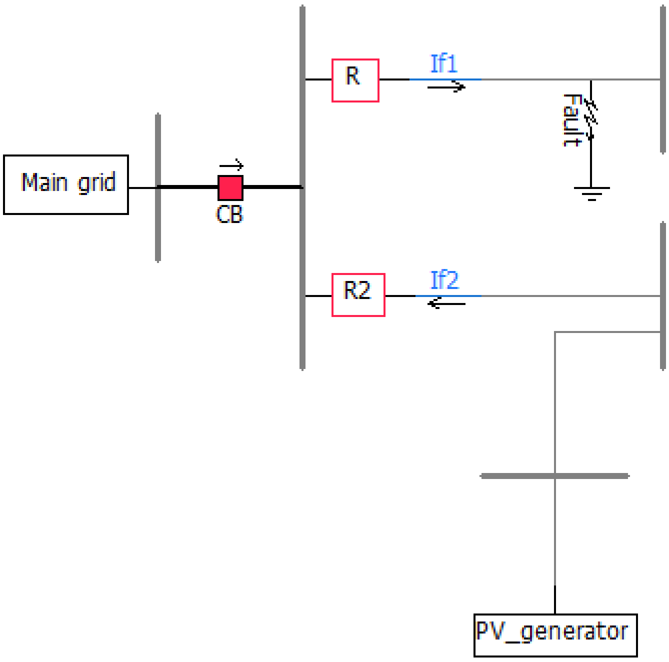

Figure 8: False tripping

One of the most relevant issues under the protection of microgrids today is the question of: *How can one design a 'complete' microgrid protection scheme that meets the three basic protection requirements of sensitivity, selectivity and reliability?* [24] Unfortunately, the conventional IDMT over-current relays would not provide adequate protection for microgrids in islanded mode, because the protection device might not distinguish a fault condition from normal loading as the margin between them is thin. Also, IDMT relays fail to operate in some situations due to a lack of coordination. This clearly hints that other protection techniques are to be sort [3]. To protect these independent systems, microgrids need modified protection schemes that are sensitive enough to accurately differentiate close faults from load currents [3]. This protection scheme should reliably protect the microgrid in both the islanded and grid connected operation modes, without changes in operation settings [3].

2.5.2 Possible Solutions for the Protection Challenges

To effectively protect microgrids, several methods have been suggested. Al-Nasseri & Redfern [26], proposed a protection scheme that is based on an inverter's output voltage harmonics content using the Total Harmonics Distortion (THD) and the Fast Fourier Transform (FFT) method [26]. Inverter-based distributed generators are a good source of harmonics and inject them to a network, despite them producing small fault current when faults occur [26]. Therefore, the inverter terminal voltage's THD is monitored by the protection relays which shuts the inverter down if the THD exceeds a set threshold. There are two stages, of which the first is the identification of the type of fault and the second stage is where the THD is used to discriminate fault zones so that the relay trips and the fault section is isolated from the rest of the unaffected network [26]. In short, the zone with the highest THD is the faulted zone and is tripped off [26]. To identify the type of fault, the method of using a fundamental frequency amplitude variation is employed, where the results will drop substantively during fault [26]. The down side of this protection scheme is that it is best employed as a complementary or backup to the main protection device as it may fail to trip when a network has several dynamic loads installed to it. It is thus important to ensure coordination of protection devices when dealing with dynamic loads [26].

Al-Nasseri, Redfern & Li in [27] proposed a voltage-based scheme for fast detection of all fault types within microgrids, a scheme that compliments traditional ways of protection [27]. The output voltages of micro-source are monitored, transformed by d-q reference frame into DC quantities. This protection scheme is a complement to traditional protection schemes, which respond to faults with high current faults. Standard voltage transformers (VTs) are used to measure input ac voltages. The input voltages disturbances are reflected as the d-q values disturbances [27]. This disturbance voltage is obtained by comparing the output to a balanced three-phase voltage set. Results obtained from the comparison give the difference between the balanced three-phase voltages set and the utility supply sensed values in d-q components [27]. Pure dc voltages are observed in the occurrence of a three-phase fault. While, an AC rippled DC voltage is observed in the event of a two-phase fault and an oscillating signal which varies from zero to the maximum value is observed in the case of a single-phase fault. These different signal characteristics are used in the discrimination of different fault types. The down side of the method is that voltage sags can also be detected by this system, but it must however not trip in the event of a voltage sag [27]. For cases where significant fault currents occur, this method is envisaged to be a complimentary protection scheme to the conventional over-current relaying system [27].

Other authors like Agrawal, Singh & Tejeswini [28], furthermore proposed that the development of a relay that is voltage current based address the problem of coordination. The principle of operation for the proposed relay is based on lowering of the nodal voltage and increase in fault current from the RES [28]. The operating time for the new proposed relay model is enhanced by use of current and the voltage signal [28]. The relay operates when nodal voltage drops below 0.9pu and current rises above 1.1pu [28]. Usually, other protection schemes are used hand in hand with the voltage-based detection scheme because in some cases it cannot provide the needed accurate fault detection and undesirable time delays may occur due to additional computations and filtering [28].

Che, Khodayar & Shahidehpour [29] presented an Adaptive Protection Scheme which has its relay settings in two sets that cater for either the islanded or grid-connected mode. Adaptive protection schemes adjust relay settings automatically when the network's operation state changes, that is when the operation mode of a microgrid is switched, the relays select the appropriate settings. The relays in the microgrid are connected to a master controller (MC) through a communication channel, and the MC sends the signal to the microgrid over current (OC) relays, in the event of a change in network topology [29]. If the mode of operation is islanded, then there is a shift of the relay's time-Over Current (TOC) curve to instantaneous or to a definite TOC setting so that there is fast response and proper adaptation to lower fault currents [29]. However, if the size of the network increases, there is also an increase in the degree of complexity associated with the switching of relay settings for the different modes of microgrid operation [29].

To both detect and differentiate fault and over-load conditions in inverter-interfaced power generators, authors like Bottrell & Green [30] suggested an impedance-based method. This method has ability to ride-thought the fault because current limiting occurs each time the observed impedance drops below a certain threshold and once the fault is cleared, there is a return to normal operation [30]. What distinguishes an over-load from a fault is the impedance that is presented [30]. Through observing the amount of voltage reduction in a constant current operation mode and estimating the impedance, a fault can, therefore, be identified once the inverter enters the over-load mode [30]. This approach further assists in separating the design criteria for thresholds [30]. What determines the impedance threshold for the over-load mode is the inverter's rating while that of the fault mode is the network characteristics to which it is connected [30]. The ratio of the measured current and voltage is what determines whether the inverter's output is due to a fault of over-load. On one hand, each time the controller detects a fault, then an already predefined fault-current gets exported. On the other hand, each time the controller detects an over-load, then an already predefined over-current gets exported [30].

Zamani, Sidhu & Yazdani [31] proposed a protection strategy that requires neither adaptive protective devices nor communication links but uses programmable microprocessor-based relays that have directional elements [31]. This is to provide a reliable protection strategy of low voltage micro-grids and address micro-grid protection strategy issues that arise in both islanded and grid-connected modes [31]. In addition, the effectiveness of this strategy is further independent of fault current levels and the size and type of energy resource distribution units. However, when dealing with medium voltage networks, the method does not operate in a satisfactory manner because the presence of a complex logic structure means that more time is required for selection requirements to be met [31].

Dewadasa, Ghosh & Ledwich [25] proposed a primary protection scheme where the micro-grid uses current differential relays viz-a-viz a communication channel. This protection scheme uses modern differential relays to ensure that protection issues that are associated with the detection of faults in low fault-current levels, meshed structure and the micro-grid islanded mode of operation are avoided [25]. Dewadasa, Ghosh & Ledwich [25] used the different subgroups of bus, feeder and distributed generation (DG) to discuss appropriate micro-grid protection and considered different protection strategies for each subgroup [25]. For the feeder subgroup, two relays are located at both ends of the feeder to protect each feeder in a micro-grid. The current entering a feeder should equal that leaving the feeder, which is not the case when there is a fault [25]. The bus subgroup uses a principle that is like the one discussed under the differential feeder protection whereas when there is a bus fault, the relay sends a trip command to circuit breakers that are connected to the bus [25]. For the DG subgroup, to protect all DGs from abnormal conditions, several protection elements (i.e. reverse power flow, under voltage, synchronism check and over voltage) are employed to each DG [25]. In the case of a detection of an abnormal condition, a trip command is sent to the DG circuit breaker by the relay that is associated with each of the protection elements [25].

Zooming in on the feeder subgroup, current differential protection schemes require a reliable communication channel so that the feeder end relay have a communication link [25]. To facilitate this relay communication, a power line carrier, a hard wire connection, Ethernet connection, fiber optic, or microwave can be used [25]. The power system has both the primary protection, which is communication aided, and backup protection, which is designed to operate when a communication failure occurs [25]. If it so happens that the primary scheme fails, protection system is then supposed to automatically switch to the backup protection scheme to provide appropriate backup protection [25]. Overcurrent and under voltage protection are the backup protection schemes. Backup overcurrent protection might fail to detect faults in islanded mode because of low fault current levels in islanded mode [25]. However, during a fault, the system voltage drops considerably, therefore under voltage protection can operate if overcurrent protection fails to operate [25]. Implementation of this system requires massive infrastructure upgrade, and results in high costs.

Keaton, Sherif & Mohamed [32] presented a hybrid protection scheme of differential protection with adaptive overcurrent protection, to reduce the requirements for infrastructure upgrade and the complexity of the computation of relay settings. In this scheme differential relays are also utilized for the protection buses and feeders in the microgrid. Whereas adaptive overcurrent relays are utilized for the protection of individual load points [32]. Adaptive overcurrent protection relays are designed to allow modification of settings and characteristics corresponding to the network conditions [32]. The relays are connected to external communication devices, which send them signals modification signals for a corresponding network topology. For effective operation of the adaptive overcurrent relays, the relays must be programmed with every possible network topology, otherwise any unprogrammed situation will result in maloperation. This can become a challenge as the microgrid network gets bigger and complex since not all possible situations can be known [32].

DCP schemes have proven to provide effective protection but there are cost and technical challenges in their practical implementation [32]. This thesis thus used DCP for protecting the microgrid.

3

Network Modelling In PSCAD

To prove the effectiveness of the solution picked from the previous chapter, simulations had to be conducted on a CIGRE low voltage distribution network. This chapter shows how the modelling of the network and protection systems was done in PSCAD and discusses the selection of the model parameters.

3.1 PSCAD

In this thesis work, the PSCAD software was selected to simulate the protection challenges for AC microgrids with inverter interfaced RES. PSCAD was chosen because it is powerful and has very flexible graphical user interface. Unfortunately, PSCAD cannot be used for load flow analysis. Yet, one of the attractive features of PSCAD is its capability of interfacing with Simulink, which gives researchers the ability to blend the greatness of the two. PSCAD interface is easy to use and has a ready to use rich library which makes it easy for researchers to research about all aspects of power systems [33].

3.2 CIGRE Network

CIGRE Task Force (TF) C6.04.02 [34] established a benchmark for low voltage distribution networks in Europe. The development of this benchmark was largely to facilitate the study of effects brought about by the interconnection of various DERs to power systems, including an in-depth analysis of control strategies for specific DER arrangements [34]. This network is fed from a 20/0.4Kv, 400kVA step down transformer. The network consists of a 3kW and 4kW PV solar generators connected to buses C and D respectively. Fixed-pitch fixed speed 5.5 kW wind generator connected to bus E. 35Kva and 25kva batteries at 0.85 lagging power factor, connected through inverters to bus A and B respectively [34]. The battery units control frequency during the islanded mode of operation and they do not produce any power when the microgrid is in grid connected mode [34]. There are unbalanced loads connected at buses C, D, E, R11 and R17. More details about loads and line parameters are provided in the appendix. A summary of the information is provided in Table 1. Figure 9 shows the CIGRE European low voltage distribution network benchmark. For demonstration purposes in this thesis work, the network was modified to balance the generation and the load so that the microgrid can operate in islanded mode. These modifications included increasing total generation to 60kW. Since this thesis focused on inverter interfaced RES, the wind turbine on bus E was replaced by a PVC source and all the 3 generators produced 20kW each. Figure 10 shows the modified version. The grid is represented by an equivalent 20kV, 50Hz source.

Table 1: Summary of CIGRE LV Network Parameters

BUS	TOTAL LOAD (kVA)	GENERATION TYPE	GENERATION AMOUNT
R11	5.70	-	-
E	19.2	WIND	5.5kW
D	19.2	PVC	4.0kW
A	-	BESS	35kVA
R17	2.70	-	-
B	-	BESS	25kVA
C	8.80	PVC	3.0kW
TOTAL	55.6		Generation = 12.5kW, Battery storage = 60kVA

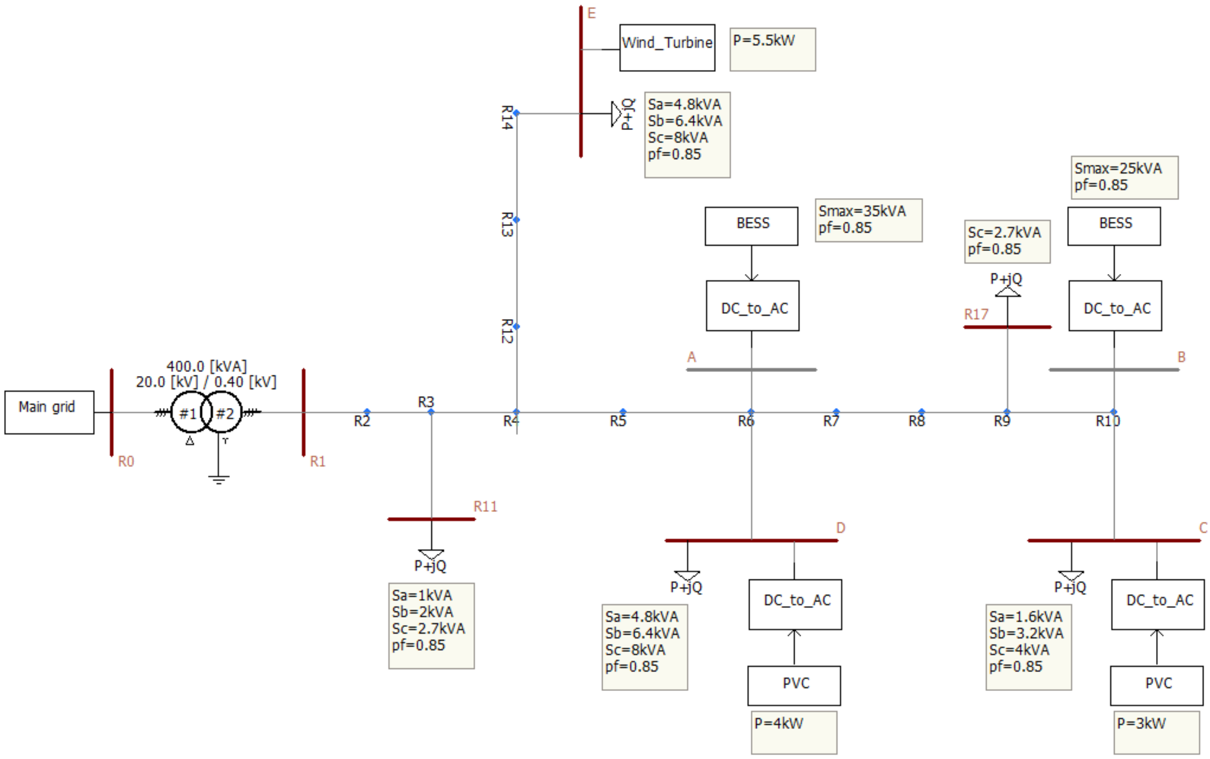

Figure 9: The CIGRE LV Distribution Network

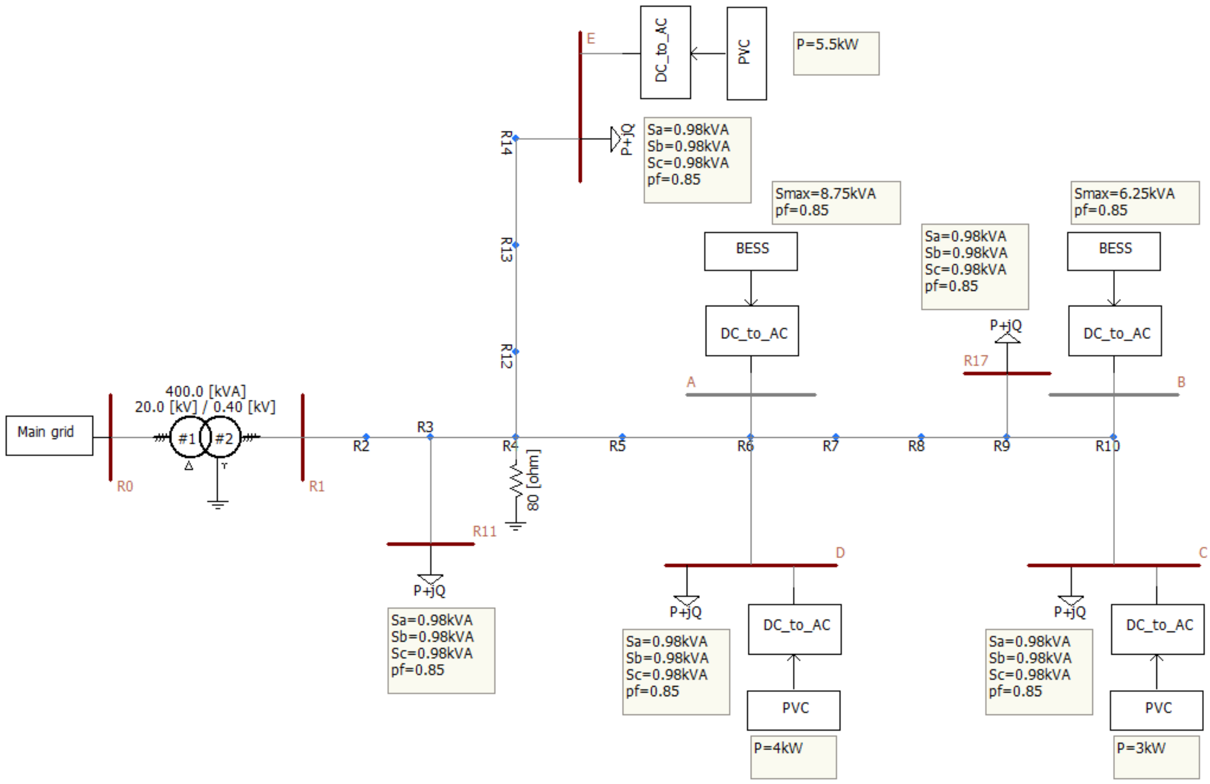

Figure 10: The Modified CIGRE LV Distribution Network

3.3 Network Components

3.3.1 Sources

The CIGRE LV distribution network is connected to a 20kV medium voltage network through a 20/0.4kV transformer. In this thesis the grid is represented by an equivalent 20kV, 50Hz source, to represent the 20kV medium voltage network. Parameters were set using the drop-down menu as shown in Figure 11.

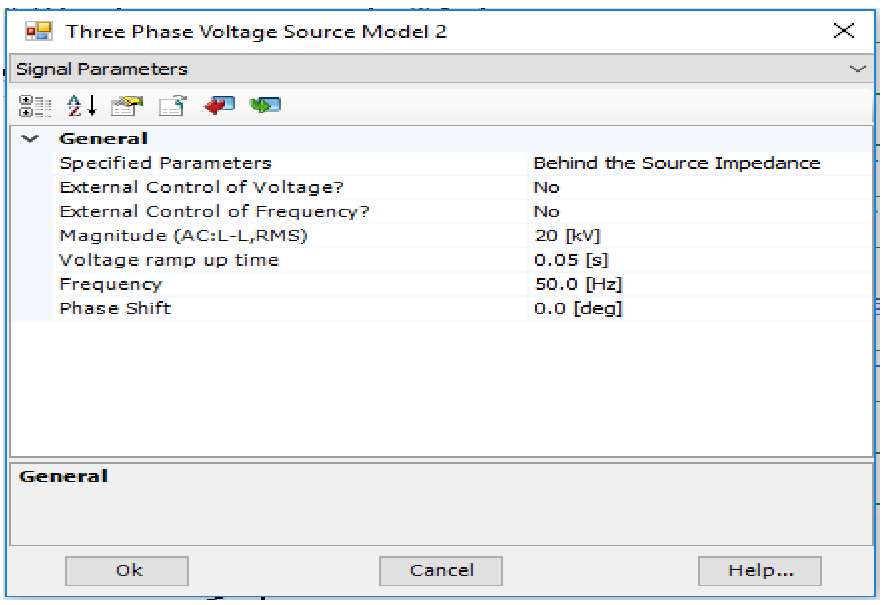

Figure 11: Source Drop-Down Menu

3.3.2 Distribution Cables

Cables were modeled using pi section in PSCAD, and parameters were set according to the CIGRE LV distribution network standards. More information about line parameters is found in the appendix. Parameters were set using the drop-down menu as shown in Figure 12.

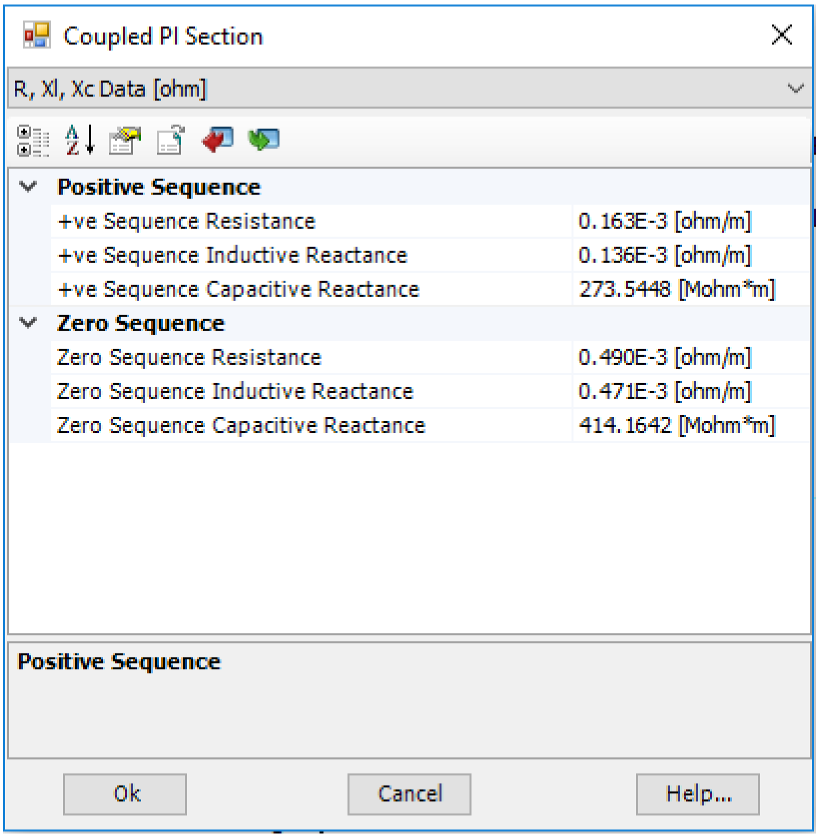

Figure 12: Coupled PI Section Drop Down Menu

3.3.3 PVC System

The PVC model in PSCAD gives the researcher an ability to build a system with a specific power rating. This is done by setting an appropriate parallel and series combination of PV cells in modules, and modules in arrays. An increase in input irradiation to the PV model results in the increase of the short circuit current while an increase in input temperature results in a decrease of the open circuit voltage [11]. The output of the PV array depends on irradiation, temperature and load. Default irradiation of 1000 W/m² and temperature of 25°C were used. PV array parameters were set using the drop-down menu as shown in Figure 13.

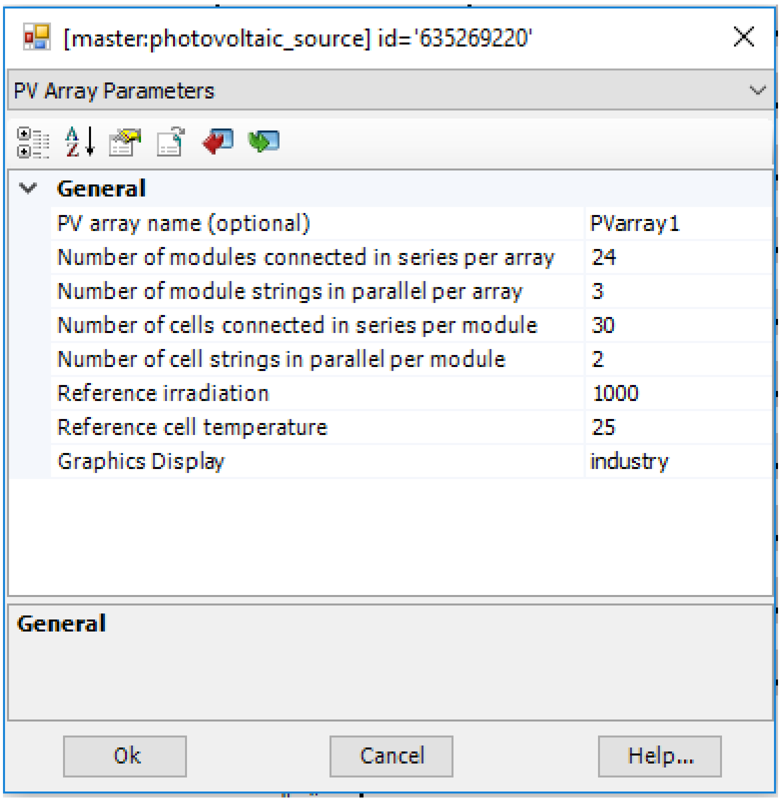

Figure 13: PV Array Drop Down Menu

3.3.4 DC Link Capacitor

The DC link capacitor of a large capacitance is used to minimize PV source current ripple to the system. To make output current from PV source ripple free, an appropriately rated capacitor needed to be used and, in this thesis, a 10 micro Farad capacitor was used [35].

3.3.5 Firing Pulse Generator

The inverter IGBT switching signals were generated using a firing pulse generator shown in Figure 13 below. The firing pulse generator used Sinusoidal Pulse Width Modulation (SPWM) technique to generate the firing pulse signals, three sinusoidal 50Hz modulating waves were created with a 120 and -120 degrees phase shifting. SPWM with high switching frequency is desirable because harmonics appear around the switching frequency which makes filtering easy, since the switching frequency is way above the fundamental frequency [35]. To get switching signals, the modulating waves were compared with a 1000hz triangular carrier wave with a maximum output level of 1 and a minimum output level of -1. IGBT 1, IGBT 3 and IGBT 5 pulse generators produced an output of 1 whenever the corresponding modulating wave is greater than the carrier wave or else 0. IGBT 2, IGBT 4 and IGBT 6 pulse generators produced an output of 1 whenever the corresponding modulating wave is less than the carrier wave or else 0 [35]. Figure 14 shows the firing pulse generator.

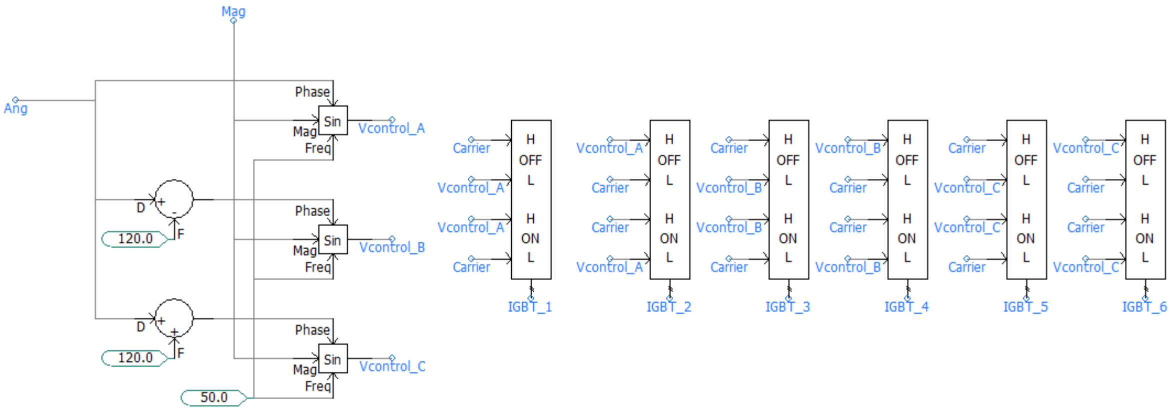

Figure 14: Firing Pulse Generator

3.3.6 Phase Inverter

A three-phase inverter is needed to connect the PV system to the micro grid. An AC Filter to further smoothen the output voltage was added. The filter was implemented by a $7mF$ capacitor and $0.2mH$ inductor [35]. Also, a transformer for voltage adjustment and galvanic isolation was added as shown in Figure 15.

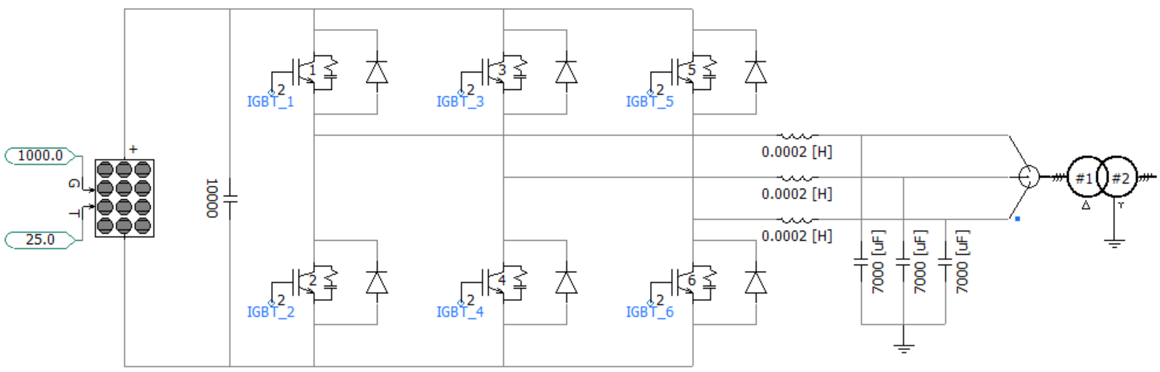

Figure 15: Three Phase Inverter Circuit

3.3.7 Meters

In this project, multimeters were used for measurements and relay input. This eliminated the need to use CTs. Default PSCAD parameters were used as shown in Figure 16.

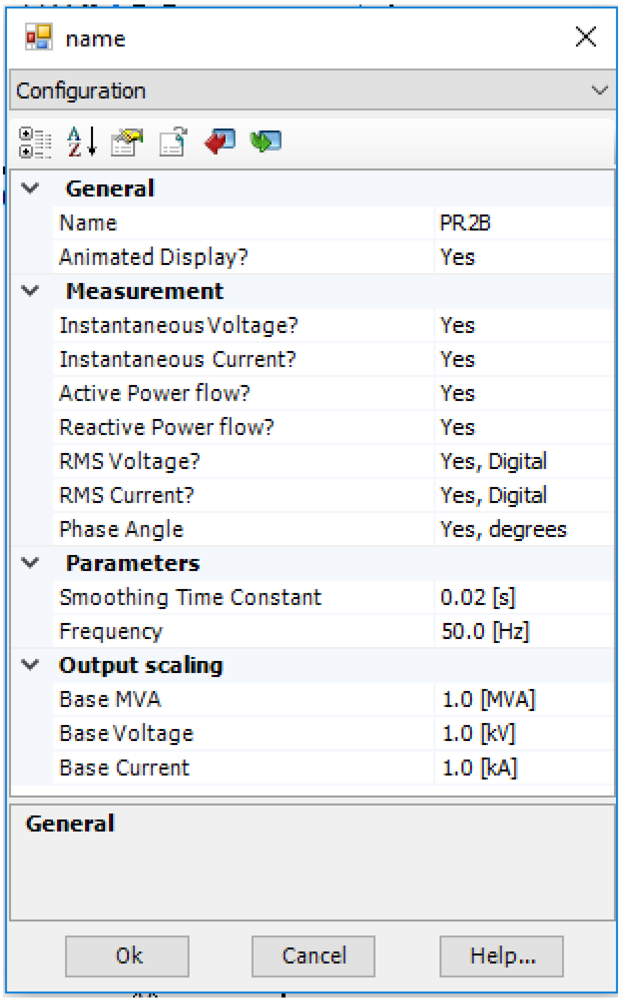

Figure 16: Multimeter Drop Down

3.3.8 Overcurrent Protection

In this thesis an inverse time overcurrent relay 51 from the PSCAD library was used for overcurrent protection, the relay is based on IEEE standard C37.112-1996. A measured current signal is input to the relay hence multimeters were used as input signal source instead of CTs. The relay issues a tripping signal when input current is greater than the pickup current and resets when the input current is lower than the pickup current [33]. Relay operates according to the following;

$$t_{trip} = TD(\frac{A}{M^p - 1} + B) + K \quad (3.1)$$

$$t_{reset} = TD(\frac{t_r}{1 - M^q}) \quad (3.2)$$

where:
t_{trip} = trip time/s
t_{reset} = reset time/s
$I_{pick\ up}$ = relay current setting
M = I_{input} / $I_{pick\ up}$

T_r=reset time for M=0
A, B, K, p and q are characteristic curve constants.

The pickup setting for the OC relays were set in such a way that it is always more or equal to twice the full load current (I_{fl}) but less or equal to a third (1/3) of the lowest possible fault current (I_{fmin}) [32]. The pickup setting is given by:

$$2I_{fl} \leq I_{pickup} \leq \frac{1}{3} I_{fmin} \qquad (3.3)$$

where:
I_{fl} = full load current
I_{fmin} = minimum fault current

To archive required coordination and selectivity, the most downstream relay was set to the minimum possible TDS of 0.01 and a progressive addition of 0.005 to TDS, was done for upstream stages [14]. The pickup current was set according to equation (3.3). Relay parameters were set using the relay drop down menu as shown in Figure 17. Explicit data entry was selected, and default parameters were used as shown in Figure 18. As alluded to, total relay operation time includes circuit breaker operating time, and for practical demonstration in this thesis a delay of 80ms was assumed for circuit breaker operation and other minor delays.

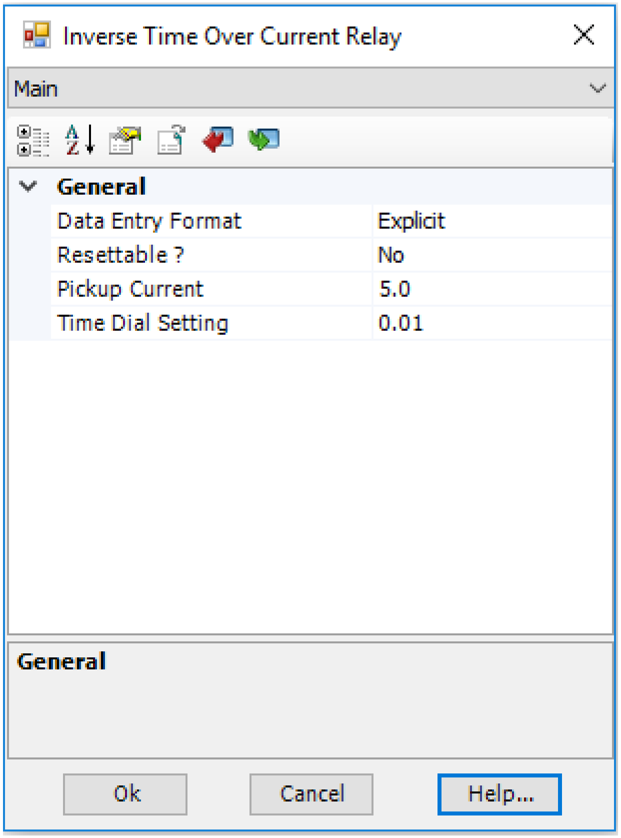

Figure 17: OC Drop Down Menu

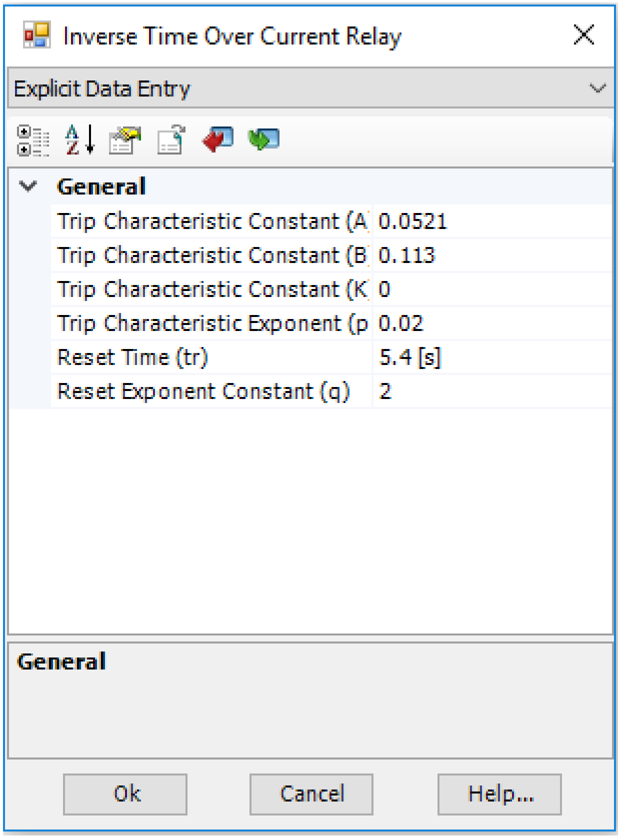

Figure 18: OC Explicit Data Entry Parameters

The relay output is connected through monostable as shown in Figure 19. This component maintains a high output for a set time after being turned on. This insures the tripping of the circuit breaker once the triggering signal has been detected.

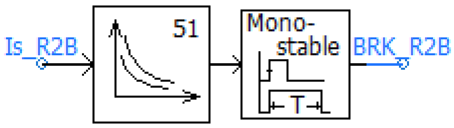

Figure 19: OC Relay Setup

3.3.9 Differential Current Protection

A non-biased differential current protection scheme was used in this thesis, since there are no CTs employed in the project and the distribution lines are short hence the system experiences negligible line charging. A simple differential current protection scheme was implemented as illustrated in Figure 20. The scheme compares set pickup current (I_{pickup}) to the absolute value of the difference between current entering the line and the one leaving (I_{diff}). A trip signal is sent to the breaker if I_{diff} is greater than I_{pickup}. I_{pickup} of 25A was used [32]. The DCP relays in this report are set to operate instantaneously. As alluded to, total relay operation time includes circuit breaker operating time and communication delay. Hence for practical demonstration in this thesis a delay of 100ms was assumed for circuit breaker operation and communication delay.

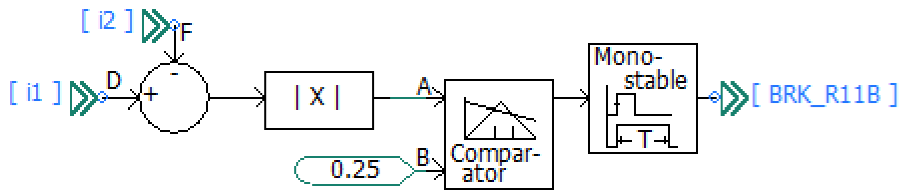

Figure 20: Differential Current Protection Setup

I_{diff} is found using the formula:

$$I_{diff} = | I_1 - I_2 | \tag{3.4}$$

where;
I_1 = Current entering the line
I_2 = Current leaving the line

The relay trips if;

$$I_{diff} \geq I_{pick\ up} \tag{3.5}$$

4

Case Study and Results

Using the models from the previous chapter, this chapter shows the methodology used to obtain the simulation results. Firstly, the case study is presented and the reasons that showcase why the case was chosen are given. This is then followed by a discussion on the methodological approach that was adopted for the research. The latter part of the chapter gives a detailed discussion of the results obtained from the simulations that were conducted on a CIGRE low voltage distribution network.

4.1 Case Study

The case study was a CIGRE low voltage distribution network. Firstly, the CIGRE low voltage distribution network was selected as a case study because the network is a standard European low voltage distribution network with RES generation. This seemed to be a suitable case as it was aligned with the aim of this thesis and would thus aid in attaining the objectives set out for this study. Secondly, the network was modified, as already alluded to in Figure 10, so that the protection challenges associated with low voltage microgrids having inverter interfaced PVC generation is demonstrated. Solar penetration is increasing at distribution level and few papers focus on the protection of distribution networks in this regard.

4.2 Approach

After the modeling of the CIGRE low voltage distribution network, a practical study of the protection challenges for micro grids with inverter interfaced PV generation was done. The method was in 3 main steps. The first step was the modelling of an Overcurrent protection scheme and relay coordination. A sustained 3phase and 1phase to ground fault at different locations at 0.01s was applied to a grid connected microgrid without PV generation. These results were documented and taken as the reference point. Again, a sustained 3phase and 1phase to ground fault at different locations at 0.01s was applied to grid modes but this time with PV generation. Tripping time results were again documented and compared to the reference results, before being comprehensively analysed to prove the reliability of the protection scheme. Unsatisfactory results led to the proposal of a solution, which in this case meant a different protection system. The unsatisfactory results accounted for the weakness of OC protection in protecting microgrids. The first step of the methodology that was used for this study is graphically summarised in Figure 21.

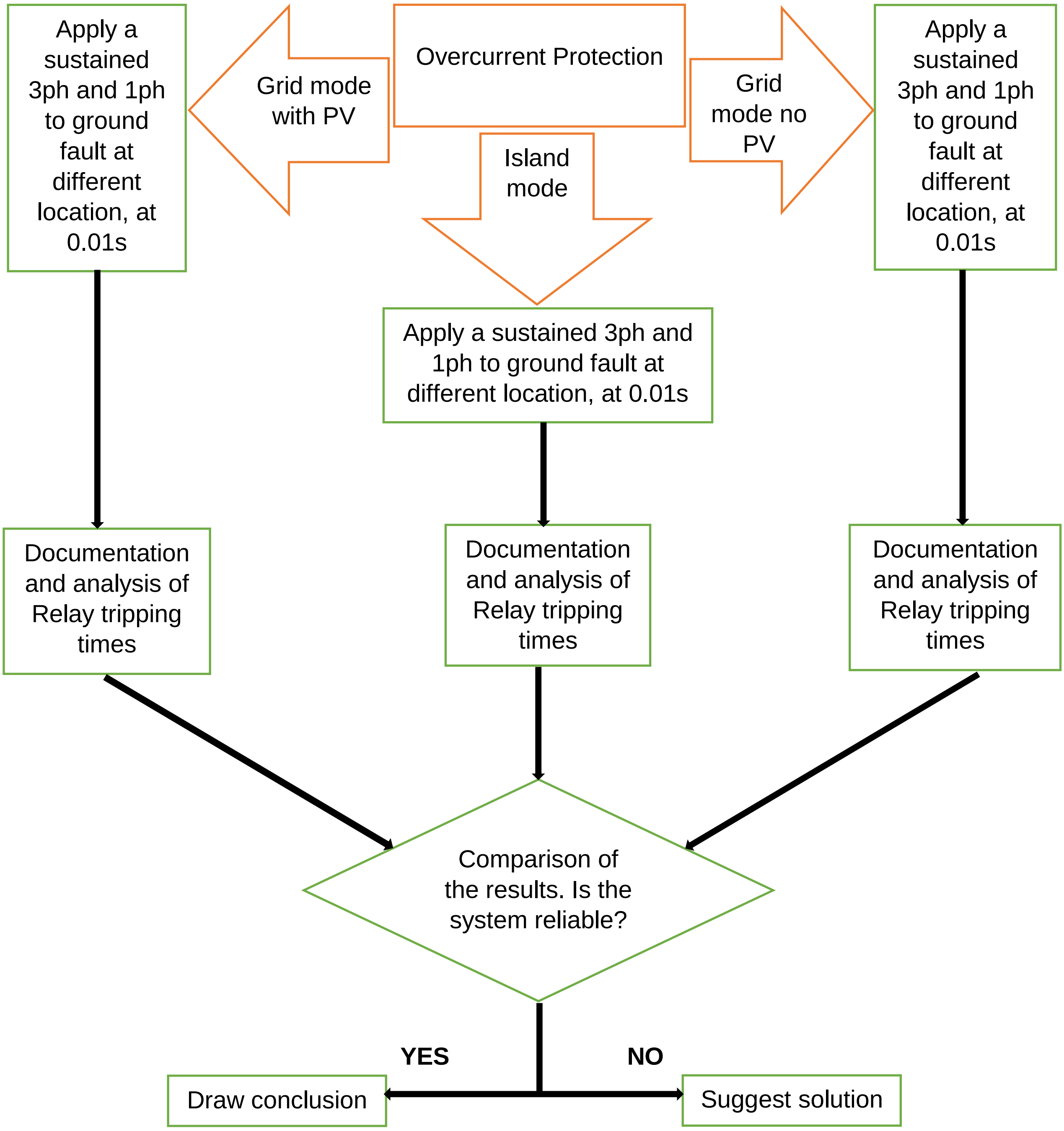

Figure 21: OCP on Grid Connected Microgrid with and without PV Generation

Due to the unsatisfactory operation of the OCP, a solution proposal had to be made. DCP was proposed as a solution for microgrid protection. This is the second step of the methodology and involves tests to prove the reliability of the system. Again, sustained 3phase and 1phase to ground fault at different locations at 0.01s was applied to grid mode with PV generation, grid mode without PV generation and island mode of operation. The first step of the methodology that was used for this study is graphically summarised in Figure 22. These results were then analysed and proved to be satisfactory, but before drawing a conclusion based on these results, further tests were conducted to validate the results.

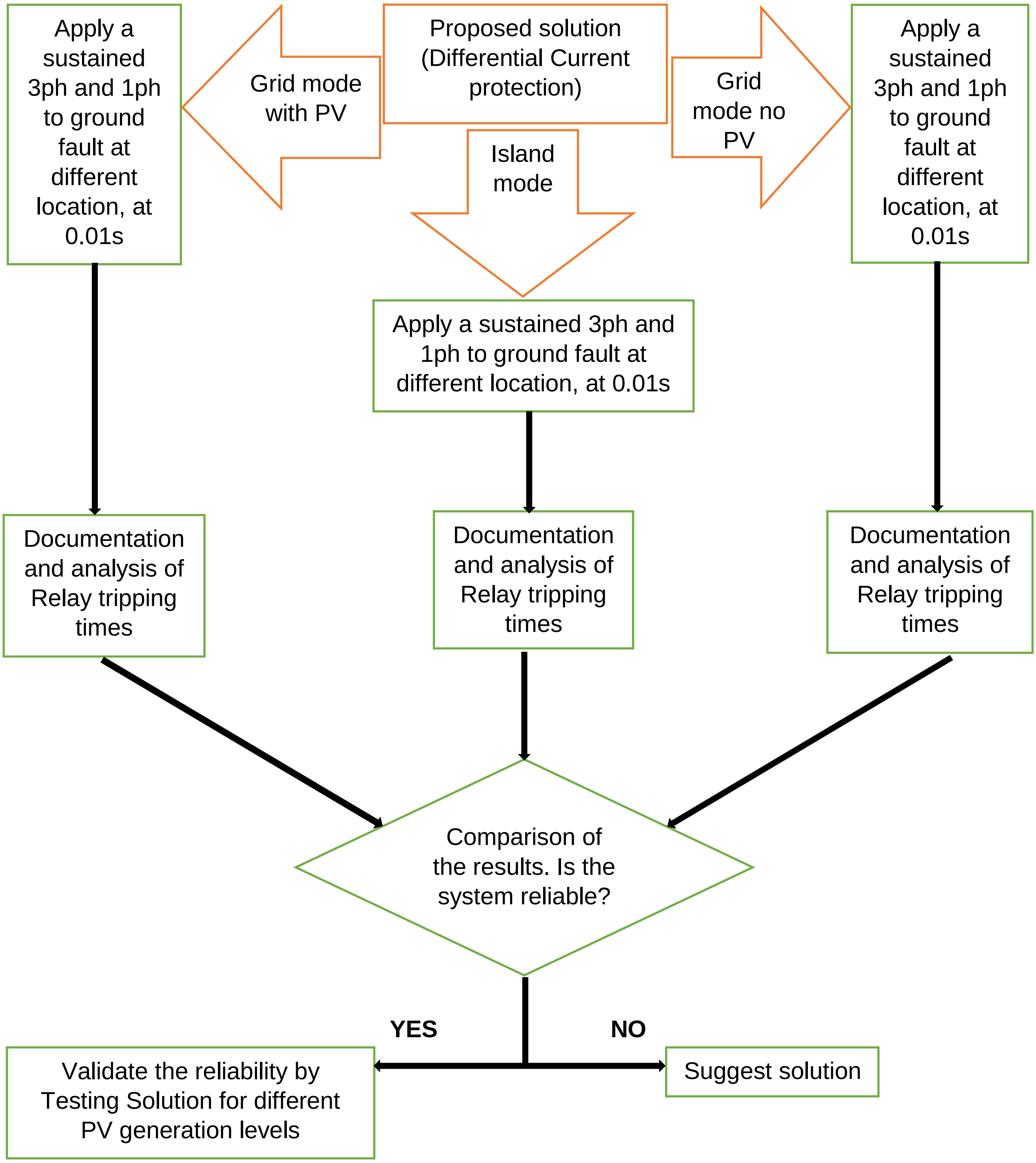

Figure 22: DCP on Grid Connected Microgrid with PV, without PV Generation and Island Mode

To validate the practical reliability of the system, DCP was tested for different PV generation levels. the levels were chosen to resemble low medium and high generation levels. The data used to attain these levels was obtained from a typical daily PV generation profile. In this step, a sustained 3phase and 1phase to ground fault at different locations at 0.01s was applied to island mode of operation with 15%, 57% and 81% levels of PV generation. This step of the methodology that was used for this study is graphically summarised in Figure 23. Results were documented, analysed and a conclusion was drawn.

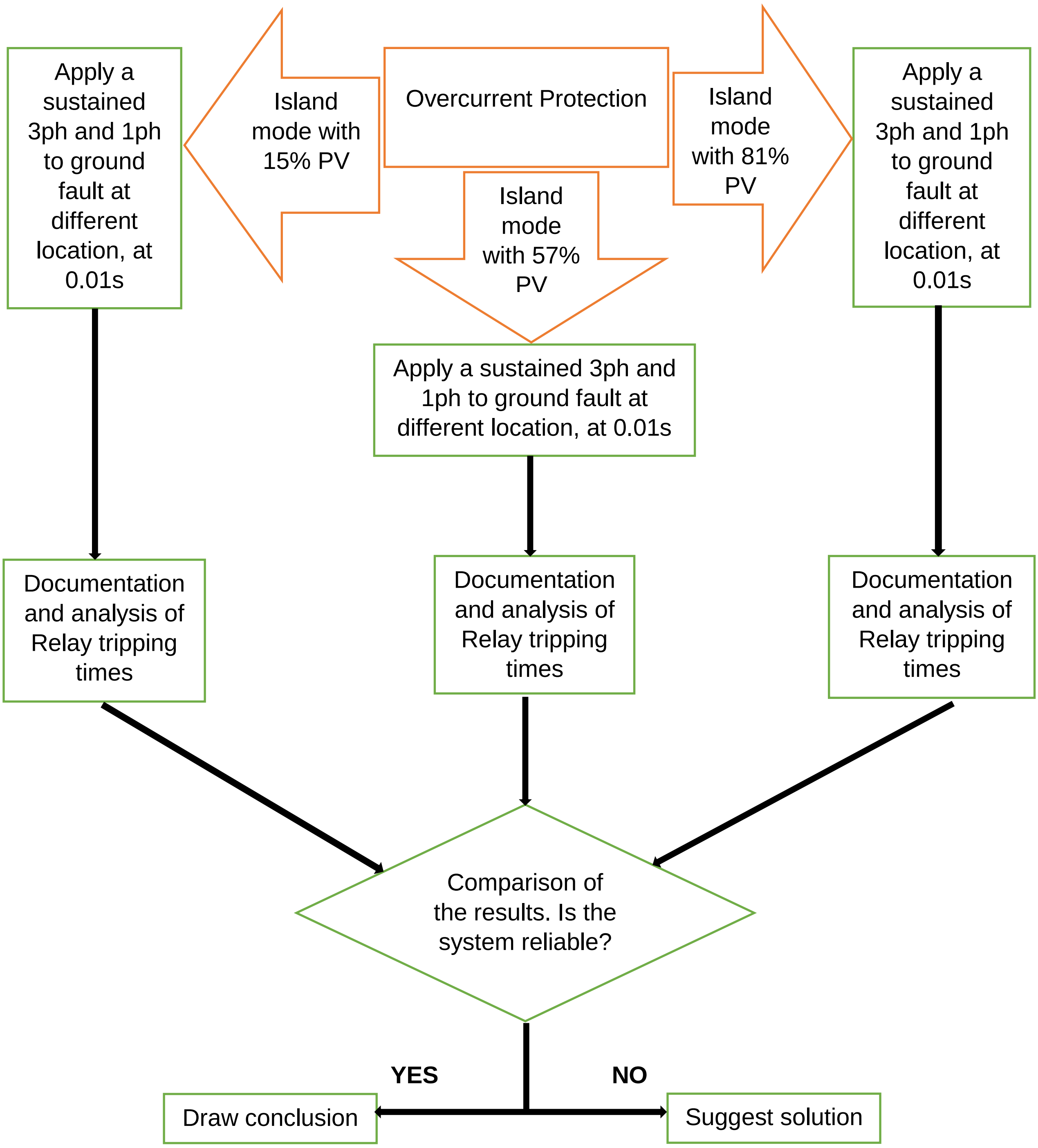

Figure 23: DCP On Island Mode of Operation With 15%, 57% And 81% Levels of PV Generation

4.3 Overcurrent Protection

In practice, a distribution network one overcurrent relay coordinating with fuses, sectionalizers and auto reclosers. For demonstration in this thesis the protection system was implemented as shown in Figure 24 and Figure 25. Upstream protection operates as back up protection for downstream faults when a downstream fault is unsuccessfully cleared by the corresponding main protection, this can be due to protection failure or inability. Primary protection must operate as fast as possible. To archive required coordination and selectivity, the most downstream relay was set to the minimum possible TDS of 0.01 and a progressive addition of

0.005 to TDS, was done for upstream stages [14]. Table 2 shows relay settings. Table 3 shows simulation results obtained after applying a sustained 3ph to ground fault at different locations at 0.01s to both grid mode of operation with and without PV generation at reference irradiance and cell temperature of 1000W/m^2 and 25^{o}C. Table 3 shows simulation results obtained after applying a sustained single phase to ground fault at different locations at 0.01s to both grid mode of operation with and without PV generation at reference irradiance and cell temperature of 1000W/m^2 and 25^{o}C.

Table 2: Relay Settings

RELAY	I_{pickup} (kA)	TDS
R1	1.20	0.020
R4T	0.50	0.015
R4A	0.75	0.015
R6	0.40	0.010

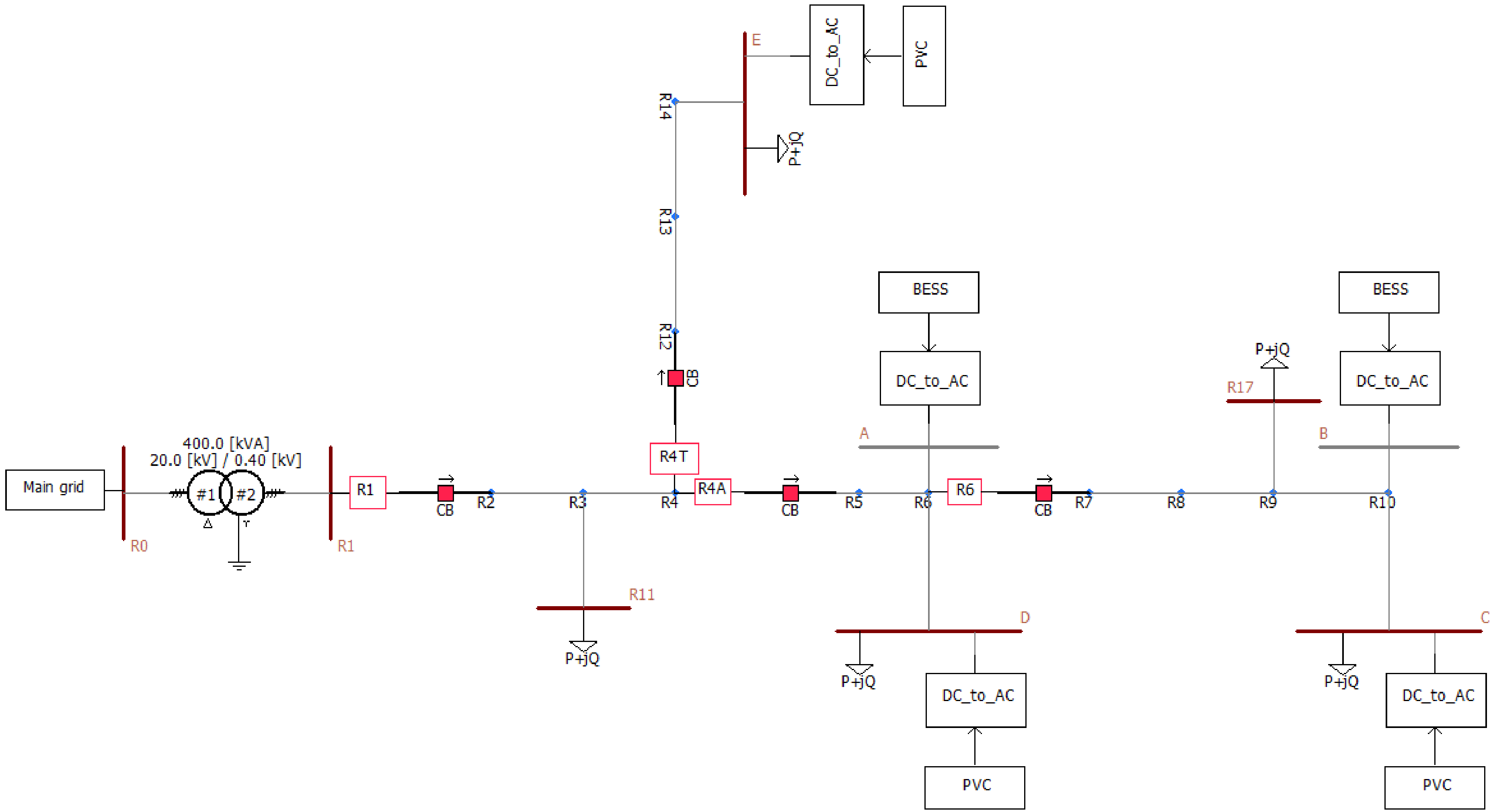

Figure 24: Overcurrent Relay Protection

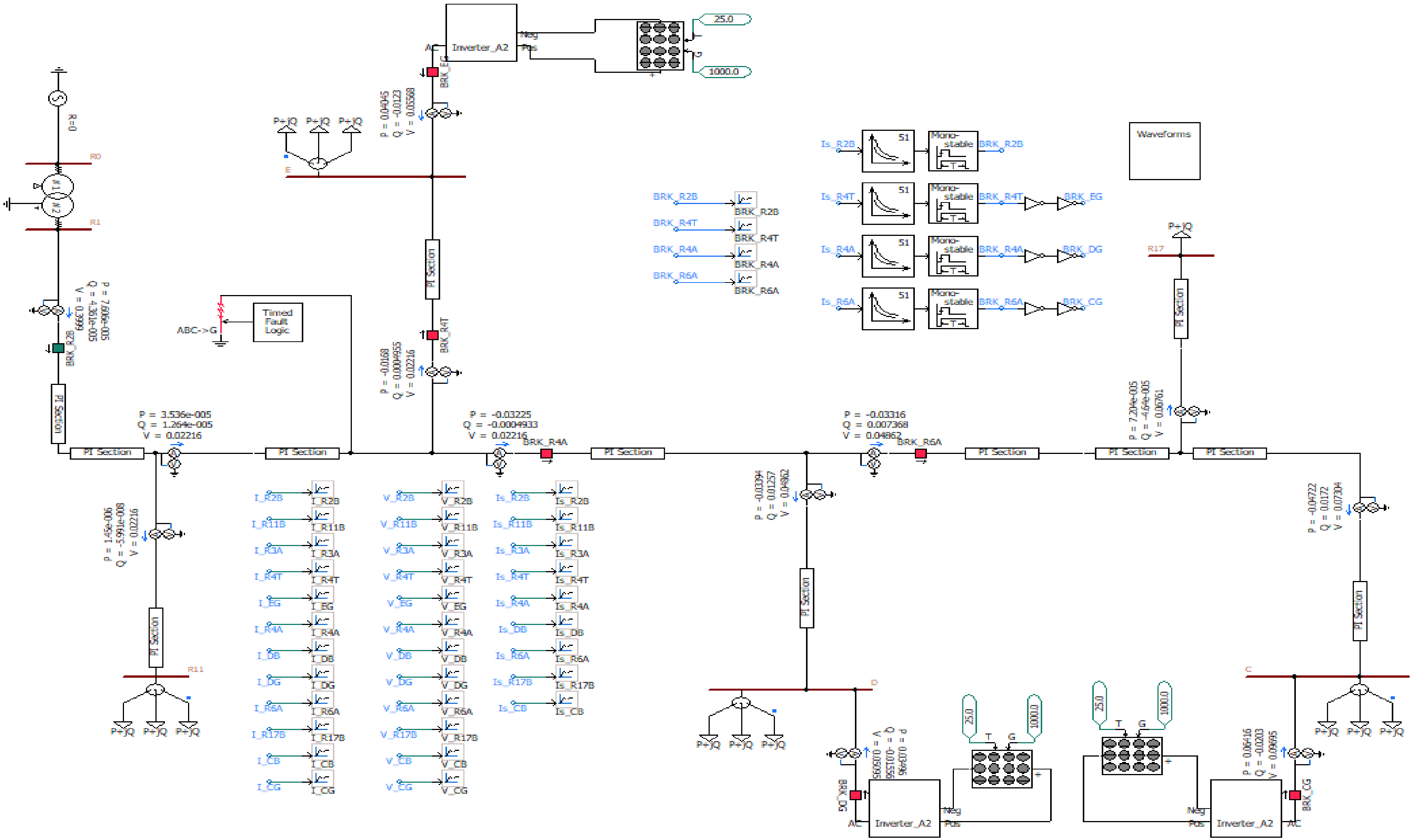

Figure 25: Overcurrent Relay Protection in PSCAD

Table 3: Overcurrent Protection Simulation Results for a 3phase fault

Fault location	Grid Mode (NO PV)	Grid Mode (With PV)	Island Mode
	Operating Relay and t_{trip} (s)	Operating Relay and t_{trip} (s)	Operating Relay and t_{trip} (s)
R1-R3	R1 - 0.121	R1 - 0.131	No Trip
R3-R11	R1 - 0.135	R1 - 0.164	No Trip
R3-R4	R1 - 0.126	R1 - 0.140	No Trip
R4-R14	R4T - 0.124	R4T - 0.131	R4T - 0.275
R4-R6	R4A - 0.115	R4A - 0.134 R6 - 0.132	R6 - 0.356
R6-D	R4A - 0.133	R4A - 0.142	No Trip
R6-R10	R6 - 0.109	R6 - 0.120	R6 - 0.144
R9-R17	R6 - 0.112	R6 - 0.126	R6 - 0.180
R10-C	R6 - 0.110	R6 - 0.125	R6 - 0.164

Table 4: Overcurrent Protection Simulation Results for a 1phase fault

Fault location	Grid Mode (NO PV)	Grid Mode (With PV)	Island Mode
	Operating Relay and t_{trip} (s)	Operating Relay and t_{trip} (s)	Operating Relay and t_{trip} (s)
R1-R3	R1 - 0.128	R1 - 0.144	No Trip
R3-R11	R1 - 0.187	R1 - 0.361	No Trip
R3-R4	R1 - 0.138	R1 - 0.176	No Trip
R4-R14	R4T - 0.128	R4T - 0.161	No Trip
R4-R6	R4A - 0.122	R4A - 0.162 R6 - 0.159	No Trip
R6-D	R4A - 0.122	R4A - 0.351	No Trip
R6-R10	R6 - 0.115	R6 - 0.132	R6 - 0.178
R9-R17	R6 - 0.116	R6 - 0.153	No Trip
R10-C	R6 - 0.120	R6 - 0.154	R6 - 0.276

It can be observed that tripping times for grid mode (no PV) is less than that of grid mode (with PV). This is because when PV generation is connected, the fault current in this case is now being contributed by both the Grid and the PV generation hence decreasing the fault current that is sensed by the primary relay [3]. Due to false tripping the lack of coordination alluded to earlier, relay R6 operated for both relay R4A's fault, this is due to bidirectional current flow caused by RES infeed. Also, when a microgrid switches mode from grid to island, a decline in fault current is experienced and this effect can be observed by several relays failing to trip in island mode. Hence, the overcurrent protection could not effectively protect the microgrid in both modes.

Furthermore, grid mode with PV system was tested at increased PV generation level. PV generation was quadrupled for every source giving a total generation of 240kW. Results from the simulations came out as shown in Table 5.

Table 5: Overcurrent Simulation Results for Grid Mode with 240kW PV Generation

Fault location	3PH fault	1PH fault
	Operating Relay and t_{trip} (s)	Operating Relay and t_{trip} (s)
R1-R3	R1 - 0.150	R1 - 0.206
R3-R11	R1 - 0.385	No Trip
R3-R4	R1 - 0.268	No Trip
R4-R14	R4T - 0.150	R4T - 0.172
R4-R6	R4A - 0.152	R4A - 0.232 R6 - 0.228
R6-D	R4A - 0.156	R4A - 0.192
R6-R10	R6 - 0.128	R6 - 0.145
R9-R17	R6 - 0.146	R6 - 0.284
R10-C	R6 - 0.144	R6 - 0.159

The results from Table 5 clearly illustrate the effects of bulk penetration of PV generators. A significant increase in tripping time can be observed. Also, failure to trip on some single-phase faults by corresponding primary relays can be observed. Both issues are due to PV contribution to fault current which inhibits fault current that can be seen by some primary relays in the network.

4.4 Differential Current Protection

Each distribution line in the microgrid was protected by one DCP relay, obtaining inputs from measuring units located at the opposite ends of the line, and operating circuit breakers at both end of the line for selectivity. Under normal conditions, the current entering the distribution line should always be the same as that leaving. This is not true when a fault occurs on the line. DCP was chosen for the protection microgrid because it is not susceptible to fault current level changes and bi-directional power flow [32]. A differential pickup current of 25A was set for all the relays in the network. Figure 26 shows the diagram of the network layout showing current measuring units marked with R1 and R2 and Figure 27 shows the real PSCAD simulation network. Further, Figure 28 shows a zoom in on one of the line segments to clearly illustrate how the protection was setup

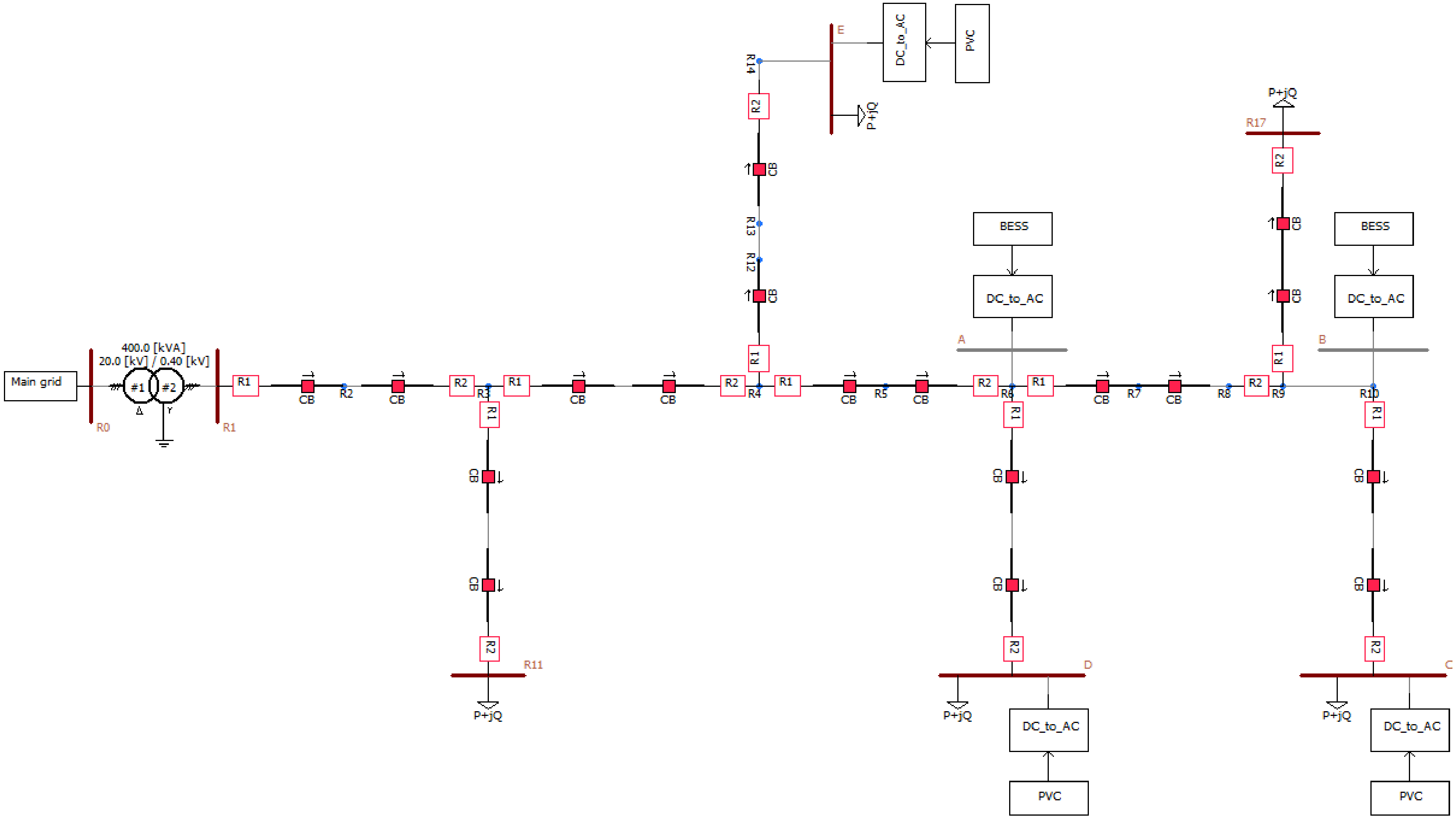

Figure 26: Differential Current Relay Setup

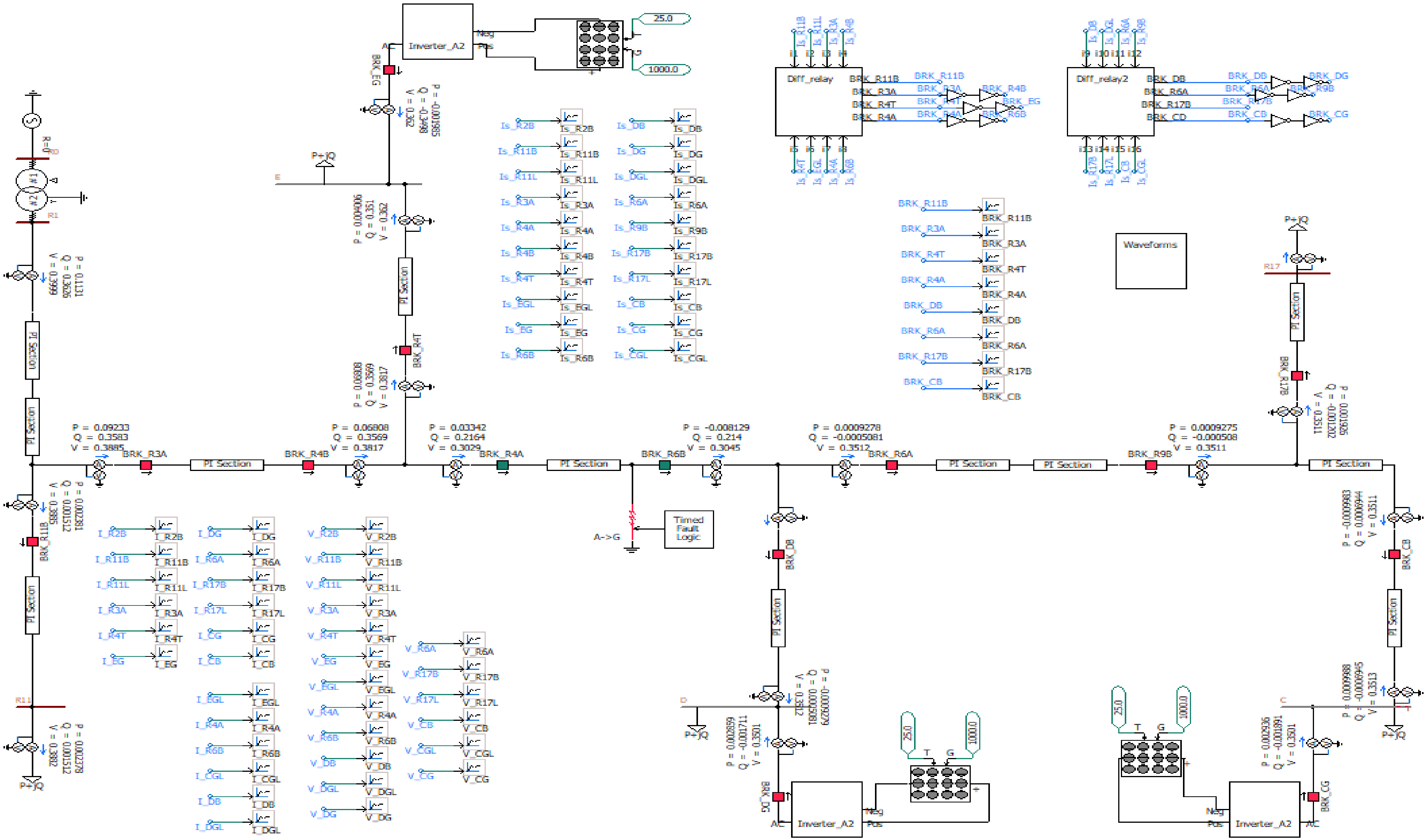

Figure 27: Differential Current Relay Setup in PSCAD

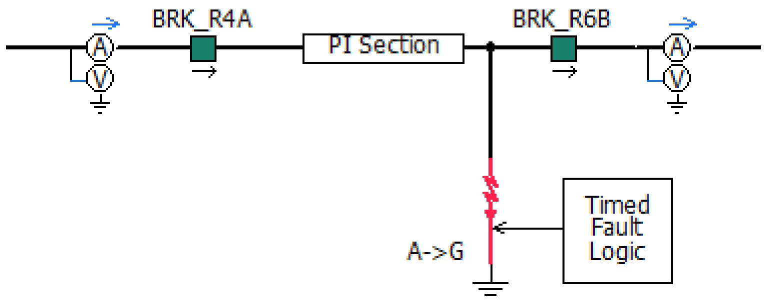

Figure 28: Differential Current Relay Setup PSCAD Zoom in on a Single Line

Tables 5 and 6 show simulation results for Differential Current Protection at the reference irradiance and cell temperature of 1000W/m^2 and 25^{o}C respectively, and the DCP method proves to be reliable enough. The results clearly show how fast, consistence and reliable DCP is, as compared to the OC protection system.

Table 6: Differential Current Protection Simulation Results for a 3phase fault

Fault location	Grid Mode (NO PV)	Grid Mode (With PV)	Island Mode
	t_{trip} (s)	t_{trip} (s)	t_{trip} (s)
R3-R11	0.10025	0.10025	0.10050
R3-R4	0.10025	0.10050	0.10075
R4-R14	0.10050	0.10125	0.10125
R4-R6	0.10050	0.10100	0.10250
R6-D	0.10050	0.10100	0.10150
R6-R10	0.10050	0.10100	0.10150
R9-R17	0.10025	0.10050	0.10050
R10-C	0.10050	0.10200	0.10275

Table 7: Differential Current Protection Simulation Results for a 1phase fault

Fault location	Grid Mode (NO PV)	Grid Mode (With PV)	Island Mode
	t_{trip} (s)	t_{trip} (s)	t_{trip} (s)
R3-R11	0.10070	0.10050	0.10075
R3-R4	0.10075	0.10125	0.10175
R4-R14	0.1010	0.10100	0.10150
R4-R6	0.10100	0.10350	0.10250
R6-D	0.10150	0.10150	0.10225
R6-R10	0.10100	0.10225	0.10175
R9-R17	0.10050	0.10100	0.10050
R10-C	0.10125	0.1020	0.10275

Simulations were also conducted at bulky penetration condition, as already alluded to, and the results for DCP are shown in Table 8. The results also consistently proved that DCP is a reliable solution.

Table 8: DCP Simulation Results for Grid Mode with 240kW PV Generation

Fault location	3PH fault	1PH fault
	t_{trip} (s)	t_{trip} (s)
R3-R11	0.10020	0.10050
R3-R4	0.10075	0.10125
R4-R14	0.10125	0.10100
R4-R6	0.10100	0.10350
R6-D	0.10100	0.10100
R6-R10	0.10100	0.10250
R9-R17	0.10025	0.10050
R10-C	0.10100	0.10200

To further validate the practical reliability of the protection system, the method was tested for different irradiance and temperature, to resemble different times of the day. A sustained single phase to ground fault at different locations at 0.01s was applied to the microgrid in island mode and the results were documented. The cell current component due to photons (I_l) is approximately directly proportional to the irradiance to the cell and it varies to a less extent with temperature. Very negligible variations are observed for temperatures below 25°C, and very notable variations for temperatures above 30°C, hence resulting in an efficiency drop [36]. For this study, irradiance is approximated to be directly proportional to power output. For demonstration purposes, a simplification of the relationship between the irradiance and power output is given by:

$$\frac{G_1}{G_0} = \frac{P_1}{P_0} \tag{4.6}$$

where:

G_0 = Reference irradiance of 1000W/m^2

P_0 = Power corresponding to the reference irradiance

G_1 = New reference radiation

P_1 = Power corresponding to the new reference radiation

The method that was adopted used settings that were extrapolated from a typical daily PV profile, as shown in Figure 29. Figure 29 shows the plot of typical power production from a PV generator connected at Chalmers University of Technology. It was observed that the generation had limited availability, and this is influenced by the availability of sunlight. The plot thus gave a good resemblance of the irradiance profile. The method assumed that the optimum operation was at 1000W/m^2 and 25°C and this happened at 11am. Three-time points where taken to represent different operating conditions during a day, that is 7am, 8am and 9am, representing 15%, 57% and 81% of the optimum power output, respectively. These points were chosen because they resemble low, medium and high PV generating levels. To be able to operate in microgrid mode, the load is assumed to follow generation pattern. Simulation results from the respective points were documented.

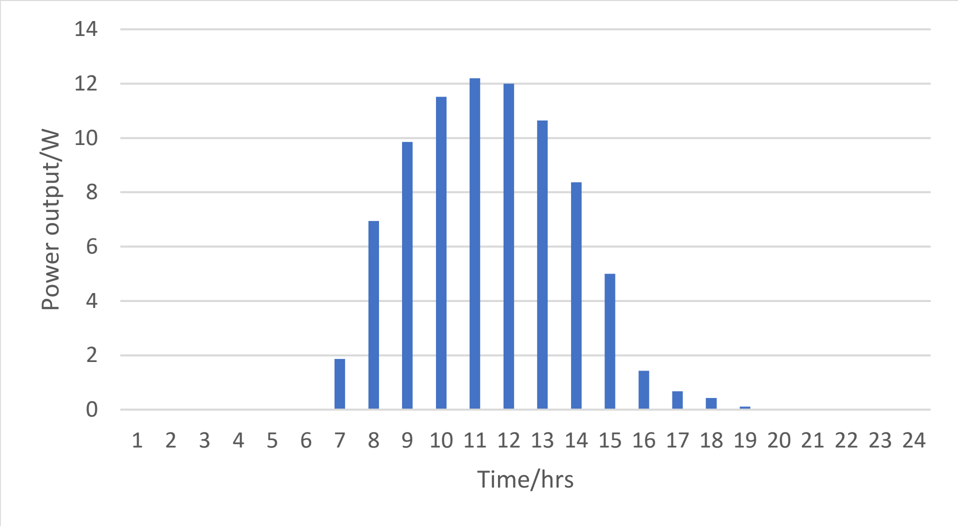

Figure 29: Typical PVC Active Power Output
***Data Source:** Kyriaki Antoniadou's data compilation*

Table 9: Differential Current Protection Simulation Results for 1 phase fault in Island Mode Operation at Different Generation Levels

Fault location	Island Mode (15%)	Island Mode (57%)	Island Mode (81%)
	t_{trip} (s)	t_{trip} (s)	t_{trip} (s)
R3-R11	0.10075	0.10075	0.10075
R3-R4	0.10200	0.10175	0.10175
R4-R14	0.10175	0.10175	0.10150
R4-R6	0.10275	0.10275	0.10250
R6-D	0.10275	0.10275	0.10225
R6-R10	0.10200	0.10175	0.10175
R9-R17	0.10075	0.10050	0.10050
R10-C	0.10300	0.10300	0.10275

Table 7 shows Differential Current Protection simulation results for island mode operation at different PV generation levels. Table 6 shows a reduction of differential current with reduced power generation because of the fault contributing capability of the PV generator at different generation levels. Also, a negligible increase in relay operating time is observed as the PV generation lowered. This however did not affect the reliability of the proposed protection system since the operating times differ by micro seconds, and the difference was too negligible to affect the power system operation. It can be clearly observed that DCP can always provide reliable, selective and fast protection for microgrids in both modes of operation at different PV generation levels. It can also be clearly observed that DCP is highly selective, operating fast for only internal faults.

5

Conclusion and Future Work

This chapter has the conclusion and suggestion on future work. The conclusion has been reached upon using the results that were found after conducting simulations in PSCAD of a CIGRE low voltage distribution network with inverter interfaced RES. It gives a succinct summary of the key results that were found in this research and underscores the implications of the results. This is then followed by suggestions on future work, taking into account the areas/ scope that this research could not cover.

5.1 Conclusion

It seems that more renewable energy sources are going to be integrated into the power system in the future and this means that systems are most likely to shift from centralized generation to distributed generation and microgrids. It becomes apparent that new ways to effectively protect microgrids are to be sort. Microgrids with inverter interfaced PV generation need modified protection schemes that reliably protect the microgrid in both islanded and grid connected modes because of the difference in faults current levels experienced by the two modes of operation. The protection challenges linked to fault current level changes and bi-directional power flow can be overcome using differential current relays. Accordingly, in this thesis report, differential current protection (DCP) was used to protect AC microgrids with inverter interfaced renewable energy resources in both operating modes.

The simulations were conducted on a model of the CIGRE low voltage distribution network. OCP was evaluated for grid connected mode with and without Photovoltaic (PV) generation. Results showed that:

- OCP average relay tripping time for single phase faults in grid mode without PV was 0.131s, and that of 3phase faults was 0.121s.
- The addition of PV generators resulted in the increase of the average relay tripping time to 0.199s and 0.135s respectively. This is due to the fault current contributed by the integration of PV generation, which limits the current that can be seen by the preset OC relays.
- Some OC relays failing to trip in island mode due to loss of coordination and reduction in fault currents.
- DCP proved to be unaffected by neither bidirectional current flow nor changes in fault levels, giving an average tripping time for single phase faults in grid mode without PV of 0.101s, and that of three phase faults was 0.100s.
- Addition of PV generation resulted in a negligible increase in relay operating time for both three phase and singe phase faults. These results also show that DCP is faster than that OCP.

- The system was further tested for different generation levels (15%, 57% and 81%) in island mode and gave a negligible difference in average tripping time for different generation levels.

In short, the results clearly highlighted the limitations of inverse time overcurrent relay protection. It was proven that inverse time overcurrent relay protection is susceptible to the short circuit level changes and relay coordination is lost when they switch from grid connected mode to island mode. In line with the aim of the thesis, the obtained results also prove the effectiveness of DCP, while demonstrating that the DCP scheme is reliable in protecting a microgrid with inverter interfaced RES in both modes of operation without changing protection settings. The results show that DCP can provide a high level of sensitivity, selectivity and fast operation for internal faults in both modes of operation, enabling a highly reliable and safe microgrid operation. The DCP system suggested in this thesis does not have overlapping protection zones and is thus unable to detect faults at terminal ends of transmission lines, hence it should be backed up by OCP or there should be an addition of more DCP relays to cater for the weakness.

The results obtained in this thesis can be applied to all low voltage microgrids with inverter interfaced RES to give reliable protections. This will contribute to the effective utilization of RESs in both the more developed and lesser developed power systems.

5.2 Future Work

DCP can provide effective protection but practical implementation is costly. Since this thesis aimed at demonstrating the reliability of the DCP scheme in protecting microgrids with invertor interfaced RES, the cost of implementing the DCP scheme was not probed. Further, as already alluded to in the study scope, this thesis did not investigate the effect of CT mismatch inaccuracy. Future work can thus focus on:

- Examining the effect of CT mismatch inaccuracy in the implementation of DCP.
- Researching on methods of reducing the implementation cost. Specifically, subsequent research can focus on the reduction of the cost of DCP relays.
- Investigating the methods of improving the reliability of less expensive methods other than DCP. This would provide a microgrid protection method that would be both reliable and cost effective.

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Appendix

Table 10: Line Parameters of CIGRE LV Distribution Network

Line segment	Node from	Node to	Conductor ID	R'_{ph}	X'_{ph}	R'_0	X'_0	L	Installation
				[Ω/km]	[Ω/km]	[Ω/km]	[Ω/km]	[M]	
1	R1	R2	UG1	0.163	0.136	0.490	0.471	35	UG 3-ph
2	R2	R3	UG1	0.163	0.136	0.490	0.471	35	UG 3-ph
3	R3	R4	UG1	0.163	0.136	0.490	0.471	35	UG 3-ph
4	R4	R5	UG1	0.163	0.136	0.490	0.471	35	UG 3-ph
5	R5	R6	UG1	0.163	0.136	0.490	0.471	35	UG 3-ph
6	R6	R7	UG1	0.163	0.136	0.490	0.471	35	UG 3-ph
7	R7	R8	UG1	0.163	0.136	0.490	0.471	35	UG 3-ph
8	R8	R9	UG1	0.163	0.136	0.490	0.471	35	UG 3-ph
1	R1	R2	UG1	0.163	0.136	0.490	0.471	35	UG 3-ph
2	R2	R3	UG1	0.163	0.136	0.490	0.471	35	UG 3-ph
3	R3	R4	UG1	0.163	0.136	0.490	0.471	35	UG 3-ph
4	R4	R5	UG1	0.163	0.136	0.490	0.471	35	UG 3-ph
5	R5	R6	UG1	0.163	0.136	0.490	0.471	35	UG 3-ph
6	R6	R7	UG1	0.163	0.136	0.490	0.471	35	UG 3-ph
7	R7	R8	UG1	0.163	0.136	0.490	0.471	35	UG 3-ph
8	R8	R9	UG1	0.163	0.136	0.490	0.471	35	UG 3-ph
1	R1	R2	UG1	0.163	0.136	0.490	0.471	35	UG 3-ph
2	R2	R3	UG1	0.163	0.136	0.490	0.471	35	UG 3-ph

Source: *[31]*

Table 11: Load details of CIGRE LV Distribution Network

Node	Maximum demand of each consumer group S_{max} (kVA)	Contribution of group to max feeder demand S_c (kVA)	Power Factor
R11	15	5.7	0.85
E	72	57	0.85
D	55	25	0.85
R17	15	5.7	0.85
C	47	25	0.85

Source: *[31]*