PHOTOVOLTAIC BASED DISTRIBUTED GENERATION POWER SYSTEM PROTECTION

by

Hermanus Lambertus Reyneke van der Walt

Submitted in partial fulfilment of the requirements for the degree
Master of Engineering (Electrical Engineering)

in the

Department of Electrical, Electronic and Computer Engineering
Faculty of Engineering, Built Environment and Information Technology

UNIVERSITY OF PRETORIA

October 2016

SUMMARY

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Hermanus Lambertus Reyneke van der Walt

Supervisor:	Prof R.C. Bansal
Co-Supervisor:	Dr R Naidoo
Department:	Electrical, Electronic and Computer Engineering
University:	University of Pretoria
Degree:	Master of Engineering (Electronic Engineering)

Keywords:	Protective relaying system, Photo Voltaic system, Distributed power generation system, embedded generation, Adaptive protection, Protection blinding, Loss of Coordination, Sympathetic tripping, power systems.

In recent years, the world has seen a significant growth in energy requirements. To meet this requirement and also driven by environmental issues with conventional power plants, engineers and consumers have started a growing trend in the deployment of distributed renewable power plants such as photovoltaic (PV) power plants and wind turbines. The introduction of distributed generation pose some serious issues for power system protection and control engineers. One of the major challenges are power system protection. Conventional distribution power systems take on a radial topology, with current flowing from the substation to the loads, yielded uni-directional power flow. With the addition of distributed generation, power flow and fault current are becoming bi-directional. This causes loss of coordination between conventional overcurrent protection devices. Adding power sources downstream of protection devices might also cause the upstream protection device to be blinded from faults. Conventional overcurrent protection is mainly based on the fault levels at specific points along the network. By adding renewable sources, the fault levels increase and become dynamic, based on weather conditions.

In this dissertation, power system faults are modelled with sequence components and simulated with *Digsilent PowerFactory* power system software. The modeling of several faults under varying power system parameters are combined with different photovoltaic penetration levels to establish a framework under which protection challenges can be better defined and understood. Understanding the effects of distributed generation on three phase power systems are simplified by modeling power systems with sequence networks. The models for asymmetrical faults shows the limited affect which distributed generation has on power system protection. The ability of inverter based distributed generators to provide active control of phase current, irrespective of unbalanced voltage occurring in the network limits their influence during asymmetrical faults. Based on this unique ability of inverter based distributed generators (of which PV energy sources are the main type), solutions are proposed to mitigate or prevent the occurrence of loss of protection under increasing penetration levels of distributed generation. The solutions include using zero and negative sequence overcurrent protection, and adapting the undervoltage disconnection time of distributed generators based on the unique network parameters where it is used. Repeating the simulations after integrating the proposed solutions show improved results and better protection coordination under high penetration levels of PV based distributed generation.

OPSOMMING

FOTOVOLTAÏES GEBASSEERDE VERSPREIDE OPWEKKING KRAG STELSEL BEVEILIGING

deur

Hermanus Lambertus Reyneke van der Walt

Studieleier:	Prof R.C. Bansal
Sekondere Studieleier:	Dr R. Naidoo
Departement:	Elektriese, Elektroniese en Rekenaaringenieurswese
Universiteit:	Universiteit van Pretoria
Graad:	Magister in Ingenieurswese (Elektroniese Ingenieurswese)
Sleutelwoorde:	Beveiliging relè stelsel, Foto Voltaiese stelsels, Verspreide opwekking, beveiliging, Beveiliging verblinding, Verlies van Koordinering, kragstelsels

‘n Skerp styging in energie-aanvraag word in afgelope jare wêreld wyd ondervind. Om die stygende aanvraag vir energie te ontmoet, en ook gedryf deur omgewingsverwante probleme met konvensionele kragstasies, het ingenieurs en verbruikers ‘n vinnig groeiende tendens begin met die onwikkeling van verspreide hernubare energiebronne, soos fotovoltaïese krag opwekkers en windturbines. Die bekendstelling van verspreide opwekkers hou egter ernstige probleme in vir kragstelselbeveiliging en beheerstelsel-ingenieurs. Een van die grootste uitdagings is kragstelselbeveiliging. Konvensionele distribusie kragstelsels neem ‘n radiale topologie aan, waar stroom in een rigting vanaf die substasie na die laste vloei. Stroomvloei in twee rigtings word ondervind met die integrasie van verspreide opwekkers. Twee rigting stroomvloei veroorsaak verlies van koördinasie tussen konvensionele oorstroom beveiligingstoestelle. Beveiligingstoestelle kan ook verhoed word om die fout te sien wanneer kragopwekkers stroomaf geplaas word van bestaande beveiligingstoestelle. Konvensionele oorstroom beveiliging is grootliks gebasseer op die foutvlakke by spesifieke punte in die netwerk. Wanneer hernubare energiebronne in ‘n bestaande stelsel geïntegreer word, word verhoogde en dinamiese foutvlakke ondervind. Die foutvlak bydrae en maksimum kapasiteit van hernubare bronne word ook sterk beïnvloed deur weer patrone.

In hierdie verhandeling word kragstelsels in die teenwoordigheid van foute gemodelleer met sekwensie komponente. Die kragstelsels word dan gesimuleer deur gebruik te maak van *Digsilent PowerFactory* kragstelsel sagteware. Verskeie foute onder veranderende stelsel toestande word gesimuleer, en gekombineer met verskillende vlakke van opwekking, om ‘n raamwerk te skep waaronder beveiligingsprobleme beter gedefinieër en verstaan kan word. Om die effek van verspreide opwekking op drie-fase kragstelsels beter te verstaan, word die stelsels gemodelleer met sekwensie komponente. Die modelle vir ongebalenseerde foute wys veral die beperkte effek wat verspreide opwekking op kragstelsel beveiliging het. Die vermoë van omkeer gebasseerde opwekkers om aktiewe beheer toe te pas van die fasestroom, ongeag die ongebalanseerde spanning wat op die netwerk mag voorkom, beperk hul invloed gedurende ongebalanseerde foute. Oplossings wat gebasseer is op hierdie unieke vermoë van omkeer gebasseerde opwekkers (waarvan fotovoltaïse bronne die hoof tipe is), word voorgestel om verlies van beveiliging te minimeer of in sommige gevalle, heeltemal te voorkom in toenemende teenwoordigheidsvlakke van verspreide opwekking in konvensionele kragstelsels. Die oplossings sluit in die gebruik van nul sekwensie en negatiewe sekwensie oorstroom beveiliging, en die aanpassing van onderspanning ontkoppelingstyd kurwes van verspreide opwekkers, wat gebasseer word op die unieke netwerk parameters waar die verspreide opwekkers gebruik sal word. Die simulasies word herhaal nadat die oplossings geïmplimenteer is, en wys die effektiwiteit van die oplossings. Verbeterde resultate onder verhoogde vlakke van verspreide opwekking is waargeneem nadat die oplossings geïmplimenteer is.

LIST OF ABBREVIATIONS

A	Ampere
AC	Alternating Current
DC	Direct Current
DG	Distributed Generation
HV	High Voltage
IED	Intelligent Electronic Device
IPP	Independent Power Producer
kV	kilo Volt
LV	Low Voltage
LVRT	Low Voltage Ride Through
MV	Medium Voltage
MW	Mega Watt
NEC	Neutral Earth Compensator
NER	Neutral Earth Resistor
NECR	Neutral Earth Compensating Resistor
OC	Overcurrent
POC	Point of Connection
PV	PhotoVoltaic
pu	Per Unit
RMS	Root Mean Square
XLPE	Cross Linked Polyethylene Insulation

NOMECLATURE

I_a	Phase A current
I_b	Phase B current
I_c	Phase C current
I_0	Zero sequence current
I_1	Positive sequence current
I_2	Negative sequence current
I_{actual}	Primary current, actual value
I_{base}	Base current
I_{pu}	per unit current or pick-up current
I_f	Fault current
$I_{f,pu}$	Fault current, per unit
$I_{f3\emptyset,pu}$	Three phase fault current, per unit
$I_{f1\emptyset,pu}$	Single phase fault current, per unit
I_{S0}	Zero sequence source current
I_{S1}	Positive sequence source current
I_{S2}	Negative sequence source current
I_{pv1}	Positive sequence PV current
I_{phase}	Phase current
S_{base}	Base apparent power
TM	Time multiplier
V_a	Phase A Voltage
V_{pv}	PV Voltage
V_f	Fault Voltage
$Z_{T,pu}$	Transformer impedance, per unit
Z_{S1}	Positive sequence source impedance
Z_{S2}	Negative sequence source impedance
Z_{T1}	Positive sequence transformer impedance
Z_{T2}	Negative sequence transformer impedance
Z_{T0}	Zero sequence transformer impedance
Z_f	Fault Impedance
Z_{pv1}	Positive sequence PV impedance

Z_{pv2}	Negative sequence PV impedance
Z_{pv0}	Zero sequence PV impedance
Z_{NER}	NER impedance
Z_{L1}	Positive sequence line impedance
Z_{L2}	Negative sequence line impedance
Z_{L11}	Line 1, positive sequence impedance
Z_{L12}	Line 1, negative sequence impedance
Z_{L21}	Line 2, positive sequence impedance
Z_{L22}	Line 2, negative sequence impedance

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CHAPTER 1 INTRODUCTION

1.1 PROBLEM STATEMENT

1.1.1 Context of the problem

In recent years, the world has faced a significant growth in energy requirements. To meet this requirement and also driven by environmental issues with conventional power plants, engineers and consumers have started a growing trend in the deployment of distributed renewable power plants such as photovoltaic PV power plants and wind turbines [1] – [4]. The utilizing of PV panels to contribute in power generation started as early as the 90s in projects such as the German "1000-roof" program that was initiated by the German Ministry for Research and Technology in 1990 [1]. Since then, Germany has surpassed the 16 GW mark of installed PV generation in 2010 [2] and doubled that figure in the following 4 years. This trend in PV generation is not limited to Germany and can be seen around the world along with research and development opportunities in this field.

The introduction of distributed generation (DG) pose some serious issues for power system protection and control engineers. Together with distributed generation, some consumers are also moving towards the forming of micro-grids in order to provide more security and quality of supply. Micro-grids are smaller than utility grids and are usually privately owned, making maintenance simpler. Owners are able to plan outages to better align with their energy requirements and do not need to rely on utilities, increasing security of supply. Since micro-grids are smaller privately owned networks, they experience less interference from external factors, increasing their quality of supply. Micro-grids are the forming of small grids consisting of balanced sources and loads. Micro-grids form when a feeder connecting a group of customers is lost due to a system fault or load shedding [5]. Distributed generation pose problems related to power system stability, severe voltage fluctuations, conventional uni-directional feeder protection, changes in feeder loading, power quality, thermal overload of distribution systems and many more.

The structure of conventional power systems are radial topology at distribution level, where a single source is used to feed several loads [6] – [8]. Conventional distribution level feeder protection is based on time grading of simple overcurrent relays. Coordination is maintained by making use of time grading between breakers in a given path to a load. This will ensure that the breaker closest to the fault will operate first and isolate only the faulted section on a line. Current research trends indicate that this type of conventional protection is being threatened by the addition of DG and that conventional overcurrent protection is no longer able to protect the power system [9] – [12]. Current research trends are looking at providing new protection solutions to highly penetrated DG power systems since conventional time overcurrent protection now becomes unable to protect the system [13] – [28].

1.1.2 Research gap

Current research shows that several solutions have been suggested to address the protection challenges in DG power systems. These suggestions include disconnection of all distributed generators immediately upon detection of a system fault [13]. This would enable conventional overcurrent protection to operate as normal. Since the biggest challenge in distributed generation power systems are increased and dynamic fault levels, suggestions have been made to disconnect protection in distribution systems from fault levels. This can be done by making use of differential protection. Using differential protection will require a communications network between all protection devices and directionality at every protection device. Another alternative would be to perform power system simulations off-line and update feeder protection settings in real time according to the system configuration, fault level and generating capacity at any given time. This is also a communications based method and will require all of the conventional protection devices to be replaced.

Available solutions are mostly aimed at generic distributed generators and does not distinguish between different technologies such as wind turbines, hydro turbines, concentrated solar heating, gas turbines and photovoltaic power plants. Rooftop PV is by far the most popular choice for private residential owners who are looking to invest in alternative and renewable power sources in residential distributions systems, due to their static nature without any moving parts, high scalability and simplicity to maintain. PV power plants are integrated into the network with inverters, which are able to manipulate current unlike conventional rotating machines. The fault current supplied from PV inverters, are less than two times the nominal current and their influence during system disturbance conditions are different from rotating machines. This is not taken into account in current research.

The available suggested solutions attempt to provide foolproof technical solutions. Several solutions are based on typical protection methods commonly used on transmission and sub-transmission levels. On these levels, large power flows are expected and the loss of any lines or equipment on transmission levels would have severe impacts. The same cannot be said for distribution level power systems and the high capital investment requirements of the proposed solutions, will not prove economically viable.

Power systems are based on three phase networks and differ significantly from single phase networks. Due to the complexity and effort to draw three phase diagrams and perform calculations, engineers often resolve to using single line diagrams and per unit systems most of which are based on balanced three phase networks. Many of the identified challenges in distributed generation power system protection are based on this assumption [20], [29] – [31]. During asymmetrical faults, the current and voltages in the three phases will not be equal and sequence network analysis is required. Using sequence network modeling and verifying the validity and severity of protection challenges, will provide a better platform from where solutions can be suggested. This is also the only method whereby the unconventional current flow from PV inverters can be integrated into power system studies to better address protection challenges [9].

1.2 RESEARCH OBJECTIVES AND QUESTIONS

The main objective of this dissertation is to investigate the effects of small scale DG on distribution power systems and to establish the validity of the challenges presented by the general scientific community with regard to what effect high penetration levels of DG will have on conventional distribution level power system protection. The objective is to investigate the reaction of conventional power system protection systems in the presence of DG, and propose possible alternative protection solutions if required. Power system simulations need to be conducted in order to establish, whether the challenges listed by the general scientific community will indeed have the negative effect on power system protection as suggested. Simulations will not only provide better insight into the existence of the challenges, but it will also give a better indication of the unique or general conditions where these challenging events might occur. By modeling a power system with sequence models, the impact of DG will be better understood in three phase power systems.

The simulation results will provide the premise of investigating possible solutions to maintain protection reliability in DG power systems. If possible, industries would be better served with solutions that will be cost effective and economically viable. Simulation results will highlight all of the strong and weak points of DG, which might aid in proposing alternative protection solutions. Any suggestions made should be tested in the same power system and under the same system conditions to prove their functionality.

The objectives of this dissertation can be summarized by the following questions:

- Does DG influence current protection schemes beyond a level where equipment and lives can no longer be protected with existing protection schemes?
- Can protection be maintained in distribution networks by only modifying protection methods at DG feed in points to effectively protect the distribution network without changing protection schemes at existing feeders and nodes?
- Is it possible to protect distribution networks with static relay settings in spite of the dynamic system configurations due to addition or removal of DG sources?
- Can conventional protection methods be adapted in ways not requiring protection devices to be replaced in order to prevent large capital investment requirements?

1.3 APPROACH

A typical South African distribution power system is presented and used for the simulations in this dissertation. The impact of DG on power system protection is investigated by performing power system simulations with *Digsilent PowerFactory* simulation software. Conventional distribution level protection methods are first investigated and explained for background information along with a literature study of the available research. The test network is modelled with sequence networks and then simulated with and without any PV based DG present. The different protection challenges will be tested by simulating relevant parts of the test network under several network conditions such as grid fault levels, cable lengths, PV penetration levels and types of faults. Based on the findings in the results, solutions can be presented to address the challenges found in their proper context. After implementing the solutions, the simulations are repeated to investigate their influence and prove their validity.

1.4 RESEARCH AIM

The first research goal of this dissertation is to establish the validity of the challenges presented by the general scientific community with regard to the effect that high penetration levels of DG will have on conventional distribution level power system protection. The simulations will highlight the conditions and system parameters that will result in loss of or risk to conventional protection will occur. The second goal is to propose cost effective and technically acceptable alternative protection methods that will be able to protect the power system under high DG penetration levels.

1.5 RESEARCH CONTRIBUTION

In South-Africa, many municipalities and power system owners are hesitant to allow DG by customers within their network because of two reasons.

1. It is a relatively new concept in South-Africa. The Integrated Resource Plan (allowing integrated resources or DG) was first launched in South Africa in 2010.
2. The impacts which DG will have on their network are unknown.

Many residential areas buy electricity from local municipalities and not from Eskom's national grid, forcing residents to comply with proprietary municipal regulations for integration of DG, many of which are still slow to develop such regulations. This dissertation will contribute to the available literature and especially within the South African environment. It will scientifically prove to power system owners, such as local municipalities, the effects of DG on their network and enable growth of DG in the South-African market. Growth of DG will provide opportunities for economic growth, place less strain on our only power utility giant, Eskom, and promote infrastructure development and growth within municipal networks. This dissertation will aid in developing integration standards and guidelines for power system owners to allow safe and reliable PV based DG into distribution grids.

1.6 DISSERTATION CHAPTERS BREAKDOWN

This dissertation consist of seven chapters. In Chapter 1, the context, objectives and goals of the research is discussed. In Chapter 2, a background study is done on distribution power systems along with it's individual components. Background information is given on conventional distribution level overcurrent protection. The sample network used for simulations are given and it's power system components and protection parameters are discussed. In Chapter 3, a review is done on distributed generation and the effect it has on power systems in general. Challenges such as reactive power support, disturbance ride through capabilities and voltage regulation are briefly discussed. This is followed by a more detailed discussion of the protection challenges engineers encounter in distribution systems with a presence of DG. Alternative protection solutions, as proposed by the general scientific community are explained and critically evaluated.

Chapter 4 follows with power system simulations using *Digsilent PowerFactory*. The network analyzed in Chapter 2, is simulated to establish the principles of conventional overcurrent protection and to highlight some of the typical constraints of basic overcurrent protection. The conventional network is simulated to establish conventional functionality and limitations on overcurrent and earth fault protection without any presence of DG.

In Chapter 5, the protection challenges listed in Chapter 3 are tested. Relevant parts of the test network are simulated under various system conditions to determine the conditions under which conventional protection might fail. Balanced and unbalanced faults are simulated on cables and overhead lines. System parameters are changed from normal to extreme values, to ensure all possible scenarios are covered. After each simulation, the results are discussed.

Based on the findings from Chapter 5, solutions are suggested in Chapter 6 to overcome the effects caused by PV based DG. The solutions are justified and explained in detail by using sequence component networks. The cases where protection failure was experience in Chapter 5 are simulated while implementing the improved protection solutions to test their validity and operational limits. Finally, the dissertation is concluded in Chapter 7 with a discussion of all the core areas that led to loss of protection, and the measures taken to overcome the challenges.

CHAPTER 2 CONVENTIONAL DISTRIBUTION POWER SYSTEM REVIEW

2.1 INTRODUCTION

This Chapter gives an overview of conventional distribution power systems. Conventional radial overcurrent and earth fault protection are presented. The radial network to be used for the simulations in this study is given along with network configuration and parameters such as cable ratings, cable lengths, fault levels and network impedances. Based on these parameters, an overview of the protection settings and philosophies are given.

2.2 CONVENTIONAL DISTRIBUTION NETWORK REVIEW

Conventional power plants were built in a centralized configuration due to their complexity, large capital investment cost and size. These includes power plants such as nuclear and coal fired power stations and were built with typical sizes of hundreds of MW up to a few GW. Since the power plants are few and wide spread, power needs to be transferred over great distances via transmission lines in order to reach customers and loads. Generation substations generally feed into the grid at transmission level voltages, ranging from 132 kV up to 400 kV. High voltages are used in order to minimize power system losses and transmission line conductor sizes. This made expensive and accurate protections schemes important and a viable option, because of the importance of the equipment and lines feeding this vast amount of power. Bi-directional power flow is common on transmission networks with power stations connected in a non-radial fashion for contingency. Transmission lines are not characterized by a high quantity of load centers and unit protection such as line differential or impedance protection schemes are mostly used.

Consumers are unable to utilize power at these voltage levels and it is not practical to supply power to residential consumers at these voltage levels. This is why distribution networks are used to distribute power to consumers and load centers. Distribution networks are fed from transmission networks and use step down transformers to bring the voltage levels down to a workable level. Typically voltage levels ranging from 400 V (consumer level) to 11 kV and 33 kV (distribution level) are used.

Distribution transformers are often chosen with a Wye-Delta configuration. Cost is saved on insulation requirements of the transformers since the voltage appearing across the windings of the Wye side is lower than on a Delta winding. A Delta winding is used on the secondary side, because it will trap 3rd order harmonics within the delta and smooth out the voltage to customers. With the Delta winding on the secondary side, there is no ground connection, making it difficult to supply single phase loads with line to ground voltage. With the absence of a ground connection, the only zero sequence current that will flow during an earth fault is through the cable stray capacitance, making earth fault detection difficult on the delta side. Grading of earth fault protection schemes are not possible with the low earth fault current flowing through the stray capacitance. To provide a path for zero sequence current, the transformer secondary is grounded with a Neutral Earthing Compensator (NEC), also called a grounding transformer or zig-zag transformer. Using a NEC enables the system to provide single phase loads and helps with the detection of earth faults. The Neutral point of the zig-zag transformer is often taken through a Neutral Earthing Resistor (NER) to limit the amount of fault current during an earth fault [32]. Typical Neutral Earthing Compensating Resistor (NECR) values of 360 A are used in South-Africa.

MV cables are used to distribute power across a region, since the loads in distribution networks are usually small distributed loads. Mini substations (mini-subs) are used to step the voltage down from MV levels to consumer usable LV levels (400 V). Loads are typically a mixture between single phase domestic resistive loads, power electronic loads such as home appliances and compact fluorescent lighting and single and three phase inductive loads such as pool pumps and air conditioning pumps.

Overhead lines are used to distribute power in cases where the loads are far from the substation. Auto-reclosers and sectionalizers are used on overhead lines where transient faults occur frequently due to lightning, veld fires or branches falling on the lines. Auto-reclosers are set to trip for faults, and reclose after a clearing time delay to allow transient faults on the lines to clear, and are frequently coordinated with fuses at tee-offs to customers.

Distribution level transformers fall in the range of 5 MVA to 80 MVA and their size is determined by the load requirements. A distribution network has at least one, and in some cases two or three transformers connected to a MV bus, to meet the load requirements and stay within the operating capacity of the transformers. The loads are distributed along lines and fluctuate throughout the day and seasons. Voltage drops are common, with cable lengths reaching several kilometers, and consumers' voltage levels depend on their distance from the substation and the capacity of the cables. On load tap changers are used on distribution transformers to regulate the customer voltage which would otherwise fluctuate. Voltage level requirements are given by National regulating authorities. No two power transformers are exactly the same (power rating could differ, percentage impedance could differ) and circulating current between transformers connected in parallel is an issue. Circulating current is current flowing between two transformers due to their secondary voltages not being equal. Circulating current heats up the transformer winding and does not deliver any effective work [33]. On load tap changers with voltage regulating relays are used to monitor and minimize circulating current by aligning their tap positions. To increase the reliability of the power systems, ring feeders are often used in substations as illustrated in Figure 2.1 [32]. It is uncommon to run the rings in closed configuration, since this create problems in sensitive earth fault protection schemes, and bring the risk of paralleling two transformers that do not have parallel regulating agreements between them. Paralleling two transformers on different busses could cause damage to the cables and equipment. The configuration of power systems described and illustrated in Figure 2.2 results in unidirectional power flow.

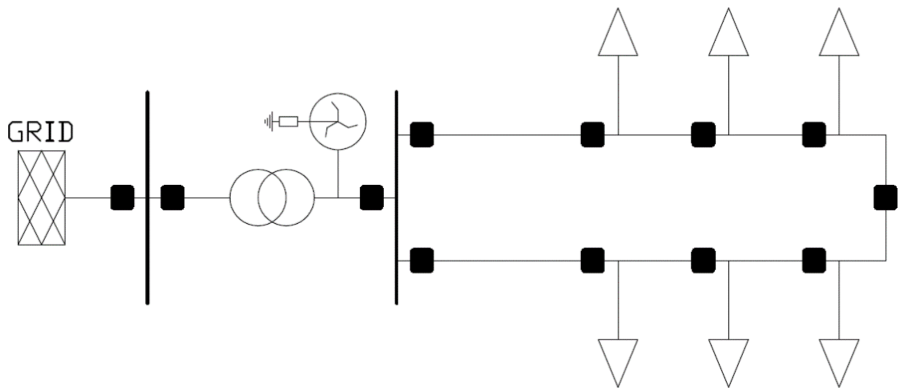

Figure 2.1 Ring feed topology

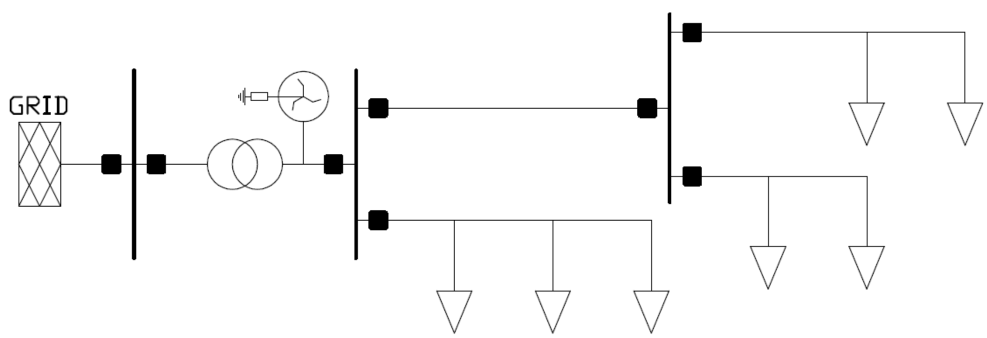

Figure 2.2 Radial feeder topology

2.3 REVIEW ON CONVENTIONAL PROTECTION SCHEME OF THE DISTRIBUTION SYSTEM

Faults on power systems are caused by lightning, damage to cables, aging cables, branches falling on lines, and incorrect operation [34]. Faults cause overcurrent to flow in the equipment, leading to damage of the equipment, damage to cables or loss of lives. Power system protection is used to protect equipment and protect lives from the damaging effects of such faults. Several points of protection are present along a given path from the source to the load to provide sufficient sensitivity to the protection relays and a high quality of supply. A feeder illustrating this is given in Figure 2.2 where overcurrent protection is present at each breaker.

Overcurrent protection was the earliest protection system to evolve, and is frequently used in distribution substations [32]. Overcurrent and earth fault protection measures current and trips the breaker, if the measured current exceeds a set threshold. Breakers with significant importance, such as substation MV breakers and mini-sub primary breakers have configurable intelligent electronic devices (IED's), to manage their protection while less significant breakers have static setting mechanical overcurrent breakers or fuses. In breakers with IED's, two types of curves are generally available, inverse time characteristic and definite time characteristic. With the inverse characteristic, the tripping time reduces as the fault current increases, providing fast tripping times for large faults, while the definite time provides a fixed tripping time for any fault over a specific threshold. Overcurrent and earth fault protection can safely detect three phase, line-line and line-earth faults.

Breakers following on each other in a given path from the substation to the load operate in a coordinated fashion, to ensure that only the section downstream of a fault is isolated and to provide better quality of supply. This is done by increasing the sensitivity or decreasing the tripping time delay of downstream breakers. When a fault occurs, all of the breakers upstream of the fault will measure the same current according to Kirchoff's current law. The breaker with the most sensitive settings (the breaker furthest downstream and closest to the fault) will operate first. Consider Figure 2.2 with a single line to ground fault after breaker 6. The same fault current will be seen by all of the breakers between the station MV bus and the fault. If the breakers operate in such a fashion that breaker 6 operates faster than breaker 5, which is faster than breaker 3, which is faster than breaker 2, then breaker 6 will operate first, clearing any fault current seen by upstream breakers and enabling isolation of only the faulted section and normal power delivery to all of the other loads. When cables lengths between protection points are long, grading is easy since the fault current that will flow in a line will be less as the fault moves further away from the substation. This is due to the internal cable impedance. For effective grading, the pick-up current is reduced as a breaker moves further away from the substation and the relay settings becomes more sensitive. This fashion of grading is referred to as grading with current [32]. For short cables, the fault levels along the line will not decrease significantly. This requires grading with time where pick-up levels for breakers in a line are fairly similar, but the operating time for a given current should be less as you move down the line. The resulting inverse time operating curves for the two methods are shown below in Figure 2.3. Grading wit time is preferred, in order to gain sufficient margin between two following breakers for high fault currents. Grading only with current does not provide sufficient grading margin for high fault currents. This could cause more than one breaker to operate for a fault, since it might not reset in time once the fault is cleared by the relevant downstream breaker.

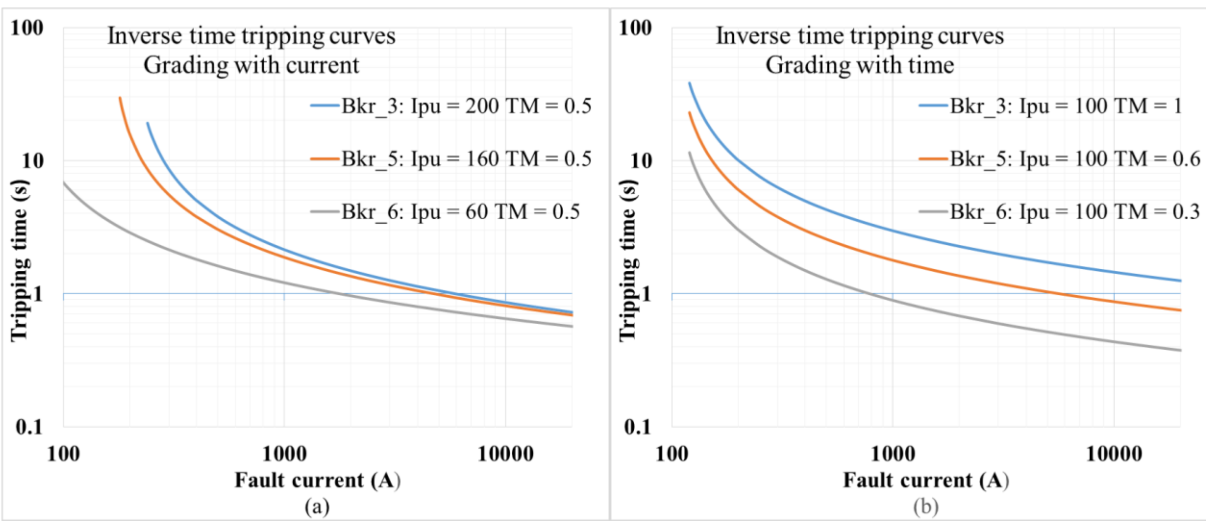

Figure 2.3 Current and Time Grading

(a) Grading with current (b) Grading with time

Grading methods given in Figure 2.3 is used to set the grading margin between auto-reclosers and fuses. Auto-reclosers typically use two tripping curves known as a fast and a slow curve [35]. As mentioned in section 2.2, auto-reclosers are often used in conjunction with fuses. Auto-reclosers are preferred on MV lines since they are at high risk of experiencing transient faults. In case of a fault, the auto-recloser is set to first trip on the fast tripping curve in order to clear a possible transient fault. The fast tripping curve is set to trip faster than the minimum fuse melting time. After a given time delay (during which the transient fault is allowed to clear) the auto-recloser is closed again, and will revert to the slow tripping curve which trips slower than the fuse maximum clearing time. If there is a solid fault on the line downstream of the fuse, the fuse will blow before the recloser trips for a second time. If a permanent fault occurred between the recloser and the fuse, the recloser will trip for a second time, isolating the whole line. This operation is known as *fuse saving* and is effective on MV overhead lines [36].

Another setup also seen frequently is reclosers used in conjunction with sectionalizers. Sectionalizers do not have protection devices as seen in reclosers. A sectionalizer can measure a high rise in current, and will recognize the rapid drop in current when the recloser trips. The sectionalizer will count the number of fault occurring events in a given time range. There are often several sectionalizers on a line in series with a recloser. Sectionalizers are set with discrete fault detecting algorithms and works as follows; All sectionalizers upstream of a fault will detect the high current when a fault occurs, followed by the rapid drop in current when the recloser trips. Each sectionalizer is set to allow such an event for a set number of times, and each sectionalizer will allow one event more than the sectionalizer immediately downstream. When the amount of reclosing events exceeds the set amount of event times in the sectionalizer, the sectionalizer will trip and isolate the section downstream. Sectionalizers are used to divide the line into sections of protection and are less expensive than reclosers [37].

The pick-up and time settings used for overcurrent and earth fault IED’s are usually based on one of two factors. The settings can be based on fault levels at the point of protection. The fault level is a measure of the fault current flowing for a solid fault at that specific point. The fault level is determined by the *Thevanin* impedance looking back into the source, or source impedance. All of the equipment from a generator to the point where the fault level is measured are taken into account, such as the transmission line impedance and transformer impedances. Alternatively, the settings can be based on the current carrying capacity of the cables or lines downstream of the protective device, also known as the protected equipment. The lowest between the two values are selected to ensure that no equipment is damaged and that all possible faults are picked up [32].

Current flow is characterized as being uni-directional, flowing from the substation towards the loads, since conventional distribution power systems employ a single source, or parallel sources feeding into a common bus. In uni-directional systems, no directionality is required and distribution level overcurrent/earth fault IED’s, generally do not use the system voltage and do not have voltage inputs since this would add unnecessary cost to the protection IED’s.

Differential protection is often used for faster protection algorithms in cases where cables or lines feeds a secondary substation and where there are no loads connected to the line. Line differential protection is based on Kirchoff's current law, which states that the sum of all current entering a node is equal to the current leaving the node. With reference to Figure 2.4, current phasors at the beginning and the end of the node are compared in the time domain (B1 being the beginning and B4 being the end of the line). If there is a difference in the two values, the feeding side of the line (B2) is tripped to isolate the fault. In the case of parallel line such as in Figure 2.4, it is possible for fault current to flow down one line, and return back towards the fault through the faulted line. In the case of parallel lines, both ends of a faulted line are required to trip. An adapted version of directional overcurrent protection has been used with successful instantaneous operation. With reference to Figure 2.4, if a fault occurs on feeder A15, current will flow from the source substation through breaker B2 towards the fault in the forward direction. Current will also flow through breaker B1 and B3 in the forward direction and return back through breaker B5 in the reverse direction towards the fault. If overcurrent is seen in the forward direction by breaker B2, and a permissive reverse overcurrent signal is sent from a downstream breaker (B5 signals to B2 in this case), then the trip can be issued instantly without waiting for timed overcurrent trip signals.

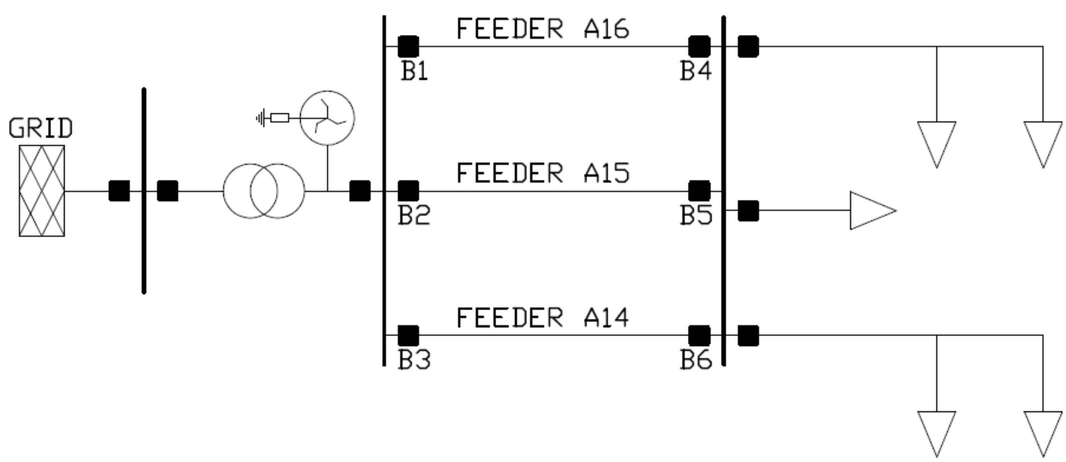

Figure 2.4 Parallel lines

2.4 DISTRIBUTION NETWORK MODEL, PARAMETERS AND PROTECTION SETTINGS

The network that will be used for simulations is a network from Orchards substation in Tshwane municipality in South-Arica (see Figure 2.5). This specific network was chosen for several reasons. The size of the network is practical for simulation purposes. Information about the network parameters and protection settings are readily available for research purposes. The network has several breakers following on each other in a line from the substation MV bus to the loads, and the loads are well distributed along these lines, making it ideal to illustrate the concept of coordination. A secondary 11 kV substation is included, with parallel cables feeding toward it without any loads connected to these cables. Cables feeding toward secondary 11 kV substations, frequently employ cable differential protection as mentioned in section 2.3, as it provides faster reaction times than overcurrent/earth fault protection. If rooftop PV, which would typically be located at the loads, is integrated into the network, it will also display a highly distributed model.

The transformer used in this network has a YNd11 vector group with a rated power of 40 MVA. The delta winding on the transformer has no neutral point, making earth fault protection difficult. As explained in section 2.2, a neutral point is created by the installation of a zig-zag transformer connected to the MV delta winding to create a path for zero sequence current to flow. A current limiting resistor is connected between the star point of the zig-zag transformer and earth, to limit the current flowing during an earth fault. Mini-sub transformers are not earthed on the MV side, to guarantee that all of the fault current flows through the substation during earth faults. A single earth point on the MV network makes fault detection and grading of earth fault relays possible.

The fault levels provided by the municipality on the 132 kV bus, is for a three phase fault is 7.211 kA and for a single phase fault it is 1.827 kA. These fault levels, indicate the fault current flowing into the high voltage bus in case of a three phase or single phase to earth fault respectively. In both cases, the current is limited only by the source impedance. Although the network connected to the HV bus is a complex network with several sources and impedances, the source network can be simplified into its equivalent *Thevanin* network. This leaves a single source with a source impedance supplying the fault currents indicated above. Table 2.1 and Table 2.2 shows the NECR and distribution transformer parameters.

Table 2.1 NECR Nameplate Data

Reactance	Resistance
24.5 Ω/ph	12.696 Ω

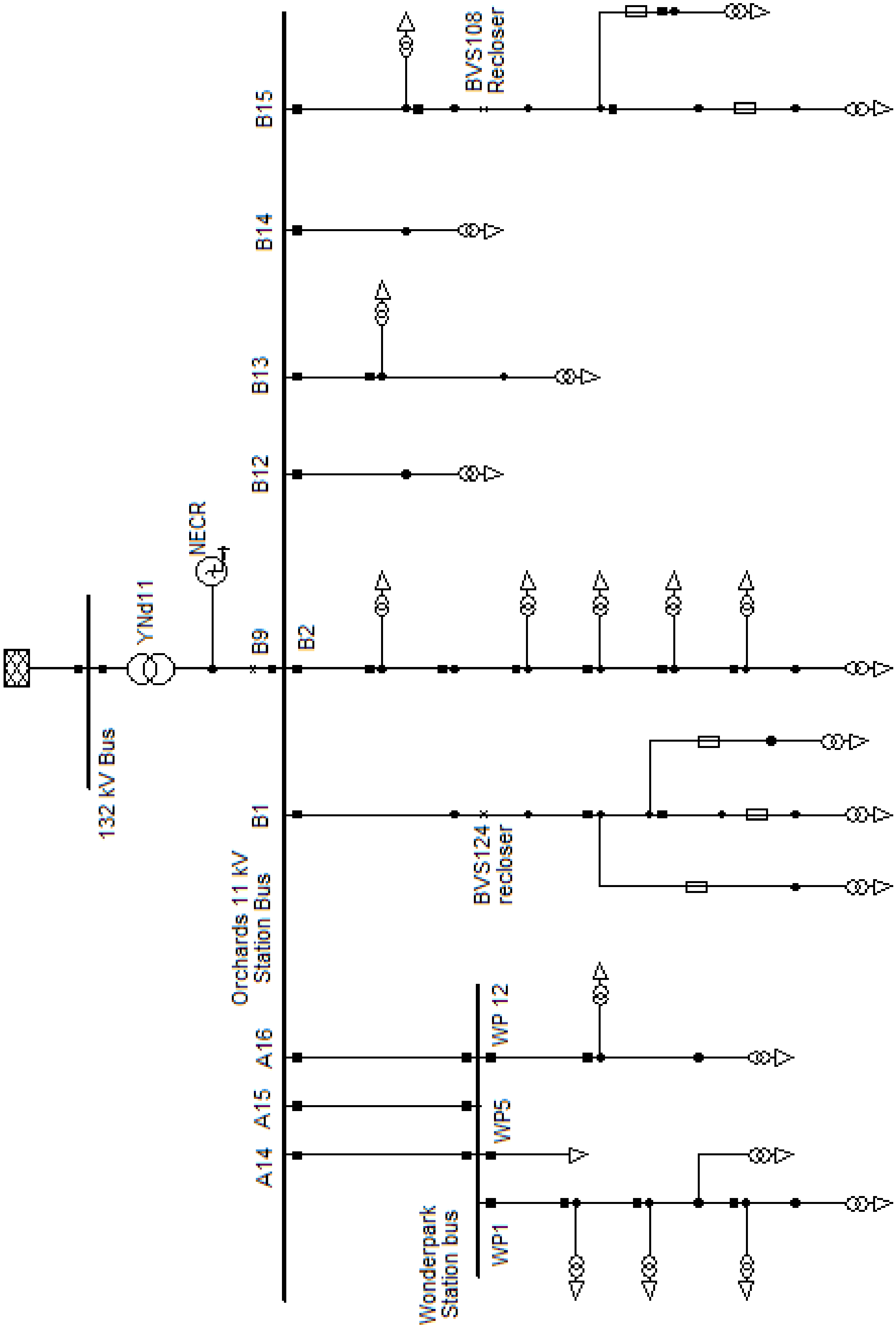

Figure 2.5 Test Network Single line Diagram

Table 2.2 Distribution Transformer Nameplate Data

Power Rating (MVA)	HV Rated Voltage @ tap 5	MV Rated Voltage	Impedance @ tap 5
40 MVA	132 kV	11 kV	21.70%

To calculate and validate the overcurrent and earth fault protection settings for the 11 kV protection IED's, the fault levels on the 11 kV bus is required for the different type of faults. To calculate the 11 kV fault levels, per unit values and sequence component networks are used [38] – [40]. For the purpose of this dissertation, per unit calculations and sequence components will only be used, but not explained as it is assumed that the reader is familiar with both these concepts. Base parameters need to be established before the fault levels can be calculated. The base MVA for the system will be chosen at 40 MVA since this is the power rating for the transformer. The base voltage will be chosen at 11 kV, since this is the voltage where the fault levels are required. The three phase and single phase fault levels on the 132 kV bus are converted to the 11 kV bus and equates to 86,532 kA and 21,924 kA respectively. The base current and fault current can be calculated from equations (and (2.2).

$$I_{base} = \frac{S_{base}}{\sqrt{3} \times V_{base}} \tag{2.1}$$

$$I_{base} = \frac{40M}{\sqrt{3} \times 11k} = 2100\ A$$

$$I_{f\ pu} = \frac{I_f}{I_{base}} \tag{2.2}$$

$$I_{f\ 3\emptyset\ pu} = \frac{86532}{2100} = 41.205\ pu$$

$$I_{f\ 1\emptyset\ pu} = \frac{21924}{2100} = 10.44\ pu$$

According to the transformer nameplate data, the transformer has an impedance of 21.7 %. This can be converted to the per unit value with equation (2.3).

$$Z_{T\,pu} = \frac{\%Z}{100} \tag{2.3}$$

$$Z_T = \frac{21.7}{100} = 0.217\,pu$$

Three phase faults are symmetrical and only positive sequence current will flow. Based on the 132 kV three phase fault level, the positive sequence source impedance can be calculated with equation (2.4) as follows with reference to Figure 2.6.

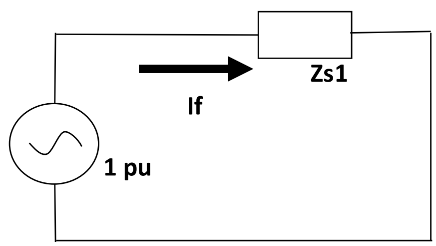

Figure 2.6 Sequence network for 132 kV three phase fault

$$\mathrm{Z}_{s1} = \frac{V_{pu}}{I_{f\ 3\emptyset\ pu}} \tag{2.4}$$

$$\mathrm{Z}_{s1} = \frac{1}{41.205} = 0.02426\,pu$$

With the source and transformer impedance known, the three phase fault level on the 11 kV bus can be calculated from equation (2.5) with reference to Figure 2.7.

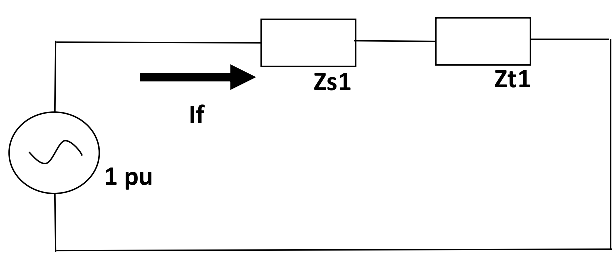

Figure 2.7 Sequence network for 11 kV, three phase fault

$$\mathrm{I}_{f\ 3\emptyset\ pu} = \frac{1}{\mathrm{Z}_{s1} + Z_{T1}} \tag{2.5}$$

$$\mathrm{I}_{f\ 3\emptyset\ pu} = \frac{1}{0.02426 + 0.217} = 4.145\ pu$$

The three phase fault current can be converted back to actual values with equation (2.6):

$$\mathrm{I}_{actual} = I_{pu} \times I_{base} \tag{2.6}$$

$$\mathrm{I}_{f\ 3\emptyset\ 11kV} = 4.145 \times 2100 = 8.704\ kA$$

If a zero sequence path exist, positive, negative and zero sequence current will flow during single phase to earth faults. A YNd11 transformer has a zero sequence network as shown in Figure 2.8 and cannot pass through zero sequence current for a single phase to earth fault on the MV bus. To create a path for zero sequence current to flow, a NECR is added and changes the circuit to that shown in Figure 2.9. The current flowing through the neutral resistor will be $3I_0$. To compensate for this, the resistance of the NER used for calculations is $3Z_n$. With this compensation and the nameplate data given in Table 2.1, Z_{NECR} = 38.088 + j24.5 Ω. Converted to polar notation as Z_{NECR} = 45.28 Ω and converted to per unit values as Z_{NECR} = 14.97 pu.

For single phase to earth faults, assuming phase A to ground, positive, negative and zero sequence current will flow. A general assumption is made to ignore load currents during fault conditions, since the fault current will be much larger than the load current which gives:

$$\mathrm{I}_b = I_c = 0 \text{ and } V_a = 0$$

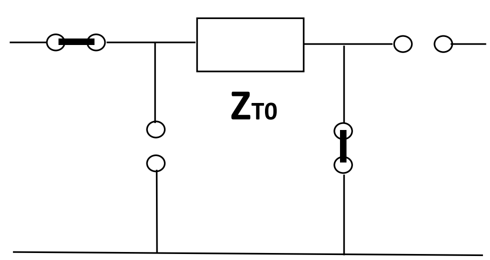

Figure 2.8 YNd11 zero sequence model

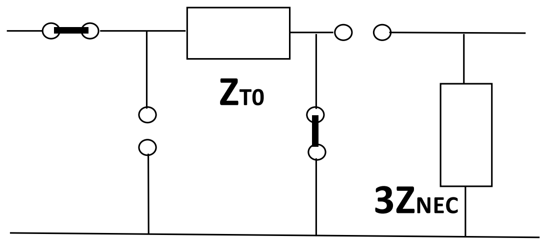

Figure 2.9 YNd11 with NECR zero sequence model

The sequence currents are given by:

$$\mathrm{I}_0 = \frac{1}{3}(I_a + I_b + I_c) \tag{2.7}$$

$$\mathrm{I}_1 = \frac{1}{3}(I_a + aI_b + a^2 I_c) \tag{2.8}$$

$$\mathrm{I}_2 = \frac{1}{3}(I_a + a^2 I_b + aI_c) \tag{2.9}$$

Substituting the above conditions for single phase to earth faults into equations (2.7) to (2.9), gives:

$$\mathrm{I}_0 = I_1 = I_2 = \frac{1}{3} I_a \text{ and } I_a = 3 \times I_0$$

The sequence networks for a single phase to earth fault are connected in series as shown in Figure 2.10 with $Z_{S2} = Z_{S1}$ and $Z_{T2} = Z_{T1}$.

The fault current I_0, can be calculated from equation (2.10) as:

$$\mathrm{I}_0 = \frac{1}{2(\mathrm{Z}_{s1} + Z_{T1}) + Z_{NECR}} \tag{2.10}$$

$$\mathrm{I}_0 = \frac{1}{2(0.02426 + 0.217) + 14.97} = 0.0647\, pu$$

The fault current can be converted to actual values with equation (2.6) as follows:

$$\mathrm{I}_0 = 0.0647 \times 2100 = 136\, A$$

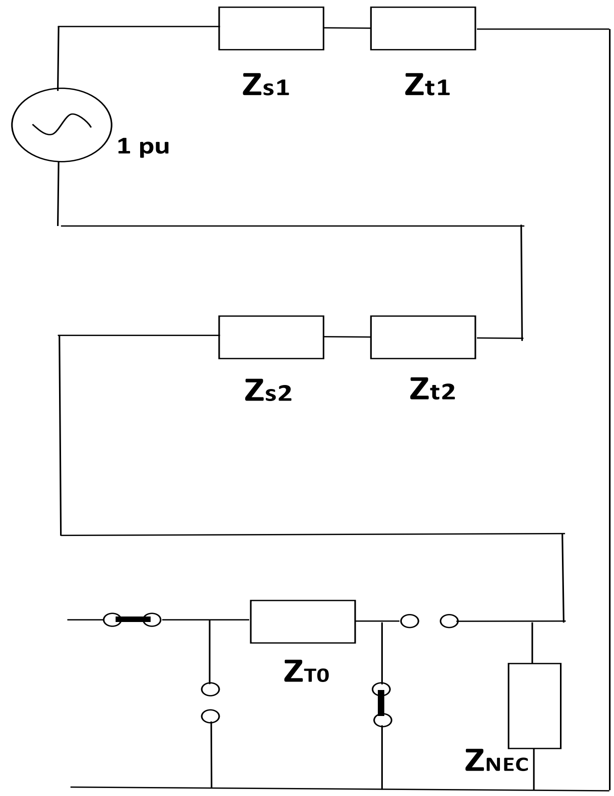

Figure 2.10 Interconnected sequence networks for a single phase to earth fault

Taking into account that the phase current in the faulted phase is $3I_0$, the single phase fault current equates to:

$$\mathrm{I}_{f\ 1ø\ 11kV} = 3 \times I_0 = 408\ A$$

To be able to recognize a fault on the system, all of the 11 kV overcurrent protection devices connected the 11 kV station bus, should at least pick-up for these fault currents. At each point where a load is connected, a mini substation is used to convert voltage levels to 400 V for use by residential consumers. Underground cables are used rather than overhead lines, since the mini-subs are relatively close to each other and reside within a residential area. All the 11 kV cables used are XLPE copper cables with standard cable data shown in Table 2.3. The cable ratings shown in Table 2.3 are standard cable ratings obtained from cable manufacturer websites [41].

The impedance of the cable is a function of the cable length, and the cable lengths for all of the cables are given in Table 2.4. The impedance of each cable on the network is also given. All of the cables are copper cables with minimum cable impedance. The parameters for the overhead lines are included in Table 2.4.

Table 2.3 XLPE Cable Data

Conductor material	Cross sectional area (mm^2)	Rated current (A)	1ø Short circuit current. 1sec (kA)	3ø Short circuit current. 1sec (kA)	Resistance (R) / km	Reactance (X) / km	Impedance (Z) / km
Copper	70	200	17.6	10.01	0.342	0.106	0.358
Aluminium		160	17.6	6.44	0.568	0.106	0.578
Copper	150	320	20.8	21.45	0.159	0.094	0.185
Aluminium		260	20.8	13.8	0.265	0.094	0.281
Copper	240	420	26.8	34.32	0.098	0.088	0.132
Aluminium		340	26.8	22.1	0.158	0.088	0.181
Hare	105	270	8.8	8.8	0.321	0.383	0.500

Table 2.4 Cable parameters for test network

Start and end point	Conductor material	Cross sectional area (mm^2)	Length (km)	Resistance (ohm)	Reactance (ohm)	Impedance (ohm)
A14 to W3	Copper	150	2.4	0.3816	0.2256	0.443
A15 to W4	Copper	150	2.4	0.3816	0.2256	0.443
A16 to W9	Copper	150	2.4	0.3816	0.2256	0.443
W1 to MS1	Copper	150	0.6	0.0954	0.0564	0.111
W1_MS1 to MS2	Copper	150	0.4	0.0636	0.0376	0.074
W1_MS2 to MS3	Copper	150	0.6	0.0954	0.0564	0.111
W5 to load	Copper	150	0.6	0.0954	0.0564	0.111
W12 to MS1	Copper	150	0.5	0.0795	0.047	0.092
W12_MS1 to MS2	Copper	150	2	0.318	0.188	0.369
W12_MS2 to MS3	Copper	150	0.3	0.0477	0.0282	0.055
B1 to BVS124/9	Copper	70	2.5	0.245	0.22	0.329
BVS124	Hare	105	13	4.173	4.979	6.496
B2 to MS1	Copper	70	4.5	0.441	0.396	0.593
B2_MS1 to MS2	Copper	70	0.35	0.0343	0.0308	0.046
B2_MS2 to MS3	Copper	70	0.4	0.0392	0.0352	0.053
B2_MS3 to MS4	Copper	70	0.4	0.0392	0.0352	0.053
B2_MS4 to MS5	Copper	70	0.4	0.0392	0.0352	0.053
B2_MS5 to MS6	Copper	70	0.4	0.0392	0.0352	0.053
B2_MS6 to MS7	Copper	70	0.4	0.0392	0.0352	0.053
B12 to MS1	Copper	150	2.7	0.4293	0.2538	0.499
B13_MS1 to MS1	Copper	150	2	0.318	0.188	0.369
B13_MS2 to MS2	Copper	150	0.7	0.1113	0.0658	0.129
B14 to MS1	Copper	150	2.6	0.4134	0.2444	0.480
B15 to BVS 108/A	Copper	150	3	0.477	0.282	0.554
B15_BVS 108/A to MS1	Hare	105	18	5.778	6.894	8.995

2.5 DISTRIBUTION NETWORK PROTECTION SETTINGS

As described in section 2.4, the fault levels on the 11 kV bus are 8.704 kA for a three phase fault and 408 A for a single phase to earth fault. The three phase fault levels are lower than on the 132 kV bus, due to the impedance introduced into the fault loop by the power transformer. The single phase fault level is made significantly lower by installing a current limiting NECR.

The main type of protection used on the network, is overcurrent protection with the exception of the cables feeding the 11 kV switching station from feeders A14 through A16. On these cables, differential protection is used, since it provides significant reduction in tripping time on occurrence of faults. If the protection of these lines were only reliant on non-directional overcurrent protection, it could result in a loss of all three feeders upon occurrence of a fault in any one of the cables.

All of the other feeder breakers are protected by overcurrent and earth fault relays, using inverse time overcurrent curves. Several types of standard curves are defined by regulatory bodies such as the IEC and IEEE. In this specific network, IEC type curves are used, but curves defined by other bodies have similar shapes [32]. IEC 60255 define a number of standard curves as follows:

- Standard Inverse – IEC A
- Very Inverse – IEC B
- Extremely inverse – IEC C
- Definite time – DT

Each inverse curve is defined by equation (2.11) and the different constants for each curve are shown in Table 2.5. IEC 60255 also define a range where this equation is valid, after which definite time operation is assumed. In most cases, sufficient grading between breakers can be achieved by using IEC curve A. In cases where sufficient grading cannot be achieved, type B or type C curves are used. All of the feeders feeding mini-subs, as well as the feeders feeding the secondary 11 kV substation are protected using IEC type A curves.

$$t = \frac{TM \times K}{\left(I_{fault}/I_{pick-up}\right)^{E} - 1} \tag{2.11}$$

Table 2.5 IEC curve constants

Curve Type	IEC Name	K	E
Standard Inverse	IEC curve A	0.14	0.02
Very Inverse	IEC curve B	13.5	1
Extremely Inverse	IEC curve C	80	2

Fuses are frequently installed on MV overhead lines due to their low cost and simplicity. The fuses selected in this network are type K fuses and presents a tripping curve very similar to IEC type C curves. Two fuse sizes are used in this network namely 15 A and 30 A fuses. Sectionalizers are installed in the overhead line when the load current exceeds these ratings. Figure 2.11 shows the recloser fast and recloser slow curves, graded with a 30 A fuse. Using a standard inverse curve would not grade consistently with the fuse. Using an IEC curve C extremely inverse curve for the recloser fast curve aligns and grades well with the minimum melting time of the fuse for the entire range of the curve, while the IEC curve B very inverse curve shows sufficient and consistent grading margins with the maximum clearing time of the fuse. Typical grading margins between numerical relays are chosen at 400 ms to allow for breaker operating time, relay timing errors, CT errors and enough clearance time for an upstream device to recognize the fault clearance [32]. Fuses are passive devices and no relays, breakers or CT's are present, allowing for smaller grading margins. Although the pick-up of the IEC curve C is set fairly low, the curve is only deemed valid from 5 times the pick-up up to 30 times the pick-up. The curve is only valid from 5 times the pick-up to grade with the fuse only for faults and not for overloading of the MV to LV transformer protected by the fuse.

For faults occurring on the MV bus of the substation, the transformer differential protection shouldn't operate, since there is no fault inside the transformer. The MV breaker of the transformer should trip on overcurrent. In South Africa, the municipalities follow the *ESKOM* rule of thumb that a power transformer should clear a through fault (assuming an infinite source) within 2 seconds. The HV breaker should trip as a back-up if the MV breaker fails to operate and clear the fault. Sufficient grading is needed for this scenario, and a grading margin of 500 ms is assumed for the HV breaker to recognize the MV breaker's failure to operate. The transformer MV breaker's pick-up is chosen at 120 % of the transformer nominal current and the time multiplier is chosen so that a through fault (had the source impedance been zero) will be cleared in 1500 ms.

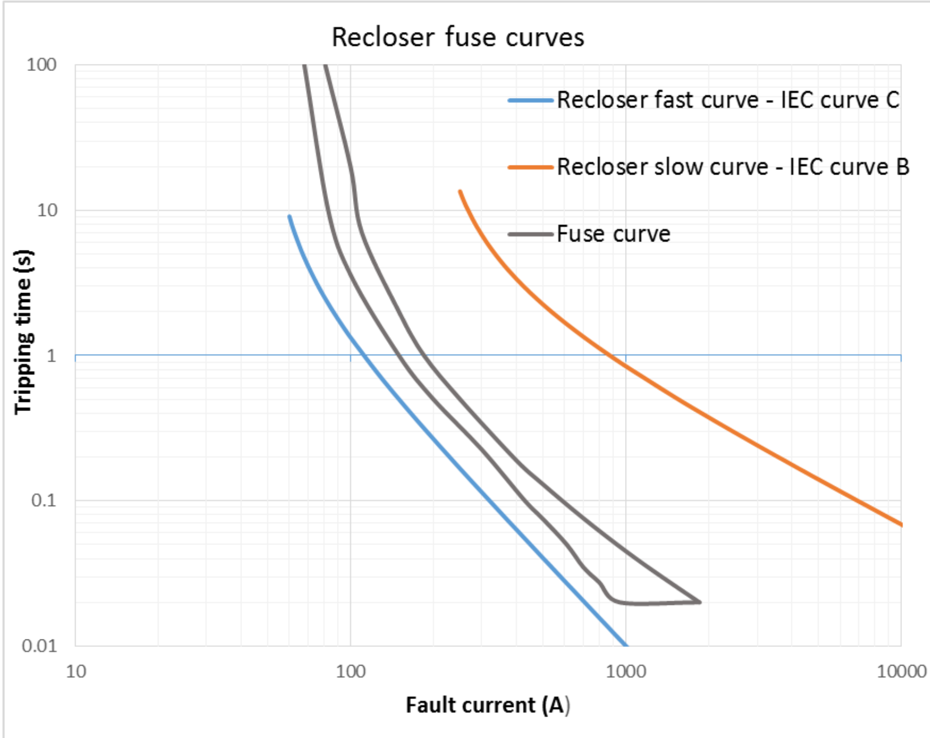

Figure 2.11 Fuse recloser curve selection

Using normal inverse curves such as the IEC curve A is generally sufficient for grading between breakers on cables. Cable parameters as given by manufacturers, usually include a maximum fault current which the cable can withstand for 1 second, as well as the nominal current rating of the cable. The pick-up of the feeder protection relay is chosen slightly below this nominal current, but above the cold load pick-up if this value is known. Cold load pick-up is a concern with motor loads as their starting current will be higher than their load current. Cold load pick-up is less of a concern with distributed loads. The time multiplier is chosen to trip the breaker in less than 1 second for the maximum fault current given by the manufacturer data sheet. The curve should allow 300 to 400 ms grading margin with any upstream protection device. For the feeders with 70 mm^2 cables as listed in Table 2.4, the data in Table 2.3 indicates that it can withstand 10 kA for 1 second with a nominal current rating of 200 A. The pick-up is chosen at 200 A and the time multiplier is chosen to ensure tripping in less than 1 second for 10 kA. The time multiplier for the 70 mm^2 is calculated at 0.58 seconds. The curve is only valid up to 30 times the pick-up, (6 kA) and the relay will never operate faster than 1.154 seconds, which is the time calculated to trip for 6 kA faults. To enable fault clearance in 1 sec for 10 kA, a smaller time multiplier is chosen to ensure operation in 1 second when the fault is 30 times the pick-up. The time multiplier to ensure this condition is 0.4 sec.

For earth fault protection, even though the cable can withstand 17.6 kA, the fault current will never reach such high levels, due to the high impedance introduced by the NECR. The minimum earth fault current that is allowed to flow through the stray capacitance and unbalanced load is selected at 40 A with a time multiplier of 0.1 seconds, to ensure fast operation during earth faults. Fast operation is required, since faults posing a risk to people are most likely to be earth faults. The same procedure is followed for the 150mm^2 cables.

The distance between the main feeders and the Wonderpark 11 kV substation is not substantial, and fault levels for both 11 kV busses are very similar. For this reason, grading with current is not possible and the feeder feeding from the Wonderpark substation is graded with time to operate faster than the upstream breakers. A smaller time multiplier is used for the feeders at the Wonderpark substation, to ensure 300 to 400 ms grading at the maximum fault levels. Most of the feeders are only required to grade with downstream mini-subs, and the time multipliers are chosen to be lower to ensure fast fault clearance while still maintaining grading margins with downstream mini-subs. The protection relay settings for all of the feeders as well as the reclosers are given in Table 2.6.

Table 2.6 Test network protection settings

Breaker	Cable Diamete	Phase Overcurrent			Earth fault		
		Curve	pick-up (A)	TM	Curve	pick-up (A)	TM
B11	na	IEC A	2520	0.3	DT	210	2
A14	150mm	IEC A	300	0.4	IEC A	60	0.2
A15	150mm	IEC A	300	0.4	IEC A	60	0.2
A16	150mm	IEC A	300	0.4	IEC A	60	0.2
B1	70mm	IEC B	200	0.75	IEC B	120	0.12
B2	70mm	IEC A	200	0.4	IEC A	40	0.1
B12	150mm	IEC A	300	0.4	IEC A	60	0.15
B13	150mm	IEC A	300	0.4	IEC A	60	0.15
B14	150mm	IEC A	300	0.4	IEC A	60	0.15
B15	150mm	IEC B	200	0.75	IEC B	120	0.12
W1	150mm	IEC A	300	0.2	IEC A	40	0.1
W5	150mm	IEC A	300	0.2	IEC A	40	0.1
W12	150mm	IEC A	300	0.2	IEC A	40	0.1
BVS124 fast	Hare	IEC C	50	0.05	IEC C	20	0.05
BVS124 slow	Hare	IEC B	200	0.4	IEC B	120	0.07
BVS108 fast	Hare	IEC C	50	0.05	IEC C	20	0.05
BVS108 slow	Hare	IEC B	200	0.4	IEC B	120	0.07

CHAPTER 3 PV BASED DG INTEGRATION REVIEW

3.1 INTRODUCTION

Distributed generation (DG) is the generation of power on various locations within a Power system. DG include small power plants ranging from 1 kW to 100 kW power plants as seen on rooftops or small pieces of land, up to 500 MW plants which are installed and operated by independent power producers (IPP's). Plants in the MW range are usually connected to transmission or sub-transmission networks and are built for the purpose of selling high quantities of power to utilities. With smaller power plants, such as residential rooftop PV, the power is self – consumed or fed back into the distribution grid if excess power is generated. DG has been increasingly popular in recent years [10]. In 1983, Fraunhofer ISE installed a 4 kW PV power plant on a residential house in Germany, which became the first DG PV power plant in Europe [3]. Today in several European countries, the United States and Japan, several GW of distributed generation can be seen on roofs and small pieces of land. In South-Africa, rooftop PV generation is gaining increasing intrest.

In 2015, the National Energy Regulator of South Africa (*NERSA*), ruled in favor of grid-tied rooftop solar embedded generation [42]. Local Municipalities such as the City of Cape Town Local Municipality and Ethekwini Municipality have welcomed this opportunity and has agreed to facilitate the implementation of renewable energy technologies and embedded generation within their municipalities [43]. Distributed generation contributions are still insignificant, and participants are not allowed to generate more electricity than they consume within a one month period. In another municipality where no official regulations are in place, a limited form of distributed generation can also be seen, but with the restriction that the plant may only be used for self-consumption and that no power may be fed into the utility grid. South Africa is expected to follow international trends in distributed generation growth and is bound to come across the same obstacles as leading countries in this technology. The expansion and continued growth of DG is only possible, if unlimited access to the utility grid is made available to DG power plants [44].

3.2 DISTRIBUTED GENERATION OVERVIEW

There are several advantages to DG. Some of the advantages include a high level of scalability, making custom sized power plants possible. The capital investment cost and the maintenance cost is low enough for residential consumers and small businesses to participate and benefit from DG [1]. DG adds the advantage of forming islands or micro-grids in the event of utility grid failure. This poses significant advantages to consumers in a stressed power grid prown to blackouts. Micro-grids are the forming of small grids consisting of a balance between sources and loads. Micro-grids form when a feeder connecting a group of customers is lost due to a system fault or load shedding. Utilities can benefit from DG with reduced transmission losses since power is generated close to load centers. The conventional large capital investment cost, required by utilities for increasing the power generation capacity is now in a sense distributed to consumers, depending on whether government offers rebate schemes and to what extent [1].

Along with the advantages, DG poses several challenges to power system operators and protection engineers who historically, designed power systems for centralised generation systems. To enable DG to grow significantly, access to the utility grid is required which is still very limited in some countries do the lack of experience and regulations. When feed in is allowed into a utility grid, challenges arise such as bi-directional power flow in distribution systems, challenging conventional feeder protection schemes, auto-recloser operation, voltage regulators and capacitor banks used for power factor correction. With high penetrations of DG in a distribution network, thermal overload of substations could become a threat. Until recently, in countries where feed in of DG is allowed, DG were required to disconnect from the utility in the event of close system faults or grid instability such as over or under frequency and over and undervoltage [2]. Grid support will become a requirement with high penetration levels of DG, since the loss of several DG sources in the event of faults or grid instability poses a threat to the grid. Disconnection of DG plant in these events could escalate the effect on the power grid. The next section provides a more detailed and technical discussion about problems and solutions to some of the mentioned aspects of DG.

3.2.1 Grid codes

Grid codes to govern the implementation and standards of distributed generation play a key role to the successful integration of PV power plants. Grid codes are required to govern all of the aspects discussed above, such as how to react and operate a PV plant under normal and abnormal system conditions. In countries such as the United States and several European countries where high levels of PV penetration can be seen, grid codes and interconnection guidelines have been established, incorporating experiences with distributed generation. In South-Africa, the national energy regulating authority (NERSA) established a grid code for renewable power plants, and governs distributed generation control and operation under normal and abnormal grid conditions. Research has been done in countries without relevant grid codes, to give guidelines to incorporate PV distributed generation [45]. These grid codes defines the standards of operation during system abnormalities when the system voltage drops, implementing voltage and reactive power control, and how to implement active power curtailment under thermal overload and over frequency conditions. Without grid codes and interconnection guide lines, the growth of small scale PV generation will not be possible. In the South-African grid code requirements for renewable power plants (from here on referred to as the grid code), defines requirements for power plants according to their rated power as listed in Table 3.1 [46]. The grid code requires that all DG with a rated power greater than 4.6 kVA must be balanced three phase. This would help prevent severe system unbalances due to single phase generation.

Table 3.1 DG rating categories [46]

Category	rated power	POC Voltage
A1	0 - 13.8 kVA	LV
A2	13.8 - 100 kVA	LV
A3	100 - 1000 kVA	LV
B	1 MVA - 20 MVA	MV
C	greater than 20 MVA	MV/HV

3.2.2 Reactive power support

Reactive power does not make any real contribution to the ability to do work. Reactive power only oscillates between a reactive source and a reactive load. It does however, contribute to losses in lines and other equipment. Many large loads and equipment such as power lines and transformers operate at a lagging power factor, and conventional induction generators are required to supply this reactive power. The amount of reactive power supply is controlled by regulating the excitation voltage of the generator. Power electronic inverters will be required to contribute to the supply of reactive power to ensure continued growth in conventional power systems. Various control algorithms and inverter schemes have been researched and implemented. These control algorithms are capable of regulating the displacement angle between the voltage and the current, independently controlling the amount of active and reactive power fed into the utility grid [47]. Reactive power contribution is also required for various other power system stability issues, such as voltage control or voltage support through reactive power contribution during system faults. The supply of only active power within a distribution grid will lead to increased voltage levels, which were previously controlled by static VAR compensators and automatic voltage regulators on transformers. The increased voltage levels could limit the amount of DG a distribution system can facilitate. By forcing DG to operate at lagging non-unity power factors, voltage support through reactive power contribution can be achieved, effectively increasing the carrying capacity of the grid. Increasing the active power being fed into the grid will however lead to an increased thermal operating level of the network, unless all of the generation and loads are well balanced within the distribution network.

In the South-African grid code, reactive power support is not required by category A1 and A2 power plants, which greatly simplifies the inverter and control requirements. Category A3, B and C generators, are required to provide voltage support through reactive power contribution, according to the characteristic reactive power support graphs shown in the South-African grid code [46]. The requirement for category A1 and A2 power plants to provide reactive power support is likely to change if residential DG increases to significant levels, where voltage levels and distribution transformer reactive power contributions are threatened.

3.2.3 Disturbance ride through capabilities

When integration of PV systems into utility grids initially started, DGs were required to simply disconnect from the grid and shut down whenever a close by fault was detected [45]. Faults were identified by monitoring the grid voltage and frequency. Whenever the voltage or frequency would move outside of a specified boundary, as seen in the case of system faults, the inverter was required to shut down, removing its generating capacity from the grid. No contribution during faults was required. This was the requirement in most countries starting off with low levels of DG integration.

In recent years, the amount of power produced by PV based DG has significantly increased and this growing trend is expected to continue. In countries that have significant levels of DG penetration, disconnection in the event of system disturbances became a challenge. If PV plants disconnect from the grid whenever system faults or disturbances in frequency or voltage occurs, the disturbance would escalate due to the sudden drop in power injected into the grid. In the event of system under frequency, a drop in power will slow down the frequency even further causing the system to potentially collapse [2]. Dynamic grid support is required by small scale low voltage distributed generation plants in order to make continued growth in this market possible. Increasing requirements are seen for PV inverters to stay connected during short duration system faults, and support the grid voltage by contributing to the reactive power requirements during a fault. Low voltage ride through (LVRT) capabilities require modification of disconnection control algorithms [44].

In countries with high penetration levels, grid codes have been developed, introducing requirements for PV plants to contribute to system stability during over and under frequency conditions, along with low voltage ride through capabilities. In order to assist in system frequency regulation, active power curtailment is required during over frequency conditions in order to draw back the frequency as described in [46]. Since PV power plants are integrated into the network via power electronic inverters with very fast reaction times, fault current contribution is not as much as with conventional generators and no significant increase in fault levels are introduced by keeping inverters connected during system faults. During close by system faults, voltage levels are bound to fluctuate/flicker. As mentioned above, DGs are required to a certain extent to stay connected during over – and undervoltage conditions ad described in [46]. By allowing DG to disconnect outside of these boundaries, protection requirements of the network are simplified.

3.2.4 Thermal overload

Distributed generation will only be able to continue its current growth, if unlimited access to the power grid is provided. Conventional distribution grids were built for the purpose of distributing power from a transmission network to end users. The sizing of distribution stations are determined by load requirements of the distribution network. The amount of power that can be transferred to the distribution network is limited by the sizing of the substation equipment, which will also limit the amount of power being generated within the distribution network and fed back to the grid. This amount of power transfer is limited specifically by the sizing of cables and transformers, as well as static capacitor banks used for power factor correction. As long as all of the power generated on a specific power line is used for self-consumption, no thermal overload can exist, but when more growth is seen in this area and power is being exported, thermal overload and maximum capacity limits could be reached. In order to overcome this barrier, expensive upgrade to distribution infrastructure is required in the long run. Short term solutions could be to limit the installed capacity in specific areas, or to utilize some form of communications to PV generators to limit the amount of active power injected at any time to the maximum capacity which the regional equipment can handle.

Active regulation of the network’s thermal level require research and development in order to plan and execute upgrades. Communication systems, in the form of radio frequency signals or power line carriers, would prove greatly beneficial to PV distributed generation, in order to give network operators better control over their networks. Thermal overload of existing equipment is one of the major subjects where system impact studies should be conducted before centralized or decentralized power stations are approved in any area.

3.2.5 Voltage regulation

Voltage fluctuations can result from several steady state and dynamic conditions, and is often seen in the form of voltage drops in overhead lines and underground armored cables due to load fluctuations. Distributed generation introduces risks to voltage stability by causing the voltage on lines to rise due to active power feed in. Distribution networks would typically have a transformer with a tap changer, feeding a long cable with distributed loads. The voltage on transformers are regulated in such a way that it remains within a specified limit across the length of the line; usually around 10 % of the nominal voltage. The voltage would drop across the length of the line due to line losses. By adding PV generators across the length of the line, and operating them at unity power factor in order to minimize inverter sizing requirements, the voltage along the line increase to levels outside of the allowed limit near the end of the line [48]. This is problematic because it will lead to frequent voltage regulating action by the tap changer, since PV power output changes significantly throughout the day, and drops down to zero during night times; To maintain the line voltage within the specified limits, amount of active power that can be fed into a distribution feeder must be controlled. Even through the sizing requirements of inverters are increased when running the inverters lagging power factors, simulations show that it significantly increases the amount of active power that can be injected into a distribution feeder [49]. DGs can assist in voltage regulation by adjusting its operating power factor, and creating an inductive feeder profile.

Voltage is usually regulated on distribution grids by using tap changers and capacitor banks, which was traditionally designed with slow response times. They were also designed to have a limited amount of safe operations. Traditional regulating equipment cannot effectively regulate voltage levels in highly penetrated DG power systems, because of the fast dynamic responses seen with PV resources due to cloud movement. Any attempt to rely on these conventional devices for voltage regulations would results in voltage flickering and pre-mature failure of the regulating devices [50]. Overhead lines used for transmission and sub-transmission networks are characterized by reactive impedance, since the long lines acts to some extent as inductors. Most electrical machines, such as synchronous motors as transformers are characterized by reactive impedances. A lagging network would lead to voltage drops over long lines and is the reason why capacitor banks are installed, in order to correct the power factor to unity or to a leading power factor to regulate voltage. Distribution networks however, are characterized by active resistance, and tap changers are used on distribution transformers [48]. The absorption of reactive power has less of an effect on highly resistive networks. However, by operating inverters at non-unity lagging power factors, reactance can be introduced into distribution networks, in order to maximize the active power that can be transferred to the network, and keep voltage levels within the allowed limits.

3.2.6 Energy storage

PV power plants have many advantages such as low maintenance, no moving parts and sustainability. Along with the advantages, there are also two major disadvantages. Firstly, it cannot produce power during night times and secondly, the output power capacity is highly affected by cloud movement. The first issue is overcome by the fact that the daily sun hours when power can be produced aligns well with the load profile of small businesses. For customers who would prefer using all of the generated power for self-consumption it is however a concern. A possible, but yet an expensive solution is using an energy storage device, such as lead-acid batteries, lithium batteries, or fuel cells. Fuel cells are the most efficient option, but also the most expensive.

The second major problem with PV power plants, are the fluctuations in their power output due to cloud movement. Both of these drawbacks can be addressed by using storage devices [51]. Power can be stored in batteries and made available during night times. The batteries can also be used to provide additional power to the grid for short durations, when cloud movement covers the PV panels. This could eliminate voltage fluctuations caused by the clouds. By stabilizing the voltage, extensive operation of line voltage regulators can be mitigated. Another advantage of using storage devices is the ability to distribute harvested power throughout a 24 hour period, instead of the PV panels only providing power during daily sun hours. Control algorithms could store energy for self-consumption at night times, and empty they storage capacity into the grid during the mornings. This method enables the batteries to contribute power during peak hours, effectively shaving off peak load from distribution networks. Expensive upgrades to under sized distribution cables could be eliminated, over-voltage conditions during periods of low load and high PV output can be mitigated, and power quality can be increased if the load is distributed over a 24 hour period [52]. All of these have significant positive impacts towards the continual growth of PV systems. The high cost of energy storage devices is still a major drawback, and outweigh the benefits in most cases.

3.3 PROTECTION CHALLENGES

Power produced by PV based DG, is a function of the solar irradiance, temperature and how well the load is matched to it at any given time. PV Sources are by nature DC sources, and is converted to AC by means of power electronic inverters, in order to connect them to the AC grid. Rotating generators have large rotating parts with stored inertia, and are able to provide large fault currents during fault conditions. PV inverters have no rotating parts, and are unable to provide large fault currents, making fault identification and isolation through overcurrent measurement a difficult task. Islanded PV based DG is typically protected using undervoltage or frequency protection. Impact studies have been done on several PV inverters from different manufacturers to determine the level of current contribution from PV inverters during system faults [53] – [56]. Simulations based on several faults were conducted, and the short circuit currents recorded. The results revealed that most PV inverters, provided sub-transient fault currents of between 100 % and 210 % of the rated current during the first cycle of the fault. The sub-transient current reduced to the steady state fault current of around 120 % nominal, within less than five cycles [53], [57], [58].

Grid tied DGs are integrated into existing systems, which largely employs overcurrent protection for fault identification and isolation. Power system faults, and specifically distribution level faults were discussed in section 2.3. With the integration of DG, a distribution network no longer has the radial topology, which is a key factor to the successful protection philosophies discussed in section 2.3. Two major problems result from adding DGs within a distribution network. Firstly, the power flow is no longer uni-directional, but becomes bi-directional since loads or faults can be located on either side of a generator. The loads or faults could be upstream or downstream of a generator. Bi-directional power flow will cause loss of timing and sensitivity coordination during system faults. Secondly, additional generation within a network will result in loss of sensitivity of upstream protection devices, and will lead to a loss of coordination. These problems, along with some other protection related challenges are discussed in more detail below with reference to Figure 3.1.

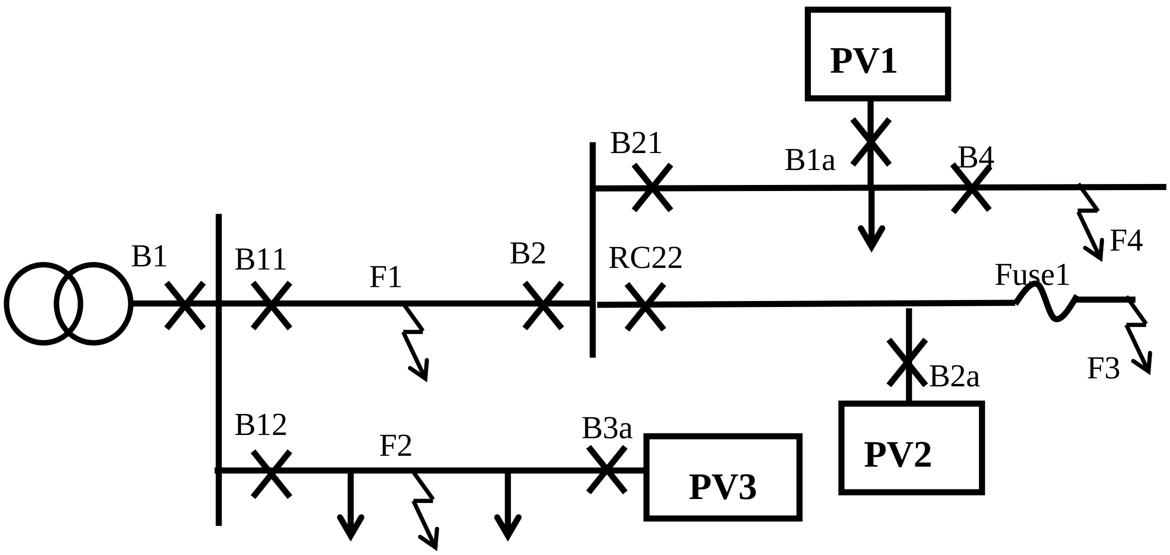

Figure 3.1 Example of DG power system

3.3.1 Sympathetic tripping

A large part of the scientific community considers the addition of generators within a distribution network a problem, since it will cause higher fault levels and sympathetic tripping due to power flow and fault current now becoming bi-directional [31], [59]. Sympathetic tripping is a condition that could occur, when a protection breaker trips for faults in adjacent feeders. With a three phase fault F1 as indicated in Figure 3.1, an overcurrent condition would arise in feeder B11. The fault F1 will also cause an undervoltage condition in the system. If the undervoltage condition is below the low voltage ride through threshold for DG protection, and the tripping time delay of B11 is longer than the low voltage ride through time of a DG, breaker B3a might operate on undervoltage, before breaker B11 will operate on overcurrent. B3a has then sympathetically operated for a fault on the adjacent feeder B11. The undervoltage condition at the terminals of PV3 would depend on the severity of the fault (fault impedance), the grid fault level, the ability of the grid to maintain the voltage during a fault, and the impedance between PV3 and the fault. As the impedance between the fault and PV3 increases, the voltage at the terminals of PV3 will increase. Sympathetic tripping is thus highly dependent on PV location, fault location and grid strength.

Depending on the fault level contribution of DGs, and the strength of the grid in terms of fault levels, another example could also arise: Due to conventional time and sensitivity coordination in distribution systems, breaker B21 in Figure 3.1 would be graded to trip faster than breaker B2, which should trip faster than breaker B11. Feeder B11 and B12 would have the same pick-up and time multiplier settings, if their cable sizes match, since they both grade with incomer B1. For a three phase fault F2 on the system, if PV1 contributes sufficient fault current, breaker B21 could operate before feeder B12, because of conventional time grading. Tripping breaker B21 will not isolate the fault, and will cause loss of supply to loads downstream of breaker B21. It would also result in loss of potential income for PV1. The fault ride through capabilities required by grid codes only applies to DG point of connection (POC) breakers. The fault ride through capabilities of PV1 would thus not have any effect on blocking the protection of breaker B21.

Sympathetic tripping is only applicable when significant fault current contribution from the DG is available. It is thus dependent on DG size, DG fault current capabilities, levels of penetration, grid fault levels and cable sizes and fault location.

3.3.2 Protection blinding

Protection blinding is a situation that occurs, when a DG provides enough voltage support during a disturbance condition to reduce the magnitude of the fault current contribution from the grid, so that the protective element will not be sensitive enough to pick-up for the overcurrent condition [29]. The condition can be illustrated with fault F2 in Figure 3.1. Without any contribution from PV3, the fault current in the cable due to fault F2 would be entirely contributed by the grid, and the entire fault current will be seen by breaker B12. Breaker B12 will trip and isolate the fault, since the fault current would be more than the pick-up setting for breaker B12. With the addition of PV3, it is possible that during a fault, PV3 can provide enough voltage support so that the fault current contribution from the grid through breaker B12, might be below the current pick-up level of breaker B12. Even if the current is above the pick-up level of breaker B12, the reduced fault contribution from the grid will result in delayed tripping times of B12. The overcurrent protection settings are often chosen to be just below the maximum current ratings of the cables, and delayed tripping times could cause damage to the cables. The addition of DG has thus completely or partially blinded breaker B12 from seeing fault F2. It can be concluded from this discussion that protection blinding, as with sympathetic tripping, is highly dependent on fault levels from the grid and DG size, as these variables will change the current contribution from DG and from the grid.

3.3.3 Loss of coordination

Protection in distribution networks consist mostly of overcurrent protection. Timed coordination is used between breakers to isolate the smallest possible portion of the network when faults occur. The breaker directly upstream to a fault should operate first, and each breaker further upstream acts as a back-up. This is possible since the current seen in a feeder, will be the same in all the breakers in series on that feeder. With reference to Figure 3.1, if there is a fault F4, breakers B1, B11, B2, B21 and B4 will all see the same current. B4 is required to trip first and only isolate the line downstream. If B4 fails to trip, B21 will be required to trip as back-up and only isolate the line downstream. This grading is possible in conventional distribution systems, since the fault current always flows from the substation downwards. Consider a fault F1 when an additional source, PV1 is introduced into the system. Under conventional conditions, breaker B21 will be set to trip faster than B2, but with the addition of PV1, fault current from PV1 will flow in the reverse direction through B21 and B2. Breaker B21 will operate first, while B2 should have operated first as it is the closest breaker to the fault.

Another case where DG has a severe impact on distribution level protection, is with the coordination between auto-reclosers and fuses. Reclosers are frequently used to clear transient faults, while fuses are used to clear permanent faults [20]. Recloser and fuse protection is typically implemented on medium voltage overhead lines, where transient faults due to falling branches or lightning occurs frequently. Reclosers are set with two tripping curves; a fast and a slow curve as illustrated in Figure 3.2. The fast curve is set just slower than what would be required for cold load pick-up. During a fault F3 in Figure 3.1, the recloser will trip on the fast curve to allow any transient fault to clear. After a minimum time delay (usually around 1 to 3 seconds), the recloser will close again. After reclosing, the fuse will blow to clear any permanent faults downstream of the fuse [20]. If the fault was located between the recloser and the fuse, the fuse will not blow, since it will not see any fault current, and the recloser will trip for a second time on the slow curve. If the same fault F3 occurs with the addition of PV2 between the recloser and the fuse, the fuse will see more fault current due to the additional fault current contributed by PV2. The current seen by the recloser will be $I_{fault\text{-}grid}$ and the current seen by the fuse will be $I_{fault\text{-}total}$, as given in Figure 3.2. This will cause, even for a transient fault, the fuse to blow before the fast curve of the recloser can clear the fault.

If the recloser is still able to trip faster than the total clearing time of the fuse, the voltage support from PV2 could feed the fault, and prevent it from clearing during the off stage of the recloser. The addition of PV2 can eliminate the ability to clear transient faults which occur frequently on MV overhead lines. Additional problems will also be introduced by PV2 during the auto-reclose stage of the recloser. If PV2 is still generating during the off state of the recloser, there could be a difference in phase angle between the grid voltage, and the voltage from PV2. The recloser will require a method for synchronizing PV2 to the grid before reclosing.

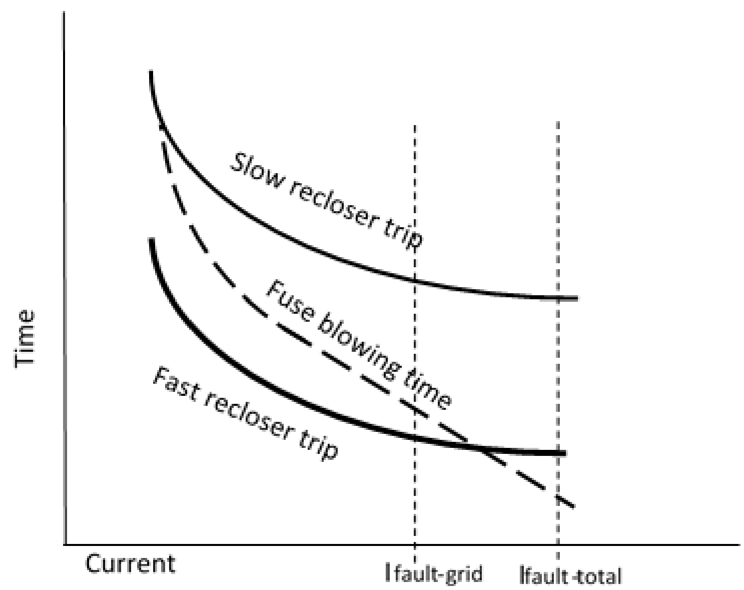

Figure 3.2 Recloser fuse coordination

3.3.4 Earth fault protection and island drifting

Current will flow from the faulted phase to earth during phase to earth faults, and will return through any earth present on the system. If the transformer used in the substation has a wye-delta configuration, it will not allow zero sequence current to flow through it. The MV to LV transformers used to step down the voltage to LV levels for customers to utilize, have delta-wye configurations, and will not allow any zero sequence current to flow. The earth fault current resulting from phase to earth faults on the MV network, can only return through earth connections on the MV network. A single earth connection is provided in the substation by the NECR. During earth faults, all of the earth fault current will return through the NECR, making it possible to detect earth faults with a single earth fault relay, located at the substation feeder [60]. If a fault on the MV network occurs, the closest breaker upstream of the fault should trip to isolate the faulted section. If there are any DGs present downstream of the breaker that tripped, they will form part of an islanded section of the distribution network. According to present grid codes [44], [46], [61], DG should disconnect when islanding is detected. If the DG did not disconnect and islanding was allowed, the islanded part of the network would operate without any earth connection and the island would be drifting. If earth faults occur on the islanded network, the remaining protection relays on the island would not be able to detect these faults. Also, if any emergency personnel are dispatched to attend to the original fault, they might expect that the cable is safe to work on, since the substation feeder has tripped. If islanding is allowed, the cable being working on might still be energized by the islanded DGs.

When the cable is repaired and normal operation can be restored, conventionally it would only require the closing of the substation feeder that tripped as the network would have a dead line/live bus configuration. If islanding is allowed, the line and the bus would be live, and synchronizing will be required before the substation feeder can be closed. Currently, distribution substations do not make use of synchronizing relays.

On MV overhead lines where transient faults occur frequently and auto-reclosers are used, the same problem of synchronizing would arise when allowing a section of the line to operate as an island. If no synchronizing is done on MV auto-reclosers, the voltages on the two sides of the recloser might not be in phase and could damage the recloser breaker upon reclosing. When reclosing, the recloser relay might detect a large current flow resulting from out of phase reclosing, as a switch on to fault event and instantaneously trip again.

The protection challenges discussed above are highly dependent on DG parameters, DG technology, grid parameters and location of generators and faults. The biggest concerns highlighted by the challenges above are rising fault levels, bi-directional power flow and islanding. Protection systems in the presence of DG will have to be upgraded, to account for bi-directional power flow and varying fault levels. Alternatively, protection systems need to be entirely disconnected from fault levels.

3.4 SUGGESTED PROTECTION SOLUTIONS

Along with the integration of renewable energy into the existing power grid, many industries are also moving towards micro-grids, which poses sever protection risks of its own. With the absence of the utility grid and a majority of energy being supplied by renewable sources, fault levels vary significantly and overcurrent protection becomes unstable [21], [30], [31]. Although the two scenarios (grid tied and islanded) differ in characteristics, much of the available research is aimed at resolving protection related problems for both scenarios with a single solution. These proposed solutions are discussed below.

3.4.1 DG disconnection

Due to the ease of scalability, DGs are frequently connected to the low or medium voltage networks close to loads, where overcurrent and earth fault protection is predominantly used. Inverter fed generators have response times much faster than conventional overcurrent relays, and it is possible to disconnect all DGs upon detection of a fault. These faults can be detected using undervoltage combined with overcurrent protection schemes. Disconnecting all DGs upon immediately upon detection of a fault, would enable conventional power system protection to operate as if no DG is installed in the network. Fault current would flow as conventional in one direction, from the substation to the loads and to the fault. The instantaneous disconnection of DG, could however cause a power swing at the distribution substation. With low levels of penetration, the power swing will be small and no significant influence will be seen in the power system. With high levels of penetration however, the power swing will be large and could cause voltage dips and flickering throughout the distribution network. The sudden loss of generation could result in power system instability and could potentially lead to a collapse of the distribution network. With high levels of penetration, overloading of feeders could occur if all DGs are suddenly lost. Disconnection of all DG in the event of a fault is discriminative towards a multi-source, multi-owned power system and could lead to a system collapse.

3.4.2 Differential protection

Differential protection is based on Kirschoff's current law, and declares that the sum of the currents entering a node should equal the sum of currents flowing out of the node. Differential protection is typically used on transmission lines, substation busbars and large power transformers, and is known as unit protection. No grading with other relays are required, allowing much faster tripping times, which is preferred for expensive equipment. Differential protection is however more expensive than overcurrent protection, and requires communication between relays on two ends of a line. An ideal protection scheme would be one that is disconnected from fault levels, since a varying fault level is the biggest concern in DG protection. Several suggestions have been made to use differential protection in DG protection, since it does not use fault levels for protection calculations [15], [16]. Distribution networks have relatively short cables (typically less than 10 km), and time synchronized measurements of the current vectors are not required, because the signal transmission time delay is insignificant over such small distances [17]. Using differential protection on distribution feeders will require a communications link between all relays connected to a common node/bus/line. A digital relay is required on all points of generation or load connected to a node/bus/line, to summate all of the currents to zero. In the event of a relay failure, comparative voltage protection is suggested as a back-up protection. Comparative voltage protection measures and compares the root mean square (rms) voltage at each relay. For a voltage sag less than 70 %, the relay with the lowest voltage will trip [17]. Both of these schemes require a communications link, and a communications failure event will leave both the main and back-up schemes unable to protect the system.

Suggestions has also been made to consider each feeder with all of its sources and loads as a single differential zone, and use decentralized differential protection [20], [62]. The zone would be relatively big, and it would be difficult to determine where in the zone a fault occurred, adding on the time required to locate and isolate a fault. AS a solution, *Brama and Girgis, 2004* [20] suggested that each zone, along with all of its loads and sources be simulated for each type of fault at different locations. After a fault occurred, the measurements from the relays can be compared to the simulation results, to identify the fault location. This would require prior knowledge of all of the loads and generators within a network. DGs such as PV or wind turbines have dynamic outputs, depending on weather conditions, time of day and time of year, and it would not be possible to determine all network condition for prior simulations. The dynamic nature of loads and municipal expansions would also make this task impossible.

Distribution feeders are seldom dedicated to a single load, and might feed to several mini-subs where MV to LV transformers are located. A differential scheme would require a differential relay located at each end of any line section. Where a distribution feeder with N loads connected to it would have conventionally had one digital protection device, it would now require 2N digital differential relays for line differential, and N+1 relays for differential zone protection. Many mini-subs are protected with mechanical relays and do not have breakers with trip coils, and differential protection would require replacing of all of the mini-sub breakers. To be able to use comparative voltage protection as a back-up, each relay will require VT's to be installed. In a micro-grid where security of supply is a key factor and investment cost is driven by private corporate body, differential protection might be a viable solution, but it is not likely to be an attractive solution for a DG distribution grid.

3.4.3 Real time overcurrent setting update

Apart from differential protection, real time updated protection methods receives the most support from the general scientific community. Directional protection is often suggested in conjunction with real time updated settings [21], [22]. Renewable sources are highly dependent on weather conditions, which makes their power output availability at any time dynamic. If the available power and resulting system parameters are known at any given moment, it would be possible to update relay overcurrent settings to compensate or any additional fault current. Calculations of the fault levels can be done offline for all possible network topologies and stored in a data-base. Based on the current network topology, the settings on all the relays can be updated via a communications protocol. Possibilities exist to use different settings groups for different scenarios. During operation, the actual network values are compared to the updated settings, to determine the operating time for each breaker to coordinate with other breakers [19], [27], [28]. This would require prior knowledge of all possible network topologies. It is highly unlikely that all possible scenarios can be catered for, taking into account the fast growing trend in DG. The available power from each DG, will need to be communicated to the decision making point. Reclosers are often used on MV overhead lines and coordinated with fuses on laterals. These fuses are not intelligent devices and would require replacement with IED's. Fuses are used to protect single MV-LV transformers, sized around 50 – 315 kVA, and installing IED's could double the installation cost. Installing IED's at each of these locations, cannot be justified by the income generated, from the electricity sold to the customers supplied by these transformers. This method will require a communications network in the MV grid along with replacement of all protection equipment. The real time network topology information will prove inaccurate, when DG is installed on a LV line in conjunction with fluctuating loads.

3.4.4 Phase jump comparison

The ideal protection scheme for highly penetrated DG networks need to be disconnected from fault levels. Using current phase jump comparison to detect faults, could help protection move away from coordinated timed overcurrent. It is possible to predict the instantaneous future value of a current sample, based on current loading and system frequency. When faults occur, the impedance seen from line ends change to incorporate the new fault impedance. The change in impedance, will cause the magnitude and phase angle of the current vector to experience sudden changes. At each end on a line, an IED will compare the magnitude and angle of a current sample to a predicted value. If a change in current direction is detected at any one of the nodes, the relay will trip and send a permissive trip signal to the relay on the other end of the line, to isolate the line from both sides [59]. This scheme is a modified differential scheme, and is aimed at reducing the communication requirements of conventional differential schemes. It has the same drawbacks as differential protection, and will also require two IED's at each spur on a line, which is currently not available.

3.4.5 Central protection unit

If the system topology, generating capacity and generator locations are known at any given time, it will be possible to determine coordinated tripping times for each relay in the network. In section 3.4.3 it was proposed to calculate these tripping times based on the network topology and offline calculations. A similar approach would be to measure the system quantities at any given time. If measurement devices are placed at each of the breaker points on a network, real time data can be collected and transmitted to a central location, such as the distribution substation. When a fault occurs, a central control unit can then calculate the faulted location based on comparative measurements throughout the network, and trip the appropriate breakers to isolate the fault [63]. With the known direction of current flow at each node, it will be simple to determine which section is accepting overcurrent form all directions. Sending this information to a central point will simplify comparison between current magnitudes and direction. Measurement, remote tripping capability and communications will still be required at each spur on a distribution feeder. With the protection of the whole system being centralized to the substation located central control unit, this system has a single point of failure. Communications failure or central control unit failure will result in complete loss of protection.

3.5 PROPOSED PROBLEM ANALYSIS

Power systems are generally three phase systems, and their analysis differ vastly from single phase systems, especially during unbalanced conditions which occurs during asymmetrical fault conditions. Due to the tediousness of drawing all phases in three phase systems, engineers often resolve to using a single phase representation, known as single line diagrams. Single line diagrams often cause confusion and disguise the complexity of three phase systems. The calculation of system conditions during unbalanced events require the use of sequence components, and cannot be solved by just looking at the single line diagrams. Present research on power system protection in the presence of distributed generation are mostly based on single line diagrams and seldom take sequence components into account [17], [20], [29], [63].

PV based DGs use switch mode inverters to generate AC, and are able to exercise active control over its output parameters. Modern inverter control techniques introduce the ability to limit unbalanced current to zero. Inverter based generators does not have any momentum stored in mechanical rotating parts which places constraints on their fault current producing capabilities. Many of the available research papers do not distinguish between different technologies used for distributed generation. In urban areas, large opportunities and growth are seen with distributed generation by use of mainly inverter based generation, such as rooftop PV generators.

It is proposed that a distribution power system be simulated in the presence of inverter based PV generators, and the results measured against the expected protection challenges listed in section 3.3. Symmetrical and asymmetrical faults must be simulated and the fault current broken down into the different sequence components, to better understand the effect that PV based DG will have on conventional protection of distribution level power systems.

- All generated voltages are assumed equal and in phase, and no loading is assumed between sources.
- Distribution power systems are mostly characterized by resistance and calculations are greatly simplified by omitting the negligible amounts of inductance.
- All shunt reactance, such as loads are neglected.

- Since inverter based generators supply steady state fault current at levels similar to load current, it is arguable that their effect on the power system is negligible during system faults.

Assumptions such as these appose available research, and the true effect of PV based DG can only be established by conducting simulations, and investigating the effect on conventional overcurrent and earth fault protection devices.

In the following chapters, the distribution power system introduced in Chapter 2 will be simulated, first without any presence of DG to establish conventional reactions, and then in the presence of varying levels of DG, to investigate the actual effect. The different sequence components in response to faults will be highlighted, to get a better understanding of PV based DG, and its effects on three phase distribution system protection.

CHAPTER 4 CONVENTIONAL DISTRIBUTION NETWORK SIMULATION

4.1 INTRODUCTION

Overcurrent protection is widely used and understood. The purpose of this chapter will not be to prove its functionality. The network analyzed in Chapter 2, will be simulated to establish the principles of conventional overcurrent protection, and to highlight some of the shortcomings of basic overcurrent protection. The conventional network is simulated to establish conventional functionality and limitations on overcurrent and earth fault protection, without any presence of DG.

4.2 UNDERVOLTAGE DURING FAULTS

During faults on the network, the entire feeder downstream of the fault will experience a severe voltage drop. Directly upstream of the fault, a severe voltage drop will also be experienced. The voltage will increase when move further upstream from the fault. The undervoltage condition will persist on the feeder, until the protection device immediately upstream of the fault trips to clear the fault. The impedance introduced into the fault loop, will be at its highest when faults occur far away from the substation. The high fault impedance will results in lower fault current. As explained in section 2.3, overcurrent protection is based on inverse time grading tripping curves. For a lower fault current, the relay tripping time will be slower. With the higher fault impedance seen when the fault is far away from the substation, the undervoltage condition will occur for a longer time period, until the overcurrent protection device trips to clear the fault.

The voltage on the MV bus will dip when faults occur close to the substation, creating a voltage dip on all of the adjacent feeders, even though there are no faults on those feeders. This is illustrated by simulating the network shown in Figure 4.1. First, a fault is simulated close to the substation, at a distance of 0.1 km on feeder B13. The tripping time of the protection device connected to feeder B13 is recorded in Table 4.1, along with the voltage on the substation MV bus. This MV bus will have the highest voltage, which any of the customers on any of the feeders connected to this bus will see, for the duration of the fault. Next, a three phase fault is simulated on feeder B13, 5 km from the substation. The voltage is recorded at all of the individual nodes. The total clearing time of the protection device at the substation is recorded and is shown in Table 4.1, along with the nodal voltages. A fault at the end of the 10 km cable connected to feeder B13 was also simulated, and the voltages recorded in Table 4.1. The undervoltage condition created in the network due to the fault will persist until the fault is cleared, when breaker B13 trips.

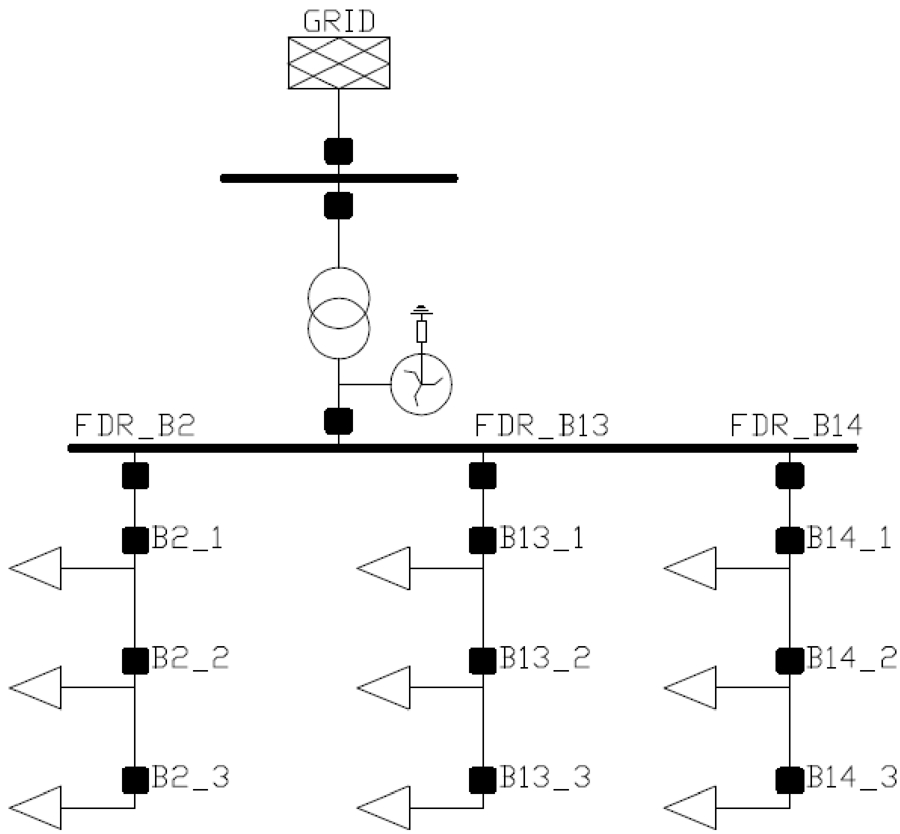

Figure 4.1 Undervoltage example in conventional network

Table 4.1 Undervoltage results in conventional network

Fault distance from substation	Fdr B13 trip time (sec)	Bus Voltage (pu)	Fdr B2_1 (pu)	Fdr B2_3 (pu)	Fdr B13_1 (pu)	Fdr B13_2 (pu)	Fdr B13_3 (pu)	Fdr B14_1 (pu)	Fdr B14_3 (pu)
0.1 km	0.816	0.02	0.02	0.02	0	0	0	0.02	0.02
5 km	1.031	0.62	0.61	0.61	0.13	0	0	0.61	0.61
10 km	1.256	0.77	0.76	0.76	0.46	0.23	0	0.76	0.76

4.3 GRADING BETWEEN PROTECTION DEVICES

More detail on why grading between protection devices are required and how it is achieved is given in Chapter 2. Even though the entire network shown in Figure 2.5 was simulated, only the part relevant to the simulation purpose will be discussed and is shown in Figure 4.2.

The network was simulated with 1, 2 and 3 feeders connected in parallel and the results are tabulated in Table 4.2. As the number of parallel feeders increase, the grading margin between the parallel feeders, and any downstream overcurrent protection devices increase proportionately.

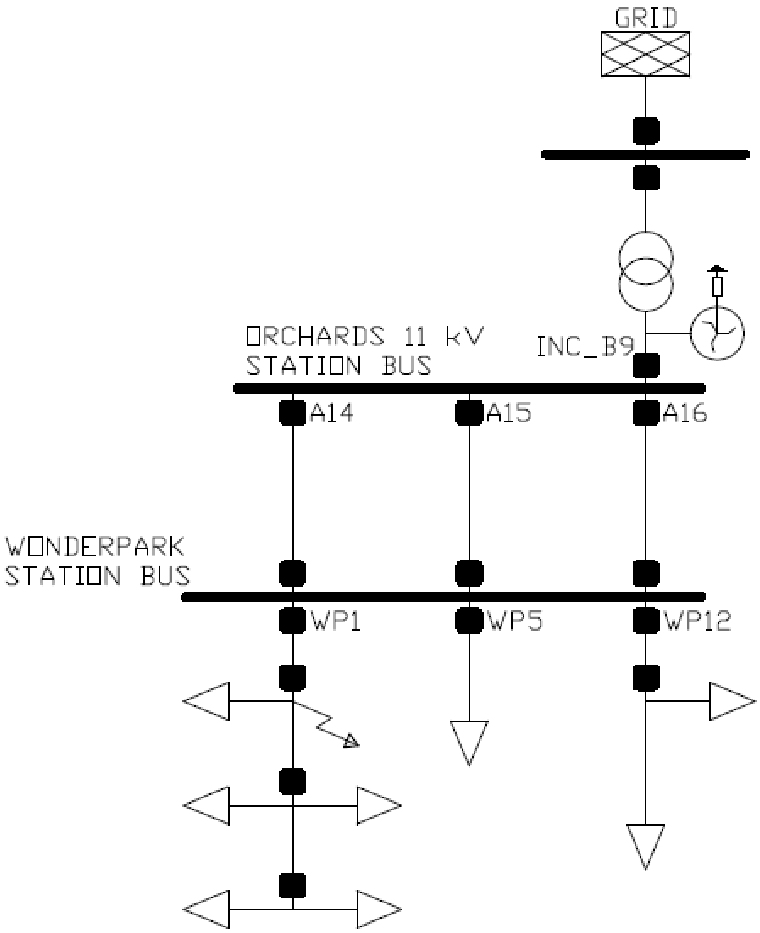

Figure 4.2 Grading between protection devices

Adding parallel feeders increase grading margin between breakers in a given path. The simulations were conducted with two different grid fault levels on the 132 kV bus. The grading margins decrease when the faults levels are higher, irrespective of the amount of parallel feeders. Tripping times for the parallel feeders A14 to A16, imply that in the event of W1 failing to operate on occurrence of a fault, the upstream feeders will trip and act as back-up protection. The entire fault current seen by W1 is seen by feeders A14, A15 and A16. This is the premise on which overcurrent protection grading validity is built.

There are constraints and limits when coordinating with parallel feeders. Table 4.2 demonstrates the difference in the fault current seen by W1 and the three upstream feeders, when two or three feeders are connected in parallel. If the fault impedance is high enough, the current through the parallel feeders will reduce, and the overcurrent relays will be blinded from seeing the fault as a results of the shared fault current. The results from Table 4.2 were simulated with a cable length of 2.2 km between Wonderpark substation, and the first mini-sub.

Table 4.2 Grading margin with parallel feeders

Grid fault level (kA)	Feeders in parallel	A14 current (A)	A15 current (A)	A16 current (A)	W1 current (A)	A14 trip time (sec)	W1 trip time (sec)	Grading margin (sec)
7.2	3	1903	1903	1903	5710	1.488	0.461	1.026
7.2	2	2716	2716	-	5432	1.243	0.470	0.774
7.2	1	4720	-	-	4720	0.988	0.494	0.494
0.6	3	1130	1130	1130	3390	2.083	0.563	1.520
0.6	2	1651	1651	-	3301	1.614	0.570	1.044
0.6	1	3053	-	-	3053	1.179	0.590	0.590

If the cable length is increased to 15 km, with three feeders connected in parallel, the three feeders will not pick-up for the fault even if it is a solid fault with 0 Ω impedance. Such long cables are however uncommon and such high fault impedances seen from the relay locations are unexpected. Another constraint would be the amount of parallel feeders. Table 4.2 illustrates the reduction in fault current per feeder as the amount of parallel feeders increase. Multiple parallel feeders where shared fault current will be below pick-up levels, are avoided for that reason. The results for phase to phase, and single phase to earth faults are similar to the results for three phase faults and are not displayed.

4.4 RECLOSER FUSE COORDINATION

Coordination between recloser and fuses are described in Chapter 2. Feeder B2 in Figure 2.5 was isolated as shown in Figure 4.4, and simulated with different types of faults with varying line lengths and grid fault levels. The reclosers are used to clear permanent faults, but also to clear transient faults on the main line before any spurs with fuses. For faults downstream of the fuse, the recloser should also trip to clear any transient fault before the fuse starts to melt. The tripping characteristic curves for the phase faults and earth faults are shown in Figure 4.3, which also shows the characteristic curves for the substation breaker B2. When grading with fuses, normal inverse are seldom used, due to the extreme inverse characteristic of the fuse. For this reason, extremely inverse curves are often used for the fast tripping curve. Very inverse curves are used for the slow curve, since there is a more margin for grading between the fuse and the recloser slow tripping curve. Breaker B2 is set to trip slower than the recloser. The recloser fast curve for phase faults has a pick-up setting of 50 A, but the curve is set not to operate for any faults less than 5 times the pick-up value. This is done to manipulate the curve to that shown in Figure 4.3.

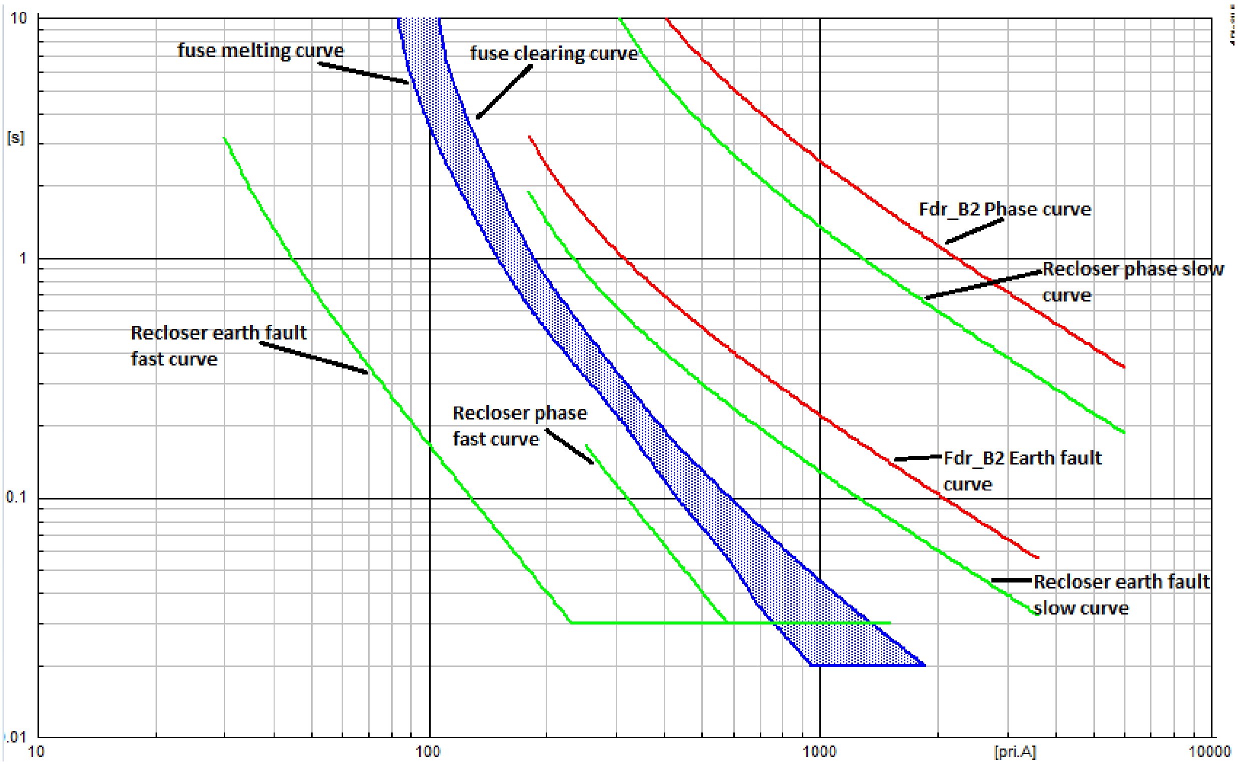

Figure 4.3 Characteristic curves for recloser fuse coordination test

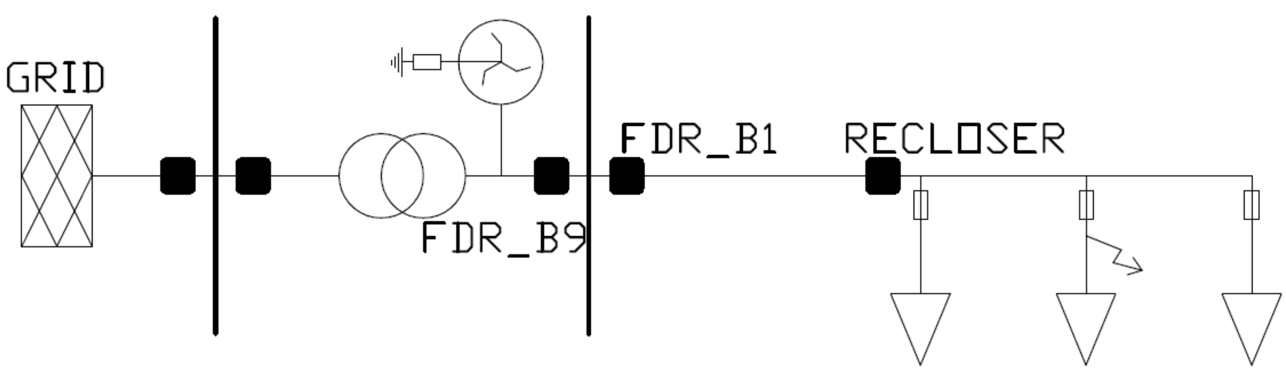

Figure 4.4 Recloser fuse coordination feeder

4.4.1 Three phase faults

A three phase fault was simulated on the network shown in Figure 4.4. The results (shown in Table 4.3) indicate that it is not possible to coordinate a recloser fast curve with a downstream fuse with short lines, or when the fault occurs close to the recloser. The fuse will blow before the minimum operating time of the recloser, when the fault is close to the substation. This is only true when the fuses are small and are only used on spurs. Fuses that are installed on the line, will likely have higher melting curves to obtain better coordination. The distance of the line from where coordination will be possible, is a function of the line type and depends on the line impedance. During three phase balance faults, only positive sequence current will flow and the fault impedance introduced by the negative and zero sequence components, will not add to the fault impedance.

Table 4.3 Recloser fuse coordination for three phase faults

Grid fault level (kA)	Line length (km)	Line fault current (A)	Recloser trip time (sec)	Fuse melt time (sec)	Grading margin (sec)
0.6	5	3001	0.03	0.02	-
0.6	15	1423	0.03	0.02	-
0.6	35	649	0.03	0.04	0.010
7.2	5	4067	0.03	0.02	-
7.2	15	1520	0.03	0.02	-
7.2	35	661	0.03	0.04	0.010

4.4.2 Phase to phase faults

The network shown in Figure 4.4 was subjected to phase to phase faults. During phase to phase faults, positive and negative sequence current will flow. The negative sequence impedance for the line will add to the total fault impedance and will result in lower fault current. For phase to phase faults, coordination is more likely achievable as a consequence of the higher fault impedance resulting in lower fault current. The results are given in Table 4.4. The results indicate that even though the fault current is less than in the case of three phase faults, coordination remains difficult to achieve, unless the lines are long and the faults occur far from the substation. Coordination will still be challenging, even when the grid fault levels are extremely low.

Table 4.4 Recloser fuse coordination for phase to phase faults

Grid fault level (kA)	Line length (km)	Line fault current (A)	Recloser trip time (sec)	Fuse melt time (sec)	Grading margin (sec)
0.6	5	2599	0.03	0.02	-
0.6	15	1232	0.03	0.02	-
0.6	35	562	0.03	0.06	0.027
7.2	5	3522	0.03	0.02	-
7.2	15	1316	0.03	0.02	-
7.2	35	572	0.03	0.06	0.026

4.4.3 Phase to earth faults

A single phase to earth fault was simulated on the network shown in Figure 4.4. During phase to earth faults, positive, negative and zero sequence current will flow. The impedance added into the zero sequence network by the NECR will significantly reduce fault current. The reduced fault current will make it more likely for coordination to be achieved. The results for the single phase to ground fault are shown in Table 4.5. The last column of Table 4.5 suggests that coordination is possible between the recloser and the fuse even for very short lines. Faults were simulated at two different 132 kV grid fault levels. At both fault levels, the recloser was able to trip and clear the fault before the fuse started melting. Reducing the grid fault levels will result in more impedance during faults, which will reduce fault current. Adding impedance to the source has little effect on the fault current, when compared to the large impedance introduced by the NECR. Reclosers coordinated with fuses has proven successful in the industry, since most faults on overhead lines are earth faults [32].

Table 4.5 Recloser fuse coordination for phase to earth faults

Grid fault level (kA)	Line length (km)	Line fault current (A)	Recloser trip time (sec)	Fuse melt time (sec)	Grading margin (sec)
0.6	5	377	0.03	0.134	0.104
0.6	15	331	0.03	0.181	0.151
0.6	35	263	0.03	0.292	0.262
7.2	5	385	0.03	0.128	0.098
7.2	15	336	0.03	0.175	0.145
7.2	35	266	0.03	0.286	0.256

CHAPTER 5 DISTRIBUTED GENERATION NETWORK SIMULATION

5.1 INTRODUCTION

The network given in Chapter 2, Figure 2.5 will be simulated here, while focusing on the negative protection effects discussed in section 3.3 of Chapter 3. As the penetration level increases, the effects of DG on power system protection, when only conventional protection methods and philosophies are used will be illustrated. The effect of DG on overcurrent protection will provide the premise for Chapter 6. To simplify the presentation, only the relevant part of the network where DG will affect the protection is used.

5.2 SYMPATHETIC TRIPPING

Section 3.3.1 describes the conditions of how sympathetic tripping could occur. Sympathetic tripping is the loss of a healthy feeder or DG due to overcurrent or undervoltage, caused by a fault on an adjacent feeder. The part of the network where DG is placed is shown in Figure 5.1. The isolated network was simulated to investigate the occurrence of sympathetic tripping due to undervoltage and reverse overcurrent.

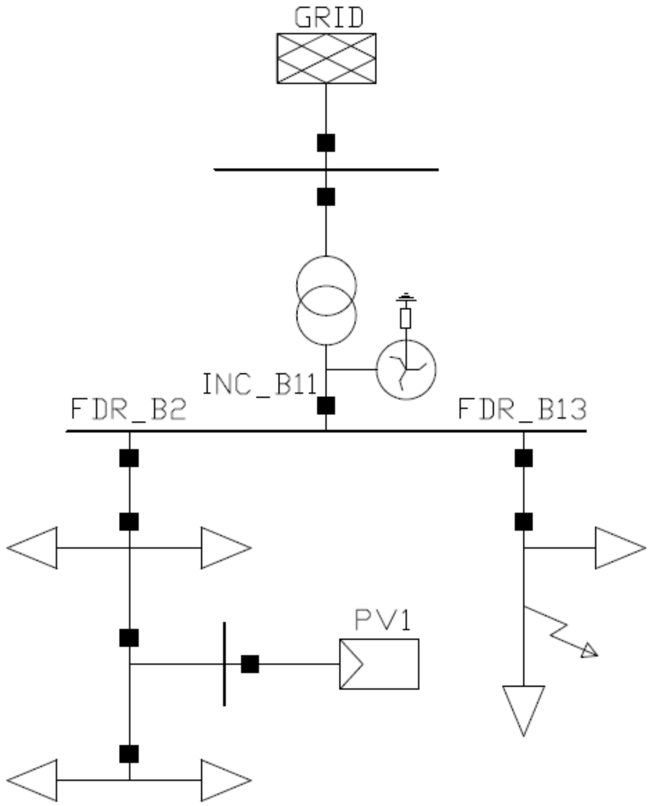

Figure 5.1 Sympathetic tripping test network

5.2.1 Undervoltage sympathetic tripping

The network in Figure 5.1 was simulated and several parameters were varied, to determine which parameters have the most significant impact on undervoltage sympathetic tripping. The amount of current fed back into the grid by PV1 is restricted by the cable's current carrying capacity, and can at most be 200 % of the feeder capacity, of which 100 % is self-consumed and the other 100 % fed back into the grid. Assuming the worst case scenario, that all the loads are disconnected when a fault occurs, 200 % of the current will be fed back through the substation to the fault. The fault contribution of the DG was set to 120 % of the rated output power according to [53]. A three phase fault was simulated on feeder B13. First, PV penetration levels were varied from 0 % to 200 % of the feeder capacity. The voltage at the point of connection (POC) terminals of the DG is plotted against the penetration level for different grid fault levels. It is apparent from the results in Figure 5.2, that varying PV penetration levels does not have a significant impact on the system voltage under fault conditions. The unchanged system voltage is a result of the limited fault current that inverter based generators provide. For all cases, the fault impedance, and distance of the PV generator from the substation were held constant at 0.08 Ω and 5 km respectively. The voltage sag during faults were found to always drop below 0.5 pu (leading to disconnection in 200 ms), at least for the given fault impedance and PV distance from the substation. The DG was found to disconnect on undervoltage for all of the different grid fault levels.

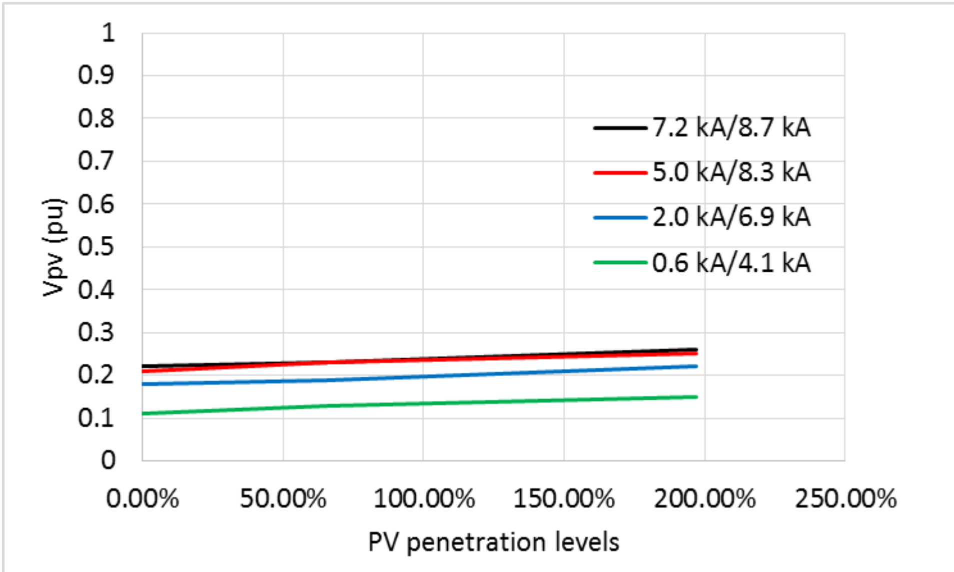

Figure 5.2 Undervoltage condition created by varying PV penetration levels

Next, the distance between the PV generator and the substation was varied, to see what effect this will have on the voltage at the PV POC. The resulting voltages are shown in Figure 5.3, which indicate that the distance between the PV generator and the substation also does not make a significant change on the undervoltage levels. The PV penetration levels were held constant at 65 % in Figure 5.3, since we saw in Figure 5.2 that varying it does not make a significant difference. The fault impedance was also held constant. The maximum distance between the PV generator and the substation was chosen at 5 km and is limited by the geographic nature of distribution power systems. The DG disconnected on undervoltage in all of the test cases.

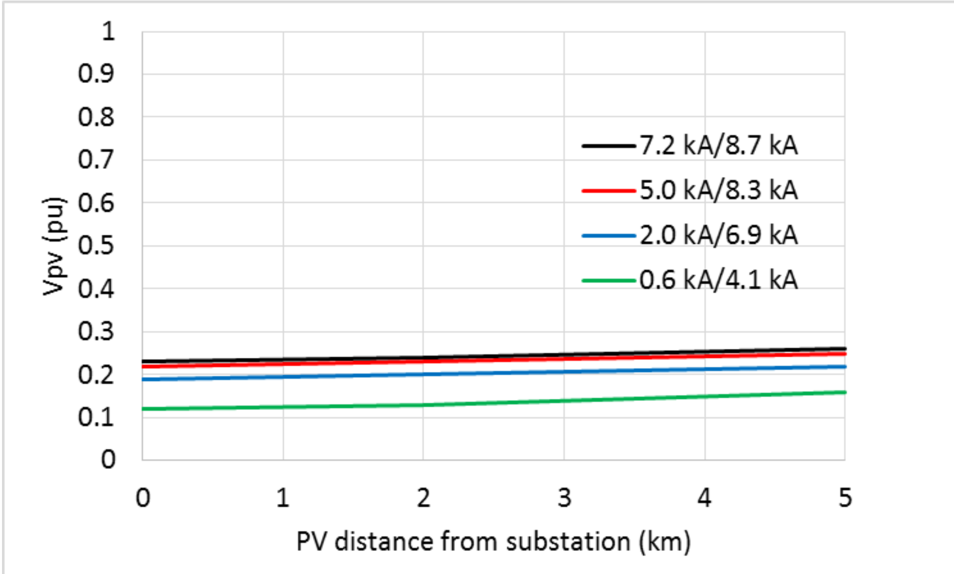

Figure 5.3 Undervoltage condition created by varying PV distance from substation

Lastly, the distance of the fault from the substation, and hence the fault impedance, was varied to measure how this will influence the undervoltage condition created at the PV POC during a fault. The results are presented in Figure 5.4, and prove that varying fault impedance have a significant impact on the undervoltage condition. The increased fault impedance results in a higher voltage at the PV POC during fault conditions. In this case, the distance between the PV generator and the substation was kept at 2 km, while the PV penetration level was kept constant at 65 %. According to the applicable grid code requirements [46], DG should disconnect within 200 ms for faults that cause the voltage to drop below 0.5 pu. The fault in feeder B13 causes the overcurrent relay to operate. The operating times for feeder B13 are shown in Figure 5.4. The fault current through feeder B13 is not enough to operate within 200 ms. For fault impedances that cause the voltage to drop below 0.5 pu, the PV generator will be disconnect before feeder B13 trips to clear the fault, and sympathetic tripping will occur.

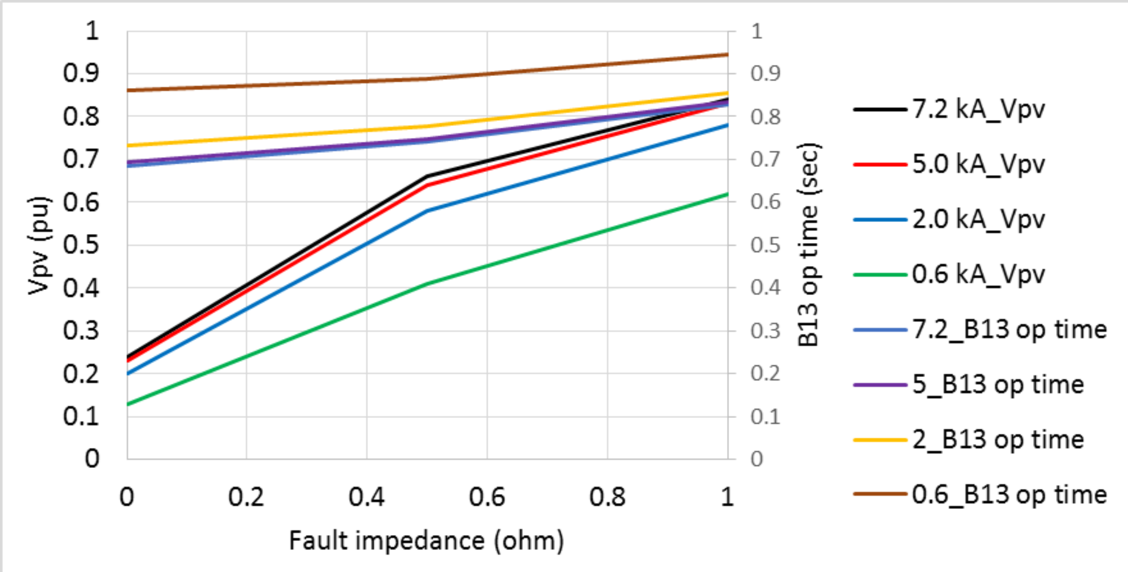

Figure 5.4 Undervoltage condition created by varying fault distance from substation

5.2.2 Reverse overcurrent sympathetic tripping

The network in Figure 5.1 was simulated again, to investigate the possible occurrence, and system conditions under which sympathetic tripping due to reverse overcurrent could occur. During a fault on feeder B13, the fault current contribution from PV1 could cause breaker B21 to operate before the breaker protecting feeder B13 operates. The overcurrent tripping times for the circuit breakers in Figure 5.1 are calculated according to the cables' current carrying capacity given in Table 2.4 as described in section 2.4. The inverse time tripping curves for feeder B2, B13 and breaker B21 are shown in Figure 5.5. In order for sympathetic tripping to occur, breaker B21 or feeder B2 is required to trip faster than what feeder B13 can trip to clear the fault. This will require the lowest possible fault current through feeder B13, and the maximum possible reverse overcurrent through breaker B21 and feeder B2. This will occur when the PV penetration levels are at its highest level and the grid fault levels at its lowest level. Increasing the fault impedance will also reduce the fault current in feeder B13. As mentioned in section 5.2.1, PV penetration cannot exceed levels that will feed more power back into the grid than the feeder cable can facilitate. PV penetration levels were set to 100 % and with all the loads set to zero, all of the current will flow upstream in the feeder to the substation and to the fault. The 132 kV fault level was varied from 0.6 kA to 7.2 kA, to see what effect the grid fault level would have. Faults on feeder B13 were simulated with different fault impedances and the results are presented in Table 5.1.

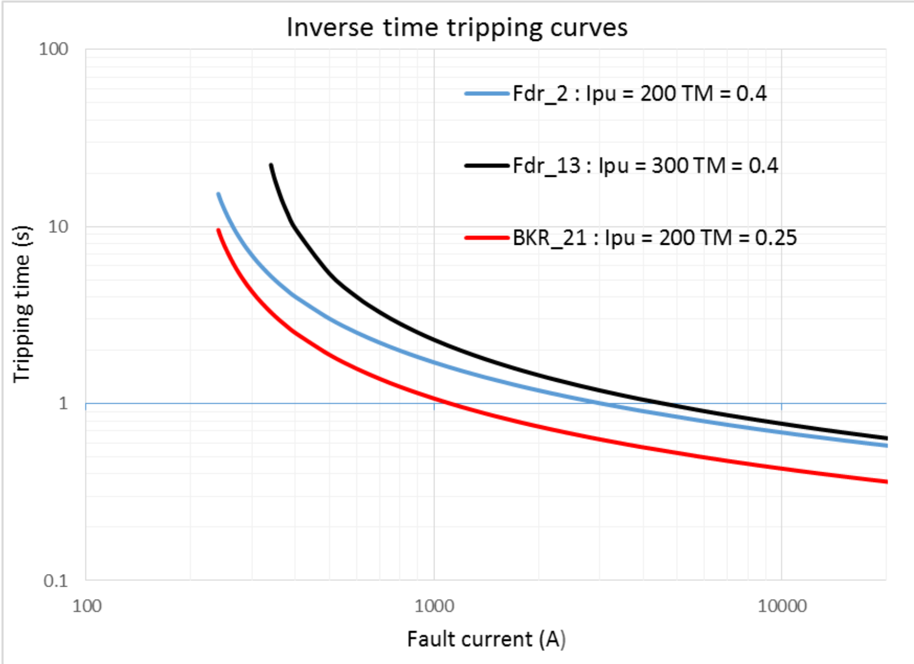

Figure 5.5 Sympathetic tripping overcurrent curves

With the DG penetration level being 100 % of the cable capacity, even with no fault, the current flowing in the feeder will be close to the pick-up level of the relay, since the relay is set to trip for any current above the cable's capacity. The feeder will trip on overcurrent during fault conditions, when the current from the PV generator will be around 120 % of the nominal. Feeder B13 was always found to trip faster than feeder B2, since the current in feeder B2 is always just slightly above the pick-up level, and no sympathetic tripping was observed.

Table 5.1 Sympathetic overcurrent tripping test results with 100 % PV penetration

Faulted line length (km)	132 kV fault level (kA)	Breaker 21 fault current (A)	Feeder 13 fault current (A)	Breaker 21 trip time (sec)	Feeder 13 trip time (sec)
1	7211	250	7503	6.372	0.842
1	600	246	4057	6.702	1.047
10	7211	232	2698	8.254	1.247
10	600	243	2164	6.977	1.389
20	7211	220	1508	10.444	1.706
20	600	231	1345	8.397	1.838
30	7211	214	1042	12.116	2.221
30	600	223	937	9.782	2.431

The PV penetration levels were increased to 200 % to provide substantial current, to ensure that breaker B21 and feeder B2 will operate. The results are shown in Table *5.2*.When the faults simulated in feeder B13 were close to the substation and had little fault impedance, the current in feeder B13 was still enough to ensure that the protection of feeder B13 operated before feeder B2 or breaker B21. However, when the faults were far away from the substation and the fault impedance increased, breaker B21 operated before the breaker at feeder B13 could trip to clear the fault. It should be noted that even if there was no fault, the protection for breaker B21 and feeder B2 would have operated, since the current provided from the PV generator exceeds the cable ratings. The operation of breaker B21 and feeder B2 is thus not due to sympathetic tripping, but is the result of overloading of the cable between the PV generator and the substation. The impedance at which sympathetic tripping occurs, would be seen only when extremely long cables are used (longer than 10 km). Such long cables are not used in distribution networks. Overhead lines are used in distribution networks when power is transferred over longer distances, with multiple protection devices along the line to shorten the part of the line protected by a single device. This allows increased sensitivity further down the line, and will prevent sympathetic tripping.

Table 5.2 Sympathetic overcurrent tripping test results with 200 % PV penetration

Faulted line length (km)	132 kV fault level (kA)	Breaker B21 fault current (A)	Feeder B13 fault current (A)	Breaker B21 trip time (sec)	Feeder B13 trip time (sec)
1	7211	504	7692	1.876	0.835
1	600	496	4273	1.909	1.026
10	7211	461	2719	2.078	1.242
10	600	448	448	2.152	1.369
20	7211	433	433	2.248	1.702
20	600	458	458	2.095	1.817
30	7211	421	421	2.334	2.217
30	600	442	978	2.189	2.342

5.3 PROTECTION BLINDING

As described in section 3.3.2, protection blinding occurs when the addition of a PV generator downstream of a protective device provides voltage support and contributes to fault current. This will result in the upstream breaker seeing less current, leading to reduced tripping times, and in severe cases completely blind the upstream protective device from seeing the fault. Adjacent feeders are ignored in this analysis, since protection blinding is only relevant to upstream protective devices. The network for this analysis is simplified to the network shown in Figure 5.6.

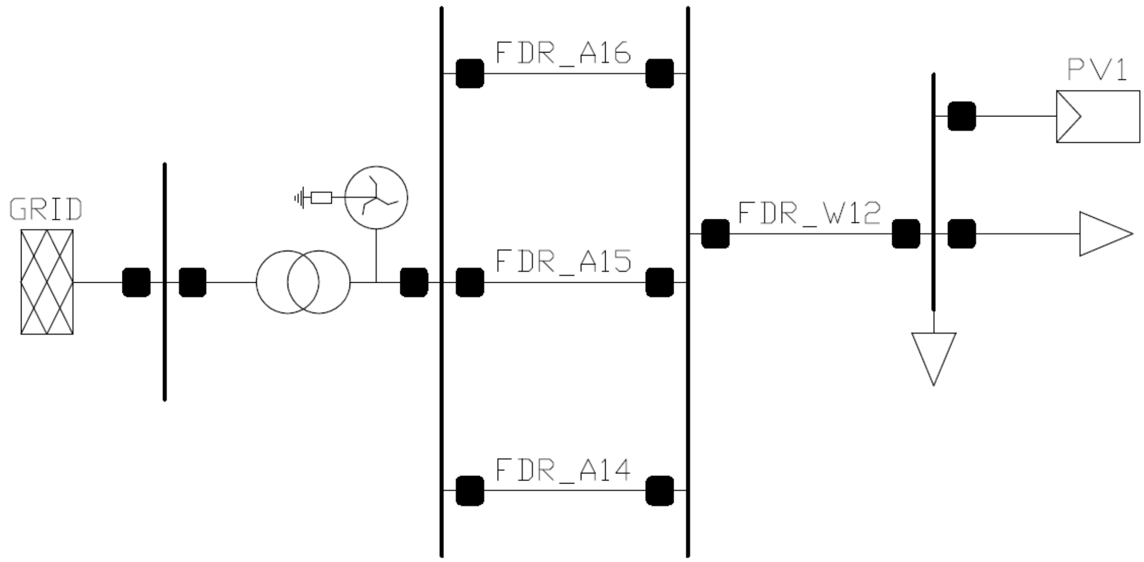

Figure 5.6 Protection blinding test network

5.3.1 3-Phase faults

A three phase fault is considered downstream of PV1 on feeder W12. For a three phase balanced fault, only positive sequence current will flow. The sequence network for this fault study is shown in Figure 5.7. In order for protection blinding to occur, current flowing through the protection relay and Zs1 should be minimized. This will occur in one of two conditions; Is1 will flow through Zs1 and Zf, and can be limited by maximizing Zs1 or by maximizing Zf. The level of penetration can be varied by changing Ipv1. The effect of protection blinding is most severe under high levels of penetration. By applying Kirchhoff's current law, equation (5.1) can be derived to represent Vf in terms of the impedances shown in the network and Ipv. Equation (5.1) reveals that if the fault impedance is low (even for a high source impedance Zs1, which represents a weak grid), Vf will be low, causing a large voltage drop over Zs1 which will lead to maximum current seen by the relay at feeder W12. Increasing the fault impedance should show the most significant effect. The fault impedance is controlled by adjusting the length of the faulted line, and assuming the fault to occur at the furthest point down the line.

$$V_f = \frac{Z_f(1 + I_{pv}Z_s)}{Z_f + Z_s} \tag{5.1}$$

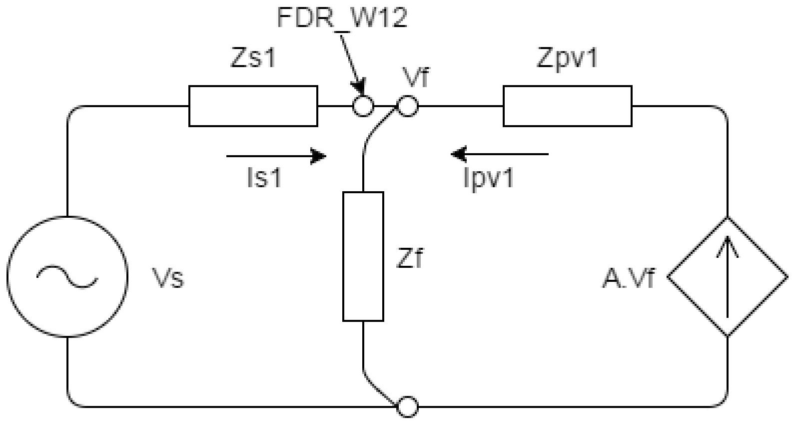

Figure 5.7 three phase fault positive sequence network

In the example network seen in Figure 5.6, the fault impedance and grid fault levels were varied along with different fault current contributions from the PV generator. The results are discussed below. In Figure 5.8 – Figure *5.11*, the three curves in each figure represents different grid fault levels. The fault currents on both the 132 kV bus, and the 11 kV bus is given. The distribution transformer impedance was given as 21.7 % in section 2.4, which is significantly larger than the source impedance (calculated at 2.4 %). Even if the source impedance is increased 10 fold (resulting in the 132 kV fault level reducing 10 times), combined with the transformer impedance, it will only result in a 50 % reduction in the 11 kV fault level.

In Figure 5.8, a fault is simulated 1 km from the PV feed in point. The only fault impedance seen between the PV generator and the fault is that of the cable. No significant change in tripping times were observed, for varying levels of penetration, when a faults occurs close to the substation (low impedance faults). The reason for this is that the voltage Vf is close to zero. The voltage drop between Vs and Vf is large, creating a maximum current flow through Zs1 and Feeder W12. The additional current from Vpv does not create significant voltage support to Vf.

Distribution networks are not characterized by long lines or cables as seen in transmission networks, running between cities and cross country. Distribution cables seldom exceed 10 km. The fault impedance becomes more significant when faults occur near the end of a cable. The fault was simulated again with a longer faulted line of 10 km. The results are shown in Figure 5.9. It should be noted that even with 0 % PV penetration, a difference in operating time is observed, compared to a fault with smaller impedance as shown in Figure 5.8. Even with no PV contribution, the additional impedance between source Vs and the zero bus would result in less current flowing through feeder W12. A small increase in tripping times are recorded as the level of PV penetration increases.

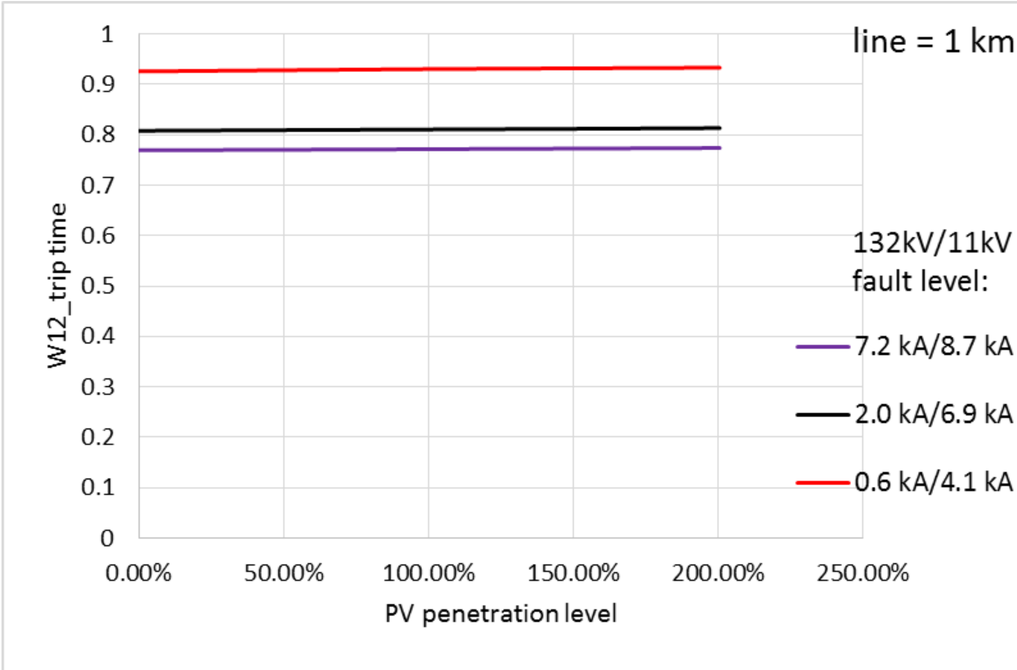

Figure 5.8 Feeder W12 trip times, line = 1 km

The additional current Ipv1 flowing through Zf creates some voltage support to Vf. The reduced voltage drop from Vs to Vf results in less current flowing in feeder W12 and the reduced current leads to delayed tripping times. Feeder W12 sees enough current to operate and clear the fault when the fault occurs at the end of the distribution line, even for 200 % PV penetration.

In Figure 5.10, the faulted line length was increased to 30 km, which simulates a fault further away from the substation. The results confirm, as expected from equation (5.1), that a higher fault impedance will result in Vf increasing, causing less current to flow though Zs1 and delayed operating times of feeder W12. The higher voltage Vf is further increased by higher PV penetration levels. The tripping time delay of the protection relay doubled from 1.7 sec – 3 sec when penetration levels were changed from 0 % – 200 %. It should however also be noted that even for 0 % PV penetration, the time delay is increased from 1 sec – 1.7 sec between a low impedance fault close to the substation and a fault 30 km down the line. The combination of increased PV penetration and high fault impedance, creates substantial delay in tripping time. All of the combinations between fault impedance, source impedance and penetration levels resulted in operation of the overcurrent protection and blinding of protection did not occur.

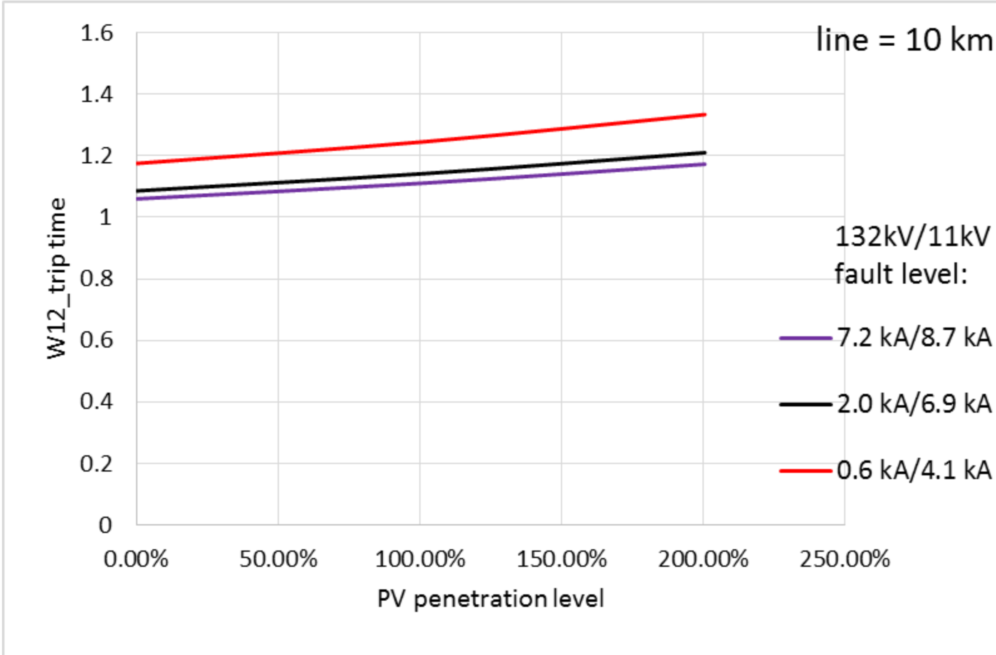

Figure 5.9 Feeder W12 trip times, line = 10 km

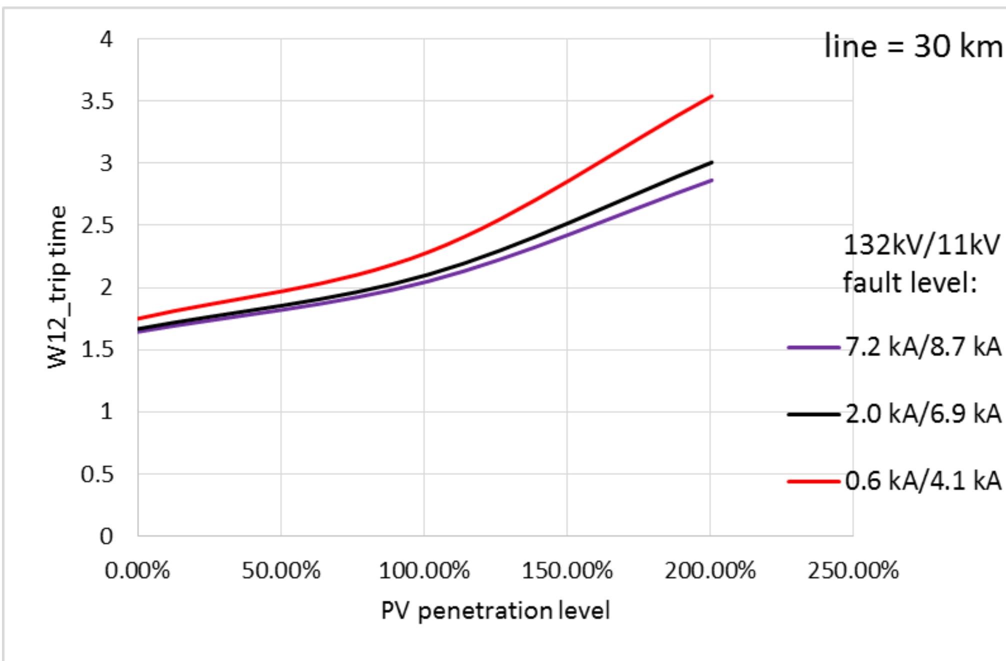

Figure 5.10 Feeder W12 trip times, line = 30 km

The network in Figure 5.6 was simulated with an even higher fault impedance, to push the network to the limit where protection blinding will occur. Operating times for feeder W12 are shown in Figure 5.11. Protection blinding did not occur for any grid fault levels, even when the fault occurred 50 km down the line. This is a function of the cable parameters and would not be the same in all networks. This is however the maximum line length where binding would not occur. The operating time did not increase significantly between 0 % and 100 % penetration. The effects of protection blinding was more severe in cases where the grid fault levels are low. Delayed tripping times were observed, even for 0 % PV penetration, when the fault impedance was increased to this extreme. Protection blinding will occur even, for 0 % PV penetration, if the fault impedance is further increased. Protection blinding is not an effect caused by the addition of DG, but is a condition resulting from faults on long cables or lines. The condition is amplified by the addition of DG. As mentioned in the case of a 30 km line, high impedance (50 km) balanced faults are very uncommon. High impedance faults are more often experienced on overhead lines, and are usually unbalanced faults such as phase to phase or phase to earth faults.

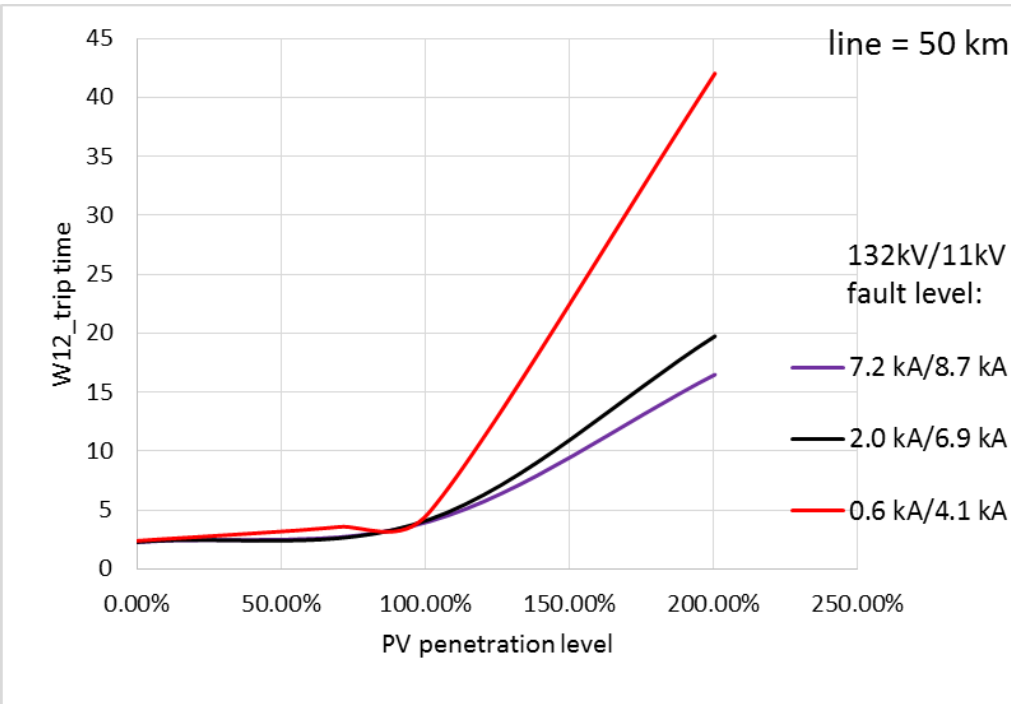

Figure 5.11 Feeder W12 trip times, line = 50 km

5.3.2 Phase to phase faults

The network in Figure 5.6 was subjected to a phase to phase fault on feeder W12, downstream of the PV generator. The occurrence of protection blinding was investigated. Again, the network was first modelled and broken down into equivalent sequence networks, to calculate and justify the results. The equivalent sequence networks are given in Figure 5.12 a and b. For a phase to phase fault, the positive and negative sequence currents are equal in magnitude but 180° apart. The positive and negative sequence networks are connected as shown in Figure 5.12 a. Inverter based generators are current sources and are able to supply only balanced current, irrespective of the unbalance caused in the voltage due to a phase to phase fault. This effectively increases its negative sequence impedance to infinity and it will not facilitate any negative sequence current [64]. With the PV negative sequence impedance being an open circuit in the steady state, the sequence network can be simplified to the circuit shown in Figure 5.12 b. The protection device situated at feeder W12 operates on phase current, and will not distinguish between sequences. Unlike with three phase balanced faults, the relay phase current will not only constitute the positive sequence current Is1, but it will see a combination of current Is1 and Is2 according to equation (5.2).

$$\begin{bmatrix} I_a \\ I_b \\ I_c \end{bmatrix} = \begin{bmatrix} I_0 + & I_1 & + & I_2 \\ I_0 + & a^2 I_1 + & & aI_2 \\ I_0 + & aI_1 & + & a^2 I_2 \end{bmatrix} \tag{5.2}$$

$$\mathrm{I}_{s2} = I_{s1} + I_{pv} \tag{5.3}$$

The negative sequence current is calculated from equation (5.3) and is expected to increase with an increase in Ipv. The negative sequence current is expected to contribute to the phase current seen by the relay at feeder W12. The tripping time at feeder W12 is thus expected to reduce with increased levels of penetration. If the tripping time does not reduce, at least the delay will not be as severe as seen in the case of three phase balanced faults with high fault impedance. The simulations were performed again with three variables namely, grid fault level, level of PV penetration and fault impedance for phase to phase faults. The resulting tripping times for feeder W12 are discussed as follows.

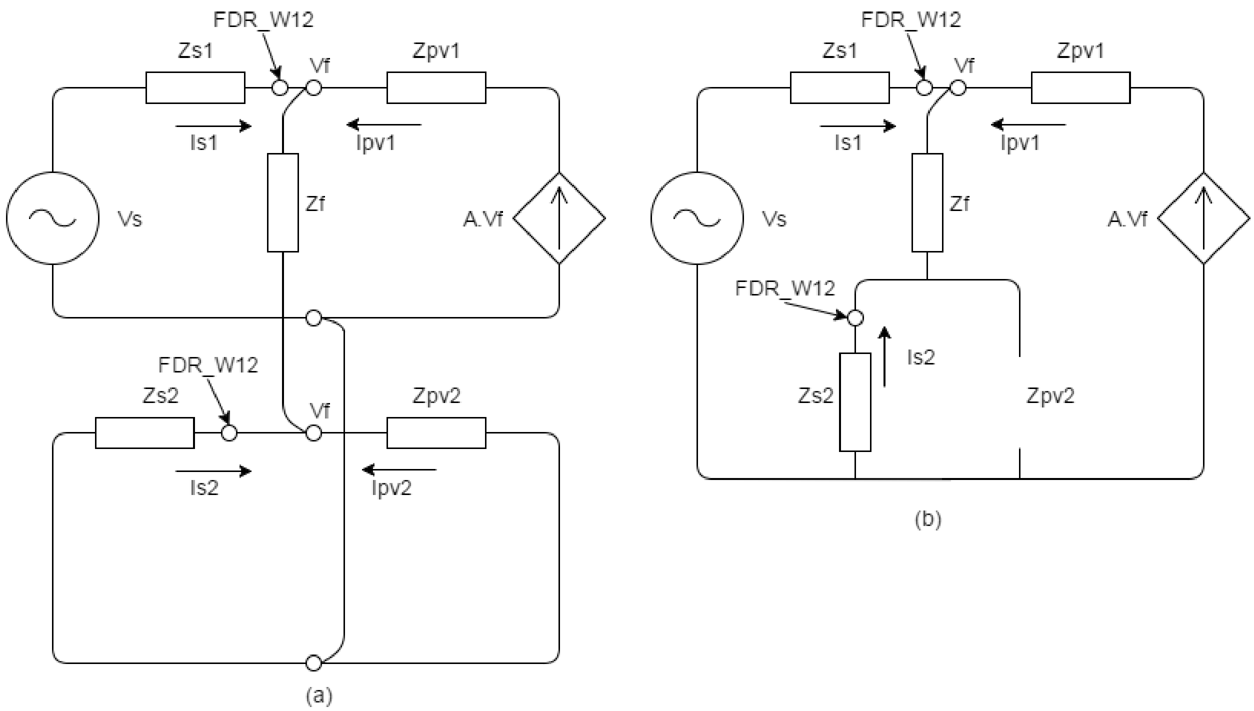

Figure 5.12 Phase to phase fault sequence network

(a) Individual sequence networks. (b) Simplified network

First, a fault close to the substation, with low impedance was simulated. The results in Figure 5.13 indicate that the tripping delay time of the relay at feeder W12, actually reduces when PV penetration levels increase, but only for low impedance faults, or faults close to the substation. As the penetration levels increase, the voltage support from the DG increases, and hence Vf in Figure 5.12 b increases. As the voltage Vf increases, the voltage drop across Zs1 will decrease, decreasing the current flow Is1 according to equation (5.4). Also, as the voltage Vf increases, for a constant Zf = 0.08 Ω, the current caused by Vf to flow in Zf and Zs2 will increase according to equation (5.5).

$$\mathrm{I}_{s1} = \frac{1 - V_f}{Z_{s1}} \tag{5.4}$$

$$\mathrm{I}_{s2} = \frac{V_f}{Z_{s2} + Z_f} \tag{5.5}$$

The relay at feeder W12 measures the phase current and will trip according to this measurement. The phase current in all three of the phases are built up of a combination of the sequence currents Is1 and Is2 accoding to equation (5.2). With the increase in Is2 being greater than the decrease in Is1, the phase current will increase, instead of decreasing as seen in the case of a three phase fault. Figure 5.14 shows the positive and negative sequence current measurements for the a grid fault level of 5 kA. The results clearly shows the reduction in positive sequence current as penetration levels increase along with the increasing negative sequence current.

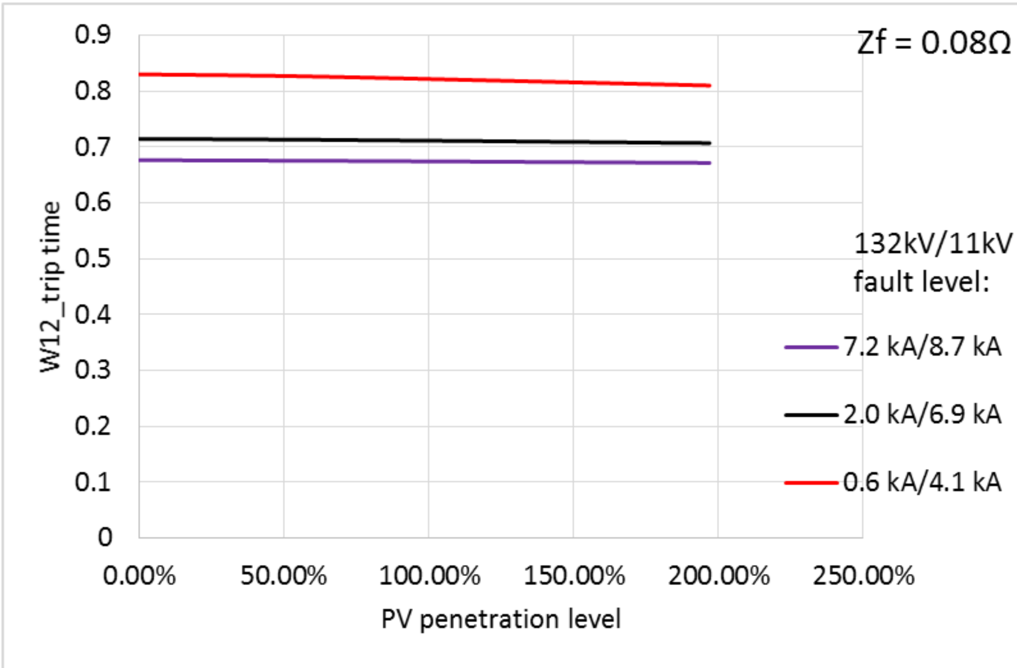

Figure 5.13 Feeder W12 trip times for phase to phase faults, Zf = 0.08 Ω

When significant fault impedance (Zf) is introduced into the system, the current Is2 will reduce accordingly, and the contribution of Is2 to the phase current seen by the protection relay at feeder W12, according to equation (5.2), becomes less prominent. As the PV penetration levels increase and provide voltage support at Vf, Is2 will still increase, but less than in the case of low fault impedance.

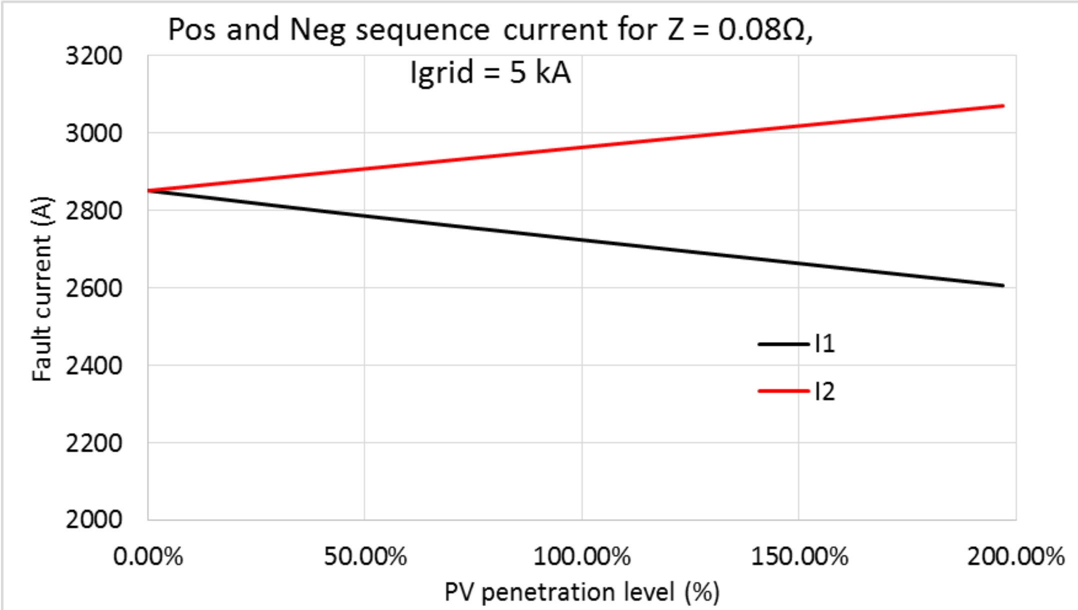

Figure 5.14 Sequence currents for phase to phase fault, Zf = 0.08 Ω

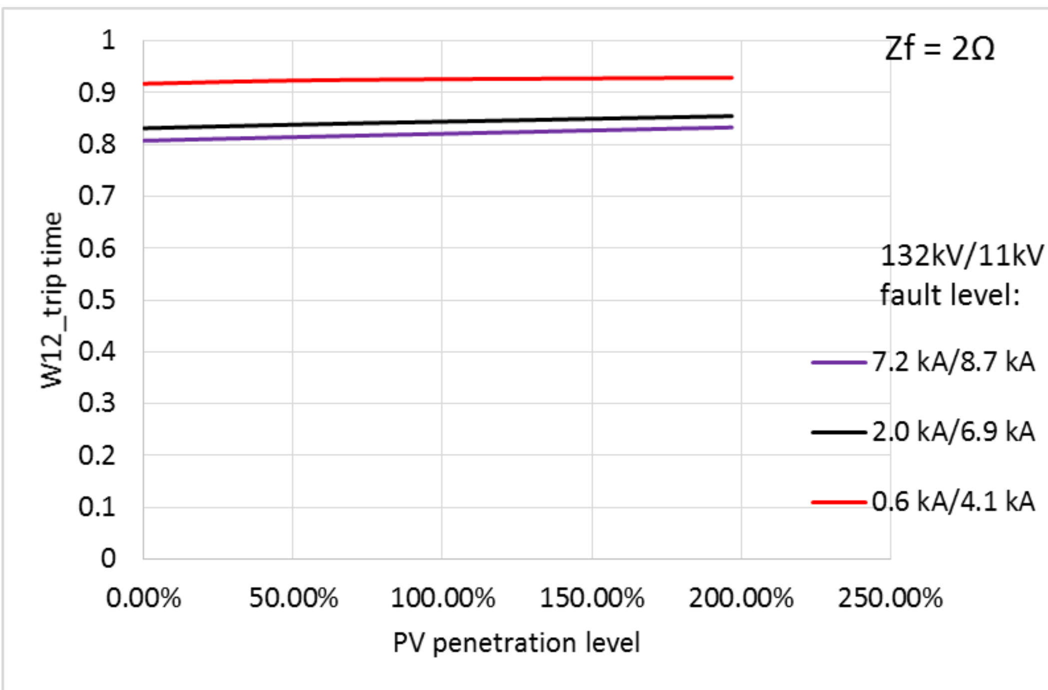

Figure 5.15 Feeder W12 trip times for phase to phase faults, Zf = 2 Ω

The impedance was increased from 2 Ω to 5 Ω and 8 Ω. A reduction in Is2 was observed, and the contribution it makes to the phase current according to equation (5.2) becomes less prominent. The overall phase current seen by the relay is reduced. The reduced phase current delays the overall tripping time of feeder W12. The negative sequence current contribution to the phase current seen by the relay at feeder W12, is always significant enough to prevent protection blinding from occurring. Protection blinding is not expected to be a concern for phase to phase faults.

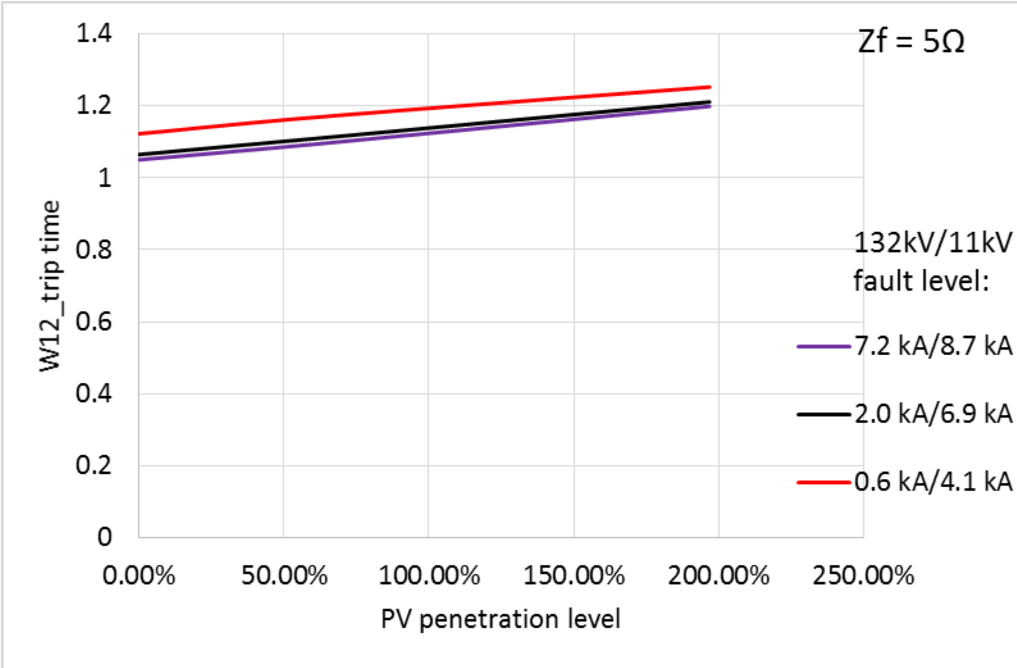

Figure 5.16 Feeder W12 trip times for phase to phase faults, Zf = 5 Ω

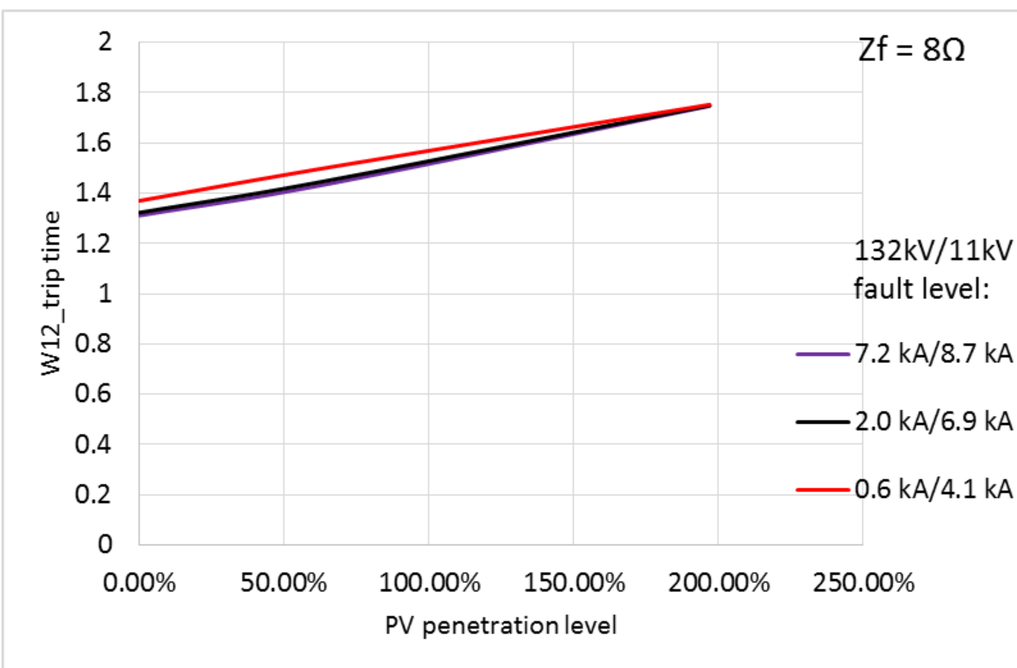

Figure 5.17 Feeder W12 trip times for phase to phase faults, Zf = 8 Ω

The negative and positive sequence current contribution, which the relay at feeder W12 sees for an 8 ohm fault is shown in Figure 5.18. A relatively small increase in negative sequence current is observed, compared to the larger decrease in positive sequence current. The decrease in positive sequence current is a result of the high fault impedance.

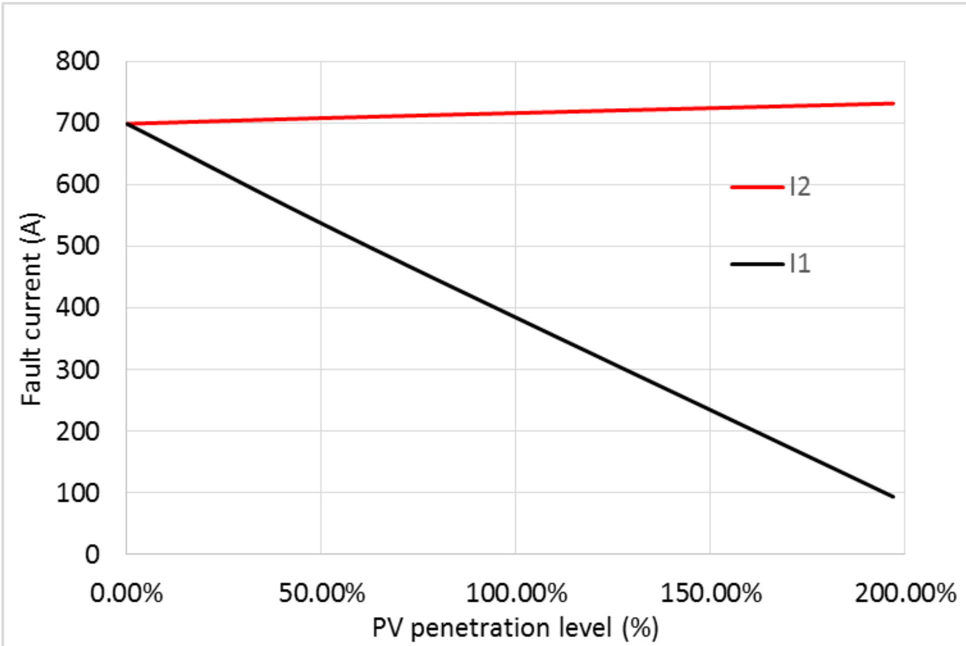

Figure 5.18 Positive and negative sequence fault current for phase to phase faults, Zf = 8 Ω

5.3.3 Phase to earth faults

The network in Figure 5.6 was again simulated with a fault on feeder W12 downstream of the PV generator. The network was subjected to phase to earth faults, to see how protection blinding can occur during these types of faults. Again, the network was first modelled and broken down into equivalent sequence networks, to calculate and justify the results. The equivalent sequence networks are given in Figure 5.19 a and b. Positive, negative and zero sequence current will flow, equal in magnitude and direction, during phase to earth faults. The sequence networks of Figure 5.19 a are connected in series for a phase to earth fault, and can be simplified to the circuit shown in Figure 5.19 b. As mentioned in section 5.3.2, PV generators can be controlled to deliver only positive sequence current, effectively increasing its negative and zero sequence impedance to infinity.

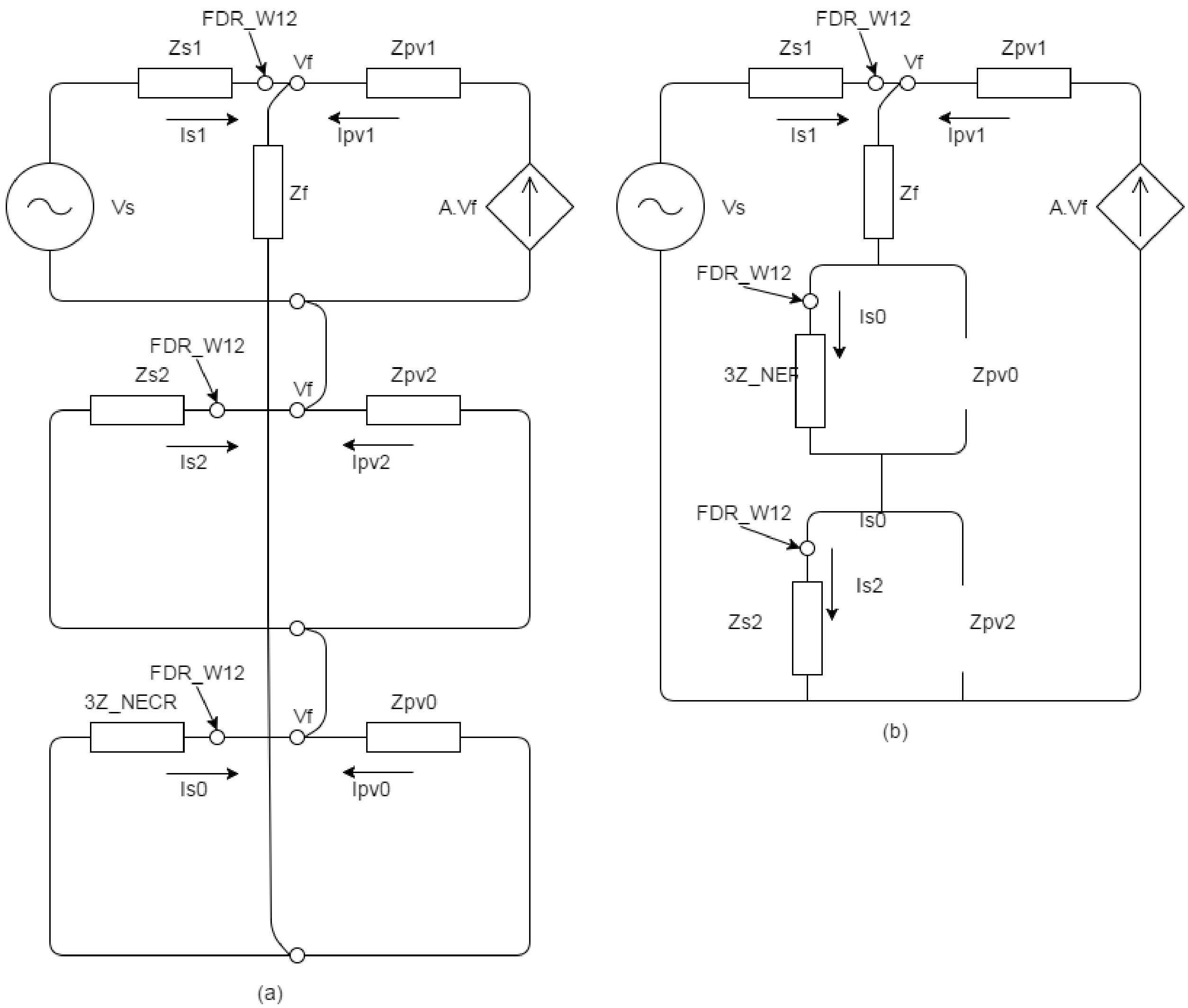

Figure 5.19 Phase to Earth fault sequence network

(a) Individual sequence networks. (b) Simplified sequence network

The relay will not use phase current as a measurement to detect ground faults as it does with three phase faults, but will use only the zero sequence current as a measurement. The zero sequence measurement is a function of the voltage Vf in Figure 5.19 b which can be described by equation (5.6).

$$V_f = \left(I_{s1} + I_{pv1}\right) \times \left(Z_f + Z_{NER} + Z_{s2}\right) \tag{5.6}$$

From equation (5.6), voltage Vf will change if Ipv, Zs, Z_{NER} or Zf changes. Z_{NER} is a fixed parameter, but the remaining three variables are again changed and the tripping time for the relay at feeder W12 is recorded. The results are shown in Figure 5.20 and Figure *5.21*.

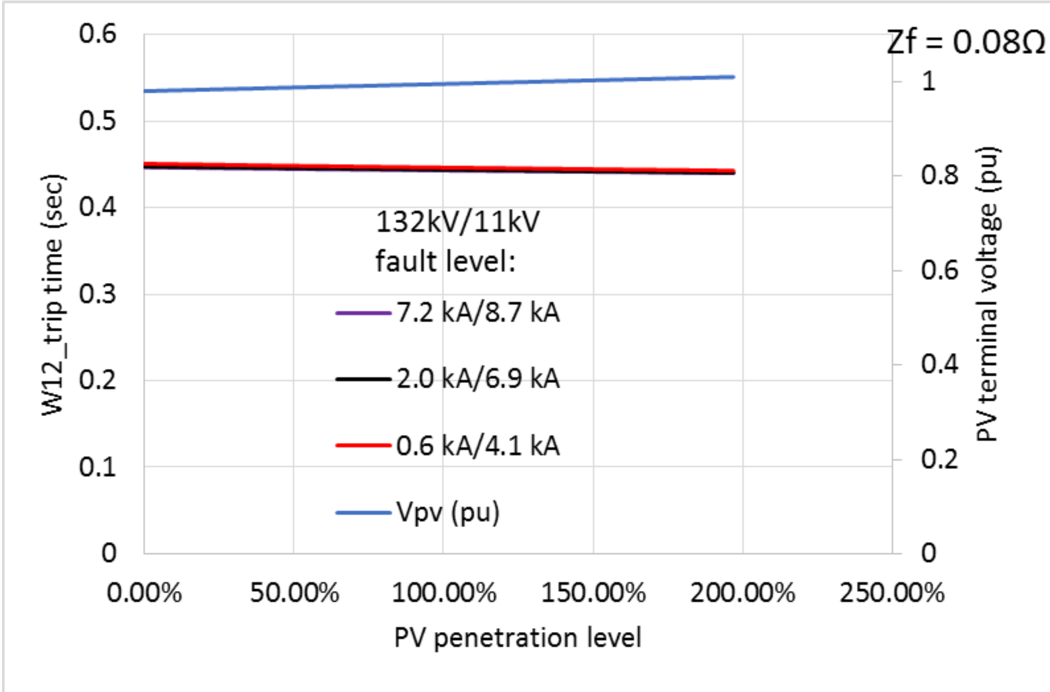

Figure 5.20 Feeder W12 trip times for phase to earth faults, Zf = 0.08 Ω

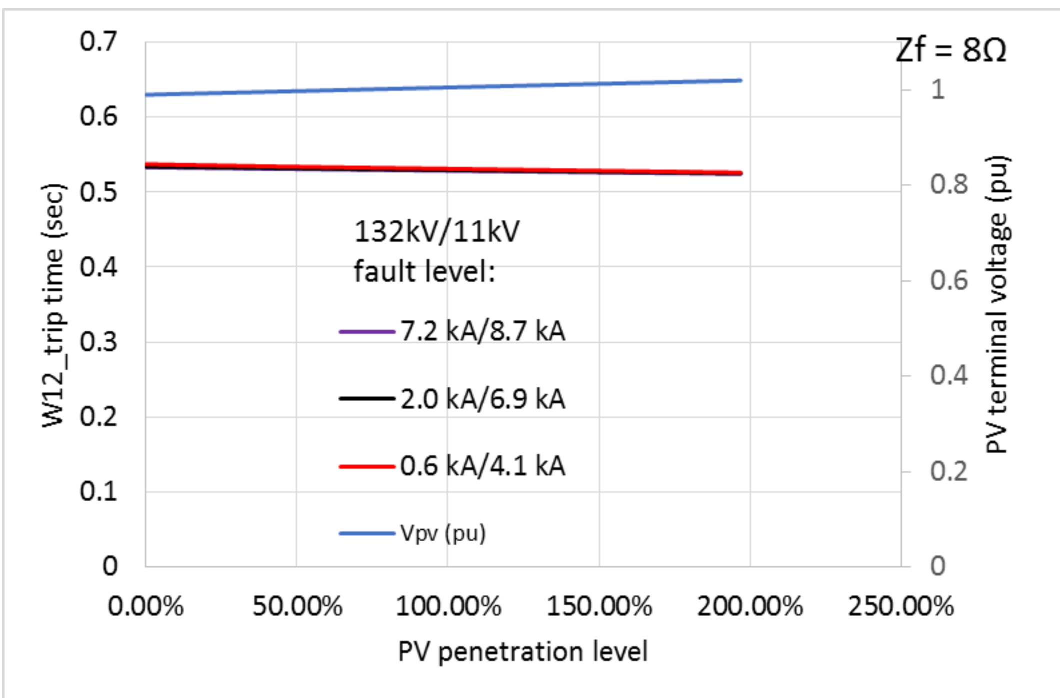

Figure 5.21 Feeder W12 trip times for phase to earth faults, Zf = 8 Ω

Figure 5.20 shows similar results as seen with phase to phase faults. There is no significant difference when the grid fault level (Zs1 and Zs2) is varied. All of the curves have similar tripping times, due to the impedance contribution from $3Z_{\_NER}$ being much greater than the source impedance.

As the PV penetration levels increase, Ipv will increase and provide more voltage support during faults. The increased voltage support to Vf will result in a bigger voltage drop across the faulted line, and increased zero sequence fault current. Even though a reduction in positive sequence current will result from an increase in Vf, it will not affect the relay tripping time, since the relay will only use zero sequence current to detect earth faults. To illustrate this, the voltage at the PV bus in Figure 5.6 is also shown on the graphs along with the tripping times for feeder W12 in Figure 5.20 and Figure *5.21*. This clearly indicates that as Vpv rises, the zero sequence current increases and the tripping time decreases. The only variable that will delay the tripping time is the fault impedance Zf. An increase in tripping time can be seen from Figure 5.20 to Figure 5.21, even for zero PV penetration levels. Protection blinding cannot occur for phase to earth faults when DG consists only of generators that are unable to provide zero sequence current. This is only true if the upstream protection devices use zero sequence current to detect earth faults and not phase current.

5.4 LOSS OF COORDINATION

The description of loss of coordination scenarios are explained and discussed in section 3.3.3. Loss of coordination is especially a concern in MV overhead networks, where auto-reclosers are coordinated with fuses to clear transient faults, and save the fuses from blowing for transient faults. Several variables will change the amount of current flowing through the reclosers and the fuses such as grid fault levels, PV penetration levels, fault distance from the substation, distance between PV generator and fault and the type of fault. The occurrence of loss of coordination is investigated by isolating a portion of the network used in this dissertation. The majority of faults (about 80 %) occurring on MV overhead lines are single phase to earth faults [32], however all types of faults are simulated with reference to Figure 5.22.

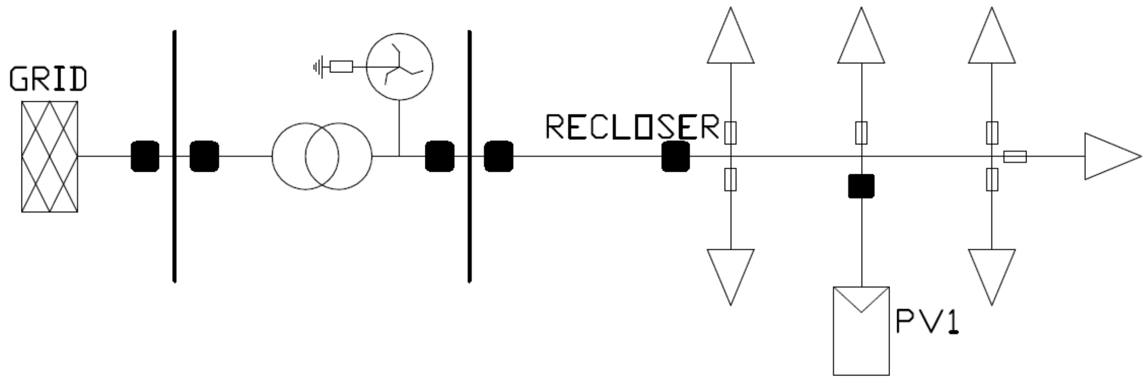

Figure 5.22 Fuse Recloser coordination test network

5.4.1 3-Phase faults

When single phase to earth, or phase to phase faults occur on three core cables, the heat generated by the arc will usually break down the isolation barriers between the three cores, and escalate into a three phase fault. On distribution overhead lines however, three phase faults are not common and only about 5 % of faults are three phase faults [32]. When three phase faults occur, the recloser will trip on phase overcurrent and will not look at individual sequence components. The phase relay coordination curves for this example are shown in Figure 5.23. Two constant values are set at 755 A and at 1347 A, which indicate where the fast recloser tripping curve cross the minimum melting curve and the maximum clearing curve of the fuse respectively. If a fault occurs downstream of any of the fuses, any fault current which the relevant fuse will see higher than 755 A will start melting the fuse before the recloser will be able to clear the fault, and the fuse will degrade. The fuse will blow before the recloser will be able to clear the fault if the fault current through the fuse is higher than 1347 A, and fuse saving will not be possible for any fault current above this threshold. The recloser fast curve follows an IEC type C (extremely inverse) curve up to the recloser relay minimum operating time of 0.03 sec, after which the recloser will trip at the definite minimum time of 0.03 sec. Changes in the fault current through the recloser beyond this point, will not influence the tripping time of the recloser.

The fault can be located between the PV generator and the recloser, or it can be located downstream of the PV generator. Only positive sequence current will flow during three phase faults, and the fault sequence networks for both scenarios are shown in Figure 5.24 and Figure *5.25*. In Figure 5.24, Zl1 represents the line impedance between the substation and the fault, and Zl2 represents the line impedance between the fault and the PV generator. Loss of coordination will occur when the current through the fuse is significantly higher than the current flowing through the recloser, causing the fuse to blow faster than what the recloser will trip.

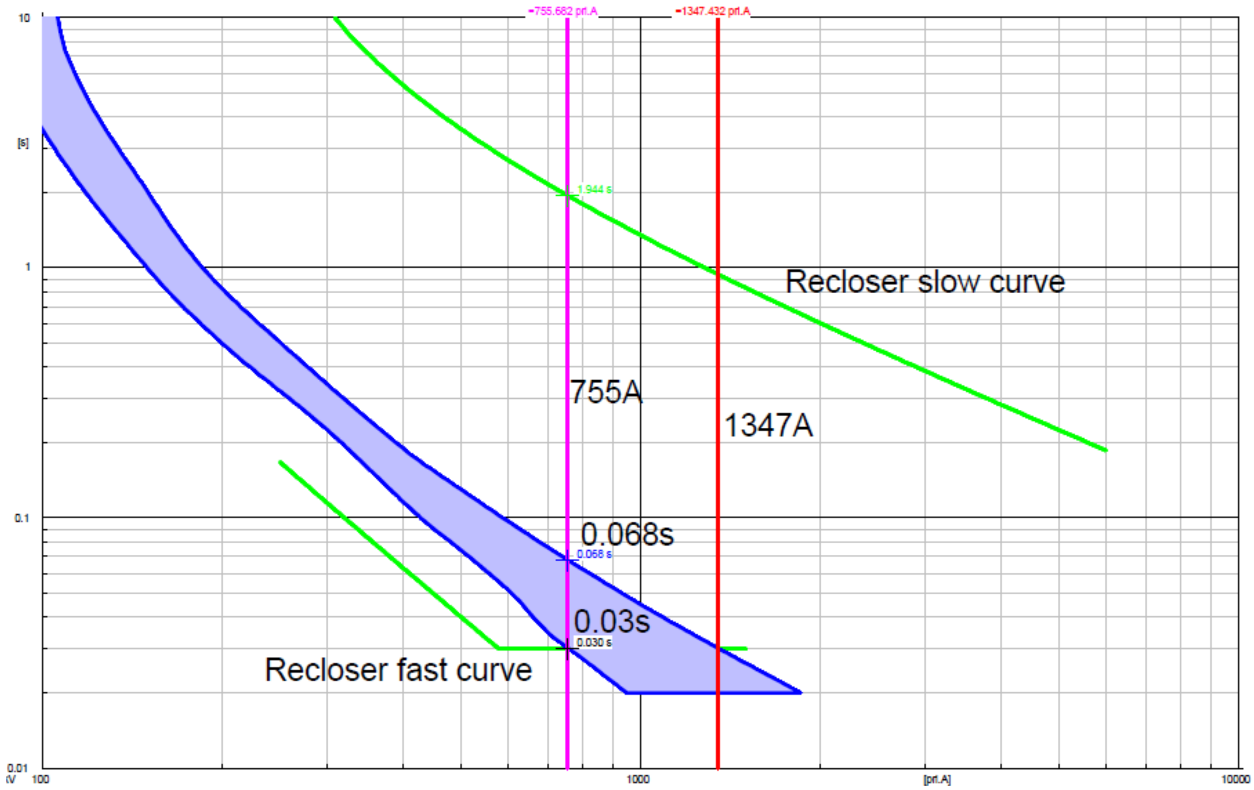

Figure 5.23 Fuse Recloser phase current coordination curves

The fuse will blow faster than the recloser will trip, if the current through the recloser is minimized and the current through the fuse maximized. In both instances of the fault location, this will occur when the source impedance and line-1 impedance is at its maximum, and at the same time Zpv1 and line-2 impedance is at its minimum. Based on these conditions, the impedances were varied as indicated in Table 5.3, along with the fault current and tripping time for all of the applicable protection devices. When the fault is located downstream of the PV generator, the line impedance between the PV generator and the fault will add to the source impedance and line-1 impedance, further reducing the current supplied from the grid and thus adding additional delay time to the recloser. For this reason, the fault was simulated downstream of the PV generator.

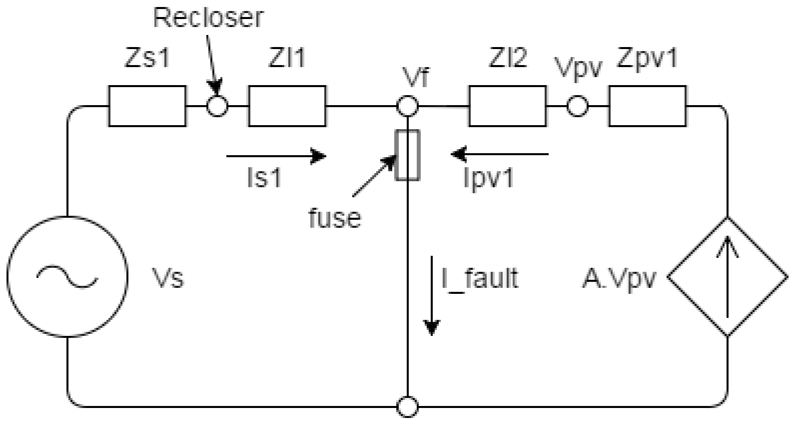

Figure 5.24 Three phase fault between generator and substation

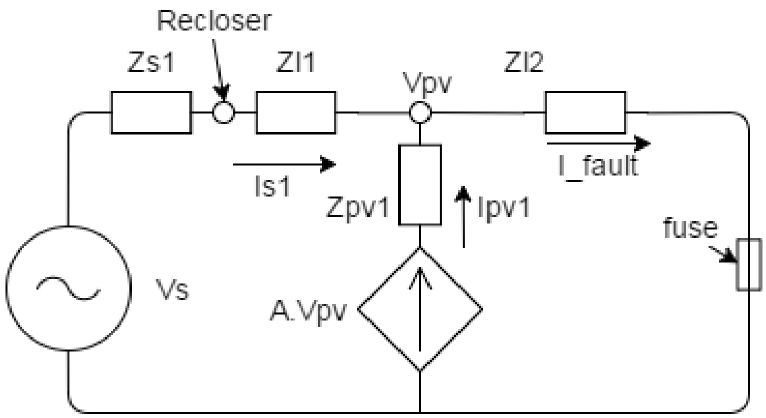

Figure 5.25 Three phase fault downstream of PV generator

The results in Table 5.3 indicate that fuse recloser coordination is lost for all levels of PV penetration, when the total line length from the substation to the fault is 25 km or less. The results also indicate that as expected from the theoretical analysis, decreasing the line length between the grid and the PV source, or increasing the grid fault level will increase the current through the recloser during a fault. The increased current however, did not cause the recloser to trip faster, due to the minimum tripping time constraint of the recloser relay. According to Figure 5.23, the fuse will start melting if the fault current is greater than 755 A. This threshold was exceeded in all instances of this simulation, even when the PV penetration levels were set to zero. Fuse saving will not be possible for three phase faults when the distance of the fault from the substation is not substantial, irrespective of the level of PV penetration. When the lines are longer enough for the fault current to be small enough to obtain coordination, the resulting voltage drop in the line during normal operation becomes problematic, due to the added impedance. It should however be noted, that this only applies to fuses used on spurs, and will not apply to fuses used in line with the recloser. In such cases, the fuse sizes will be bigger and coordination will more likely be achievable.

Table 5.3 Fuse Recloser coordination test results for a three phase fault

Line 1 distance (km)	Line 2 distance (km)	PV penetration level	Grid fault current (kA)	Recloser fault current (A)	PV POC voltage (pu)	PV fault current (A)	Fuse fault current (A)	Recloser trip time (s)	Fuse melt time (s)
10	5	100%	2	1518	0.35	205	1628	0.03	0.02
10	5	100%	0.6	1439	0.34	219	1579	0.03	0.02
10	5	200%	2	1483	0.38	412	1747	0.03	0.02
10	5	200%	0.6	1401	0.37	439	1726	0.03	0.02
10	1	100%	2	2052	0.09	229	2165	0.03	0.02
10	1	100%	0.6	1884	0.09	234	2032	0.03	0.02
10	1	200%	2	2046	0.1	455	2301	0.03	0.02
10	1	200%	0.6	1876	0.09	465	2202	0.03	0.02
20	5	100%	2	931	0.22	214	1027	0.03	0.02
20	5	100%	0.6	911	0.22	219	1027	0.03	0.02
20	5	200%	2	915	0.25	432	1152	0.03	0.02
20	5	200%	0.6	893	0.25	441	1172	0.03	0.02
20	1	100%	2	1115	0.05	233	1210	0.03	0.02
20	1	100%	0.6	1084	0.05	234	1202	0.03	0.02
20	1	200%	2	1112	0.06	463	1342	0.03	0.02
20	1	200%	0.6	1080	0.06	465	1355	0.03	0.02
10	1	200%	7.2	2901	0.1	452	2319	0.03	0.02
10	1	0%	2	2059	-----	0	2059	0.03	0.02
10	1	0%	0.6	1895	-----	0	1895	0.03	0.02
5	1	200%	7.2	3595	0.17	449	3889	0.03	0.02
1	1	200%	7.2	7057	0.32	520	7536	0.03	0.02
1	1	0%	7.2	7131	-----	0	7131	0.03	0.02
20	5	0%	0.6	933	-----	0	903	0.03	0.022
20	5	0%	7.2	953	-----	0	923	0.03	0.021

5.4.2 Phase to phase faults

Similar to three phase faults, fault levels for phase to phase faults are often too high to obtain proper coordination between fuses and reclosers. The ability of inverter based DG to only generate positive sequence current forces all of the negative sequence current to be supplied from the grid during phase to phase faults. The sequence networks for a phase to phase fault are connected together as shown in Figure 5.26. Zl11 and Zl12 represent the positive and negative sequence impedance of the line impedance between the PV generator and the substation, while Zl21 and Zl22 represent the line impedance between the PV generator and the fault. The positive sequence current flowing into the fault is increased by the addition of PV generators. If a fault occurs downstream of a fuse in the network shown in Figure 5.22, the increase in positive sequence current is seen by the fuse at the fault, but will not be seen by the recloser relay. The positive and negative sequence current during a phase to phase fault are equal in magnitude, but opposing in direction at the fault location. The increased positive sequence current at the fault, will also result in a proportional increase in the negative sequence current at the fault. This entire negative sequence current will flow from the grid and through the recloser relay, since the inverter based PV generator will not facilitate any negative sequence current. The relay will trip on phase current for a phase to phase fault and will summate the positive and negative sequence currents according to equation (5.2).

The network shown in Figure 5.22 was simulated with a phase to phase fault downstream of the furthest fuse, to test the sequence model shown in Figure 5.26. Similar to the simulation of three phase faults, an increase of the line length between the PV generator and the substation will result in a decrease of both positive sequence and negative sequence grid fault current. It was clear from the case of three phase faults, that for short lines, the impedance in the fault network will not be enough to obtain coordination. Coordination between fuses and reclosers are only possible when the lines are long and fault current low. For this reason, the case of phase to phase faults was simulated with longer lines to obtain coordination at least when 0 % PV is present. The simulation results are shown in Table 5.4.

When the line is at its shortest, and the PV penetration level at its highest, coordination was not possible and the fuse started melting before the recloser was able to clear the fault. If PV penetration levels are at its maximum on a line with low grid fault levels, coordination will be challenging, since the grid fault current and hence the current through the recloser is low. When the lines are short, increasing the grid fault level will not make coordination possible, since the increased grid fault current will increase both recloser and fuse current making coordination challenging. As the lines become longer, the grid fault level has less of an effect and coordination becomes easier, even with high levels of penetration. Similar to three phase faults, coordination between fuses and reclosers for phase to phase faults will only be possible for long lines, irrespective of the level of PV penetration. This is because the fault current will be higher for short lines due to the decreased line impedance. The tripping time of the recloser will be limited by the physical breaker opening time, and will not be able to trip fast enough to prevent damage to the fuse. The fuse melting time will be at it’s minimum due to the high fault current.

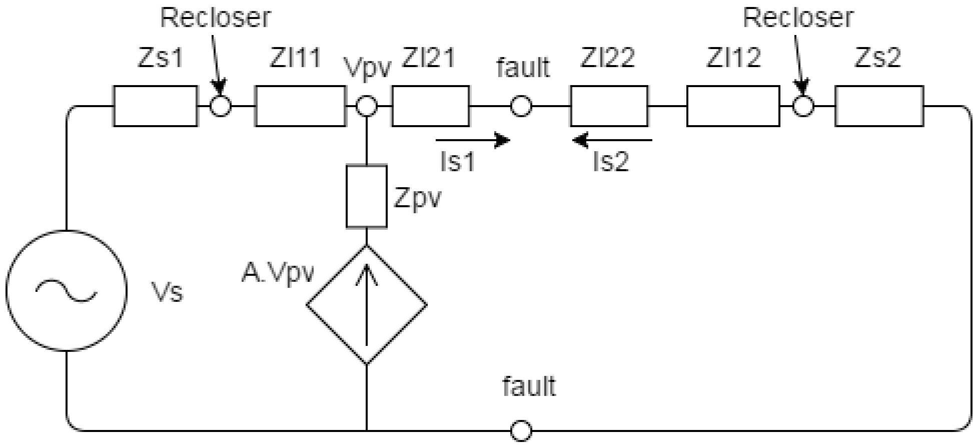

Figure 5.26 Fuse recloser sequence network for a phase to phase fault

Table 5.4 Phase to phase simulation results on fuse recloser coordination

Line 1 dist (km)	Line 2 dist (km)	PV penetration level	Grid fault current (kA)	Recloser fault current phase (A)	Recloser fault current pos (A)	Recloser fault current neg (A)	PV POC voltage (pu)	PV fault current (A)	Fuse fault current (A)	Recloser trip time (s)	Fuse melt time (s)
20	20	100%	2	474	178	329	0.85	166	570	0.045	0.058
20	20	100%	0.6	462	169	329	0.86	170	569	0.047	0.058
20	20	200%	2	474	106	368	0.95	323	638	0.045	0.045
20	20	200%	0.6	454	84	370	0.96	331	641	0.049	0.044
20	10	100%	2	668	290	435	0.75	166	753	0.030	0.03
20	10	100%	0.6	649	277	432	0.76	170	748	0.030	0.031
20	10	200%	2	685	214	488	0.84	330	844	0.030	0.025
20	10	200%	0.6	658	189	488	0.85	337	845	0.030	0.025
30	20	100%	2	401	140	277	0.84	164	480	0.063	0.081
30	20	100%	0.6	393	133	278	0.84	167	481	0.066	0.081
30	20	200%	2	424	106	323	0.98	324	560	0.056	0.06
30	20	200%	0.6	409	89	326	0.99	328	565	0.061	0.059
30	10	100%	2	525	211	344	0.74	167	595	0.037	0.053
30	10	100%	0.6	513	201	343	0.75	169	594	0.038	0.053
30	10	200%	2	562	160	403	0.87	336	697	0.032	0.035
30	10	200%	0.6	543	140	405	0.88	338	702	0.034	0.035
20	10	0%	2	664	383	383	0.66	0	664	0.030	0.04
20	10	0%	0.6	652	377	377	0.66	0	652	0.030	0.042

Table 5.5 Phase to Phase fault simulation results showing the effects of PV penetration level

Line 1 distance (km)	Line 2 distance (km)	PV penetration level	Recloser fault current phase (A)	Recloser fault current pos (A)	Recloser fault current neg (A)	PV POC voltage (pu)	PV fault current (A)	Fuse fault current (A)	Recloser trip time (s)	Fuse melt time (s)
20	10	0%	664	383	383	0.66	0	664	0.030	0.04
20	10	100%	668	290	435	0.75	166	753	0.030	0.03
20	10	200%	685	214	488	0.84	330	844	0.030	0.025

Table 5.5 shows what effect PV penetration level has on the fault current during phase to phase faults. Unlike the simulation of three phase faults, coordination here is possible at 0 % penetration, due to the longer lines introducing more impedance into the fault loop. As expected from the discussion on the sequence network shown in Figure 5.26, the voltage support from the PV generator will increase as PV penetration levels increase. The higher voltage will in turn result in a lower voltage drop between the grid and the PV generator, resulting in a reduction of positive sequence current contributed by the grid, which can be seen in Table 5.5. Table 5.5 also shows that negative sequence current increase, along with the phase current seen by the fuse during a fault when PV penetration levels increases. Similar to the results seen for protection blinding, the increasing negative sequence current will contribute to the phase current seen by the recloser, so that even if the positive sequence current is reduced for higher levels of PV penetration, the phase current still increase slightly as PV penetration levels increase. The large increase in phase current seen by the fuse, compared to the small increase in phase current seen by the recloser, will eventually result in loss of coordination as seen by the yellow highlighted cells in Table 5.5. However, this will also result from the minimum tripping time constraint of the recloser relay when fault levels increase. Even if the recloser was able to see the same fault current as the fuse, at that high fault current, coordination will be lost even if no PV had been present, due to the minimum tripping time constraint of the recloser relay.

5.4.3 Phase to earth faults

The ability of cables and other equipment to withstand earth fault current, are usually less than their capacity to withstand phase to phase or three phase faults, and since people are more likely to be involved during earth faults, current limiters are installed in the zero sequence path to limit earth fault current in distribution systems. 80 % of faults on overhead lines are earth faults caused by lightning, "*veld fires*" or branches growing into the lines [32]. By limiting the fault current, it is unlikely that the fault current will reach high levels where coordination will not be possible, even when lines are very short and have little or no impedance and when high levels of PV penetration is present. The sequence model representation of a single line to earth fault is shown in Figure 5.27. Similar to phase to phase faults, an increased level of PV penetration will result in a reduction of positive sequence current, and an increase in negative sequence current flowing from the grid. Both these parameters will not have any influence on the relay tripping time, since the recloser protection relay will only look at zero sequence current to detect earth faults. However, as PV penetration levels increase, additional positive sequence current will be injected into the fault by the PV generator, despite the decrease in positive sequence current contributed from the grid. For earth faults, the positive, negative and zero sequence currents are equal in size and direction at the fault location. For this to be valid, the additional positive sequence current introduced by the PV generator will result in a proportional increase in negative and zero sequence current flowing in the fuse. This additional negative and zero sequence current can only flow from the grid. Fuses are not able to distinguish between sequence components and will melt purely based on the amount of phase current flowing through it. Solving equation (5.2) for an earth fault in phase a with I1 = I2 = I0, gives equation (5.7), which is the phase current seen by the fuse. The fuse and the relay will see the same amount of current, since the relay will operate on 3 x I0, and coordination should hold. The network shown in Figure 5.22 was simulated with a single phase to earth fault downstream of the furthest fuse from the substation. The fault current was maximized by increasing the grid fault level and reducing line length, since the minimum tripping time constraint will be reached for high fault currents,. The simulation results were tabulated and are shown in Table 5.6.

$$\mathrm{I}_a = 3 \times I_0 \tag{5.7}$$

The results confirm the theoretical model described with reference to Figure 5.27. The fault current resulting from earth faults are limited by the NECR and is evident from the low fault currents recorded in Table 5.6. As PV penetration levels increase, the recloser zero sequence current increases, even though the phase current stays almost constant. The recloser and the fuse measures the same fault current, since the only existing zero sequence path is between the substation and the fault. Even for PV penetration levels as high as 200 %, fuse recloser coordination will not be lost during earth faults. Single phase to earth faults account for most of the faults on overhead lines, and protection with conventional overcurrent and earth fault relays will in most cases, remain able to protect the power system.

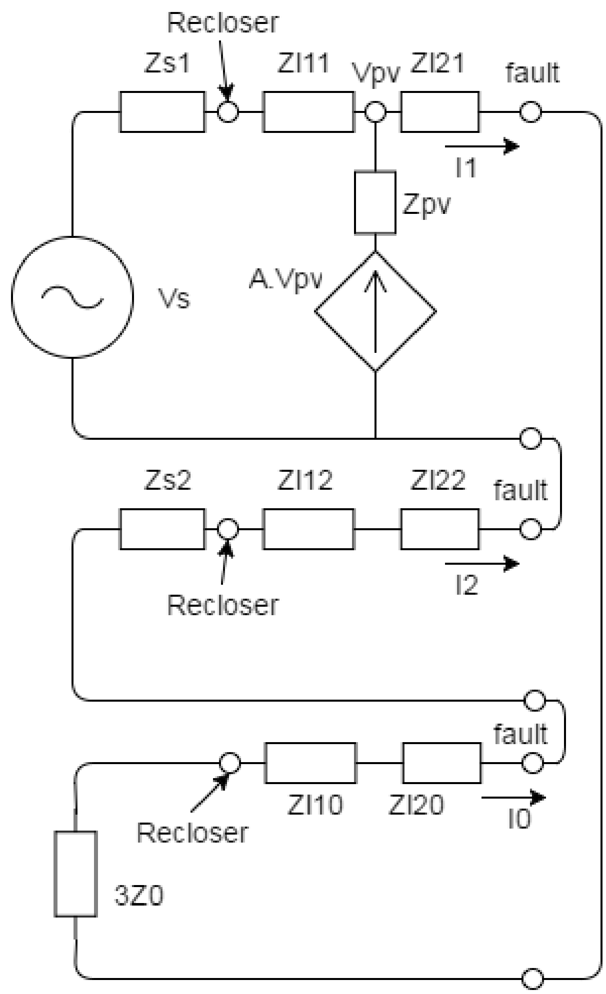

Figure 5.27 Sequence network for earth fault in fuse recloser coordination test

Table 5.6 Earth fault simulation results on fuse recloser coordination

Line 1 distance (km)	Line 2 distance (km)	PV penetration level	Grid fault current (kA)	Recloser fault current phase (A)	Recloser fault current 3I0 (A)	PV fault current (A)	Fuse fault current (A)	Recloser trip time (s)	Fuse melt time (s)
10	1	0%	7.2	355	355	0	355	0.030	0.155
10	1	100%	7.2	235	382	175	382	0.030	0.130
10	1	200%	7.2	331	406	327	406	0.030	0.114
10	1	0%	0.6	349	349	0	349	0.030	0.161
10	1	100%	0.6	229	376	178	376	0.030	0.135
10	1	200%	0.6	337	401	333	401	0.030	0.117

CHAPTER 6 PROTECTION SOLUTIONS

6.1 INTRODUCTION

Expensive solutions, such as communication based adaptive overcurrent protection or differential protection might be economically viable in smart grids or new developments, but in existing distributions systems, such advanced solutions which differ vastly from conventional protection, could result in a negative outcome of cost benefit studies and less expensive solutions are necessary. In this chapter, the results obtained from Chapter 5 are discussed along with possible solutions to either eliminate the problems or to improve protection reliability, under high penetration levels of PV based DG. These solutions are not aimed at providing the best technical solution, but is rather aimed at providing practical low cost practical solutions.

6.2 SYMPATHETIC TRIPPING

Sympathetic tripping does not result in a loss of protection or the inability of conventional protection to protect equipment from damage occurring due to system faults. Sympathetic tripping will not prevent or delay the operation of relays on a faulted line, but will cause loss of supply to healthy sections and will thus only result in reduced security of supply. No threat exists from the occurrence of sympathetic tripping, from a pure protection standpoint.

6.2.1 Undervoltage sympathetic tripping

From the results in section 5.2.1, it is evident that the undervoltage condition resulting from system faults are more severe when grid fault levels are low and when the fault impedance is low. Low fault impedance will be seen when faults occur close to the substation. The fault impedance is an unknown variable and cannot be compensated for. The grid fault level is a known variable and can be compensated for by changing the undervoltage disconnection threshold, or the disconnection time based on the grid fault levels.

Figure 5.2 indicates that undervoltage is experienced on adjacent feeders when faults occur, even when no DG is present. The duration of the undervoltage condition is determined by the tripping time delay of the faulted feeder. This undervoltage condition would occur even on conventional power systems, and it can be argued that the undervoltage condition should also be allowed in the presence of DG for the same period. By introducing alternative undervoltage disconnection thresholds and disconnection times, undervoltage sympathetic tripping can be avoided. To avoid problems with voltage regulation which cause undervoltage during nonfaulted conditions, undervoltage disconnection below a threshold of 0.85 pu is still suggested with a disconnection time of 2 sec, in accordance with [46]. The suggested disconnection curve presented in Figure 6.1 is proposed for undervoltage conditions below 0.5 pu, where t_min is 0.1 sec higher than the minimum tripping time of any adjacent feeder for the given fault level. If an adjacent feeder will trip in a minimum time of 1 sec for the given 11 kV fault level, then t_min should be 1.1 sec. This curve is chosen so that for any undervoltage condition caused by a fault, the DG will always disconnect slower than what the faulted feeder will trip on overcurrent. The undervoltage condition arising from system faults in the presence of DG, will not be more severe and will only be marginally longer than that undervoltage condition would have lasted without any DG present.

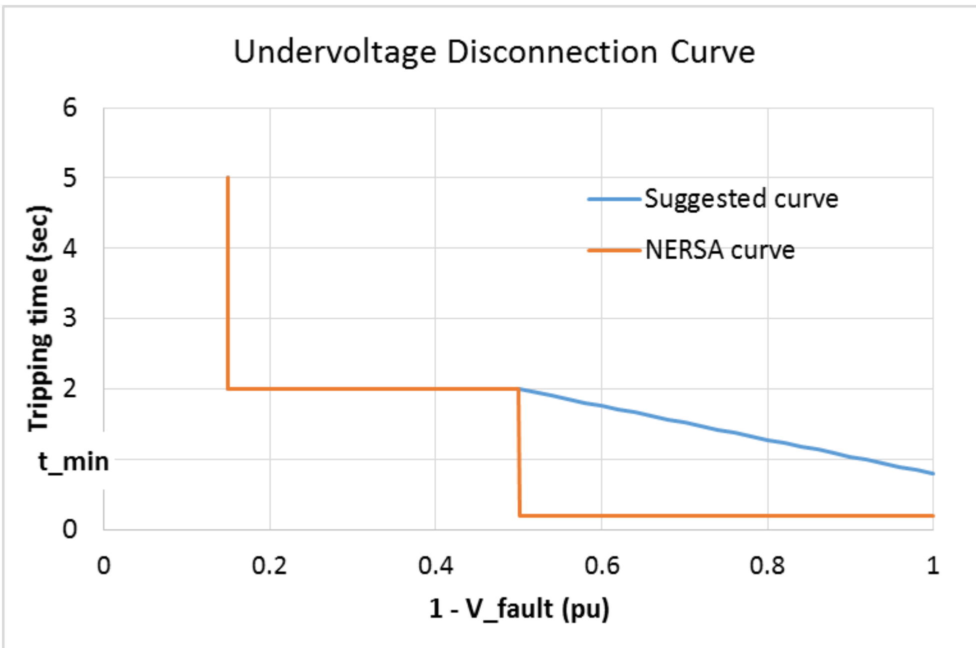

Figure 6.1 Proposed undervoltage disconnection curve [46]

The network shown in Figure 5.1 was simulated again with the new suggested undervoltage tripping curve. Several faults were simulated on feeder B13 at different distances from the substation. The voltage at the DG POC was recorded for every fault along with the operating time of feeder B13.. Tripping times for the DG and feeder B13 are graphically shown on the curves in Figure 6.2 and Figure 6.3. It is clear that the faulted feeder will trip before the DG is disconnected on undervoltage. These measures can be implemented to prevent undervoltage sympathetic tripping, even though it is not a loss of protection risk.

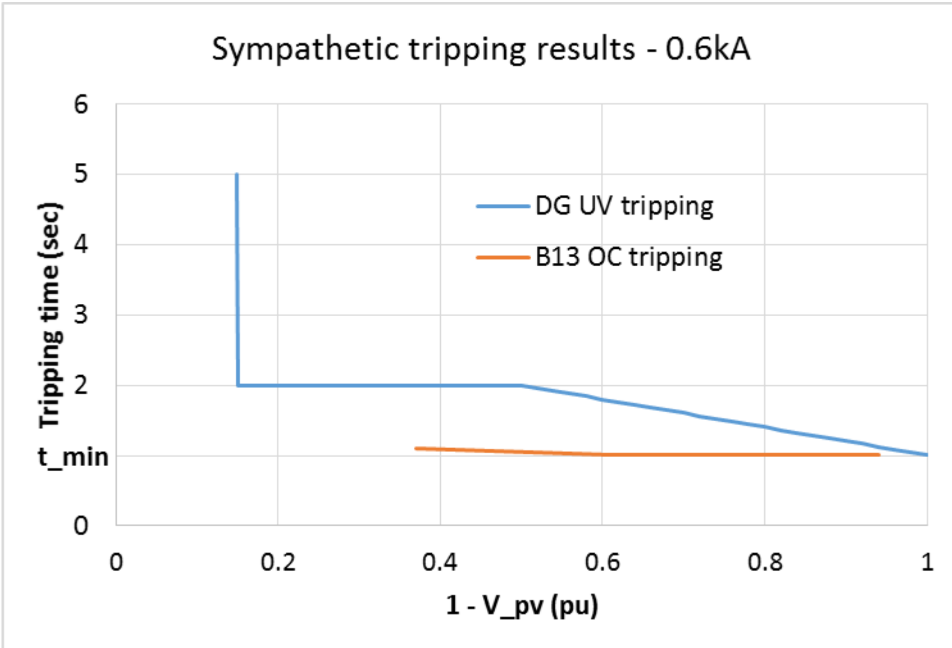

Figure 6.2 Sympathetic tripping results with improved undervoltage curve for 0.6 kA fault level

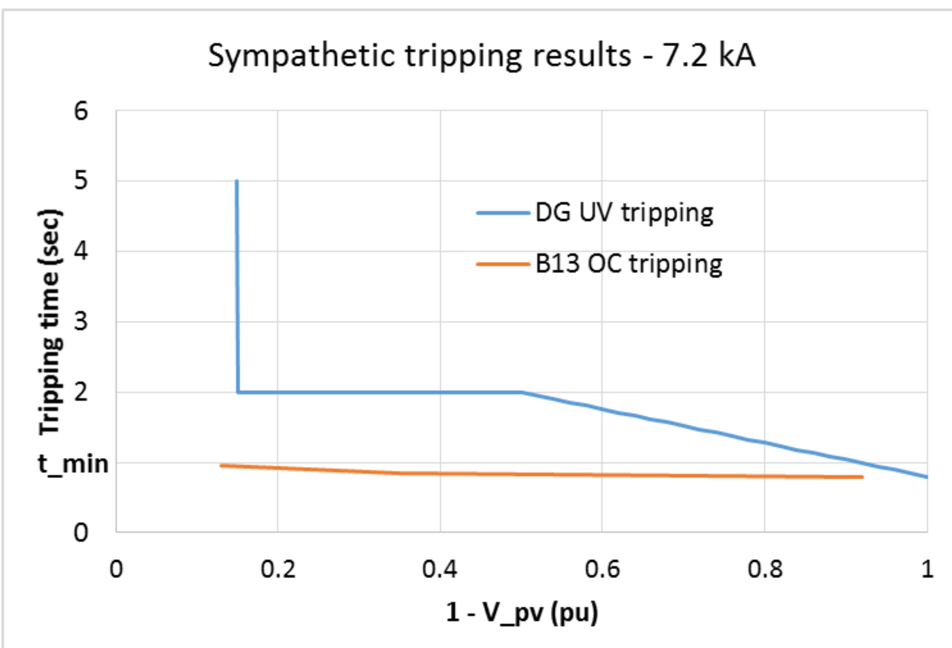

Figure 6.3 Sympathetic tripping results with improved undervoltage curve for 7.2 kA fault level

6.2.2 Reverse overcurrent sympathetic tripping

It is uncommon to find long cables in distribution networks that introduce significant impedance into the system. Cable lengths are kept at a minimum to avoid losses. On overhead lines in rural areas and farming communities where lines are longer, auto-reclosers are used with a limited distance between reclosers. This enables better sensitivity to faults and prevents under reach of a single relay. In section 5.2.2, sympathetic tripping due to reverse overcurrent was only observed when faults occurred at the end of long lines. Such long lines would typically have more than just the one overcurrent protection relay at the substation, allowing more sensitivity to faults at the end of long lines. Even though sympathetic tripping due to reverse overcurrent is not expected to be a problem, there are measures which can be taken to minimize its effects in a distribution power system, if not completely eliminate its occurrence.

The protection relays, on a feeder with several loads connected to it and more than one breaker in series, are coordinated with time grading as discussed in section 2.3. In Figure 5.1, the overcurrent relay at breaker B21 would thus not be set to trip at the maximum cable current carrying capacity. It would be set more sensitive, in order to coordinate with feeder B2. If directional overcurrent protection is available in the relay, reverse overcurrent settings can be set with the same settings as the relay at the substation (feeder B2) would have in the forward direction. In the event of a fault on feeder B13, the reverse settings of breaker B21 would not be as sensitive, and would allow Feeder B13 to clear the fault in time. The network in Figure 5.1 was simulated again, with the reverse overcurrent settings on breaker B21 equal to the forward overcurrent settings of feeder B2. The results for the faults that caused sympathetic tripping in section 5.2.2, are presented in Table 6.1. The cases where faults on feeder B13 occurred at the end of a long cable caused reverse overcurrent sympathetic tripping. This is eliminated by the directional method suggested above.

It should be noted that the simulations were performed with all of the loads on both feeder B2 and feeder B13 disconnected, indicating unloaded lines. This is not practical, especially when the PV penetration levels are increased to 200 %. Even if no faults occur, feeder B2 would trip on overload. The parameters such as PV penetration level and minimum line loading were pushed to the maximum to indicate the conditions under which sympathetic tripping would occur. These parameters are however only experimental, but the simulations using improved measures indicate that sympathetic tripping can be avoided even under these severe circumstances. Sympathetic tripping is not expected to occur in a typical distribution power system, but their occurrence can be further mitigated by using directional overcurrent protection as suggested above.

Table 6.1 Sympathetic overcurrent tripping with directional overcurrent at 200 % PV penetration

Faulted line length (km)	132 kV fault level (kA)	Breaker B21 fault current (A)	Feeder B13 fault current (A)	Breaker B21 trip time (sec)	Feeder B13 trip time (sec)
10	7211	461	2719	3.325	1.242
10	600	448	2227	3.444	1.369
20	7211	433	1514	3.597	1.702
20	600	458	1368	3.351	1.817
30	7211	421	1044	3.734	2.217
30	600	442	978	3.503	2.342
40	7211	415	797	3.808	2.838
40	600	432	759	3.608	2.989

6.3 PROTECTION BLINDING

If the settings on an overcurrent relay are chosen incorrectly, or if the cable being protected is too long, under-reach will occur. Cables in distribution power systems are usually short enough to prevent this from occurring. The reach of the relay is decreased by introducing additional sources downstream of an overcurrent protective relay. Fault studies should be performed to prevent protection blinding from occurring. The fault current through the relay for a fault at the furthest possible location should always exceed the pick-up setting of the relay. Proper power system analysis should be sufficient to determine the level of penetration, which any specific feeder can accommodate. In order to increase penetration levels, additional overcurrent protection will be required along the line to increase sensitivity and prevent under-reach of a single protection relay. Protection blinding was only experienced when the fault impedance was significantly high, and its occurrence can be mitigated by keeping cable lengths at a minimum.

6.3.1 Three phase faults

From the simulations in section 5.3, protection blinding was only seen to occur during three phase faults for extremely long cables. This was due to high fault impedance introduced by long cables and the fact that during three phase faults, only positive sequence current will flow. Both the DG and the grid would provide positive sequence current during a three phase fault. When protection blinding, or under-reach occurs on conventional distribution systems, there are one of two possible solutions to increase protection sensitivity. The zone of protection for the overcurrent relay can be made smaller. This is done by making the protected line shorter. An additional protection device needs to be installed into the line to extend the reach of the overall protection. To ensure that a fault near the end of the cable is detected, additional protection devices further downstream can be set with more sensitive settings.

Alternatively, a thicker cable can be installed. The parameters for different cable sizes are presented in Table 2.3, from where we see a decrease in cable impedance for thicker cables. By installing a thicker cable, the total impedance seen during a fault would decrease, making the faults easier to pick-up. The sequence network as seen during a three phase fault from section 5.3.1 is shown again in Figure 6.4. By installing a larger diameter cable, the impedance Zf would decrease. During a fault, the reduced impedance Zf would lead to a linear decrease in Vf, according to ohm's law. The decrease in Vf would lead to increased current Is1 flowing from the grid, however, since PV generators are current sources, the change in Vf would not lead to proportionally more current flowing from the PV source. For this specific example, the current flowing from the PV source was plotted against the voltage Vf to illustrate this non-linear relationship and is shown in Figure 6.5. If the voltage Vf decreases, the current Ipv will also decrease, as opposed to the increasing grid fault current Is1.

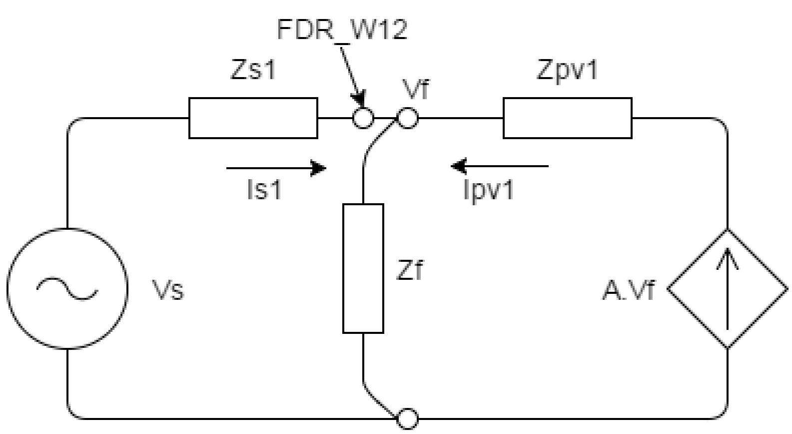

Figure 6.4 Sequence network during a three phase fault

The network shown in Figure 5.6 was simulated with an increased cable capacity between feeder W12 and the fault. The cable was increased from 150 mm^2 to 240 mm^2 XLPE cable. Only the simulations with a 50 km cable were repeated, since this was the only simulation where significant increases in tripping times were observed. The resulting tripping times are shown in Figure 6.6, and presents a significant reduction in relay tripping time. The tripping time for a grid fault level of 600 A reduced from 42 sec to 3.8 sec, while the tripping time for the case of 7.2 kA reduced from 16.5 sec to 3.14 sec. The increased cable diameter reduced the fault impedance and allowed more current to flow from the grid. For longer cables such as this case, bigger cables are often used to reduce the voltage drop and maintain customer voltage levels.

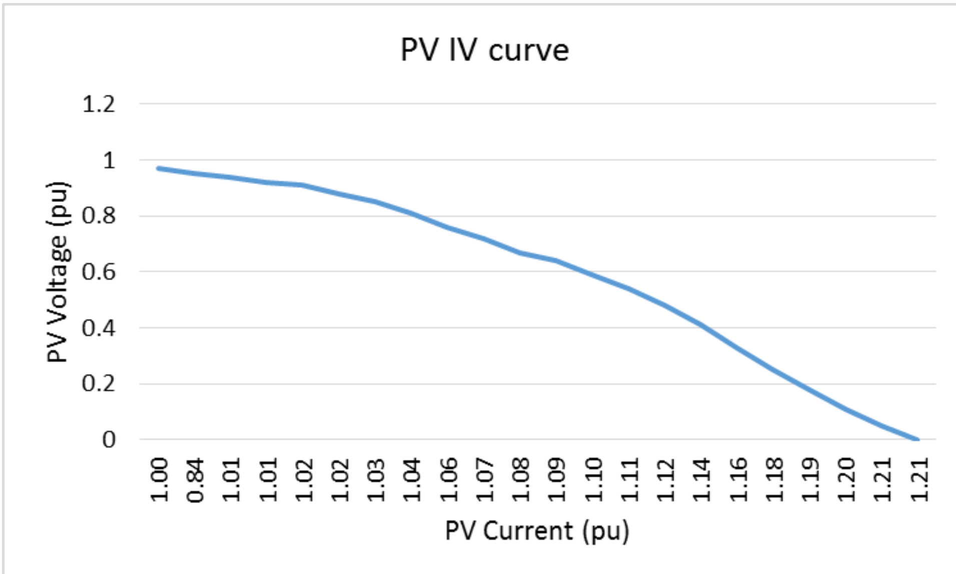

Figure 6.5 PV voltage current curve

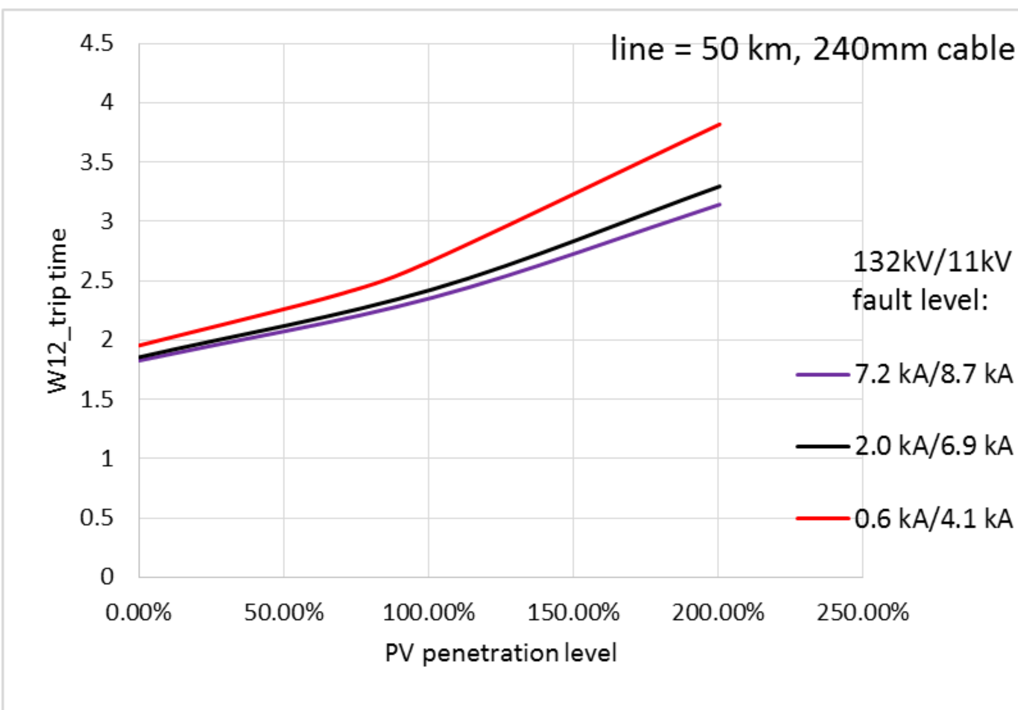

Figure 6.6 Feeder W12 trip times for 50 km, 240 mm cable

6.3.2 Phase to phase faults

In the simulations from section 5.3.2, protection blinding never occurred for phase to phase faults. This was due to the fact that inverter based generators are controlled to deliver only positive sequence current. During a phase to phase fault, positive and negative sequence current will flow. The negative sequence current will be completely supplied by the grid, keeping the phase current seen by the upstream protection relay high enough to pick-up, and operate when a phase to phase fault occurs. There was however a reduction in phase current recorded, which will result in delayed operating times under high levels of penetration. Figure 5.14 and Figure *5.18* from section 5.3.2 showed a constant increase in negative sequence current as the penetration level increased. During a phase to phase fault, the positive and negative sequence current at the fault will be equal in magnitude but 180° apart. In conventional distribution systems, this is the same current which the protection relay would have seen. The increased DG penetration levels result in a decrease in the positive sequence current flowing from the grid, but it does not result in a reduction in negative sequence current. It also results in an increase in positive sequence current flowing into the fault. The same amount of negative sequence current flowing into the fault will also be flowing from the grid through the protection relay upstream of the fault. By using the negative sequence current as a method of detecting phase to phase faults, the delay in tripping times caused by DG can be eliminated.

For a fault between phase b and phase c, no zero sequence current will flow. The fault current in phase b can be described by equation (6.1) and is derived from equation (5.2). For a phase to phase fault, the negative and positive sequence currents will be equal in magnitude, but 180° apart at the fault. Substituting $I_0 = 0$, and $I_1 = -I_2$ into equation (6.1) yields equation (6.2).

$$\mathrm{I}_b = I_0 + I_1 < 120° + I_2 < 240° \tag{6.1}$$

$$\mathrm{I}_b = I_2 < 120° - 180° + I_2 < 240° \tag{6.2}$$

Equation (6.2) can be simplified to:

$$\mathrm{I}_b = 2 \times \sin 60° \, I_2 < -90°$$

$$\mathrm{I}_2 = \frac{I_{phase}}{\tan 60°}$$

The phase current at the fault location can be calculated by using equations (6.1) and (6.2), since the negative sequence current flowing into the fault will also be flowing through the upstream protection relay. If the pick-up setting for the negative sequence curve is made 1/tan60° more sensitive, the negative sequence curve will trip in the same time as the phase curve would have operated had no PV been present. In cases where no PV is present, using the additional negative sequence curve in conjunction with the phase curve would not compromise conventional tripping times. The negative sequence curve will match the phase tripping curve under zero penetration levels.

The network shown in Figure 5.6 was simulated with phase to phase faults. The protection relay at feeder W12 was configured to use a negative sequence tripping curve. A fault with an impedance of 0.08 Ω was simulated. The tripping times using normal phase current, and the times using negative sequence current were recorded and are shown in Figure 6.7. Using negative sequence current is an accurate measurement of the actual fault current. The setting for the curve are chosen to give the same tripping times as would have been expected from phase tripping under 0 % PV penetration.

The simulation was repeated for a fault far away from the substation when the tripping times of conventional protection is most affected. The resulting tripping times using phase current and using negative sequence current are shown in Figure 6.8. Under high fault impedance when the effect of protection blinding are most sever, the solution of using a negative sequence current tripping curve is most effective.

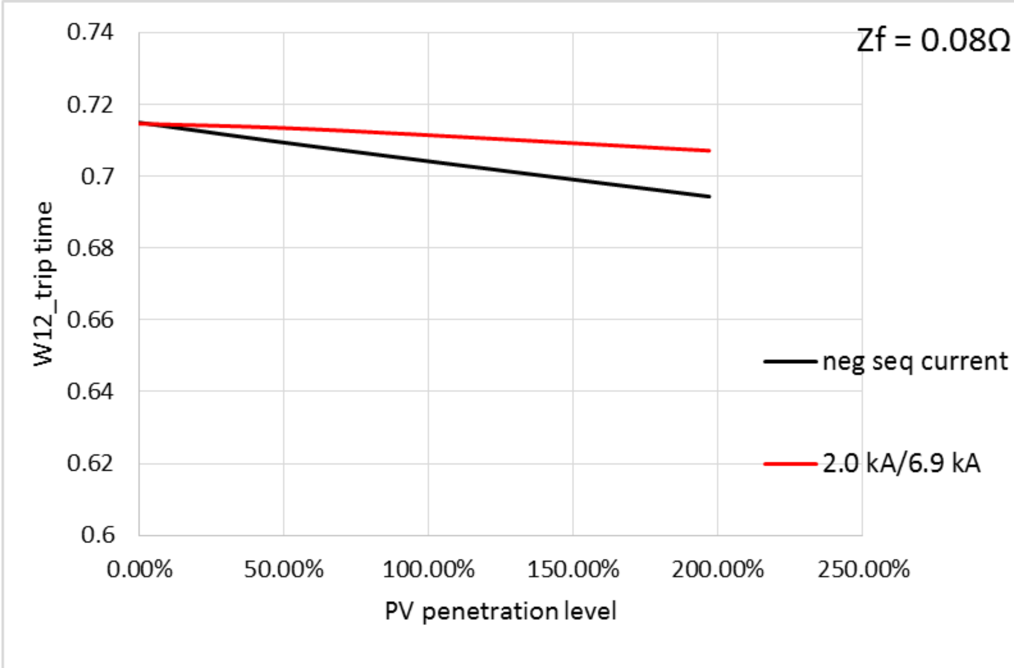

Figure 6.7 Negative sequence tripping times for phase to phase faults, Zf = 0.08 Ω

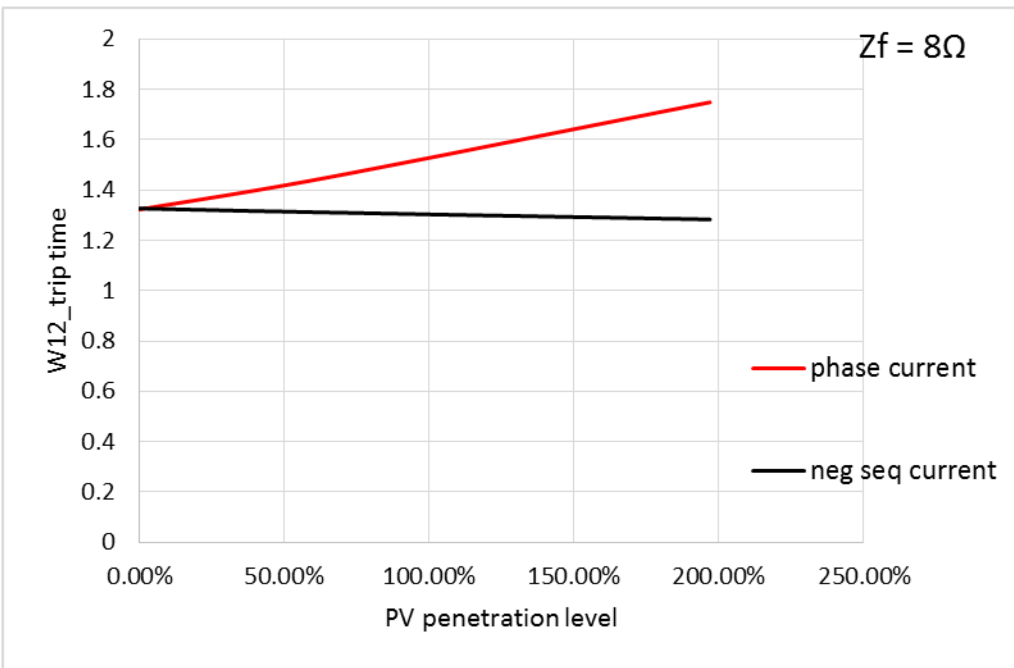

Figure 6.8 Negative sequence tripping times for phase to phase faults, Zf = 8 Ω

6.3.3 Phase to earth faults

Phase to earth faults are protected with earth fault relays making use of a measurement of the zero sequence current flowing into the fault. In order for this type of protection to be efficient, only one ground connection is allowed on distribution systems. The ground connection is situated at the distribution power transformer. Distributed generators and any other equipment or loads on the MV network, are not allowed to be grounded to prevent zero sequence current from splitting up between multiple paths during earth faults. The flow of earth fault current between the substation and the fault in a radial topology is not threatened by the addition of DGs.

From Figure 5.19 b, it can be seen that the amount of positive, negative and zero sequence current flowing into the fault are equal in size and direction. The addition of DGs will add an additional positive sequence source, adding to the positive sequence current flowing into the fault. All three sequence components are equal in size and direction at the fault, and the additional negative and zero sequence current to balance out the increased positive sequence current can only be supplied from the grid. Higher DG penetration levels increase the amount of zero sequence current flowing through the relays between the substation and the fault. This higher current will result in increased tripping times. The addition of DG does not threaten conventional earth fault protection using zero sequence current for fault detection.

6.4 LOSS OF COORDINATION

Faults on overhead lines are often protected with auto-reclosers coordinated with low current fuses. The fuses are situated close to the fault and are used for protection from faults, and also from protecting the MV to LV transformer from overload. The fuses that are being used, do not follow normal inverse curves, but rather resembles extremely inverse curves. This causes fast melting times under high fault currents. To coordinate a recloser, the recloser fast curve needs to be set more sensitive than the fuse. The advantage of having a sensitive curve is that protection blinding is not likely to occur, since even a small fault current will be picked up by the recloser relay. The drawback of this is the minimum tripping time constraint of the recloser. For high fault currents, coordination will always be challenging. There are however some solutions that can be used to prevent or mitigate loss of coordination. These methods are described and discussed below.

6.4.1 Three phase faults

Several three phase faults under different circumstances were simulated on an overhead line in section 5.4.1. For three phase faults on overhead lines, coordination between fuses and recloser are not possible, unless the line is significantly long. The loss of coordination is not caused by increased levels of PV penetration, but is the result of the fast tripping requirements for reclosers to coordinate with low current fuses. Low current fuses are installed not only to protect against fault, but also to protect MV to LV transformers against overload.

If faults occur on the overhead line upstream of any fuse, the recloser will still detect the fault even under high penetration levels. This is possible due to the sensitive tripping curves used for the recloser fast curve to coordinate with low current fuses. The tripping time results illustrated in Table 5.3 clearly indicate that the recloser will be able to trip for permanent faults, and be able to clear any transient faults occurring on overhead lines upstream of any fuse. Only around 5 % of fault occurring on overhead lines are three phase faults [32] and the section of the line before any spurs with fuses are much longer than the section of the line after fuses. This makes the probability of three phase faults downstream of a fuse even less than 5 %. With such a small percentage of faults for which fuse saving will not be possible, it is an unfortunate drawback of conventional overhead line protection that should be accepted. It is important to note that this is not only the case under increasing levels of PV penetration, but that the same drawback exists in conventional distribution systems.

6.4.2 Phase to phase faults

For phase to phase faults on underground cables, it was proposed to use negative sequence overcurrent curves to detect unbalanced faults. The same solution can be proposed here. All of the negative sequence current flowing into the fault through the fuse would also flow through the upstream recloser. Using negative sequence tripping curves eliminates the issue of loss of coordination caused by higher levels of PV penetration. It would not eliminate the problem of loss of coordination caused by excessive overcurrent as seen when lines are short and fault currents are high.

Phase to phase faults were simulated again on the overhead line network shown in Figure 5.26. Negative sequence overcurrent protection was implemented and the tripping times of the recloser recorded. Along with this, conventional phase overcurrent protection was also used and its operating times recorded. The results are shown in Table 6.2, which shows the tripping times of both methods of protection. The tripping times when using negative sequence overcurrent protection are equal to the tripping times of phase overcurrent protection when the penetration level is zero. This can be seen in lines 17 and 18 of Table 6.2. Using negative sequence overcurrent protection would thus not threaten the protection grading in conventional distribution systems with no DG present. When PV penetration levels increase, negative sequence overcurrent protection decreases the tripping time of the upstream recloser proportional to the increase in current seen at the fault location. Using the negative sequence tripping curve, prevents loss of recloser fuse coordination in the test cases depicted by lines 4 and 12. Coordination is lost when conventional phase overcurrent protection was used, but is regained when negative sequence overcurrent protection is implemented. Using negative sequence overcurrent will not help maintain coordination in cases where coordination is lost due to the minimum tripping time constraint of the recloser. This can be seen in lines 7 and 8 where the fuse will start to melt before the minimum tripping time of the recloser. Using negative sequence overcurrent protection will not improve conventional fuse recloser coordination, but is will prevent loss of coordination caused by the addition of DGs into the network.

Table 6.2 Phase to phase tripping results using negative sequence overcurrent protection

	Line 1 dist (km)	**Line 2 dist (km)**	**PV pen level**	**Grid fault level (kA)**	**Recl fault current phase (A)**	**Recl fault current pos (A)**	**Recl fault current neg (A)**	**Fuse fault current (A)**	**Recl trip time phase (s)**	**Recl trip time neg seq (s)**	**Fuse melt time (s)**
1.	20	20	100%	2	474	178	329	570	0.045	0.031	0.058
2.	20	20	100%	0.6	462	169	329	569	0.047	0.031	0.058
3.	20	20	200%	2	474	106	368	638	0.045	0.030	0.045
4.	20	20	200%	0.6	454	84	370	641	0.049	0.030	0.044
5.	20	10	100%	2	668	290	435	753	0.030	0.030	0.03
6.	20	10	100%	0.6	649	277	432	748	0.030	0.030	0.031
7.	20	10	200%	2	685	214	488	844	0.030	0.030	0.025
8.	20	10	200%	0.6	658	189	488	845	0.030	0.030	0.025
9.	30	20	100%	2	401	140	277	480	0.063	0.044	0.081
10.	30	20	100%	0.6	393	133	278	481	0.066	0.044	0.081
11.	30	20	200%	2	424	106	323	560	0.056	0.033	0.06
12.	30	20	200%	0.6	409	89	326	565	0.061	0.032	0.059
13.	30	10	100%	2	525	211	344	595	0.037	0.030	0.053
14.	30	10	100%	0.6	513	201	343	594	0.038	0.030	0.053
15.	30	10	200%	2	562	160	403	697	0.032	0.030	0.035
16.	30	10	200%	0.6	543	140	405	702	0.034	0.030	0.035
17.	20	10	0%	2	664	383	383	664	0.030	0.030	0.04
18.	20	10	0%	0.6	652	377	377	652	0.030	0.030	0.042

6.4.3 Phase to earth faults

The positive, negative and zero sequence currents are equal in size and direction during phase to earth faults. When a PV generator is introduced downstream of a recloser and faults occur downstream of the recloser, both the grid and the PV generator will supply positive sequence current to the fault. Since the positive, negative and zero sequence currents are equal in size and direction at the fault, the increased positive sequence current supplied by the PV source will have to be balanced out by and equal increase in negative and zero sequence current. This increase in zero sequence current, can only be supplied form the substation is this is where the only other earth connection exists through the NECR.

The phase current flowing at the substation can be equated in one of two possible ways. Solving equation (5.2) for a phase to earth fault in phase a will give:

$$\mathrm{I}_a = I_0 + I_1 + I_2 \tag{6.3}$$

With the positive, negative and zero sequence current being equal for a phase to earth fault, equation (6.3) can also be expressed as shown in equation (6.4).

$$\mathrm{I}_a = 3 \times I_0 \tag{6.4}$$

With the presence of an additional positive sequence source downstream of the recloser relay, the three sequence currents will no longer be equal upstream of the DG at the location of the recloser relay. The sequence currents downstream of the DG will still be equal, so the additional zero sequence current to balance the positive sequence current supplied by the DG will be supplied from the grid through the recloser relay. This means that equation (6.4) (calculated upstream or downstream of the DG) will still equal equation (6.3) downstream of the DG at the fuse or fault location. By using equation (6.4) in the recloser relay to calculate fault current, the actual phase current at the fuse or fault location (as described by equation (6.3) can be calculated. This would enable fuse recloser coordination under any level of PV penetration, when phase to earth faults occur.

CHAPTER 7 CONCLUSION

7.1 OVERVIEW

The continued growth of PV based DG will only be possible, if unlimited access to the utility grid is made available. Access can only be expected if the risks and challenges related to PV based DG is resolved and viable solutions provided. The addition of PV based DG into a conventional distribution power system causes three main problems related to power system protection:

- Protection blinding caused by the additional current injected by DGs installed downstream of existing protection devices.
- Bi-directional current flow and undervoltage conditions, resulting from faults on adjacent feeders, can cause sympathetic tripping.
- Coordination between reclosers and fuses can be lost when DGs are installed between these devices.

The risks posed by DG to conventional overcurrent protection was addressed in this dissertation. A conventional distribution power system was subjected to increasing levels of PV based DG. The power system was modelled with sequence component networks, to understand the system conditions and parameters under which loss of protection might occur. After modeling, the power systems were simulated to verify the models, and to establish whether loss of protection would occur in the presence of PV based DG. Statements that conventional overcurrent will become completely unable to protect power systems in the presence of PV based DG, cannot be justified unless sufficient simulations are performed to verify this.

In most cases, it was found that the PV based DGs did not supply enough fault current to present significant changes in conventional protection, since PV sources are current sources, limited by the short circuit current capabilities of the PV panels. The protection challenges listed by the general scientific community, are often based on single line diagrams and balanced system faults. By evaluating the challenges with reference to sequence component models, many of the challenges present results different from that expected from general protection discussions.

The distribution network used for simulation purposes in this example is a network from a local municipality in South Africa. It is however desirable to obtain generalized results which can be applied to any network, and should not be specific only to this example. To establish this, it is important to first establish the factors which differentiate this network for any others. For a given sequence model, the results will be similar and therefor, the results for symmetrical faults found in the simulations will be similar on any distribution network, and is in no way limited to this specific configuration. The results on other networks will be influenced by network parameters such as conductor lengths, fault levels, and penetration levels in the same way as these parameters influenced the results in this dissertation. The sequence model for phase to phase faults will only differ if the DG's facilitate unbalanced current, and is independent of the network configuration (such as transformer vector group, transformer earthing etc.).

The sequence model for phase to ground faults is however highly dependent on the network earthing configuration, and will only be applicable in networks with similar earthing configurations. On un-earthed networks, the only zero sequence current that can flow is the current flowing through the stray capacitance of the cables. The predominant zero sequence current which allows conventional substation circuit breakers to detect earth faults will no longer be present, and no differentiating factors will exist between conventional substation protection devices and the protection devices used at DG's. Earth faults are not considered crucial on un-earthed networks. The inability to detect earth faults will be the same with, or without any DG connected to the network. Additional studies will have to be performed on solidly earthed networks, but it is expected that the results will be very similar to those seen in phase to phase faults (assuming that only one earth path is created on the network at the substation). The current distribution between the DG and the grid will be similar in terms of sequence components because the DG will still not facilitate any unbalanced current, irrespective of the network earthing configuration.

7.2 PROTECTION RISKS CLARIFIED

7.2.1 Undervoltage sympathetic tripping

Undervoltage sympathetic tripping is a valid risk to power system stability and reliability in PV based DG power systems. Many of the current grid codes require some form of low voltage ride through (LVRT) capability when faults occur. The duration that the DG is required to ride through the fault depends on the severity and proximity of the fault, which will influence the voltage at the POC terminals of the DG. In South-Africa, the requirement is to disconnect in a maximum of 2 sec when the voltage drops below 0.85 pu, and in 200 ms when the voltage drops below 0.5 pu. For any faults on the distribution network, the voltage of the entire network will experience a voltage dip, due to the short cables and small geographic nature of distribution networks. In all the simulated cases (using the undervoltage disconnecting requirements from [46]) undervoltage sympathetic tripping was experienced on adjacent feeders.

Undervoltage sympathetic tripping can be overcome by changing the LVRT specifications. By allowing DGs to stay connected to the grid marginally longer than the fault duration, DGs will ride through the faults and allow conventional overcurrent protection devices to clear any faults on the network.

7.2.2 Loss of protection – balanced faults

Protection blinding was not found to be a problem during three phase faults, even when cable lengths are made extremely long and grid fault levels very low. The high fault current seen during three phase faults ensures that overcurrent relays always pick-up the faults.

Though an advantage in cable networks, the high fault current resulted in loss of coordination between fuses and reclosers on overhead lines. The high fault current cause fuses to clear faster than the minimum operating time of recloser relays and breakers. This is the case even in conventional distribution systems when no PV is present. The addition of PV based DG did not present significant changes to coordination challenges between reclosers and fuses, due to the low fault current contributions form PV based DGs.

7.2.3 Loss of protection – unbalanced faults

Unbalanced faults present results differing from those expected when sequence component models are not taken into account. PV based sources are integrated into the network using inverters, that are able to actively control the unbalanced current supplied by the inverter, allowing only positive sequence current to flow, irrespective of voltage unbalances occurring at the POC terminals. Negative and zero sequence current is present during asymmetrical faults, and since the inverter will not supply or facilitate the flow of negative or zero sequence current, it is supplied from the grid.

The ratio between the different sequence components are known for different types of faults. Using zero sequence overcurrent protection for earth faults eliminates the occurrence of protection blinding and loss of coordination between fuses and reclosers, since the zero sequence current flowing through the upstream breakers is not compromised by the addition of DGs. Zero sequence current remains an effect method of detecting earth faults in distribution power systems, even under high penetration levels of DG.

The same argument is valid for using negative sequence overcurrent protection. During unbalanced faults, all of the negative sequence current flowing into the fault will flow from the grid and through any upstream breaker seen from the fault location. Since the ratio between the positive and negative sequence current at the fault location is known, it is possible to set the negative sequence overcurrent curve to trip in the same time as a conventional phase overcurrent curve would have if no DG was present. Using this method also takes into account the increase in positive sequence current flowing into the fault from the PV source which the upstream relay cannot directly measure.

7.3 SUGGESTIONS FOR FUTURE WORK

The research presented in this dissertation can be expanded by performing tests on different overcurrent relays and measuring the effectiveness of the solutions in an actual distribution power system. Suggestions for future work are listed below.

- On distribution feeders, the phase current seen by the overcurrent protection relay during a fault will include the fault current and the load current. The loads on distribution systems are single phase loads more often than three phase loads. Power system planners and operators attempt to place equal loading on all three phases, but some level of unbalance will always be present. Using negative sequence overcurrent detection will take the unbalanced phase current into account, but will not include load current when identifying faults. Tests should be conducted to compare the tripping times between phase overcurrent relays and negative sequence overcurrent relays when no DG is present.
- The revised undervoltage protection can be implemented on DGs in an actual distribution power system to confirm correct operation and measure the effectiveness of the proposed solution.
- When islanding is allowed on overhead lines with auto-reclosers, the voltage between the grid and the line could drift away from each other during the off stage of the recloser. When reclosing, the voltage angle difference could damage the breaker when overcurrent occurs due to the voltage difference. The dead time of the recloser is typically chosen between 1 – 3 seconds, and it is possible that the line voltage will not drift significantly during this time. Tests should be conducted on an overhead line with DG to establish the severity of this occurrence.

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