University of Southern Queensland
Faculty of Engineering and Surveying

The Effects of Small Distributed Generation on the Electrical Distribution Network

A dissertation submitted by

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ABSTRACT

The traditional electrical supply network relies on large remote power generating stations feeding energy radially over long transmission lines, through distribution networks to the electrical energy customer. This network has been optimised for the radial flow of power from the large power stations to the customer.

There has been increasing political and social pressures to move towards renewable power sources to generate electrical energy. A substantial portion of the renewable generation is being installed within the distribution networks. The smallest of the distributed generation (DG) systems are installed at residential and commercial customer's premises. In Queensland these systems can be up to 10 kW per phase and can export energy back onto the electrical grid.

The addition of large numbers of Small DG Systems onto a distribution network can see the power flowing back into the upstream network. This research project examines the effect that high numbers of these Small DG Systems will have on the protection systems and quality of supply (QoS) of distribution networks.

This research project sought to examine the effects of high penetration of Small DG Systems on two representative distribution feeders. The feeders chosen were a high quality residential feeder called Ross Plains number 4 (ROPL-04) and a long rural single wire earth return (SWER) known at Karara. These two feeders represented the extremes of the possible distribution feeder types. They were chosen so that an understanding of the extent of issues surrounding high penetration of Small DG Systems on distribution networks could be developed.

The power system modelling software PSS Sincal was used to develop models of the two distribution feeders and the Small DG Systems. The models were tested with a number of credible Small DG Systems penetration scenarios in order to see if and at what level of penetration the QoS became unacceptable. This was achieved by modelling the networks with realistic customer load and solar insolation values to see if the feeder low voltage (LV) exceeded prescribed limits. The QoS became unacceptable when eth prescribed limits had been exceeded. Testing was also was conducted using credible changes in insolation due to cloud movement in order to test for unacceptable LV values. Further testing was carried out using reactive compensation to resolve excessive voltage problems.

The protection systems were tested by comparing the protection device settings and ratings with fault current values obtained from the network models when the Small DG System penetrations were high.

It was found that the ROPL-04 feeder had substantial resilience to high levels of Small DG System penetrations for both QoS and protection performance. The Karara SWER network was much less resilient and showed excessive voltage problems at low levels of Small DG System penetrations. The protection systems on the Karara SWER were not seriously compromised by high levels of Small DG System penetration.

It is possible that most grid-connect inverters can be enabled to generate reactive power as well as active power generation The use of reactive compensation can correct QoS problems created by the high penetration of Small DG Systems. This compensation can be either large stand alone units or come from the inverter themselves.

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Limitations of Use

CERTIFICATION

I certify that the ideas, designs and experimental work, results, analyses and conclusions set out in this dissertation are entirely my own effort, except where otherwise indicated and acknowledged.

I further certify that the work is original and not been previously submitted for assessment in any other course or institution, except where specifically stated.

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Signature

Date

ACKNOLEDGEMENTS

This research was carried out under the supervision of Dr Tony Ahfock who showed great patients in guiding me to the conclusion of this research project.

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NOMENCLATURE

Term	**Description**	**Unit**
V	Voltage	V
A	Ampere	A
W	Watt	W
P	Power	W
S	Apparent Power	VA
Q	Reactive Power	VAr
pf	Power Factor	
kW	kilo watt	kW

GLOSSARY OF ABREVIATIONS AND TERM

Abbreviation	Description
RMS	Root mean square.
d.c.	Direct Current, containing less than 10% RMS ripple (AS 3000:2006)
a.c.	Alternating Current. In this document shall be taken to mean at the frequency of 50Hz (AS 3000:2006)
LV	Low Voltage, defined in the AS3000 as being between 50 and 1000V ac (AS 3000:2006). In the context of this document shall be taken to mean the Queensland distribution low voltage of 415V (three phase a.c.)
HV	High Voltage, defined in the AS3000 as exceeding 1000V ac. In the context of this document shall be taken to mean the Queensland distribution high voltage of 6.6, 11 or 22kV (three phase a.c.)
DG	Distributed Generation, generation distributed through out the lower voltage electrical supply network.
Small DG	Distributed Generation below 10kW single phase and 30kW three phase.
PV	Photo Voltaic, technology using cells of material such as silicon that converts solar energy into electrical energy and in this document taken to mean a panel of cells.
Small DG System	Single phase Distributed Generation system being supplied by 2kW of PV array
OC	Over Current, protection method that operates as a result of higher than expected current.
EF	Earth Fault, protection method that operates as a result of higher than expected current flowing in the earth path.
SEF	Sensitive Earth Fault, protection method that operates when a higher than expected current is flowing in the earth path (although lower than that for EF).
IDMT	Inverse Definite Minimum Time, protection system operating parameter that see faster operation at high currents and slower at low currents.
SI	Standard Inverse – One of the common IDMT curves
VI	Very Inverse – Another of the common IDMT curves

Abbreviation	Description
EI	Extremely Inverse – Another of the common IDMT curves
Grid Supply	Supply of electrical energy taken from the interconnected electrical supply network or the grid.
QoS	Quality of Supply, referring to the quality of electrical supply in term of voltage, stability and harmonics
SWER	Single Wire Earth Return, a long low density rural network built to economically supply a few widely spaced customers
OLTC	On Load Tap Changer – device used to change winding ratio of a transformer automatically in order to maintain the output voltage.
Reclosing	The closing of a circuit breaker after recently tripping for a fault. Done so because most faults are transient and supply can be restored without further tripping.
Auto-Reclosing	Automatic closing of a circuit breaker after recent tripping for a fault.
Islanding	Distributed Generation system continuing to operate after being isolated from the rest of the electrical supply network or the grid.
Anti-Islanding	A process where a generator connected to a network ceases to operate soon after the grid supply is interrupted to the network.
CT	Current Transformer – Device for reducing the high voltage line currents down to manageable levels for use in control and protection devices.
AEMC	The Australian Energy Market Commission – Independent Authority which controls and regulates the electrical and gas energy markets in Australia
p.u.	Per Unit – refers to the capacity or rating of electrical plant where a value of 1 is 100% of these values.

CHAPTER 1 - INTRODUCTION

1.1 *Overview*

The electrical energy supply network is presently in the process of change. There is increasing impetus for the customers of electrical supply authorities to install their own small scale electrical generation systems powered by a variety of sources such as solar energy. These generation systems are usually connected to the electrical supply network and are able to export energy to this network when the total output is not consumed by the load within the owner's premises. This method of generation is loosely known as Distributed Generation (DG).

There is also increasing numbers of electric vehicles that can both take energy from the electrical supply network to charge their batteries and deliver energy to the network from their batteries through inverters. The electrical supply authorities are considering the ability to deliver energy into the electrical supply network as a method to relieve infrastructure constraints at peak energy demand periods. These systems would also effectively be considered DG.

The traditional configuration of the electrical supply grid is to have large remote power generators feeding electrical energy to the customers over a complex transmission and distribution grid in a radial manner. The operation of the entire existing electrical supply grid is optimised for this configuration.

The inclusion of DG into the existing electrical supply grid will change the operation of this network. This research project investigates the effects that the increasing number of Small DG Systems will have on the operation of the lower levels of the electrical supply network and endeavours to understand the saturation (or penetration) levels where the effect becomes significant.

This research project focuses on the Queensland electrical supply network and the effects of these Small DG Systems. There will be a number of parallels with the effects on similar electrical supply networks.

1.2 *Fundamental Information*

The following information will provide the fundamental information required to understand the basics of this research project and set the scene for this document. Greater details will be provided in the next chapter of this document.

In this document the phrase "this research project" will be taken literally and so only refer to aspects of "The Effects of Small Distributed Generation on the Electrical Distribution Network".

1.2.1 Electrical Supply Network Overview

The majority of the world's electrical energy is produced by large generators that are owned and operated by specialist generation entities, both government and privately owned. The electrical energy is distributed and sold to customers using a large interconnected network of generators, transformers and power lines, which is usually known as the electricity supply network or electrical grid. In general the electrical energy flows radially away from the generators to the customers.

The cost of building and operating the electrical grid is very high. These costs can be loosely categorised into a number of areas, which include:

1. The value of the items of plant that constitute the electrical grid.
2. The cost of generation equipment and fuel sources.
3. The cost of supply failure due to lost revenue.
4. The losses associated with transmitting the energy to the customer.

As a result of the high costs the electrical grid is controlled and protected in a way that is intended to balance the optimisation of performance whilst minimise the costs. The control and protection systems are generally set up for power flowing from the generators towards the customers.

1.2.2 Electrical Supply Networks in Australia

The generation of electrical energy in Australia is essentially controlled by a regulation authority called The Australian Energy Market Commission (AEMC). The AEMC describes its formation and purpose as follows “The Council of Australian Governments (COAG), through the Ministerial Council on Energy (MCE) established the Australian Energy Market Commission (AEMC) in July 2005 to be the rule maker for national energy markets.” The AEMC goes on to be more specific as follows: “The Australian Energy Market Commission is the rule maker and developer for the nation's energy markets. As a national, independent body we make and amend the detailed rules for the National Electricity Market and elements of natural gas markets.” (AEMC Who we are web page, viewed 19th Sept 2010, <http://www.aemc.gov.au/About-Us/Who-we-are.html>)

The AEMC produces the National Electricity Rules that sets out the conditions for which the supply of electrical energy is achieved in the interconnected networks within Australia.

The Australian Energy Regulator (AER) is the authority that determines the factors affecting the transmission and distribution networks. “The AER regulates the wholesale electricity market and is responsible for the economic regulation of the electricity transmission and distribution networks in the national electricity market (NEM).” (AER About us web page, viewed online 19th Sept 2010, < http://www.aer.gov.au/content/index.phtml/tag/aerAboutUs/>)

1.2.3 Queensland Electrical Supply Network

The generation, distribution and supply of electrical energy in Queensland are controlled by the legislation, “Electricity Act 1994”. This act points to a number of other legislated documents, including the National Electricity Rules and a number of Australian Standards.

The Queensland electrical supply network consists of a number of large electrical generators, which are owned by private companies or government owned corporations. An interconnected network of lines and cables takes energy from the generators and supplies the customers.

The higher voltage transmission network is owned and operated by Powerlink Queensland. The lower voltage sub-transmission and distribution networks are owned and operated by Energex and Ergon Energy. A very small part of the Queensland network is owned and operated by Country Energy. This small section of the Queensland network operated by Country Energy is insignificant when compared to that operated by Ergon Energy and Energex and will not be considered in this report.

1.2.4 Generation in Queensland

The electrical energy generators in Queensland are connected to Powerlink, Energex and Ergon Energy networks. They are all subjected to rigorous connection conditions that ensure that they do not negatively impact the supply network security and quality of supply.

The large generators are generally connected to the Powerlink Queensland network and range in size from a few MVA to over 1500 MVA. A large number of smaller generators are connected to the sub-transmission and distribution networks of both Energex and Ergon Energy.

1.2.5 Distributed Generation in Queensland

The electrical supply network in Queensland is extensive with over 13,000 km of transmission lines, 350,000 km of distribution lines and 65,000 transformers (Queensland Department of Employment, Economic Development and Education, Queensland electrical supply network statistics, viewed online on the 19th of September 2010, <http://www.dme.qld.gov.au/Energy/transmission_and_distribution.cfm>).

There are over 50 individual generation sites within these networks. These generators are distributed through out the Queensland electrical supply network and so it could be said that they are all distributed generators, although most are not considered to be due to their large size.

Distributed generators are generally distinguished from other generators in two main aspects. Firstly their size is at the smaller end of the generation spectrum of sizes. Secondly they are usually powered by either renewable energy or energy that is a by product of another process (co-generation).

1.2.6 The Present State of Small DG Systems in Queensland

The Queensland Electricity Act 1994 sets down a set of definitions and conditions that allow for the connection of small DG systems to the electrical supply network (grid connection). These small DG systems do not require the rigorous compliance that larger generators must undergo in order to ensure network security and supply quality.
The Electricity Act 1994 (Qld) defines that which constitutes a Small DG System in Queensland as follows:

> ***qualifying generator*** means a small photovoltaic generator that—
>
> (a) is installed at the premises of a small customer in a way that allows electricity generated by the generator to be first used by the small customer and, if not used by the small customer, supplied to a supply network; and
>
> (b) complies with any safety or technical requirements prescribed under a regulation.

The Queensland Electricity Act 1994 also defines the size of Small DG Systems in Queensland as follows:

> ***small photovoltaic generator*** means a photovoltaic system with capacity up to 10 kilovolt amperes for a single phase connection and up to 30 kilovolt amperes for a 3 phase connection.

Clause 44A of the Electricity Act 1994 (Qld) allows for the export of excess energy produced by the Small DG Systems and the key points are as follows:

- Distribution Authority (Energex and Ergon Energy) must connect a qualifying generator to their network if it is technically and economically practical.
- Excess electrical energy may be exported to the electrical supply network and the distribution authority must pay the customer 44c per kWhr.
- This scheme must be reviewed by 2018 and expires in 2028.
- Must be reviewed if the total capacity of all the qualifying generators exceeds 8 MW.

1.2.7 Increasing Distributed Generation

A number of issues are increasing the attractiveness for the installation of DG systems, and these include:

1. The concerns over carbon dioxide (CO_2) production as a result of electrical energy generation using fossil fuels, which can be reduced by the installation of renewable energy sources to produce electricity.
2. The reducing costs of production for equipment that can convert energy sources into electrical energy that can be exported onto the electrical grid.
3. The increasing incentives provided by government entities for:
    - Larger electrical energy producers to develop renewable and clean (low CO_2 production compared to coal) energy DG systems;
    - Electrical energy customers to install their own renewable energy small DG systems that can export excess energy onto the electrical grid and be paid for this excess energy at rates that are more than the cost of importing energy.
4. The increasing flexibility and encouragement by government entities for the installation of renewable and cleaner electrical energy production (for both the larger producers and electricity customers).

This research project will be concentrating on the effects of small DG systems, which are connected to the low voltage distribution network (in Queensland this means three phase 415V). The small DG systems in Queensland are presently almost exclusively supplied by solar energy. The numbers connected to the electrical grid (or penetration) is increasing at a steady rate that does not look like reducing any time soon.

1.2.8 The Future of Small DG Systems in Queensland

The Queensland Government Department of Employment, Economic Development and Innovation Office of Clean Energy are presently the organisation that advises the state government on policy and initiatives regarding renewable and clean energy. The following quote is taken from their web site home page and encapsulates the present thinking of future renewable and clean energy directions, "Global concerns over climate change and demand for cleaner, greener energy will be major drivers of strong growth in the clean energy sector in the years ahead" (Queensland Department of Employment, Economic Development and Education, Office of Clean Energy, web site home page, viewed online on the 25th of September 2010,

< http://www.cleanenergy.qld.gov.au/office_clean_energy.cfm>). It can be seen from this statement that the focus on renewable and clean energy will continue and by virtue

of this there will continue to be some encouragement of the establishment of small DG systems.

Small DG systems in Queensland are presently powered almost exclusively by renewable energy sources; however there are other avenues of use presently being developed. These avenues include the use of battery storage systems that integrate to the grid using an inverter that can both charge the batteries and export the battery energy to the grid. These systems are intended to assist electrical supply authorities with grid management. Hydrogen fuel-cell technology could employ grid connected inverters to interface the discharge of energy to the electrical supply network. The battery systems that power electric vehicles are mostly charged with on-board inverters and there is interest by electrical supply authorities to control and utilise the available storage capacity in the batteries for grid management also.

The increasing interest in small DG systems and other grid connect inverter applications such as battery storage, hydrogen fuel-cells and electric vehicles battery systems may see the continued penetration of these systems into the electrical supply network. It is likely that these penetration levels may approach saturation where every dwelling and commercial establishment could include one or more grid connect inverters connected to the electrical supply network.

1.2.9 Small DG Systems Defined

The great majority of small DG systems use either wind or solar as their energy source and in Queensland almost all systems use solar. Small DG Systems using solar energy almost exclusively use panels of Photovoltaic (PV) cells to convert the sun's energy to electrical energy. The PV panels produce d.c. voltages up to about 48V each and a number of these panels are connected in series to form a PV array with outputs up to several hundred volts. The d.c. output of the PV array is fed into an inverter that converts the d.c. into a sinusoidal voltage of one or three phases and with an amplitude dependent on the application (in Queensland 240V single-phase and 415V three-phase).

The inverters can supply local isolated loads, which sometimes integrate some form of battery storage. The alternate would be that they connect to the electrical supply network (the grid), mostly without any storage and this is presently the most common arrangement in Queensland (and for that matter globally).

In this research project the term "Small DG System" will be taken to mean a PV grid connected inverter system of less than 10 kW per phase.

1.2.10 Low and High Voltage Distribution

This research project is intended to investigate the effects that the increasing penetration of Small DG System may have on the lower levels of the electrical grid. The lowest level of the electrical grid is the Low Voltage (LV) Distribution where the nominal supply voltage in Queensland is 415V (three-phase). The next level is the High Voltage (HV) Distribution where the nominal voltages in Queensland range from 6.6kV to 33kV. The next level is the Sub-Transmission voltages, which in Queensland are 33kV, 66kV, 110kV and 132kV.

An individual LV Distribution network could be defined as the network downstream of a Distribution Substation, which for example could constitute a three-phase 200kVA 11kV to 415V transformer providing supply over several hundred metres of LV lines to 50 residential customers taking supply at single-phase 240V.

An individual HV Distribution network could be defined as a single 11kV distribution feeder which is the entire network downstream of a zone substation circuit breaker and could comprise several kilometres of HV lines supplying ten to twenty LV Distribution networks.

The Zone Substation is usually configured as one or two large transformers stepping down a sub-transmission voltage to the HV distribution voltage. The zone substation transformers in Queensland range in size from 1MVA to 63MVA. The transformer low voltage windings feed the various distribution feeders through an arrangement of circuit breakers.

1.2.11 Voltage Control

The HV distribution network is presently arranged with a number of distribution substations supplied by the HV lines and cables running radial away from the zone substation. These distribution substations incorporate fixed tap transformers, which are set to provide the appropriate voltage when the flow of electrical energy is away from the zone substation.

The voltage of the distribution feeders at the zone substation is generally controlled at somewhere from 101% to 103% of nominal voltage. This is achieved by automatically changing the winding ratio of the zone substation transformer incrementally to maintain these values regardless of load levels. The incremental changes of winding ratio range from 1% to 2.5% of the nominal ratio and these ratio changes can boost the output voltage by up to 20% and buck by up to 10%. The load supply is not broken by this process and the method is usually known as On Load Tap Changing (OLTC). The OLTC operation can be complicated but are essentially set up to operate when voltage deviates from the prescribed range by a set amount for a set time, for example if the voltage deviates outside the limits of 101% and 102.5% for more than 90 seconds.

The majority of distribution feeders have only the voltage at their source (at the zone substations) regulated to a set value and rely on their construction and set up of the distribution substations to keep the customer voltage within an acceptable range. On some excessively loaded distribution feeder this arrangement does not deliver suitable voltages to the customer. These feeders require additional voltage support, which is generally provided by Voltage Regulators. A Voltage Regulator is a transformer with a winding ratio of nominally 100% and an OLTC with a tap range of up to 20% boost and 20% buck and tap step from 0.5% to 2%. The Voltage Regulator OLTC is controlled to maintain the output voltage in the same way as that done for Zone Substation transformers. These regulators can be operated to maintain the voltage on their downstream side regardless of the direction of power flow and so can be bi-directional.

1.2.12 Impacts of Small DG Systems

The typical domestic customer uses on average about 3.5kW with peaks of little more than 10kW. The inclusion of Small DG Systems will subtract from this load and export energy when exceeding the load. This means that the Small DG Systems will have some effect on the dynamics of the electrical grid. Whilst the numbers of Small DG Systems are small the effects will be negligible, however large numbers could potentially see the electrical grid operating in a manner for which is was not designed.

The inclusion of great numbers of Small DG Systems across a large electrical grid would take a number of years and would most likely have a very substantial impact on all aspects of the control and protection systems. The grid wide impacts are still some time away and issues will be investigated and strategies developed to cope with the problems as they become apparent.

At this point in time the penetration of Small DG Systems is low and so the impacts are presently negligible. The penetration level is however increasing and it is possible that in the near future the effects on the lower levels of the electrical grid will become noticeable.

1.2.13 Quality of Supply

It is generally expected that the supply of electrical energy to the consumer is of a reasonable quality or in other words the Quality of Supply (QoS) meets relevant standards. In the perspective of this research project, QoS is measured in two ways. They are:

1. The duration and frequency of power supply failure.
2. The size, duration and frequency of voltage fluctuations outside the limits considered reasonable.

1.2.14 Protection Systems

The electrical supply network protection systems are intended to interrupt supply to a section of network where there is a fault. A fault is defined as an abnormal system occurrence. In general protection systems operate during a fault to:

- Prevent damage to network equipment.
- Prevent the occurrence of a situation that is dangerous.
- Reduce the disturbance to other network customers (or increase QoS).

In general protection systems are intended to cover a specific section of network and usually not operate for faults outside of their intended network section (unless acting as a back up when the primary protection system fails). The methods and equipment used in protection systems vary widely and depend on the type of network being protected. This research project will be concentrating on the LV and HV Distribution network only and for this reason only the protection systems typically used on these network sections will be discussed.

LV Distribution almost exclusively employs fuses to protect this network type. HV Distribution use fuses also as well as circuit breakers controlled by some type of protection relay. Protections relays measure current or current and voltage and send a signal for the circuit breaker to operate when a predetermined fault condition is experienced.

1.3 *Research Project Justification*

It is anticipated that high penetration levels of Small DG Systems will at some level begin to negatively effect the operation of the LV Distribution portion of the electrical grid. As the penetration level increase further then it is possible that effects will become more widespread and will be noticed on the HV Distribution. The level of penetration where these issues become noticeable will depend on many variables, which will mostly relate to the network type.

This research project intends to investigate what level of penetration of Small DG Systems causes problems on two representative distribution feeders.

1.3.1 Effects on the LV Distribution

One of the measures of Quality of Supply (QoS) of the electrical energy is the number and size of voltage fluctuations. The control of the present distribution network relies totally on power flows towards the customers. It is likely that the uncontrolled and variable nature of generation of power by the Small DG Systems away from the customers will cause voltage fluctuations on the LV Distribution grid that will be considered excessive and so the QoS will as a result be substandard.

It is also possible that during fault conditions the input from the Small DG Systems will negatively change the way that the protection systems deal with the disruption and removal of the faulted network.

1.3.2 Effects on the HV Distribution

It is probable that the effects seen on the LV Distribution network will be more pronounced than those on the HV network. Therefore it is likely that they will become noticeable on the HV Distribution at a higher level of penetration compared to the LV Distribution.

The problems seen on the HV Distribution network may also be similar in nature to those seen on the LV Distribution.

1.3.3 General Research Objectives

The most likely consequence of high levels of penetration of Small DG Systems will manifest in two specific ways that are:

1. Reduction of Quality of Supply to unacceptable standards.
2. Negatively affecting the operation of HV and LV Distribution network protection systems.

This research project will investigate how the increasing penetration of Small DG System will affect QoS and protection system operations.

1.4 *Methodology*

The following sections describe the methodology that will be used in the investigation that the effects of increasing penetration of Small DG Systems have on the HV and LV Distribution network.

1.4.1 Investigation Overview

Distribution feeders vary widely in their makeup within the electrical supply network. One end of the spectrum is represented by heavy commercial, which are short systems that supply a large load within the central business districts of large cities or single large commercial customer such as a shopping centre. The opposite extreme is an extremely long rural network that incorporates large Single Wire Earth Return (SWER) networks and supplies few widely spaced small loads.

It is unlikely that enough Small DG Systems can be installed within heavy commercial distribution feeders to negatively affect the network and so they will not be considered in this project.

The intention of this research project is to choose two representative feeders from within the Ergon Energy network that represent the strongest and weakest networks where there is the possibility of high levels of Small DG Systems penetration. Information on these two feeders will be collected to develop models and data sets.

Data will be collected on the behaviour of the Small DG Systems in various operational circumstances. Further data will also be assembled on electrical network equipment that may be used to mitigate the negative impacts of Small DG Systems.

The network models will incorporate various permutations of penetration levels of Small DG Systems and will be run to determine the effects of system faults and fluctuation in the output of the Small DG Systems. The models that demonstrate problems will be run with the additional equipment intended to correct the problems in order to investigate their effectiveness.

1.4.2 Distribution Feeder Types

The two distribution feeder types with the addition of Small DG Systems that will be investigated in this research project will be:

A. Major urban residential – regional city purely suburban with very little commercial or industrial customers. This feeder will be referred to as a residential feeder.

B. Principally SWER – very isolated long rural network with small loads representative of free range livestock farming. This feeder will known as a SWER feeder.

1.4.3 Expected Small DG System Dispersion

The initial uptake of Small DG Systems in Queensland was stimulated by federal and state government subsidisation. This subsidisation was means tested and was most attractive to residential customers. The net result is that at the moment the majority of Small DG Systems are installed in residential customer's premises. As a result the dispersion of Small DG Systems within the community is reasonably random and evenly dispersed across residential customers. The exception to the even residential dispersion is seen in retirement villages where the density of dwellings is high and the uptake of Small DG Systems can be up to 100%. There are cases in Queensland where up to 300 installations are lumped in a 25ha community in the midst of residential feeder networks.

There have been instances where individual property owners have several connections to the grid and have installed Small DG Systems on each of their connection to SWER network. These are further examples of lumped installations and can be up to 10 in number on a SWER feeder.

The future growth and dispersion of Small DG Systems is difficult to predict at this point in time. It is not an entirely unreasonable possibility that the penetration levels could reach 100%.

1.4.4 Expected Small DG System Types

The variations in Small DG Systems sizes range from 1 kW to 30 kW, although at present the sizes generally range from 1 to 3 kW. The future could see a move towards larger units as the costs reduce through mass production price scaling.

1.4.5 Network Model Permutations

The permutations of models that could be tested on the representative feeders are large in number. The possibilities range from 0 to 100% penetration with dispersions ranging from even to concentrated groups or lumped installation. It is likely that the lumped installations will initially only be seen in retirement villages and other medium density residential arrangements.

In order to keep the number of differing network models to a reasonable quantity and to progress across a spectrum of penetration levels where problems may become obvious it will be necessary to use some judgement to select suitable penetration arrangements. This has been done by selecting appropriate incremental even distribution of Small DG Systems penetrations and also situations where a concentrated group of Small DG Systems are lumped onto a network section as well as combinations of both. The following tables show which permutations of these penetration levels will be developed into models and tested. Each model tested will be either even distribution or a combination of even distribution and lumped installations near the centre or end on the HV network; for example the Model Test A-9 would involve 50% even distribution as well as a lumped installation of 120 Small DG Systems at the centre of the residential feeder.

Table 1.1 – Models for Major urban residential Network

A – Residential Feeder													
Model Test	**Even Distribution**									**Lumped Installation**			
	20%	30%	40%	50%	60%	70%	80%	90%	100%	120 Centre	240 Centre	120 End	240 End
A-1	✓												
A-2		✓											
A-3			✓										
A-4				✓									
A-5					✓								
A-6						✓							
A-7							✓						
A-8									✓				
A-9				✓						✓			
A-10				✓							✓		
A-11				✓								✓	
A-12				✓									✓
A-13							✓			✓			
A-14							✓				✓		
A-15							✓					✓	
A-15							✓						✓

Table 1.2 – Models for Principally SWER Network

B – SWER Feeder													
Model Number	**Even Distribution**									**Lumped Installation**			
	20%	30%	40%	50%	60%	70%	80%	90%	100%	5 Centre	10 Centre	5 Fringe	10 Fringe
B-1	✓												
B-2		✓											
B-3			✓										
B-4				✓									
B-5					✓								
B-6						✓							
B-7							✓						
B-8									✓				
B-9				✓						✓			
B-10				✓							✓		
B-11				✓								✓	
B-12				✓									✓
B-13							✓			✓			
B-14							✓				✓		
B-15							✓					✓	
B-16							✓						✓

1.4.6 Small DG System Weather Performance

The change in the output from Small DG Systems will vary from 0 to 100% depending on the time of day and weather conditions. The output values experienced during a sunny day are relatively easy to predict and apply as are those at night.

The output and behaviour of the Small DG Systems during the transition of clouds over head is less simple to predict. It is likely that there will be some change that can range from very little to up to 80% drop in output over a matter of seconds.

The inclusion of the dynamic cloud related performance in models of feeder networks that include Small DG Systems may highlight problems related to QoS. A comparison of Small DG System performance data, feeder load data and wind speed would be needed to determine the greatest step change of power in-feed into each feeder type.

1.4.7 Methodology to Investigate Protection Problem

The importance of a protection system operating is paramount and so they are designed to function when the network that they are protecting is operating in its most arduous state.

This research project will investigate to see if the protection systems used on the LV and HV Distribution are adversely affected by the inclusion of Small DG Systems. This will be done by running the network models with the differing levels of Small DG System penetration levels and placing faults at various places within the network. The fault levels through the protective devices will be examined to see whether the device has operated correctly or not.

1.4.8 Methodology to Investigate QoS Problem

The investigation of the QoS issues will be split into two areas, which are:

1. The network voltage fluctuations caused by the steady state operation of the Small DG Systems.
2. The network voltage fluctuations as a result of cloud movement affecting the output of the Small DG Systems.

The HV Distribution network is presently arranged with a number of distribution substations supplied by the HV lines and cables running radial away from the zone substation. These distribution substations incorporate fixed tap transformers, which are set to provide the appropriate voltage when the flow of electrical energy is away from the zone substation. The inclusion of Small DG Systems will see this energy flow during sunny periods in a less radial manner than previously experienced. During low insolation periods the energy flows will be radial as before. This difference will see the voltages fluctuating depending on the amount of energy being fed in by the Small DG Systems and the feeder loads.

The feeder network models will again be used with differing penetration levels and location of Small DG Systems and load flows conducted to see how the system voltages are affected.

1.4.9 Corrective Network Devices

The investigation of the models of the representative group of distribution feeders with the various incremental penetration levels of Small DG Systems will produce data on the affects of these systems for both Protection Systems and QoS. This data will allow an analysis that will highlight a point where these problems begin. This further information can be used to expand the investigation to test the corrective effects of additional network devices and so generate a second data set.

1.5 *Objectives*

The key objectives of this research project are as follows:

1. Develop a data set of fault levels using network models of the two representative distribution feeders with various incremental penetration levels of Small DG Systems.
2. Develop a data set of voltage levels using network models of the representative distribution feeders with various incremental penetration levels of Small DG Systems.
3. Determine at what level of Small DG System penetration cause incorrect operation of protection systems for each representative distribution feeder.
4. Determine at what level of Small DG System penetration cause an unacceptable QoS for each representative distribution feeder.
5. Develop secondary data sets of fault levels using network models incorporating corrective devices.

6. Develop secondary data sets of voltage levels using network models incorporating corrective devices.

1.6 *Dissertation Outline*

The following sections will give a brief description of the content of the subsequent chapters of this document.

1.6.1 Background Information

The section will contain the information relating to the two distribution feeders as well as related equipment, data and software used in this research project. These will include the following:

- Legislation, regulation and standards relevant to this research project.
- Distribution feeder protection systems overview.
- QoS overview.
- Voltage regulation.
- Distribution Feeder Related - The information regarding the two representative distribution feeders selected for this research project, which includes:
  - Physical and electrical characteristics.
  - Customer numbers and types.
  - Load profiles
  - Protection Systems.
  - Weather data.
- Small DG Systems Related – Such as types, sizes and performance characteristics of the equipment that comprises a Small DG System.
- Expected problems with high penetration of Small DG Systems on the distribution networks.
- Feeder Modelling – Describing the selection and choice of modelling tools and the various model permutations.

1.6.2 Literature Review

This chapter will include a brief examination of research papers on the following categories:

- The effects of steady state in-feed from high penetration levels of DG.
- The effects of transient in-feed (cloud induced) from high penetrations of DG.
- The effects on protection systems by high penetration levels of DG.

The chapter will include a summary of the information relevant to this research project that has been derived from the literature review. The chapter will conclude with an analysis of the areas where previous research appears to be insufficient or inadequate in the field relevant to this research project.

1.6.3 Test Data

An outcome from the literature review is that there was insufficient data available to develop aspects of this research project. A small number of experimental data sets were collected for this research project in order to effectively enable the modelling and analysis phase of this research project.

The experimental data sets include:

- Actual fault contributions data from a Small DG System
- Performance of a Small DG System as a result of cloud movement.
- Experimental performance of grid-connect inverters using laboratory power supplies.

1.6.4 Network System Modelling

This chapter describes the development of the network models of the two representative distribution feeders.

1.6.5 Network System Modelling

This chapter describes the outcomes produced from the fault modelling exercise of the two representative distribution feeders. The intention is to develop a data set that shows the fault levels at protective devices with and without the inclusion of Small DG Systems.

The chapter also provides an analysis of the fault modelling techniques in order to ascertain whether confidence can be had in the results.

1.6.6 Quality of Supply Modelling

This chapter describes the outcomes produced from the load flow modelling exercise of the two representative distribution feeders. The intention is to develop a data set that shows the voltage levels at the customers LV supply with and without the inclusion of Small DG Systems during both steady state and fluctuating in-feed.

The chapter also provides an analysis of the load flow modelling techniques in order to ascertain whether confidence can be had in the results.

1.6.7 Analysis of Protection Impacts

The data collected during the protection system modelling exercise will be analysed in order to develop a better understanding of the methods and problems associated with the existing power network modelling software.

1.6.8 Analysis of QoS Impacts

The data collected during the QoS system modelling exercise will be analysed in order to develop a better understanding of the methods and problems associated with the impacts of high penetration levels of Small DG Systems on the existing distribution networks.

1.6.9 Conclusions

The section of the report will see the development of conclusions drawn from the analysis of the information and data collected. This will be followed by a summary of the negative issues discovered during this research project. A set of recommendations can be developed for use as a guide for electrical supply authorities in their handling of future high penetration levels of Small DG Systems. This recommendation may also be used to develop future policy in the connection of these systems.

The last section of this chapter will list and describe the issues of interest that became apparent during this research project, but are outside the bounds of the objectives available for this research project.

CHAPTER 2 - BACKGROUND INFORMATION

2.1 *Outline of Background Information*

The previous chapter provided a broad outline of information relevant to this research project and this chapter will present the specific information that will be considered in the development of this research project.

2.2 *Legislation and Regulations*

2.2.1 Queensland Electricity Act 1994

The overriding legislation that governs the production and supply of electricity in Queensland is called the Electricity Act 1994.

The key points to be taken from the Queensland Electricity Act 1994 that relate specifically to this research project include:

- A feed in tariff where grid-connected inverter systems can receive 44c per kWh of energy exported onto the electrical supply network.
- Only small grid-connected inverter systems powered by photovoltaic arrays with a capacity up to 10 kW per phase qualify for feed in tariffs.
- That supply authorities must agree to connect these Small DG Systems to their network so long as there are no technical or financial barriers.

The Queensland Electricity Act 1994 has an additional and subordinate legislation known as the Electricity Regulation 2006. The key points taken from this document that relate specifically to this research project include:

- The nominal supply frequency will be 50 Hz.
- The low voltage (LV) distribution is a three-phase and multiple earthed neutral system.
- The nominal distribution LV is 415 V RMS phase to phase and 240 V RMS phase to neutral.
- The distribution LV must be maintained at the customer's terminals (point of connection) at 6% more or less than the nominal voltage.
- The distribution HV at 22 kV or less must be maintained at the customer's terminals at 5% more or less than the nominal voltage.
- The distribution HV at more than 22 kV must be maintained at a voltage agreed between the electricity entity and the customer.

2.2.2 Australian Standards

The Small DG Systems considered in this report will be connected to the LV distribution networks in Queensland. The supply authorities who own and operate this network are principally Ergon Energy and Energex. These two authorities provide guidelines for the connection of Small DG Systems that say that they shall comply with the Australian Standards AS3000 and AS4777 (Ergon Energy web site, Renewable Energy System Connection information, viewed online on the 2nd of October 2010, <http://www.ergon.com.au/your-business/connections/renewable-energy-system-connection>).

The Australian Standard AS3000 is titled the Wiring Rules and as its name suggests, covers information relating to wiring standards. This information is not used in this research project as it is assumed that the installation of the Small DG Systems is compliant with this standard.

The Australian Standard AS4777 is composed of three volumes and is titled “Grid connection of energy systems via inverters”. The first two AS4777.1 and AS4777.2 cover installation and inverter requirements respectively. The assumption will again be made that the inverters and their installations are compliant. The third volume AS4777.3 is of interest in this research project and covers the grid connection requirements.

2.2.3 AS4777.3 Clause 5.3

The first key area of AS4777.3 which is relevant to this research project is the clause 5.3, which describes the conditions by which the inverter must disconnect in order to prevent generation when the supply from the grid is lost (anti-islanding). The clause is as follows:

> **5.3 Voltage and frequency limits (passive anti-islanding protection)**
>
> The grid protection device shall incorporate passive anti-island protection in the form of under- and over-voltage and under- and over-frequency protection. If the voltage goes outside the range Vmin to Vmax or its frequency goes outside the range fmin to fmax, the disconnection device (see Clause 5.2) shall operate within 2 s, where—
>
> (a) Vmin shall lie in the range 200-230 V for a single-phase system or 350-400 V for a three-phase system;
>
> (b) Vmax shall lie in the range 230-270 V for a single-phase system or 400-470 V for a three-phase system;
>
> (c) fmin shall lie in the range 45-50 Hz; and
>
> (d) fmax shall lie in the range 50-55 Hz.
>
> The limits Vmax, Vmin, fmax and fmin may be either preset or programmable. The values Vmax, Vmin, fmax and fmin may be negotiated with the relevant electricity distributor. The settings of the grid protection device shall not exceed the capability of the inverter.

It can be seen that the operation voltages range from -16.7% to +12.5% of the nominal 240 V to neutral and this is well outside the legislated limits of ±6%. This means that the network voltages could extend to these limits set by the inverters.

The second key area of AS4777-3 is clause 5.5 as follows:

> 5.5 Active anti-islanding protection
> The grid protection device shall incorporate at least one method of active anti-islanding protection. Examples of such methods include shifting the frequency of the inverter away from nominal conditions in the absence of a reference frequency (frequency shift), allowing the frequency of the inverter to be inherently unstable in the absence of a reference frequency (frequency instability), periodically varying the output power of the inverter (power variation) and monitoring for sudden changes in the impedance of the grid by periodically injecting a current pulse (current injection).

It is possible that the passive anti-islanding would not operate if a number of inverters were in operation and the load was similar to their collective output. The active anti-islanding described would acts as a backup in the rare event that the passive functions do not operate.

The third key area of this standard describes the procedure of reconnection of the inverters at start up and after anti-islanding has been detected and they have automatically disconnected themselves. This feature is described under clause 5.6 and is as follows:

> 5.6 Reconnection procedure
> Only after all the following conditions have been met shall the disconnection device operate to reconnect the inverter to the electricity distribution network–
> (a) the voltage of the electricity distribution network has been maintained within the range Vmin–Vmax for at least 1 minutes, where Vmin and Vmax are as defined in Clause 5.3; and
> (b) the frequency of the electricity distribution network has been maintained within the range fmin–fmax for at least 1 minutes, where fmin and fmax are as defined in Clause 5.3; and
> (c) the inverter energy system and the electricity distribution network are synchronized and in-phase with each other.

It can be seen that the inverters wait one minute after they have determined that the grid supply has been restored before reconnection.

2.2.4 Inverter Operating Limits

To connect a Small DG System to the Ergon Energy or Energex networks requires the completion of an Inverter Energy System (IES) Network Agreement (Ergon Energy, Inverter Energy System (IES) Network Agreement, viewed online 3rd of August 2010, <http://www.ergon.com.au/__data/assets/pdf_file/0017/7055/Ergon-Energy-IES-Network-Agreement.pdf>). This document says that:

> **5 - GRID PROTECTION REQUIREMENTS**
>
> The IES output voltage, frequency and waveform must match that of our Supply Network such that any distortion of these parameters shall be within acceptable limits. There shall be no significant reduction in quality of Supply to other network users or risk of damage to apparatus belonging to other network users or us.
>
> Passive protection arrangements shall comply with AS 4777.3 "Grid Connection of Energy systems via Inverters Part 3: Grid Protection Requirements".
>
> In addition, the following specific voltage and frequency settings shall be programmed into the Inverter:
>
> (a) Voltage: Maximum voltage trip point (Vmax) shall be 255 V for a single phase system or 440 V for a three phase system.
>
> (b) Frequency:
>
> (i) Minimum frequency trip point (Fmin) shall be 48 Hz
>
> (ii) Maximum voltage trip point (Fmax) shall be 52 Hz

> If voltage and/or frequency falls outside the set limits, the IES must be automatically disconnected from the network. Reconnection procedure shall comply with AS 4777.3 "Grid Connection of Energy Systems via Inverters Part 3: Grid Protection Requirements.

The key point from these requirements is that the inverter must disconnect when the voltage reaches 255 V. Several sources from within Ergon Energy and Energex reported that virtually none of the existing approximately 8000 Small DG Systems have their anti-islanding upper voltage limit set lower than the maximum 270 V. They also report that there is little chance of enforcing this arrangement in the near future, although they are working towards the compliance. Due to the varied nature and restricted access to the inverters in many of the existing installation it is expected that they will not be changed from their present 270 V upper limits.

2.2.5 IEC 60909

The International Electrotechnical Commission (IEC) is an organisation that prepares and publishes International Standards for all electrical, electronic and related technologies. The suite of standards known as IEC60909 and are titled "Short-circuit currents in three-phase AC systems". The third part of this standard IEC909-3 and is called "Part 3: Currents during two separate simultaneous line-to-earth short circuits and partial short-circuit currents flowing through earth".

The principles and methods described in the standard IEC60909-3 are employed in electrical supply network modelling software.

2.2.6 IEC 60255

The IEC suite of standards IEC60255 covers the specification and application of electrical relays used for metering and protection purposes. The individual standard IEC60255-3 is titled "Single input energizing quantity measuring relays with dependent or independent time" will be considered in this document as it covers the typical application of protection relays used on distribution networks.

2.3 *Distribution Feeder Protection*

A protection system has two main functions, firstly to prevent dangerous situations and secondly to prevent damage to equipment during abnormal system events (faults). An example of a dangerous situation would be when an over head 11 kV conductor breaks and falls to the ground remaining energised. This is extremely dangerous for any living thing to approach from the ground. An example of an event that could cause damage to equipment would be a short between two conductors that is not cleared and damages upstream equipment such as conductors and transformer by overloading.

The protection systems used on the representative feeders in this research project will be either protection relays controlling a circuit breaking device or fuses. The feeder protection at the zone substation busbar will be protection relays. The protection on the network that is remote from the zone substation will be either a protection device such as an automatic circuit recloser (ACR or simply a recloser) and/or fuses.

The feeder HV line current in a normal system state can be up to 1000 A (although typically less than 300 A) and during fault conditions can be up to 30000 A. This current cannot be applied directly to the protection relay and is transformed and isolated from the high voltage by a current transformer (CT). The transformation will usually provide current to the relay of 1 or 5 A in a normal system state and so use ratios of between 50 and 1000 to 1 or 5.

The protection relays and reclosers monitor the current measured by a CT and will operate to disconnect supply if the current exceeds certain limits.

2.3.1 Inverse Definite Minimum Time

The majority of protection relays and reclosers employ a method where they operate when a value of current is present for a period of time. The greater the current the smaller the time needed to operate and vice versa. This method is known as Inverse Definite Minimum Time (IDMT) and the parameters are usually governed by formula and specifications set down in the standard IEC60255-3, although other standards groups and some manufacturers employ variations as well as their own unique formulas.

The IEC60255 formula is:

$$T = \frac{K}{\left(\frac{G}{G_S}\right)^{\alpha} - 1} \times Tms$$

Where:

T is the time

G is the value of the characteristic quantity (actual current value)

G_S is known as the value of the characterising quantity (also called current pickup)

α is the index characterising the algebraic function

K is the constant characterising the relay

Tms is known as the time multiplier

The table 2.1 below shows the values of the variable for the three variations published in the IEC 60255. The table also includes alternate names used the curves that result form the application of the formula and variables.

Table 2.1 – IDMT Curve Formulae Data

IEC Name	α	K	Other Name
Curve A	0.02	0.14	Standard Inverse
Curve B	1	13	Very Inverse
Curve C	2	80	Extremely Inverse

An example of an application of Curve A, B and C can be seen in figure 2.1 below.

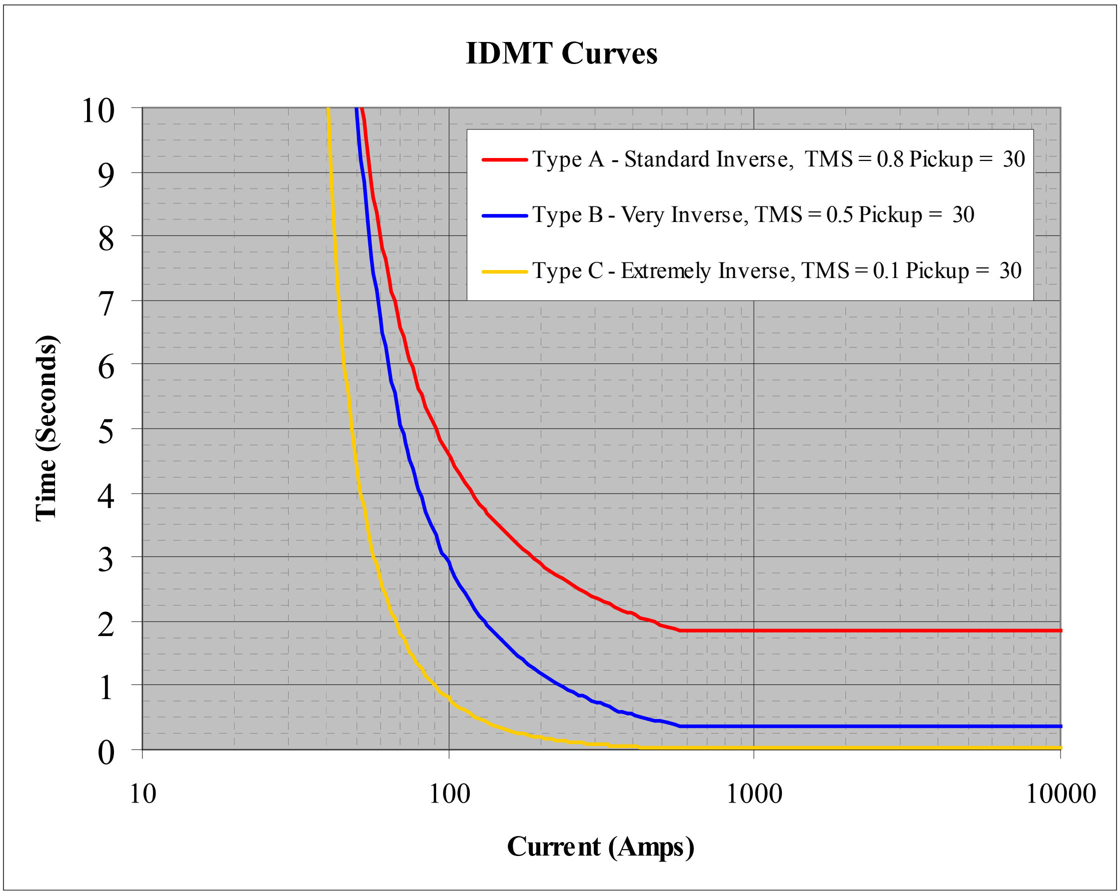


Figure 2.1 – Various IDMT Curves

These curve types evolved as a result of the development of electro-mechanical relays over the last 100 years. An addition to the capability of the various curve types is the inclusion of a definite time setting. This can allow an immediate trip for currents above a certain level. The majority of protection relays on the market today are fully electronic and use micro-controllers to process the input currents from the CT and respond based on IDMT curve settings.

There are also a number of other curve types that have been developed by other standards groups (such as IEEE) as well as various manufacturers. These additional curves will not be described in any detail in this document as the three IEC curves are sufficient to demonstrate any issues with protection problems.

2.3.2 Over-Current, Earth-Fault and Sensitive Earth-Fault Protection

The most common types of protection used on the HV of distribution feeders are Over-Current (OC), Earth-Fault (EF) and Sensitive Earth-Fault (SEF). Over-current protection operates when one of the phase currents exceeds the limits determined by an IDMT curve. Earth-fault protection operates for a condition when the earth (or neutral) current reaches a prescribed limit defined by the IDMT curve. Sensitive earth-fault protection operates on a defined earth current for a definite time and is effectively an adjunct to standard earth-fault settings.

Over-current and earth-fault are set with their pick-up currents low enough to operate for all relevant fault conditions within the network they are intended to protect, with some additional capacity in reserve. The reserve capacity is known as protection reach factor and the reserve is usually an additional 30% to 100% meaning the reach factor is 1.3 to 2.0. As an example if the lowest fault level is 100 A then the protection would be set to at least 50 A for a reach factor of 2.0 and at worst 77 A for a reach factor of 1.3.

The sensitive earth fault protection in intended to operate for sustained low levels of earth current fault and is generally an extension of the main EF protection. The SEF protection will generally operate for earth faults that would not cause the EF protection to operate and are there for long duration.

Both OC and EF curves can also have a definite time characteristic where the relay will operate immediately when a value of fault current is measured. This function is sometimes known as instantaneous over-current or instantaneous earth-fault. These values are set to operate for large values of fault current and are intended to limit the energy that the faulted equipment is being exposed to during the fault.

2.3.3 Three Phase Network HV IDMT Protection

On a three phase distribution network all three protection types will be implemented simultaneously. The OC protection will usually be set well above the maximum load currents and with a reach factor of greater than 1.5. The EF protection is set with a pick up much lower than the OC and also to achieve a reach factor of greater than 1.5. The SEF is set at a level lower than the pick up of the EF protection, usually for currents less than 10 A and for times above 5 s. An example of some typical OC and EF / SEF settings can be seen in figure 2.2 below. The SEF section is where the curve on the left becomes a horizontal straight line.

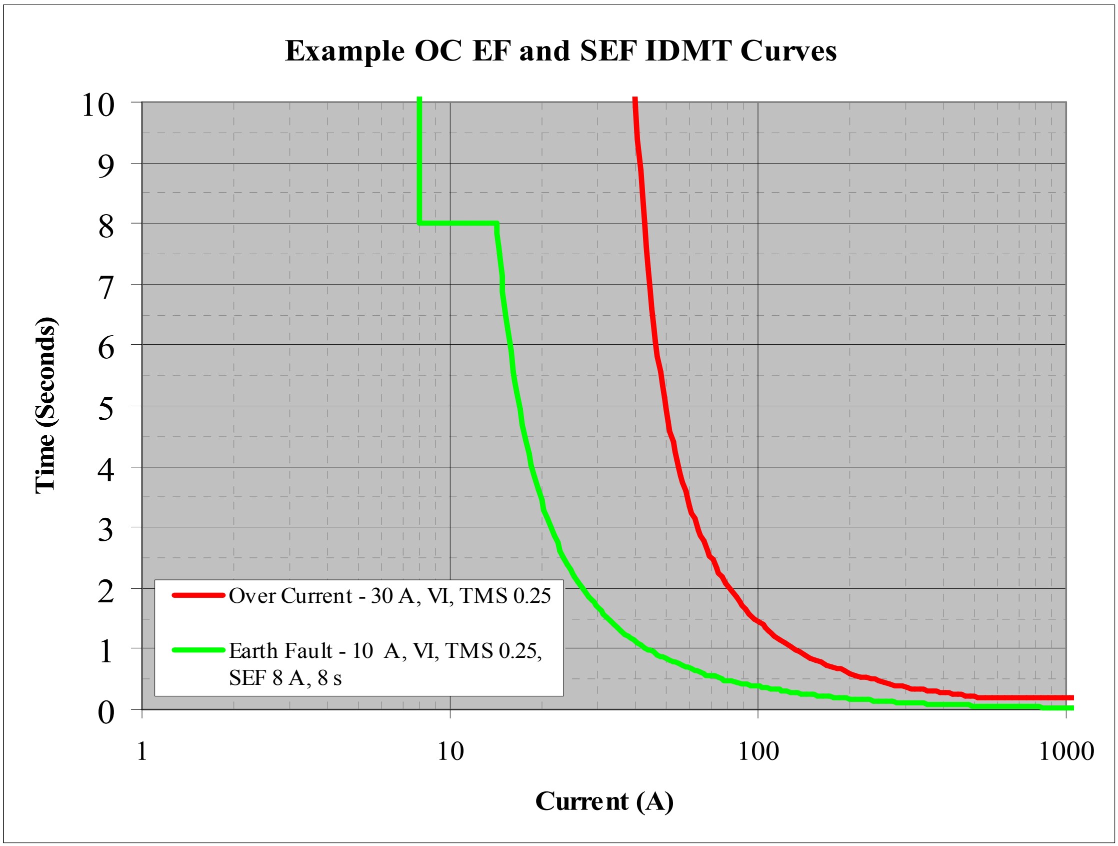


Figure 2.2 – Example Three Phase Protection Curves

2.3.4 SWER Network HV IDMT Protection

A SWER network utilises only one phase and uses the earth as the return path. This means that the only method of current based protection can be over-current, which when implemented is essentially an earth-fault protection.

A typical setting for a SWER OC protection would be similar to the OC curve seen in the previous figure 2.2.

2.3.5 Distribution Network HV Fuse Protection

The application of fuses for over-current protection is employed in the HV distribution networks for both three-phase and SWER. At present they are rarely used as the first protective device on a feeder and are usually deployed on a remote network section that is downstream of an electro-mechanical protective device such as a circuit breaker or recloser. Fuses are commonly deployed on section of a network where it is uneconomic to implement a circuit breaker or recloser. They are also used as the protective device on the HV side of a distribution transformer or substation. The fuses used to protect the HV side of a distribution transformer are sized relative to the transformer size.

Line fuses are meant to allow their rated current to flow continuously without operating. They are intended to operate for a fault at currents well above their rating and usually at least twice and sometimes three times this rating. It is not common in Queensland for line fuses to be used to protect HV network with large downstream loads. The line fuse sizes are usually well above the maximum load current. In most cases the minimum fault current downstream of a line fuse is four times or more of their ratings and so many time the actual load currents.

The contribution to fault currents by Small DG Systems is unlikely to be more than two times their continuous rating. The capacity of Small DG Systems downstream of a line fuse is unlikely to be anywhere near the fault level experienced on that network section and so unlikely to reduce the current through the line fuse during a fault by an amount that would prevent the line fuses operation.

The conclusion that can be drawn from this is that it is unlikely that the HV fuse operation will be adversely effected by the inclusion of Small DG Systems. The effects by Small DG Systems on HV fuses will not be investigated in this research project.

2.3.6 Distribution Network LV Protection

The use of circuit breakers on the LV network is relatively uncommon and usually only employed on very large distribution transformer of 1 MVA and above. These sized distribution transformers are not in use in the two networks chosen for this research project. The great majority of protection on the LV distribution network is afforded by fuses.

It was described in the previous section of this report that it was unlikely that a HV line fuse operation would be adversely effected by the inclusion of Small DG Systems. The same line of reasoning would suggest that LV fuses will most likely be unaffected by the inclusion of Small DG Systems also.

2.3.7 Distribution Network Protection Grading

Protection systems are designed so that individual protective devices operate only for faults for which they are intended to operate. The design method used to provide this function when using IDMT devices and fuses is known as protection grading. When two protective devices experience a fault current the device closest to the fault should operate.

Protection grading is achieved by ensuring that there is an adequate margin between consecutive protective devices. In most cases this would be achieved by ensuring that the time taken to operate is greater for the upstream device by 200 ms to 400 ms. Figure 2.3 below shows an example of how the first protective device would grade with the second, where a grading margin of 470 ms occurs for a common fault current of 200 A.

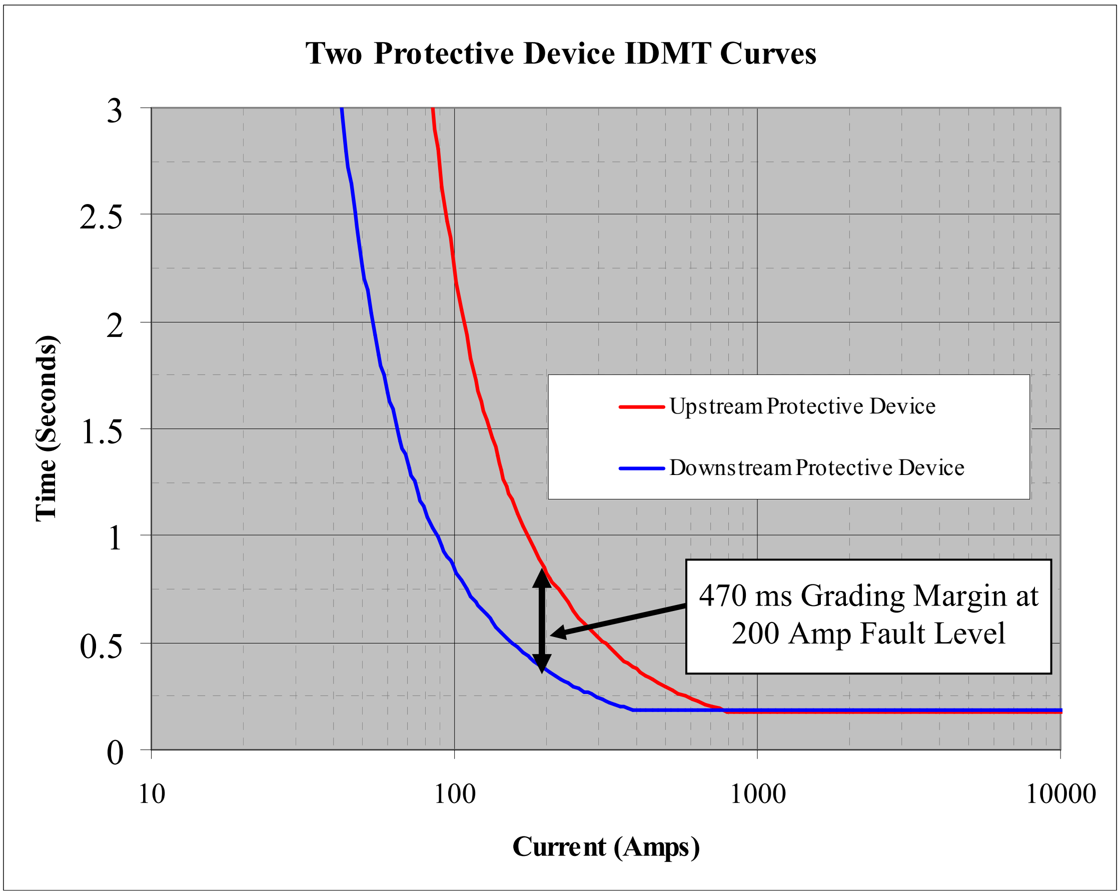


Figure 2.3 – Example of Grading Margin

2.3.8 Protection Failure

Protection system failures can be classified into three general areas, which include:

1. Incorrect operation, where a device fails to operate but an upstream device does operate and the fault is cleared.
2. Islanding, where a protective device operates but generators remain active and energise the faulted area.
3. Failure to operate and the fault is not cleared.

The first issue is more a reliability problem as more of a network is removed from service than is necessary. The second issue is meant to be addressed by the anti-islanding methods within the grid connect inverters themselves. It is possible that a large number of Small DG Systems in some circumstances could cause an island arrangement. This problem will not be investigated in this research project but could be the investigated in future research.

The third issue is of great concern to electrical supply authorities and will be one area of focus for investigation in this research project.

2.4 *Distribution Feeder Quality of Supply*

The electrical customer has a broad expectation that the electrical energy they purchase from the electrical authority is of a reasonable standard. This generally means that the supply is maintained most of the time and that damage to the customer's electrical appliances is very infrequent.

The electrical supply industry regulatory bodies provide guidelines and jurisdictional control of supply authorities and generators to ensure that the quality of energy is at a suitable standard and that Quality of Supply (QoS) is acceptable.

2.4.1 QoS and Grid Connected Inverters

The grid-connect inverters used in Small DG Systems are only intended to operate in the presence of the electrical supply grid. Their output is covered in the Australian Standard AS4777 and they are tested for compliance with this standard before use in Queensland. It is reasonable to say that the individual Small DG Systems have no negative impact on the QoS.

2.4.2 Responsibility of a Generator

The electrical generators that supply energy to the electrical supply network are strictly controlled for QoS. Transgressions of less than the prescribed QoS are punished with financial penalties.

The Small DG Systems described in this report are all generation installations. Their small size also would generally mean that as an individual generator they would have a very negligible impact on QoS. A number of Small DG Systems grouped together could negatively impact QoS. The regulation only considers individual generators and so Small DG Systems are precluded from the same regulation as the larger generators. This means that the affects by individual Small DG Systems is not considered further in this report.

2.4.3 Responsibility of an Electrical Supply Authority

The QoS of electrical energy supplied by an authority such as Ergon Energy and Energex is governed by the Queensland Electricity Act 1994. The key point taken from this legislation with respect to this research project is that LV voltages must be maintained to within 6% of the nominal voltage and HV within 5% of nominal voltage.

When considering the effects of Small DG Systems on the distribution network it is very unlikely they could impact the HV network by more than the 5% without first causing fluctuations greater than 6% on the LV network. This research project will focus on the effects on the LV network and will consider it unacceptable when the voltage moves outside the 6% range. It will be assumed that the changes to the HV will occur after the impacts to the LV have exceeded the statutory limits.

2.5 *Voltage Control*

The network between a customer and the generators producing the electrical energy is always seen as impedance when considered from the customer's perspective. The load currents flowing vary as the customers load varies. This means that the voltage drop across the supply network varies with customers load. In order to maintain the voltage within the statutory limits it is necessary to implement dynamic voltage control.

2.5.1 Zone Substation Voltage Control

The voltage at the zone substation HV distribution bus is almost exclusively controlled by on load tap changing (OLTC). The transformers that convert the higher sub-transmission voltages down to the distribution voltage change transformation ratios automatically using OLTC. The voltage is usually maintained at somewhere between 100% and 104% of the nominal HV distribution voltage.

There are a number of arrangements for OLTC control; however the most common simply monitors the transformer load side terminal voltage and change taps when an excursion occurs. The excursion must also occur for more than a specific period otherwise the transformer would change taps too frequently. An example would be to regulate to 103% of nominal and change taps of 1.25% ratio when the voltage moves outside the range or 101% to 105% for more than a 90 s time period.

2.5.2 Line Regulators

As the network length increases the impedances between the zone substation bus and the customer's increases and so the voltage variations due to load variations increase. Additional voltage control is implemented along the distribution network when these voltage variations exceed the statutory limits. This is achieved using voltage regulators (or line regulators), which are essentially a power transformer with similar high and low voltage windings and an OLTC arrangement. This allows them to buck or boost the transformation ratio in order to control the voltage on the downstream side in the same manner used by the power transformers at the zone substations.

These line regulators must work in concert with the zone substation transformer and not cause each other to change taps too frequently trying to correct each other. This is done by making either the line regulator of the zone substation power transformer time period greater, although usually the line regulator. As an example the line regulator could regulate to 103% of nominal voltage and change taps of 0.5% ratio when the voltage moves outside the range of 102% to 104% for more than 120 s time period.

2.5.3 Residential Distribution Network Voltage Control

The distribution transformers almost always have fixed tap arrangements. This means that the transformation ratio can be changed manually and is effectively fixed when they are in service. The voltage is maintained on a residential distribution feeder by setting the taps on the distribution transformers close to the zone substation at a low ratio and as the distance increases the tap ratio is increased. The use of line regulators on short and major urban residential feeder is not a common practice and is usually employed on longer rural networks.

2.5.4 SWER Network Voltage Control

The SWER network is almost always very long and constructed of small (high impedance) lines. This means that the voltage variations as a result of load current variations are more pronounced when compared to other distribution networks. The voltage control on a SWER network commonly is assisted by one or more line regulators. The distribution transformers used on SWER networks also employ a fixed tap arrangement where those closer to the zone substation utilise lower tap ratios and as the distance increases so does the tap ratio.

2.5.5 Reactive Power and Network Voltage Control

The injection of reactive power into the electrical supply network can be used to control voltages. The method injects capacitive or leading VAr's to raise voltage and inductive or lagging VAr's to reduce voltages. This can be done in large quanta and slow speed for very coarse control or smaller quanta and higher speed for finer control.

The large quantum steps can be achieved by using line reactors (inductors) or line capacitors and switching them into the network. The smaller quantum steps can be achieved by using static compensation where semiconductor switching methods recreate a.c. voltage waveforms that either lead or lag the grid and effectively import or export VAr's.

The former coarse method of voltage control that has been employed at the transmission and sub-transmission levels of the electrical supply network for many years and is the least expensive. The later static compensation (or STATCOM) is a more recent development and is presently gaining popularity for use in lower grid voltages.

2.6 *Distribution Feeders*

There are many permutations of HV configuration in the Ergon Energy network. All of the distribution feeders in the Ergon Energy network are radial in nature. Very small quantities of these feeders have short sections of multiple conduction paths within their radial structure. The HV distribution in the Ergon Energy networks range from 6.6 kV through to 33 kV, although the great majority are nominally 11 kV. The representative feeders chosen for this research project will represent the two extremes of the distribution feeders that would support very high levels of Small DG System penetrations.

This research project aims to identify problems with high penetration levels of Small DG Systems on two specific distribution feeders within the Ergon Energy network. The first will be a major urban residential feeder as they would most likely to have the greatest opportunity for the largest number of Small DG Systems to be included and are the most likely to have a very strong sub-transmission source. The second feeder will be a principally SWER network. These feeders have the lowest number of customers and are traditionally electrically very weak.

2.7 *Residential Distribution Feeder*

The following sections of this report cover the basic information relating to the chosen residential distribution feeder.

2.7.1 Major Urban Residential Feeder

The feeder chosen to represent the major urban residential feeder will be an 11 kV network fed from the Ross Plains Zone Substation (ZS) and is known as Ross Plains number 4, which in Ergon Energy nomenclature is known as ROPL-04. This feeder is located in the central suburbs of Townsville in Queensland. Figure 2.4 below shows the location within Townsville and Queensland and also the extent of this feeder.

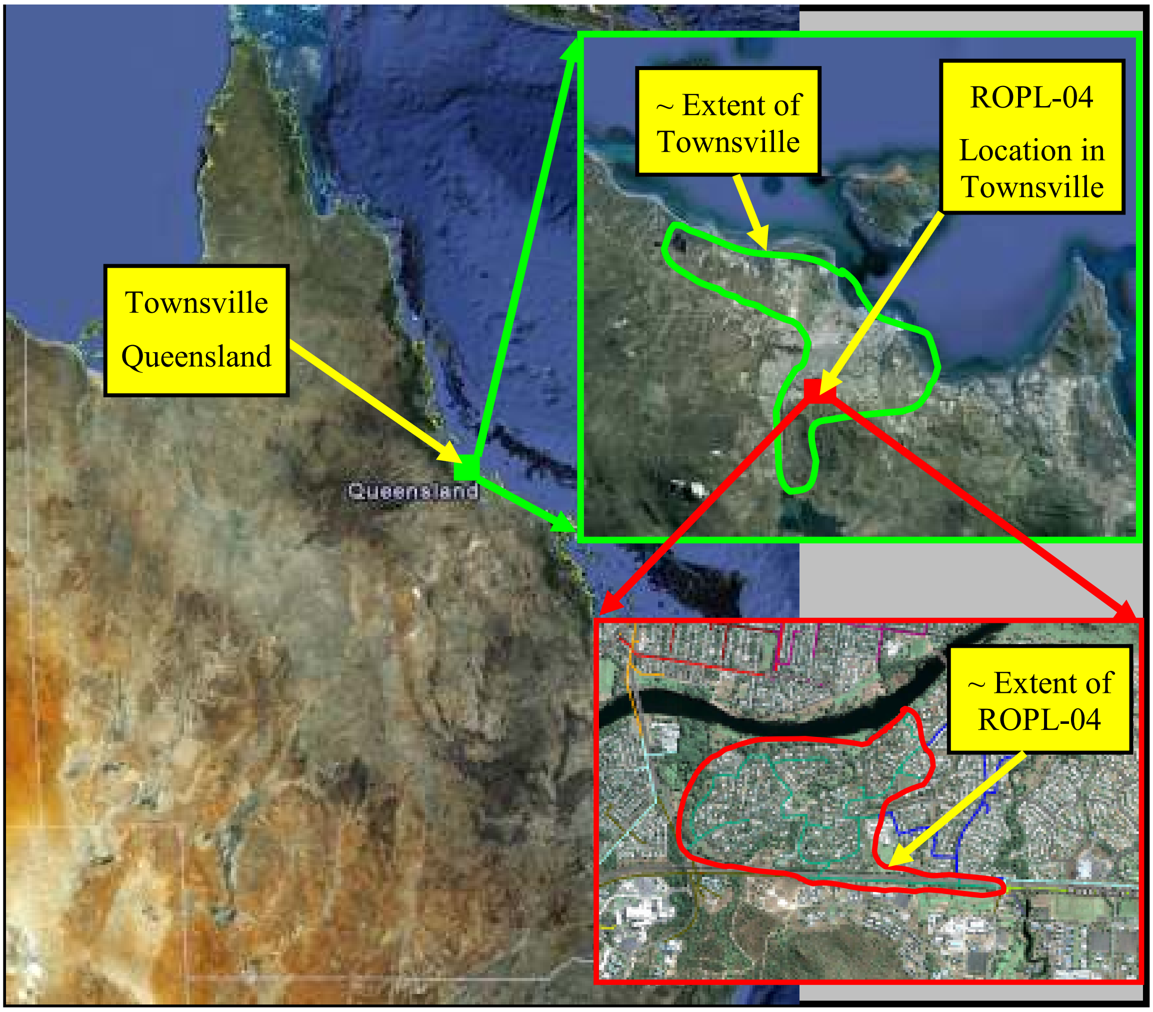


Figure 2.4 – Location of Distribution Feeder ROPL-04

This feeder supplies 964 residential customers, 13 small commercial customers and one small school. This effectively means that the load is as close to being totally residential as is possible within the Ergon Energy network. The residences fed by this feeder were established between 15 and 25 years ago and are what is now considered low density residential. The average land area occupied by an individual residence (residential customer) is approximately 700 m^2 and the total area of land serviced by this feeder is about 90 ha. Figure 2.5 below shows a closer view of the ROPL-04 feeder where the dark blue lines indicate the route of the HV distribution lines and cables.

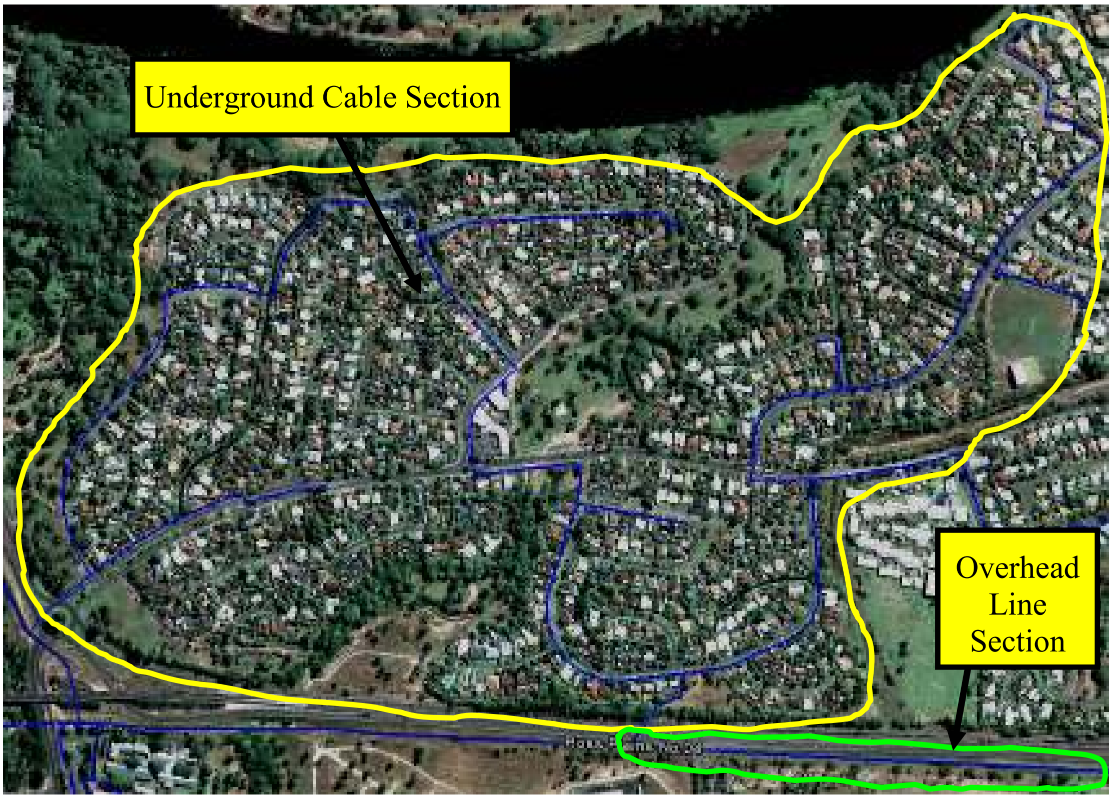


Figure 2.5 – HV Lines and Cables of Distribution Feeder ROPL-04

2.7.2 Ross Plains Zone Substation Configuration

The Ross Plains zone substation is fed with two 66 kV sub-transmission feeders that supply a 66 kV bus. There are two 20 MVA 66/11 kV transformers that each feed a section of an 11 kV bus. In total there are seven 11 kV distribution feeders that supply local residential and commercial loads. There is also a large customer who takes supply from two dedicated distribution feeders.

The 11kV bus at Ross Plains ZS is configured as two sections (Number One and Two) each fed individually from the low voltage of the 66/11 kV transformers. The two bus sections are connected with a bus section circuit breaker. The 11 kV bus is operated with both 66/11 kV transformers in service and the bus section circuit breaker open. The ROPL-04 feeder is fed from the Number One bus section.

The Ross Plains ZS also incorporates a 2 MVAr and a 3 MVAr 11 kV capacitor banks. The 3 MVAr bank is fed from the Number One bus section and the 2 MVAr bank is fed from the Number Two bus sections. The 2 MVAr bank has been in service for some time and the 3 MVAr capacitor bank was commissioned in early 2010. Each bank is controlled independently and is switched in at predetermined VAr levels measured at each bus section. The large local customer also employs power factor correction. The result of the combined power factor correction is that the overall power factor is very high at Ross Plains ZS and usually approaches unity. Figure 2.6 below shows a graph of the total substation load for the year from the 1st of October 2009 to 1st of October 2010 where it can be seen that the apparent and real power are very similar. It can also be seen that the reactive power sometimes moves into a leading power factor as the VAr's on the graph become negative.

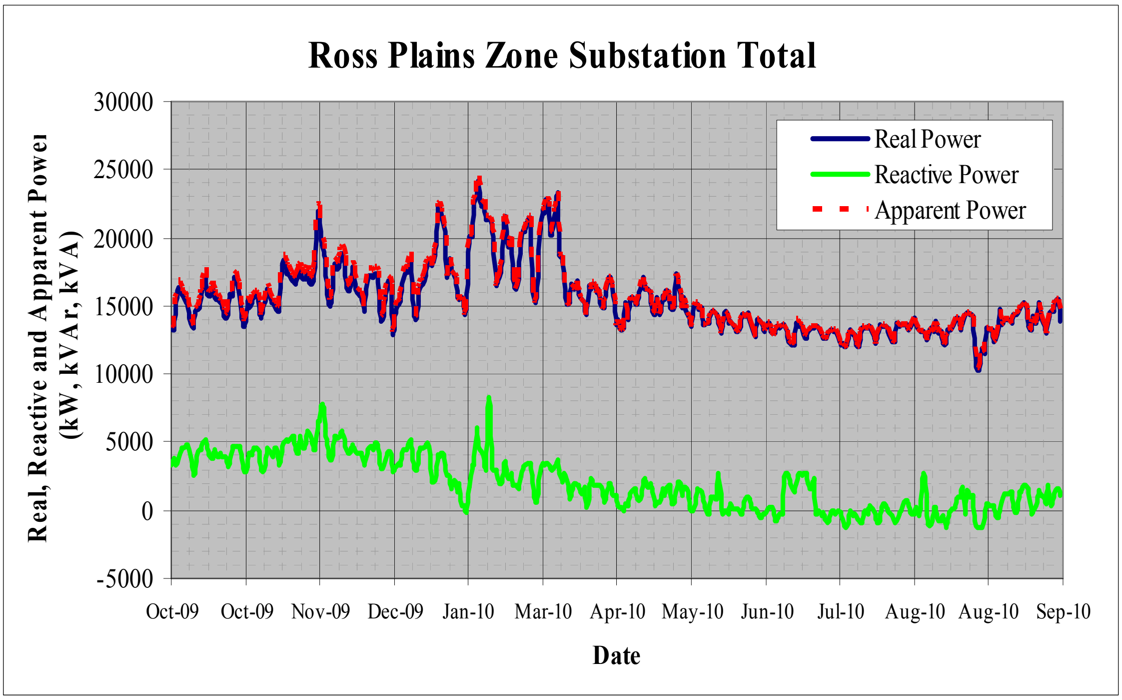


Figure 2.6 – Ross Plains ZS Total Loads

2.7.3 ROPL-04 Feeder Configuration

The Ross Plains ZS feeder ROPL-04 leaves the 11kV bus section Number One via an underground cable that runs for ~100m. This cable is terminated at a distribution pole and the feeder continues as overhead. The feeder then transitions to underground and all the distribution transformers on this feeder are fed from these underground cables.

In all there are thirteen distribution substations ranging in size from 300 kVA to 500 kVA. All bar two of these distribution substations supply residential loads. One 500 kVA distribution substation supplies a small school. One of the 500 kVA units supplies the thirteen small commercial customers and ninety residential customers.

2.7.4 ROPL-04 Loads

The graph in figure 2.7 below shows three daily load profiles on the ROPL-04 feeder. These load profiles were taken from data collected over the year from the 1st of October 2009 to 1st of October 2010 and include:

1. The maximum load was measured on this feeder, 4th of February 2010.
2. The lowest maximum was measured on this feeder, 27th of August 2010.
3. The average of each half hourly period on every day.

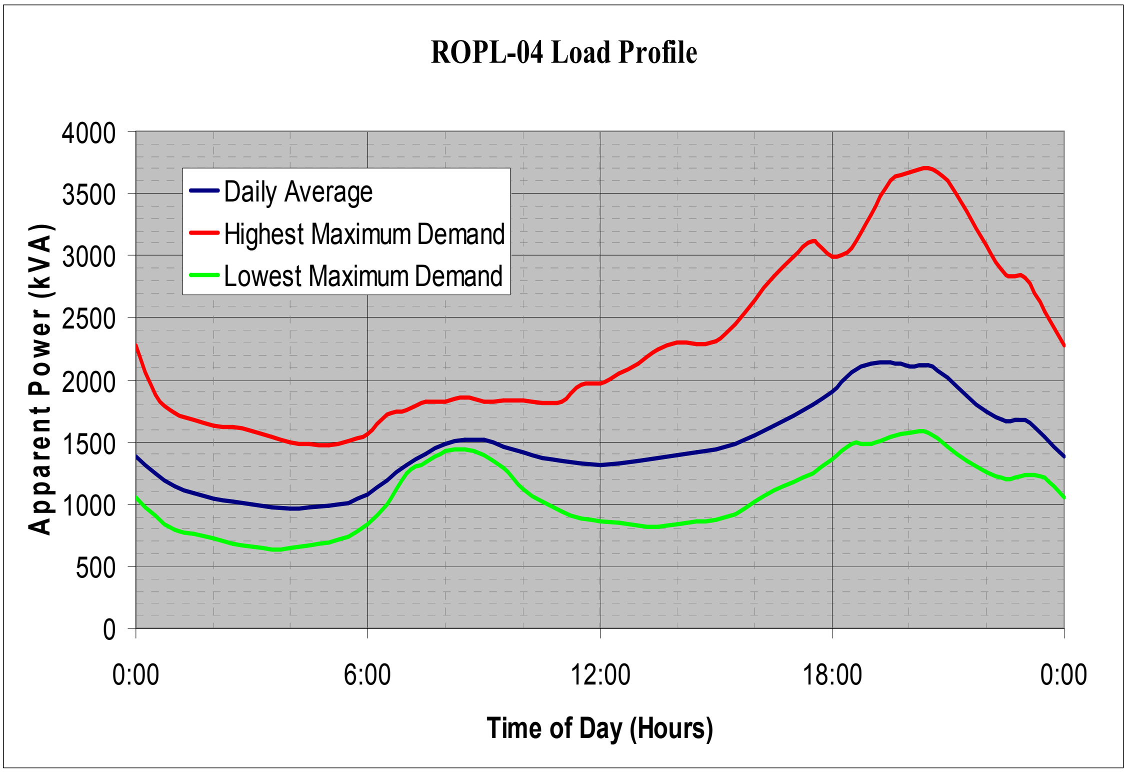


Figure 2.7 – ROPL-04 Load Profiles

2.7.5 ROPL-04 Protection Systems

The distribution feeder ROPL-04 has a protective circuit breaker at the zone substation, which is controlled by a protection relay. There are no other protective devices on the lines and cables on this feeder. The distribution transformers all have HRC fuses on both the primary and secondary windings. The settings for the protection relay are as summarised in the table 2.2 below.

Table 2.2 – ROPL-04 Protection Settings

Protection Type	Curve Type	Current Pickup	Time Multiplier or Time Value	Instantaneous Value
Over Current	Standard Inverse	300 A	0.1	3000 A
Earth Fault	Standard Inverse	60 A	0.1	3000 A
Sensitive Earth Fault		6 A	6 s	

2.7.6 ROPL-04 Voltage Control

The voltage at the 11 kV bus at Ross Plains zone substation is regulated to approximately 102% of the nominal 11kV. The OLTC on a high voltage side of a 66/11kV transformer changes the transformation ratio by 1.25% for each step and is controlled by a voltage regulating relay and the settings for this device are as follows:

- Set point – 102%
- Upper limit – 103%
- Lower limit – 101%.
- Time delay period – 60 s

2.7.7 ROPL-04 Weather Data

The critical weather data that is of consequence in this research project is wind speed on the days when the large broken cumulus clouds pass over the network. The specific data is not available for this detail of weather conditions and so the average wind speed and direction for Townsville will be used and this is 10 to 20 km/hr at 135^{o} (Australian Bureau of Meteorology website, Wind speed and direction data, viewed online 17th of Oct 2010, <http://www.bom.gov.au/cgi-bin/climate/cgi_bin_scripts/windrose_selector.cgi>). The middle of this range (15 km/hr) can be assumed for this research project.

2.8 *SWER Distribution Feeder*

The following sections of this report cover the basic information relating to the chosen SWER distribution feeder.

2.8.1 SWER Feeder Location

The SWER feeder being considered in this research project is the Karara SWER, which is a section of a feeder knows as Lemontree that is supplied by the Pampas zone substation in south west Queensland. The Pampas ZS is located between the towns of Pittsworth and Millmerran. Figure 2.8 below shows the location and extent of the Karara SWER feeder.

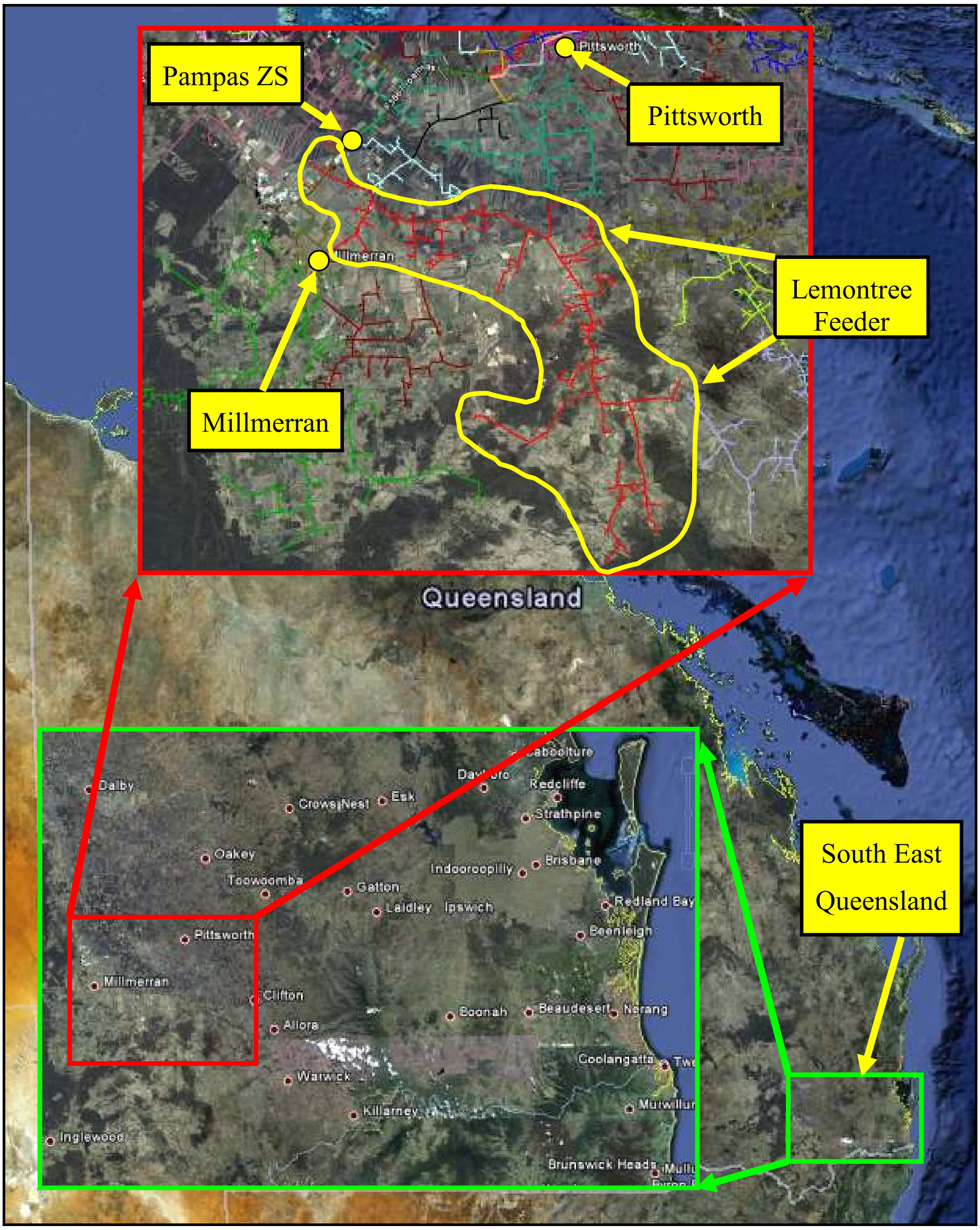


Figure 2.8 – Location of the Lemontree 11kV Feeder

The Lemontree Feeder is one of four 11 kV distribution feeders supplied from the Pampas ZS. The first section of the Lemontree feeder is configured as three phase 11 kV and the south east end is a 12.7 kV SWER network. The Lemontree feeder supplies 400 rural customers, 302 on the 11 kV portion and 98 on the SWER portion. Figure 2.9 below shows the extent of the 11 kV three phase and 12.7 kV SWER portions known as the Karara SWER.

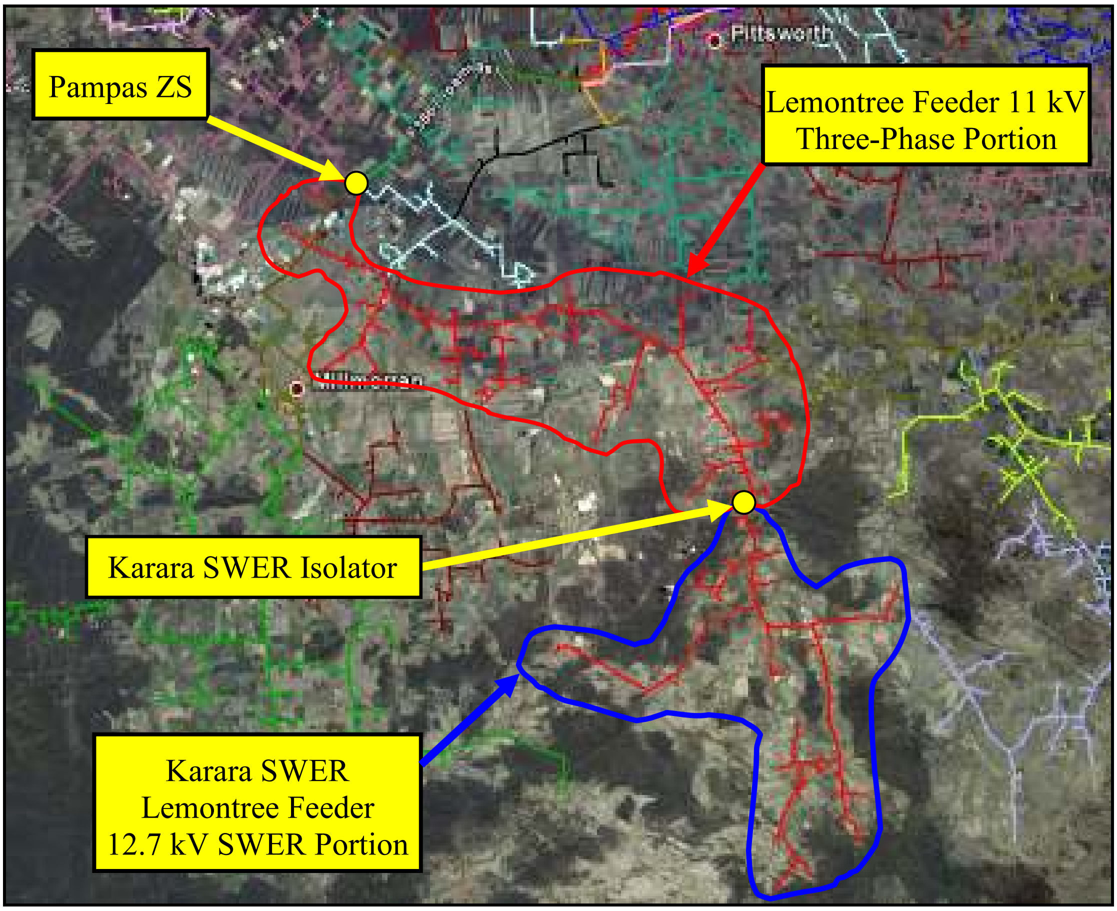


Figure 2.9 – Lemontree Feeder 11kV and 12.7 kV SWER

2.8.2 Lemontree and Karara SWER Feeder Configuration

The Pampas ZS is fed from the Yarranlea bulk supply substation by a 33 kV sub-transmission feeder. Pampas ZS is configured with a 33 kV regulator that feeds a 33 kV bus that in turn feeds two 5 MVA 33/11 kV transformer (as well as an additional out going 33 kV feeder to Millmerran ZS). These two transformers feed an 11 kV outdoor bus that supplies four distribution feeders. One of the distribution feeders is the Lemontree feeder, which is a long heavily loaded rural network. Figure 2.10 below shows a single line diagram of the configuration of the Lemontree feeder and the various transformers, regulators and descriptions loads.

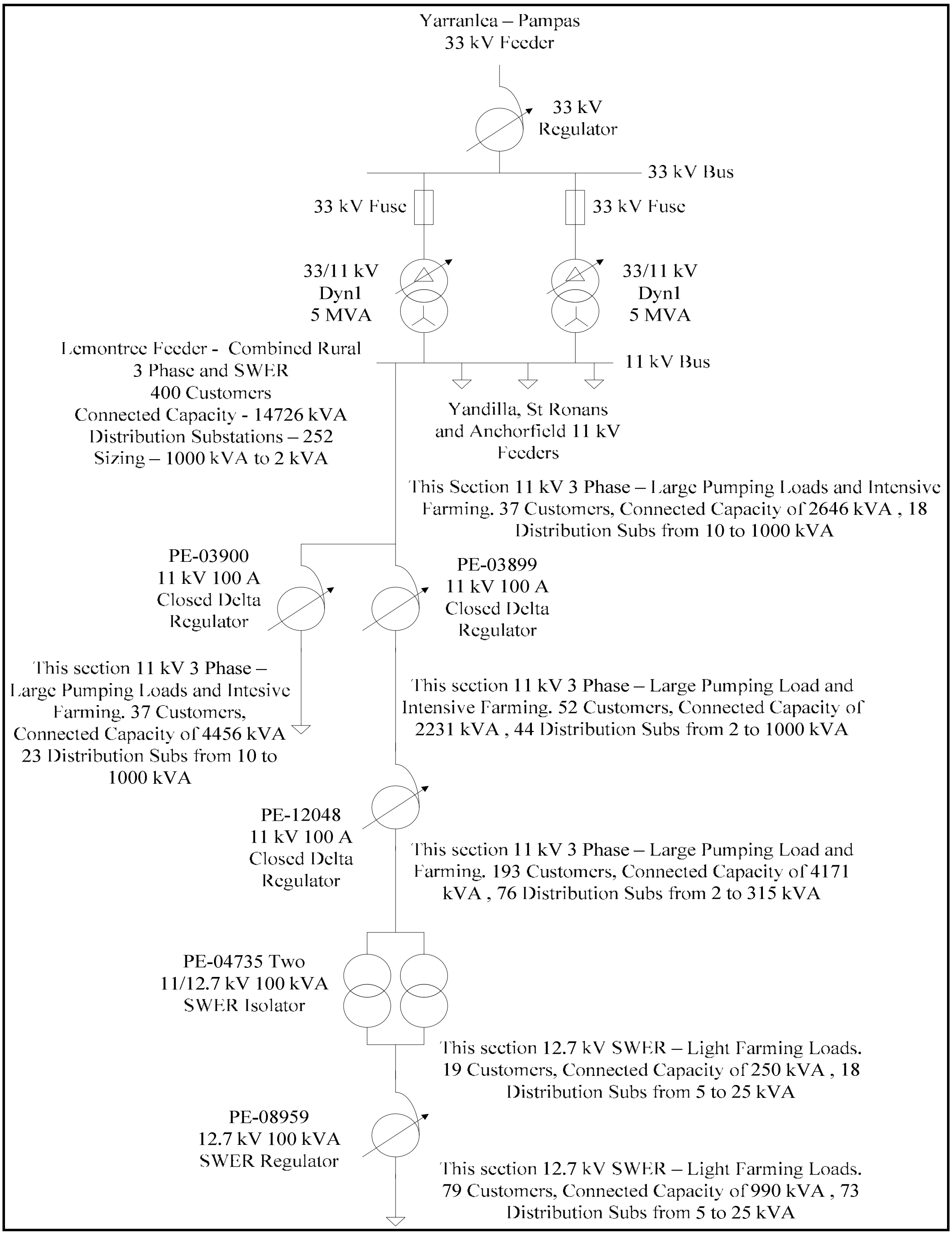


Figure 2.10 – Configuration of the Lemontree Feeder and Karara SWER

This research project will concentrate on the Karara SWER portion of the Lemontree feeder. The Karara SWER network supplies 92 customers using 91 distribution substations. Figure 2.11 below shows the extent of SWER network and shows some distances so that some understanding of the scale can be had.

Figure 2.11 – Extent and size of the Karara SWER network

2.8.3 SWER Network Loads

The graph in figure 2.12 below shows three daily load profiles on the Lemontree feeder. These load profiles were taken from data collected over the year from the 1st of October 2009 to 1st of October 2010 and include:

1. The day when the maximum load was measured on this feeder (23rd of February 2010).
2. The day when the lowest maximum was measured on this feeder (19th of September 2010).
3. The average of each half hourly period on every day.

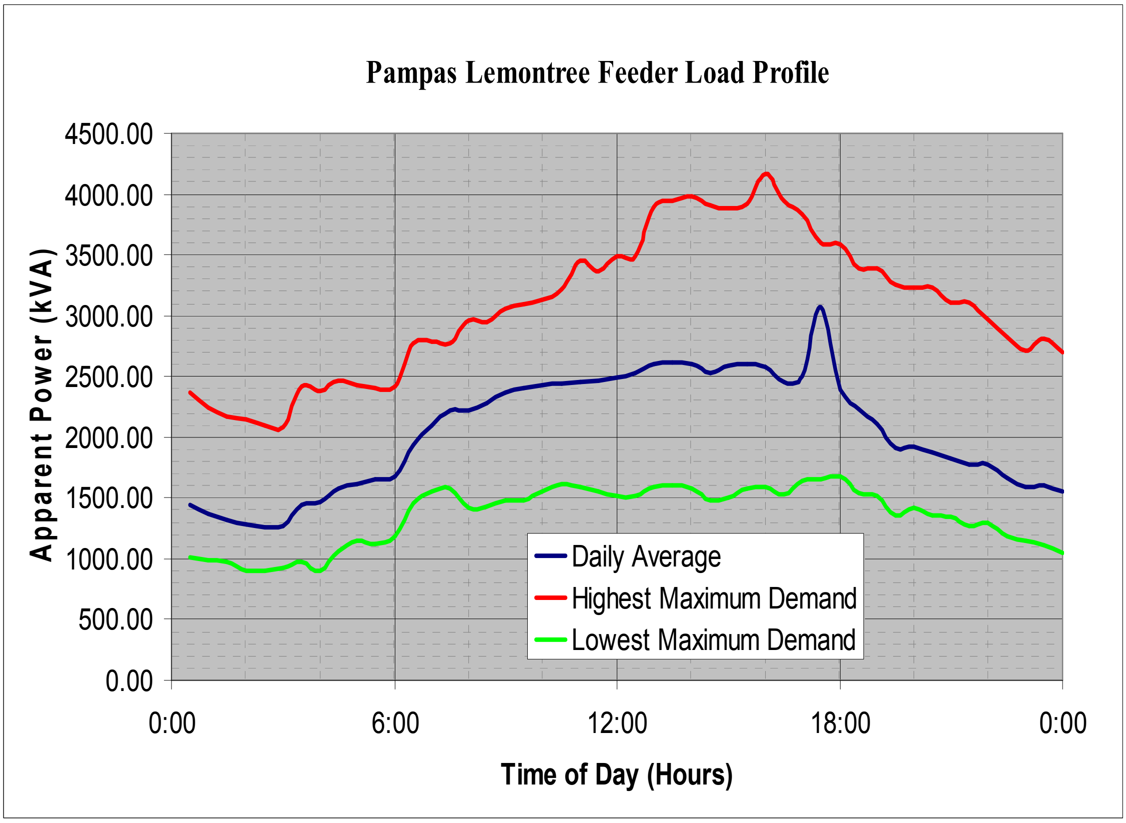


Figure 2.12 – Lemontree Feeder Load Profiles

The Lemontree feeder contains a number of large distribution substations that supply rural applications. A number of these are used to supply very large water pumps that are used very infrequently for water harvesting (where large quantities of water are pumped from local streams and into storage dams) as well as other intensive farming practises such as piggeries and chicken farms. In all there is a total of 14,726 kVA of connected capacity on the Lemontree feeder and of this total 10,245 kVA is consumed by transformers sized between 100 kVA and 1,000 kVA. The average connected capacity per customer on the 11 kV portion of the Lemontree feeder is 43.94 kVA.

The connected capacity on the Karara SWER network is 1190 kVA and is made up of one 5 kVA, sixty-nine 10 kVA, one 20 KVA and nineteen 25 kVA transformers. In general the smallest transformer installed is 10 kVA and these tend to supply farm houses. The 25 kVA units are installed usually to supply a larger load such as a pump or farm workshop. The average connected capacity per customer on the Karara SWER is 13.47 kVA, which is significantly less than the 11kV network.

It could be argued that the loads depicted in figure 2.12 possibly do not contain much of the water harvesting loads but do contain the intensive farming loads. In many ways this may present a similar load profile and utilisation factor to the SWER network loads. It will be assumed that the Karara SWER network will have a load that is proportionate to the connected capacity compared to the total Lemontree feeder connected capacity (1190 kVA divided by 14726 kVA or 8.08%). This value can be applied to the total feeder loads to develop the Karara SWER loads. Figure 2.13 below shows these assumed Karara SWER loads.

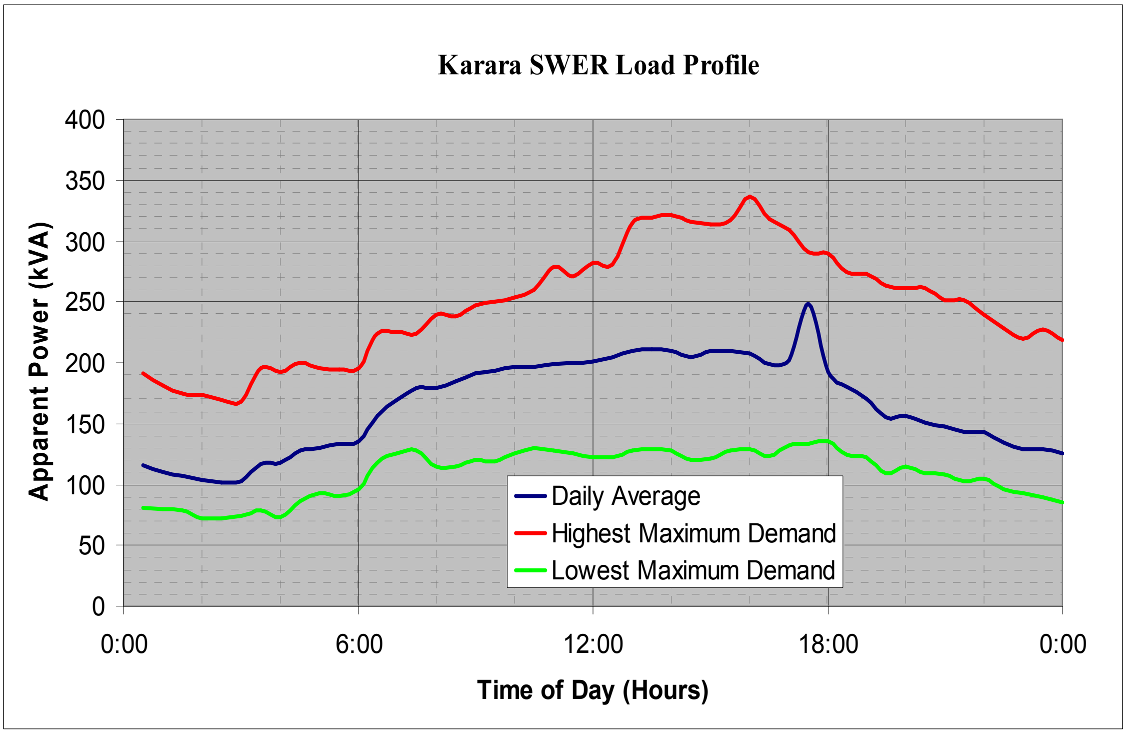


Figure 2.13 – Assumed Karara SWER network load profiles

2.8.4 SWER Network Protection Systems

The Lemontree distribution feeder has a number of protective circuit breaker in the both the 11kV and SWER portions of the network. Figure 2.14 below shows a single line diagram of the network and these protective devices as well as some descriptive details.

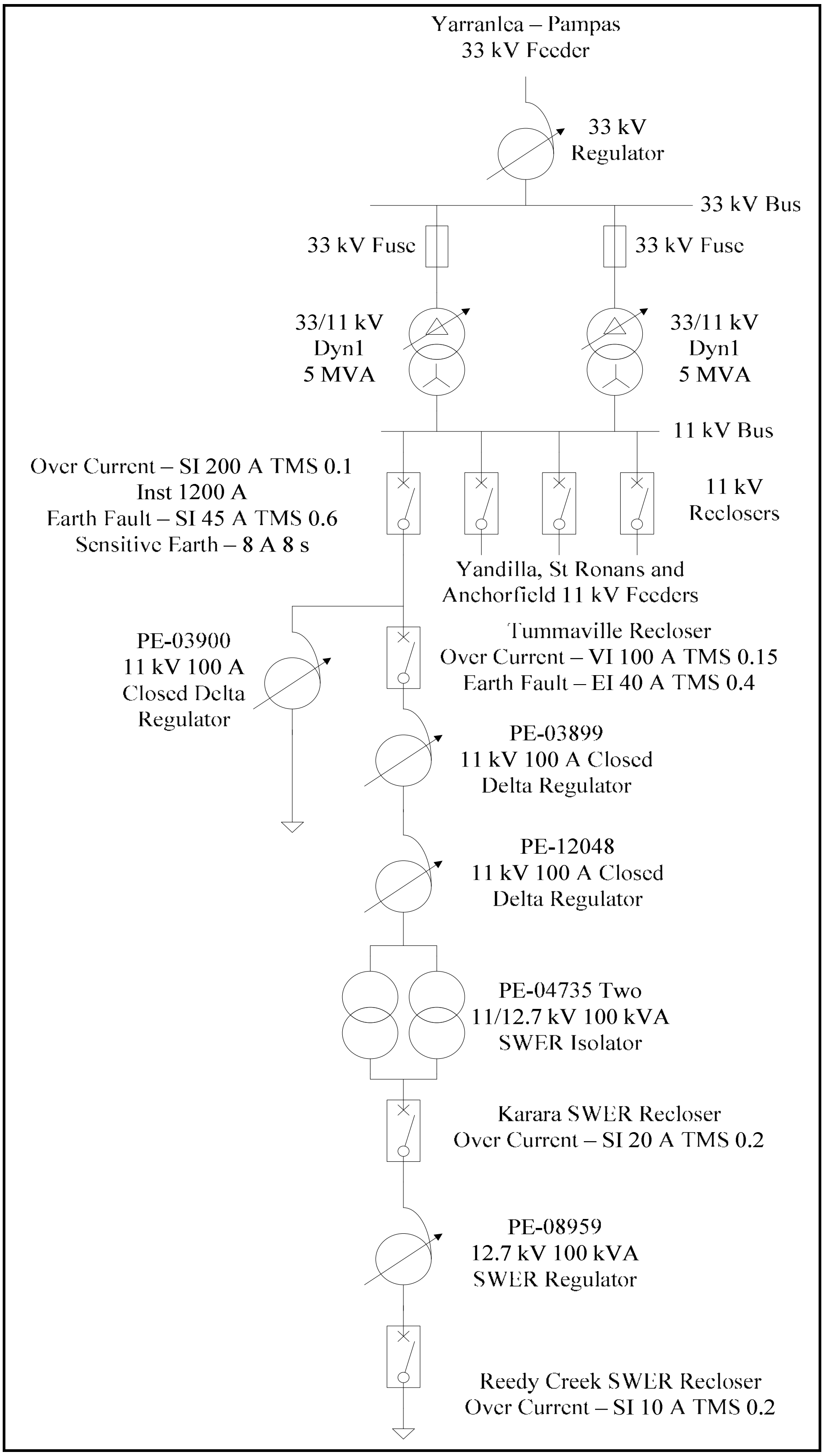


Figure 2.14- Lemontree Feeder protective device arrangement

The table 2.3 below summarises the protection settings for the Lemontree feeder, showing the different types of IDMT and their values for the individual protective devices.

Table 2.3 – Lemontree Feeder Protection Settings

Protection Type	Curve Type	Current Pickup	Time Multiplier or Time Value	Instantaneous Value
Lemontree Feeder Recloser				
Over Current	Standard Inverse	200 A	0.1	1200 A
Earth Fault	Standard Inverse	45 A	0.6	
Sensitive Earth Fault		8 A	8 s	
Tummaville Recloser				
Over Current	Standard Inverse	100 A	0.15	
Earth Fault	Extremely Inverse	40 A	0.4	
Sensitive Earth Fault				
Karara SWER Recloser				
Over Current	Standard Inverse	20 A	0.2	1200 A
Reedy Creek SWER Recloser				
Over Current	Standard Inverse	10 A	0.2	1200 A

2.8.5 SWER Network Voltage Control

The voltage control on the Lemontree feeder is achieved by using the tap changing at the Pampas ZS as well as a number of regulators in the network. Figure 2.15 below shows the devices used in the Lemontree feeder.

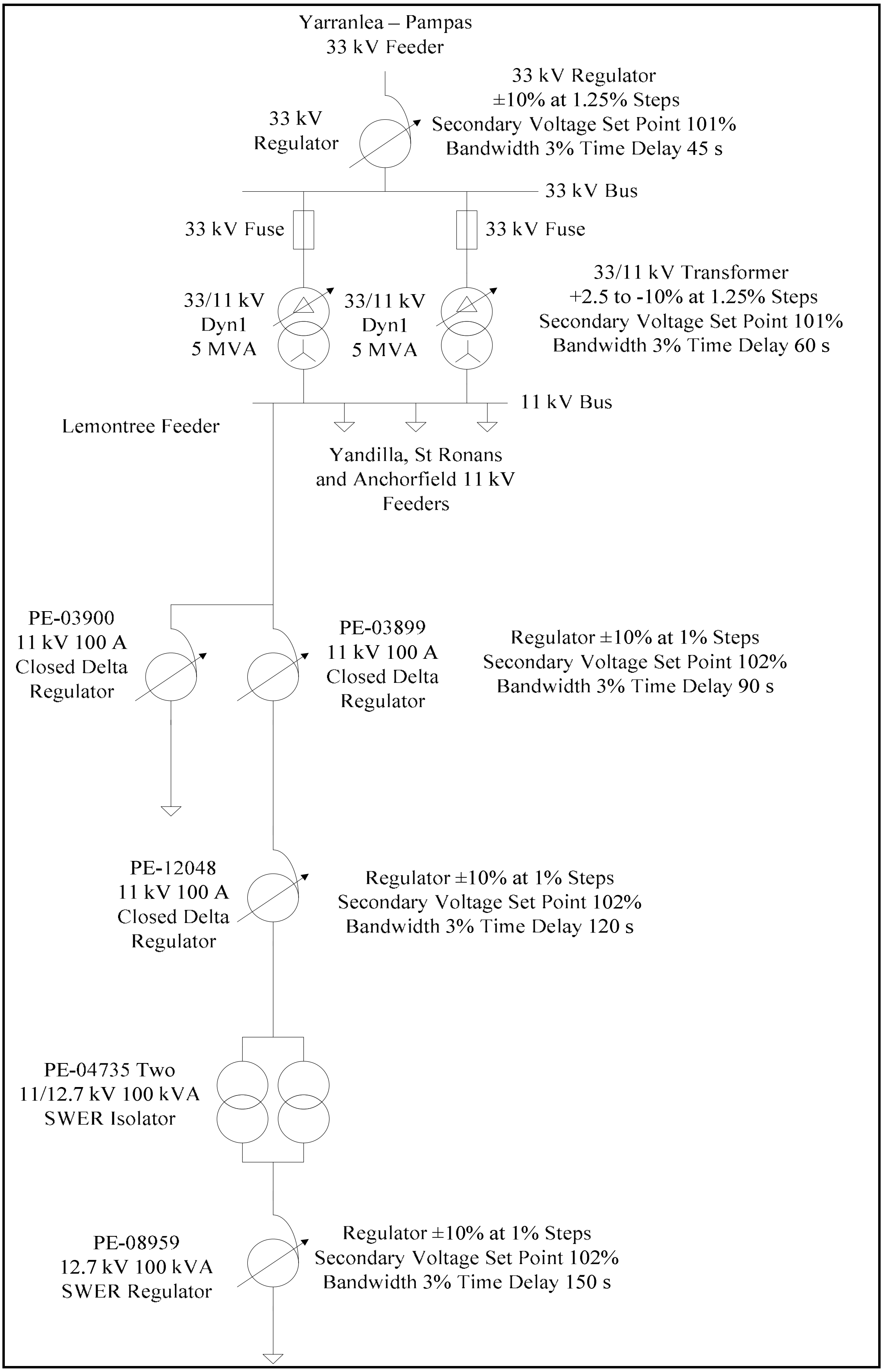


Figure 2.15- Lemontree Feeder regulating device arrangement

A summary of these setting can be seen table 2.4 below.

Table 2.4 – ROPL-04 Protection Settings

Transformer or Regulator	Tap Range	Tap Percentage	Set Point	Bandwidth	Delay
33 kV Regulator	±10%	1.25%	101%	3%	45 s
33/11 kV Transformer	+2.5 to -10%	1.25%	101%	3%	60 s
Tummaville 11 kV Regulator PE-03899	±10%	1.00%	102%	3%	90 s
11 kV Regulator PE-12048	±10%	1.00%	102%	3%	120 s
12.7 kV Regulator PE-08959	±10%	1.00%	102%	3%	150 s
Tummaville 11 kV Regulator PE-03900	Unknown				

The second Tummaville regulator PE-03900 does not feed the Karara SWER and so does little to effect the SWER networks operation.

2.8.6 Karara SWER Weather Data

The critical weather data that is of consequence in this research project is wind speed on the days when the large broken cumulus clouds pass over the network. The specific data is not available for this detail of weather conditions and so the average wind speed and direction for the closest location will be used. This location is Tenterfield and the average wind speed and direction is up to 10 km/hr at 45^o (Australian Bureau of Meteorology website, Wind speed and direction data, viewed online 17th of October 2010, < http://www.bom.gov.au/cgi-bin/climate/cgi_bin_scripts/windrose_selector.cgi>). The upper end of this range (10 km/hr) can be assumed for this research project.

2.9 *The Small DG Systems*

The Small DG Systems considered in the research project are those that can be connected to the electrical supply network in Queensland and are sized up to 10 kW per phase. The following sections describe the characteristics of the components and the complete arrangement that constitutes a DG System.

2.9.1 Photo Voltaic Panels

Photovoltaic (PV) panels are the only source of energy for Small DG Systems considered for this research project. The panels convert solar energy (sun light) into electrical energy using thin sections (wafer) of silicon semiconductors. Other materials are used for solar panels; however silicon is the most common and will be the only material considered in this research project. Each silicon wafer generates a voltage across itself when exposed to sunlight and when an electrical circuit is made current will flow. A solar panel contains a number of the silicon wafers connected together and then to external electrical connection.

The silicon converts different wavelengths of light to electrical energy at different rates. Figure 2.16 below (Apogee web site, spectral response of silicon photovoltaic panel, viewed 12 Oct 2010, <http://www.apogeeinstruments.com/pyranometer/spectralresponse.html>) shows the relative wavelength of visible light verses the electrical energy produced. This curve is the same for small silicon photodiodes as well as large silicon wafers used in photovoltaic panels.

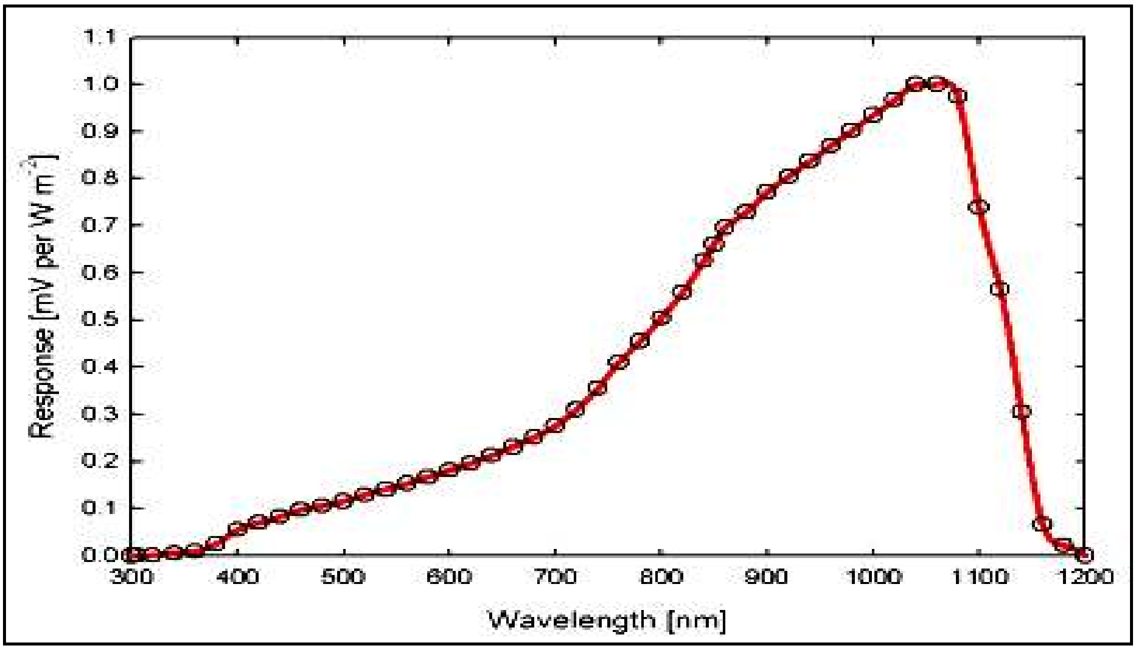


Figure 2.16 – Typical Silicon PV Wavelength verses Output (Apogee Instruments 2010)

The average conversion rate for a typical PV panel is presently about 12%, meaning that 1 W of solar radiation will generate about 120 mW of electrical energy. The actual rate of power generation depends on a number of variables including the suns elevation, time of year, orientation of the PV panel, atmospheric conditions, mounting method of the PV panels and temperature. In reality these variables can be distilled to the incident solar radiation and panel temperature.

The individual PV panels can be connected together to form an array and configured in parallel for higher current or series for higher voltages. In general PV panels are connected in series to increase the voltage and lessen the losses experienced when transmitting their energy to the grid-connect inverter. The PV panels for use on Small DG Systems range in size up to about 200 W and voltages of up to 48 V d.c. They are usually configured into an array that produces open circuit voltages from 200 V up to about 500 V.

The PV panels themselves consist or a number of silicon wafers connected in series and parallel to achieve the desired voltage and current outputs. If one of the wafers in a series is covered then the output from the series will be constricted. The majority of PV arrays consist of a number of panels connected in series, so if one wafer in one panel is obstructed then the output from the complete array will be compromised. This means that shading any part of the PV array will reduce the output to near zero.

2.9.2 Grid Connect Inverters

The device that converts the d.c. output from the PV array into the a.c. suitable for grid-connection is known as an inverter. A number of techniques are employed to convert the d.c. to a.c. although they are all similar in respect that they switch the d.c. at high frequency and filter to create 50 Hz.

The great majority of the grid-connect inverters employ a maximum power point tracking (MPPT) method. This method essentially changes the conversion to maximise the output power by changing the input current to keep the input voltage at the level where the power is maximum. Figure 2.17 below (Suntech, residential solar, viewed online 10th of Oct 2010, <http://ap.suntech-power.com/en/products/residential.html>) shows a voltage versus power curve of a typical silicon PV panel. The MPPT will endeavour to keep the input voltage at the peak of the power curve.

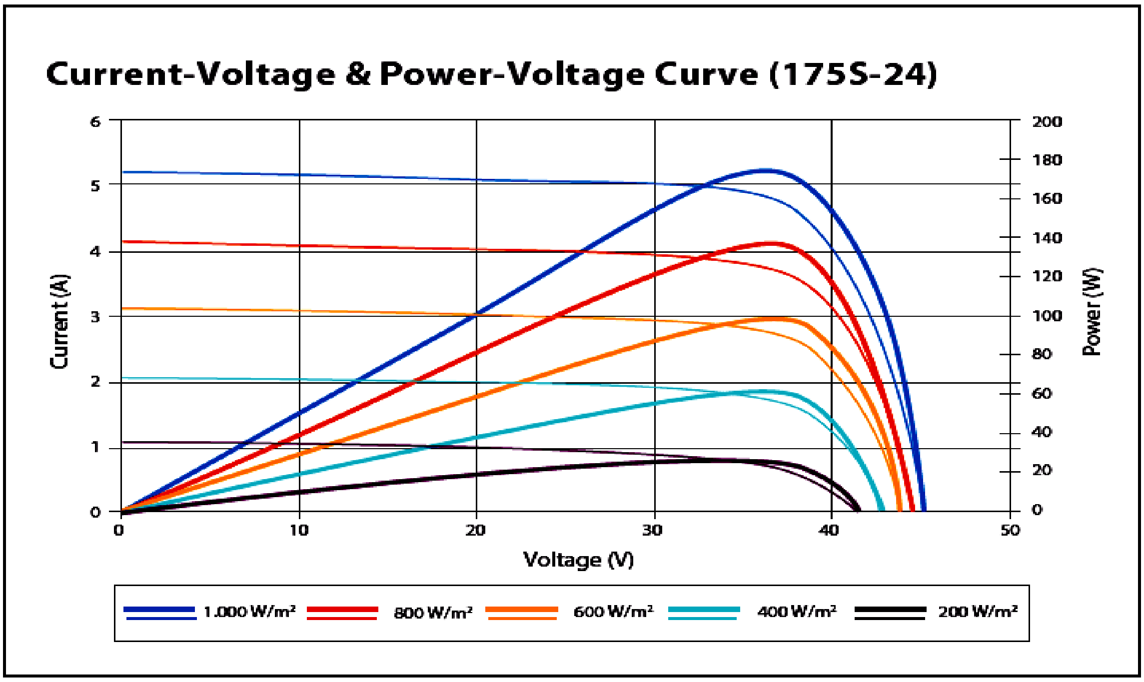


Figure 2.17 – PV Panel Current, Voltage and Power Relationship to Solar Radiation (Suntech 2010)

The speed of the inverter to change conversion or track is not something described by the manufacturers, although it expected to be relatively consistent and quick in most applications.

The grid connect-inverters used in the Small DG Systems in Queensland produce only real power (watts) and do not import or export any apparent power (VAr's). The ability to produce apparent power would be possible with most grid-connect inverter platforms and would generally only require a change of control software.

2.9.3 Complete System

A complete Small DG System consists of a PV array and a grid-connect inverter wired together in a manner compliant with the relevant Australian Standards. This means that the PV array current passes through a circuit breaker between the array and the inverter and the inverter current passes through a circuit breaker between the inverter and the grid connection in the customer's switchboard. Figure 2.18 below illustrates a typical Small DG System arrangement.

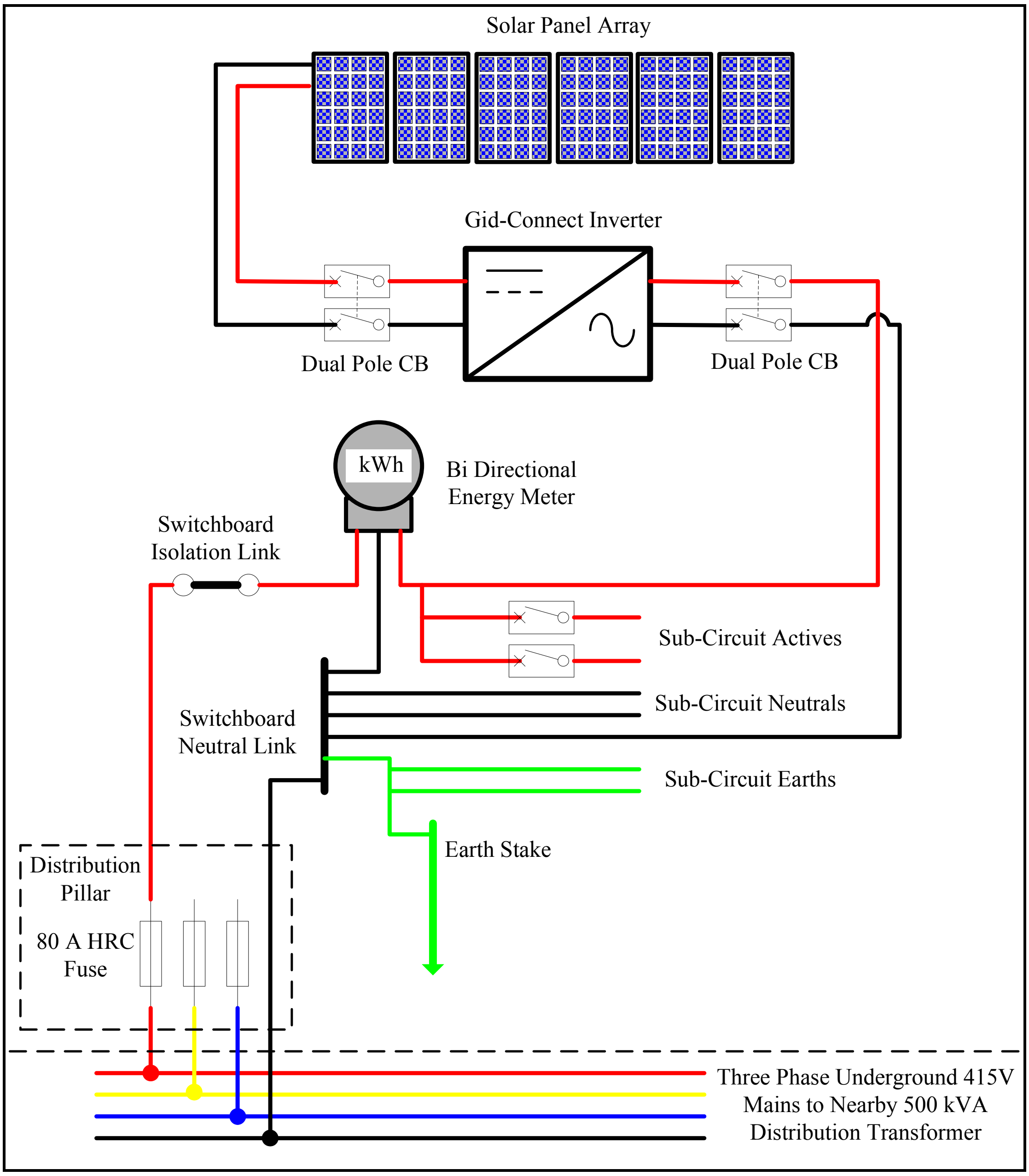


Figure 2.18 – Typical Small DG System Arrangement

The Small DG Systems are essentially connected directly to the LV distribution network near to the customer's point of connection. This means they have the ability to deliver all of their surplus power onto the grid virtually without any constraint.

2.9.4 Grid Connect Performance

The grid-connect inverters used in Small DG Systems in Queensland have passive and active anti-islanding features enabled. It is very likely that when the grid supply is interrupted to a distribution network that the anti-islanding features of the grid-connect inverters will disconnect their supply from the network also.

When the grid supply is active it is possible that the anti-islanding upper voltage limits may activate if the Small DG Systems cause the voltage to increase above their setting. This feature could be a positive method of preventing excessive voltage rise if the Ergon Energy guideline of setting this value to 255 V was applied.

The anecdotal evidence is derived from a conversation with the compliance testing facility staff is that the anti-islanding upper voltage limit is always left at the maximum from AS4777-3 clause 5.3 of 270 V. Further anecdotal evidence derived from conversations with Ergon Energy staff suggest that all the installed inverters on Small DG Systems have their upper voltage limits left at the 270 V and are not adjusted to the desired 255 V during installation.

2.9.5 Weather Related Performance

The main limiting factor in the performance of Small DG Systems is the output from the PV array. The output from the PV array is limited in turn by the quantum of incident solar radiation reaching the panels and the temperature of the panels.

The orientation of the PV array with respect to the direction of the sun is an obvious limitation. The majority of PV arrays in Queensland are fixed in place and are orientated to face north. They are almost always tilted and the ideal angle of this tilt depends on latitude. The tilt also helps rain wash dust away and prevents debris such as leaves lying on the panels. In many cases the PV arrays of Small DG Systems are mounted on building rooves and the exact orientation and angle is compromised by being mounted flat in the best possible location. This usually means that the output is a little less than ideal, although in most cases this would most likely mean a reduction of around 10%. The output of most fixed PV arrays on a clear day is then generally only a sine response with respect to time of day and the peak value would change depending on the time of year. Figure 2.19 below demonstrates a PV array output in watts versus the time of day.

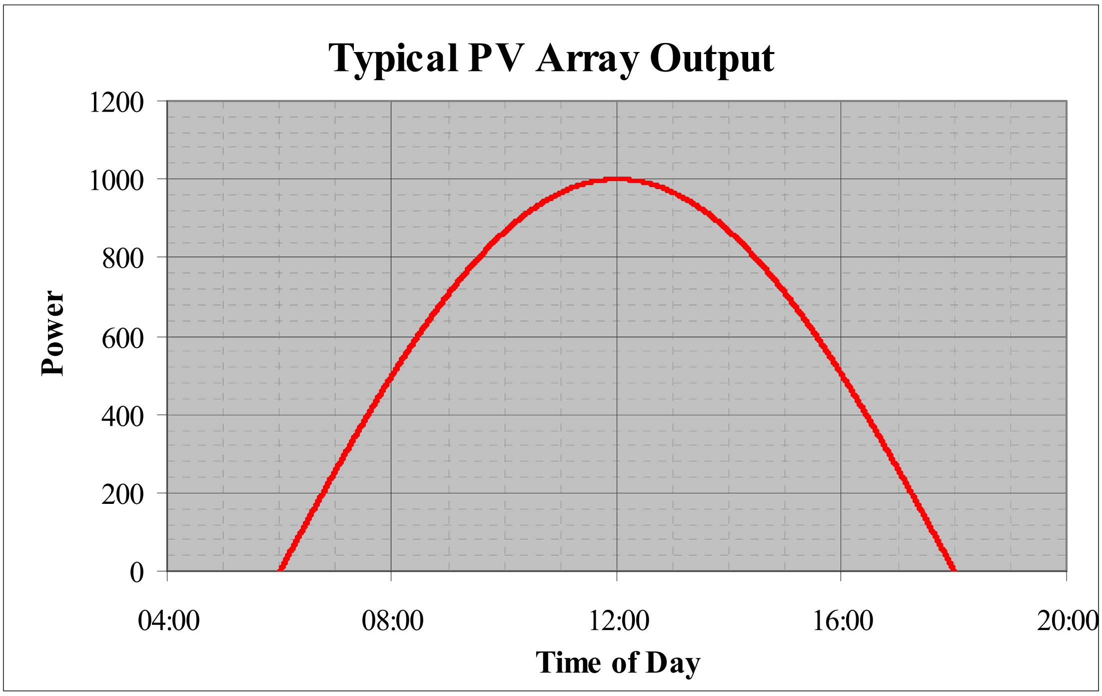


Figure 2.19 - Typical Clear Day PV Array Output Power versus Time of Day

The other factors causing reduce solar radiation are numerous and include clouds types, water vapour, dust and pollution. The reduction in solar radiation will be relatively constant during the day for most of these issues with the exception of cloud, which vary far more rapidly than the rest. The output changes due to cloud type and movements at the rate that can affect the PV array output are a relatively unknown quantity in Queensland.

2.10 *Expected Small DG System Related Issues*

The discussion so far has presented the key components in this research project. The traditional electrical supply network operates on power flowing radially from large remote power stations, through very high voltage transmission lines to substation where the voltage is reduced and further transmitted to culminate at the distribution network where the majority of customer's take supply. Figure 2.20 below shows a very simplified view of such an arrangement with the red lines indicating radial power flow.

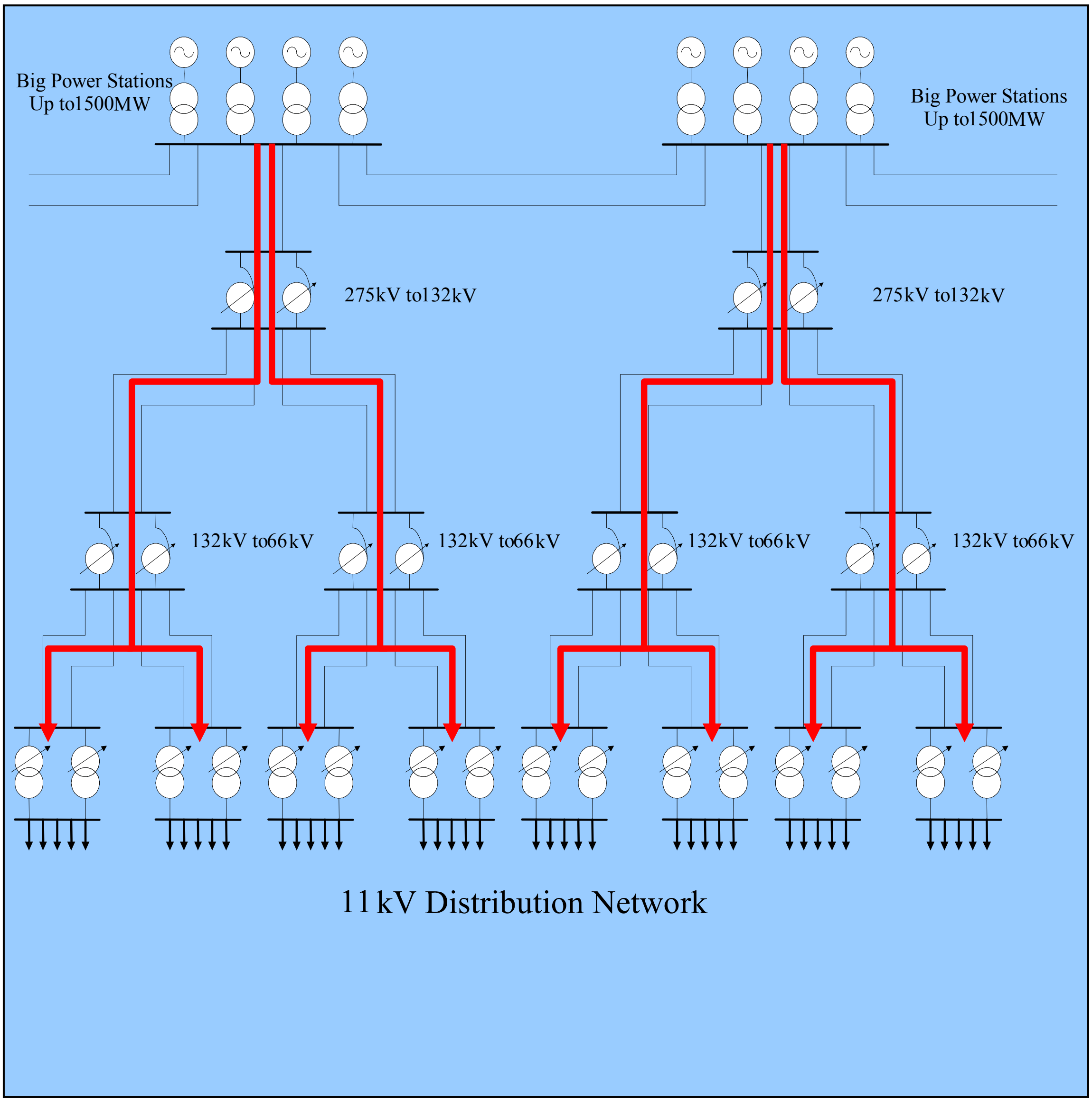


Figure 2.20 – Simplified Electrical Supply Network and Radial Power Flow

The same networks are presently undergoing a transformation where the inclusion of distributed generation (DG) at the lower voltage is taking place. The effect of this DG inclusion will eventually see the power flows in manners that the network was never designed to encounter. Figure 2.21 below shows the same simplified network with the inclusion of DG and possible differing power flows.

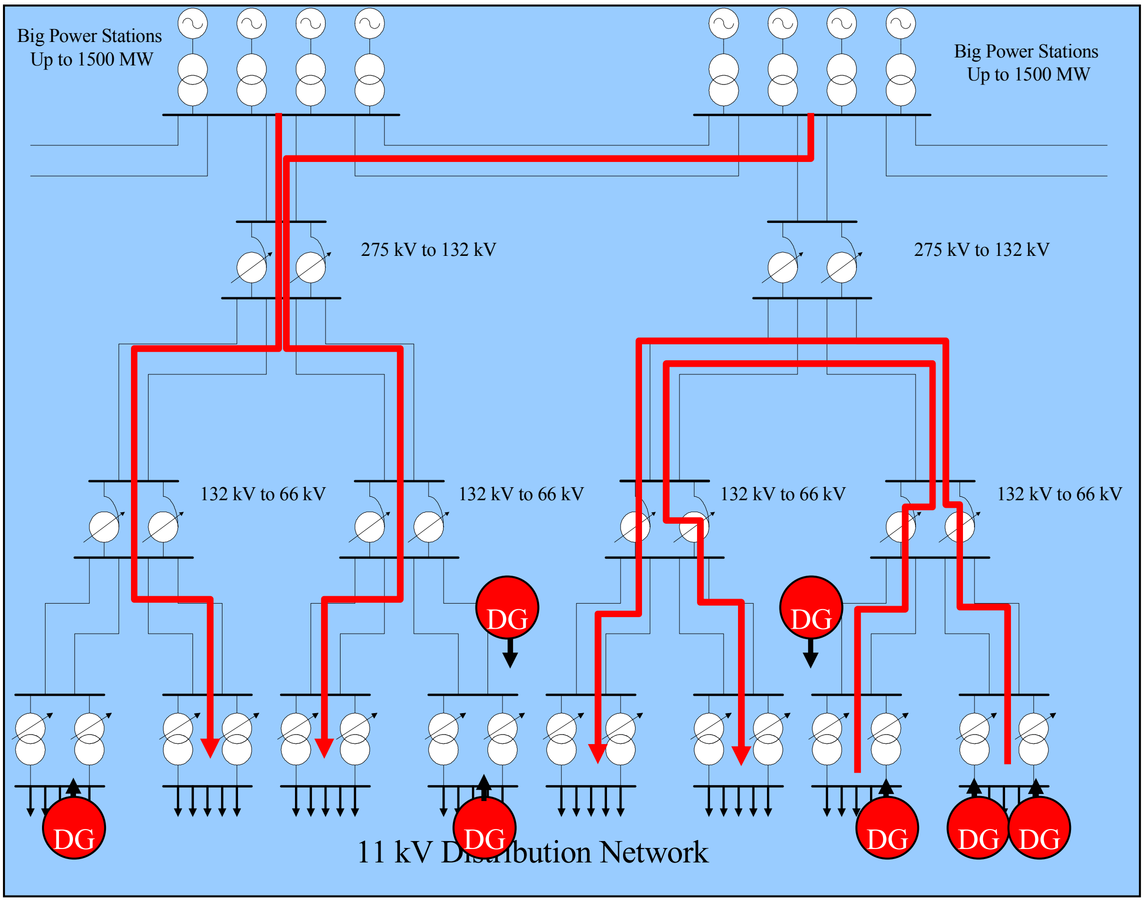


Figure 2.21 – Possible Power Flows as a Result of DG Inclusion

It is possible that the traditional electrical supply network may not behave in the manner for which it was designed when large amounts of DG are included. DG larger than 10 kW per phase is subject to rigorous network analysis and the network is reconfigured to suit. The DG smaller than 10 kW per phase is not readily subject to this analysis and this research project will investigate the effects by focusing on the two areas of protection systems and QoS.

2.10.1 Anticipated Protection System Problems

The protection systems on distribution networks are designed for radial power flows. They are almost exclusively current based systems employing IDMT characteristics. There is usually some margin built into the protection settings to account for numerous inaccuracies in equipment and system models and this margin is known as protection reach.

The inclusion of Small DG Systems within a distribution network will have some impact on the current flows within a network. The effects will be greatest where the Small DG Systems combined capacity compared to customer load is high and if the network is extensive and electrically weak. The changes to current are most likely to affect networks where the protection reach is very close to prescribed lower limits. These issues are most likely on long SWER networks and least likely on strong urban residential feeders.

2.10.2 Anticipated QoS Problems

The voltage control of the distribution networks is also designed specifically for radial power flows. Once again the inclusion of many Small DG Systems into these networks will affect power flows and so affect the voltage control. The effects will be a function of the combined capacity of the Small DG Systems compared to customer loads and also the length and electrical strength of the network. The problems will be greatest when there are many Small DG Systems installed on a long weak network such as a SWER and less on the strong feeders such as the urban residential.

2.11 *Network Support Devices*

The performance of a distribution network can sometimes be improved with the application of devices that regulate voltage or inject reactive power. A number of devices are used to correct

2.11.1 Voltage Regulators

A voltage regulator is a transformer with the same nominal primary and secondary voltages. These transformers are usually auto-transformers meaning that they share a common winding for both primary and secondary. They also include an on load tap changer (OLTC) that allows them to change their winding ratios and so adjust their output voltages.

In general the OLTC and winding arrangements allow the regulators to buck or boost the output voltage by similar amounts such as ±10% by increments of about 1%.This also means that these devices can be set up to regulate when power is flowing in either direction.

The operation of the OLTC is caused when the voltage and line currents that are being monitored fall outside a predetermined limit for a predetermined time. The control methods of the OLTC operation are numerous. The most simplified measures line voltage and changes when the voltage is outside the set limits for a set period. More complex methods assume line impedance values and attempt to compensate for perceived voltages at remote locations and is known as line drop compensation.

The regulators used on the two representative feeders all apply the simplified voltage method only and all are set for one direction of power flow only.

2.11.2 Reactive Compensation

The operation of an a.c. network inevitably means that there will be reactive power involved as a result of partially reactive loads and the reactive components of the supply network. This reactive power is mostly detrimental to network operation and when minimised improves the network functionality. The control of reactive power usually results in improved voltage regulation.

In most networks the reactive power is inductive (lagging power factor) when the loads are high and capacitive (leading power factor) when the loads are low. This is because the customer's loads are mostly inductive and network components are more inductive when current is flowing. Network components such as cables, transmission lines and SWER lines are capacitive at low current levels.

A common method of improving network operation is to control the reactive power by injecting VAr's. This can be achieved by switching reactive components that counteract the network reactivity. This has been traditionally accomplished using capacitors or reactors (inductive reactance) both of which can be connected either in series or shunt.

The ideal arrangement would be to connect capacitors in series and as the current increases so does their capacitive reactivity, which would counter the increasing inductive reactivity of a network. This however is rarely done because it is more difficult to prevent through fault currents from damaging these device when they are connected in series. Generally capacitor banks are connected to the electrical network in a shunt arrangement.

Capacitor banks sizes depend on the application and range in size from a few kVAr to many MVAr. An example of a large bank used on transmission network can be seen below on the left of figure 2.22 and on the right is a small pole mounted bank used on a distribution network (ABB, Power Capacitors for high voltage applications, viewed online 19th Oct 2010, < http://www.abb.com/product/us/9AAC751420.aspx >).

Figure 2.22 – Examples of Shunt Capacitor Banks (ABB 2010)

Inductive reactors can be connected in either shunt or series depending on the requirements. A reactor connected in shunt will have a fixed reactivity that can be used counteract capacitive reactance. Reactors connected in series will see their reactivity increase with an increase in current flow. A series reactor is rarely beneficial for reactive power compensation and is usually intended to limit fault currents.

2.11.3 Static Reactive Compensation

There is a family of devices that can produce reactive power using electronic switching devices and are generally called Static Compensators (STATCOM). A block diagram of a STATCOM can be seen in figure 2.23 below (Suresh Kumar, Article on Static Synchronous Compensators (STATCOM) at Distribution and Transmission Levels, viewed online 19th Oct 2010, <http://sureshks.netfirms.com/index.htm>).

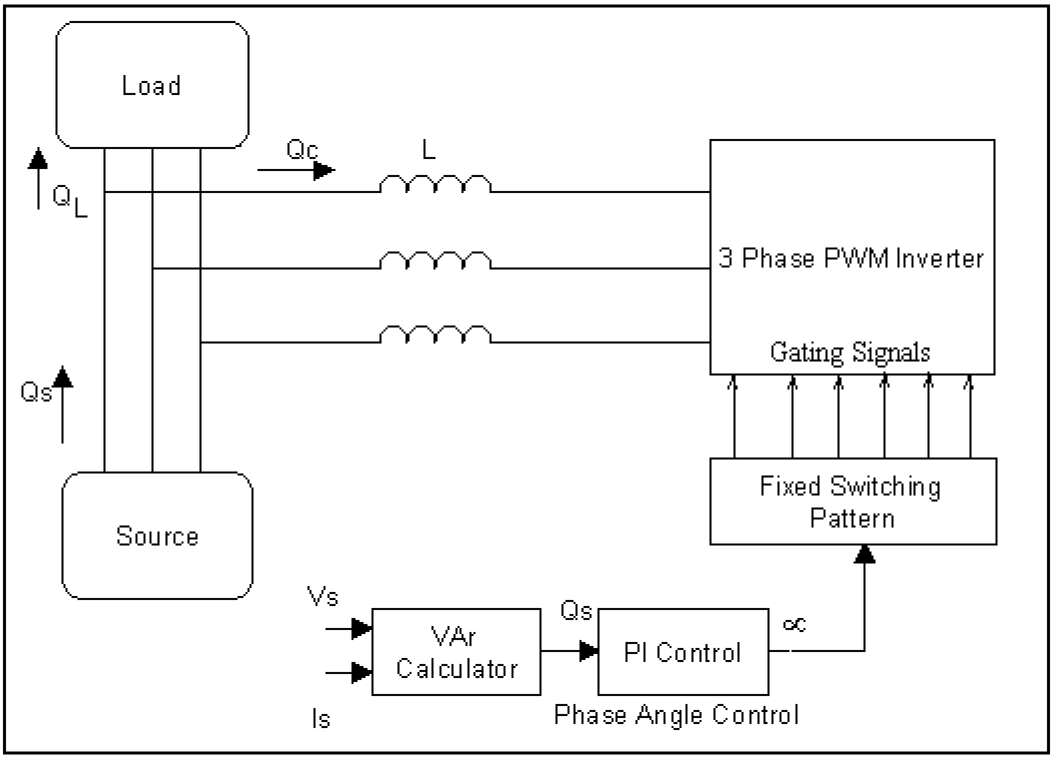


Figure 2.23 – STATCOM Block Diagram (Suresh Kumar 2010)

Reactive power can be generated by static switching devices, which are used to create three phase voltage as shown by the three phase Pulse Width Modulating (PWM) Inverter in figure 2.23 This inverter is coupled to the electrical supply network through series inductors (although in reality usually a coupling transformer). When the voltage at the PWM inverter is higher that the grid the device will cause current to flow out to the grid, effectively importing reactive VAr's or producing capacitive VAr's. The opposite happens when the voltage at the PWM inverter is lower than the grid and so the device imports inductive VAr's. This ability to import or export VAr's can be adjusted at sub-cycle speeds and so be used to compensate a network for very rapid changes in reactive power. This can be used to compensate for voltage fluctuations caused by changes in load or excessive reactive power.

STATCOMS range in size from tens of KVAr's to tens of MVAr's and can be applied to voltages ranging from transmission levels down to distribution levels by using appropriate coupling transformers.

2.12 *Network Modelling*

The large size and high cost of testing and measuring the impacts of network modifications precludes the use of in-situ testing. The electrical supply industry presently relies almost exclusively on models of their networks when managing decisions on the operation of their network assets.

A number of software packages specifically designed for network modelling are presently used by electrical supply authorities throughout the world. These software tools cost $10,000 or more for licenses. There were two software packages readily available for this research project and they were the only ones considered as the price of an alternative was too high:

1. DINIS(E) which is owned by the Fujitsu Corporation and models three phase systems only.
2. PSS SINCAL which is owned by the Siemens Corporation and claims to model three and single phase applications.

The Small DG Systems are mostly single phase and so the choice of software was clearly in favour of PSS SINCAL.

2.12.1 Major Urban Residential Feeder Models

The network chosen to represent the major urban residential feeder is the Ross Plains zone substation number 4 (ROPL-04). The PSS SINCAL model will include:

- The equivalent source impedance of the incoming 66 kV.
- The two 66/11 kV transformer that supplies the 11 kV bus.
- The complete 11 kV bus (both bus sections).
- The two 11 kV capacitor banks.
- The complete HV network of ROPL-04.
- An equivalent LV network for each distribution transformer, although with numbers that equate to the actual customer number fed from that distribution substation transformer.
- An equivalent load connected at each customer point of connection.
- The Small DG Systems will be modelled and connected at each customer point of connection.

Greater details of this model will be provided in a later chapter of this document.

2.12.2 SWER Feeder Models

The network chosen to represent the SWER feeder is the SWER section of the Pampas zone substation Lemontree distribution feeder. The Lemontree feeder is a composite of 11kV three phase and 12.7kW SWER networks. There are two 11kV voltage regulators in the 11kV network backbone, the last of which is approximately 15km from the beginning of the SWER network. The single SWER regulator is about 6km downstream of the beginning of the SWER network. In order to simulate the voltage regulation a simplified section of the 11kV network starting at the last 11kV regulator is included in the model. The model will include:

- Equivalent source impedance supplying the last 11kV voltage regulator.
- 15km of 11kV feeder with a point load representing all the 11kV loads downstream of this regulator.
- The SWER isolating transformer, which supplies the complete SWER network.
- The complete HV SWER network.
- The SWER distribution transformers are not included in the model; instead the loads are represented as connecting directly to the 12.7kV lines almost every distribution transformer supplies an individual customer.

- The Small DG Systems will be modelled and connected at each customer load as this is a single phase system.

Greater details of this model will be provided in a later chapter of this document.

CHAPTER 3 - LITERATURE REVIEW

3.1 *Outline of Literature Review*

A review was conducted into the existing literature that has been published on the inclusion of DG Systems on the distribution networks. Three specific fields were considered when searching for literature relevant to this research project and these were:

1. Application of DG Systems where QoS is affected by steady state in-feed.
2. Application of DG Systems where QoS is affected by fluctuating PV in-feed as a result of weather conditions.
3. Application of DG Systems where Protection Systems are affected.

3.2 *Steady State DG In-Feed Issues*

3.2.1 Steady State – Paper One

Optimal Distribution Voltage Control and Coordination with Distributed Generation

(Tomonobu et al, IEEE transaction on Power Delivery, Vol 23. No. 2, April 2008)

This paper develops an algorithm for centralised control of a distributed network of voltage regulators, high speed VAr injection to dynamically control the effects of PV DG.

This research project aims to understand where the problems begin to occur and resolve the problems with autonomous devices. The system proposed by Tomonobu et al would be applicable in the future on distribution networks such as Ergon Energy's when the communications systems are more extensively established.

3.2.2 Steady State – Paper Two

Maximum Penetration Level of Distributed Generation without Violating Voltage Limits

(Johan Morren and Sjoerd deHann 20th International Conference on Electricity Distribution, Prague, June 2009)

This paper discusses the issue that increasing penetration of DG on distribution networks will raise the voltages. The paper investigates the level of penetration required to cause the voltage to exceed acceptable limits. The paper also discusses the control of reactive and active power generation by the DG inverters in order to control the voltage levels.

"Reactive compensation: The first way to increase the maximum penetration level is to use the DG units to absorb reactive power from the grid. In this way the DG units can compensate (a part of) the voltage change they cause."

"Generation curtailment: Another possibility to improve the voltage control capability is to lower the amount of active power that is supplied by the DG unit when the upper voltage limit is exceeded (generation curtailment)."

The paper focuses on the ability of the DG inverters to control both active and reactive power. This is not a function that is available on the inverters used on Small DG Systems. The paper also uses a very simplified model with a single DG source and determines the $\frac{X}{R}$ ratio compared to DG capacity where the voltage limits are exceeded.

The paper does highlight the possibility of using reactive power to compensate for excessive voltage fluctuations.

3.2.3 Steady State – Paper Three

New Tests at Grid-Connected PV Inverters: Overview over Test Results and Measured Values of Total Efficiency η_{tot}

(H. Haeberlin, L. Borgna, M. Kaempfer and U. Zwahlen, 21st European Solar Energy Conference, Dresden, September 2006)

This paper is a summary of test results of eleven different inverters. The tests include the overall efficiency (η_{tot}) at differing input voltages and the ability to track the maximum power point. These tests were conducted as the manufacturers are sparing with this type of information and tend to exaggerate a best case derived from improbable operation.

The notable aspects from this paper is that η_{tot} was above 90% in almost all situations and generally above 95% and also the maximum power point tracking was considered good on most inverters.

3.3 *Fluctuating DG In-Feed Issues*

3.3.1 Fluctuating In-Feed – Paper One

Limits On Cloud-Induced Fluctuation In Photovoltaic Generation

(Ward and Unruh, IEEE Transactions on Energy Conversions, Vol. 5, No. 1, March 1990)

This research paper examines the effects that fluctuations in DG output due to cloud movement have on the cost of operating the network. These costs are determined based on unit commitment values. This aspect of DG penetration is not considered in this research project.

The data considered was for system loads over 1000MW and PV penetrations, with no focus on smaller quanta. There was information that at 15% penetration levels the power flows in sub-transmission line would reverse and cause mis operation of protective equipment. This is DG at levels that are well above those being examined in this project.

3.3.2 Fluctuating In-Feed – Paper Two

Modelling and Simulation of Solar PV Arrays Under Changing Illumination Conditions

(Dzung Nguyen and Brad Lehman Ward and Unruh, IEEE COMPEL Workshop, July 2006)

This research paper describes the development of modelling and simulation of changes in illumination levels on large PV arrays. The paper studies the dynamics of large arrays where a portion has reduced output and acts as a load to the remaining active panels producing hot spots. The hot spots further exacerbate the problem by increasing resistance to current flow.

This paper has little relevance as it considers very large arrays and not the smaller units of up to 30 kW.

3.3.3 Fluctuating In-Feed – Paper Three

Cloud Effect on Distributed Photovoltaic Generation: Slow Transients at the Gardner, Massachusetts Photovoltaic Experiment

(Edward Kern, Edward Gulachenski and Gregory Kern, IEEE Transaction on Energy Conversion, Vol. 4, No. 2, June 1989)

This research paper describes the measurement and evaluation of irradiance levels on twenty eight 2 kW photovoltaic systems that are connected to the B phase of a 13.8 kV distribution feeder. The installation are spread out over a 600 metre by 400 metre area and are a representation of 50% penetration of a very low density residential (hobby farm) area.

The results from this study showed excursions in PV output of 10% per second for individual systems and 3% per second for all 28 systems. Total excursion of 75% for single systems and 60% for the total 28 systems was also recorded. It was found that voltage regulation at the site was not a problem; however it was noted that excessive tap changing was taking place.

This paper looked at residential dwelling densities of about 2 per hectare whereas the feeders being examined in this research project will examine similar effects on densities of 8 to 10 per hectare for the major urban residential feeder and 0.001 per hectare of the principally SWER feeder. The values are of interest for the individual installation; however the overall values fall well between the two areas of interest in this research project.

3.3.4 Fluctuating In-Feed – Paper Four

The Effects of Moving Clouds on Electric Utilities with Dispersed Photovoltaic Generation

(Ward Jewell and R. Ramakumar, IEEE transaction on Energy Conversion, Vol EC-2, No.4, December 1987)

This research paper looks at the technical and economic impacts of the increasing penetration of grid-connected inverter photovoltaic systems and their fluctuating outputs as a result of cloud movements. The paper looked in details at the aspects of clouds that would affect the output of a photovoltaic system and chose only cumuliform clouds to use in simulations as they would produce the greatest variations. The simulation was fully developed and applied to model of the city of Stillwater Oklahoma in the U.S. and also a section of Tulsa Oklahoma in the U.S.

The overall areas and connected capacity of photovoltaic considered in this paper are substantially greater than those investigated in this research project. These area start at 10 km^2 and range up to 100,000 km^2 and show 1 minute rates of output change of up to 15.9%.

3.3.5 Fluctuating In-Feed – Paper Five

The Effects of Dispersed Utility Connected Photovoltaic Generation on the Distribution System

(A. Ahfock and S. Sharma, Paper presented at Conference on Electrical Energy, Brisbane, October 19-21 1992)

This research paper investigated the broad issue of voltage fluctuation as a result of Small DG Systems penetration on the distribution network. There are references to problems with steady state in-feed as well as fluctuation as a result of cloud movement. This paper discussed the use of energy storage as a method of mitigating the voltage problems.

3.3.6 Fluctuating In-Feed – Paper Six

Solar Spectral Irradiance under Overcast Skies

(Stefan Nann and Carol Riordan, IEEE COMPEL Workshop, July 2006)

This research paper looked at the spectral components of the sunlight under cloudy conditions and the effects on PV array outputs. The intention was to provide a better reference for PV systems based on average cloud covers. This data can be used to help determine the long term performance of large arrays.

The relevance is limited as the focus on long term performance is not relevant to this research project.

3.4 *Protection Systems and DG Issues*

3.4.1 DG Protection Issues – Paper One

Reliability Analysis of Distribution System with Distributed Generation Considering Loss of Protection Coordination

(Chaitunusaney and Yokoyama, Paper presented at the 9th International Conference on Probabilistic Methods Applied to Power Systems KTH, Stockholm, Sweden – June 11-15, 2006)

This research paper examined simplified networks that include DG systems. The protection systems used on these networks differed in the philosophy to that used for the Ergon Energy network. Their protection system employed reclosers and spur line fuses. The first recloser trip was fast in order to allow for transient faults beyond the fuses not to cause these fuses to blow. A re-close and subsequent trip for a permanent fault was slower and would allow the fuse to blow and isolate the faulted network section. The next re-close would be successful in returning the majority of the network to service.

The analysis of network reliability due to false operation of the fuses for the first fault was the main focus of the paper. The Ergon Energy network does not employ a fast first trip and so this analysis is not relevant to this research project.

3.4.2 DG Protection Issues – Paper Two

Analytical Model for PV – Distributed Generators, suitable for Power Systems Studies

(Papanikolaou, Tatkis and Kyristis, 03ED400 research project "Reinforcing Programme of Human Manpower", Technological Educational Institute of Lamia, University of Patras, Centre for Renewable Energy Sources and Savings, Greece)

This research paper focused on developing a model of PV DG systems as the authors believed that the present models were inadequate. The present models suggested fault levels in the sub-transient period to be 1.2pu. The more accurate models developed for this research showed fault levels of up to 1.65pu in the sub-transient period. This value may be used as an upper limit in the fault studies conducted in this research project.

3.4.3 DG Protection Issues – Paper Three

A Protection and Reconfiguration Scheme for Distribution Networks with DG

(Javadian, Tamizkar and Haghifam, Paper presented at 2009 Bucharest Power tech Conference, June 28th – July 2nd, Bucharest, Romania)

This research paper outlines a method for identifying a faulted area and intelligently reconfiguring to restore supply to the majority of customers. The DG sizes described are large and the network examined is relatively simplified.

This may be a useful technique and could be developed further for implementation on a smaller scale, which would make it useful for the level of network being investigated in this research project. The implementation of these concepts is outside the bounds of the resources (time) available for this research project.

3.4.4 DG Protection Issues – Paper Four

Effects of Distributed Generation (DG) Interconnections on Protection of Distribution Feeders

(Gurkiran and Vaziri, IEEE Power Engineering General Conference, 2006)

A number of protection issues related to the impacts of DG, were touched upon in this research paper. There was discussion on large HV DG equipment and the effects of factors such as nuisance tripping, relay desensitization, unintentional islanding, ground fault detection, resonance. The main focus was on damage caused as a result of the contributions by the DG systems. Gurikan and Vaziri have examined large machines feeding in at the HV level with capacities that are the equivalent of a substantial portion of the connected capacity.

This research project is looking for the levels where the issues just become apparent. Also the Small DG Systems researched for this project feed in at the LV and will perform in a very different manner to those feeding into the HV network.

3.4.5 DG Protection Issues – Paper Five

The Study of the Protection Revision Method Based on the DG Effect to Protection Sensitivity

(Lin Xia, Lu Yu-ping and Wang Lian-he, Paper presented at IEEE International Conference on Sustainable Energy Conference, 2008)

This research paper described the effects that large DG systems have on protection grading and sensitivity. The analysis shows that the effects are a function of size and location relative to the protective device. The results of simulations were reported but it appeared that the determination of protection adjustment to cope with the DG was empirical.

The outcome from this research paper did align with the expectation that the DG penetration effect on protection would depend on size and location. The analysis by trial and error is no great revelation and easily transferable to this research project.

3.4.6 DG Protection Issues – Paper Six

Impact of Distributed Generation on the Protection of Distribution Networks

(Kumpulainen and Kauhaniemi, Eighth IEEE International Conference on Developments in Power System Protection 2004)

This research paper looks at the effects DG has on protection coordination for distribution networks. The DG systems examined are large and the networks simplified, with two distribution feeders from one zone substation and one DG. The outcome of the study was to suggest that there will be problems with rotating DG as the fault contributions will be high and to a lesser degree with inverter based DG. The suggested solutions were relatively simplified such as directional over-current.

The use of directional over-current will be considered as a matter of course if during this research projects large current reversals are detected in the network modelling exercise.

3.4.7 DG Protection Issues – Paper Seven

Analysis of the impact of Distributed generation on automatic reclosing

(Kumpulainen and Kauhaniemi, IEEE PES Power Systems Conference and Exposition 2004)

This research paper considers the effects of the in-feed from large DG systems when they continue to generate after being isolated from the rest of the the grid when a circuit breaker has tripped for a fault on adjacent network. The continuation of the DG to operate after being isolated is known as “islanding”. The main focus is on auto-reclosing onto an islanded network, the problems and how to minimise them. The sizes of the DG systems studied were a 1.65 MW asynchronous wind generator and a 7.94 MVA synchronous generator and they were connected to a 20kV network.

The size of DG and connection to a distribution voltage differs from the focus of this research project in size, number and voltage. The effects due to islanding such and the solutions such as inter-tripping schemes are not applicable to the Small DG Systems considered in this research project.

3.4.8 DG Protection Issues – Paper Eight

Dispersed Generators Interfaced with Distribution Systems: Dynamic Response to Faults and Perturbations

(A. Borghetti, R. Caldon, S. Guerrieri and F. Rossetto, IEEE Power Tech Conference 2003)

This research paper looked at a range of scenarios where small distributed generation was dispersed within a distribution network. Two generation types were investigated, firstly two 0.5 MW conventional synchronous generators and secondly ten 50 kW micro turbine connected through static converters (inverters).

Models of the two types of generation were applied to network models and fault conditions were simulated. A key outcome from this paper was that the fault contribution by the inverter connected device was less than 1.5 p.u. and that due to the electronic control of current that the fault contributions and voltages swings were much smaller than during faults with the conventional generation. The authors suggest in their conclusion that: “In particular, the negligible contribution of these devices to the fault current levels may allow many generating units to be embedded on the same network without the need of re-designing the existing feeder protection schemes.”

3.4.9 DG Protection Issues – Paper Nine

Evaluation of Fault Contribution in the Presence of PV Grid-Connected Systems

(S. Phuttapatimok, A. Sangswang, M. Seapan, D. Chenvidya and K. Kirtikara, Department of Electrical Engineering, CES Solar Cells Testing Center, King Monghut’s University of Technology Thonburi, Thailand)

This research paper described the development of Matlab and Simulink models of PV and grid connect inverters and relatively realistic 22kV distribution networks. The models were run with arbitrary PV penetrations equivalent to 100% and 150% of the feeder load of 2.48 MVA. The fault currents at a three phase fault midway along the distribution feeder increased by 0.5 and 0.7% respectively for the 100% and 150% penetration levels when compared to no penetration.

The authors make the statement in the concluding section of the paper, “With increasing level of penetration of PV systems on the distribution feeder, the fault contribution of PV generators must be seriously taken into consideration”. They go to say that the issue is associated with fault rating of equipment at the zone substation bus.

3.4.10 DG Protection Issues – Paper Ten

Fault Contribution of Grid-Connect Inverters

(Dave Turcotte and Farid KKatiraeri, IEEE Power Conference, 2009 Canada)

This research conducted fault modelling using the power systems analysis software PSCAD. A typical feeder arrangement as used in Ontario-Canada was modelled with traditional 7.5 MW rotating synchronous generation and this was compared to the same network with 7.5 MW of PV grid-connected inverter generation.
The authors concluded that, “the short-circuit contribution
of inverter-based DG units are insignificant” and also “ that inverters, even with disabled protective functions, will feed a current in the range of 1.1 to 1.5 times their nominal currents which is significantly lower than the 4 to 10 times fault to nominal current ratio typically caused by rotating machines. For a worst case scenario, the contribution of an inverter will not exceed 1.5 p.u.”

3.5 *Conclusions to Literature Review*

The notable aspect of the literature review was that there was very little published on the impacts of Small DG Systems (less than 30kW). There was a great deal of research literature published in the field of DG for equipment that is in the region of 1 to 10MW.

The majority of the research conducted into DG penetration of distribution feeders is for systems that feed into the HV at levels of 1 MW or more. This size of systems and in-feed voltages are well outside the bounds of this research project and are of little practical application.

There were a number of points found during the literature review that is relevant to this research project and they are:

1. That high DG penetration levels will cause QoS problems.
2. The QoS problems can be resolved by injection of reactive power near the DG.
3. The QoS problems can be resolved by including energy storage within the distribution network affected by the Small DG System penetration.
4. That cloud transitions over PV systems can see fluctuations in output of 100% per second and 75% overall.
5. The fault contribution by grid connected inverters is theoretically limited to less than 1.6 p.u.

3.6 *Information Gaps*

The literature review failed to deliver any information that could be used specifically on the application of the analysis of Small DG System penetration of up to 100%. The most obvious omissions include:

1. What level of penetration of Small DG Systems causes problems for QoS both in the steady state domain and fluctuating output due to cloud movements?
2. What rate of change can be expected in tropical and sub-tropical areas as a result of cloud movements?
3. What level of penetration of Small DG Systems cause protection system problems?
4. What are the real (not theoretical) fault contributions from a Small DG System?

CHAPTER 4 - SMALL DG SYSTEM TEST DATA

4.1 *Testing*

The previous sections of this report showed that there is a shortage of data on:

- The actual contribution of a Small DG System to a nearby fault.
- The effects of cloud movements of a typical Small DG System.

A series of tests were conducted on Small DG Systems and the grid-connect inverters used for them in order to generate some real data. This data is used to configure the Small DG System in the network modelling exercises.

4.2 *Small DG System Fault Contribution Test*

A fault condition was simulated on a 1 kW Small DG System and the contribution by the Small DG System was measured. Figure 4.1 below shows the schematic of the test circuit.

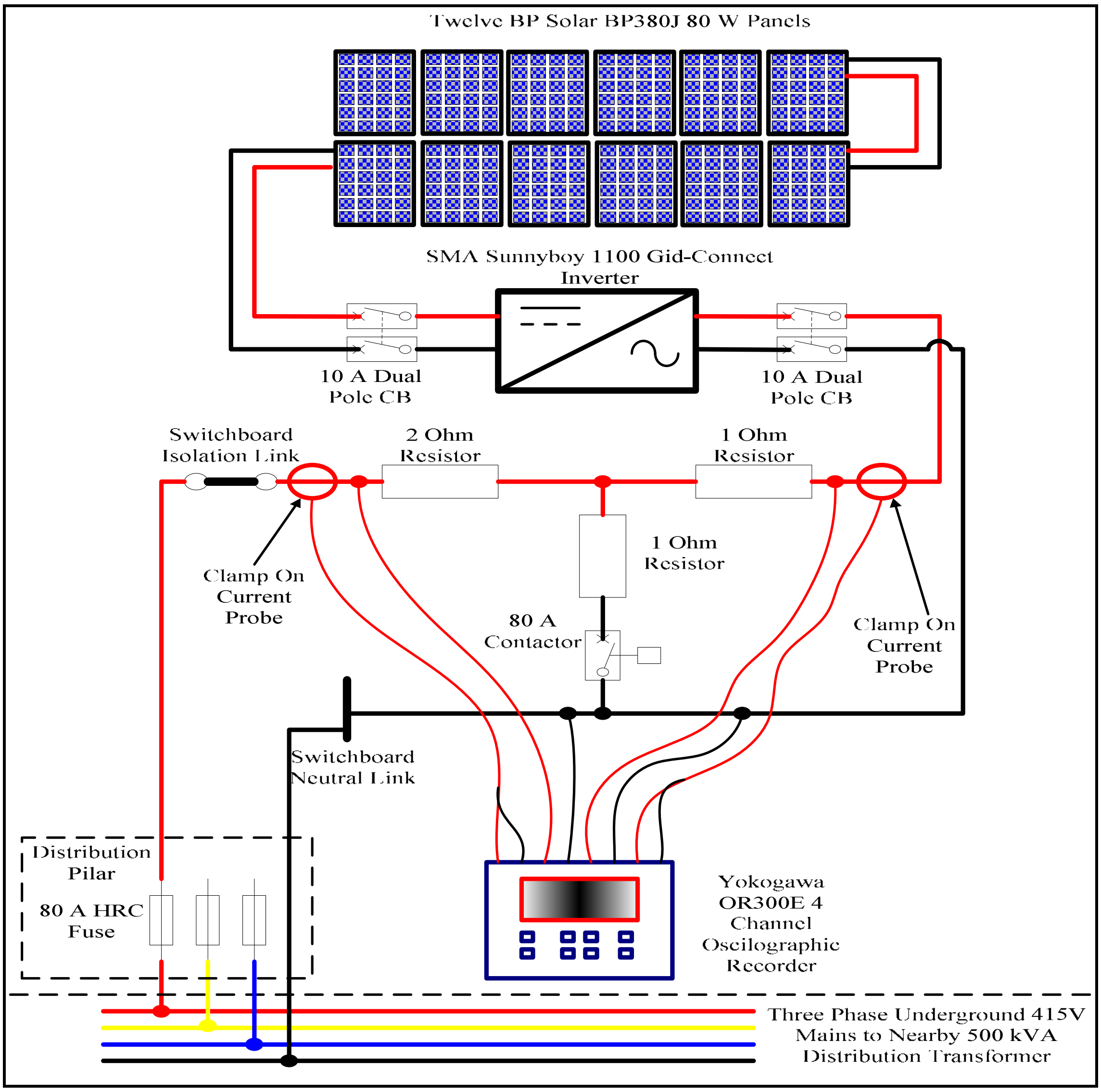


Figure 4.1 – Fault Test Circuit

The fault was created by energising the contactor coil and so closing the contact, which effectively put a fault to earth on the output of the inverter.

4.2.1 Fault Contribution Results

The fault contribution testing was carried out a number of times and the results obtained by the Yokogawa recorder were relatively repeatable. Figure 4.2 below shows the current on the grid side of the fault limiting resistors for approximately 100 ms before the fault was applied and for 50 ms after the application of the fault.

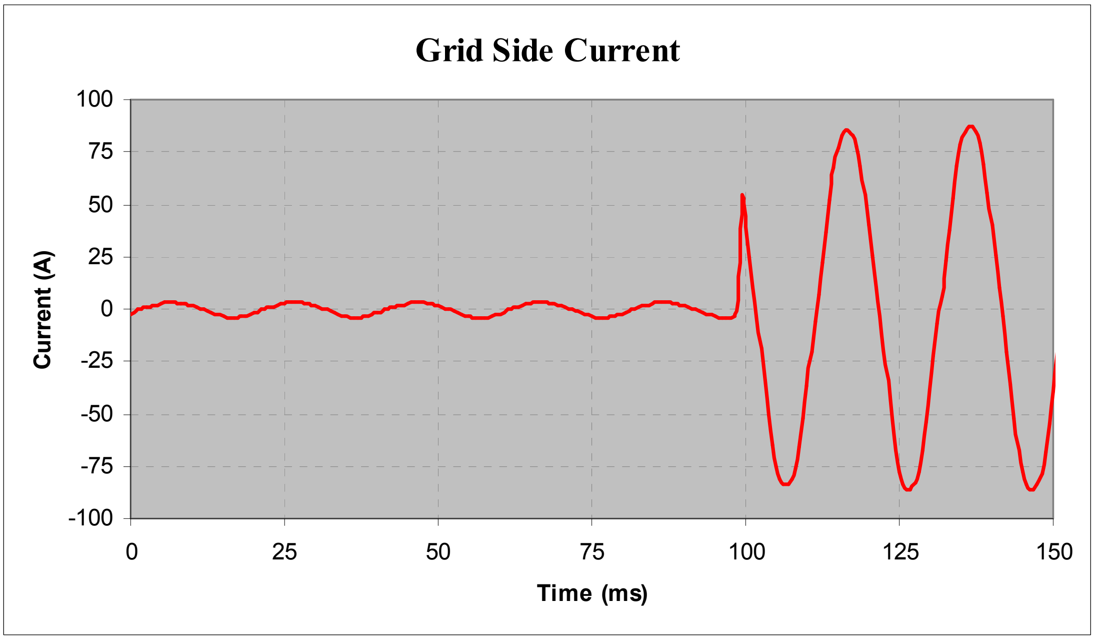


Figure 4.2 - Grid Side Current Before and After the Fault Event

It is worth noting that prior to the fault the inverter is exporting to the grid and then after the fault the current reverses.

Figure 4.3 shows the current from the inverter over the same 150 ms time period.

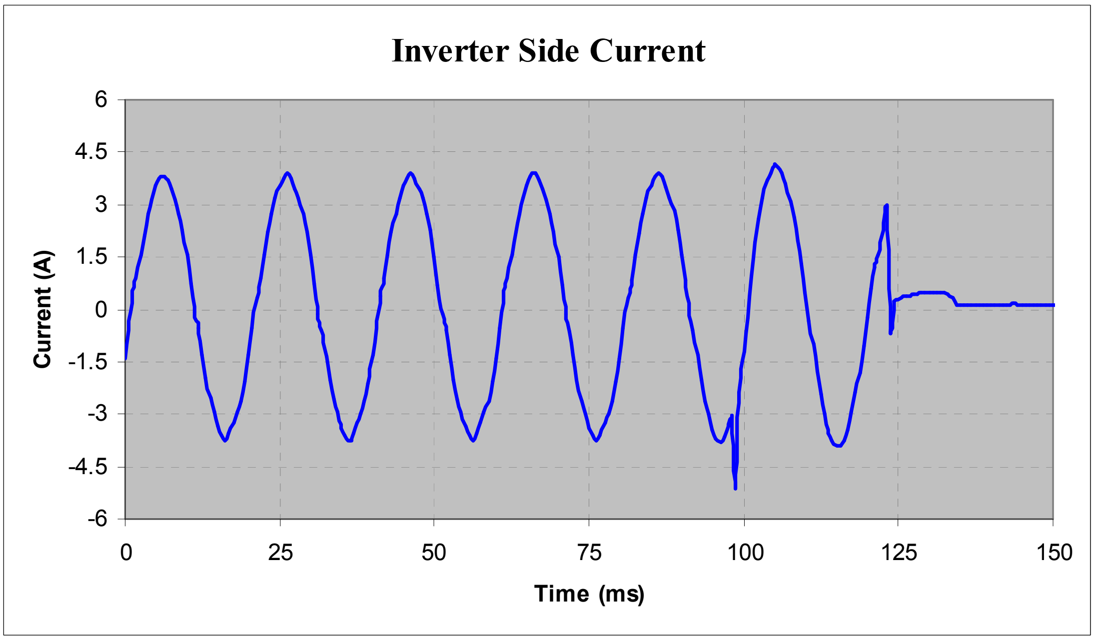


Figure 4.3 – Inverter Side Current Before and After the Fault Event

A small spike in current occurs immediately after the fault and then the inverter delivers a current that was a small increase compared to before the fault before shutting down in one and a half cycles.

The following figure 4.4 shows both grid and inverter current before and after the instigation of the fault. This diagram demonstrates the increase grid current coincides with the small spike in inverter current and that the spike is not anomalous.

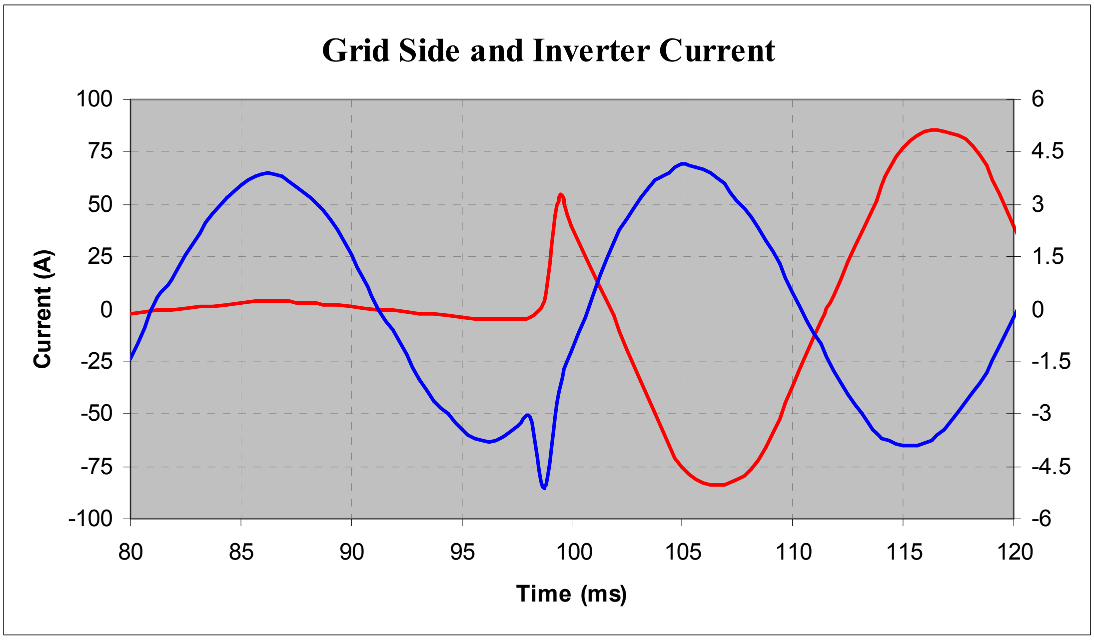


Figure 4.4 – Inverter Side and Grid Current Before and After the Fault Event

4.3 *Small DG System Cloud Movement Test*

Data was collected for the solar energy, PV array output current and voltage in order to develop some data that could be used to represent the effects of cloud movement over a Small DG System.

The solar radiation was measured using an Apogee SP-110 pyranometer, which uses a silicon photo-diode and has the same spectral response as a PV panel. This means that the output of the pyranometer is directly equitable to the solar energy that will create electrical energy in the PV panel. The output of the SP-110 is a voltage of 5.00 $W/m^2/mV$. The spectral response of the Apogee SP-110 pyranometer can be seen in figure 4.5 below (Apogee web site, spectral response of silicon photovoltaic panel, viewed 2 Oct 2010, <http://www.apogeeinstruments.com/pyranometer/spectralresponse.html>). If this diagram is compared to figure 2.15 (silicon PV panel response) and it can be seen that the two curves are very similar.

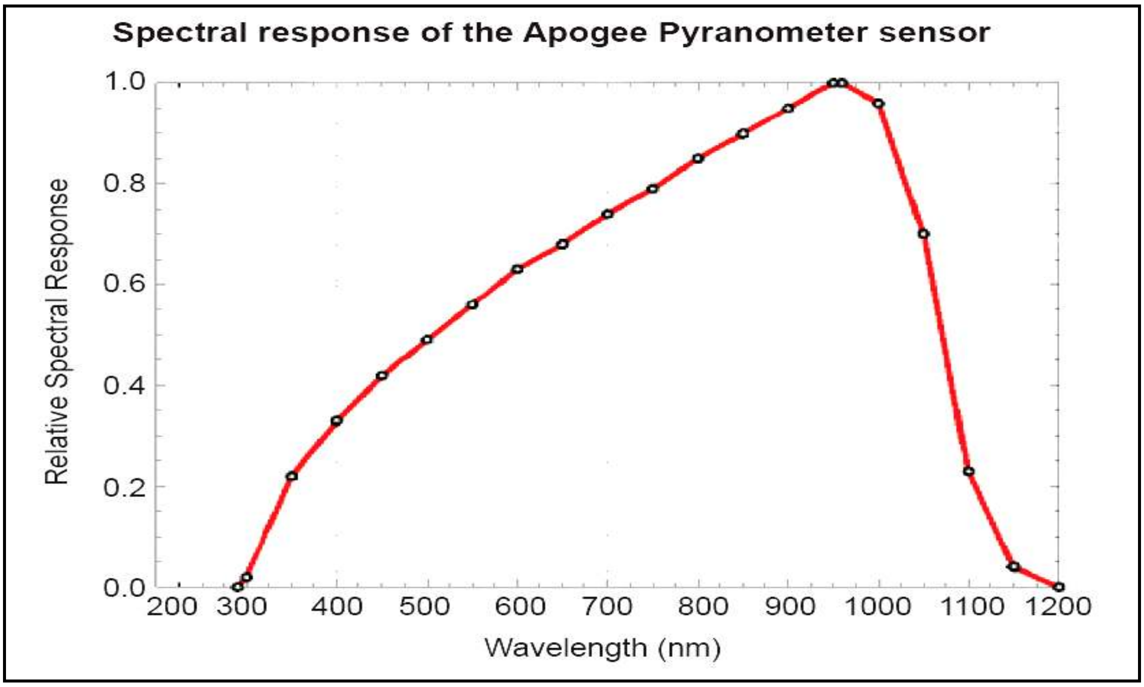


Figure 4.5 – Apogee SP-110 Pyranometer Output verse Solar Radiation Spectrum (Apogee 2010)

The PV array voltage was measured using a simple 10:1 voltage divider to reduce the 200 V d.c. down to a more manageable 20 V d.c.

The current was measured using an LEM LTS 15-NP Hall Effect transducer, which produces a voltage output proportional to the input current. The sensor is powered by a 5 V supply and the input pins can be configured for three different current ranges form ±5 A to ±15 A. The frequency response of these devices is from d.c to 100 kHz with less than 0.5dB of variation in the output. Figure 4.6 below (Lem Components, current transducer LTS 15-NP spec sheet, viewed July 2010, <http://www.lem.com/docs/products/lts%2015-np%20e.pdf>) shows the voltage output versus current characteristics of this device. The value I_{PN} is the nominal current range and I_P for maximum short term currents.

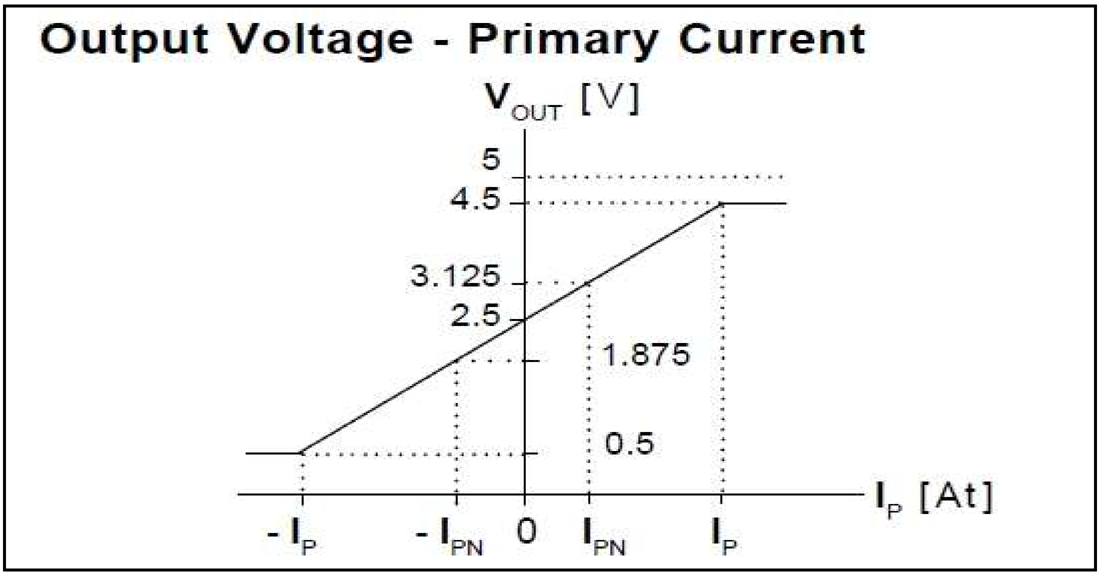


Figure 4.6 – LEM LTS 15-NP input current versus output voltage curve

A DATAQ DI-148UP USB data acquisition device was used along with a personal computer to log the analogue signals from the three sensors described above. The DATAQ DI-148UP has 12 bit resolution and differential programmable gain inputs that allow up to ±64 V signals. This arrangement allowed sampling rates on all three analogue channels of up to 14 kHz, although in reality only 2 Hz sampling was used. The lower sampling rate was sufficient to capture the PV array changes and did not create unnecessarily large data files.

Figure 4.7 below shows the schematic of the circuit and equipment used to record the data.

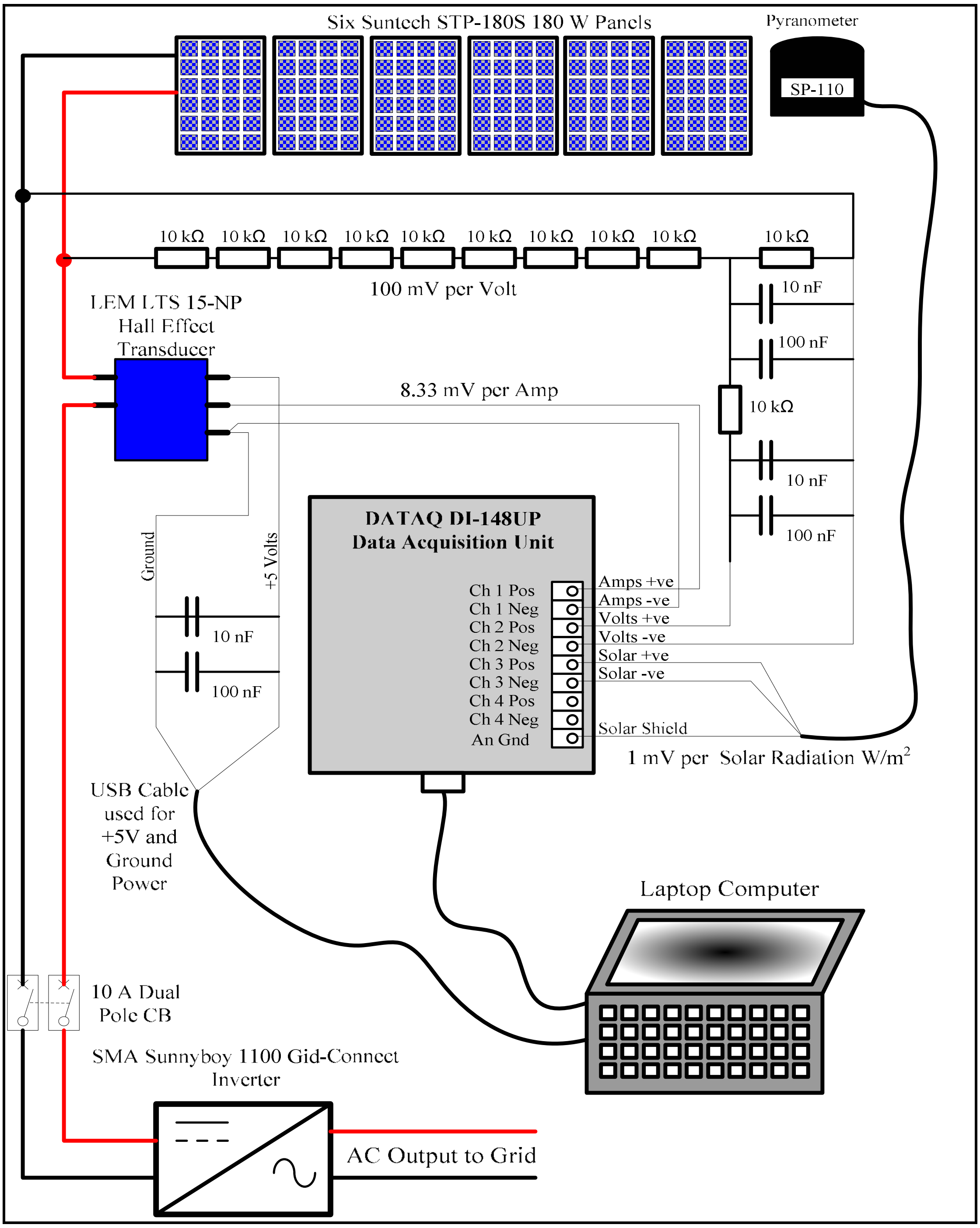


Figure 4.7 – Schematic of Solar Radiation Data Collection Circuit

4.3.1 Solar Radiation Data Collection

The equipment described in the previous section was assembled to measure the solar radiation incident to a PV array. The PV array consists of six 180 W Suntech STP-180S silicon PV panels. This array connects to an SMA Sunnyboy 1100 grid-connect inverter. This Small DG System is located in Townsville, Queensland.

The voltage and current sensors are mounted in an enclosure, which breaks into the d.c. cable between the PV array and the inverter. The interface to the pyranometer and the data acquisition unit is also mounted in this enclosure.

The Apogee SP-110 pyranometer is mounted with the same orientation as the PV array in order to lessen the need to correct the data for their orientation. Figure 4.8 below shows the PV array and the pyranometer.

Figure 4.8 – PV Array and Pyranometer

4.3.2 Typical Sunny Day

The sampled PV array voltage, PV array current and solar radiation data was continuously collected and processed.

A day where the sun was relatively unimpeded by clouds was chosen (16th of August 2010) and the PV array voltage and PV array current can be seen in figure 4.9 below.

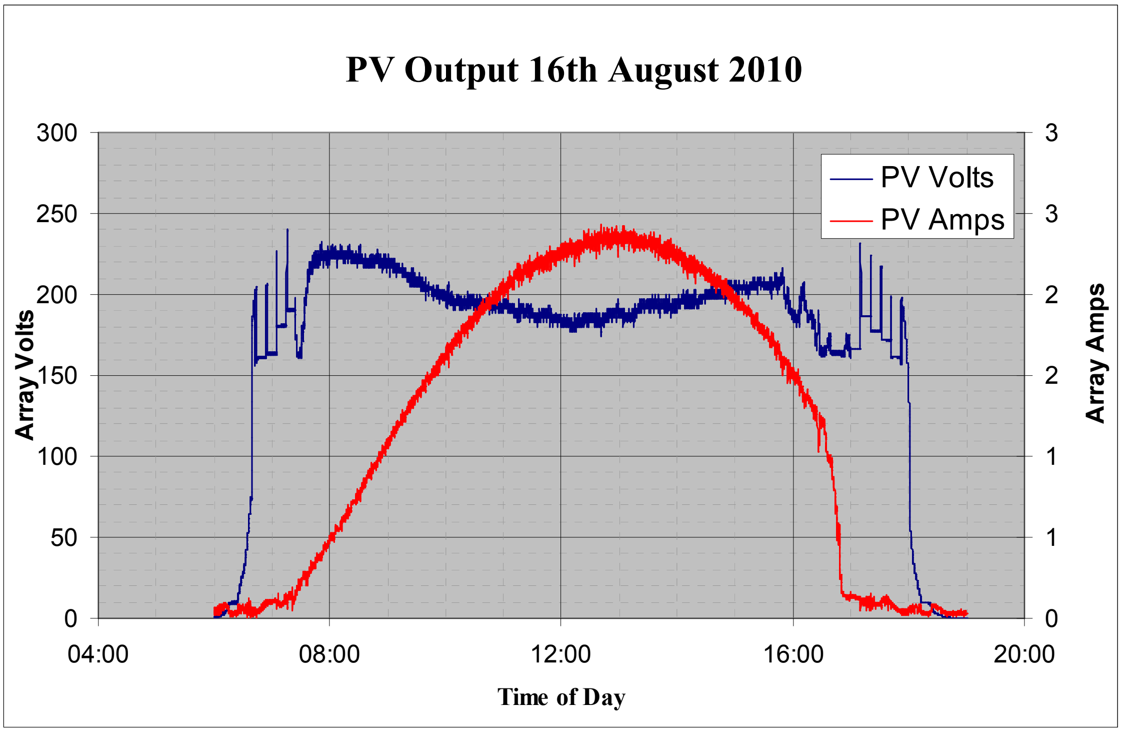


Figure 4.9 - Cloud Free Data for PV Array voltage and current

The PV array voltage and current were processed into power and this value can be seen graphed with the solar radiation power in figure 4.10 below.

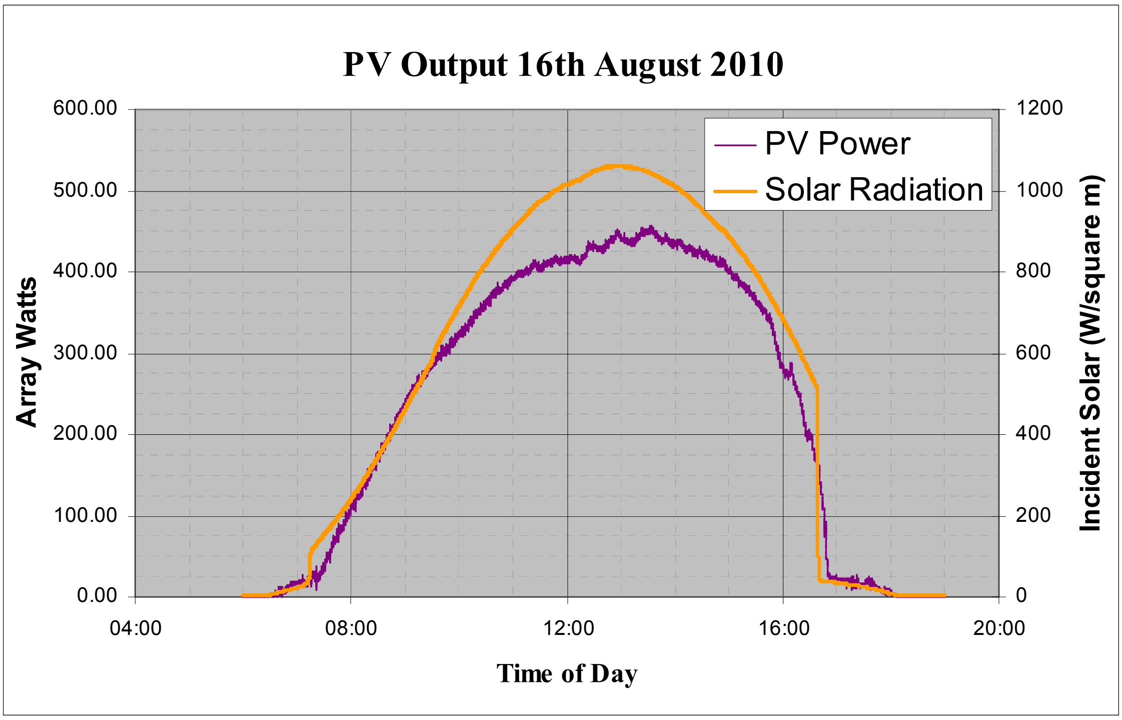


Figure 4.10 - PV Array Power and Solar Radiation Power

The data displayed in the two diagrams above show that the array was partially obscured by a shadow at about 17:00 (5 pm) and ceased to produce any meaningful power. This has little bearing on the outcome of this research project as the object of this experiment was to collect relative data during the peak periods in the middle of the day.

The second notable aspect was that the pyranometer shows a peak reading of about 1050 W/m^2 which is close to the global maximum of 1100 W/ m^2. This was because the sensor was angled at about the same angle as the sun and so was pointing at the sun when it was at the azimuth (coincidence of mounting and time of the year). The PV array area is about 7.2 m^2 and this means that the peak solar radiation should be about 7560 W (7.2 m^2 multiplied by 1050 W/m^2). The PV panel efficiency is stated at 14.1% in the data sheet; however the measured efficiency was about 6% (peak power of about 460 W divided by 7560 W). An explanation for this may be de-rating due high temperatures as a result of the close mounting on the metal roof in the tropics. Also the manufacturer's data is exaggerated to demonstrate a maximum power output under very ideal (probably unlikely) conditions.

4.3.3 Cloudy Day Data

A similar set of data to that shown in the previous section of this report was collected and processed for a day with a number of small cumulus clouds (dense, white and puffy). This type of cloud was chosen as it causes the greatest rate of change in a PV array output.

Figure 4.11 below shows the test PV array output of voltage and current on the chosen day (15th of August 2010) and the cloud movement period between about 10:30 and 12:00.

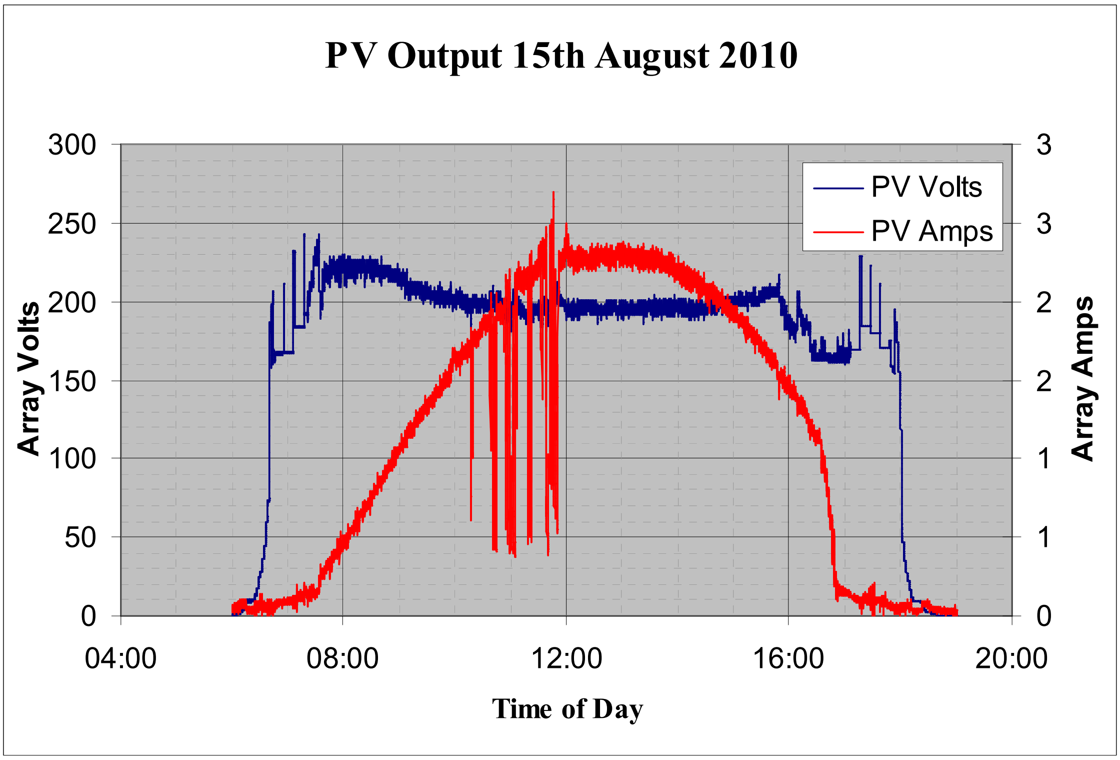


Figure 4.11 – PV Array Voltage and Current during Cloud Movement

Figure 4.12 shows the solar radiation power and PV array power for the same day.

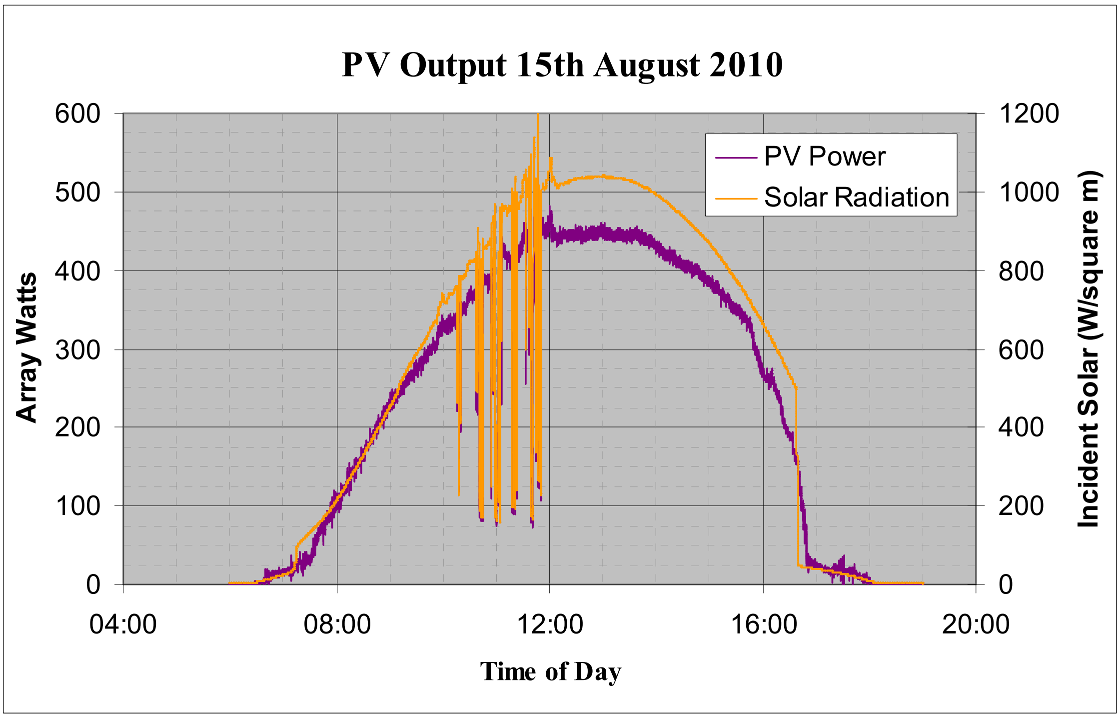


Figure 4.12 – Solar Radiation and PV Array Power during Cloud Movement

Figure 4.13 shows PV array current and voltage over a five minute period between 11:45 and 11:50 on this day. This shows in much greater detail the effect of cloud movements.

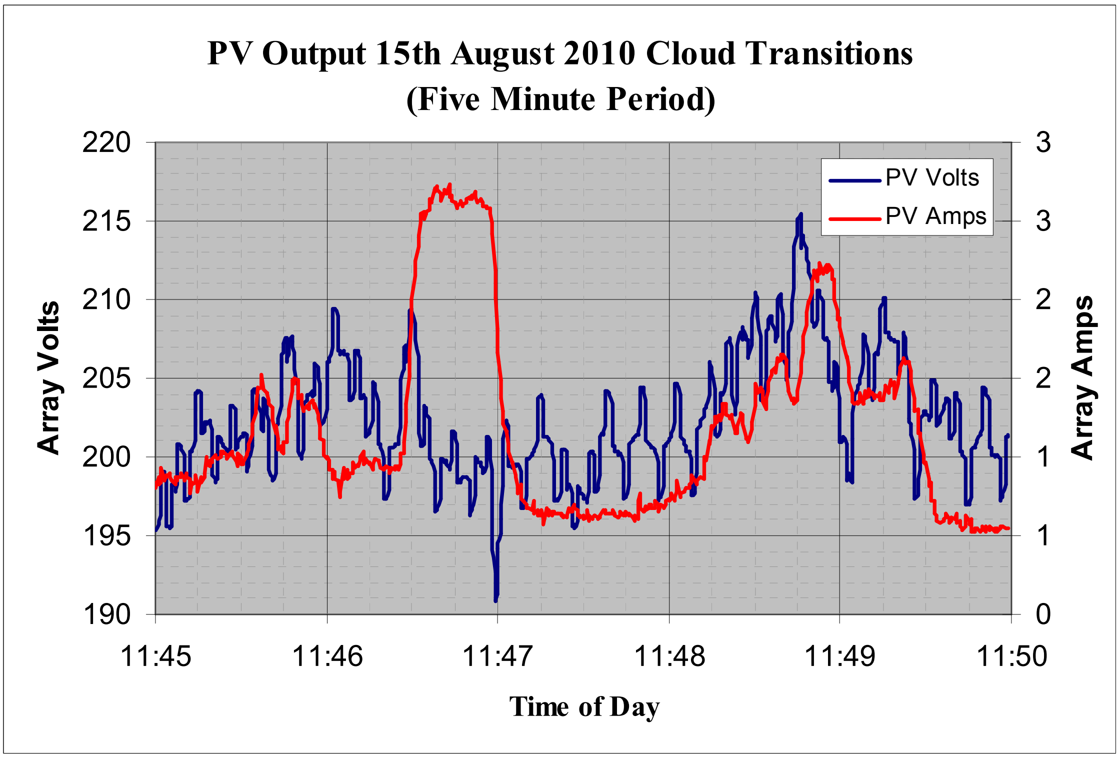


Figure 4.13 – Five Minute PV Array Voltage and Current during Cloud Movement

Figure 4.14 below shows the solar radiation power and the PV array power over the same five minute period.

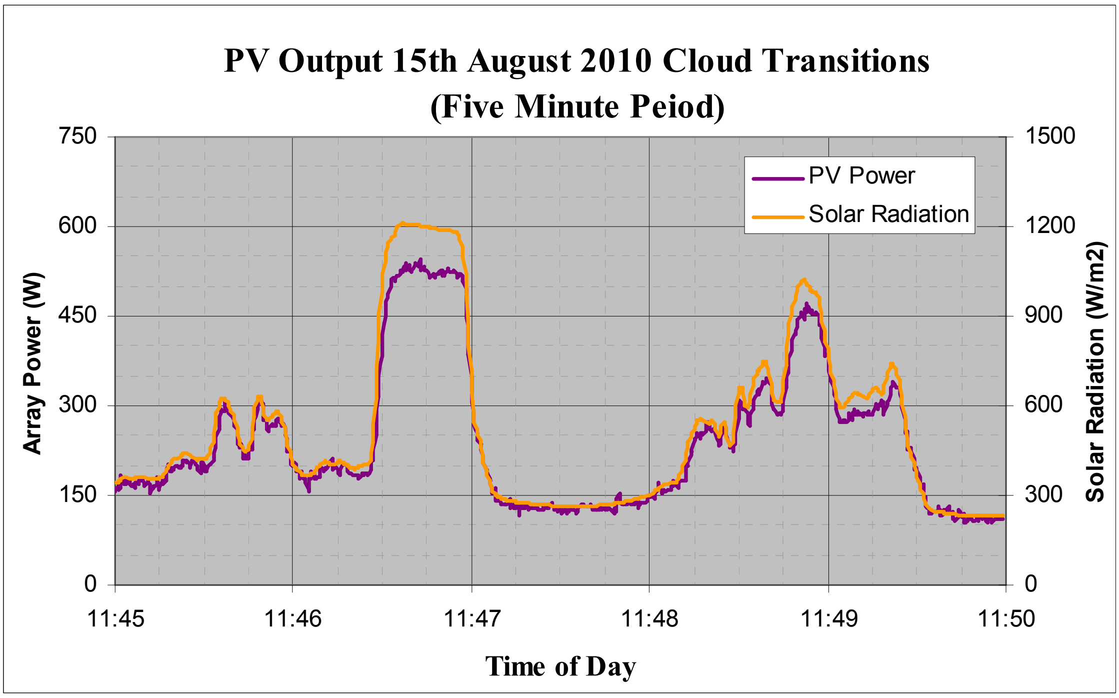


Figure 4.14 – Five Minute Solar and PV Array Power during Cloud Movement

The following figure 4.15 shows a range of rates of change in PV array output power for during the same five minute period.

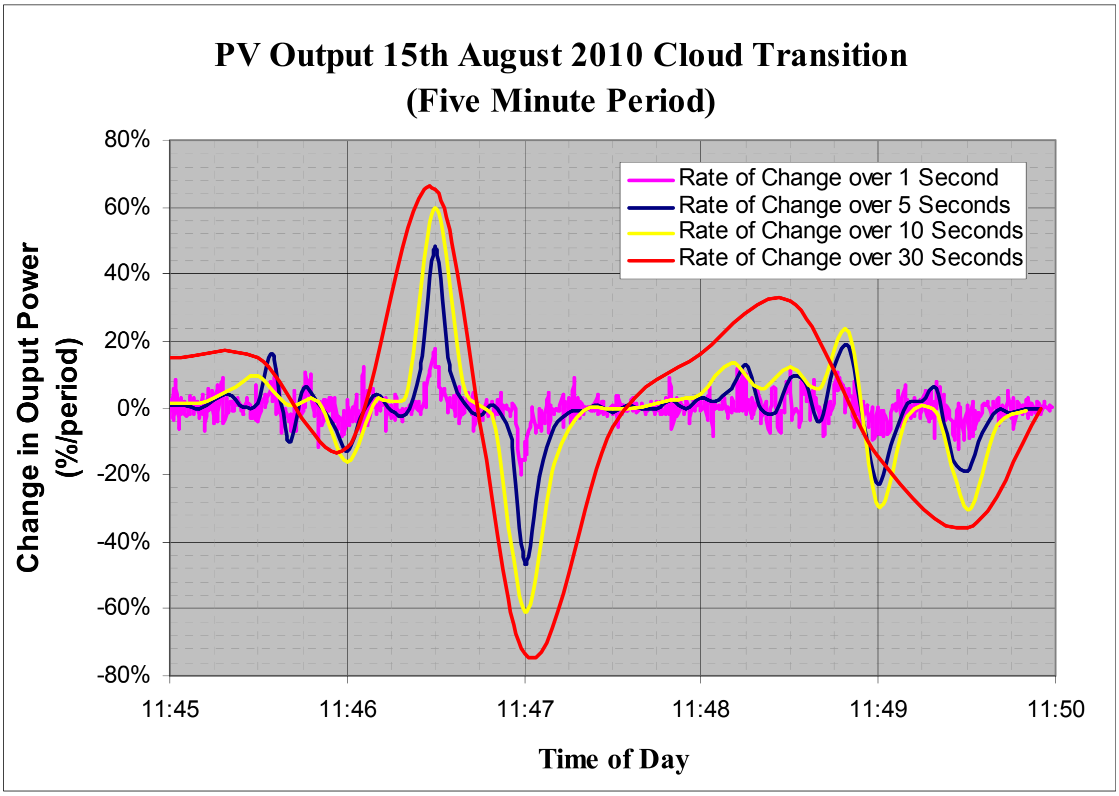


Figure 4.15 – PV Array Power Rates of Change during Cloud Movement

A notable aspect of the results shown in this section of the report is that the solar radiation power measured by the pyranometer rose well above the anticipated value during the time the shadow of the cloud edge crossed the PV array. The increase was up from an expected 1000 W/m^2 and was about 1200 W/m^2 an increase of 20%. At the same time the PV array power rose about the same amount above the expected value. It could be possible that the edge of a cloud acts as a lens and focuses more energy than would normally occur during clear sky periods.

4.4 *Testing – Other Issues*

A number of tests were planned and executed on two other grid-connect inverters. These tests were conducted with laboratory power supplies and both inverters responded badly to the laboratory power supply.

The laboratory power supply consisted of a 100 A 240 V variable auto-transformer whose output is full wave rectified and filtered with 6.4 mF of shunt capacitance and a pair of series filter inductors.

4.4.1 Inverter One Response

The first inverter was a 2000 W Aurora PVI-2000-OUTD-AU unit (serial number 075122). The inverter was supplied from the power supply described above and the output was connected to a strong mains supply. An oscilloscope was used to measure voltage and currents on the input and output of the inverter. Figure 4.16 below shows a number of oscilloscope traces, which are showing various test points around the inverter.

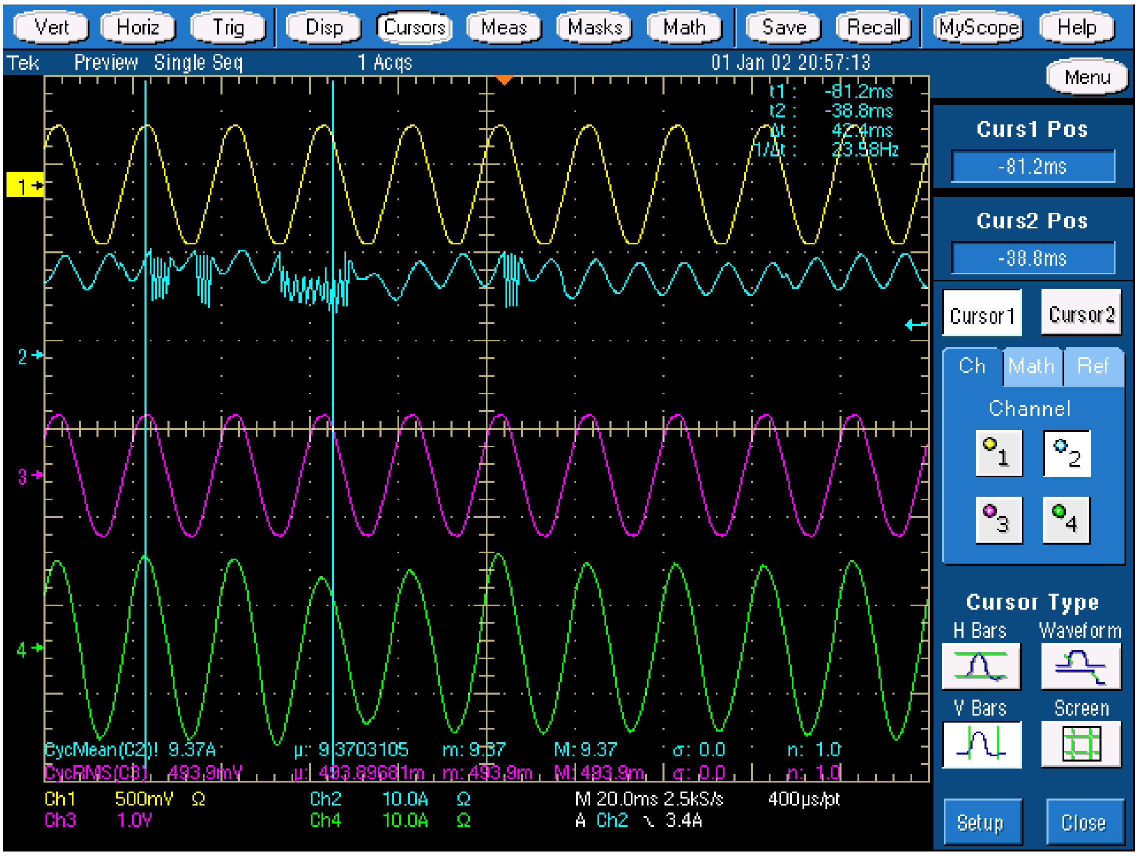


Figure 4.16 – Aurora PVI-2000 Input and Output Voltage and Current Waveforms

The orange waveform 1 at the top is the grid a.c. voltage, the blue waveform 2 is the d.c. input current, the pink waveform 3 is the inverter a.c. output voltage and the green waveform 4 id the inverter output a.c. current. The notable waveforms from the figure above are the blue (second from the top), which is the inverter input d.c. current. This should be a smooth line and is clearly not the case. The bottom trace is the output current from the inverter to the grid. This waveform has fluctuating amplitude when it should be consistent in size.

4.4.2 Inverter Two Response

The first inverter was a 2000 W SMA 1700 unit (serial number 2000865831). The inverter was supplied from the power supply described above and the output was connected to a strong mains supply. An oscilloscope was used to measure input and output voltage and currents. Figure 4.17 below shows a number of oscilloscope traces, which are showing various test points around the inverter.

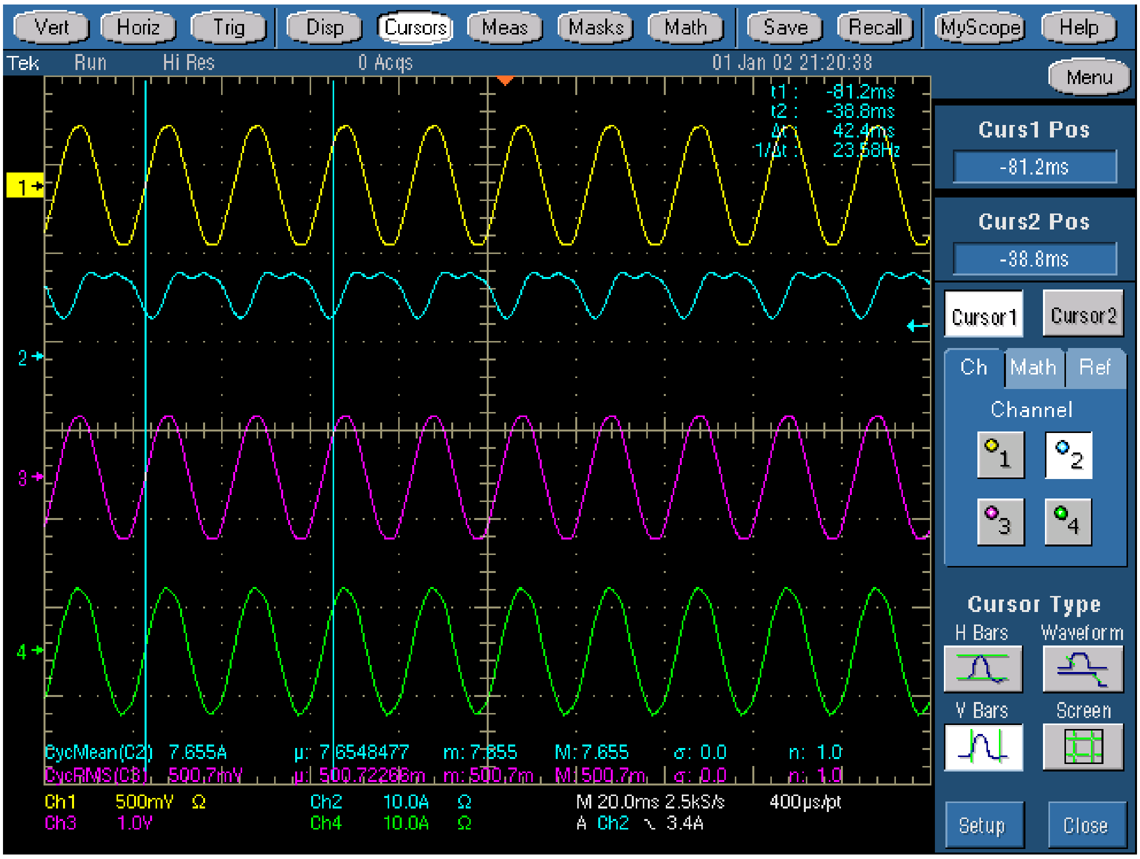


Figure 4.17 – SMA 1700 Input and Output Voltage and Current Waveforms

The waveform order is the same as that explained for the previous diagram. The notable waveforms from the figure above are the pale blue (second from the top), which is the inverter input d.c. current. This should be a smooth line and is clearly not the case. The bottom green waveform is the inverter output current. The variance in amplitude evident in figure 4.16 (the Aurora inverter) is not evident on this waveform. The waveform is distorted with the peaks showing a more pointed top then would be expected.

4.4.3 Laboratory Fault Testing

Several tests were performed on the Aurora PVI-2000-OUTD-AU and the SMA 1700 inverters in order to understand the contribution to fault conditions. The same test arrangement as that described in section 4.2 of this report and shown in figure 4.1 with the exception that the d.c. supply is not the PV array but is the laboratory power supply. Figure 4.18 below shows the result of one of these tests.

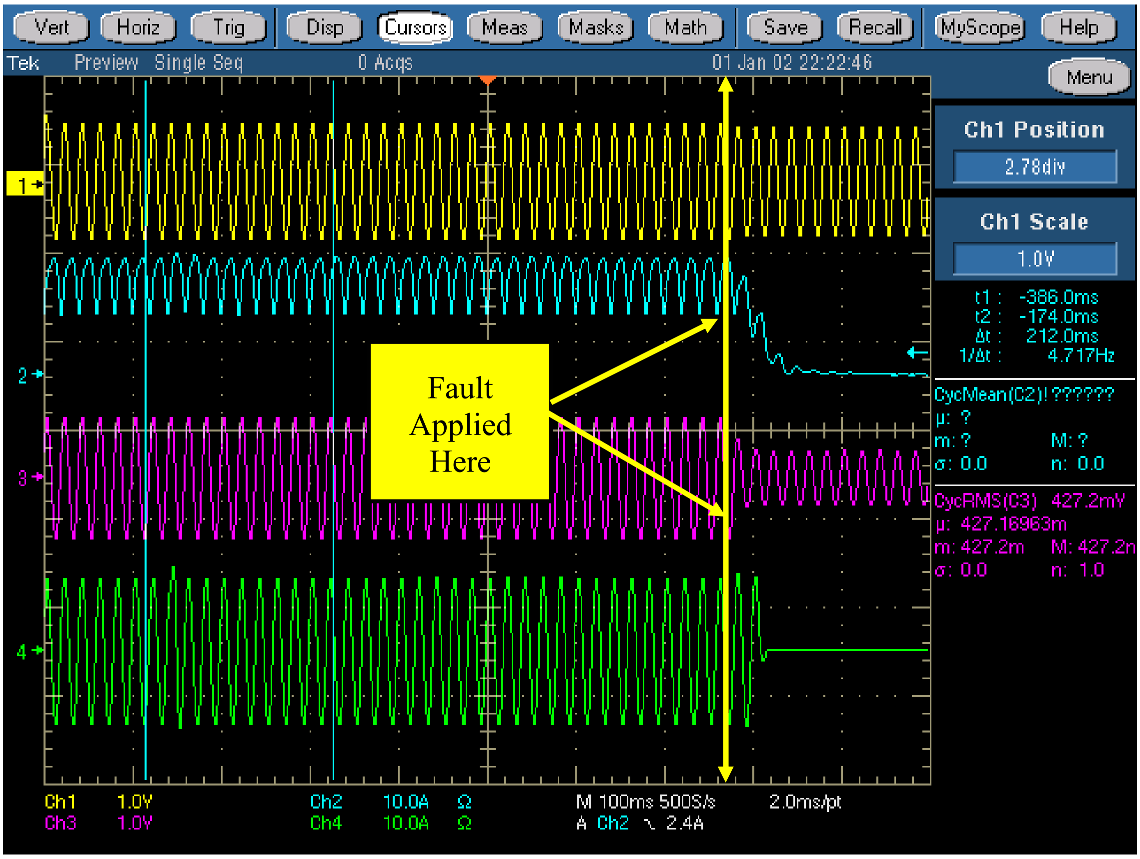


Figure 4.18 - SMA 1700 Fault Test Input and Output Currents and Voltages

The figure above shows that the time the fault was applied. The inverter input current shown on the blue waveform 2 begins to decay to zero. The inverter output a.c. current shown on the green waveform 4 persists for about one and a half cycles after the fault and may show a small increase in amplitude.

4.4.4 Laboratory Testing Conclusions

It is suspected that the fluctuations in input current when the inverters were operating normally were as a result of the inverter MPPT attempting to follow the ripple on the d.c. input voltage. The two inverters tested showed that they require a much more stable d.c. supply than that used in the tests.

The fault testing showed that the inverter shut down within a small number of cycles after a fault was applied to a nearby network and that the current contribution to the fault was about 1.0 p.u. and was less than 1.2 p.u. These tests provided results that were similar to the test on the smaller inverter unit described in section 4.2.

4.5 *Conclusions to Testing*

The key conclusions that can be drawn from the two test procedures described in detail in this section of this report include:

- The fault contribution by a grid-connect inverter was no more than 1.3 p.u. at a sub-transient time period.

- The duration of this fault contribution endured for only 30 ms probably because the voltage at the terminals of the inverter was below the anti-islanding lower limits
- It is possible a fault more remote from the inverter may see the inverter contribute all the reserve active power so long as the terminal voltage stay above the anti-islanding lower limits.
- The longer term or synchronous time period fault contribution is no more than 1.0 p.u.
- The reduction in PV array output observed during the testing showed that the rates can be at least:
    - 20% in one second.
    - 60% in ten seconds
    - 75% in thirty second

These values can be used directly with the network models.

CHAPTER 5 - NETWORK MODELLING

5.1 *Network Models*

The two key areas that this research project sought to investigate was the effect that high penetrations of Small DG Systems could have on distribution network protection systems and quality of supply. To achieve this goal using actual hardware installed on a real network is totally impractical. The alternative is to model the desired networks and apply equivalent generation that would simulate Small DG Systems. The software chosen to develop the network models is the Siemens PSS Sincal version 6.5.

Models of the two representative distribution feeders were developed from a number of the Ergon Energy network data sources. The basic models are used for both protection systems and QoS modelling exercises. The basic models are described in some detail in the following sections.

5.2 *ROPL-04 Feeder Model*

The following section provides the details of the development of the ROPL-04 feeder model.

5.2.1 ROPL-04 Feeder Model – Zone Substation

The Ross Plains ZS distribution feeder ROPL-04 was developed from network data and assembled manually as there were no PSS Sincal 6.5 models available.

The model includes a source impedance that was obtained from the Ergon Energy sub-transmission network models (which are modelled in DINIS(E)) at the 66 kV bus at Ross Plains ZS. The values below are the synchronous sequence impedances:

- Positive sequence impedance - $Z_1 = 0.8668 + j3.6982\Omega$
- Negative sequence impedance - $Z_2 = 0.8668 + j3.6982\Omega$
- Zero sequence impedance - $Z_0 = 1.6204 + j7.1830\Omega$

These values are used to configure a PSS Sincal Infeeder. This Infeeder is also arranged to maintain its 66 kV bus voltage at 104% of the nominal voltage during load flow analysis. This Infeeder supplies a 66 kV bus that in turn supplies two 66/11 kV transformers. These two power transformer each supply a section of an 11 kV bus, which has the bus tie circuit breaker left open as this is the present normal operating condition. The Number One section of the 11 kV bus (left side in following figures) supplies the ROPL-04 feeder and an equivalent load that represents all the other feeders normally fed from this bus section. This bus section also feeds the 3 MVAr capacitor bank, which has recently been commissioned. The Number Two bus section (right side in following figures) feeds an equivalent load to represent al the feeders that are normally fed from this bus section as well as the 2 MVAr capacitor bank.

The data required for the two power transformers is shown in figure 5.1 below, which is an image of the PSS Sincal two winding transformer basic data input page for one of the two power transformers. This page includes the voltage, vector groups, rating, and impedances. Figure 5.2 shows another image of a PSS Sincal two winding transformer controller page for the data of the same 66/ 11kV power transformers at Ross Plains ZS.

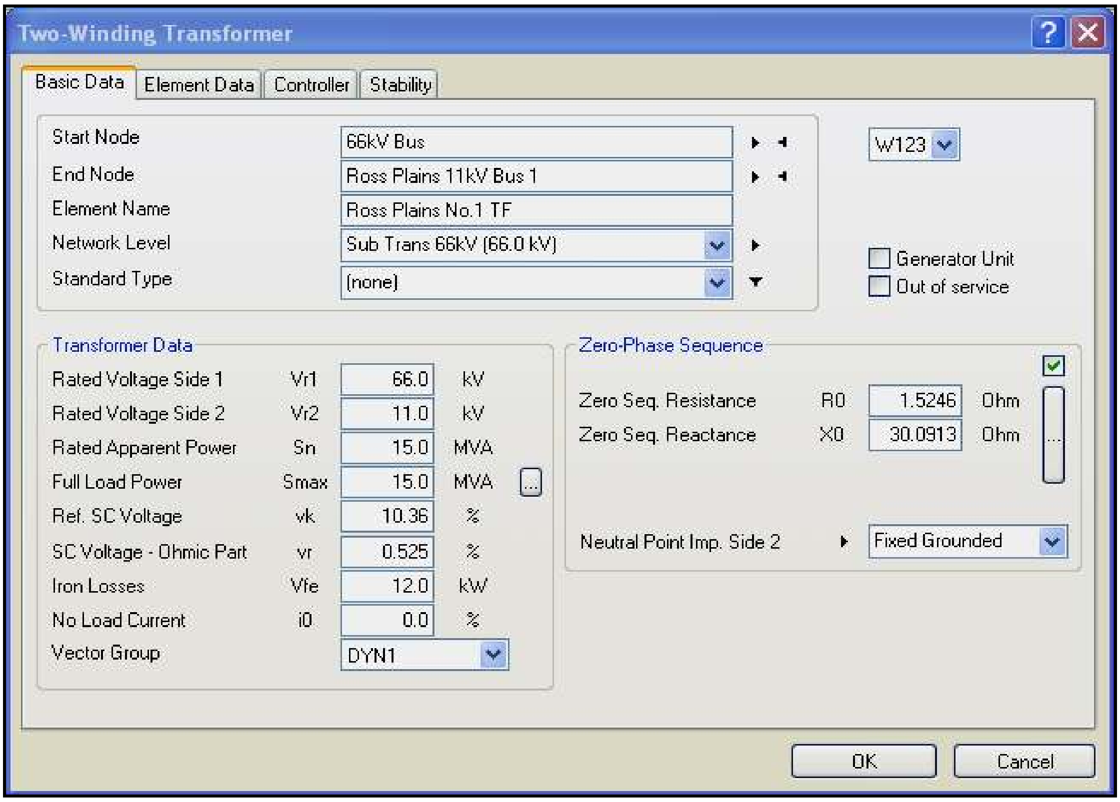


Figure 5.1 – PSS Sincal Transformer Basic Data Ross Plains ZS 66/11 kV Transformer

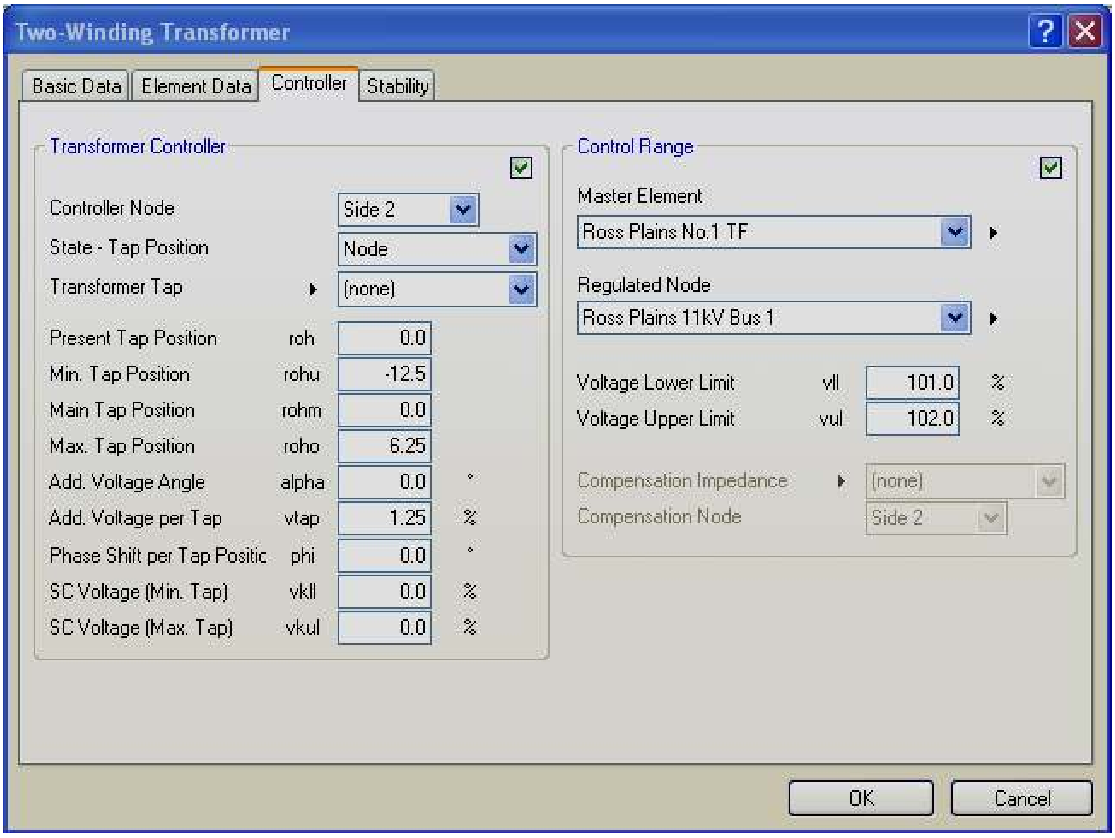


Figure 5.2 – PSS Sincal transformer controller for Ross Plains ZS 66/11 kV transformer

The arrangement of the Infeeder, 66/11 kV transformers, 66 kV bus, 11 kV bus, two capacitor banks, two equivalent 11 kV loads and the outgoing feeder cable for ROPL-04 is shown in figure 5.3 below, which is an image of the PSS Sincal network.

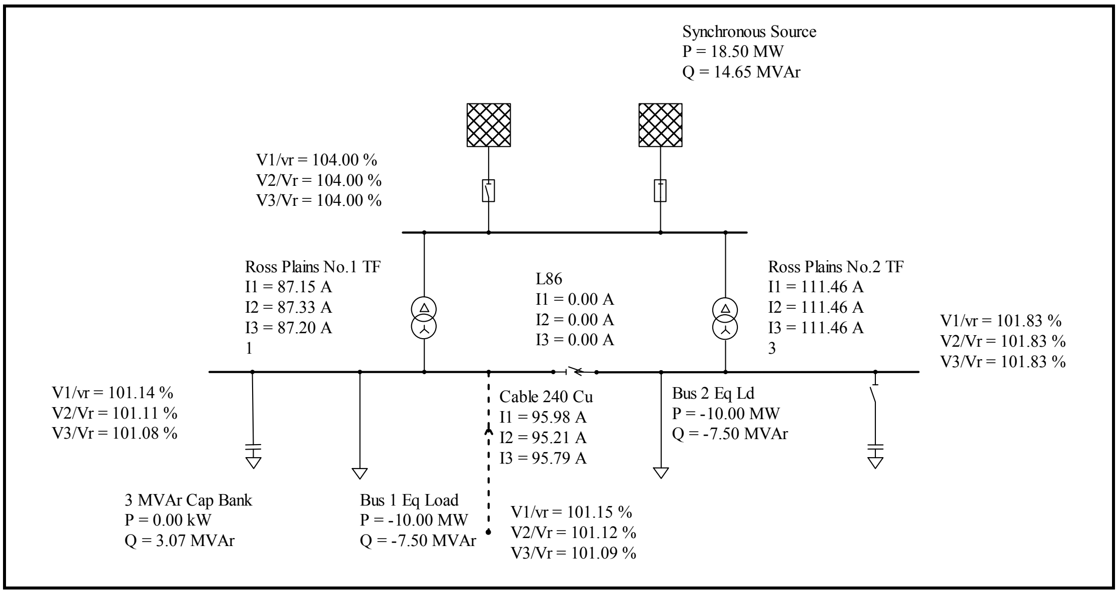


Figure 5.3 – Ross Plains ZS Arrangement.

One Infeeder (top left hand side of the 66 kV bus) is switched out in this image. This Infeeder is configured with lower sub-transient sequence impedances and is used for maximum fault calculations. The equipment used in the electrical supply network usually has a rating for the maximum fault levels; for example an 11 kV switchboard may have a fault rating of 25 kA for 3 s. The sub-transient fault level presently experienced at Ross Plains ZS is about 11 kA with the bus tie closed and both 66/11 kV transformers in service. The maximum possible Small DG System penetration on ROLP-04 would be 963 10 kW installations and this translates to 9.6 MW or about 500 A. It is unlikely that any amount of Small DG Systems penetration will push the fault levels up by an amount that will cause concern at Ross Plains ZS. The main concern will be on protection reach and this is almost always considered at the synchronous levels. For these reasons that maximum fault values or sub-transient fault levels are not considered in this research project.

5.2.2 ROPL-04 Feeder Model – HV Distribution Network

The HV distribution network is configured in PSS Sincal as a schematic view and not geographic. All of the overhead line and cable sections and all of the distribution substations are represented according to Ergon Energy data. The diagram of the complete HV distribution network is too large to display within this section of the report and is included in a larger format as Appendix B.

5.2.3 ROPL-04 Feeder Model – HV Distribution Substations

The HV distribution substations are modelled as 11 kV / 415 V delta star transformers with fixed tap arrangements. Their size and impedances are the same as the Ergon Energy network data suggests. Figure 5.4 below shows PSS Sincal two winding basic data for a 300 kVA transformer with an impedance of 8% on its own base. Figure 5.5 shows the tap arrangement in the PSS Sincal two winding transformer controller section of the same transformer.

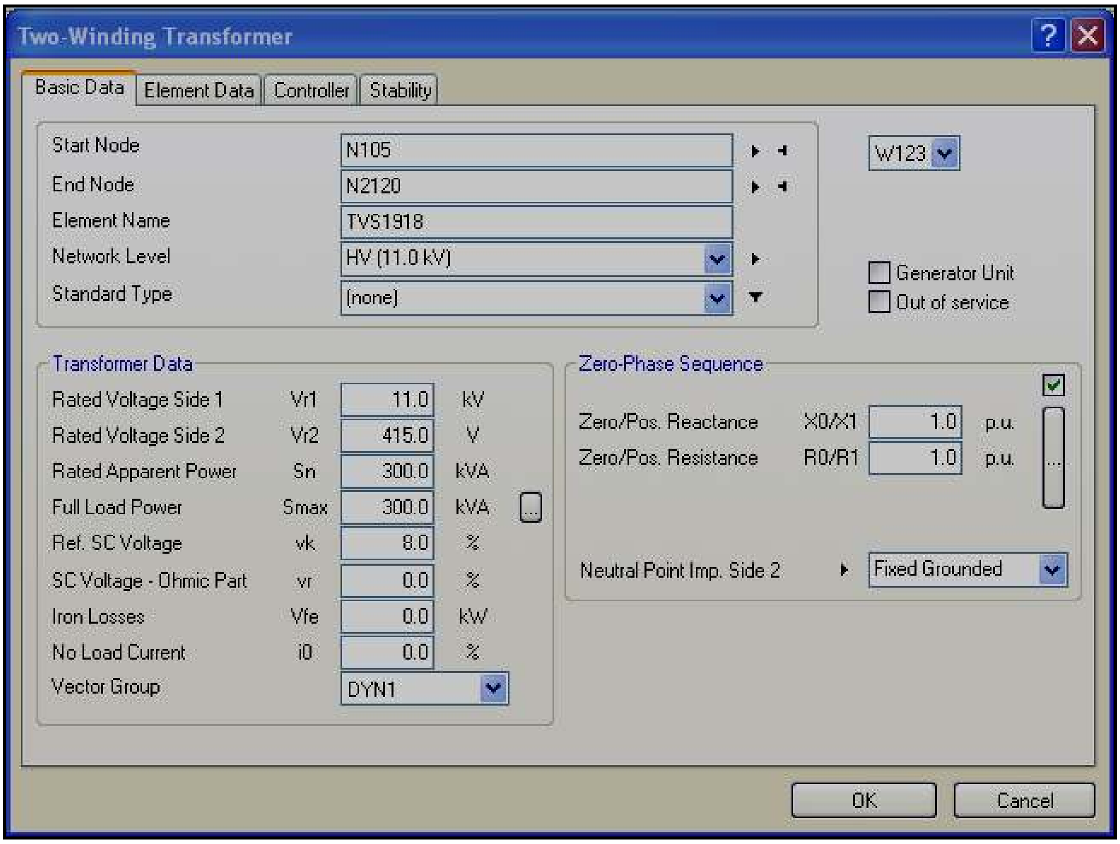


Figure 5.4 – PSS Sincal Two Winding Transformer Basic Data for Distribution Transformer

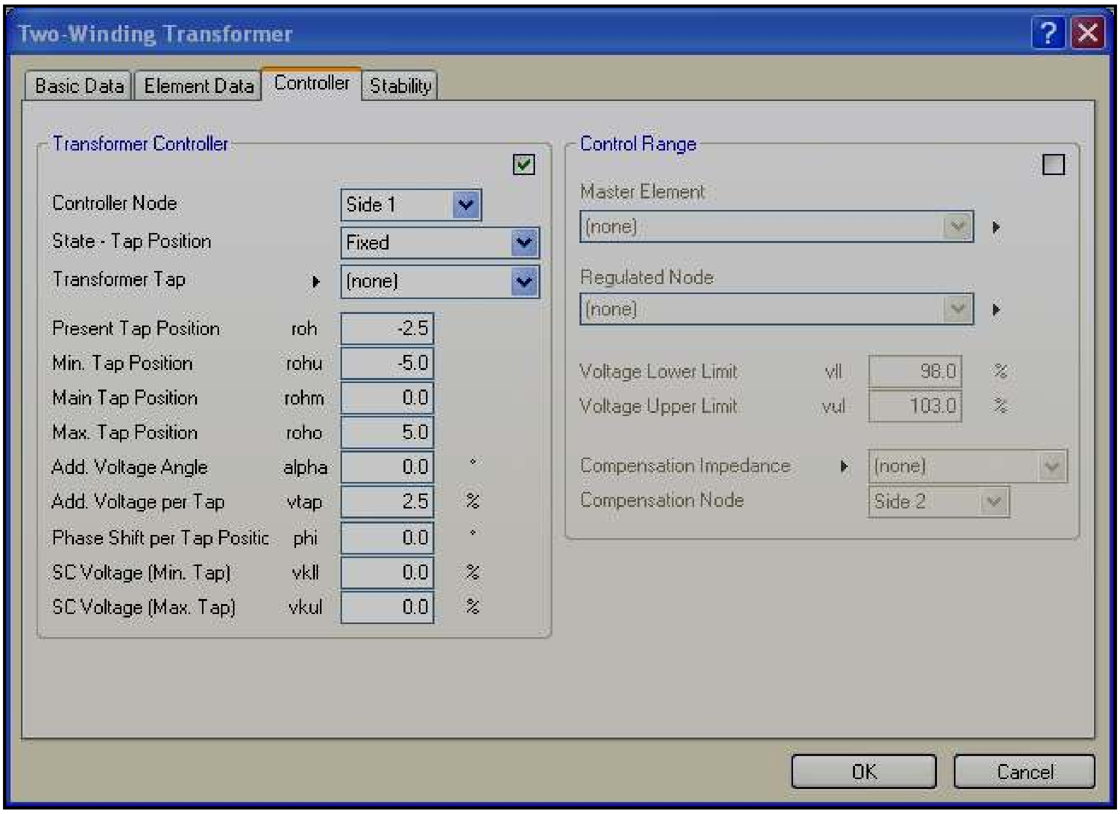


Figure 5.5 – PSS Sincal Two Winding Transformer Controller for Distribution Transformer

5.2.4 ROPL-04 Feeder Model – LV Distribution Network

The LV distribution networks connected to each distribution substation are similar in configuration and have been developed to be representative of a residential underground network. These networks are radial with an individual LV three phase 240 mm^2 aluminium cable feeding twelve single phase customers. The cable length to the first of the twelve customers in a group are either 50 m, 100m, 150m or 200m depending on how many cables radiate from the distribution substation. The cable length between each successive customer is 25m interspersed with one 50m length. Each customer is represented by a load and these loads are supplied by single phase 16 mm^2 copper cables 10m long, which are fed from alternate phases.

Figure 5.6 below shows an image taken from PSS Sincal of three customers represented as loads and DC-Infeeder (which will be described in a later section of this report). Figure 5.7 shows a group of twelve customers and the DC-Infeeders and following this is figure 5.8 which shows 120 customers connected to a distribution substation transformer (with the distribution transformer section highlighted and expanded).

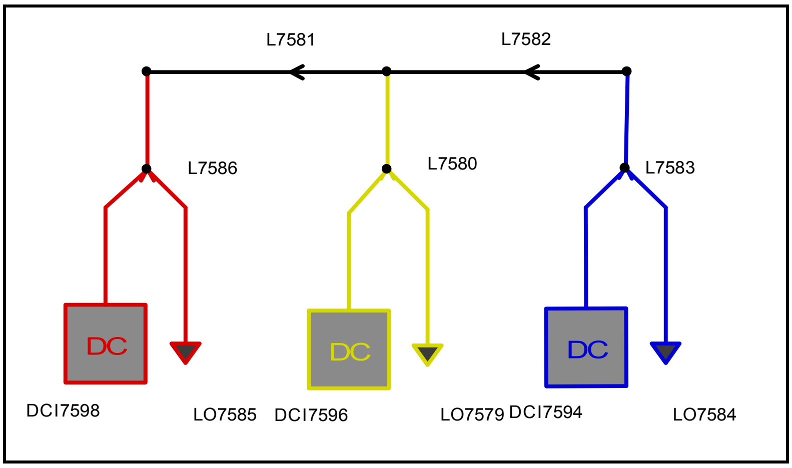


Figure 5.6 – Three LV Customers and DC-Infeeders

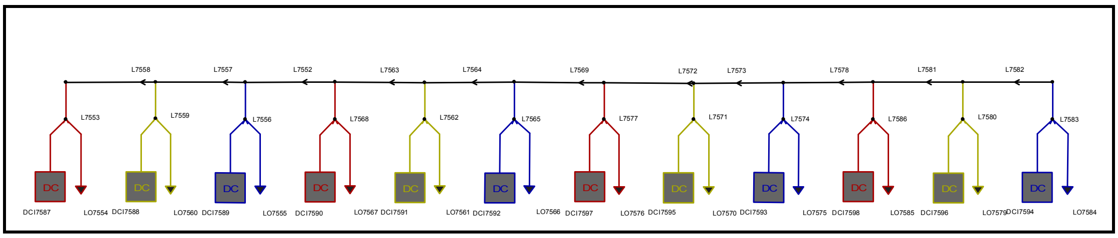


Figure 5.7 – Twelve LV Customers and DC-Infeeders

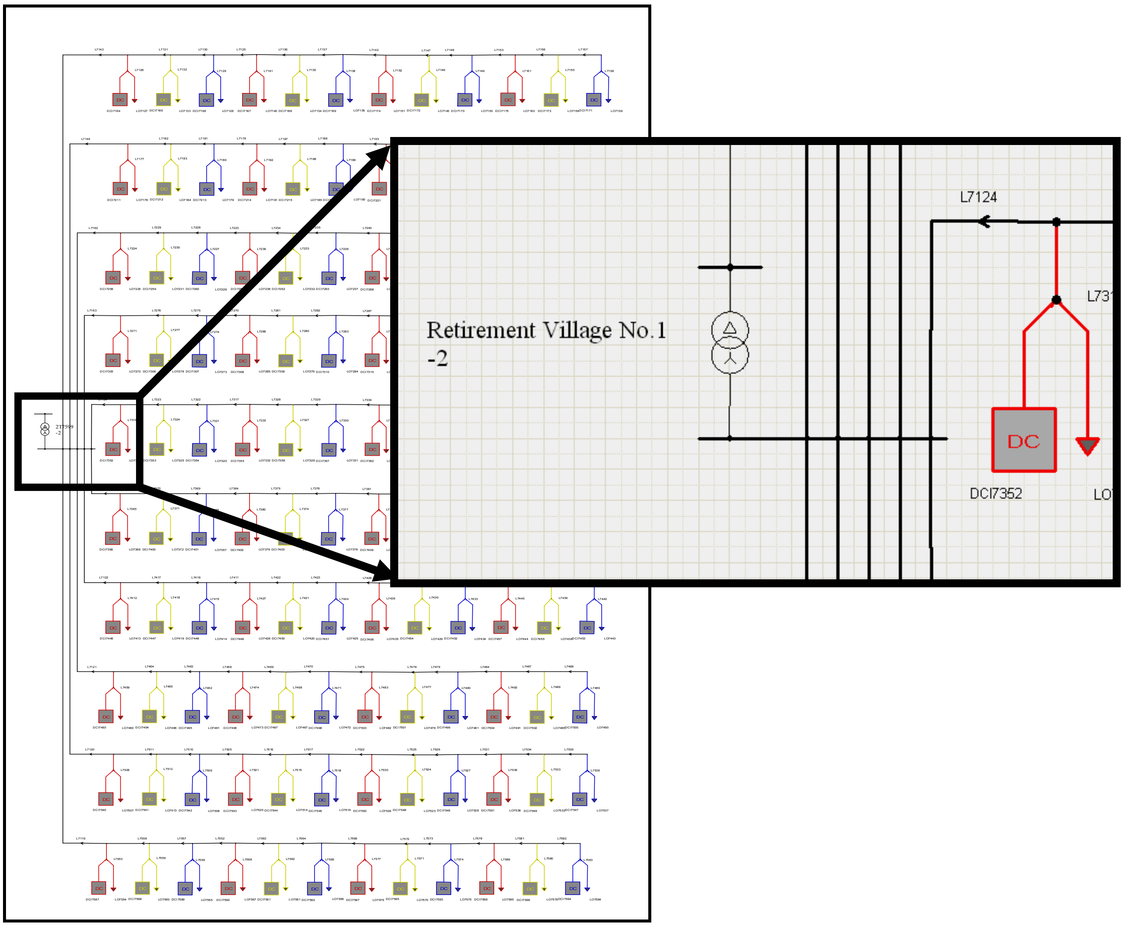


Figure 5.8 – Complete LV Network Supplied by Distribution Substation

5.2.5 ROPL-04 Feeder Model – DC-Infeeder

PSS Sincal has a generation device (node element) called a DC-Infeeder which is meant to represent the equivalent of a Small DG System. Figure 5.9 below shows the PSS Sincal DC-Infeeder page where the parameters of the system configuration are set. This Infeeder allows for a PV array size as well as realistic losses between the array and the inverter and inverter efficiency. The upper and lower operating voltages can be set so the DC-Infeeder ceases to operate when the values are surpassed. The upper voltage is set to 112.5% or 270 V to reflect the worst case scenario. The lower voltage is set to 80% as the algorithm used by PSS Sincal has trouble converging with the DC-Infeeders set at higher percentages.

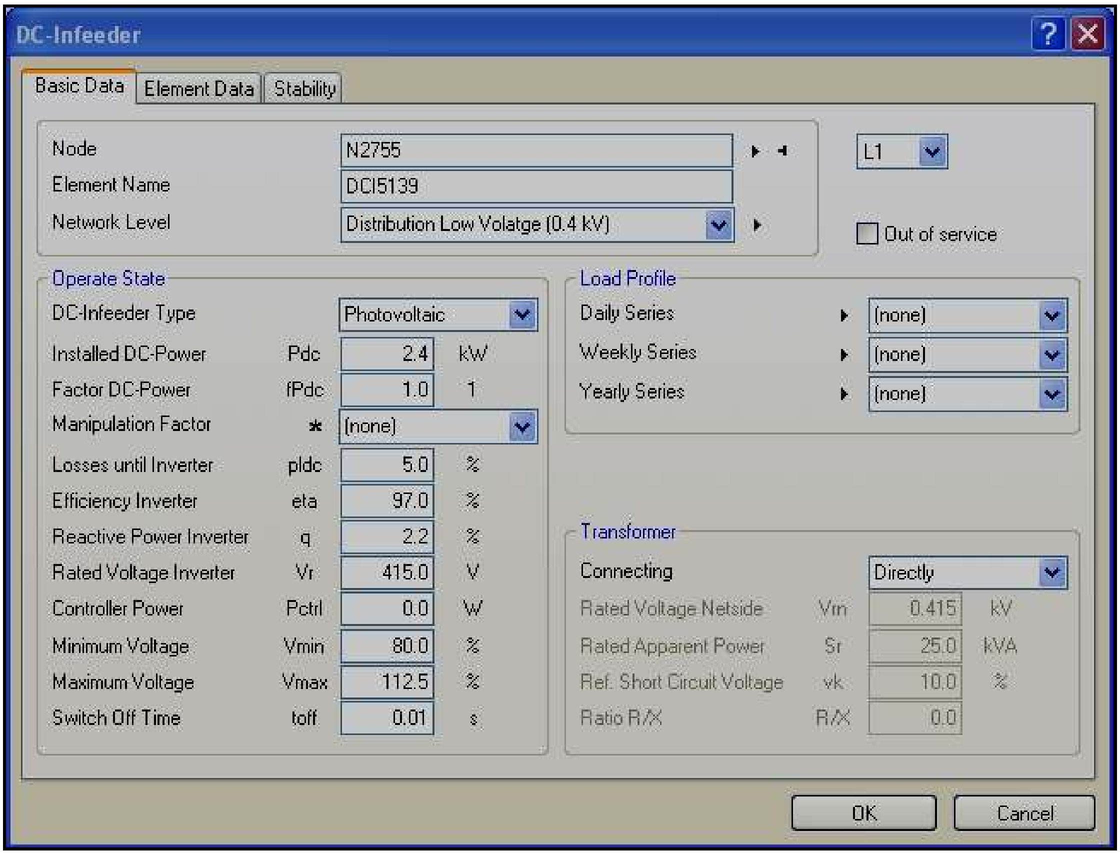


Figure 5.9 – PSS Sincal DC-Infeeder Basic Data Page

The maximum Small DG Systems size for most customers on the ROPL-04 would be 10 kW as almost all of the customers take supply at single phase. The Small DG Systems used in residential applications will be limited by a number of factors including the north facing roof area available to mount the PV array, the orientation of the PV array and shading during part of the day. This means that it is very unlikely that every customer could ever have 10 kW of Small DG System. A value of 2.4 kW was chosen as a maximum size per customer on the ROPL-04 network and represents an average per customer when the limitations experienced by them are accounted for.

5.2.6 ROPL-04 Model and Lumped Installations

A factor being investigated in this research project is the effect that the inclusion of a large lump of Small DG Systems somewhere within the HV network. An example of a lumped installation on a residential feeder such as ROPL-04 would be a retirement village or a medium density residential development. An area such as a retirement village would have the potential to include a Small DG System on every customer's premises when the rest of the network has a more even distribution.

An equivalent model of a retirement village would be similar to other LV networks downstream of a distribution transformer. In this research project a retirement village will consist of an 11 kV / 415 V 500 kVA distribution transformer and 120 residential customers or two transformers and 240 customers. The 120 customer lumped installations will resemble in every way what was shown described earlier in this report as figure 5.8.

An example of a lumped installation on the ROPL-04 network can be seen if figure 5.10 below where a red rectangle in the lower right of the figure surrounds the lumped installation that represents a retirement village or similar medium density residential development.

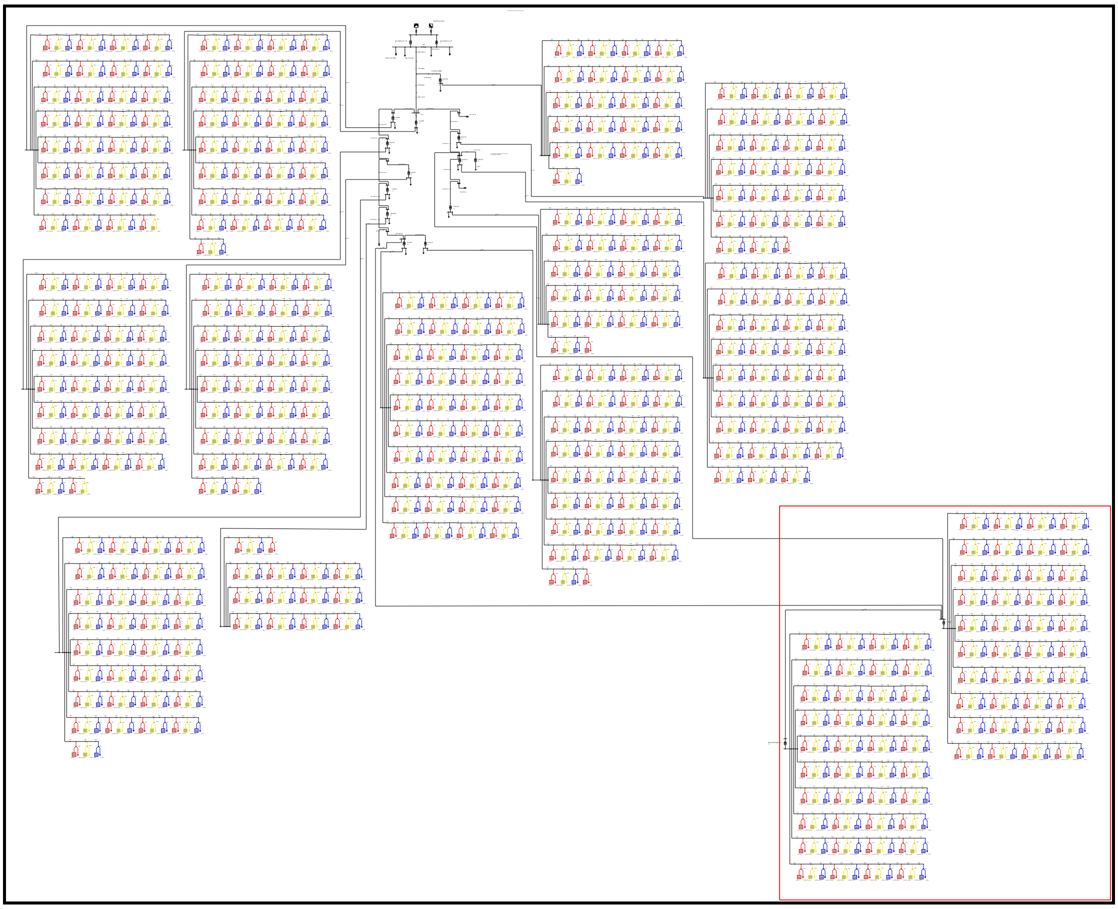


Figure 5.10 – Complete ROPL-04 Model with Lumped Installation

The values of the load real and reactive power and also the DC-Infeeder power are adjusted for each customer of the lumped installation will be treated the same way as every other customer on the network model, unless stated otherwise.

5.3 *Karara SWER Feeder Model*

The following section provides the details of the development of the Karara SWER feeder model.

5.3.1 Karara SWER Feeder Model – 11kV Source

The Karara SWER is a portion of the Lemontree feeder which is supplied from the Pampas zone substation. This feeder has two 11kV regulators in the three phase network before the SWER isolator and also a single SWER regulator. The last of these 11kV regulators is located 15 km before the SWER isolator and the SWER regulator is located 6 km after the SWER isolator. The last of the 11 kV regulators and the following section of 11 kV three phase network will need to be included in the model along with the entire SWER network so that relevant voltage drop values are seen in the first section of the SWER network. The 11kV network preceding the last of the 11kV regulators will not be required as the focus will most likely be on the extremities of the SWER lines and so well away from the 11 kV.

The Karara SWER PSS Sincal model begins with an Infeeder set to maintain the 11 kV voltages at 102% of the nominal. The Infeeder has the following source impedance that was obtained from the Ergon Energy distribution network models (which are modelled in DINIS(E)) at the last 11 kV regulator PE-12048. The values below are the synchronous sequence impedances:

- Positive sequence impedance - $Z_1 = 12.69 + j8.88\Omega$
- Negative sequence impedance - $Z_2 = 12.69 + j8.88\Omega$
- Zero sequence impedance - $Z_0 = 15.18 + j31.67\Omega$

The configuration for the 11 kV source is shown in figure 5.11 below, which is an image of the PSS Sincal Infeeder basic data page.

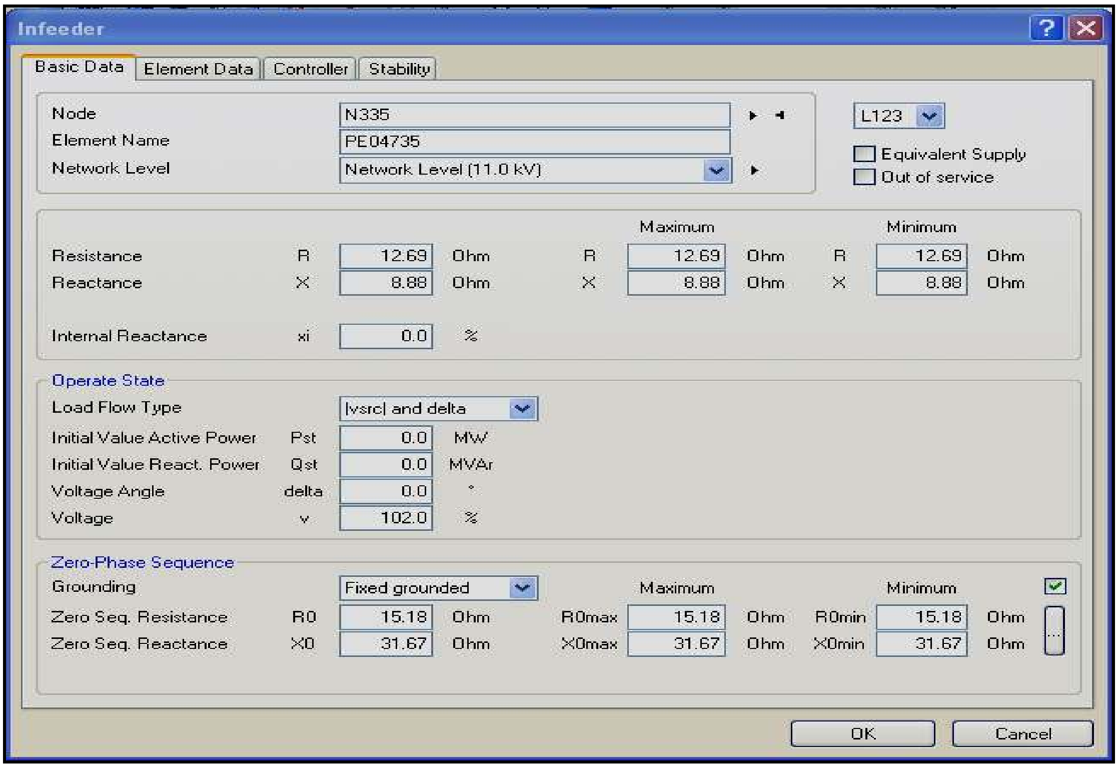


Figure 5.11 – 11 kV Source Infeeder Basic Data

5.3.2 Karara SWER Feeder Model – SWER Isolators

The Karara SWER is isolated from the three phase network using two 100 kVA SWER isolation transformers in parallel. A SWER isolator is a transformer that has a primary winding that is connected across two of the 11 kV phases and a secondary winding that is connected between the active SWER line and the earth as can be seen in figure 5.12 below.

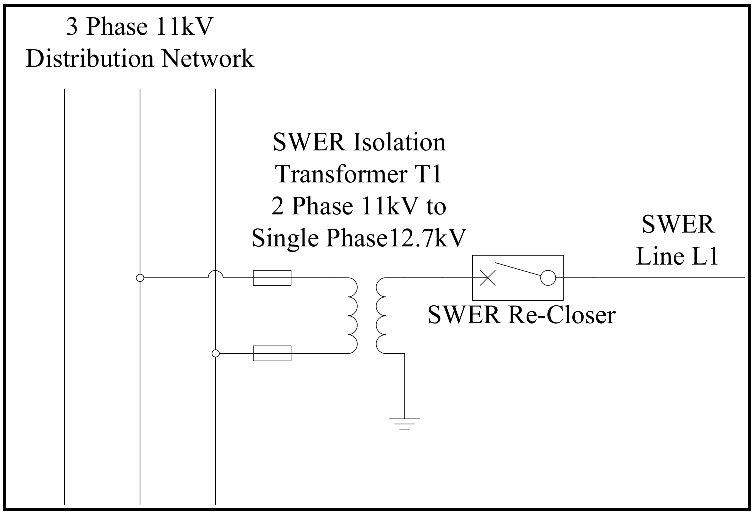


Figure 5.12 – Karara SWER Isolating Transformer

A direct equivalent is simulated in PSS Sincal by using a delta star transformer with voltages of 11 kV on the primary and 22 kV on the secondary. The secondary 22 kV voltage is 12.7 kV between phase and neutral. The primary winding is enabled for two phases only and the secondary star winding is earthed, effectively producing the desired SWER isolating transformer. Figure 5.13 below shows one of the PSS Sincal two winding transformer basic data page used for the Karara SWER isolator.

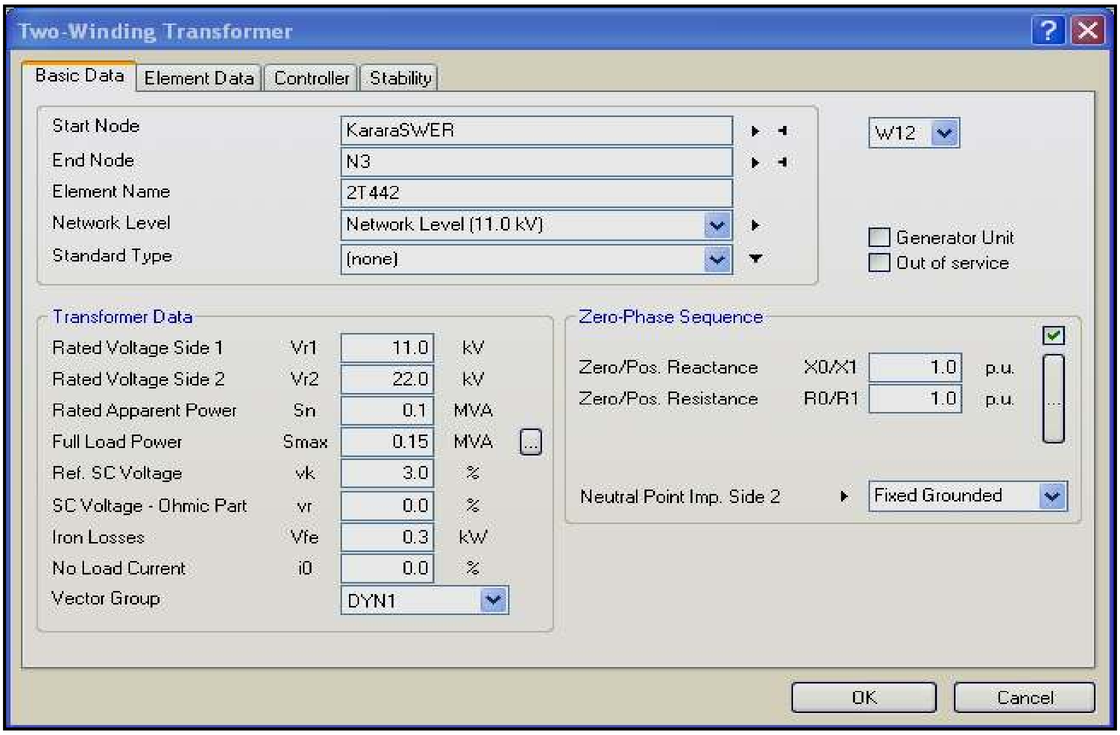


Figure 5.13 – PSS Sincal Two Winding Transformer Basic Data for SWER Isolator

The SWER isolator is also a fixed tap transformer and configured the same way in PSS Sincal. Figure 5.14 below shows the fixed tap arrangement used by PSS Sincal for the SWER isolators.

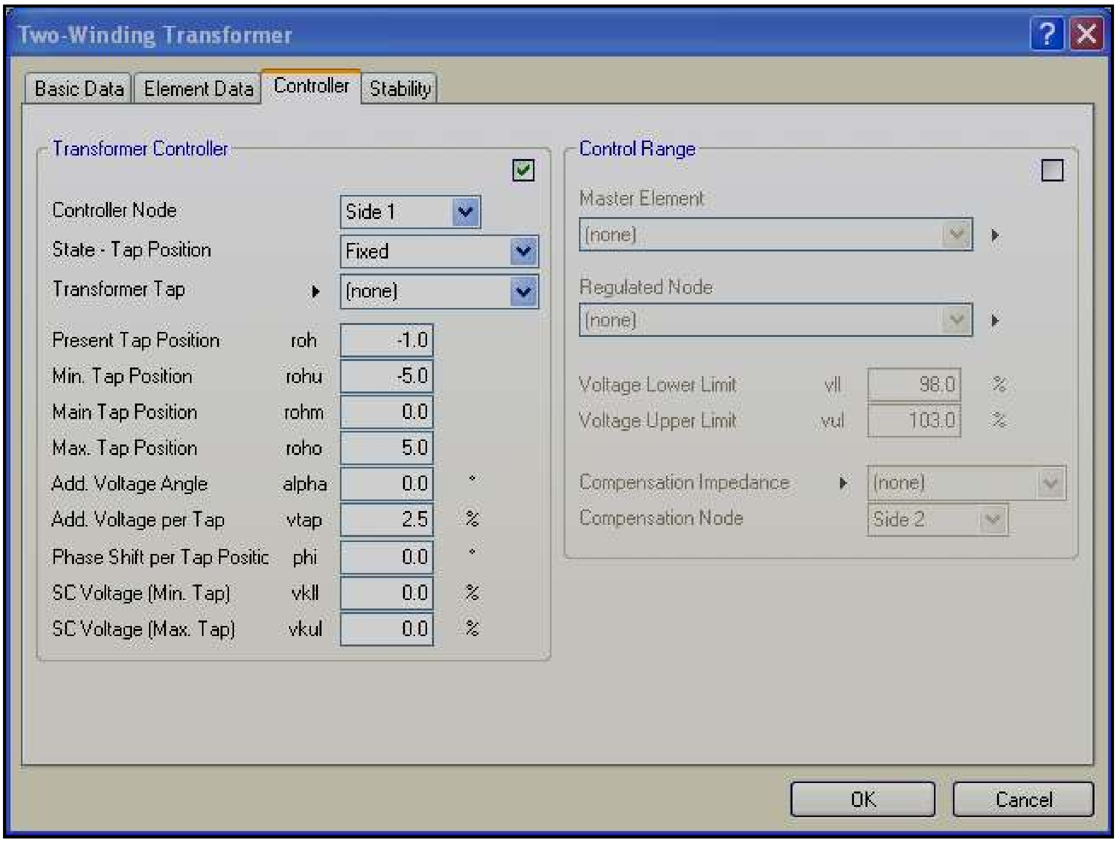


Figure 5.14 – PSS Sincal Two Winding Transformer Controller for SWER Isolator

5.3.3 Karara SWER Feeder Model – Regulator

A SWER regulator is a single phase auto transformer with the primary winding connected between the incoming SWER line and earth and the outgoing winding connected between the outgoing SWER line and earth as can be seen in figure 5.15 below.

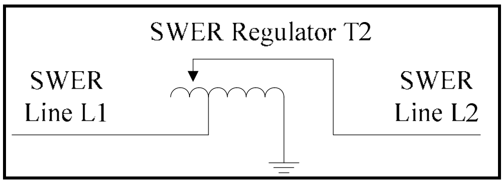


Figure 5.15 - SWER Regulator

A direct equivalent is simulated in PSS Sincal by using a star/star auto transformer with voltages of 22 kV on the primary and 22 kV on the secondary. The primary and the secondary star winding are not earthed as little current flows to earth in a SWER regulator. This arrangement effectively produces the desired SWER regulating transformer. Figure 5.16 below shows a PSS Sincal two winding transformer basic data page used for the Karara SWER regulator.

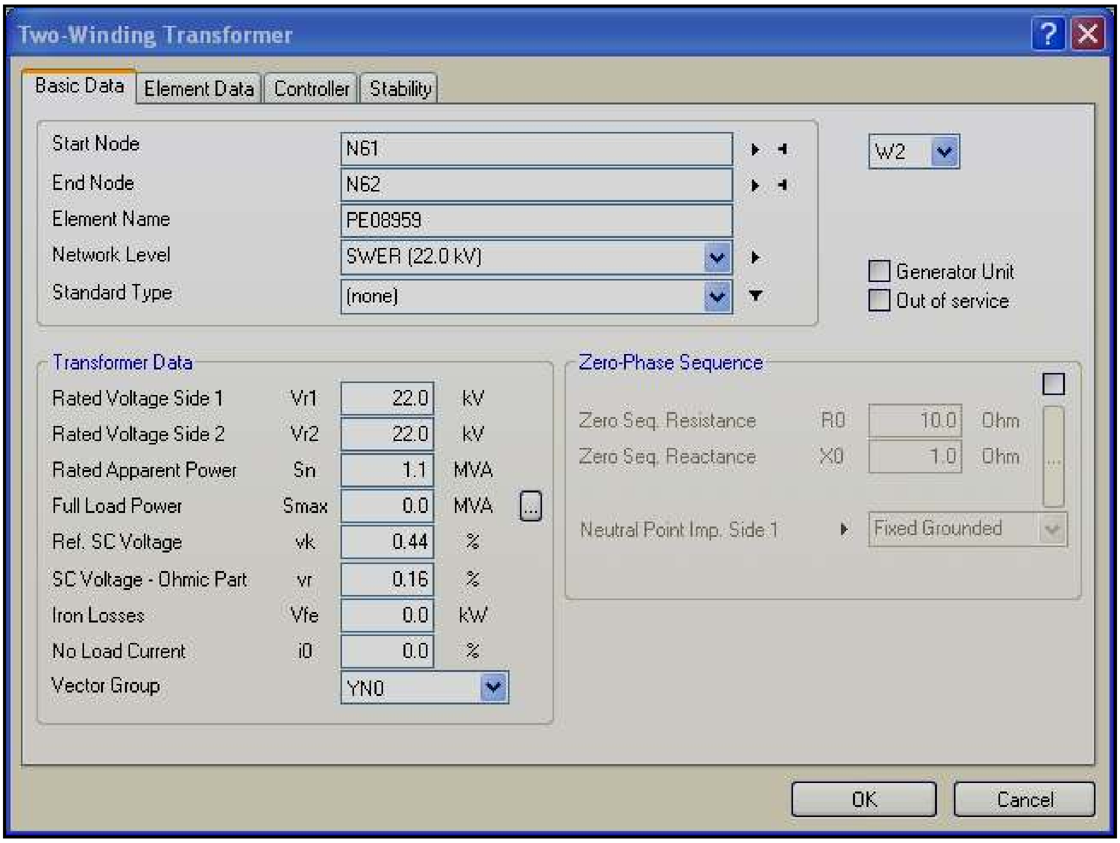


Figure 5.16 – PSS Sincal Two Winding Transformer Basic Data for SWER Regulator

The SWER regulator employs an OLTC and this is configured using the controller page of the PSS Sincal two winding transformer as can be seen in figure 5.17 below.

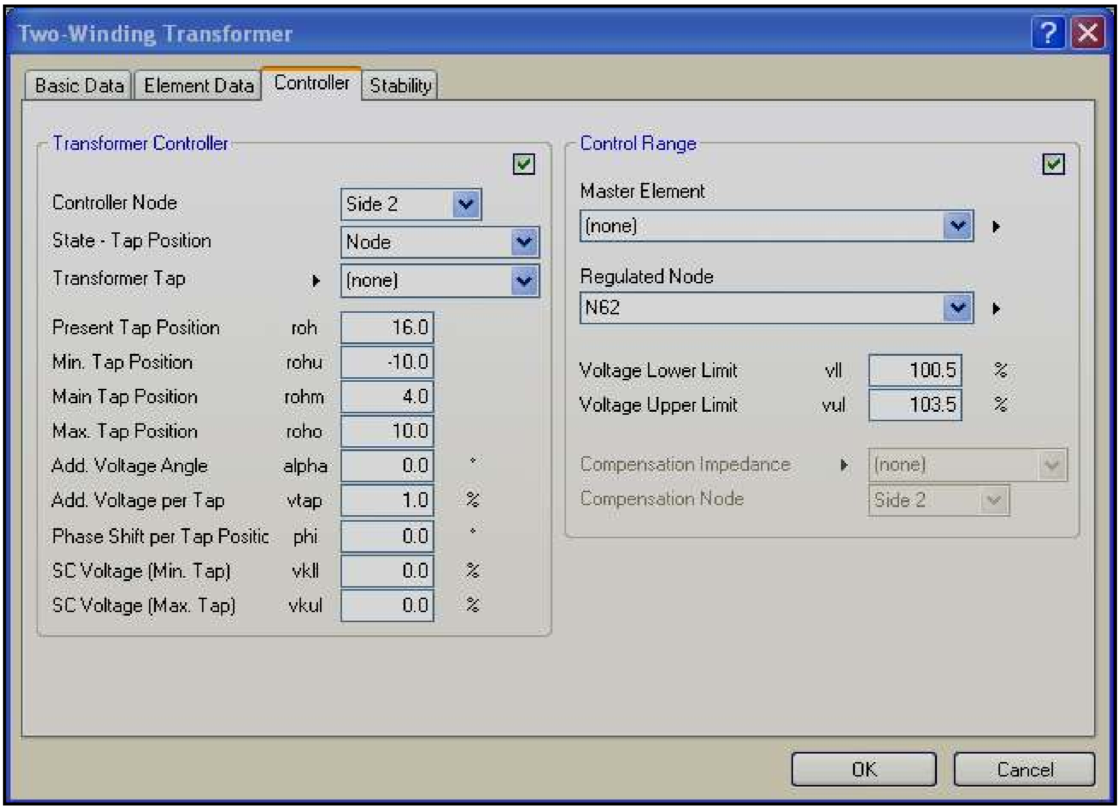


Figure 5.17 - PSS Sincal Two Winding Transformer Controller for SWER Regulator

5.3.4 Karara SWER Feeder Model – Distribution Transformer

A customer is connected to a SWER line using a SWER distribution transformer. These transformers are a single phase where the primary is connected between the SWER line and earth and the secondary is connected to the customers LV active and neutral with the neutral earthed. Figure 5.18 below shows the windings of a SWER distribution transformer.

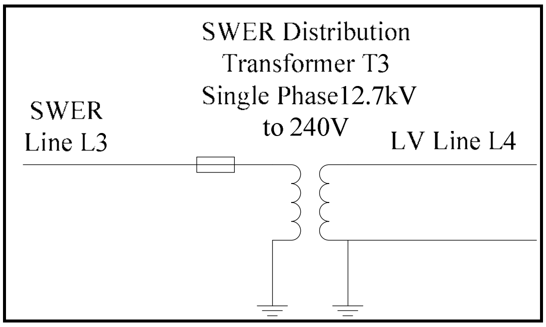


Figure 5.18 - SWER Distribution Transformer

The PSS Sincal does not model single phase transformers. The alternative is to use an auto transformer with the primary voltage set to 22 kV and the secondary set to 415 V and only one phase enabled. Figure 5.19 below shows the PSS Sincal two winding transformer basic data input page used for the SWER distribution transformer basic data regulator.

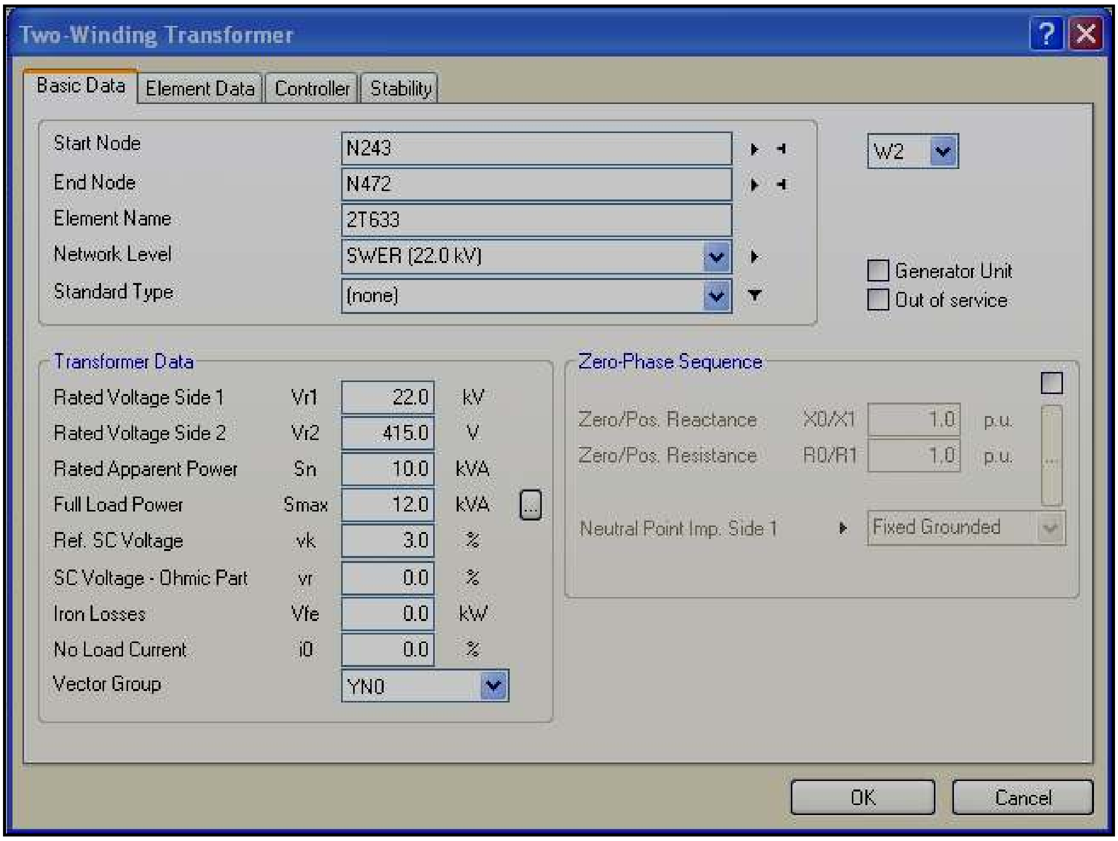


Figure 5.19 - PSS Sincal Two Winding Transformer Basic Data for SWER Distribution Transformer

The SWER distribution transformer employs a fixed tap arrangement and this is configured using the controller page of the PSS Sincal two winding transformer as can be seen in Figure 5.20 below.

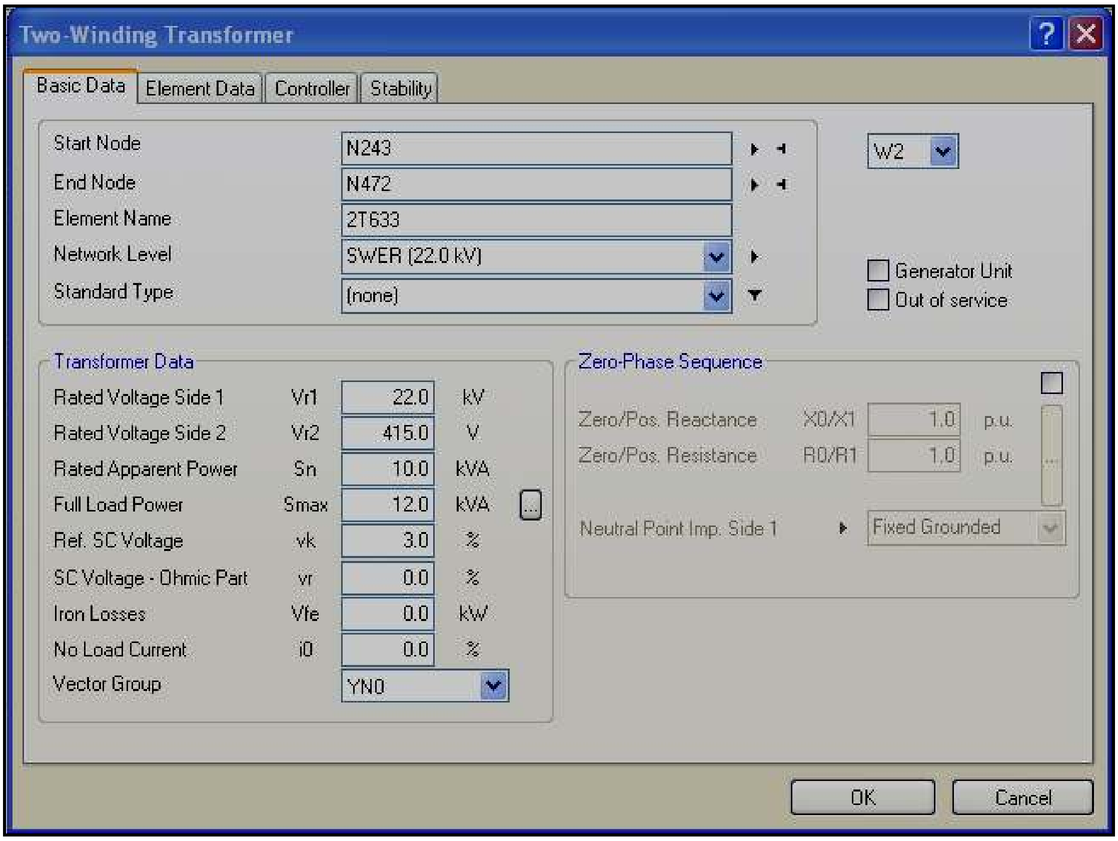


Figure 5.20 - PSS Sincal Two Winding Transformer Controller for SWER Distribution Transformer

The Karara SWER model uses the distribution transformer described above and a load to represent each customer. There are 98 distribution transformers and 99 customers on the SWER feeder but for simplicity all customers will have a distribution transformer.

5.3.5 Karara SWER Feeder Model – DC-Infeeder

The DC-Infeeder described previously in this report is also used to model the Small DG Systems for the Karara SWER.

The maximum size Small DG Systems that can be installed by customers on the Karara SWER network will be 10 kW as they take supply at single phase only. The Small DG Systems used in rural applications will be limited by a number of factors including the north facing roof area available to mount the PV array, the orientation of the PV array, and shading. In many situations the roof areas available in rural areas will be much larger than residential areas and so a size value of 4.8 kW was chosen that represents an average of the limitations experienced by each customer.

Figure 5.21 below shows a DC-Infeeder, customer load and SWER distribution transformer. This arrangement is placed at every customer's point of connection on the Karara SWER network.

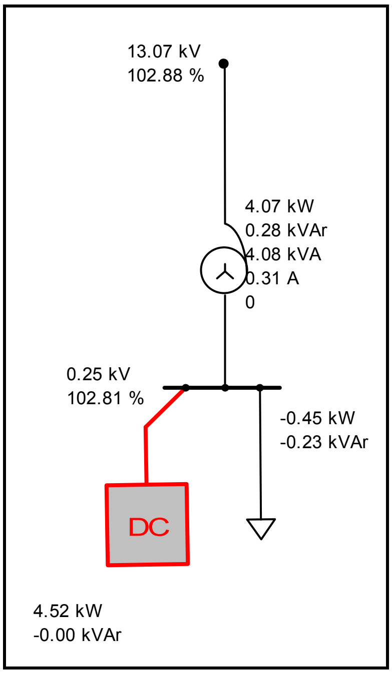


Figure 5.21 - PSS Sincal Customer Load, DC-Infeeder and SWER Distribution Transformer

5.3.6 Complete Karara SWER Feeder Model

The 11 kV three phase section of the Karara SWER model includes the 11 kV source to represent the last 11 kV regulator, 10 km of three phase line, a point load to represent all the loads between the last 11 kV regulator and the SWER isolator and the two SWER isolators. Figure 5.22 below shows the initial section of the Karara SWER model.

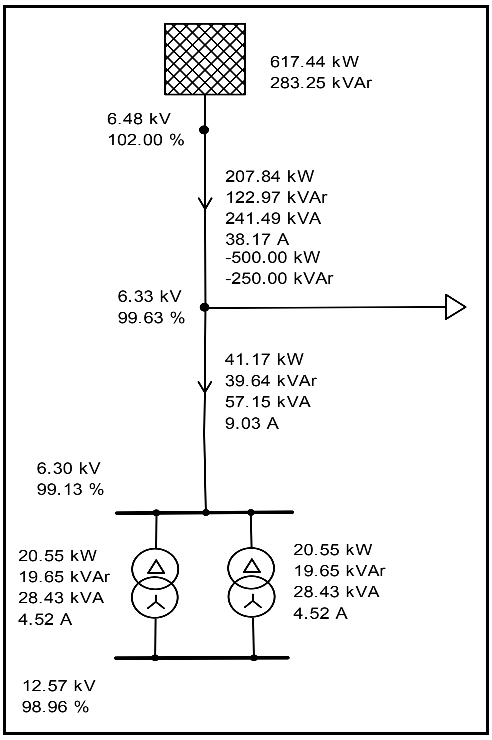


Figure 5.22 – PSS Sincal Initial Section of Karara SWER Model

The remainder of the model is represented in a geographic format and this can be seen in figure 5.23 below along with a small section of the network expanded for a better view.

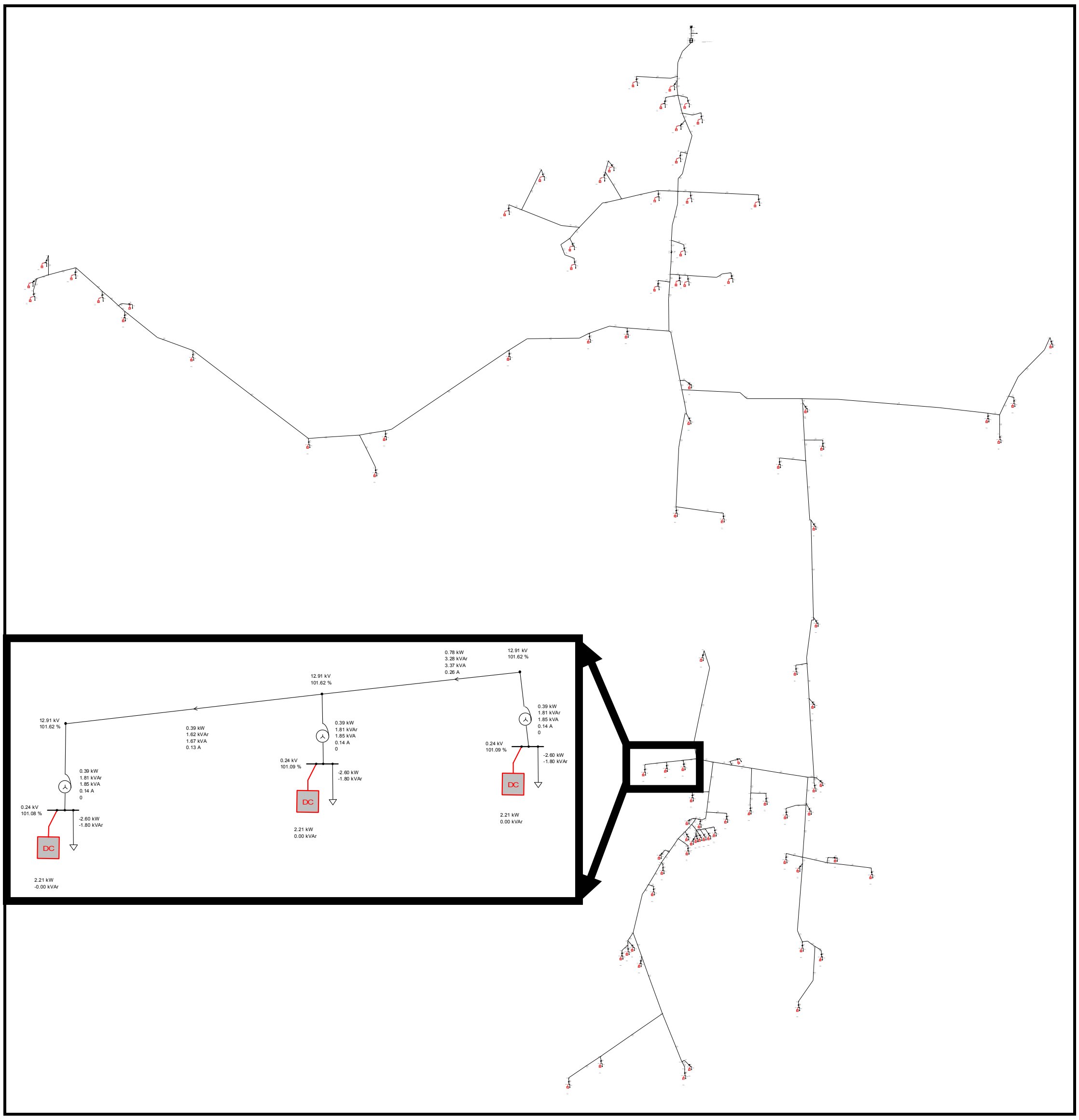


Figure 5.23 – PSS Sincal Complete Karara SWER Geographic View

This model was developed using a tool that converted a DINIS(E) model to an earlier software version of PSS Sincal. The earlier software version was then converted to the latest version of PSS Sincal. The conversion tool does not produce models that will directly run on the latest version of PSS Sincal. Ergon Energy has no operating examples of the earlier software version and so no way at present to create PSS Sincal models from their existing DINIS(E) models except by manually building them. Manually building a SWER model is very time consuming due to their great number of line sections. The Karara SWER was one of the few existing PSS Sincal models of a SWER network and this was one of the reasons it was chosen for this research project.

5.3.7 Karara SWER Model and Lumped Installations

A lumped installation on a SWER network is very different to that possible on a residential feeder. A SWER network is only intended to supply light customer loads separated by large distances. The greatest possible lumped installation on SWER network may be a farm with a number of closely group machinery sheds or light agricultural loads of up to ten installations.

The model of the Karara SWER feeder will be tested with lumped installations of five or ten customers connected to one point within the network. Figure 5.24 below shows the configuration of a SWER lumped installation of ten customers.

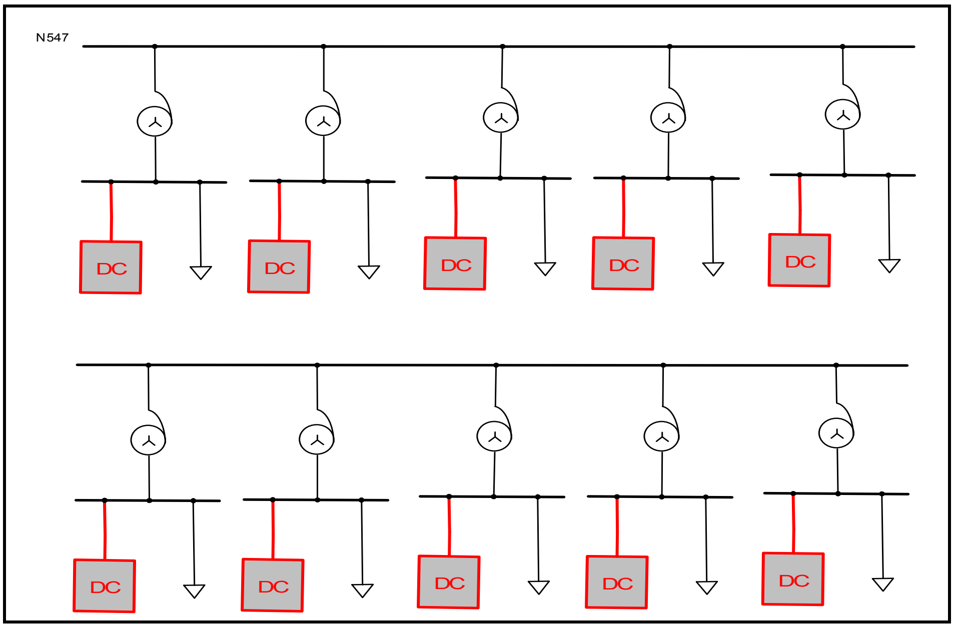


Figure 5.24 – Karara SWER Lumped Installation

The values of the load real and reactive power and also the DC-Infeeder power are adjusted for each model permutation and will be the same as every other customer on the network unless stated otherwise.

5.4 *Model Validation*

This section describes the process of checking and validating the models.

5.4.1 ROPL-04 Model Validation

It is necessary to be sure that the model is set up with the appropriate arrangement of fixed taps on the distribution substation. This can be achieved by running a load flow of the model with no Small DG Systems for the highest loads and the lowest loads and checking to see if the voltages are within the prescribed ±6% of the nominal LV voltage.

Figure 5.25 below shows the graph of apparent, real and reactive power for the day when the highest demand was measured in the last year on the ROPL-04 feeder.

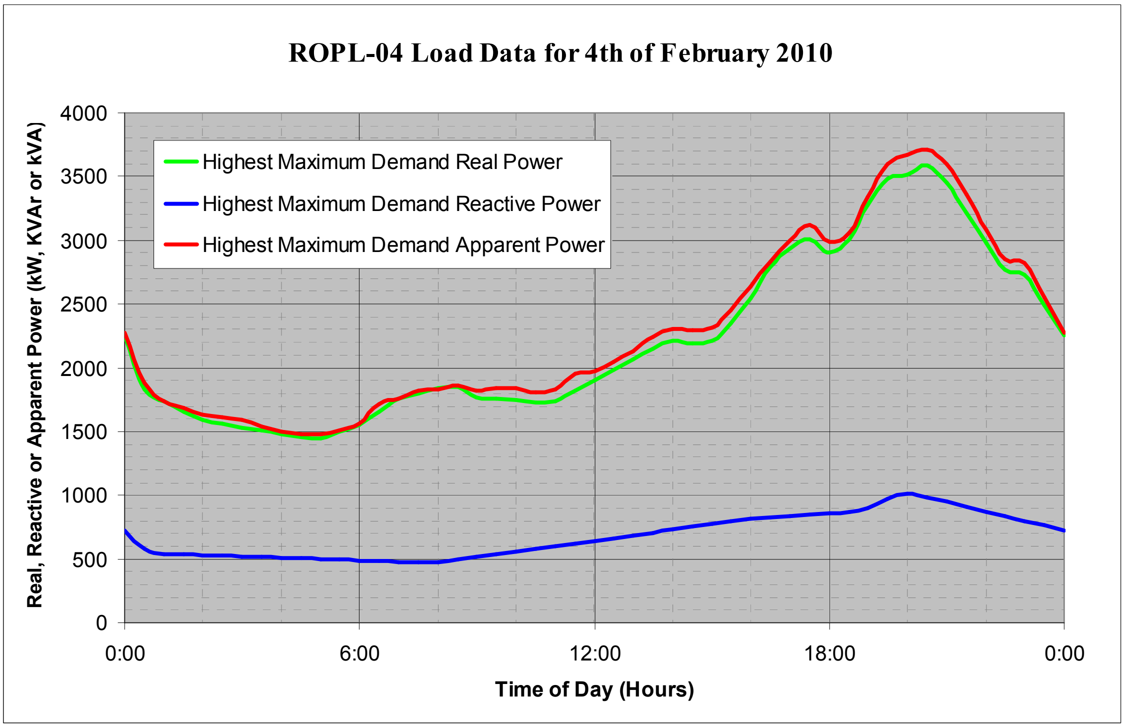


Figure 5.25 – ROPL-04 Load data for the 4th of February 2010

It can be seen in the graphs in the figure above that the reactive power is relatively low and does not get below a 0.92 lagging power factor. This is because of the 3 MVAr and 2 MVAr capacitor banks located at the Ross Plains ZS along and the large customer power factor correction capacitors were all in service during the high demand period of the 4th of February 2010.

The maximum real power is 3590 kW and this figure can be apportioned to all of the 980 customers evenly, except the school which will have a load of 50 kW (as the peak of 3590 kW is at 20:30 and after school hours). This means that each customer will have 3.46 kW; however at high loads there are some losses on a distribution network and the actual value used will be 3.4 kW per customer. A reasonable value of power factor for a residential load would be 0.9 lagging. This would see each residential customer have 1.7 kVAr and at the same power factor the school would have 25 kVAr. Applying these values to the loads on ROPL-04 model resulted LV ranged from in 94.7% to 101.8%.

The lowest load period would be during the cooler months of the year and at night. This value is difficult to determine with any certainty and for this exercise a value of about one sixth of the maximum demand could be used and so 570 W and 290 VAr. The school loads would be about the same as the maximum demand period as the minimum can also be after school hours. Applying these values to the loads on ROPL-04 model resulted LV ranging from in 103.0% to 104.1%.

Both the maximum demand loads and minimum loads were tested on the network model and the voltages at the customers terminals were within the prescribed ±6% of the nominal LV voltage.

5.4.2 ROPL-04 with Lumped Load Model Validation

The ROPL-04 model was modified with the addition of the lumped installation of the retirement village and tested without Small DG Systems. The lumped installation was tested by connection at the distribution substation TVS1322, which is in the centre of one of the radial HV cables. The second location used during testing was the distribution substation TVS 650, which is a the end of an HV radial cable.

When the lumped installation of 240 retirement village units was located at the centre of the HV network at distribution substation TVS 650and maximum load values of 3.4 kW and 1.7 kVAr was applied to the entire feeder the network voltages ranged from 94.1% to 100.5%. In the same situation but with the minimum load of 570 W and 290 VAr applied to all the customers on the feeder the voltages ranged from 102.9% to 103.9%.

When the lumped installation of 240 retirement village units was located at the end of the HV network and maximum load values of 3.4 kW and 1.7 kVAr was applied to the entire feeder the network voltages ranged from 94.5 % to 101.6%. In the same situation but with the minimum load of 570 W and 290 VAr applied to all the customers on the feeder the voltages ranged from 102.6% to 103.9%.

Both the maximum demand loads and minimum loads were tested on the network model with the inclusion of lumped installations at both the centre and end of the HV network and the voltages at the customers terminals were within the prescribed ±6% of the nominal LV voltage.

5.4.3 Karara SWER Model Validation

There is no useful load data specifically for the Karara SWER section of the Lemontree feeder. The Karara SWER load has been assumed to be 8.08% of the Lemontree feeder as the connected capacity on the SWER network is 8.08% of the total connected capacity of the entire feeder. The value of reactive power on the Karara SWER is difficult to determine without actual data and so will be assumed as the same proportion as the total load. Figure 5.26 shows the estimated Karara SWER active, reactive and apparent power on the maximum demand day for the Lemontree feeder during the year from the 1st of October 2009.

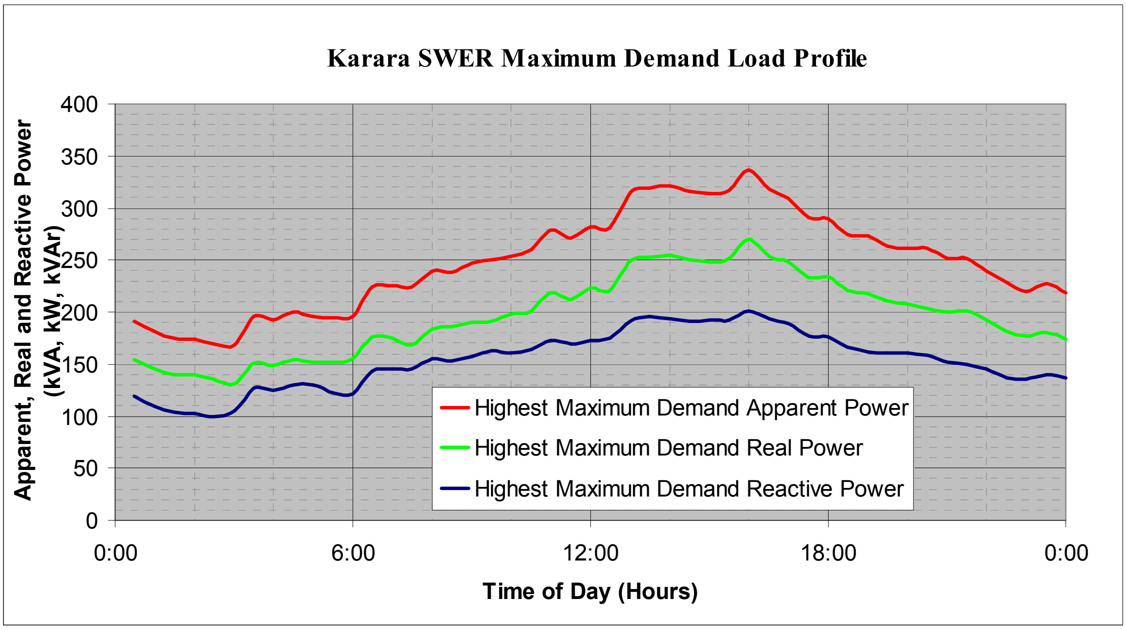


Figure 5.26 – Karara SWER Estimated Load Data for the 23rd of February 2010

The maximum power consumed by the customers on the Karara SWER is 270 kW. The power factor of the loads during this day ranged from 0.48 lagging to 0.76 lagging. This suggests that there is little correction of power factor by devices on the Lemontree feeder and that the reactivity is in a large part due to the great line length of the network. It will be assumed that the loads on the Karara SWER consume the same amount of real power each and that their power factor is 0.9 lagging. This means the customer loads consist of 2.7 kW and 1.4 kVAr. When these values were applied to the model the voltages ranged from 95.5% to 100.9%.

The minimum power period can be assumed to be one sixth of the maximum power and so 450 W and 230 VAr. When these values were applied to the model the voltages ranged from 101.9% to 105.9%.

Both the maximum demand loads and minimum loads were tested on the network model and the voltages at the customers terminals were within the prescribed ±6% of the nominal LV voltage.

5.4.4 Karara SWER with Lumped Load Model Validation

The Karara SWER model was modified with the addition of the lumped installation of ten farm sheds and tested without Small DG Systems.

When the lumped installation of 10 farm shed installations was located at the centre of the HV network and maximum load values of 2.7 kW and 1.4 kVAr was applied to the entire feeder the network voltages ranged from 95.7% to 101.1%. In the same situation but with the minimum load of 450 W and 230 VAr applied to all the customers on the feeder the voltages ranged from 102.8% to 105.6%.

When the lumped installation of 10 farm shed was located at the end of the HV network and maximum load values of 2.7 kW and 1.4 kVAr was applied to the entire feeder the network voltages ranged from 95.5 % to 101.0%. In the same situation but with the minimum load of 570 W and 290 VAr applied to all the customers on the feeder the voltages ranged from 102.7% to 105.6%.

Both the maximum demand loads and minimum loads were tested on the network model with the inclusion of lumped installations at both the centre and end of the HV network and the voltages at the customers terminals were within the prescribed ±6% of the nominal LV voltage.

CHAPTER 6 - PROTECTION SYSTEM MODELLING

6.1 *Protection System Models*

The effectiveness of a protection system's operation can be determined by comparing results of fault currents from modelling exercises and the current through protective devices with the protection settings of these devices. This chapter examines the ability of PSS Sincal to appropriately determine fault current with the inclusion of Small DG Systems.

6.1.1 PSS Sincal Fault Calculations

PSS Sincal uses the method of symmetrical components when calculating values of unbalanced fault current in a symmetrical network. This method was developed by C.L Fortescue (C.L Fortescue, Methods of Symmetrical Coordinates Applied to the Solution of Polyphase Networks, AIEE Transaction, 1918, pp. 1027-1140). In a three phase network the positive, negative and zero sequence impedances Z_1 Z_2 and Z_0 respectively are required if every fault types is to be analysed.

Figure 6.1 below shows a simplified sequence diagram for a single phase to earth fault at the end of a line which is supplied by an Infeeder.

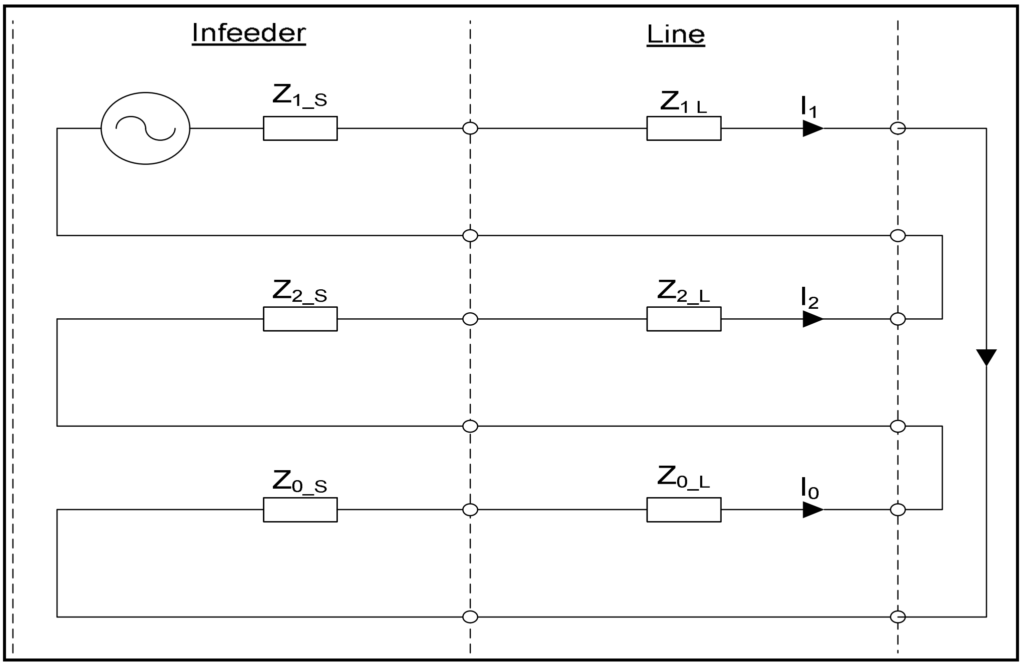


Figure 6.1 – Sequence Network for Phase to Earth Fault

Considering the circuit above the vales are:

- $Z_{1\_S} = Z_{2\_S} = Z_{0\_S} = Z_{1\_L} = Z_{2\_L} = Z_{0\_L} = 10\Omega$
- and the phase to ground voltage of the source was $V_S = 239.6V$

The sequence fault currents will be:

$$I_1 = I_2 = I_0 = \frac{V_S}{Z_{1\_S} + Z_{2\_S} + Z_{0\_S} + Z_{1\_L} + Z_{2\_L} + Z_{0\_L}} = \frac{239.6}{60} = 3.99A$$

The fault current:

$$I_F = I_1 + I_2 + I_0 = 11.98A.$$

The actual impedance of all passive components and Infeeders in PSS Sincal is defined and this value is used as the positive and negative sequence impedance during fault calculations. A separate field allows the inclusion of zero sequence impedance, which must be enabled if the device is in a path of a phase to earth fault. Figure 6.2 below shows a PSS Sincal Infeeder basic data page where the internal and zero sequence impedance data can be seen.

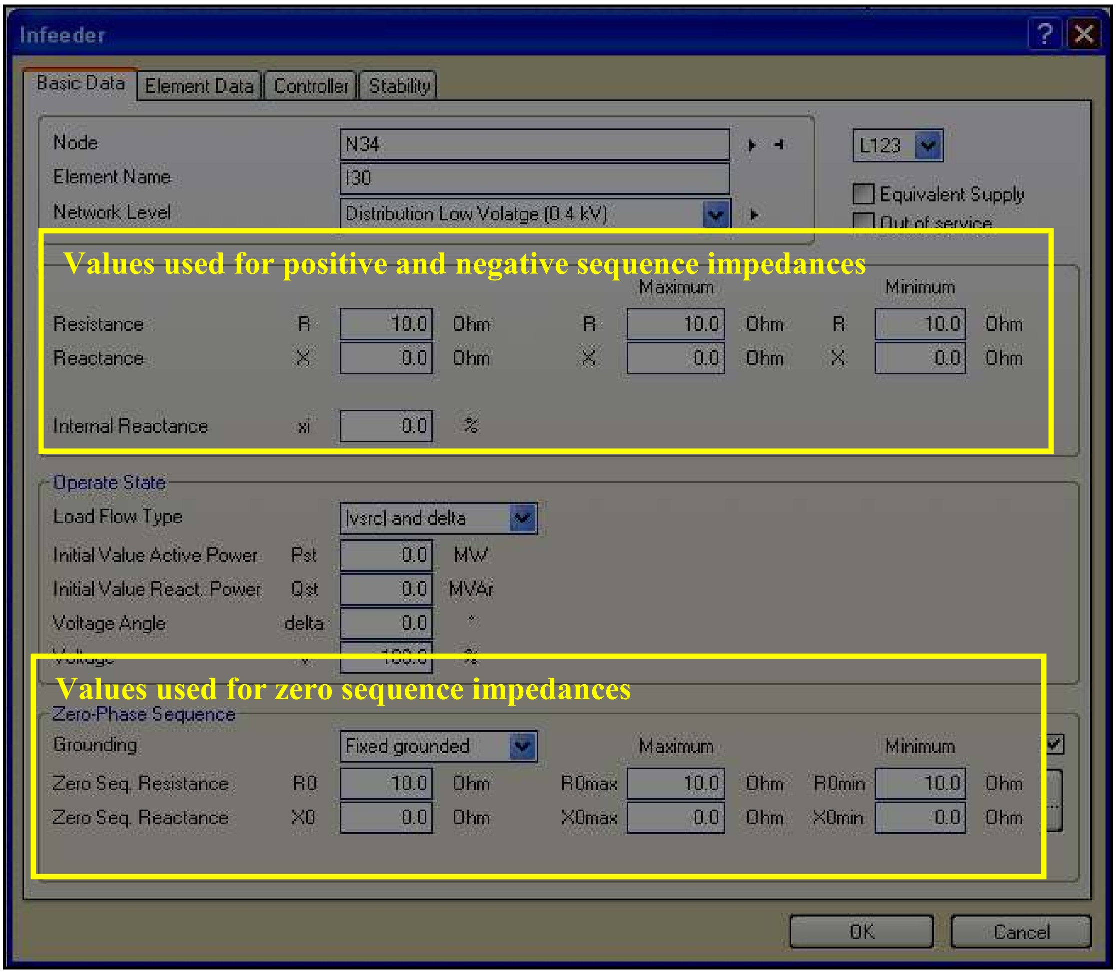


Figure 6.2 – PSS Sincal Infeeder Basic Data Page Showing Sequence Impedances

PSS Sincal sets the Infeeder as a voltage source and the sequence impedances in series with this source. The voltage value of the source depends on the PSS Sincal setting. These settings comply with standards that include those described in the IEC 60909 International Standard. The standard setting chosen sets the LV sources at 1.0 p.u and HV voltage source at 1.10 p.u. This setting is used for all fault calculations in this research project.

An example of a PSS Sincal calculation of fault current can be seen in figure 6.3 below. This simplified circuit includes a 415 V phase voltage Infeeder with $Z_1 = Z_2 = Z_0 = 10\Omega$ and a line with the same impedance values feeding a single phase to earth fault at the end of the line section. The contribution by the Infeeder I_{IF} will be given by $I_{IF} = \dfrac{V_S}{Z_1 + Z_2 + Z_0} \times 3$ where the impedances include the sum of both the Infeeder and line values. The voltage source V_S of the Infeeder is the phase to earth voltage and using the PSS Sincal IEC 60909 standard that sets the source voltage at 1 p.u. $V_S = \dfrac{415V}{\sqrt{3}} = 239.6V$. The expected fault current contribution will be given by $I_{IF} = \dfrac{239.6}{10+10+10+10+10+10} \times 3 = 11.98A$ and this can be seen in the elements of this circuit below.

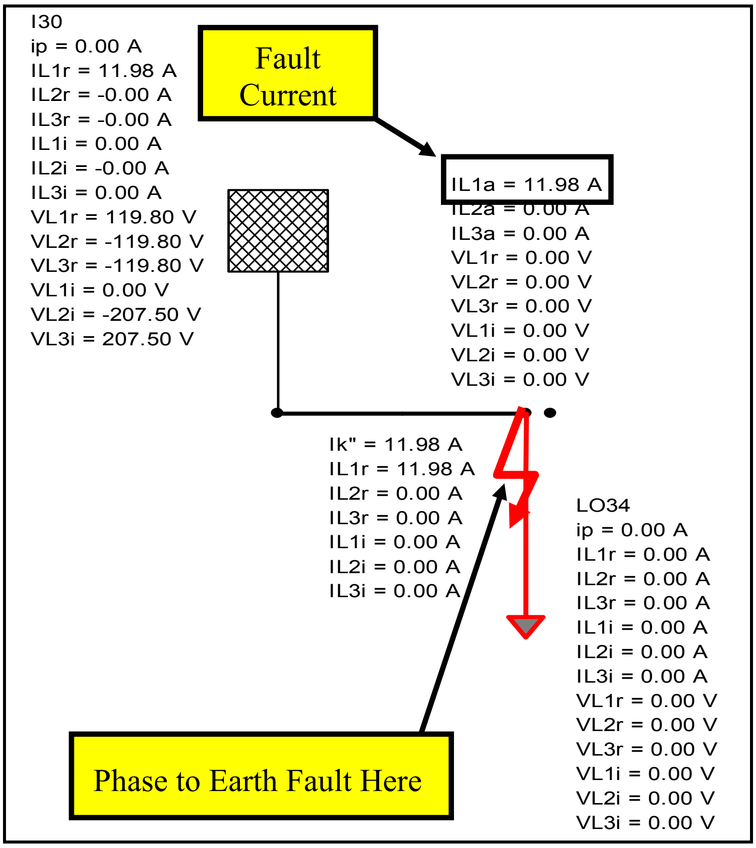


Figure 6.3 - PSS Sincal Single Phase to Earth Fault

6.1.2 PSS Sincal DC-Infeeder and Fault Calculations

An accurate replication of a Small DG System is a constant power source that operates until the lower voltage threshold at its terminals is reached. The figure 6.4 below shows PSS Sincal DC-Infeeder basic data page where the device parameters are configured.

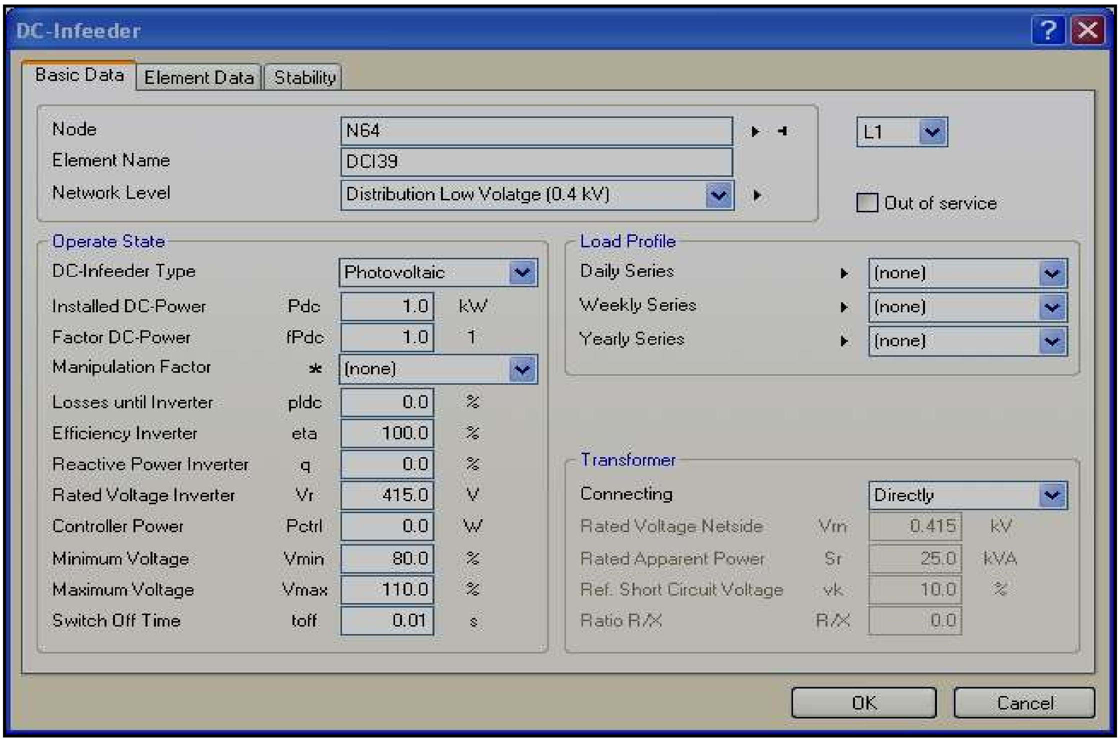


Figure 6.4 – PSS Sincal DC-Infeeder Basic Data Page

A PSS Sincal DC-Infeeder included into a network does contribute to the fault currents of all fault types including a phase to earth fault. It does so at a current that equates to its power level at its rated voltage, for example a 1 kW 239.6 V unit will contribute $\frac{1000}{239.6} = 4.17A$ to a fault. Figure 6.5 below shows a simple circuit with a DC-Infeeder contributing 4.17 A and an Infeeder contributing 11.98 A to a phase to earth fault of 16.15 A.

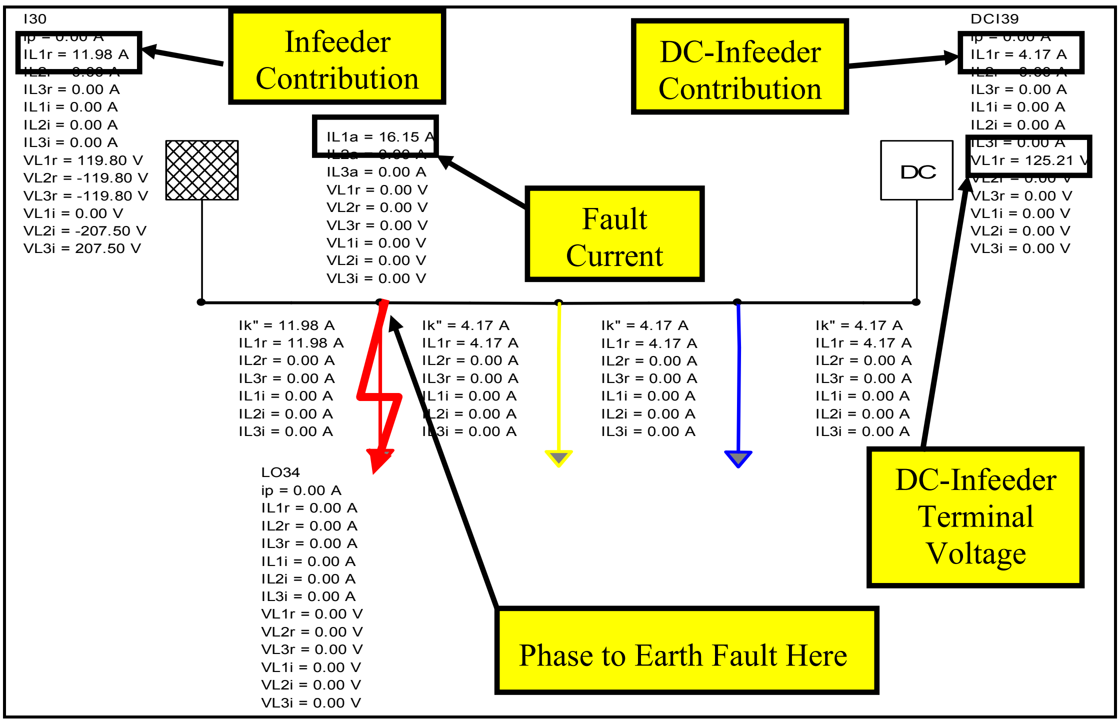


Figure 6.5 – PSS Sincal single phase to earth fault with DC-Infeeder

It can be seen in this diagram that the terminal voltage of the DC-Infeeder is 125.21 V or 52% of the nominal, which is well below the 80% specified in the basic data shown in figure 6.4. An accurate model of a Small DG System would see the current value increase until the terminal voltage of this DC-Infeeder had dropped to 80% or 192 V and then would cease to operate and deliver zero current.

The addition of another Infeeder to the circuit shown above can be seen in figure 6.6 below.

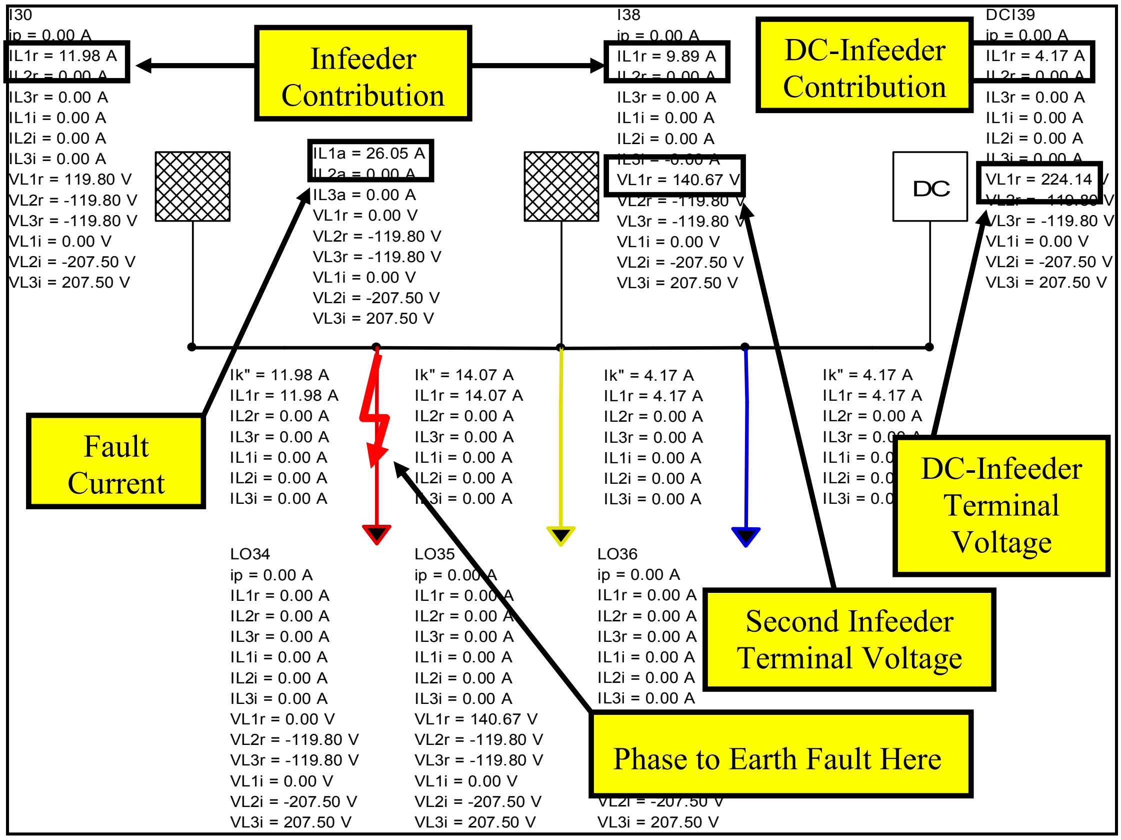


Figure 6.6 – PSS Sincal Fault Results with two Infeeders and a DC-Infeeder

The initial Infeeder on the left is seeing an unchanged circuit and contributes the same amount as previous 11.98 A. It can be seen that the DC-Infeeder is continuing to contribute 4.17 A however this contribution is increasing the voltage at the point where the additional Infeeder is connected to the centre of the circuit. The increased voltage at the terminals of the second Infeeder reduces the contribution by this device as it is a voltage source behind its own impedance or a Thévenin equivalent source. It can be seen in the diagram that the voltage at the terminals of the second Infeeder is $V_T = 140.67V$ and this means that the current contribution supplied to the fault will be given by:

$$\frac{(V_S - V_T)}{Z_1 + Z_2 + Z_0} \times 3 = \frac{(239.6 - 140.67)}{10 + 10 + 10} \times 3 = 9.89A.$$

The result of this is that the contribution by the second Infeeder is less than the first. The current at the fault is the sum of the two Infeeders and the DC-Infeeder of 26.05 A.

The voltage at the terminals of the DC-Infeeder is 224.14 V and this would suggest that the current contribution should be 4.46 A if it were a constant power source.

6.1.3 PSS Sincal LV and Fault Calculations

The effect of an LV fault on the HV depends on the type of fault and the type of transformer. A typical three phase distribution transformer used by Ergon Energy is usually an 11 kV / 415 V delta star. A phase to earth fault on the LV side will see current in one LV phase and reflected fault current in two on the HV phases. Figure 6.7 below shows the current path in a delta star transformer for a phase to earth fault on the LV.

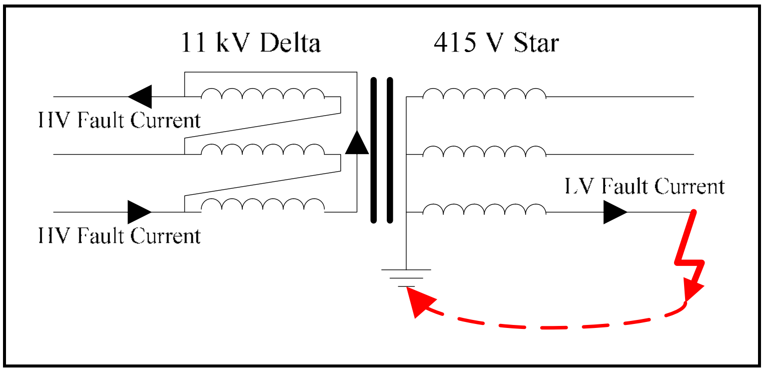


Figure 6.7 – Delta Star Transformer Fault Current Paths

Figure 6.8 below shows that PSS Sincal accurately deals with the same situation.

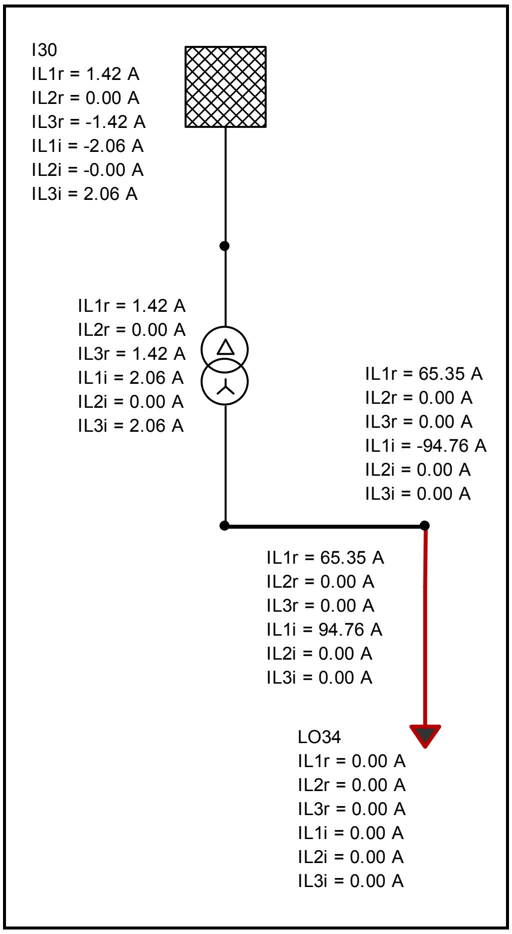


Figure 6.8 - PSS Sincal Delta Star Transformer Fault Current Paths

The LV fault current is reflected onto the HV winding and should maintain an Ampere turns balance where:

$$I_{HV} = \frac{V_{HV} \times \sqrt{3} \times I_{LV}}{V_{LV}}.$$

It can be seen in the diagram above that:

$$I_{LV} = 65.35 - j94.76 = 115.11\angle -55.41^{o}\,A \text{ and}$$

$$I_{HV} = 1.42 - j2.06 = 2.50\angle -55.41^{o}\,A.$$

These values do maintain the Ampere turn balance for this 11 kV / 415 V transformer and the currents do appear on two of the HV phase as expected. What is noticeable about the value of HV and LV currents is that there is no 30 degree phase shift that should occur in a delta star transformer.

It can be seen that PSS Sincal apportions currents correctly throughout the LV and HV three phase network for LV fault types through a delta star transformer.

6.1.4 PSS Sincal HV Fault Calculations

The PSS Sincal DC-Infeeder operates as a constant current source during fault conditions. The current injected by a DC-Infeeder is related to the power value and the operating voltage. As an example consider the simple circuit in the figure 6.9 below.

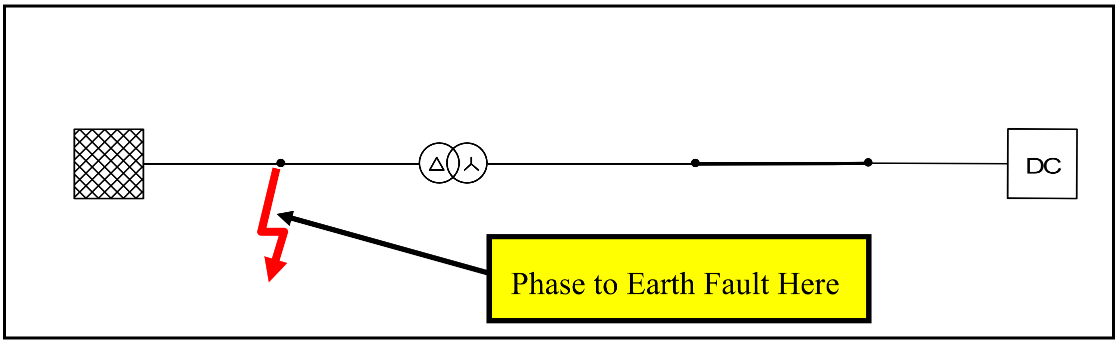


Figure 6.9 - Simple Infeeder and DC-Infeeder Circuit

Ergon Energy generally uses a delta star (Dy) transformer for three phase distribution purposes. Figure 6.9 shows a simple circuit with a three phase 11 kV Infeeders at the left supplying the HV of an 11 kV /415 V Dy transformer and a single phase 10 kW DC-Infeeder at the right supplying a section of line which is connected to the LV of the transformer. The figure also shows the location of a phase to ground fault.

The DC-Infeeder acts a constant current source and the value of the current is determined by the rating of the device output. The example in the diagram above is rated at 10 kW with no internal losses and an operating voltage of 1.0 p.u. or 239.6 V phase to neutral. The current value is therefore:

$$I_{DC} = \frac{10000}{239.9} = 41.73A$$

The DC-Infeeder current reduced through the transformer and maintains the Ampere turns balance and on the HV winding is

$$I_{DC} = \frac{41.73 \times 415}{11000 \times \sqrt{3}} = 0.909A$$

This current should be seen on two phases of the HV and shifted by 30°. Figure 6.11 below shows that the current through the transformer agrees with the calculations and is shifted by 30° resulting in $I_{DC} = 0.787 + j0.454 = 0.909 \angle 30^o A$.

The Infeeder at left has a phase to ground voltage of 1.10 p.u. or

$$V_{In} = 6350.9 \times 1.1 = 6985.9V$$

The sequence impedances of the Infeeder are $Z_{In1} = Z_{In2} = Z_{In0} = 10 + j0\Omega$

The sequence currents supplied from the 11 kV Infeeder is:

$$I_{In-1.1} = I_{In-1.2} = I_{In-1.0} = \frac{V_{In}}{Z_{In1} + Z_{In2} + Z_{In.0}}$$

$$I_{In-1.1} = I_{In-1.2} = I_{In-1.0} = \frac{6985.9}{30 + j0} = 232.86A$$

The fault current supplied from the Infeeder is:

$$I_{Fault\_In} = I_{In-1.1} + I_{In-1.2} + I_{In-1.0} = 232.86 \times 3 = 698.59A$$

Figure 6.10 below shows the results of a phase to earth fault in this circuit and it can be seen that the current values agree.

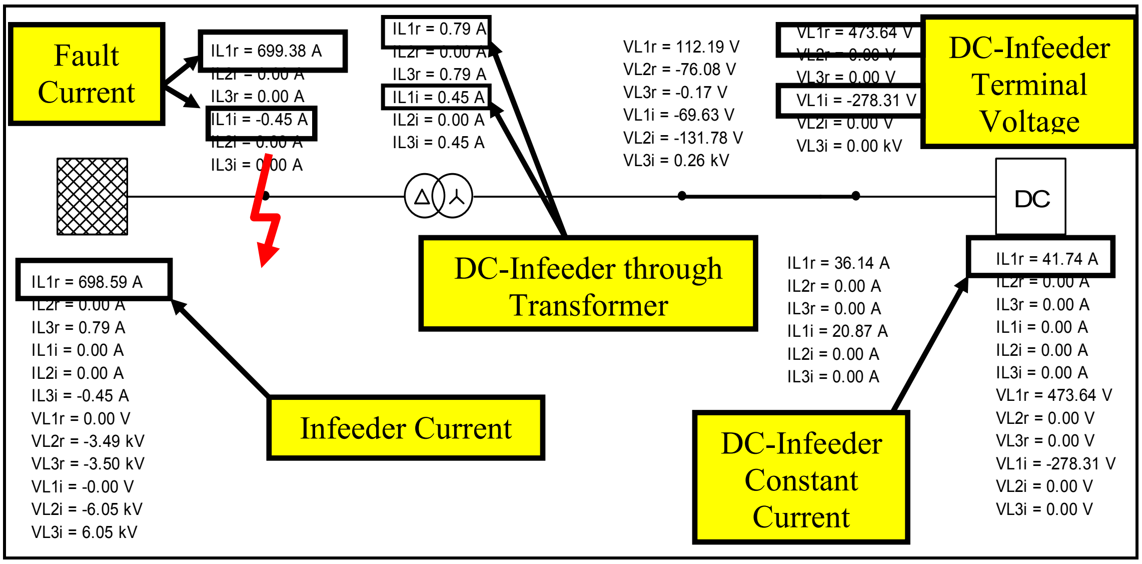


Figure 6.10 - Results of the phase to earth fault.

The total fault current I_F is the sum of the 11 kV Infeeder currents and the contribution by the 415 V DC-Infeeder at 11 kV and is:

$$I_F = 698.59 + 0.787 + j0.454 = 699.38 - j0.45A$$

The phase to neutral voltage at the terminals of the 415 DC-Infeeder in figure 6.10 $473.64 - j273.31V$ or $546.83\angle -30^o V$ which is well above the normal operating voltage of 239.6 V.

The figure 6.11 below shows another set of results with the same circuit and fault location but different values for the line impedance.

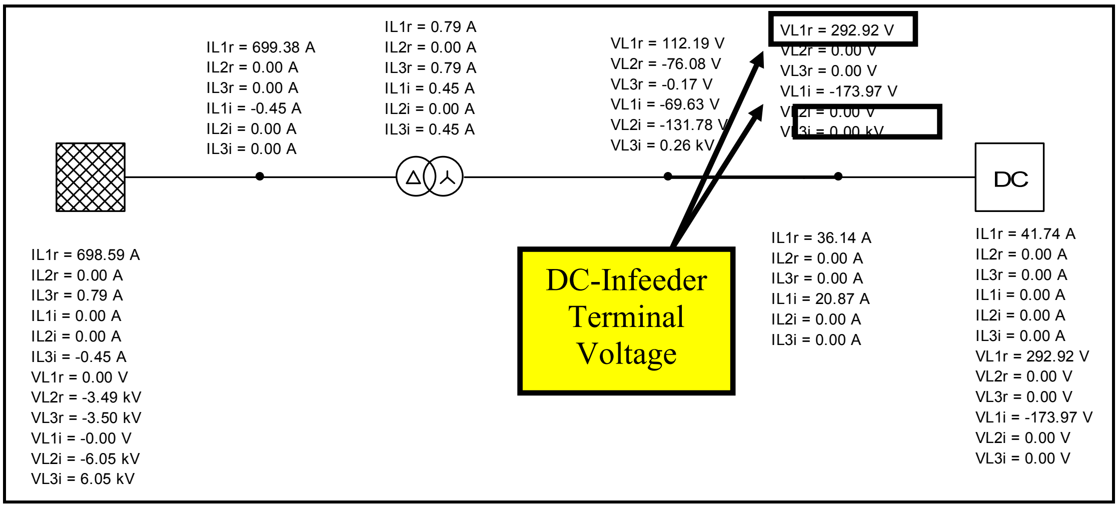


Figure 6.11 – Differing Results of Phase to Earth Fault

The voltage at the terminals of the 415 V DC-Infeeder is now $292.92 - j173.97V$ or $340.69\angle -30^o V$

Figure 6.12 below shows a third set of results for the same circuit and same fault but with lower line and transformer impedances. It can be seen that the voltage at the terminal of the DC-Infeeder is now $76.40 - j131.80V$ or $152.34\angle -60^o V$

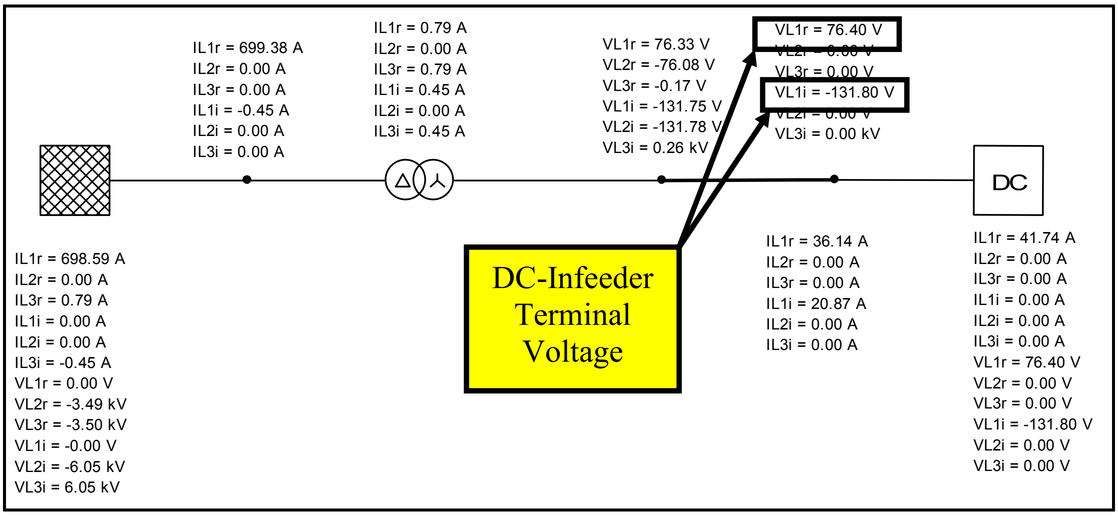


Figure 6.12 – Third Results for Phase to Earth Fault

6.1.5 PSS Sincal Fault Modelling Conclusions

There are a number of points that can be made regarding the methods used by PSS Sincal to determine fault currents and they include:

- The DC-Infeeder acts as a constant current source and not as a constant power source.

- The DC-Infeeder does not shut down as a result of low terminal voltage.
- The DC-Infeeder will allow its terminal voltage rise to a high value to maintain the constant current output.

The issues described above make the effective use of PSS Sincal for modelling fault conditions with the inclusion of Small DG Systems limited.

PSS Sincal does produce a software add-on package that models generators in the time domain and this is known as the Stability Module. Small DG Systems are generation installations and would require software that accounted for their operation in the time domain in order to accurately model their behaviour during a fault condition. Ergon Energy does not own a license for a PSS Sincal Stability Module and the cost is about $15,000 each.

6.2 *Small DG System Fault Model*

An understanding of how a grid-connect inverter may act in a situation where their is a fault on the nearby network is essential if their effects on protection systems are to be fully understood. It has been shown that PSS Sincal does not model an inverter accurately and so in many cases provides results of little value.

It has been seen that when the fault is close by (as in the simulated fault reported earlier in this report) that the inverter shuts down rapidly. This would not necessarily cause too many problems for mal-operation of protective equipment as the shut down time is faster than most protective devices used on a distribution network.

A fault more remote from an inverter would see the inverter endeavour to contribute to the fault current. It is possible that the active anti-islanding functions may shut down the output; however the passive anti-islanding may not. The design of protection systems is generally intended so that they operate in the most arduous circumstance and it could be argued that the inverters continuing to operate during a fault is one such situation.

It is possible that the inverters could deliver their rated power down to their anti-islanding voltage lower limit, which in most cases is 200 V phase to neutral. If the nominal voltage is 240 V then it is possible to see up to 1.2 p.u. of current contributed to a fault before the inverter ceases operation. An accurate model of a Small DG System would be a constant power device that can range down to a phase to neutral voltage of 200 V before disconnection.

6.2.1 Example of Fault Contribution by Small DG System

Any contribution by a Small DG System downstream from a protective device will see less current flowing through the protective device when a fault remote to both the Small DG System and the protective device occurs.

As an example consider the following simple single phase circuit in figure 6.13.

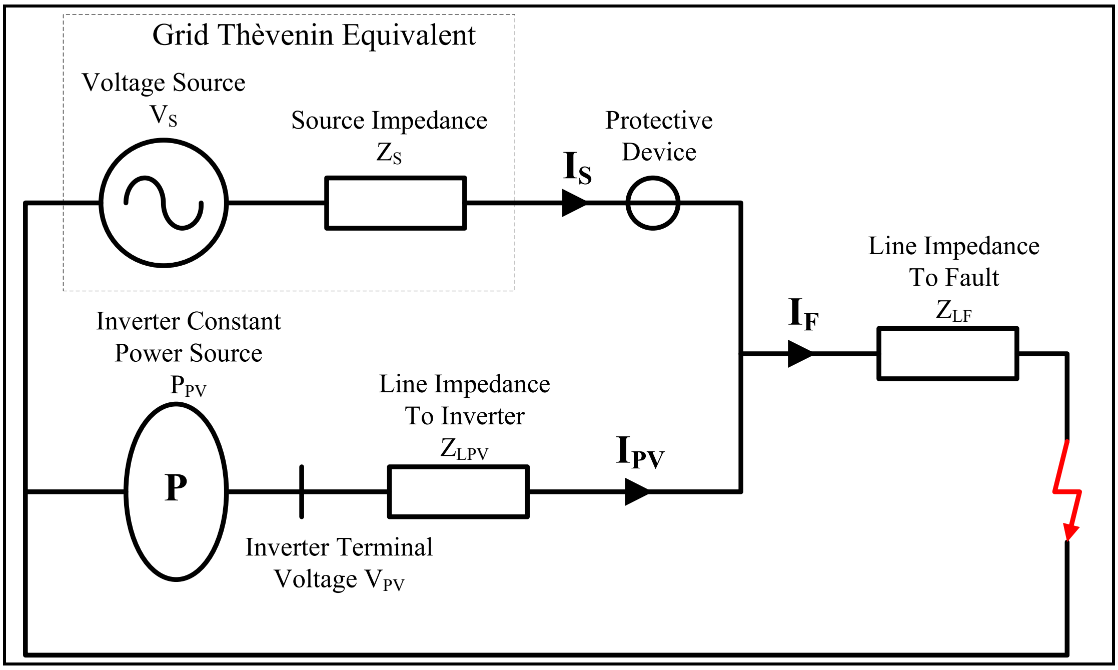


Figure 6.13 – Simplified Single Phase Circuit Diagram

The actual current through the protective device without the contribution by the inverter is given by:

$$I_F = \frac{V_S}{(Z_S + Z_{LF})} \qquad \text{(Equation 6. 1)}$$

The inclusion of the inverter constant power source presents the following equations:

$$V_S = I_S(Z_S + Z_{LF}) + I_{PV} \cdot Z_{LF} \qquad \text{(Equation 6.2)}$$

$$P_{PV} = V_{PV} \cdot I_{PV} \qquad \text{(Equation 6.3)}$$

These two equations have three unknowns (V_{PV}, I_{PV}, I_S) and can not be solved algebraically. They can be solved iteratively if an initial assumed value is assigned to V_{PV} allowing the values of I_{PV} & I_S to be solved.

When these values are determined the validity of the three can be checked by back substituting into the following formula:

$$Error = (V_S - (I_S \cdot Z_S)) - (V_{PV} - (I_{PV} \cdot Z_{PV})) \qquad \text{(Equation 6.4)}$$

The value of the "Error" will be zero if the correct values are determined. In an iterative process the error value can be checked to see if it is below an acceptable standard and if it is the values are accepted as sufficiently accurate.

The procedure described above can be achieved for the simplified circuit by a straightforward computer program, which cycles through incremental changes in V_{PV} until the error is below the desired maximum.

As an example consider that the following values are applied to the devices in figure 6.12 above:

$$V_S = 240V \quad Z_S = 2\Omega \quad P_{PV} = 1000W \quad Z_{PV} = 5\Omega \quad Z_{LF} = 10\Omega$$

Without the inverter constant power source P_{PV} the value of the fault current through the protective device will be given by Equation 1:

$I_F = I_S = 20A$

With the inverter constant power source P_{PV} the value of the fault current through the protective device will be given by Equation 2 and Equation 3 and by an iterative process the values of currents in the circuit can be determined as: $I_F = 20.73A$ $I_{PV} = 4.37A$ $I_S = 16.36A$ and the voltage at the terminals of the inverter constant power source is therefore $V_{PV} = 229.09V$

It can be seen that the voltage at the terminals of the inverter constant power source is within the bounds of 200 to 270 V and that the current through the protective device has dropped from 20 A to 16.36 A or by 17%.

The information above shows that an injection of current by a Small DG System downstream of a protective device will reduce the current through that protective device. All protection systems on the two representative feeders considered in this research project are operated by current. This means that the inclusion of Small DG Systems downstream of protective devices will reduce the fault currents seen by the protective devices and so will reduce the effectiveness or sensitivity of these protection systems. The amount of this reduction in sensitivity may be sufficient to prevent the protective devices operation during a fault if there is enough Small DG Systems on the downstream network.

6.3 *Faults on the ROPL-04 Network*

The ROPL-04 network consists of three phase HV and LV networks where the voltages are transformed using delta star transformers. The network protective devices consist of the 11 kV circuit breaker and protection relay at Ross Plains ZS and the HV and LV distribution substation fuses. This section of the report examines the effectiveness of PSS Sincal to determine if the models can provide any information on whether the inclusion of the Small DG Systems will compromise the operation of these protective devices.

Ergon Energy would generally use a synchronous source impedance with a voltage of 1.0 p.u. when determining fault levels for use in protection reach calculations. The method employed by PSS Sincal sets the LV voltage sources at 1.0 p.u. and the HV sources at 1.10 p.u. This will increase the fault current values by up to 10% and should be considered when determining whether protection reach is adequate.

6.3.1 ROPL HV Fault Levels

The faults possible on the HV network include, three phase, two phase, two phase to earth and single phase to earth. The supply from Ross Plains ZS will contribute to all of these fault types. The synchronous fault levels determined by the PPSS Sincal model of the ROPL-04 network at the 11 kV bus at Ross Plains ZS without any Small DG Systems are:

- Three phase – 6.89 kA
- Two phase – 5.97 kA
- Two phase to earth – 7.21 kA
- Phase to earth – 7.23 kA

The lowest fault levels experienced on the HV network with a fault at the most remote distribution substation TVS650 and without any Small DG Systems these fault levels are:

- Three Phase – 1.91 kA
- Two phase – 1.76 kA
- Two phase to earth – kA
- Phase to earth – 1.23 kA
- Phase to earth with 50 ohms of fault resistance – 124 A

The HV fault levels at the distribution substation TVS650 when the fault is also experienced at the distribution substation TVS650 and with 963 2.4 kW Small DG Systems are:

- Three phase – 1.91 kA
- Two phase – 1.66 kA
- Two phase to earth – 1.80 kA
- Phase to earth – 1.27 kA
- Phase to earth with 50 ohms of fault resistance – 127 A

The HV fault levels at the Ross Plains ZS 11 kV bus when the fault occurs at the distribution substation TVS650 and with 963 2.4 kW Small DG Systems are:

- Three phase – 1.81 kA
- Two phase – 1.60 kA
- Two phase to earth – 1.69 kA
- Phase to earth – 1.16 kA
- Phase to earth with 50 ohms of fault resistance – 115 A

The value at the terminals of the DC-Infeeders ranged from 0.8 V up to 280 V during a two phase fault with about 60% under 200V and 25% above 270 V. Some of these values are within the possible range of anti-islanding voltage thresholds of 200 V to 270 V. All the inverters injected 9.23 A, which is their output current when their internal loss setting are accounted for and their terminal voltage is at the nominal value.

The value at the terminals of the DC-Infeeders ranged from 253 V up to 280 V during a phase to earth fault with over 90% above 270 V. None of these values are within the possible range of anti-islanding voltage thresholds.

6.3.2 ROPL HV Transformer Fault Levels

The lowest fault within the winding of a distribution transformer on the ROPL-04 network will occur at TVS650 LV terminals. This transformer is a 500 kVA unit and the HV fuses are rated at 80 A and this means that they need at least 160 A to operate and preferably 240 A.

The fault levels at the HV of TVS650 without any Small DG Systems are:

- Three phase fault on the LV – HV fault current is 385 A
- Two phase fault on the LV - HV fault current is 385 A
- Two phase fault and earth on the LV - HV fault current is 385 A
- One Phase and earth fault on the LV - HV fault current is 235 A

The fault levels at the HV of TVS650 without any Small DG Systems are:

- Three phase fault on the LV – HV fault current is 393 A
- Two phase fault on the LV - HV fault current is 393 A
- Two phase fault and earth on the LV - HV fault current is 393 A
- One phase and earth fault on the LV - HV fault current is 245 A

6.3.3 ROPL LV Fault Levels

The fault levels were checked on the three phase LV network at the point farthest from the Ross Plain ZS on the PSS Sincal model of ROPL-04. This point was at the end of 500 m of LV cable connected to the TVS 650 distribution substation. The LV fuse used on 500 kVA distribution transformers can range up to 1000 A rating and in some cases over this value on commercial loads. It is likely that the fuses used on a 500 kVA distribution substation such as TVS650 for a radial residential load will be rated at up to 400 A which will need at least 800 A to operate and preferably 1.2 kA.

The fault levels at this point and with no Small DG Systems operating are:

- Three phase – 2.28 kA
- Two phase – 1.97 kA
- Two phase to earth – 2.19 kA
- Phase to earth – 1.29 kA

The fault levels at the same point with all 963 Small DG Systems operating are:

- Three phase – 2.37 kA
- Two phase – 2.05 kA
- Two phase to earth – 2.28 kA
- Phase to earth – 1.34 kA

It can be seen that the LV fault levels increase as a result of the inclusion of Small DG Systems. The LV fault levels are improved by the inclusion of the Small DG Systems and are adequate to operate the LV fuses in all circumstances.

6.4 *Faults on the Karara SWER Network*

The Karara SWER feeder consists of single phase SWER HV and LV networks. The only fault type that can occur on this feeder is a phase to earth fault. These faults are seen by the protection systems as an over current fault.

6.4.1 Karara SWER HV Fault Levels

The Karara SWER has two reclosers on the HV network. These are the Karara recloser located at the downstream side of the SWER isolators. The second recloser is located midway along the backbone is called Reedy Creek recloser.

6.4.2 Karara Recloser Section HV Fault Levels

The lowest fault levels on the Karara recloser section of the PSS Sincal Karara SWER network occur when there is a fault at the distribution substation PE10899.

With no Small DG Systems operating - the fault levels seen by the Karara recloser are:

- Phase to earth fault – 74 A
- Phase to earth with 50 ohms fault resistance – 61 A

With all 99 customers Small DG Systems operating with 4.8 kW of PV in-feed - the fault levels at the distribution substation PE10899 are:

- Phase to earth fault – 89 A
- Phase to earth with 50 ohms fault resistance – 72 A

With all 99 customers Small DG Systems operating with 4.8 kW of PV in-feed- the fault levels seen by Karara recloser are:

- Phase to earth fault – 57 A
- Phase to earth with 50 ohms fault resistance – 39 A

The DC-Infeeder are all acting as constant current devices and are delivering 18.87 A to the LV of their distribution transformers, which is transformed to 0.36 A on the HV. The voltages at the terminals of the DC-Infeeders range from 82 V to 169 V.

With all 99 customers Small DG Systems operating with 2.4 kW of PV in-feed - the fault levels at the distribution substation PE10899 are:

- Phase to earth fault – 82 A
- Phase to earth with 50 ohms fault resistance – 67 A

With all 99 customers Small DG Systems operating with 2.4 kW of PV in-feed- the fault levels seen by Karara recloser are:

- Phase to earth fault – 65 A
- Phase to earth with 50 ohms fault resistance – 49 A

The DC-Infeeder are all acting as constant current devices and are delivering 9.44 A to the LV of their distribution transformers, which is transformed to 0.18 A on the HV. The voltages at the terminals of the DC-Infeeders range from 76 V to 161 V.

6.4.3 Reedy Creek Recloser Section HV Fault Levels

The lowest fault levels on the Reed Creek recloser section of the PSS Sincal Karara SWER network occur when their is a fault at the distribution substation PE4763.

With no Small DG Systems operating - the fault levels seen by the Reedy Creek recloser are:

- Phase to earth fault – 68 A
- Phase to earth with 50 ohms fault resistance – 56 A

With all 99 customers Small DG Systems operating with 4.8 kW of PV in-feed - the fault levels at the distribution substation PE4763 are:

- Phase to earth fault – 84 A
- Phase to earth with 50 ohms fault resistance – 70A

With all 99 customers Small DG Systems operating with 4.8 kW of PV in-feed- the fault levels seen by Reedy Creek recloser are:

- Phase to earth fault – 66 A
- Phase to earth with 50 ohms fault resistance – 51 A

The DC-Infeeder are all acting as constant current devices and are delivering 18.87 A to the LV of their distribution transformers, which is transformed to 0.36 A on the HV. The voltages at the terminals of the DC-Infeeders range from 89 V to 178 V when the phase to earth fault occurred at PE 4763.

With all 99 customers Small DG Systems operating with 2.4 kW of PV in-feed - the fault levels at the distribution substation PE4763 are:

- Phase to earth fault – 77 A
- Phase to earth with 50 ohms fault resistance – 64A

With all 99 customers Small DG Systems operating with 2.4 kW of PPV in-feed- the fault levels seen by Reedy Creek recloser are:

- Phase to earth fault – 66 A
- Phase to earth with 50 ohms fault resistance – 53A

The DC-Infeeder are all acting as constant current devices and are delivering 9.44 A to the LV of their distribution transformers, which is transformed to 0.18 A on the HV. The voltages at the terminals of the DC-Infeeders range from 71 V to 169 V when the phase to earth fault occurred at PE4763.

6.4.4 Karara SWER LV Fault Levels

The test conducted on the HV network showed that the behaviour of the DC-Infeeders distorted the results due to their continued operation at voltages well under the lower anti-islanding threshold. It is unlikely that further testing of the effects on the LV would provide any useful results.

CHAPTER 7 - QUALITY OF SUPPLY MODELLING

7.1 *QoS System Models*

The key area of interest for QoS in this research project is the movement of the distribution LV outside the prescribed ±6% of the nominal voltage as a result of the penetration of Small DG Systems. This chapter describes the process of testing the models for the desired permutations of Small DG System penetration and correlating the results.

7.1.1 PSS Sincal Load Flow

The PSS Sincal load flow operations will be used to simulate the network models operating conditions and ascertain the nodal voltages which are of interest when determining QoS. PSS Sincal offers a number of iterative methods to enable a load flow calculation for a network. The mode chosen for this research project is the Newton-Raphson method.

A check of the method's validity can be achieved by performing a load flow on a simple network. Figure 7.1 below shows the results of a load flow on a simple network.

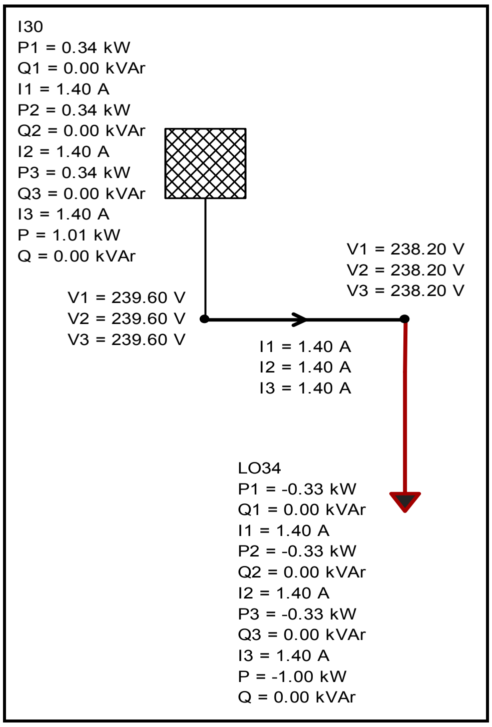


Figure 7.1 – Simple Load Flow Example

The load flow example in the diagram above used a three phase 415 V Infeeder supplying a 1 kW three phase load over a line with $1 + j0\Omega$ impedance. The load flow values show that the 1.40 A of line current was flowing and this was correct for the per phase load of 333 W at its 238.2 V line to neutral terminal voltage $1.40A = \frac{333W}{238.2V}$. The Infeeder terminal voltage was 239.6 V and the loads terminal voltage was 238.2 V and so the line voltage drop of 1.40 V was correct for the current of 1.40 A flowing through the line impedance of $1+j0\Omega$. It can be seen that the load flow process operated correctly for this simple circuit.

Figure 7.2 below shows another simplified model with thee single-phase 1 kW loads being fed by a single 415 V Infeeder, connected with $1+j1\Omega$ impedance lines. The load flow results show expected values of currents and voltages for this circuit.

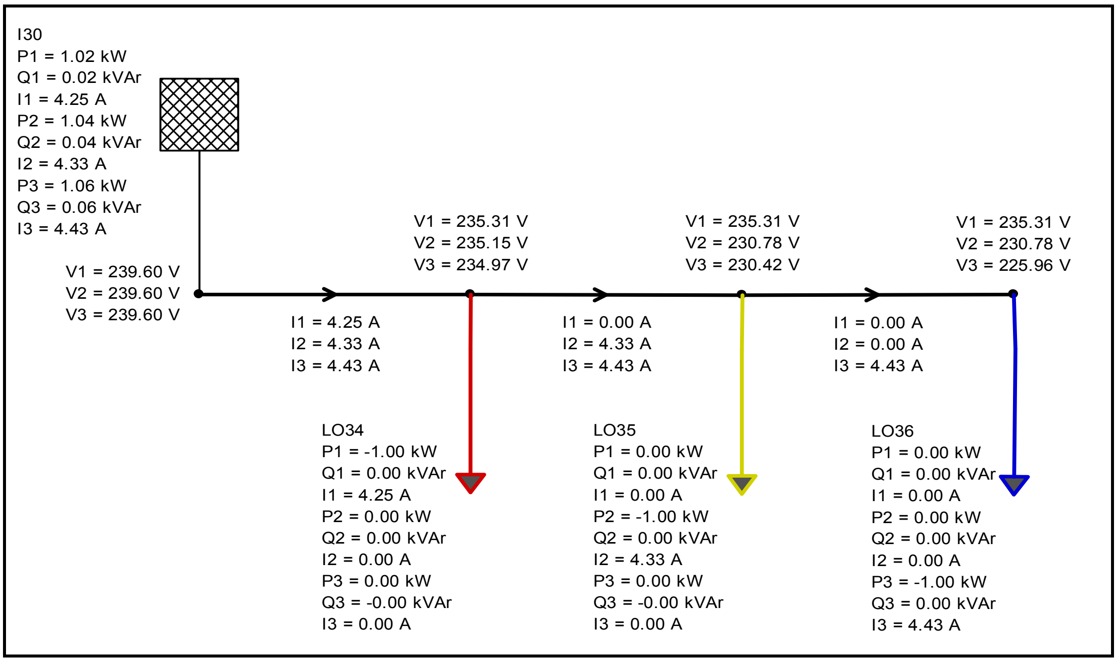


Figure 7.2 – Simplified Three Phase Load Flow Example

An expansion on the simplified model shown in the diagram above by the addition of a second three phase in feeder can be seen in figure 7.3 below. Once again the currents and voltages are as expected for this circuit.

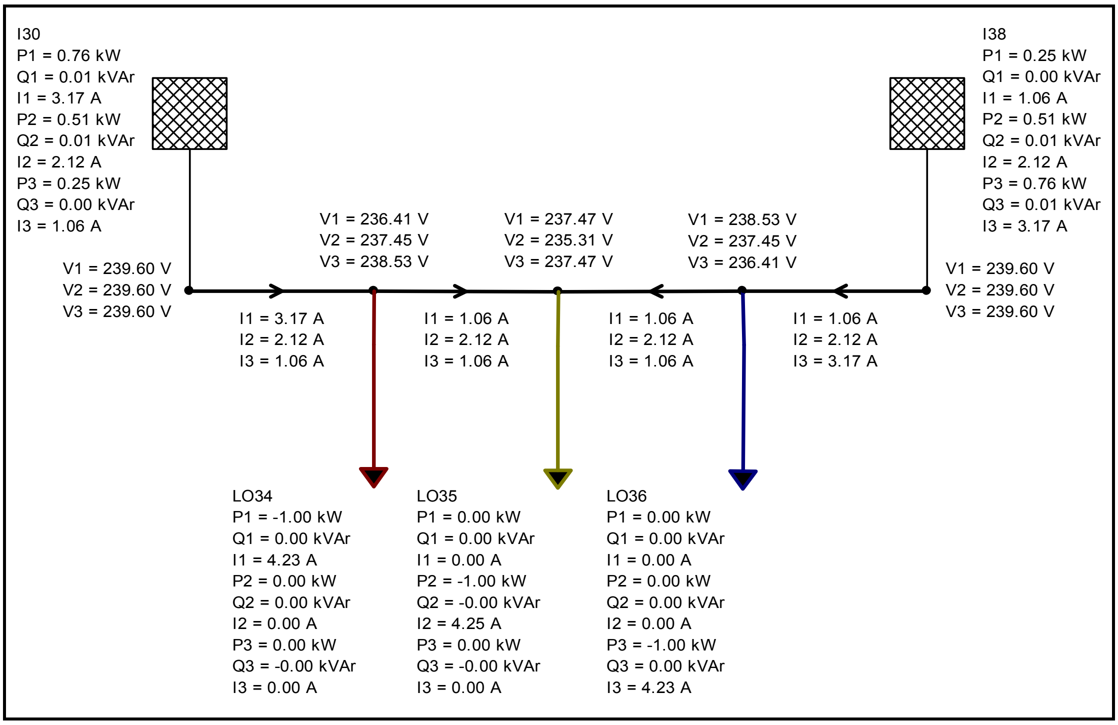


Figure 7.3 – Simplified Three Phase Load Flow Example with Two Infeeders

The DC-Infeeders used to simulate the Small DG Systems are a constant power device. Figure 7.4 below shows a simplified model with the one single-phase DC-Infeeder and one three-phase 415 V Infeeder supplying the same three single phase 1 kW loads used in previous examples.

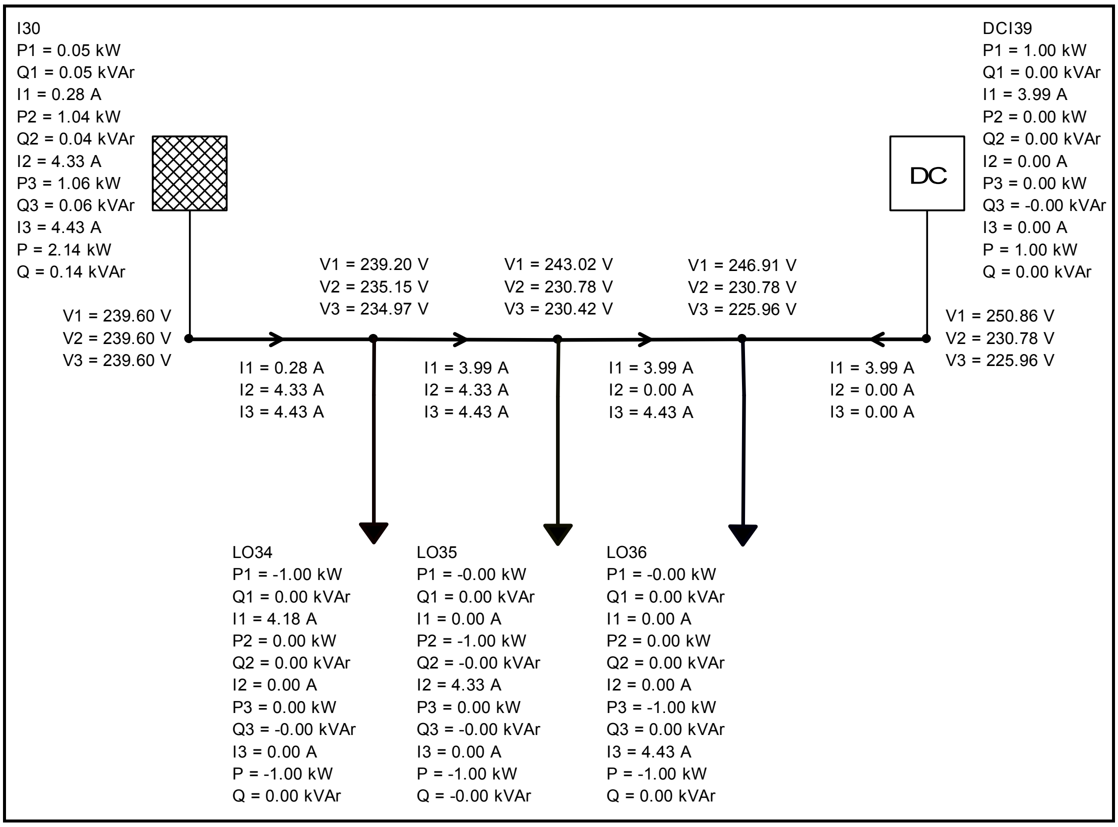


Figure 7.4 – Simplified Three Phase Load Flow Example with DC Infeeder

It can be seen in the diagram above that the A phase contribution by the DC-Infeeder of 3.99 A is flowing from the DC-Infeeder to the A phase load on the left hand bottom of the line. The voltage on the A phase (number 1 phase in the diagram) has been increased along the line sections as a result of the injection of active power by the DC-Infeeder as would be expected.

It can be concluded from the diagrams above that PSS Sincal produces appropriate results for load flow modelling when the network devices are set up correctly. It can also be concluded that the DC-Infeeder operates as a constant power source as expected.

7.2 *Constant PV In-feed*

The two feeder networks will be tested to see what the effect of Small DG System penetration has on the LV on a normal cloud free day when the PV in-feed is constant.

7.2.1 ROPL-04 and Constant PV In-feed

The voltage level on the ROPL-04 feeder is only controlled by the on line tap changer (OLTC) in the 66/11 kV transformers at the Ross Plains ZS. It was shown that the network model with this tap changer along with the fixed taps on the distribution transformers will adequately control the voltages under normal conditions. There is a need to test whether the system can control the voltages to within the prescribed ±6% on the distribution LV with the inclusion of various penetrations of Small DG Systems.

The most likely scenario that will cause excessive voltage on the LV will occur when the loads are low and the in-feed from the Small DG Systems is the highest. The graph in the figure 7.5 below shows the power load on the day of the lowest maximum demand as well as an example of solar power in-feed on a clear day. The third trace in the graph shows the difference between the load and the solar power in-feed and is called Network Demand Power in this graph.

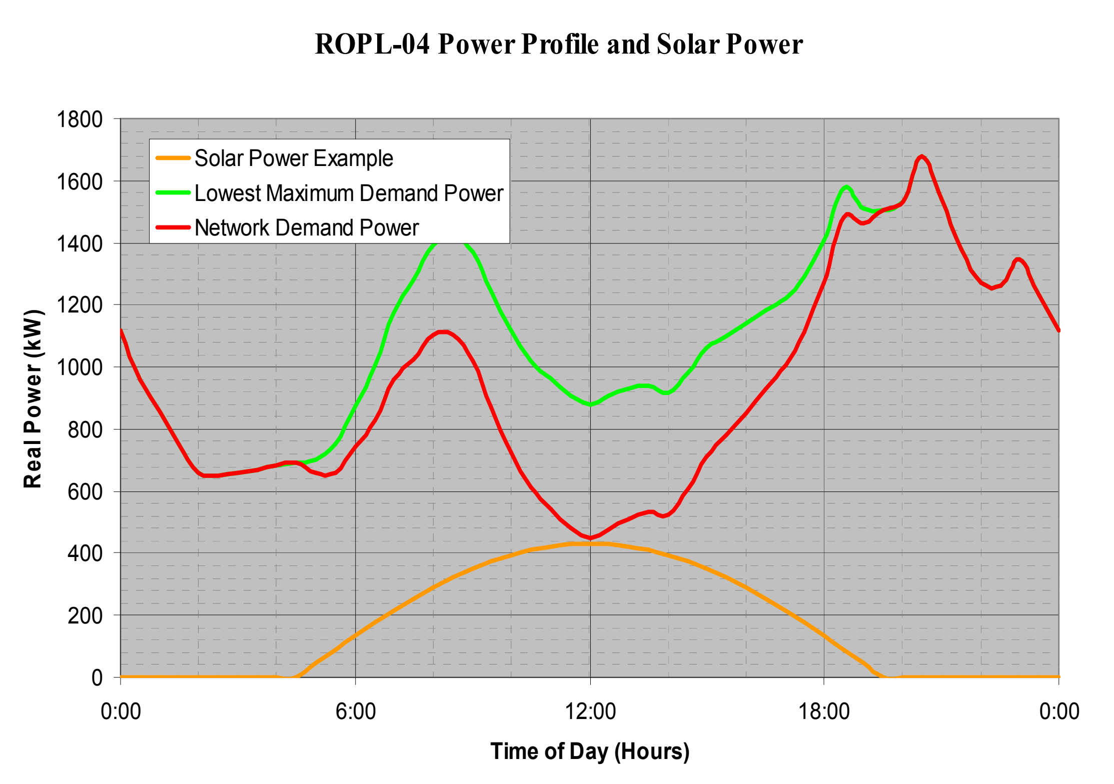


Figure 7.5 –Solar Power Effect at Low Demand Period on ROPL-04 Network

The graph in the figure above shows that the lowest network power requirements with the inclusion of solar occurs at about the zenith of the solar power (about 12:00) and so the lowest overall load through the zone substation will be at this time.

Applying these values of load power to the network model can be achieved by apportioning the power evenly to all 963 customers. Using a power factor of 0.9 lagging will provide the load apparent power requirements. The school could consume 150kW and 75 kVAr as the period under consideration is during school hours; however the feeder low demand period will most likely be during cooler weather and so this school will not be at peak demand.

The overall load power at 12:00 is 879.7 kW and without the school will be 729 kW and so the individual customer loads will be 760 W and 380 VAr. It is also expected that the two capacitor banks at Ross Plains ZS are in service. These values will be applied to the network models with the various permutations of Small DG System penetration.

7.2.2 ROPL-04 and Constant PV In-feed Modelling - Results

The various tests were described in the introduction of this report. The results of applying these tests to the ROPL-04 model without the lumped installations can be seen in the table 7.1 below. These tests would be applied with:

- The load described in the previous section of 760 W and 380 VAr applied to every customer;
- The school load of 150 kW and 75 kVAr;
- The 3 MVAr capacitor bank on the 11 kV Bus 1 and the 2 MVAr capacitor bank on the 11 kV Bus 2 in service.
- The point load on 11 kV Bus 1 and 2 each of 10 MW and 2.0 MVAr (the low reactive value set to comply with known high power factors at this substation).
- A Small DG System installed at the percentage of customers indicated by the test parameter.

As an example Model Test A-1 would see 20% of the 963 customers with a 2.4kW Small DG System installed at their premises.

Table 7.1 – ROPL-04 Constant In-feed and Even Distribution Results

Results - ROPL-04 Constant In-feed			
Model Test	Test Parameters	Minimum	Maximum
A-1	20% Even Distribution	101.9%	103.4%
A-2	30% Even Distribution	102.1%	103.4%
A-3	40% Even Distribution	102.2%	103.5%
A-4	50% Even Distribution	102.4%	103.8%
A-5	60% Even Distribution	102.5%	104.2%
A-6	70% Even Distribution	102.6%	104.5%
A-7	80% Even Distribution	102.8%	104.8%
A-8	100% Even Distribution	103.4%	105.5%

The results of applying the tests to the ROPL-04 model with the lumped installations can be seen in the table 7.2 below. These tests would be applied with:

- The load described in the previous section of 760 W and 380 VAr applied to every customer including those in the lumped installation;
- The school load of 150kW and 75 kVAr;

- The 3 MVAr capacitor bank on the 11 kV Bus 1 and the 2 MVAr capacitor bank on the 11 kV Bus 2 in service.
- The point load on 11 kV Bus 1 and 2 each of 10 MW and 2.0 MVAr (the low reactive value set to comply with known high power factors at this substation).
- A Small DG System installed at the percentage of customers indicated by the test parameter;
- A Small DG System installed on every customer in the lumped installation.

As an example model test A-9 would see 50% of the 964 customers with a 2.4kW Small DG System installed at their premises and 120 new lumped customers at the centre of the HV network with 100% of them having a 2.4kW Small DG System installed at their premises.

Table 7.2 – ROPL-04 Constant In-feed and Lumped Installation Results

Results - ROPL-04 Constant In-feed			
Model Test	Test Parameters	Minimum	Maximum
A-9	50% Even Distribution plus 120 Lumped Installation at centre of HV network	102.5%	104.0%
A-10	50% Even Distribution plus 240 Lumped Installation at centre of HV network	102.6%	104.1%
A-11	50% Even Distribution plus 120 Lumped Installation at end of HV network	102.4%	104.5%
A-12	50% Even Distribution plus 240 Lumped Installation at end of HV network	102.5%	104.9%
A-13	80% Even Distribution plus 120 Lumped Installation at centre of HV network	102.9%	104.9%
A-14	80% Even Distribution plus 240 Lumped Installation at centre of HV network	103.0%	104.9%
A-15	80% Even Distribution plus 120 Lumped Installation at end of HV network	102.8%	105.3%
A-16	80% Even Distribution plus 240 Lumped Installation at end of HV network	103.6%	105.9%

7.2.3 Karara SWER and Constant PV In-feed

The voltage levels on the Karara SWER feeder model are controlled by the on line tap changer (OLTC) in the 11 kV regulator and the 12.7 kV SWER regulator. The network model with these tap changers along with the fixed taps on the distribution transformers has been shown to adequately control the voltages under normal conditions. There is a need to test whether the system can control the voltages to within the prescribed ±6% on the distribution LV with the inclusion of various penetrations of Small DG Systems. The most likely scenario that will cause excessive voltage on the LV will occur when the loads are low and the in-feed from the Small DG Systems is the highest. The graph in figure 7.6 below shows the power load on the day of the lowest maximum demand as well as an example of solar power in-feed on a clear day. The third trace in the graph shows the difference between the load and the solar power in-feed.

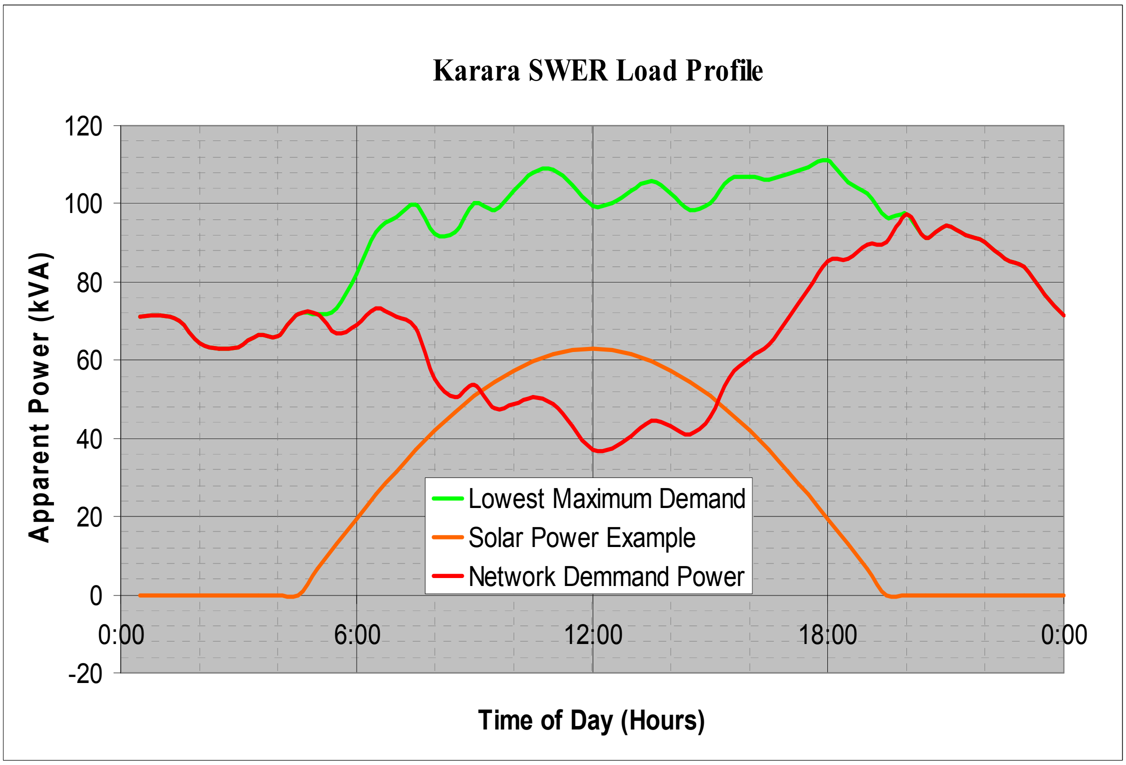


Figure 7.6 –Solar Power Effect at Low Demand Period on Karara SWER Network

The graph above shows that the lowest power requirements occurs at about the zenith of the solar power (about 12:00) and so the lowest overall load through the zone substation. The values of load power will be applied evenly to all 99 customers and a power factor of 0.9 lagging will provide the load apparent power requirements.

The overall load power at 12:00 is 99.5 kW and so the individual customer loads will be 1 kW and 500VAr. These values will be applied to the network models with the various permutations of Small DG System penetration.

7.2.4 Karara SWER and Constant PV In-feed Modelling - Results

The various test penetrations to be tested were described in the introduction of this report. The results of applying these tests to the Karara SWER model without the lumped installations can be seen in the table 7.3 below. These tests have been applied with:

- The customer load described in the previous section of 1.0 kW and 500 VAr applied to every customer.

- A Small DG System installed at the percentage of customers indicated by the test parameter.

As an example model test B-1 would see 20% of the 99 customers with a 4.8kW Small DG System installed at their premises.

Table 7.3 – Karara SWER Constant In-feed with Even Distribution Results

Results – Karara SWER Constant In-feed Even Distribution			
Model Test	Test Parameters	Minimum	Maximum
B-1	20% Even Distribution	102.4%	104.8%
B-2	30% Even Distribution	103.3%	105.4%
B-3	40% Even Distribution	102.4%	106.0%
B-4	50% Even Distribution	102.4%	106.6%
B-5	60% Even Distribution	102.9%	107.1%
B-6	70% Even Distribution	103.4%	107.5%
B-7	80% Even Distribution	102.8%	107.9%
B-8	100% Even Distribution	102.4%	108.6%

The results of applying the tests to the Karara SWER model with the lumped installations can be seen in the table 7.4 below. These tests would be applied with:

- The load described in the previous section of 1.0 kW and 500 VAr applied to every customer including those in the lumped installation;
- A Small DG System installed at the percentage of customers indicated by the test parameter;
- A Small DG System installed on every customer in the lumped installation.

As an example model test B-9 would see 30% of the 99 customers with a 4.8kW Small DG System installed at their premises and 5 new lumped customers at the centre of the HV network with 100% of them having a 4.8 kW Small DG System installed at their premises.

Table 7.4 – Karara SWER Constant In-feed and Lumped Installation Results

Results – Karara SWER Constant In-feed Even and Lumped Distribution			
Model Test	Test Parameters	Minimum	Maximum
B-9	30% Even Distribution plus 5 Lumped Installation at centre of HV network	102.5%	105.7%
B-10	30% Even Distribution plus 10 Lumped Installation at centre of HV network	102.6%	105.9%
B-11	30% Even Distribution plus 5 Lumped Installation at end of HV network	102.6%	105.7%
B-12	30% Even Distribution plus 10 Lumped Installation at end of HV network	102.7%	105.8%
B-13	50% Even Distribution plus 5 Lumped Installation at centre of HV network	102.5%	106.7%
B-14	50% Even Distribution plus 10 Lumped Installation at centre of HV network	102.6%	106.8%
B-15	50% Even Distribution plus 5 Lumped Installation at end of HV network	102.5%	106.7%
B-16	50% Even Distribution plus 10 Lumped Installation at end of HV network	102.7%	106.8%

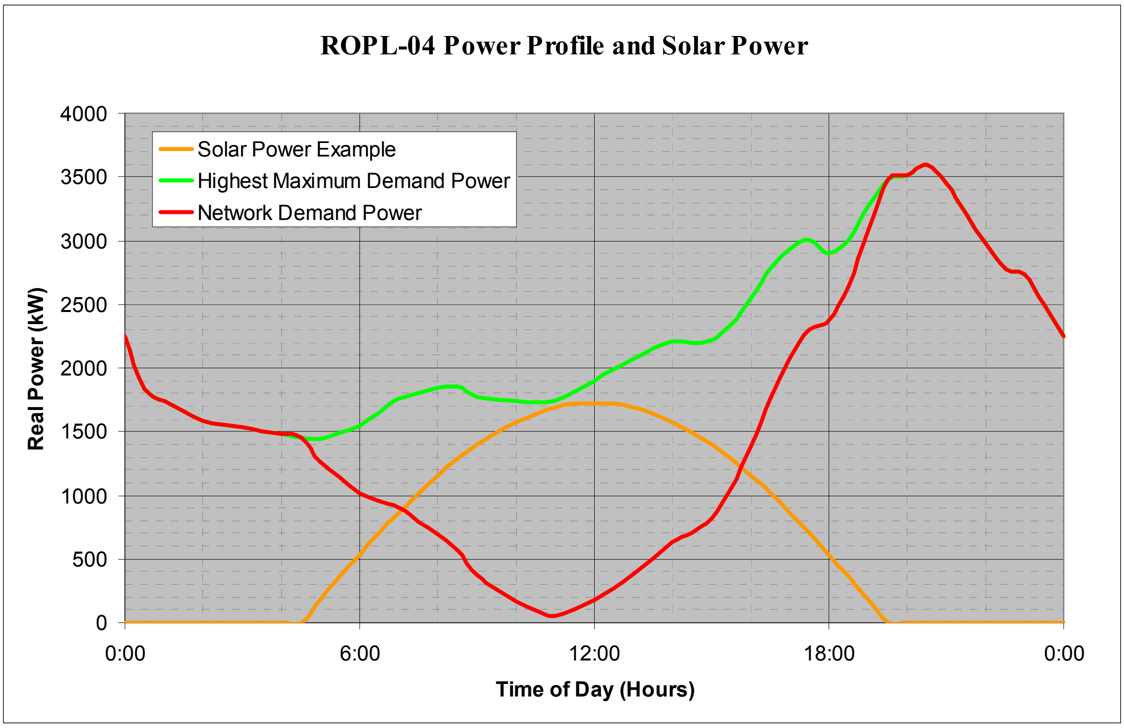
7.3 *Fluctuating PV In-feed*

The two feeder networks will be tested to see what the effect of Small DG System penetration has on the LV on a day when cloud moves across the area and causes fluctuating PV in-feed.

7.3.1 ROPL-04 and Fluctuating PV In-feed at High Demand

There is a need to test whether the system can control the voltages to within the prescribed ±6% on the distribution LV with the inclusion of various penetrations of Small DG Systems as cloud passes over the area causing the PV in-feed to fluctuate. A scenario that will cause the large power fluctuation and hence large voltage fluctuations in the shortest time will be when the load is high and the cloud movement causes a drop in PV in-feed before the tap changer on the transformer at Ross Plains ZS can react.

The graph in figure 7.7 below shows the ROPL-04 power load on the day of the highest maximum demand as well as an example of solar power in-feed on a clear day. The third trace in the graph shows the difference between the load and the solar power in-feed and is called Network Demand Power in this graph.



Figurer 7.7 – ROPL-04 Maximum demand day and example solar in-feed

It can be seen that the lowest network demand power is about 11:00 to 12:00. At this time the load is 1800 kW. This period would also be during a hot period and school hours, which means the schools load will be high and could be 200 kW and 100 kVAr. The remainder of the load is spread evenly across the 963 customers. Taking into account line losses each would consume 1.60 kW and at a power factor of 0.9 lagging would see 800 VAr's.

Considering the following points:

- The tap changer on the Ross Plains ZS 66/11 kV transformer has a time delay of 60 s.
- The estimated wind speed when large broken cumulus clouds are passing over the Townsville region is 15 km/hr or 4.2 m/s.
- The output of PV can change by 75% in 30 s as a result of cloud movement overhead.
- The ROPL-04 feeder covers an area of about 800 m by 1000m.

A tap changer would need to see a voltage outside the control ban for more than its delay time. The worst case would see a voltage near the top of the OLTC control range and as a cloud transitions the network the PV in-feed is reduced and the network voltage drops. After one minute the voltage is just above the lower threshold and after a further minute the cloud has transition has caused the network voltage to drop below the lower threshold and the tap changer reacts. This is a very unlikely scenario and so a more conservative test is conducted where a cloud front movement in one minute is considered. This would see the cloud move about 250 m in 60 s and so the PV in-feed across a 250 m by 1000 m section of the ROPL-04 feeder or 30% of the customers could be reduced by 75% before the tap changer can react.

A reasonable test for the ROPL-04 feeder model to determine the effect of cloud movement would be to set the 963 customer loads at 1.60 kW and 800 VAr's with the desired penetration of Small DG Systems and run a load flow. This would be followed by changing from controlled to fixed tap position on the 66/11kV transformer, reducing the PV in-feed by 75% from 2.4 kW to 0.6 kW to 30% or 290 of the Small DG Systems on one side of the network and running the load flow again. The voltages after the second load flow will be of interest and should show the effect before the OLTC operates on the 66/11 kV transformer.

An additional test would be when the ROPL-04 feeder is at a low load and cloud transition the area. The load values used in the constant in-feed section of this report could be used for this test. The methodology would otherwise remain the same.

An alternate would be to run the test described above in the opposite direction starting with the same customer loads and 25% PV in-feed to all the Small DG Systems and running the load flow model. This would be followed by fixing or locking the tap on the 66/11 kV transformer, increasing the PV in-feed to 2.4 kW on 290 customers on one side of the model and running the load flow again.

7.3.2 ROPL-04 Maximum Load and Fluctuating PV - Results

The various permutations of tests were described in an earlier section of this report. The results of applying these tests with fluctuating PV in-feed to the ROPL-04 model without the lumped installations can be seen in the table 7.5 below. These tests would be applied with:

- A normal load flow will be run with the 66/11 kV transformer OLTC operating and:
    - The load described in the previous section of 1.6 kW and 800 VAr applied to every customer;
    - The school load of 200 kW and 100 kVAr;
    - The 3 MVAr capacitor bank on the 11 kV Bus 1 and the 2 MVAr capacitor bank on the 11 kV Bus 2 in service.
    - The point load on 11 kV Bus 1 and 2 each of 10 MW and 2.0 MVAr (the low reactive value set to comply with known high power factors at this substation).
    - A 2.4 kW Small DG System installed at the percentage of customers indicated by the test parameter.
- A second load flow will be run with the 66/11kV transformer OLTC disabled and a fixed tap chosen that is the same as the previous load flow and:
    - All customer loads remain the same.
    - The Small DG Systems in the percentage of 290 customers on one side of the model will be reduced by 75% to 0.6 kW.

As an example model test A-1 would see 20% of the 963 customers with a 2.4kW Small DG System installed at their premises and the load flow run. The taps would be locked on the 66/11 kV transformer; the PV in-feed would be reduced to 0.6 kW to 30% or 58 customers with the installed Small DG Systems and the load flow run again. The network voltages after the second load flow is run will be recorded.

Table 7.5 – ROPL-04 Fluctuating In-feed and Even Distribution Results at Maximum Demand Period

Results - ROPL-04 Fluctuating In-feed at Maximum Demand Period			
Model Test	Test Parameters	Minimum	Maximum
A-1	20% Even Distribution	99.6%	102.2%
A-2	30% Even Distribution	99.8%	102.2%
A-3	40% Even Distribution	100.0%	102.3%
A-4	50% Even Distribution	100.2%	102.3%
A-5	60% Even Distribution	100.4%	102.3%
A-6	70% Even Distribution	100.6%	102.4%
A-7	80% Even Distribution	100.8%	102.4%
A-8	100% Even Distribution	101.1%	102.5%

A worst case scenario was also tested where 100% penetration was tested for a reduction in PV in-feed by 75% for all of the Small DG Systems. This test saw the LV range from 100.3 to 101.5%

The results of applying the tests to the ROPL-04 model with the lumped installations can be seen in the table 7.6 below. These tests would be applied with:

- A normal load flow will be run with the 66/11 kV transformer OLTC operating and:
    - The load described in the previous section of 1.6 kW and 800 VAr applied to every customer including the lumped installation customers;
    - The school load of 200 kW and 100 kVAr;
    - The 3 MVAr capacitor bank on the 11 kV Bus 1 and the 2 MVAr capacitor bank on the 11 kV Bus 2 in service.
    - The point load on 11 kV Bus 1 and 2 each of 10 MW and 2.0 MVAr (the low reactive value set to comply with known high power factors at this substation).
    - A 2.4 kW Small DG System installed at the percentage of customers indicated by the test parameter.
    - A 2.4 kW Small DG System installed at every of customer of the lumped load installation.
- A second load flow will be run with the 66/11kV transformer OLTC disabled and a fixed tap chosen that is the same as the previous load flow and:
    - All customer loads remain the same.

    - The Small DG Systems in lumped installation and a relevant percentage of the 290 customers on the same of the model as the lumped load will be reduced by 75% to 0.6 kW.

As an example Model Test A-14 would see 80% of the 963 customers with a 2.4kW Small DG System installed at their premises and 240 customers with 2.4 kW on every premises in a lumped installation connected at the centre of the HV network. A load flow would be run. The taps would be locked on the 66/11 kV transformer. The PV in-feed would be reduced to 0.6 kW on the 80% of the 290 customers with a 2.4kW Small DG System installed at their premises and all of the 120 lumped installation customers. The load flow would be run again and the maximum and minimum voltages recorded.

Table 7.6 – ROPL-04 Fluctuating In-feed and Lumped Installation Results at Maximum Demand Period

Results - ROPL-04 Fluctuating In-feed at Maximum Demand Period			
Model Test	Test Parameters	Minimum	Maximum
A-14	80% Even Distribution plus 240 Lumped Installation at centre of HV network	100.6%	102.1%
A-16	80% Even Distribution plus 240 Lumped Installation at end of HV network	100.5%	102.1%

Note that the number of tests was limited as the results showed no problems with the voltage fluctuations.

7.3.3 ROPL-04 at Minimum Load and Fluctuating PV - Results

The results of applying these tests with fluctuating PV in-feed to the ROPL-04 model without the lumped installations during low load periods can be seen in the table 7.7 below. These tests would be applied with:

- A normal load flow will be run with the 66/11 kV transformer OLTC operating and:
    - The load described in the previous section of 760 W and 380 VAr applied to every customer;
    - The school load of 150 kW and 75 kVAr;
    - The 3 MVAr capacitor bank on the 11 kV Bus 1 and the 2 MVAr capacitor bank on the 11 kV Bus 2 in service.
    - The point load on 11 kV Bus 1 and 2 each of 10 MW and 2.0 MVAr (the low reactive value set to comply with known high power factors at this substation).
    - A 2.4 kW Small DG System installed at the percentage of customers indicated by the test parameter.

- A second load flow will be run with the 66/11kV transformer OLTC disabled and a fixed tap chosen that is the same as the previous load flow and:
    - o All customer loads remain the same.
    - o The Small DG Systems in the percentage of 290 customers on one side of the model will be reduced by 75% to 0.6 kW.

As an example model test A-1 would see 20% of the 963 customers with a 2.4kW Small DG System installed at their premises and the load flow run. The taps would be locked on the 66/11 kV transformer; the PV in-feed would be reduced to 0.6 kW to 30% or 58 customers with the installed Small DG Systems and the load flow run again. The network voltages after the second load flow is run will be recorded.

Table 7.7 – ROPL-04 Fluctuating In-feed and Even Distribution Results at Minimum Demand Period

Results - ROPL-04 Fluctuating In-feed at Minimum Demand Period			
Model Test	Test Parameters	Minimum	Maximum
A-1	20% Even Distribution	102.3%	103.4%
A-2	30% Even Distribution	102.4%	103.3%
A-3	40% Even Distribution	102.5%	103.5%
A-4	50% Even Distribution	102.6%	103.8%
A-5	60% Even Distribution	102.7%	104.0%
A-6	70% Even Distribution	102.8%	104.3%
A-7	80% Even Distribution	102.9%	104.6%
A-8	100% Even Distribution	103.1%	105.2%

A worst case scenario was also tested where 100% penetration was tested for a reduction in PV in-feed by 75% for all of the Small DG Systems. This test saw the LV range from 103.0% to 103.5%.

The results of applying the tests to the ROPL-04 model with the lumped installations can be seen in the table 7.8 below. These tests would be applied with:

- A normal load flow will be run with the 66/11 kV transformer OLTC operating and:
    - o The load described in the previous section of 780 W and 380 VAr applied to every customer including the lumped installation customers;
    - o The school load of 150 kW and 75 kVAr;

- The 3 MVAr capacitor bank on the 11 kV Bus 1 and the 2 MVAr capacitor bank on the 11 kV Bus 2 in service.
- The point load on 11 kV Bus 1 and 2 each of 10 MW and 2.0 MVAr (the low reactive value set to comply with known high power factors at this substation).
- A 2.4 kW Small DG System installed at the percentage of customers indicated by the test parameter.
- A 2.4 kW Small DG System installed at every of customer of the lumped load installation.

- A second load flow will be run with the 66/11kV transformer OLTC disabled and a fixed tap chosen that is the same as the previous load flow and:
  - All customer loads remain the same.
  - The Small DG Systems in lumped installation and a relevant percentage of the 290 customers on the same of the model as the lumped load will be reduced by 75% to 0.6 kW.

As an example Model Test A-14 would see 80% of the 963 customers with a 2.4kW Small DG System installed at their premises and 240 customers with 2.4 kW on every premises in a lumped installation connected at the centre of the HV network. A load flow would be run. The taps would be locked on the 66/11 kV transformer. The PV in-feed would be reduced to 0.6 kW on the 80% of the 290 customers with a 2.4kW Small DG System installed at their premises and all of the 120 lumped installation customers. The load flow would be run again and the maximum and minimum voltages recorded.

Table 7.8 – ROPL-04 Fluctuating In-feed and Lumped Installation Results at Minimum Demand Period

Results - ROPL-04 Fluctuating In-feed at Minimum Demand Period			
Model Test	Test Parameters	Minimum	Maximum
A-14	80% Even Distribution plus 240 Lumped Installation at centre of HV network	102.7%	104.5%
A-16	80% Even Distribution plus 240 Lumped Installation at end of HV network	103.3%	104.6%

7.3.4 Karara SWER and Fluctuating PV In-feed Modelling Results

The distance between installations on the Karara SWER is considerable and can be up to 5 km. The SWER lines tend to be run in the straightest possible manner and their length is a good approximation of the distance between the loads. The average line length is about 800 m which means that the customer and hence the Small DG Systems are also on average 800 m apart.

The wind speed in the area when large broken cumulus clouds are passing is assumed to be 10 km/hr. This means that the cloud fronts will move from Small DG System to the next on average 288 seconds.

The slowest tap changing operation occurs on the SWER regulator and is 150 s. This means that cloud movement over the Karara SWER network is unlikely to cause voltage fluctuations of greater concern than would already exist as a result of the installation of Small DG Systems.

7.4 *Reactive Compensation*

The use of reactive compensation is a well established method of voltage control on electrical supply networks. The following section describes tests on the two representative feeders using reactive or VAr compensation to control the high voltages caused by Small DG System penetration.

7.4.1 PSS Sincal Reactive Compensation Devices

PSS Sincal provides discrete reactive components such as shunt reactors and capacitors and also dynamic devices such as static compensators.

The discrete devices have settings for their resistive and reactive values. They also provide control modes akin to an OLTC in a transformers where they change their values by small discrete amounts to compensate for an excursion outside an upper and lower threshold of voltage of power factor.

The dynamic devices are similar to the discrete devices except that they provide both inductive and capacitive reactance and only control for excursions outside an upper and lower voltage level.

7.4.2 ROPL-04 Additional Tests

The results for the testing on ROPL-04 feeder have so far not shown any adverse effect of high penetration of Small DG Systems. A further test was conducted to create voltage on the LV that exceeded the ±6% limits and then test the effect of reactive compensation devices

The test was conducted on the 963 residential customers and no lumped installation and included:

- Every residential customer with a load of the 760 W and 380 VAr
- Every customer to have a 2.4 kW Small DG System.
- The 3 MVAr and 2 MVAr 11 kV capacitor banks out of service.
- The 11 kV point loads set to 10 MW and 7.5 MVAr.

This test saw the LV range from 103.8% to 107.2%. The high voltages created on the LV are on the distribution feeders farthest from the Ross Plains ZS.

A solution to the high LV on the distribution network is to inject inductively reactive power into the network. The location of the reactive compensation within the network has a bearing on the effectiveness at stabilising excessive voltage.

7.4.3 ROPL-04 and Reactive Compensation - Results

The excessive voltage levels experienced in the test model describe above requires the injection of inductive reactive power and not capacitive. The greatest voltages were experienced at the extremities of the network at the distribution substation TVS650.

A 1 MVAr static compensator with a voltage set point of 100% of the nominal voltage was installed at various locations within the network in order to determine the effectiveness. These installed locations, VAr's exported and maximum LV are as follows:

- TVS650 LV terminals, imported 456 kVAr and LV maximum was 106.3%.
- TVS650 HV terminals, imported 1 MVAr and LV maximum was 105.5%
- TVS796 HV terminals (mid way along HV radial), imported 1 MVAr and LV maximum was 105.8%.
- Ross Plains ZS 11 kV bus, imported 980 kVAr and LV maximum was 106.4%

The inclusion of the static compensator at the Ross Plains ZS 11 kV bus would not allow the model to converge to a result unless the voltage set point was increased to 102.5%. This was most likely because the 11 kV is regulated by the 66/11 kV transformer to about this value. This may have meant the controller on the transformer and the static compensator was working against each other.

It can be seen in the results that the greatest effect was had by placing the reactive compensation closest to the problem excessive LV areas. Increasing the value of the reactive compensation to 2 MVAr at the HV terminals of TVS650 reduced the maximum LV to 105.1%. Increasing the value further to 3.0 MVAr at this extremity of the HV brought the LV maximum down to 103.5%.

An alternative to large network reactive compensation is to use the grid-connect inverters themselves to generate reactive power. The devices presently installed on the Queensland electrical network are not enabled for this function. It is likely that the majority of the grid-connect inverters would be capable with only minor modifications and possibly only a software change.

As an example of the possibility of using the grid-connect inverters for reactive compensation all of the 963 customers 3.6 kW units were set to 10% reactive power. The active power produced by the devices after an internal loss was 3.32 kW and so the reactive power was 0.33 kVAr. In total there was 318 kVAr provided by all 963 devices and this reduced the LV maximum to 106.3%. Increasing the reactive content of the inverter output to 20% or 0.66 kVAr each reduced the maximum LV to 105.4%.

7.4.4 Karara SWER and Reactive Compensation - Results

The Karara SWER model exhibited excessive voltage problems at Small DG Systems penetration above 30% of the 4.8 kW installations. The same test parameters as that used in section 7.2.4 of this report with penetration of 100% was used and this test produced an LV maximum 108.6%.

A 200 kVAr static compensator with a voltage set point of 102% of the nominal voltage was installed at various locations within the network in order to determine the effectiveness. These installed locations, VAr's exported and maximum LV are as follows:

- SWER isolator, imported 129 kVAr and LV maximum was 105.1%.
- SWER regulator upstream terminals, imported 167 kVAr and LV maximum was 106.0%.
- SWER regulator downstream terminals, imported 195 kVAr and LV maximum was 102.7%
- Extremity of the HV network at PE4763, imported 175 kVAr and the LV was 102.3%.

All of the 99 DC-Infeeders were set to 10% reactive power which meant each device was importing 450 VAr and in total 44.6 kVAr. This caused the maximum LV to reduce to 106.9%. Increasing the reactive power to 20% or 900 VAr for each inverter reduced the maximum LV further to 105.8%.

7.5 *QoS Modelling Summary*

There are a number of key points that can be made regarding the QoS modelling exercises described in this chapter. The following sections of this report provide a brief summary of these points.

7.5.1 ROPL-04 QoS modelling Summary

The QoS modelling of the ROPL-04 distribution feeder showed that:

- The network could support a 100% penetration of 2.4 kW Small DG Systems without exceeding the ±6% deviation from the nominal LV; although at this level of penetration the LV is at 105.5%.
- The network could support a large lumped installation such as a 240 unit retirement village with 2.4 kW of Small DG Systems on every customer's roof, whilst the remainder of the network was already saturated with 80% penetration of the same size Small DG Systems without exceeding the ±6% deviation from the nominal LV. At this level of penetration of Small DG Systems the LV had risen to 105.9%
- The investigation of cloud movement suggested that 30% of the network could see the transition of a cloud front within the 60 s time delay taken for the operation of the 66/11 kV transformer OLTC. The investigation suggested that the maximum change of the PV array power during the cloud transition was 75%. The testing of cloud movement across the network showed that the voltages did not exceed the ±6% deviation from the nominal LV. These tests showed that 100% penetration of 2.4 kW Small DG Systems with a step change of 30% of these systems by 75% of their capacity caused no problems.
- A worst case scenario for cloud movement was also tested where all of the 963 customers had 2.4 kW Small DG Systems and the cloud movement saw every installations drop to 75% PV array power. This test also showed that the LV stayed within the ±6% of the nominal LV.
- A similar situation occurred when testing cloud transition with a lumped installation where 240 customers with 100% penetration and 80% penetration of the other 963 customer were tested. When the 240 lumped installations and 30% of the 963 residential customers saw their PV array power drop or increase by 75% there was no excessive LV changes.

- The testing with the inclusion of reactive compensation had no effect when located at the zone substation but did reduce the LV when placed away from the zone substation. The most effective location was at the end of the HV network.
- The testing of reactive compensation provided within the grid-connect inverters was useful but needed to be up to 20% to solve the problems created in the test arrangement of the network.

7.5.2 Karara SWER QoS Modelling Summary

The QoS modelling of the Karara SWER distribution feeder showed that:

- The network LV exceeded the ±6% deviation from the nominal when the penetration of 4.8 kW Small DG Systems reached 30%.
- The network LV reached 108.6% with 100% penetration of 4.8 kW Small DG Systems.
- The customers are spaced on average 800 m apart and the cloud fronts move across these customers at about 288 s for each customer. There is little chance that cloud movement will cause greater LV then for constant PV in-feed.
- The testing with the inclusion of reactive compensation did reduce the LV when placed at various points within the HV network. The best results were obtained by placing the compensation at the extremities of the HV network.
- The testing of reactive compensation provided within the grid-connect inverters was useful but needed to be up to 20% to solve the problems created in the test arrangement of the network.

CHAPTER 8 - ANALYSIS

8.1 *Protection System Modelling*

The protection system modelling was constrained by the inability of PSS Sincal to effectively model the Small DG Systems. The addition of the Stability Module to the main software may have provided an effective solution to this issue.

The results obtained for the two distribution feeders have some usefulness and will be discussed in the following sections.

8.1.1 Three Phase Distribution HV Protection

The two fault types that are considered when determining the lowest fault level on the HV network are the two phase fault and a phase to earth with 50 ohms of fault resistance. The two phase fault is used to examine the effectiveness of over current protection (OC) and is used because this is the lowest credible fault type that will see only phase current flowing. The phase to earth and fifty ohms of fault resistance is used when considering the effectiveness of earth fault (EF) protection. The value of 50 ohms is used because it is seen as a credible upper limit to earth fault resistance on a HV network.

The lowest acceptable fault current required for the operation of an OC protection device is considered by Ergon Energy to be 1.7 times greater than the protection device setting or to have a pickup of 1.7 for a normal network operating arrangement. The lowest acceptable fault current required for the operation of an EF protection device is considered by Ergon Energy to be 2.0 times greater than the protection device setting or to have a pickup of 2.0 for a normal network operating arrangement. It is sometimes considered acceptable to have pickup values less than those described above for contingent network arrangements. This research project is not considering the contingent arrangements and so 1.7 will be the value for OC and 2.0 for EF settings.

8.1.2 ROPL-04 HV Protection

The lowest two phase fault on the ROPL-04 network occurs at the most remote section of the HV network at the distribution substation TVS650. A two phase fault at TVS650 causes the current levels at the protective device on the 11 kV bus at Ross Plains ZS to reduce when there are Small DG Systems contributing. When all 963 Small DG Systems are set to 2.4 kW of PV in-feed the PSS Sincal model suggest that the two phase fault at TVS 650 has reduced the fault level at the Ross Plains 11k kV bus from 1.76 kA to 1.60 kA. The OC setting for ROPL-04 is presently 300A and this means that the protection reach is 1600A / 300 A or 5.33. This value of protection reach is well above the lower limit of 1.7 and considered adequate.

The terminal voltages of the DC-Infeeders during the fault described above ranged from 3 V to 280 V. About 15% of the inverters terminal voltages are within the possible range of anti-islanding voltage thresholds of 200 V to 270 V. All the inverters injected 9.23 A, which is their output current when their internal losses are accounted for and at their nominal voltage value. In reality the currents injected by the DC-Infeeder should have been zero for voltages under 200 V and over 270 V as they should shut down within 2 s. The current should have been higher than 9.23 A when the terminal voltages were between 200 V and 239.6 V and lower between 239.6 V and 270 V. It is difficult to accurately predict what would happen if the inverters were modelled appropriately. It could be argued that the changes in current at Ross Plains ZS from 1.76 kA without the inverters to 1.60 KA with 100% penetration are the upper and lower possible lowest phase to phase fault current values. This would suggest that the real value of the lowest phase fault current at Ross Plains ZS with 100% penetration would lie between the two values and so the protection reach is somewhere between 5.33 and 5.87.

The lowest level fault that will be seen by EF protection will be an earth fault with 50 ohms of fault resistance at TVS 650. The fault level on ROPL-04 model with no Small DG Systems was 124 A. The inclusion of all 963 Small DG Systems set to 2.4 kW of PV in-feed reduced this current to 117 A at the Ross Plains ZS 11 kV bus. The protection setting is 60 A and this means that the protection reach has dropped from 2.07 to 1.95 and the later value is lower than the desired 2.00. The HV voltage source is also set to 1.10 p.u. which elevates the current levels and so both the 124 A and 117 A values may be lower when the HV voltage source are at 1.00 p.u.

The value at the terminals of the DC-Infeeders ranged from 253 V up to 280 V during a phase to earth fault with 50 ohms of fault resistance with 90% of the DC-Infeeders over 270V. A small percentage of these values are within the possible range of anti-islanding voltage thresholds of 200 V to 270 V although 90% of the inverters were over 270 V. The inverters over 270 V should shut down within 2 s. If the 90% of inverters over 270 V had shut down then the fault current at Ross Plains ZS 11 kV bus would rise and this may bring the protection reach back over the desired 2.00.

Again it is difficult to predict the effects of the high penetration of Small DG Systems on the EF currents. The two values described above are the upper and lower possibilities of the lowest fault levels and so the real reach factor should lie in-between 1.95 to 2.07.

8.1.3 ROPL-04 HV Transformer Fuse Protection

All of the distribution substations on the ROPL-04 network use fuses on their HV protection. The lowest acceptable operating current for these fuses should be twice their rating and preferably three times their rating.

The lowest fault level experienced at the HV terminals of any distribution substation on the ROPL-04 network was for a phase to earth fault on the LV terminals of the distribution substation TVS650. The HV fuse on the distribution substation TVS650 is rated at 80 A and so would require over 160 A and preferably 240 A to operate.

The fault levels experienced at the HV terminals of the distribution transformer TVS650 for an earth fault on the LV terminals showed an increase from 235 A with no Small DG Systems to 245 A with 100% penetration of 2.4 kW Small DG Systems. The accuracy of the value of the increase is under some doubt as all the inverters were injecting current, whilst their terminal voltages were mostly outside the anti-islanding thresholds and so should not have been contributing to the fault current.

The two values of fault current could reasonably be assumed as the upper and lower values of the lowest fault current possible when Small DG Systems are included in the network. This means that the real value of fault current when Small DG Systems are included in the network will lie in between these two limits. The fact that the current increases with the inclusion of Small DG Systems means that there is an improvement and not a reduction in the protection provided by the transformer HV fuses.

8.1.4 ROPL-04 LV Transformer Fuse Protection

The lowest fault level on the ROPL-04 LV network is seen by the LV fuses when there is a phase to ground fault at the end of a 500 m LV radial cable running from the distribution substation TVS650. The LV fuse rating on the distribution substation TVS650 transformer can be rated at up to 800 A and are most likely 400 A or smaller, although the exact value is unknown.

The value of fault current at the LV terminals without any Small DG Systems on the network was 1.29 kA and with 100% 2.4 kW Small DG Systems was 1.34 kA. The accuracy of the value of the increase is under some doubt as all the inverters were injecting current, whilst their terminal voltages were mostly outside the anti-islanding thresholds and so should not have been contributing to the fault current.

The lowest acceptable operating current should be over 800 A and preferably 1.2 kA. The values with and without 100% penetration of Small DG Systems were both just above the preferred operating current for 400 A rated fuse.

The two values of fault current could reasonably be assumed as the upper and lower values of the lowest possible fault current when Small DG Systems are included in the network. This means that the real value of fault current when Small DG Systems are included in the network will lie in between theses two limits. The fact that the current increases with the inclusion of Small DG Systems means that there is an improvement and so not a reduction in the protection provided by the transformer LV fuses.

8.1.5 Karara SWER HV Protection

The value of current where a protective device is expected to operate on a SWER network is twice the protective device setting. This means that the minimum protection reach on a SWER network should be 2.0. A SWER protective device has over current protection only. There is no earth fault protection as the current flows in one wire and the return path for the current is through the earth and so there is nothing but earth current.

The Karara SWER network includes two protective devices. The first is at the beginning of the network just after the SWER isolators and is called the Karara recloser. The second is mid way along the main backbone of the SWER line and is called the Reedy Creek recloser.

8.1.6 Karara Recloser HV Protection

The Karara recloser OC setting is 20 A and so the fault current seen by this device should be at least 40 A. The lowest fault level on the Karara recloser section occurs at the distribution substation PE10899. The fault current for a phase to earth fault with 50 ohms of fault resistance at PE10899 and indicated by the PSS Sincal model without any Small DG Systems is 61 A. This value equates to a protection reach of 3.05 and is well over the acceptable value of 2.0.

The fault current indicated by the PSS Sincal model with 100% penetration of 4.8 kW is Small DG Systems and seen by the Karara recloser is 39 A for a phase to earth fault with 50 ohms of fault resistance at PE10899. This equates to a protection reach of 1.95 and is slightly below the acceptable value of 2.0

The DC-Infeeder were all acting as constant current devices and were delivering 18.87 A to the LV of their distribution transformers, which is transformed to 0.36 A on the

HV. The voltages at the terminals of the DC-Infeeders range from 82 V to 169 V. It can be seen that the voltages are well under the anti-islanding lower range of 200 V and should not have been operating.

The two values of 61 A and 39 A fault current could reasonably be assumed as the upper and lower possibilities of the lowest possible values of fault current when Small DG Systems are included in the network. This means that the lowest real value of fault current when Small DG Systems are included in the network will lie in between their values.

A second fault study was conducted with 100% penetration with 2.4 kW of Small DG Systems instead of the 4.8 kW units. The fault location and type were the same and the fault current seen by the Karara recloser was 49 A. The DC-Infeeder are all acting as constant current devices and are delivering 9.44 A to the LV of their distribution transformers, which is transformed to 0.18 A on the HV. The voltages at the terminals of the DC-Infeeders range from 76 V to 161 V and so under the 200 V limit.

It is notable that the reduction in Small DG Systems penetration power from 4.8 kW to 2.4 kW improved the fault level seen by the Karara recloser from 39 A to 49 A and took the protection reach factor from an un-acceptable 1.95 to an acceptable 2.45.

8.1.7 Reedy Creek Recloser HV Protection

The Reedy Creek recloser OC setting is 10 A and so the fault current seen by this device should be at least 20 A. The lowest fault level on the Karara recloser section occurs at the distribution substation PE4763. The fault current for a phase to earth fault with 50 ohms of fault resistance at PE4763 and indicated by the PSS Sincal model without any Small DG Systems is 56 A. This value equates to a protection reach of 3.05 and is well over the acceptable value of 5.6.

The fault current indicated by the PSS Sincal model with 100% penetration of 4.8 kW Small DG Systems and seen by the Reedy Creek recloser is 51 A for a phase to earth fault with 50 ohms of fault resistance at PE4763. This equates to a protection reach of 5.1 and is well over the acceptable value of 2.0

The DC-Infeeder were all acting as constant current devices and were delivering 18.87 A to the LV of their distribution transformers, which is transformed to 0.36 A on the HV. The voltages at the terminals of the DC-Infeeders range from 82 V to 169 V. It can be seen that the voltages are well under the anti-islanding lower range of 200 V and should not have been operating.

The two values of 56 A and 51 A fault current could reasonably be assumed as the upper and lower possibilities of the lowest possible values of fault current when Small DG Systems are included in the network. This means that the lowest real value of fault current when Small DG Systems are included in the network will lie in between their values.

A second fault study was conducted with 100% penetration with 2.4 kW of Small DG Systems instead of the 4.8 kW units. The fault location and type were the same and the fault current seen by the Reedy Creek recloser was 53 A and a slight increase from 51 A.

8.1.8 Karara SWER HV and LV Distribution Substation Fuses

The fuses used on the HV of the Karara SWER distribution substation are either 3 A or 6 A fuses. The value of fault current required to operate these fuses should be at least three times their value.

The lowest value of fault current seen by these fuses is very similar to the phase to earth with 50 ohms of fault resistance. The lowest value seen at the most remote distribution substation PE4673 was 56 A. This value well above the 18 A lower limit need to operate the 6 A largest fuse. The fault current value was experienced when no Small DG Systems are operating and increases when any are operational.

8.2 *Quality of Supply Modelling*

The only aspect considered during the quality of supply (QoS) modelling exercises was whether the LV voltage exceeded the prescribed ±6% of the nominal voltage. The two distribution feeders modelled during this research project saw their voltages rise as the penetration of Small DG Systems increased. The following sections discuss the notable aspects of this modelling exercise.

8.2.1 ROPL-04 Constant In-Feed QoS Modelling

It was determined that a credible average Small DG System size that would be used on a residential feeder such as ROPL-04 was 2.4 kW. The ROPL-04 distribution feeder was modelled with numerous penetration levels of 2.4 kW Small DG Systems in both evenly distributed and lumped installations. These models were run when the PV in-feed was constant and whilst the loads on the feeder were at the lowest maximum daily demand encountered during the year from 1st of October 2009 to 1st of October 2010.

It was discovered that the network could carry 100% evenly distributed penetration without exceeding the prescribed ±6% of the nominal voltage. The maximum LV voltage with 100% penetration was at 105.5% and just under the 106% limit. It is possible that the 106% limit would be exceeded if the overall penetration power was slightly more. In other words 100% penetration of 2.4 kW Small DG Systems was close to the maximum this feeder can sustain when the PV in-feed is constant.

It was also discovered that the network could carry 80% evenly distributed penetration and a 240 unit lumped installation with 100% penetration connected at the extremities of the HV network without exceeding the prescribed ±6% of the nominal voltage. The maximum LV voltage with 100% penetration was at 105.9% and very close to the 106% limit. It is possible that the 106% limit would be exceeded with a slight increase in the number of Small DG Systems.

8.2.2 ROPL-04 Fluctuating In-Feed QoS Modelling

The ROPL-04 feeder was tested for the effects of cloud movement over the network causing the PV in-feed to the Small DG Systems to fluctuate whilst the customer load was set at the highest maximum demand encountered during the year from 1st of October 2009 to 1st of October 2010.

The test was performed by setting the PV in-feed at a level on all the Small DG Systems and conducting a load flow operation on the network, which involved allowing the on load tap changer (OLTC) to operate automatically on the 66/11 kV transformer at Ross Plains ZS. A portion of the Small DG Systems had their PV in-feed reduced by 75% and the OLTC on the 66/11 kV transformer was fixed at the tap used during the load flow operation. The load flow was conducted again to see how much the voltage had deviated as a result of the drop in PV in-feed and also because the taps were fixed on the 66/11 kV transformer. The size of the portion of Small DG Systems that had their PV in-feed reduced was determined as 30% as this was seen as a conservative amount of the network to be transgressed by clouds before the OLTC could operate and change the voltage at the Ross Plains 11 kV bus.

The tests described above were conducted for various levels of Small DG Systems penetrations and lumped installations. These tests showed that the ROPL-04 network was very resilient to this type of fluctuating PV in-feed with the LV never rising higher than 102.5% at 100% even penetration. A worst case tests was conducted on the ROPL-04 feeder where 100% penetration was tested for a reduction in PV in-feed by 75% for all of the Small DG Systems. This test saw the LV range from 100.3 to 101.5%

A second set of test were conducted on ROPL-04 with the same conditions except the lowest daily maximum load values were applied to the customers. This resulted in greater voltage fluctuations, although no greater than 105.2% was experienced on the LV. A worst case scenario was also tested where 100% penetration was tested for a reduction in PV in-feed by 75% for all of the Small DG Systems. This test saw the LV range from 103.0% to 103.5%.

8.2.3 ROPL-04 Reactive Compensation QoS Modelling

The ROPL-04 network model was modified in order to create an excessive voltage problem. This was done by removing the reactive compensation at the Ross Plains ZS 11 kV bus and using 100% penetration of Small DG Systems. This arrangement produced LV levels up to 107.2%.

The installation of single stand alone reactive compensation unit was tested at various locations on the network. The most effective location of the reactive compensation was at the extremities of the HV network at the distribution substation TVS650. The installation of the reactive compensation on the LV of TVS650 was relatively ineffective.

The highest voltages were experienced on the extremities of the network. The location of the reactive compensation in close proximity to the problem region on the network was a more effective solution.

The installation of 1 MVAr of inductive compensation at the HV of TVS 650 was sufficient to reduce the maximum LV to 105.5%. Increasing the value to 3 MVAr reduced the maximum LV further to 103.5%.

The use of reactive compensation generated by the grid-connect inverters used in the Small DG Systems had some effect. Setting their reactive power to 20% of their real power on every Small DG Systems when the penetration was 100% reduced the voltage from 107.2% down to 105.4%.

8.2.4 Karara SWER Constant In-Feed QoS Modelling

The Karara SWER network was tested in the same way as the ROPL-04 feeder with some minor exceptions. These exceptions were that the Small DG Systems were 4.8 kW and not 2.4 kW and that the lumped installations were 5 and 10 customers that represented a cluster of farm sheds.

The even distribution models showed excessive voltages when the penetration reached 30% and by the time the level of penetration reached 100% the LV maximum was up to 108.6%.

The inclusion of the lumped installations tests caused excessive LV as they were conducted with 30% existing even penetration, which was a problem without the lumped installations. Subsequently the addition of the lumped installation made the situation worse.

8.2.5 Karara SWER Fluctuating In-Feed QoS Modelling

The average distance between customers on the Karara SWER network was about 800 m and the time taken for clouds to transverse this distance was much greater than any tap changer time delay. This would mean that voltage fluctuations before the tap changer could react would be very unlikely. For these reasons the fluctuating infeed test were not carried out on the Karara SWER.

8.2.6 Karara SWER Reactive Compensation QoS Modelling

The inclusion of reactive compensation on the Karara SWER did reduce the excessive voltages on the network. The location of the compensation had a bearing on the effectiveness. The most effective location was on the extremities of the network and this effectiveness was reduced as the location approached the SWER isolators.

A 200 kVAr unit at the extremities reduced the maximum LV from 108.6% to 102.3% whereas the same unit at the SWER isolator reduced the LV to 105.1%. Both situations are acceptable; however the former is a much better improvement.

A test was also conducted to determine the effectiveness of using the grid-connect inverters themselves to produce reactive power. It was found that the inverters needed to generate 20% or 900 VAr each in order to bring the maximum LV to an acceptable 105.8% and that 10% or 450 VAr for each inverter was not sufficient.

CHAPTER 9 - CONCLUSIONS

9.1 *Network Modelling*

The modelling software chosen for this research project was PSS Sincal version 6.5. The add-on package known as the Stability module is intended to model generation equipment in the time domain and Ergon Energy does not own a copy of this module. The Small DG Systems are generation device and they would react dynamically as the network they are connected to changes. The network conditions would change dynamically during a fault condition when Small DG Systems are connected.

The PSS Sincal device known as the DC-Infeeder was used to replicate Small DG Systems during the modelling exercises conducted for this research project.

9.1.1 PSS Sincal and Protection Modelling

The grid-connect inverters are designed to cease operation when the grid conditions change rapidly. This function is generally called anti-islanding and must contain active and passive functions. One of the passive functions operates when the terminal voltages fall outside prescribed limits. These limits must be at least set to a lower value of 200 V and an upper value of 270 V.

In a fault situation the grid-connect inverters used should cease operation relatively quickly; however there is a possibility that they do not and will do so only when the passive upper or lower voltage threshold is reached. In this case the inverter would act as a constant power source until either threshold voltage is reached. The inverter could deliver into a fault 1.2 p.u. of current at the lower threshold of 200 V and down to 0.88 p.u current at the upper threshold of 270 V. This is the situation that was investigated in this research project as it is considered the worst case scenario with Small DG Systems.

The PSS Sincal DC-Infeeder acts as a constant current device when a fault calculation is performed on a network using this software. This means that they contribute 1.0 p.u. of current and they do this regardless of their terminal voltages. It could be argued that delivering a constant 1.0 p.u at any terminal voltage is a more arduous situation then operating as a constant power source between 200 V and 270 V. The parameters of the DC-Infeeder could be configured to deliver 1.2 p.u. and so provide the absolute worst case that a Small DG Systems could deliver.

A test of a current based protection system involves using the current values obtained in a network model when a worst case fault is placed on a network and comparing these values against the protection device setting or rating to determine if the protection device will operate or not. Testing a protection system with modelling results obtained using the PSS Sincal DC-Infeeder to mimic all Small DG Systems at 1.2 p.u. regardless of the terminal voltages, would be a worst case test and reality will most likely be much less demanding. Testing using the DC-Infeeder set to 1.0 p.u. is slightly less demanding and in the two distribution network arrangements used for this research project, still much more arduous than any real situation as many of the DC-Infeeder terminal voltages were outside the anti-islanding voltage thresholds and would have shut down their contributions.

Using the values from a test where the DC-Infeeder developed 1.0 p.u. constant current provided a good worst case value when Small DG Systems are included in a network.

The fault value at a protective device was also obtained without the contributions by the Small DG Systems as the best case value. It was understood that the actual fault level with Small DG Systems would fall somewhere between the worst and best case values.

9.1.2 PSS Sincal and QoS Modelling

The QoS modelling exercises in this research project used the PSS Sincal load flows to determine node voltages within the network to determine if they were lower than 94% or higher than 106% when Small DG Systems were included in the network. The DC-Infeeder was used to mimic the Small DG Systems and provided results that seemed to be credible.

9.1.3 Future Modelling

The software package PSS Sincal 6.5 used with the DC-Infeeder device provided an effective tool for modelling Small DG Systems when conducting load flow exercises and so was effective for use in determining the impacts of quality of supply.

The DC-Infeeder could provide the absolute worst case scenario for the contribution by Small DG Systems to fault currents. It is likely in most cases to be excessive and a more accurate model would use a dynamic generator model that provided constant power whilst the terminal voltage is between the specified limits. This method would need the Stability Module of PSS Sincal.

9.2 *Protection System Modelling Conclusions*

The values obtained using PSS Sincal to obtain fault current values was shown to provide contribution levels by Small DG Systems that were almost certainly more than the real situation. In all cases the values for the fault current through a protective device were determined with and without 100% penetration of Small DG Systems. These values were both used in comparing to see if the protective devices operated properly.

Ergon Energy suggests that a protective device should see a fault current that is:

- 1.7 times greater than the setting of an over current device on a three phase network.
- 2.0 time greater than the setting of an earth fault device on a three phase network.
- 2.0 times greater than the setting of an over current device on a SWER network.

9.2.1 ROPL Protection System Modelling Conclusions

A worst case fault that would cause the over current (OC) protection at the Ross Plains ZS bus to operate was checked. It was found that the fault current with 100% penetration of Small DG Systems was 10% lower than the fault current without. Both values provided protection reach over 5.0 and were considered more than adequate to operate the OC protection device.

A worst case fault that would cause the earth fault (EF) protection at the Ross Plains ZS bus to operate was checked. It was found that the fault current with 100% penetration of Small DG Systems was lower than the fault current without. The value with Small DG Systems provided a protection reach of 1.95, which is just below the acceptable level of 2.0. The value without was 2.07 and considered adequate. The value obtained with the inclusion of Small DG Systems showed that almost all the DC-Infeeder terminal voltages were outside the anti-islanding thresholds. This would mean that the value obtained without the Small DG Systems is closer to the real value with Small DG Systems. It could be concluded that the reach is over the acceptable value of 2.0 with 100% Small DG Systems and so the protection setting is suitable.

A worst case fault that would operate a HV fuse on a distribution transformer was checked. It was found that the current through this protective device increases with the inclusion of Small DG Systems. This means that any additional Small DG Systems will improve the operation of distribution transformer fuses.

A worst case fault that would operate a LV fuse on a distribution transformer was checked. It was found that the current through this protective device increases with the inclusion of Small DG Systems. This means that any additional Small DG Systems will improve the operation of distribution transformer fuses.

9.2.2 Karara SWER Protection System Modelling Conclusions

A worst case fault that would cause the OC protection at the Karara recloser to operate was checked. It was found that the fault current with 100% penetration of Small DG Systems was 35% lower than the fault current without. The value without Small DG Systems saw an acceptable reach factor of 3.05 and with 100% penetration of Small DG Systems was 1.95, which was marginally below the acceptable value of 2.0. In this case the model showed all of the DC-Infeeders with terminal voltages below the 200V anti-islanding threshold, which means that they should all have ceased to operate.

A worst case fault that would cause the OC protection at the Reedy Creek recloser to operate was checked. It was found that the fault current with 100% penetration of Small DG Systems was 10% lower than the fault current without. The value without Small DG Systems saw an acceptable reach factor of 5.6 and with 100% penetration of Small DG Systems was 5.1, which are well above the acceptable lowest value of 2.0.

The currents seen by both the HV and LV distribution substation fuses increased for the worst case fault type when the network included Small DG Systems and so improved the operation of these fuses.

9.2.3 General Protection Conclusions

The modelling exercise showed that worst case faults where there was 100% Small DG Systems penetration and every unit was contributing 1.0 p.u. of current to the fault caused the currents through HV main network protective device on a strong residential network to reduce by up to 10%. In the same circumstances on a SWER network it was found that the current through the HV main protective device was reduced by up to 35%. In all cases the actual value would be closer to the current seen with no Small DG Systems.

It was found that the worse case faults downstream of distribution transformer HV and LV fuses increased when the networks included Small DG Systems. This means that the fuse operation is enhanced in the presence of even distributed Small DG Systems.

It can be concluded that strong networks such as ROPL-04 have the ability to absorb very high levels of Small DG Systems penetration with only minor decrease in fault currents at their source, whereas weak networks such as the Karara SWER can see significant decreases. In all cases these are the worst case scenario and reality is most likely much less problematic.

9.3 *Quality of Supply Modelling Conclusions*

The QoS modelling exercise was conducted with the intention of understanding the effects that the maximum Small DG Systems had on the LV levels on two representative distribution feeders. In Queensland the prescribed limits of the LV are no less than 94% and no greater than 106%.

The exercise was conducted at various penetration levels and also with lumped installations such as retirement villages and clusters of farm sheds. The tests were conducted with both constant PV in-feed during clear days and also fluctuating PV in-feed on cloudy days.

The idea with the clear day PV in-feed tests was to understand at what level does the penetration of Small DG Systems cause the LV to exceed 106%. The testing with fluctuating PV in-feed on a cloudy day was intended to understand whether the penetrations of Small DG Systems would cause voltage fluctuation of ±6% deviation from the nominal voltage before the tap changers on the transformers could react to correct the problems.

9.3.1 ROPL-04 Residential Feeder QoS

The ROPL-04 network was shown to be capable of taking 100% penetration of 2.4 kW Small DG Systems without exceeding 106% on the LV. It showed it could also take 80% penetration of 2.4 kW Small DG Systems along with a lumped installation of 240 Small DG Systems connected to the extremities of the HV network without exceeding 106% on the LV.

The fluctuating PV in-feed tests showed again the resilience of the ROPL-04 network where all credible scenarios tested showed that the LV stayed well within the 94% to 106% limits regardless of the penetration of Small DG Systems.

The ROPL-04 feeder is located in a solid sub-transmission network with strong 66 kV supplies that originates close by at two bulk supply substations. The distribution network is well constructed, not overloaded, relatively short in length and originates from the nearby zone substation Ross Plains ZS. The power factor at Ross Plains ZS is presently close to unity in normal operating conditions. These factors have contributed to what can be described as a strong distribution network. It would be reasonable to conclude that the resilience of the ROPL-04 network to the inclusion of high levels of Small DG Systems is due to the high strength of the distribution and local sub-transmission networks.

9.3.2 Karara SWER Long Rural Feeder QoS

The Karara SWER network was shown to be adequate to take up to 30% penetration by 4.8 kW Small DG Systems before the voltage on the LV became excessive. Any addition to this penetration, including the lumped installations caused even greater voltage problems.

The Karara SWER feeder is a very long and extensive network. The Karara SWER feeder is fed from the Lemontree feeder, which is a long and heavily loaded rural 11kV three phase network. The Lemontree feeder is fed from the Pampas ZS, which is in turn fed by a long heavily loaded sub-transmission feeder. These factors suggest that the resilience of the Karara SWER to absorb adverse network conditions is limited.

The conductor used on the Karara SWER is shown in the Ergon Energy data sources to be constructed totally from Raisin conductor, which is a very good conductor for a SWER network. It is possible that there are sections of less capable conductor used on the spurs running from the main backbone. If there are less capable conductors used in this network then the excessive voltage problems may be greater than those shown in the modelling exercises for this research project.

9.3.3 Reactive Compensation and QoS

Reactive compensation was demonstrated on both feeder networks to resolve excessive voltage problems. In both cases the most effective placement of stand alone devices such as small static compensators (STATCOM) was on the extremities of the network.

9.3.4 ROPL-04 and Reactive Compensation

The installation of a 1 MVAr STATCOM at the extremities of the HV network provided a solution to excessive voltage problems arising from conditions that exceeded the most realistic worst case penetration levels. Installing the same size STATCOM on the LV terminals of a distribution transformer at the extremities of the HV network had much less effect on reducing the excessive voltage when compared to an installation on the HV. There was no benefit at all in placing reactive compensation at the Ross Plains ZS as the large 66/11 kV transformer swamped the effects.

Enabling the grid connect inverters used in Small DG Systems to generate reactive power as well as active also provided a solution to excessive voltage problems. Most inverters are already able to provide this function and all that is required is a software change in the device. The draw back for the customer would be that they would not be able to generate as much active power and so not generate as much revenue through the feed in tariff.

9.3.5 Karara SWER and Reactive Compensation

The installation of 200 kVAr reactive compensation at most locations on the Karara SWER solved the voltage problems experienced with 100% penetration of Small DG Systems. A location on the extremities provided the best solution and produced the lowest maximum LV. This would also mean that a smaller unit could be installed at this remote location when compared to a location closer to the SWER isolator.

Once again enabling the grid-connect inverters ability to generate reactive power provided the same benefits as the stand alone device.

The effectiveness of the reactive compensation would depend on the x on r ratio at the point of injection.

9.3.6 Reactive Compensation Conclusions

The inclusion of stand alone reactive compensation improved the excessive voltage problems caused by high penetrations of Small DG Systems. The improvements were maximised when the reactive compensation device was installed at the extremities of the HV network. The disadvantage is that the electrical supply authority must purchase, install and maintain these expensive devices for the foreseeable future. A failure of a large stand alone reactive compensation device will put the whole distribution network at risk of high voltages.

Similar improvements can be had by using the grid-connect inverters to generate reactive power. The advantage of this method is that the problems of high voltage will be rectified by the equipment causing the problem. The distributed nature of the devices will mean that the total reactive compensation on a network will grow as the problem grows. Also a failure of one device will have no impact on the remainder of the network.

9.4 *Future Research*

The research conducted for this project provided a general overview in two broad areas of the electrical supply network when high penetrations of Small DG Systems are included. There are a number of future research avenues that have become evident during this research project. These include;

- Determining an absolute worst case cloud related step change in PV array output and combine with better wind speed and direction data. This will allow the ultimate worst case prediction on Small DG Systems changes in output due to cloud transition over a distribution network.
- It was noted that the test PV array showed efficiencies of 6%, which is much less than that described in manufacturers literature. The low efficiency could be because the array is mounted close to a steel roof in a hot tropical environment. It would be useful to determine what causes this low efficiency and this information could be used to more accurately predict the behaviour of high penetrations of Small DG Systems.
- It is possible that better use of voltage regulators on SWER feeders may resolve excessive voltage problems experienced with high penetration of Small DG Systems. Such functions as line drop compensation may provide a solution.
- It is possible that the number of operations of a tap changer is increased when high penetrations of Small DG Systems cause voltage fluctuations during cloud movement. An investigation into the effects of the increased number of operation would enable better maintenance and lifespan planning of these tap changers.
- A lower voltage threshold setting for the passive anti-islanding could solve many of the high voltage problems associated with high penetration of Small DG Systems. This would see the installations cease to operate and so cease to produce revenue for their owners. An analysis on the effects of lowering the anti-islanding threshold on customer's revenue would be useful information for power authorities when planning these changes.
- Investigating the effectiveness of enabling the grid-connect inverters ability to generate reactive power which can be used to resolve excessive voltage problems. This investigation could consider the reduction in revenue for the customer and this information would help supply authorities when planning for better network operations.
- Investigate the possibility that the active and passive anti-islanding may not operate in some situations. Determine the likelihood and what actions a supply authority may need to take to ensure that it does not happen..

APPENDIX A

University of Southern Queensland

FACULTY OF ENGINEERING AND SURVEYING

ENG 4111 / 4112 Research Project

PROJECT SPECIFICATION

FOR: Paul Gordon MILLERS

TOPIC: AN ANALYSIS OF THE IMPACT OF DISTRIBUTED GENERATION ON ELECTRICAL DISTRIBUTION NETWORKS

SUPERVISOR: Dr Tony Ahfock

PROJECT AIM: To investigate the effects that increasing the density of small distributed photovoltaic generation systems have on the protection systems, power quality and grid management on electrical distribution networks.

PROGRAMME: (Issue A, 14th of March 2010)

1. Assemble and develop a representative data set of:
   - Fault characteristics for Grid-Connect Inverters ranging from 1 to 30kW.
   - Weather data set incorporating effects of cloud movements for a sample site.
   - Load profile data for a representative group of distribution networks.
2. Develop a model of a distribution network with the inclusion of the differing densities of Grid-Connect Inverters, weather conditions and load profiles.
3. Analyse outcomes of the distribution models for the implications to protection systems, power quality and grid management.
4. Develop a strategy to ameliorate the negative effects of the increasing number of distributed generation to an acceptable level.

AS TIME PERMITS:

5. Expand the complete analysis to include a representative range of distribution networks from weak to strong.
6. Analyse the effects of the distributed generation on network augmentation strategies.

AGREED ___________________ (Student) _____APPROVED______ (Supervisor)

Date: / / 2010 Date: / / 2010

Examiner / Co-Examiner: ______APPROVED_______

APPENDIX B

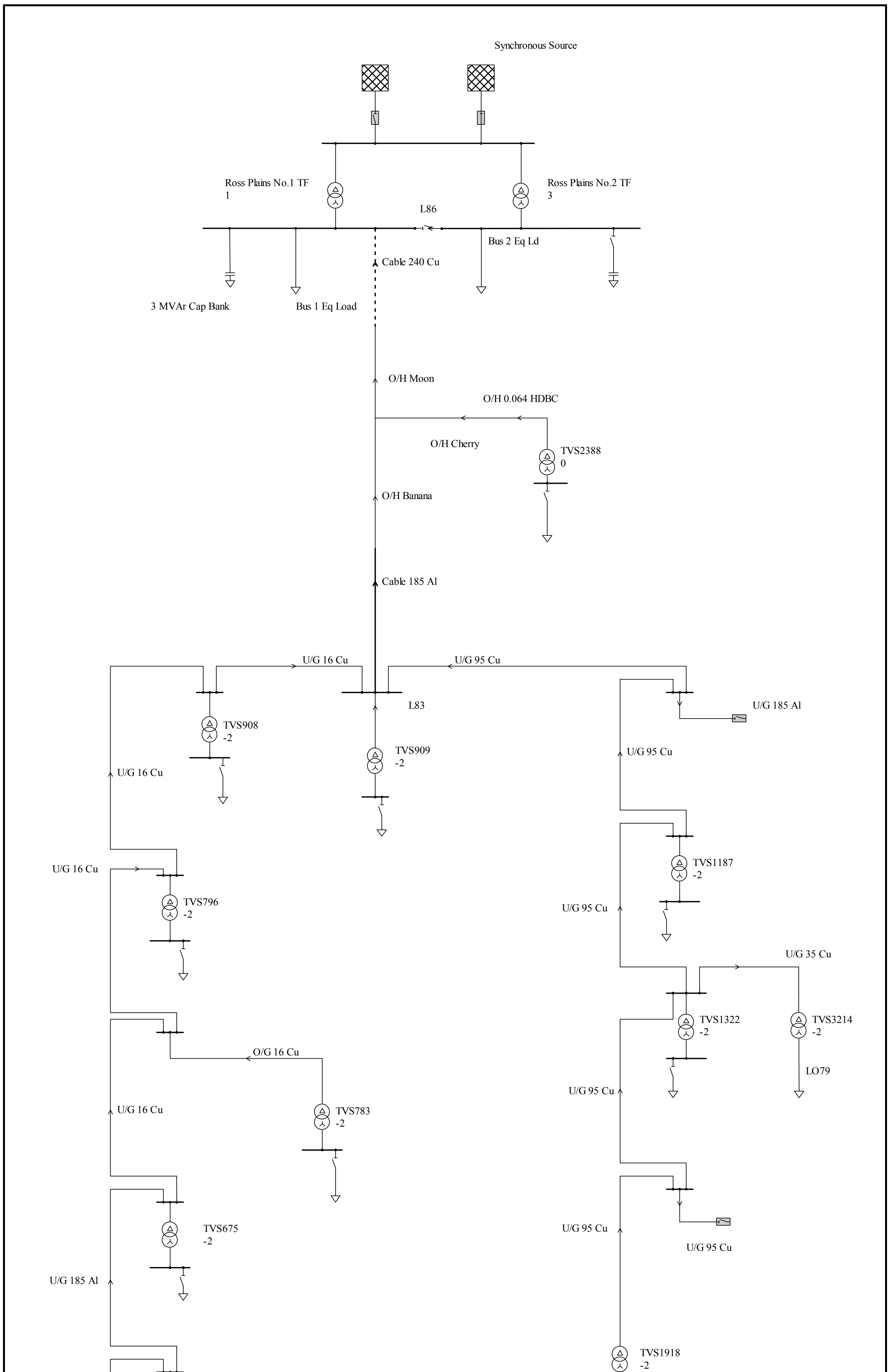


Figure A – Ross Plains ZS feeder ROPL-04 HV Distribution Network