METERING AND ADAPTIVE PROTECTION FOR A MICROGRID WITH DISTRIBUTED GENERATION

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Key Words: Microgrid, Smart Metering, Adaptive Protection

Declaration

I know that plagiarism is wrong. Plagiarism is to use another's work and pretend that it is one's own.

I have used the IEEE convention for citation and referencing. Each contribution to, and quotation in, this final year project report from the work(s) of other people, has been attributed and has been cited and referenced.

This final year project report is my own work.

I have not allowed, and will not allow, anyone to copy my work with the intention of passing it off as their own work or part thereof.

Name: Claudio Buque

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Terms of Reference

With regards to this project the supervisor's instructions were to:

1. Prepare a literature review based on the topic of the project, particularly adaptive protection and metering systems for microgrids with distributed generation. With the principal aim of investigating modern systems being used in the industry;
2. Develop a comprehensive protection system for a microgrid and investigate load management techniques using smart metering;
3. Simulate the protection schemes under different scenarios including faults, load variations and operational switching;
4. Test the developed scheme under different conditions to identify the protection system's strengths, capabilities and areas for improvement;
5. Analyse the results from the tests performed;
6. Draw conclusions from those results to objectively evaluate the characteristics of the system;
7. Recommend ways of improving the developed scheme as well as present ideas for future research.

Acknowledgements

I would like to send a special thank you the following people who supported me through the duration of my degree.

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- To my mentor, Prof SP Chowdhury for his guidance and advice during the composition of this dissertation.
- Last but not least, to Susan for her patience and understanding over the past few years.

Nomenclature

Ω - Ohms

A - Amperes

AC – Alternating Current CB – Circuit Breaker

CHP – Combined Heat and Power CO – Carbon Oxide

CT – Current Transformer

CTI – Coordination Time Interval DC – Direct Current

DG – Distributed Generation/Generator DLG – Double line to ground

Hz - Hertz

IDMT – Inverse definite minimum time IPP – Independent Power Producer

LL – Line to Line

MATLAB – Matrix Laboratory MVA – Mega Volts-Amperes

NERSA – National Energy Regulator of South Africa PS – Plug Setting

REFIT – Renewable Energy Feed in Tariff RMS – Root Mean Square

s - Seconds

SLG – Single Line to Ground SS – Static Switch

T&D – Transmission and Distribution TMS – Time Multiplier Setting

VA – Voltage Amperes W – Watts

Abstract

The idea of distributed generation is proving to be successful and it is leading to the development of microgrids. Microgrids are tiny power grids, that may operate connected to a larger network (utility grid) or they can operate in isolated mode, these are known as the two modes of operation. The microgrid, like any other power grid requires a certain level of control and protection. This protection will prevent extensive damage to the network. If a fault occurs it will isolate it or cancel its effects as best as it can.

The model developed in this project is a 2 bus power system resembling the connection of a microgrid with the utility grid. This model also contains 3 circuit breakers and a static switch which are controlled by various, separate, but coordinated relays.

The protection system and power system models were simulated in Matlab Simulink. Both power system and relay models are hypothetical; they behave as typical systems but do not resemble any specific or real operational system.

A total of 19 tests were performed in this project. During the tests the power system behaviour, in terms of current, voltage and frequency, was monitored, measured and recorded. The recorded data and plotted graphs were used to derive conclusions about the power system and protection system. The relay trip signals were also interpreted. This was done to confirm that they comply with the expected outcomes. In these simulations the circuit breaker is opened when the trip signal has a magnitude of 0.

The main objective of this project is to develop an adaptive relaying system that will protect the microgrid both in connected and isolated modes. Therefore the settings for the different relays will be observed for the two modes of operation. This will determine whether they are correctly coordinated in order to operate as an adaptive relaying system. A secondary but also important objective is to identify load management techniques through smart metering that could facilitate power system operation and in turn power system protection.

To achieve the goal of this project the proposed relaying system will have to prove appropriate in all the test cases.

Based on the results obtained in the simulations, conclusions about the relaying scheme were drawn. Based on cases where the scheme seemed inappropriate or could be improved, recommendations were made.

The relaying scheme proposed in this project proved highly successful in detecting abnormalities and protecting the power system when necessary.

Table of Contents

List of Figures

List of Illustrations

List of Tables

1. Introduction

1.1 Background to the study

For many years, electricity has been generated from a central station, to feed to a network, where power is transmitted over long distances and eventually distributed to various loads. The generic idea of how electricity should be transported and where it should be generated is changing constantly. This change led to the development of distributed generation. Distributed generation involves the local (close to the load), small-scale generation of power to feed a load. In many cases this distributed generation is in the form of renewable energy, this is possibly because it is less economic to produce such low quantities of power from fossil fuels. For the power generation levels required from Distributed Generators, it is faster and cheaper to produce from renewable power generation sources. In some generation plants two or more energy resources are used to generate electricity, for example wind and sun, a specific name is given to such generation plants, these are hybrid generation plants.

In South Africa there is currently a programme in place called the Renewable Energy Independent Power Producer Procurement (REIPPP) programme, which encourages private developers to produce electrical power from renewable resources for sale to the national utility ESKOM. For this reason distributed generation and renewable energy have become a popular topic in South Africa.

Globally the idea of distributed generation proved successful and it led to the development of microgrids. These are smaller power grids, that may operate connected to a utility network or they can operate in isolated mode, these are known as the two modes of operation. The microgrid, like any other power grid requires a certain level of control and protection. This protection will prevent extensive damage to the network. If a fault occurs it will isolate it or cancel its effects to isolate and minimise disturbances. The objective of a protection system is not to prevent a fault but to reduce the negative effects when a fault does occur.

The protection systems for a microgrid are different to the protection systems for a conventional grid. Microgrids operate in different modes, for these different modes the relays in the grid will see different fault condition characteristics, for example lower fault currents, higher frequency variations, reverse currents, etc. and it is important that the relays can operate efficiently in both of these modes. It is also common that the system operation tolerances, for frequency, current and voltage vary in the different modes of operation. In order for the protection to be effective it usually has to be interconnected with the generation control system. This interconnection leads to optimal operation of the system. The protection systems developed in this project are intended to suit the Distribution System Grid Code established by the National Electricity Regulator of South Africa (NERSA).

The aim of this project is to present and investigate innovative ways to protect a microgrid with a Solar PV generation plant which may be connected to the local utility grid at distribution level.

1.2 Objectives to this study

The main objectives of this project are therefore to:

- Present a literature review of relevant topics especially microgrid adaptive protection.
- Develop an adaptive relaying scheme for a microgrid where the mode of operation of the microgrid determines the settings of the relays. The scheme should overcome the common protection problems associated with distributed generation integration with the utility grid, including false tripping and lack of fault detection.
- Analyse possible uses of Smart Metering and load Management in Microgrid protection.
- Simulate and test the developed load management and relaying schemes.
- Draw conclusions based on the test results.
- Make recommendations based on the conclusions.

1.3 Scope and limitations

Even though other issues do arise through the development of the project, this thesis focuses only on adaptive relaying and load management for microgrids. This research is developed in such a way that abnormalities caused by faults and system operations are explored. In order to cover the aspect of adaptive relaying, only digital relay configurations are used in the development of the relaying scheme and smart metering is considered for load management. In terms of distributed generation technologies, this research explores the capabilities of power generation from solar resources. Even though DGs can be implemented from various technologies, due to time limitations only PV Solar Generation was focused on.

The developed scheme was simulated and tested using the Matlab & Simulink tool. The settings and configurations used in this project are only useful for the microgrid presented in this research; however the means of development may be used to develop other schemes for other microgrids.

The scheme will not be put to practice as part of this research; it is limited to software simulations. Some deviations in results can be expected from actual practical schemes, due to the non-idealistic behaviour of electrical hardware.

1.4 Plan of Development

This project is structured as follows:

Chapter 1: Introduction

This chapter introduces the topics discussed in the research. It also gives some of the background to the study carried out.

Chapter 2: Literature Review

This chapter provides a detailed review of literature on Power System Protection, Distributed Generation, Smart Metering, Load Management, Microgrids and adaptive relaying schemes in microgrids. The literature reviewed is from a wide variety of journals and books written on the specific topics.

Chapter 3: Introduction of Models

This chapter introduces the microgrid for which the relaying scheme will be developed; it also includes the development of the adaptive relaying scheme to be used. Single line diagrams and simulation models will be presented in this chapter. Each relay used and developed in this research will be explained and its settings will be calculated in this chapter.

Chapter 4: Methods of Testing

In this chapter all of the tests will be explained and their purpose will be presented. These include the tests in isolated and grid-connected modes, for system mal-operation, faults and operation without faults.

Chapter 5: Results and Discussions

This chapter is dedicated to the presentation of the key results and interpretation of results from all the simulations and tests. It presents a comprehensive analysis of the results and a description of the power system behaviour during the tests. The meanings of the different results will be discussed but no conclusions will be drawn at this stage.

Chapter 6: Conclusions

This chapter presents the conclusions drawn based on the results and interpretations mentioned in **chapter 5.** The advantages of the proposed protection system are stated and the achievements of this research are discussed.

Chapter 7: Recommendations

This chapter hosts recommendations and suggestions for future work, based on the conclusions drawn in the preceding chapter and perspective gained during the period of this research.

Chapter 8: List of References

All of the papers, books, websites and other resources used to support the information in this research are listed in this chapter. The IEEE referencing style was used throughout this thesis.

Chapter 9: Additional Results

In this chapter additional results are presented. These results further demonstrate the system measurements during the simulations and testing. The intention of these results is to support the results presented in Chapter 5.

Chapter 10: EBE Faculty: Assessment of Ethics in Research Projects

Chapter 10 contains the completed ethics assessment form for this research project.

2. Literature Review

2.1 Electricity Market in South Africa

The electricity industry in South Africa is dominated by state-owned Eskom Holdings Limited (Eskom). This is a vertically integrated company, this means that it generates, transmits and distributes electricity. Eskom is active within South Africa as well as in the Southern African region through the Southern African Power Pool (SAPP). Currently privately owned companies produce approximately 2% of the electrical energy consumed in South Africa [3]. This private generation is for off-grid consumption, at present, no Independent Power Producers (IPPs) connected to the Eskom grid had been commissioned in South Africa. The generation capacity of Eskom is now close to 43,000MW, with this capacity, it is Africa's largest electricity producer, and it produces 45% of the total electricity in Africa. Majority, about 92%, of the power produced in the country is generated in large coal fired power stations, since this is the cheapest technology to implement for the amount of electrical energy to be produced and most available resource in the country.

Table I. Electrical Energy Consumption in South Africa 2011/2012 [3]

Generated	2012 (GWh)	2011 (GWh)
Coal	218 212	220 219
Nuclear	13 502	12 099
Hydro	1 904	1 960
Pump Storage	2 962	2 953
Gas Turbines	709	197
Wind Power	2	2
IPPs	4 107	1 833
Imported	13 038	13 613
Other	7 653	7 539
Total	**262 089**	**260 415**

Table I shows the breakdown of energy consumed in South Africa in the years 2011 and 2012. The general trend is that energy consumption is increasing in the country; this is in line with the country's development and population growth. The energy to be produced from most sources will be increased. There is an intention to decrease the energy imported from surrounding countries. Renewable resources have not yet become a significant contributor to energy generation in the country this is because of the historical background of large power generation from cheaply obtained coal. The large coal reserves in the northern region of the country make coal largely accessible and affordable for power generation.

Even with the small energy reserve margins Eskom managed to produce very positive results, arguably the best performers in the power sector, in the Southern- Africa region. They achieved a total system average interruption duration index of 45.75 hours for 2012 [3].

The map in Figure 2.1 shows the location of the electricity generation and the transmission line routes in South Africa. As previously mentioned majority of the power is generated from Thermal Power stations, all of which are concentrated in Gauteng, Mpumalanga and Limpopo provinces, towards the north-east of the country. For this power to be transmitted to other parts of the country, long high voltage transmission lines are used. These lines are the cause of large transmission losses. These losses are one of the motivations for the spread of generation capability throughout the country. This generation capability includes Renewable energy generation, in the form of distributed generators.

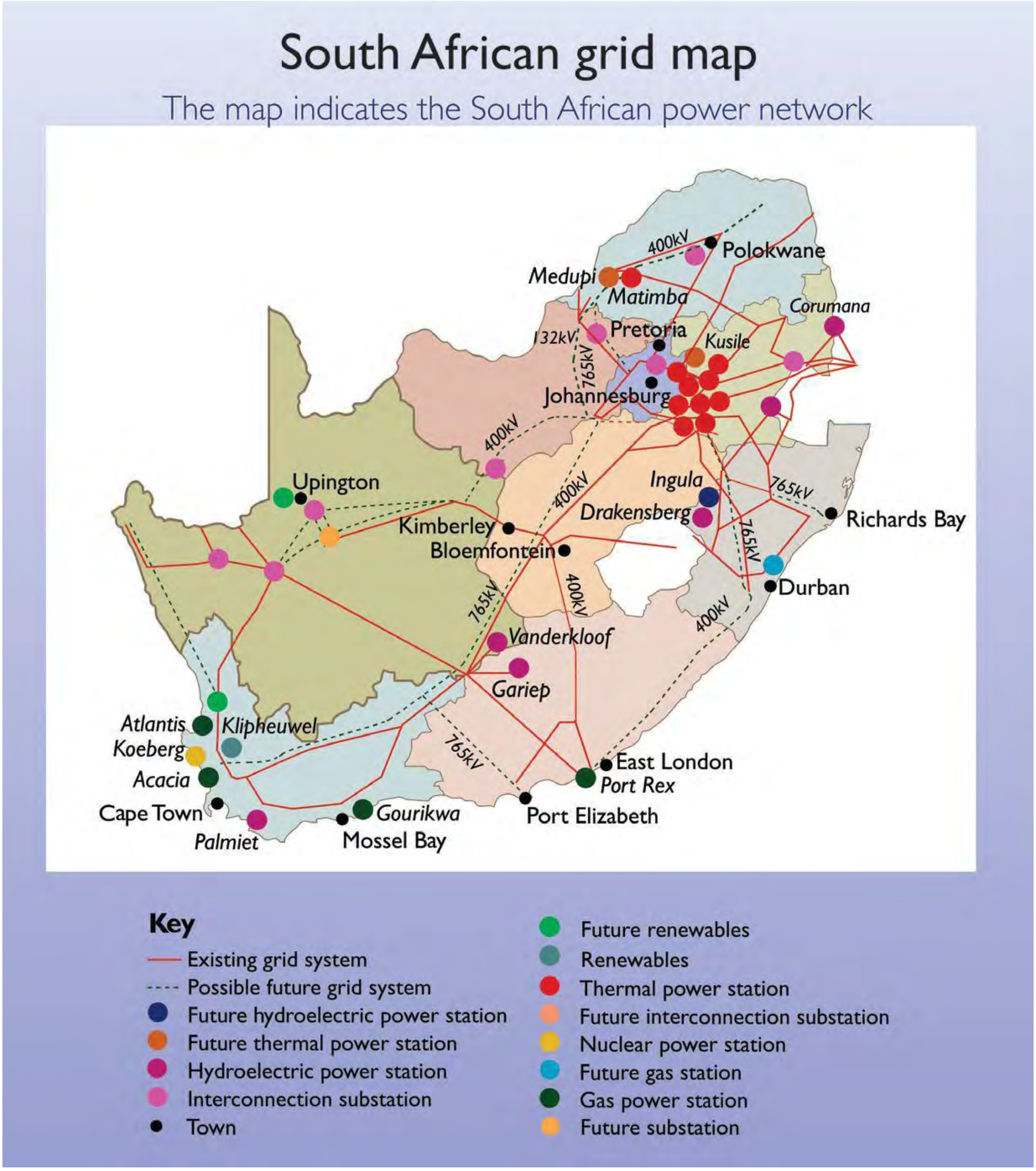


Figure 2.1 The South African grid map [3]

The Department of Energy (DoE) established in May 2009, in South Africa, a single mandate which is to ensure secure and sustainable provision of energy for socio-economic development. It has a short term goal, known as Vision 2014, which is, to have a transformed and sustainable energy sector with universal access to modern energy carriers for all by 2014. There is also a long term vision, which is, improving their energy mix by having 30% of clean energy by 2025 [4].

The White Paper on Renewable Energy was published by the Government in November 2003. The aim of this policy is to give an overview of government's vision, policy principles and strategic objectives for promoting and encouraging the use of renewable energy in the country [4]. Their 10 year goal was to achieve the generation of 10 000 GWh in a single year from renewable resources, this was approximately 4% of the predicted energy demand for the country for 2013. This goal has not been achieved yet and the paper is currently undergoing a review process by the department, with an aim of creating more realistic and reachable goals.

More recently, in 2010, the government came up with the Integrated Resource Plan (IRP2010). This plan supersedes the Energy Security Master Plan which was approved by cabinet in 2001. The IRP2010 determines the demand profile for the next 20 years and details how this demand can be most effectively met from different sources, such as nuclear energy, coal, gas and renewable energies [5].

All energy sources will play a major role in effectively matching the demand; however this research will focus on distributed generation renewable energy sources specifically solar power generated form photovoltaic technology.

2.2 Distributed Generation

Several researchers have defined distributed generation (DG) from different perspectives. However, generally DG is defined as electricity generation at a smaller scale compared to conventional centralised bulk power generation. The generators used for DG systems can be connected to the large-scale power system at any point, at the load side or closer to the utility source though the placement needs to be strategically planned before DG integration for maximising the benefits of DG or minimizing the adverse effects of integration. [1]

DG has recently become popular as a way of reducing environmental pollution and global warming by deploying renewable and low carbon energy resources. Apart from that DG increases reliability of the power system as a whole and can provide several ancillary services to the utility such as reactive power support during contingencies, peaking power and black start power. Although renewable DG power may have the advantages of supporting utility sources, it is unreliable when working on its own. Renewable power sources are dependent on the daily weather patterns, which can make power generation difficult to predict. If there is a fault in the utility grid or a lack of power capacity the microgrid can isolate itself and supply its load through distributed generation. Distributed generation systems play a big role in addressing the issues of power shortages and they are well aligned with the goals set towards energy efficient power generation.

The conventional power systems have a linear or vertically integrated structure which has proven to be less efficient. In this structure the generation is set up in one end of the line; the lines consist of transmission and distribution systems; the loads are connected at the downstream end of the system. This is not the case with DG where the power is generated near the consumers [2]. This arrangement eliminates transmission and distribution (T&D) losses by transmission inefficiencies.

2.2.1 Solar Power

i. Solar Power Market in South Africa

South Africa has an abundance of solar energy, one of the largest solar power capabilities in the world. In South Africa solar power is used for a variety of applications including: space heating, solar cookers, crop drying and photovoltaic for electricity generation and heat pumps for pumping water [4].

Almost the whole of the interior of the country has an average solar energy insolation in excess of 5kWh/m^2/day. Parts of the Northern Cape have an average insolation of 6kWh/m^2/day. The annual 24 hour solar radiation average for South Africa is 220W/m^2, compared with 150 W/m^2 for most parts of the USA and 100 W/m^2 for Europe. There is a large potential for solar power to contribute to South Africa's Energy needs. So far, however, solar power does not generate any electricity for the national grid [4]. This will change in the near future as Solar Plants approved in Round 1 of the REIPPP programme are already in construction. There is some electrical power being produced for domestic consumption but it is not close to the level where it should be.

Figure 2.2 is a clear graphical demonstration of the significant solar resources in South Africa compared to the resources in the rest of the continent.

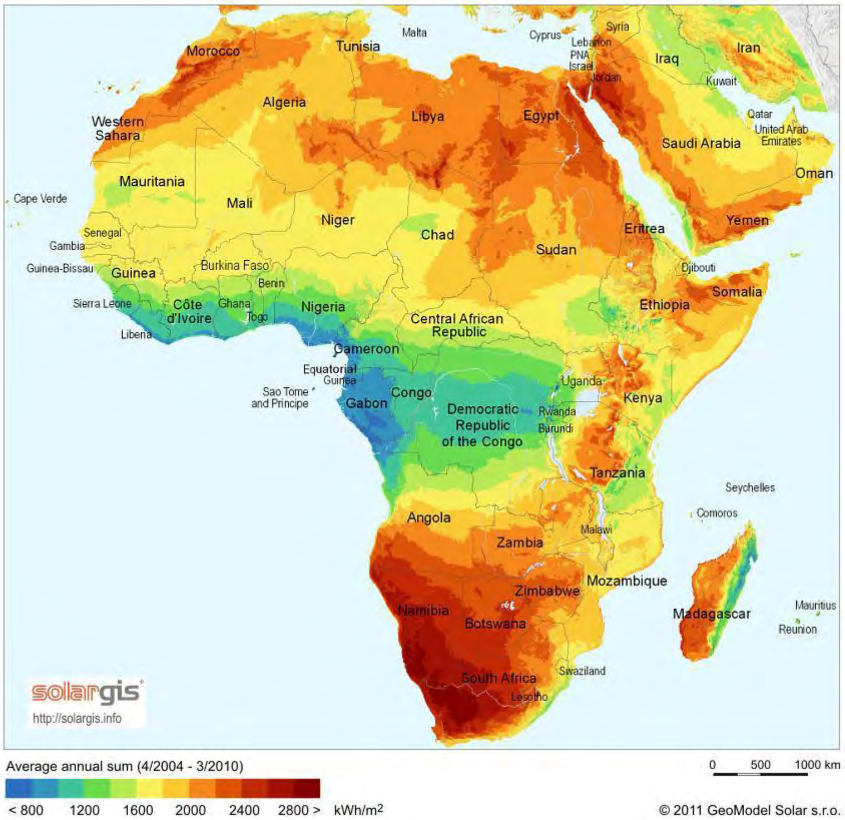


Figure 2.2 African Solar Radiation Map [6]

Figure 2.3 compliments Figure 2.2 in that it focuses specifically on South Africa's solar resources and it is more detailed. Although solar resources are abundant in the country, they are not evenly spread throughout the provinces. The central and western regions have the highest annual solar radiation values. This fact is well known by solar power developers in South Africa. The Northern Cape is the most highly competed region in the country for development of solar generation plants.

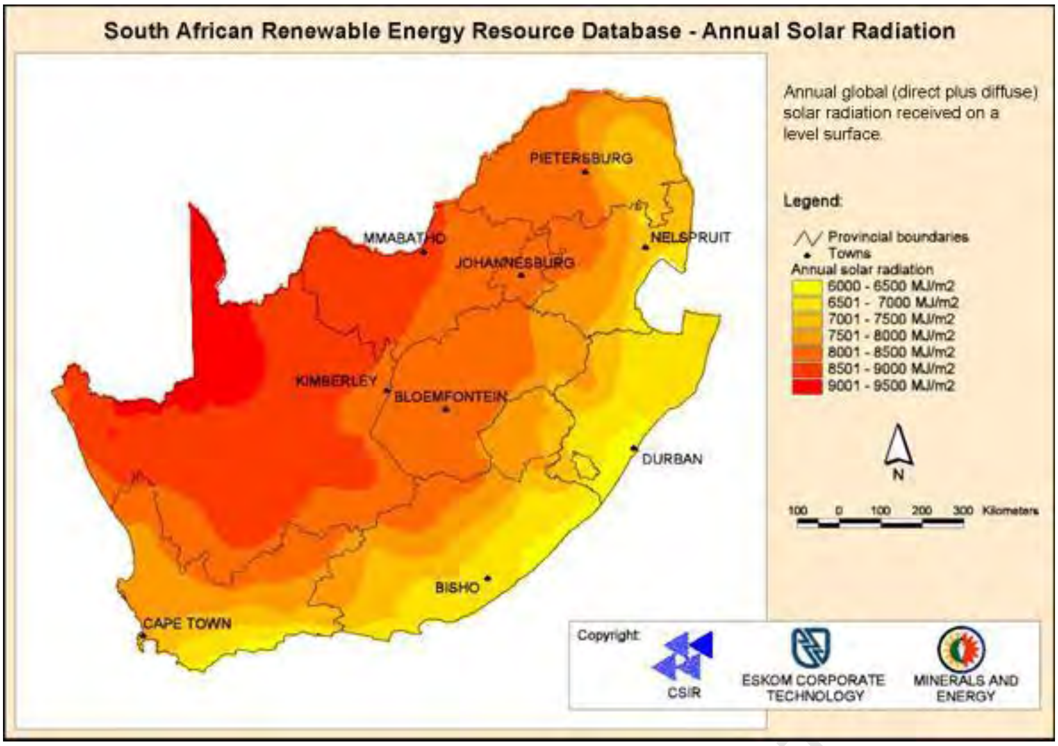


Figure 2.3 South African Solar Radiation Map [7]

The best applications of solar power are the heating of water for households and the provision of photovoltaic electricity for remote rural communities in houses, schools and clinics. The Department of Energy, through the Integrated National Electrification Programme (INEP) has embarked on electrification of schools, clinics and poverty stricken residential areas. The programme is funded through the DoRA allocation while implementation is undertaken by Eskom for schools and clinics, and by non-grid services providers for residential electrification [4].

Currently the South African government is considering the best way to mobilise industrial development around an ambitious solar-park concept, which it hopes to deploy in the Northern Cape Province over the coming years, primarily due to the intense solar radiation in the province. The project could produce 5GW of renewable energy, predominantly from thermal solar power; this is equivalent to one coal fired power station.

The project is being run by the Central Energy Fund (CEF), a company controlled by the Minister of Minerals and Energy. CEF is involved in the acquisition, generation, manufacturing, marketing, etc. of all forms of energy.

ii. Solar Power Technology

Figure 2.4 75MW PV Solar Plant under construction in Northern Cape (South Africa)

There are different types of solar power technologies. These technologies can be divided into several groups, in this research they will be split into 4 major groups and then those will be broken down further. There is reference suggesting that solar power generation started as far back as 1975 [12]. Technology at that stage had very low efficiency, but with extensive research new technologies with higher efficiencies and lower costs are continuously developed. Table II displays most of the solar power generator technologies. Each technology has its advantages and disadvantages, manufacturers and project developers can choose which panels to use to suit their business strategy. There is normally a balance between capital and maintenance costs, some technologies may seem cheaper to purchase but they have a higher maintenance cost. Therefore the lifetime costs of the different technologies are similar.

Table II. Different types of Solar Power generation technologies

Thin-Film Technologies	Crystalline Silicon Cells	Concentrating Photovoltaic	Thermal Solar Power
CIS	Single Crystal	Three-junction (2-terminal, monolithic)	Central Receiver
CIGS	Multicrystalline	Two-junction (2-terminal, monolithic)	Parabolic Trough
Amorphous Silicon	Thick Silicon Film	Single crystal	Linear Fresnel
Cadmium Telluride		Concentrator	
Nano-, micro-, poly- Silicon		Thin Film	
Multijunction Polycrystalline			

The following section of this report will only focus on the most popular solar power technologies in South Africa.

Thin Film Technologies

In thin layer technologies a thin layer of semiconductor is used. This layer is usually a couple of microns thick. The layer replaces the traditional silicon wafer. It is easier to manufacture and makes more efficient use of raw materials and today it accounts for approximately 18% of global PV sales. The typical thin layer panel consists of a semiconductor and several other thin films bonded to a sheet of glass, covered by another sheet of glass and sealed with an industrial laminate. The technology normally lasts 25 years during operation which is enough time to provide competitive rates of return. Thin film technologies are relatively simple to recycle at the end of their life span and allow for re-use of some of the raw materials.

In South Africa, thin film panels are considered to be electronic waste. This means they have to be disposed according to specific regulations. There are no electronic waste sites in South Africa, therefore if a panel breaks it needs to either be completely dismantled for recycle or it can be fixed and reused.

Cadmium Telluride (CdTe)

Currently the most used thin-film technology uses cadmium telluride as primary semiconductor material. The material has unique physical and environmental characteristics. It is preferred because of its relatively low cost. This technology like most other thin-film technologies can meet the highest environment, health and safety standards both in the factory and in the field. There are many methods of manufacture such as: high-rate sublimation, screen printing/ sintering and electro-deposition. Manufacturers normally focus on one of these methods; they focus on the one that better suits them and their long term goals [8]. Through optimisation and specialisation in one method, manufacturers can streamline their production of panels to make the process more efficient.

CIS/CIGS

This technology employs a semiconductor consisting of Copper, Indium, Gallium and Selenium and/or Sulphur. It is particularly well suited for Building Integrated Photovoltaics (BIPV) applications, because of their light weight. CIS and CIGS have a big potential for significant efficiency improvements. The addition of Gallium improves efficiency and morphology [8]. This is one of the most costly technologies to purchase.

Amorphous Silicon (a-Si)

This is the oldest form of Thin-film technology; it has been in operation since the 1980s. In the early 1990s it was written off by most manufacturers and investors because of its low efficiency. Towards the end of the 1990s it was brought back into the industry and back into operation. The return of this technology was mainly due to solutions found for multi-junction cells/modules. Now companies such as Solarex-Enron and United Solar have built multi-MW facilities. This serves as a reminder that the PV technologies go through difficult periods, but some, usually due to investment in research, emerge with realistic chances of success [8].

Crystalline Silicon Cells

Most utility sized PV Generation plants use Crystalline Silicon cells. This is made of self-supporting bulk crystalline or multi-crystalline silicon wafers. The materials used to produce a cell are similar to those used in modern day microelectronics industry. Waste silicon from the microelectronics industry is generally used to make solar crystalline silicon cells. Very few manufacturers produce or supply “Solar-grade silicon” [49], this creates a large demand for supply of materials and is a bottleneck in the industry. The silicon used is sliced from crystals grown either by the Czochralski crystal growth technique or from larger ingots prepared by cruder techniques. Electronically, the cell has an indirect band-gap; the cell is basically a very large area p-n junction diode with minimized avenues for carrier recombination within the cell.

Crystalline and Polycrystalline silicon cells are expected to satisfy most of the rapidly growing demand for solar photovoltaic products. Cells are expected to become thinner and higher performing, with possibly a shift in preferred wafer type [48].

Concentrating Photovoltaics

This technology uses lenses or mirrors to concentrate sunlight onto high-efficiency solar cells. They are typically more expensive per installed kW than conventional cells used for flat-plate photovoltaic systems. However, the concentration decreases the required cell area which means that the quantity of land required per MW produced is less than that in flat plate PV, while also increasing cell efficiency. In 2010 cell efficiency for this technology reached it's highest at about 40%. Concentrating Photovoltaics have the following advantages [12]:

- Potential for high solar cell efficiencies;
- Smaller plant size for the same amount of MW produced;
- Near-ambient temperature operation;
- No thermal mass allowing for fast response;
- Reduction in costs of cells relative to optics;
- Scalable to a range of sizes.

The high cost of advanced, high-efficiency solar cells requires the use of concentrated sunlight for systems to achieve a cost effective comparison with both the cost of the concentrator optics and other solar power options. This is a fairly new technology. It is most suited for utility scale installations. However, most installations have only been used for demonstration and research purposes; none have been connected to a grid. This is a topic that would render credible research. It could be a useful technology in South Africa in the future. At present the country does not face major constraints in terms of available space for solar PV plants, but in the future it could become an issue which will need to be addressed.

Thermal Solar Power

Thermal Solar technologies have reached a significant maturity as has been demonstrated by pilot projects around the world. Some improvements in technology still have to be made in order for the technology to be competitive with conventional power generating technologies. In a country like South Africa where solar resources are so abundant it could be feasible that thermal solar technologies replace a considerable amount of fossil fuel generated power.

Solar thermal technologies are based on the concept of concentrating solar radiation to produce steam or hot air, which can then be used for electricity generation using more conventional power cycles. Normally glass mirrors are used to concentrate sun light energy to a particular region. There are 2 ways of focusing the light energy: point focusing in the form of central receiver (tower) and line focusing in the form of parabolic trough. These systems use only direct light, i.e. solar light incident angle of 90°. The diffuse part of sun light cannot be concentrated. Line focusing is generally easier to achieve and to handle, but has a lower concentration factor and hence achieve lower temperatures than point focusing systems.

Today these systems achieve solar-to-electricity efficiencies of 10 – 15% [9]. Due to the thermal nature of Concentrated Solar Power (CSP) technologies, they can be combined with other technologies that use fossil fuels. This combination of technologies has the potential to improve the value of CSP by increasing its power capability, availability and dispachability.

Solar heat can be collected during the day time and stored in concrete, molten salt, ceramics or phase-change media. At night, energy can be extracted from storage to run the power block. It is generally assumed that solar concentrating systems are only economically viable for locations with direct incidence radiation above 1800kWh/m^2/year, which is a suitable amount in South Africa. To generate 1MWh in a year a CSP plant would need about 4-12m^2 of open area [9].

Central Receiver

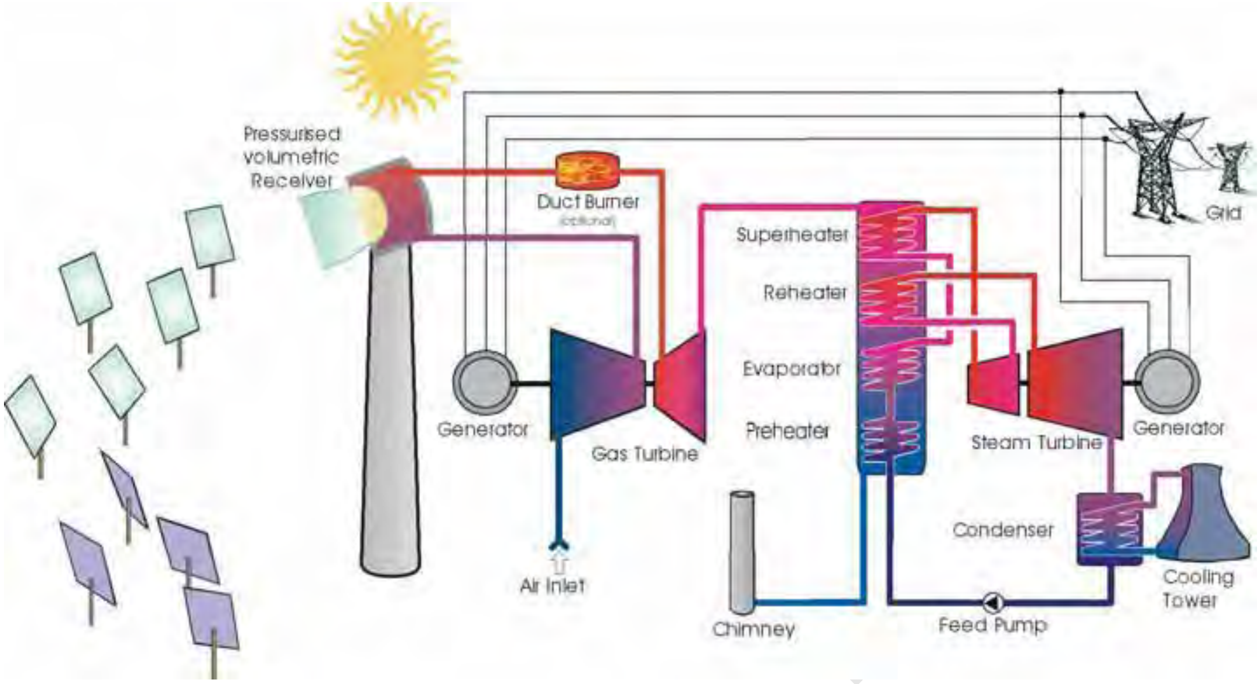


Figure 2.5 Schematic diagram of power generation using central receiver technology [9]

Central Receiver also known as power tower is a form of point focusing technology. These systems use a field of distributed mirrors and heliostats that individually track the sun and focus the sun light on the top of a tower. Temperatures of 800°C to 1000°C can be achieved at the tower if the sun light is effectively concentrated 600 to 1000 times. The energy is absorbed by a working gas turbine and then used to generate steam to power a conventional turbine. The high temperatures available in solar towers can be used not only to drive steam cycles, but also for gas turbines and combined cycle systems.

Parabolic Trough

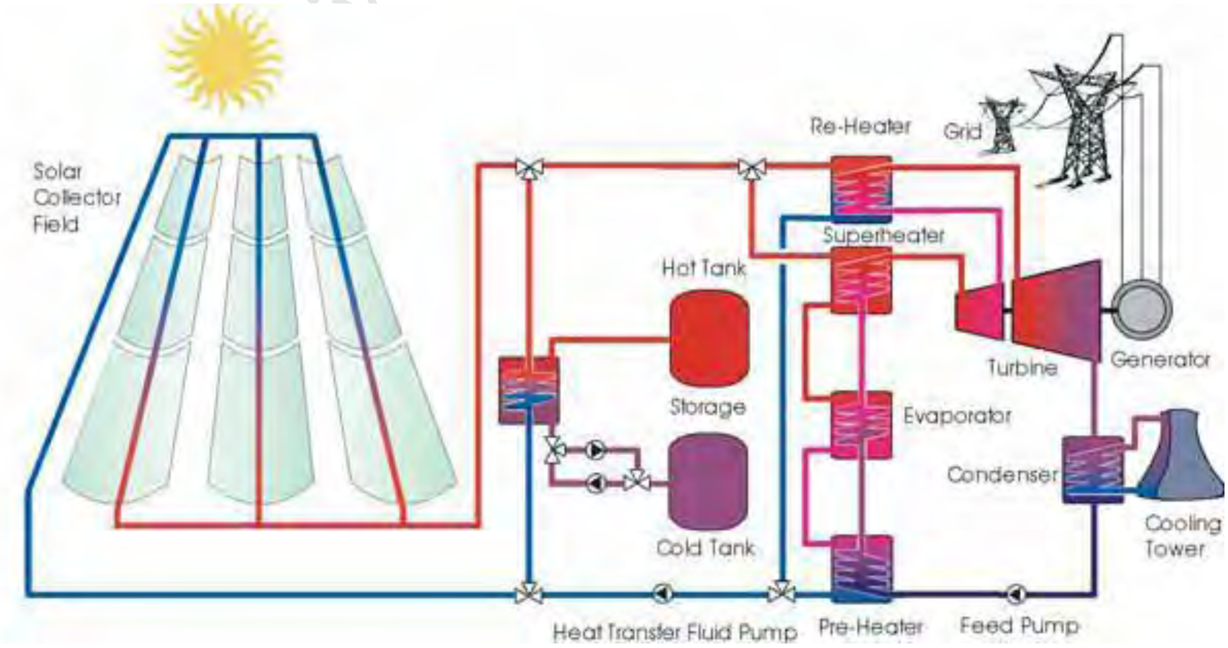


Figure 2.6 Schematic diagram of power generation using parabolic trough [9]

This is a form of line focusing system. It uses a trough like mirror and a special coated steel absorber tube to convert sunlight into useful heat. These troughs are usually designed to track the sun along a single axis predominantly north to south. To generate electricity, the fluid flowing through the absorber tube usually synthetic oil or water/steam transfers the heat to a conventional steam turbine power cycle. Operating temperatures can reach 350°C to 550°C (this is about half of the temperature reached by the central tower) if the sunlight can be efficiently concentrated 70 to 100 times. The technology is improving its efficiency and costs are reducing. There are large amounts of water used by this technology. This is a constraint since areas with the highest levels of solar radiation tend to have the smallest water resources. In South Africa there is a significant shortage of water, for this reason, the central tower technology could be favoured to the parabolic trough.

iii. ***Photovoltaic System Operation***

PV systems use properties of semiconductors to convert sunlight into electrical energy. The smallest and fundamental unit of a PV installation is a cell. The PV cells are made of some kind of semiconductor material, usually silicon. Generally the type of semiconductor determines the type of cell it is. The broad overview is that cells absorb light energy which energizes the electrons to produce electricity. This process occurs slightly differently for the different types of technology but the basic physics is the same [10].

Semiconductors allow electricity to flow with a resistance somewhere between a conductor, which ideally has no resistance, and an insulator, which ideally has infinite resistance. It is possible to add conductors to a semiconductor; this gives the user the ability to choose the type of semiconductor. There are only two types of conductors that can be added, these are positive conductors and negative conductors. Negative conductors are usually known as electrons. The positive conductors are conceptually more difficult to understand, they are basically holes or lack of electrons. A semiconductor with more positive conductors is called a p-type conductor and one with more negative conductors is called a n-type conductor. By adding conductors to the semiconductor the user does not add charge to the semiconductor, but simply increases the number of current carriers so that charges are free to move about. Each charge is balanced out by a charge of the opposite type so the overall charge of the semiconductor remains neutral [10].

A PV cell requires both p and n-type conductors to operate. If the p and n type semiconductors are brought together and a junction formed, charges can flow between them. The loose positive and negative carriers are attracted to each other so some of the electrons in the n-type material migrate out of the n-type material into the p-type material and vice-versa. The attraction of unlike charges is counterbalanced by the electric field that is created as the charge of the material is changed when it loses some of its charged particles. This region surrounding the junction is called the depletion region and is what gives the p-n junction the ability to convert light into electricity. When the sunlight that hits the p-junction has enough energy an electron can be separated from its respective atom. If the separated electron is not re-absorbed by another atom and manages to reach the depletion region, it gets swept through the electric field (created by charge separation) to a higher potential. The electron can be collected by an electrode placed on the junction and used to do some work in the circuit. This is how the two junctions create usable electricity.

A number of solar cells electrically connected to each other and mounted in a support structure or frame, behind a glass sheet to protect the cells from the environment, is called a PV module. A number of cells form a module and a number of modules form an array as displayed in Figure 2.7. Modules are arranged in section sizes of approximately 40x5m called tables and are installed on racks which are made of aluminium or steel. Modules are designed to supply electricity at a certain voltage. The current produced is directly dependent on how much light strikes the module. The arrays are arranged into rows that form the solar field.

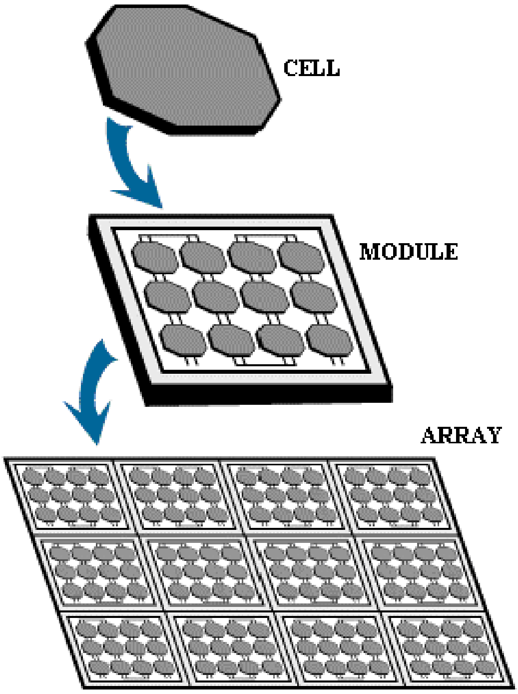


Figure 2.7 Differentiation between a cell, a module and an array [11]

The arrays and racks are founded into the ground through either concrete, screw or pile foundations. The arrays are wired to inverters that convert direct current (DC) into alternate current (AC) at a specific voltage, this voltage is then stepped up at a local transformer to meet the requirements of the utility grid.

The fundamental difference between PV and CPV technology is that CPV uses optics such as lenses to concentrate a large amount of sunlight onto a small area of solar PV materials to generate electricity. It is argued that CPV technology can reduce overall cost by using more advanced technologies with higher efficiencies. Using CPV technology does require tracking systems to ensure the sunlight is focused on the small cell. Tracking systems include motors, light sensors and timers which do increase the capital cost and O&M cost of the project.

PV Panels can also be mounted on tracking systems which follow the path of the sun to maximize the benefit of each ray of sunlight and allowing for the land underneath to be utilized as well. Shade crops can be cultivated under solar panels, increasing the diversity of crops that can be cultivated in sunny regions.

Water could be obtained from underground water sources depending on the legal agreements and compensation with the landowners. Water might also have to be extracted and permitted by the Department of Water Affairs (DWA). This water is generally used to clean the panels, as dirt, dust, pollen and bird excretions can decrease the energy conversion efficiency. The frequency of panel cleaning would depend on the site conditions. Modules would be washed with water and a mild, organic, and non-abrasive detergent. Maintenance of modules is very important for the PV plant’s longevity.

Flat panels can be mounted in 3 different ways as displayed in Figure 2.8: fixed axis, single axis tracking and double axis tracking. Fixed axis is the cheapest and least efficient in terms of maximum use of available resources because it does not follow the sunlight throughout the day. It is maintained fixed therefore it only sees maximum operation during a certain time of day for a certain climatic season. Single and double axis frames can change their position to maximise the amount of sunlight that hits the panels. To track the sunlight the frames are adjusted by small motors. These motors are controlled based on either the time of the day or the position of the sun detected by light sensors. Again these mechanical system controls will not be investigated further in this research which focuses on the electrical system. Single axis tracking can be used to follow the path of the sun during the day or to suit different seasons. This technology definitely has a higher capacity factor than fixed axis but it is also more costly because it uses sunlight sensors and a motor per module to follow the sunlight. Double axis tracking systems usually use two motors to track the sunlight. One motor will be used to track the sunlight position during the day and the other will track sunlight position during the change of seasons. Double axis tracking is the most expensive form of tracking; many manufacturers argue that the cost incurred for double axis tracking is not worth the increase of energy produced.

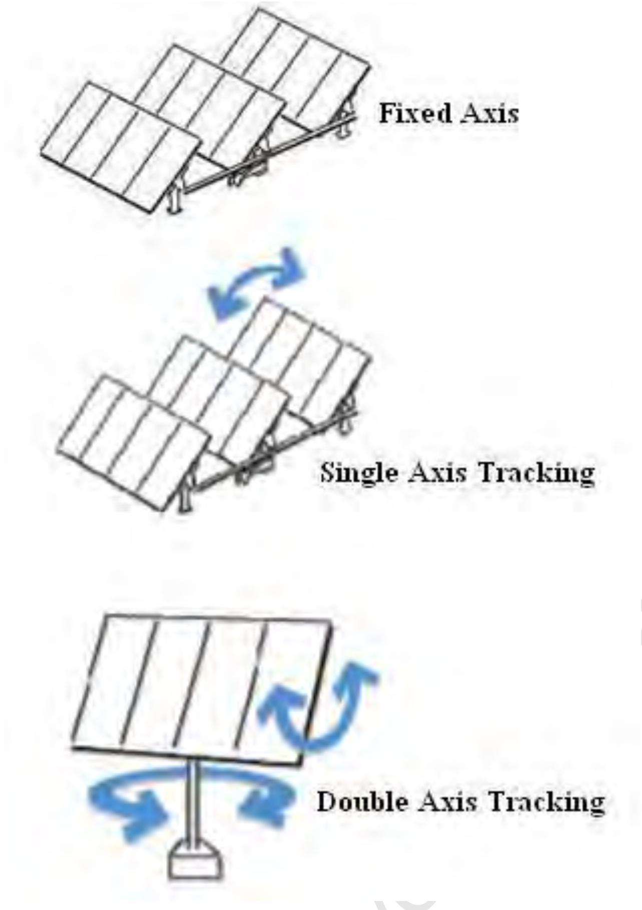


Figure 2.8 Mounting Structures for PV Panels [11]

iv. Solar Power Technology Efficiencies

The graph in Figure 2.9 shows the efficiencies of the different cell technologies. It is clear that some of the technologies are improving their efficiencies faster than others; however, it is evident that all of the different technologies are improving. The constant efficiency improvement is due to investment and the need for the technology to compete with other well established forms of electricity generation. Governments and Investors will not be drawn to solar power generation if the high capital costs impede a good return of investments. Technology efficiency plays a big part in return of investments. A large quantity of this investment is due to the global trend towards green energy. Solar power is a highly regarded form of renewable energy. Global acceptance of the technology has led to extensive research which in turn led to improved efficiencies.

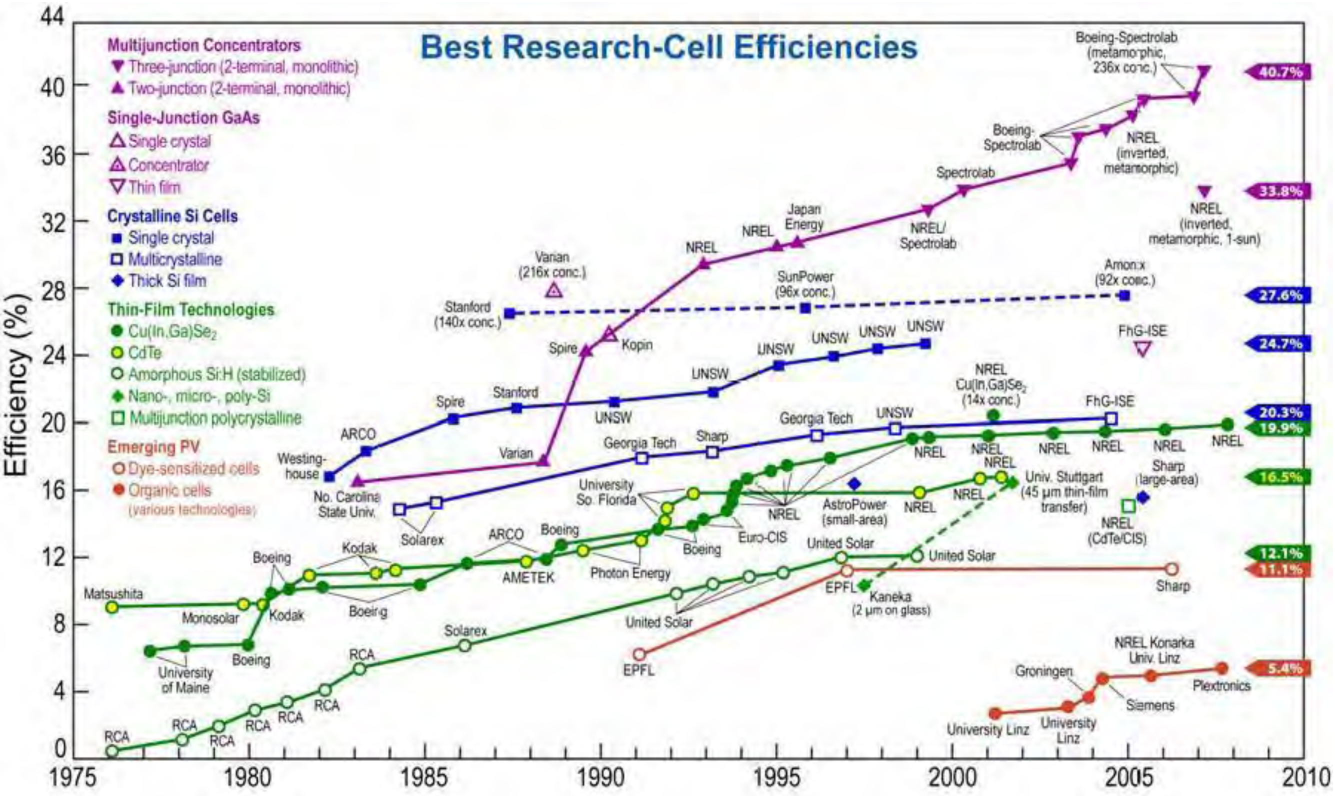


Figure 2.9 Solar Technology Laboratory Efficiencies trend from 1975 to 2020 [12]

v. Grid Code Compliance for Solar Energy Facilities in South Africa

Unlike for wind energy facilities, a set of Grid Code tests has not been defined for solar power facilities in South Africa. For this reason it is assumed that the facility will be connected to the national distribution network, i.e. below 132kV. This is the general trend for solar PV generation in South Africa. There will some thermal solar power plants connected at 220kV due to the ease of practicality in handling a high capacity in a higher voltage level. This research is focused on small PV generation; therefore it will be focused on distribution networks only. The distribution code has a number of technical requirements and embedded generators connection conditions which will be reviewed in this research.

Embedded Generators Connection Conditions

Responsibilities of Embedded Generators to Distributors

The Distributed Generator (DG) must enter into connection agreement with the Distributor, be it Eskom or the Local Municipality before connecting to the network. This agreement will determine various conditions amongst these are the plant reliability and quality of supply. It is the DG owner's/operator's responsibility to ensure that all the relevant standards are complied with. The DG must comply with the Distributor's protection requirement guide as well as protection of own plant against abnormalities, which could arise from the distributor's side. Any connection costs shall be incurred by the DG, in compliance with the Tariff Code. It is the DG's responsibility to synchronize the generating facility to the Distribution System within pre-agreed settings. In South Africa the DG owner has the option to pay Eskom for a connection or build and hand over to Eskom for operation after completion [13].

Connection Point technical Requirements

The DG is responsible for the design, construction, maintenance and operation of the equipment and technology on the generation side of the connection point. Technical specifications of the connection must be agreed upon by the participants based on the distribution system impact assessment studies. A circuit breaker and visible isolation must be located in a position visible to both participants and must be installed at the connection point to provide the means of electrically isolating the distribution system from the generating facility. It is the responsibility of the DG to have a circuit breaker to connect and disconnect the generator. These are the general requirements; Eskom usually determines the scope of work at the point of interconnection [13].

Protection Requirement for Distributed Generators

General Protection Requirements:

DGs with a capacity lower than 10MVA only have to comply with the requirements of the South African Distribution Code. If the DG has a capacity higher than 10MVA it has to comply with section 3.1 of the Transmission Network Code. Additional protection features such as inter-tripping and generator plant status are to be agreed upon by the two parties. The protection schemes used by the DG must incorporate facilities for testing and maintenance; it must also be approved by the distributor and/or the National Transmission Company (NTC), depending on which code the DG falls under.

Specific Protection Requirements:

1. Phase and Earth Fault Protection

The protection system of the DG must fully coordinate with the protective relays of the Distribution system. The DG is also responsible for the installation and maintenance of all protection relays at the connection point.

2. Over-voltage and Over-frequency Protection

The DG must install over-voltage and over-frequency protection to disconnect the generating facility under abnormal network conditions.

3. Faults on the Distribution System

The DG must be responsible for protecting the generating facility in the event of faults and other disturbances arising on the distribution system.

4. Islanding

The distributor has authority to specify when the DG may remain connected if the section of the distribution system to which the DG is connected is isolated from the rest of the network. The DG must be equipped with dead-line detection protection system to prevent the generator from being connected to a de-energised system. For unintentional network islanding, the DG and Distributor must agree on methodology for disconnecting and connecting the DG.

This thesis aims to accommodate the 4 above mentioned points related to Protection requirements for a DG.

Quality of supply requirements

1. Frequency Variations

The DG must remain synchronised to the Distribution System while the network frequency remains within the agreed frequency limitations.

2. Power factor

The power factor at the connection point must be maintained within the limits agreed upon by the participants.

3. Fault Levels

It is the DGs responsibility to ensure that the fault level contributions from the generation facility are not exceeded.

vi. Financing Solar Power Generation in South Africa

Financing solar power projects in South Africa is still a difficult obstacle. Although the country has vast flat lands with abundant solar resources which makes solar projects technically feasible, low electricity tariffs and a large amount of competition from cheaper technologies makes it less attractive to investors. With the present electricity tariffs it is difficult to justify the investments because of the low rates of return.

In addition to the low tariffs which make it an unattractive investment, there are also construction skills and material constraints. A large amount of money is spent during the construction stage because a lot of the material is imported and the local work force is not yet skilled in installing the materials. This results in a large amount of damaged equipment and slow construction rates.

Solar technologies are globally regarded as expensive technologies, but it is even more expensive to implement in South Africa than the rest of the world because it is such a new technology. The following tables display indicative costs associated with building solar plants in South Africa.

Table III. Costs associated with Thin-film technologies [14]

	Cadmium Telluride	Amorphous Silicon
Capital Costs (ZAR/kW)	38,000	40,000
Operation and Maintenance Costs (ZAR/kW/annum)	400	400

Table IV. Costs associated with Concentrating PV Technology [14]

	Concentrating PV Technology
Capital Costs (ZAR/kW)	37,000
Operation and Maintenance Costs (ZAR/kW/annum)	500

Table V. Costs associated with Thermal Solar Technology [14]

	Parabolic Trough	Central Receiver
Capital Costs (ZAR/kW)	50,000	36,000
Operation and Maintenance Costs (ZAR/kW/annum)	650	600

It is evident that thermal solar technologies are the most expensive to build, operate and maintain. However, they are the most dispachable and reliable technologies in terms of solar power.

2.2.2 Hybrid

Hybrid generation is a concept where two or more generation technologies are joined together to form a single generation facility. In Africa it is common in rural areas isolated from the electricity network, to have hybrid facilities which contain a form of renewable energy such as wind or solar power, but have diesel generators as a back-up system. This is highly effective in terms of provision of constant supply; however, the use of diesel generators defeats the purpose of aiming for low carbon emissions as planned by the South African Government. Diesel generators are also costly to operate due to the fuel costs.

In 2001, the then president of South Africa, Thabo Mbeki, stated in his state of the nation address that, “With regards to the energy sector, among other things,…, localised energy grids for rural areas will be developed.” Hybrid facilities are ideal for rural areas because of their fast lead times and low operation and maintenance costs.

Pilot Hybrid projects have been initiated in the country. An example of this is the Hluleka Nature Reserve hybrid mini-grid, located in the Transkei region of the Eastern Cape Province. The system allows for provision of comprehensive electricity service, 220V AC 50Hz can be supplied to local customers. CSIR was contracted by the Ministry of Minerals and Energy to coordinate the development of the project implementation plan. Shell Solar South Africa (Pty) Ltd was the implementation company [15].

In order to map good resource locations for Hybrid generation researchers can use the South African Renewable Energy Resource Database (SARERD) together with the Hybrid Optimization Model for Electric Renewables (HOMER). This will give an indication of the most suitable locations in terms of resources and predicted project costs [15].

From basic interpretation of the solar resource map and the wind resource map it can be assumed that there are various locations in South Africa capable of providing suitable locations. An investigation, however, would have to be carried out to determine whether those resourceful regions have the demand that justifies installation of a generation facility. After all the point of distributed generation is to produce electricity close enough to the load centre.

i. Challenges caused by Hybrid Generation Facilities

Hybrid generation facilities face the same challenges encountered by all distributed generators and more. The increased challenges arise from the fact that there is essentially more than one generation technology present in the facility. If wind power and solar power technologies are installed there can be difficulties related to system protection and control. Both of these technologies use inverters to convert DC signals to 50Hz AC signals to be sent to the national grid.

Challenges in active and reactive power management will be encountered. This happens when there are plenty of resources and generation capacity is high, but the demand is too low. The fact that two renewable technologies are being used there is also a challenge in dispachability; the operator can only base capacity predictions on weather predictions. Renewable technologies are unreliable in the sense that the operator will not know well in advance the plant capability and availability [16].

System protection and control challenges will have to be overcome. Grid codes and standards are put in place and these state certain specifications which cannot be overlooked. The designed protection and control systems have to comply with the regulations as well as complement each other to avoid nuisance tripping. These systems have to effectively handle faults, overcurrent, overvoltage and over frequency situations. This is not designed in the same manner as conventional generation systems because of specific characteristics of distributed generation such as back-flow of current and in this case sensitivities of power electronics systems.

2.3 Microgrids

2.3.1 Interconnection between the microgrid and the utility grid

The microgrid can operate in two modes: grid connected mode and isolated mode. In the isolated mode the microgrid is supported by its own means of distributed generation. However, in grid connected mode it is supported by the central generation of the utility.

The point of connection between the microgrids is very important and it serves for more than linking the two independent power grids. This point consists of a power electronics device called a static switch (SS) as shown in Figure 2.10. This switch is used to automatically disconnect the microgrid from the utility grid in cases of disturbances and insufficient power capacity. This makes the power supply to the loads in the microgrid more reliable.

It is important that the microgrid meets the utility standards. At the point of connection, both grids must be operating at the same voltage and frequency. These grids have adequate control systems to ensure that the necessary requirements are met. This is important because if the standards don’t agree within certain percentages, the grids can cause each other to collapse. By most contractual means the microgrid cannot compromise the utility’s grid in terms of safety, reliability and quality of supply [17].

For microgrids a meshed network is preferred because of its balanced voltage profile and high system reliability. However, meshed networks have a very high short circuit power. The other network design methods, radial networks, are simpler to develop and implement. They have a lower short circuit power, but they have an unreliable voltage profile which can put the utility grid in danger. The advantages and disadvantages in each case should be considered in order to select the most appropriate network configuration.

Another factor to consider is the interconnection of the microgrids amongst themselves. These can be interconnected via a single LV line, via a connection of all the LV lines to a single MV/LV transformer or via the connection of all MV/LV transformers to a bus ring [18]. These connections are simpler than the static switch connection even though they may sound more complicated.

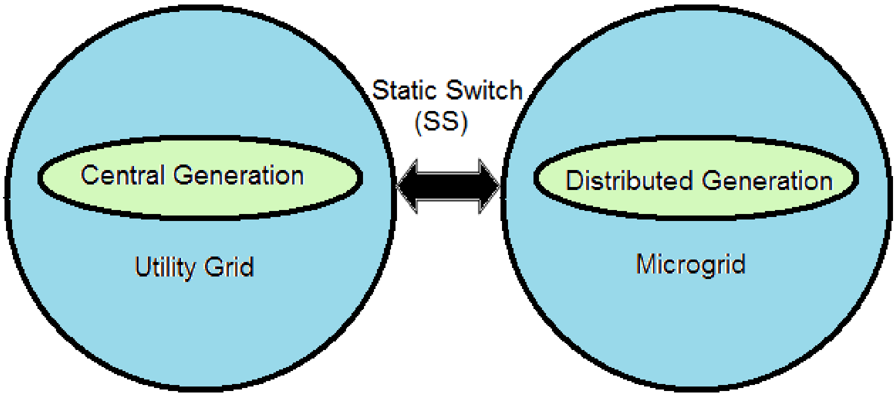


Figure 2.10 Interconnection between Microgrid and Utility Grid

2.3.2 Microgrids in South Africa

Currently national utility Eskom is the sole electricity provider in South Africa. They generate most of the power used and sell it to Municipalities, who in turn sell the power to residential, commercial and some industrial customers. The common trend around developed countries is that there are several electricity utilities or system operators; the market is deregulated, which creates competition and in turn renders a better service. South Africa is also advancing in the same direction. The need for competition and deregulation has been realised. At the moment most of the distributed generation and microgrids are found in the industrial sector, where distributed generation is used in emergency and standby modes.

The country is fortunate to have an abundance of coal resources, which enables Eskom to produce and sell electricity at a very low price. This fact has discouraged independent power producers (IPP) to invest in South Africa because the profit margins were not viable. However, the National Energy Regulator of South Africa (NERSA) has released the renewable energy feed-in tariff (REFIT). This REFIT increases the electricity tariffs, ensuring that renewable resources and IPP investments are financially viable [19]. A rising trend can already be identified by the growth of Wind farm proposals in the Eastern Cape and southern coast of the country, as well as solar plants in the Northern Cape region.

This trend should continue to grow in the years to come. DG and Microgrids have the technologies needed to solve many of the issues the government wants to address in terms of electricity supply. One of these issues is the reduction of greenhouse gas effects the other is the reduction of power losses by generating power closer to source. Microgrids generally improve industrial energy efficiency and are therefore environmentally friendly [19].

2.3.3 Standards and Regulations

The microgrid to be modelled and simulated in this research will operate at 11kV. In South Africa this voltage is considered to be medium voltage. Like any other system of any voltage level it must comply with the NRS 048-2: Electricity Supply – Quality of Supply. This standard regulates the quality of most parameters related to the power grid and it protects the customers connected to the grid and forces the electricity providers to maintain a relatively high quality of supply. In South Africa, currently, the distributors are Eskom and the various local municipalities. If the market becomes de-regulated private suppliers will also have to abide by the quality standards in this document.

The NRS048-2 focus amongst others, on the following parameters and conditions:

1. Voltage
2. Frequency

3. Voltage Unbalance
4. Voltage harmonics and inter-harmonics
5. Voltage Flicker
6. Voltage Dips
7. Voltage Swells and transient overvoltage

Voltage

The reference system voltage in medium, high and extra high voltage networks is the nominal or declared voltage for that system. The declared voltage is agreed between the customer and the utility. Eskom being the national electricity utility company with a transmission industry monopoly tends to determine the voltage levels. It is recommended that the declared voltage remains within 5% of the nominal voltage, in per unit terms, between 0.95 and 1.05p.u. All phases in the system must be continuously monitored.

The NRS048-2 forces electricity providers to maintain voltage levels at agreed levels and not to exceed these values for long periods of time. The standard allows for some deviation but not such a big variance that will damage equipment connected to the grid.

In cases where the nominal system voltage is above 500V the supply voltage shall not deviate from the declared or agreed voltage by more than 5% for any period longer than 10 consecutive minutes.

Table VI. Maximum allowed voltage for different voltage levels [20]

Nominal Voltage (kV)	Maximum Voltage (kV)
400	420
275	300
220	245
132	145
88	100
66	72,5
44 and below	Nominal Voltage +10%

Where voltage decreases to a value less than 0.85 p.u for a period longer than 3 seconds on one or more phases, it shall be logged as an under-voltage event.

Frequency

The nominal frequency for all electrical AC systems in South Africa is 50Hz. Again due to the nature of electrical systems there is provision for some deviations in this value. These deviations are displayed in the table below:

Table VII. Frequency compatibility in electrical power systems [20]

Network Type	Compatibility
Grid	±2% (± 1Hz)
Island	±2.5% (±1.25Hz)

The constraints on the island are less than on the grid because a variation of frequency on an islanded network will have less of a knock-on effect on other systems. If the deviation is greater in the grid, the negative effects are noticeable.

The limits for frequency deviations are as shown in the table below:

Table VIII. Frequency limits in electrical power systems [20]

Network Type	Limit
Grid	±2.5% (± 1.25Hz)
Island	±5% (±2.5Hz)

Frequency must be measured continuously and under-frequency relays are critical in achieving grid compliance.

Voltage Unbalance

This is a condition in a polyphase system in which the rms values of the line (phase) voltages or the phase angles between consecutive line voltages are not equal. Unbalanced voltages can be represented by the sum of 3 sets of symmetrical vectors, namely:

1. The positive sequence set, consisting of 3 vectors all equal in magnitude and symmetrically spaced, at 120° intervals, in time-phase, their order being equal to the phase order of the system generated voltages.
2. The negative sequence set, consisting of 3 vectors all equal in magnitude and symmetrically spaced, at 120° intervals, in time-phase, their phase order being the reverse of the positive sequence phase order, and,
3. The zero sequence set, consisting of 3 vectors, all equal in magnitude and phase.

Voltage Unbalance is calculated as follows:

UB = (Vn/Vp) x 100

Where,

V_n is the negative sequence voltage and V_p is the positive sequence voltage.

Alternatively, simultaneous measurement of the 3 rms line-to-line voltages can be used to calculate unbalance.

$$UB=\sqrt{\frac{1-\sqrt{3-6}}{1+\sqrt{3-6}}}\quad 100$$

Where,

$$=\frac{V_{12}{}^4+V_{23}{}^4+V_{31}{}^4}{(V_{12}{}^2+V_{23}{}^2+V_{31}{}^2)^2}$$

The voltage unbalance compatibility level for LV, MV and HV networks is 2%.

Voltage harmonics and inter-harmonics

Voltage harmonics are sinusoidal components of the fundamental waveform that have a frequency that is an integral multiple of the fundamental frequency.

- Odd harmonics are defined as the 3rd (150Hz), 5th (250Hz), etc.
- Even harmonics are defined as the 2nd (100Hz), 4th (200Hz), etc.
- Inter-harmonics are frequency components that are not an integral multiple of the fundamental frequency.
- Total harmonic distortion (THD) is given by:

$$THD = \sqrt{\sum_{h=1}^{N} V_n^2}$$

Where,

V_n is the per cent rms value of the hth harmonic or inter-harmonic voltage component and N is the highest harmonic considered in the calculation.

Long term effects of harmonic and inter-harmonic distortion relate mainly to thermal effects on cables, transformers, motors, capacitors, etc. Very short effects relate mainly to disturbing effects on electronic devices that may be susceptible to harmonic distortion. As a regulation, the THD of the supply voltage, including all harmonics up to the order 40, shall not exceed 8%.

Voltage Flicker

Voltage flicker is a modulation of the amplitude of the supply voltage, perceived by the observer as a fluctuation of light intensity in electric lighting. For low voltage and medium voltage networks, the compatibility level for long-term flicker severity (P_{lt}) must be 1.

$$P_{lt} = \sqrt[3]{\frac{\sum_{k=1}^{12} {P_{st}}^3}{12}}$$

Voltage Dips

Voltage dips are also known as voltage sag, this is the sudden reduction in the rms voltage for a period of between 20ms to 3s, of any or all of the phase voltages of a single-phase or a polyphase supply. The duration of a voltage dip is the period of time measured from when the system voltage drops below 0.9p.u. of the declared voltage to when it rises above 0.9p.u. of the declared voltage.

Faults on overhead lines are a great contributor to voltage dips. The network topology also contributes to the magnitude and duration of voltage dips. The definition of the dip categories (Y, X, S, T, and Z) is based on a combination of the network protection characteristics and customer load compatibility.

Table IX. Voltage Dip Categorisation

Range of dip depth ΔU (expressed as a % of U_d)	**Range of residual voltage** U_r (expressed as a % of U_d)	**Duration** t		
		20 < t ≤150 ms	150 < t ≤ 600 ms	0,6 < t ≤ 3s
$10 < \Delta U \leq 15$	$90 > U_r \geq 85$	▨	▨ Y	▨
$15 < \Delta U \leq 20$	$85 > U_r \geq 80$	▨	▨	Z1
$20 < \Delta U \leq 30$	$80 > U_r \geq 70$	▨	S	
$30 < \Delta U \leq 40$	$70 > U_r \geq 60$	X1		Z2
$40 < \Delta U \leq 60$	$60 > U_r \geq 40$	X2		
$60 < \Delta U \leq 100$	$40 > U_r \geq 0$	T		

Dip categorisation is based on the philosophy that:

- Licensees should manage protection performance times;
- Licensees should place particular emphasis on managing the number of faults that occur close to a particular customer;
- Customers in the industrial and commercial sectors should specify the dip sensitivity of their process equipment, to enable appropriate mitigation measures to be considered, so as to limit the number of licensee fault events that actually affect the plant.

Voltage swells and transient overvoltage

Voltage swells are experienced generally due to events such as switching out large loads or sections of the network, or problems with voltage control devices such as regulators, tap changers or capacitors. Phase-to-phase voltage swells usually do not exceed 1.15 of the declared voltage.

Voltage swells are an important topic in distributed generation. Bidirectional currents are a common phenomenon which can lead to voltage swells if the load magnitude is small. In a later chapter in this thesis, voltage swells are looked at in more detail with emphasis on voltage swells in microgrids.

2.4 Control

In electrical systems it is important to have control systems. These control systems help to achieve the best operational results in the system. Control units are implemented in all aspects of engineering in different manners. In most cases there is more than one way to control a system. The efficiency of the control system has an impact on the cost of the control unit. Engineers all around the world spend a lot of time trying to design control units that can strike the balance between cost and efficiency. In electrical engineering today most of the control systems are electronically based. This includes analogue and digital electronics. With the development of technology, system designers are tending towards digital electronics because of their superior accuracy and ease of development.

In this research the focus is on a Solar PV generation plant. It is important to control the amounts of power that are fed into the grid at any time. In addition to this system frequency, current and voltage must also be monitored and controlled. Solar PV panels are an inverter based generator. Inverters are a very important component in the system. These devices convert dc signals into ac signals for grid interconnection. Wind generators also use inverters, they usually differ in inverter control methods to the inverters used for solar power, and therefore it is common practice for inverter manufacturers to focus on one type of inverter, either for solar power or for wind power generation. The same inverter cannot be used for both generating technologies.

2.4.1 Inverters

Switch mode dc-ac inverters are used in ac motor drives and uninterruptible ac power supplies where the objective is to produce ac output whose magnitude and frequency can be controlled.

i. Pulse Width Modulated (PWM) inverters

The input dc voltage is essentially constant in magnitude. A diode rectifier is used to rectify the line voltage. The inverter controls the magnitude and frequency of the ac output voltages. This is achieved by PWM of the inverter switches. Out of Various schemes, the chosen one is the sinusoidal PWM, to be discussed in detail in this project.

ii. Square Wave inverters

The input dc voltage is controlled in order to control the magnitude of the output ac voltage; therefore the inverter only controls the frequency of the output voltage. The output ac voltage has a waveform similar to a square wave.

iii. Single-phase inverters with voltage cancellation

These inverters combine the characteristics of the previous 2 inverters, the voltage cancellation technique works only with single-phase inverters and not with 3-phase inverters.

Basic concepts of switch-mode inverters

The inverter is assumed to supply an inductive load such as an ac motor, i_o will lag v_o. In cases where v_o and i_o are both positive or negative, p_o is positive, because $p_o = v_o \times i_o$, therefore the power flows from the dc side to the ac side. In cases where v_o and i_o are of opposite signs p_o flows from the ac side to the dc side. Switch-mode inverters must be able to operate in all 4 quadrants of the $v_o - i_o$ plane as displayed in Figure 2.11.

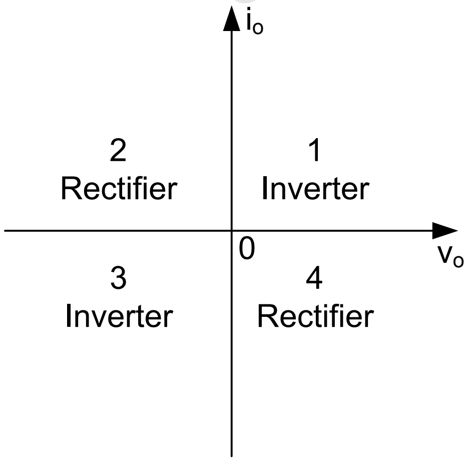


Figure 2.11 Four quadrants of inverter operation

i_o is reversible and v_o can be of either polarity independent of the direction of i_o.

i. *One leg switch-mode inverter*

This is the basis from which all other topologies are derived.

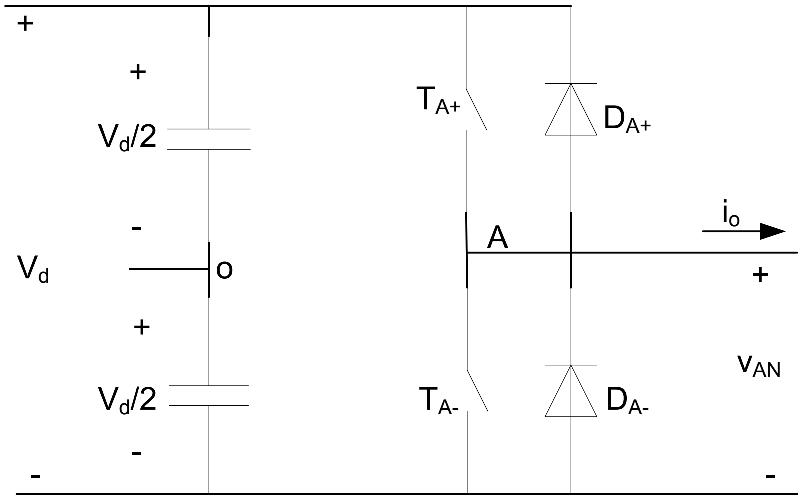


Figure 2.12 One leg switch mode inverter [21]

ii. *PWM Switching Schemes*

In order to produce a sinusoidal output voltage waveform at a desired frequency a sinusoidal control signal at the desired frequency is compared with a triangular waveform. The frequency of the triangular waveform establishes the inverter switching frequency and is generally kept constant along with its amplitude V_{tri}.

f_s= frequency with which the inverter switches are switched, i.e. carrier frequency

f_1 = desired fundamental frequency of the inverter voltage output, i.e. modulating frequency

The amplitude modulation ratio is defined as:

$$ma = \frac{V_{control}}{V_{tri}}$$

Where $V_{control}$ is the peak amplitude of the control signal

V_{tri} is the amplitude of the triangular signal

The frequency modulation ratio is defined as:

$$\mathrm{mf}= \frac{\mathrm{f_s}}{\mathrm{f_1}}$$

In inverters, the switches T_{A+} and T_{A-} are controlled based on the comparison of $V_{control}$ and V_{tri}, independent of i_o:

$V_{control} > V_{tri}$; T_{A+} is on, V_{AO} = ½ V_d or $V_{control} < V_{tri}$; T_{A-} is on, V_{AO} = -½ V_d

The two switches are never off at the same time in other words v_o fluctuates between ½ V_d and -½ V_d.

iii. *Single-Phase Inverters*

These are common in household installations. They are ideal for small roof-top PV installations. Modern single phase inverters come with communications interfacing, anti-islanding protection, ground fault protection, reverse polarity protection to avoid damage if wiring is not done properly, overcurrent protection and PV Array isolation control.

Half-Bridge Inverters (Single Phase)

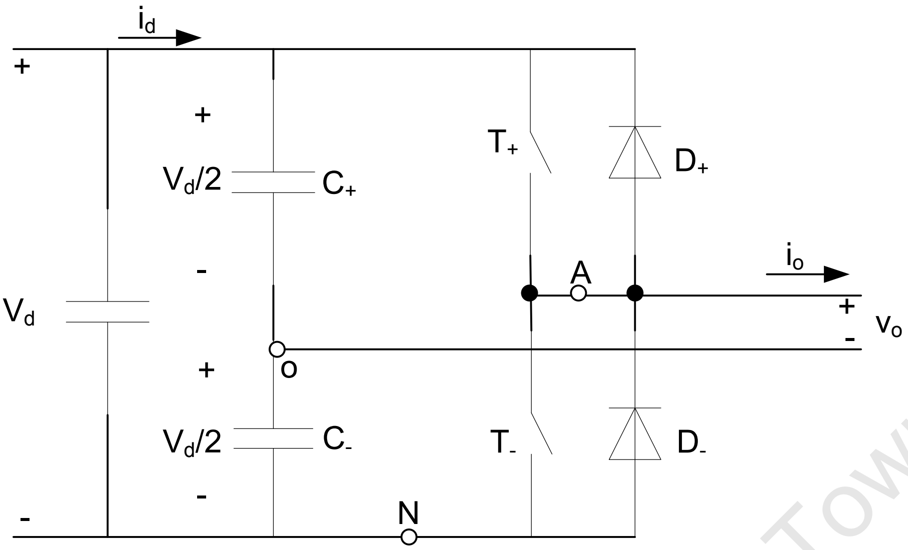


Figure 2.13 Schematic diagram of a single phase half bridge inverter [21]

$V_o = V_{AO}$

When T+ is on, either T+ or D+ conducts depending on the direction of the output current, i_O splits equally between the 2 capacitors.

Full Bridge Inverters (Single Phase)

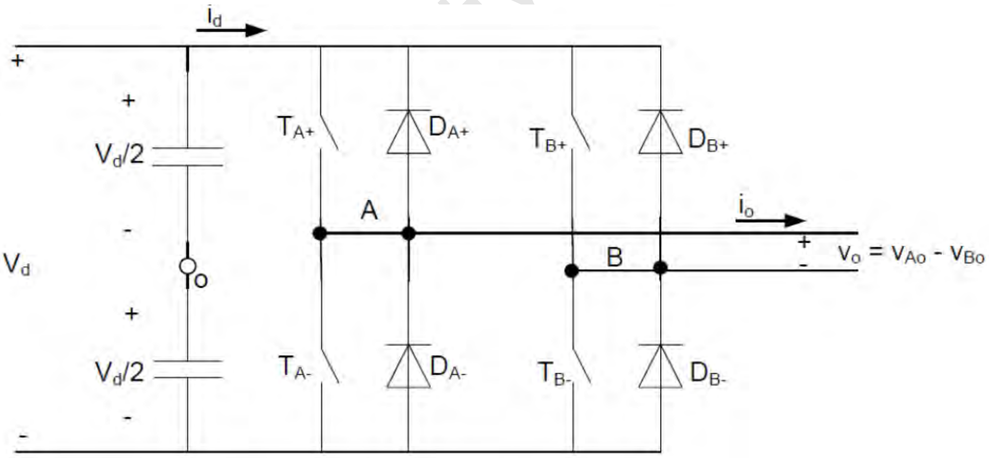


Figure 2.14 Schematic diagram of full bridge inverter

This consists of two one leg inverters; it is preferred in higher power ratings. With the same dc input voltage, the maximum output voltage of the full-bridge inverter is twice that of the half-bridge inverter. For the same power, the output current and the switch currents are half of those for a half bridge inverter.

PWM with Bipolar voltage switching

Diagonally opposite switches (T_{A+}, T_{B-}) and (T_{A-}, T_{B+}) from the two legs switched as switch pairs 1 and 2 respectively. The output voltage waveform of leg A is identical to the output of the basic one-leg inverter, which is determined by comparison of $V_{control}$ and V_{tri}. The output of inverter leg b is negative of the leg A output.

V_{BO} (t) = V_{AO} (t)

$V_O(t)$ = V_{AO} (t) - V_{BO} (t) = $2V_{AO}$ (t)

PWM with Unipolar Voltage Switching

The switches in the two legs of the full-bridge inverter are not switched simultaneously. The legs A and B of the full-bridge inverter are controlled separately by comparing v_{tri} and $v_{control}$ and $-v_{control}$ respectively. The following logic controls leg A:

$V_{control} > V_{tri}$; T_{A+} is on, $V_{AN} = V_d$ or $V_{control} < V_{tri}$; T_{A-} is on, $V_{AN} = 0$

For controlling leg B switches, -Vcontrol is compared with the same triangular waveform, which yields the following:

$-V_{control} > V_{tri}$; T_{B+} is on, $V_{BN} = V_d$ or $-V_{control} < V_{tri}$; T_{B-} is on, $V_{BN} = 0$

The switching operation has the following sequence.

1. T_{A+}, T_{B-} on: $V_{AN} = V_d$, $V_{BN} = 0$; $v_o = V_d$
2. T_{A-}, T_{B+} on: $V_{AN} = 0$, $V_{BN} = V_d$; $v_o = -V_d$
3. T_{A+}, T_{B+} on: $V_{AN} = V_d$, $V_{BN} = V_d$; $v_o = 0$
4. T_{A-}, T_{B-} on: $V_{AN} = 0$, $V_{BN} = 0$; $v_o = 0$

When switching occurs, the output voltage changes between zero and + V_d or between zero and $-V_d$ voltage levels. For this reason, this type of PWM scheme is called PWM with a unipolar voltage switching, as opposed to the PWM with bipolar (between $+V_d$ and $-V_d$).

The advantage of doubling the switching frequency is that the lowest harmonics appear as sidebands of twice the switching frequency. This means there is a lower harmonic content is present in the output signal.

Three-Phase Inverters

It is possible to supply 3-phase loads using 3 separate single phase inverters. This configuration is not ideal because it will require 12 switches and either a 3-phase output transformer or separate access to each of the 3-phases of the load, such access is often not available. Having 3 separate inverters is also space consuming. Chances of all 3 inverters failing are lower than the chance of a single 3-phase inverter failing, therefore, the separate inverters configuration is arguably more reliable. Separate inverters would have outputs 120^o apart. For 3 phase installations a 3-phase inverter as displayed in Figure 2.15, is recommended. These are easier to control and operate than 3 different single phase inverters.

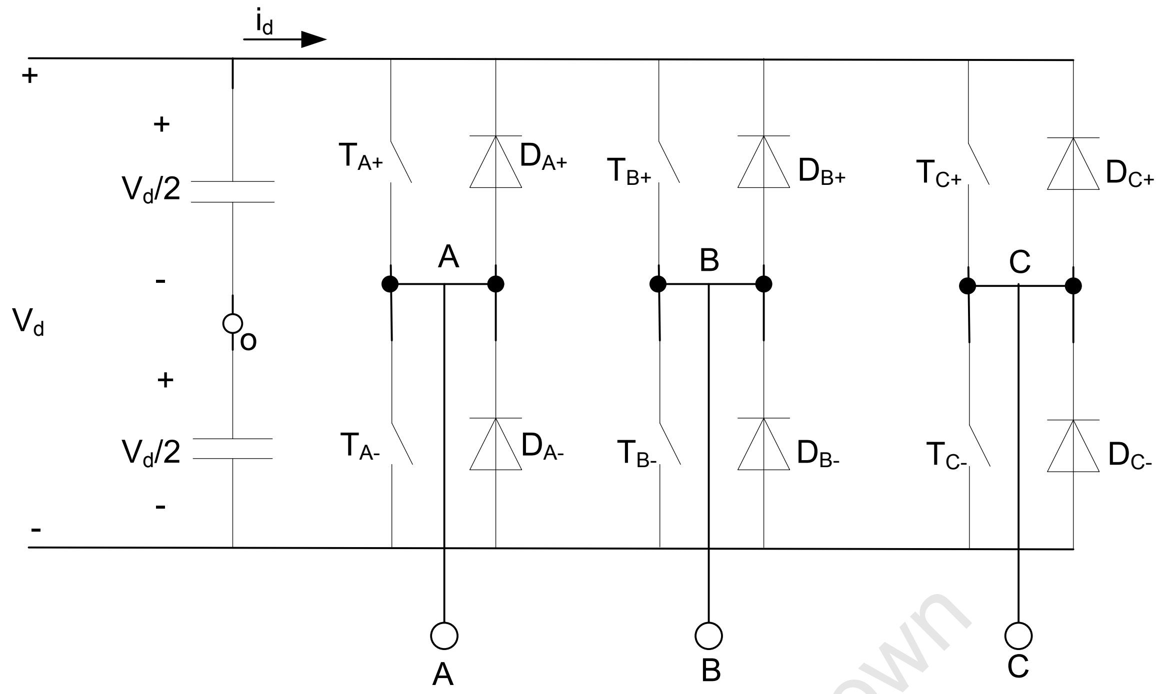


Figure 2.15 Schematic diagram of a 3-phase inverter [21]

The output voltage is independent of the output load current since one of the 2 switches in a leg is always on at any instant.

Fixed Frequency Control

The error between the reference and the actual current is amplified or fed through a proportional integral (PI) controller. The output $V_{control}$ of the amplifier is compared with a fixed-frequency (switching frequency f_S) triangular waveform V_{tri}. A positive error (i_A^*-i_A) and, hence, a positive $V_{control}$ result in a larger inverter output voltage, thus bringing i_A to its reference value. Similar action takes place in the other two phases. Often the load voltage (derived from the model of the load) is used as a compensating fee forward signal, shown as the dashed arrow in the diagram below. This is an example of how the frequency is controlled in an inverter. Frequency controllers are not investigated in great detail in this thesis.

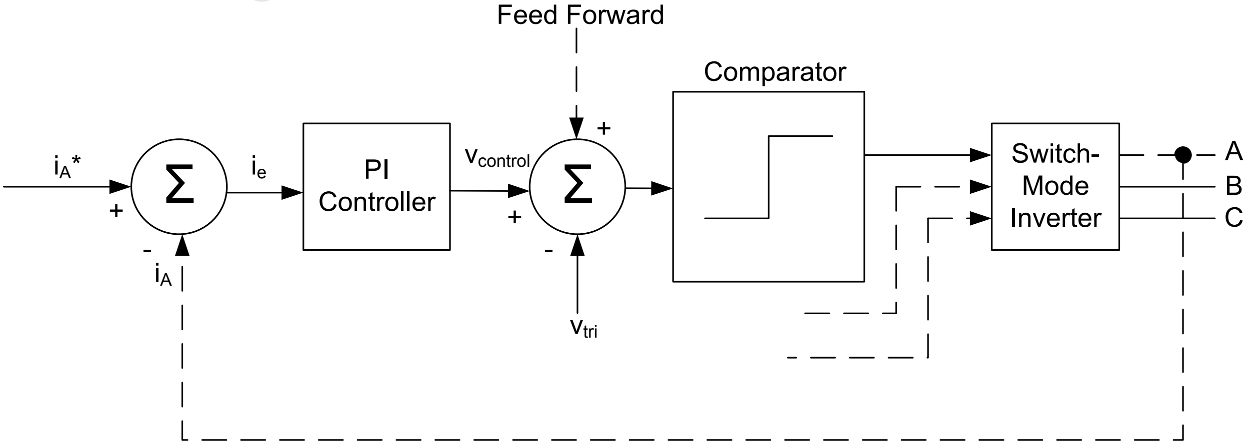


Figure 2.16 Schematic diagram of fixed frequency control system [21]

2.5 Protection

There are many factors that play a part in the development of a protection system. Amongst these factors are economics, the personality of the protection system designer, the availability of materials and the availability of fault indicators [22]. The economics refers to the amount of money available to develop the protection system. Some utilities prefer not to have protection systems in parts of their grid because it can become more costly to place protection in that part of the grid than to deal with the damage if a fault occurs. Personality refers to the engineer/technician responsible for the development of the protection system as well as the power system to be protected. The characterisation of power systems is very diverse, therefore it is difficult to standardise protection systems for power systems. The availability of protection devices and fault indicators also plays a major role in the development of practical protection systems because different devices connect to each other in different ways to perform protection functions. If for example, only distance relays are available, the protection system developed has to be based on those relays and not any others. There are always limitations in protection systems. It is too costly and complex to implement a protection system that can cater for every single possible event. Engineers usually cater for the most common or severe faults, which would have the highest impact on the network. Some utilities have their own protection philosophies which they make standard and apply to their network.

Power Systems are an asset that needs to be protected. It consists of expensive equipment and if it is not adequately protected a lot of money can be lost due to a single incident. Faults can occur on a daily basis, if there is no protection system, these faults can cause great losses to the utility and its customers. Besides the monetary loss, there could be loss of equipment and loss of lives. Without protection, power systems become vulnerable and unsustainable. There are 3 main characteristics that should be considered for all power protection systems; these are accessibility, availability and acceptability [23]. It is important that the system is always ready to detect and clear faults and that it does not interfere with the rest of the power system in a negative way.

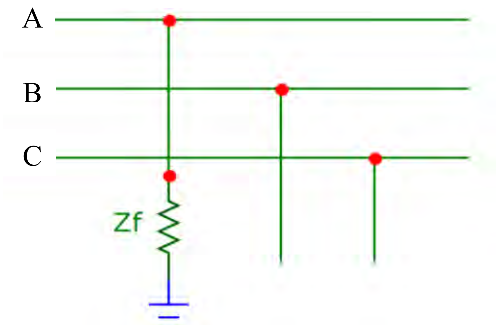
In power system protection there is usually primary protection as well as back up protection. Primary protection refers to the first set of equipment to be alerted when a fault occurs. Usually, the intention is to design a primary protection system which operates accordingly every time a fault occurs. However, this is not possible every time. Unforeseen events like the relay not detecting an irregularity or the circuit breaker not opening may occur. For this reason we need back-up protection as well. Back-up protection is designed to operate only when the primary protection fails to clear a fault. The co-ordination of these two forms of protection is very important. It is used to ensure that back-up protection is not unnecessarily activated. This co-ordination is achieved by relay time and reach parameterisation [24].

Research into microgrid protection is growing quickly as the adoption of distributed generation continues to increase. Researchers have realised that this is an important topic that will contribute immensely to the development of future power networks. Even though the general protection philosophy for microgrids does not vary much from the ideas used in utility grids, the technology available gives way for more efficient protection schemes. Microgrids have slightly different network characteristics, with distributed generation comes the introduction of static electronic devices such as inverters. All of this novelty needs to be catered for in the new protection systems.

2.5.1 Faults

Faults are disturbance or contingency events against which all power systems should to be protected. There are four main types of faults, such as, single line to ground faults (SLG), line to line faults (LL), double line to ground faults (DLG) and 3 phase faults. Faults can be classified as balanced or unbalanced. 3 phase faults are balanced while the rest are unbalanced [25].

The single line to ground fault occurs when a phase comes to contact with the ground, this can occur due to a broken line or tower structure. It is the most common type of fault, because it the one that occurs the easiest. Figure 2.17 below demonstrates the equivalent diagram for this fault. The resistance of Zf represents the fault impedance.



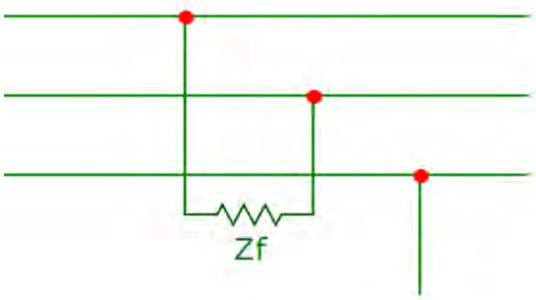
$V_a = I_a \times Z_f$;

$I_b = 0$;

$I_c = 0$;

Figure 2.17: Schematic diagram of Single line to ground fault

The line-to-line fault as the name suggests is a fault that occurs when two lines come to contact with each other. This may occur when a line has too much sag and the wind blows it into contact with another line, or when a branch falls on two lines and connects them together. Figure 2.18 shows a schematic diagram of the power system under this fault. Again, Zf represents the fault impedance.



$I_c = 0$;

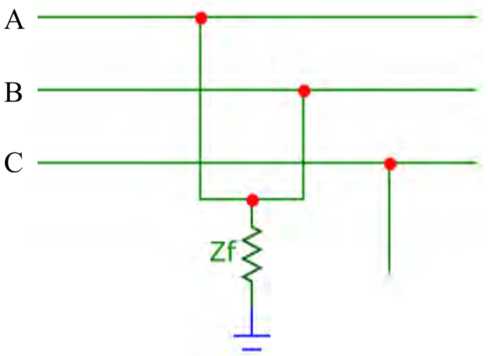
$I_a = -I_b$;

$I_b = -I_f$;

$V_a - V_b = Z_f I_a$;

Figure 2.18: Schematic diagram of a line to line fault

The double line to ground fault occurs when two phases are connected together and through a fault impedance Zf. Figure 2.19 below shows a diagram of the power system under this fault.



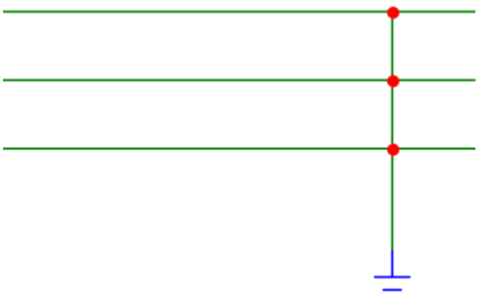
$I_c = 0$;

$V_a = V_b$;

$V_a = Z_f I_f = Z_f (I_a + I_b)$;

Figure 2.19: Schematic diagram of a double line to ground fault

The three phase fault is as mentioned before a balanced fault. This is the most severe type of fault; therefore it is important that it is simulated to confirm that the circuit breakers have adequate interrupting ratings [25] and that the relays can detect this type of fault. Figure 2.20 below shows a schematic diagram of the fault.



$I_a + I_b + I_c = 0;$

$\mathbf{V_a = V_b = V_c = 0;}$

Figure 2.20: Schematic diagram of a 3 phase fault

2.5.2 Loss of Mains Events

Loss of mains occurs when the utility source/generator is disconnected to the grid, but some of the utility load is still electrically connected to the distributed generator [26, 27]. This occurs due to faults in the utility grid, maintenance in the system or even circuit breaker nuisance trip. This occurrence may have many negative effects on the distributed generator and Microgrid.

In some cases the distributed generator is large enough to support the part of the utility grid to which it is connected after the loss of mains. However, in other cases the distributed generator is too weak or small to supply both the Microgrid load and the utility load on its own. This is when the real challenge faced by the system operators comes in. As a systems engineer it is important to determine at design stage whether the DG is suitable to support the utility load or not. In some areas, for example, the UK, the DG is by no means allowed to support the utility load under a loss of mains scenario [28]. This is because of the reliability of the grid, when operating with a DG as its only source. When the DG is too small, loss of mains has a strong effect on the voltage and frequency in the system. Loss of mains, for whatever reason it may occur is a severe situation which design engineers must take into account, especially in terms of system control and protection during the occurrence.

i. *Loss of Mains Detection*

Over the years there have been many detection techniques developed, each of these have their own advantages and disadvantages. For this reason no definite industry standard method has been identified yet. There are two types of local loss of mains detection methods:

1. Active Method
2. Passive Method

Active Methods

In the active method the detection device functions by directly interacting with the system under consideration. Perturbations are purposely injected to the system. The system's response to the perturbations determines whether loss of mains has occurred or not. Examples of active techniques are [29]:

- Reactive power export error detection (RPEED)
- Impedance measurement method (IM)
- Slip-mode frequency shift method (SMS)

- Active Frequency Drift method (AFD)
- Automatic phase-shift method (APS)

Active methods of detection have the disadvantage of directly affecting the system to which they are applied. If the injected signal is not adjusted correctly they may have a significant effect on the magnitude of the frequency of the voltage, current and power output of the DG. If used incorrectly, the injected signal can break the power balance between the DG and the local loads. However, it has a significant advantage in that it is cheaper than passive means of detection.

Passive Methods

In passive techniques there is no added signal to the system. This technique relies on the detection of certain distinct patterns at the DG output when islanding occurs. A difficulty faced when dealing with passive techniques is the correct selection of detection thresholds. This technique depends vastly on load condition. When there are local balanced loads LOM detection becomes difficult [30]. Examples of these techniques are:

- Rate of change of output power (ROCOP)
- Reverse Power Detection (RPD)
- Rate of change of frequency (ROCOF)
- Rate of change of frequency over power (ROCOFOP)
- Harmonics Detection (HD)

Remote Methods

Lastly there are remote techniques for LOM detection. These are based on communication systems between the utility and the DG. Remote techniques are relatively expensive to implement, especially when small DGs are involved. Examples of mechanisms used for remote detection include:

- Power Line carrier communications (PLCC)
- Supervisory Control and Data Acquisition (SCADA) systems

In this project a passive means of LOM detection will be used. The selected method is the reverse power detection method.

Reverse Power Relaying

Reverse power protection is generally applied to prevent damage to mechanical plant items in the event of failure of the prime mover. Common generator damage includes gearbox damage and mechanical damage to shafts.

Power relays currently used in industry are capable of accurately measuring system voltage and current. They also measure the angle between these two signals, the angle θ. With this information they can calculate real power which is as shown in Equation 1.

$$P = V \times I \times \cos\theta \qquad (1)$$

Under normal operation, real power flow is in a determined forward direction and $-90° < \theta < 90°$, in the case of reverse power flow $90° < \theta < 270°$. The relay would allow for a predetermined unidirectional flow of active power. Power flow in the opposite direction should trigger the relay to trip.

When reverse power relaying is used to protect a generator a relay setting is chosen based on the type of generator it is. An example of this is protection of a Diesel Engine the allowable motoring power is 5 to 25% of the rated generation capacity. The relay setting is chosen based on Equation 2 [29]:

$$\text{Setting} = \frac{\text{Motoring Power(\%) x Generating Capacity (MVA)}}{\text{CTratio x VTratio}} \qquad (2)$$

For Loss of mains detection the method of determining allowable reverse power flow is different because it is not the generator that is primarily being protected, it is the microgrid in its entirety. The relay parameters would be determined based of the power system configuration and the allowable reverse power flow. Time delays are important in reverse power protection because slight disturbances can lead to reverse power flow for an instant and the relay shouldn't cause the breaker to open instantly.

ii. ***Loss of Mains Protection***

When implementing Passive techniques of detection, the DG protection against LOM is provided for by the relays used to detect LOM. Once they detect an occurrence they send a signal to open the appropriate CB and from those pre-determined actions, the DG and Microgrids are guaranteed protection.

When implementing remote techniques, the communication links can be used to communicate with the Point of Common Coupling (PCC) or the Static Switch to disconnect the microgrid from the utility grid when LOM occurs. The communications systems are usually reliable enough to provide effective communications.

However, when active detection techniques are implemented depending on the infrastructure, not always are appropriate protection mechanisms activated. If the impedance measurement method for instance, this will merely warn the operator/engineer that LOM has occurred, it will not necessarily open any breakers or disconnect the microgrid at the Point of common coupling. An effective way of making use of the information provided by the detector is to send it to the overcurrent relays located at the microgrid. Based on pre-determined settings, the OC relay can activate the SS at the PCC to open and leave the microgrid to operate in isolated mode or remain closed and just adjust its (OC relay) settings accordingly.

2.5.3 Reverse Power Flow and Voltage Profiles

Generally in radial systems current flows from a single point (the utility generator), to the loads. As this is a unidirectional flow, it is simple to coordinate or predict the voltage profile.

The power system modelled for the purposes of this thesis consists of a utility power source, photovoltaic generation plant, a utility load and a smaller local load. If the PV plant is operating close to unity power factor which is common for this type of technology and the utility voltage is at a power factor higher than 1 but within the legal limits. At some point A between the PV generator and the utility grid there could be an overvoltage [45]. Figure 2.21 displays the possible current flow which may lead to a system overvoltage.

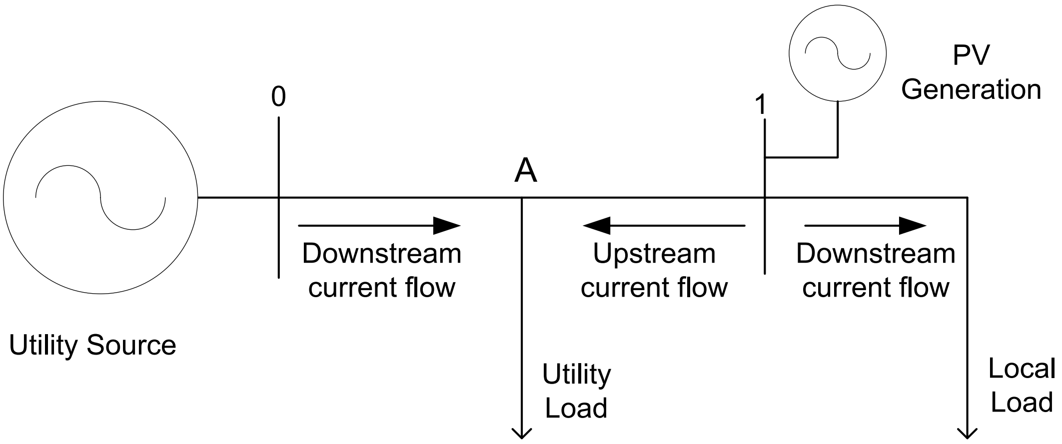


Figure 2.21 PV Generation Integration with Utility Grid

Various literatures suggest different means of controlling this overvoltage, including, output power limitation. Later in this thesis a switching scheme for solar PV generation will be presented and this scheme could enable engineers and operators to control the amount of power added to the grid by the distributed generator.

2.6 The essential elements used in power system protection

Some may consider that protection systems consist of only relays. However, protection systems consist of many other subsystems/ equipment to detect and isolate disturbances [32]. Figure 2.22 shows a simple protection system, to identify the different components and how they are interconnected.

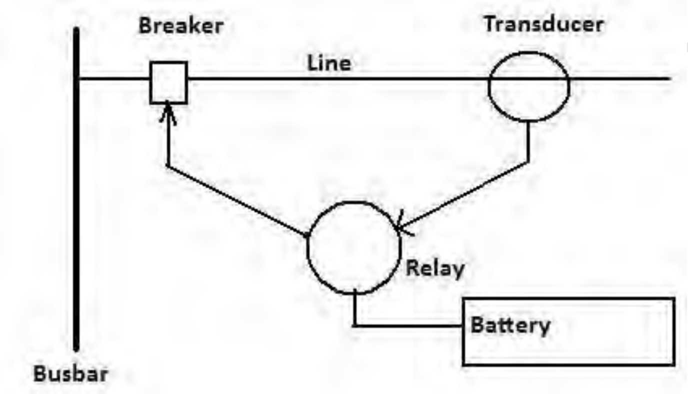


Figure 2.22: Schematic diagram of protection system elements [32]

Transducer

Transducer is the collective name given to current and voltage instrument transformers. These are used to step the current and voltage down to such a level that the relay can handle and act on when a fault occurs. Current Transformers – these are transformers used to convert high currents to lower values that can be measured safely by electronic devices. These are used for metering and protection purposes. The primary winding would have the high current and the secondary side would have the lower current. These devices operate under almost short circuit conditions. The primary and secondary sides are nearly always electrically independent and insulated from each other as required by the operating voltage.

Voltage Transformers - these are transformers used to convert high voltages to lower values that can be measured safely by electronic devices. Like current transformers these are used for metering and protection purposes. The primary winding is connected to the service voltage. The voltage in the secondary winding is proportional to the value on the primary side and in phase with the primary voltage. The ratios and voltage angles may vary slightly due to transformer errors. Voltage Transformers operate at no load conditions.

Battery

The battery also known as a DC supply, consists of lithium batteries connected together. These are used to supply the relay with power. They are an important component of the power system; therefore they are usually kept in locked, air conditioned rooms in the substations. During a fault the ac voltage at the substation may be too low or even reach zero. In this condition the substations mains supply cannot supply power to the relays. Lack of power can impede relays from fulfilling their purpose; therefore it is important to have a constant supply at all times, hence the batteries. These batteries usually operate continuously for 8- 12 hours after the substation blackout [32]. It is normal to separate electromechanical and solid state equipment by connecting them to different batteries. This is because of the transients that electromechanical relays can cause on battery leads.

Circuit Breakers

Circuit breakers as their name suggests are the devices that break/open the circuit in the case of a fault. These are usually responsible for breaking electrical fault currents. They are switching devices that allow current to pass through when they are closed and prevent current from passing when they are open. It is a combination of breaker operation and performance that leads to successful fault clearing. A set of circuit breakers can isolate the fault by interrupting the current at or near a fault. There are many designs of circuit breakers in power systems. Older designs used tank oils in which the mechanisms were immersed, recent designs use SF6 and other means of environmentally safe and reliable designs. Circuit breakers are more mechanically focused devices. This device is closely connected to the protection panel; some manufacturers even incorporate them into the panel.

Relays

Relays are the logic devices which start the tripping and closing operations. A protection relay may include more than one electrical element and accessories. In many cases, it is not feasible to protect against all hazards with a relay that responds to a single power system quantity. An arrangement using several quantities may be required. In this case, either several relays, each responding to a single quantity, or, more commonly, a single relay containing several elements, each responding independently to a different quantity may be used. These have developed immensely over the years. Now there are different types of relays which operate differently in different conditions. This project however focuses on Overcurrent Relays, Frequency Relays, Overvoltage Relays and Reverse Power relays.

Relays may be classified according to the technology used [33]:

- Electromechanical
- Static
- Digital
- Numerical

In the above list Electromechanical is the oldest and least technologically advanced and Numerical is the newest and most technologically advanced. In many Eskom power stations and substations, there are still electromechanical relays which are in good use. The different types have varying capabilities, according to the limitations of the technology used. For the goals of this project, digital relays will be used. The reasons why will be explained as the chapter progresses.

Digital Relaying

Before there were digital relays, there were static and electromechanical relays. As the power systems grew and the demand for better technology in relays became stronger, the digital relay was developed. There is currently an even more technologically advanced relay, the numerical relay. However, for the development of the relaying scheme in this project, the digital relay offers all the required technology. The introduction of the digital relay into the market was also the introduction of the analogue to digital conversion in relays. This provided a counting technique, which had better accuracy than the previously developed relays. These relays have a small but sufficient processing capacity [34]. They also have a digital memory, which can store various settings for different modes of operation. The digital relay has the ability to communicate to other relays as well as computers via a link, which is normally fibre optic. This gives the user the ability to operate it remotely. All of these features and characteristics make it a useful relay when developing an adaptive relaying scheme for a system. However, like many other devices it presents some difficulties. The difficulty with this device is the conjunction of analogue and digital signals [34]. It is also said to have a higher failure rate than the previous electro-magnetic relay [35]. The reason for a higher failure rate is that operators still struggle to program the correct settings on to these relays, leading to relay blinding and nuisance tripping.

The digital relay is highly multifunctional; it contains many features that will not be necessary in the development of the relay model in this project. The attributes that will be incorporated to the developed model are: Data acquisition for metering, capability for remote interrogation and setting application and the ability to change its settings automatically based on system conditions [35].

In order for a protection scheme to be effective and serve its purpose it should have some fundamental characteristics, these include [33]:

- Reliability
- Selectivity
- Sensitivity
- Stability
- Speed

Each of which is described in more detail below.

Reliability refers to the ability of the protection scheme to perform as designed when it is required to. If the scheme is not reliable a fault may occur and the relays will not pick it up, circuit breakers will not open and damage to expensive equipment may be a result. Selectivity refers to the ability to activate only the necessary circuit breakers when a fault occurs. It can become costly if the whole power system is shut down every time a fault occurs. Sensitivity refers to the lowest level at which a relay operates. The lower the level the more sensitive the relay is. This is important because it allows operators to determine at which fault levels the relays should operate. Stability refers to the ability of the relay to maintain its state and remain unaffected by conditions outside of its operating zone. Speed refers to the pace at which a scheme is able to clear a fault. The most efficient protection schemes are fast and are able to clear a fault before any damage is done to the protected equipment. If the system is slow it could also allow for a spread of lack of synchronism thus affecting the stability of the system. It is important to not make the relay too fast because sometimes an intermittent event will occur and relays should have enough of a delay to allow these events to occur without tripping the breaker.

2.6.1 Over-current Protection

Protection against excess current was the earliest protection philosophy to evolve. From this basic principle, the graded overcurrent system, a discriminative fault protection, has been developed. Overcurrent protection is directed entirely to the clearance of faults. Currents above an adjustable threshold value are detected in one or more phases and interrupted after a pre-settable time. The release time may vary depending on how much the threshold has been exceeded by.

Relay Co-ordination Procedure [33]

Correct overcurrent relay application requires knowledge of the fault current that can flow in each part of the network. Since large-scale tests are normally impracticable, system analysis must be used. The data required for a relay setting study are:

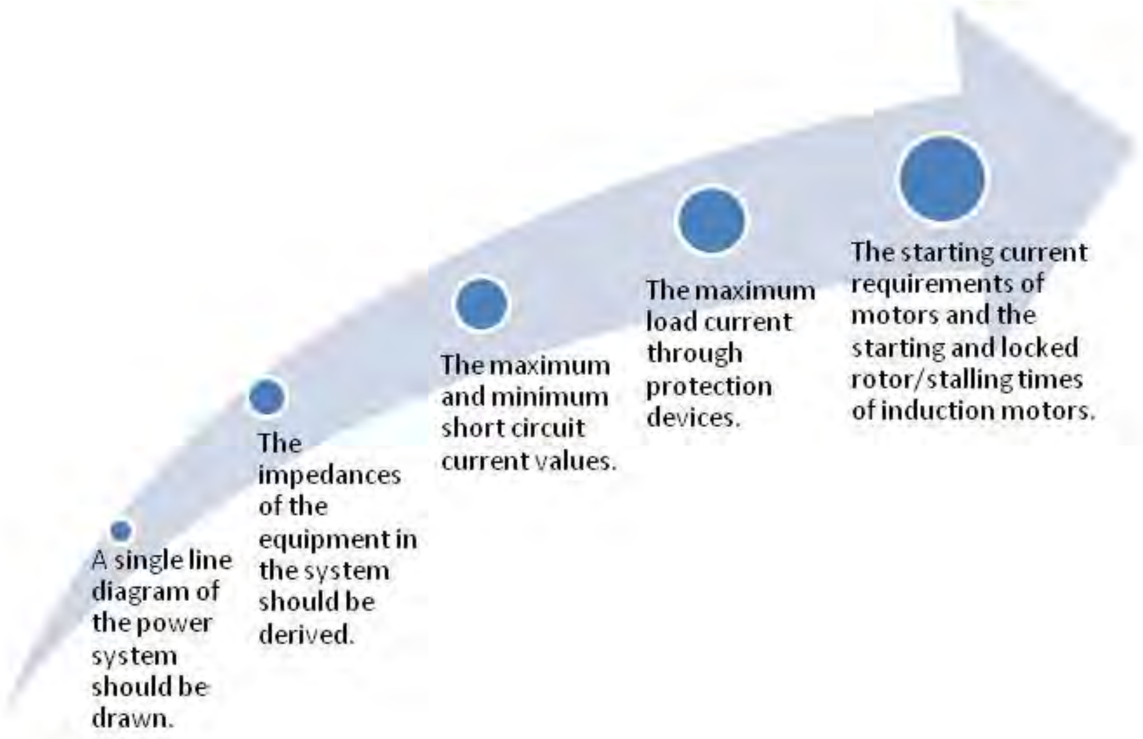


Figure 2.23 Requirements for accurate relay setting [33]

The overcurrent relay parameters are originally set to give the shortest operating times at maximum fault levels. Engineers usually plot curves of relays and other protection devices such as fuses that operate in series, on a common scale. These scales include current scales, voltage scales and MVA scales.

The basic rules for correct relay co-ordination can generally be stated as follows:

- Whenever possible, use relays with the same operating characteristic in series with each other [33].
- Ensure that the relay positioned the furthest from the generator has current settings equal to or less than the relays behind it. In other words, the primary current needed to operate the relay in front is always equal to or less than the primary current needed to operate the relay behind it [33].

Grading for Selectivity

One of the ways to develop the right relay co-ordination is by using time or overcurrent or more commonly today a combination of both. This plays an important role in selectivity. It is important to have the ability to isolate part of the power system without disturbing the other parts, in other words be selective [33].

Selectivity by time

In this co-ordination method, the correct time setting is coded on to each relay controlling the circuit breaker. This is done to create a protection system where the circuit breaker closest to the fault opens first. In this case the current sensing element triggers the timer [33]. A relay operating in this mode is also known as an 'independent definite-time delay relay' because it's operating time is independent of the overcurrent levels.

The time interval between the different relays' trigger times must be long enough to make sure that the upstream relays do not operate before the circuit breaker at the expected fault location has tripped and cleared the fault. The down side to this method is that the longest fault clearance time occurs for faults in the section closest to the power source, where the fault level is the highest. Figure 2.24 shows the relationship between fault current and time in this form of relay configuration.

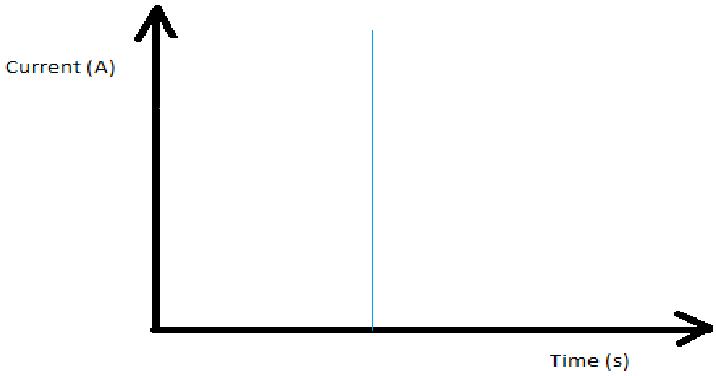


Figure 2.24: Graph of Current vs. Time relationship for selectivity by Time

Selectivity by current

In this co-ordination method relays are set to trigger the breakers at a current value so that only the relay nearest to the fault trips the breaker. This is based on the idea that the fault current varies with the position of the disturbance. The variance is because of the change in impedance values between the source and the fault. The down side to this method is that it is unreliable when the distance between the fault and the source is small, in other words the resistance between them is small.

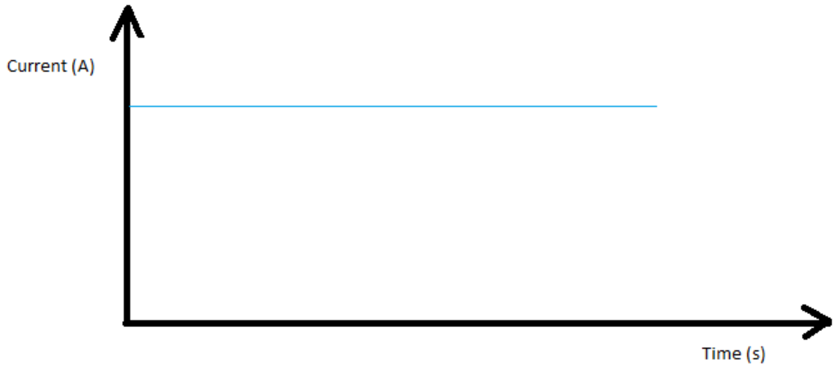


Figure 2.25: Graph showing Current vs. Time relationship for selectivity by Current

Selectivity by both time and current

Due to the constraints imposed by the two above mentioned methods, a new method combining the two was developed. With this method of operation the time operation is inversely proportional to the fault current. Using this method, a quicker clearance time can be achieved by the relays nearest to the source of power, where the disturbance levels are the highest. A common way of achieving this method of selectivity is by using inverse Definite Minimum Time (IDMT) overcurrent relay settings [33]. Figure 2.25 shows the relationship between fault current and time in this form of relay configuration.

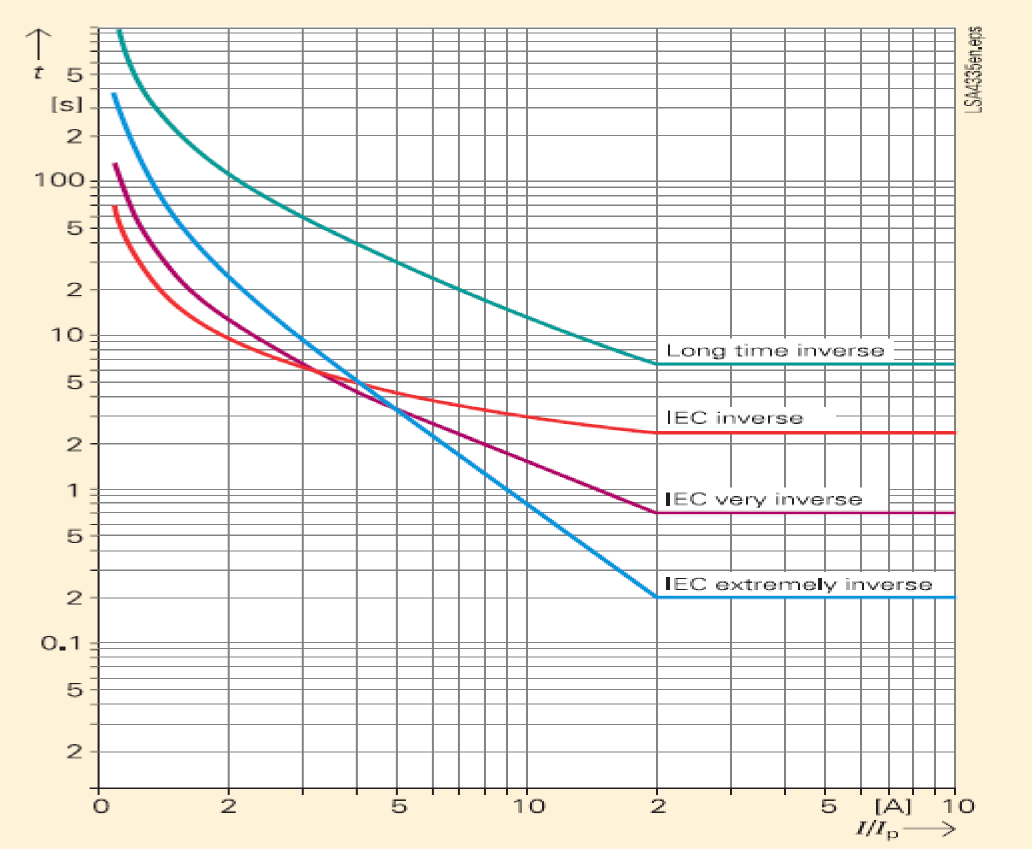


Figure 2.26 Graph showing IDMT characteristics

Relay Coordination

There are various valid characteristic functions for overcurrent relays, for its ease of simulation the IEEE standard is used throughout this research. This function is also useful because it enables the user to approach the coordination problem as a linear programming problem [36]. The function is described in Equation 3:

$$t = \frac{0.14*\mathrm{TM}}{(\frac{\mathrm{Is}}{\mathrm{CTratio}}/\mathrm{PS})^{0.02}-1}; \qquad (3)$$

Where:

t = Trip time;

TM = Time multiplier; PS = Plug Setting;

CT ratio = Current Transformer Ratio;

The above function represents the normal inverse IDMT function. This is used because it provides fast operating times and is effectively used for coordination.

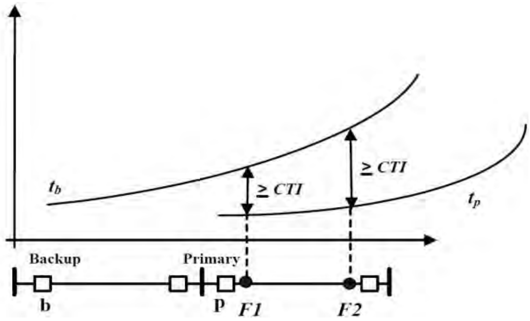


Figure 2.27: Overcurrent Relay Coordination [36]

As mentioned previously, power system protection operates through two different subsystems. These subsystems are the primary protection and the back-up protection. For the protection system to be effective these two subsystems have to be coordinated as suggested in Figure 2.27. In Figure 2.27 there are two Time vs. Current curves, t_b for the backup relay and t_p for the primary protection relay. In between these two curves are arrows labelled CTI, which stands for Coordination Time Interval. CTI is the time between the operations of the two relays for the same fault [36]. This relationship can be described as follows:

$t_b (F1) - t_p(F1) \geq CTI$[36]
$t_b (F2) - t_p(F2) \geq CTI$[36]

2.6.2 Adaptive Digital Overcurrent Relaying Scheme in a Microgrid

This section will introduce the principles to be used to develop the adaptive overcurrent relaying scheme for a given microgrid. As mentioned before a microgrid has two modes of operation, the isolated mode and the grid-connected mode. This creates the need for an adaptive relaying scheme. This scheme will have the ability to adapt to and operate in both of the microgrid's modes of operation. The relays in the scheme will change their settings automatically by detecting the grid's mode of operation. This is not the only way to effectively protect a microgrid, but it is an effective and novel manner, which can be implemented in future grids.

The protection elements required are the same as the ones used in a conventional grid, namely, transducer, circuit breaker and relays. The only specificity is that the relays have to be microprocessor based digital relays with adaptive capabilities. The overcurrent relaying method uses the overall impedance of the system to calculate the current through it, if the impedance is too low and the current too high, in other words a fault is present, it will trigger the circuit breaker to open and isolate the fault. In the two modes of operation the overall impedance of the power system consisting of the microgrid and utility grid will vary. The fault level of the network and the magnitude of the fault current may reduce immensely when a microgrid changes from grid connected mode to isolated mode. This might lead to reduced sensitivity of the overcurrent relays set to operate for high fault currents under the grid connected mode of operation. Therefore it is important that the relays are communicated with and informed of what mode of operation the microgrid is in, otherwise it may trip unnecessarily.

This section of the thesis involves the development of an adaptive relaying scheme for a microgrid. This development is based on the requirements of the microgrid protection. It will be based on the technique of linear programming, where the network's current will enter the relay. The relays will react according to the entered current, based on a fixed Time Multiplier, Pick –up current and Normal Inverse characteristic. The development will suit the protection requirements for a microgrid. The relays in the power network will be coordinated in such a manner that the breaker closest to the fault will open first. The circuit breakers further away from the fault will open later and only if necessary.

2.6.3 Over-voltage Protection

There are essentially two types of overvoltage that can occur in a network, generators, motors and other equipment. These two different types are the transient overvoltage and voltage swells.

i. Transient Overvoltage

Transient overvoltage is a voltage peak with a maximum duration of less than 1 millisecond. There are three main causes of instantaneous overvoltage. These are direct lightning, indirect effects of lightning strikes and equipment operating/switching actions. Lightning strikes carry a lot of energy which can damage equipment, this is less likely to occur but if it does happen it has severe consequences. Operating and switching over voltages happen more often but they have less severe consequences. Both causes can lead to either aging or damaging of equipment therefore it is important to protect the system for both types.

Direct lightning strikes

This occurs when lightning strikes a conductor which is earthed, the lightning current is dissipated into the ground. The impedance of the ground and the current flowing through it create a large potential difference. This high potential difference which is also known as overvoltage creates a high current which is conducted through a system via cables and damages equipment on the way. They are referred to as direct because it is a direct strike on a device or electrically connected equipment.

Indirect lightning

This is a phenomenon which occurs if lightning strikes an object or structure near to electrical equipment. This causes an increase in potential of the ground at the point of impact. The electromagnetic fields created by the lightning current generate inductive and capacitive coupling, leading to overvoltage.

Overvoltage caused by operating or switching actions

Equipment containing electronic switching components is also likely to generate electrical disturbances comparable to overvoltage when reactive or capacitive equipment is switched on and off. Interrupting factory production, lighting or transformers can generate overvoltage which will cause greater damage to nearby electrical equipment [38].

ii. Protection for Transient Overvoltage

To prevent damages that can be caused by this overvoltage system designers generally use surge arresters. Surge arresters are devices designed and used to limit transient overvoltage and run-off lightning currents. It consists of at least 1 non-linear component [38].

These surge arresters can be connected in two configurations:

- Common mode: Protection between live conductors and earth.
- Differential mode: Protection between phase and neutral conductors.

Making the choice between the two modes can be a challenge as both of these methods have their disadvantages. For this reason engineers choose to have a combination of both modes, this comes at a higher price but is definitely the solution to go for especially when dealing with sensitive power electronics.

Figure 2.28, Figure 2.29 and Figure 2.30 show the different configurations and how the fuses are connected to provide overvoltage protection.

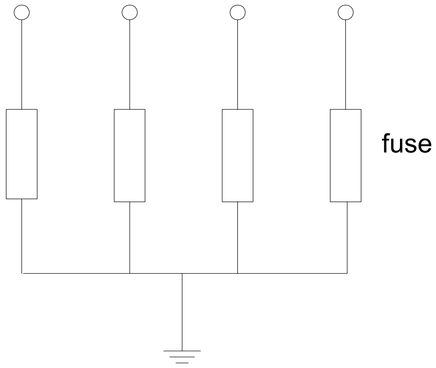


Figure 2.28 Common Mode Configuration

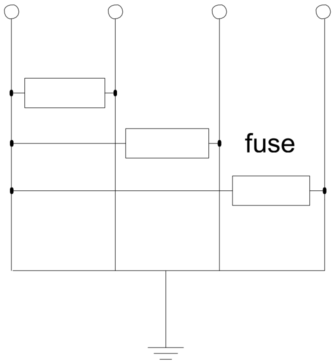


Figure 2.29 Differential Mode Configuration

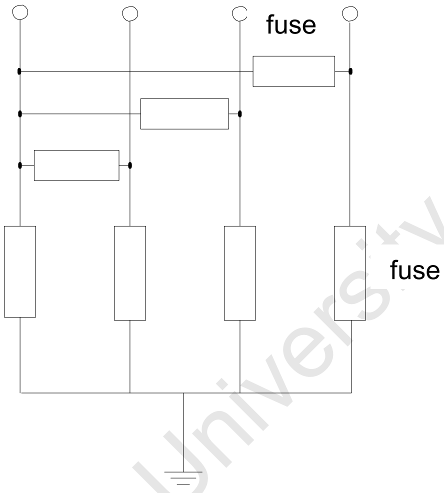


Figure 2.30 Combination Configuration

iii. ***Voltage swells***

To resolve this form of overvoltage, digital relays are commonly used to detect and clear disturbances. These relays usually have 3 independent voltage inputs connected to the overvoltage transformers of the equipment to be protected. Voltage transformers have different configurations to accommodate phase to phase or phase to neutral voltages.

There are two stages of overvoltage protection: Low-set overvoltage and high-set overvoltage. If voltage rises above the set low-set overvoltage value, the low-set overvoltage element sends a signal to the contact output. After a pre-set delay time, determined by the designer, the overvoltage element delivers a trip signal to the contact output.

iv. ***Coordination of overvoltage relays***

Overvoltage relays have an Inverse time delay characteristic similar to that of overcurrent relays. The main idea behind the development of this characteristic is that higher overvoltage should be cleared with a shorter time delay than lower overvoltage. Some utilities have standards that determine the delay for each incurred overvoltage. Equation 4 determines the time delay for tripping [37, 39]:

$t = TMS / ((V/V_s) - 1);$ (4)

where:

t= operating time in seconds;

TMS = time multiplier setting;

V = applied input voltage;

Vs = relay setting voltage.

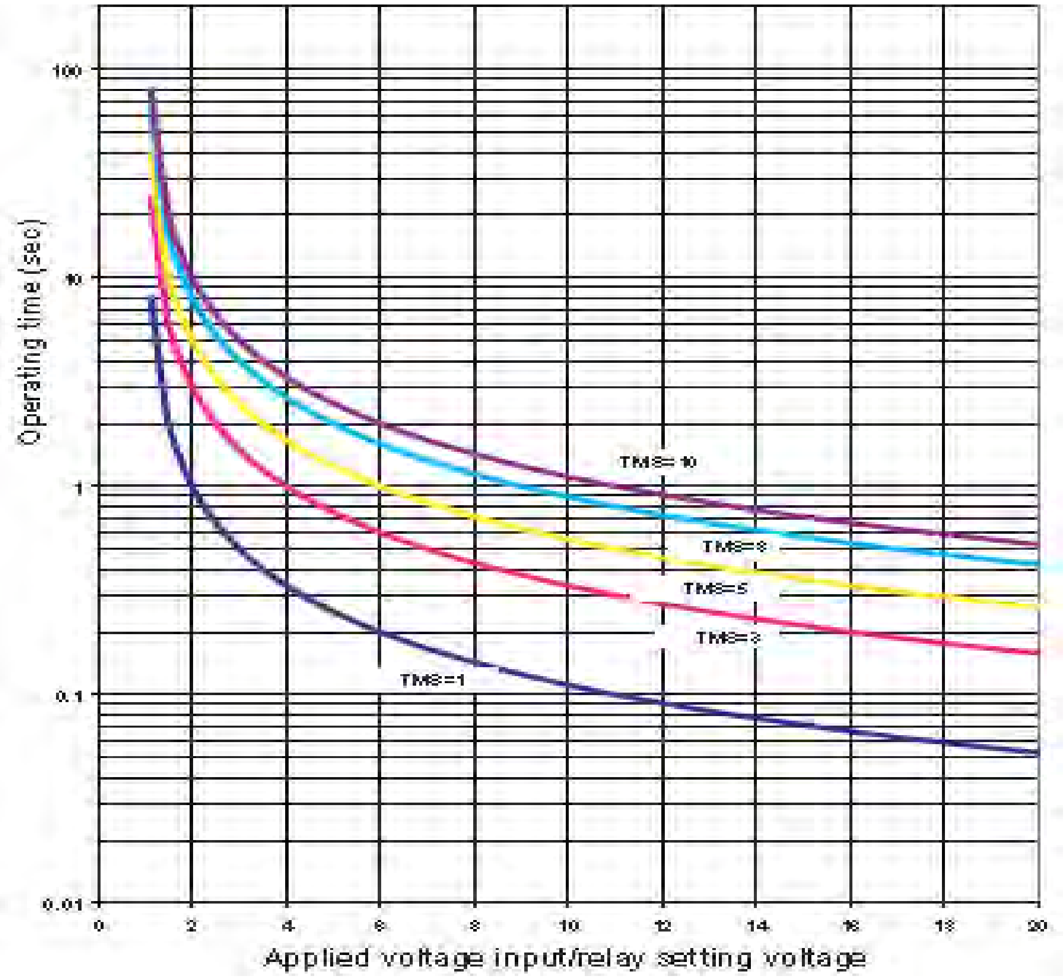


Figure 2.31 Overvoltage Relay IDMT Settings [37]

Figure 2.31 displays the relationship between relay operating time and the applied voltage. As the TMS rate increases, the operating time gets longer.

2.6.4 Over-frequency and Under-frequency Protection

Power system frequency is one of the most important factors of the system. It is ideal that it is measured in a continuous manner, however this can only be achieved using a limited amount of technologies, and the more accurate the measurement method the more expensive it becomes. In systems where the accuracy is not an important factor it is adequate to use simpler measurement methods. Frequency is constant during steady state operation but it decreases when the load demand exceeds the generation capability and similarly frequency increases when the generation exceeds the load demand [40]. Power system control systems are used to maintain frequency constant at 50Hz or 60Hz, depending on the regional standards. In South Africa the power system frequency is 50Hz. Frequency deviation is a good indicator of islanding, loss of bulk generation or rapid increase/decrease of load.

The frequency of an alternating signal is the number of times the signal crosses the zero level from negative to positive (or from positive to negative) in a unit time (e.g. per second). The period of an alternating signal is the time the signal takes from one zero-level crossing to the next zero-level crossing in the same direction. Period is inversely proportional to the frequency, i.e. P=1/f.

There are different methods of measuring system frequency, namely: Period measuring approaches, FFT leakage, “stationary” phasor phase, Kalman filtering and least squares fitting [41]. The speed and accuracy of the measurement will vary with the method. Instantaneous measurement has the disadvantage that it may actuate a circuit breaker for every impulse that occurs in the system. In power systems the voltage and current are sinusoidal signals, however it is preferable to measure frequency based on the voltage signal rather than the current signal because the voltage signal has a regulated and fairly constant amplitude.

i. Use of Frequency relays

Frequency based relays can detect whether the system is operating at a lower or higher frequency compared to the nominal frequency value. Some relays can also monitor the rate of change of frequency. If the frequency goes above or below set limits or fluctuates at an unacceptable rate (df/dt), this is detected, resulting in disconnection or load rejection [31]. It is understood that power system frequency varies based on active power balance between power suppliers and loads [53].

Frequency variations that are large enough to cause problems are most often encountered in small isolated networks, due to faulty or maladjusted governors. Other causes are serious overloads on a network, or governor failures. On an interconnected network, a single governor failure is unlikely to cause widespread disturbances of this nature. Serious network faults leading to islanding of part of an interconnected network can also lead to frequency problems.

Under abnormal system conditions, relays signal a circuit breaker to open to isolate the abnormality or fault. Frequency relaying has been particularly important in synchronous motor and compensator applications. However, it can also be used in Microgrid applications especially when it comes to system restoration and reconnection after isolation.

Under frequency protection will respond to the falling frequency on loss of supply. The use of under frequency relays is also important for many utilities because it is the mechanism used for load shedding. Under frequency load shedding is used when the electricity demand exceeds the generation capability [54]. This may occur if a grid system suffers major fault on transmission lines linking parts of the system, and the system splits into smaller parts. It is likely that some parts will have excess of generation over load, and the others will have a corresponding deficit. Frequency will fall in regions where there is a generation deficit and the normal response is under frequency load shedding, either by load shedding relays or operator action [55].

As protection system engineering develops, engineers and researchers are finding more uses for frequency relaying and it is becoming an increasingly important component in the power system.

Frequency relays that can detect both over frequency and under frequency in a single device are common in the industry. However these relays can only accommodate one over frequency setting and one under frequency setting, this is a limitation when it comes to Microgrid protection because these settings may need to change based on the mode of operation. If a relay is set to grid connected operation mode the non- detection region will be narrow and set to suit the ±2.5% variation as shown in Figure 2.32, while if the relay is set to island mode of operation the non-detection zone will be wider to allow for ±5% frequency variation as shown in Figure 2.33. Setting the relay to a single mode may cause relay blinding or nuisance tripping. It is useful if the relay can accommodate both settings and automatically switch between them based on the Microgrid mode of operation.

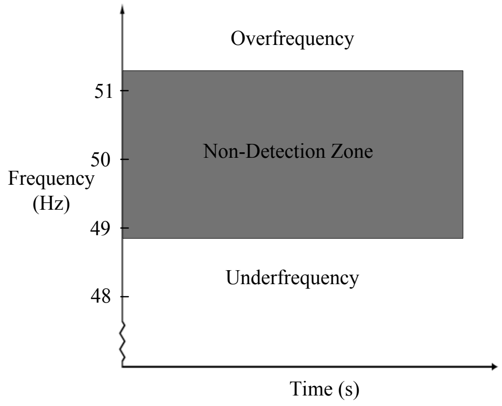


Figure 2.32. Non-Detection Zone in Grid Connected Mode

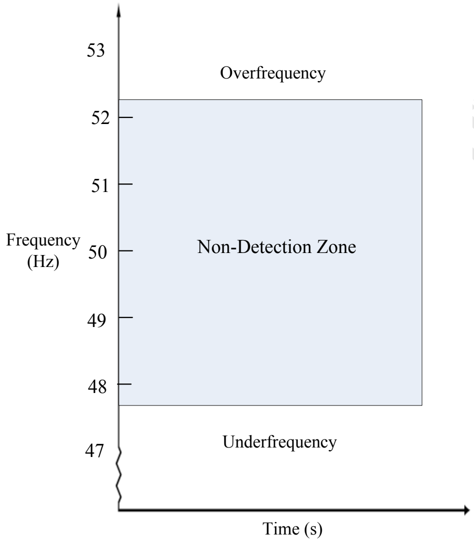


Figure 2.33. Non-Detection Zone for Island Mode

In this research, a period measuring approach will be used, the process for this is shown in Figure 2.34. This can be achieved in two different ways:

1. Counting the number of times of zero-level crossing in the same direction in a unit of time. The frequency equals this number.
2. Measuring the time from one zero-level crossing to the next zero-level crossing in the same direction.

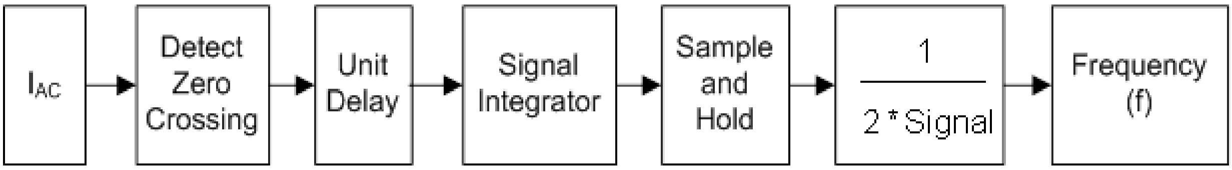


Figure 2.34 Process diagram for frequency measurement

An example of a 50Hz signal can be found in Figure 2.35 below. This signal has a period of 0.02s.

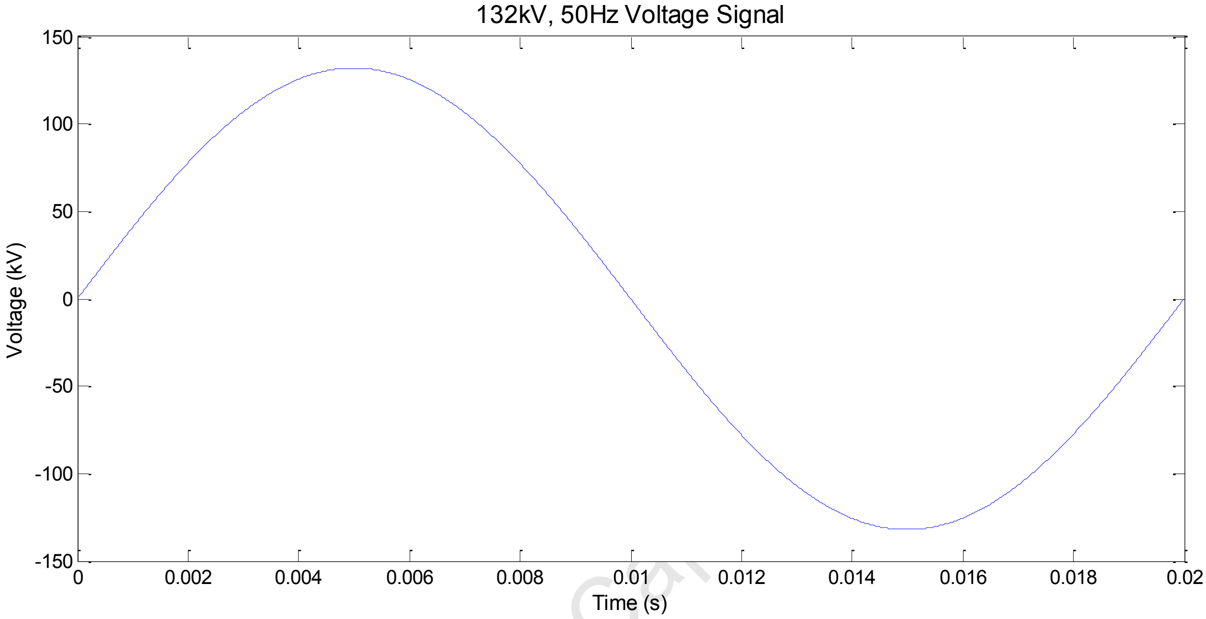


Figure 2.35 132kV, 50Hz Voltage Signal

Once the system frequency has been measured it is fairly simple to implement under-frequency and over-frequency protection using digital relays. In South Africa the minimum accepted frequency value is 49Hz and the maximum accepted value is 51Hz for grid connected networks as determined by the NRS-048 [20].

If there is a variation in system frequency, the frequency relay becomes active. Frequency relays can be adjusted using multi-stages; therefore, instantaneous and time-delay settings can be employed simultaneously. If the terminal voltage drops below an adjustable level V_{min} the relay can be blocked from operating. This is to avoid, for example, the activation of the relay during generator start-up.

2.7 Power System Metering

2.7.1 Conventional Power System Metering

Metering like protection plays an important role in a power system. For many years it has been the means for revenue collection, this revenue is used in amongst other things to maintain the grid and keep its components in optimal condition to ensure good quality of electricity supply.

The first meters to be implemented were operated on liquid movements, these were then replaced by mechanical meters. Mechanical meters used a coil mechanism and generally lost accuracy with time. Mechanical meters were used for many years but have now become obsolete in today's highly electronic and computer based environment. Another downside to mechanical meters is that they can be tampered with easily, making them an unreliable source of information for the meter reader, who has to physically read the monthly energy consumption [42].

As technology developed we are now seeing digital meters which are far more accurate than the mechanical meters used to be. The digital meter is preferred for measuring electricity production and distribution, and in the customer service payment processing arena.

With metering technology developing so fast, it has been difficult to produce international standards that govern these modern digital meters. It is important to take care when purchasing meters. Customers and utilities should aim to buy meters with a potential to upgrade without many difficulties. If low grade, non-upgradeable meters are purchased the owner runs the risk of having to replace them entirely when international standards are introduced.

2.7.2 Importance of Metering

Energy Meter is a cash register of an electrical Utility, these meters are an important commercial and technical element in the electricity supply business. The accuracy of the meters determines the accuracy of recorded revenue. This accuracy is crucial to both the Utility and the customer, so that the Utility doesn't experience major financial losses and the customer is not unfairly overcharged.

Primarily meters were only used as a means to track energy consumption over a period of time. Modern meters can store large amounts of data which can become useful to both the Utility and the customer. Data can be used for electricity consumption and generation planning. Meters can also assist in load control, system planning, tariff structuring and Transmission and Distribution losses monitoring.

Metering costs are becoming lower as the technology develops, together with Advanced Metering Infrastructure (AMI), meters can provide load profiling, outage management and distribution planning, two-way Advanced Meter Reading (AMR) can do many functions that a distribution SCADA scheme can provide [42], with the advantage that AMR Data is accessible to the consumer, while SCADA information is only accessible to the Utility.

Even though meters of different kinds may support different functions, their core function is still to measure and record energy consumption at a supply point. This function should always be functional regardless of the other meter functionalities.

2.7.3 Prepaid Meters

Prepaid metering as the name suggests, refers to paying for electricity before it is used. The consumer purchases credit and then uses the electricity until the credit expires. The concept of prepaid metering is not new, having first been introduced in the UK before World War 2. These pioneering meters operated with coins and tokens. Meters which operate in the same manner are rarely found in operation today. Change took place when electronic or numeric transfer of credit was introduced.

A traditional electronic prepaid metering system operates on three levels. First are the meters, which are installed at the customer's premises. The next level consists of vending stations, situated at the utility's offices or at appointed agents such as convenience stores and petrol stations. The communication between the vending stations and the meters is in the form of a token, which is used to top up the meter and in some cases upload information back to the vending station. At the top level is the Master Station, which is necessary to ensure a common database for reporting and to provide total management, administration, financial and engineering control. Master Stations are generally the most expensive component of an Advanced Metering System, depending on the amount of meters to be rolled out. The Master Station communicates with the various vending stations via a modem or other data link. Information on consumers, tariff changes and so on is communicated to the vending station and detailed customer sales are communicated back to the Master Station.

There are many advantages and incentives for the utility to implement prepaid metering, these advantages include improved cash flow, no need for account posting or additional billing processes, elimination of bad debts, elimination of disconnection and reconnection fees, ease of installation, no need to access consumers' property for meter reading and elimination of inaccurate meter readings [42].

There are also advantages to the customer, including budget management, control of energy usage, no cost for disconnection/reconnection and no waiting for reconnection, no deposits and the ability to pay back debts.

These benefits are the main reasons why so many African Utilities are tending towards prepaid metering systems. In Africa many customers are poverty stricken and cannot always afford to pay their electricity bills. This puts a burden on the Utility. The use of prepaid metering decreases this burden and eliminates debt. Only energy that has been paid for is supplied to each household.

2.7.4 Advanced Meter Reading (AMR) Technologies

Advanced Meter Reading (AMR) refers to methods of obtaining meter readings remotely and was introduced in North America to read difficult-to-read meters placed at inaccessible locations and hazardous to access meters. In an African content, this would be useful for metering remote rural areas which are difficult to access. It was a costly solution in the early nineties. However with rapid advancements in technology, the cost of AMR started falling and the utilities that went in for technologies have realised that AMR can deliver much more value than mere meter readings for billing. Utility management is beginning to appreciate the big-picture benefits of AMR. Many utilities are able to justify AMR solely on the basis of the intelligence it brings to strategic and tactical decision making. The emerging benefits of AMR include distribution planning, outage management, supply and load management, load forecasting, energy diversion, call centre operations and credit and collections [42].

At the heart of any AMR is a small electronic device called ERT module. This ERT (Encoder, Receiver and Transmitter) unit can be integrated with any electronic meters and is used for data communications. There are various means of collecting the meter data from these ERT modules.

AMR is broadly classified into Mobile AMR and Fixed Network AMR. In the mobile scheme a vehicle is equipped with radio device and computer and driven around the area where meters are installed. The radio device on the vehicle communicates with the ERT module in the meters and the meter data is downloaded over RF frequency, which accommodates short distance data transfers. This is cheaper and more secure to implement than GPRS communications to a master station, when the metering point is distant from the metering control centre.

Fixed Network AMR is a two-way communication scheme where a group of meters in one area communicates with a concentrator installed in the vicinity. A group of concentrators are connected to a network control node (NCN) in the area, which acts like a router in the network, and the NCNs are connected to a host computer. There are different communication platforms that exist for the communications between ERTs, Concentrators, NCN and the host computer. RF technology, Zigbee, utilizing the 2.4GHz spectrum is the market leader.

AMR has the following advantages:

- Network Optimization and Asset Utilization Improvements
- Outage Detection and Restoration Notification
- Load Profiling and Forecasting
- Monitoring Power Quality and Reliability
- Remote connect/disconnect services, tracking of meter tampering etc. are also possible through two way AMR systems.

2.7.5 Communications

In a smart metering system there is a large amount of data transfer, it is important that good communications infrastructures are put in place to ensure constant communications between the meter and the master station as well as between the meter and the appropriate local devices such as in a Home Area Network. The communication system is essentially the difference between a smart metering system and a conventional metering system. The data being transferred between devices is confidential and access to this data should be restricted. Energy consumption data can reveal information such as consumers' history of electricity consumption giving hackers information that could help them in theft. Data must represent complete information regarding the energy consumption by the customer and status of the grids without any potential manipulations or miscalculations. Secure communication plays a major role in a smart metering infrastructure.

Communications in a smart metering system can be split into two different configurations, namely, local communications and remote communications. Both of these methods of communication should be two way communications.

Local Communications

Local communication methods are important because the meter needs to communicate with the devices in the installation point such as load control units, customer interface units and concentrators. This short distance communication is also used for local meter configurations and data downloads which may be useful from time to time. Local communications should allow the meter to be configurable locally using a Hand-Held Terminal (HHT) via the communications hub. Such local interrogation and configuration could be via Zigbee or a local programming port; e.g. an optical port.

Even though local communications are based on short distance mechanisms it is still important that it is secure and that each meter communicates only to the devices dedicated to it to avoid interference with other household installed devices.

Common methods of local communication include Power Line Carrier (PLC), Zigbee, RS485 and M-bus. Other forms such as Infrared and Bluetooth are not recommended because they are not secure enough.

Remote Communications

Remote communications are the most important form of communications in a smart metering system because it is the means of communication between the meter and the control master station. It is also the fundamental way of communication between the consumer and the system controller. Important messages and real-time control commands can be sent back and forwards between the two parties. Common methods of remote communications include Ethernet, GSM/GPRS and UTMS/3G.

2.7.6 Issues and challenges

Smart metering technologies are still expensive to deploy and maintain, justifying the investment is difficult for some Utilities. Lack of proper infrastructure for synchronising new technology makes it harder to install and commission the systems. Smart metering is only fully functional if there is an appropriate communications network. Analysts have critiqued South Africa's mobile network infrastructure and described it as inadequate for smart metering implementation. For this reason mobile networks would need to be improved, or other communications methods would have to be used.

In some cases utilities get incentives for selling more electricity; therefore it is in their best interest if customers do not use smart meters to manage and save electricity.

There are social issues involved with the implementation of smart metering. Even though there are numerous advantages for the implementation of smart metering systems Consumers can strongly object to this initiative especially if the Consumer is responsible for purchasing the meter. The biggest challenge that Utilities have faced today is ensuring data transfer security. Many Consumers still believe that their energy consumption information especially load profiling is personal and sensitive information that should not be shared even with the Utility.

Quantification of the benefits of smart metering is very difficult due to the lack of historical data. Not many smart metering systems have been implemented around the world therefore there is very little evidence for smart metering promoters to base their case on.

Design Issues for a Smart Meter System

Figure 2.36 shows some of the issues involved when designing a smart metering system. It is evident that the actual meter is not such a big issue. The most important thing to consider when implementing smart metering is the system communication.

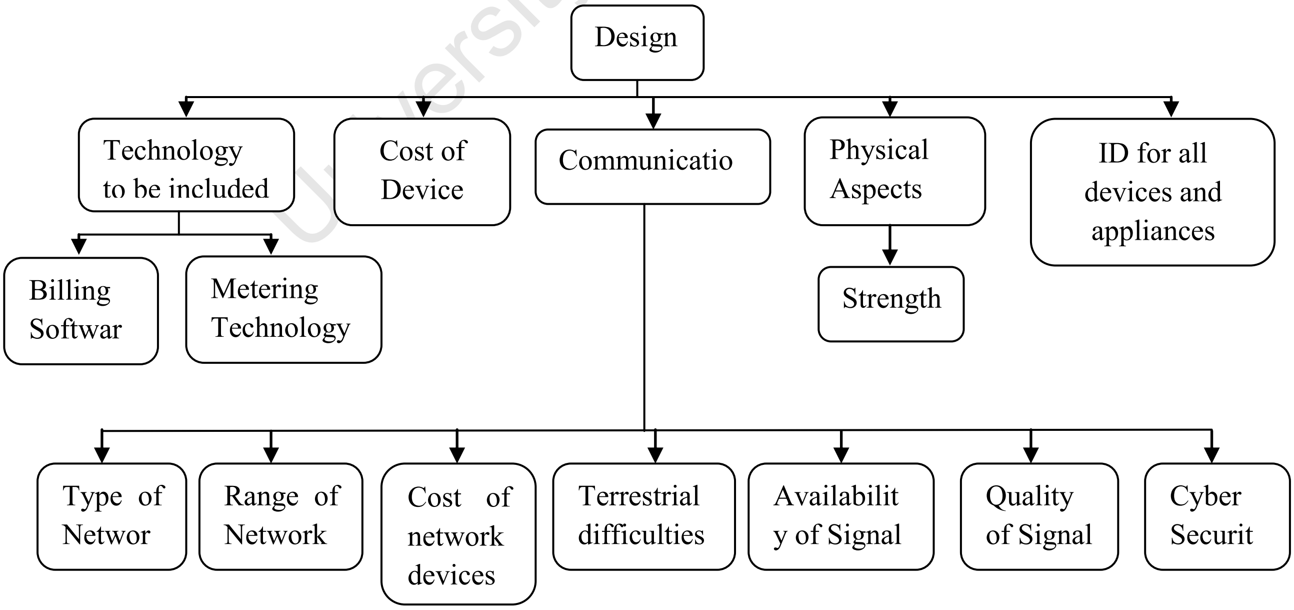


Figure 2.36 Diagram of contents considered in smart meter system design

2.7.7 Metering Architecture

Conventional Energy Meter

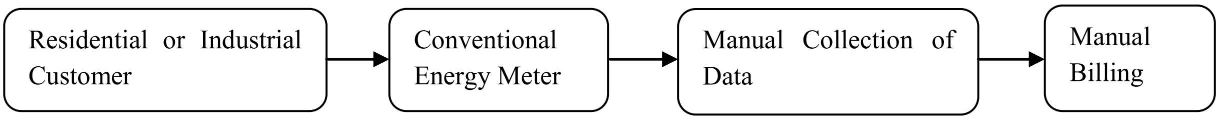


Figure 2.37 Billing process for conventional metering systems

In a conventional metering system, meter reading is a manual exercise, the basics of the process are shown in Figure 2.37. The meter reader will go from metering point to metering point and physically read the digits displayed on the meter. This process is time consuming and erroneous. It is a unidirectional cycle and does not provide a great deal of functionality. Many times Readers will not be granted access into properties and will not be allowed to read the meters. Once and if the meters have been read, the billing is done manually 30 days after the reading was taken and the Consumer is usually granted 30 days to pay the bill. This means that the Utility can receive payment 60 days after the meter reading. This has major implications on the Utility's cash flows.

Conventional metering also opens room for disputes in cases where Consumers don't agree with the amount they have been billed. Many of the disadvantages presented in conventional metering are overcome in smart metering systems.

Smart Meter System Architecture

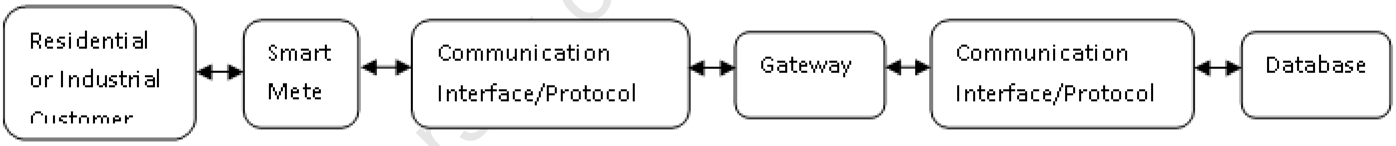


Figure 2.38 Smart metering process

Smart metering systems provide increased functionality in comparison to conventional metering systems. The billing process is not as unidirectional as in conventional systems. The whole architecture allows for two way communications throughout the consumption and billing process. This system is more automatic therefore it is less prone to human errors. The billing process is also automatic, so instead of taking 30 days to receive a bill the customer receives the bill on the last day of the month and has a 30 day period to pay the bill. This process can have a major positive effect on the Utility's cash flows.

The system architecture should allow remote two way communications from head-end systems to the local system through the Wide Area Network (WAN). Some meters used in smart metering systems do not support remote communications, they only support local communications. This is not a limiting factor as the meter can communicate with a concentrator and in turn the concentrator provides remote communications. This system should also include a Customer Interface Unit (CIU) that may communicate with each meter and the Load Control Unit (LCU). Such local communications will be established via a Home Area Network (HAN). If there is a need for multiple meters on a single site, the system should allow for multiple meters to communicate with a single CIU and multiple CIUs.

The complete smart metering system should not rely upon a CIU to deliver its core functional requirements. If the CIU becomes dysfunctional or damaged the meter should maintain its core functionalities and Communications.

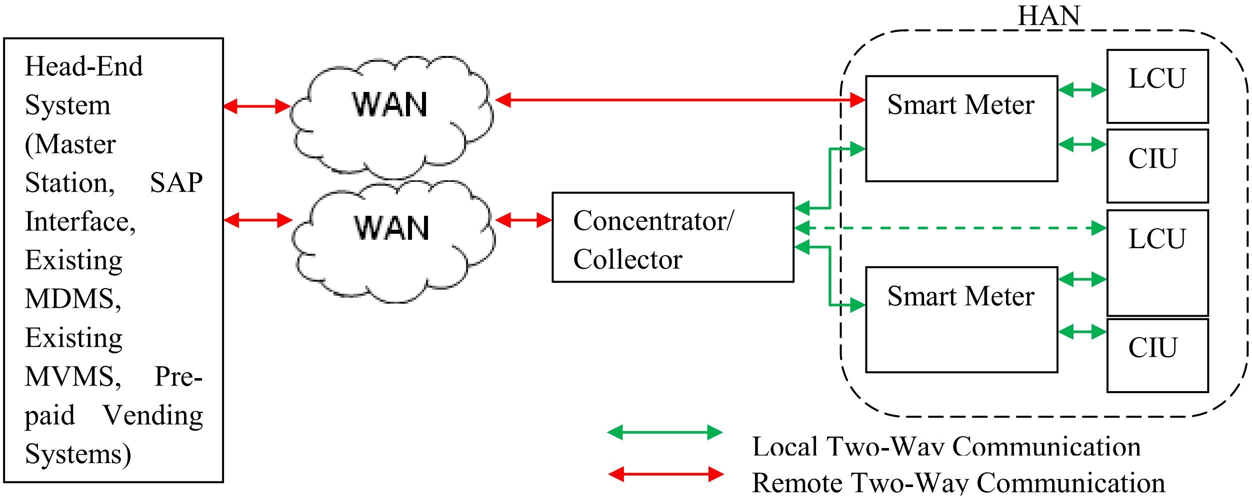


Figure 2.39 High Level Smart Meter System Architecture

The scope of this project only covers the Smart Meter, Load Control Unit, Customer Interface Unit and Concentrator in terms of smart metering systems. The Head-End System is not covered in this project. It is expected that systems can provide a means of two-way communication to the head-end system, which may be designed and installed by another manufacturer.

2.7.8 Smart Metering

Smart Metering is similar to adaptive protection in that it allows the microgrid to be self-sustained. It decreases the need for human interaction and manual procedures which can be erroneous and time consuming. A smart meter is an advanced energy meter that measures consumption of electrical energy providing additional information compared to a conventional meter.

The smart metering system should as a minimum include the following components:

- *Clock*
- Data Store
- Electricity Meter
- Home Area Network Interface
- A Load Switch
- A User Interface Device
- Wide Area Network Interface

Deployment of smart meters needs proper selection and implementation of a communications network satisfying the security standards of smart grid communication. Smart metering has its implementation difficulties but it provides many advantages such as the ability to read real time energy consumption information such as voltages, phase angles and frequency. Modern smart meters have the ability to communicate this data to data management system, via two-way communication networks. Smart meters can be used to monitor and also control home appliances and devices at the customer’s premises. Meters can be programmed such that only the power consumed from the utility grid is billed, while the power consumed from DG sources owned by the customers are not billed. Smart meters can limit the maximum electricity consumption of a particular household or building, through predetermined settings which can be remotely or locally configured. Load control capability that a smart metering system provides is the feature that will be mostly explored in this project, as a means of load management through smart metering.

Different Smart Metering architectures can be implemented and this varies according to equipment supplier, system user and price. Smart metering is an essential component in a smart grid, however, installing smart metering does not guarantee that the grid is smart, there are other requirements to form a smart grid.

Geographic Information Systems (GIS) can be integrated to the smart meter system in order to obtain specific information regarding the geographical location of a potential fault. This reduces power outage duration because technicians don’t have to waste time on site looking for fault location.

2.7.9 Load Management

In recent years there has been a global increase in demand for electricity. Some researchers believe that the only way to meet this increase in demand is by increasing the electricity generation capacity. Other researchers believe that the solution to the problem is to control and manage the existing loads so that demand peaks are curtailed. Smart meters play a big role in load management. The information that they provide enables system managers to estimate peak demand times and additional functionality that they contain allows for loads to be controlled remotely.

There are currently many methods of load management. This means that system managers may use different parameters to perform load management, and load control takes place in different ways. Load control will depend vastly on the system infrastructure such as the type of loads and load control device technology. The more sophisticated the infrastructure the more efficient the load control will be.

This research will focus on three different ways of load control, namely, scheduling, load threshold and direct load device control.

Scheduling

Smart meters should be able to handle load scheduling. This is a feature that allows the meter and associated devices to switch loads on and off according to Master Station instructions. This would then allow the system operators to control energy consumption based on a predetermined utilisation schedule.

With the use of the meter’s memory storage facility the meter can store sets of "turn on" and "turn off" times per week day and weekend day or holiday. Times are remotely settable for each meter individually and in groups by broadcast, through the AMI communications system via a GPRS or Ethernet connection. Sometimes the consumer also has the ability to schedule power consumption of certain devices based on their own preference and lifestyle. Load of consumer premises can be controlled by Appliance controlled device. This feature shall be remotely configurable manually or automatically scheduled [43].

Load Threshold

Smart meters should have programmable load threshold limit control, which can be set remotely via the Master Station. This is to ensure that the consumer does not exceed the allowable peak power consumption at any period of time. Some tariffs are structured in such a way that the consumer pays a fee corresponding to the peak power demand. This feature of load control can help the customer to control this peak effectively.

The electricity meters are capable of limiting electricity to the consumer in both post and pre-payment modes. The electricity meter shall provide a facility to limit total load to a configurable current rating above which the supply to the consumer shall be interrupted. The load limit should be configurable to be active for times of day, days of week, months of year, and special days. The load limit functionality can be used as a rule within the meter instead of disconnection. When load limiting is inactive, it shall not be possible for load limiting to occur. It may be possible for manufacturers to include an overload protection device as part of the meter to prevent engineer call outs for blown main service fuses. The meter and CIU shall display the current being drawn as a percentage or fraction of the load limit setting when load limiting is active. The load limiting capability shall be configurable locally and remotely by authorised personnel;

The load limiting capability shall be capable of being overridden under configurable rules that are updateable locally and remotely by authorised personnel; e.g. in the case of a vulnerable consumer. Meters and CIU shall generate an audible sound and/or visual message when a configurable percentage of the load limit has been exceeded and it shall be possible for the consumer to mute the sound. The sound and/or visual message described in previous clause shall always be reactivated every time a new load limiting event is initiated;

The load limiting functionality should proceed as follows:

a) If configurable current limit warning is exceeded, generate a warning until current drops below warning limit or current increases to load limit;

b) If configurable current load limit is exceeded:

  1) Generate a different non mutable audible sound and/or visual message continuously for a set time period for whichever occurs first:

    i) After which the supply is interrupted and the warnings cease; or

    ii) until the consumption drops below the configurable limit; or

    iii) for selected consumers additional tariff levels could be switched to.

Consumers shall be able to restore the supply locally following interruption caused by exceeding the load limit.

Direct Load Device Control

Some metering systems support an architecture that includes Load Control Units/Switches that communicate with the meter, concentrator or MDMS. LCUs are used to connect/disconnect high energy consumption devices. Smart metering systems can support multiple LCUs per metering point. A back-up power source shall be installed on the LCU to ensure minimal functionality during power outages. LCUs shall be surface mounted or DIN-rail mounted units.

The advantage of having this method of load control is that the consumers are rarely completely cut off from electricity supply. In this method of load control some devices in the consumer's premises will be disconnected according to consumption constraints. Large power consuming devices such as water geysers and air conditioning systems are usually the ones that get cut from supply first [43].

In this research all 3 methods of load control will modelled and their differences will be thoroughly discussed to investigate which is the best solution for a Microgrid application with a distributed generator.

2.7.10 Smart Metering in a Microgrid Application

Microgrids are smaller and sometimes easier to manage than the conventional power grid. Even though distributed generation comes with grid control difficulties there are means to manage the challenges effectively. Smart metering can play a very important role in the management of microgrids.

Smart metering system provides several benefits such as efficient power System control and monitoring, operational decisions which are taken timely to minimize outages and financial losses to the utility. This is efficient particularly in microgrids, smart meters can perform energy cost allocation, fault analysis, demand control and power quality analysis [46].

Primarily they provide information and data that was hardly accessible before. Customer and regional load profiles, communication infrastructure and load management facilities are all useful functions that smart meters provide [46].

In a microgrid where bi-directional current flows are common the use of four quadrant meters is imperative. This means that customers have the liberty not to only buy electricity from providers, but they can also sell locally produced power to the grid. This is a novel concept which is subject to policies and power purchase agreements; however it is technically possible with the use of smart meters.

Some researchers believe that load management is more difficult in a microgrid environment because the system controller does not have extensive information on the entire grid. This makes decision making more challenging [44, 47].

Smart metering systems can provide real time price information to customers through communications networks.

The conventional utility scheme which is globally well known is being restructured, to reduce central generation and transmission losses due to long transmission lines. Local power generation is a growing topic and one that researchers are spending a lot of time exploring. Objectives of restructuring are to economically separate a vertically integrated monolithic utility into smaller generation companies, transmission companies and distribution companies, and to introduce competitive power market where those companies and customers can sell and buy electricity to reduce cost.

Effective optimization methods for load shedding are being researched globally and a variety of methods have been developed based on analytical models and fuzzy logic models [44].

Direct control of residential loads was rarely considered in the past due to a lack of control equipment.

AMR systems can read data without physical access to meters. AMR and Smart metering provide the basic platform for direct load control.

Smart meters are a useful tool in Microgrid protection and monitoring. Important features can be of great advantage to system control engineers.

3. Introduction of Models

3.1 Power System Model

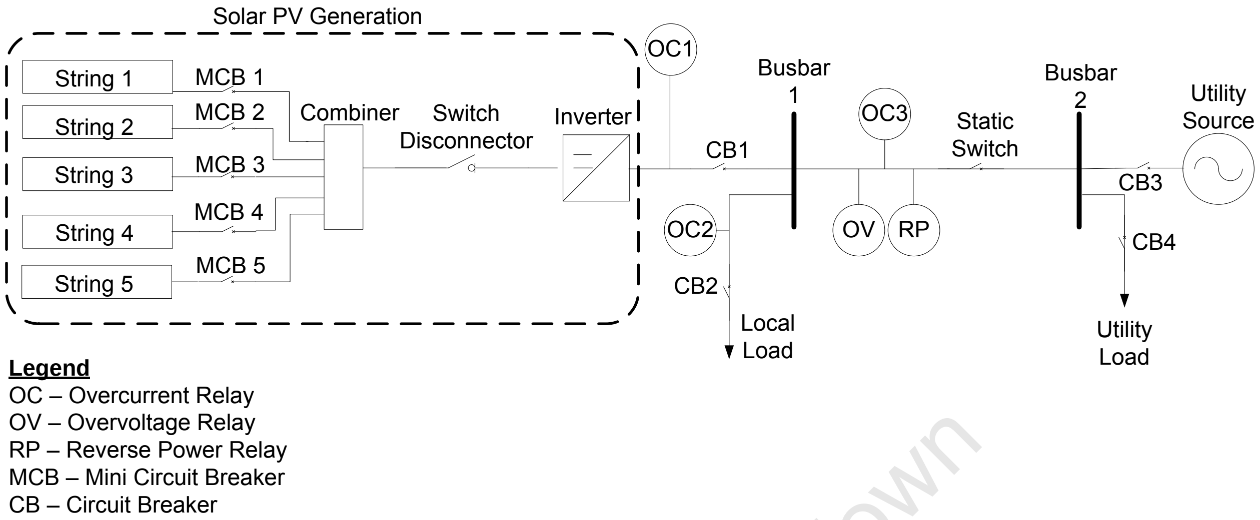


Figure 3.1 Power System Model

3.1.1 Voltage

The system voltage is 11kV during normal operation. The Utility Source, PV Generation Plant and loads all operate at 11kV. PV Generation plants are generally modelled and simulated as current sources because in reality it is difficult to control the voltage output of PV generation. This voltage level is chosen because it is a distribution level voltage in South Africa. This level of voltage would be found feeding a mini-substation in a Municipal Area where it would then be converted to 400V to supply households and small commercial establishments or used as the feeding voltage for industrial customers. 11kV is the voltage level in both isolated and grid connected modes of operation.

3.1.2 Current

The current output of the PV plant is 180A. This is maintained constant as long as all 5 strings remain connected to the grid and the solar radiation remains at 1000W/m^2. This is the current supplied in both grid connected and isolated modes of operation. The current supplied by the utility source is 730A in grid connected mode and 700A in Isolated mode. This difference is because in isolated mode, the load supplied by the utility source is smaller. This current is seemingly low but in a real system it would be increased by a power transformer when the voltage is stepped down to 400V. The currents simulated are common at distribution level and are suitable to supply households and commercial establishments.

3.1.3 Frequency

During normal operation the system frequency is 50Hz. This is maintained constant during normal system operation. The only cases in which the system frequency varies are when the frequency relays are being tested by rapidly increasing or decreasing the loads. The 50Hz applies to both isolated and grid connected modes of operation and it is the frequency in the grid throughout South Africa. The only place in the country that doesn't use 50Hz is Eskom's Apollo Substation in Mpumalanga which receives the HVDC line from Mozambique and then converts it to a 50Hz signal to supply the national grid.

3.1.4 System Capacity

The total system capacity is approximately 52MVA. The PV Power generation contributes 2MVA and the utility source contributes 50MVA. These are reasonable values because the utility generation would normally have a much higher capacity than a renewable energy generation source. The PV Generation is used to supply the microgrid which consists of the PV Generation plant and the local load, which has a small energy demand.

3.1.5 Loads

The local load is 2MVA and the Utility load is modelled as 10MVA. It was important to model the loads at a value less than the system capacity to ensure that the system is somewhat stable during normal operation.

3.2 Substation Model

A typical substation design for a power intake substation was used. To provide good grid interconnection for renewable generation it is important that the point of interconnection is well designed and suitable to support the amount of generation. Substations can be designed for a loop-in loop-out connection or for direct connection. Loop-in loop-out designs are preferred when there is a suitable overhead line on site. In this research the design was chosen to accommodate a straight generation connection to the grid. In addition to the protection components described in section 2.6, a substation would be equipped with Surge Arresters and Isolators.

Surge Arresters – this device is responsible for draining fast fronted surges and protects substation equipment from high voltages. When the load is normal the devices do not conduct electricity however, under fault conditions these devices conduct electricity.

Isolators – these devices are also known as disconnectors. They are mechanical switching devices for making small electrical currents close onto a circuit. They can continuously carry electrical currents and also break small currents. This device is important because it provides a visual break in the circuit, which is important during system operation and maintenance.

3.3 Solar PV Generation Module

In this research a mathematical approach was taken to modelling of the solar panels. The current (A) and power (W) produced by the panels is calculated using Equations 5 and 6 respectively. Equation 1 is explained in detail in [50]. Each string in the simulated model has a power capacity of 400kW, making the plant's total capacity 2MW.

$$= [I_{SC} + k_I\,(T_C - T_{ref})]\lambda$$

I_{PH} is the light-generated current or photocurrent, this is the ideal current that would be generated if there were no system losses and the solar radiation energy was captured completely over the cell's surface area. This current value is never reached in a cell because of efficiency related issues.

$$I_S = I_{RS}\left(\frac{T_C}{T_{ref}}\right)^3 \exp\left[qE_G\frac{\left(\frac{1}{T_{ref}} - \frac{1}{T_C}\right)}{kA}\right]$$

I_S is the cell saturation of dark current. Dark current is referred to as the current that flows in the circuit when no light shines on it. This is a small value mainly dependent on the cell temperature.

$$- \ s \left[e\ p\left(\frac{(\qquad s)}{k\ {}_{c}A}\right)-1\right]- \qquad {}_{s}/\ \ s$$

Where:

IPH = Light Generated Current or Photo Current (A) IS = Cell Saturation of Dark Current (A)

q = electron charge = 1.6 x 10^{-19}C

k Bo ltzmann's Constant 1.38 10^{-23} J/K

TC = Cell Working Temperature (°C)

A = ideal factor (1.2 to 5) RSH = Shunt Resistance (Ω) RS = Series Resistance (Ω)

λ Solar insolation in kw/m^2

kI = Short-Circuit Current Temperature

Power =V×I (6)

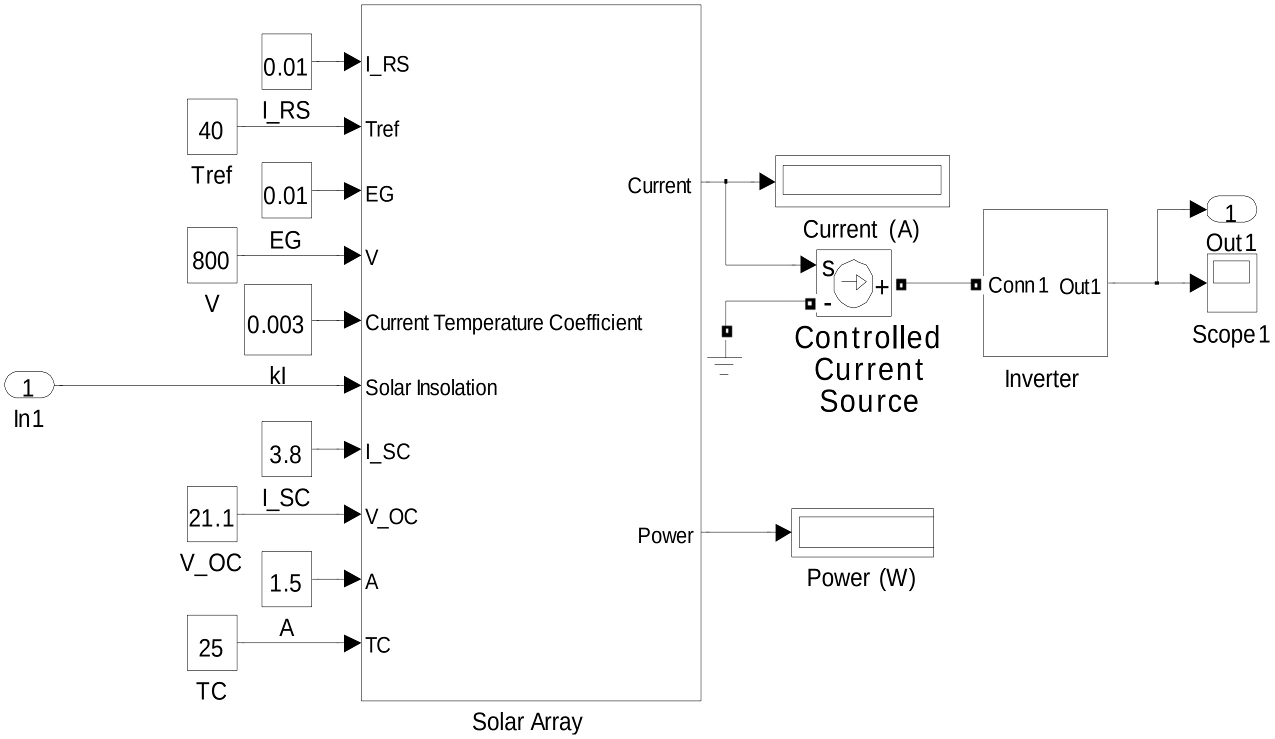


Figure 3.2 Solar PV module model

In Figure 3.2 the inputs used to calculate the current and powers produced are shown on the block and the symbols and their significance are detailed in Table X.

Table X Description of Solar Calculator Inputs

Symbol	Variable	Description
I_RS	Reverse Saturation Current	This value is selected for a particular reference temperature and solar radiation.
Tref	Cell's Reference Temperature	This is the nominal cell operating temperature. It is the temperature at which the cell would be tested in a laboratory to provide optimal results.

EG	Band-Gap Energy of the semi-conductor used in the cell	This is the gap in energy between the valence band and conduction band. It is the minimum change in energy required to excite the electron so that it can participate in conduction.
V	System Voltage	This is the voltage at which the system operates. In this case it is 11kV as mentioned earlier in the document.
kI	Solar Insolation	A measure of the solar radiation energy received in a surface area. In this case 1000W/m^2 was used as it is a possible measurement in South Africa.
I_SC	Short Circuit Current	This value is determined for 25°C and 1000W/m^2
V_OC	Open Circuit Voltage	This is the maximum available voltage out of a solar cell, it can only be provided at zero current.
A	Ideal factor	This is a factor which varies from 1.2 to 5 and is dependent on the PV technology. For this research a value of 1.5 was chosen because the cells are expected to be of CdTe technology.
TC	Cells' Working Temperature	This would be the ambient temperature in the region where the solar panel is installed. In South Africa it is reasonable to use 25°C as it is a common day time temperature in most parts of the country throughout the year.

3.4 Inverter Model

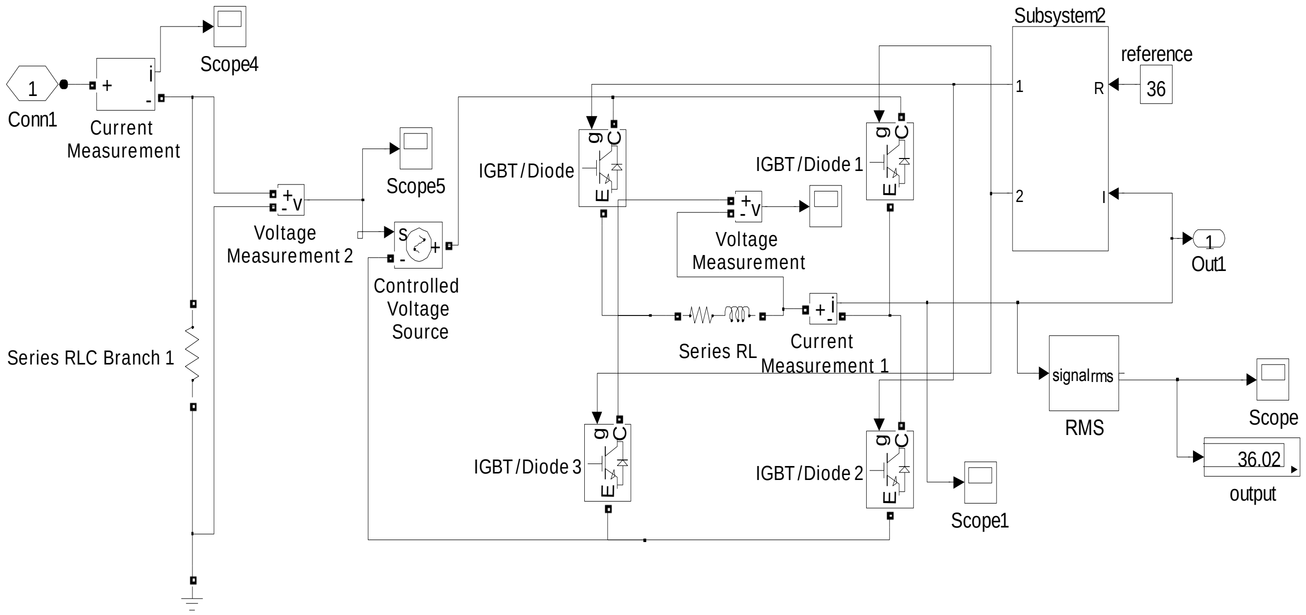


Figure 3.3 Single-Phase Full Bridge Inverter model

i. Full Bridge Inverter

This is a model incorporating a single-phase full bridge inverter and a hysteresis current controller. The expected operation of this type of inverter is explained in Section 2.4. The Conn1 device would connect to the output of the PV string. The two systems can connect seamlessly, however it is common to place the MCB between them as displayed in Figure 3.1 for protection purposes. The inverter uses Bipolar switching which means that Switches 1 and 3 open and close in pairs while switches 2 and 4 also open and close as a pair. Full bridge inverters are the preferred arrangement in higher power ratings because for the same amount of power as a half bridge inverter the output current and switch currents are halved.

The magnitude and frequency of the reference current is chosen and entered on the subsystem 2. This current signal is used as a reference or control signal for the switching to take place effectively. The output of leg A in the system is negative to the output of leg B. The output signal labelled output 1 is the 50Hz current signal of RMS current of 36A. This value is chosen because of the current output of the PV string. This single phase signal is fed to the utility grid when the microgrid is in grid connected mode.

ii. Hysteresis Current Controller

Subsystem 2 is a Hysteresis Current Controller, this control system has the advantage of providing fast dynamic response, however it has a variable switching frequency, which is a drawback in the control system. Figure 3.4 below shows a schematic circuit of a simple full-bridge grid connected inverter whose dc side is connected to the dc side of a power supply such as the solar PV panel investigated in this research. The power flows from the dc side to the ac grid by current injection. This inverter would normally operate at unity power factor to decrease the current stress on semiconductor devices. Hysteresis control is based on the use of physical current ripple bands to limit the inductor current operating within a channel. When the inductor reaches the upper band, a turn-OFF command is generated to switch S1 OFF. The same process occurs for the turn-ON command.

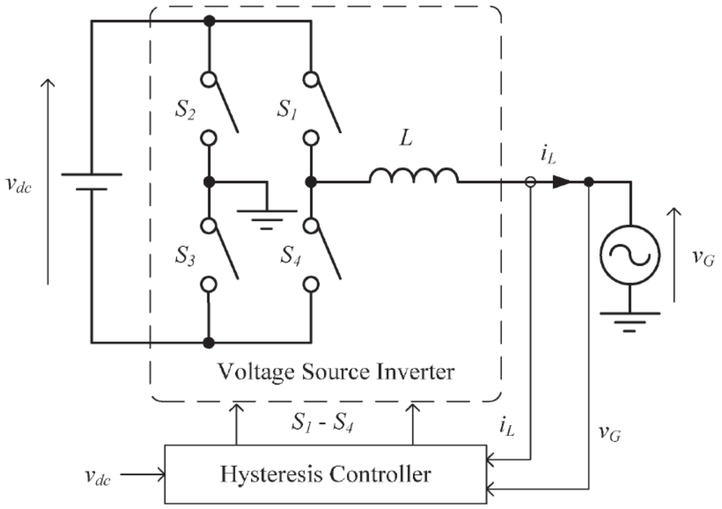


Figure 3.4 Full-Bridge Inverter with Current Control

3.5 Overcurrent Relay Model

In this project the overcurrent relay model was designed based on the IEEE IDMT overcurrent relay model. The flow diagram for the relay operation is shown in Figure 3.5 below.

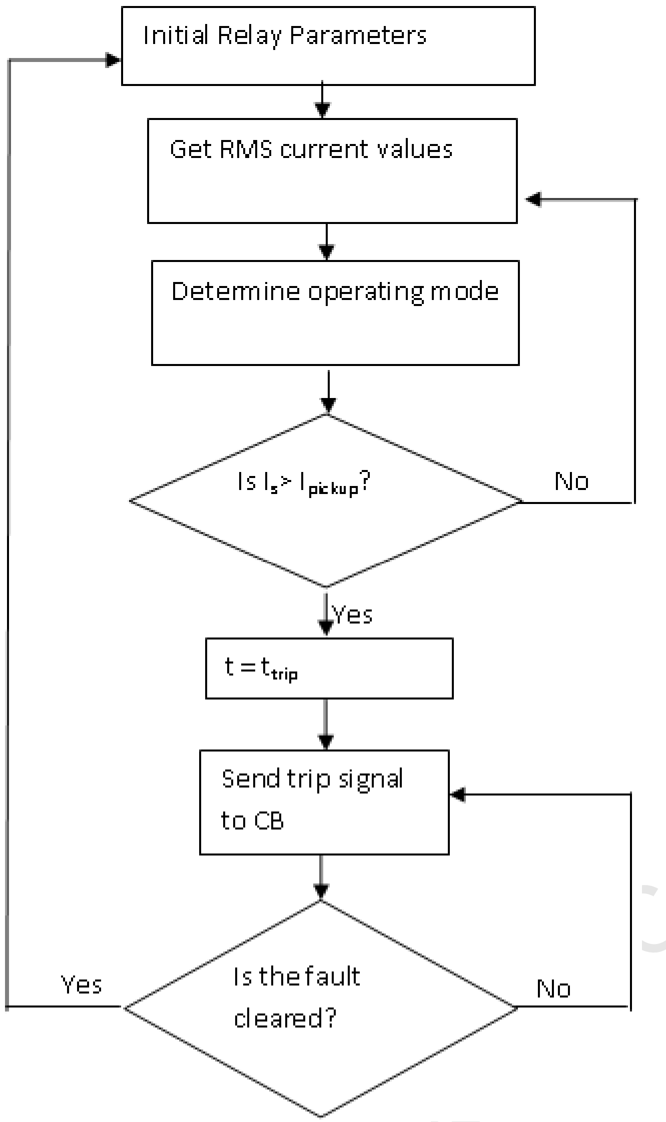


Figure 3.5 Flow Diagram of modelled adaptive overcurrent relay

This model represents a special relay because it can be incorporated in an adaptive relaying scheme. The relay will be able to determine which mode of operation the microgrid is on, from that decision it will determine whether the current is above nominal current or not. This is a useful method of relaying for microgrids because it avoids false tripping of the circuit breakers. Faults in both modes of operation can be detected by this overcurrent relay.

The IDMT characteristic was used because this is easier to coordinate. If all of the overcurrent relays in a protection system are set to operate based on IDMT curves the trip time and trip current coordination between the various relays becomes easier to manage. In this mode of operation, the higher the fault current, the faster the clearance time. This characteristic as well as the ability of selectivity were the reasons for this choice of relay characteristic.

The IDMT characteristics for the relay models follow the IEEE model closely. The TMS is derived using a modified standard inverse formula, which was previously displayed in Equation 3. This formula is as follows:

$$TMS = \frac{T*[\frac{I_{fault}}{I_{pick_{up}}}]^{0.02}-1}{0.14};$$

Where:
T = trip time(s);
Ifault = Fault current (A);
Ipickup= Pick-up Current (A);

As mentioned by Chowdhury et al in [27], at medium level voltage it takes a relay 2 cycles to pick up the fault and the circuit breaker another 3 to 5 cycles to open. Therefore, in addition to the set trip time, it takes from 5 to 7 cycles (0.1s to 0.14s) from the time the fault occurs to the time the fault is cleared.

Total time to clearance = Trip time + Relay Time Delay + Breaker Time Delay

With the above equation in mind the Trip time of the primary relay was selected to be 0.3 seconds.

As mentioned in Chapter 2 there has to be an operation time delay between the primary and the back-up relays. This time delay is known as the coordination time interval (CTI). For this protection scheme the CTI was selected to be 0.5 seconds. This value was chosen because it will allow sufficient time for any delays in the primary relay, but at the same time the back-up relay will be fast enough to clear any faults and preventing extensive damage.

The selected CT ratios were chosen based on the nominal currents flowing through the buses that the relays protect. The ratios are smaller in the isolated mode because there is less current flowing through the buses in the isolated mode of operation.

The Plug setting (PS) was chosen, using a rule of thumb mentioned by Bedekar et al in [51]. This rule states that:

$S \geq 1.25$ * maximum load current (7)
$S \leq 2/3$ * minimum fault current (8)

For the Grid Connected mode of operation Relay1 and Relay 2:
Maximum Load Current = 145 A
Minimum Fault Current = 164 A
Therefore,
$S \geq 1.25 * 145/200$
$S \leq 2/3 * 2590/200$
$0.91 \leq S \leq 8.63$

For the Grid Connected mode of operation Relay 3:
Maximum Load Current = 52 A
Minimum Fault Current = 3660 A
$PS \geq 1.25 * 52/200$
$S \leq 2/3 * 2590/200$
$0.325 \leq S \leq 8.63$

For the Isolated mode of operation Relay1 and Relay 2:
Maximum Load Current = 280 A
Minimum Fault Current = 6000 A
Therefore,

$S \geq 1.25 * 280/400$

$S \leq 2/3 * 6000/400$

$0.875 \leq S \leq 10$

For the Isolated mode of operation Relay 3: Maximum Load Current = 450 A Minimum Fault Current = 4000 A

$S \geq 1.25 * 450/600$

$S \leq 2/3 * 4000/600$

$0.94 \leq S \leq 4.44$

From the PS value ranges calculated it was decided that PS = 1 would be an appropriate setting because this value fits within all of the ranges, makes calculations simple and is a common setting in digital relays.

After considering the TMS and PS selection criteria, as well as analysing the currents in the power system, the following parameters were chosen for the different relays. These values were calculated to obtain the determined trip time values as well as to achieve appropriate coordination between the relays.

Relay 1 Parameters

Grid Connected Mode

CT ratio	200:1
TM	0.1
PS	1

Isolated Mode

CT ratio	200:1
TM	0.1
PS	1

Relay 2 Parameters

Grid Connected Mode

CT ratio	200:1
TM	0.11
PS	1

Isolated Mode

CT ratio	200:1
TM	0.12
PS	1

Relay 3 Parameters

Grid Connected Mode

CT ratio	200:1
M	0.1
PS	1

Isolated Mode

CT ratio	300:1
TM	0.11
PS	1

The relay model used in this project is displayed in Figure 3.6. This model was designed because it includes some functions that are necessary for the protection system model. The relay does not resemble any particular industry model. However, it does contain an input, output, a timer and a selective function that allows it to determine whether it is operating in isolated or grid connected mode.

The relay model works as follows [61]:

1. It receives a single phase current signal from phase A of the power system.
2. The RMS value of this current is then calculated using the RMS block in SimPower systems, set to 50Hz.
3. The zero-order hold block is used to ensure that the signal changes are instant overtime, rather than

stagnant, this provides accurate results. This block has a sampling rate of 0.1s, meaning that it reads the incoming signal once every 0.1 seconds. It is common in industry to vary sampling rates depending on the application. In metering for example, it is likely that readings will be more accurate and sampling rates will be higher because the readings have higher implications and are more significant.

4. The signal then goes through an “ f” block. This block determines which mode of operation the microgrid is in. If the current value ranges from 150A to 4000A, it is assumed that a fault in the isolated mode has occurred. If the current ranges from 4000A to 2590A, it is assumed that a fault occurred while the system was in the grid connected mode. If the system is in grid connected mode the signal is transferred to the “ elay” block and the “ DM Curve Grid Connected Mode” block, if it is in isolated mode of operation the signal is sent to “ elay1” block and “ DM Curve Isolated Mode” block.
5. Once the signal has reached either “ elay” or “ elay1”, these blocks determine whether the current is above the nominal current or not. If it happens to be above the nominal, i.e. there is a fault, these blocks will output a signal of value 1.
6. The “ DM Curve Grid Connected Mode” and “ DM Curve Isolated Mode” blocks will determine the time delay by comparing the fault current to the values placed in a table in the blocks.
7. The combination of two blocks “ DM Curve” and “ elay” work together to generate a time delayed trip signal.
8. The blocks “Add1” and “Gain” are used to invert the produced signal so that it can be recognised by the Circuit breaker which receives the signal. The 3-phase circuit breaker opens when a signal of value 0 is sent to it.

The developed relay was placed in a single phase, at different points in the power system. This was because the faults simulated in this project were 3 phase faults, so the phase which it was attached to was indifferent. 3-phase faults were chosen because even though they are the least common, they create the largest fault current. This project investigates the worst case scenario in terms of fault types. If single phase faults were to be investigated, the same relay design would be attached to all the 3 phases of the power system. This would ensure that the power system is protected from all types of faults.

The 3-phase circuit breakers were also chosen because only 3-pahse faults were being examined in this project. If a fault occurs all of the phases are opened and no current flows through any of them.

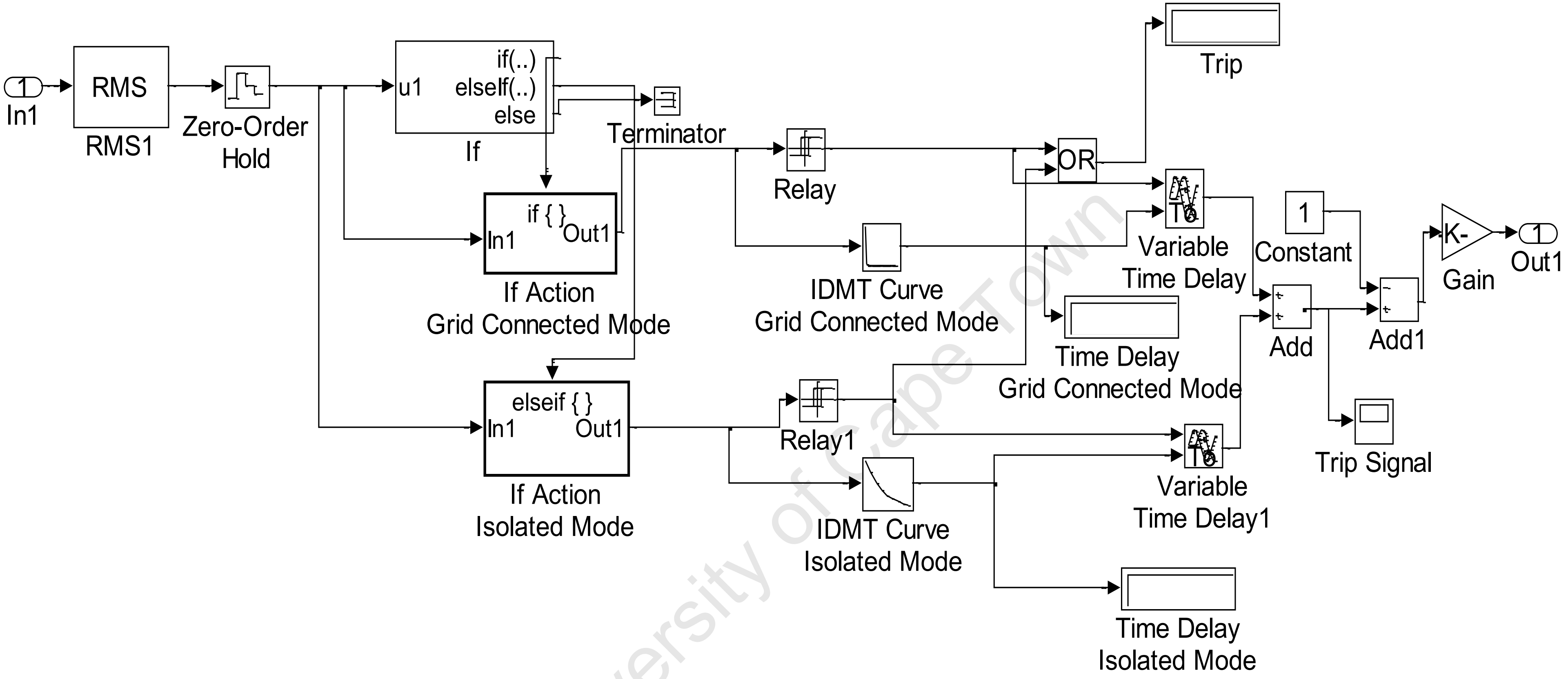


Figure 3.6 Overcurrent Relay Model

3.6 Reverse Power Relay Model

Reverse power protection is generally applied to prevent damage to mechanical plant items in the event of failure of the prime mover. This is very important in power generation plants to prevent damage during back feeds and energisation. Common generator damage includes gearbox damage and mechanical damage to shafts.

Power relays currently used in industry are capable of measuring system voltage and current. They also measure the angle between these two signals, the angle θ. With this information they can calculate real power which is as shown in Equation 9.

$$P = V \times I \times \cos\theta \tag{9}$$

Under normal operation, real power flow is in a determined forward direction and $-90° < \theta < 90°$, in the case of reverse power flow $90° < \theta < 270°$. h e reverse power relay allows for unidirectional flow of active power from A to B.

The “reverse” element of the relay is the most important in identifying an abnormal condition, therefore it is the most important in modelling the relay. In this research the directional component of the relay is adopted from [52], where a similar relay is used for generator protection.

In this model, as depicted in Figure 3.7, voltage and current signals are modified to square waves, with maximum and minimum values of 1 and -1. When the signal is positive, the value is 1 and when the signal is negative it is represented by -1. The two signals are then multiplied to give an output of 1 when the signals overlap and -1 when they don’t. The product is then integrated from 0 to –L. The upper limit of the integrator is 0 so that under normal power flow conditions the integral remains less than 0. However, under reversed power flow conditions the integral output tends to fall until it reaches a threshold value of L. The value of L varies according to the allowable reverse power, the higher the value of L, the higher the amount of reverse power. Once there is a reverse power flow in the location where the relay is situated the relay identifies the abnormal condition and can immediately react to it.

A time delay component is incorporated in the relay. This ensures that the circuit breaker only trips if a prolonged fault or abnormal event occurs. he relays shouldn’t trip for transient power swings.

The last 4 elements in the model are used to ensure a logic 0 is sent to the CB when an abnormality is detected so that the CB can open.

i. ***Definition of Reverse Power Level***

When reverse power relaying is used to protect a generator a relay setting is chosen based on the type of generator it is. An example of this is protection of a Diesel Engine the allowable motoring power is 5 to 25% of the rated generation capacity. The relay setting is chosen based on the previously presented Equation 2 [31]:

$$\text{Setting} \quad \frac{\text{Motoring} \quad \text{ower} \; (\quad) \; \text{G enerating Capacity} \quad \text{M} \quad \text{A}}{\text{C}_{\text{ratio}} \qquad {}_{\text{ratio}}}$$

For Loss of mains detection the method of determining allowable reverse power flow is different because it is not the generator that is primarily being protected. In this case -0.01 was chosen as the lower limit because this is the lowest integral value during normal system operation. For other systems this value would have to be chosen based on modelling results as it depends on the size of the generation capacity and the system loads.

ii. Definition of Trip Time

Reverse power relays with either built in timers or external timers must be used in industry and are simulated in this research to avoid spurious isolation under transient reversal of power, which may arise following synchronisation or in the event of a power transmission system disturbance. The bigger the generating capacity, the lower the time delay should be.

For loss of mains detection the delay time will essentially be defined by breaker reclosing times. When using high speed auto-reclosing, it is important to know the time for which the line must be de-energised in order to allow complete de-ionization of the arc, so that it will not strike when the voltage is re-applied. The de-ionization time depends on various factors, of these factors circuit voltage is the most important. Utility reclosers usually reclose after 0.1s for a 66kV and below system as shown in Table XI. For this reason loss of mains relays must activate before the circuit breakers attempt to reclose and reconnect the utility power source, this is to avoid reclosing on to unsynchronised systems.

Table XI. Arc de-energisation times for different Voltage levels [31]

Transmission Line Voltage (kV)	Minimum de-energisation time (seconds)
66 and below	0.1
110	0.15
132	0.17
220	0.28
275	0.3

The trip signal time delay has to be long enough to not trip for transient cases but fast enough to open the circuit breaker before the recloser activates an unsynchronised circuit to be reconnected. It is assumed that [27], at medium level voltage it takes a relay 2 cycles to pick up the fault and the circuit breaker another 3 to 5 cycles to open. Therefore, in addition to the set trip time, it takes from 5 to 7 cycles (0.1s to 0.14s in a 50Hz system) from the time the fault occurs to the time the fault is cleared.

Based on the preceding argument the trip time delay should be: 0.1s < t < 0.1s. The value chosen for t in this research is 0.1s, which corresponds to 5 cycles in a 50Hz system.

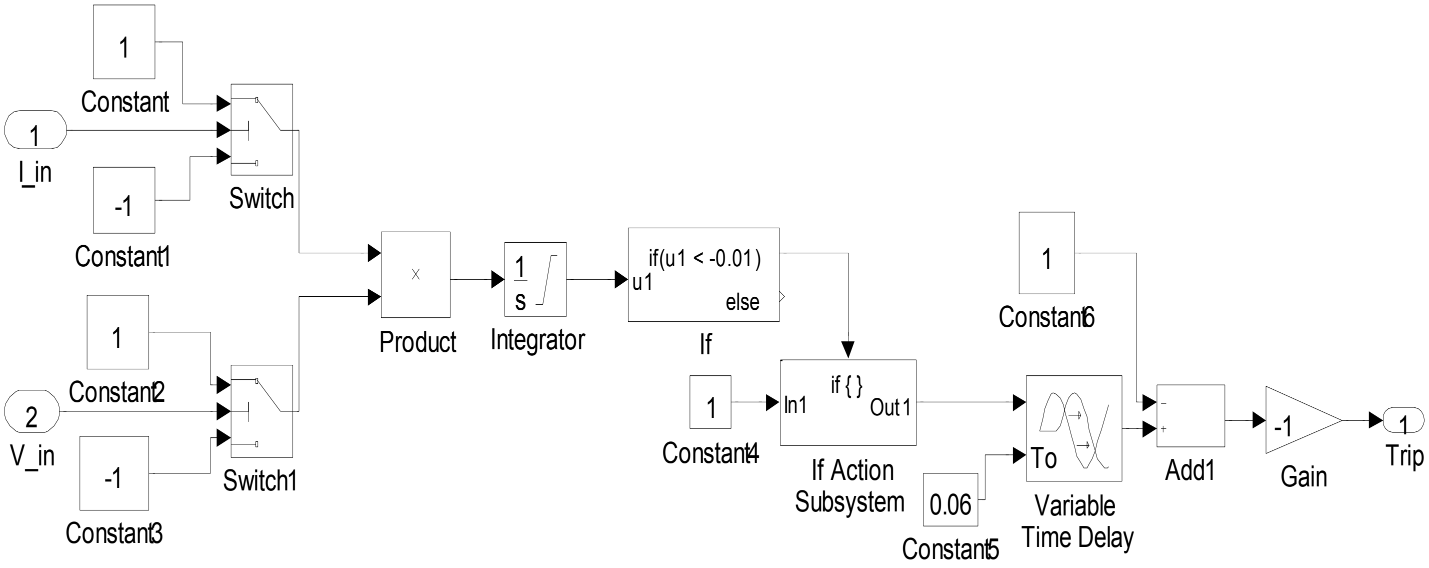


Figure 3.7 Reverse Power Relay Matlab Model [62]

3.7 Adaptive Frequency Relay Model

In order to measure the system frequency a frequency measuring unit which was connected to the relay was developed. In industry such devices are readily available, however, due to simulation package limitations, for this research a measuring unit had to be developed from first principles. A signal period measuring approach was used. This can be achieved in two different ways:

1. Counting the number of times of zero-level crossing in the same direction in a unit of time. The frequency equals this number, or
2. Measuring the time from one zero-level crossing to the next zero-level crossing in the same direction.

The first method was used and the process is shown in Figure 3.8.

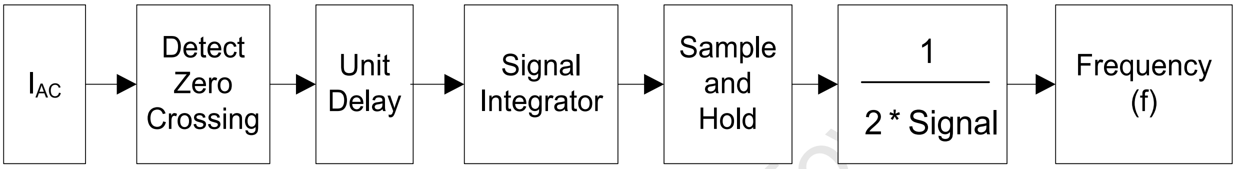


Figure 3.8. Frequency Measuring Process Diagram

This frequency value f is then sent to the relaying component of the model.

The adaptive relay model was designed as displayed in Figure 3.9. The relay is designed solely to respond to the limits specified by the South African Grid Code. If there is sufficient variation in system frequency, the frequency relay becomes active. Frequency relays can be adjusted using multi-stages; therefore, instantaneous and time-delay settings can be employed simultaneously. In this research only instantaneous settings are applied for frequency relays, no time delays were used. This is because the Author believes that it takes time for the frequency to reach the levels outside the allowable limits. An additional time delay could make the response to a disturbance unreasonably slow.

The relay is assumed to have a communications connection to the Static Switch (SS). The information received from the Static Switch at the point of common coupling is a binary value, i.e. 0 or 1. This will enable the relay to configure its settings to suit the Microgrid's mode of operation. If the signal is 0 the Microgrid is in Island mode, if the signal is 1 it is in grid connected mode.

Once the mode of operation has been established the frequency is read. This system frequency (f) is compared to the allowed variation limits. If the value of f is within the non-detection zone, the trip signal is zero. However, if f is higher than the upper limit or lower than the lower limit, i.e. outside of the non-detection zone, the relay will attempt to send out a Trip Signal to the relevant circuit breaker.

Before the Trip Signal is sent out, the system voltage is measured. If the terminal voltage drops below an adjustable level V_{min} the relay can be blocked from operating. This is to avoid, for example, the activation of the relay during generator start-up.

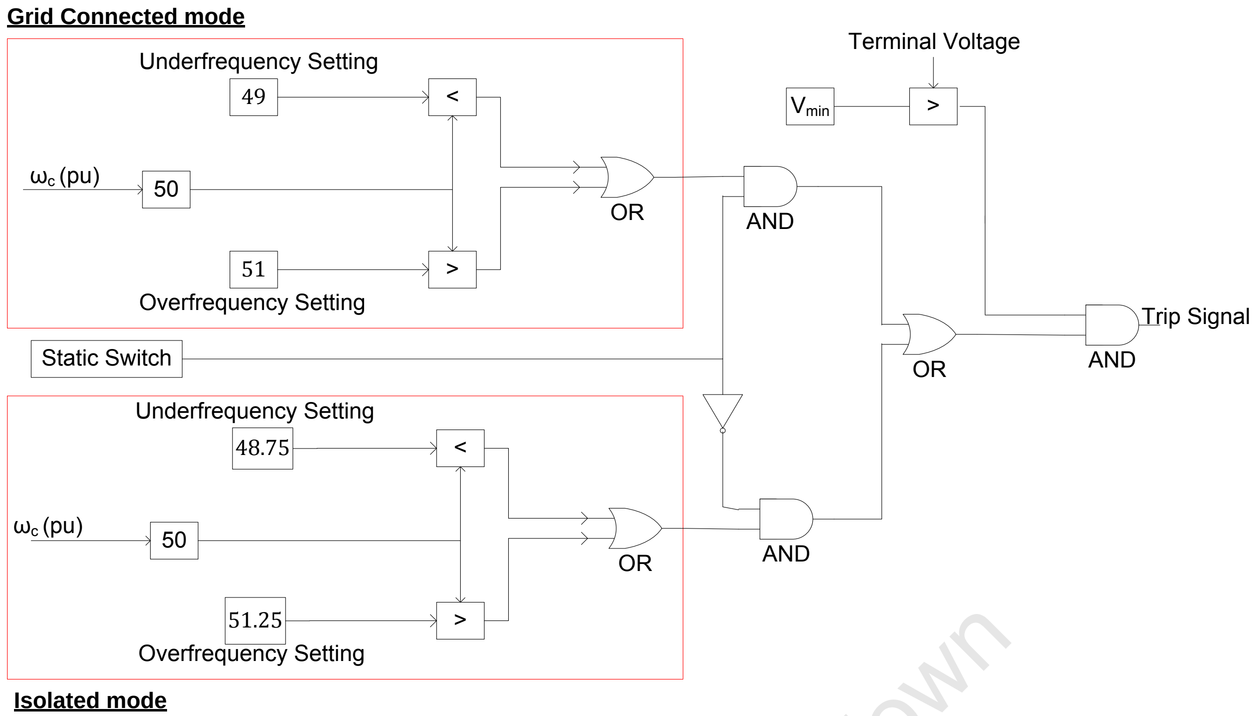


Figure 3.9 Adaptive Frequency Relay Model

3.8 Overvoltage relays for PV Generation Plants

Overvoltage relays can have an Inverse time delay characteristic similar to that of overcurrent relays. The main idea behind the development of this characteristic is that higher overvoltages should be cleared with a shorter time delay than lower overvoltage. Some utilities have standards that determine the delay for each incurred overvoltage. Equation 10 is used to determine the time delay [56]. For the simulations described in this thesis the relay setting voltage is 12100V, which corresponds to 1.1p.u of the nominal 11000V.

$$t \quad \frac{\mathrm{MS}}{\left(\frac{\quad}{s}\right)-1} \qquad (10)$$

where:

t= operating time in seconds;

TMS = time multiplier setting;

V = applied input voltage;

Vs = relay setting voltage.

i. Overvoltage relay coordination

For the protection scheme proposed in this project to be effective it is important that the switches are coordinated efficiently. Once an overvoltage occurs the switches should open in stages so that not all the power from the PV generation plant is lost at the same time [57]. On the other hand it is important that the time delays are not so long that the electronic devices connected to the system incur strenuous conditions for long periods of time. The delays between switching would depend on the sensitivity of the loads and are up to the system designers' discretion.

In this part of the thesis, TMS values of 0.5, 0.75, 1 and 1.25 were used to determine the delays for the 4 different switches. Using this method of coordination has the advantage of the switch opening faster for more severe overvoltage and having a longer time delay for lower overvoltage. Figure 3.10 displays the expected trip times for the different switches when the system is exposed to overvoltage.

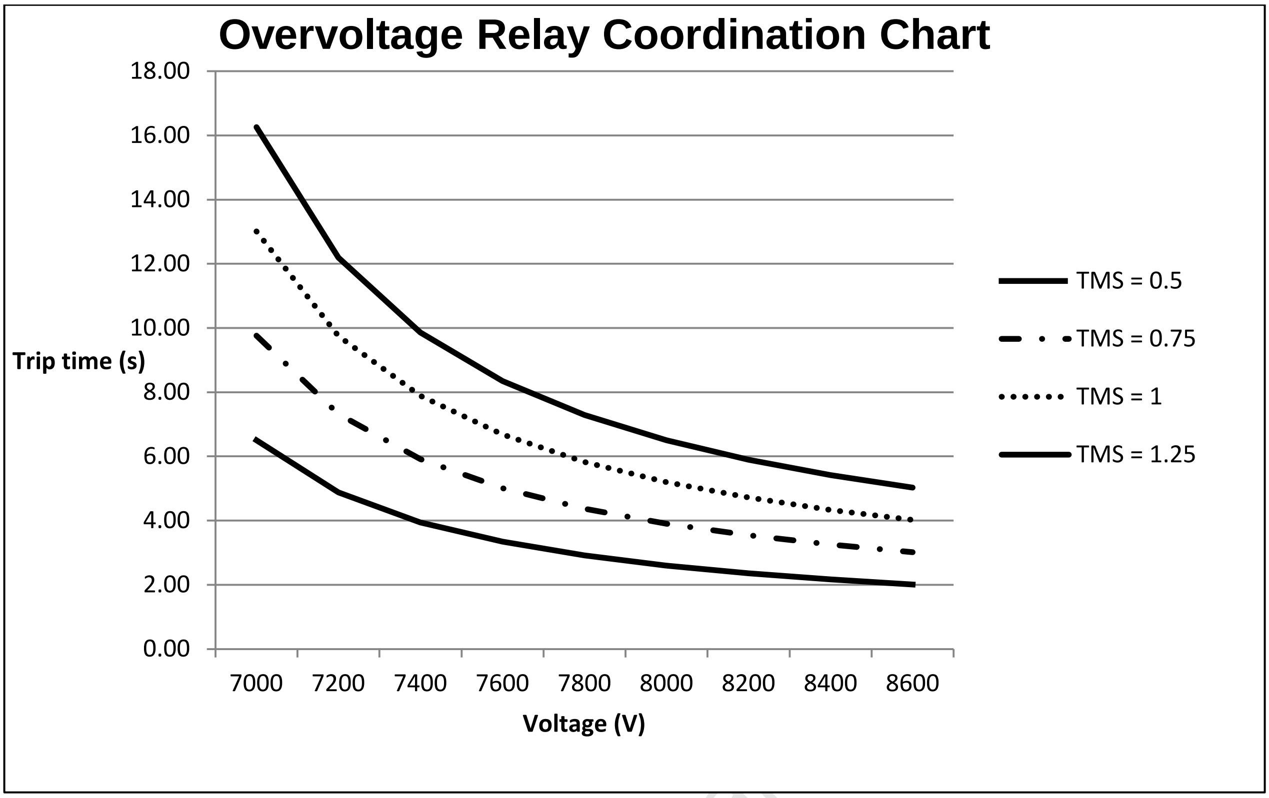


Figure 3.10 Overvoltage relay coordination

II. *Overvoltage Relay Model*

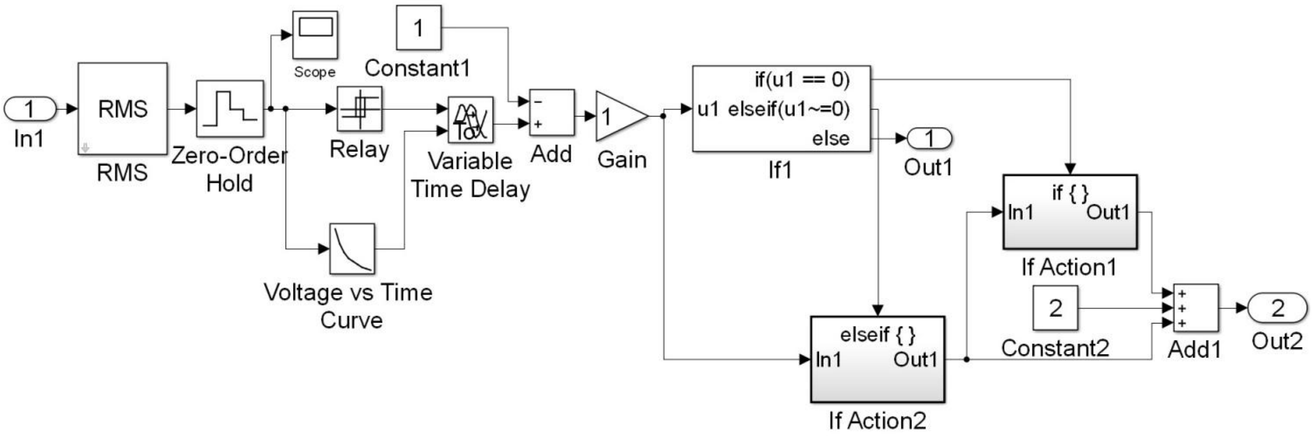


Figure 3.11 Matlab Simulink Overvoltage relay model [63]

This model was designed and tested using Matlab Simulink package. This enabled an accurate idealistic test of the proposed system. Further investigation on hardware could be carried out to validate the results presented in this thesis. The Matlab model is illustrated in Figure 3.11.

The relay receives an input which is the voltage measurement at the output of the inverter, this is a 50 Hz signal. The voltage reading then goes through an RMS block where the RMS voltage is calculated for ease of analysis. The calculated RMS then goes through a relay block and voltage vs. time block. The relay block determines whether the signal value is above the set trip value, if it is, it will trigger a trip signal. The voltage vs. time block determines the time delay depending on the magnitude of the RMS of the voltage at that point. Two signals then lead to the variable time delay block which combines the trip signal with the time delay. The outcome of the variable time delay block is subtracted by 1 and multiplied by -1 so that the switch opens when a signal of value equal to 0 is sent to it an remains closed when a signal of value equal to 1 is input to it. The " f" block and the associated action blocks are used to prevent the relay from reclosing once the abnormality has been resolved.

Various literatures suggest different means of controlling this overvoltage, including, output power limitation.

The switching scheme proposed in this project is reliant on the fact that in large-scale PV installations, PV panel strings are connected in parallel as depicted in Figure 3.1, to reach the desired power output.

For the following power systems the green arrows represent the direction of current flow, while the symbols ↯ and ↯ represent the position of the fault. The parameters of the generators, transformer and loads can be found in the Appendix B attached. Most of the test cases explained below resemble a microgrid that is continuously operating. In cases where a fault occurs, the fault is a permanent 3-phase fault.

4. Method of Testing

4.1 Normal Operation Case

The purpose of simulating the model in its normal operating mode is to measure System Voltage, current and Frequency in both modes of operation, when there are no disturbances in the system. The protection system is not being tested at this stage. It is expected that the system voltage will be 11kV, frequency of 50Hz. The Current will be bi-directional, flowing from the sources to the loads. The Solar PV plant has a fairly small capacity, therefore it is expected that some current will flow from the utility source to feed into the microgrid load.

The model as described in section 3.1 is run for 10 seconds. This is sufficient time to obtain the results at this stage of the study. The model will first be run with the Static Switch closed (Grid Connected Mode) and then with the Static Switch Open (Isolated Mode). Figures 4.1 and 4.2 show the expected current flows in the system. When the Static Switch is open no current flow is expected between Busbar 1 and Busbar 2.

The expected current flow directions are represented by the arrows on the diagrams.

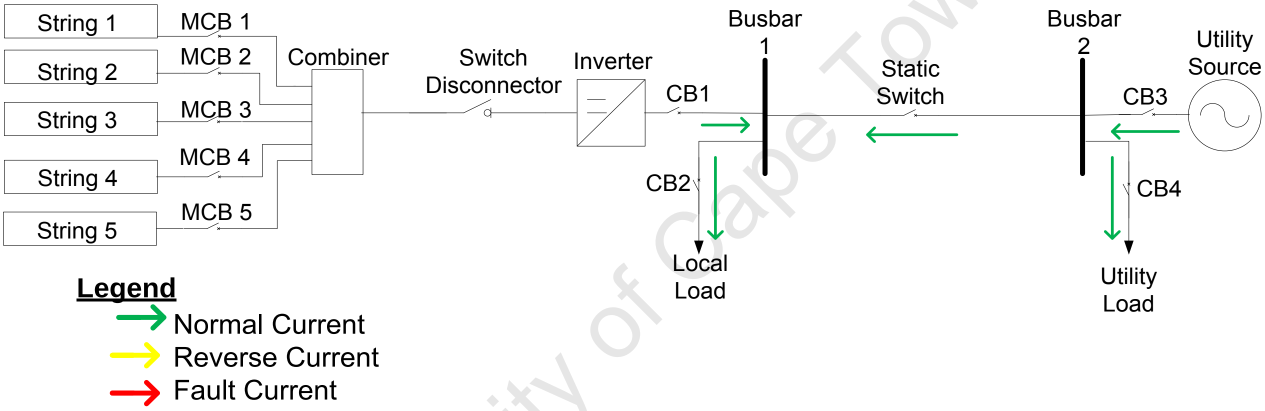


Figure 4.1 **Current Flow during normal operation case in grid connected mode**

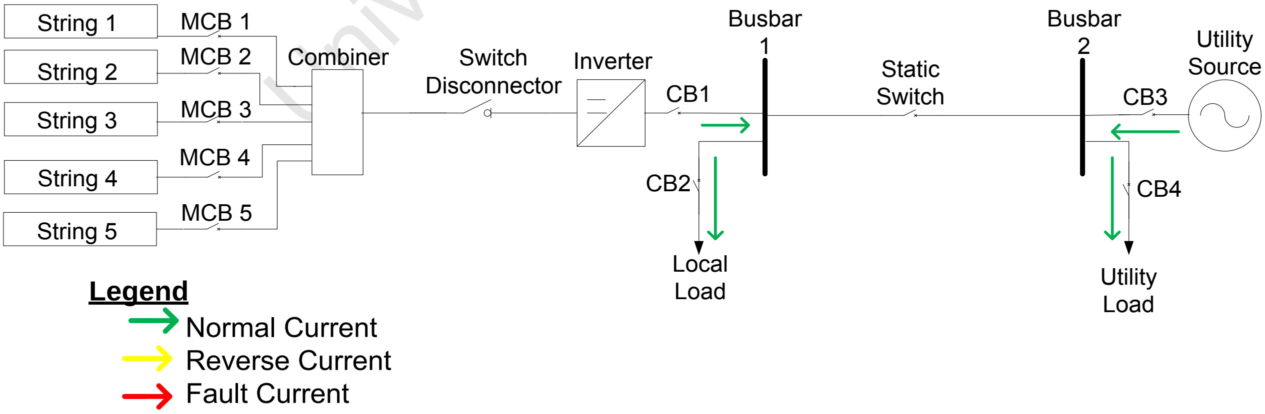


Figure 4.2 Current Flow during normal operation case in isolated mode

4.2 Overcurrent Relay Testing

The purpose of running this simulation is to test the overcurrent relays during faults, to ensure that the power system is protected against overcurrent. When the test is carried out while the microgrid is in grid connected mode the fault currents are expected to be higher, therefore the relays are set for higher trip currents. The trip currents are lower in the isolated mode of operation. The relays will have to adapt to the different modes operation and clear the faults timeously.

4.2.1 Test Case 1: Fault on Microgrid side while in isolated mode

In this test the protection system's ability to clear a fault in the microgrid while in isolated mode will be tested. The fault current will be fed from the PV Plant, therefore it is expected to be less than in grid connected mode. Utility load is expected to operate normally, because this fault is only on the microgrid. The local load, however, is expected to be deprived of any current because the PV generators feed the fault only.

This simulation is run for 10 seconds. The fault is injected into the circuit 2 seconds after the simulation is started. The reason why it was run for 10 seconds is because, this gives enough time for the primary protection to operate and for the back-up protection to operate in case the primary fails.

In order to pass this test relay 1 must clear the fault effectively without relay 2 having to send its trip signal to the switch. Relay 3 should not recognise that the fault has occurred because the load it is protecting is not affected by the fault. Figure 4.5 depicts the predicted current flows during this test case.

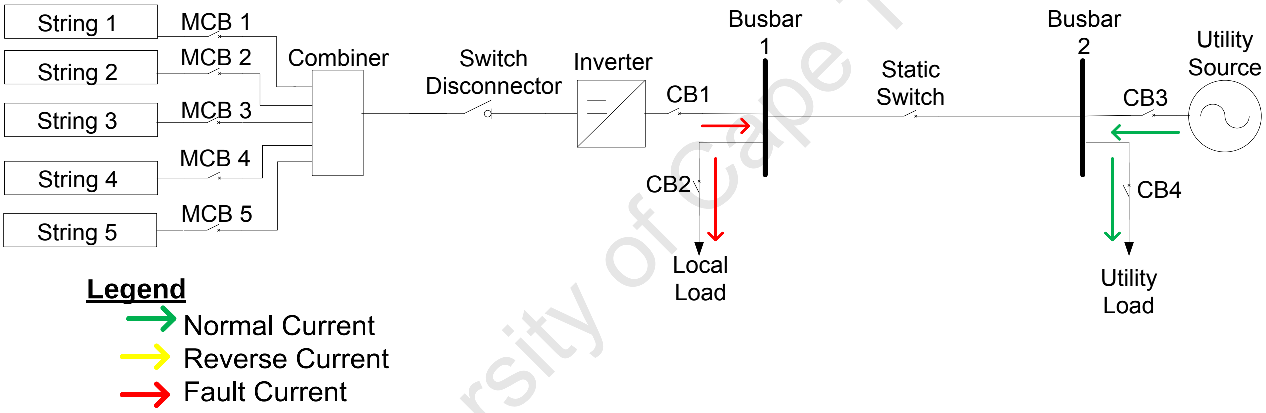


Figure 4.3 Current flow during fault on microgrid while in isolated mode

4.2.2 Test Case 2: Fault on Microgrid side while in Grid Connected mode

In this test the protection system's ability to clear a fault in the microgrid while in grid connected mode will be tested. The fault current will be fed from the PV Plant as well as the utility generator. As there are more sources feeding the fault than in the previous case, the fault current is expected to be higher. While the fault is not cleared, both loads will be deprived of any current. This is because all of the current goes towards the fault. In order to pass this test the protection system must clear the fault and allow the required currents to be restored to all the loads.

This simulation runs for 10 seconds. The fault is injected into the circuit 2 seconds after the simulation is started.

In order to pass this test relay 2 must clear the fault effectively without relays 1 and 3 having to send its trip signal to the switch. Relay 3 should recognise that the fault has occurred because the current flows through the static switch and the point of interconnection which it protects. Figure 4.4 shows the current flows during this test case.

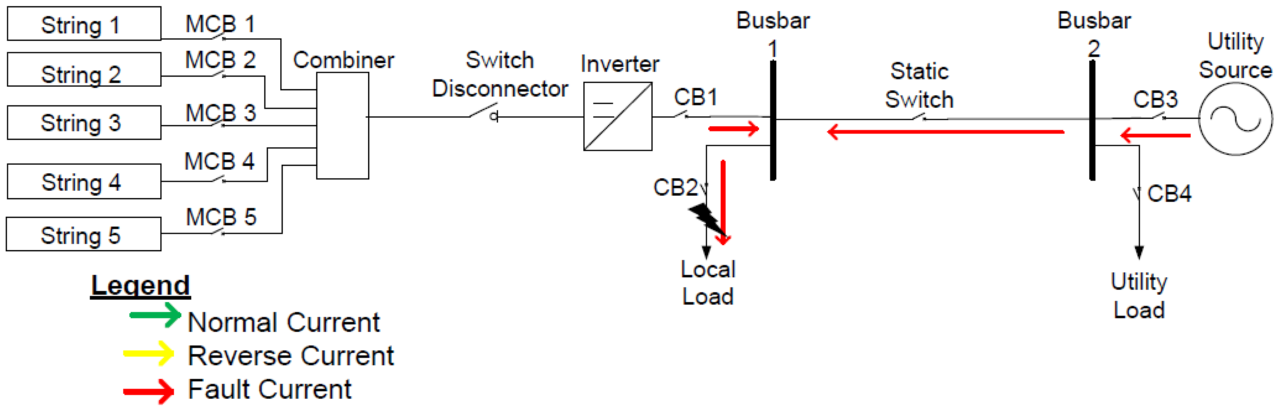


Figure 4.4 Current flow during fault on microgrid in grid connected mode

4.2.3 Test Case 3: Fault on Utility side while in Grid Connected mode

In this test the protection system's ability to protect the microgrid from the effects of a fault in the utility grid while in grid connected mode will be tested. The expected fault current levels for this test are higher than that of test 2. This is because the PV Plant and the utility generator contribute to the fault current. To prove that the protection system is acceptable, it will have to clear the fault within the respective IDMT time.

In this case the primary protection (relay 3) should operate first and if it fails the back-up protection (relay 1) should operate.

In order to pass this test relay 3 must clear the fault effectively without the back-up relay having to send its trip signal to their related CBs. Relay 1 will recognise the fault because of the increased current flowing from the PV distributed generator towards the fault location. Relay 2 will experience an undercurrent; therefore it is not expected to react in this test case. Figure 4.5 below depicts the current flow during this test case. It is apparent that once the fault occurs only abnormal current flow occurs.

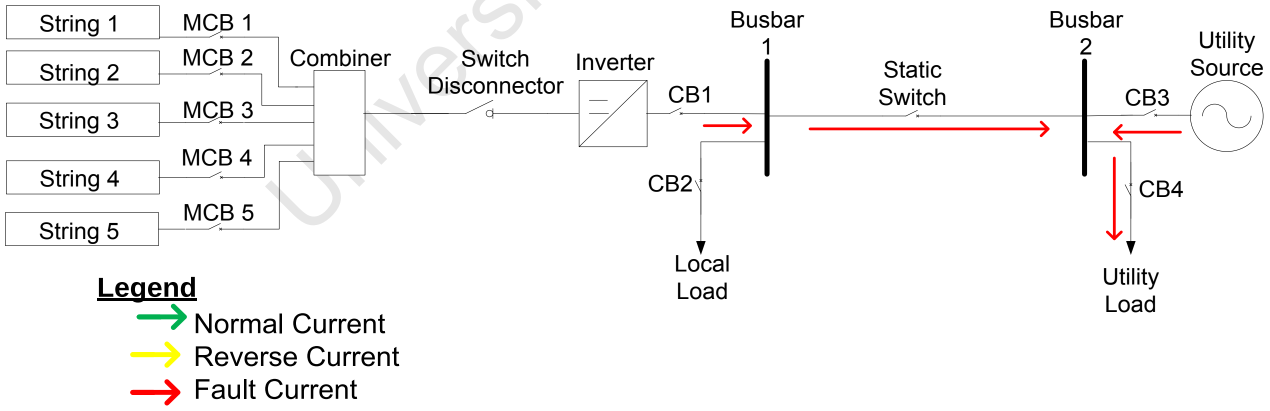


Figure 4.5 Current flow during fault in utility grid in grid connected mode

4.3 Reverse Power Relay Testing

The next 4 tests are performed over a 10 second period. Abnormalities such as opening switches out of turn and faults are simulated at the 2 second mark. It is expected that the witnessed reverse power will be higher in cases where there is loss of mains due to a fault rather than in cases when a switch is opened. Any Reverse current of a significant magnitude should be detected by the relay and the SS should open accordingly.

4.3.1 Test Case 4: Loss of Mains due to open utility switch, large DG Capacity.

In Test Case 1, CB3 is opened after 2 seconds. This represents a scenario where there is maloperation of a switch or nuisance tripping. It causes reverse power flow into the utility load from the 2MVA PV Plant source. It is important that the reverse power relay detects this scenario because it will prevent unsynchronized reconnection of the utility power source with the microgrid. In this case the reverse power relay is expected to cause the reverse power relay to make the static switch at the point of common coupling to open. Figure 4.6 shows the expected effects of the event. The reverse current represented by the yellow arrow is the one that will cause the SS to open.

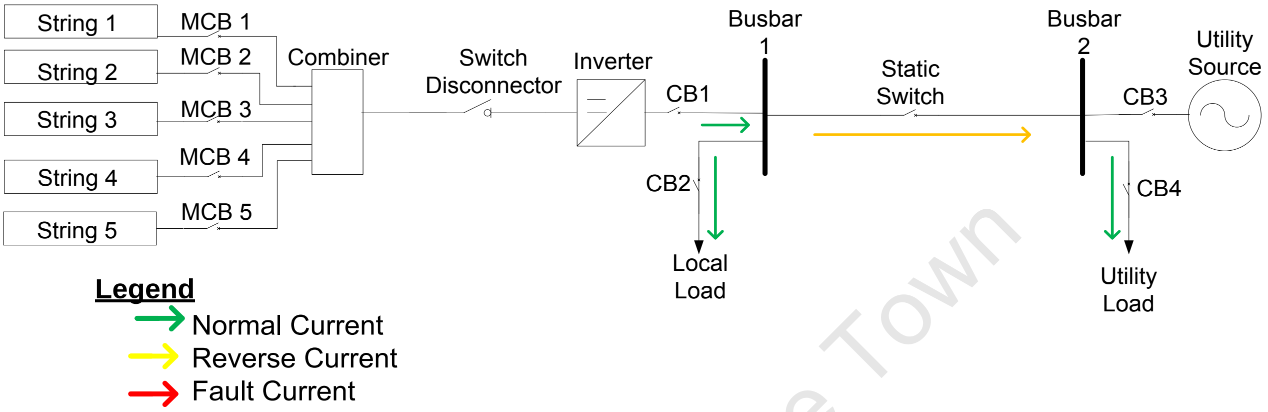


Figure 4.6 Current flow during loss of mains event due to open utility switch with large DG capacity

4.3.2 Test Case 5: Loss of Mains due to a 3-phase Fault, with large DG Capacity.

3-phase faults are the most severe faults in terms of system stability. It is important to provide a protection system that can handle such high currents. This type of fault does not always create the highest levels of fault current. A phase-to ground fault current could be higher than the per phase current of a 3-phase fault. In this case the Utility Source is lost due to a 3-phase fault, which is located between CB3 and busbar 2. After the fault has occurred, power will flow from the DG towards the fault. This power in the reverse direction should be detected by the reverse power relay and the fault is expected to be cleared by the reverse power relay and static switch combination in between busbar 1 and busbar 2 as shown in Figure 4.7.

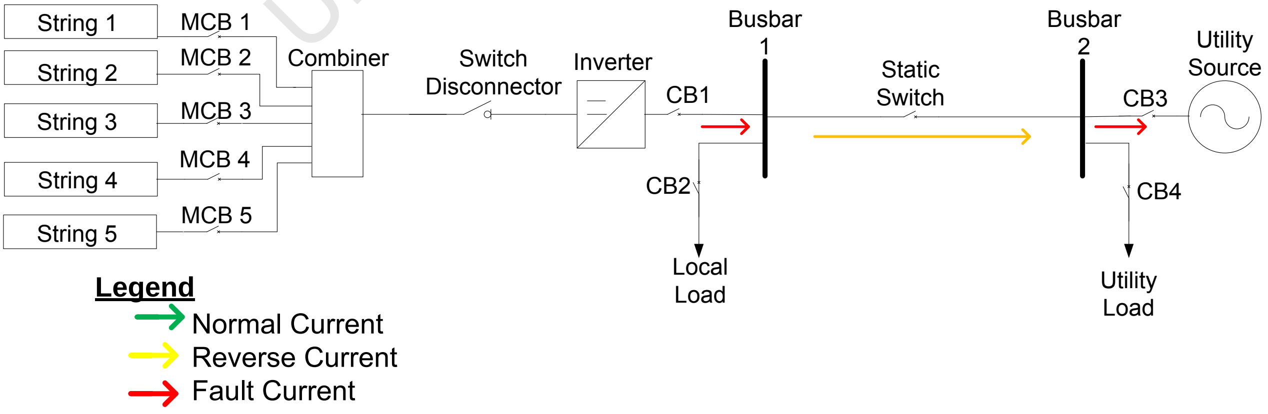


Figure 4.7 Current flow during loss of mains due to a 3-phase fault, with large DG capacity

4.3.3 Test Case 6: Loss of Mains due to open utility switch, with Small DG Capacity.

This case is similar to test Case 1 but here it is expected that there will be the least active power flow which might make it more difficult for the reverse power relay to detect the abnormality. This test is included in order to test the sensitivity of the reverse power relay. Again the switch CB3 will be opened at 2 seconds. This case will demonstrate the impact on the size of the DG with regards to reverse power relaying for loss of mains. Again the expected current flows are displayed for this test case in Figure 4.8.

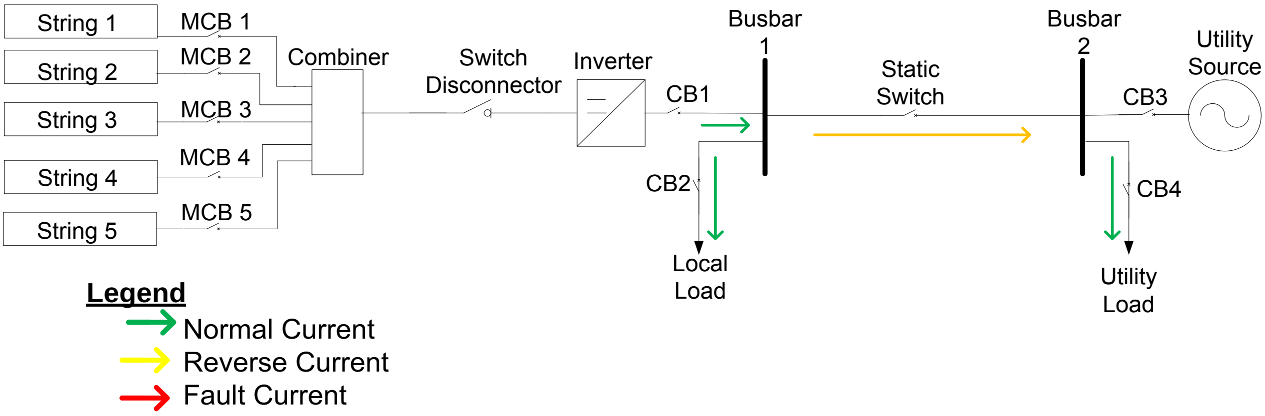


Figure 4.8 Current flow during loss of mains due to open utility switch, with small DG capacity

4.3.4 *Test Case 7: Loss of Mains due to a 3-phase Fault, with Small DG Capacity.*

When it comes to reverse power flow with small DG, detection is the main issue and sensitivity of the relay model is of paramount importance. The reverse current is so small that it makes it difficult to detect the reverse active power. In this case the three phase fault will cause a relatively high reverse power flow and the relay is expected to detect it. The direction of current flow is predicted to be the same as Test Case 5 for this relay and is displayed in Figure 4.9. The current magnitude however, is expected to be lower.

In all of the test cases the relay setting is the same. The relay plays the vital role of detecting reverse active power. For all the tests the setting is as described in Section 3.6.

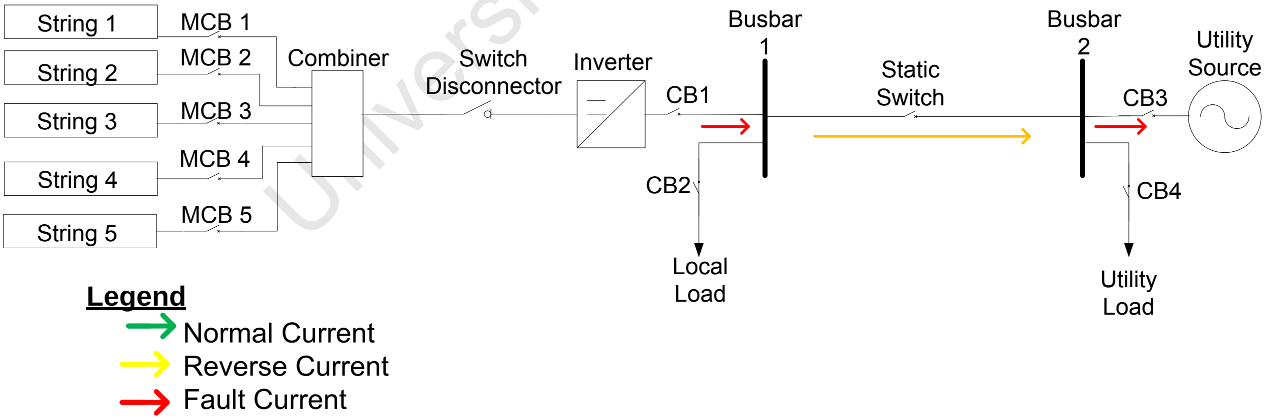


Figure 4.9 Current flow during loss of mains due to a 3-phase fault, with small DG capacity

4.4 Adaptive Frequency Relay Testing

Adaptive frequency relaying is yet another innovative manner to protect microgrids during unforeseen events. Simulating the power system under the testing conditions described below allows for analysing of the efficiency of the model in protecting the microgrid under abnormal conditions. It is expected that a higher frequency variation will take place while in isolated mode. This is due to relay settings, programmed in accordance to the South African Grid Code.

4.4.1 Test Case 8 – Under frequency Test in Grid Connected Mode

Variable load is switched on at 2s and steadily increased; this was done to create a sudden load pick-up scenario. This increases the system load until the system becomes unstable and the frequency starts dropping. It will be at 48.75 Hz that the relay will detect an abnormality and attempt to protect the Microgrid by opening CB5 and disconnecting the variable load. In Figure 4.10, the current flow in the power system during the under frequency testing is depicted.

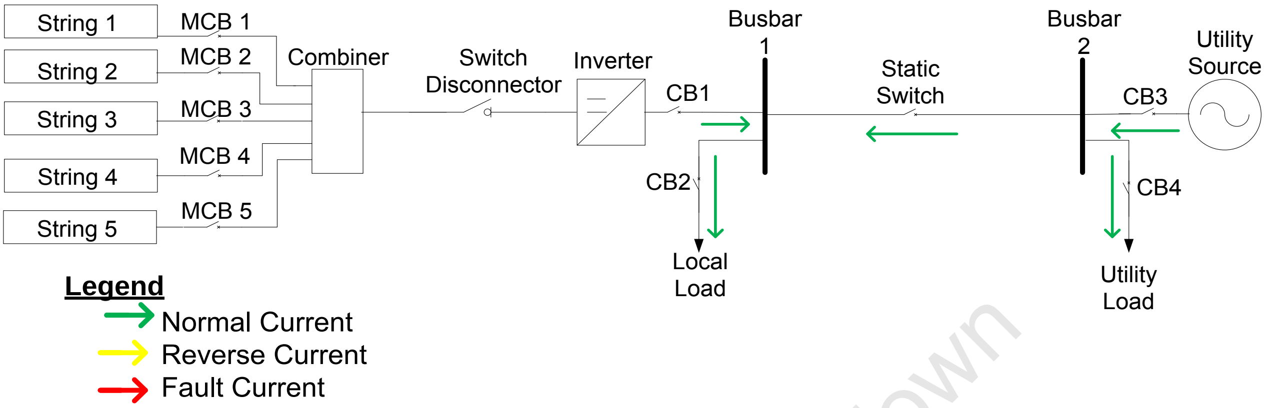


Figure 4.10 Current flow during under frequency testing in grid connected mode

4.4.2 Test Case 9 – Under frequency Test in Island Mode

This is an under frequency test similar to Test Case 1, but with the Microgrid in Island mode. Again the variable load is switched on at 2s and steadily increased. This increases the system load until the system becomes unstable and the frequency drops. The relay should trigger CB2 to open once the frequency reaches

47.5 Hz. The relay will change the under frequency tolerance after observing the status of the static switch. Figure 4.11 shows the current flow during this test case.

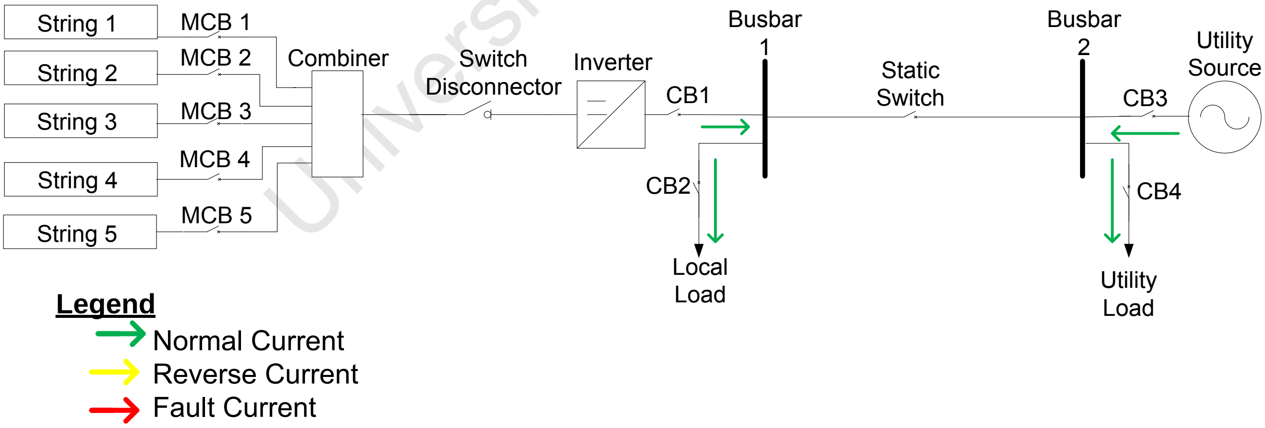


Figure 4.11 Current flow during under frequency testing in isolated mode

4.4.3 Test Case 10 – Over frequency Test in Grid Connected Mode

Case 3 is an Over frequency test in Grid Connected mode. In this case the simulation starts with the variable load of 2MVA on. At 2s the load is lost causing the generators to be under loaded. This leads to a system over frequency. In this case the Microgrid is isolated from the Utility grid once the abnormality is detected by opening the Static Switch. This way the Utility will not be affected by the Microgrid system over frequency. The SS should open once the frequency reaches 51.25Hz. The over frequency is only cleared once the load becomes stable and stops decreasing. The current flow in this case is similar to that of Test case 8.

4.4.4 *Test Case 11 – Over Frequency Test in Island Mode*

This is an Over frequency test in Island mode. Again the variable load is lost after 2s. The CB 2 should only open once the frequency reaches 52.5Hz. This would be to ensure that local loads are not damaged by large frequency variations. Once the switch opens the frequency should return to its normal value.

4.5 Overvoltage Control Testing

The simulations testing the overvoltage control are of high importance and this relay could prove useful in cases of system stability and compliance with regulations. When PV generation is connected to the grid it is clear that the bidirectional currents will meet at a point and cause a voltage higher than surrounding points on the network. It is important to maintain this relatively higher voltage and possible overvoltage at a minimum and when necessary apply control mechanisms to limit it.

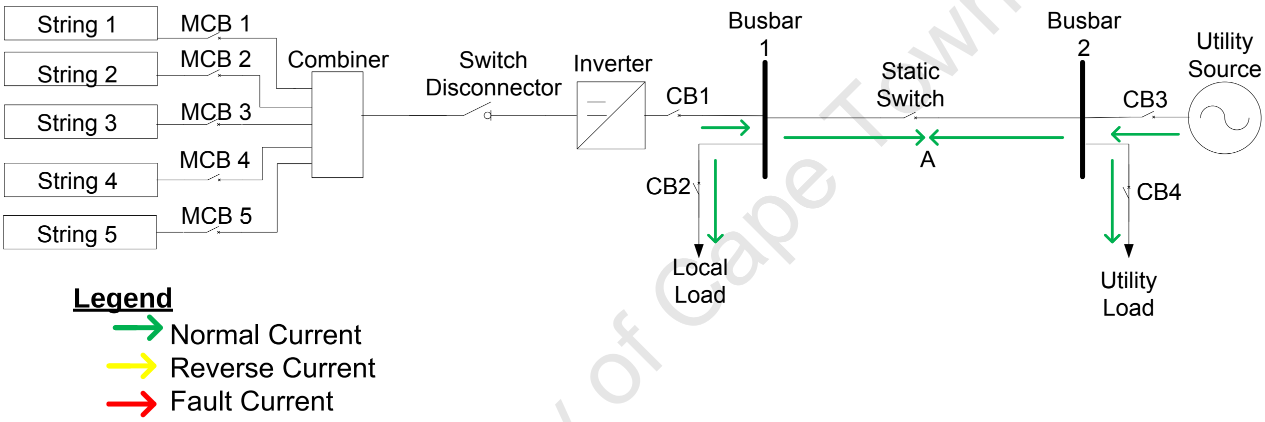


Figure 4.12 Current flow during overvoltage testing

4.5.1 *Test 12 High Overvoltage*

In this case the voltage at point A is increased by increasing the utility voltage level, assuming that it reaches 1.1pu. This is done to cause point A to reach 11200V peak. In this case it is expected that the trip delay time will be short and that the relay will have to trigger a disconnect signal to more than one solar panel string, by switching more than one of the MCBs displayed in Figure 4.13.

4.5.2 *Test 13 Low Overvoltage*

In this case the system voltage at point A will be increased slightly to reach a voltage of 11100V peak, this is achieved by increasing the utility source voltage to 1.05pu without changing the load characteristics in the system. The relays will detect this increase and start counting their respective trip delay times. It is expected that disconnecting one string will be sufficient to restore the voltage to a level acceptable to the Grid Codes.

4.6 Adaptive Protection System for a Microgrid with Solar PV generation

In the following test cases the entire protection system will be tested and the different relays will be used in a single system to test for their interoperability with each other. The purpose of this test is to prove that when the different relays designed in this research are put together they really do form a holistic protection scheme for microgrids with Solar PV generation.

It is important that, when placed in a system, the relays can operate with each other so that no nuisance tripping or relay blinding occurs. Based on the fact that the different relays measure and react due to different system characteristics, there shouldn't be cases where nuisance tripping occurs. In fact the relays should complement each other and act as back-up systems to each other to create a more secure system.

In addition to showcasing the strengths of the relays, these tests will show the protection system's shortfalls and how it can be improved in future research. The system being tested will be the same system as the other cases, however only a selected amount of tests will be carried out with all the relays in the system.

The tests to be carried out are explained in the proceeding sections.

4.6.1 Test 14 - 3-phase fault on microgrid

This test case will be similar to the test performed when the microgrid was only protected by the adaptive overcurrent relay. The purpose of carrying this test when all the relays are connected to the system is to ensure that the capabilities of the overcurrent relay are not hindered by the fact that more relays will be added to the system. It is expected that the overcurrent relays will not be blinded or negatively affected by the addition of other relays to the system. 3-phase faults are highly common in power networks, therefore it is important that the grid is adequately protected against faults of this nature.

4.6.2 Test 15 - Overvoltage Control switching

A high overvoltage will be simulated in the system by increasing the solar insolation value in this test case. It is expected that the overvoltage switching scheme will react to this change and disconnect some of the strings in the PV system. Increased solar insolation may also lead to higher current flow from the PV generation plant. This could have an effect on the overcurrent protection system. The purpose of this test is to identify any effects that the string switching may have on the system that will trigger other relays to send out a trip signal to other circuit breakers. The overvoltage switching scheme is more of a control scheme than a protection scheme, even though its actions protect the loads in the power network.

4.6.3 Test 16 - Loss of mains due to a fault

This will be a case where both the overcurrent relay system and the reverse power relay will detect an abnormality in the system and react against it. The time delays in the specific relays will determine which of the relays triggers the switches to open first. Whichever relay is programmed to open second will become the secondary protection or back-up protection. The success of this test will be an example of how the different relays can complement each other. If the test presents negative results it will show that combining the different types of relays actually deteriorates the quality of the protection system rather than improve it.

4.7 Testing Load Management techniques to assist with System Protection

Most different techniques for load management aim to flatten the load profiles to reflect a moderate and constant consumption throughout the day. This is hardly achievable due to routine consumer behaviour. Ideally, in some periods load would be reduced and in other periods it would be increased. Load management actions can be taken on the supply or demand side. The demand response programs aim to change the consumer's load curve, influencing and shifting their consumption, based on electricity pricing and other incentives [58].

There are two groups of load management techniques, namely direct and indirect. Direct methods involve the Utility's management of consumer loads through a contract or agreement. Indirect methods involve pricing programs and other incentives that would motivate consumers to use electricity at certain times based on applicable tariffs. If indirect methods are applied the consumer is not forced to participate in load management, it becomes voluntary and out of the Utility's control.

Load management is usually oriented towards limiting consumption of water heating and air conditioning in domestic environments as these are large power consuming devices. Historically, most programs were directed towards industrial and commercial consumers with larger loads and bigger potential for load reduction. In recent times this philosophy has changed because of the available technology.

In this research three methods of load control will be modelled and their differences will be thoroughly discussed to investigate which is the most attractive solution for a South African Electricity network.

This thesis will focus on Direct methods of load management and the methods applied can be used for both large and small consumers. Load management assists system protection by reducing the constraints on the generation and transmission systems. The power system is less exposed to abnormalities such as overloading or underloading which can cause frequency variations and voltage instability.

4.7.1 Regional Load Shedding

Regional Load Shedding is possibly the most common method of load management used in South Africa. In this method the Utility company or Municipality would cut out completely the supply to a certain region in order to provide the generated power at peak levels to another region. This results in some consumers having no power for a certain period of the day, usually when the system is under strain.

This procedure may cause large discomfort to the consumer. For part of the day they will have no access to electricity. In South Africa this generally lasts for two-hours of the day and is usually applied in the winter period. Utilities try to be fair about the load shedding schedule and rotate regions so that the same region is not affected every time load shedding takes place.

This technique is highly inefficient for the Utility because during the period of load shedding there is a loss of revenue from the customers out of supply.

Regional Load Shedding is easily achievable through grid control mechanisms. The system control can disconnect an entire region by remotely disconnecting a bulk supply point such as a mini-substation.

4.7.2 Load Shifting

Load Shifting is a technique where the load usage is scheduled in such a way as to attempt to spread electricity consumption evenly throughout the day. This is not easily achievable as consumers have their daily routines and preferences as to when they want to use certain devices. A completely flat load profile is hardly ever achieved but it is possible to reduce power consumption peaks.

Some metering systems support an architecture that includes Load Control Units (LCUs)/Switches that communicate with the meter, concentrator or master station. LCUs are used to connect/disconnect high energy consumption devices. In this method loads can be switched on or off depending on the constraints of the grid. This load shifting can be achieved through a scheduling function currently available on smart meters. Consumers can program their own schedule or this can be done at the master station controlled by the utility or service provider. Either way a flatter load profile can be achieved.

The advantage of having this method of load control is that the consumers are rarely completely cut off from electricity supply. Only some devices in the consumer's premises will be disconnected according to consumption constraints.

Although, load shifting requires training and educating consumers and operators it is a convenient method for both consumers and utilities because the consumer does not have the discomfort of no electricity supply and the utility can still receive all of its revenue provided that the technique is applied properly.

4.7.3 Maximum Load Curtailment (Peak Clipping)

Peak Clipping also known as Peak Load Curtailment is also performed in order to flatten the load profile and reduce demand peaks. This is to ensure that the consumer does not exceed the allowable peak power consumption at any period of time. Some tariffs are structured in such a way that the consumer pays a fee corresponding to the peak power demand. This feature of load control can help the consumer to control this peak effectively.

This technique normally functions in such a way that if the consumer exceeds their peak consumption limit, their supply is cut off and restored shortly after provided that the consumption is back to a value below the limit. This method can be a applied to an entire region to ensure that the region does not exceed the expected generating capacity.

In this case the customer may go through the discomfort of lack of electricity, but this is only temporarily. The utility will lose some revenue during the periods while the consumer is cut off, but this is for small amounts of period at a time.

4.7.4 Electricity Tariffs

In South Africa some Consumers are supplied by Eskom and others are supplied by the local municipalities. Depending on who supplies the electricity and how much the peak demand is for a particular load point, the tariff will vary. This thesis focuses on the Homelight Tariff applied by Eskom [59]. This tariff is suitable to low-usage single phase residential areas. The tariff includes an energy usage charge (c/kWh) and an environmental levy charge (c/kWh). Any combination of appliances may be used at the same time as long as the capacity of all appliances in combined usage does not exceed a maximum of 4 200W for a 20A connection and 12 500W for a 60A limited connection. In this research a 60A connection will be analysed.

The tariff is separated into blocks as shown in Table XII. Based on the day load profile displayed in Figure 4.13, the estimated monthly consumption is less than 350kWh, therefore Block 2 was used. The total charge assumed was 85.60 c/kWh including VAT. This was used to calculate the daily revenue collection for the Utility.

Table XII. Homelight Tariff Structure [59]

July 2012 to March 2013	Energy Charge (c/kWh) VAT incl	Environmental levy charge (c/kWh) VAT incl	Total VAT incl
Block 1 ($\leq$ 50kWh)	65.36	3.99	69.35
Block 2 ($\geq$ 50 - $\leq$ 350 kWh)	81.61	3.99	85.60
Block 3 ($\geq$ 350 - $\leq$ 600 kWh)	123.03	3.99	127.02
Block 4 (> 600 kWh)	135.32	3.99	139.31

4.7.5 Method of Analysis

i. Normal Case

A typical domestic load profile with two daily electricity consumption peaks one in the morning and another in the late afternoon was used. This load profile was obtained from [60]. It was done to obtain a realistic view of a domestic load profile in South Africa, without any load management methods being applied. The load profile is depicted in Fig. 4.13.

The vertical axis on the left hand side represents the consumption as measured in 30 minute intervals, while the vertical axis on the right hand side represents the cumulative energy consumption for the day.

It is evident from the graph that the demand peak of 0.7kWh/30min is found between 20:00h and 21:00h. This generally corresponds to the time of the day when people are at home and using electricity demanding appliances. The period with the lowest consumption is between 2:00 and 4:00 o’clock. The load profile for an industrial or commercial load would present different peak times and probably a completely different load profile based on economic factors rather than comfort. During this time most people are sleeping, consumption is due to devices that operate throughout the day such as refrigerators.

Based on the load profile and chosen tariff the total daily revenue can be calculated as displayed in (1):

Revenue = Consumption (kWh) x Tariff (c/kWh) (1)

During the normal case without load management, the Utility can collect up to ZAR9.81 per day, this corresponds to 11.46kWh being used during the day.

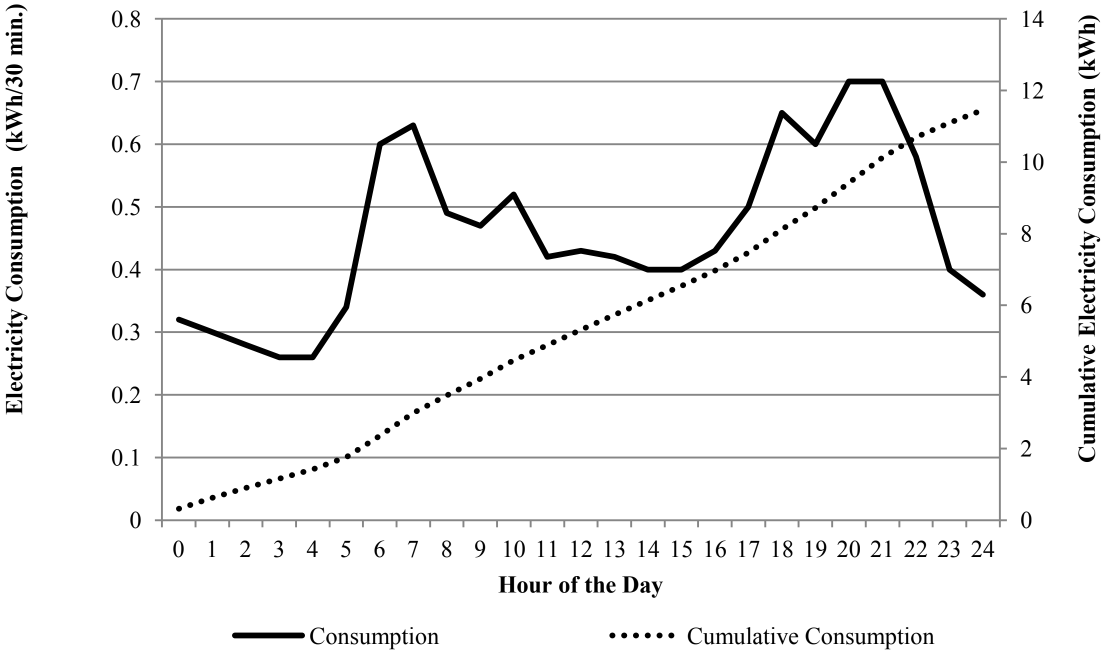


Figure 4.13. Domestic Load Profile without Load Management

ii. Test Case 17 - Regional Load Shedding

To demonstrate this method a modification of the normal case was carried out. It was assumed that the load was completely cut off for two hours of the day, as typically applied in Utility load shedding schemes, from 18:00 to 20:00. During this period the consumer would have no access to electricity and the utility would receive no revenue from the consumer.

iii. Test Case 18 - Load Shifting

In this case the peak consumption was limited to 0.55kWh/30min. This can be achieved by using load limiting devices or timing the use of electrical equipment with high consumption. In this research only the load profile was used, the load wasn't modeled. he load consumption was then reorganized to achieve the same daily cumulative consumption as the normal case. This assumes that the consumer or the utility has scheduled the consumption in such a way that the same amount of energy is used during the day but the peak demand is not excessive. The Utility still receives the expected daily revenue and the consumer is not inconvenienced by not having a constant electricity supply.

iv. Test Case 19 - Peak Clipping

Peak Clipping was done by limiting the peak load to 0.55kWh/30min. This load profile was once again adapted from the Normal Case, there was no model of the load, however, in a real case smart meters with load management capabilities could be used to cut off the electricity supply to the load once consumption goes above a certain level. At times where the load exceeded the accepted peak value the peak demand was limited to 0.55kWh/30min. No load shifting was done in this case, therefore the utility would be affected by a reduction of revenue from this operation.

5. Results and Discussions

The results of the tests and simulations are displayed and discussed in this chapter. In addition to this chapter, supporting results can be found in Chapter 9 – Additional Results. The additional results give a different perspective of the results, for example if the RMS signal is shown in Chapter 5, the corresponding sinusoidal signal will be displayed in Chapter 9.

5.1 Normal Operation

5.1.1 Grid Connected Mode

i. ***Busbar 1***

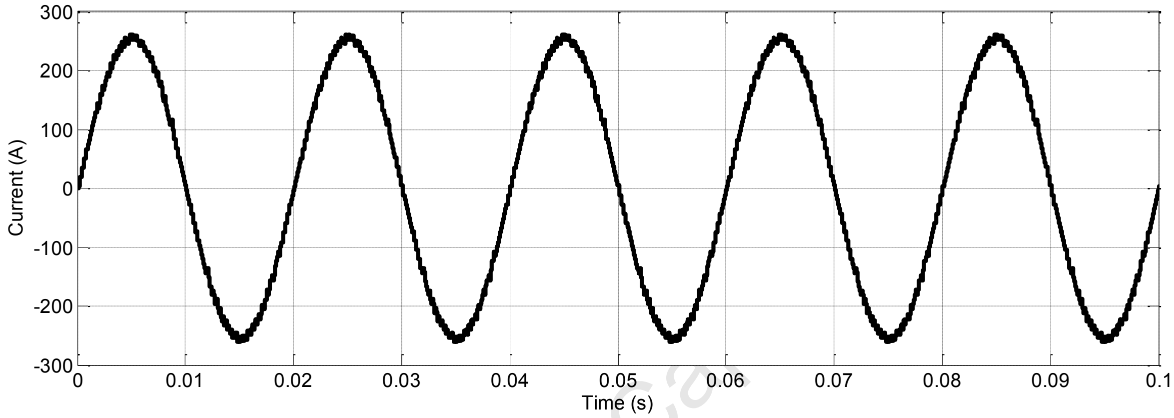


Figure 5.1 Current Output form PV Generation during Normal Operation

During normal operation, the output of the PV Generation is sinusoidal, this output current is displayed in Figure 5.1 and is the current measured at the output of the DC/AC inverter used in the simulations. The inverter used resembles a realistic inverter whose output would present such an output. The peak to peak current is 376A with a frequency of 50Hz. This is the maximum produced current when the solar radiation is set at 1000W/m^2.

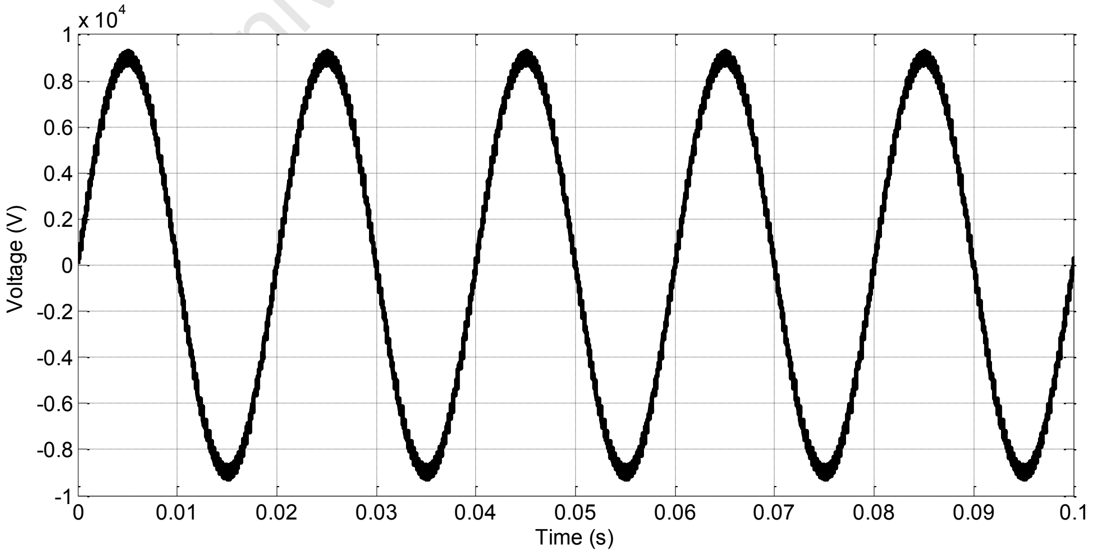


Figure 5.2 Voltage at Busbar 1 during Normal Operation

In Figure 5.2 the voltage signal at busbar 1 is depicted. This voltage signal is harder to control than the current signal. In this case the voltage was approximately 9kV peak to peak. The RMS of this signal can be found in Figure 9.2 in section 9.

ii. Utility Source

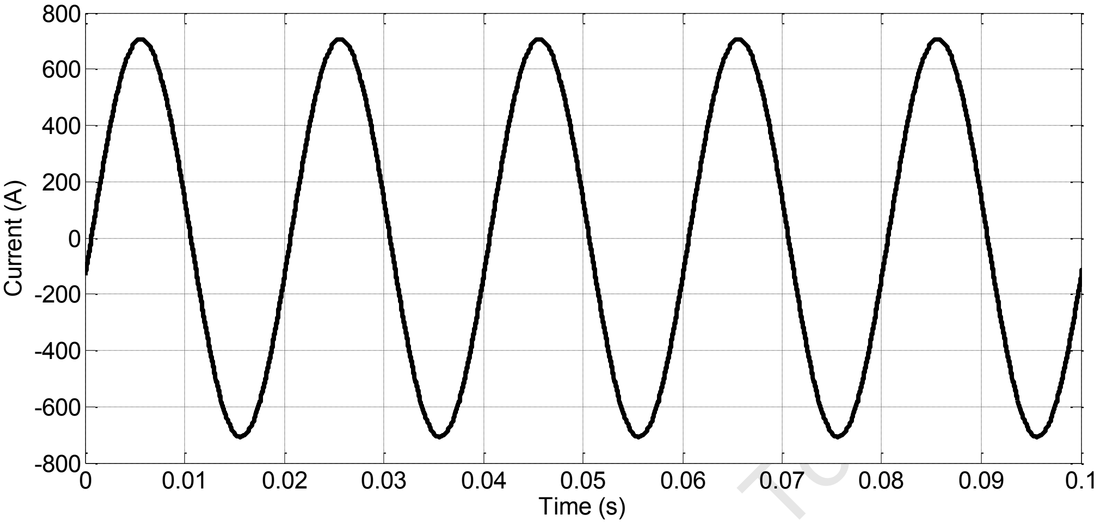


Figure 5.3 Current Output form Utility Source during Normal Operation in Grid Connected Mode

The Utility Source produces a current higher than that of the PV Generation Source, about 1400A peak-to-peak as displayed in Figure 5.13. This is because the Utility generator has a higher capacity than the Solar PV distributed generator and supplies a bigger load. In grid connected mode some of this current flows towards the local load to support the distributed generator.

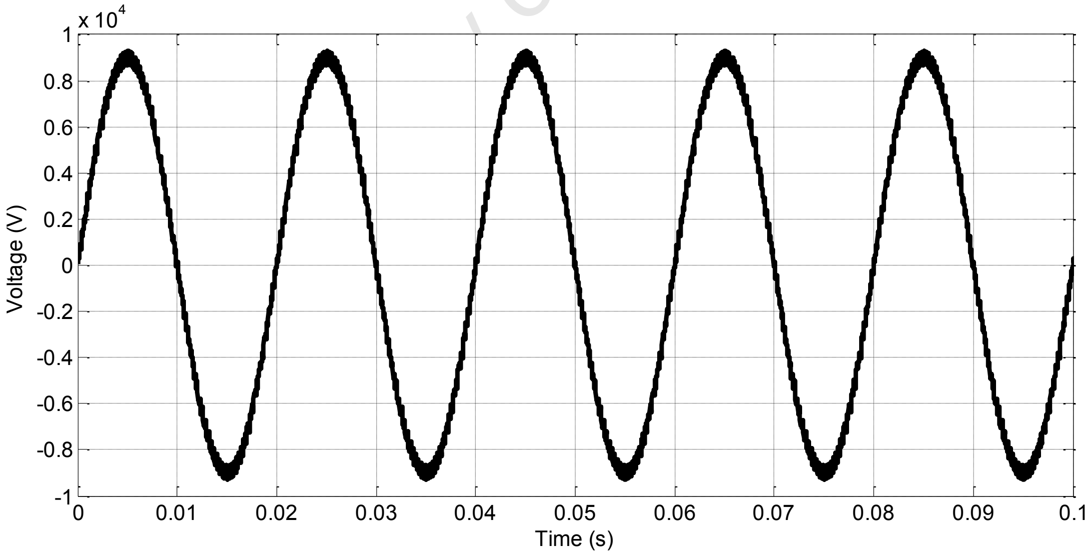


Figure 5.4 Voltage at busbar 2 during Normal Operation

The voltage level at the utility busbar is the same as the voltage level at the distributed generator, this is shown in Figure 5.4. The system voltage is uniform in both busbars.

iii. ***System Frequency***

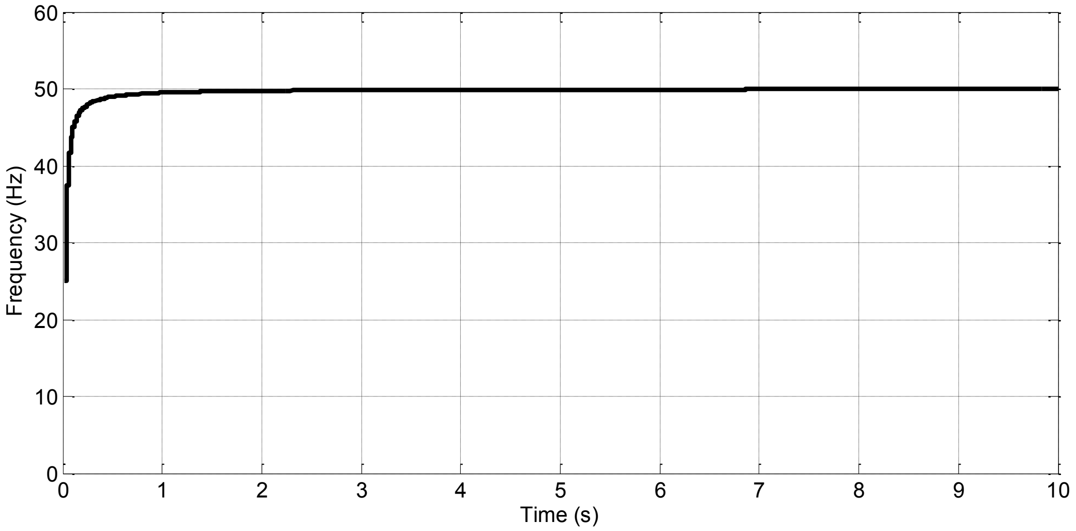


Figure 5.5 System Frequency during Normal Operation

The system frequency is 50Hz, as displayed in Figure 5.5. For the first second the frequency is rising, this is common in non-inverter based generation. If only PV generation was involved in the system, the start-up time would be much shorter. Once the frequency reaches 50Hz, it remains at that level for the rest of the simulation.

5.1.2 Isolated mode of operation

i. ***Busbar 1***

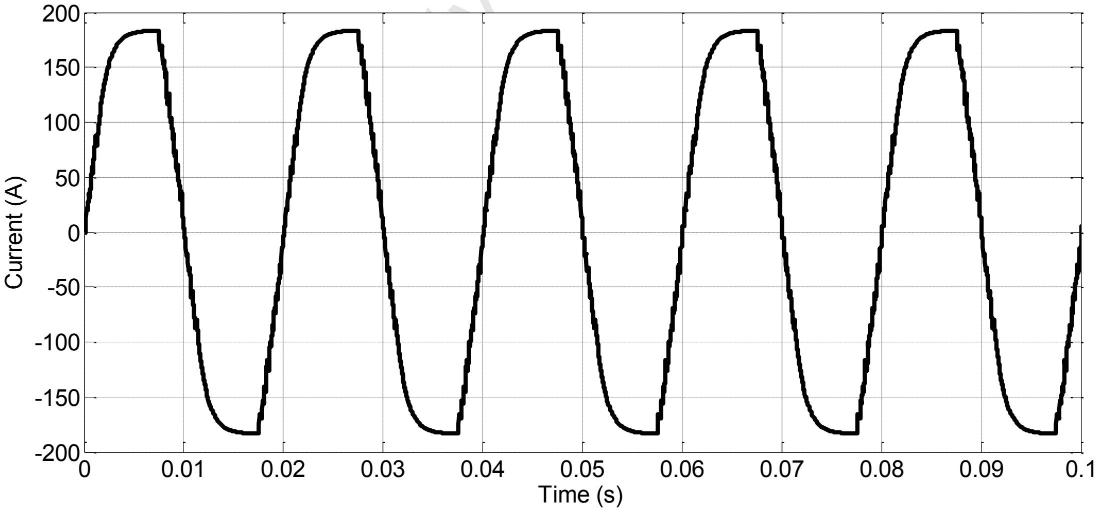


Figure 5.6 Current Output from PV Generation during Normal Isolated Operation

The current output from the PV Source is the same in isolated mode as it was in the grid connected mode, this is depicted in Figure 5.6. This shows that this current output is independent of the mode of operation. The 376A peak to peak signal is recorded in this mode of operation, the RMS for this signal is again present in Section 9 Additional Results.

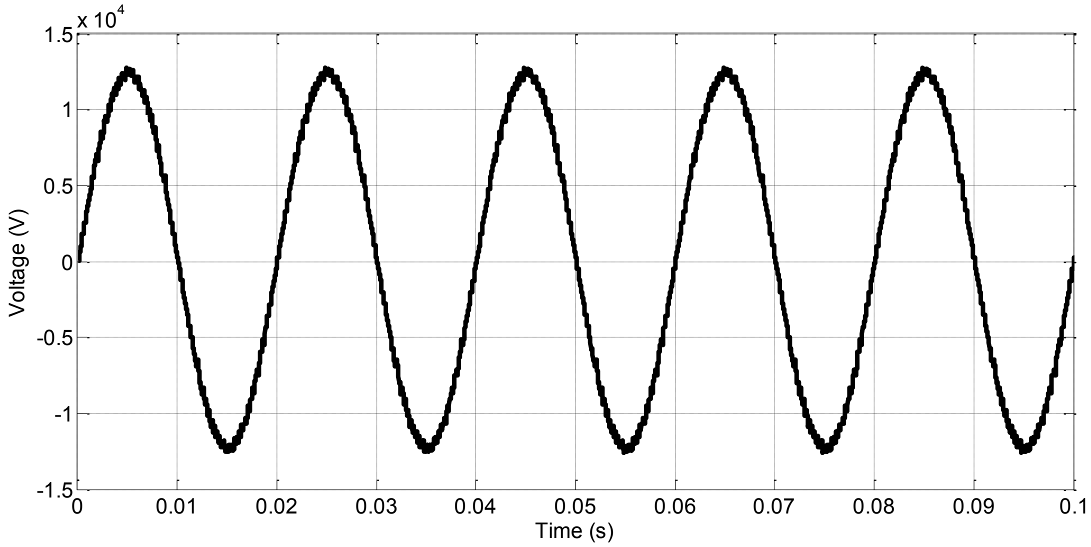


Figure 5.7 Busbar 1 Voltage during Isolated mode normal operation

The voltage level during the isolated mode of operation is closer to the nominal value. This is because there are less voltage losses in the system, this is displayed in Figure 5.7. The RMS value for this signal is displayed in Section 9.

ii. ***Busbar 2***

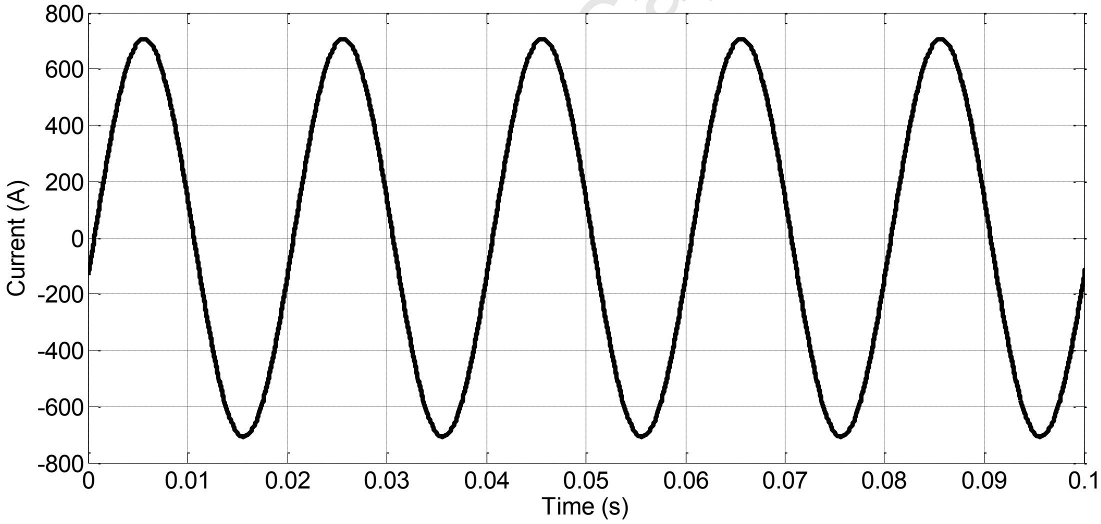


Figure 5.8 Utility Source Current during isolated operation

The current produced by the utility source is slightly lower in this case, this is depicted in Figure 5.8, because the current that previously flowed to the microgrid is no longer present. Now only the current used by the utility load is present in the signal.

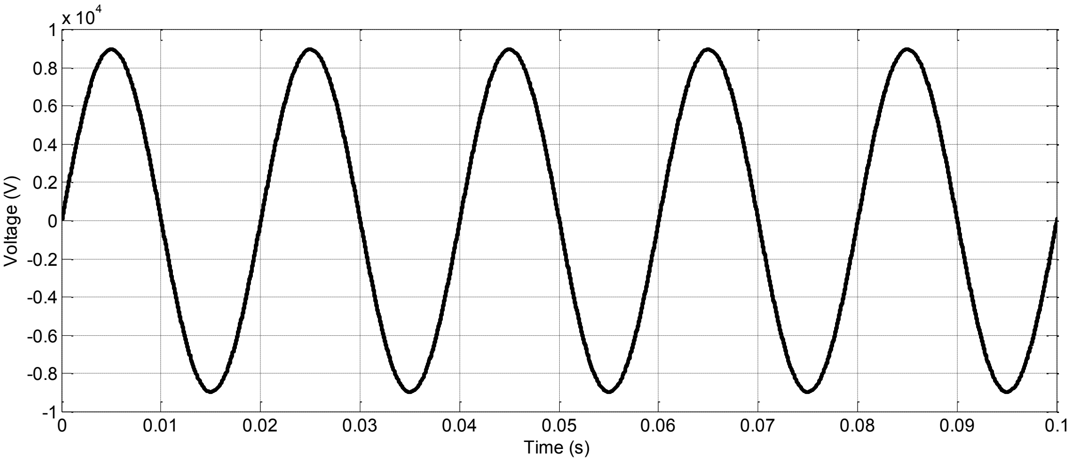


Figure 5.9 Busbar 2 Voltage during isolated mode of operation

In Figure 5.9 it can be seen that the voltage level for the microgrid and the voltage level for the utility grid are different. The two systems are no longer capable of regulating each other. The voltage losses at the two measuring points are no longer the same because, they are essentially two separate systems.

iii. ***System Frequency***

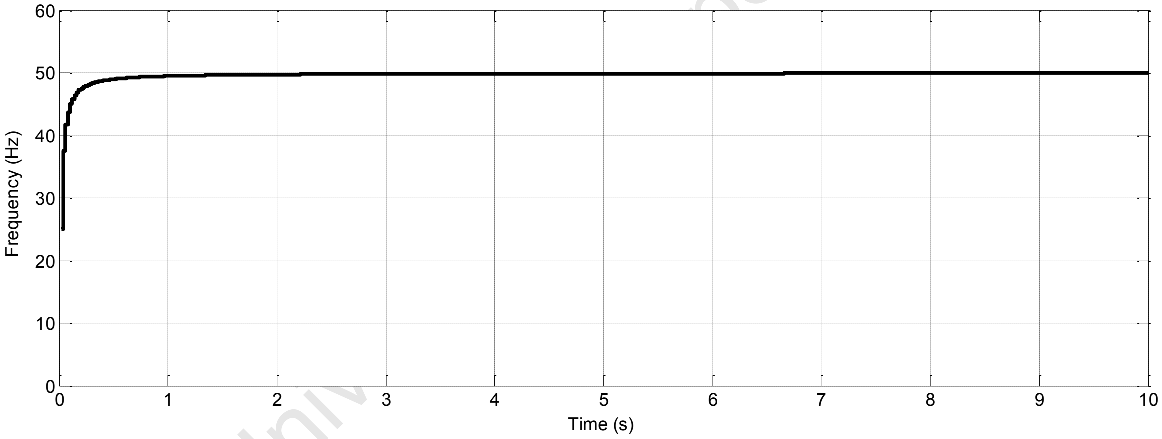


Figure 5.10 System Frequency during isolated mode of operation

Figure 5.10 shows that again the system frequency of the utility side is 50Hz. In this case the frequency reaches 50Hz faster because the system consists of a PV Generation plant and a small local load. Therefore the system reaches stability and the nominal frequency faster.

5.2 Overcurrent Relay Testing

Test 1 – Microgrid Fault in Isolated Mode of Operation

5.2.1 Solar PV plant

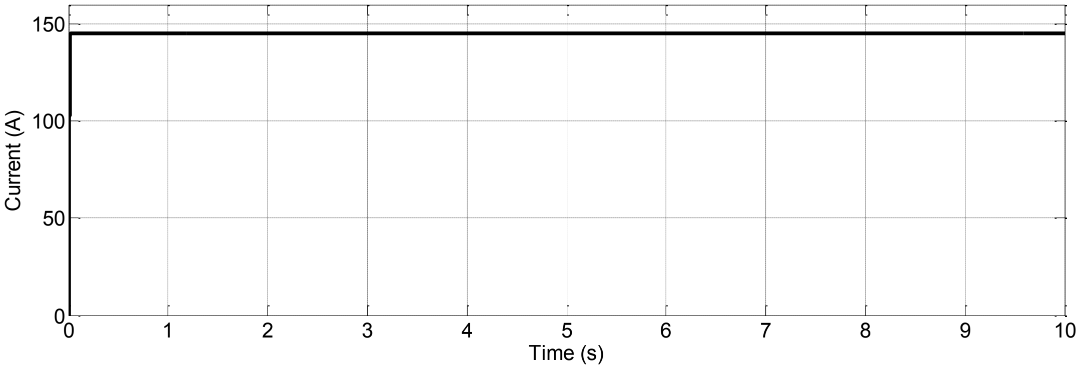


Figure 5.11 PV Generation Current RMS before and during fault

The signal displayed in Figure 5.11 resembles the current output of the PV generation plant for a period starting before the fault occurred at 2 seconds and ending once the fault had occurred. It is evident that the current output does not vary due to the 3-phase fault on the system. This proves the fact that faults don't increase the fault current from the PV generator.

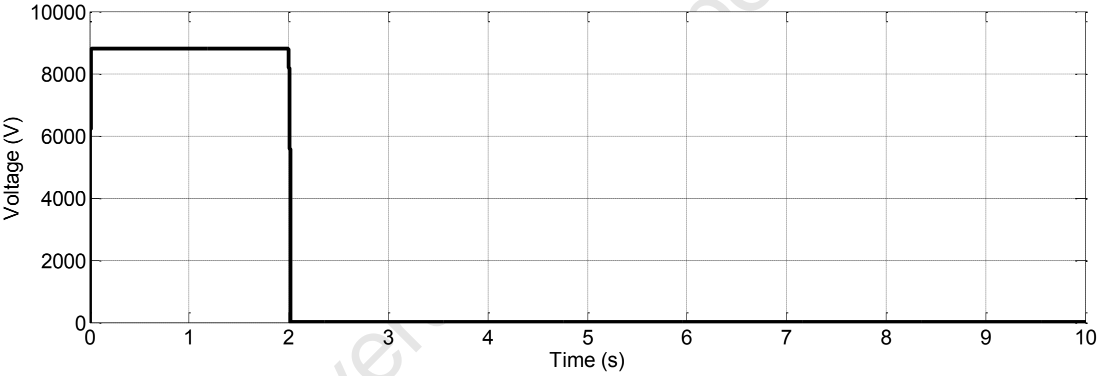


Figure 5.12 Busbar 1 Voltage RMS before and during fault

Unlike the current output from the PV generation plant, the voltage level at the grid connection busbar (busbar 1) does vary due to the fault. Figure 5.12 shows this phenomenon, the voltage level before the fault is the nominal voltage level and the voltage after the fault drops to almost 0V. The RMS value of this signal for the entire duration of the simulation is demonstrated in section 9.

5.2.2 Local Load

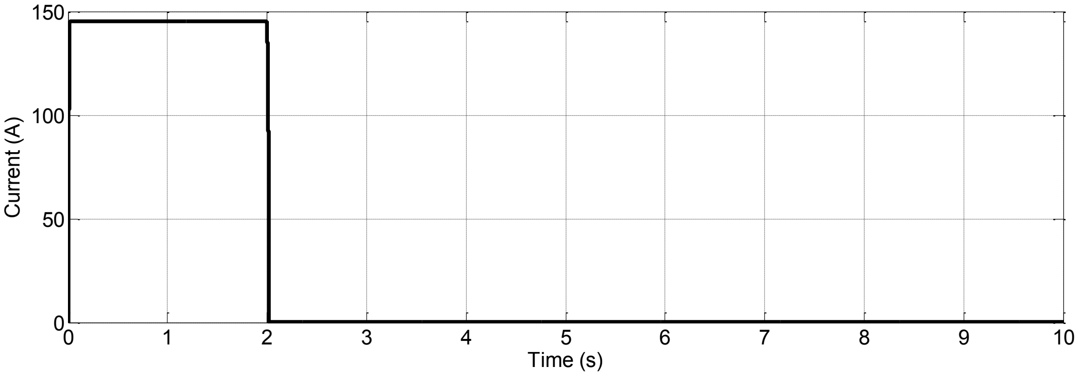


Figure 5.13 Local load current RMS before and during fault

The fault is simulated to occur between the PV source and the local load. For this reason once the fault occurs the local loads become deprived of any current. In Figure 5.13 the local current due to the event can be seen. After the fault, the current to the load is approximately 0A. The load still receives some leakage current, but this would not be sufficient to sustain a considerable load.

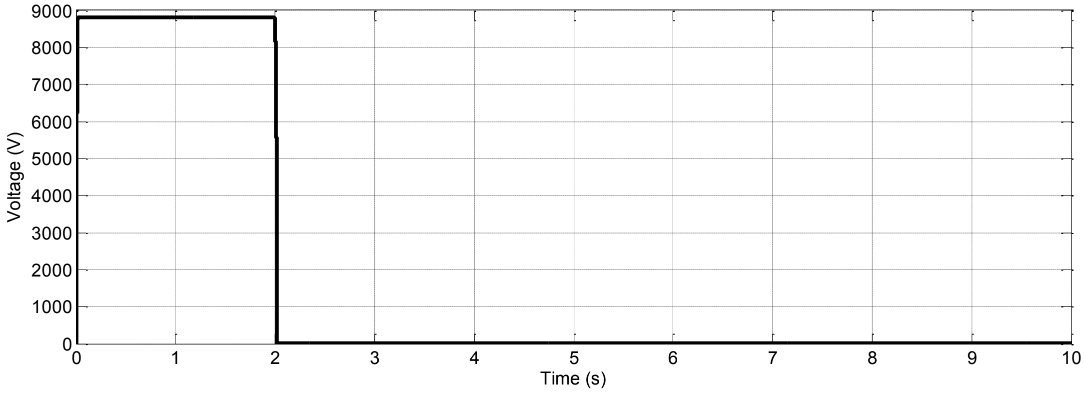


Figure 5.14 Local load voltage RMS level before and during fault

The Local load voltage is also affected by the fault. Figure 5.14 shows that the local load voltage drops due to the fault that occurs. The voltage at the load follows a similar pattern to the current. Again this is a case where the drop is not to zero, there is a small voltage drop across the load even after the fault has occurred.

5.2.3 System Frequency

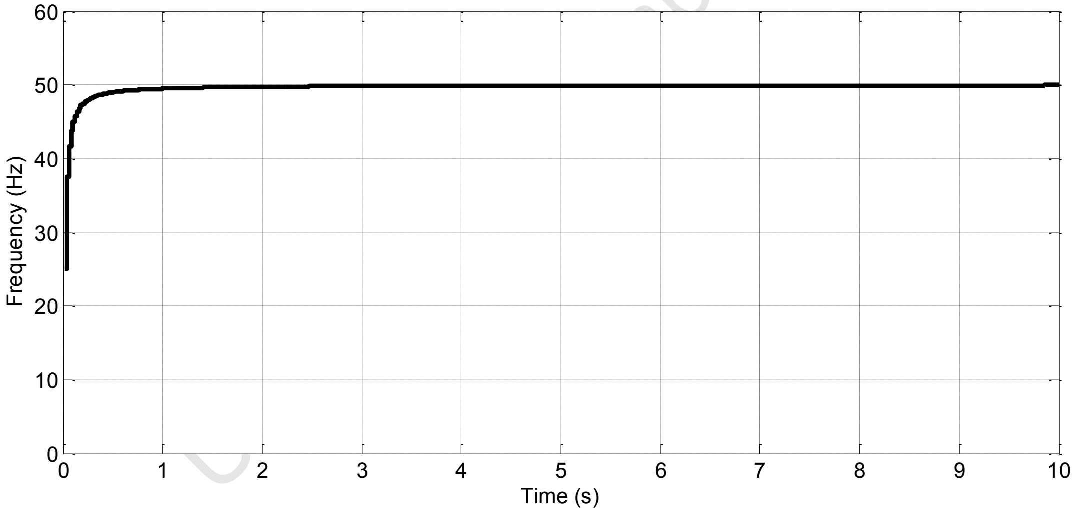


Figure 5.15 System frequency before and during fault

The system frequency does not seem to be affected by the fault. The frequency remains constant at 50Hz during the fault. Figure 5.15 shows the system frequency throughout the duration of the simulation.

5.2.4 Overcurrent Relays

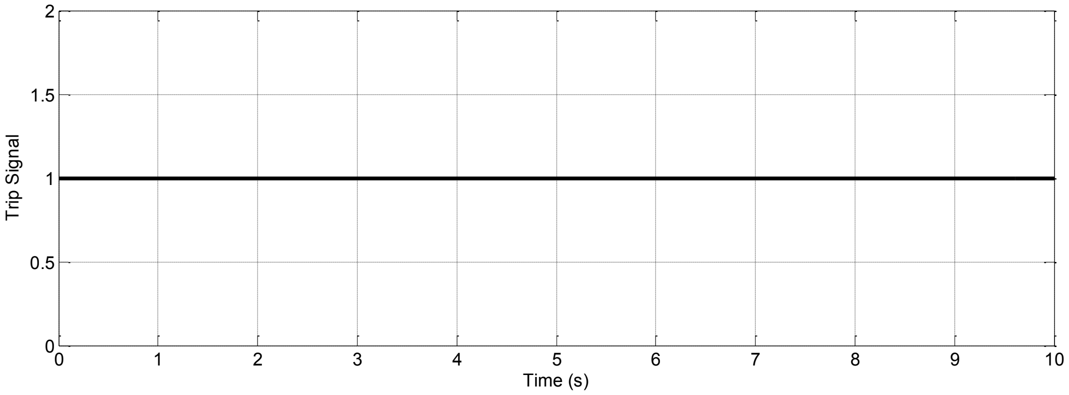


Figure 5.16 Overcurrent Relay 1 Trip Signal during Test 1

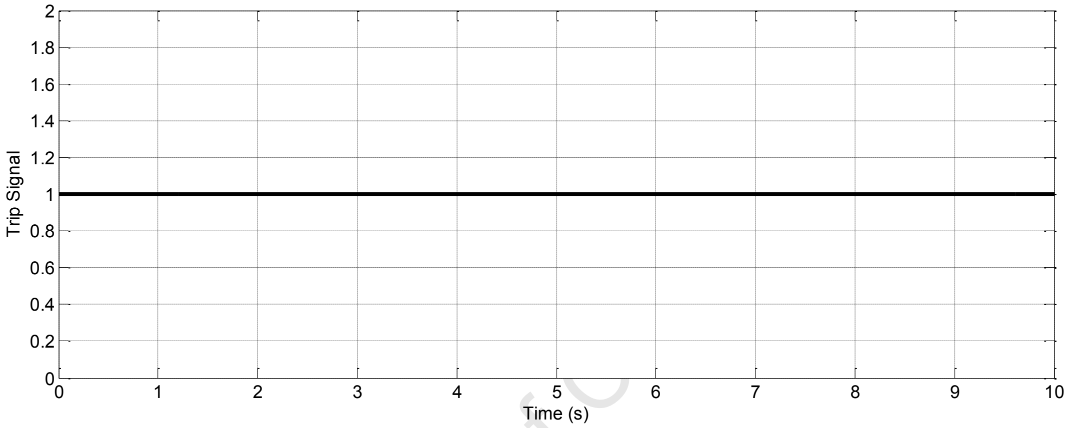


Figure 5.17 **Overcurrent Relay 2 Trip Signal during Test 1**

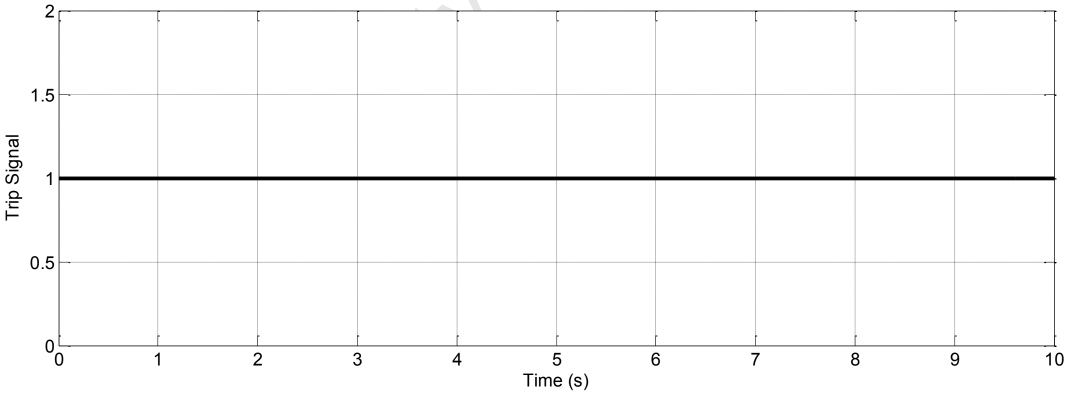


Figure 5.18 **Overcurrent Relay 3 Trip Signal during Test 1**

As can be seen in Figures 5.16 to 5.18, none of the OC relays triggered a C to open in this test case, this is because no overcurrent was seen by the relays. This relay blinding is caused by the fact that solar PV generation output current is dependent on the solar radiation it absorbs and not dependent on the of the fact that there is a fault in the system. A different type of relay should be added to the protection system to accommodate this type of fault.

Test 2 – Microgrid Fault in Grid Connected mode

5.2.5 Busbar 1

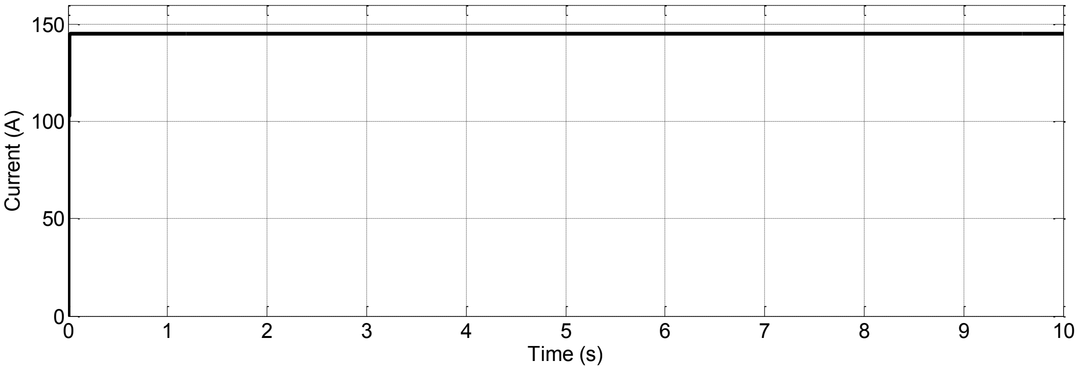


Figure 5.19 PV Generation Current RMS output before and during a fault in Test Case 2

The current flowing through busbar 1 is primarily supplied by the Distributed Generator. In previous tests we have established that the DG current supply remains constant regardless of whether there is a fault in the system or not. Figure 5.19 shows the current out of the PV generation before and during the fault. The Current level remains constant.

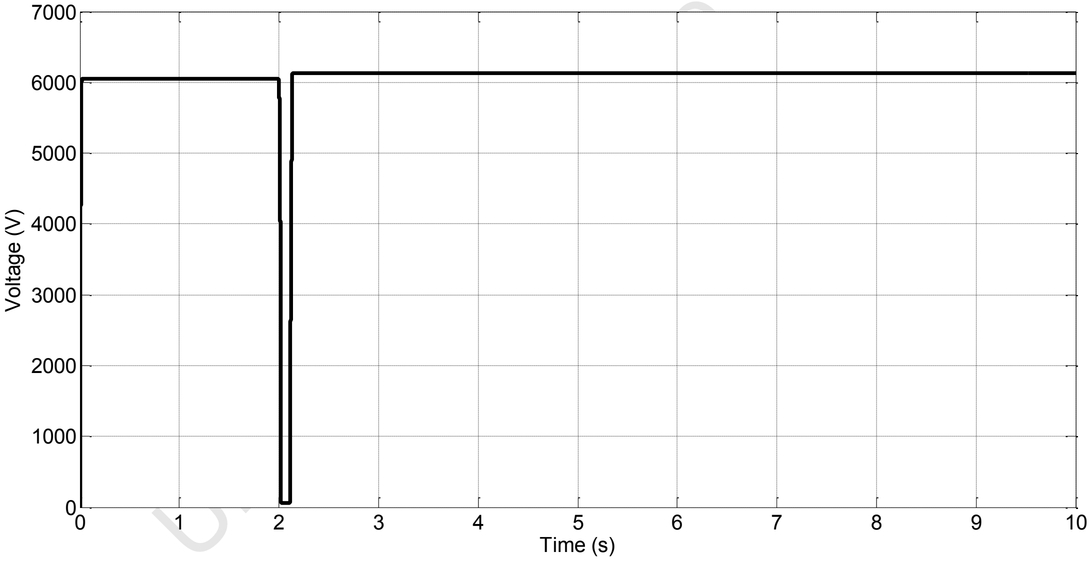


Figure 5.20 PV Generation Voltage RMS before, during and after a fault in test case 2

Unlike the Current levels, the voltage levels at the PV output during a fault do vary considerably. The voltage drops during the fault this can be seen in Figure 5.20. In this case this voltage is restored once the fault is cleared from the microgrid. In this case the scheme has successfully identified a fault and cleared it efficiently.

5.2.6 Busbar 2

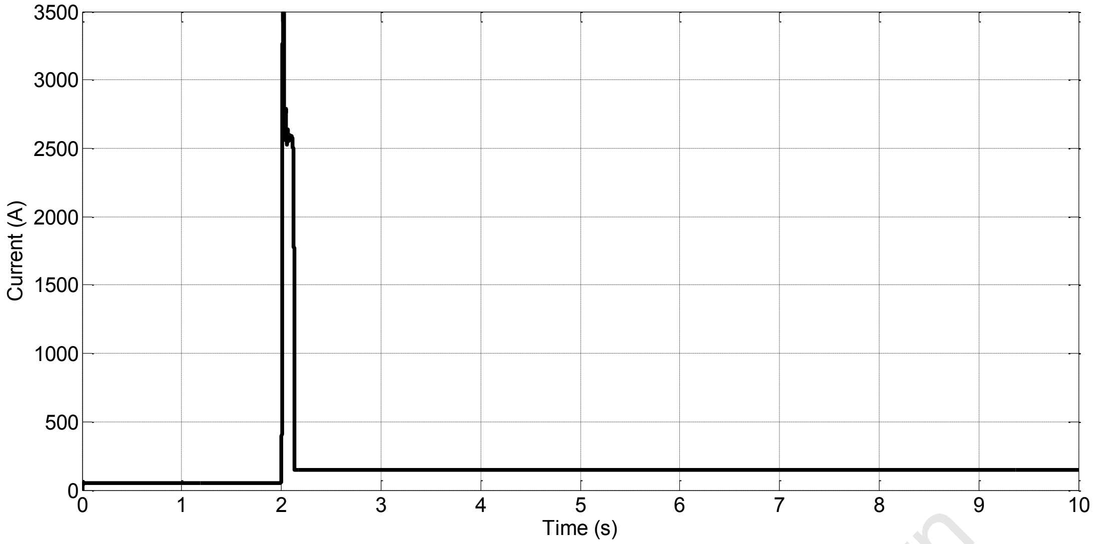


Figure 5.21 Utility Source current RMS before, during and after a fault in test case 2

The current at busbar 2 is primarily supplied from the utility source. Therefore the current trend in this busbar resembles the current output at the utility source. It is evident from Figure 5.21 that the current increases during the fault, this current contributes mostly to the fault current, and a very small portion of this current is supplied to the loads. This will be further demonstrated in the other results of this test.

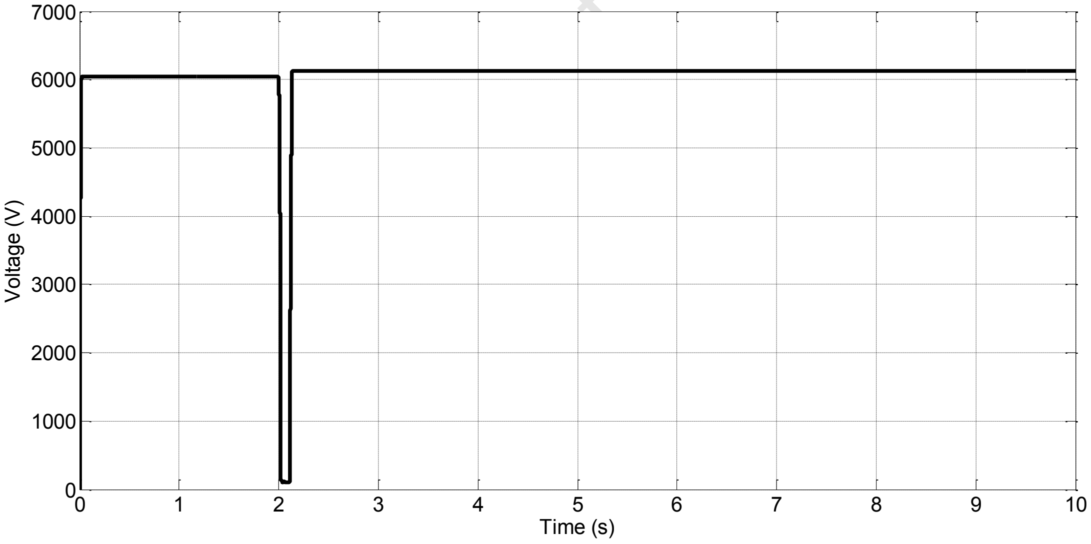


Figure 5.22 Utility Source Voltage RMS before, during and after fault in Test Case 2

Much like the DG voltage the utility source voltage drops during the fault. This drop is way below the voltage drops accepted by the authorities. It is important to restore the voltage to the correct levels. In this test case the utility network voltage is restored at the same time as the Microgrid voltage, this is an important factor to consider when networks need to be re-synchronised. Figure 5.22 clearly shows the voltage signal during the entire simulation. The AC voltage signal for the critical points of the simulation is displayed in Figure 9.16 in section 9.

5.2.7 Local Load

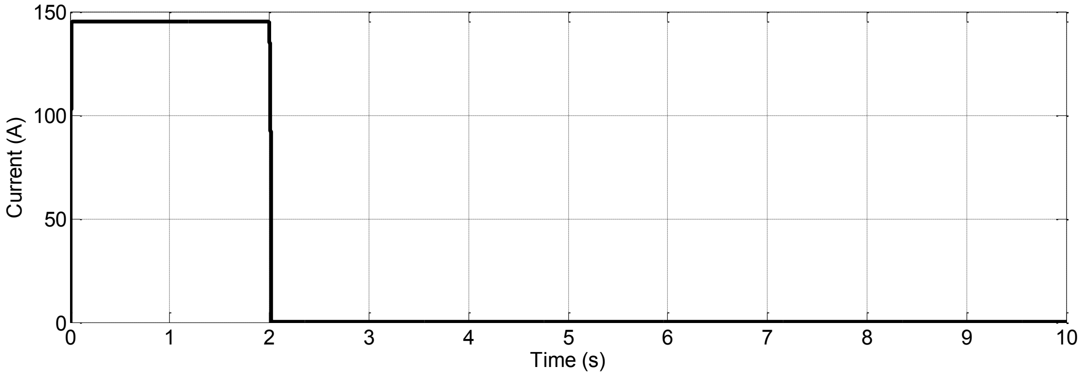


Figure 5.23 Local load current RMS before and during the fault in Test Case 2

The local load is the most affected during this test case. The fault occurs in close proximity to the local load, point A, as shown in Figure 4.4. During the fault, the local load does not receive any current from the power generation sources because all of the current is directed to the fault. Once the fault is cleared the local load still does not receive any current because the circuit breaker opens to isolate the fault hence the load also becomes isolated from any of the PV generation. Figure 5.23 depicts the local load current during the simulation. In a practical scenario, an operator would have to go to the fault site, identify the fault and manually fix it before the circuit breaker can be reclosed.

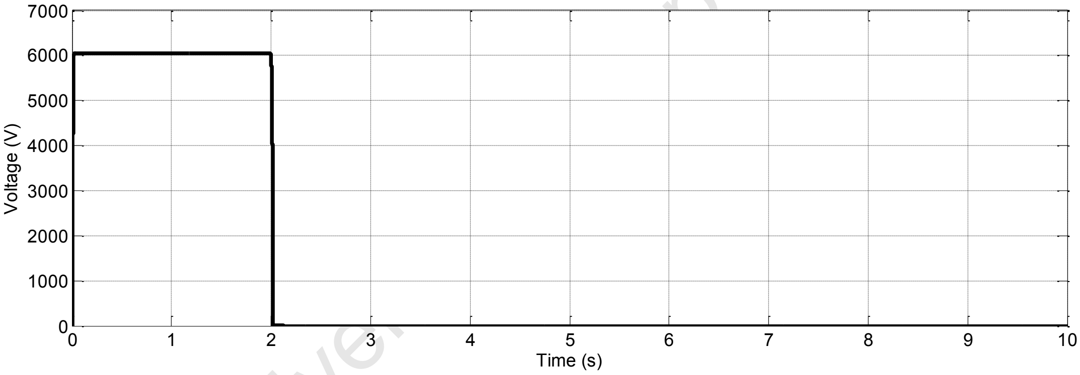


Figure 5.24 Local load voltage RMS before and during a fault in Test case 2

The Voltage levels for the local load in this case follow a similar pattern to the current levels. The voltage is decreased instantly after the fault occurs. This is because the load is separated from the generation sources. Like the current, the voltage is not restored in this test case. It would only be restored once the fault is cleared or the fault causing equipment is repaired.

5.2.8 System Frequency

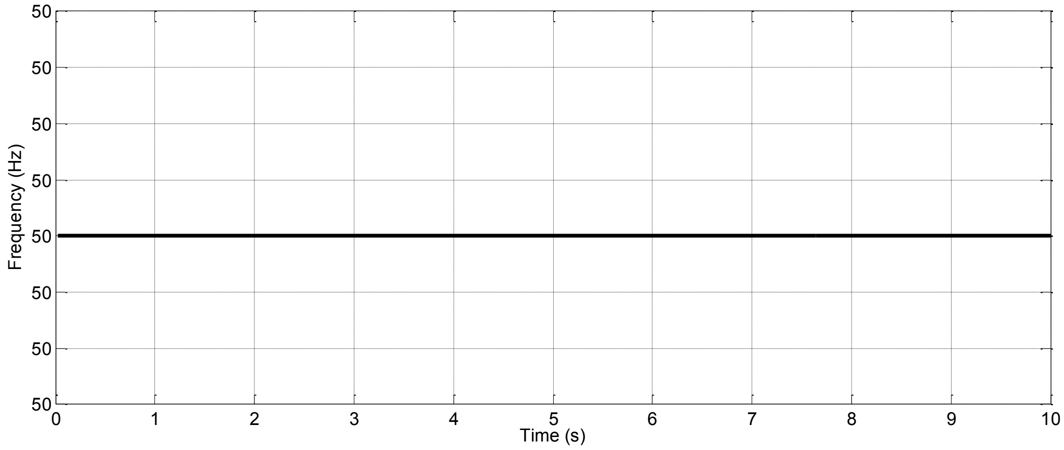


Figure 5.25 System Frequency during Test case 2

The system frequency in this test case remained constant at 50Hz. This is shown in Figure 5.25.

5.2.9 Overcurrent Relays

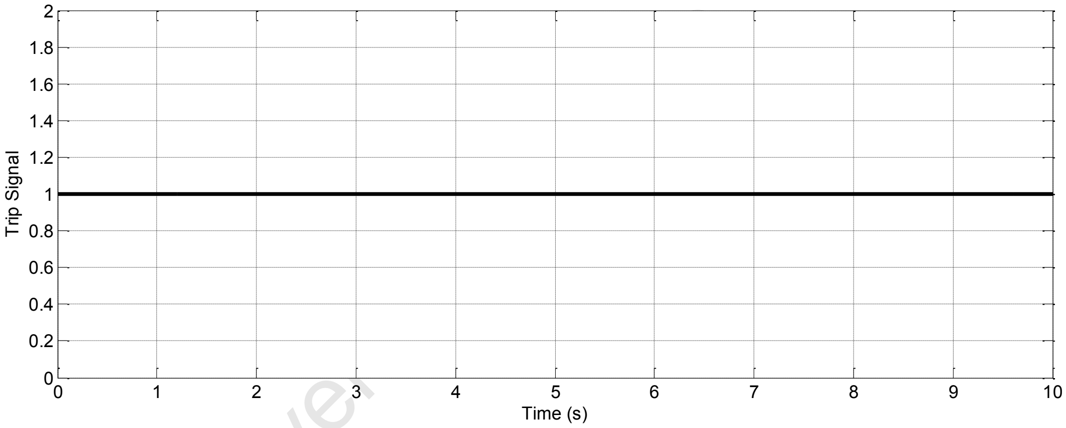


Figure 5.26 Overcurrent Relay 1 Trip Signal during Test case 2

Relay 1 was not expected to cause a trip in this test case, Figure 5.26 shows that it didn't. This relay would have seen the same amount of current as in the normal case because it monitors the current from the PV generation which remains unchanged.

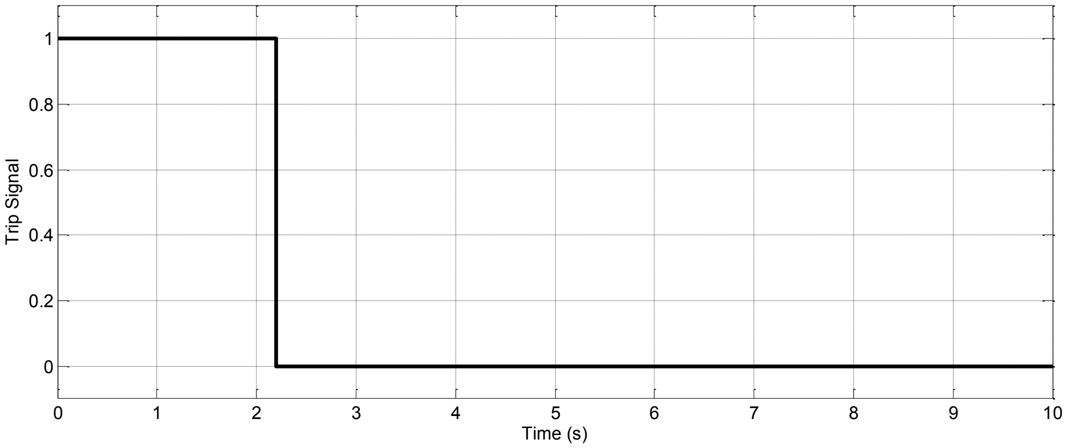


Figure 5.27 Overcurrent Relay 2 Trip Signal during Test Case 2

Relay 2 was the responsible relay in detecting the fault and opening a relevant circuit breaker to isolate the fault. This relay was closest to the fault therefore it saw the highest fault current, at a value of 3646A RMS (an addition of the Solar PV current and the Utility Source Current), for this reason it had the shortest trip time of the relays in the scheme. The scheme has proven to be effectively coordinated with Relay 2 as primary protection and Relay 3 as back-up protection. Figure 5.27 shows the trip signal from relay 2.

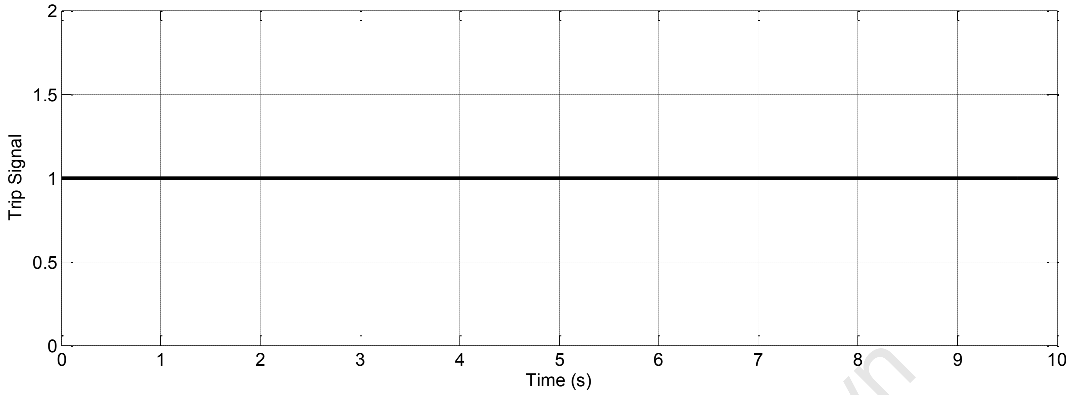


Figure 5.28 Overcurrent Relay 3 Trip Signal during Test Case 2

Relay 3 acts as a back-up relay in this test case. If Relay 2 had failed send a trip signal for the CB to open, this relay would have become active in sending the trip signal to the circuit breaker. It would have been inefficient to have them open at the same time due to a single fault in the system.

Test 3 – Utility Fault in Grid Connected mode

5.2.10 Utility Load

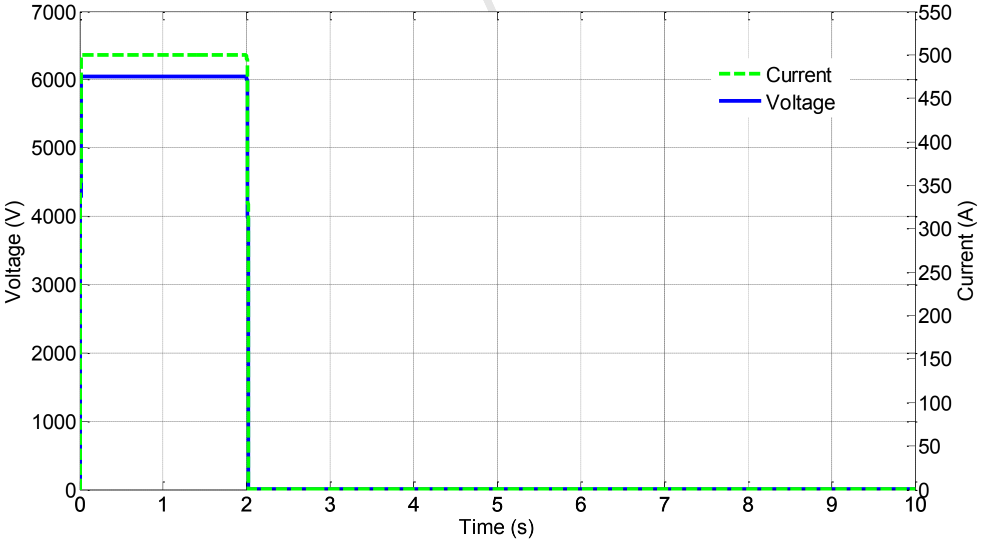


Figure 5.29 Utility Load Current and Voltage RMS before and during the fault in Test Case 3

The fault on the Utility network positioned in Point B as depicted in Figure 4.5, has a major impact on the utility load. The fault occurs at 2 seconds and from then the utility load is deprived of any current. This is evident in Figure 5.29. The current that was supplied to the utility load before the fault occurred is redirected towards the fault. In this case again the fault is not cleared, it is only isolated or separated from the Microgrid network by opening the SS at the point of common coupling. For this reason, it continues to have an effect on the utility load even after the relays have opened the relevant circuit breakers.

The Utility load voltage behaves in a slightly different manner to the current. The voltage (also displayed in Figure 5.29) is restored once the fault is isolated. This is an important point to consider, it means that the source continues to supply the fault current at the same voltage level as when there was no fault.

5.2.11 Local Load

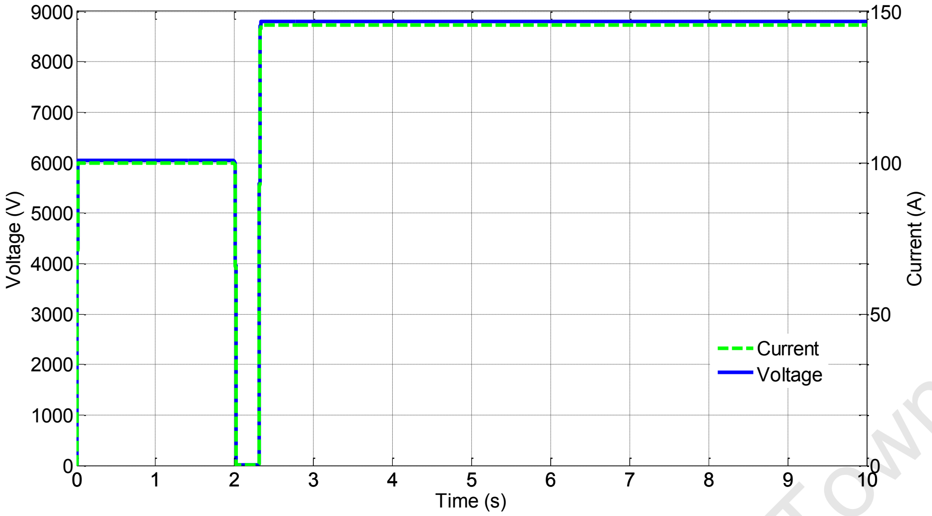


Figure 5.30 Local Load Current and Voltage RMS before, during and after the fault in Test case 3

Figure 5.30 shows that the fault on the Utility side while the microgrid is in grid connected mode has an effect on the local load current. Once the fault occurs the local load is deprived of any current. Only after the fault is cleared does the current get restored. The time to fault clearance is slightly longer in this case than the previous case. This is because the time setting in Relay 3 is slightly delayed in comparison to the time set in Relay 2.

The voltage level in the local load followed a similar pattern to that of the current, this phenomenon is depicted in Figure 5.30. The voltage levels are restored once the fault is cleared. These results show that the relaying scheme was successful in restoring microgrid operation after a fault occurred on the utility network.

5.2.12 Utility Source

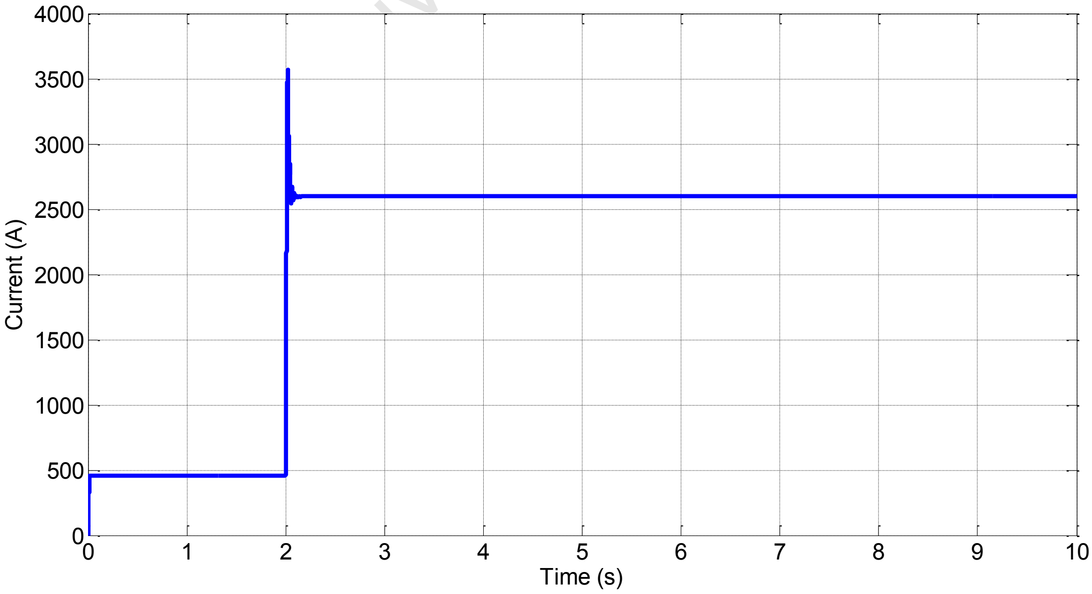


Figure 5.31 Utility Source Current RMS before and during the fault in Test case 3

The Utility Source is the one that provides the additional fault current during the fault. Figure 5.31 shows the increase in current supplied by the Utility source during the fault. The reason why this current is not reduced after the fault is isolated is because the scheme provided in this research focuses on protecting the microgrid only. In a practical setting an extra circuit breaker would be added to the scheme to provide protection to the utility grid as well.

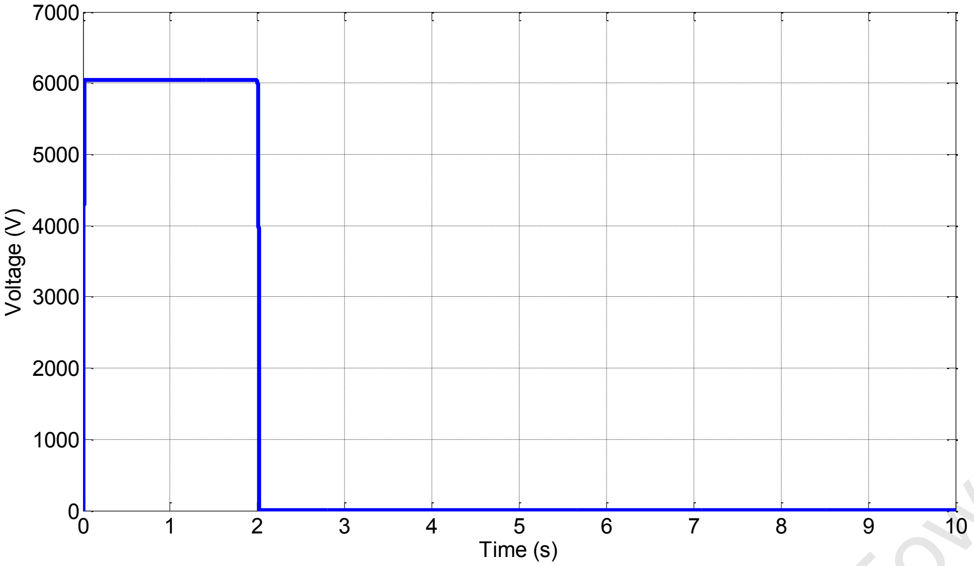


Figure 5.32 Utility Source Voltage RMS before and after the fault in test case 3

The voltage at the Utility Source is also affected continuously, even after the fault is isolated from the microgrid. We can see in Figure 5.32 that the voltage reduces considerably once the voltage drops and is not restored. The AC waveform for a short period of the simulation is displayed in Figure 9.17.

5.2.13 Distributed Generator

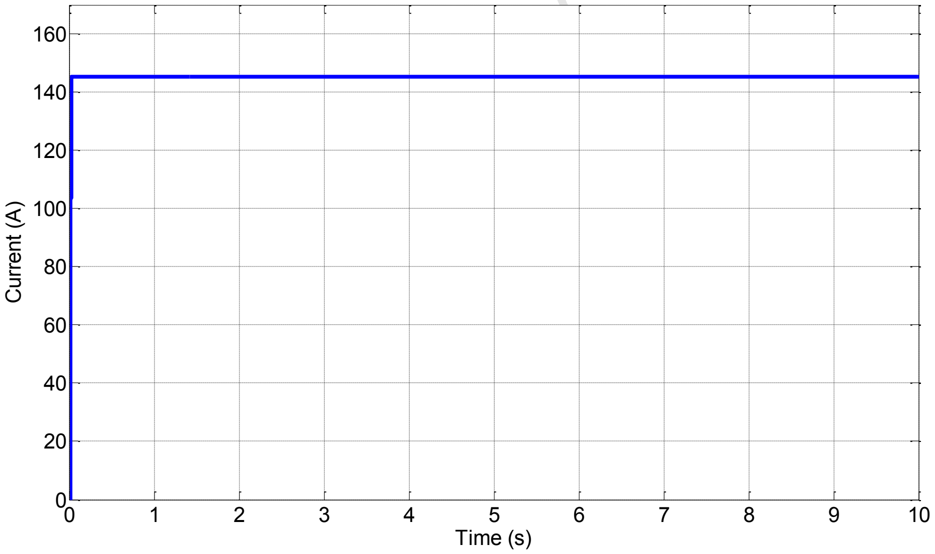


Figure 5.33 PV Generation current RMS during Test Case 3

The current signal out of the DG is shown in Figure 5.33. This signal remains unchanged during the fault on the utility network.

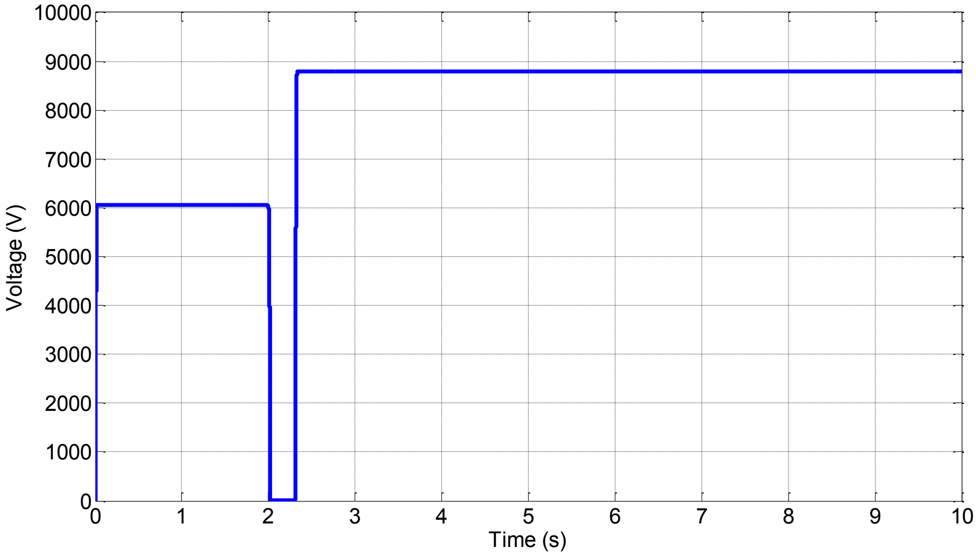


Figure 5.34 PV Generation voltage RMS before, during and after the fault in Test Case 3

The voltage level of the DG changed during the fault and was restored after the fault was isolated. Voltage restoration was important in making the microgrid function correctly once the fault was cleared. The fault clearance time witnessed by the DG is the same witnessed by the local load. Only once the fault is cleared, the DG and local load work together to form a microgrid in stand-alone mode of operation.

5.2.14 System Frequency

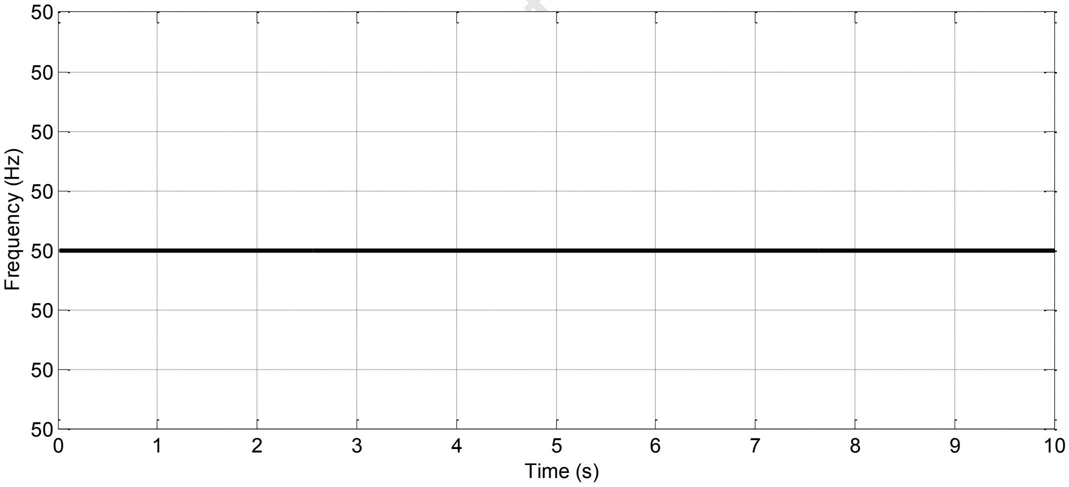


Figure 5.35 System Frequency during Test Case 3

The system frequency is constant throughout the simulation of a fault in Test Case 3.

5.2.15 Overcurrent Relays

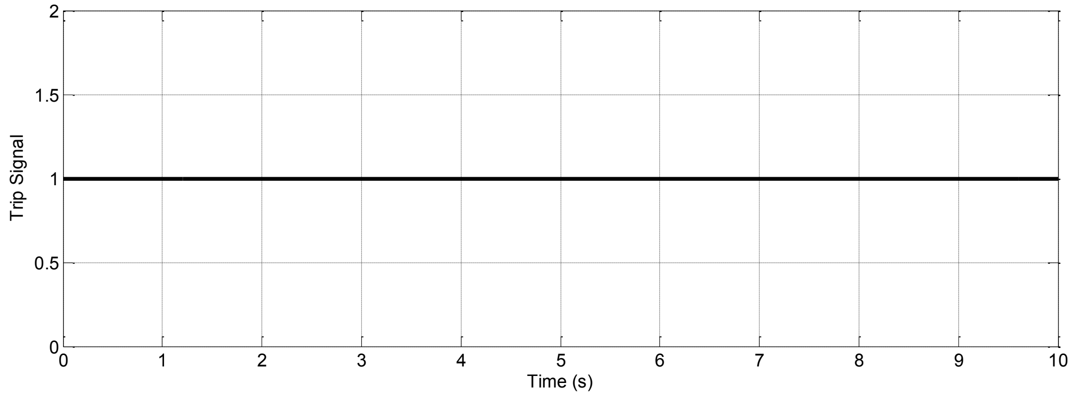


Figure 5.36 Relay 1 Trip Signal during test case 3

Relay 1 again does not recognise the fault has occurred because the current from the DG does not increase during the fault. This is represented by the lack of change in the output signal as shown in Figure 5.36.

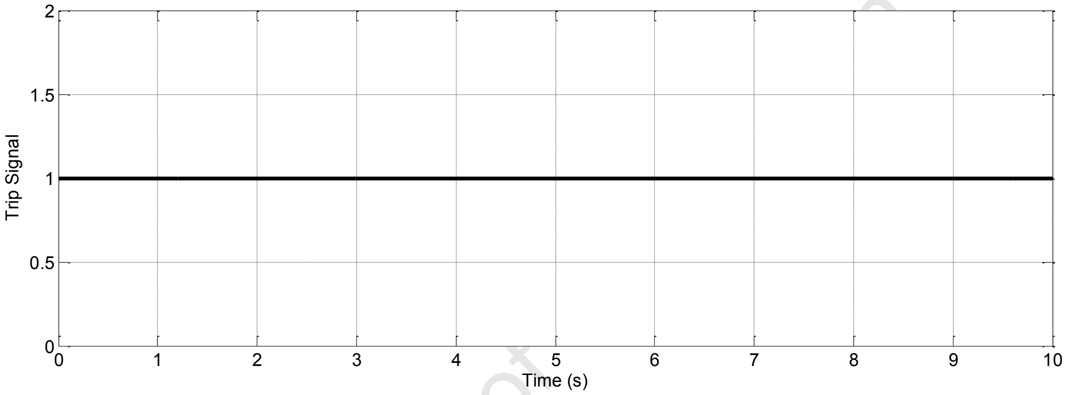


Figure 5.37 Relay 2 Trip Signal during Test Case 3

During the fault Relay 2 would have seen less current than it did in normal mode of operation, for this reason it is not expected to trip and it doesn't trip. The output signal is unchanged during the simulation as shown in Figure 5.37.

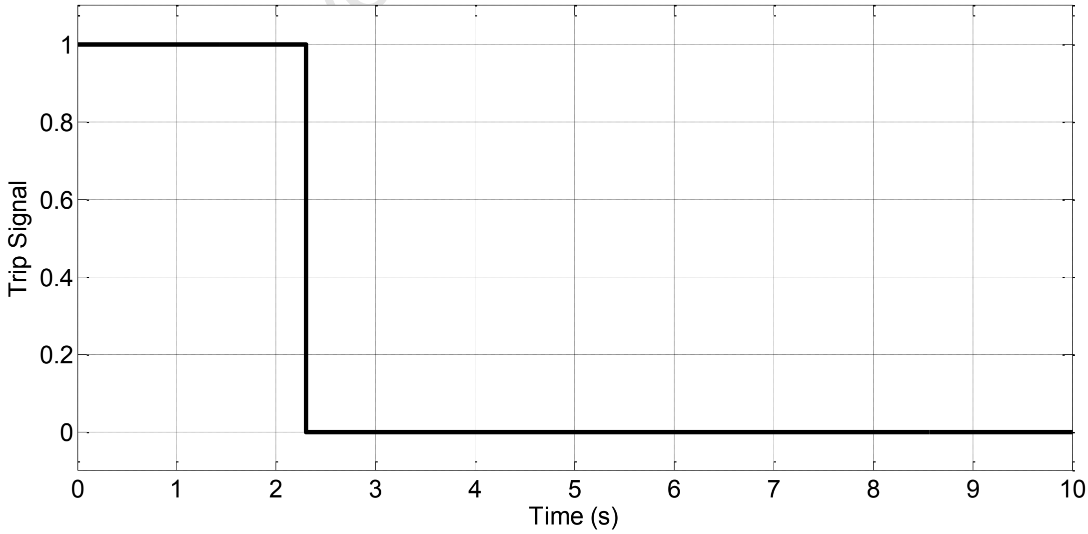


Figure 5.38 Relay 3 Trip Signal during Test Case 3

Relay 3 is the relay expected to send a trip signal to the circuit breaker for the fault that occurred. Figure 5.38 shows that the trip signal was sent 0.3s after the fault had occurred. The operation of this relay shows that the scheme is functional for protecting the microgrid against faults in the utility grid.

5.3 Reverse Power Relay Testing

5.3.1 Test 4- Loss of Mains due to open utility switch, large DG Capacity.

i. PV Generation

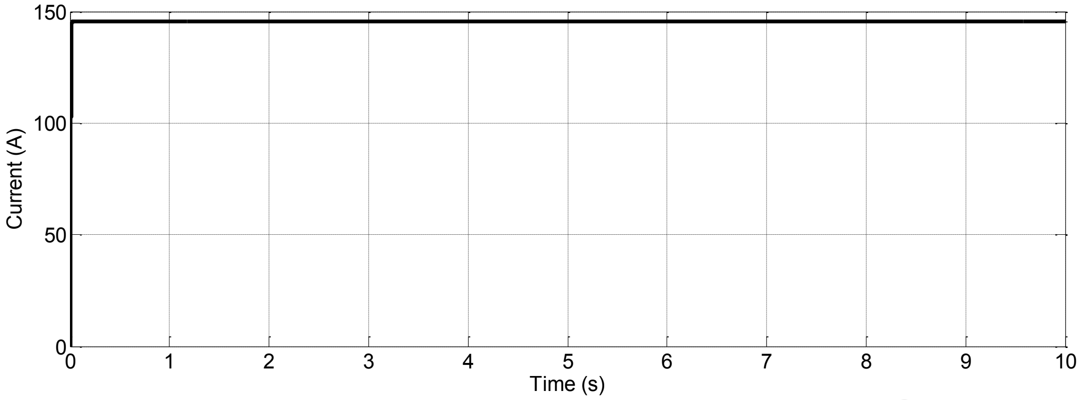


Figure 5.39 PV Generation Source Current RMS during Test Case 4

The current output from the PV source remains constant during the abnormal event. The PV station current is unaffected by the loss of mains. This shows solar generation stability as a current source. The current remains constant at 366A peak to peak.

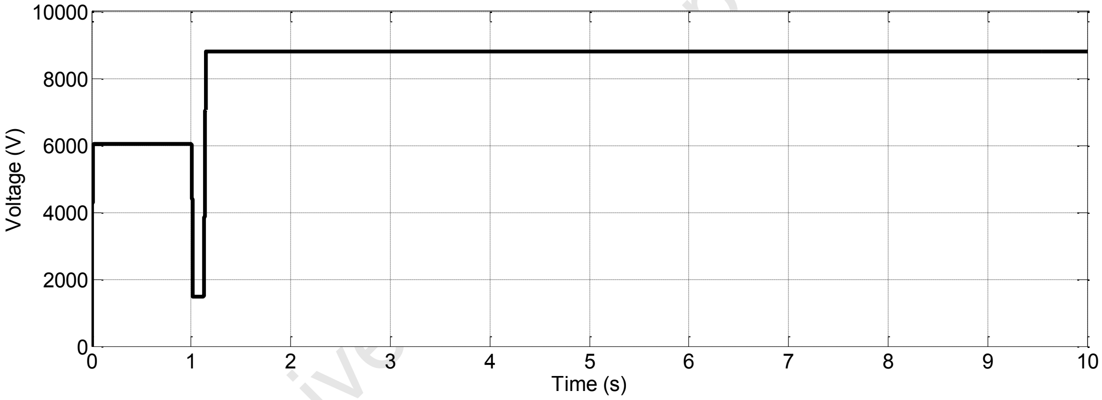


Figure 5.40 **PV Generation Source Voltage RMS before, during and after the event in Test Case 4**

In this test case the voltage level dips when the loss of mains event occurs. The dip is caused by the overload of the DG, the system is greatly affected by the switching. This dip lasts from 1s when the switch is opened to 1.13s when the SS is opened and the microgrid is isolated from the utility grid. This restoration of voltage levels is a demonstration that the protection system is effective in protecting the microgrid against loss of mains.

ii. Utility Generation Source

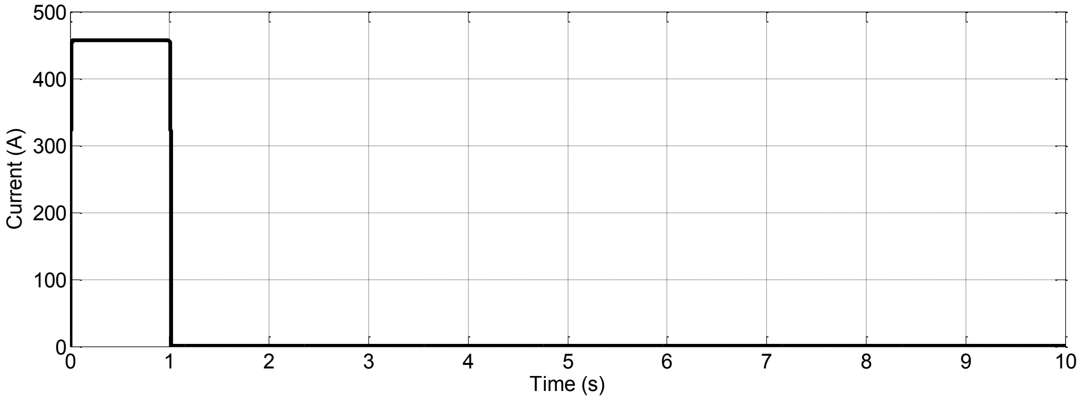


Figure 5.41 Utility Generator current RMS during Test Case 4

The utility current level drops once the switch is opened, this is because it becomes an open circuit with no load to feed. This current does not return to its normal value for the rest of the simulation because the switch that causes the loss of mains is not reclosed. A small ripple current is visible, this would be common in a real system but it has very little effect.

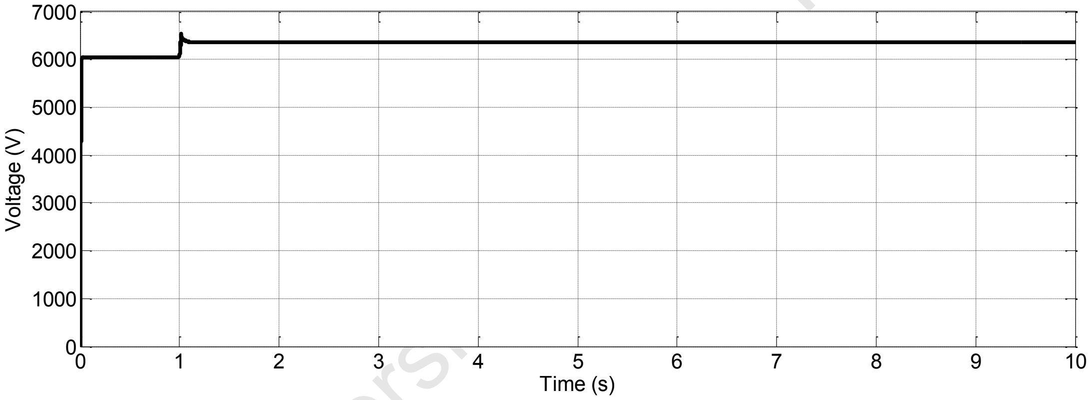


Figure 5.42 Utility Generator voltage RMS during Test Case 4

The voltage level in the utility source increases slightly after the switch is opened. This is also an effect of the loss of load. The voltage drop in the system becomes less, therefore the voltage measured at the output of the generator becomes higher.

iii. Utility Load

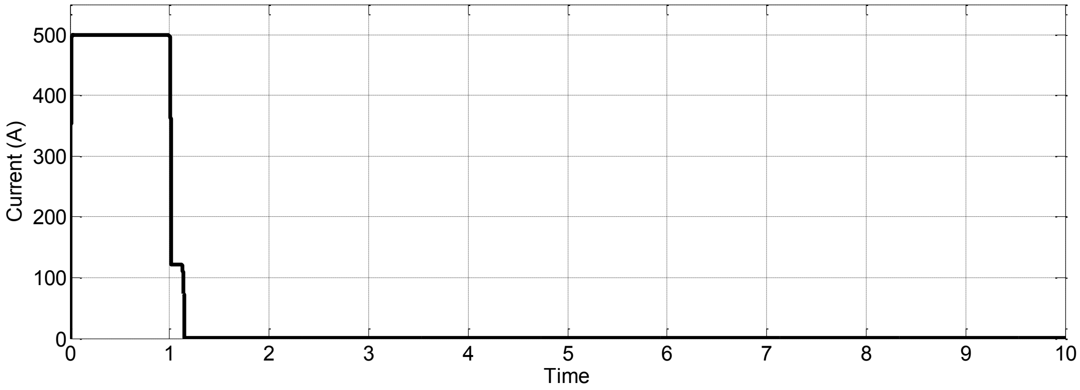


Figure 5.43 Utility Load Current RMS before, during and after the event in Test Case 4

The current at the Utility load is highly affected by the loss of mains event. Before the switch is opened the current is at nominal level and it is predominantly supplied by the utility generator. However, when the utility switch is opened the current level becomes less because it is supplied from the DG. This DG has a small maximum capacity. This is not an efficient way to supply the utility loads and it compromises the quality of supply to the loads in the microgrid. Therefore it is important that the microgrid becomes isolated at this point. At 1.13s when the SS is opened the current becomes approximately 0A, this is because this load becomes completely separated from any power sources. This is the expected result from this test case.

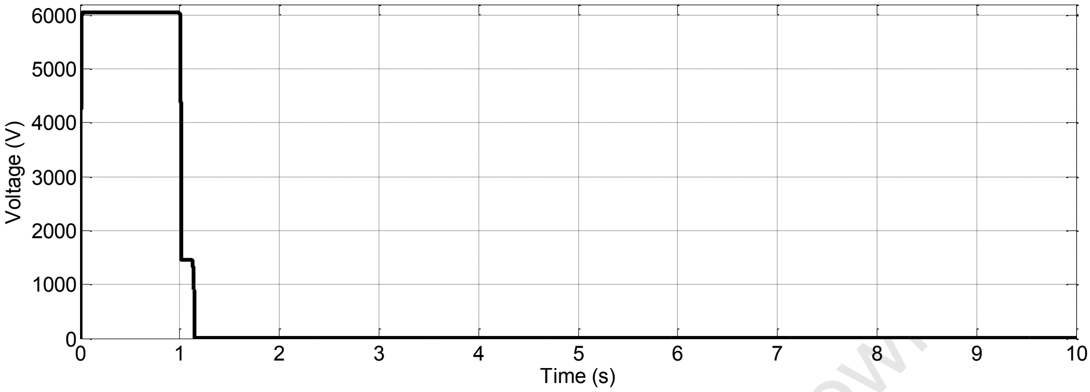


Figure 5.44 Utility Load Voltage RMS during Test Case 4

The voltage profile again shows a variation once the switching takes place. There is a significant voltage drop when the utility load is supplied by the DG. The overloading of the distributed generator causes a voltage dip throughout the power system, this is one of the reasons why it is not advised to maintain the microgrid in grid connected mode after a loss of mains event. Once the SS is open the voltage drops to approximately zero because the load is not connected to any power source.

iv. Local Load

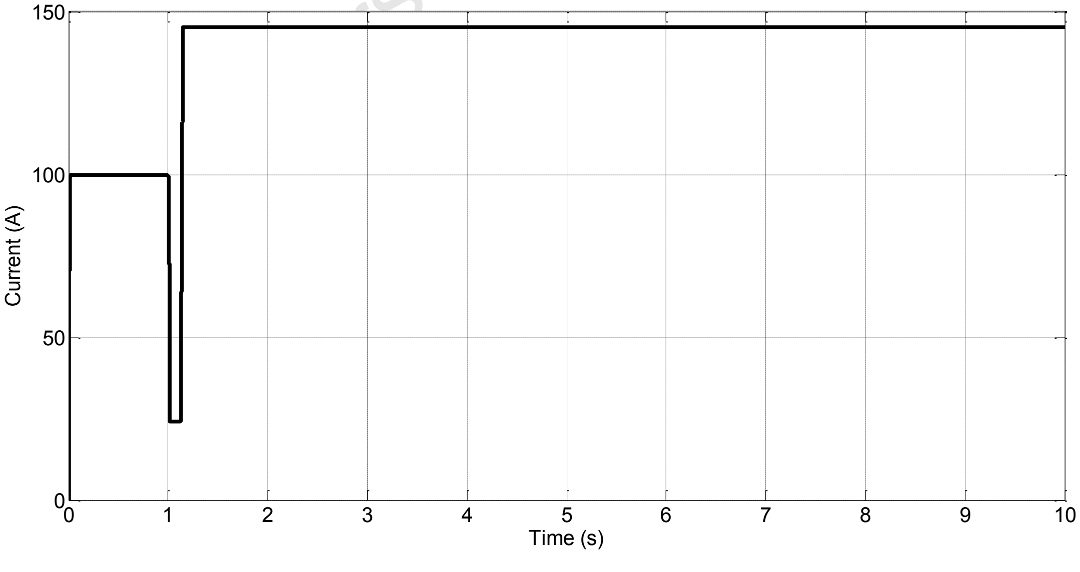


Figure 5.45 Local Load Current before, during and after the event in Test Case 4

The local load current is displayed in Figure 5.45, the characteristics of the display are aligned with the requirements of effective protection systems. Once the microgrid becomes separated from the utility grid the current is restored. When the microgrid is isolated all of the current produced by the DG is supplied to the local load, therefore the current consumed by the local load after the SS is opened is slightly higher than the current consumed before the switching event occurs.

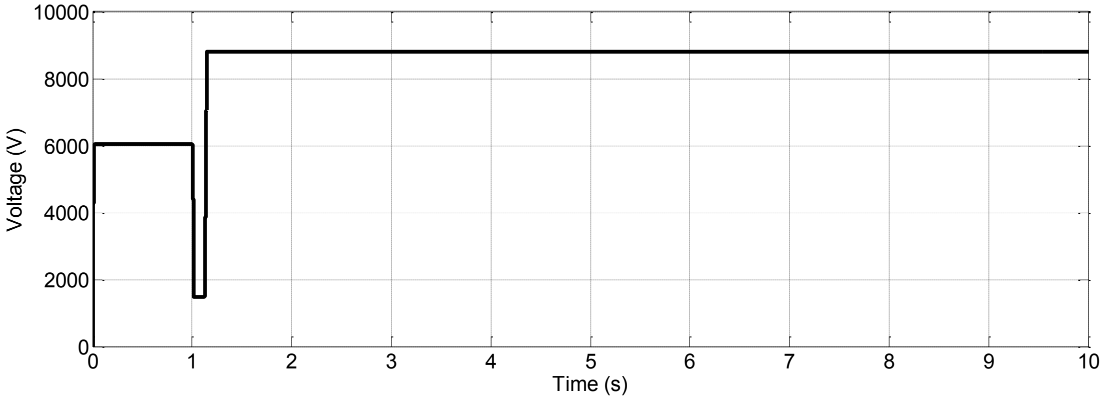


Figure 5.46 Local Load voltage before, during and after the event in Test Case 4

The voltage level shows similar characteristics to the current consumed. During the abnormal period the voltage dip is similar to that of the utility grid. When the microgrid becomes isolated, the system becomes more stable than before with the voltage level being closer to the nominal level.

v. Trip Signal

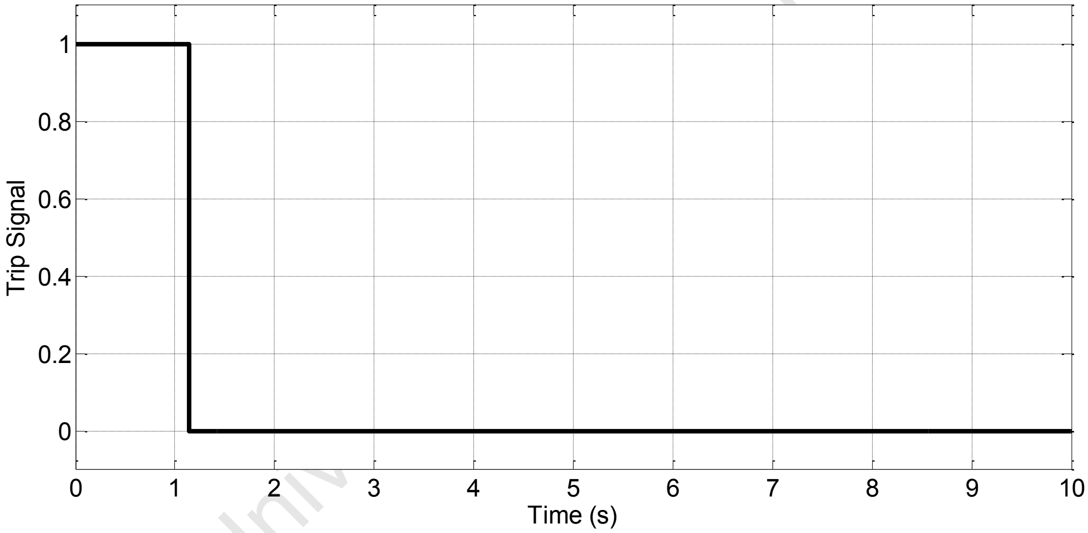


Figure 5.47 Reverse Power Relay Trip Signal during Test Case 4

The relay sends out a trip signal at 1.13s after the programmed 0.13s delay. This causes the SS to open and the microgrid to be isolated.

vi. System Frequency

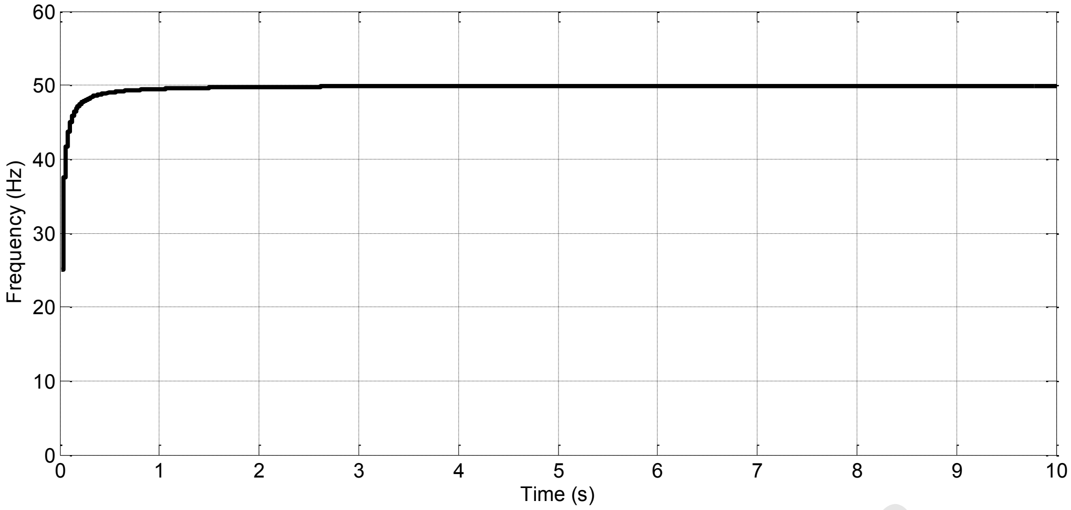


Figure 5.48 Microgrid System Frequency during Test Case 4

The system frequency seems to be unaffected by the loss of mains event due to opening a utility switch.

5.3.2 Test 5 - Loss of Mains due to a 3-phase Fault, with large DG Capacity.

i. PV Generation

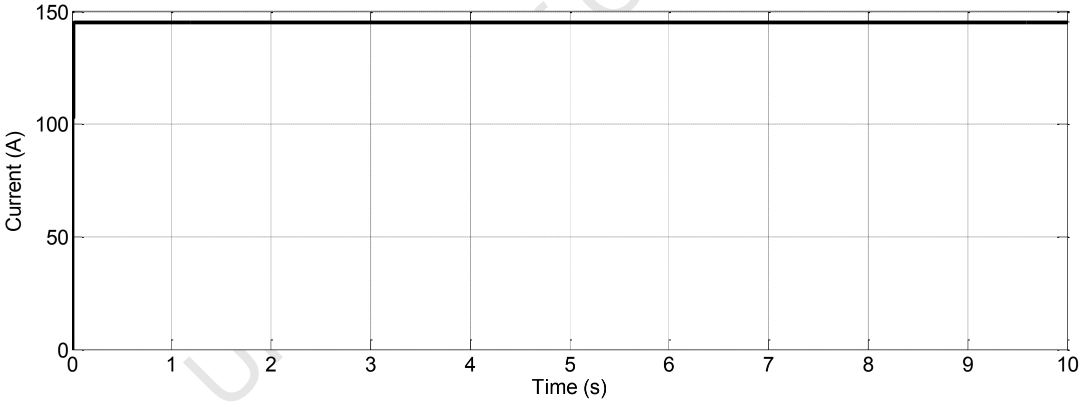


Figure 5.49 PV Generation current output during Test Case 5

As seen in test case 1, the current output at the PV generator is constant throughout the fault. This is consistent with the idea of a PV plant being a source of constant current.

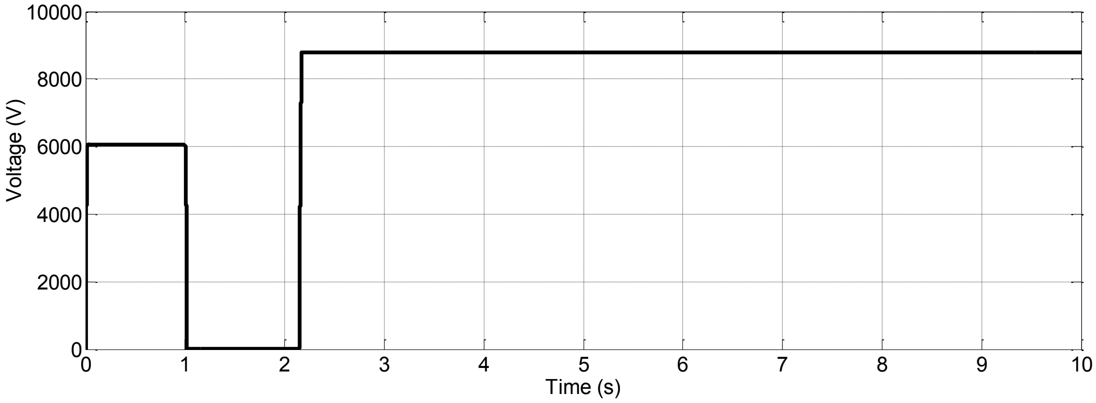


Figure 5.50 PV Generation voltage RMS before, during and after the event in Test Case 5

The voltage level is again affected by the fault on the utility grid. The voltage drops because of the system overload caused by the fault. Once the microgrid is isolated the voltage level is restored and the microgrid begins operating at optimal level again.

ii. ***Utility Generation***

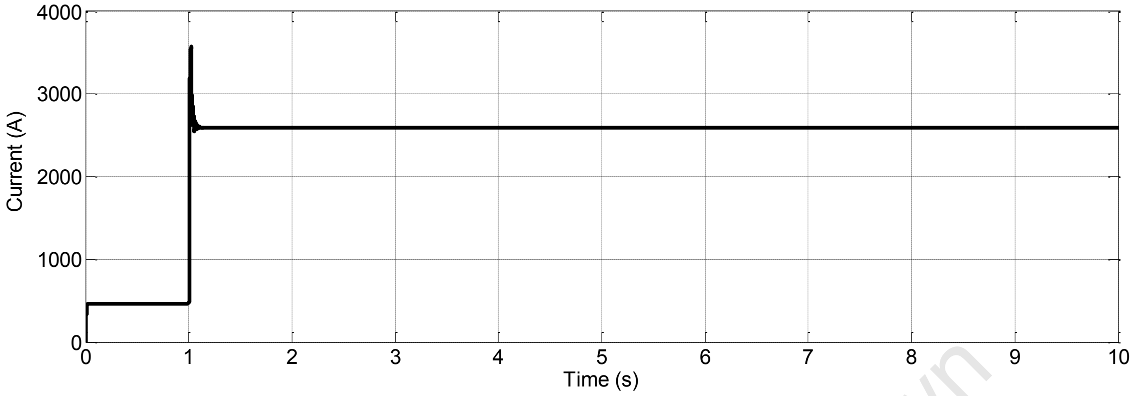


Figure 5.51 Utility Generator output current RMS during Test Case 5

The Utility Generator current profile is depicted in Figure 5.51. During this test case loss of mains is caused by a fault. For this reason the output current is much higher. The current generated is directed towards the fault and is not supplied to any of the loads.

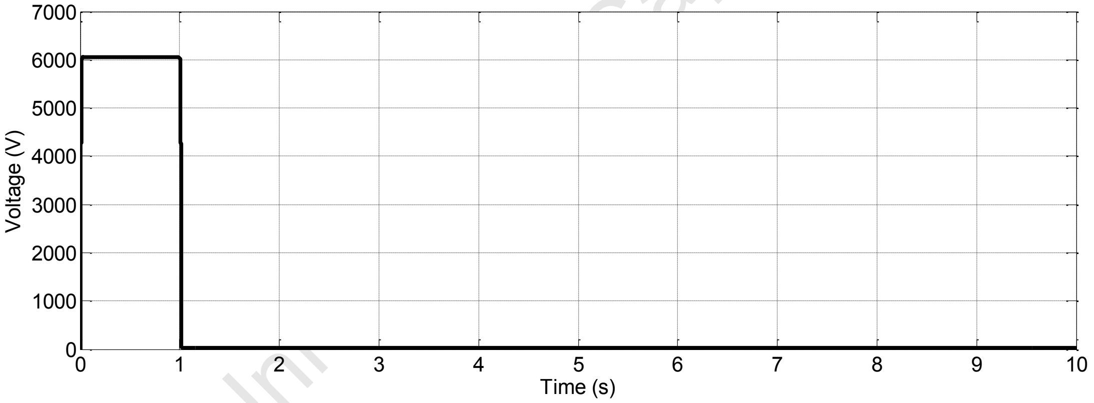


Figure 5.52 Utility Generator Voltage level during Test Case 5

The generator operation voltage in this case drops once the fault occurs and is never recovered because the fault is not actually cleared, it is only separated from the rest of the grid. This fault has a continuous effect on the generator. This continuous effect is depicted in Figure 5.52, the only way the voltage would be restored is if the fault is physically cleared.

iii. *Utility Load*

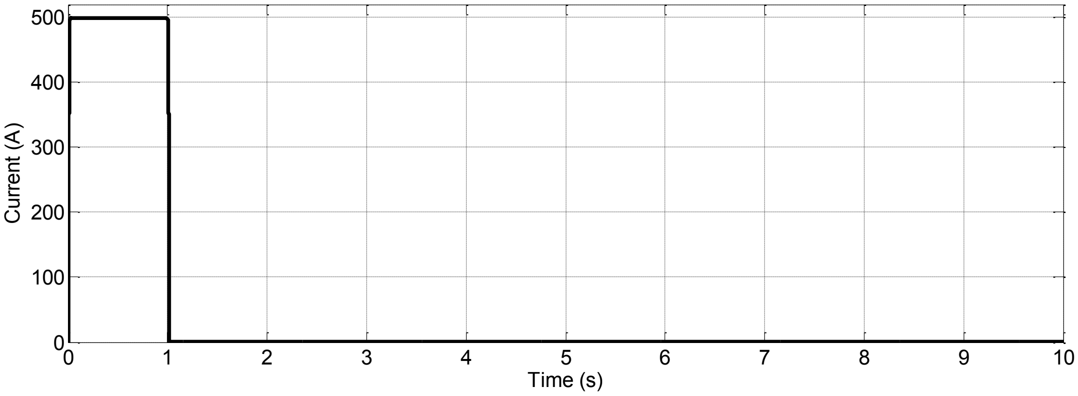


Figure 5.53 Utility Load Current before, during and after fault during Test Case 5

For the period during the fault all the power generated by both power sources is guided towards the fault. This is the reason why the Utility Load current is low during the fault. Once the fault is cleared the current remains low because the utility load becomes disconnected from both generators and it has no source of power. Again, this current would only be restored if the fault was fixed and the Utility source was reconnected to the Utility Load.

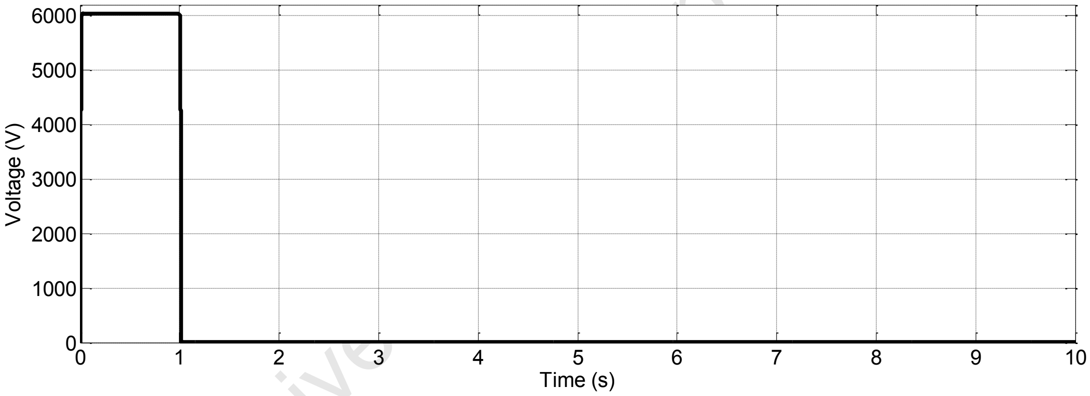


Figure 5.54 Utility Load Voltage level before, during and after fault in Test Case 5

The Utility load Voltage level follows the same characteristics as the Utility Generator voltage levels. After 1s the load voltage drops, almost reaching zero. This voltage is never recovered in this simulation.

iv. *Local Load*

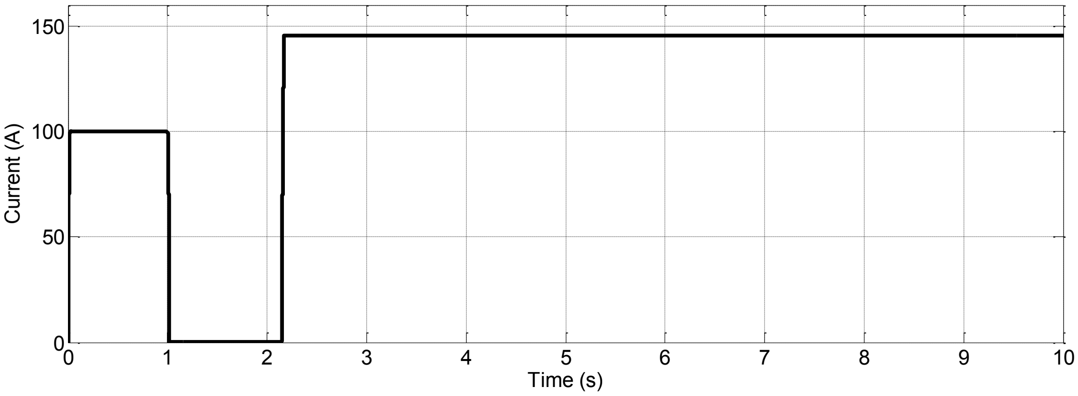


Figure 5.55 Local Load current before, during and after fault in Test Case 5

The local load in this test case is slightly better protected than the Utility load. In this case the current flowing towards the local load is restored and even optimised after the SS is opened. The opening of the SS completely isolates the fault from the microgrid and thus enables this microgrid to function optimally. The experienced fault only lasts for 0.23s, which is the expected delay.

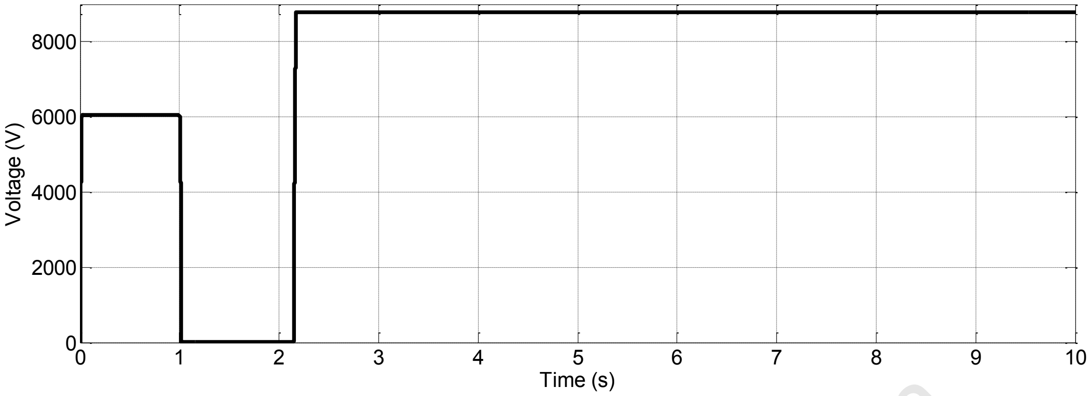


Figure 5.56 Local Load voltage level, before, during and after Test Case 5

In the same was the current is restored in the microgrid, so is the voltage. This recovery is depicted in Figure 5.56. It appears from the results obtained in this test case that the system operating conditions are closer to the nominal values when the microgrid is operating in a stand-alone ,mode.

v. *Trip Signal*

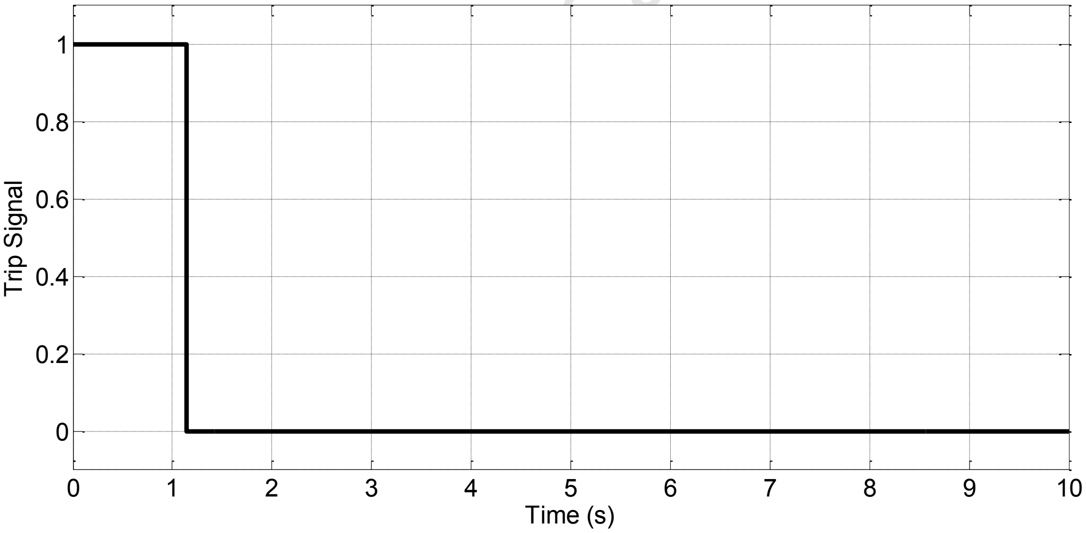


Figure 5.57 Reverse Power Relay Trip Signal during Test case 5

The trip signal is sent to the SS at 1.13s and this causes the microgrid to be isolated.

vi. ***System Frequency***

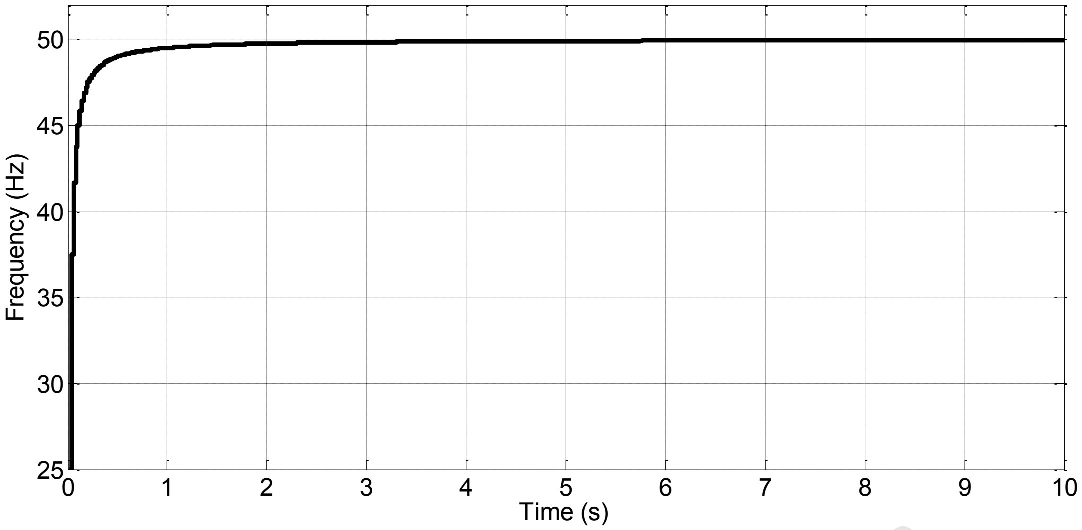


Figure 5.58 **Microgrid System Frequency during Test Case 5**

The system frequency is 50Hz for most of the simulation of this test case. There seems to be no effect on the frequency due to the fault.

5.3.3 Test 6 - Loss of Mains due to open utility switch, small DG Capacity

i. ***PV Generation***

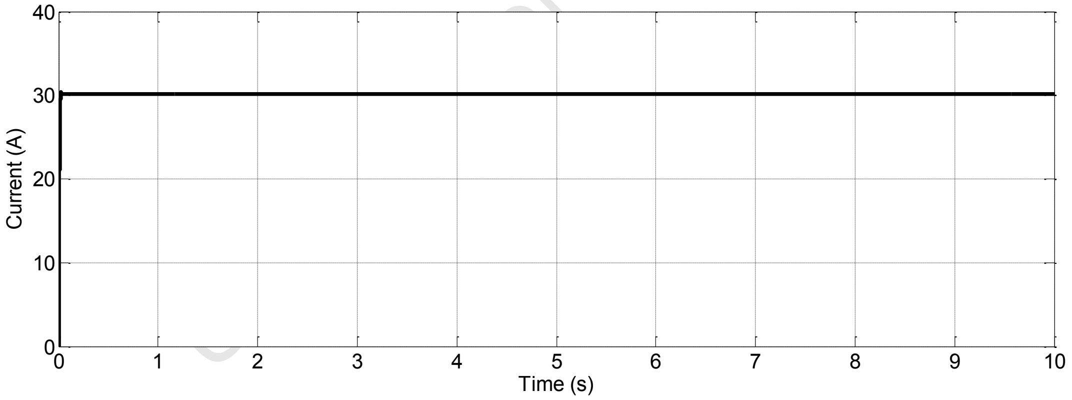


Figure 5.59 PV Generation Current RMS during Test Case 6

For this test case the output current was decreased by decreasing the solar insolation to 200W/m^2. This is the reason why the peak to peak values have decreased to 66A. Nevertheless, the current output does not vary with the loss of mains event. This is a common characteristic that remains even when the PV Solar power contribution to the grid is smaller.

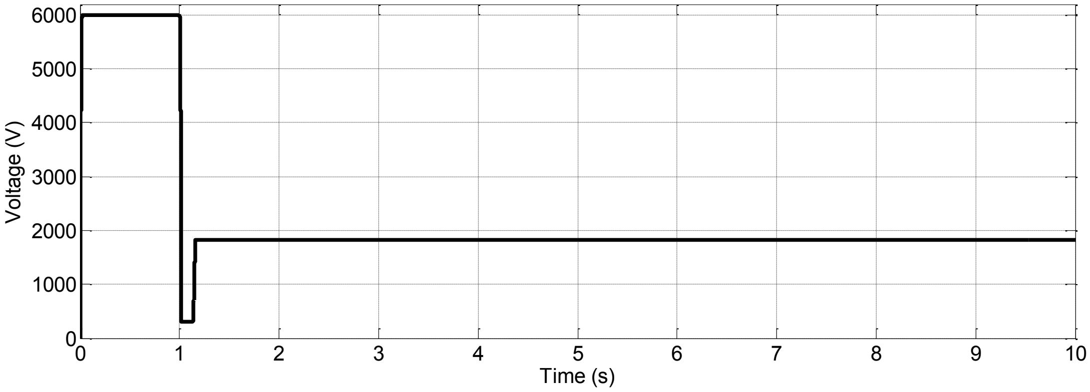


Figure 5.60 PV Generation voltage level before, during and after the event in Test Case 6

The PV Solar voltage level is not regulated by solar insolation. For this reason the voltage level is at a similar level to that of the previous test cases. Once the utility switch is opened the voltage drops as the DG supplies power to both local load and utility load. The system becomes very overloaded and as a consequence the voltage drops. Once the SS is opened the DG becomes slightly less overloaded but the strain remains. In this test case the system voltage is never restored to its nominal voltage, which would not be acceptable to authorities and most loads would not operate at this voltage level.

ii. *Utility Generator*

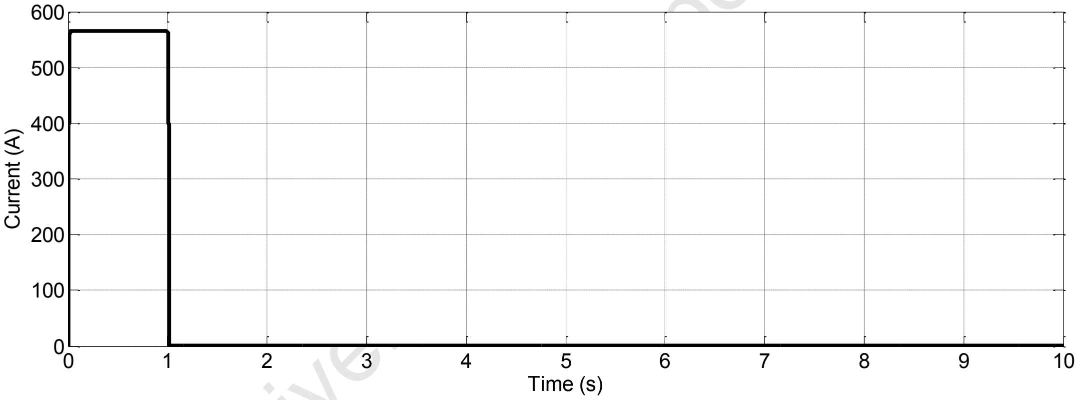


Figure 5.61 Utility Generator output current RMS during Test Case 6

The utility source current during the Test Case is displayed in Figure 5.61. It is important to note that when loss of mains occurs due to a switch opening in the utility network, the generator current drops instantaneously, this is different to the behaviour witnessed when loss of mains occurs due to a fault where the current increases immediately after the fault occurs. This is a significant difference in behaviour and one that protection engineers should take into account. Regardless of whether the current drops or increases due to the event the reverse power relay detects the abnormality and triggers the SS to open.

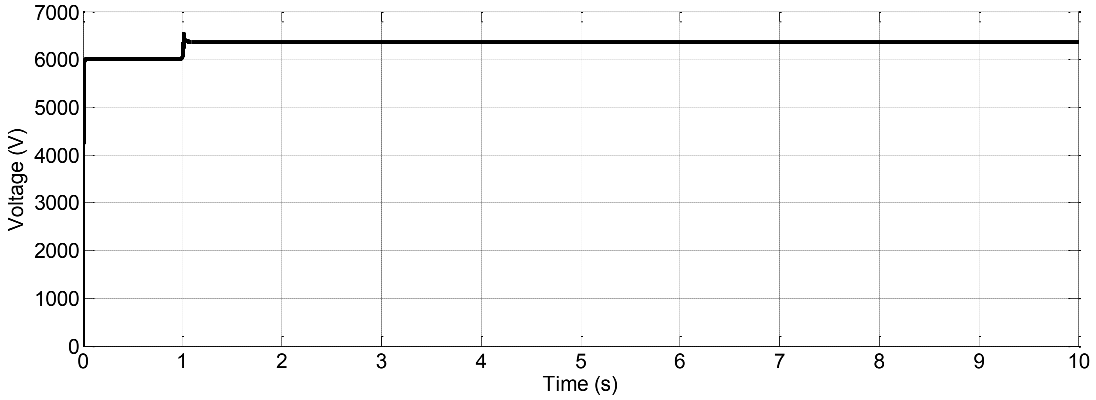


Figure 5.62 Utility Generator Voltage RMS during Test Case 6

This behaviour also differs to that experienced when the loss of mains is due to a fault. When loss of mains occurs due to a fault the utility generator voltage drops as a result, but when loss of mains occurs due to a switching operation the voltage increases slightly. This is another interesting phenomenon and it is again vital to note that the reverse power relay behaves indifferently regardless of the source of the event.

iii. Utility Load

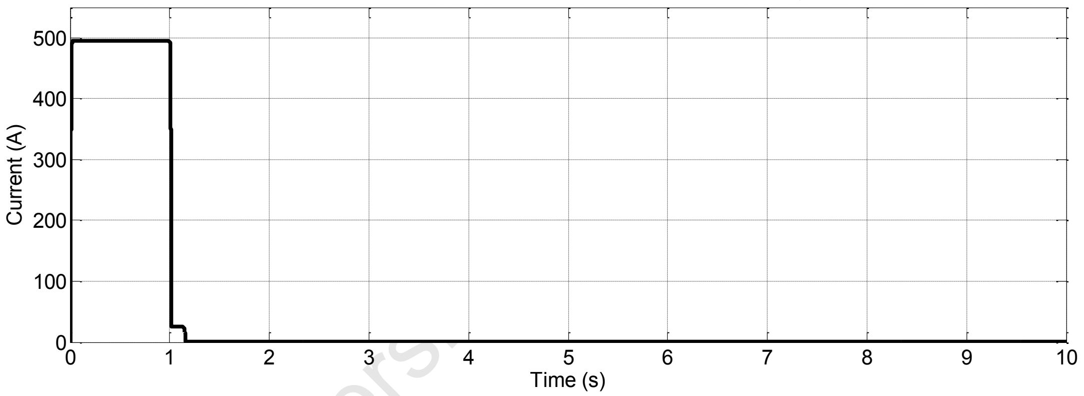


Figure 5.63 Utility Load current RMS before, during and after the event in Test Case 6

The utility load is the main cause of overload for the system once the utility switch is opened. This load is too large for the PV Solar plant to handle. For this reason once LOM occurs the current to the utility load is significantly reduced. These values are again not suitable for power system operation. The small current supplied to the utility load after 1s is reverse current which causes the reverse power relay to send out a trip signal. Once the SS is opened, the utility load becomes disconnected to any power sources, for this reason the current to the utility load becomes approximately 0A.

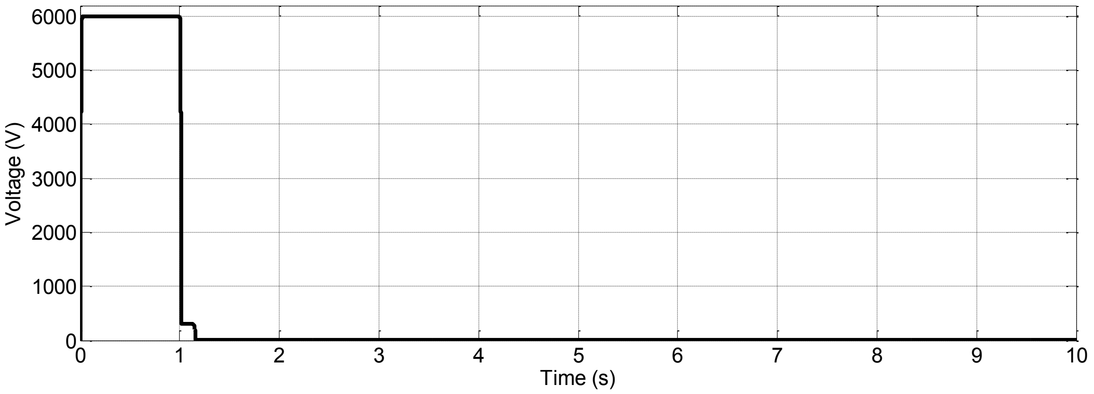


Figure 5.64 Utility Load Voltage level during Test Case 6

The utility load voltage does not follow the same voltage characteristic to the utility generator voltage. The Voltage changes are identical to those in Test Case 1. The Voltage drop after the incident is even bigger in this case because the DG generation power is smaller. The voltage becomes even smaller when the SS is tripped due to the reverse current.

iv. ***Local Load***

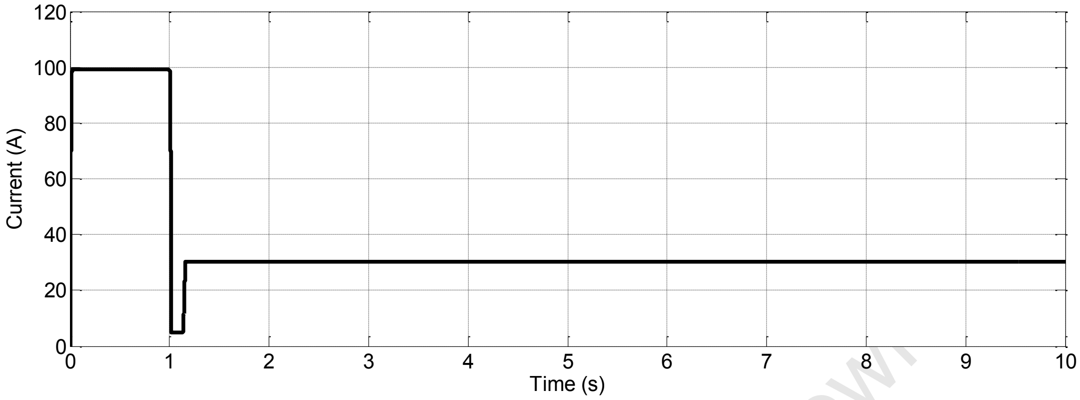


Figure 5.65 Local load current before, during and after the event in Test Case 6

The local load is highly affected by the loss of mains event. Once this switching occurs, the local load shares the current produced by the DG with the utility load as per Kirchoff's current law. This creates a huge deficit of current for this load. Once the SS is tripped, the current to the local load is increased slightly but it is still insufficient to sustain the microgrid. This is a case where the DG has proved to be too small to sustain the load in the microgrid. In cases like these it is important to restore the connection to the utility source or to be able to manage the loads in the microgrid.

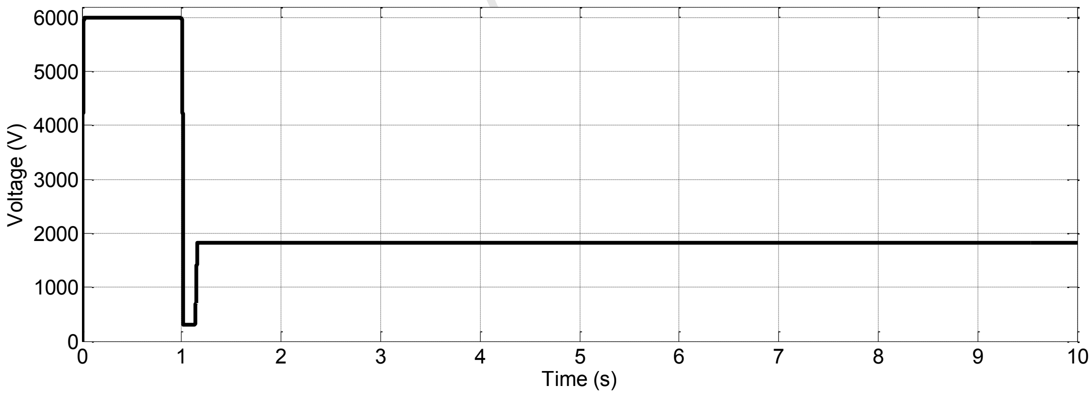


Figure 5.66 Local Load voltage RMS before, during and after the event in Test case 6

The local load voltage is also highly affected by the loss of mains. The voltage is not restored and the only way to fix this very low voltage level would be by reclosing the utility switch and the SS. Figure 5.66 depicts the voltage abnormalities in the local load.

v. *Trip Signal*

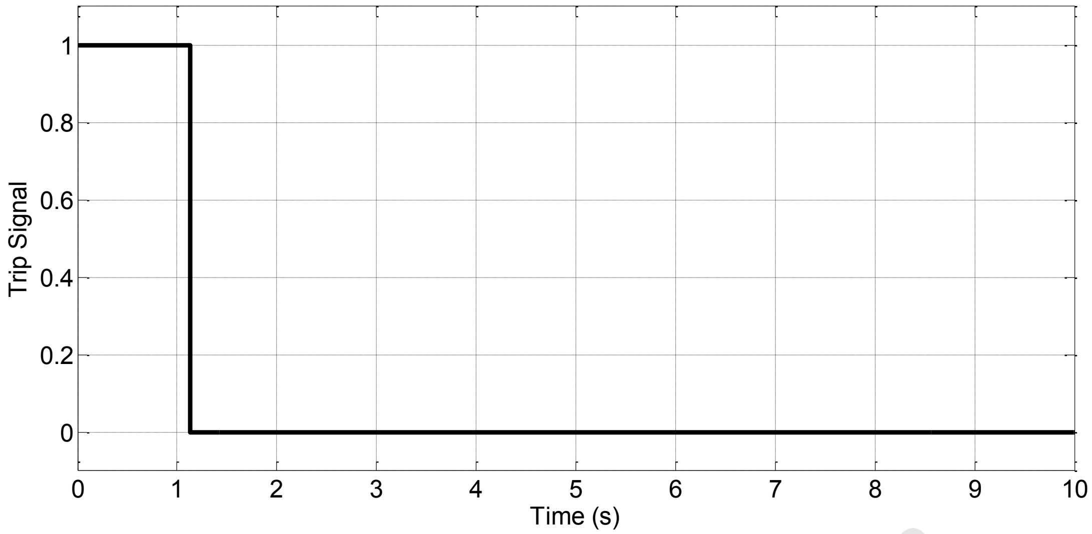


Figure 5.67 Reverse Power Relay Trip Signal during Test Case 6

In a similar manner to the other test cases for reverse power relaying the trip signal is sent at 1.13s indicating a 0.13s delay after the switching operation causes loss of mains at 1s.

vi. *System Frequency*

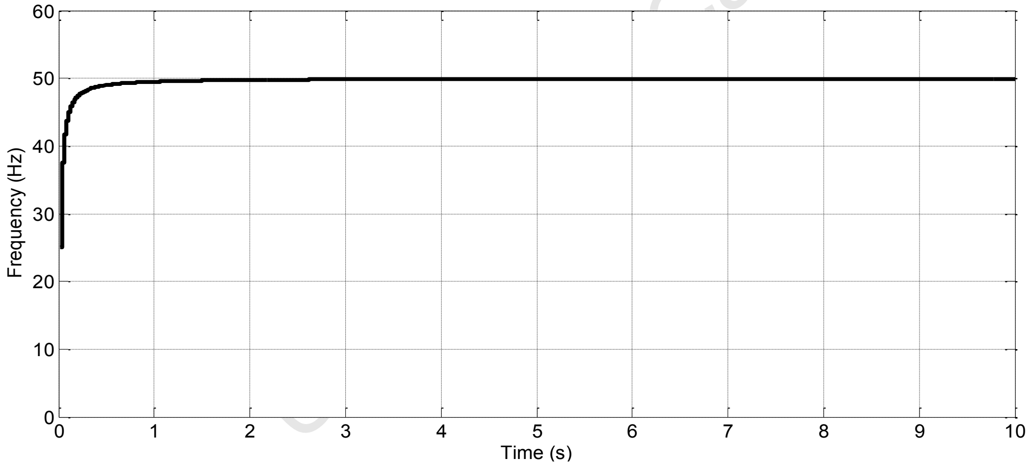


Figure 5.68 Microgrid System frequency during Test Case 6

The system frequency again seems constant during the loss of mains event, this is unexpected due to the large defect in active power balance. During most of this test case the system is overloaded which should have triggered a change in frequency levels.

5.3.4 Test 7 - Loss of Mains due to a 3-phase Fault, with small DG Capacity

i. PV Generation

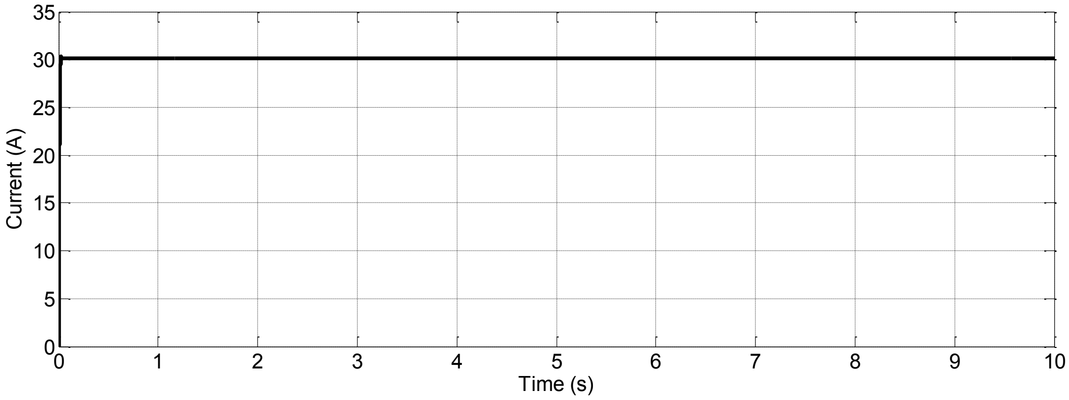


Figure 5.69 PV Generation current RMS during Test Case 7

The current levels are lower than in the normal case, this is because the solar insolation level is again set to 200W/m^2. The current produced by the DG remains unchanged during the period of this simulation. This is consistent with all other cases.

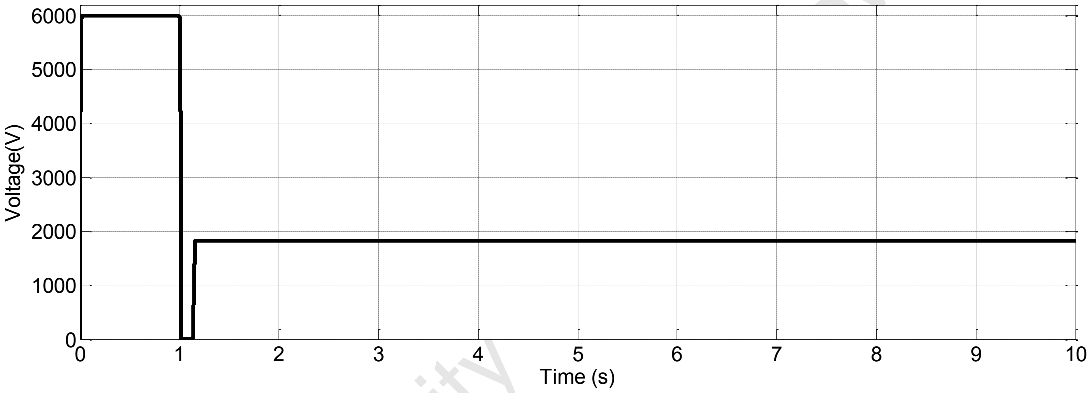


Figure 5.70 PV Generation voltage levels before during and after the fault in Test Case 7

The voltage at the output of the DG, on the contrary, varied during the simulation in Test case 4. Before the fault, the voltage is close to its nominal value. During the fault, the voltage drops to a value close to zero, this is because the system is overloaded as the fault presents a high resistance. After the fault, the voltage increases but it is still too low for the network to operate efficiently. When the microgrid is disconnected from the utility grid and the level of sunlight energy is too low, the microgrid cannot operate at acceptable levels.

ii. Utility Power Source

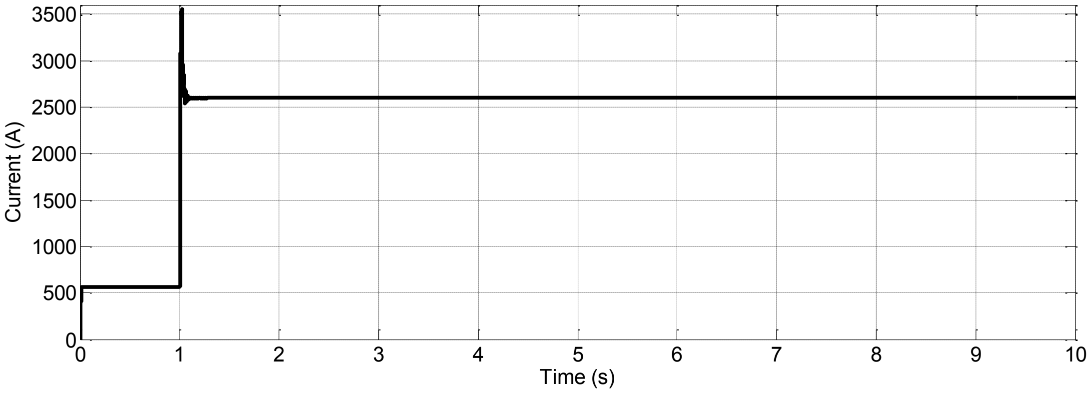


Figure 5.71 Utility Generator current RMS during Test case 7

The utility generator behaves differently to the DG when a fault occurs. In this case a fault occurs after 1 second and the currently immediately increases because of this fault. The fault current remains in the system because the fault is not completely cleared or isolated. In real power networks the generator would have a CB to protect it and this CB would help to isolate the fault. However in this research only protection for the microgrid is being considered.

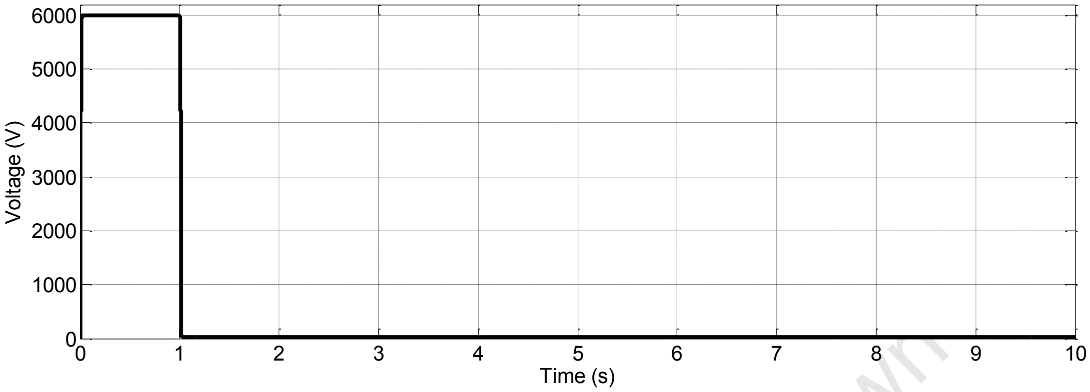


Figure 5.72 Utility Generation Voltage RMS during Test Case 7

Expectedly, the voltage drops once the fault occurs. This complements the behaviour noticed in the current signal. The voltage is also not restored because the fault is not completely cleared.

iii. Local Load

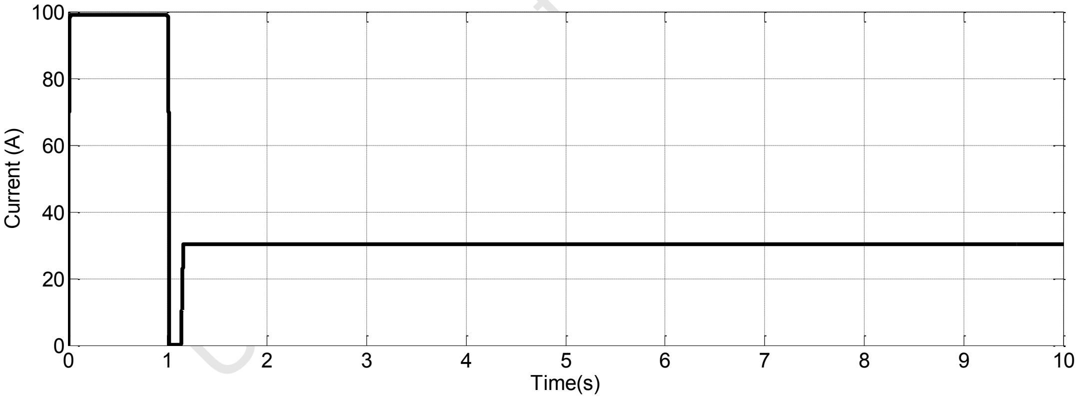


Figure 5.73 Local Load current RMS before, during and after Test Case 7

Figure 5.73 depicts the local load current during this test case. The current levels for the local load depend highly on the utility source. Once loss of mains occurs and the local load becomes disconnected to the utility grid, there is a shortage of current to the local load which does not get recovered. This test affirms that loads can’t be efficiently sustained if the DG is too small.

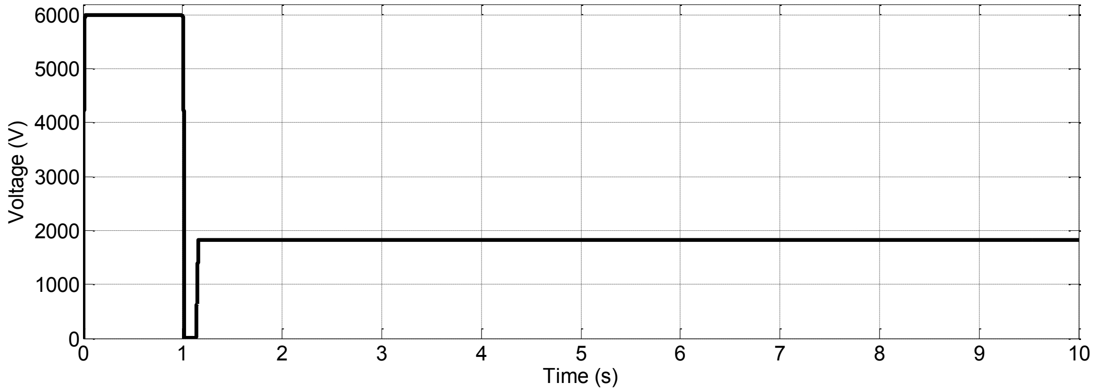


Figure 5.74 Local Load voltage RMS before, during and after fault in Test Case 7

Voltage levels for the local load in this test case are also affected by the fact that the DG is too small to sustain the loads on its own. The loss of mains event has a significant impact on the local load, especially because the DG is too small to support the load.

iv. Utility Load

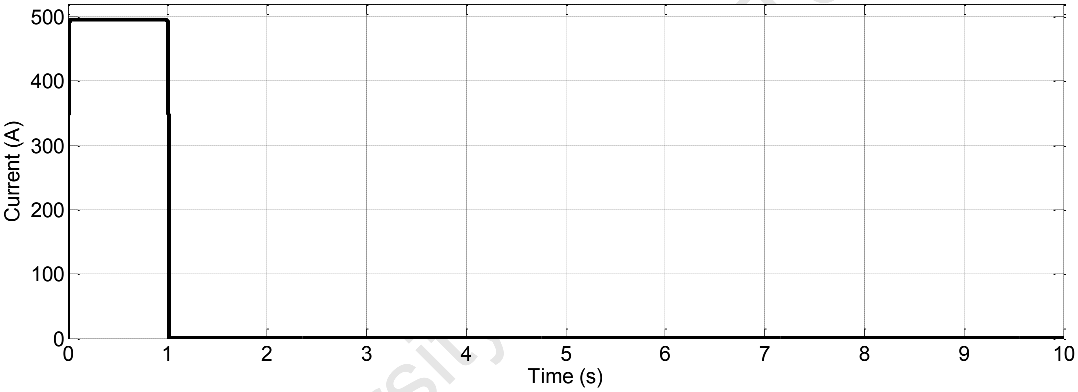


Figure 5.75 Utility Load Current RMS during Test Case 7

The fault that occurs leads to the load being deprived of current. The current originally supplied to the load was produced by the utility grid. Once loss of mains occurs, the power supply to the load is cut-off. After the fault is cleared the current is still not supplied to the load because the DG is too small to supply sufficient power to the utility load.

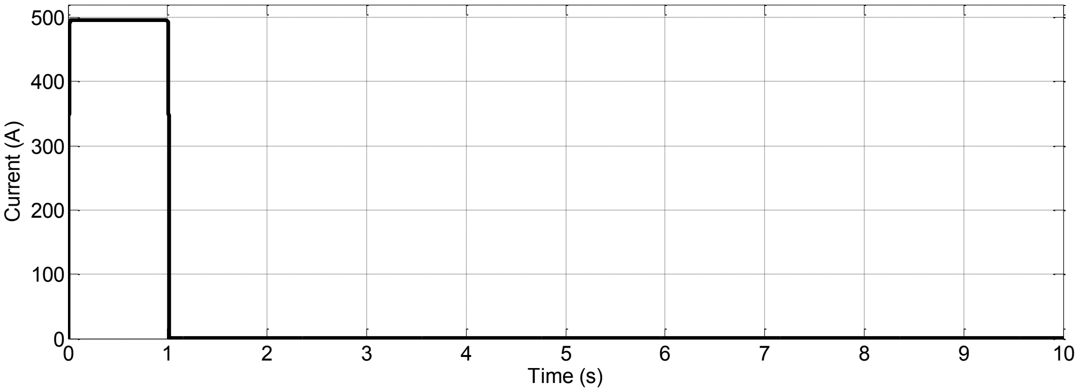


Figure 5.76 Utility Load Voltage during Test Case 7

The utility load voltage depicted in Figure 5.76 above shows that the voltage dropped after the fault which caused a loss of mains. For the same reason the current was never restored, this voltage was never recovered. A way to recover the voltage would be to remove and fix the fault and reconnect to the utility power generation source.

v. ***Trip Signal***

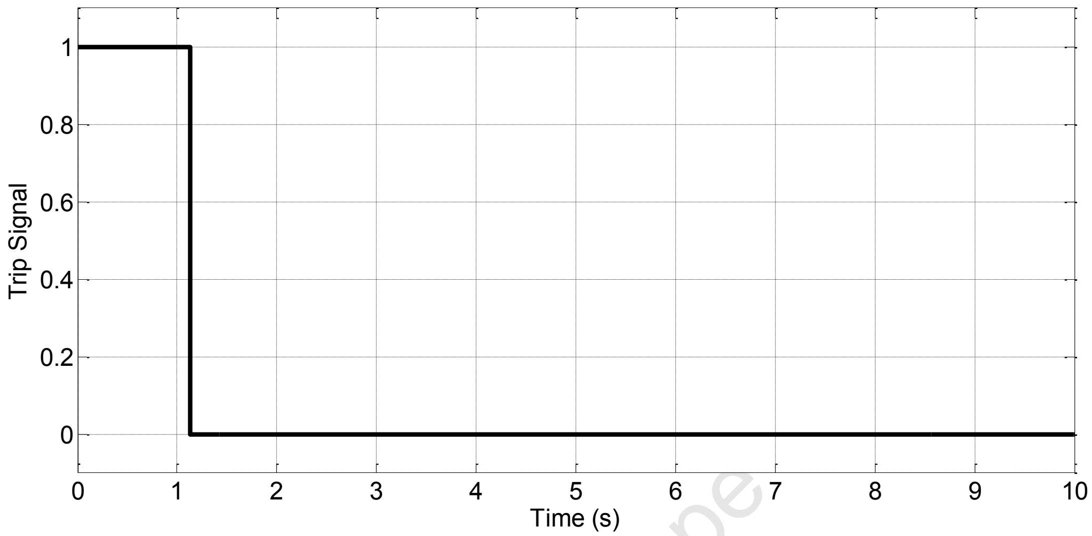


Figure 5.77 Reverse Power Relay trip signal during Test Case 7

The relay triggers the circuit breaker to open at 1.13s, 0.13s after the fault occurs. This is reasonable delay in the trip signal. It is important that the breaker does not trip instantly, this allows for transient faults to occur without disconnecting the system.

vi. ***System Frequency***

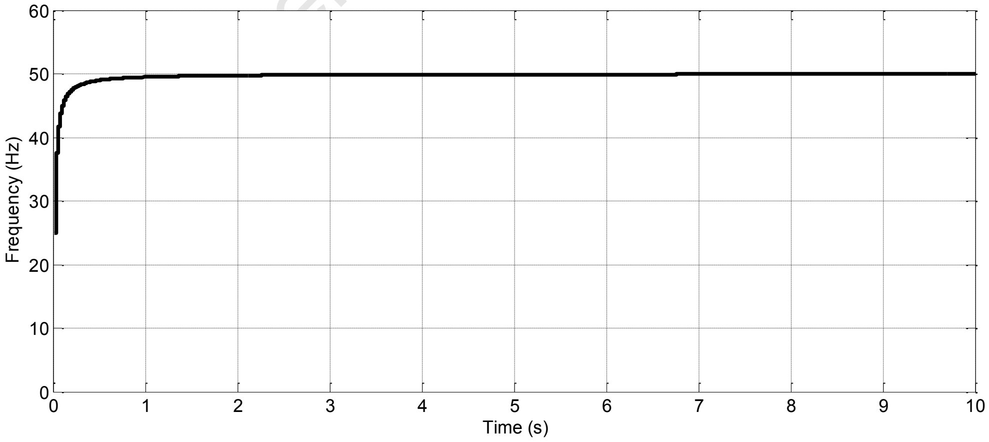


Figure 5.78 Microgrid System frequency during Test Case 7

The system frequency remains the same as in other cases, it is not affected by the fault that occurs in this test case.

5.4 Adaptive Frequency Relay Testing

5.4.1 Test 8 - Under Frequency Grid Connected Mode

i. System Frequency

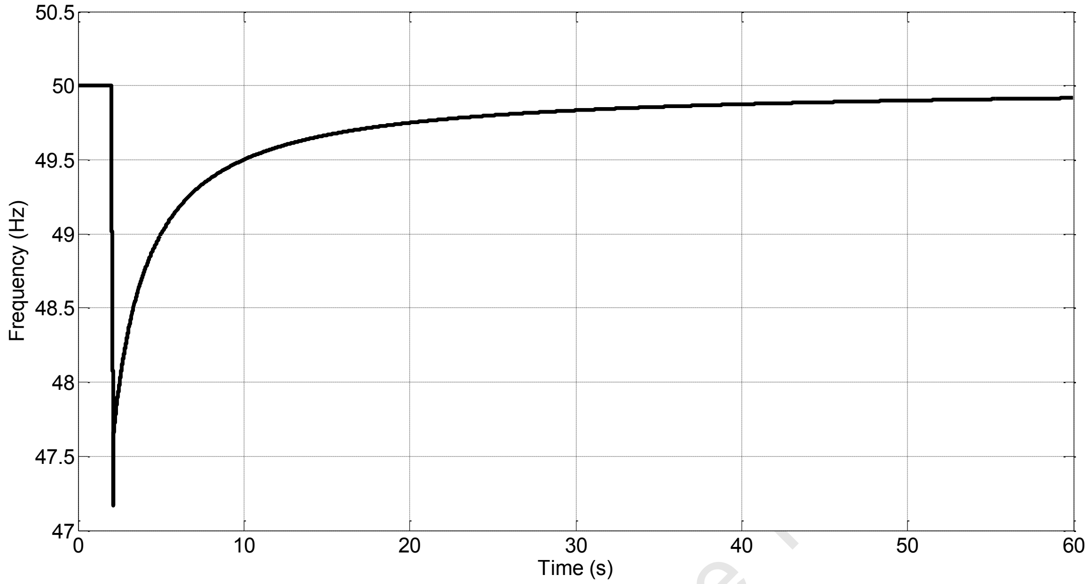


Figure 5.79 System frequency during grid connected under frequency test

The frequency drops after the additional load is steadily increased. This frequency decrease is caused by a system overload. In this case the load demand exceeds the power supplied by the two sources in the system. It is important that systems are protected against frequency drops, because this event can have a knock on effect on other system components and eventually cause a black-out.

ii. Trip Signal

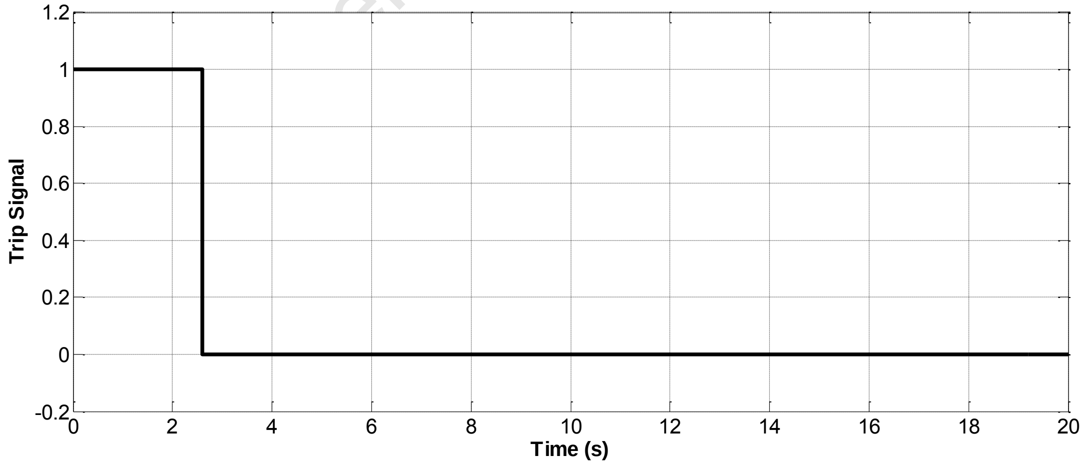


Figure 5.80 Frequency Relay trip signal during grid connected under frequency test

Figure 5.80 depicts the relay trip signal during this test. The plot shows that the trip signal was sent at 2.5 seconds, this is a 0.5 second delay from the time the load started increasing. The adaptive frequency relay does not have a specific time delay. This is because it takes time for the frequency to decrease to a level where it breaches the regulations that monitor it. An additional delay would cause an extensive time between the event and the trip signal, which may put the grid in danger.

5.4.2 Test 9 – Under frequency Isolated Mode

i. System Frequency

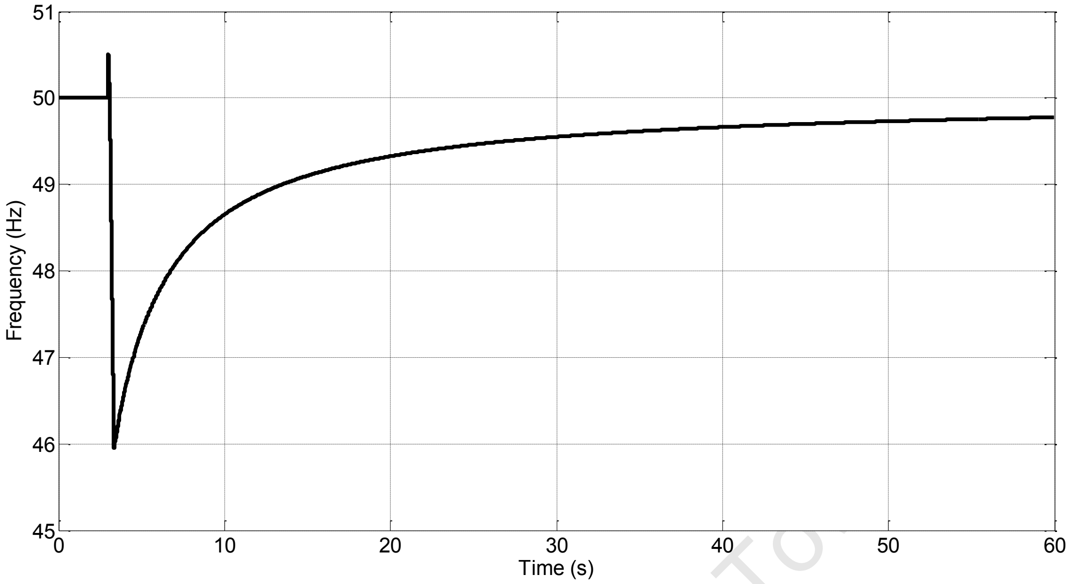


Figure 5.81 System frequency during Isolated mode under frequency test

The frequency drop in Isolated mode is higher than the frequency drop witnessed in grid connected mode. The higher drop is attributed to the fact that the relay has a higher frequency threshold when the microgrid is operating in islanded mode. The system frequency does not start recovering immediately after the switch is opened, the frequency drops further until it gets to a point where the effects of the event have stopped.

ii. Trip Signal

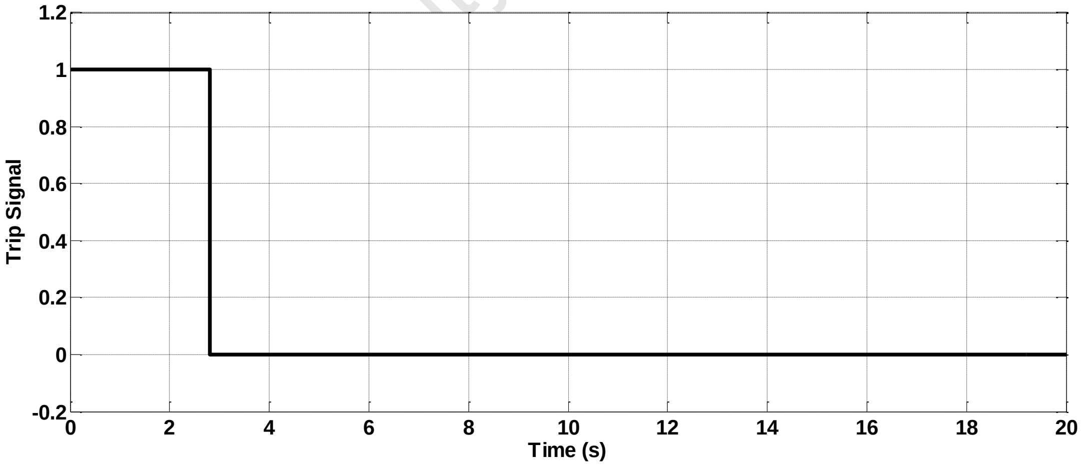


Figure 5.82 Frequency Relay trip signal during Isolated under frequency test

The trip signal shown in Figure 5.82 above shows that the trip time is the same whether the system is operating in grid connected or isolated mode. Setting a time delay for this relay is not crucial because there are no other frequency relays in the network. There is only one frequency relay because the occurrence of frequency variation is rare. In more complex systems with more loads and busbars there would be more frequency relays.

5.4.3 Test 10 - Over Frequency in Grid Connected Mode

i. System Frequency

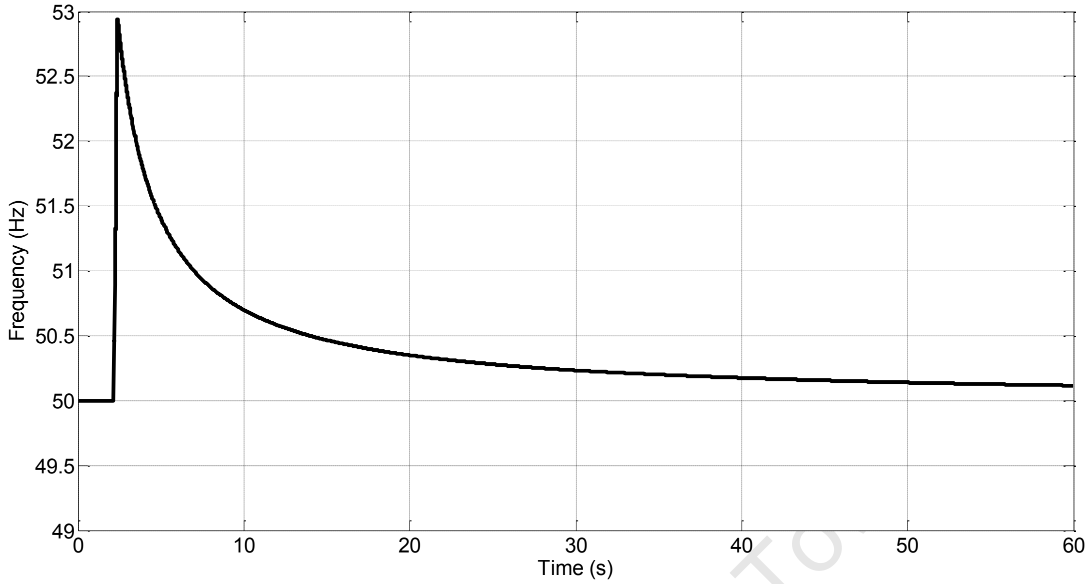


Figure 5.83 System Frequency during grid connected over frequency test

The over frequency in the grid is caused by a sudden loss of load in the grid. The rapid decrease in load causes the frequency to increase immediately as shown in Figure 5.83 above. The same relay that detected the under frequency in the previous two tests detected the over frequency in this test case. This proves that the relay is capable of detecting and protecting the system in cases of both over frequency and under frequency.

ii. Trip Signal

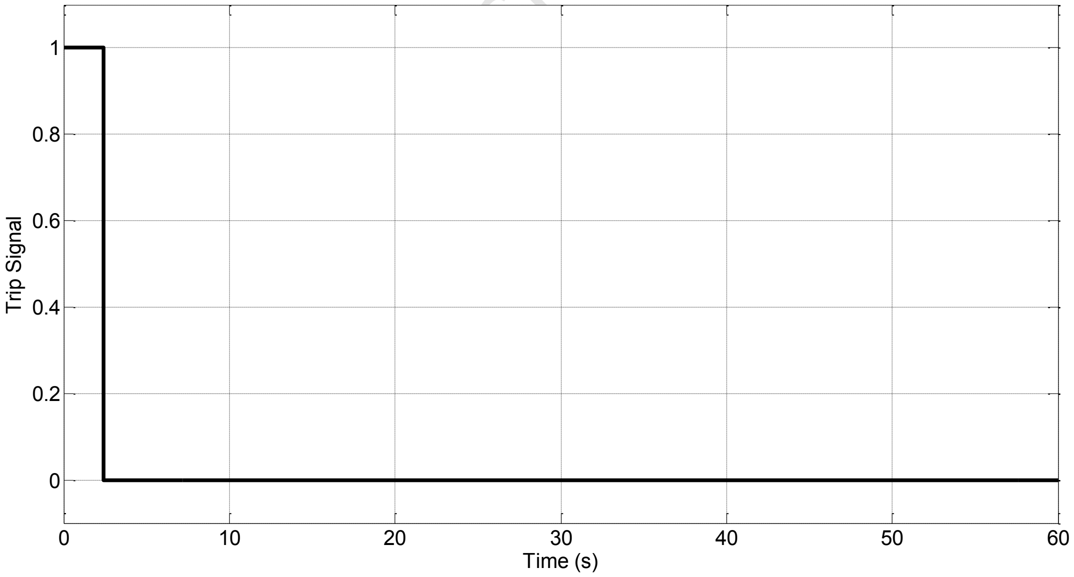


Figure 5.84 Frequency Relay trip signal during grid connected over frequency test

The trip signal shown in the figure above shows the relay signal for the full duration of the simulation. Again, the relay becomes active as soon as it detects the higher frequency value. This happens shortly after the load loss at 2 seconds. The relay output signal did not change after the switch was opened, this shows that the relay is capable of maintaining its output and that it will not try to reclose the switch once the over frequency has been resolved.

5.4.4 Test 11 – Over frequency in Island Mode

i. System Frequency

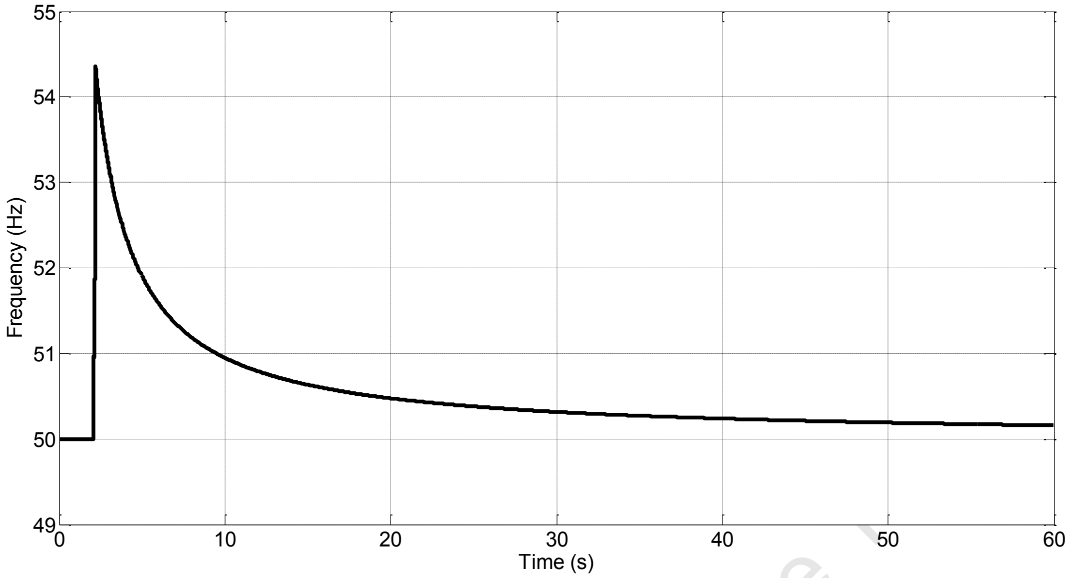


Figure 5.85 System Frequency during Isolated Mode over frequency test

The frequency variation in this test case is higher than in the previous case, this is because the microgrid is operating in isolated mode and the variation tolerance is higher. The time taken for the system to reach an acceptable frequency after the Static switch is opened is longer in this test case because the frequency deviation is also higher.

ii. Trip Signal

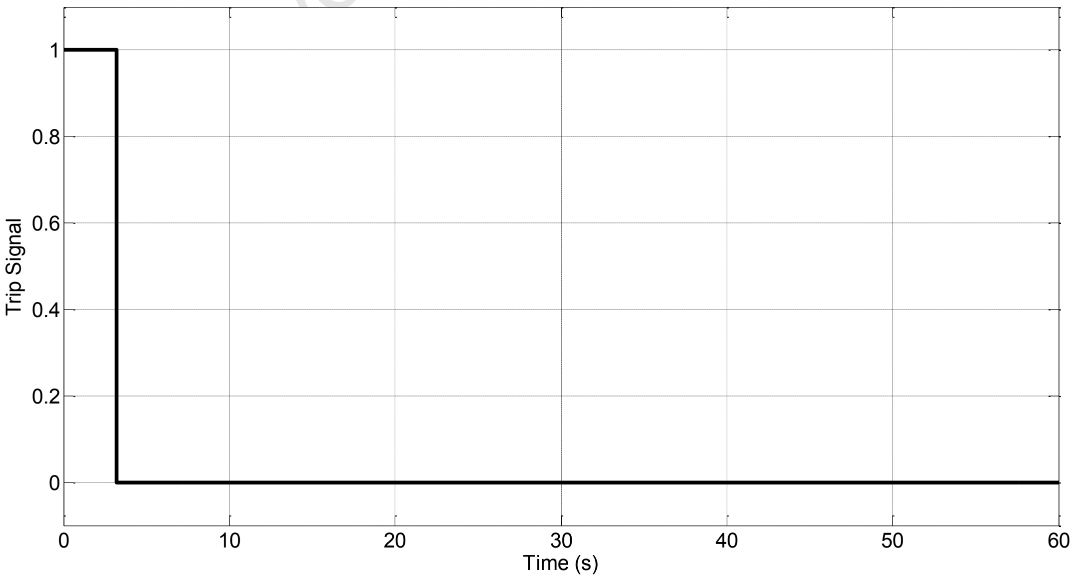


Figure 5.86 Frequency Relay trip signal during Isolated over frequency test

The relay trip signal also known as the output remains the same as in previous cases. This confirms the fact that the trip time is unaffected by the mode of operation or whether it is an under frequency or over frequency case.

5.5 Overvoltage Control System

5.5.1 Test case 12 - High Voltage Swell

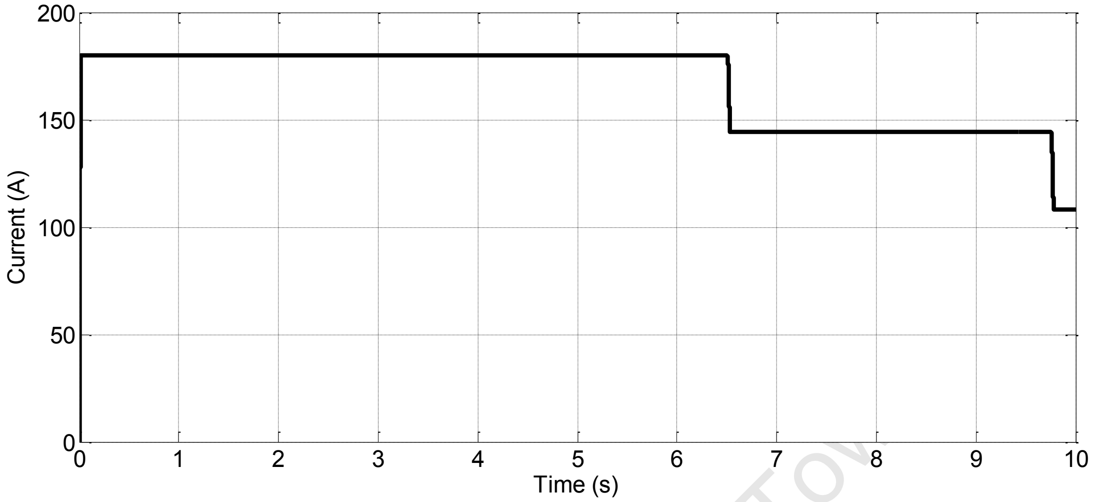


Figure 5.87 Net RMS current through busbar 1 during High Voltage Swell Test case

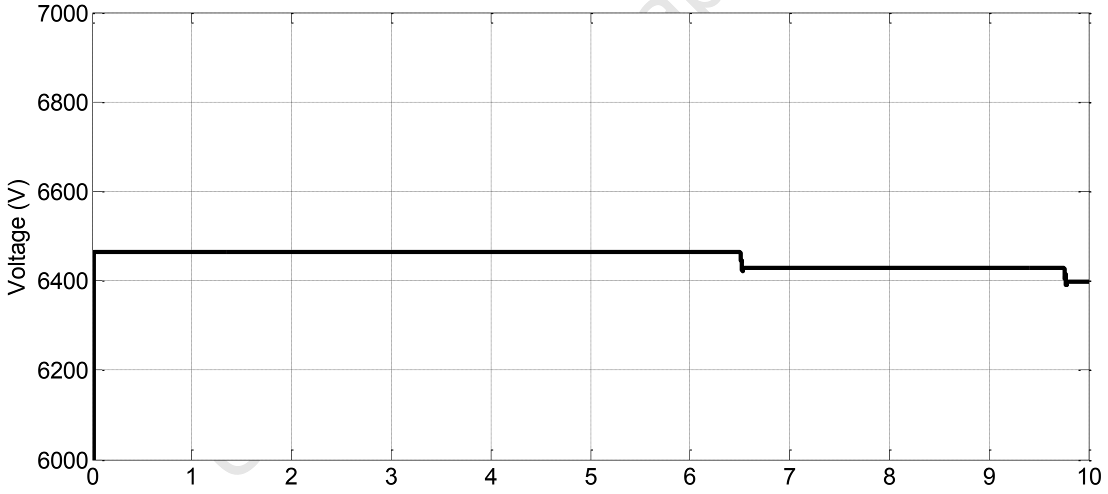


Figure 5.88 Net RMS voltage through busbar 1 during High Voltage Swell Test case

The RMS current displayed in Figure 5.87 is the net current through busbar 1. Net current is the resultant current from the DG and the Utility generator. Initially the solar insolation is 1200W/m^2, this makes the nominal current 180A RMS. This current is slightly higher than expected; this causes an overvoltage in the system. This overvoltage is the cause for opening of Switches 1 and 2. When these switches open the current output from the DG becomes lower. The decrease in current can be seen at 6.5s and 9.7s. These string disconnections help to bring the system voltage back to the nominal level.

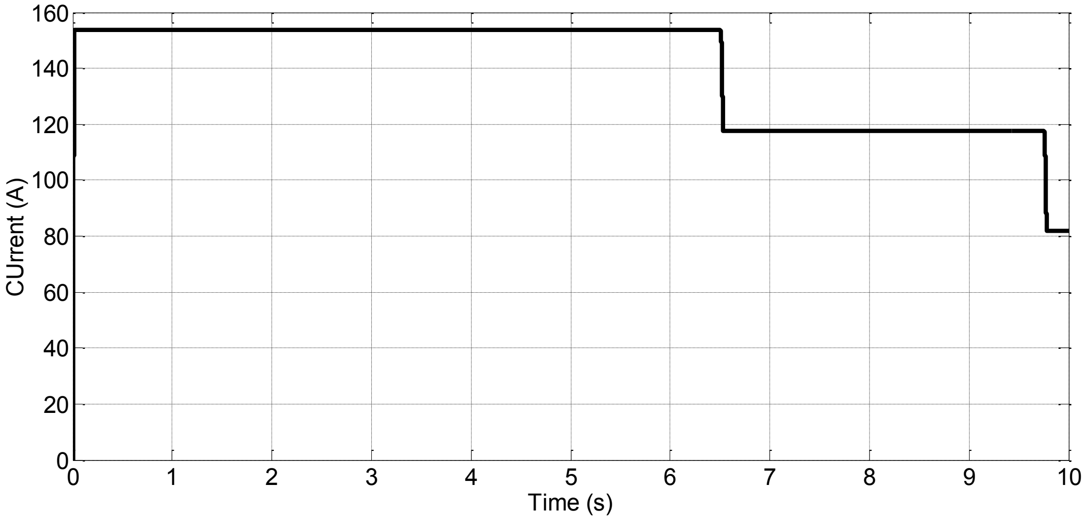


Figure 5.89 Net RMS current through busbar 2 during High Voltage Swell Test case

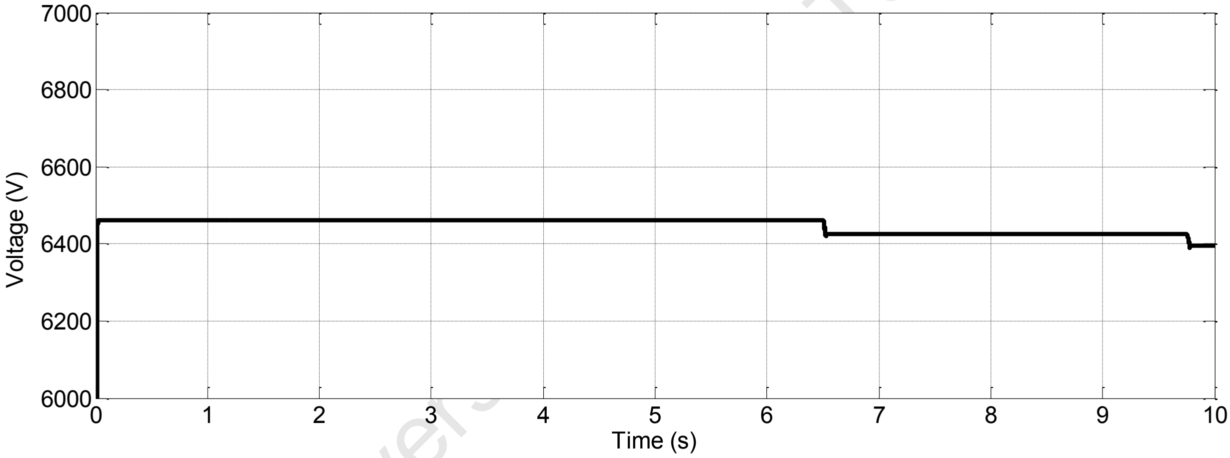


Figure 5.90 Net RMS voltage through busbar 2 during High Voltage Swell Test case

The voltage and current levels in the utility portion of the scheme are also affected by the excessive current from the DG. Figure 5.89 and Figure 5.90 show similar patterns to the previous two plots. The voltage is initially high in this simulation; however the relays have specific delays associated with each of them. These delays are the reason why the circuit breakers don't open immediately after the simulation started.

The following plots show the reaction times for the relays, due to the overvoltage caused by the excessive power generation by the DG.

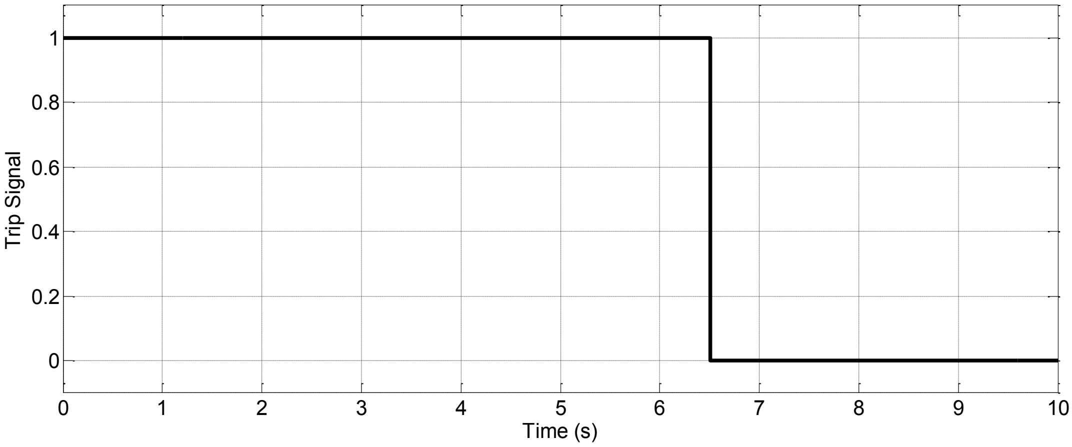


Figure 5.91 Solar switch 1 trip signal during High Voltage Swell Test Case

Switch 1 is connected to overvoltage relay 1 which has the shortest time delay out of the 4 overvoltage switches, for this reason it is the first one to open if an overvoltage is present in the network. As shown in Figure 5.91 the relay causes the switch to open 6.5seconds after the simulation starts. This means that for this specific voltage level the time delay was 6.5s, this is the expected trip time based on Figure 3.10.

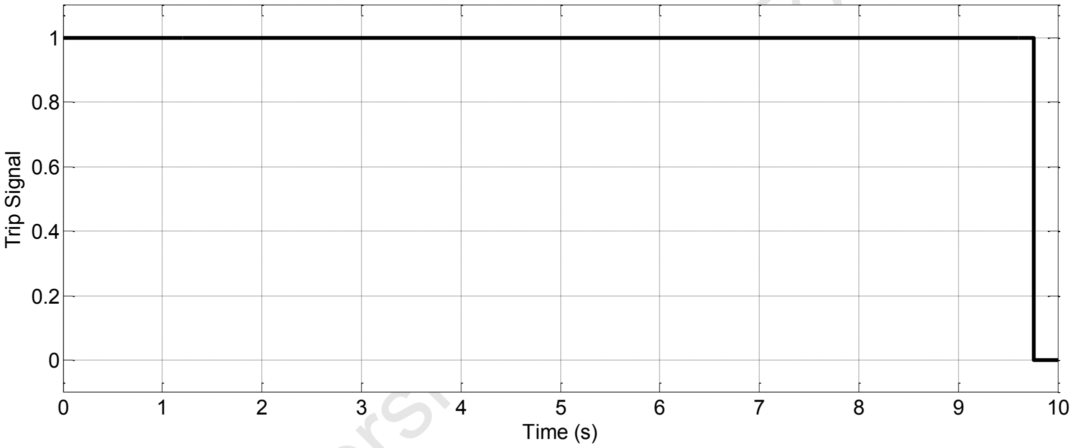


Figure 5.92 Solar switch 2 trip signal during High Voltage Swell Test Case

In this case, even after switch 1 is opened, the voltage remains relatively high compared to the nominal voltage level. For this reason overvoltage relay 2 causes solar switch 2 to open and an additional string becomes disconnected. Disconnecting a second string leads to a second current drop, which helps the voltage to be restored to a value closer to the nominal value.

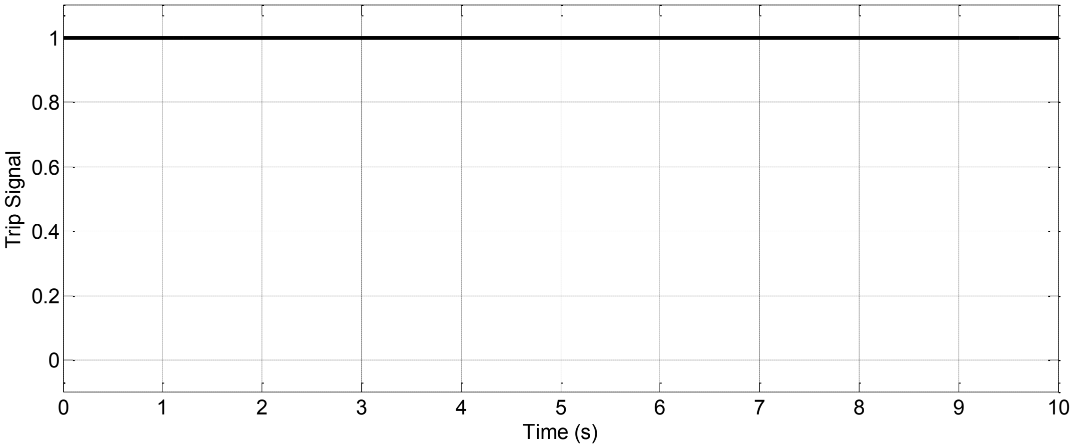


Figure 5.93 Solar switch 3 trip signal during High Voltage Swell Test Case

The flat line in Figure 5.93 suggests that switch 3 was never opened. This is because opening the first 2 switches is sufficient to protect the grid from overvoltage. If the overvoltage was higher this switch would have opened to alleviate the strain on the grid.

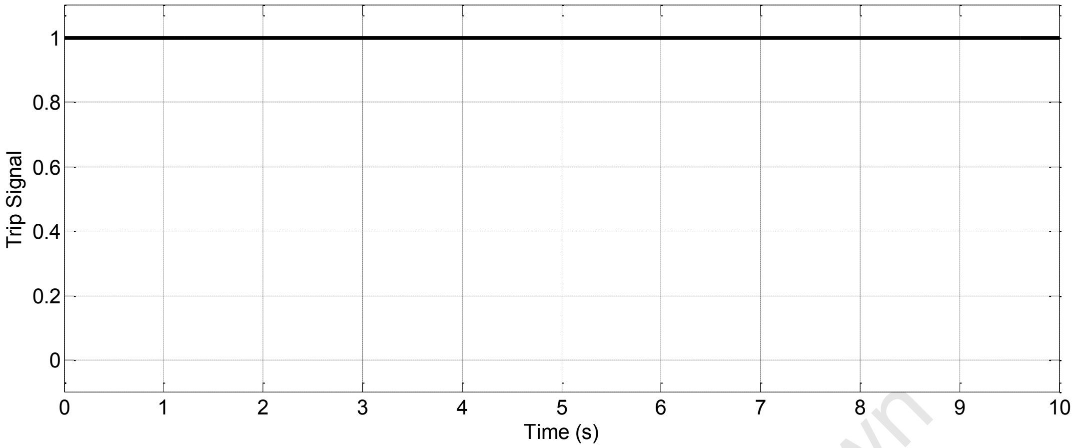


Figure 5.94 Solar switch 4 trip signal during High Voltage Swell Test Case

Switch 4 is the last switch expected to trip. In this case it does not trip because opening the first two switches is enough to protect the microgrid in this case. In this simulation switches 2, 3 and 4 all act as back up protection. Only switch 2 became of use, the other two weren't necessary and would only be needed if the primary protection failed or if the overvoltage was too high.

5.5.2 Test Case 13 - Low Voltage Swell

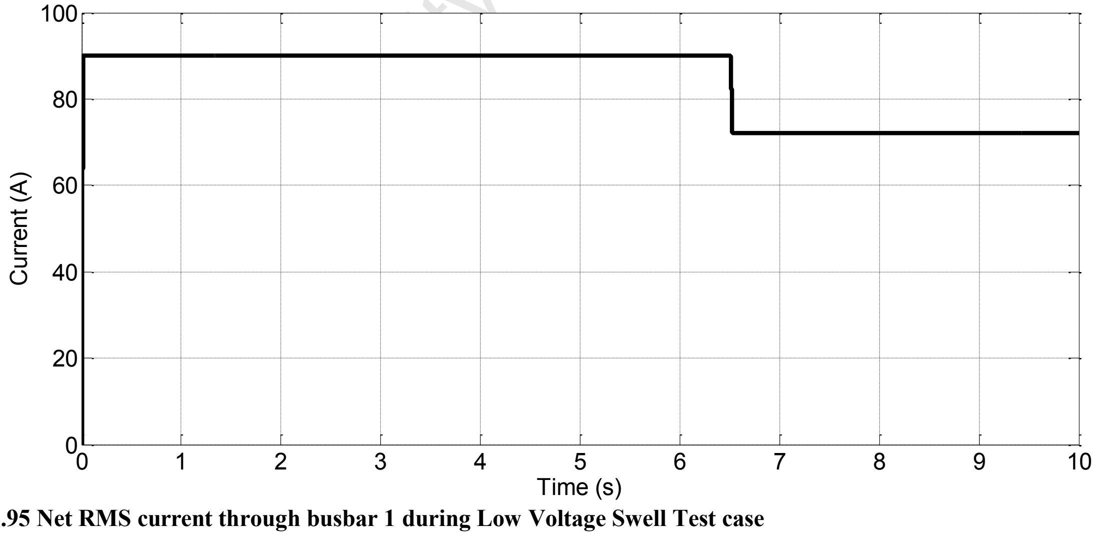


Figure 5.95 Net RMS current through busbar 1 during Low Voltage Swell Test case

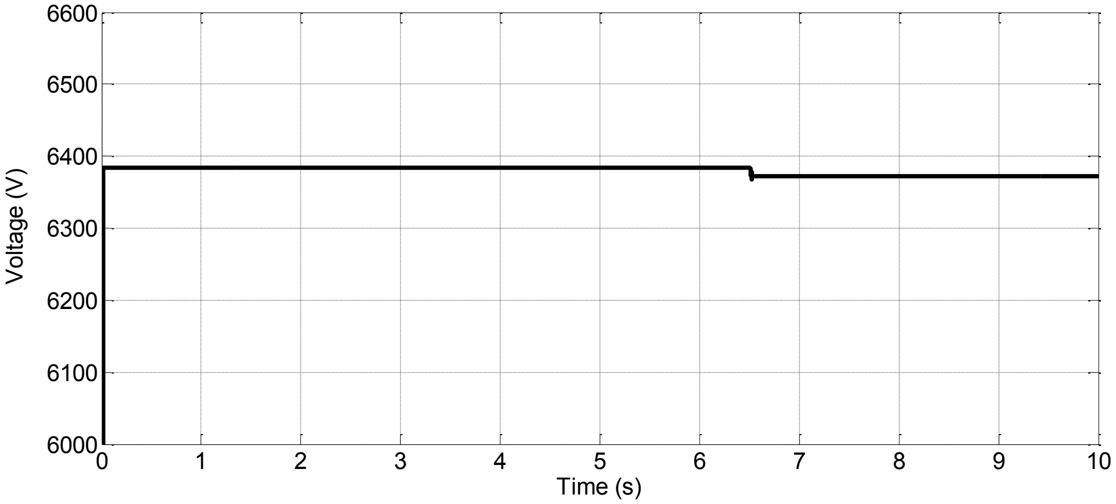


Figure 5.96 **Net RMS voltage through busbar 1 during Low Voltage Swell Test case**

In this case the current from the PV Source is also initially higher than the normal value. However, in this case the overvoltage in the grid is lower than the overvoltage experienced in the previous case. For this reason the relay trip time is slightly longer than previously and only one switch had to be opened to restore the voltage to normal levels. The voltage drop caused by opening a solar switch is the same in both cases. Only one voltage and current drop is witnessed in the duration of this test because out of the three switches only opens. This test shows that this is a form of controlling the overvoltage to protect against the grid from strains caused by voltage swells.

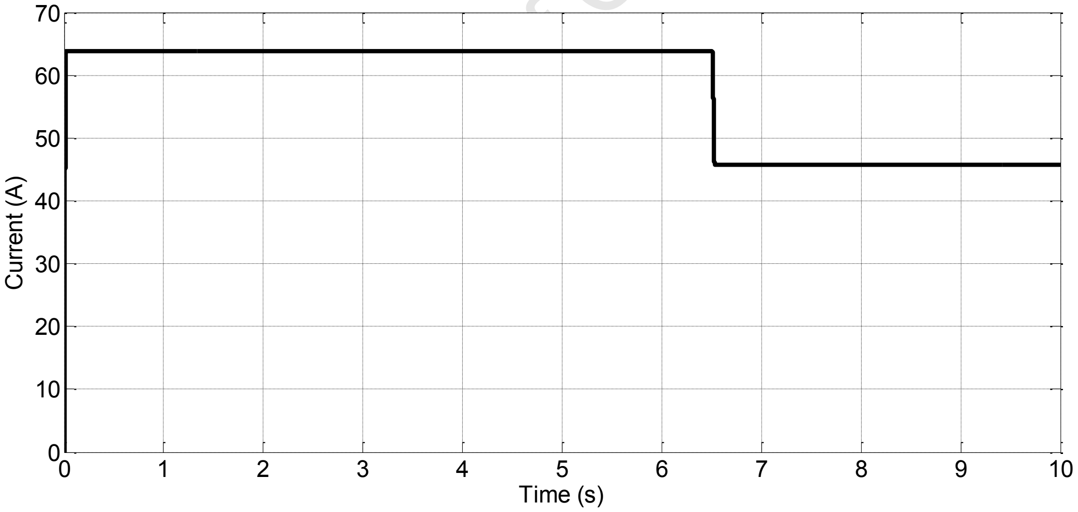


Figure 5.97 **Net RMS current through busbar 2 during Low Voltage Swell Test case**

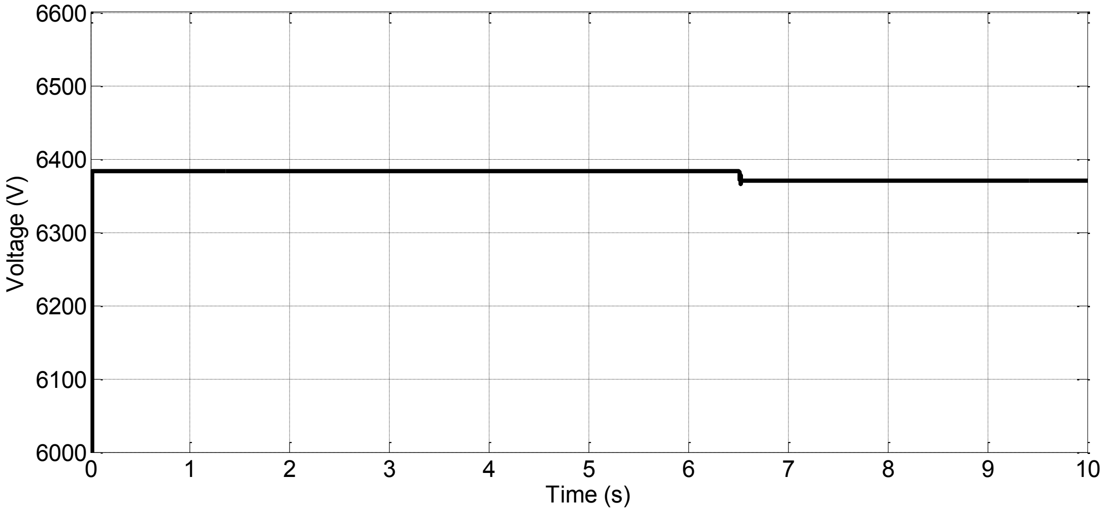


Figure 5.98 **Net RMS voltage through busbar 2 during Low Voltage Swell Test case**

In a similar manner to how busbar 2 in the previous test case was affected by the excessive power generation from the DG, the utility grid and busbar 2 are also affected in this test case. This phenomenon is depicted in Figure 5.97 and Figure 5.98, which show the RMS current and voltage respectively, during the test case. These results further demonstrate the fact that only one of the switches tripped during this test case.

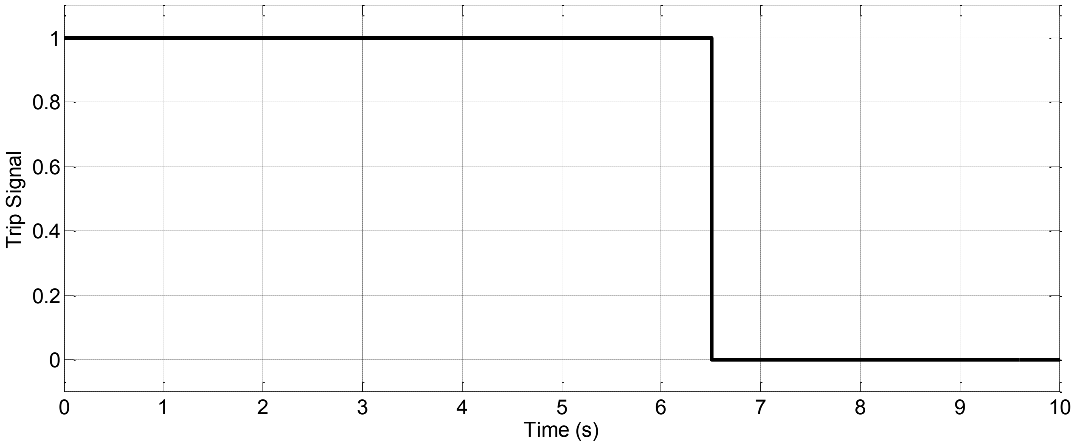


Figure 5.99 Solar switch 1 trip signal during Low Voltage Swell Test Case

Figure 5.99 shows the trip signal from the relay that did cause a switch to open. From the plot it can be concluded that the relay sent the mentioned trip signal at 6.5s. This is a longer delay because the overvoltage is lower. The trip times are set by an IDMT curve displayed in Figure 3.10.

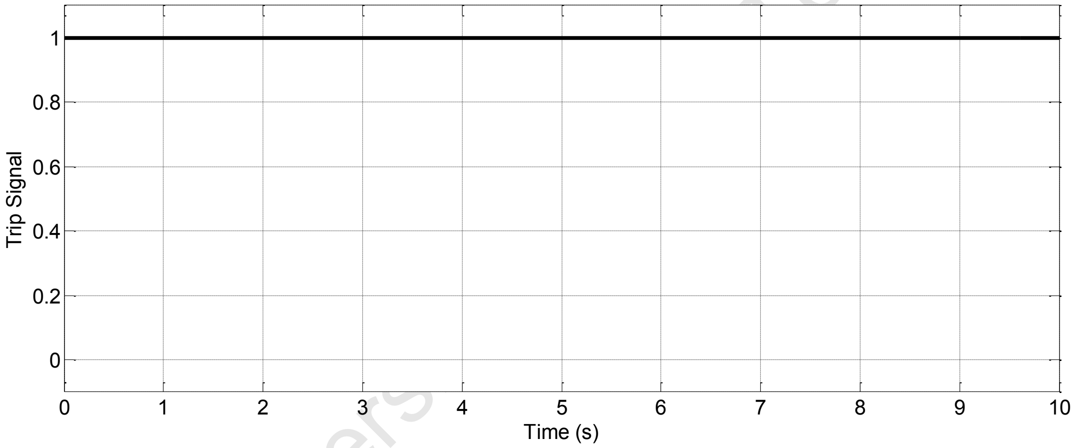


Figure 5.100 Solar switch 2 trip signal during Low Voltage Swell Test Case

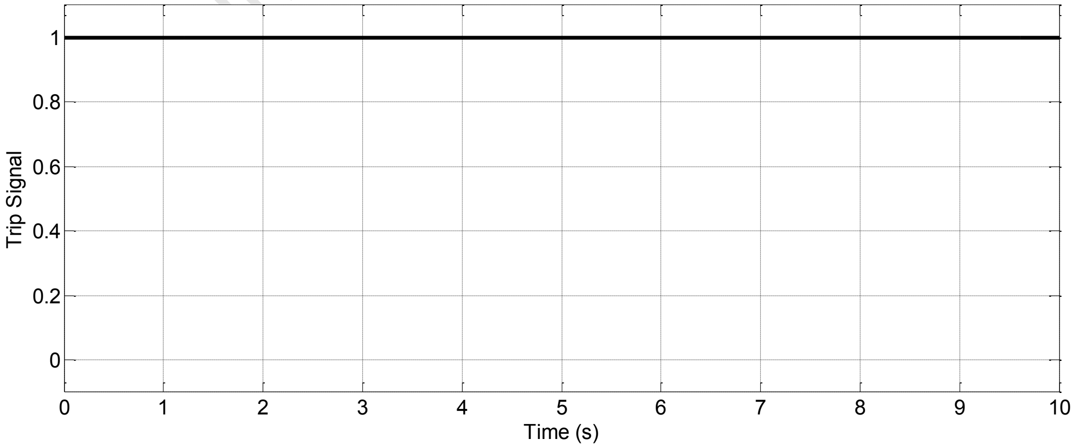


Figure 5.101 **Solar switch 3 trip signal during Low Voltage Swell Test Case**

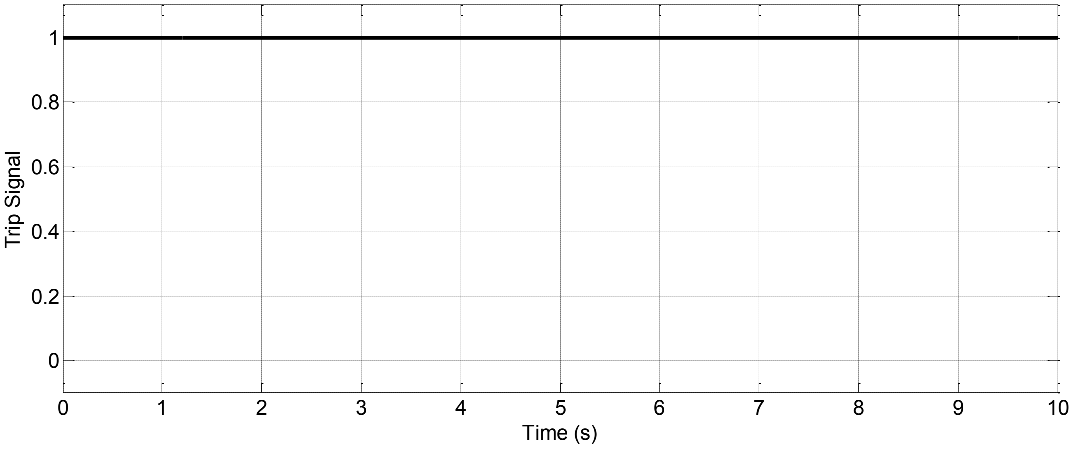


Figure 5.102 **Solar switch 4 trip signal during Low Voltage Swell Test Case**

The 3 previously shown pictures display flat relay trip signals, this shows that the other switches in the control scheme did not open. These switches would have opened in a sequential order, i.e. 2, 3, 4, if the preceding switch in the sequence failed to open the following switch would open to decrease the voltage in the system. However in the simulations in this test case none of the switches failed to open, therefore, no back-up protection was used.

5.6 Adaptive Protection System for a Microgrid with Solar PV generation

5.6.1 Test 14 - 3-phase fault on microgrid

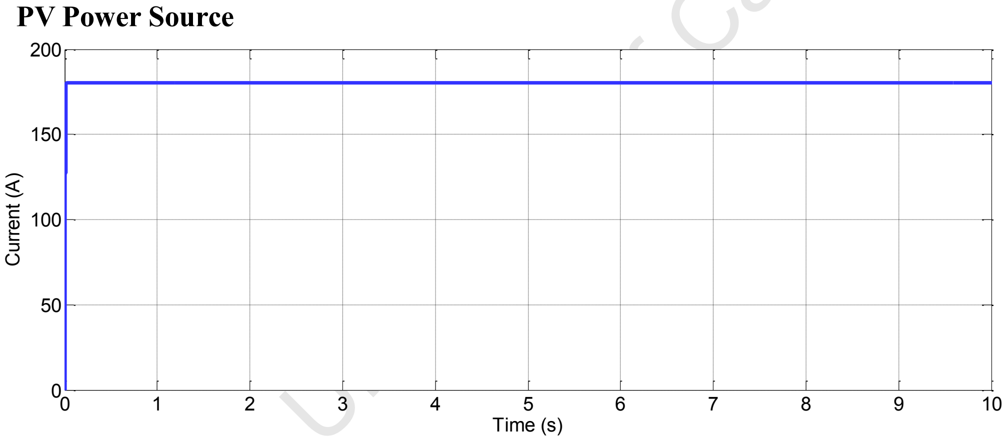


Figure 5.103 Solar PV output current RMS during Test Case 14

The plot above shows that once again the current generated from the solar PV source does not vary in the case of a 3-phase fault in the microgrid. This is consistent with the results obtained in previous test cases. This result is not abnormal and it is the exact result expected from the simulated model.

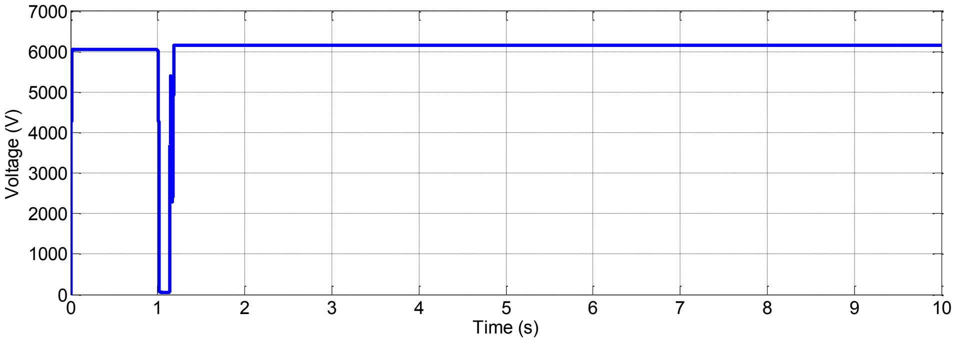


Figure 5.104 Solar PV Voltage RMS during Test Case 14

The voltage level at the Solar PV generator output shows some deviation from the norm in the case of a fault. During the fault, the voltage drops drastically in relation to the nominal voltage when the system is operating in normal conditions. Once the fault is cleared the voltage is restored to its nominal value at the nominal frequency. This is an important situation to achieve, particularly in a short period of time. The plot demonstrates the crucial portion of the simulation. Figure 9.60 in section 9 shows the RMS value of the signal for the entire simulation period.

Utility Power Source

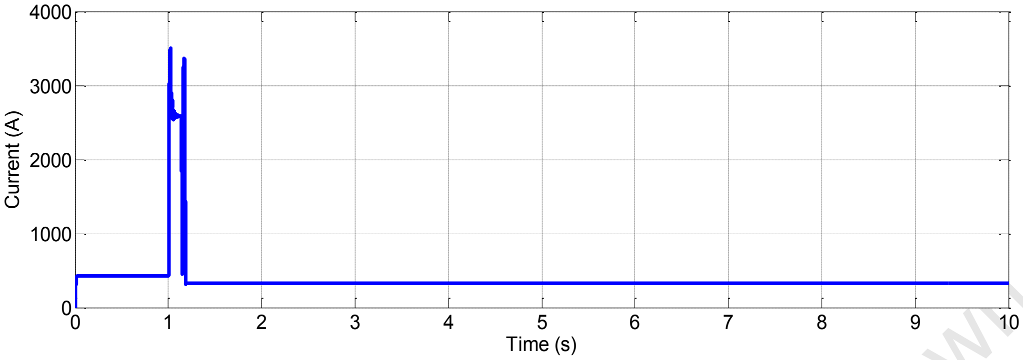


Figure 5.105 Utility Power source Current output during Test Case 14

The utility power source does not have a stable current source as the DG. The DG is limited as to how much current it can provide to the grid. Figure 5.105 shows the current variation during the test case. The signal shows 2 distinct peaks, one when the fault occurs and the other when the fault is cleared. The fault lasts for 0.16s, this is evident from the plot. Once the fault is cleared the current level is restored to its expected value. This shows that there is successful restoration of the system from a utility power source point of view.

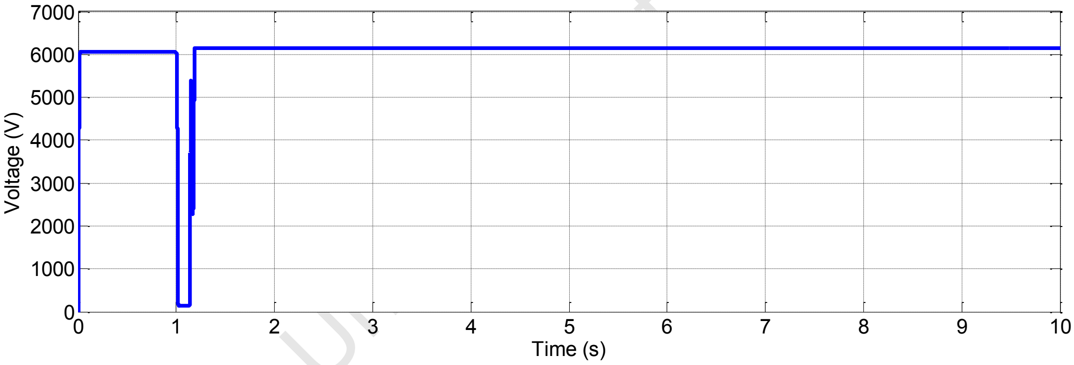


Figure 5.106 Utility Power source voltage level during Test Case 14

As well as the current, the voltage level in the utility generator was affected by the fault in the microgrid. The voltage dropped during the fault and recovered after the fault was cleared. This emphasises the point that the protection system is highly effective because from a utility point of view the fault occurred and was cleared without prolonged disruptions to the microgrid.

Local Load

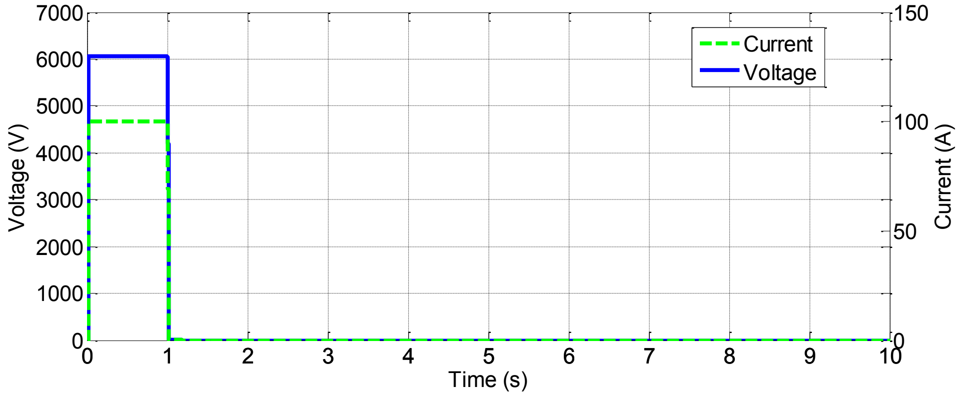


Figure 5.107 Local Load current and voltage RMS during Test Case 14

The local load is more affected than the utility load in this case because the fault occurs in close proximity to the local load. Once the fault occurs, at 1s after the simulation starts, the current does not reach the microgrid load. All the current generated by the utility power source and the DG is directed towards the fault and the two loads become deprived of any current. This state continues for the local load because once the circuit breaker is opened to isolate the fault, it isolates the load as well. In practical systems isolation of the load is avoided by designing networks with double busbars, so that if a supply point is affected by the fault, another point can be used to feed the loads without major delays. In a case where these is only a single point of supply, current to the load will only be restored once the fault has been fixed.

The voltage level in the local load was affected in the same manner as the current. For the same reason, practically, the voltage would only be restored once the fault has been fixed by maintenance personnel or the damaged equipment had been replaced.

Utility Load

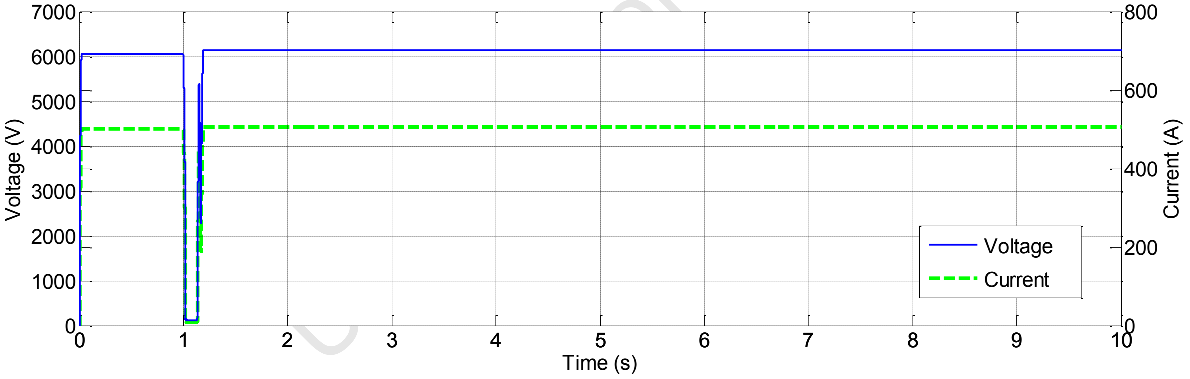


Figure 5.108 Utility Load Current consumption and voltage RMS during Test Case 14

The utility load and the local load are not equally affected by the fault. Figure 5.108 shows that the current through the utility load was only affected for a short period during the simulation. Once the fault was cleared the current was restored and the utility load was expectedly returned to its normal scenario. This result is important to note because it shows that a fault in the microgrid will not affect the utility grid for a long period of time because there is an efficient protection system in place.

The utility load voltage was affected in a similar manner to the current. This was restored to the normal value after the fault on the microgrid was cleared.

System Frequency

System frequency remained constant for the duration of this test case, for this reason the adaptive frequency relay is no expected to trigger a trip signal to the point of Common Coupling.

Relay Outputs

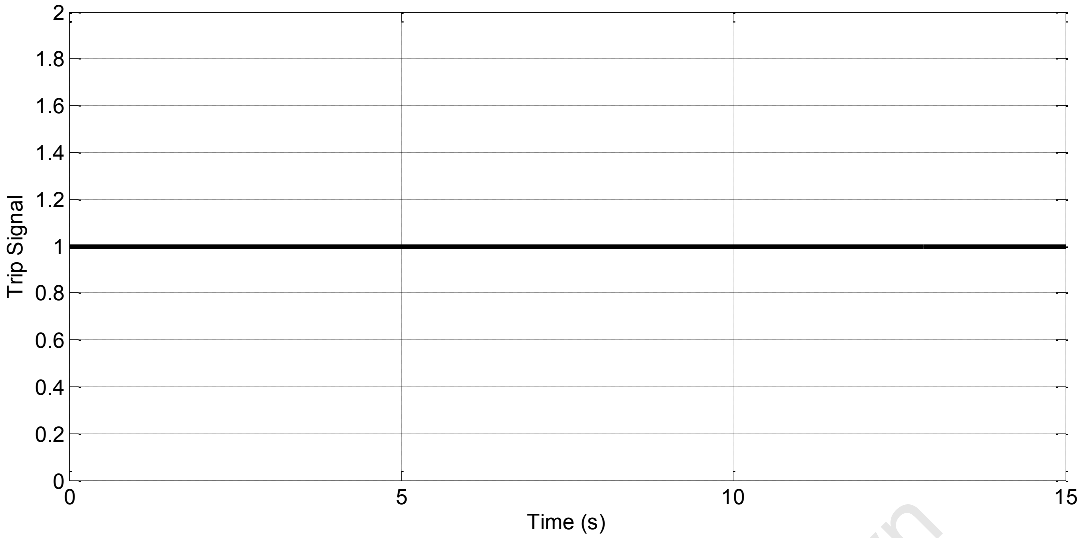


Figure 5.109 Overcurrent Relay 1 Trip Signal during Test Case 14

The relay outputs for this test case are similarly interpreted as the outputs for the other test cases. When the relay detects the fault, the signal changes from 1 = CB closed to 0 = CB opened. Overcurrent Relay 1 did not detect the fault, this is why the trip signal is constantly at 1 for the entire duration of the simulation.

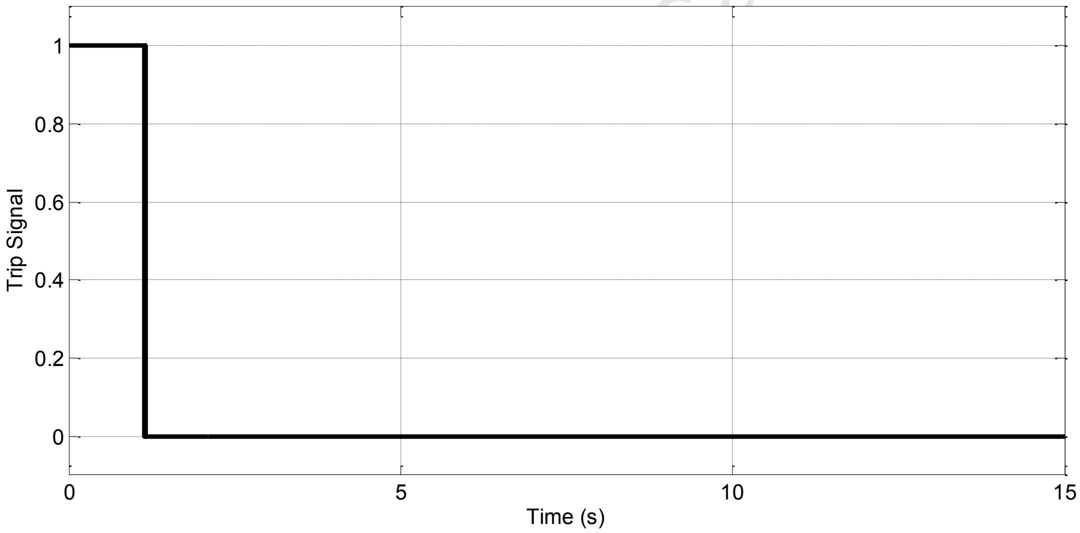


Figure 5.110 Overcurrent Relay 2 Trip Signal during Test Case 14

Overcurrent relay 2 is the closest overcurrent relay to the local load and to the 3-phase fault. Its location makes it ideal that it is the relay that triggers the circuit breaker to open and clear the fault. If any other circuit breaker had opened in this test case it could have caused more disruptions than necessary. This is a test result that shows the ability of the protection system to be selective, i.e. to open only the relevant or necessary circuit breakers. In this case there was a 0.16s time delay between the time the fault occurred and the time the fault was cleared. This delay is in line with the programmed delay for overcurrent relay 2.

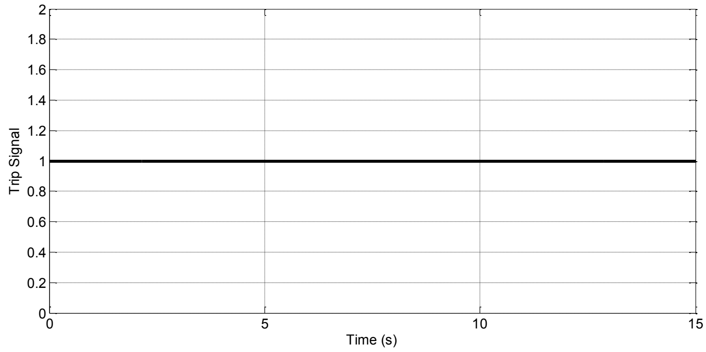


Figure 5.111 Overcurrent Relay 3 Trip Signal during Test Case 14

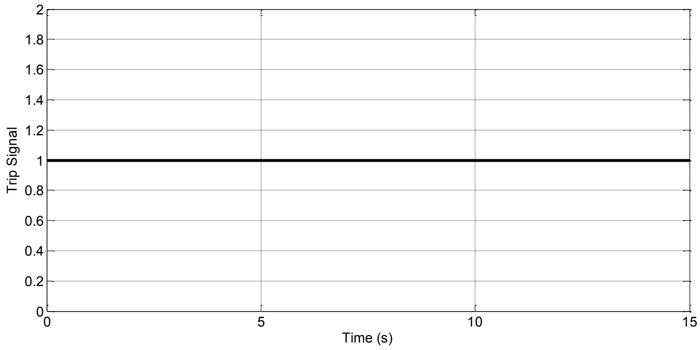


Figure 5.112 Frequency Relay Trip Signal during Test Case 14

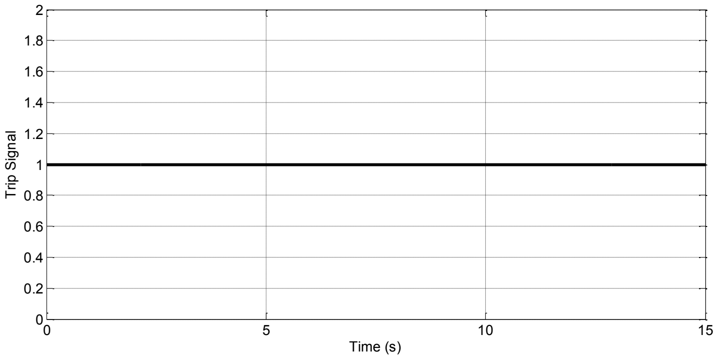


Figure 5.113 **Reverse Power Relay Trip Signal during Test Case 14**

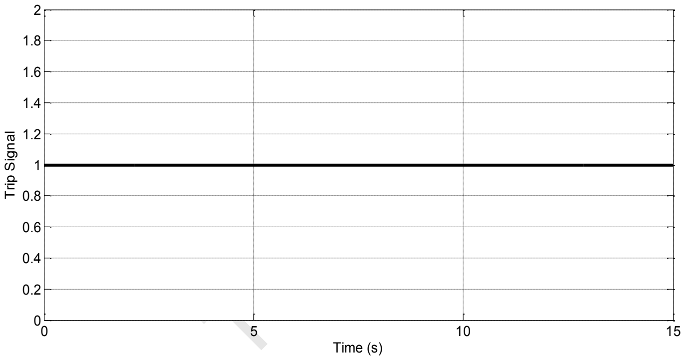


Figure 5.114 Overvoltage switch 1 status during Test Case 14

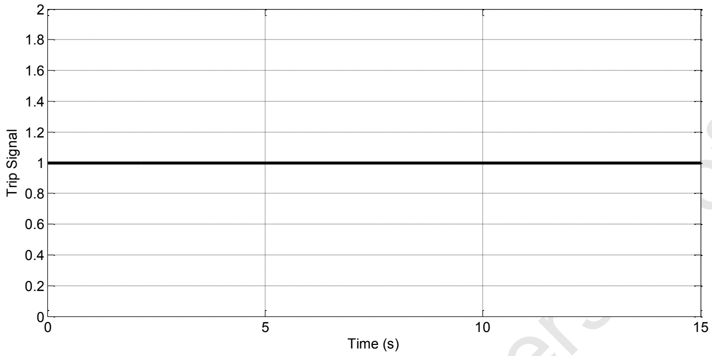


Figure 5.115 **Overvoltage switch 2 status during Test Case 14**

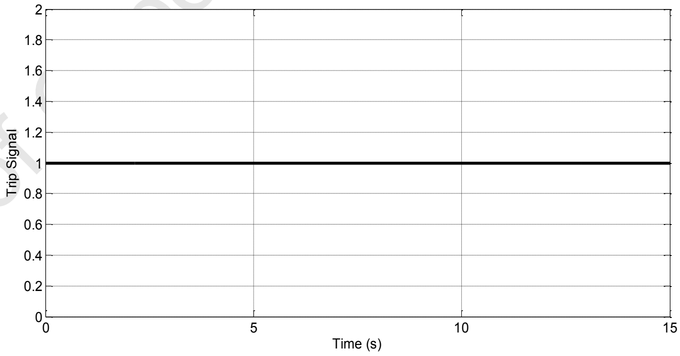


Figure 5.116 Overvoltage switch 3 status during Test Case 14

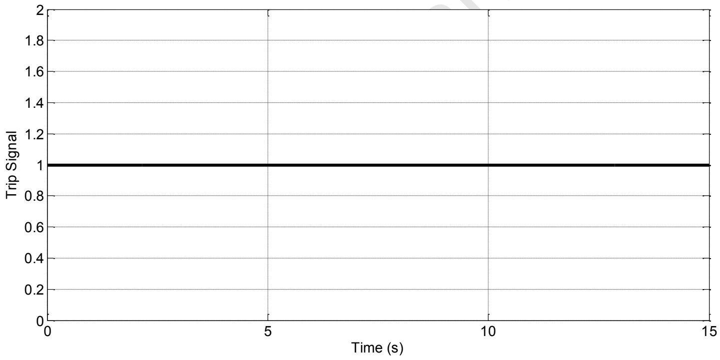


Figure 5.117 **Overvoltage switch 4 status during Test Case 14**

Figure 5.111 to Figure 5.117 show that no other relays detected the fault. Even though Overcurrent Relay 3 would have detected the fault, it did not trigger a trip signal because the overcurrent relays are coordinated in such a way that Relay 3 was a back-up to relay 2. There was a trip signal delay between the two relays and the fault was cleared before the delay was reached, for this reason only one relay caused a circuit breaker to trip.

5.6.2 Test 15 - Overvoltage Control Switching

PV Power Source

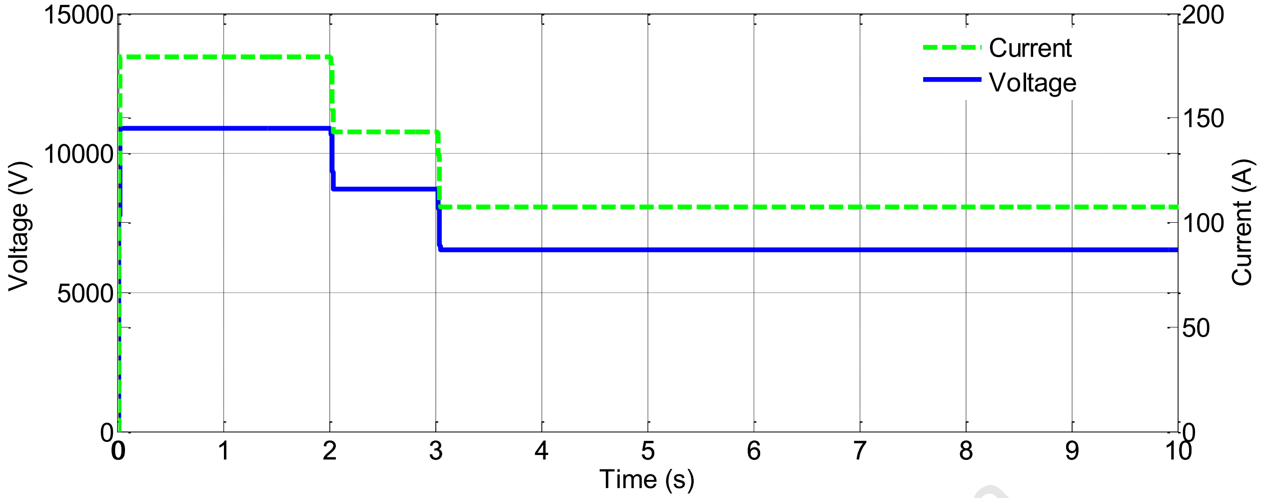


Figure 5.118 Solar PV Source Current and Voltage RMS during Test Case 15

Since this does not completely restore the voltage to acceptable levels (± 5%), a second switch (MCB2) is caused to open at 3s. The output current drop is the same with each switching operation because each string supplies the same amount of power to the network. Fig. 16 depicts the voltage level behaviour and current during the test case. From Fig.16 it is evident that the voltage level rises above the nominal 11kV when solar insolation is increased. The plots show that as switching occurs, the voltage is gradually restored to the nominal level.

Utility Power Source

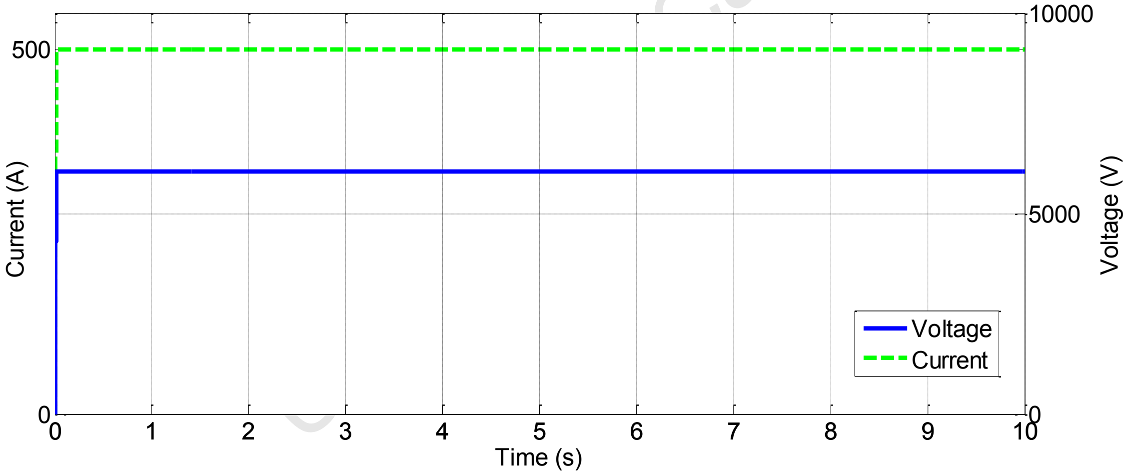


Figure 5.119 Utility Power Source output current and voltage RMS during Test Case 15

Local Load

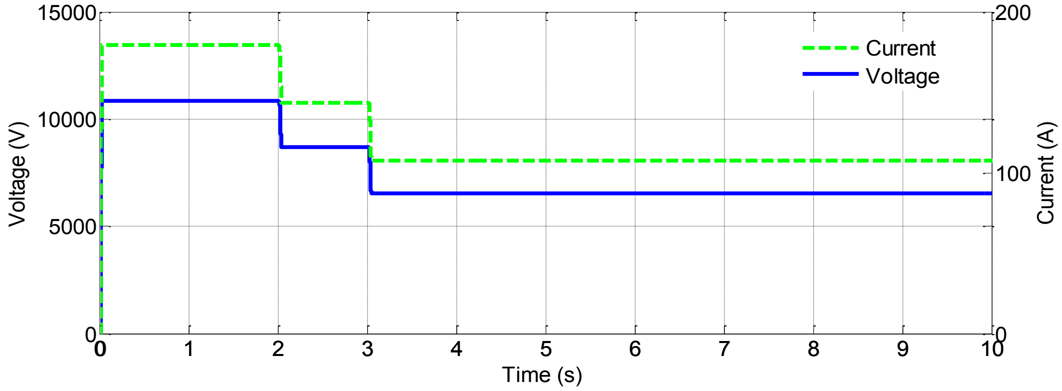


Figure 5.1 **Local Load Voltage level and current RMS during Test Case 15**

The switching activity that takes place in the solar PV generator has an effect on the microgrid load. The same current decrease patterns that are experienced in the generator are experienced in the nearby load. This is an important observation because the microgrid is in grid-connected mode. Fig. 5.120 shows the effects that the switching activities have on the load voltage and current.

The main aim of the switching system is to protect electronic loads from overvoltage. Electronic loads are the ones that are most prone to overvoltage damage. The fact that the voltage is reduced after a short period of time shows that the overvoltage switching scheme is highly effective in protecting the loads from strenuous conditions.

Utility Load

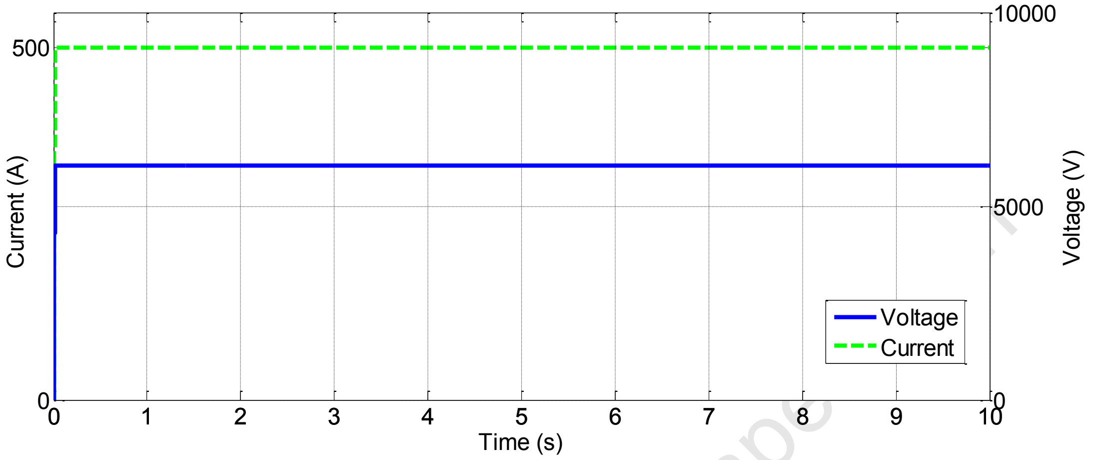


Figure 5.121 Utility Load Current during Test Case 15

The utility load current consumption is not affected by the overvoltage in the system or by the switching off of certain strings in the Solar PV Source. This is clearly depicted in the figure above. A reason for the current remaining constant is that any current demand deficit that the load may incur is compensated by an increase in current output from the utility power source.

The utility load voltage behaves in a similar manner to the current. It remains unchanged during the testing period. It is important to note that this load does not experience overvoltage, this abnormality is experienced in other regions of the power system. The utility load voltage is also depicted in Figure 5.121 above.

Relay Outputs

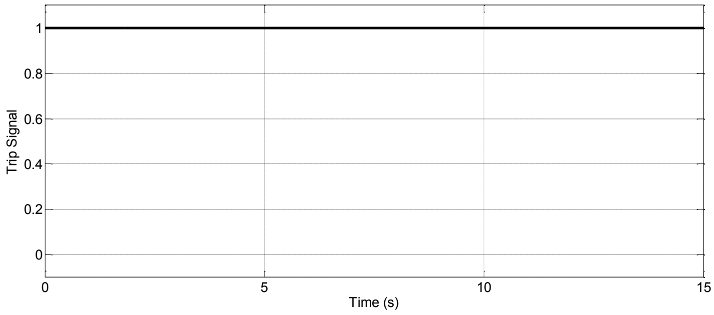


Figure 5.122 Overcurrent Relay 1 Trip Signal

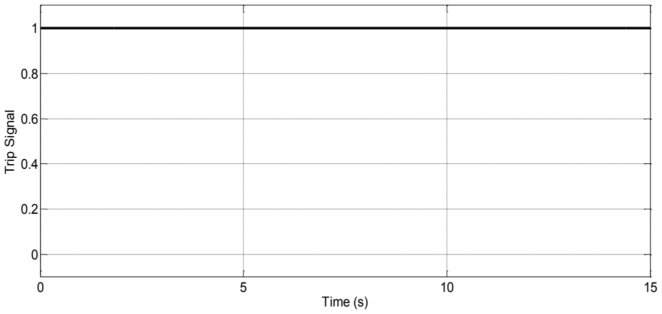


Figure 5.123 Overcurrent Relay 2 Trip Signal

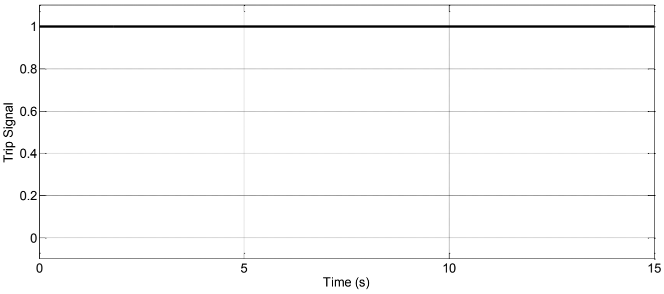


Figure 5.124 **Overcurrent Relay 3 Trip Signal**

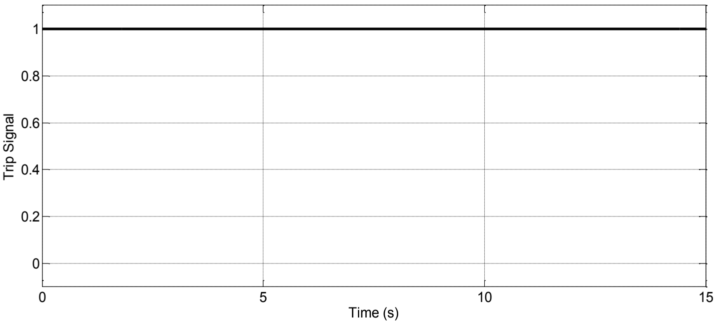


Figure 5.125 Frequency Relay Trip Signal

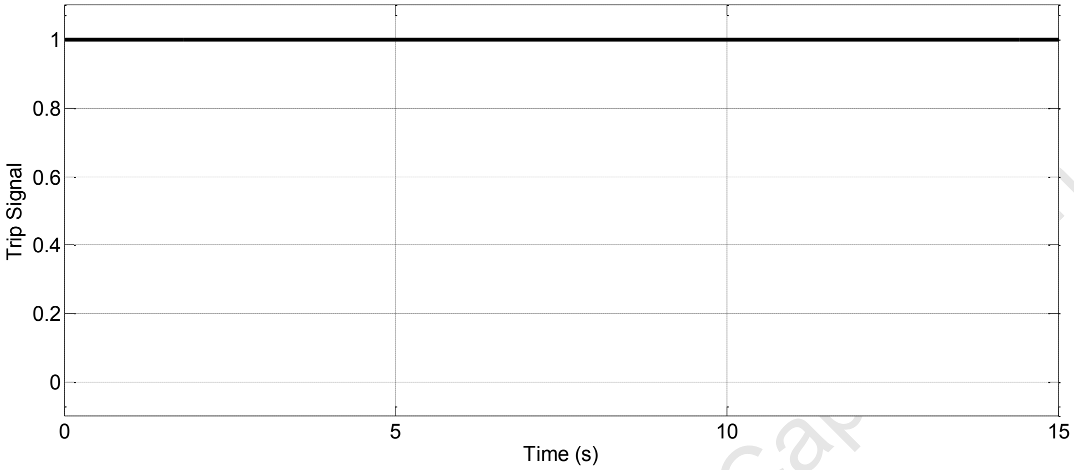


Figure 5.126 **Reverse Power Trip Signal during Test Case 15**

The relay signals depicted in Figure 5.122 – to Figure 5.126, show that the other relays in the power system did not react to the overvoltage scenario. Although the current output of the PV Solar source was higher than usual, it was not high enough to trigger the operation of overcurrent relays. There was no reverse power flow or system frequency deviation caused by higher solar radiation, for this reason the adaptive frequency relay and the reverse power relay did not pick up an abnormality.

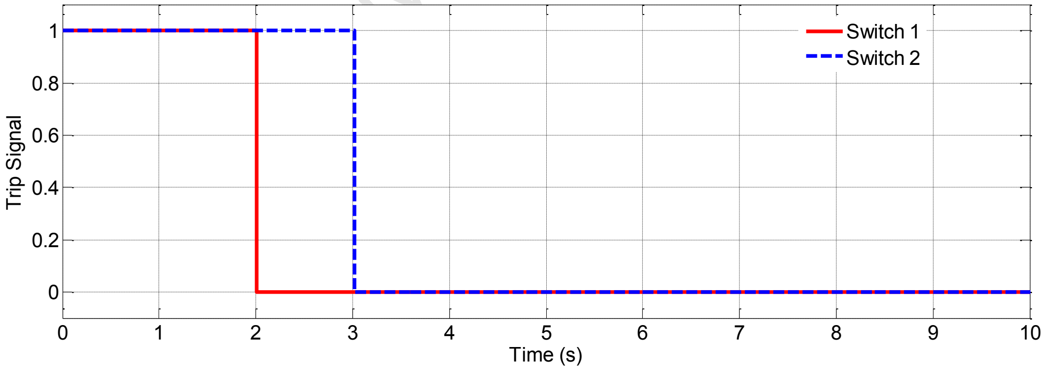


Figure 5.127 Overvoltage relay 2 Trip Signal during Test Case 15

Fig. 128 shows the trip signals generated by the overvoltage relay. Switch 1 opened at 2s and switch 2 opened after 3.1 s. The 1.1s delay between operations is due to the time delay set by the relay for operational delay between switches. This was done so that not all strings are disconnected at the same time and all generation is lost at once.

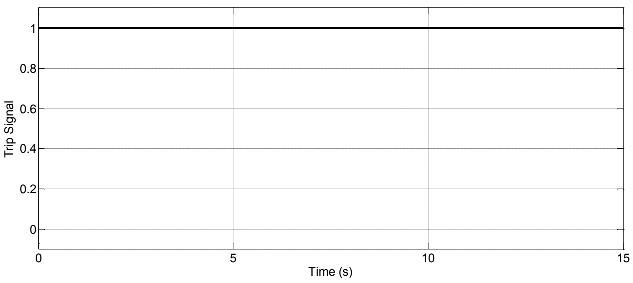


Figure 5.128 Overvoltage Relay 3 Trip Signal

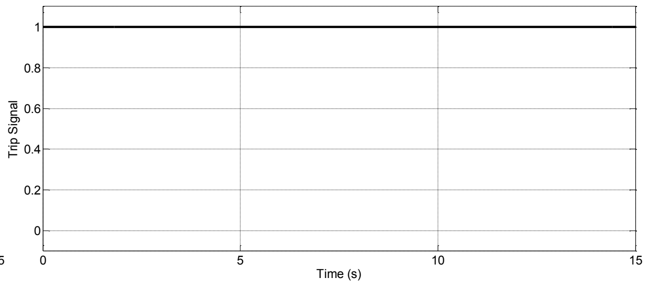


Figure 5.129 Overvoltage Relay 4 Trip Signal

Overvoltage switch 3 and overvoltage switch 4 do not open in this test case. This is because the solar radiation did not cause a high enough voltage to render the operation of these switches. If the simulated system overvoltage was higher these switches would have opened to disconnect the appropriate strings in the solar PV generation.

5.6.3 Test 16 - Loss of mains due to a fault

PV Power Source

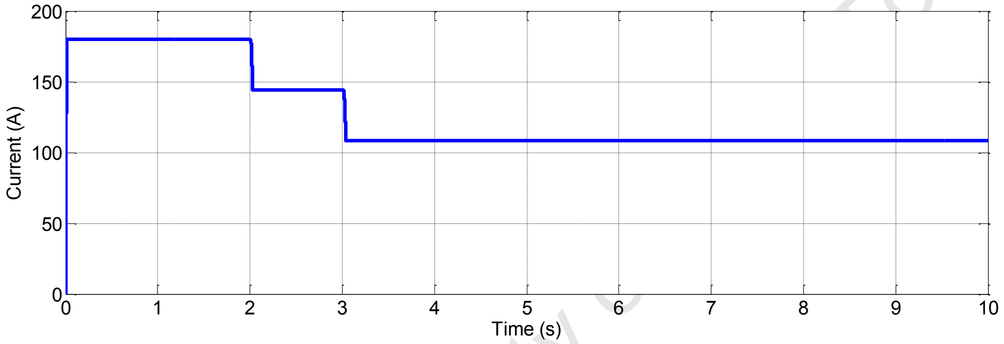


Figure 5.130 Solar PV Current during Test Case 16

Fig. 20 depicts the solar PV current output during the test. This figure shows that the current decreases during the test. The loss of mains event occurs at 1s after the simulation starts. The plots above show that the current does not vary after the loss of mains event this further shows that the current from the solar PV source does not increase during a fault. The drop in the current levels occurs once the overvoltage relays detect an overvoltage in the system and strings in the PV source are disconnected.

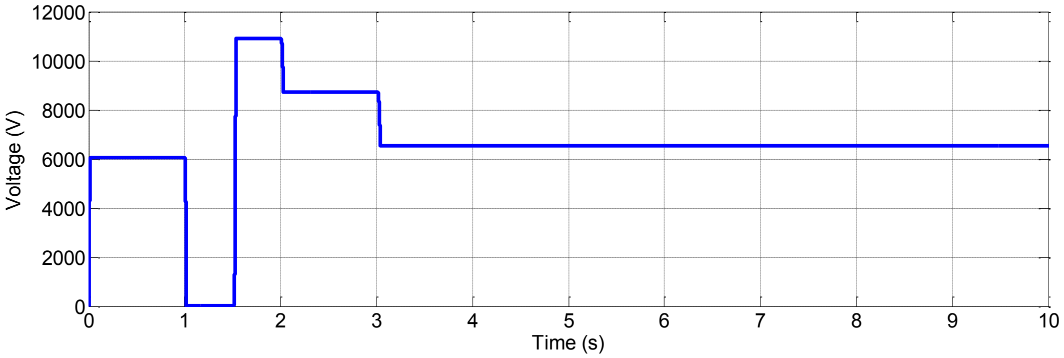


Figure 5.131 Solar PV voltage level during Test Case 16

Once the microgrid is turned to isolated mode the system voltage is not restored to its usual value, this is shown in Fig. 21. The value is higher than usual because the microgrid in isolated mode is under-loaded. As the overvoltage relay witnesses this excessive system voltage it triggers MCB1 and MCB2 to open in due times. This shows the adaptive quality of the overvoltage switching scheme because it is able to operate effectively in islanded mode, as well as in grid-connected mode as described in Test 2.

Utility Power Source

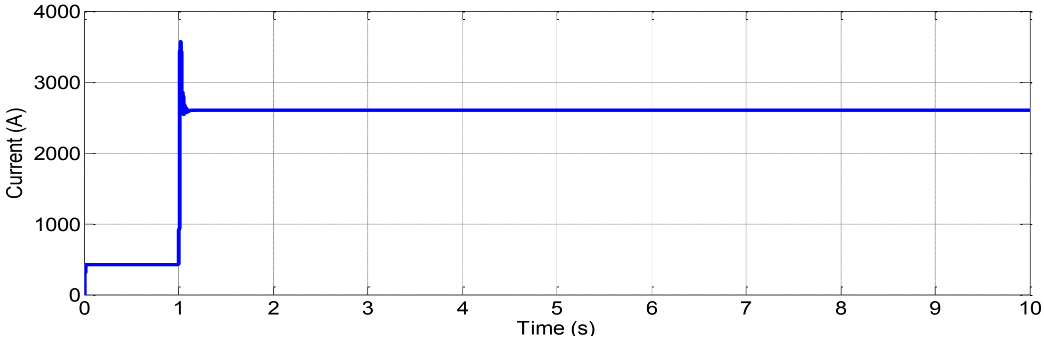


Figure 5.132 Utility Power Source Current output during Test Case 16

The utility generator behaves differently to the solar PV when a fault occurs, this can be seen in Fig. 22. In this case a fault occurs after 1 second and the current immediately increases because of this fault. The fault current remains in the system because the fault is not completely cleared or isolated. In real power networks the generator would have a CB to protect it and this CB would help to isolate the fault. However in this thesis only protection for the microgrid is being considered. The voltage drops to approximately zero once the fault occurs. The voltage is also not restored because the fault is not completely cleared.

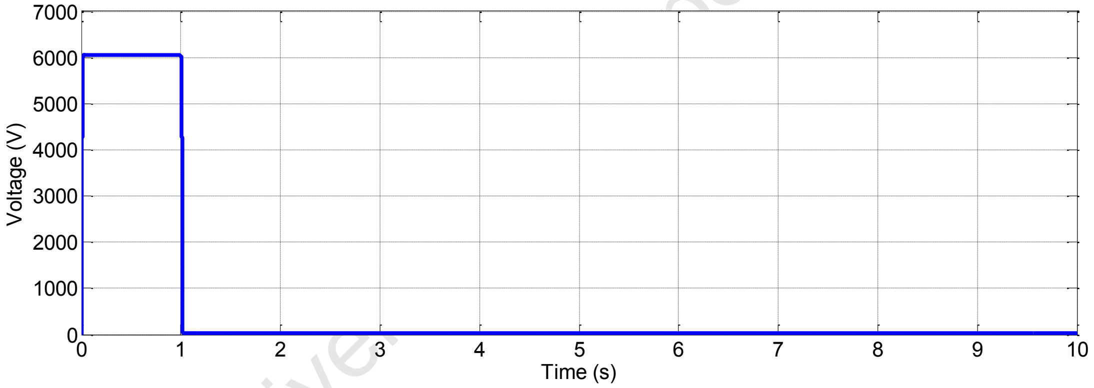


Figure 5.133 Utility Power Source Voltage level during Test Case 16

The utility source voltage dropped due to the fault event. This is a common and expected occurrence under the given circumstance. In order to restore the current and voltage levels the fault would have to be repaired in its entirety. The protection system presented in this research is not capable of clearing this fault completely, but it does protect the microgrid in the case of loss of mains.

Local Load

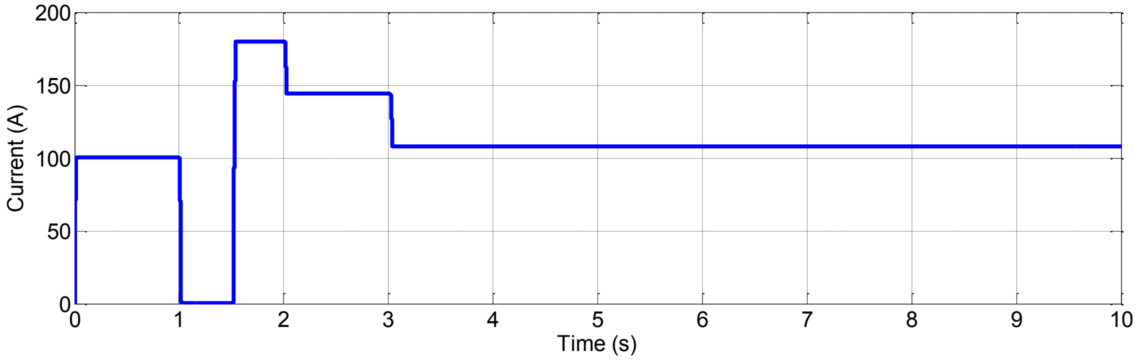


Figure 5.134 Local Load Current during Test Case 16

The microgrid load is affected by the loss of mains event. When the event occurs the current supplied to the microgrid load decreases to approximately 0A. This is because most of the generated current is supplied to the fault. Once the fault is cleared by switching the microgrid to isolated mode, the current to the load is excessive and needs to be reduced. This occurs by disconnecting some of the PV strings. After 3 seconds the microgrid load is restored to normal operation as depicted in Fig. 23. The microgrid load voltage level was affected in a similar way to the current but was also successfully restored.

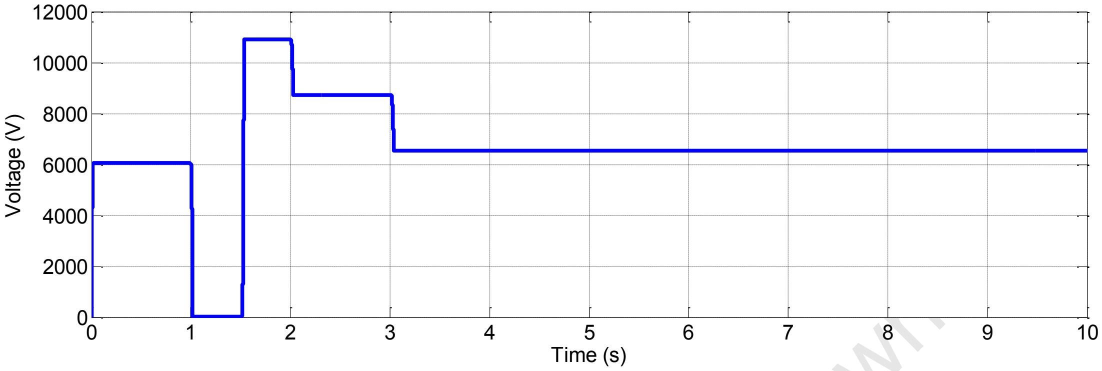


Figure 5.135 Local Load Voltage level during Test Case 16

The voltage level started off at the nominal voltage level. Once the 3-phase fault occurred the voltage dropped and there was a reverse power flow in the power system. This reverse power flow triggered the opening of the static switch which in turn led to isolation of the microgrid. The overvoltage switches disconnected 2 strings in the PV generator causing the step drop in voltage in the system.

Utility Load

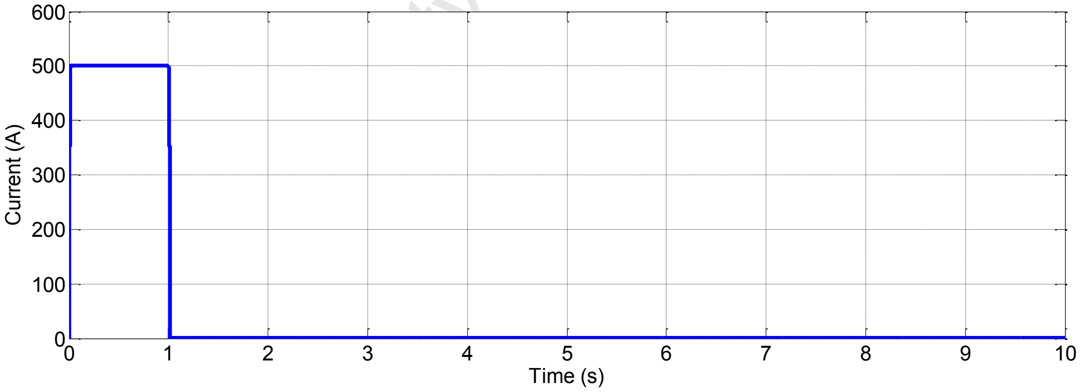


Figure 5.136 Utility Load current consumption during Test Case 16

The current and voltage in the utility load are affected directly after the fault occurs. The fault in location of Point B has the effect of preventing the current flow to the utility load. The fault becomes isolated from the microgrid after 1.5s, however, the utility load remains affected by the fault, and hence the current and voltage levels on the utility load are not restored. Figure 5.136 shows the RMS utility load current consumption during the simulation of Test Case 16.

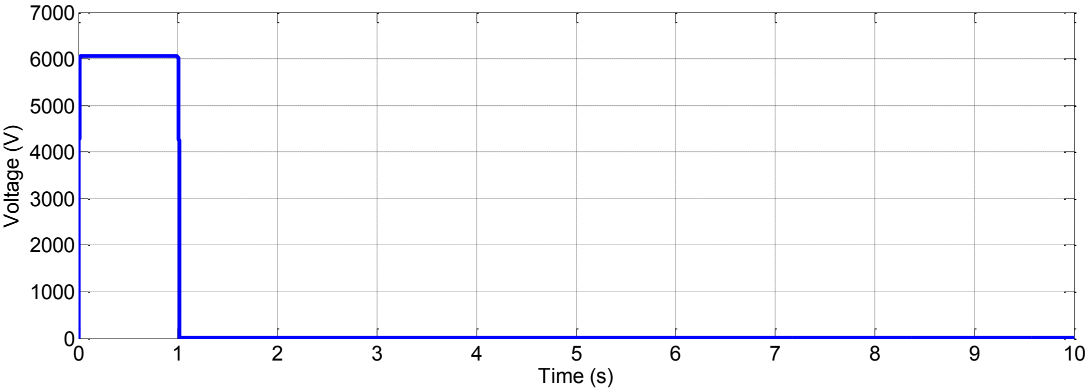


Figure 5.137 Utility Load Voltage level during Test Case 16

As previously discussed the voltage of the utility load is affected by the fault which causes the loss of mains. This is shown in Figure 5.137. The voltage is decreased because the solar PV source is too small and becomes overloaded. Once the fault is isolated the voltage is not restored because the utility load is not connected to any generation sources.

Relay Outputs

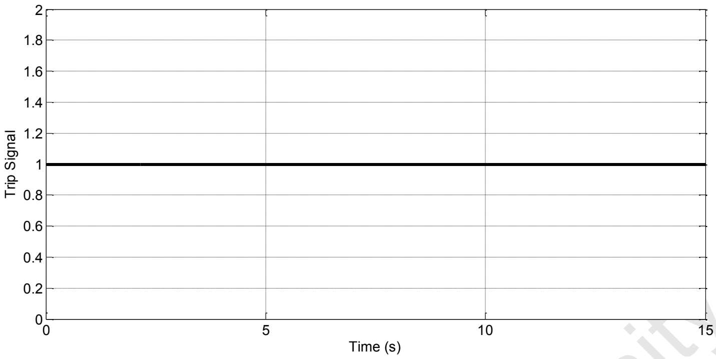


Figure 5.138 Overcurrent Relay 1 Trip Signal

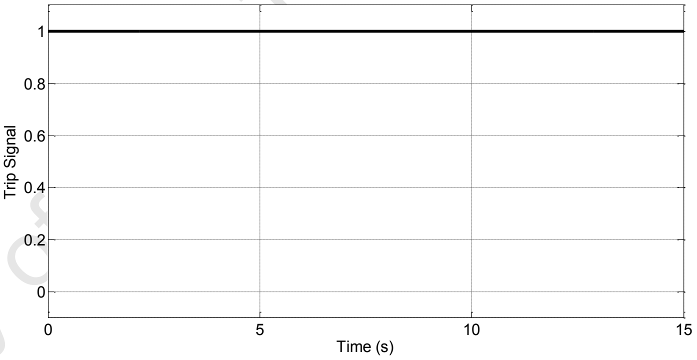


Figure 5.139 Overcurrent Relay 2 Trip Signal

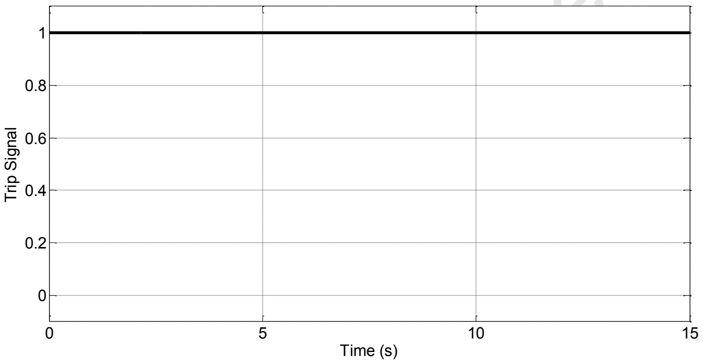


Figure 5.140 **Overcurrent Relay 3 Trip Signal**

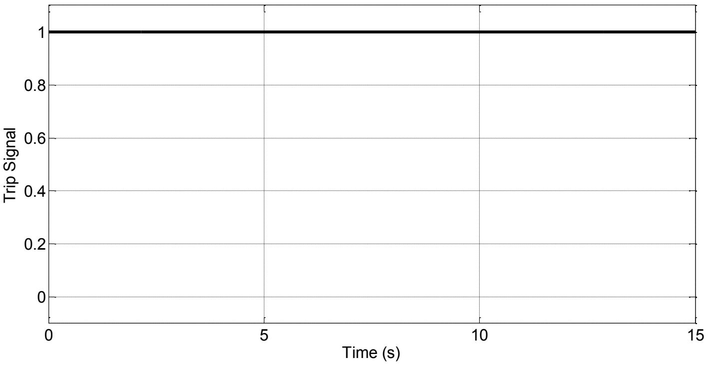


Figure 5.141 Frequency Relay Trip Signal

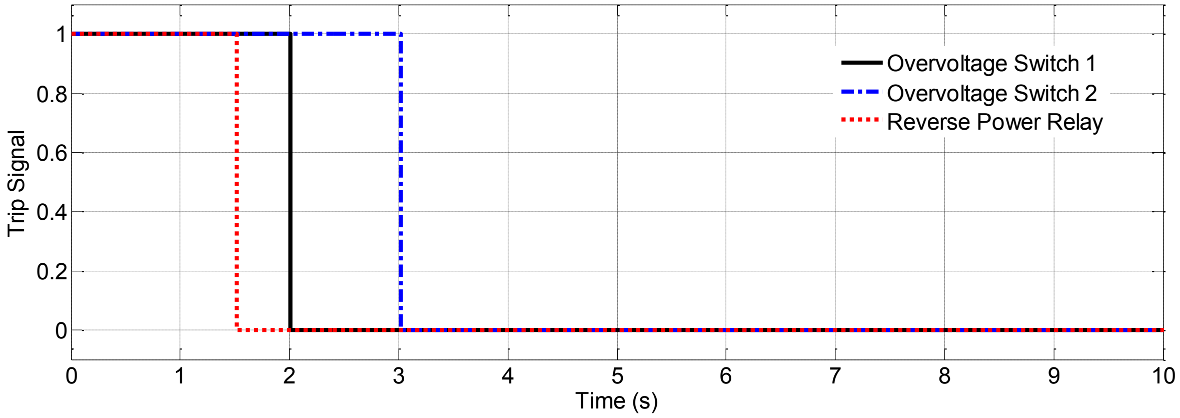


Figure 5.142 **Overvoltage Relay 2 Trip Signal**

The relay outputs plot for this test case further demonstrates the complexity of the protection requirements in this test case. Fig. 24 shows the various relay outputs during Test 16. The reverse power relay was the first to react at 0.5s after the fault occurred. Then the overvoltage controlled switching played its role by opening MCB1 and MCB2 at 1s and 2.1s respectively after the fault occurred.

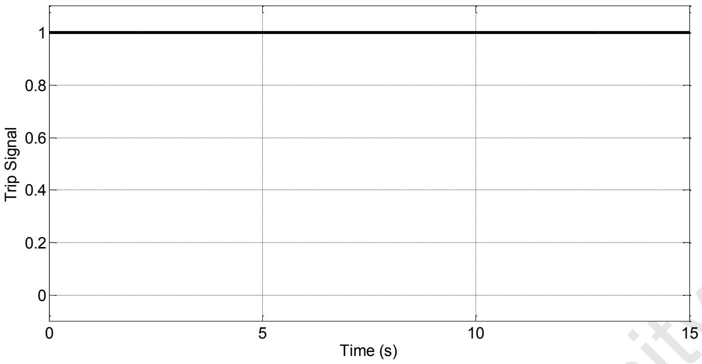


Figure 5.143 Overvoltage Relay 3 Trip Signal

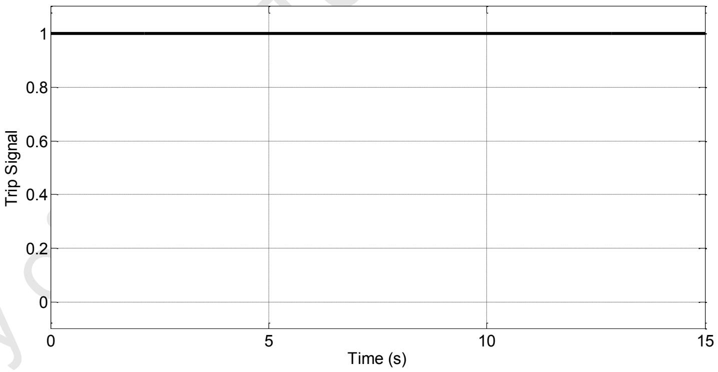


Figure 5.144 Overvoltage Relay 4 Trip Signal

5.7 Use of Load Management techniques to aid System Protection

5.7.1 Test Case 17 - Regional Load Shedding

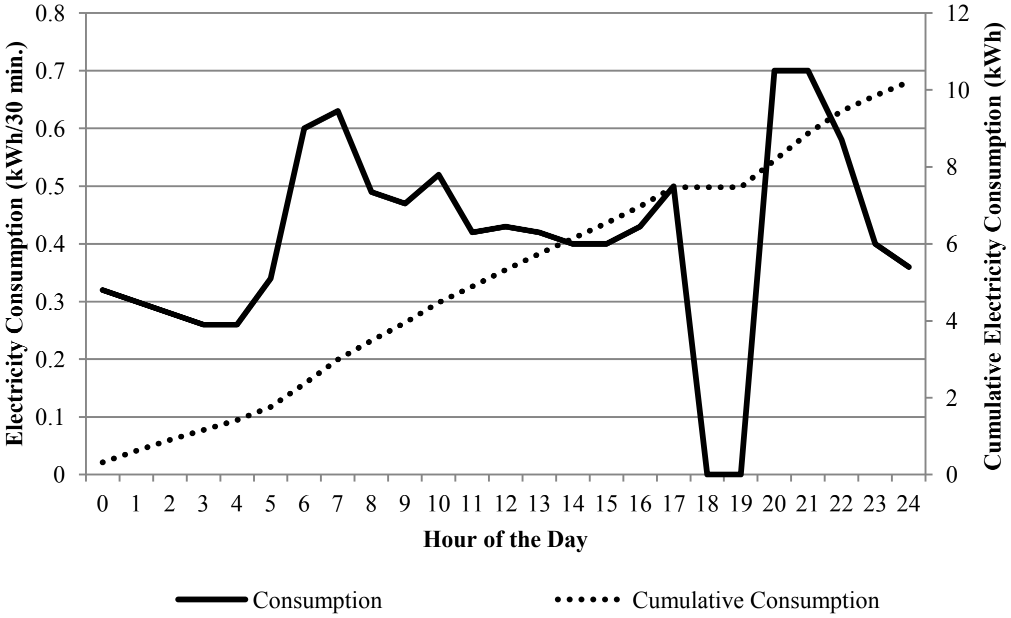


Figure 5.145 Domestic Load Profile with Regional Load Shedding

The load profile resulting from this form of load management is displayed in Fig. 5.145. For two hours of the day the consumer has no access to electricity. This means that the Utility deals with a shorter peak demand period, making system operation easier and putting less strain on the generating units. This method may facilitate operation but is very unpopular amongst consumers and reduces the daily revenue collected by the Utility.

In this case the total energy consumption would be 10.21kWh, which corresponds to a daily revenue collection of ZAR8.73.

5.7.2 Test Case 18 - Load Shifting

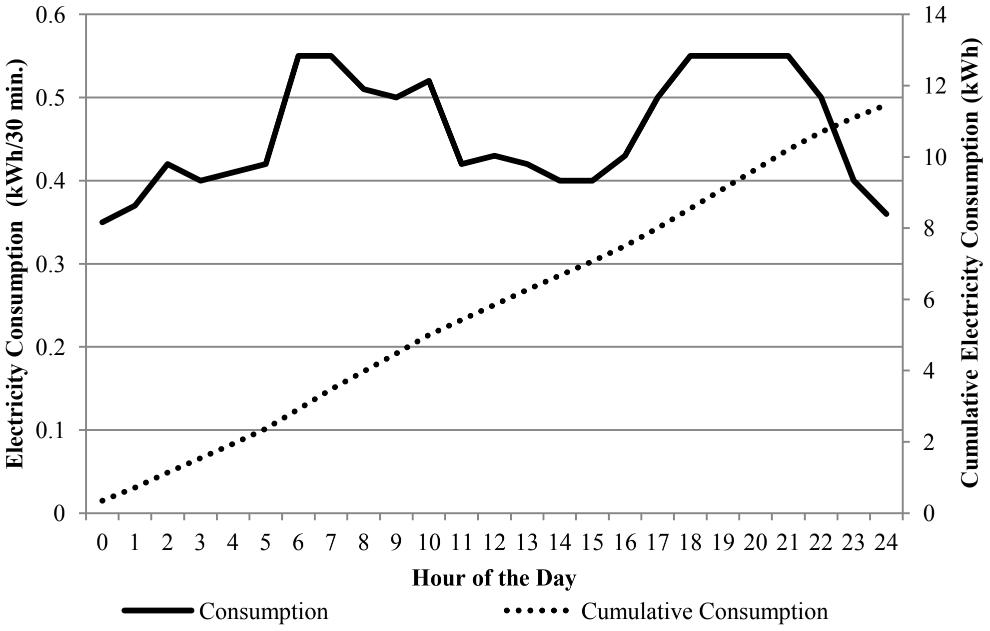


Figure 5.146. Domestic Load Profile with Load Shifting

During this model run the daily energy consumption was kept the same as the normal case but it was spread more evenly throughout the day, reducing the peaks to 0.55kWh/30min and increasing consumption during the low consumption periods, minimum consumption was 0.36kWh/30min. This method could prove convenient to customers who can afford load control or load scheduling devices. This way some loads such as washing machines and pool pumps could be programmed to operate during periods of low demand even if the consumer is not at home. This would enable the consumer to have a firm electricity supply throughout the day and the Utility would not lose any revenue due to the disconnection of loads.

The load profile is depicted in Fig. 5.146. Again the cumulative consumption was 11.46kWh, allowing for a revenue collection of ZAR9.81 for the day.

5.7.3 *Test Case 19 - Peak Clipping*

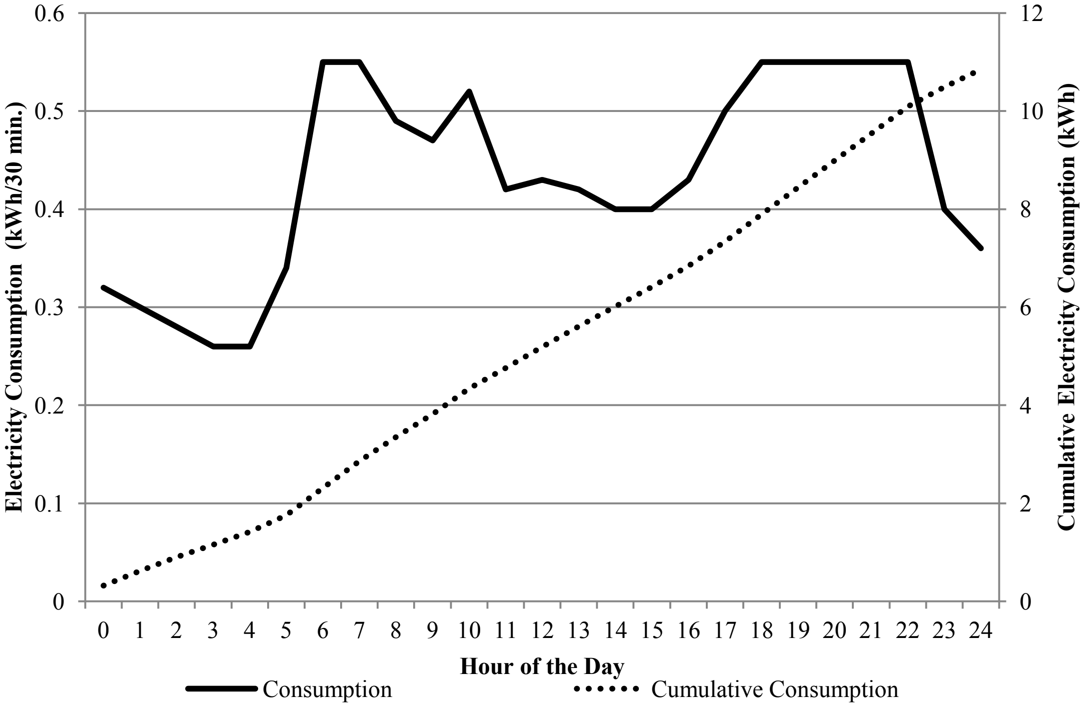


Figure 5.147. Domestic Load Profile with Peak Clipping

In this case the load was curtailed at 0.55kWh/30min, this method is applied by the Utility to reduce the strain on generating units. However, in simple peak clipping, no mechanisms are adopted to increase the load during low demand times. This means that the Utility collects less revenue than the normal case, which is not ideal.

The cumulative electricity consumption in this case is 10.85kWh, which leads to a revenue collection of ZAR9.28 per day.

6. Conclusions

Based on the foregoing information, the following conclusions have been drawn.

The relay models developed using Matlab Simulink are based on the functionality of digital relays. Unlike electromagnetic relays, digital relays have additional options such as mode of operation. This additional function was used to develop the relay model used in this project. The relays' ability to operate in different modes makes them effective in adaptive relaying. Load management can be used to reduce the strain on power networks, this decreases the likelihood of system failure, hence supporting the protection system.

6.1 Adaptive Overcurrent Relay

As can be seen from tests 1 to 3, the fault currents in Microgrids differ with the mode in which they are operating. In the grid connected mode the fault current is generally higher than that in isolated mode of operation. This is because more sources contribute to the fault current in the grid connected mode. This influences the protection system used in microgrids and in utility grids connected to microgrids.

The primary and back-up components are coordinated in the same manner as in utility grids, but because the loads are sensitive, there is a need for a smaller coordination time interval.

From all the tests it can be concluded that the fault current for the photovoltaic generator does not vary. Current from this renewable energy source is dependent on solar radiation rather than the presence of a fault. The adaptive overcurrent relaying scheme developed in this thesis takes into account the difference in fault currents, modified protection system coordination and digital relaying. The combination of all these different factors created an effective adaptive protection system. The developed scheme passed tests 2 and 3. This demonstrates that it is appropriate in cases when the microgrid is connected to the utility. When the microgrid is operating in isolated mode the relays don't see the overcurrent or the fault because the PV source does not produce an excess in current. This is an interesting fact and from it, it can be concluded that overcurrent relaying alone is not appropriate for protecting microgrids with solar PV generation.

6.2 Overvoltage Switching Scheme

The results of the simulations in test cases 12 and 13 analysed in this thesis show that system overvoltage in grids with PV generation can be avoided by controlled switching of solar panel strings. Reverse currents can be decreased by decreasing the amount of power generated by the PV plant. Effective switching coordination through time delays is important for the switching scheme to be useful. A scheme similar to the one presented in this thesis can be implemented on existing plants as well as future PV plants to facilitate compliance with distribution system grid codes.

The proposed overvoltage switching scheme is a big advancement from the present systems, which use inaccurate manual switching methods or voltage control mechanisms which are expensive.

6.3 Reverse Power relay

It can be concluded from the test cases 4 to 7 and results that reverse power relaying is most effective in detecting loss of mains when the DG capacity is large. This is useful because most methods of loss of mains protection being used at the moment are least effective when the DG capacity is large. This reverse active power relaying method can be used to compliment or as back-up to more traditional loss of mains protection methods, such as ROCOF relaying, to provide a complete solution which will detect all of the abnormalities and protect the microgrid from all of the harms of Loss of Mains. This scheme is useful when other methods such as ROCOF and frequency drop relays are not sensitive enough to detect an abnormal scenario. It is also better than active systems because it is not intrusive and better than most passive systems because it is reliable.

6.4 Adaptive Frequency Relay

From the review of literature and test cases 8 to 11carried out it can be concluded that there is a need for adaptive frequency relaying in Microgrids. This relay can be included at the Point of Common Coupling where it would be useful in detecting events such as loss of loads and sudden load pick-up in the Microgrid. To satisfy the grid codes in both Island and Grid Connected modes of operation, the relay needs to have multi-setting capabilities and it is preferable if it has adaptive capabilities for faster configuration.

Tests 8 to 11 show that the proposed adaptive relay will be suitable for a relay operating in Grid connected mode or Island mode. Its connection to the static switch, which may be via any reliable communication media, informs the relay of the mode of operation of the Microgrid and allows for settings to be adjusted accordingly. If anomalies are detected, the appropriate circuit breaker is opened, the disturbance is cleared and the system frequency can be restored to acceptable levels.

This thesis presents a use for an adaptive over and under frequency relay, which can make the protection system more robust and allows the protection devices to cater for a wider range of abnormal events which in turn makes the protection system more reliable. This is definitely a change from the conventional frequency relaying schemes. The novelty of the design is both useful and practical.

6.5 Load Management Techniques for a Microgrid

From the load profile models investigated it is evident that each load management technique has its advantages and shortfalls. The method that appears to be more attractive is the load shifting technique because through the use of this method the Utility still collects as much revenue as in the normal case and the consumer will have the minor inconvenience of having to operate some loads during less demanding periods. Peak clipping would be the second favoured method of the three because the Utility still loses some revenue by limiting the peak demand available. Regional Load Shedding is the least favourable of the three methods because it leads to loss of revenue by the utility and consumer discomfort.

Even though some of these techniques are being applied in some regions at a small scale, it would be a progressive step if these methods were implemented country wide. In order to accommodate the demand growth in the country, South African Utilities should look more closely at the advantages of using load management techniques, specifically load shifting, as a means of a short term solution to the supply-demand imbalance. Load management will also relieve the strain on DGs and overloaded Utility networks, this supports the protection system by decreasing the amount of times it needs to operate.

6.6 Overall Adaptive Protection Scheme

It is evident from the results that the Solar PV Generator current magnitude is not affected by faults in the system. This poses difficulties in protection systems since most protection systems are based on current measurements. This thesis presents a scheme that can overcome this difficulty by providing different types of relays that operate based on other system characteristics in addition to current. Efficient coordination of the relays and prioritisation of fault conditions is important in achieving robust protection of the electrical network. The presented systems have proved to be adaptive by successfully clearing faults while the microgrid is operating in both modes of operation. In most test cases the protection system is intelligent enough to restore the microgrid to normal operation without external intervention. The relaying scheme proposed in this thesis proved highly successful in detecting abnormalities and protecting the power system when necessary.

Although the cost of implementing such a protection system was not analysed or compared to present protection systems, the proposed methods are technically viable and if put to practice could prove to be beneficial in the many ways suggested in the thesis.

7. Recommendations

On the basis of the above conclusions the following recommendations are made:

7.1 Use more connections between static switch and relays to share information

In future work the detection of mode of operation by PCC static switch status could be investigated. This could possibly make the protection system more reliable. Instead of having predictive relays which detect the mode of microgrid operation based on system conditions. The relays could be modified to communicate with the static switch, which would provide accurate information regarding the state of microgrid operation.

7.2 Conduct Tests with different types of faults

Through the duration of this project a 3-phase fault has been simulated to get the presented results. This was done because 3 phase faults produce the highest fault current and in terms of fault magnitude, it is the worst case scenario. In future work, different types of faults such as single line to ground and line to line faults could be simulated to observe the protection system's performance under those conditions.

7.3 Apply the relay models to practical systems

Not many researchers have applied adaptive relaying technologies to real microgrids. The application of these methods on to real practical systems would provide valuable results to the industry. It is a well-known fact, that software simulated tests vary in results to tests carried out in hardware. It is important to implement these tests in microgrids with PV solar generation to validate the results obtained.

7.4 Use the relay models to implement microgrid self-restoration

Another advantage of digital relaying is that relays can interface directly with network control systems. I step ahead from the research presented in this thesis, would be to use protection systems to aid in microgrid restoration after a fault. Some characteristics such as system re-synchronisation would have to be investigated to find ways in which adaptive protection systems can help with microgrid self-restoration.

7.5 Investigate adaptive protection methods for the DC portion of the microgrid

Microgrids containing renewable energy generally have a DC component which feeds DC loads. This component would include a DC busbar which like any other busbar is exposed to faults. It is important to investigate the best ways to protect the DC busbar and the loads. In this research only faults after the inverter where investigated, these faults only had an AC component. Faults of a DC nature need to be catered for and the protection systems for those, should not interfere with the protection relays on the AC side of the inverter.

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9. Additional Results

This chapter presents some additional results from the tests and simulations. These results further demonstrate and compliment the results previously presented in Chapter 5.

9.1 Normal Case

9.1.1 Grid Connected Case

Busbar 1 Current

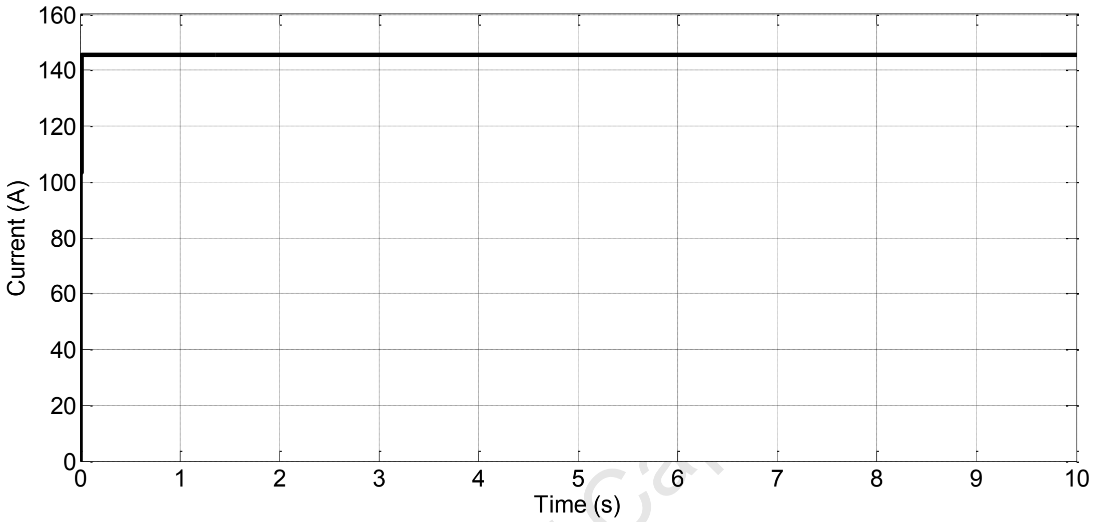


Figure 9.1 RMS Current output from PV Generation during normal grid-connected operation

Busbar 1 Voltage

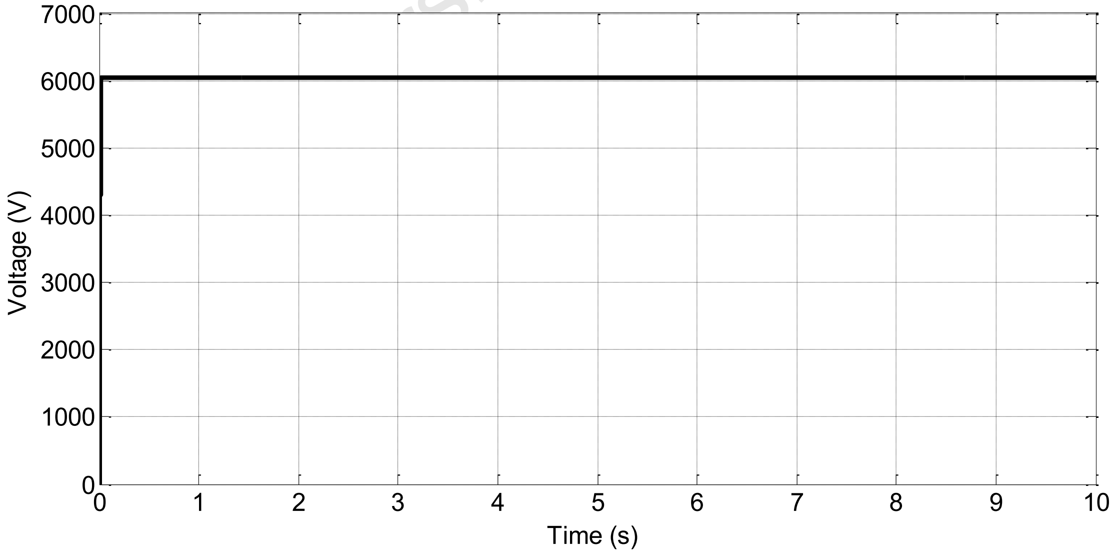


Figure 9.2 Voltage RMS at Busbar 1 during normal grid-connected operation

Busbar 2 Current

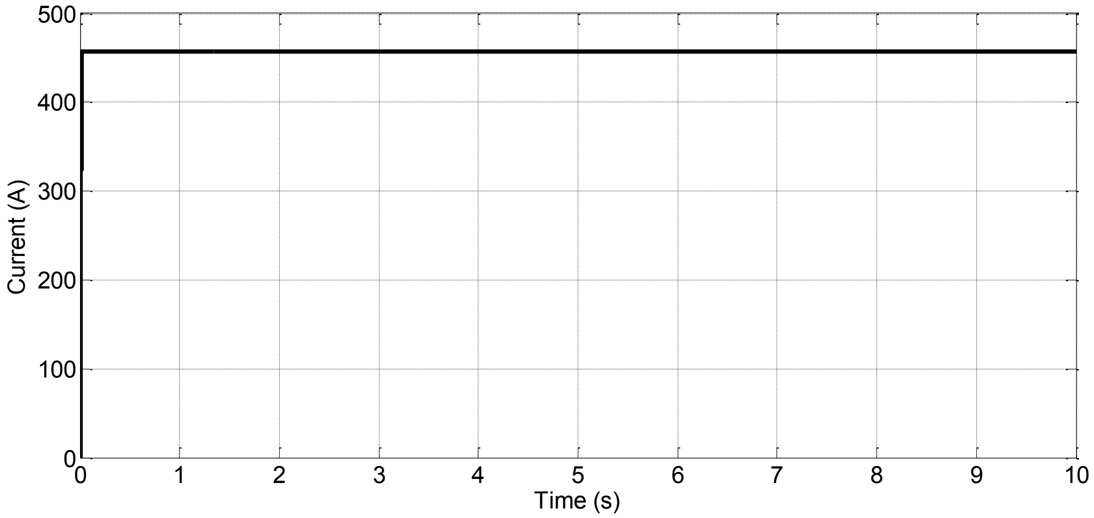


Figure 9.3 **Current output RMS from utility source during normal operation in grid-connected mode**

Busbar 2 Voltage

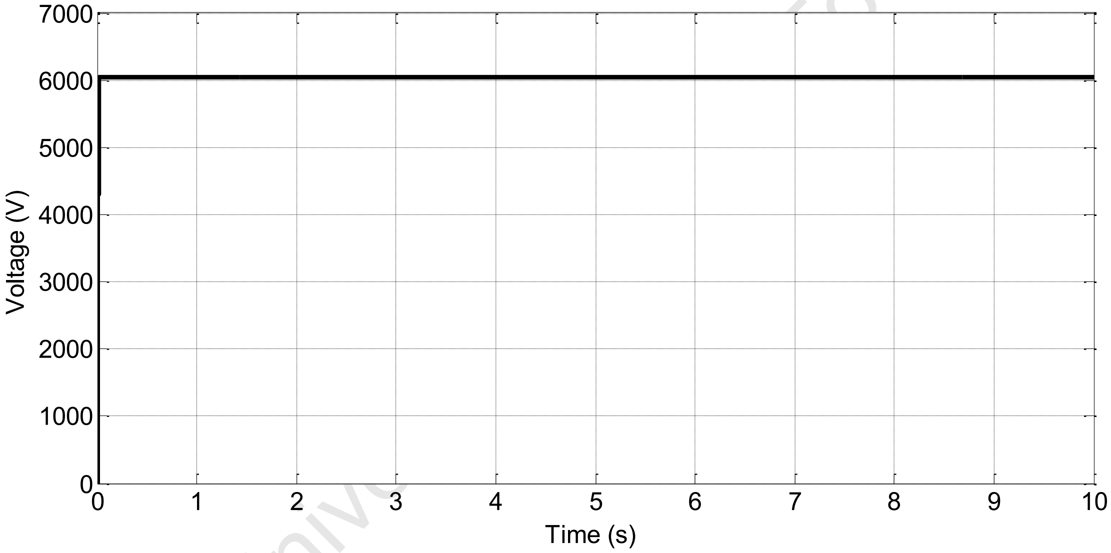


Figure 9.4 **Voltage RMS at busbar 2 during Normal operation**

9.1.2 Isolated Case

PV Generation Current

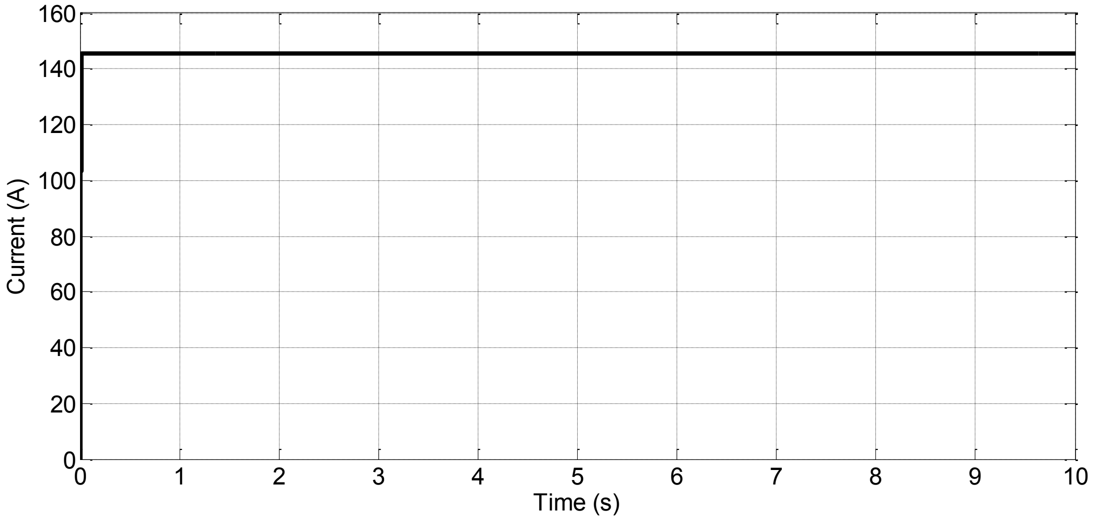


Figure 9.5 Current output RMS from PV Generation during normal isolated operation

Busbar 1 Voltage

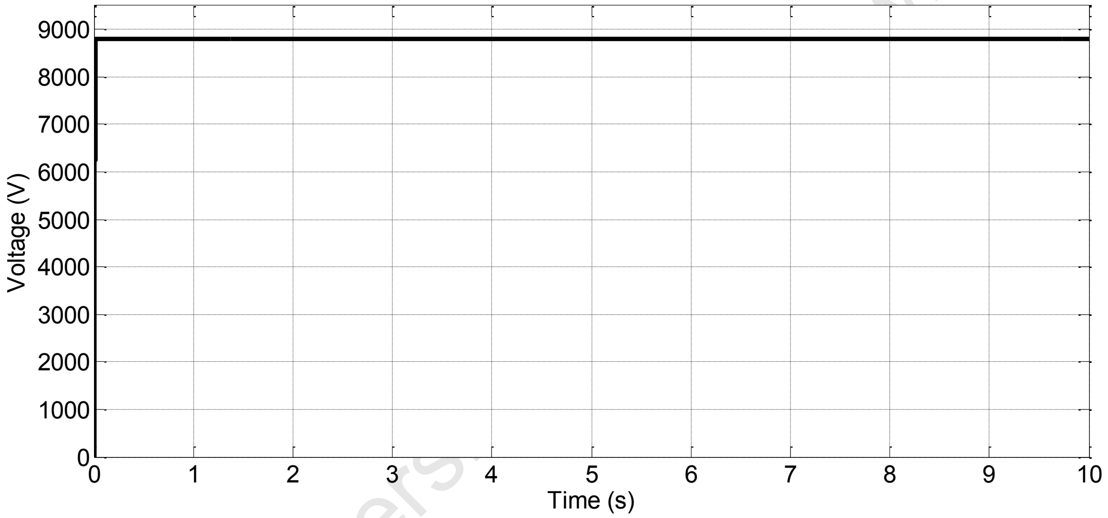


Figure 9.6 **Busbar 1 Voltage RMS during Isolated mode normal operation**

Utility Source Current

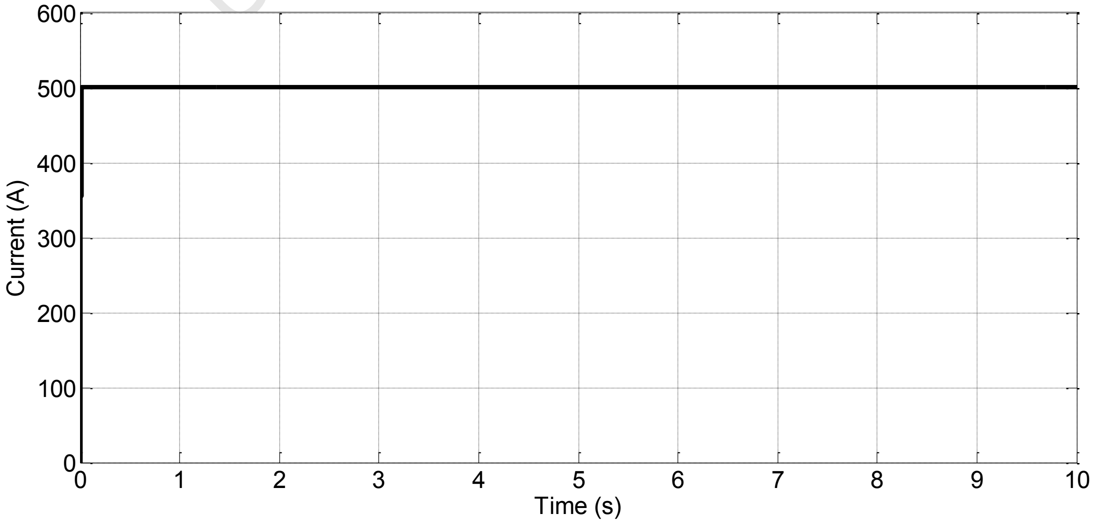


Figure 9.7 **Utility Source current RMS during isolated operation**

Busbar 2 Voltage

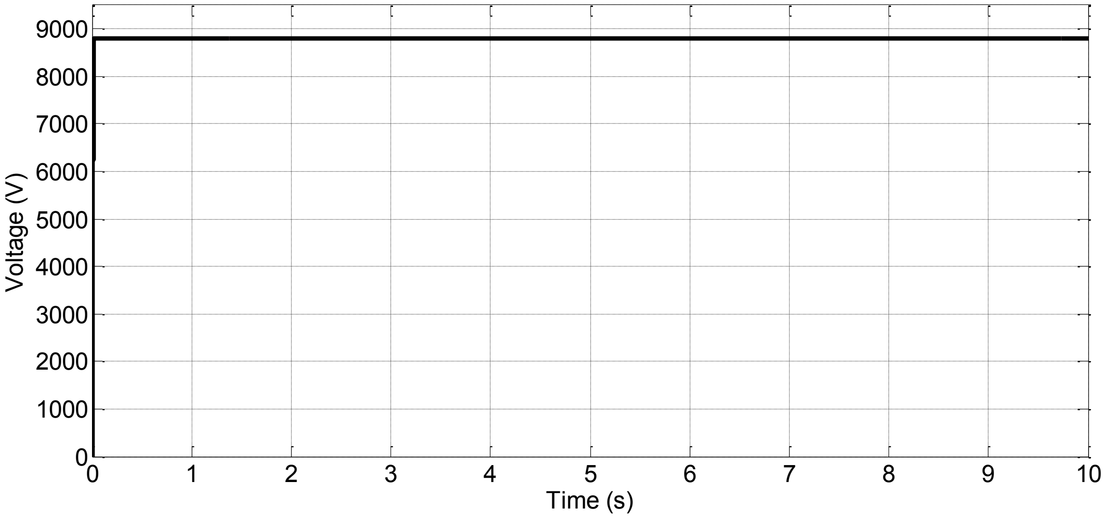


Figure 9.8 **Busbar 2 voltage RMS during isolated mode of operation**

9.2 Overcurrent Relay Test Cases

9.2.1 Test Case 1

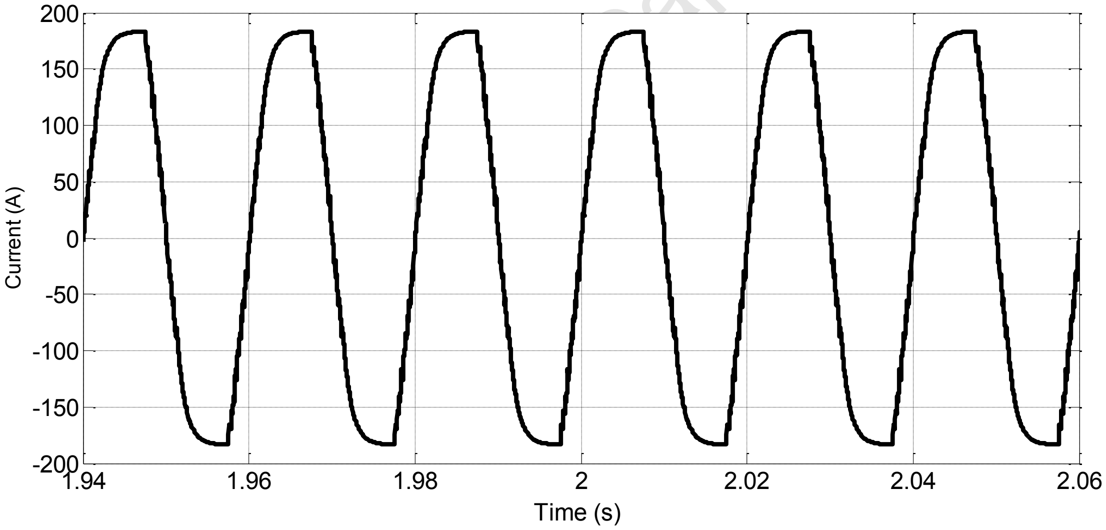


Figure 9.9 PV Generation current before and during the fault

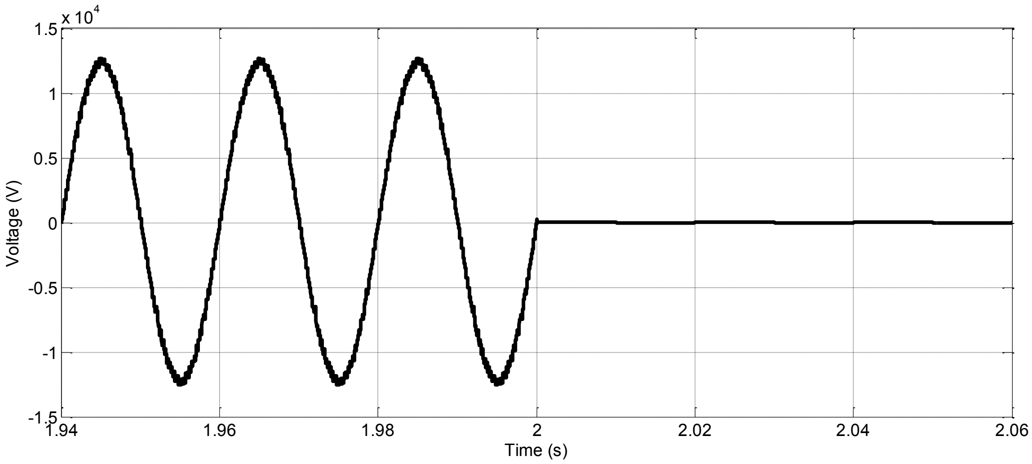


Figure 9.10 Busbar 1 voltage before and during the fault in Test Case 1

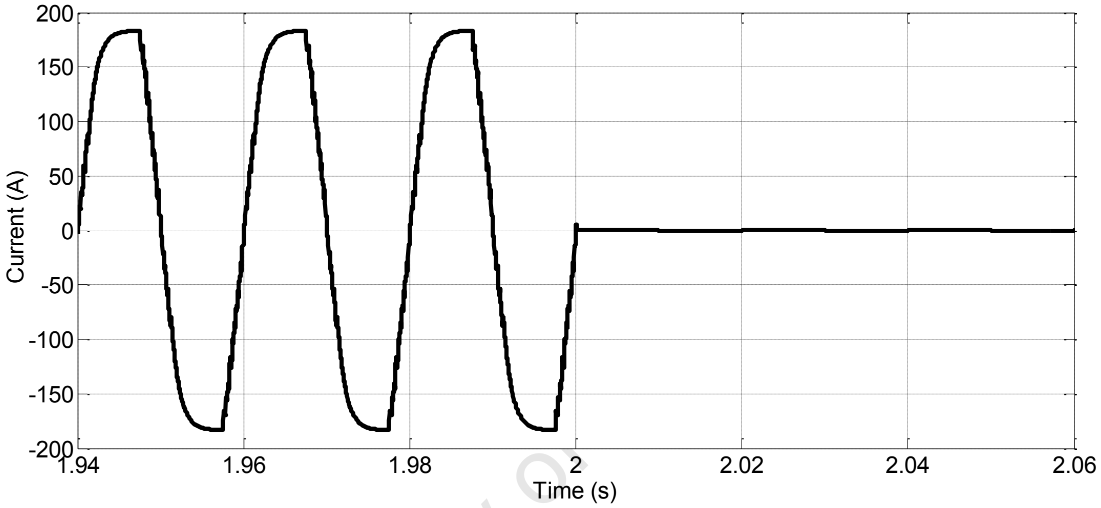


Figure 9.11 **Local load current before and during the fault in Test Case 1**

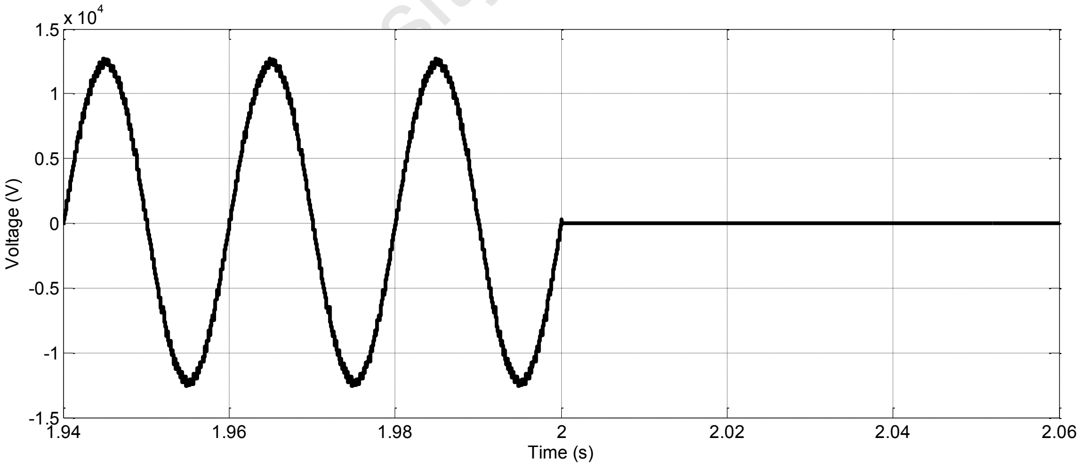


Figure 9.12 **Local load voltage level before and during a fault in Test Case 1**

9.2.2 Test Case 2

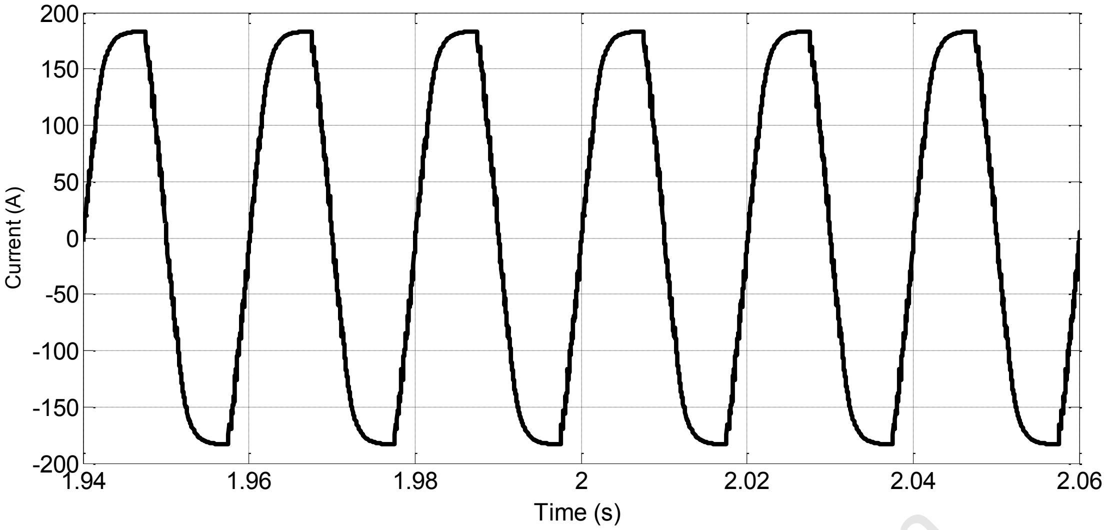


Figure 9.13 PV Generation current output before and during a fault in Test Case 2

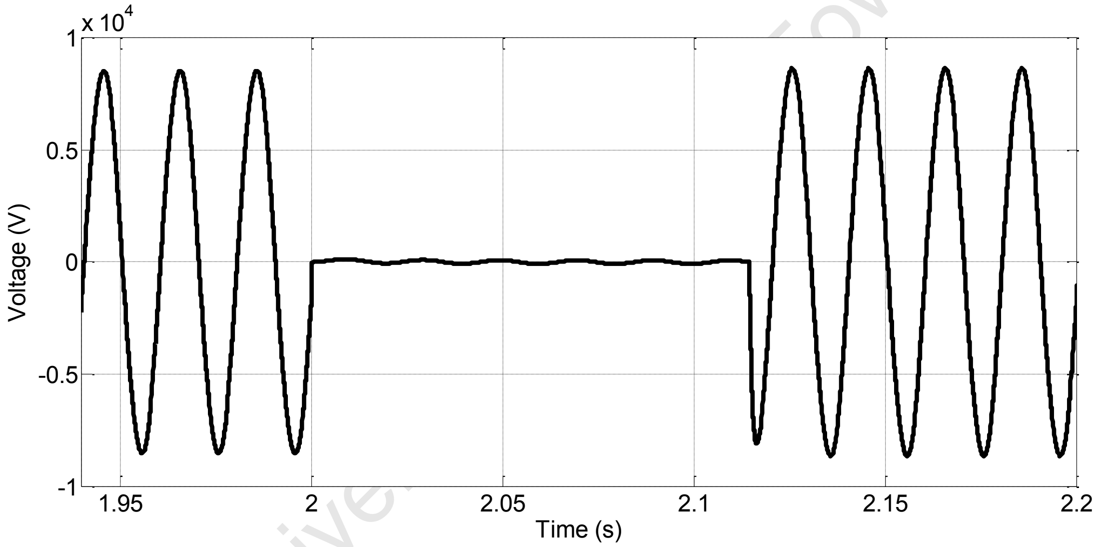


Figure 9.14 **PV Generation voltage level before, during and after a fault in Test Case 2**

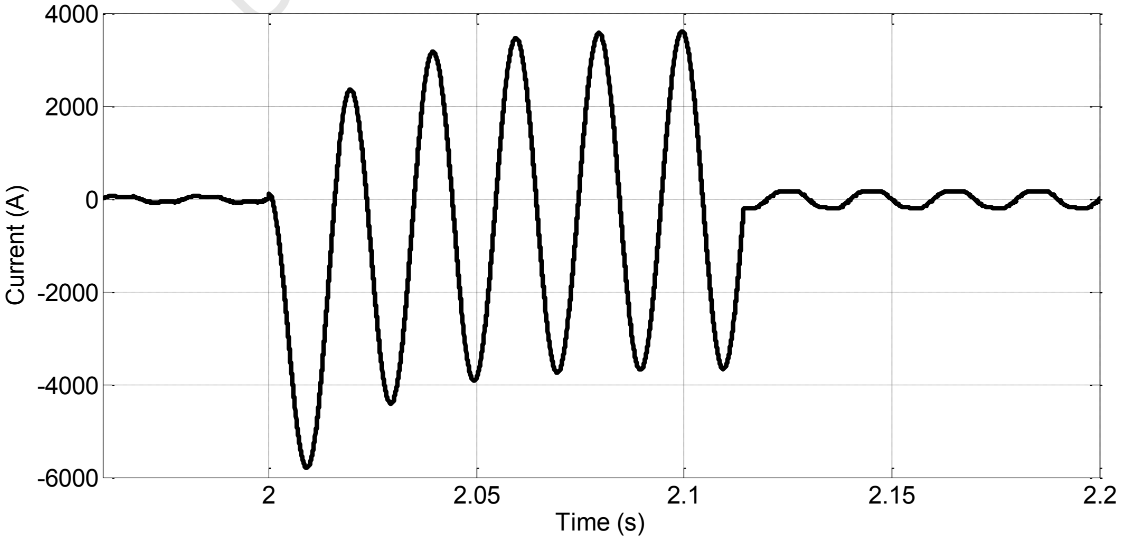


Figure 9.15 **Utility Source current output before, during and after a fault in Test Case 2**

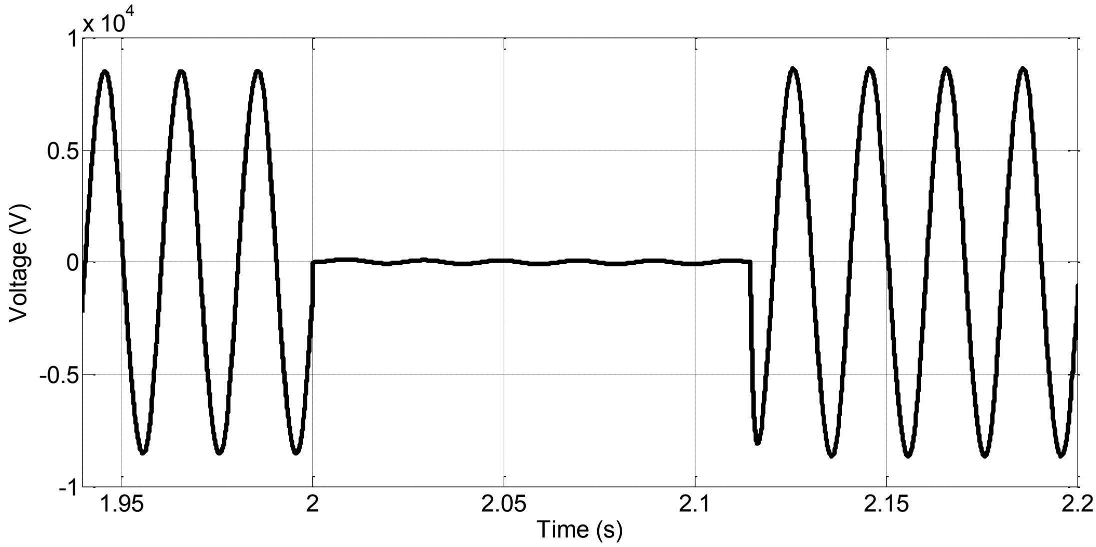


Figure 9.1 **Utility Source voltage level before, during and after the fault in Test Case 2**

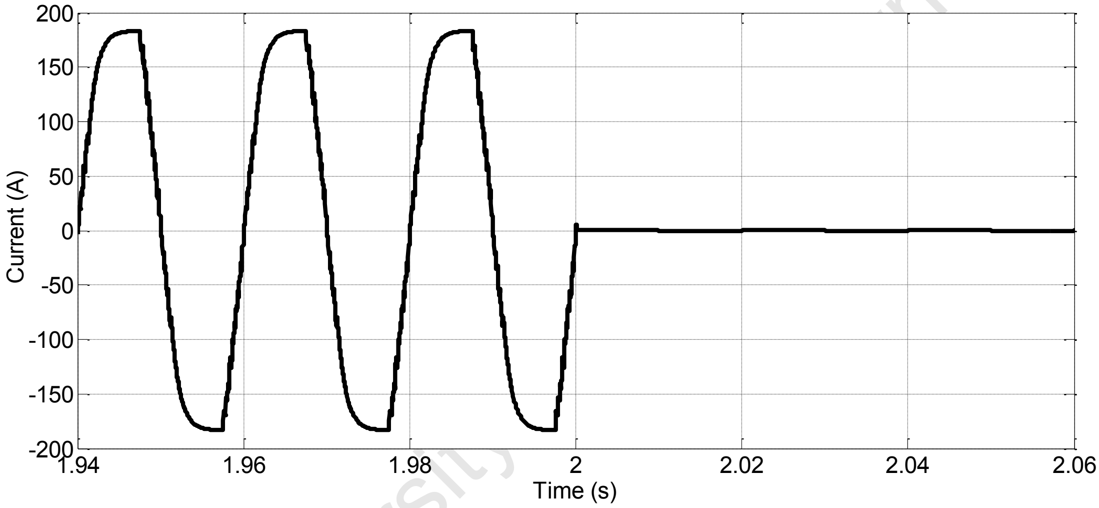


Figure 9.17 **Local load current consumption before and during the fault in Test Case 2**

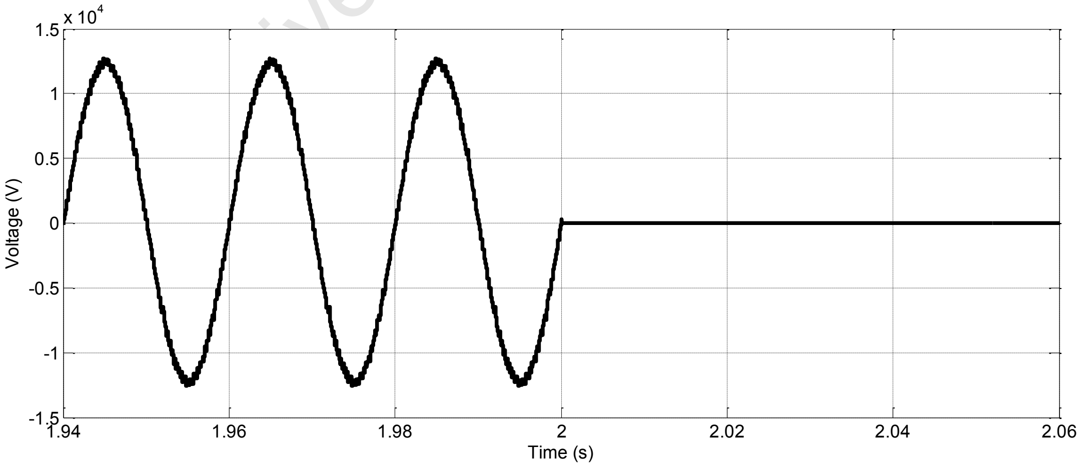


Figure 9.18 **Local load current consumption before and during the fault in Test Case 2**

9.2.3 Test Case 3

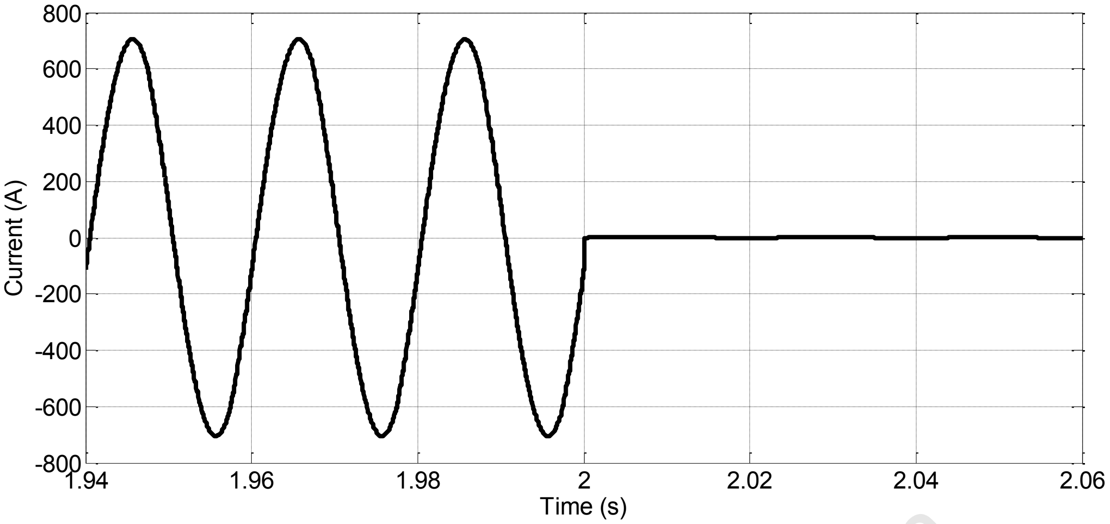


Figure 9.19 Utility load current consumption before and during the fault in Test Case 3

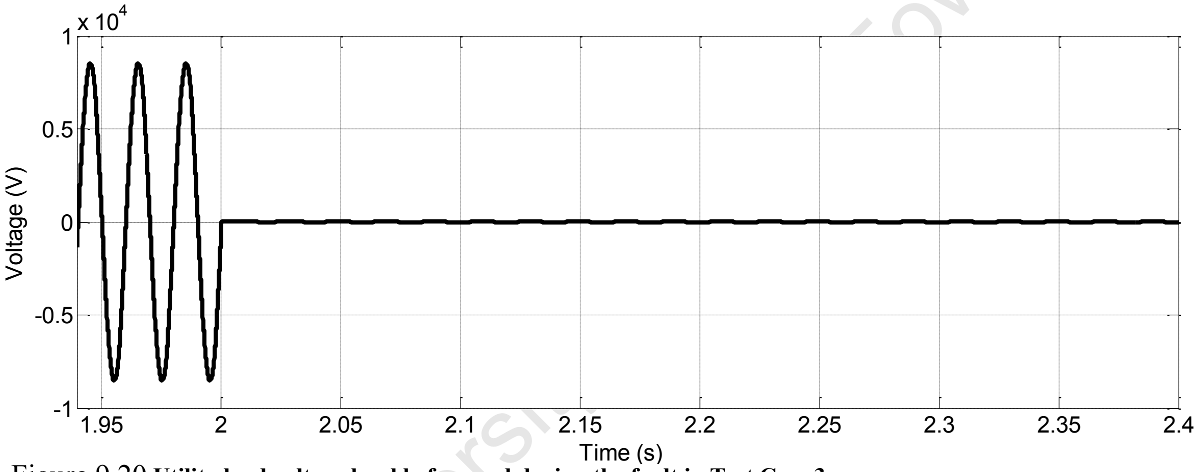


Figure 9.20 **Utility load voltage level before and during the fault in Test Case 3**

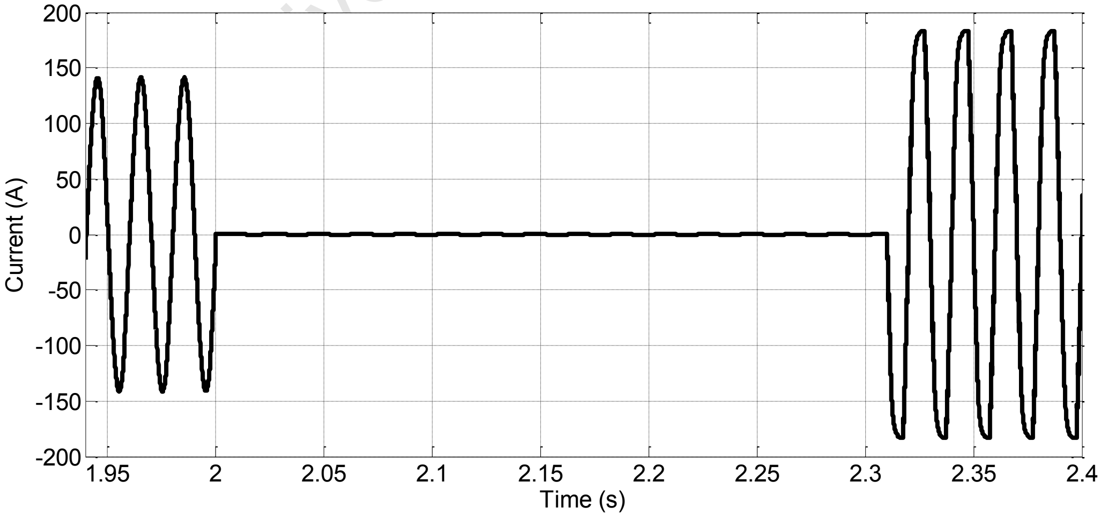


Figure 9.21 **Local load current before, during and after the fault in Test Case 3**

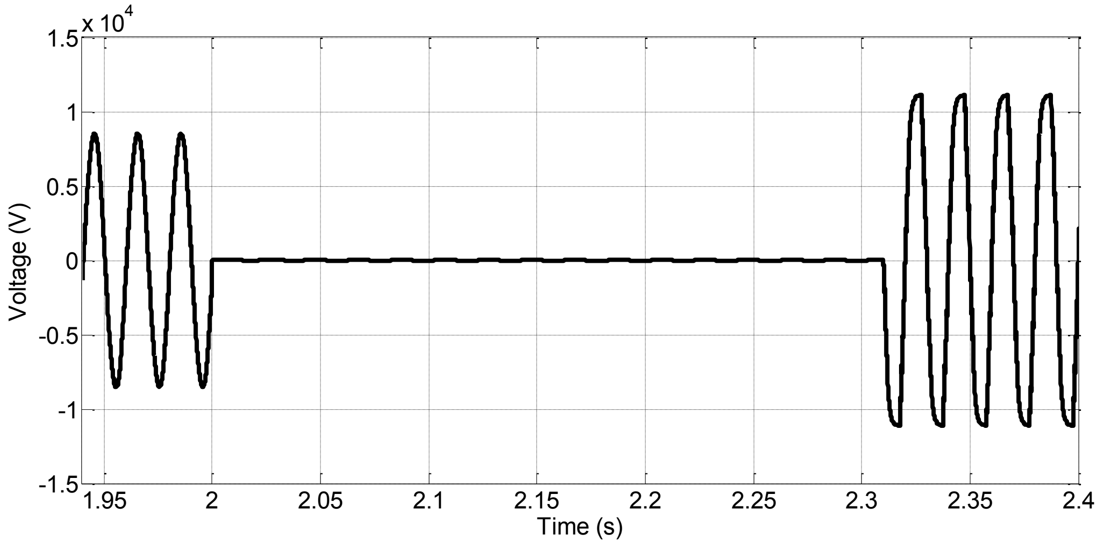


Figure 9.22 **Local load voltage level before, during and after the fault in Test Case 3**

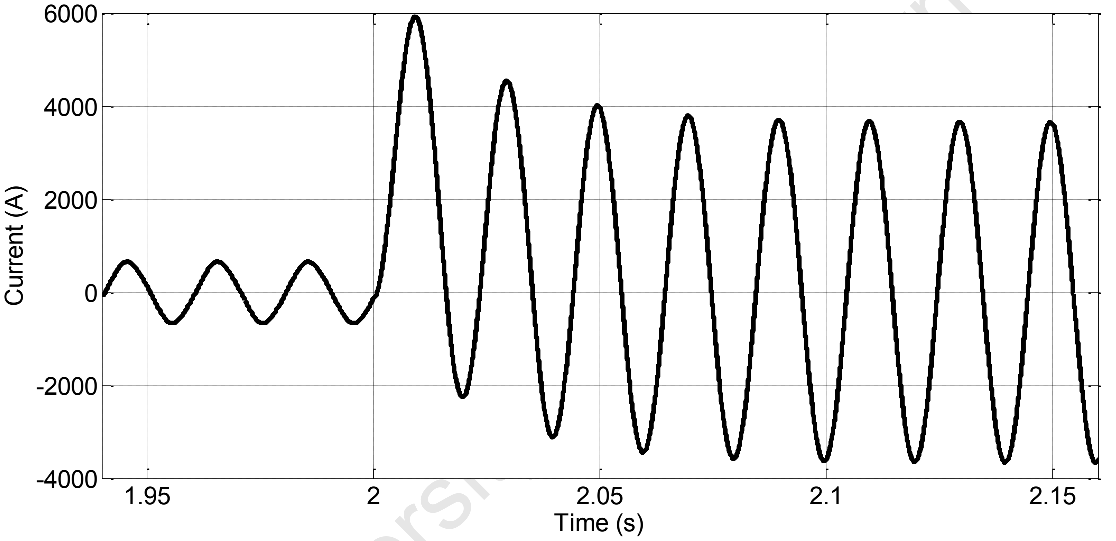


Figure 9.23 **Utility Source current before and during the fault in Test Case 3**

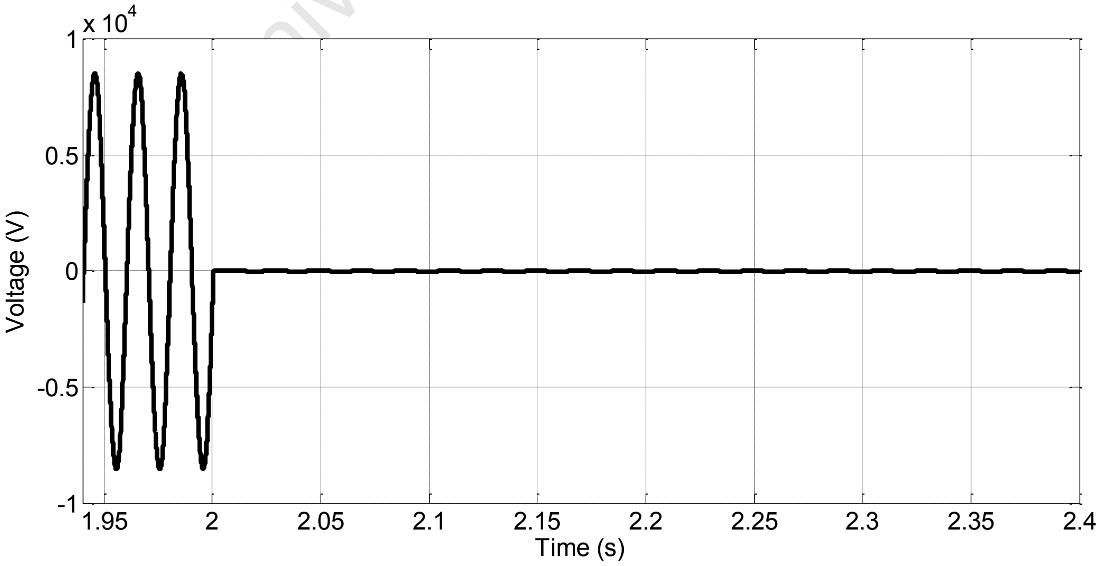


Figure 9.24 **Utility source voltage level before and after the fault in Test Case 3**

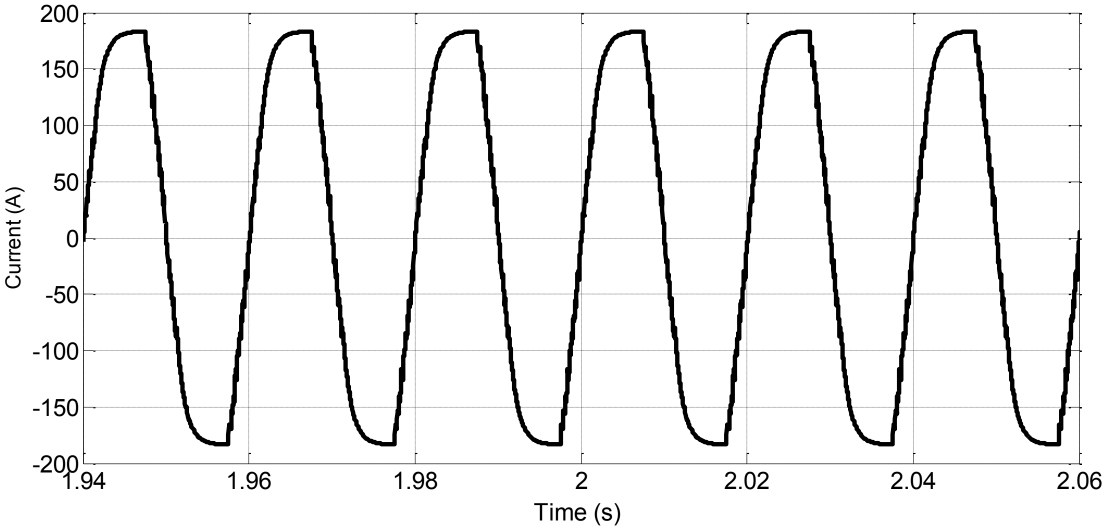


Figure 9.25. **PV Generation current output during Test Case 3**

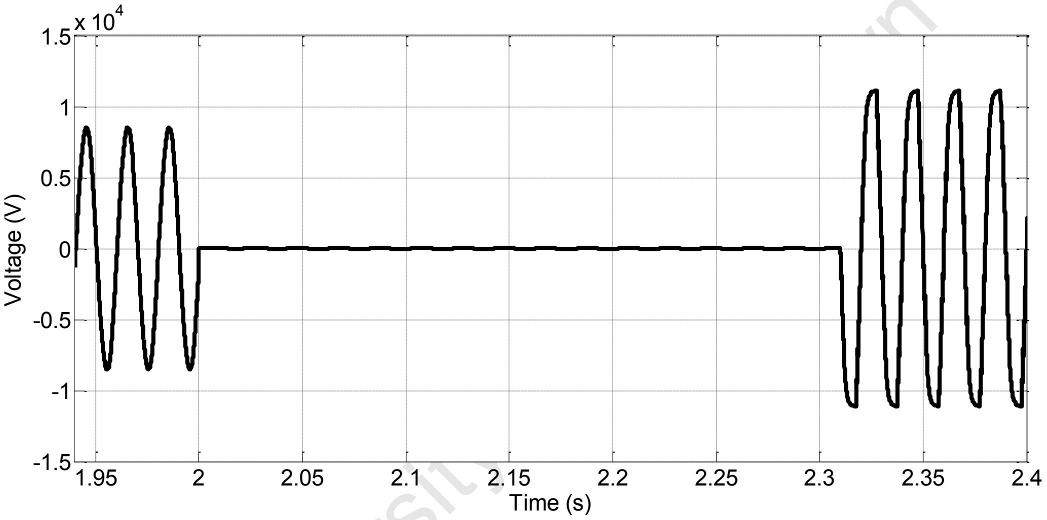


Figure 9.26 PV Generation voltage level before, during and after the fault in Test Case 3

9.3 Reverse Power Relay Testing

9.3.1 Test Case 4

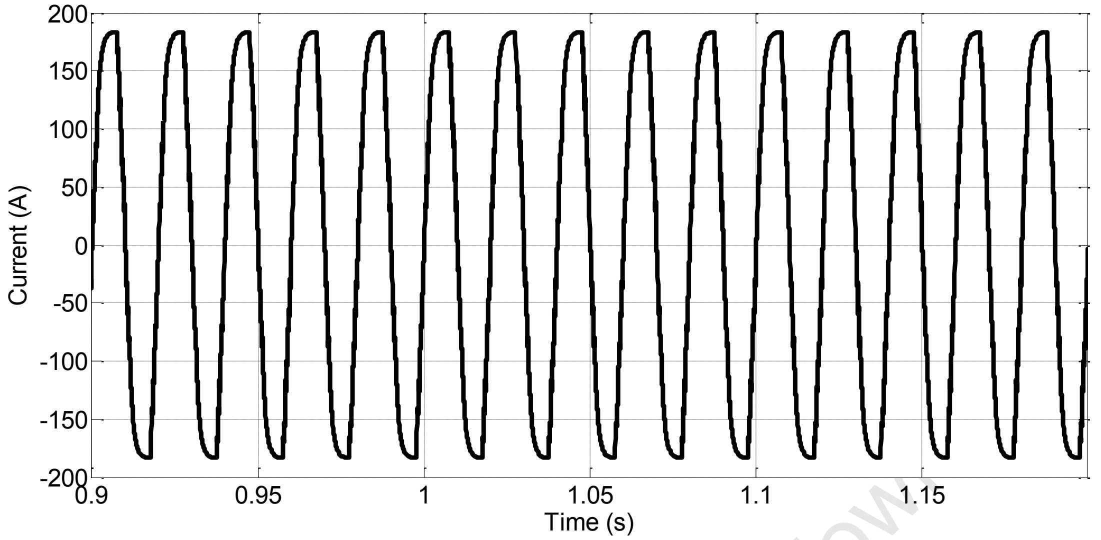


Figure 9.27 PV Generation Source current during Test Case 4

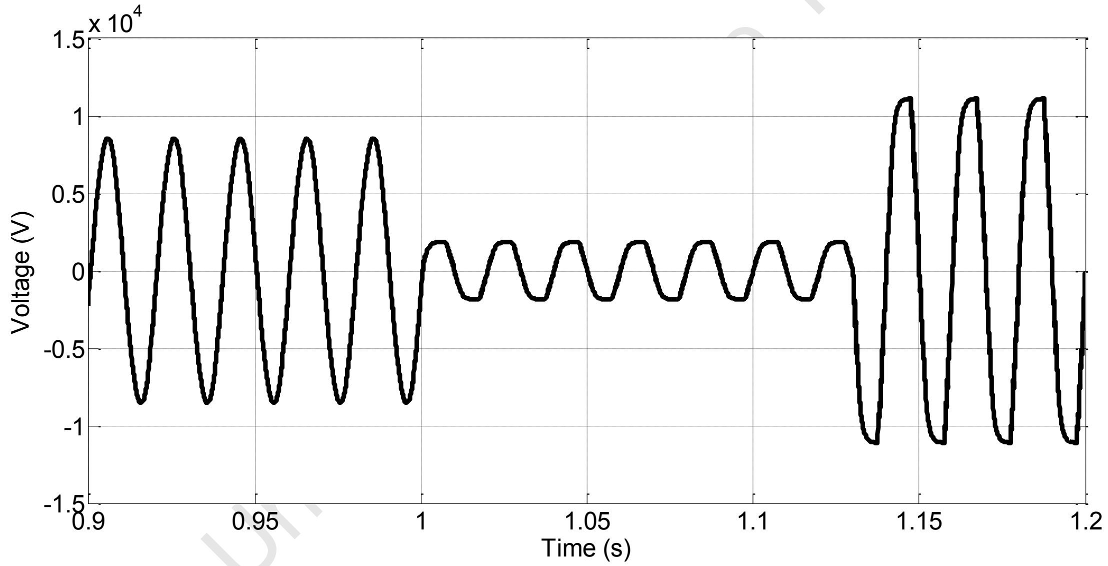


Figure 9.28 **PV Generation Source Voltage level before, during and after the event in Test case 4**

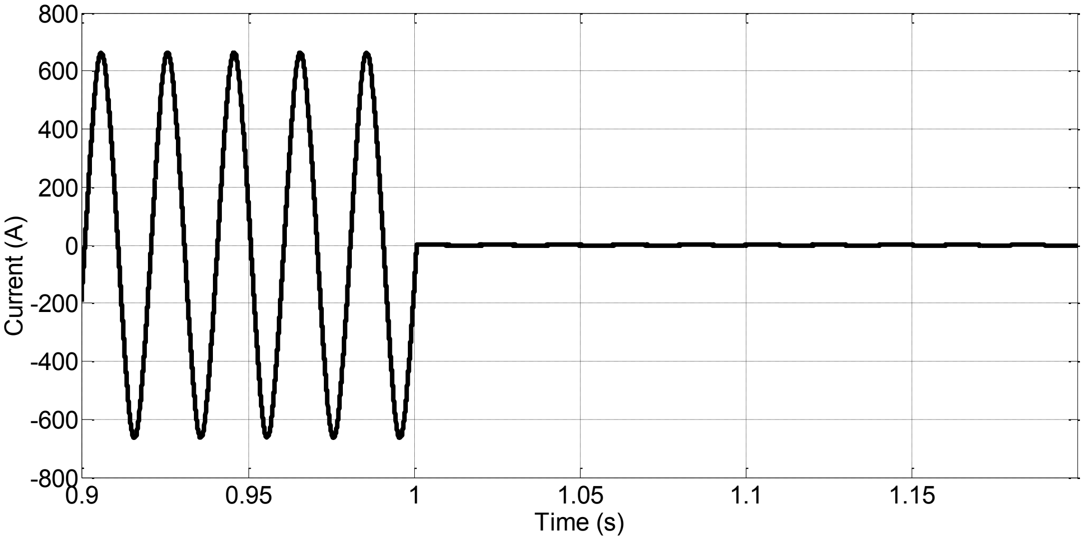


Figure 9.29 **Utility Generator current output during Test Case 4**

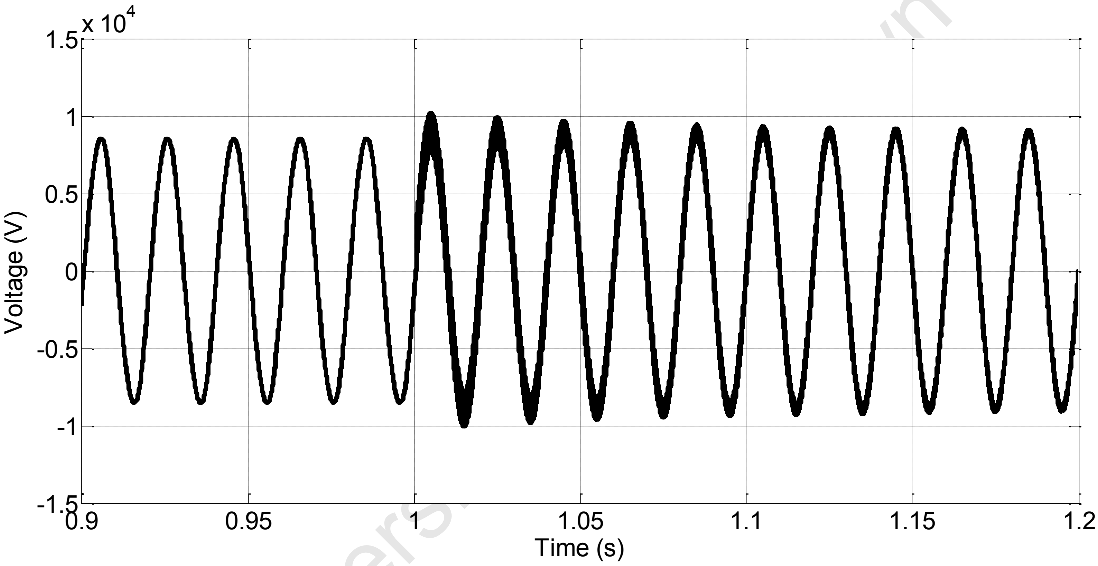


Figure 9.30 **Utility Generator voltage level during Test Case 4**

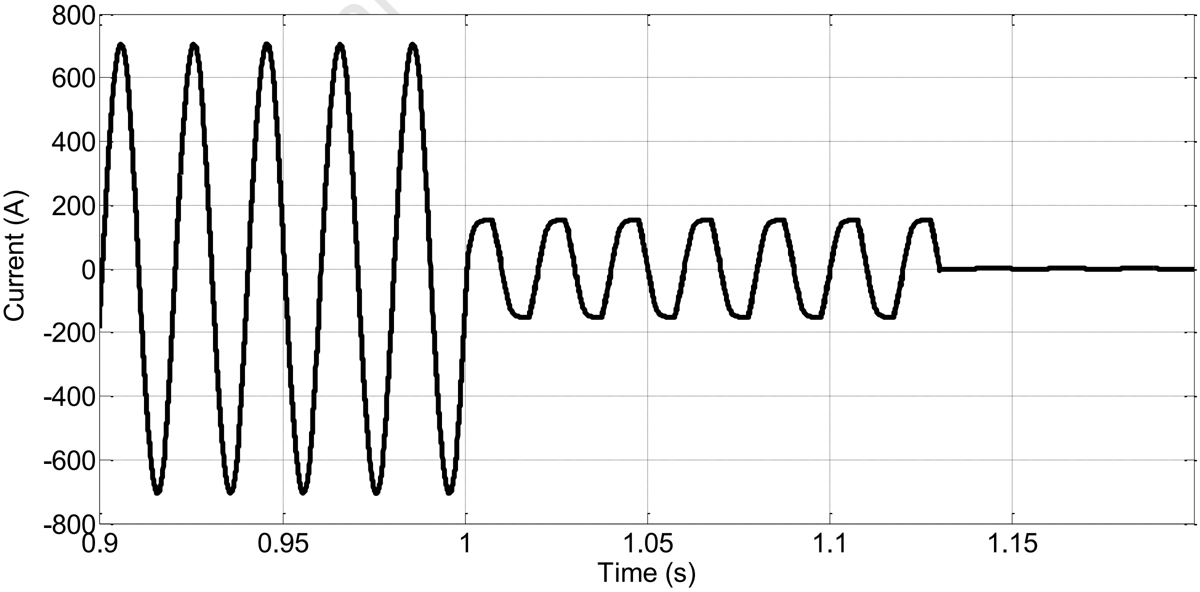


Figure 9.31 **Utility load current before, during and after the event in Test Case 4**

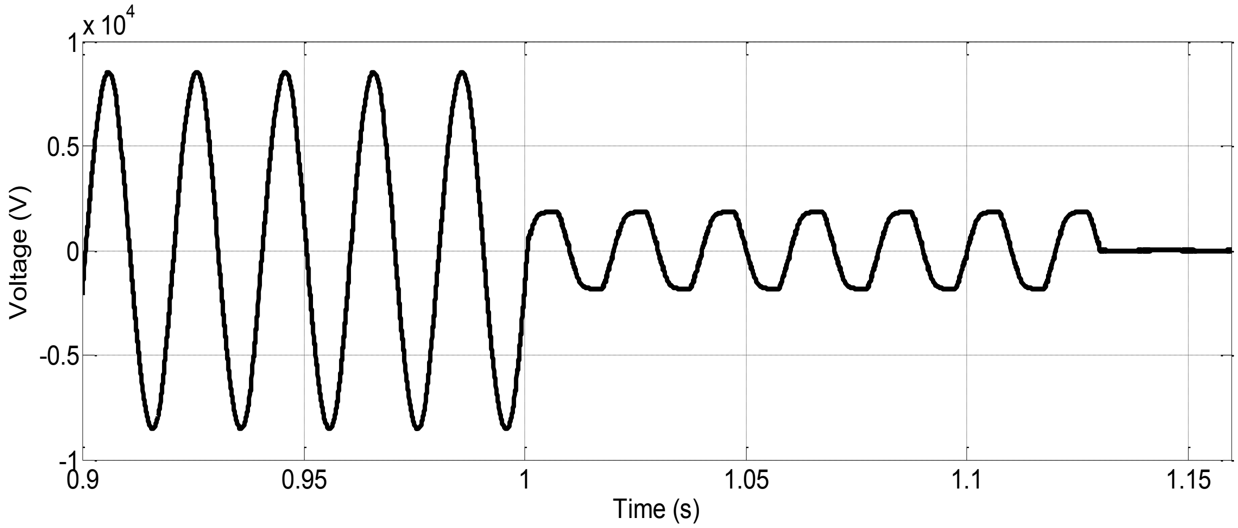


Figure 9.32 **Utility Load voltage level during Test Case 4**

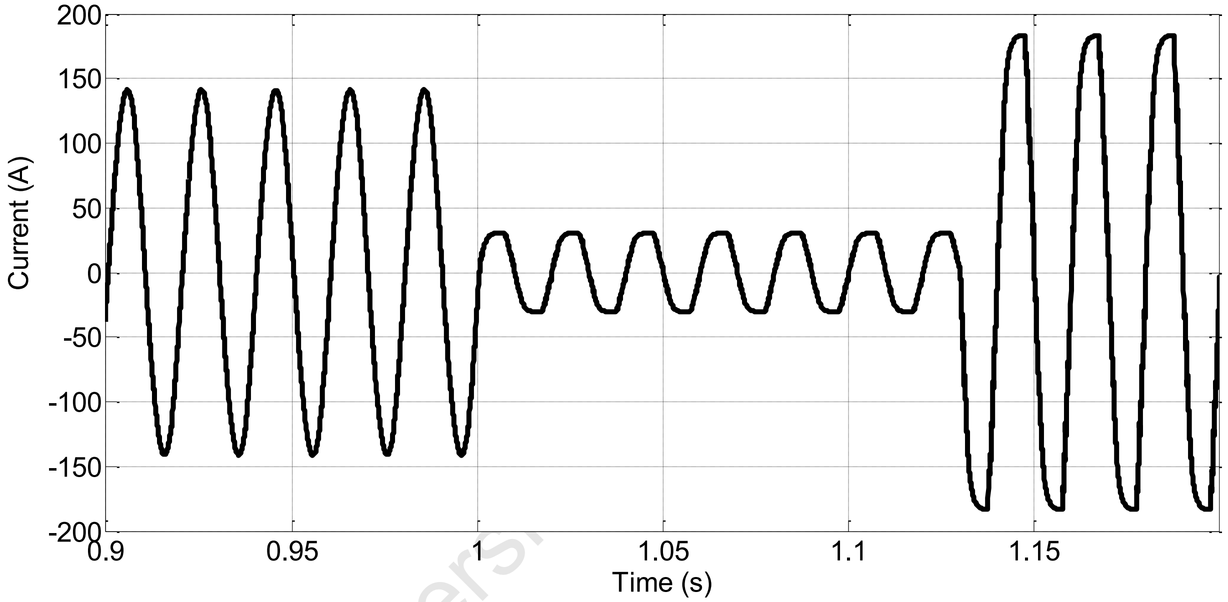


Figure 9.33 **Local load current before, during and after the event in Test Case 4**

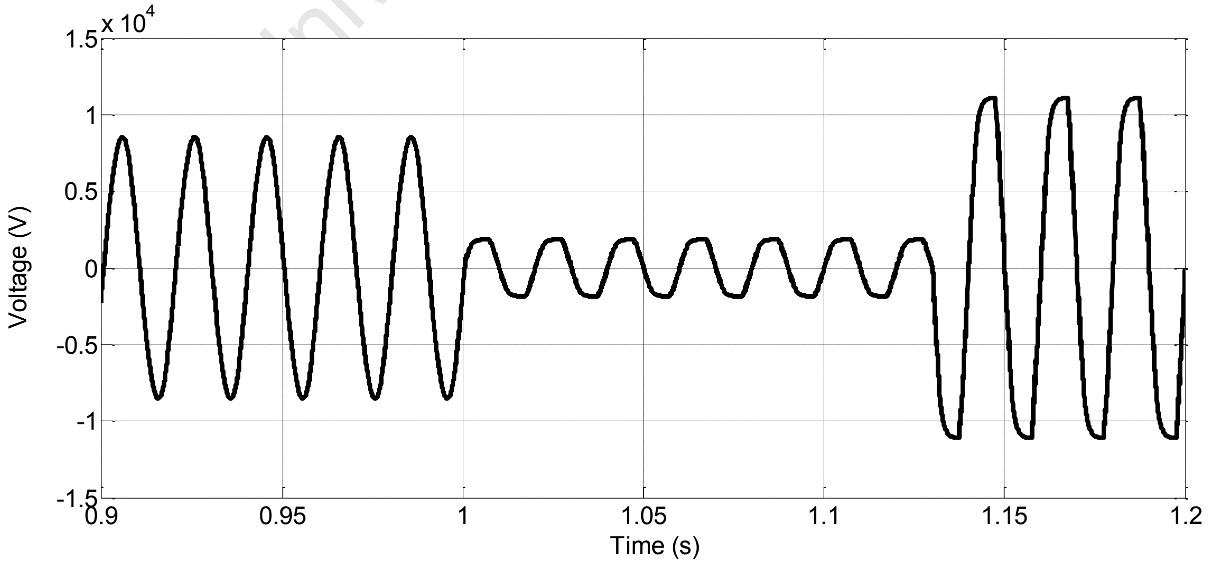


Figure 9.34 **Local load voltage before, during and after the event in Test Case 4**

9.3.2 Test Case 5

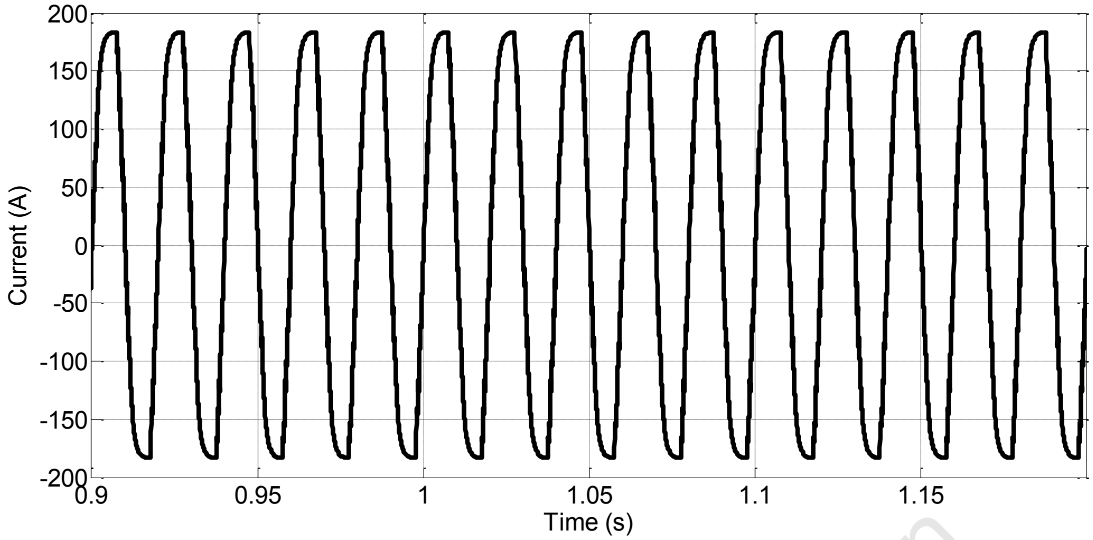


Figure 9.35 PV Generation current output during Test Case 5

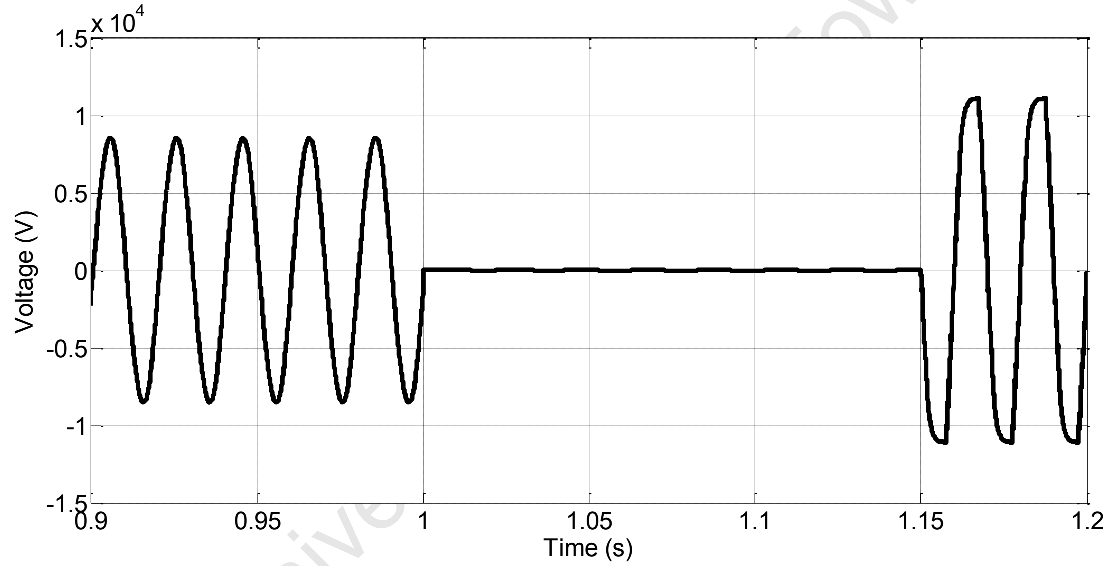


Figure 9.36 **PV Generation voltage level before, during and after the event in Test Case 5**

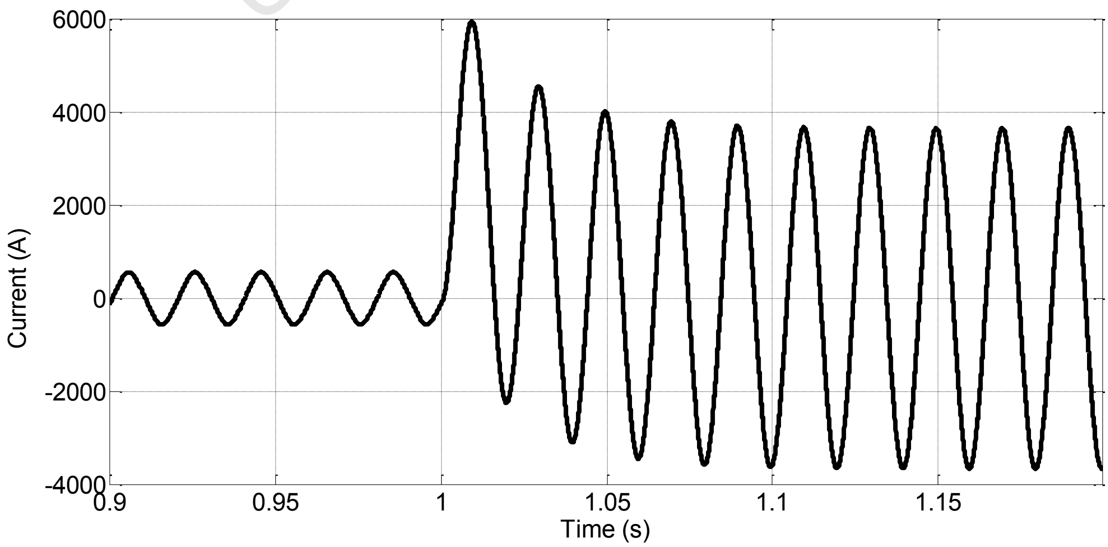


Figure 9.37 **Utility Generator output current during Test Case 5**

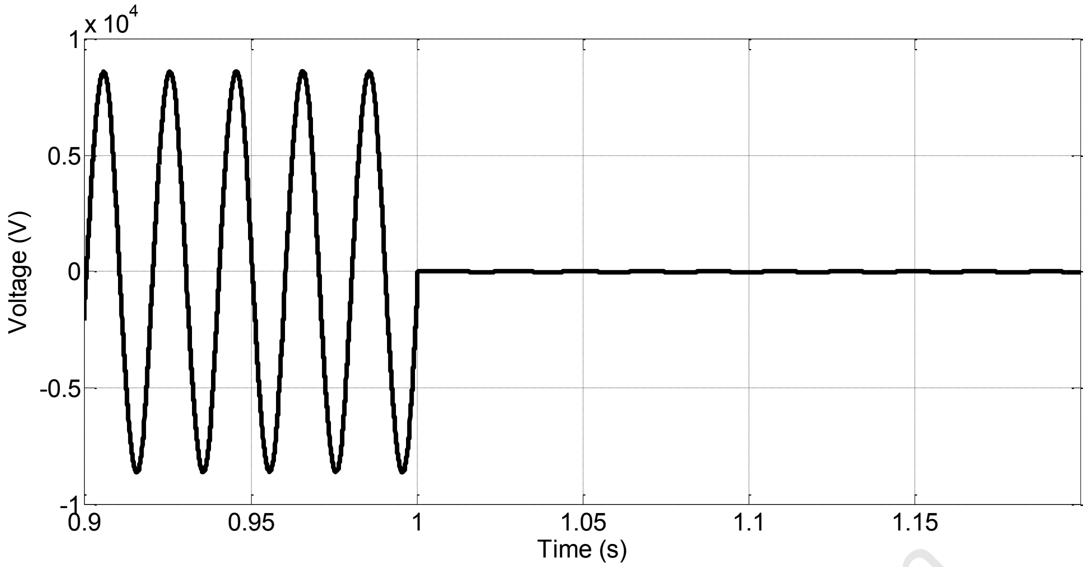


Figure 9.38 **Utility Generator voltage level during Test Case 5**

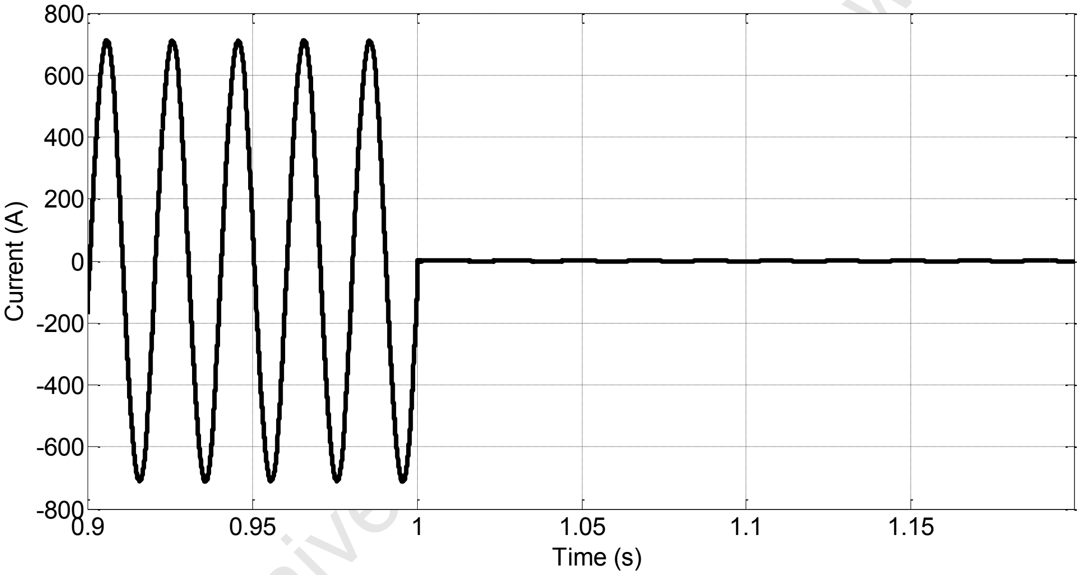


Figure 9.39 **Utility load current before and during a fault in Test Case 5**

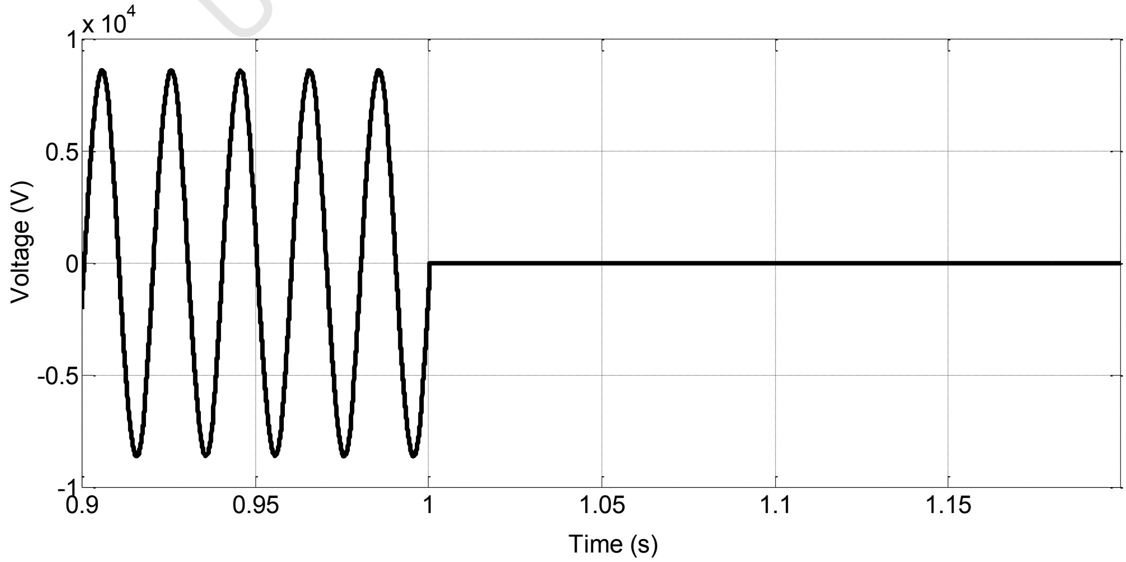


Figure 9.40 **Utility load voltage level before and during the fault in Test Case 5**

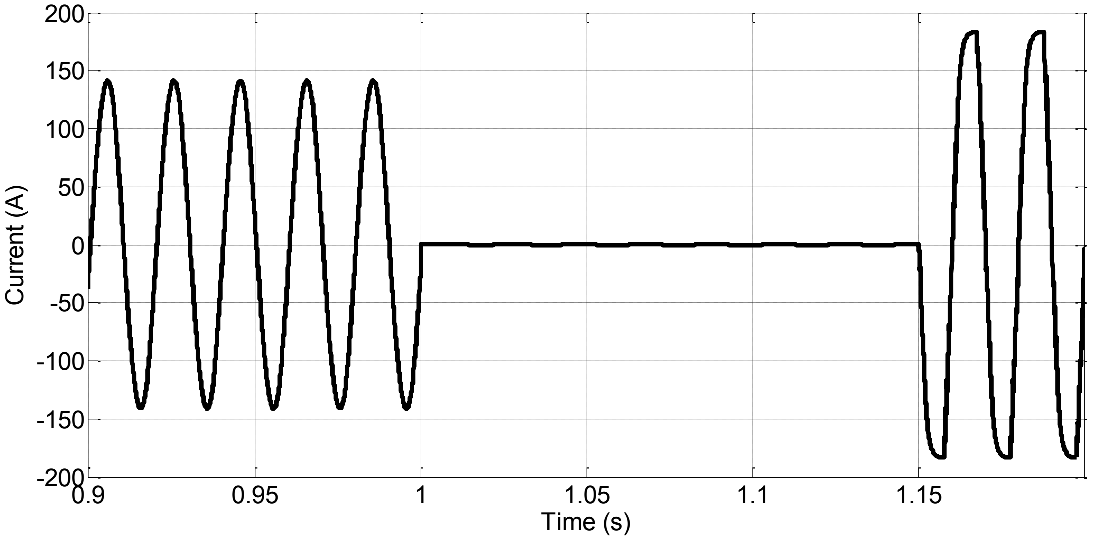


Figure 9.41 **Local load current before, during and after the fault in Test Case 5**

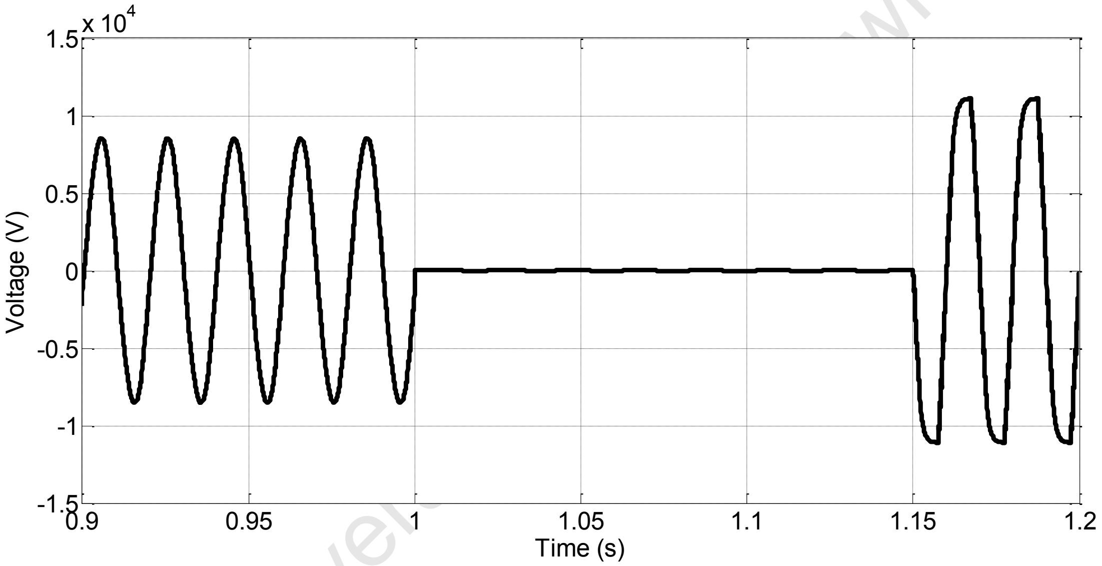


Figure 9.42 **Local Load voltage level before, during and after Test Case 5**

9.3.3 Test Case 6

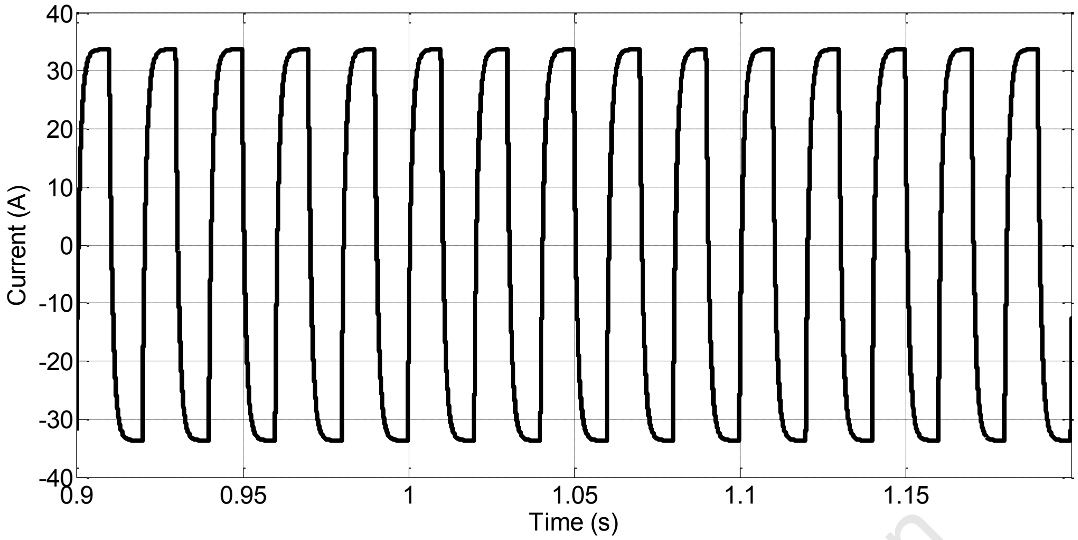


Figure 9.43 PV Generation current output during Test Case 6

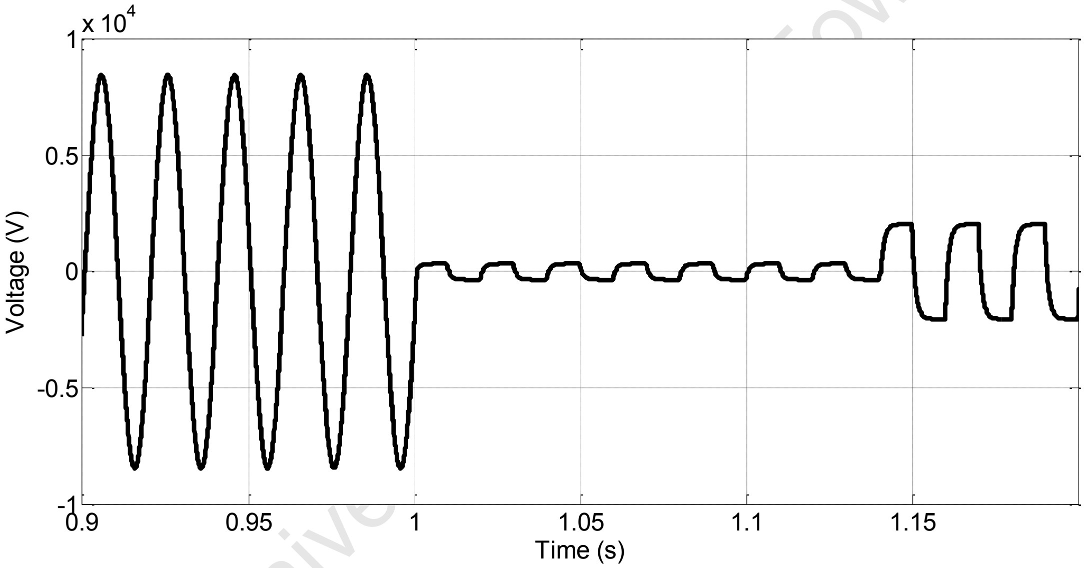


Figure 9.44 **PV Generation voltage level before, during and after the event in Test Case 6**

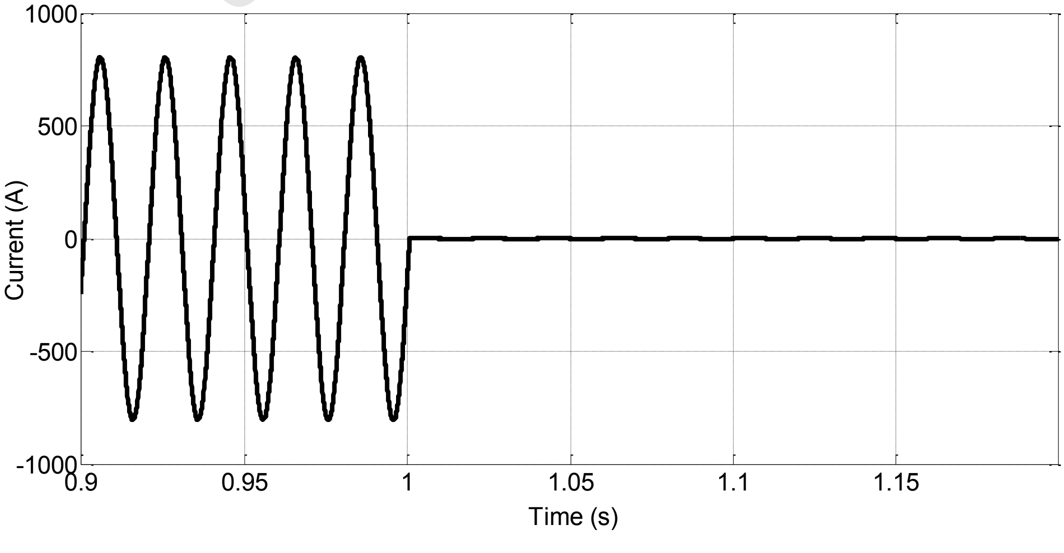


Figure 9.45 **Utility Generation output current during Test Case 6**

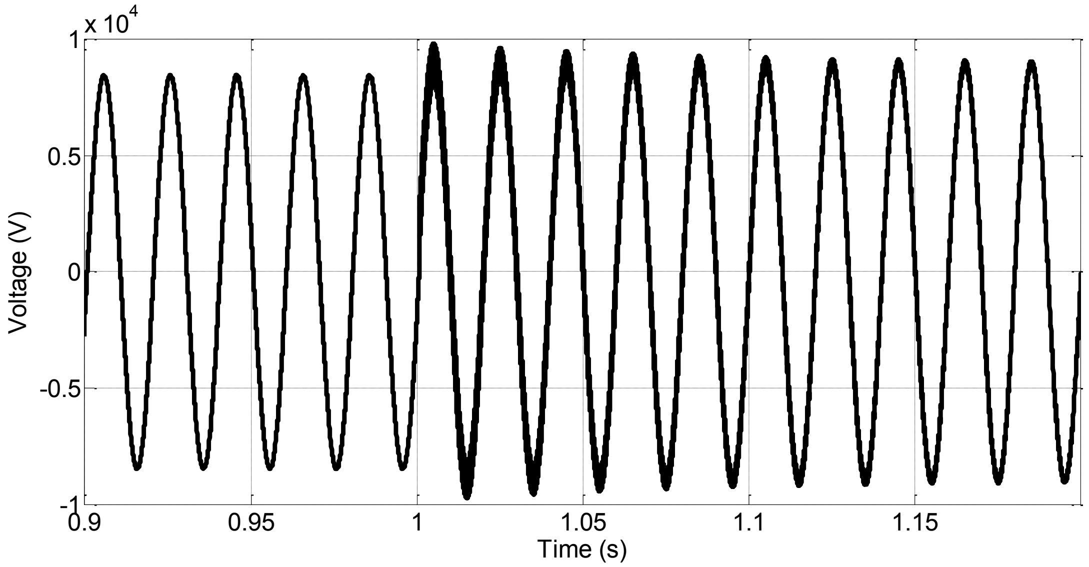


Figure 9.46 U**tility Generator Voltage level during Test Case 6**

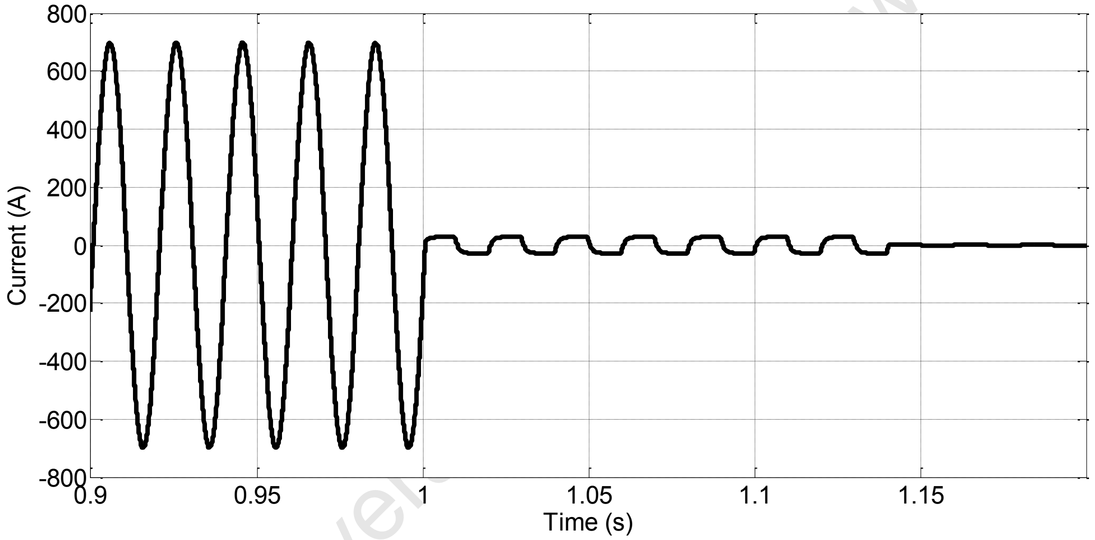


Figure 9.47 **Utility load current before, during and after the event in Test Case 6**

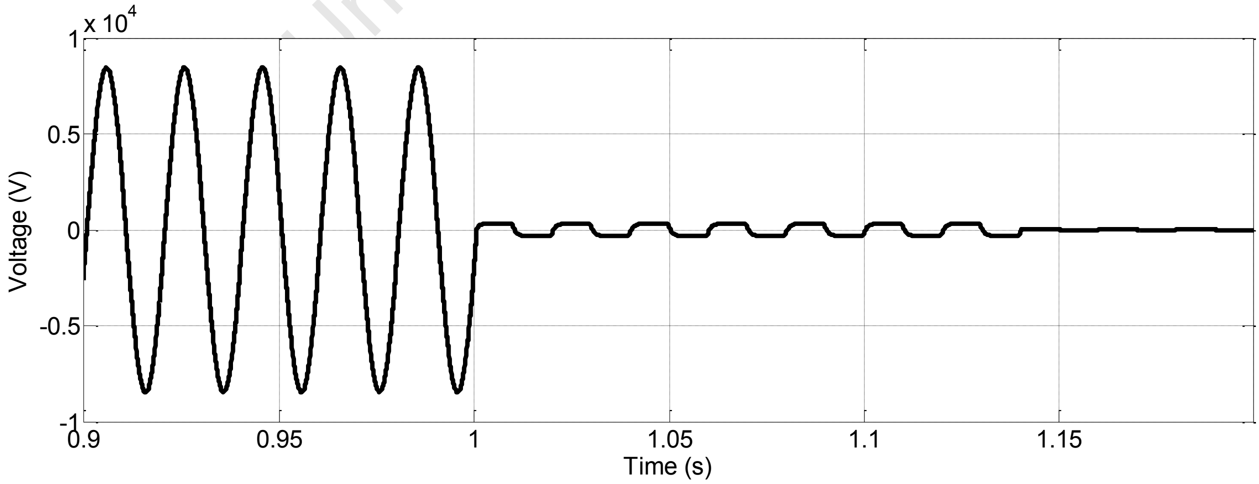


Figure 9.48 **Utility load voltage level during Test Case 6**

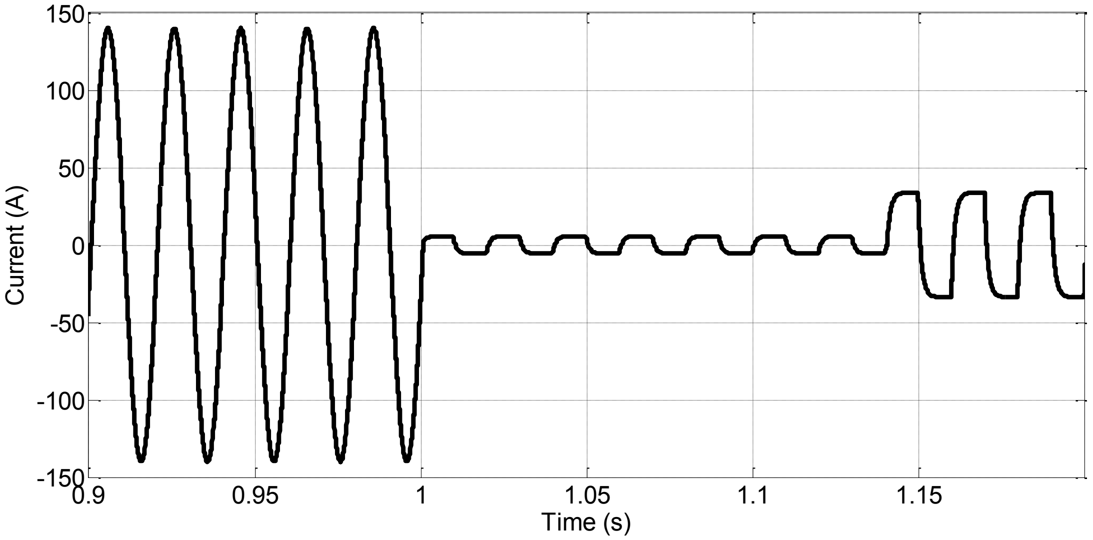


Figure 9.49 **Local load current before, during and after the event in Test Case 6**

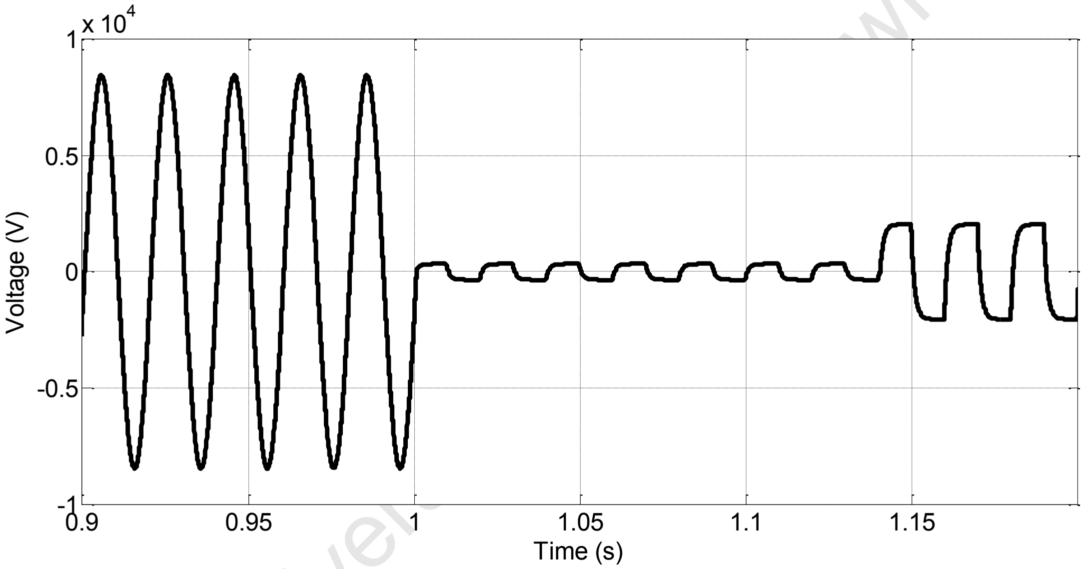


Figure 9.50 **Local load voltage level before, during and after the event in Test Case 6**

9.3.4 Test Case 7

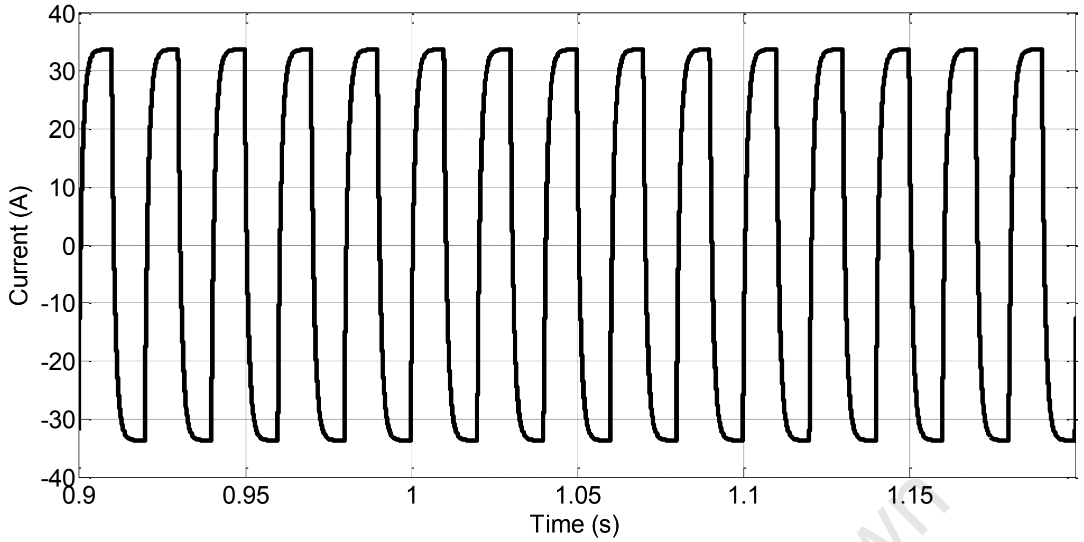


Figure 9.51 PV Generation current output during Test Case 7

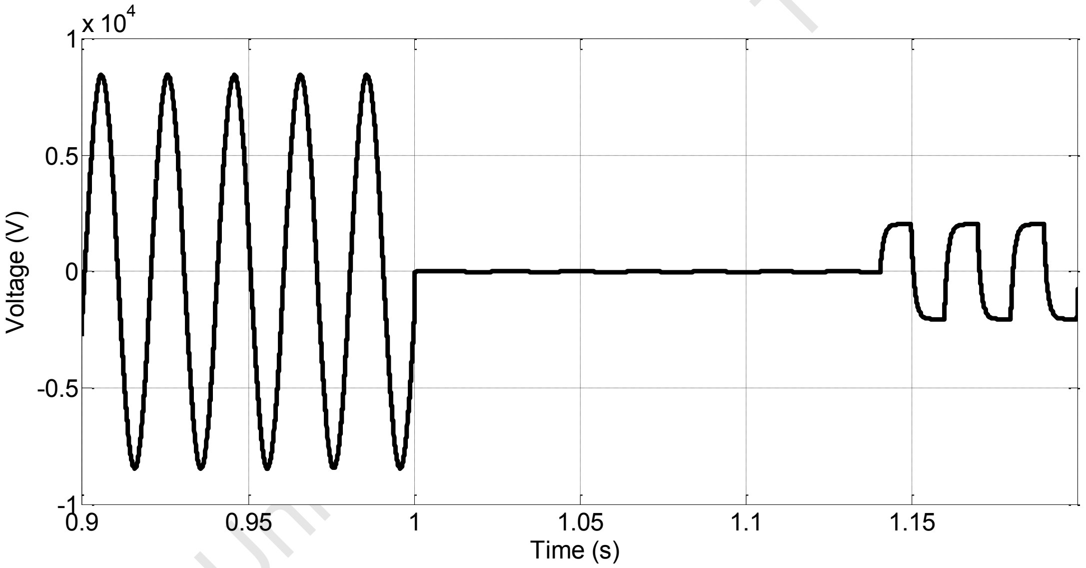


Figure 9.52 **PV Generation voltage levels before, during and after the fault in Test Case 7**

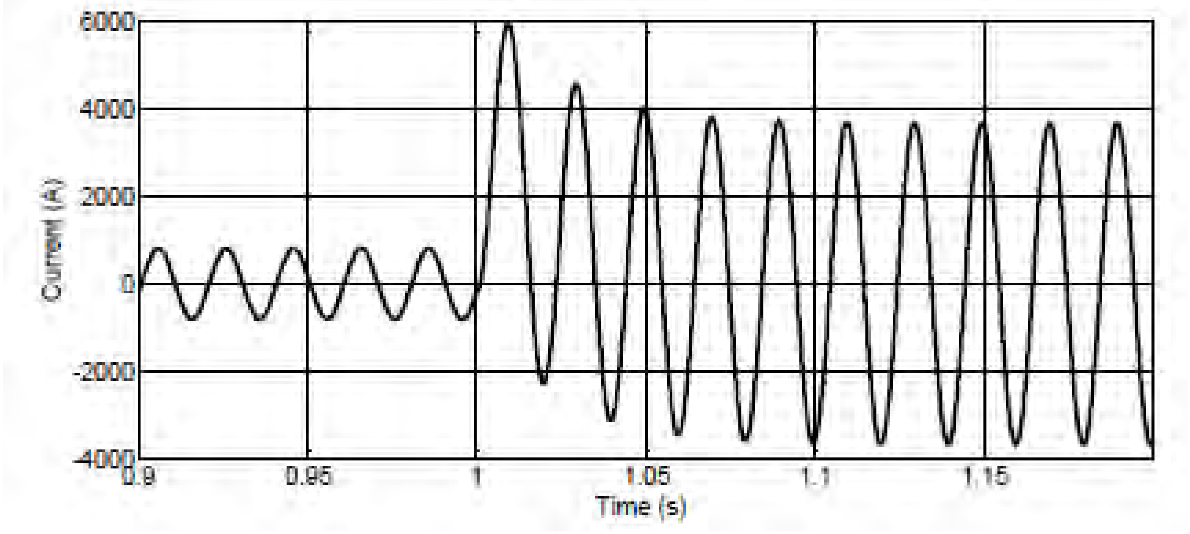


Figure 9.53 Utility Generator current output during Test Case 7

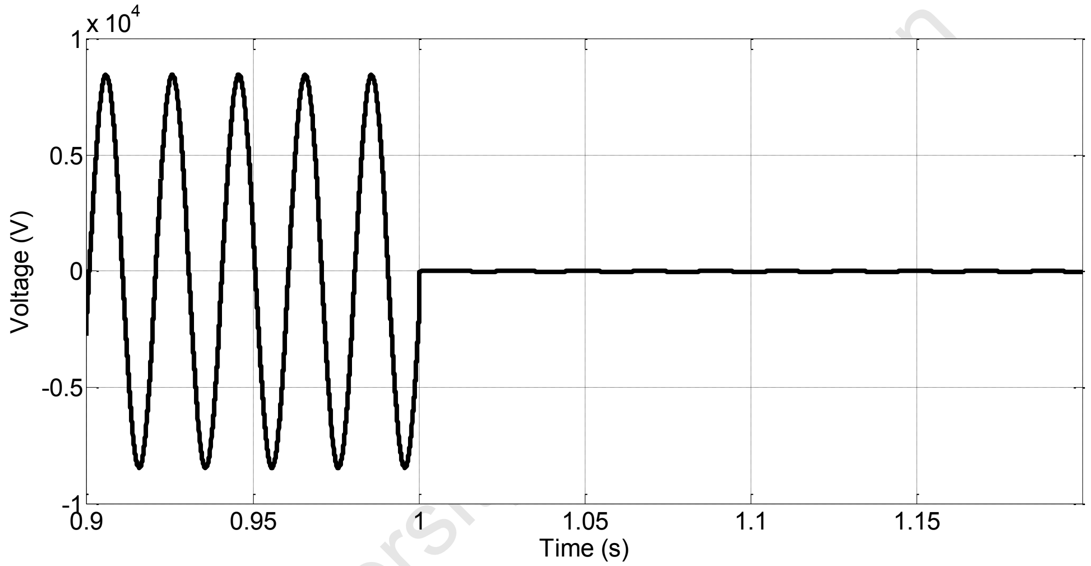


Figure 9.54 **Utility Generator voltage level during Test Case 7**

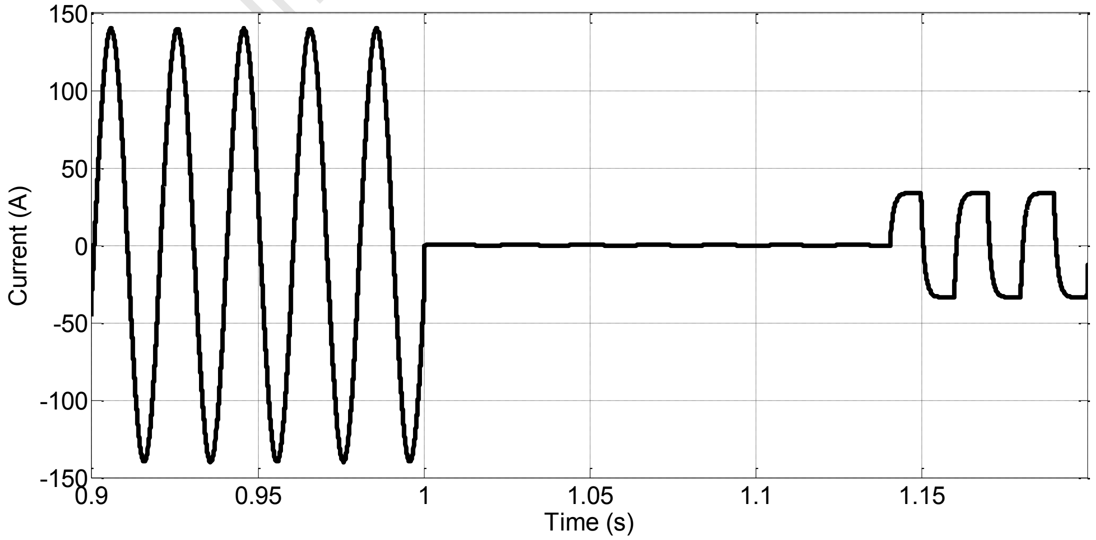


Figure 9.55 **Local load current before, during and after the event in Test Case 7**

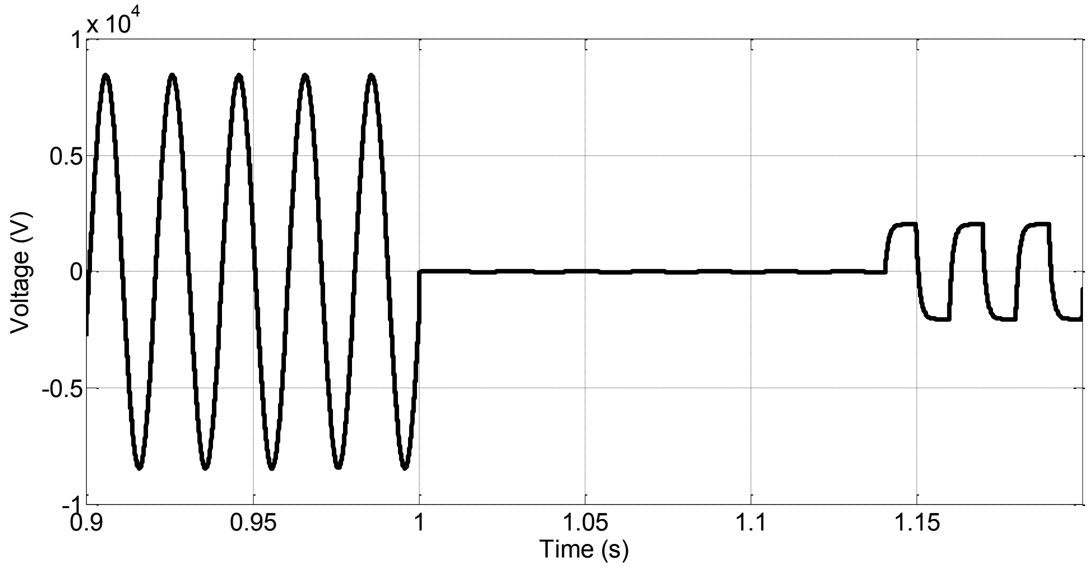


Figure 9.56 **Local load voltage level before, during and after a fault in Test Case 7**

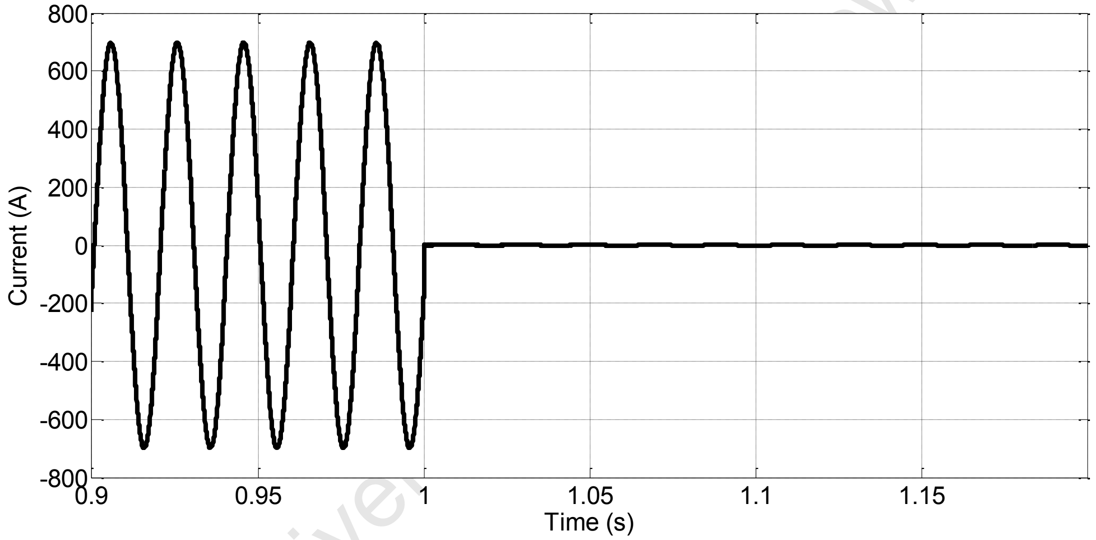


Figure 9.57 **Utility Load Current consumption during Test Case 7**

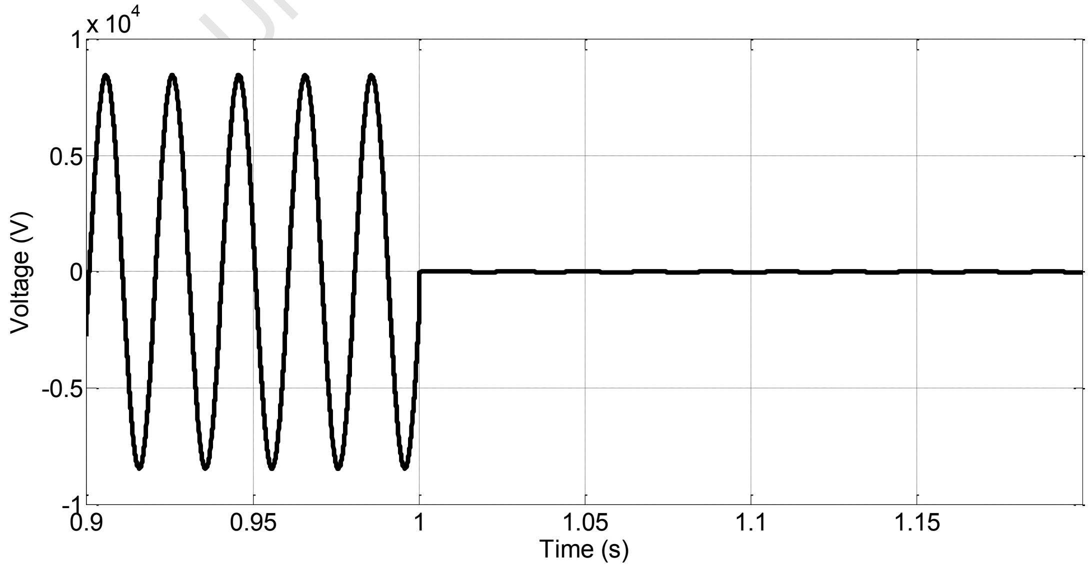


Figure 9.58 **Utility load voltage during Test Case 7**

9.4 Adaptive Protection System for a Microgrid with Solar PV generation

9.4.1 Test Case 14

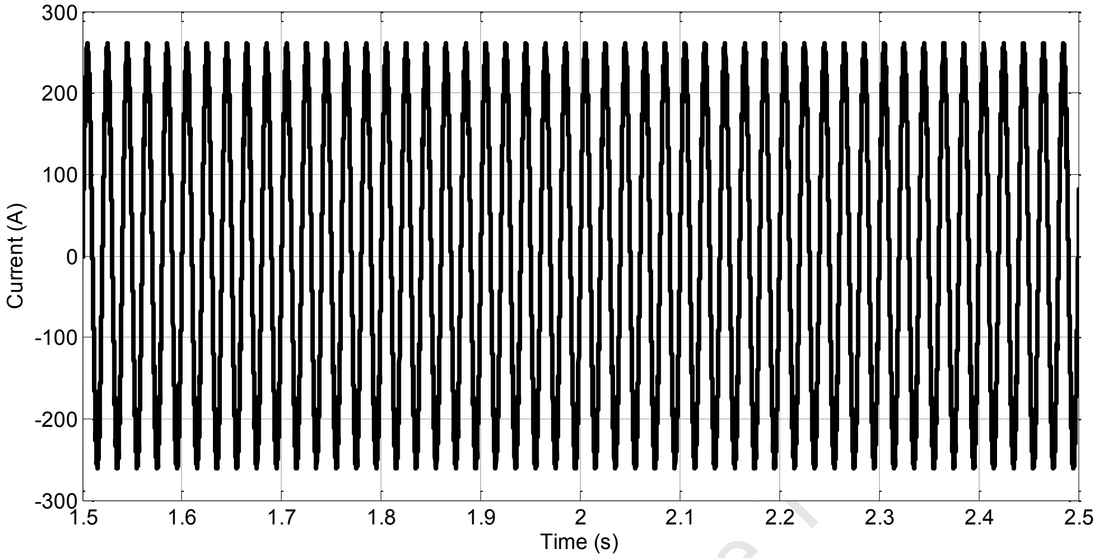


Figure 9.59 Solar PV output current during Test Case 14

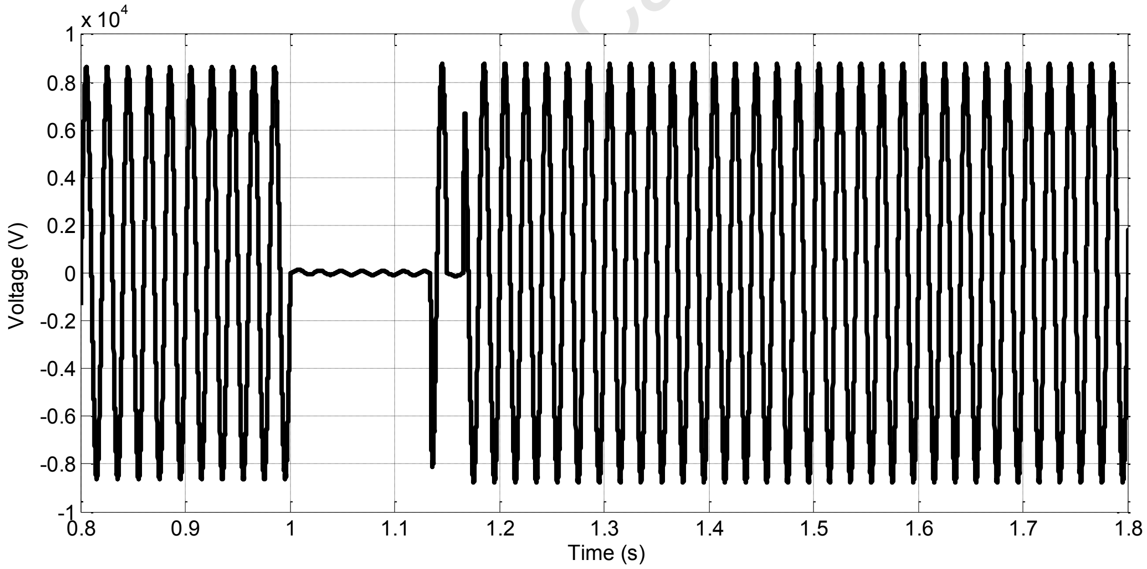


Figure 9.60 Solar PV voltage level during Test Case 14

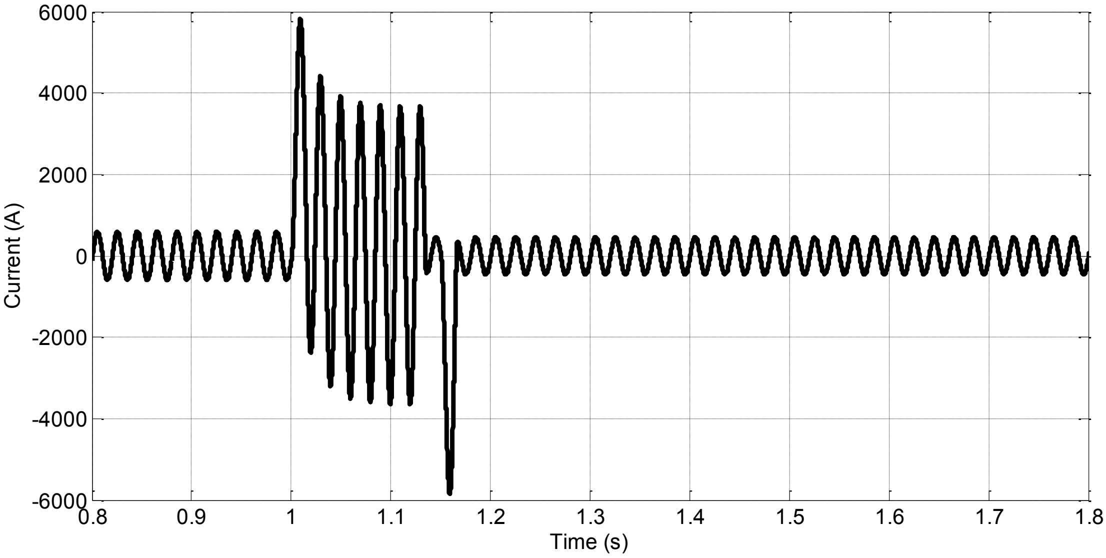


Figure 9.61 **Utility Power Source current output during Test Case 14**

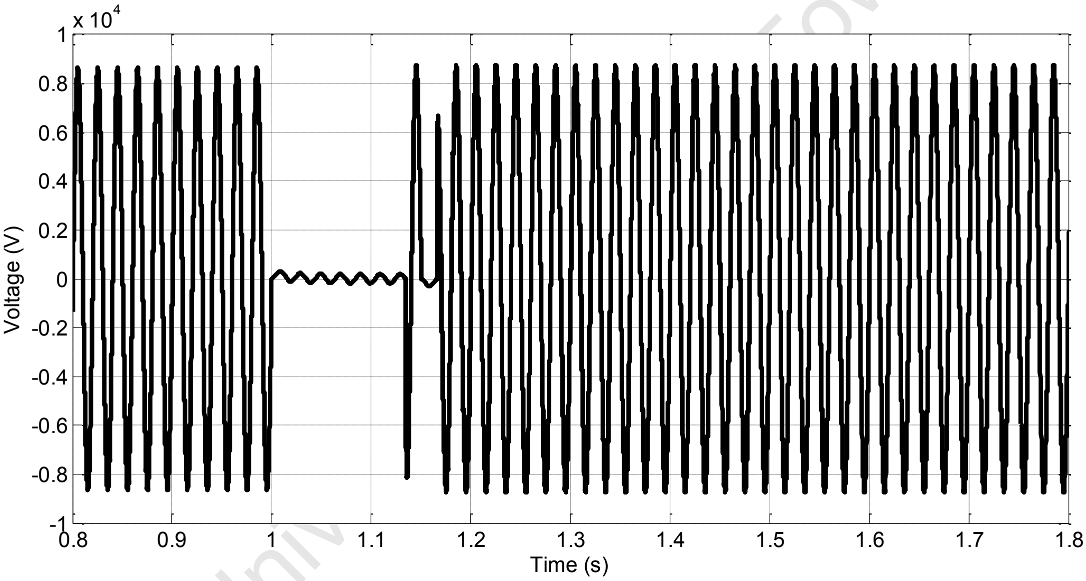


Figure 9.62 **Utility Power Source voltage level during Test Case 14**

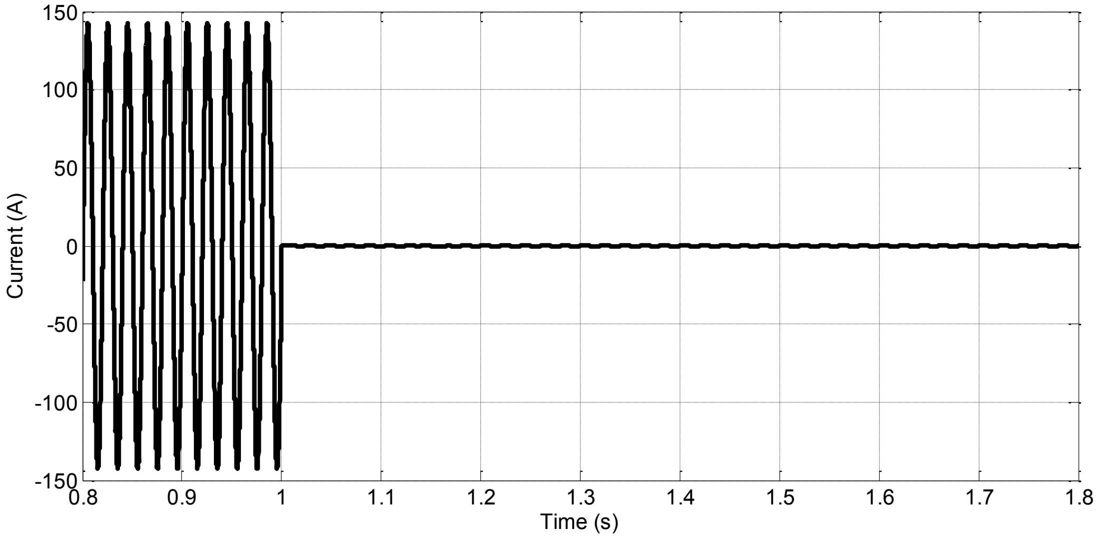


Figure 9.63 **Local load current during Test Case 14**

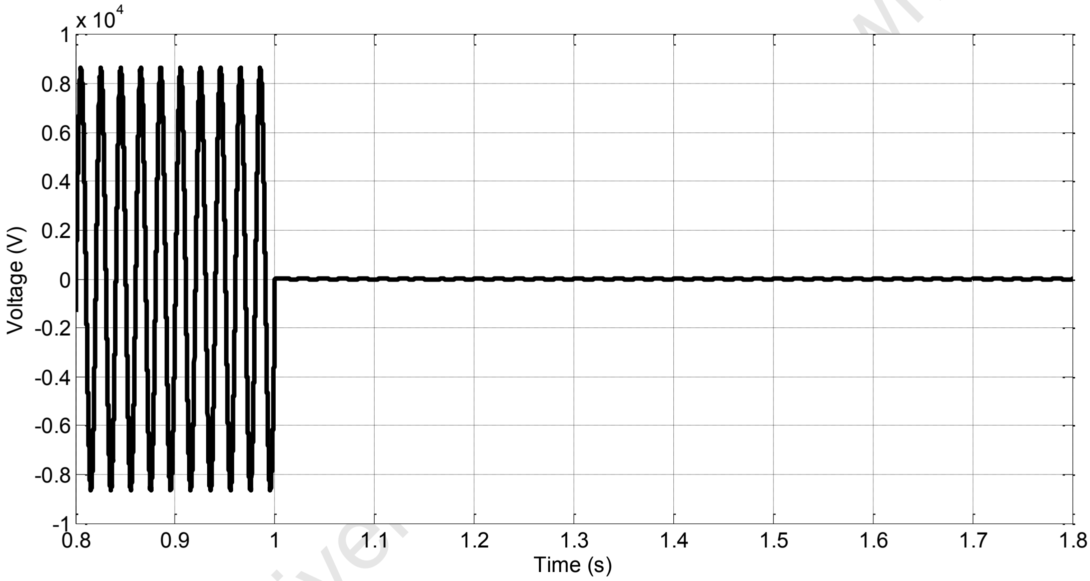


Figure 9.64 **Local load voltage during Test Case 14**

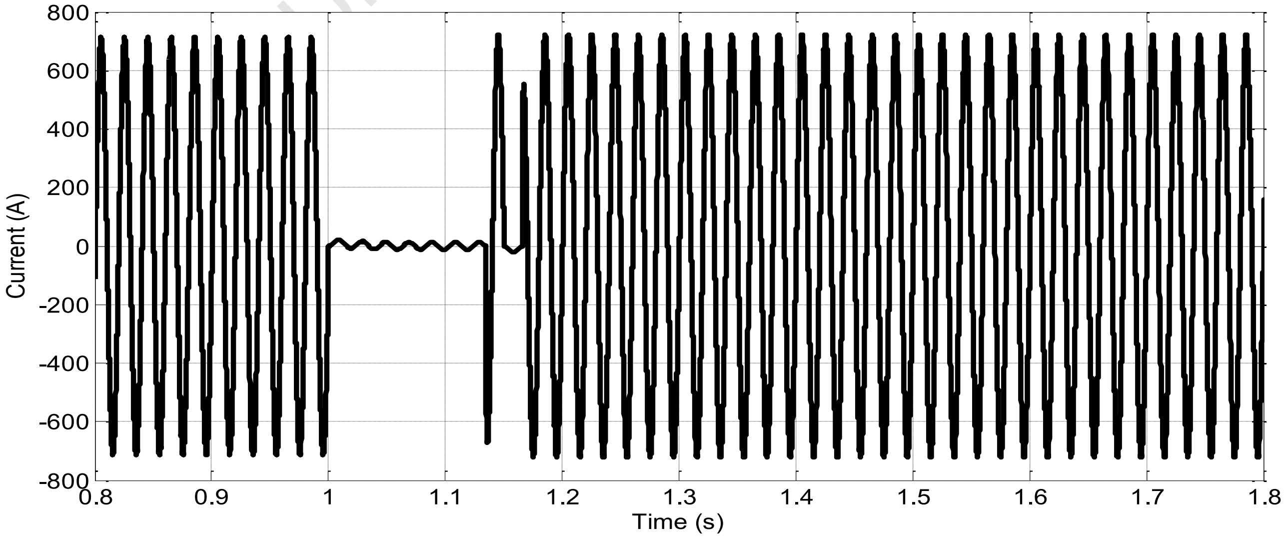


Figure 9.65 **Utility load current before, during and after the fault in Test Case 14**

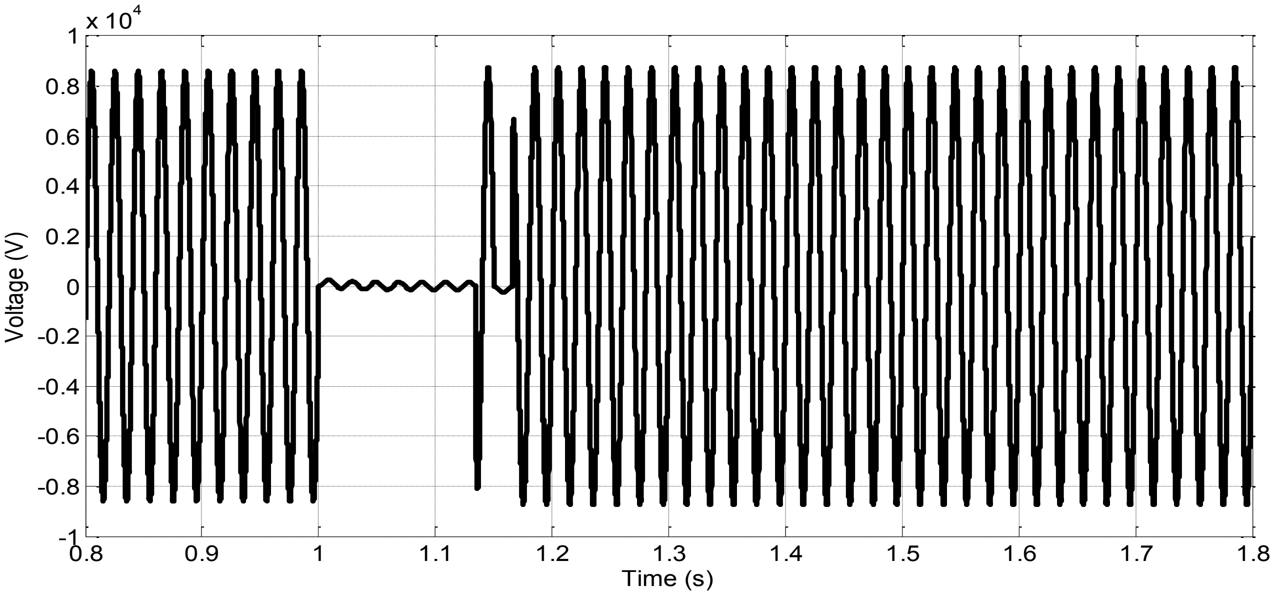
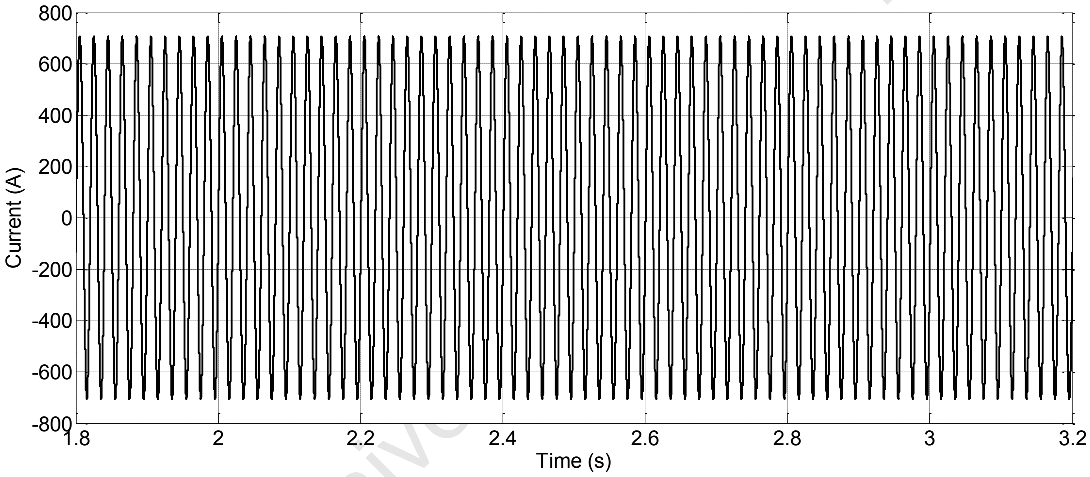
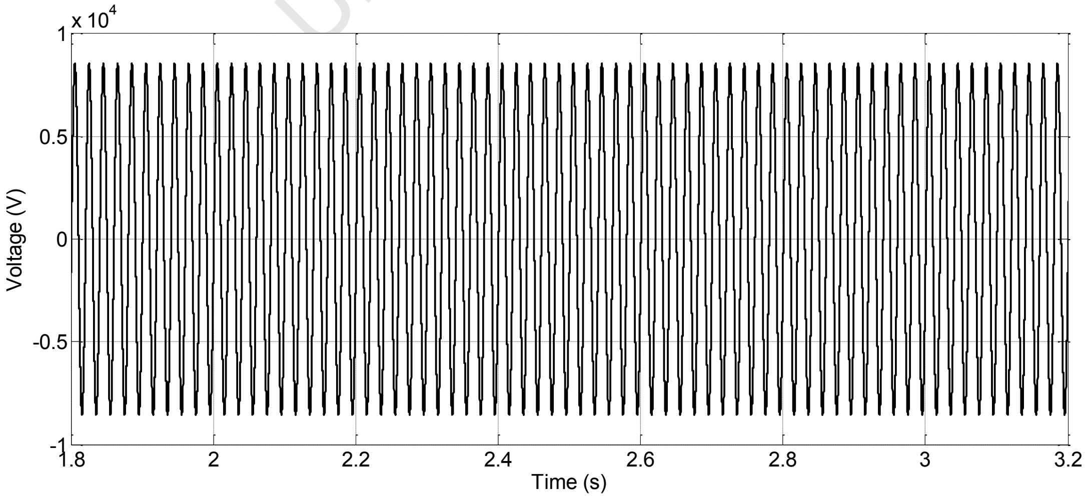
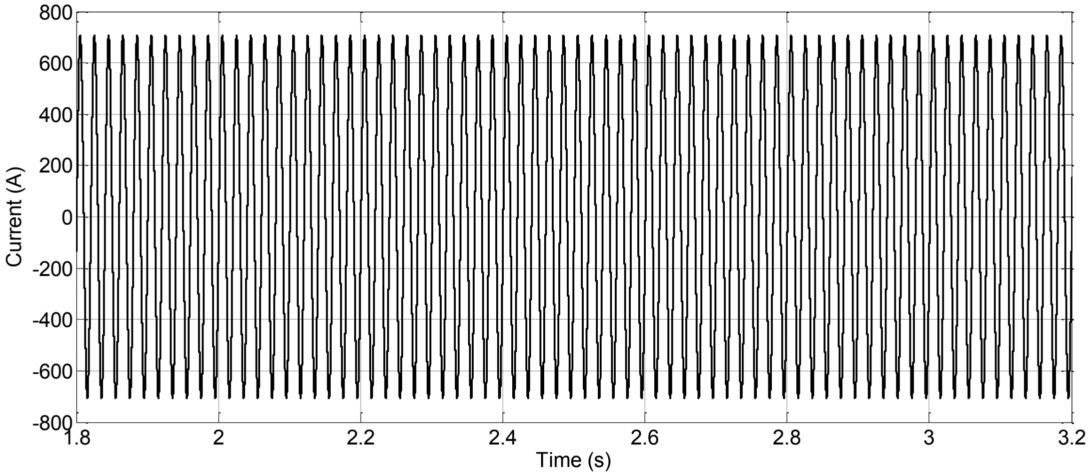


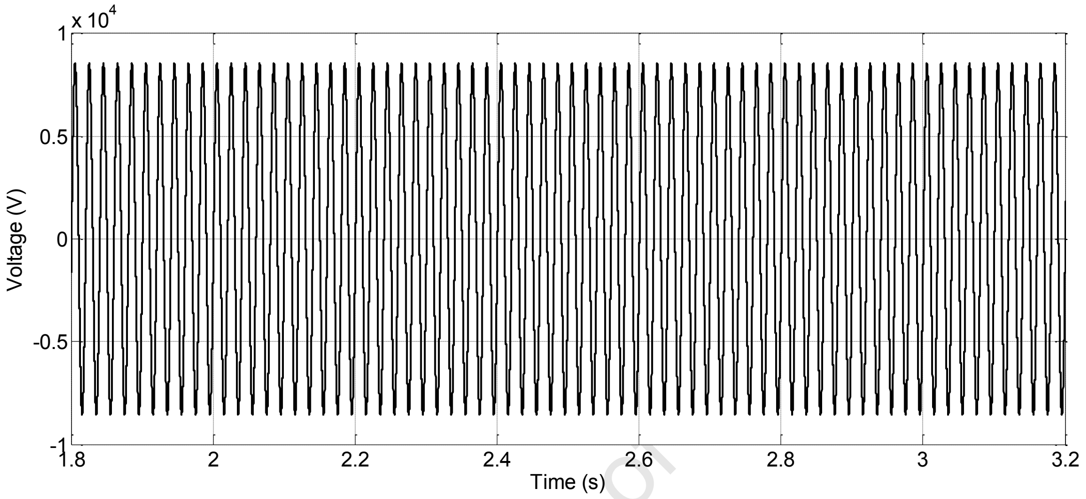
Figure 9.66 **Utility load voltage level before, during and after the fault in Test Case 14**

9.4.2 Test Case 15









9.4.3 Test Case 16

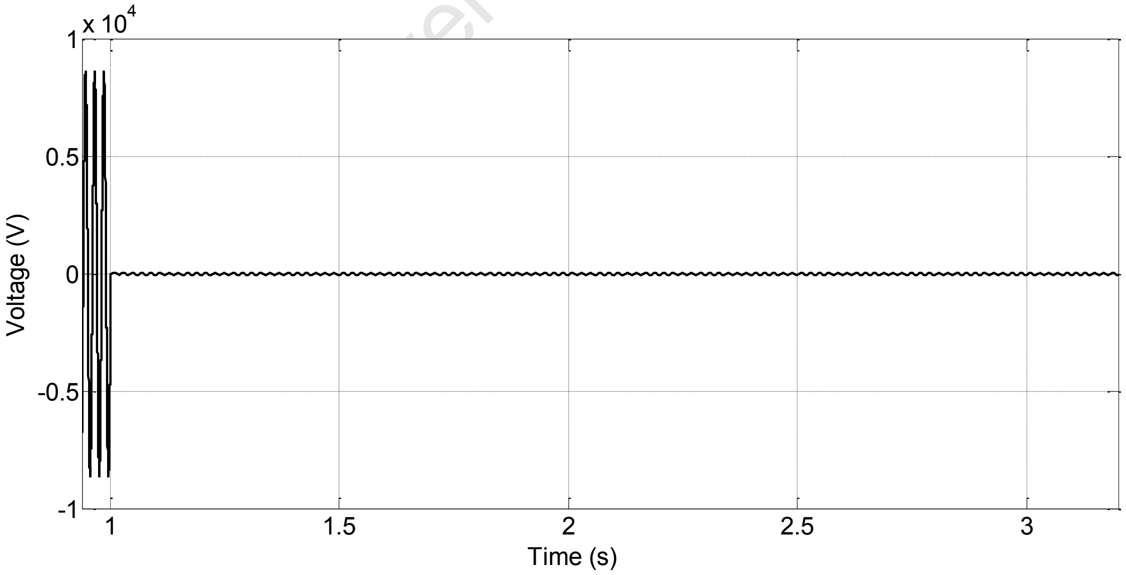


Figure 9.67 Utility Power source voltage during Test Case 16

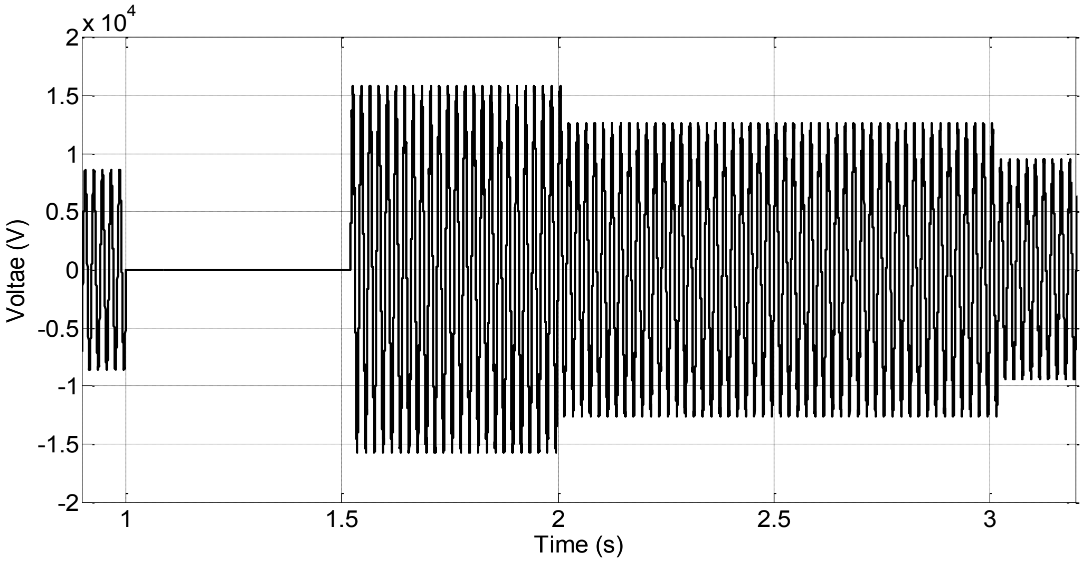


Figure 9.68 **Solar PV voltage level during Test Case 16**

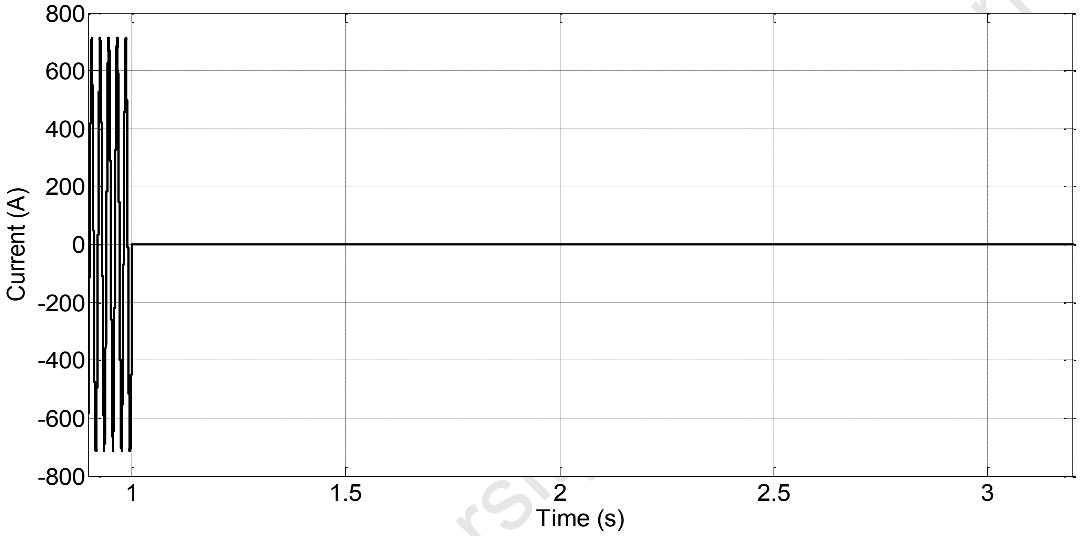


Figure 9.69 **Utility load current consumption during Test Case 16**

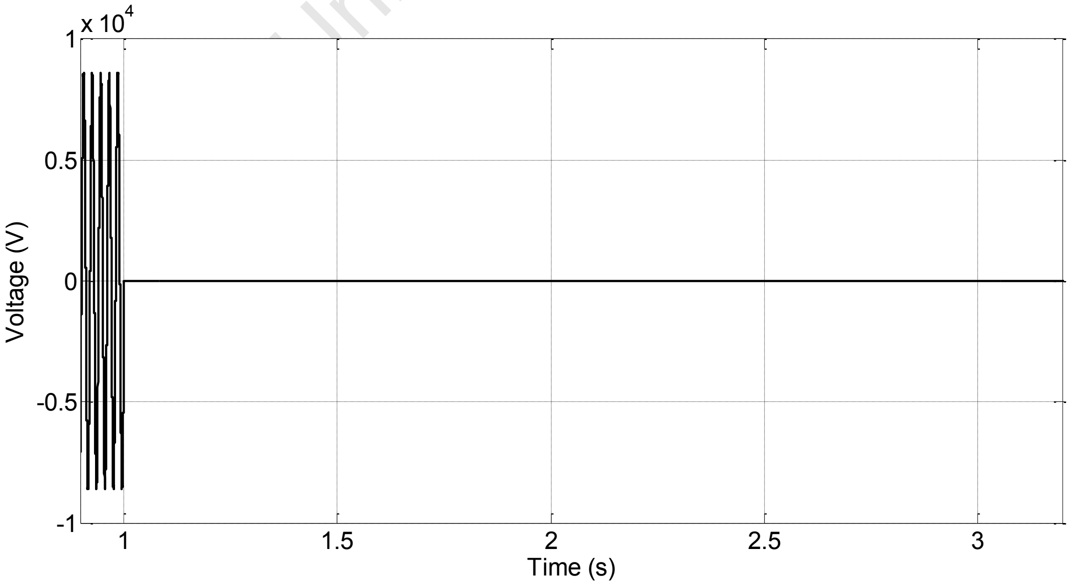


Figure 9.70 **Utility load voltage during Test Case 16**

10. EBE Faculty: Assessment of Ethics in Research Projects

Any person planning to undertake research in the Faculty of Engineering and the Built Environment at the University of Cape Town is required to complete this form before collecting or analysing data. When completed it should be submitted to the supervisor (where applicable) and from there to the Head of Department. If any of the questions below have been answered YES, and the applicant is NOT a fourth year student, the Head should forward this form for approval by the Faculty EIR committee: submit to Ms Zulpha Geyer (Zulpha.Geyer@uct.ac.za; Chem Eng Building, Ph 021 650 4791).Students must include a copy of the completed form with the final year project when it is submitted for examination.

Name of Principal Researcher/Student: Claudio Buque
Department: ELECTRICAL ENGINEERING
If a Student: YES
Degree: MSc. Electrical Engineering
Supervisor: Dr Sunetra Chowdhury
If a Research Contract indicate source of funding/sponsorship:
Research Project Title: Metering and Adaptive Protection for Microgrid with Distributed Generation

Overview of ethics issues in your research project:

Question 1: Is there a possibility that your research could cause harm to a third party (i.e. a person not involved in your project)?	YES	NO
Question 2: Is your research making use of human subjects as sources of data? If your answer is YES, please complete Addendum 2.	YES	NO
Question 3: Does your research involve the participation of or provision of services to communities? If your answer is YES, please complete Addendum 3.	YES	NO
Question 4: If your research is sponsored, is there any potential for conflicts of interest? If your answer is YES, please complete Addendum 4.	YES	NO

If you have answered YES to any of the above questions, please append a copy of your research proposal, as well as any interview schedules or questionnaires (Addendum 1) and please complete further addenda as appropriate.

I hereby undertake to carry out my research in such a way that

- there is no apparent legal objection to the nature or the method of research; and
- the research will not compromise staff or students or the other responsibilities of the University;
- the stated objective will be achieved, and the findings will have a high degree of validity;
- limitations and alternative interpretations will be considered;
- the findings could be subject to peer review and publicly available; and
- I will comply with the conventions of copyright and avoid any practice that would constitute plagiarism.

Signed by:

	Full name and signature	Date
Principal Researcher/Student:	Claudio Buque	15 November 2013

This application is approved by:

Supervisor (if applicable):	Dr Sunetra Chowdhury	15 November 2013
HOD (or delegated nominee): Final authority for all assessments with NO to all questions and for all undergraduate research.	Janine Buxey	15 November 2013
Chair : Faculty EIR Committee For applicants other than undergraduate students who have answered YES to any of the above questions.		

ADDENDUM 1:
Please append a copy of the research proposal here, as well as any interview schedules or questionnaires:

ADDENDUM 2: To be completed if you answered YES to Question 2:

It is assumed that you have read the UCT Code for Research involving Human Subjects (available at http://web.uct.ac.za/depts/educate/download/uctcodeforresearchinvolvinghumansubjects.pdf) in order to be able to answer the questions in this addendum.

2.1 Does the research discriminate against participation by individuals, or differentiate between participants, on the grounds of gender, race or ethnic group, age range, religion, income, handicap, illness or any similar classification?	YES	NO
2.2 Does the research require the participation of socially or physically vulnerable people (children, aged, disabled, etc) or legally restricted groups?	YES	NO
2.3 Will you not be able to secure the informed consent of all participants in the research? (In the case of children, will you not be able to obtain the consent of their guardians or parents?)	YES	NO
2.4 Will any confidential data be collected or will identifiable records of individuals be kept?	YES	NO
2.5 In reporting on this research is there any possibility that you will not be able to keep the identities of the individuals involved anonymous?	YES	NO
2.6 Are there any foreseeable risks of physical, psychological or social harm to participants that might occur in the course of the research?	YES	NO
2.7 Does the research include making payments or giving gifts to any participants?	YES	NO

If you have answered YES to any of these questions, please describe below how you plan to address these issues:

ADDENDUM 3: To be completed if you answered YES to Question 3:

3.1 Is the community expected to make decisions for, during or based on the research?	YES	NO
3.2 At the end of the research will any economic or social process be terminated or left unsupported, or equipment or facilities used in the research be recovered from the participants or community?	YES	NO
3.3 Will any service be provided at a level below the generally accepted standards?	YES	NO

If you have answered YES to any of these questions, please describe below how you plan to address these issues:

ADDENDUM 4: To be completed if you answered YES to Question 4

4.1 Is there any existing or potential conflict of interest between a research sponsor, academic supervisor, other researchers or participants?	YES	NO
4.2 Will information that reveals the identity of participants be supplied to a research sponsor, other than with the permission of the individuals?	YES	NO
4.3 Does the proposed research potentially conflict with the research of any other individual or group within the University?	YES	NO

If you have answered YES to any of these questions, please describe below how you plan to address these issues: