SURVEY AND ASSESSMENT OF THE IMPACT OF EMBEDDED GENERATION ON THE ETHEKWINI ELECTRICITY DISTRIBUTION GRID

by

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2016: First Place for the Outstanding Student Paper by the Power Systems Conference (PSC) Technical Program Committee, 2016 Clemson University Power Systems Conference, March 8-11, 2016, for the paper: 'S. Sewchurran, I.E. Davidson and J.O Ojo', "Intelligent Disbursement and Impact Analysis of DG on Distribution Networks to Mitigate SA Energy Shortages", March 2016, ($300 prize money)

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[4] S Sewchurran and I E Davidson, "Drivers and Application of Small Scale DG on Municipal Distribution Networks in South Africa". *In Proceedings of the 24th South African Universities Power Engineering Conference*, 26-28 January 2016, Vereeniging, South Africa, pp. 105 – 114, ISBN 978-1-77012-386.

[5] S Sewchurran and IE Davidson, "Optimisation and Financial Viability of Landfill Gas to Electricity Projects in South Africa". *In Proceedings of the 5th International Conference on Renewable Energy Research and Applications,* Birmingham, United Kingdom, 20-22 November 2016.

[6] S Sewchurran and IE Davidson, "Guiding Principles for Grid Code Compliance of Large Utility Scale Renewable Power Plant Integration onto South Africa's Transmission/Distribution Networks". *In*

Proceedings of the 5th International Conference on Renewable Energy Research and Applications, Birmingham, United Kingdom, 20-22 November 2016.

[7] S Sewchurran, J Kalichuran and S Maphumulo, “Drivers and Application of Small Scale DG on Municipal Distribution Networks in South Africa: An eThekwini Electricity Case Study”, *Association for Municipal Undertakings*, Vereeniging, South Africa, 1- 5 October 2016

[8] S Sewchurran, J Kalichuran and S Maphumulo, “Guiding Principles for Grid Code Compliance of Medium-High Voltage Renewable Power Plant Distributed Generation Integration onto South Africa’s Transmission and Distribution Networks”, *Association for Municipal Undertakings*, Vereeniging, South Africa, 1- 5 October 2016

[9] S Sewchurran and I E Davidson, “Method for Evaluating the Feasibility of Residential Rooftop Solar PV in Durban”, *Submitted to 2017 IEEE PES PowerAfrica Conference*, 27 – 30 June 2017, Accra, Ghana

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[12] S Sewchurran and I E Davidson, “Drivers and Barriers of Small Scale Rooftop PV projects in South Africa”, *Submitted to 2017 IEEE PES PowerAfrica Conference*, 27 – 30 June 2017, Accra, Ghana

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ABSTRACT

Under frequency load shedding, rising electricity tariffs, environmental concerns, reducing costs of renewable energy technology and delays in constructing new power stations has lead consumers and producers alike to explore various energy generation options to reduce their own electricity needs whilst assisting the sector. Embedded Generation (EG), Distributed Energy Resources (DER) or Distributed Generation (DG) is further predicted to play a substantial role in the electrical power system in the near future. Various EG technologies are entering a period of major growth and commercialization. Small scale Embedded Generation (SSEG) projects are quickly becoming a popular sight locally within the city of Durban and numerous projects are been connected to the eThekwini Electricity distribution grids. In these projects, there seems to be a reluctance to couple expensive energy storage technologies to these systems but rather synchronize and utilise the municipal grid as a virtual battery. Whilst the advantages make synchronization to the grid a logical choice, the municipal network architecture and framework was not designed to facilitate this. The municipal mandated core function is to procure electricity from Eskom (the national energy generator), transform it and distribute it to its customers. Power flow is from generation (Eskom), transmission (Eskom) and distribution to the end customer. This includes all technical, regulatory, administrative and legal aspects that have been structured to support this unidirectional power flow. The introduction of DER/DG/EG introduces bi-directional power flow on the existing distribution network. An analysis of the impact of this phenomenon is required as it affects fault level, protection selectivity and sensitivity, network losses, quality of supply, network planning, metering and control of power flow on the existing distribution grid.

In order to address and understand the impacts of EG on the existing eThekwini Electricity distribution grid, an investigation was first carried out to identify the drivers and available renewable energy resources in Durban. 5 cases studies were selected based on the investigation which showed that there will be growth and projects in these sectors in Durban. These cases studies were selected to address growth in residential rooftop PV, commercial/industrial rooftop solar PV, PV farm potential on closed landfill sites, wind farm potential at identified sites around the city and landfill gas to electricity projects from existing landfill sites in the city. Accurate models of these sources and their interaction with the grid were then studies. Studies were also carried out on the recently published NRS guidelines for SSEG and the South African Renewable Energy Grid Code to understand how this will

provide operational flexibility to the System Operator and assist with mitigating the negative impacts to the distribution network.

The 5 case studies provide excellent results and greater understanding of the impacts of increased penetration of EG onto the existing eThekwini Electricity distribution grid. The impacts of increased penetration of EG on the existing eThekwini Electricity distribution network included impacts to the network voltage, fault level rise, losses, power flow, network planning and revenue loss. Based on the results and studies from the case studies methods were then derived to mitigate the impacts of increased penetration of EG on the existing distribution network.

The following outcomes and key contributions, were achieved in this research investigation, namely:

- An understanding of the drivers of EG in eThekwini Municipality.
- Evaluation of the available renewable energy resources within eThekwini Municipality.
- The feasibility of residential rooftop solar PV in Durban.
- Identified factors affecting residential rooftop solar PV feasibility in Durban.
- Assessed the feasibility of municipal landfill gas to electricity EG projects.
- Developed and propose methods to improve operational and financial viability of landfill gas to electricity projects in Durban.
- Provides results showing the impacts of increasing EG on the eThekwini Municipality distribution network design and performance.
- Developed methods to assist and enable distribution network designers when designing distribution networks with increasing EG.
- Developed a methodology for selecting EG size on an existing eThekwini Electricity distribution network.
- Provide methods to minimise the impacts of preselected size of EG given that the municipality has no control over the size selection which may be dictated by the IPP.
- An understanding of the local South African guidelines on small scale EG, and the South African Renewable Energy Grid code requirements.
- Provide controllability options to assist manage EG plants on the existing distribution network in eThekwini Municipality.

- Understand the operation and effects of different EG sources available within eThekwini Municipality.

These have been accomplished using the 5 case-studies, modelling and simulation, field tests and measurements; as well as extensive research investigation and analysis.

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LIST OF ABBREVIATIONS

ABC	Aerial Bundle Conductor
AC	Alternating Current
ADMD	After Diversity Maximum Demand
AGL	Above Ground Level
AL XLPE	Aluminium Cross Linked Polyethylene
AMEU	Association of Municipal Electricity Utilities
AMI	Advanced Metering Infrastructure
ANSI	American National Standards Institute
APC	Absolute Production Constraint
AUD	Australian Dollar
CB	Circuit Breaker
B&G	Business & General
CDU	Consumer Distribution Unit
CEM	Clean Energy Ministerial
CIGRE	Conseil International des Grands Reseaux Electriques
CIU	Customer Information Units
CLR	Current Limiting Reactors
CPV	Concentrated Photovoltaic
CSP	Concentrated Solar Plant
DC	Direct Current
DC	Data Concentrators
DFIG	Doubly Fed Induction Generator
DG	Distributed Generation
DNI	Direct Normal Irradiance
DOE	Department of Energy
DSS	Distributor Substation
EE	eThekwini Electricity
EG	Embedded Generation
EMA	Exponential Moving Average
ER	Emission Reduction

LIST OF ABBREVIATIONS

EU	European Union
EUR	Euro
FIT	Feed-in-Tariff
FOD	First Order Decay
GBP	Great British Pound
GDP	Gross Domestic Product
GEJ	General Electric Jenbacher
GHG	Greenhouse Gas
HDPE	High Density Polyethylene
HFC	Hydrofluorocarbons
HGW	Horizontal Gas Wells
HQ	Head Quarters
HV	High Voltage
HVRT	High Voltage Ride Through
IBT	Inclining Block Tariff
IEA	International Energy Agency
IEEE	Institute of Electrical and Electronic Engineers
IPP	Independent Power Producer
IRP	Integrated Resource Plan
ISGAN	International Smart Grid Action Network
KZN	KwaZulu Natal
LCOE	Levelised Cost of Electricity
LFG	landfill Gas
LV	Low Voltage
LVRT	Low Voltage Ride Through
MD	Maximum Demand
MDMS	Meter Data Management System
MFMA	Municipal Financial Management Act
MJ	Mega Joules
MPPT	Maximum Power Point Tracking

LIST OF ABBREVIATIONS

MV	Medium Voltage
MVMS	Multi-Vendor Master Stations
MYPD3	Multi Year Price Determination 3
NECR	Neutral Earthing Compensator Resistor
NER	Neutral Earthing Resistor
NERSA	National Energy Regulator of South Africa
NMD	Notified Maximum Demand
NMOC	Non-Methane Organic Compounds
NRS	National Rationalisation Standard
NSP	Network Service Provider
OCGT	Open Cycle Gas Turbines
OD	Outside Diameter
OLTC	On Load Tap Changer
PCC	Point of Common Coupling
PD	Protection Devices
PFC	Perfluorocarbons
PGC	Point of Generator Connection
PILC	Paper Insulated Lead Covered
PM	Permanent Magnet
POC	Point of Connection
PQ	Power Quality
PR	Performance Ratio
PUC	Point of Utility Connection
PV	Photovoltaic
RDP	Reconstruction and Development Programme
RE	Renewable Energy
REFIT	Renewable Energy Feed in Tariff
REFSO	Renewable Energy Finance and Subsidy Office
REIPPPP	Renewable Energy Independent Power Producer Procurement Program
RMS	Root Mean Square

LIST OF ABBREVIATIONS

RPP	Renewable Power Plant
SA	South Africa
SAREGC	South African Renewable Energy Grid Code
SCADA	Supervisory Control and Data Acquisition
SCM	Supply Chain Management
SEA	Sustainable Energy Africa
SG	Synchronous Generators
SO	System Operator
SSDG	Small Scale Distribution Generation
SSEG	Small Scale Embedded Generation
TOU	Time of Use
UK	United Kingdom
USA	United States of America
USD	United States Dollar
VAR	Volt – Ampere Reactive
VGW	Vertical Gas Wells
VOSC	Volatile Organic Silicon Compounds
VRTC	Voltage-Ride-Through-Capability

LIST OF SYMBOLS AND UNIT

$	Dollar
R	Rand
c	Cents
MW	Megawatt
GW	Gigawatt
kWhp	Kilo Watt Hour Peak
kW	kilowatt
MVA	Mega Volt Ampere
kV	Kilo Volt
V	Volts
kVA	Kilo Volt Ampere
GWh	Gigawatt hour
CO_2	Carbon dioxide
SOx	Sulphur Oxides
kg	Kilogram
Amp	Ampere
U	Voltage
pu	Per Unit
mm	Millimetre
AL	Aluminium
MVAr	Mega Volt Ampere Reactive
A	Amps
s	Second
m	Meter
Nm^3/hr	Normal Cubic Meter per hour
Ha	Hectors
H_2S	Hydrogen Sulphide
CH_4	Methane
C	Celcius
O_2	Oxygen

LIST OF SYMBOLS AND UNIT

H_2O	Water
AC	Activated Carbon
N_20	Nitrous Oxide
SF_6	Sulphur Hexafluoride
Hz	Hertz
kWh	Kilowatt Hour

CHAPTER 1: INTRODUCTION

1.1. Introduction

Under frequency load shedding, rising electricity tariffs, reducing EG technology prices and delays in constructing new power stations have led South Africans to explore the option of renewable energy EG. [1] Various EG technologies are entering a period of major growth and commercialization. [2] These schemes have been driven in part by the impact of environmental, regulatory and economic challenges, as well as changing public perception prevalent in the 1990s. [3] Generally a low penetration of EG does not cause a significant impact to the grid but as the penetration level increases, the impacts can have a major impact on the grid [4]

South Africa is located on the southern tip of the African continent and is a newly industrialized country with a population in excess of 53 million people. [5] South Africa is currently facing a major challenge in its electricity sector due to inadequate generation, which has often lead to under frequency load shedding in order to stabilise the system frequency and provide a balance between genration and load demand. Currently, bulk of Eskoms base load generation comes from large coal fired power stations and a nuclear power station whilst peaking plants are made up of pump storage schemes and open cycle gas turbines. Eskom, South Africas national electricity generators has started to build two new 4800 MW coal fired power station which are significantly behind schedule. Renewable energy with its short lead times have become an attractive alternative to assist in solving the country's current energy crisis. In order to assist the country with its electricity needs, the Renewable Energy Independent Power Producer Procurement Program (REIPPPP) was then launched. This provided a mechanism for the country to procure renewable energy generation from Independent Power Producers through a competitive bidding process in order to assist in solving the energy crisis in the country. [5]

Further to the utility scale generation projects, DG/EG is said to play a substantial role in the electrical power system going into the future. EG is further predicted to play a substantial role in the electrical power system in the near future [2]. The South African Integrated Resource Plan (IRP) 2010 – 2030 indicates that 9 770 MW of solar photovoltaic (PV) capacity is planned to be installed by 2030. The IRP 2010 – 2030 also indicates growth up to 22.5 GW by the residential and commerical sector by year 2030. Given the recent reduction in the cost of PV, it has become highly probable that residential, commercial and to some extent industry will begin installing small scale distribution generation (SSDG) to meet some or all of their electricity requirements as per the recently published IRP Update Report. Although biogas, biomass and wind can be used as forms of EG, the Department of Energy's 'Updated Report" on its IRP sees photovoltaic as playing a material role going forward in South Africa. A study included in the IRP Update Report also predicts that half the households in South Africa above Living Standard Measure 7 or higher will invest in roof top PV by 2020. [6]

Research carried out by the National Energy Regulator of South Africa (NERSA) indicated that PV will have the biggest growth in demand than any other renewable technology in the country going forward. [7] Frost and Sullivan, an international consultant carried out study in South Africa which idicated that PV will be the cheapest generation source by 2020. They predicated that the cost to generate electricity from PV between 65c/kWh and R1.36/kWh whilst the cost from the Eskom grid is expected to reach R1.69/kWh. [1]

Due to the reduced costs of the SSEG projects namely roof top PV installations and the levelised cost of electricity of these systems reaching parity with domestic and commercial tariffs. There is a growing interest by South African customers to install these small scale projects. [7] These small scale EG projects are already becoming a common sight in South Africa, and locally within the city of Durban. Numerous projects have already been connected to the eThekwini Electricity distribution grid. Studies have shown that Durban is well situated and blessed with good climatic conditions and resources. [1] The concerns by the local South African utilities is to understand more about the residential solar PV market in order to manage this sector better. Studies have shown if not properly managed, many network quality of supply and revenue loss problems can be experienced which will have a detrimental impact on their business. [1]

Within the eThekwini Electricity area of supply in Durban, there seems to be a reluctance to couple expensive energy storage technologies to these DG/EG systems. Rather, the tendency by developers is to synchronize and utilise the municipal grid as a virtual battery. Whilst the advantages make synchronization to the grid a logical choice, the municipal network architecture and framework is not designed to facilitate this. The municipal mandated core function is to procure electricity from Eskom (the national energy generator), transform it and distribute it to its customers. [1]

As a result of the growing number of synchronized EG (landfill gas to electricity, solar-PV, solar CPV, wastewater treatment gas to electricity generation plants, co-generation plants); to the eThekwini Electricity distribution grid, the municipality is faced with severe risks in understanding the performance of its distribution grids. Research has shown that EG has the ability to impact the distribution grids by influencing network losses, fault levels, voltage profiles, reduce Carbon emissions, increase efficiency, enhance systems reliability and energy security, improve power quality and relieve distribution network congestion. [8] Increased EG penetration may increase network losses although this is dependent on the type, size, location and technology of the EG used. [2] Studies have shown that EG impacts can be positive or negative influenced by numerous factors. Accurate models of these sources and their interaction with the grid is required to be studied. There has been a massive uptake of EG especially solar PV in many distribution networks around South Africa (SA). Some of the PV projects installed and in operation in SA are listed in Table 1.1.

Table 1.1: List of some PV generation projects in South Africa [9]

Project	Province	Capacity (kWp)
Cronimet Chrome Mining SA (Pty) Ltd	Limpopo	1,000
Belgotex's factory	KwaZulu-Natal	1,000
Dube Trade Port	KwaZulu-Natal	750
Black River Park	Western Cape	700
Eskom Kendal PV	Mpumalanga	620
Eskom Lethabo PV	Free State	575
Rooibos Storage Facilities	Western Cape	511
Ceres Koelkamers	Western Cape	505
Vodacom Century City	Western Cape	500
Eskom Rosherville PV Eskom's R&D site	Gauteng	400
Eskom Megawatt Park Carport PV + Rooftop	Gauteng	756
Bosco Factory PV Plant	Gauteng	304
Pick n Pay distribution centre	Western Cape	300
Kriel Mine	Mpumalanga	240
Vrede en Lust Wine Farm	Western Cape	218
Novo Packhouse	Western Cape	200
Leeupan Solar PV project	Gauteng	200
Pick n Pay Distribution Centre	Gauteng	150
Villera Winefarms	Western Cape	132
Standard Bank PV Installation,	KwaZulu-Natal	105
Pick n Pay Store	Gauteng	100
Lelifontein wine cellar and admin offices	Western Cape	88
BP Offices V&A	Western Cape	67
Mitchells Plain Hospital	Western Cape	64
Cavalli Wine & Stud Farm	Western Cape	51
Oldenburg Vineyards	Western Cape	45
BMS	Gauteng	36
BT	Gauteng	36
Med	Gauteng	31
WTP	Mpumalanga	30
Coca Cola water bottling plant	Gauteng	30
Glaxo Smith Kline	Western Cape	30
Impahla Clothing	Western Cape	30
Khayelitsha District Hospital	Western Cape	25
Total	**9829**	

Table 1.1 outlines some of the authorized PV projects within the different provinces in South Africa which cumulatively adds up to 9.8 MW. There is however numerous other unauthorised projects connected to the grid that is unknown. Table 1.2 outlines the existing projects within eThekwini Electricity that are authorized and connected onto the grid. At eThekwini Electricity, most of the existing EG projects have been either landfill gas to electricity or PV to date. EG connections currently amount to over 10 MW on the eThekwini Electricity distribution networks.

Table 1.2: List of distribution generation projects in Durban [9]

Existing Project Name	Fuel Source	Size kW	Status
Bisasar Road Landfill Site	Landfill Gas	6500	Generating
Marianhill Landfill Site	Landfill Gas	1000	Generating
Hullets Maidstone Mill	Bagasse	1000	Generating
KSIA Roof Top PV	PV	1000	Generating
CPV Hazelmere	PV	500	Generating
NCP Alcohols Co-Gen	Gas	500	Generating
Standard Bank	PV	30	Generating
Mr Price	PV	210	Generating
Man Truck and Bus	PV	580	Generating
Total		**10 030**	

Table 1.3 outlines the list of proposed gas to electricity projects that are currently proposed to connect onto the eThekwini Electricity grid. There is currently in excess of 61 MW gas to electricity projects proposed to be installed on the eThekwini Electricity distribution/transmission grid.

Table 1.3: Proposed gas to electricity generation plants [9]

Project Name – Gas	Fuel Source	Proposed Size (kW)	Connection Network
Gas Peaking Plant	Pipeline Gas	42 000	HV - Transmission
Buffelsdraai Landfill Site	Landfill gas	10 000	MV - Distribution
Kwa Mashu Waste Water Works	Methane (Bio) gas	1000	MV - Distribution
Phoenix Waste Water Works	Methane (Bio) gas	1500	MV - Distribution
Toti Waste Water Works	Methane (Bio) gas	1000	MV - Distribution
Southern Waste Water Works	Methane (Bio) gas	1500	MV - Distribution
Shongweni Landfill Site	Landfill (Bio) gas	1000	MV - Distribution
Bul Bul Drive Landfill Site	Landfill gas	1000	MV - Distribution
Northern Waste Water Works	Methane (Bio) gas	1000	MV - Distribution
Shongweni Landfill Site	Landfill gas	1000	MV - Distribution
Total		**61 000**	

Table 1.4 outlines the proposed wind turbine proposed projects. There are currently 4 applications and proposals for the connection of wind projects to the eThekwini Electricity grid.

Table 1.4: Proposed wind generation projects at eThekwini Electricity [9]

Project Description	Fuel Source	Proposed Size (kW)	Connection Network
Vertical Axis Wind Turbines	Wind	6	LV - Distribution
Mt Moreland Wind Turbine	Wind	2	LV - Distribution
Potential Wind Farms (10 Sites)	Wind	15000 – 27500	MV - HV
Total		**215 508**	

Durban does not have any worthy natural hydro potential such as large rivers and dams that could be utilised for the generation of hydro power. However, the eThekwini Water Department has proposed 7 projects in which they propose to exploit the water flowing into reservoirs and pipelines to generate electricity using hydro turbines. Table 1.5 outlines the list of proposed hydro projects at eThekwini Municipality. Table 1.6 outlines the list of potential and proposed solar PV projects in eThekwini Municipality.

Table 1.5: Proposed hydro projects at eThekwini Electricity [9]

Project Name - Hydro	Fuel Source	Size (kW)	Connection Level
Western Aquaduct 1	Hydro	3600	MV - Distribution
Western Aquaduct 2	Hydro	3000	MV - Distribution
Theomore Reservoir	Hydro	Between 26 - 177	LV - Distribution
Stone Bridge Drive Reservoir	Hydro	Between 26 - 177	LV - Distribution
Umhlanga Rocks	Hydro	Between 26 - 177	LV - Distribution
Yellowfin and Escolar	Hydro	Between 26 - 177	LV - Distribution
Avocado and Pomegranate	Hydro	Between 26 - 177	LV - Distribution
Total		**±7 000**	

Table 1.6: List of proposed PV projects at eThekwini Electricity [9]

Project Name - PV	Fuel Source	Size (kW)	Connection Level
PV Farm – Bisasar Road Landfill site (Closed portion)	PV	10 000	MV/HV
Man Trucks	PV	580	MV - Distribution
Metro Police Headquarters	PV	115	LV - Distribution
17 Intersite Avenue	PV	503	MV - Distribution
8 Ficus Place, Mahogany Rodge	PV	333	MV - Distribution
uShaka Marine World	PV	135	LV - Distribution
103 Stockville Road, Westmead	PV	130	LV - Distribution
Kings Park Pool	PV	110	LV - Distribution
Moses Mabhida Stadium – Peoples Park restaurant	PV	110	MV - Distribution
Edstan Business Park, Riverhorse Valley	PV	80	LV - Distribution
eThekwini Water and Sanitation building	PV	45	LV - Distribution
Bufflesdraai Visitor Centre	PV	10	LV - Distribution
Loram House	PV	5	LV - Distribution
103 Marianhill Road, Ashey, Pinetown	PV	5	LV - Distribution
Moses Mabhida Stadium – base of North Arch	PV	5	LV - Distribution
15 Roosevelt Road, Gillits	PV	4	LV - Distribution
Total	**12 160**		

From the list of existing EG projects at eThekwini Electricity it can be seen that up until now, there has been a few EG projects making up under 1% of the 2015 maximum demand (1713 MVA) at eThekwini Electricity connected onto their distribution networks. The level of EG penetration is however drastically starting to increase and should the number of proposed and potential projects be implemented then the contribution of EG towards the eThekwini Electricity maximum demand (MD) will exceed 20% of the 2015 MD should all projects go ahead. From the list of projects, there seem to be great interest in landfill gas to electricity projects, waste water treatment works gas to electricity projects and PV projects. From the proposed list of projects, it can be seen that there are various sizes and technologies that will be connecting onto the eThekwini Electricity distribution networks in the near future. Many of these sources have variable output generation profiles directly influenced by their fuel sources and will produce outputs based on the fuel resource such as wind and the sun. This is further complicated as some of these EG are installed beyond the consumers meter and the generated electricity will be first used for self-consumption. The excess is exported to the grid as and when not required. This then completely changes the load profile. However, with these variable source generation, provisions need to be made by the network designers to cater for the consumers load when these generation sources are not producing any electricity or reduced amounts of electricity. This makes it difficult to predict the impacts of increased EG penetration on the existing distribution network and planning of the distribution networks going forward. The impacts of EG affects the distribution network design and performance and it is crucial to understand these impacts as the level of EG penetration drastically increases on the distribution grid.

Researchers in the past has evaluated the impacts of EG connections in terms of voltage profiles, network operation, fault levels, network losses and harmonics. In the South African context of concern is that most studies carried out were based on the European and United States EG sources which are mostly wind technology and combined heat and power (CHP). [10] Research is hence required to be carried out for the local South African network conditions based on the potential local generation sources to evaluate the impacts. This is important information that will assist utilities around the country.

Studies will be carried out utilizing the DigSILENT PowerFactory, ERACS and the PVSyst power systems simulation package by modeling different EG sources and the eThekwini Electricity distribution grid. The results from these studies will assist us in understanding the impacts of EG/DG on the eThekwini Electricity distribution grid. The current NRS 097 guideline and the South African Renewable Energy Grid Code requirements will be discussed as part of the case studies. This will assist to provide us with controllability options and guidelines that can be utilized to understand how the EG can be managed to reduce the negative impacts to the existing distribution grid at eThekwini Electricity. This study is important as the South African distribution networks are designed differently from those within the US and Europe. However it can be seen that in countries with high penetration of embedded renewable generation, the bulk of this is at LV level, e.g. Germany has approximately 90% of its total installation of 35.67 GW installed on rooftops. [11]

1.2. Study Objectives

Increased penertration of EG on the existing eThekwini Electricity distribution network will negatively affect the design and performance of the existing distribution network. Studies have shown that EG has the ability to impact the distribution networks by affecting network losses, fault levels, voltage profiles, system energy efficiency, network security, power quality and distribution network loading. [5]

"When properly integrated with the grid, Distribution Resources offer potential benefits including reduced electric losses; reduced transmission and distribution congestion; grid investment deferment and improved grid asset utilization; improved grid reliability; ancillary services such as voltage support or stability, VAR support, contingency reserves and black start capability; clean energy; lower-cost electricity; reduced price volatility; greater reliability and power quality; energy and load management; and combined heat and power synergies." [12]

However on the contrary, if EG is installed incorrectly, the impact becomes negative. This can increase losses on the distribution network, initiate voltage rises, influence power quality, influence the system protection, influence the reliability of the network and influence the fault levels on the network. [13]

Studies have further shown that EG impacts can be influenced by a number of factors which then affects the distribution network accordingly. These vary from network to network around the world. In order to understand the impacts that increased EG penetration will have on the eThekwini Electricity distribution networks, an investigation needs to be carried out into the availability and drivers of renewable energy resources in Durban to identify the potential technologies that will be deployed and connected to the eThekwini Electricity grid. Thereafter accurate modelling and simulations of the existing networks and generation resources will need to be carried out in order to study the impacts increased penetration of these EG sources on the existing networks design and performance.

By then understanding the impacts and the local South African guidelines and grid codes, we can then introduce proper network planning and design process and criteria which will ensure that the impacts are managed within statutory limits dictated by the utilities licence condition. Criteria can then be drawn up to manage the size selection, mitigation factors, planning guidelines and generator operations guidelines to manage increased penertration of EG on the existing network. This will assist the utility in managing the networks within the required statutory limits.

1.3. Methodology

[1] The approach adopted to understand the impacts of increased penetration of DG/EG on the existing eThekwini Electricity design and performance is as follows:

[2] Carry out back ground research into the impacts of EG on existing distribution networks (local and international)

[3] Carry out back ground research on the impacts of EG projects and case studies on the existing eThekwini Electricity distribution networks

[4] Identify the drivers and potential technology for future EG penetration at eThekwini Electricity

[5] Select the eThekwini Electricity distribution network to carry out studies upon (a 132/11 kV and 33/11 kV distribution network)

[6] Carry out field and data capture of the eThekwini Electricity distribution network to be studied

[7] Model the eThekwini Electricity distribution to be studied in DigSilent Powerfactory and ERACS power systems simulation package

[8] Carry out background research into generation technologies that will be supported by the local resources.

[9] Create models of these EG technologies such as wind, solar, landfill gas to electricity

[10] Obtain field capture data of typical generation output from existing projects

[11] Use PVSyst software to determine annual PV generation potential in the eThekwini Electricity area of supply for different rooftop inclination angles and orientation towards the sun.

[12] Carry out the impact studies by simulating different scenario's and penetration levels of residential rooftop solar PV on the eThekwini Electricity LV networks.

[13] Indicate the impacts of EG on the distribution network

[14] Indicate the impacts of EG on the distribution network planning process

Table 1.7 shows the methodology for studies to be carried out in order to achieve the set out study outcomes.

Table 1.7: Methodology for studies to be carried out in order to achieve the objectives

MODEL 132/11 kV GRID NETWORK DATA HV MV LV MODEL 33/11 kV GRID NETWORK DATA HV MV LV	Identify eThekwini Electricity Distribution Networks to be modelled. Gather network data for eThekwini Electricity HV, MV and LV networks and model the 132/11 kV and 33/11 kV networks to use used for the studies.
OBTAIN LOAD DATA RESIDENTIAL: 11 kV, 400 V, 230 V COMMERCIAL: 11 kV, 400 V INDUSTRIAL: 11 kV, 400 V	Obtain load data for the customers at different voltage levels to be utilized in the network models.
MODEL DIFFERENT SOURCES OF GENERATION PV: RESIDENTIAL, COMMERCIAL/INDUSTRIAL, PV FARM GAS TO ELEC: 400 V, 11 kV WIND: 11 kV	Carry out extensive background research and analysis to identify available resources in eThekwini in order to identify the type of potential generation technology. Then model these different embedded generation sources
CASE STUDIES 1 - 5 SIMULATIONS DIGSILENT/ERACS/PV Syst FIELD MEASUREMENTS RESULTS	ANALYSIS CONCLUSIONS The case studies will be carried out using Digsilent and the UKZN Smart Grid Lab to obtain results.

1.4. Study Outcomes

The results obtained from this research investigation will be as follows:

[1] Understand the drivers of EG in eThekwini Municipality.

[2] Understand the available renewable energy resources within eThekwini Municipality.

[3] Investigate the feasibility of residential rooftop solar PV in Durban.

[4] Identify factors affecting residential rooftop solar PV feasibility in Durban.

[5] Investigate the feasibility of municipal landfill gas to electricity EG projects.

[6] Proposed methods to improve operational and financial viability of landfill gas to electricity projects in Durban.

[7] Study the impacts of increasing EG on the eThekwini Municipality distribution network design and performance.

[8] Provides methods to assist the distribution network designers when designing distribution networks with increasing EG.

[9] Provide methods to assist with selecting EG size on an existing eThekwini Electricity distribution network.

[10] Provide methods to minimise the impacts of preselected size of EG given that the municipality has no control over the size selection which may be dictated by the IPP.

[11] Understand the local guidelines on small scale EG.

[12] Understand the South African Renewable Energy Grid code.

[13] Provide controllability options to assist manage EG plants on the existing distribution network in eThekwini Municipality.

[14] Understand the operation and effects of different EG sources available within eThekwini Municipality.

CHAPTER 2: LITERATURE REVIEW

2.1. Introduction to Chapter 2

This chapter provides investigation into the local and international drivers of EG and the impacts experienced with the introduction of EG to the grid. This is was achieved though the study of local and international drivers of EG. In order to understand the impacts of EG on a distribution network, a number of local and international case studies were investigated to understand the impacts that are experienced. The investigation also looked at the impacts on the network planning process. This chapter hence provides a through background into the local and international work done on EG.

2.2. Distribution/Embedded Generation vs. Traditional Bulk Generation

Figure 2.1 shows a typical utility scenario in South Africa where generation is located far away from the load centres and linked by high voltage long distance transmission networks. As the load grows over time, the demand will start to outstrip the generation. Typically in a South African scenario if the demand in Kwa-Zulu Natal (KZN) outgrew the transmission and generation capacity, traditionally a new generation station would be built in Mpumalanga close to the coal/fuel source. Thereafter a substation would be upgraded or built in Mpumalanga to step up the voltage which will then transmit the power via the high voltage transmission network to another substation in KZN where it will be stepped down. This could be simplified with the potential use of EG to supliment the generation where the actual generation can take place in KZN at distribution level deferring the cost of a new generation, transmission, substation and feeder equipment. However, this will depend on the technology, amount of generation and the distribution network load profiles. [14]

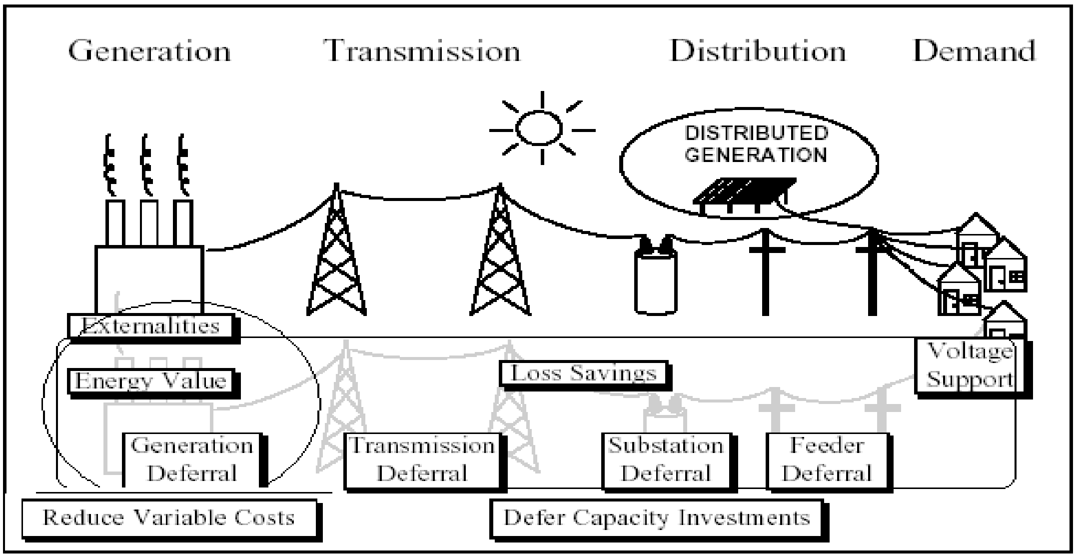


Figure 2.1: Benefits of Distribution/Embedded Generation [14]

2.3. What is Distributed Generation, Dispersed Generation or Embedded Generation?

According to the working group of CIGRE "Distributed Generation is defined as all generation units with a maximum capacity of 50 MW to 100 MW that are usually connected to the distribution network and are not centrally planned nor centrally dispatched." According to a report by CIRED, based on a questionnaire from 16 countries, the definition of Dispersed Generation was often based on voltage level, type of prime mover, maximum power rating and availability for dispatch. [14]

The Institute of Electrical and Electronic Engineers (IEEE) defines DG as "generation of electricity by facilities that are sufficiently smaller than central generating plants so as to allow interconnection at nearly any point in a power system." Whilst the International Energy Agency (IEA) defines DG as "units producing power on a customer's site or within local distribution utilities and supplying power directly to the local distribution network." [14]

NERSA defines DG as "the installation and operation of electric power generation units connected directly to the distribution network or connected to the network on the customer's side of the meter." [6]

The local South African National Rationalisation Standard 097 (NRS 097) workgroup refers specifically to EG as "one or more energy generation sources which include the energy conversion device(s), static power converter(s) if applicable as well as the control and protection gear within a customer network that operates in synchronism with the utility supply." [15]

The South African Renewable Energy Grid (SAREGC) defines Renewable Power Plant (RPP) as "one or more unit(s) and associated equipment, with a stated rated power, which has been connected to the same Point of Connection (POC) and operating as a single power plant." The Renewable Power Plant (RPP) types referred to in the code includes PV, concentrated solar power (CSP), small hydro, landfill gas to electricity, biomass, biogas and wind power plants. The code further distinguishes between the different sizes of plants in terms of categories. Different requirements for each category is then required for grid code compliance. The categories are defined in Table 2.1.

Table 2.1: Generation size categories per South African Renewable Energy Grid Code [16]

Grid Code Category	**Description**
Category A 0 – 1 MVA	Plants conencted to the LV network. This category is further broken down into 3 sub-categories:
Category A1 0 - 13.8 kVA	This includes plants that up to 13.8 kVA connected to the LV network. Any plant that exceeds 4.6 kVA has to be a three phase system.
Category A2 13.8 kVA – 100 kVA	This includes plants rated between 13.8 kVA and 100 kVA that are connected to the LV network.
Category A3 100 kVA – 1 MVA	This includes plants rated between 100 kVA and 1000 kVA connected to the LV network.
Category B 0 – 20 MVA MV connected RPPs	This category includes plants rated up to 20 MW that are connected to the MV network.
Category C 20 MVA or greater	This includes plants with rated power greater than or equal to 20 MVA which connects either to the MV or HV networks.

2.4. International Drivers of Embedded Generation

During the late 90s, there have been two main drivers of renewable energy generation and EG namely the Feed-In-Tariffs (FITs) in countries such as Germany and Denmark and competitive tenders in countries such as United Kingdom (UK) and France. Countries with FIT had considerable more success compared to those countries with tendering schemes. As a result of this, France and Ireland switched to FITs whilst UK switched to tradable credits under its Renewable Obligation. In the 2000s, there was a drive to harmonise the renewable energy policy in the European Union (EU) which was not achieved. Majority of the EU countries now prefer FITs. The policies apply differently even within countries. These differentiations are made according to systems sizes (eg. smaller systems in the UK use FIT) and technologies (eg. in Italy FITs apply to PV but tradable certificates are used for other technologies). [7]

Developing countries are constantly changing their policies. Brazil and South Africa recently moved from FIT to an auctioning scheme. Argentina, Mexico, Peru, Honduras, Morocco, Egypt and Uruguay are further examples of developing countries introducing tendering schemes. China is a country that moved from a tendering scheme to FIT scheme for wind. Countries are combining policy options to best suit their needs. [7]

From Table 2.2 it can be seen that in order to stimulate the EG market there has to be some sort of incentive financial schemes which isn’t currently present in the local eThekwini Municipality in Durban or most utilities in South Africa except for projects that are accepted under the REIPPPP. International incentive schemes include Feed in Tariffs (FIT), net metering, generation export tariff and net billing. With revenue loss and inadequate guidelines been seen as a major threat in this sector.

Table 2.2: Drivers of DG around the world [17]

Country	Scheme Description	Comments
Australia	Feed–in–tariff (FIT)	The FIT is lower than the retail electricity price.
Belgium	Net – metering	Brussels and Wallonia also have green certificates.
Brazil	Net – metering	Virtual net-metering is available.
Canada (Ontario)	Net metering and FIT	Also a FIT scheme, with compensation higher than retail electricity price.
China	Feed–in–tariff	FIT is equal to the wholesale electricity price plus a bonus.
Denmark	Feed–in–tariff	The FIT is lower than the retail electricity price.
France	Feed–in–tariff	FIT is above retail electricity price.
Germany	Feed–in–tariff	The FIT is lower than the retail electricity price.
Israel	Net metering	T&D costs are subtracted from the credits.
Italy	Net billing	Quarterly compensation.
Japan	Feed–in–tariff	FIT is above retail electricity price.
Mexico	Net metering	Virtual net-metering is available.
Spain	Self-Consumption	PV excess are not compensated but are charged to cover T&D costs.
Switzerland	Feed–in–tariff	The FIT is lower than the retail electricity price.
Netherlands	Net metering	For up to 5 MW/h per year.
United Kingdom	Generation export tariff	A generation tariff remunerates PV generation and an export tariff is added to electricity exported to the grid.
USA (California)	Net-metering	Positive balance at the end of each year can be either cashed in or rolled over.

2.5. Drivers of Medium/Large Scale Generation Projects in South Africa

SA is currently facing its worst energy crisis in more than 40 years. This has resulted in the need to implement under frequency load shedding as a last resort in order to to prevent a collapse of the national grid. The construction of the two new 4800 MW base load coal-fired power plants are behind schedule and have exceeded budgeted costs. There has been wide spread interest in the usage of Independent Power Producer (IPP) to generate renewable energy worldwide to sustain energy security. Even within South Africa there has been an increasing number of requests to connect RPPs onto Eskom and local municipal networks driven by energy shortages, load shedding, rising electricity tariff, reducing prices of renewable energy technology, proposed carbon taxes, reducing Carbon emissions for green marketing purposes, the Department of Energy (DOE) Renewable Energy Independent Power Producer Procurement Programme (REIPPPP), distributed generation (DG) ability to alleviate network congestion and to improve overall electricity security in South Africa [17].

Eskom currently generates around 90% of the countries electricity needs from coal fired power stations. They have struggling to build additional generation capacity to meet the countries growing electricity demand. They have in the past tried to suppliment the electricity shortfall by running their expensive diesel peaking plants to make up the electricity shortfalls which has resulted in significant over spending of their budgets in the 2015 financial year and leading to increasing electricity tariffs. [18]

National debates continue over which options to solve the crisis are the quickest to construct, the most affordable and the most technically feasible. There are also pressures to meet national commitments to climate change mitigation pledged in 2009. In February 2015, the State President promised to do 'everything we can', including developing a 9600 MW nuclear fleet; constructing yet more coal-fired power plants; importing hydro from the Democratic Republic of Congo; importing gas from neighbouring countries; developing the country's shale gas reserves; and undertaking demand-side management measures such as solar hot water heaters and rooftop solar PV. Decision-making over the ideal electricity mix reflects deeper struggles over what gets supported by the state, who gets to build it, and who gets to benefit. In the last three years, however, carbon-intensive, coal-dependent South Africa has become one of the leading destinations for renewable energy (RE) investment. The REIPPPP programme has successfully created an enabling framework for attracting substantial private sector expertise and investment for utility scale RE. It has delivered cost effective, clean energy infrastructure to the country and contributed to security of electricity supply that is expected to bring about a virtuous circle of investment and economic growth. In a period of just less than five years, the country is proud to have secured significant investments in RE technologies. [18]

To date, South Africa's renewable energy policy of 2003 has largely been driven by a 10000 GWh target set by 2013 and renewable energy project subsidies offered through the Renewable Energy Finance and Subsidy Office (REFSO). From 2009 to 2011, a Renewable Energy Feed-In Tariff (REFIT) was considered and published, which resulted in great interest by IPPs to develop renewable energy projects in South Africa. However due to legislative constraint in 2011, a competitive procurement entitled REIPPPP was launched by the DOE in its place. [19]

In terms of Section 34 of the South African Electricity Regulation Act (Act No. 4 of 2006), the Minister has determined that 3725 Megawatts (MW) to be generated from renewable energy sources is required to ensure the continued uninterrupted supply of electricity. This 3725 MW is broadly in accordance with the capacity allocated to RE generation in the IRP 2010 – 2030. This IRP procurement program has been designed to contribute towards the target of 3725 MW and towards social-economic and environmentally sustainable growth. On the 19th of December 2012, the Minister of Energy made a new determination for the procurement of an additional 3200 MW capacity to the previous determination of 3750 MW. The total capacity to be procured is currently 6925 MW. [19]

While REIPPPP includes allocations for a range of technologies, the majority of capacity allocated is for wind, solar PV and solar CSP outlined in Table 2.3. The process was launched in the same year as the country's IRP 2010, an electricity master plan covering total generation requirements from 2010 to 2030. Under revision since 2013, IRP 2010 plans to double national capacity from approximately 41 000 MW to 89 532 MW by 2030. While coal is still set to dominate the generation mix, IRP (2010) seeks to increase the overall contribution of new renewable energy generation to 17 800 MW by 2030 (42% of all new-build generation). This will be generated by projects approved under REIPPPP and other private and state-managed projects. Winners of rounds 1, 2 and 3 were announced in December 2011, May 2012 and November 2013 respectively. Projects range in size from 20 MW to 139 MW for wind; 5 MW to 86 MW for solar PV; and 50 MW to 100 MW for solar CSP. The rounds 1 to 3 collectively represent combined foreign and domestic investment commitments of approximately $14 billion/ R168 million. [18]

In round one of the programme, 28 successful bidders were selected making up a total of 1416 MW of capacity from these 28 projects. In round two, 19 projects were selected making up a capacity of 1045 MW. In round three, 17 projects were selected making up a capacity of 1486 MW, and in round 3.5 two projects of 200 MW capacity was selected. Round 4 consisted of 26 projects with a capacity of 2206 MW. Wind (3347 MW) and Solar PV (2327 MW) makes up the largest portion of the projects (6330 MW) selected under round 1 to round 4 of the DOE REIPPPP. [18]

Table 2.3: Selected bidders in REIPPPP: Round 1 to 4 [18]

Technology	MW Awarded Round 1	MW Awarded Round 2	MW Awarded Round 3-3.5	Total MW's Awarded Round 4	Total MW's Awarded Round 1 - 4
Solar PV	632	417	465	813	2327
Wind	634	563	787	1363	3347
Solar CSP	150	50	400	0	600
Landfill Gas	0	0	18	0	18
Biomass	0	0	16	25	41
Small hydro	0	15	0	0	15
Total	**1416**	**1045**	**1686**	**2206**	**6330**

Figure 2.2 shows the locations of the Department of Energy (DOE) REIPPPP projects in the difference provinces in South Africa. The largest concentration of installed capacity of these projects are in the Northern Cape Province (2229.7 MW) and Free State Province (1072.6 MW). This is due to the good solar resources in the Northern Cape and good wind resources in the Eastern Cape. There is only one project situated in KwaZulu-Natal and even that does not fall within the eThekwini Electricity area of supply. [19]

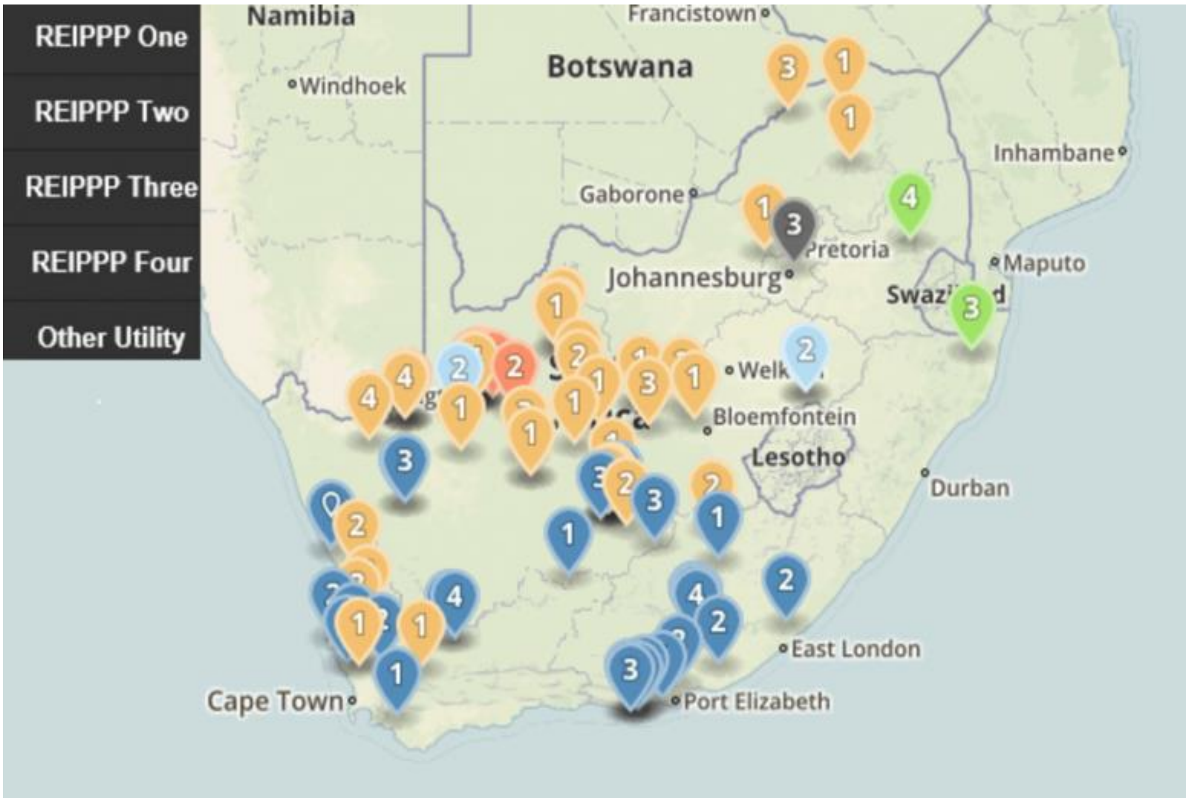


Figure 2.2: DOE RE round 1, 2, 3 and 4 preferred bidder's location in South Africa [20]

Since the launch of the REIPPP, investment has gone from a few hundred million dollars in 2011 to $5.7 billion in 2012, of which approximately $1.5 billion was for wind and $4.2 billion for solar, and $4.8 billion in 2013, of which $1.9 billion was for wind and $3 billion for solar. This investment can largely be attributed to the unprecedented take off of the country's REIPPPP. Since then a privately-generated, utility scale, renewable energy sector has being integrated into an electricity network that has historically been dependent on the country's abundant coal resources and dominated by Eskom. REIPPPP is the first renewable electricity initiative to have gained traction at the national level in South Africa. Despite a significant delay in the introduction of this programme since its inception in 2007 as a feed-in tariff, it has been hailed as an unprecedented success. The Renewable energy country attractiveness index of EY (previously Ernest and Young) rated South Africa the 15th most attractive destination for renewable energy investment. [18]

However in South Africa, local utilities are receiving an increasing number of requests from consumers and private generators to allow connection of EG onto their distribution and transmission networks. These include projects falling outside the REIPPPP and include private generators, customers and other municipal departments. As stated in the South African Distribution Network Code, the utility is obliged to provide an offer to connect the EG under the conditions in "Application for Connection", referred to in 3.2 of the South African Distribution Network Code. [15]

2.6. SA Renewable Energy Grid Code

The Renewable Energy Grid Code was created in 2010 and provide mandatory minimum guidelines for RPPs to connect onto the Transmission and Distribution networks in South Africa. The code was developed to help the country deal with the influx for IPP generation sources and to ensure that the grid stability and quality of supply standards were maintained. The grid code mainly deals with the medium and large scale EG projects regarding the requirements to allow connection onto the utility grid. With the current SA Renewable Energy Grid Code, all technical aspects have been covered for these large scale commercial renewable energy power plants. There is however no REIPPPP projects in any of the bid rounds that will be commissioned in Durban. With these large scale renewable power plants, all the projects were identified and selected by DOE and their locations, plant size, technologies, etc are all known and in order to commercially operate, the plants have to comply with the SA Renewable Energy Grid Code. All RPPs will have detailed studies carried out, modeling and site testing to ensure grid code compliance prior to commercial operation of these plants. There will be visibility and control of these plants from the Eskom or Network Service Providers Control Centre which will make it easier to manage and operate these plants.

These project drivers were the higher tariffs offered on these projects based on the bid by the IPP's in the PEIPPPP as shown in Table 2.4.

Table 2.4: Price caps and average REIPPPP for Round 1 to 3 [18]

Tariffs	Round 1 Bid Cap (August 2011)	Round 1 Average Bid (Per kWh)	Round 2 Average Bid (Per kWh)	Round 3 Average Bid (Per kWh)
Wind	R1.15	R1.14	R0.90	R0.66
Solar PV	R2.85	R2.76	R1.65	R0.88
CSP	R2.85	R2.69	R2.51	R1.46

2.7. Small Scale Embedded Generation (≤1MW) in South Africa

Small Scale embedded generation (SSEG) is defined as less than 1 MW LV connected generation defined as Category A (A1, A2 and A3) in the South African Renewable Energy Grid Code.There has been growing interest in the renewable enegy sector in South Africa. This has been driven by many factors which includes:

(i) National objectives to explore renewable energy technologies.
(ii) Energy sustainability.
(iii) Climate change concerns
(iv) Load shedding
(v) Energy shortages
(vi) Reduction in the payback period for SSEG projects.
(vii) SSEG offers many benefits to the customer and utility and when connected to the grid.

If utilities can allow embedded renewable energy generation to feed into their networks, this provides a relatively easy way for private sector companies, institutions and individuals to invest their own resources in renewable generation, without having to undertake detailed own load and storage requirements analysis. The grid acts as a storage facility. This allows considerable leverage of financial resources into the overall renewable energy generation capacity development process. When national or local government define renewable energy objectives, and decide to financially incentivize these through attractive feed-in-tariffs or renewable energy certificates or similar trading systems, small scale grid connected options will become an important component of the renewable energy market. [21]

2.8. Drivers of Category A SSEG Projects in South Africa

South Africa was historically the cheapest electricity supplier in the world, and this position has evolved within the last 7 years as a result of new generation plants being built within the country. This has forced electricity prices in the country to more than double over the past 7 years at the local municipalities in South Africa. Load shedding and the lack of electricity in the country have hurt the economy dearly, and the nation is now more aware of the concepts of electricity usage and is continuously seeking for innovative ways to reduce their consumption. Many are turning to energy efficiency projects whilst others are looking into the feasibility of SSEG. With electricity prices soaring in the country, the pay back periods and viability of small scale generation projects are becoming more feasible. [1]

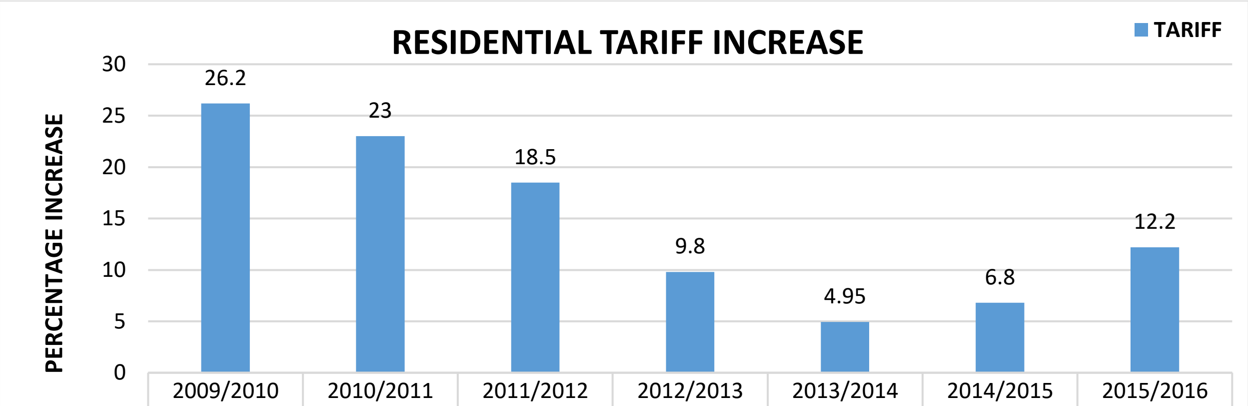
The IRP predicts 22.5 GW of solar PV in the SA residential and commerical sector. This indicates a significant level of small-scale PV projects to be installed in South Africa by 2030. [1] The AMEU "Guideline on Embedded Generation" predicts 45 000 PV installations in the residential sector, 4000 in the commercial sector and 670 in the industrial sector only in city of Johannesburg itself over the next 10 years. [22] Research carried out by NERSA indicated that PV will have the biggest growth in demand than any other renewable technology in the country going forward. [7] This is largely in the under 1 MW installation category. [1] There have been several requests to eThekwini Electricity for the installation and connection of small scale rooftop PV projects to the distribution network. This suggests a demand out there for these systems in South Africa.

2.8.1. Load Shedding

South Africa is currently facing one of its greatest challenges of all time in the electricity sector, often leading to daily load shedding in order to prevent a collapse of the national grid. Since the commencement of loading shedding in 2008, the country has been struggling to meet its electricity demands. To date there has been numerous delays in the commissioning of units at the two new (4800 MW) coal fired power stations. Only one 800 MW unit from the Medupi Power station was brought online and approximately 2800 MW of renewable energy IPP projects have started to contribute to the country's electricity needs. Eskom has also supplemented its energy shortages by running its expensive diesel Open Cycle Gas Turbines to provide electricity generation shortfalls but even this has not averted the constant need for load shedding. Government has hence encouraged the country to explore renewable energy sources. [5]

2.8.2. Rising Electricity Tariffs

Since the start of load shedding on 2008, there have been large increases in the electricity tariffs year on year. Figure 2.3 shows the residential tariff increase for the eThekwini Municipality who purchases its electricity from the national generator (Eskom) and then passes it onto its consumers. The annual average electricity increase in the residential sector at eThekwini Municipality was 14.5 percentage. [21]



	2009/2010	2010/2011	2011/2012	2012/2013	2013/2014	2014/2015	2015/2016
TARIFF	26.2	23	18.5	9.8	4.95	6.8	12.2

Figure 2.3: Rising Municipal electricity tariffs [21]

Since residence are installing SSEG systems (mostly roof top PV systems) with the intention of maximizing savings, many opt for systems with no storage options to keep the overall installation costs low. This has been largely driven by the residential electricity price increases over the past few years in South Africa and at eThekwini Electricity. Hence there are times where excess electricity may be generated and exported to the municipal grid. Any kWh saved by the residence is a R1.5878 saving to his monthly bill and payback towards the cost of installing the PV system. The currently eThekwini Electricity (EE) residential single and three phase tariffs are R1.5878/kWh and shown in Table 2.5. There are presently 319 875 (44%) single and three phase credit residential customers that utilize an average of 700 kWh a month. There are also 358 411 (49%) prepaid customers that are made up of rural, RDP and informal dwellings that utilize an average of 200 kWh on average a month. Based on their consumption figures, dwelling sizes and income levels, credit customers are more likely to install rooftop PV systems. [21]

Table 2.5: Residential Tariff R/kWh [21]

EE Tariff Scales	Descriptions	2016/2017 – Tariff (R/kWh)
3, 4 , 8 & 9	Single and three phase residential tariffs	1.5878

There are also 44 164 Business and General (B&G) customers that use an average of 3855 kWh a month. There is also large potential for the B&G and bulk customers to deploy technologies such as rooftop PV in Durban. The B&G cost per a kWh is R1.793 and is shown in Table 2.6.

Table 2.6: Business and General Tariff [21]

EE Tariff Scales	Descriptions	2016/2017 – Tariff (R/kWh)
B&G	Business and General	1.7930

2.8.3. Environmental Benefits of Renewable Generation

There are numerous consumers in Durban that are installing environmentally friendly EG technologies such as rooftop PV, gas to electricity, micro hydro turbines on pipelines, etc. to reduce their overall Carbon footprints. One such company is Man Truck and Bus Manufacturing situated in Westmead, Durban. They are currently the first Carbon Neutral truck production company in Africa. Figure 2.4 shows their rooftop PV installation which was installed for the purpose of offsetting their Carbon footprint. This driver was also used by other companies in Durban such as Standard Bank (45 kW rooftop PV installation), Dube Tradeport (1000 kW rooftop PV installation) and eThekwini Municipality.

Figure 2.4: First Carbon neutral truck manufacturing facility [1]

With the use of renewable energy generation, the environmental benefits on every kWh generated from a renewable energy source as opposed to using a kWh of electricity generated from an Eskom Power Station is shown in Table 2.7. The figures calculated are based on total electricity generated by Eskom from Eskom's coal, nuclear, pumped storage, wind, hydro and gas turbines power stations. [21]

Table 2.7: Environmental benefit from renewables [21]

kWh Generated	Environmental Benefit	Impact Avoided
1 kWh	CO_2 emissions	0.99 kg
1 kWh	Coal saved	0.54 kg
1 kWh	Ash reduction	155 grams
1 kWh	SO_x reduction	7.9 grams
1 kWh	NO_X	4.19 grams

2.8.4. Reduction in the payback period of EG installations

Rising electricity tariffs have resulted in a reduction in the payback period of various EG technologies. Frost and Sullivan, an international consultant carried out study in South Africa which indicated that PV will be the cheapest generation source by 2020. They predicated that the cost to generate electricity from PV between 65c/kWh and R1.36/kWh whilst the cost from the Eskom grid is expected to reach R1.69/kWh. [21]

Hence, there is potential of a large number of SSEG connections onto the local utility grids in South Africa going forward.

2.8.5. Block Inclining Tariff Structure

One of the tariff structures offered by some of the Municipalities and Eskom Distribution in South Africa is the Inclining Block Tariff (IBT). IBT divide electricity used by the consumer into two or more blocks or steps made up of kWh's used. A predetermined number of kWh's makes up a block and the tariff applied to each block increases as the number of blocks increases with the first block being the cheapest, and the last the most expensive.

Figure 2.5 shows an example of the Eskom residential IBT structure. This tariff structure can consist of up to 4 inclining blocks. Residential consumers are starting to install SSEG eg. roof top PV in order to reduce the total kWh's used in the month. Any savings achieved by the resident is subtracted from the highest block which has the highest tariff applicable per a kWh making this an attractive driver of residential EG.

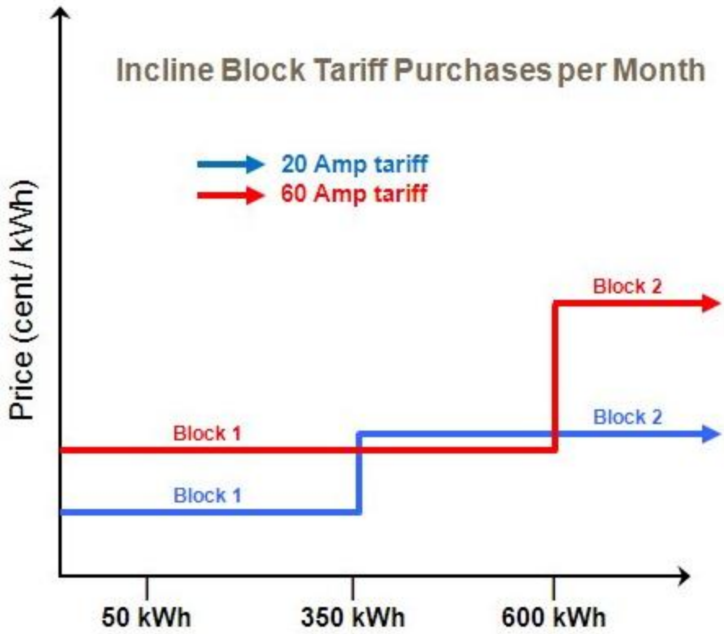


Figure 2.5: Eskom Inclining block tariff structure [23]

Table 2.8: Eskom residential IBT [24]

Eskom Residential Block Inclining Tariff	
Block 1 (0 – 600 kWh)	95.61c
Block 2 (600.1 >> kWh)	162.51c

An example will be a scenario where an Eskom 60 Amp consumer on the IBT uses 1200 kWh a certain month. A calculation of his cost of electricity is shown in Equation (2.1).

Total Cost of Electricity = ((Usage in Block 1) ×95.61) + (Usage in Block 2 ×162.51) (2.1)

Total Cost of Electricity = ((600kwh ×95.61) + (600×162.51)

Total Cost of Electricity = 573.66 + 975.06 = R1 548. 72

If the consumer had to install a roof top PV system which then generated some kWh for the month. This then means that the consumer will save R1.6251 for every kWh generated for the first 600 kWh and thereafter R0.9561 for every kWh thereafter. eThekwini Electricity has however not introduced any IBT structures to date.

2.8.6. eThekwini Electricity Commercial/Industrial Time of Use Tariff Structure

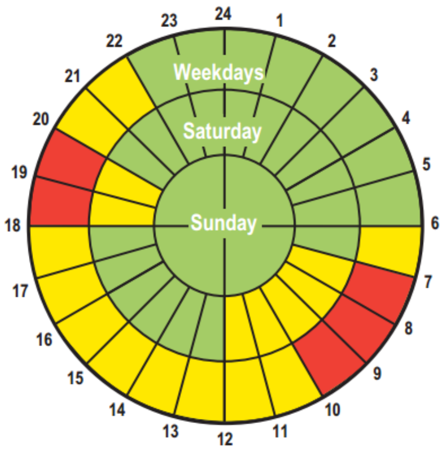
Most commercial and industrial customers at eThekwini Electricity are either on the Commercial or Industrial Time of Use tariff structures. These tariffs are much more complicated than the flat rate residential and Business and General tariffs. The tariff are split into peak, standard and off peak rates which depend on the day of the week and month of the year. The eThekwini Electricity Commercial TOU (<100 kVA) or Industrial TOU (>100kVA) is applied for any electricity purchased from the grid on the respective commercial or industrial consumer. However any kWh generated by the consumer will mean that the consumer will save the respective eThekwini Electricity TOU tariff. Table 2.9 shows the winter (June – August) high demand season and summer (September – May) low demand season tariffs for eThekwini Electricity Commercial and Industrial. The reason for the more expensive peak tariffs are due to the fact that Eskom needs to operate their more expensive peaking plants to meet the electricity demand during the peak periods more especialy to meet the winter (high demand) peak demands in the county which is much greater then the summer peak demand.

Table 2.9: Comparison on winter/summer energy rates [24]

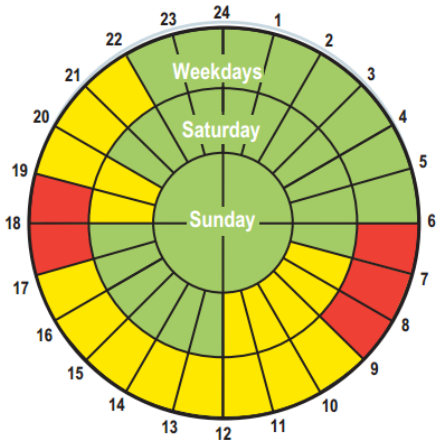
CTOU	Tariff Structure: Commercial Time of Use					
Tariff	**High Demand Season**			**Low Demand Season**		
Period	Peak	Standard	Off-Peak	Peak	Standard	Off-Peak
Rates	**R2.6171**	**R1.3094**	**R0.6378**	**R1.2912**	**R1.0387**	**R0.6042**
ITOU	**Tariff Structure: Industrial Time of Use**					
Tariff	**High Demand Season**			**Low Demand Season**		
Period	Peak	Standard	Off-Peak	Peak	Standard	Off-Peak
Rates	**R2.4071**	**R0.7802**	**R0.4516**	**R0.8210**	**R0.5921**	**R0.4061**

The day and time periods for the tariff billing structure (peak, standard and off-peak) are shown in the graph in Figure 2.6. The Tariff Structure is divided into two seasonal tariff (high demand season and low demand season) and three different types of tariffs (peak, standard and off peak).

Peak Standard Off-Peak



LOW DEMAND			
TIME PERIODS	MON - FRI	SAT	SUN
22h00 - 06h00	OFF-PEAK	OFF-PEAK	OFF-PEAK
06h00 - 07h00	STANDARD	OFF-PEAK	OFF-PEAK
07h00 - 10h00	PEAK	STANDARD	OFF-PEAK
10h00 - 12h00	STANDARD	STANDARD	OFF-PEAK
12h00 - 18h00	STANDARD	OFF-PEAK	OFF-PEAK
18h00 - 20h00	PEAK	STANDARD	OFF-PEAK
20h00 - 22h00	STANDARD	OFF-PEAK	OFF-PEAK



HIGH DEMAND - as of 1 July 2015			
TIME PERIODS	MON - FRI	SAT	SUN
22h00 - 06h00	OFF-PEAK	OFF-PEAK	OFF-PEAK
06h00 - 07h00	PEAK	OFF-PEAK	OFF-PEAK
07h00 - 09h00	PEAK	STANDARD	OFF-PEAK
09h00 - 12h00	STANDARD	STANDARD	OFF-PEAK
12h00 - 17h00	STANDARD	OFF-PEAK	OFF-PEAK
17h00 - 18h00	PEAK	OFF-PEAK	OFF-PEAK
18h00 - 19h00	PEAK	STANDARD	OFF-PEAK
19h00 - 20h00	STANDARD	STANDARD	OFF-PEAK
20h00 - 22h00	STANDARD	OFF-PEAK	OFF-PEAK

Figure 2.6: Time of Use period classifications [24]

Depending on the type of generation technology utilized and the period in which the generated electricity falls within, the savings or avoided costs will be as per the TOU tariff structure. However in the case of most commercial and industrial consumers, the primary objective of installing renewable EG technology is due to Carbon reduction and greening image purposes, as with the banks and product manufacturing companies such as Standard Bank, and Man Truck and Bus in Durban.

2.9. Smart Grids Global Drivers: Developing and Developed Countries

"The International Smart Grid Action Network (ISGAN), launched at the first Clean Energy Ministerial (CEM) in July 2010, which creates a mechanism for multilateral collaboration to accelerate world-wide development and deployment of smarter electricity grids. ISGAN has launched key projects (known as Annexes) across its five principal areas of focus (Policies, Standards, and Regulation; Finance and Business Models; Technology and Systems Development; User and Consumer Engagement; and Workforce Skills and Knowledge). The Global Smart Grid Inventory project, that is, Annex 1, has the objectives of identifying countries' specific motivating drivers for pursuing smart grids, cataloguing the wide range of smart grid activities underway, and collecting and organizing the wealth of experience currently being generated into a resource available first to ISGAN Participants and then to a broader, global audience." [25]

Earlier ISGAN participants undertook to be part of the survey to understand the particular drivers of each country in achieving a Smart Grid. The countries who participated in the survey and for whom results have been validated are; Australia, Austria, Belgium, Canada, China, Finland, France, India, Ireland, Italy, Japan, Republic of Korea, Mexico, The Netherlands, Russia, Spain, Sweden, Switzerland, and the United States. [25]

The scores of the top 6 drivers from the assessment results of 19 countries is shown in Figure 2.7. [25]

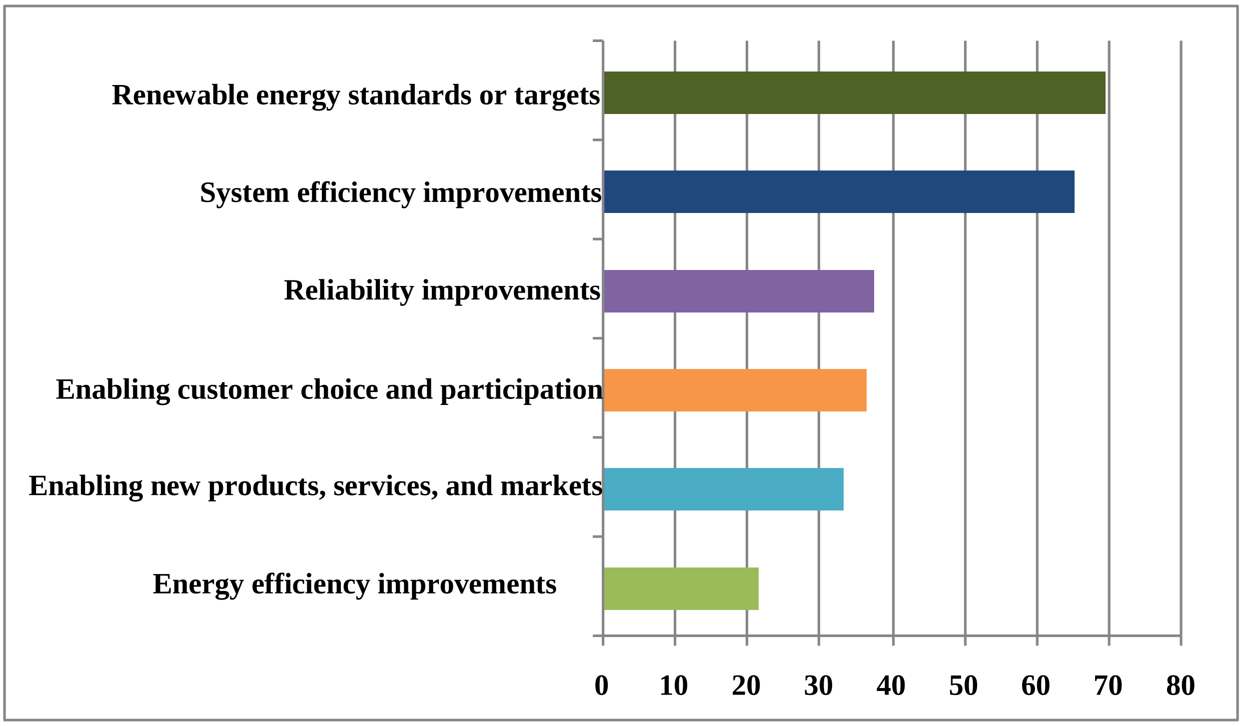


Figure 2.7: Top 6 motivating drivers of smart grids [25]

With the introduction of Smart Grids and Smart Grid Technology deployment within utilities, this will serve to assist the utilities with the management and integration of renewable energy to the grid together with many added benefits which are not currently available from the grid as shown in Table 2.10. eThekwini Electricity is currently embarking on a journey towards implementing a Smart Grid.

Table 2.10: Technology Deployments [25]

Enterprise back office system	**System wide monitoring, measurement, and control**	**Demand response**
Distribution and outage management systems	Advanced metering infrastructure (AMI)	Voltage & VAR control
Tools for planning, operation, analysis	Fault detection, identification, and restoration (FDIR)	Substation & transmission line sensors
Resource planning, forecasting and analysis	Large scale renewable energy plant integration	Distributed energy resources integration
Cyber security	Condition-based monitoring and maintenance	Synchrophasors
State Estimation	Analytics for managing big data	Telecommunication Infrastructure

2.9.1. International Smart Grid Initiatives

2.9.1.1. China

"The Chinese government has developed a large, long-term stimulus plan to invest in water systems, rural infrastructures and power grids, including a substantial investment in smart grids. Smart grids are seen as a way to reduce energy consumption, increase the efficiency of the electricity network and manage electricity generation from renewable technologies. China's State Grid Corporation outlined plans in 2010 for a pilot smart grid programme that maps out deployment to 2030. Smart grids investments will reach at least USD 96 billion by 2020." [25]

2.9.1.2. USA

"USD 4.5 billion was allocated to grid modernisation under the American Recovery Reinvestment Act of 2009, including: USD 3.48 billion for the quick integration of proven technologies into existing electric grids, USD 435 million for regional smart grid demonstrations, and USD 185 million for energy storage and demonstrations." [25]

2.9.1.3. Italy

"Building on the success of the Telegestore project, in 2011 the Italian regulator (Autorità per l'Energia Elettrica ed il Gas) has awarded eight tariff-based funded projects on active medium voltage distribution systems, to demonstrate at-scale advanced network management and automation solutions necessary to integrate distributed generation. The Ministry of Economic Development has also granted over EUR 200 million for demonstration of smart grids features and network modernisation in Southern Italian regions." [25]

2.9.1.4. Japan

"The Federation of Electric Power Companies of Japan is developing a smart grid that incorporates solar power generation by 2020 with government investment of over USD 100 million. The Japanese government has announced a national smart metering initiative and large utilities have announced smart grid programmes." [25]

2.9.1.5. South Korea

"The Korean government has launched a USD 65 million pilot programme on Jeju Island in partnership with industry. The pilot consists of a fully integrated smart grid system for 6 000 households, wind farms and four distribution lines. Korea has announced plans to implement smart grids nationwide by 2030." [25]

2.9.1.6. Spain

"In 2008, the government mandated distribution companies to replace existing meters with new smart meters; this must be done at no additional cost to the customer. The utility Endesa aimed to deploy automated meter management to more than 13 million customers on the low voltage network from 2010 to 2015, building on past efforts by the Italian utility ENEL. The communication protocol used was to be open. The utility Iberdrola was to then replace a further 10 million meters." [25].

2.9.1.7. Australia

"The Australian government announced the AUD 100 million "Smart Grid, Smart City" initiative in 2009 to deliver a commercial-scale smart grid demonstration project. Additional efforts in the area of renewable energy deployments are resulting in further study on smart grids." [25]

2.9.1.8. United Kingdom

"The energy regulator OFGEM has an initiative called the Registered Power Zone that will encourage distributors to develop and implement innovative solutions to connect distributed generators to the network. OFGEM has set up a Low Carbon Networks fund that will allow up to GPB 500 million support to DSO projects that test new technology, operating and commercial arrangements." [25]

2.9.1.9. France

"The electricity distribution operator ERDF is deploying 300 000 smart meters in a pilot project based on an advanced communication protocol named Linky. If the pilot is deemed a success, ERDF will replace all of its 35 million meters with Linky smart meters from 2012 to 2016."[25]

2.9.1.10. Brazil

"APTEL, a utility association, has been working with the Brazilian government on narrowband power line carrier trials with a social and educational focus. Several utilities are also managing smart grid pilots, including Ampla, a power distributor in Rio de Janeiro State owned by the Spanish utility Endesa, which has been deploying smart meters and secure networks to reduce losses from illegal connections. AES Eletropaulo, a distributor in São Paulo State, has developed a smart grid business plan using the existing fibre-optic backbone. The utility CEMIG has started a smart grid project based on system architecture developed by the IntelliGrid Consortium, an initiative of the California-based Electric Power Research Institute." [25]

2.10. Bi-directional metering

With the introduction EG on the local distribution networks, there is a need for bi-directional metering in order to allow the utility to continuously and accurately measure the import and export of electricity by the consumer. These are done with the use of four quadrant meters which measures import and export of electricity in separate registers. Figure 2.8 shows a typical bi-directional meter installation that will meter import and export electricity data for billing purposes.

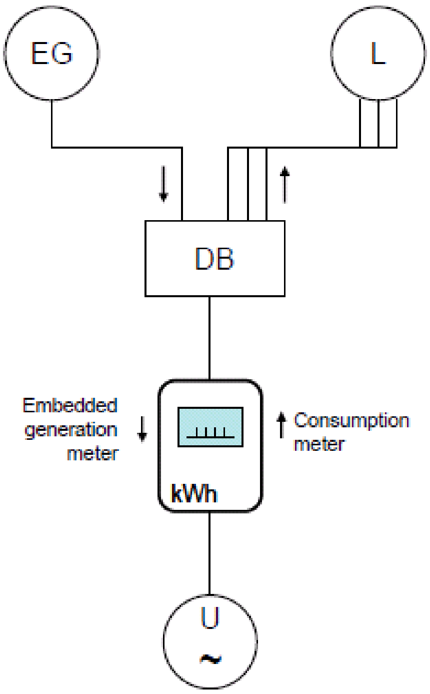


Figure 2.8: Typical bi-directional meter recording import and export in different registers [15]

These meters can be programmed for various tariff structures as well such as single rate, two rate and time of use. The meters also have the ability to do net metering although this is currently not the standard at eThekwini Electricity or South Africa. Electricity utilized and electricity generated are calculated at different tariff structures. This is too ensure that the municipality revenue is protected and that there isn't cross subsidy by the non-generators subsiding the generators. With the planned introduction of smart meters as part of the smart grid project at eThekwini Electricity, there will be a roll out of smart meters. These smart meters will have the functionality to perform bi-directional metering.

2.11. Technical Impacts of Embedded Generation

2.11.1. Interconnection between a EG and the Grid

An EG plant can be either connected as grid independent or grid parallel as well as a combination of both. Figure 2.9 shows a typical grid parallel EG interconnection onto a medium voltage distribution network.

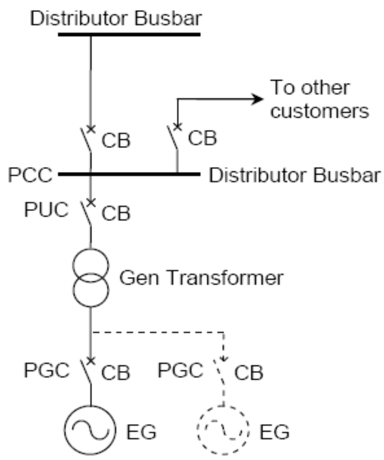


Figure 2.9: EG interconnection to a DSS bus bar via a generator transformer [14]

In this connection scenario, the EG connects directly onto a Distributor Substation (DSS) via a generator transformer. This is a common method of connection where the EG generates electricity at a lower voltage e.g. 400V or 6600 V and the electricity is then stepped up using a step up generator transformer to a higher voltage, e.g. 11 000V or 22 000V. This is then injected directly into the local distribution grid. Generation injection can also be done directly into the Major Substation MV bus bars however, this depends on the amount of generation, location of the generation plant to the Major Substation and availability of spare circuit breakers at the Major Substation [14].

2.11.2. Technical Impacts of Embedded Generation on the existing distribution network design and performance

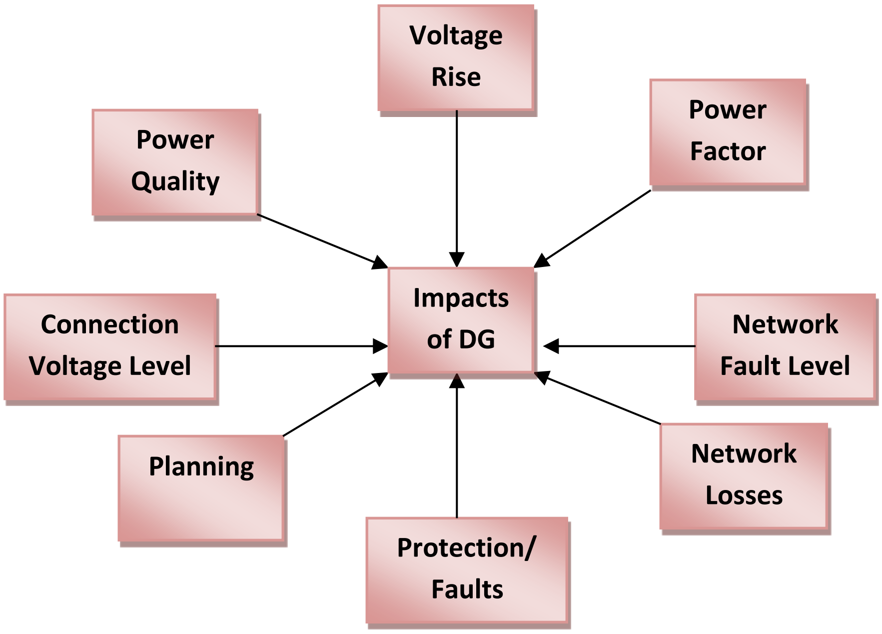


Figure 2.10: Impacts of EG on the utility network

Figure 2.10 depicts the impact of EG on the existing distribution networks experienced on local and international EG projects. The addition of EG onto an existing distribution network affects various parameters of the distribution network. We will study the experience of EG on existing distribution networks locally and internationally.

2.11.3. Impacts of EG Sources on the Existing Distribution Network

When properly integrated with the grid, EG offer potential benefits including reduced electricity losses; reduced transmission and distribution congestion; grid investment deferment and improved grid asset utilization; improved grid reliability; ancillary services such as voltage support or stability, VAR support, contingency reserves and black start capability; clean energy; lower-cost electricity; reduced price volatility; greater reliability and power quality; energy and load management; and combined heat and power synergies. [14]

However on the contrary, if EG is installed incorrectly, the impact becomes negative. This can increase losses on the distribution network, initiate voltage rises, influence power quality, influence the system protection, influence the reliability of the network and influence the fault levels on the network. [14]

Clearly EG can offer a utility many positive and negative benefits of which is largely dependent on the location of the EG unit, network configuration, network demand, control, etc. Some of the aspects that lead to positive application of EG to provide benefits are those that are owned or operated by the utility themselves because the amount of power generated at a particular point in time remains in the control of the utility and not an IPP or co-generator. [14]

The location of the EG unit has great influence on the type of impact that will be experienced in an existing distribution network. However, for accurate impact assessment of EG units on an existing network, simulation tools need to be used to simulate conditions of peak/off peak load demand, distribution network contingencies analysis, dispatch and control methods to determine the capacity limits of the EG and impacts to the distribution network. [14]

The impact of EG on an existing network grid design and performance are influenced by many factors which often vary from distribution network to distribution network around the world. Some of the factors which will influence the impact of EG on an existing utility distribution grids are shown in Table 2.11.

Table 2.11: Factors that determine the impact of EG on an existing distribution grid [14]

Network Structure		**Load Type and Characteristics for MV/LV Networks**	
1	Types of circuit breakers/relays/switches	1	Load classification and characterization
2	Number of lines/bus bars in network	2	Three and single phase load percentage
3	Line/cable lengths	3	Rotating machine load percentage
4	Number of conductors (3 Phase, 3 Phase + Neutral, etc)	4	Composite Loads (coincidence and diversity)
Operating Criteria and Parameters for Normal and Emergency Condition		**Types of Equipment and Standardized Sizes**	
1	Radial or meshed network	1	Capacitor banks in network
2	Classification of system grounding (isolated, solidly earthed, earthed through resistor/reactor)	2	Transformers (Nominal power, turns ratio, regulation range, OLTC, losses (winding, core losses))
3	Abnormal operation limits (over voltage, over current limits)	3	Generators (synchronous, asynchronous, converters)
4	Protection systems (protection coordination)	4	Fault type (single phase short-circuit, 3 phase short circuit)
5	Voltage drop limits (statutory limits)	5	Types of protection
6	Power factor (acceptable value)	6	Existence of existing load control devices
7	DG operation mode (parallel or island)		
8	Regulation (voltage and reactive power)		
9	Availability of measurements devices		

The factors can be broadly defined into 4 main categories namely; network structure, load type and classification, normal and emergency operating criteria and network equipment size. With the addition of EG or co-generation to the utilities existing network, problems are generally encountered during off peak periods where the co-generator dumps excess power or the IPP continues to generate maximum power from their units. This is injected into the distribution network and the network is unable to absorb all the generated power during this period. The effect is negative in that instead of reducing the current flowing from the grid it brings about a reversal in direction of the current flow and this then result in a voltage rise at the bus bars with the maximum voltage rise occurring at the EG point of connection onto the distribution network. This voltage rise can exceed statutory voltage regulation limits. This "voltage rise effect" has been encountered in EG interconnections in Europe and is a key constraint on the EG applications in Europe. [14]

2.11.4. The "Voltage Rise Effect" using Simple Network Analysis

The EG initiated "voltage rise effect" may be understood in its simplest form by applying basic engineering principles to a simple 2 node network model.

Consider two nodes (Node 1 and Node 2) interconnected by a conductor of given impedance (R+*j*X) and a constant load of $P_2 + jQ_2$ at Node 2 shown in Figure 2.11.

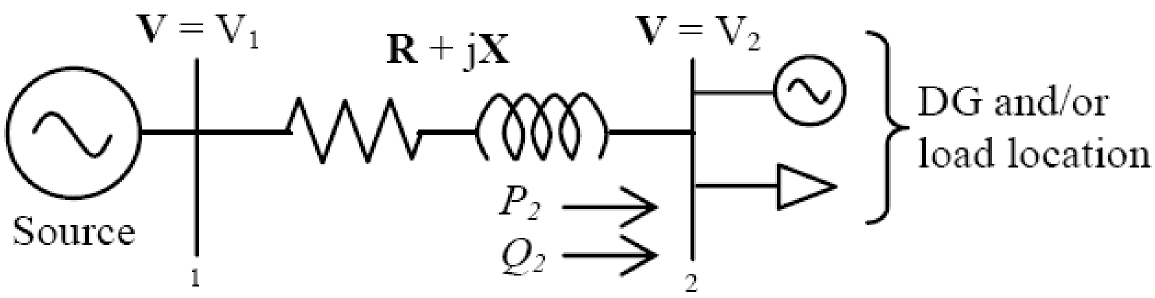


Figure 2.11: Two node network used to illustrate the "voltage rise effect" [26]

Using the simple two node network it is possible to derive an approximate expression ΔV_2 in pu for the difference between the sending end (V_1) and receiving end (V_2) voltage as in (2.2).

$$\Delta V_2 = -\frac{RP_2 + XQ_2}{V_2} \tag{2.2}$$

In a passive distribution network, P_2 and Q_2 will flow into bus bar 2, giving rise to a negative ΔV_2 or voltage drop between the sending and receiving end bus bars. However with the introduction of an EG at bus bar 2, it is possible to reverse the direction of the real power P_2 flow. Since EG normally can and may operate close to unity power factor, this will have little impact on the reactive power Q_2 term. However it is possible during off peak or high EG output periods that the reverse (negative) P_2 term will overcome the positive Q_2 term. This will then cause a net voltage rise at the receiving end bus bar with respect to the sending end bus bar voltage. [26]

2.11.5. Methods to evaluate voltage rise in EG networks

The CIGRE Task Force 38.06.03 describes two methods to evaluate "voltage rise" initiated by EG on distribution networks. The first method is based on the location of the machine and the voltage level at which it connects to whilst the second method consider the three phase fault level at the EG connection point. "Both methods however tend to be too conservative and many countries prefer to conduct their own detailed case studies per application" [26]. Hence a more generalized method was derived to calculate the maximum EG penetration limits using a simple 4 node model. Figure 2.12 represents a 4 node model which allows for representation of a wide range of radial distribution networks at different voltage level, conductor types and EG locations.

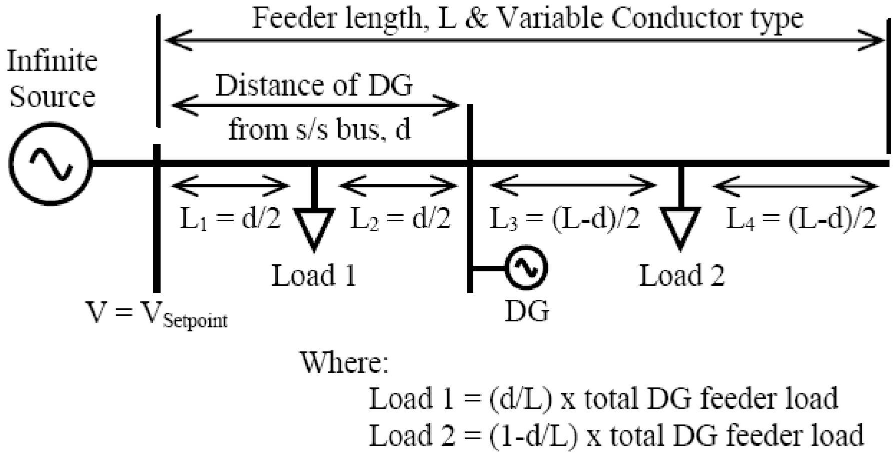


Figure 2.12: Four node model used to derive the generalized analysis method [26]

A simple approximate algebraic equation was derived from the generalised model of the radial distribution line to understand how different distribution network variables effects voltage rise in EG Networks [26].

$$P_{DG} = \underbrace{\left[\frac{V_{Max} \times (V_{Max} - V_{Setpo\,\mathrm{int}})}{r \times d}\right]}_{\text{1. No-Load}} + \underbrace{\left[S_{Tot} \times (1 - \frac{d}{2 \times L}) \times (\cos\phi + \frac{x}{r}\sin\phi)\right]}_{\text{2. Load}} - \underbrace{\left[\frac{x}{r} \times Q_{DG}\right]}_{\text{3. DG Reactive Power}} \tag{2.3}$$

Where:

V_{Max}	= Upper voltage regulation limit
$V_{Setpoint}$	= OLTC set point voltage
R+jx	= pu length of line impedance between source bus bar and EG
D	= distance between source substation and EG
L	= Total length of the EG feeder
$S_{Tot}\angle\Phi$	= Total apparent power load on feeder
Q_{DG}	= Reactive Power export from EG to network

The above expression is made up of three terms namely; No Load, Load and EG Reactive Power Generation. [26]

Using the expression (2.3), we are able to analyse and better understand EG initiated voltage rise on a distribution network. From Equation (2.3), if we assume that the EG is operated at unity power factor then term 3 (EG reactive power generated term) equals to zero and if the there is little or no load on the feeder then term 2 (load term) equals to zero. This then means that the EG penetration limit is entirely determined by term 1 which is the “No Load Term”. This then indicates that the voltage rise effect increases when the EG is connected at a lower voltage level. The effect is further compounded if high resistance conductors are used (increasing r) and if the EG is located far from the Source Substation (increasing d). The no load penetration limit is also affected by the maximum network voltage and the set point of the OLTC at the Source Substation. [26]

2.11.6. Local Voltage Rise with PV

The critical quality of supply problem experienced with PV systems integration has been the problem of voltage rise in the vicinty of the injection point on to the local grid. In traditional distribution networks, the terminal voltage was the highest at the distribution transformer and reduced along the length of the low voltage feeder due to the network impedance. However with the connection of PV systems to the local network, problems of voltage rise can occur when the PV system feeds the local load and continue to inject excess generation into the local feeder. This can result in the voltage rise which can result in the voltage on the feeder exceeding the voltage at the transformer terminals. This concept of voltage rise is shown in Figure 2.13. [27]

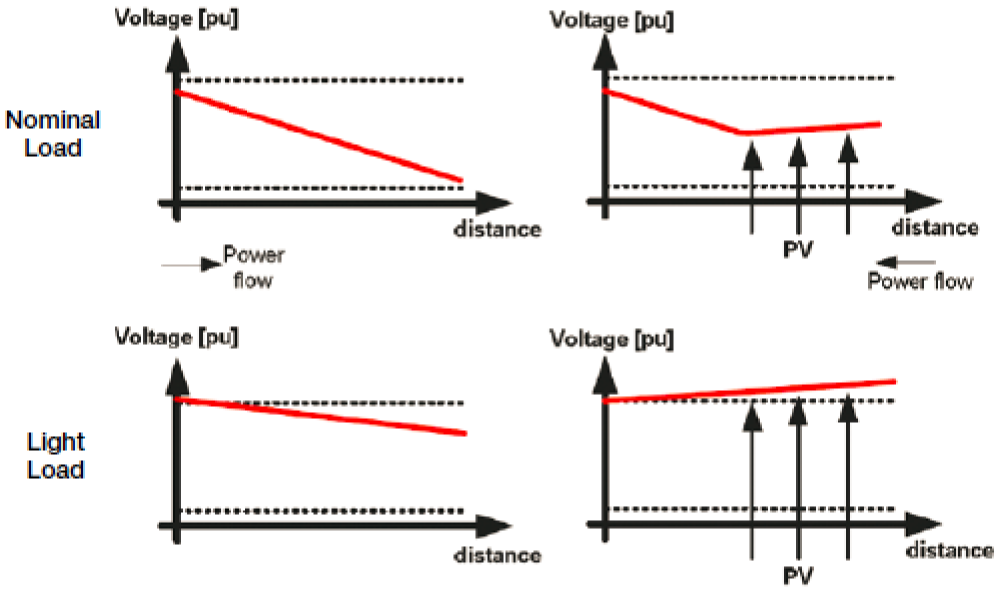


Figure 2.13: Concept of voltage rise due to PV sources along the feeder [27]

The influence of voltage rise along the feeder is influenced by the strenght and impedance of the local grid. The problem of voltage rise has been observed in networks under load load demand on weak networks (high network impedance) with a high levels of PV generation. Voltage rise at the local injection point on the grid often results in the disconnection of the PV generation unit on over voltage. [27]

2.11.7. Impacts of Power Factor with local PV Systems on the Distribution Network

In most distribution grids, PV inverters operate at unity power factor. However in this case, when the PV is generation, it supplies all or part of the local real power power component demand of the network whilst the network supplies the reactive power. This results in a larger reactive to active power ratio passing through the local distribution transformer changing the power factor at the transformer. Local generation of active power reduces the the network losses since the generation is consumed locally. An example is shown in Figure 2.14 where the grid power factor is reduced from 0.912 to 0.743 with a PV system. [27]

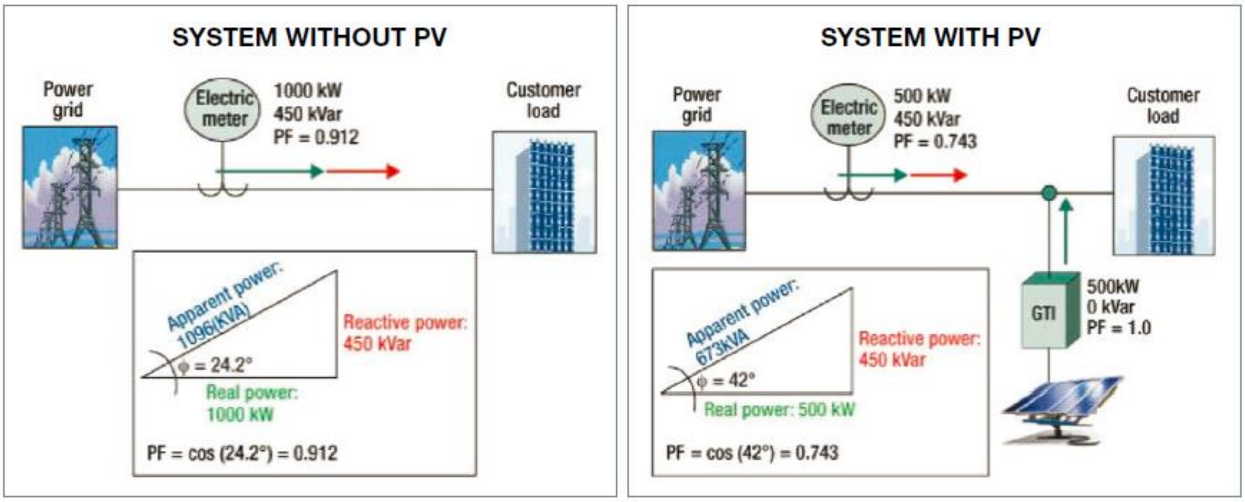


Figure 2.14: Impacts of PV system on distribution transformer [27]

2.11.8. Effects of Distribution Generation on Network Losses

The distribution network losses depend mainly on power flow which is affected by EG, hence the introduction of EG to an existing network will affect losses. Studies have shown that EG can either reduce or increase the distribution network losses. The outcome of which is based on factors such as location of the EG, distribution network topology and size of the EG unit with respect to the network loading. [14]

To get a better understanding of this concept, a simple radial distribution network with EG connected, shown in Figure 2.15, can be used to explain the effects on power loss.

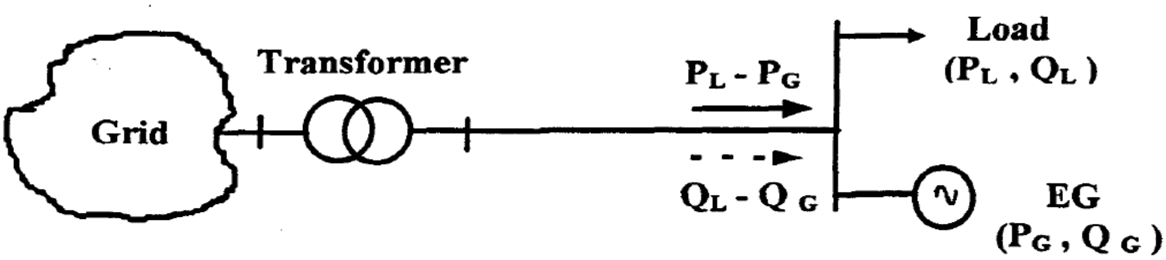


Figure 2.15: Radial distribution network with EG connected [14]

The power loss on the simple radial network shown below with no EG connected can be expressed as follows:

$$P_{Loss} = I^2 \times R \tag{2.4}$$

Where R = feeder resistance

I = Current flowing in the feeder

When EG is connected onto the network, the magnitude of current flowing in the feeder changes, affecting the power loss in the network. This will depend on the size of the EG unit and the amount of power that flows back into the grid. If the amount of current flowing in the opposite direction is greater than the case prior to the installation of the EG then the power loss incurred will be greater at the local level. [14]

However if the transmission and transformation losses were taken into account, then things could look different. Power is generally purchased at high voltage and then transformed a couple of times before it reaches the distribution voltage level. Losses are also incurred during this transformation and transmission process from central generation to distribution level. [14]

2.11.9. EG Location

The benefit of any EG installation is dependent on its location. Most utilities would want the EG unit to be installed on heavily loaded feeders or feeders where voltage drop problems are experienced or in a location where the distribution network losses need to be reduced. However, with the encouragement and emphasis placed on renewable energy sources for generation and the large amounts of incentives given for these projects, the location of these EG plants will often be dictated by the location of the fuel source such as water for hydro projects. This will hence mean that in lots of future cases, the utility will not have an option of the EG location.[14]

2.11.10. Influence of EG on Distribution Network Reliability

EG when operated in parallel with the grid does not make the grid any more reliable since utilities do not allow these EG plants to operate when there is an outage on the grid side. EG plants are often required to be equipped with “Loss of Mains” protection schemes which trip the EG plants when a loss of mains is detected and hence does not allow the EG to operate in island mode. Although on the other hand when there are faults on feeders in interconnected networks, EG can help in supplying more of the loads without overloading other cables and lines on the network. This is dependent on the size of the EG unit, but problems could arise when there is an outage of the EG unit and the existing network feeders get overloaded or network switching is required to ensure that all the loads are still supplied. The reliability is, however, increased when the EG plant is operated in standby mode and is used when there is an outage on the grid in “Island” mode. [14].

2.11.11. Impacts of EG on System Operation and Control

In a power system there always needs to be a balance between the power generated and the power consumed hence the most important characteristic of the traditional power plants is the controllability of the output power. This characteristic is often missing from small EG units or IPP plants where the output power is dependent on the availability of the primary fuel source (e.g. Methane produced from a landfill site) or in the case of IPPs where maximum output power mean maximum revenue. [14]

This imbalance of power generated vs. power consumed is generally found in networks that are made up of large number of EG or depending on the network loading e.g. off-peak energy consumption. [14]

The benefit of any EG is dependent of the location of the EG plant within the existing distribution network. There is much research done on the optimum location of EG within an existing distribution network. The strategies are based on many different methods which look at reducing the losses on the network, improving the voltage profile of the network or reducing the loading on critical feeders. However in practice, IPPs may dictate the location of their EG plant based on available pockets of energy sources within the distribution networks. [14]

2.11.12. Feeder Loading

Depending on the location of the EG unit in the distribution network and the power output of the EG unit, the feeder loading can be reduced or increased. In a case study carried out in an existing distribution network which consisted of a main 132/33 kV substation with 40 MVA capacity connected to a bus bar (bus 9) in the network which then supplied 8 load centres shown in Figure 2.16 through a 33/11 kV distribution transformer. The thermal capacities of the feeders are 12 MVA. When a study was done taking load centre growth in the distribution network over a period of 4 years, the results revealed that certain feeders were close to its thermal capacity whilst others would be overloaded in the study time period. However with optimally placed EG units in the network, the results shown in Figure 2.17 indicated that the feeder loading is then reduced to acceptable limits. [14]

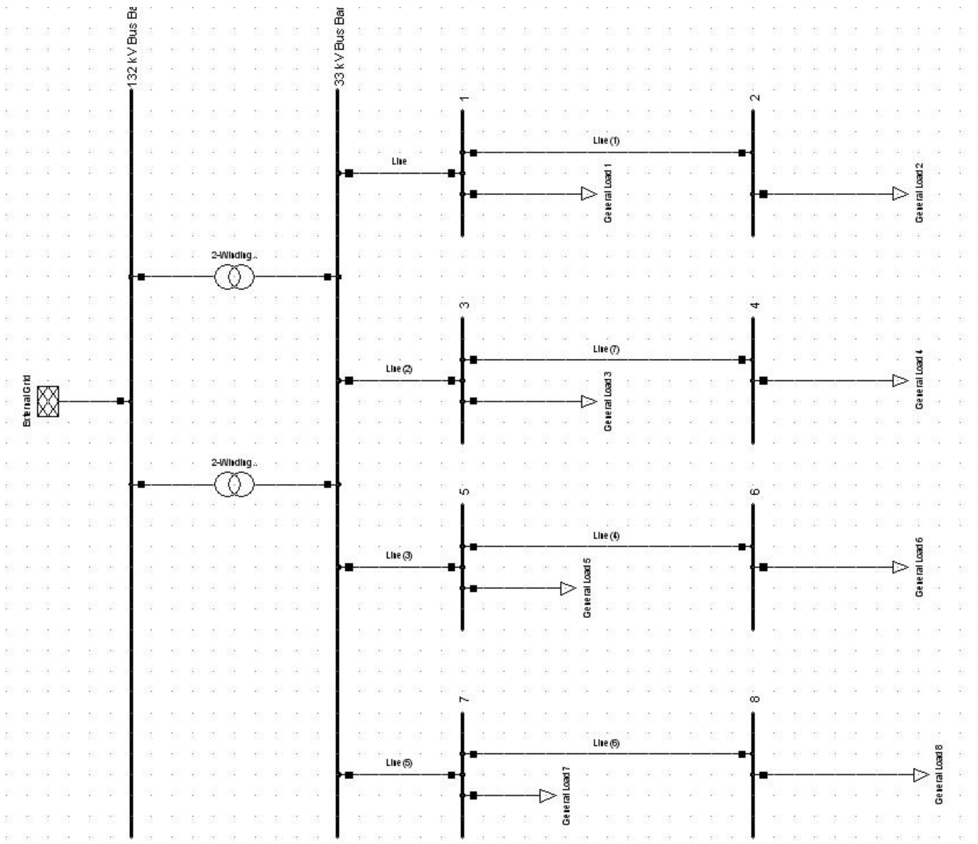


Figure 2.16: Bus bar feeder arrangement [14]

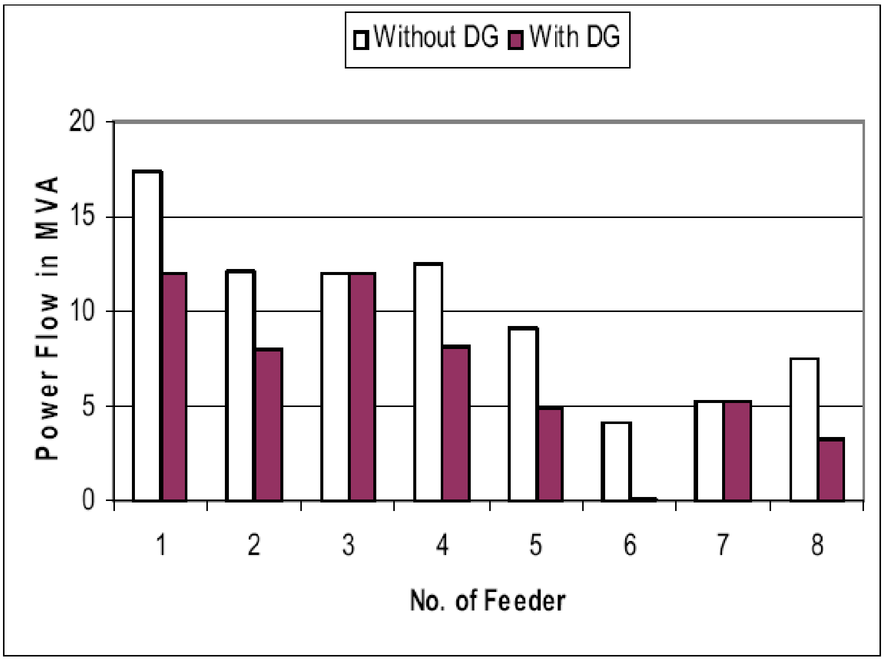


Figure 2.17: Feeder loading with/without the EG [14]

Figure 2.17 shows a reduction in the feeder loading when EG units had been optimally sited in the distribution network. Optimisation was done based on the following factors; to improve busbar voltage; reduce power flow from the main feeders (prevent over loading) whilst sitting and sizing was done to serve the network peak loading by minimising the total system cost. Power flow through the primary feeders are reduced hence resulting in a reduction in total losses. This also shows that no feeder upgrades need to be implemented in the short term although in the future upgrades may need to be implemented. [14]

2.11.13. Impacts of EG on the Grid Protection

Power flow is central generation plants, through the transmission network and then down to distribution however with an increased level of EG penetration, bi-directional power flow occurs. This could even result in power flow from the LV network through the distribution transformer through to the MV networks hence protection schemes are required at both MV and LV levels on the network. The protection system has to provide selectivity to disconnect faulted sections of the network in order to improve the network reliability and the availability of suply on the network. This is further complicated on distribution networks with EG sources where fault current is supplied from the grid and the EG sources. This makes fault detection on the network much more complex and existing protection schemes may fail to correctly detect faults on the network. [3]

The protection problem is shown in Figure 2.18 with the use of a 5 feeder distribution grid. In the event of a short circuit fault at F2 or F3, fault current is supplied by the generators connected to feeder 1 (G1 and G2) and G3 from feeder 4. [3]

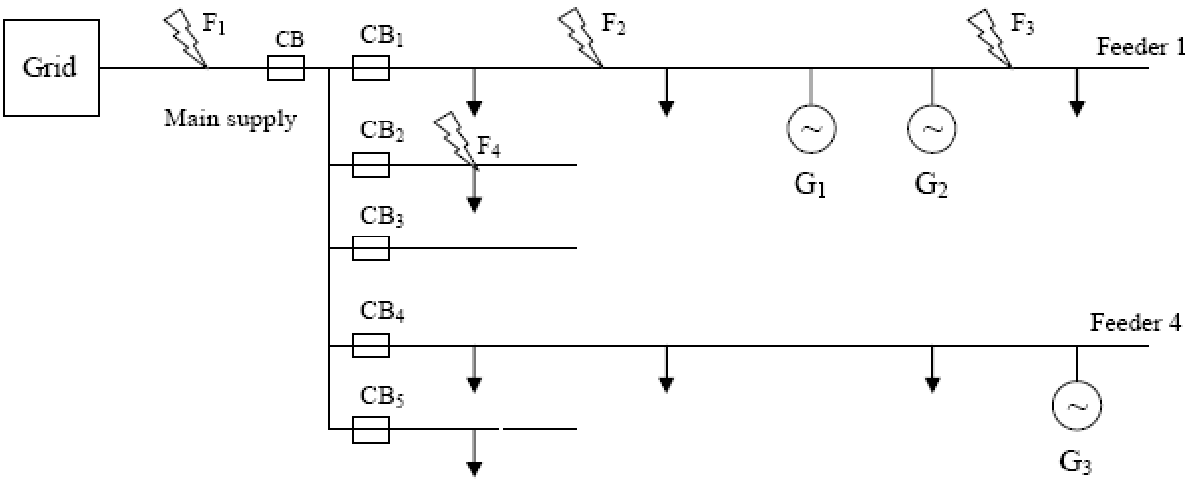


Figure 2.18: Protection problems encountered with high penetration of EG [3]

Should the fault contribution from generators (G1 and G2) is large in comparison to to the fault current contribution from the grid and other generators on the network, it is possible that the fault current through the cirsuit breaker and the fuse might not be sufficient to operate and remove the fault on the network. Depending on the fault contribution from G3, there is a chance that that feeder 4 protection may operate before the feeder 1 protection operates resulting in incorrect disconnection of a healthy feeder. [3]

"According to technical standards (e.g IEEE 1547), EG must be automatically disconnected, when faults or abnormal conditions occur, with the assumption that interconnected systems detect such conditions. In this way, conventional protection selectivity can be restored, guaranteeing personnel and equipment safety. To make optimum use of EG, unnecessary disconnection of EG should be avoided. Generators should be able to ride through minor disturbances." [3]

2.11.14. Fault Level Contribution from the EG Plant

Various factors such as fallen conductors or damaged cables may cause faults on a distribution network. When a fault occurs on the network, the resistance of the network at that point is drastically reduced and therefore very high currents can flow into the fault. Fault current contribution to this point may come from three different sources namely; the in-feed from the transmission network, in-feed from the EG and in-feed from the loads with induction motors. The prospective fault current that could flow into a fault is known as the fault level all pieces of equipment on the network has a rated maximum fault level that the equipment can safely handle before it damages. [14]

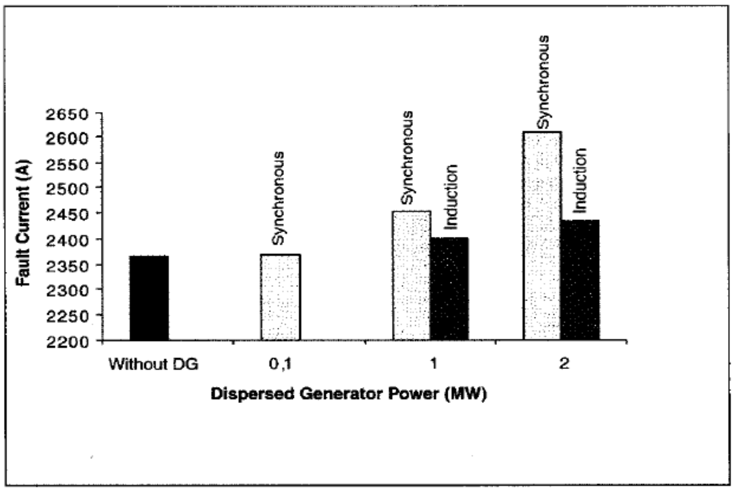


Figure 2.19: Fault current rise with connection of EG [14]

Figure 2.19 shows the effects on the distribution network fault levels when connecting a synchronous or asynchronous generator to the 12.5 kV network. Hence adding EG from both synchronous and asynchronous generators can make a significant contribution to the existing distribution network fault levels. Problems arise when an existing distribution network infrastructure is close to its rated fault level limit, the connection of an EG to this network may result in the distribution network fault levels been exceeded. Circuit breakers are the most common plant that will be affected by fault level rise in the network. Other equipment such as transformers and cables may be affected as well through electromechanical and/or thermal mechanisms although this effect may be “hidden’ but may have a serious life expectancy reduction of the plant. The risk of fault levels been exceeded are damage to plant, injury to personal and loss of supply. [14]

Studies have also shown that EG can increase the fault level by such a degree that system reinforcement is necessary. The fault current increase when EG is connected to an existing distribution network cannot be generalized and is difficult to specify any levels of rise as the level will depend on many factors such as the network configuration, the type of generators used and what network fault current limiting devices are used such as NERs, NECRs, reactors, etc. The increase in fault current can also affect the selectivity and sensitivity of the protection devices in the network hence selectivity and sensitivity must be checked with every new EG connection onto an existing distribution network. [14]

2.11.15. Technical Planning Considerations for Connecting EG

Distribution network in South Africa were historically designed for power flow from the high voltage transmission networks to the medium and low voltage distribution networks. Urban distribution cable networks are designed as ring fed networks which were operated as radial fed networks in order to reduce fault levels and simplify protection schemes. There are a number of factors that influence the level of EG that can be absorbed onto an existing distribution network, such as: [28]

- Voltage Levels
- Voltage at the primary substation
- Distance from the primary substation
- Size of conductor
- Demand on the network

- Other generation on the network
- Operating regime of the generator
- The location where the generator is connected (a strong or a weak distribution network)

2.11.16. Impacts of EG on the South African Distribution Networks

Connecting EG onto local distribution networks can cause the following network impacts:

- **Steady State Voltage Limits:** During peak and off peak periods, voltage regulation needs to be kept with the South African statutory limits. Care needs to be taken to ensure that reverse power flow does not cause voltage rise on the network. [28]
- **Equipment thermal ratings:** Care must be taken to ensure that no network infrastructure such as cables and transformers are over loaded during off peak loading. [28]
- **Raid voltage change:** Voltage changes may be experienced on the network with the connection and disconnection of EG such as induction generators. 29]
- **Fault levels:** Fault level increases with EG and care must be taken to ensure not network equipment fault ratings are exceeded. [28]
- **Transient stability:** Generator instability problems may be experienced on lines with long protection clearance times on the network. [28]
- **Network reliability:** Since islanding of EG are not allowed in SA, there is no significant increase in network reliability. [28]
- **Technical losses:** EG connections may increase or decrease distribution network losses. [28]

2.11.17. The Impacts of EG on the Distribution Network Planning

The introduction of EG technology brings about a substantial challenge to traditional distribution network planning. EG introduction will make load forecasting, planning and operation of the power system have greater uncertainty than in the past. With an increased penetration of EG on the distribution network, network planners have more difficulties to accurately forecast load growth which in turns affects the follow up accuracy of the distribution network planning. In addition, EG can reduce energy loss and can delay or reduce the investment of distribution network upgrades. But if the location and capacity of the EG is inappropriate, it can lead to an increase in the losses of power, result in the voltage in some nodes to increase or decrease and change the magnitude, duration and direction of fault current. [29]

2.11.18. Impacts of PV penetration on a UK LV network

The objective of this case study was to study the impact of increasing penertration of PV on the network voltages of a UK distribution network. This was achieved by carrying out a load flow to determine the voltage violations and PV hosting capacity on the network. The Engineering Recommendations G83/1 requires all PV systems in the UK to switch off once the voltage exceed 1.1 pu. Voltage rise will therefore affect the PV production if the PV system is forced to shutdown for voltage violations and hence lead to reduction in the PV generation yield. Reduced PV yield affects the Levelised Cost of Electricity (LCOE) and financial viability. The daily PV generation profiles based on the irradiation for an optimally designed 3 kW residential grid connected PV system in Newcastle upon Tyne was used for the case study. In the 100% penetration scenario, it was assumed that all the residential customers had a PV installation. [30]

"The UK LV distribution grid model shown in Figure 2.20 was used for the case study. The model consisted of a 33/11 kV substation with two 15 MVA transformers supplying six outgoing feeders and each 11 kV feeder in turn supply eight 11/0.4 kV substations. To simplify the analysis, only one 400V feeder from a 11/0.4 kV substation, supplying 384 houses through four 400V outgoing radial feeders was modelled in detail. The other feeders together with their connected loads and PV generation were represented as individual lumped loads connected to the respective 11/0.4 kV substations." [30]

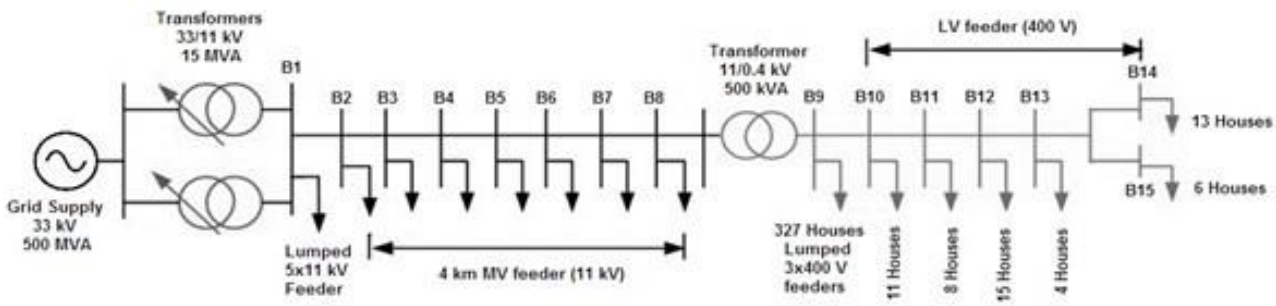


Figure 2.20: Typical UK distribution network used for the case study [30]

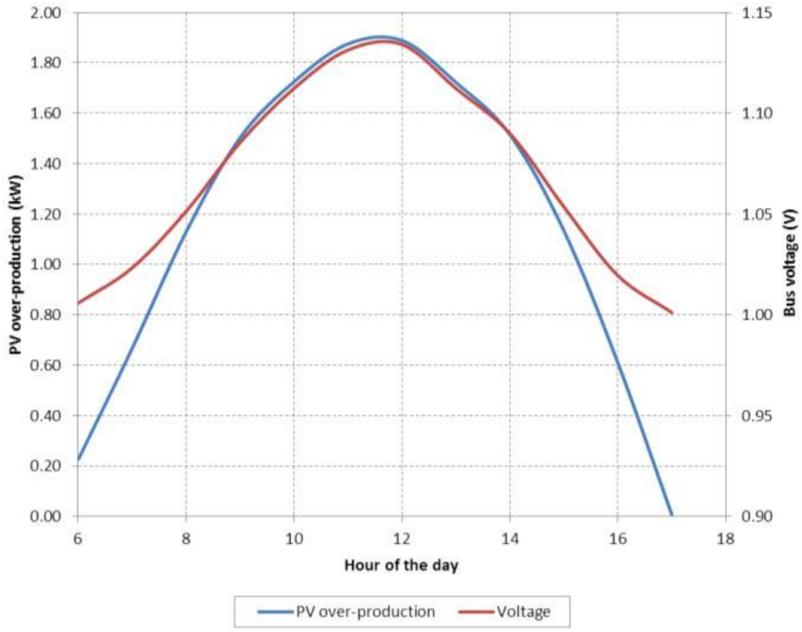


Figure 2.21: Voltage profile at B15 and PV over-production for peak PV generation and low demand [30]

The simulations were done in Distflow software. Various case study and scenarios were carried out utilizing the loading data for the lowest load demand which occurred in May. The voltage profile results indicated in Figure 2.21 is for a 50% PV penetration level at B15. Voltage violations above 1.1 pu is seen between 10am and 1pm which will lead to the inverters shutting down resulting in a reduction in PV generation[30]

2.11.19. Impacts of increased penetration of PV in India

The negative and positive impacts of increased PV penetration levels on the distribution network in India was studied. Based on the experience of PV on the Indian distribution networks, the following impacts are highlighted in Table 2.12.

Table 2.12: Impacts of increased PV penetration [impacts of increasing PV [31]

No	Impacts	Impact On	Nature	Impact with 5% PV Penetration	Impact with >40% PV Penetration
1	Voltage rise due to reverse power flow	Dist. Transformer and Grid	☹	No problem	☹
2	Transformer tap changing	Transformer	☹	No problem	☹
3	Phase imbalance	Distribution Network	☹	No problem	☹
4	Transformer insulation	Transformer	☺	☺	☺
5	Transformer lifeline	Transformer	☺	☺	☺
6	Harmonics	Transformer	☹	☹	☹
7	Dc bias	Transformer	☹	No problem	☹
8	Power factor	Dist. Transformer and Grid	☹	☹	☹
9	Fault current	Transformer/ Protection devices	☹	No problem	☹
10	Protection	Circuit breakers	☹	No problem	☹
11	PV system islanding	Distribution side	☹	No problem	☹

1. **Voltage Rise:** This is experienced when the PV generation exceeds the network load demand resulting with voltage rise at the Point of Common Coupling (PCC) with the grid.

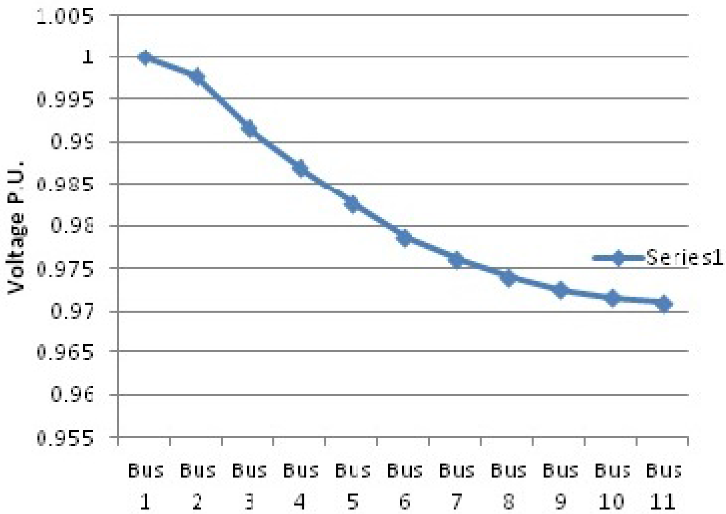


Figure 2.22: Voltage drop along a distribution line [31]

Figure 2.22 indicates the voltage drop experienced along a typical distribution line with no PV penetration due to line impedances. The voltage drop is within the required ±5% in order to comply with the ANSI standards.

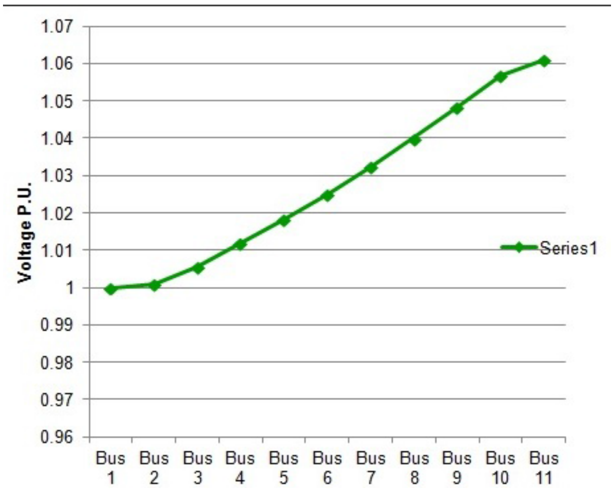


Figure 2.23: Voltage rise along a distribution line due to PV [32]

Figure 2.23 indicates the voltage rise experienced along the distribution line when the PV generation exceeeds the network load demand resulting in some of the bus bar violating the requirements of the ANSI standards. [31]

2. **Transformer Tap Changing:** Voltage rise and subsequent violation of the ANSI 84 standards are experienced when the PV generation exceed the network load demand. In order to counteract this, the voltage at the feeder level is regulated using a tap changing transformer. As the PV penetration levels increases, the number of tap changing per a day required will likely increase resulting in reduced life time of the on load tap changer mechanism and the transformer. [31]
3. **Phase Imbalance:** If all the single phase PV systems are not balanced on the network then problems of phase unbalance maybe experienced during reverse power flow on the network resulting in power quality problems on the network. [31]
4. **Transformer Insulations:** The transformer insulation life is dependent on the temperature rise within the transformer. The peak load reduction of PV is less when compared to the reduction in the average power through the transformer downstream in a day. As a result the load factor is reduced resulting in a decrease in the transformer oil temperature and hence extending the transformer life. [31]
5. **Harmonics:** Certain inverters may inject harmonics into the distribution network. If these high frequency harmonics produced by the filters are not properly filtered, the

stray and eddy current losses of the transformer could increase resulting in increased temperature of the windings and hence reducing the transformer life. [31]

6. **DC bias:** Depending on the inverter design, DC bias may be introduced into the network. This influences the heating of the transformer windings and subsequently affect the transformer core losses. [31]
7. **Transformer lifetime:** The transformer life is influenced by a number of factors such as the level of PV penetration, tap changes required, network load factor, power quality, phase imbalance, etc. [31]
8. **Power Factor:** The ratio of real to reactive power changes as the PV real power generation increases thus affecting the power factor through the transformer and network. [31]
9. **Fault current:** High penetration of PV results in higher fault current compared to the case with no PV installed. This is due to the fact that during a fault, the PV continues to inject current into the feeder until islanding conditions are detected and breakers are opened. [31]
10. **Protection devices (PD):** Depending on the location of the PV system, it will influence the fault current seen by the PD. "Since PD is controlled by over current relays, any change in fault currents requires changes in the timing of relay operation. Else, protection under-reach may happen, if the downstream PV source currents during a fault such that the current seen by the over current relay will fall below the relay's pickup value, and the relay will not see the fault" as shown in Figure 2.24. [31]

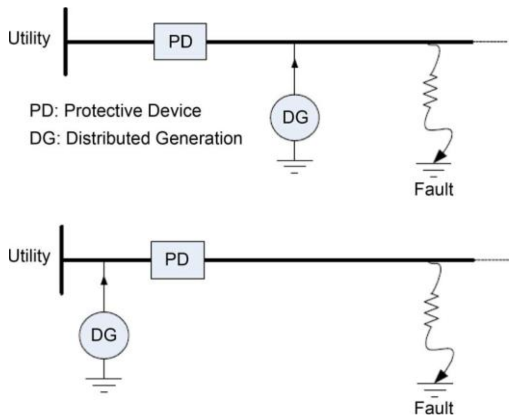


Figure 2.24: Effects of PV on network Protection Device [31]

11. **PV system islanding:** Depending on the level of PV generation with respect to the network loading at that point in time, there is a possibility in the event of a network

loss of power that the PV remains on and feed the local network loading. This could lead to serious safety concerns to both plant and peronnel. [31]

2.11.20. Impacts of Residential PV on a Malaysian LV distribution network

A case study was carried out to indentify the impacts of residential PV intergration on the Malaysian LV distribution network. A typical Malaysian three phase four wire radial LV distribution network was utilised fed off a 11kV/415V distribution transformer. The network feeder cables used were 500 mm^2 PVC Aluminium (AL) whilst 185 mm^2 4 core AL XLPE cables were used between the feeder pillars and the poles. Aerial bundle cable (ABC) of 185 mm^2 and 120 mm^2 is then used to distribute electricity to the houses. Feeder 5 is 332m long and Feeder 4 is 186m. Each feeder serves approximately 27 to 33 terrace houses with the average After Diversity Maximum Demand (ADMD) of 2 kW per customer. All customers were modeled as constant power load with Power Factor of 0.95. Each feeder is loaded at approximately 54 kW to 66 kW. The total maximum demand of the network is 298 kW (a total of 149 terrace houses). Figure 2.25 shows the network utilized for the case study [32]

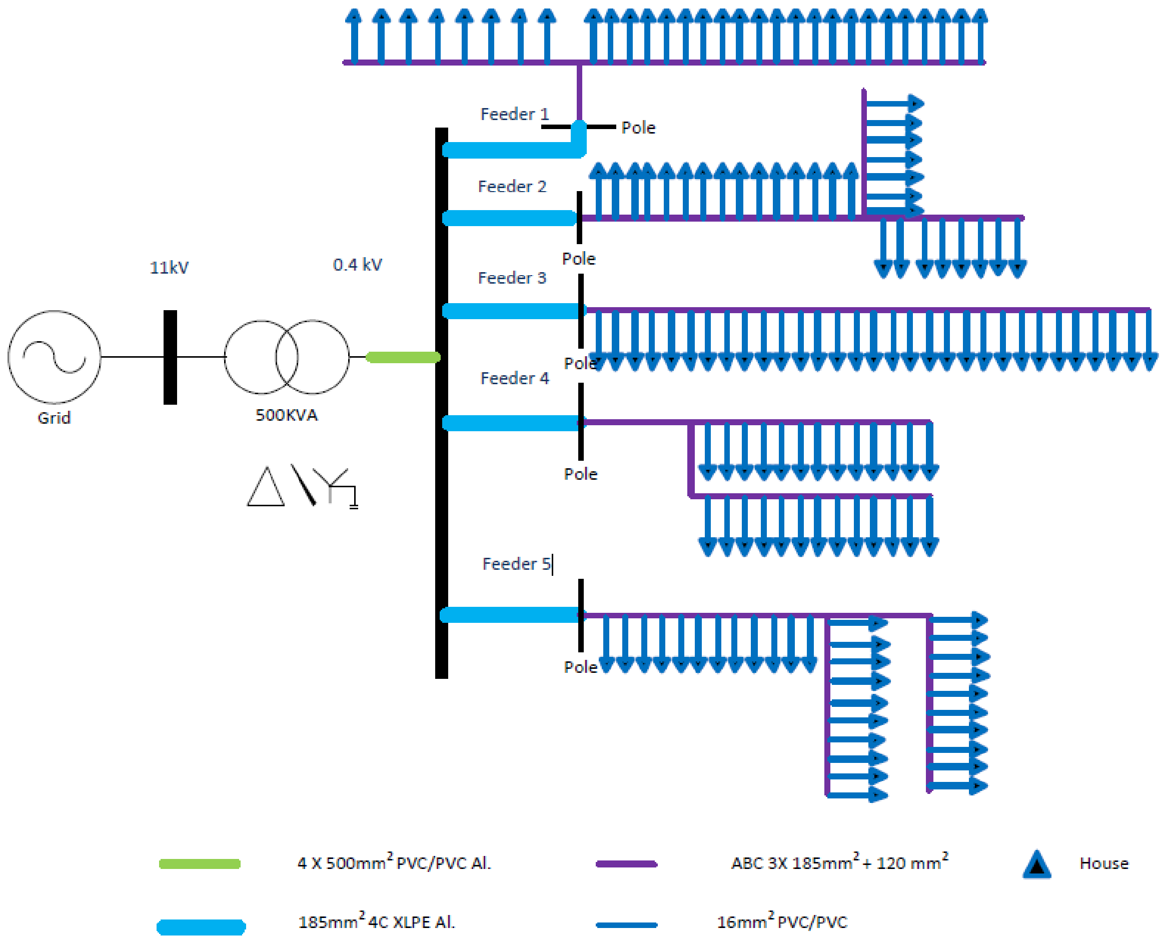


Figure 2.25: Single line diagram of the LV distribution network of Taman PD Impian Putra [32]

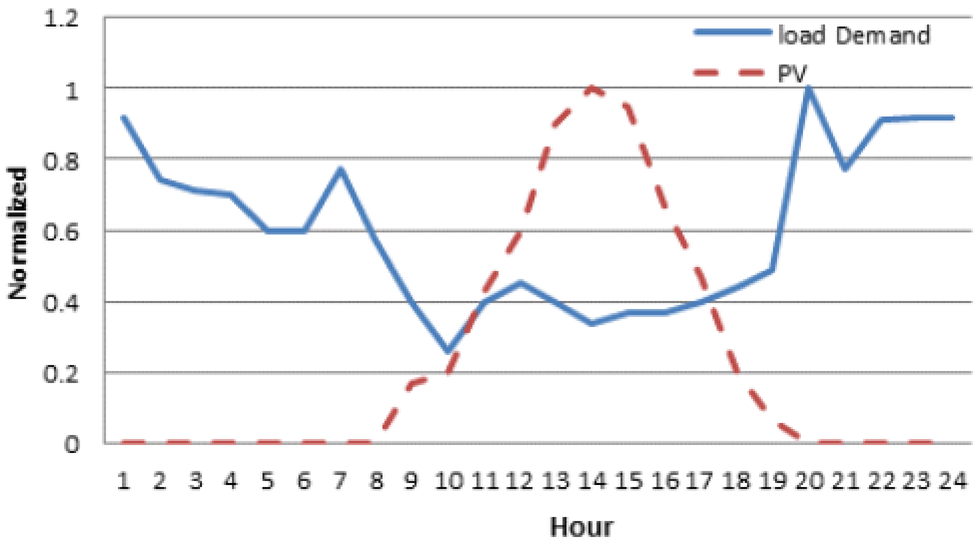


Figure 2.26: The residential demand and the PV generation profile [32]

Figure 2.26 shows the typical Malaysian domestic load profile used in the study for each house. The evening peak starts around 5pm and continues until midnight due to the use of air conditioners. Three case studies were carried out.

2.11.20.1. Case Study 1: Impacts of PV on Voltage profile

In this case study different number of 4 kW PV were connected to the terrace houses for various levels of PV penetrations ranging from 0% - 200%. The penetration level is defined as the number of houses connected with PV to the total number of houses. The results in 2.27 indicate that the higher the PV penetration, the higher the recorded maximum voltage. The results obtained from increasing the PV penetration level from 0% to 200% shows that the voltage remains within the -6% to +10% of nominal voltage statutory limit. This is attributed to the fact that a relatively large cable was used and was utilized to less than half its rating. [32]

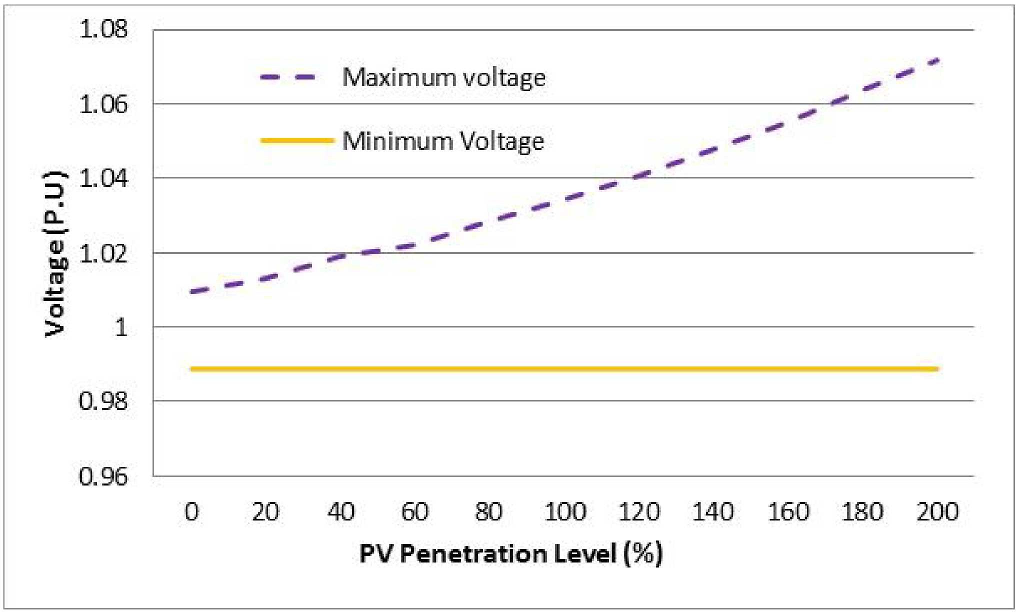


Figure 2.27: Maximum and minimum voltages at Feeder 1 [32]

2.11.20.1.1. Case Study 2: Effects of different cable ratings on voltage rise caused by PV reverse power flow

"Based on the 200% PV penetration level in Case Study 1, the base case cable of 185 mm^2 for Feeder 1 was replaced with a cable of lower (70 mm^2) and higher (300 mm^2) rating. The objective of this study is to assess the impact of changing the cable size on voltage profile with the given PV penetration level." [32]

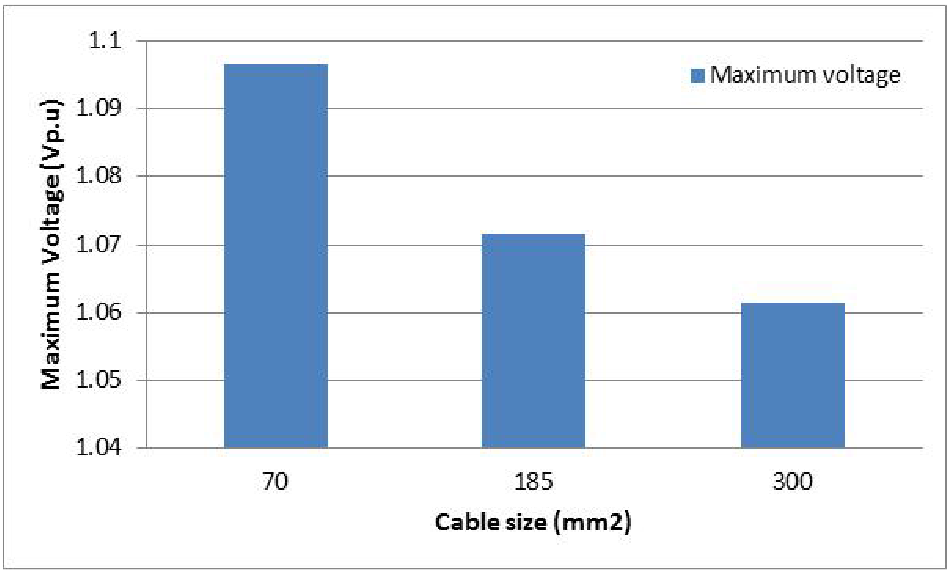


Figure 2.28: Maximum voltage rise with different size cables [32]

Figure 2.28 indicates that cable size has an influence on voltage rise and hence a lare cable size can be used to mitigate the effects of voltage rise on the network. It can hence be concluded from the case studies that the greater the penetration of PV generation, the greater the voltage rise experienced. However in the case studies carried out, the voltage rise for up to 200% PV penetration still remained within the statutory limits. This was largely due to higher rated cables used and relatively short feeder lengths used on the LV networks. Cable size can be utilised to reduce the effects of voltage rise. [32]

2.11.21. A Belgian distribution network case study on impacts of EG

The relationship between EG and power quality is ambiguous. Many researcher have shown the positive benefits of EG whilst other researchers have shown the negative impacts of EG. A CIRED questionnaire recorded that "a rise in voltage level on radial feeders were noted as the main technical connection issue of EG." Whilst IEA also mentions that "voltage control as an issue when EG connects to the distribution grid. This is not a problem when the grid operator faces difficulties with low voltages, as in that case the EG can contribute to voltage support but in other situations it can result in additional problems." [3]

EG technologies that produce DC requires inverters in order to interconnection onto the grid and these inverters may contribute to harmonics on the local network. [3]

An existing Belgian MV distribution network shown in Figure 2.29 was utilised to study voltage stability with different types of EG units. The network under study included a 14 MVA 70/10 kV transformer and four feeder cables. The distribution network was operated as a radial network with 2, 3 and 4 normally open at node 111. [3]

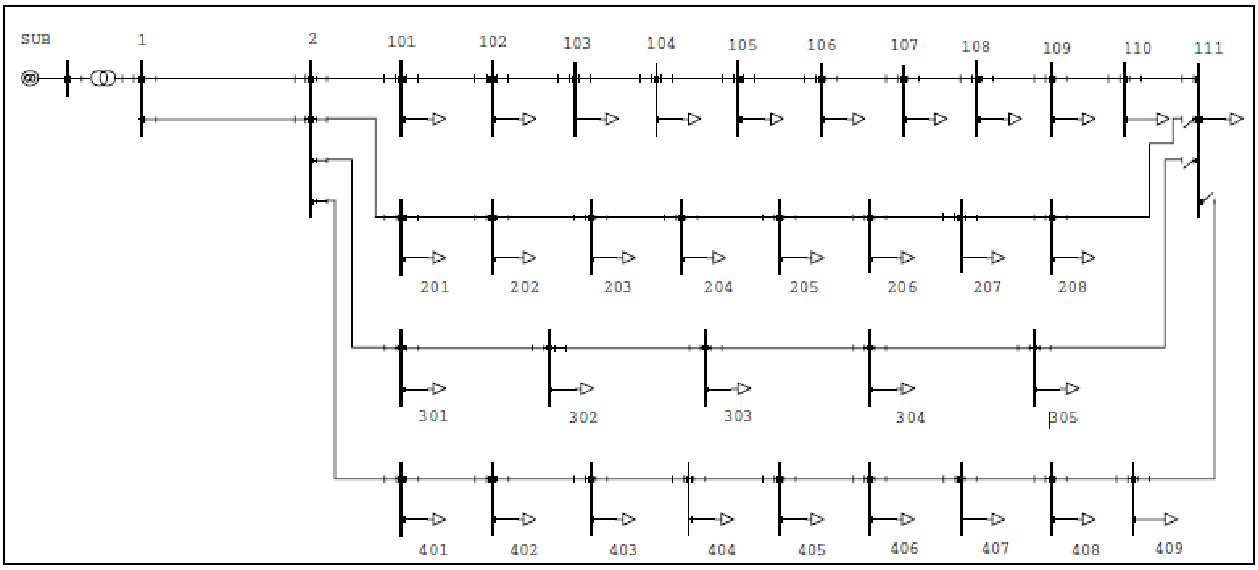


Figure 2.29: Existing Belgian medium voltage distribution network system segment [3]

"An EG unit was connected at node 406 on feeder 4. The total load in the system was 9.92 MW and 4.9 MVAr. A synchronous and induction generator was simulated with different power output. The synchronous generator is simulated at 0.98 leading Power Factor at 3 and 6 MW. The induction generator is simulated at 0.95 lagging Power Factor also at 3 and 6 MW." [3]

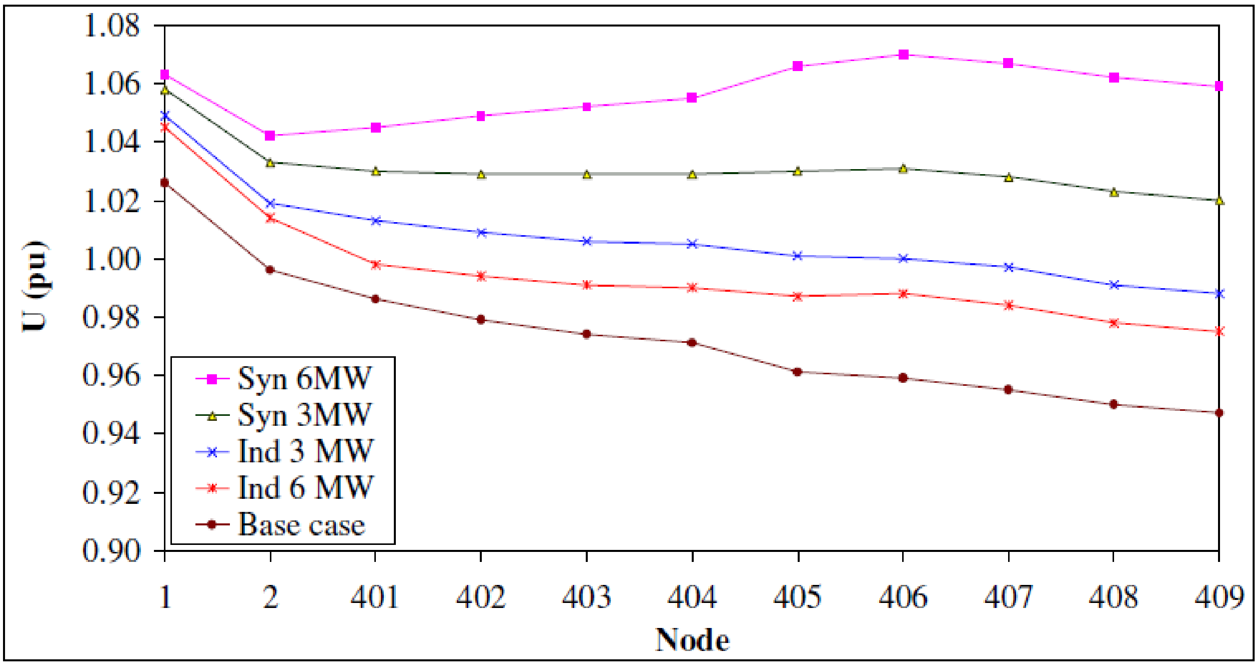


Figure 2.30: Voltage profile at feeder 4 with EG connected at Node 406 [3]

The voltage of both the synchronous and induction generator raised the voltages of feeder 4 as depicted in Figure 2.30. Whilst with the synchronous (6 MW) generation at leading power factor results in over voltage at node 406 and its surrounding nodes.

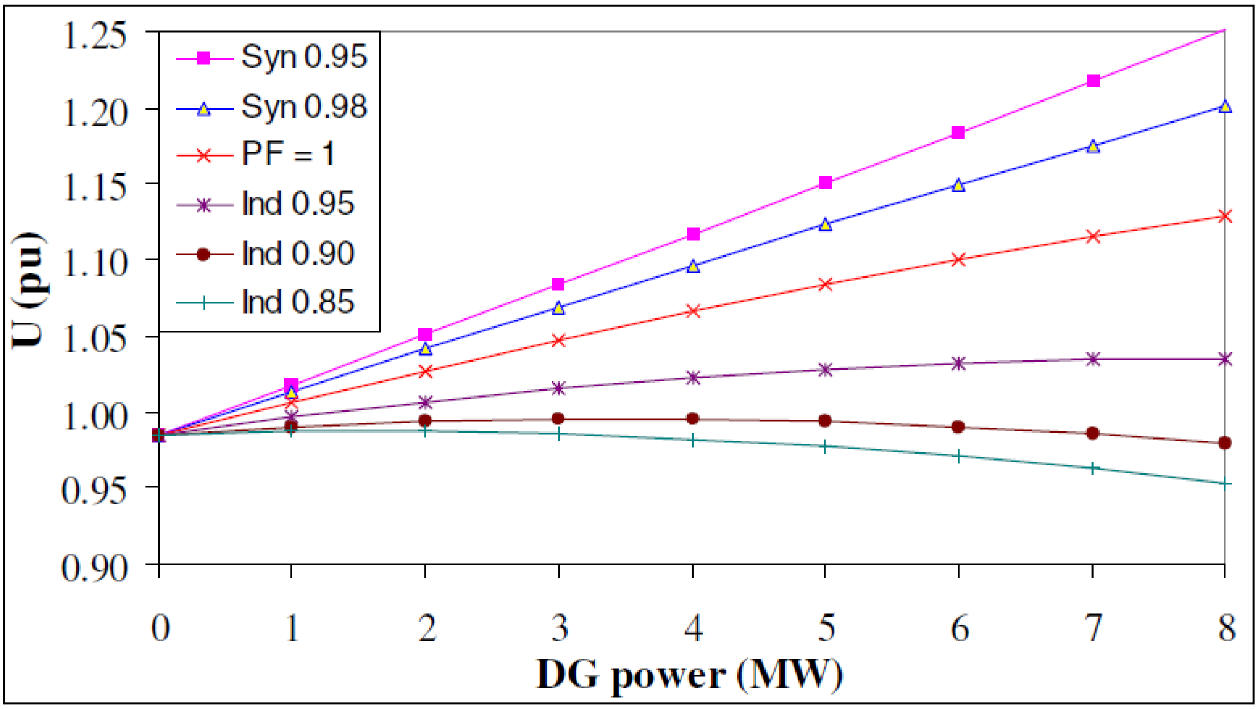


Figure 2.31: Voltage at node 406 with different power factors [3]

Figure 2.31shows the voltage impact at node 406 with different generation outputs and generator power factor. Synchronous generators raise the voltage of the system more than the generators operating at lagging and unity power factor. This is due to reactive power support. Whilst induction generators, reduce the voltage after a certain point due to reactive power consumption. [3]

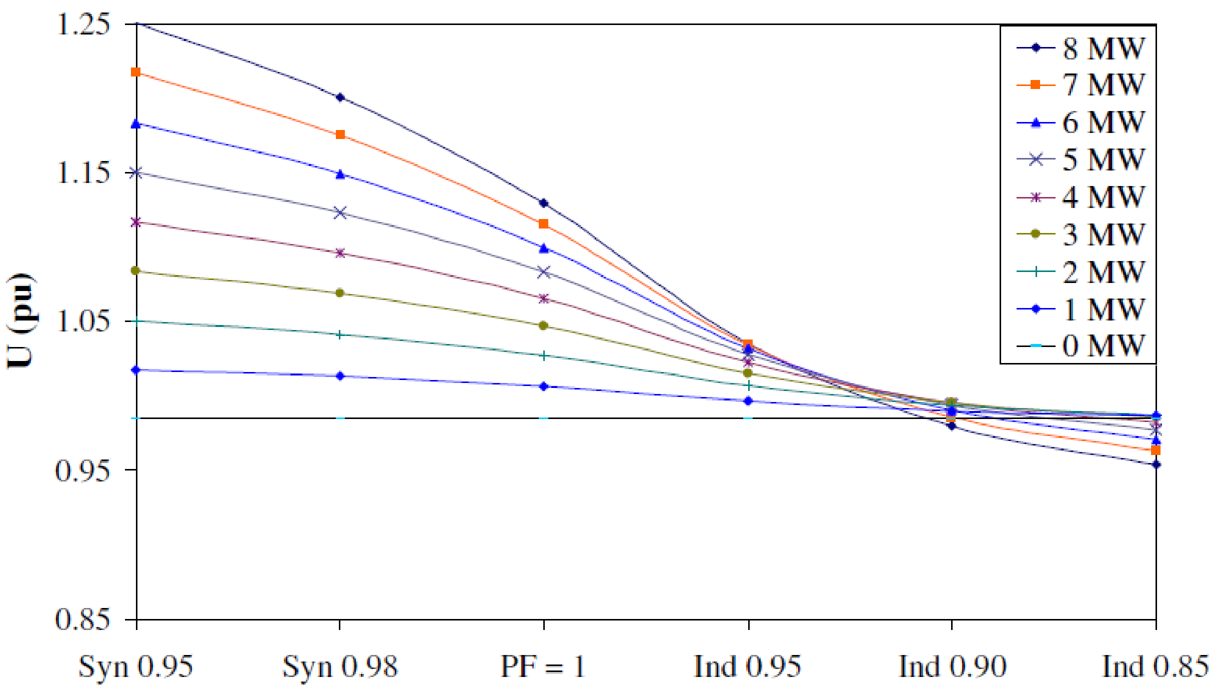


Figure 2.32: Voltage at node 406 with different power generation levels [3]

From Figure 2.32, it can be seen that the voltage rise impacts of induction generators are much lower than that of the synchronous generator. Synchronous genrators also offer the benefit of operating at lagging power factor or in under excited mode to absorb reactive power should voltage rise problems be experienced on the distribution network. [3]

2.12. Summary of Chapter 2

The investigation revealed that the international drivers of EG are mainly financial incentive schemes and green energy certificates whilst in South African the drivers include load shedding, increasing electricity tariffs, environmental concerns and reducing payback periods of EG. The case studies revealed that the impacts experienced range from voltage rise, increase in fault levels, changes in losses, the network planning process, protection feeder co-ordination, feeder loading and network Power Factor. These impacts however vary from project to project and are influenced by a number of factors which vary from network to network around the world. In order to understand the impacts of EG on the local eThekwini Electricity distribution networks, we will need to model the network and carry out our own case studies.

CHAPTER 3: FEASIBILITY STUDY OF AVAILABLE RENEWABLE ENERGY RESOURCES IN ETHEKWINI

3.1. Introduction to Chapter 3

Chapter 3 investigates the availability of renewable energy resources available locally in Durban. This was achieved by investigating the availability of renewable energy resources in the sun, wind, landfill gas, bio gas, co-generation and hydro generation. Five case studies will then be selected that will be used to carry out further investigations into the impacts of increasing penetration of EG on the eThekwini Electricity distribution network in order to achieve our study objectives.

3.2. Availability of Solar Resources in Durban

"As a developing country with a growing power shortage problem, SA is well placed to exploit its abundant solar resources all across the country. The climate in Durban on the east coast of SA is humid subtropical with hot summers and mild winters." [21] Figure 3.1 depicts the solar map of SA which indicates the annual sun of global horizontal irradiation average across the country.

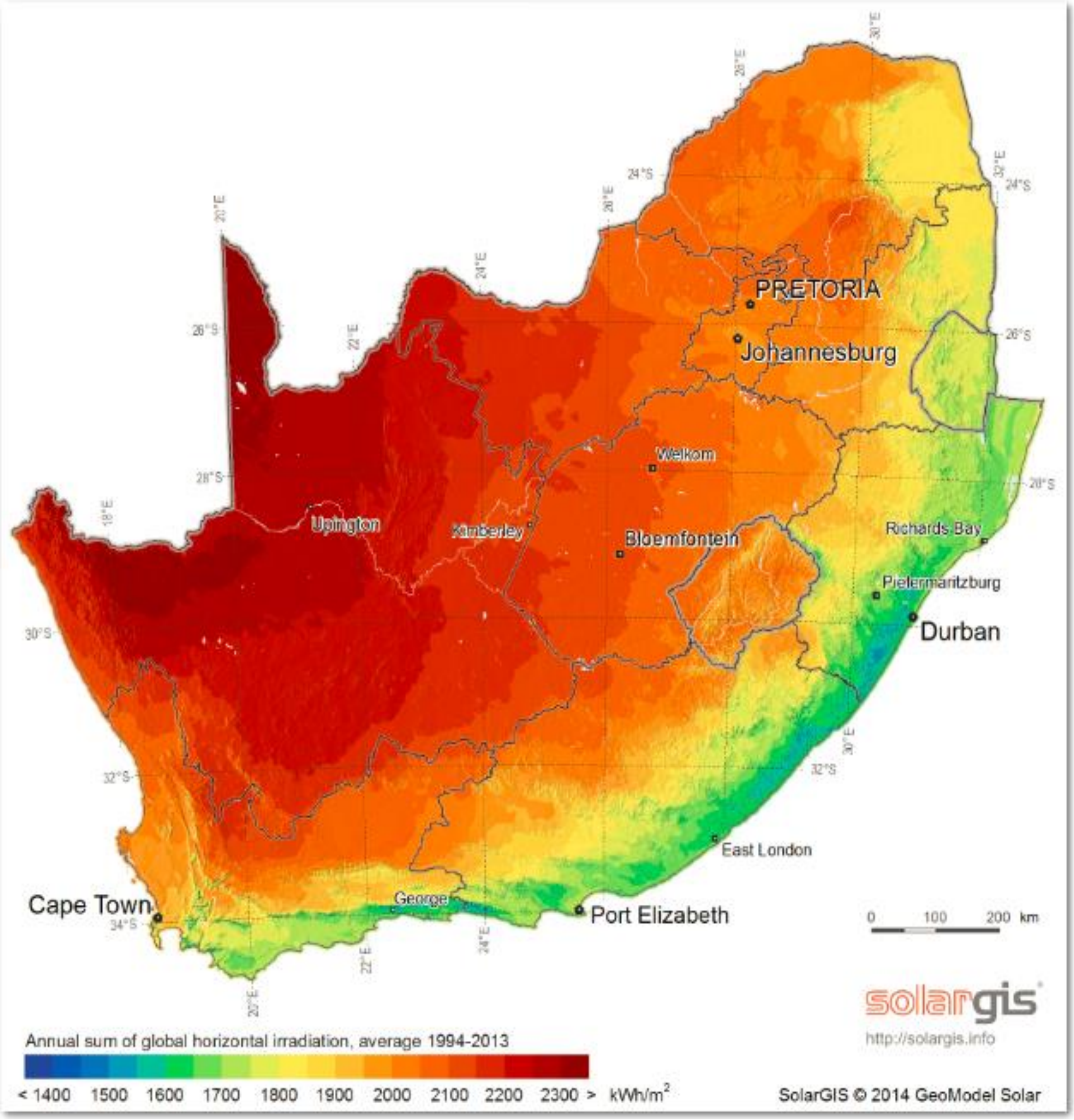


Figure 3.1: Map of the annual sum of global horizontal irradiation average in South Africa [33]

"There is an average of 2343 hours of sunlight hours a year with an average of 6.4 hours of sunlight a day. Solar radiation data measure over a year period confirms that SA has solar energy resources that compares favourably with other global cities where sustainable energy systems have been embraced." [21] From Figure 3.1, it can be seen that the west coast of SA is more suited for solar PV and hence most of the large RPP's have selected the west coast of SA to install their large plants. However whilst Durban has less irradiation than other parts of SA, it has far more than European countries that have made solar PV work. The direct, diffused and global radiation was measured at two sites in Durban and Table 3.1 provides a summary of the current and most accurate data on solar resources for Durban. The average value of the global radiation for Durban is 4.45 kWh/m^2/day shown in Table 3.1 equates to an annual average of 1625 kWh/m^2/year. [21]

Table 3.1: Monthly radiation variation for Durban [21]

Month	Period	˚C	kWh/m^2/d	Ave Sun Rise Time	Ave Sun Set Time
January	Low Demand	24.1	6.39	05:10	18:59
February	Low Demand	24.3	6.14	05:35	18:43
March	Low Demand	23.7	4.77	05:56	18:11
April	Low Demand	21.6	3.86	06:15	17:36
May	Low Demand	19.1	3.64	06:34	17:10
June	High Demand	16.6	2.81	06:48	17:04
July	High Demand	16.5	3.17	06:48	17:15
August	High Demand	17.7	3.71	06:27	17:32
September	Low Demand	19.2	4.1	05:53	17:48
October	Low Demand	20.1	4.07	05:17	18:06
November	Low Demand	21.4	4.85	04:52	18:30
December	Low Demand	23.1	5.93	04:51	18:52
Yearly Average		**20.6**	**4.45**		

3.3. PV Projects connected to the eThekwini Electricity Distribution Grid

3.3.1. Soitec Hazelmere Concentrated Photovoltaic Solar (CPV) Farm

The first Concentrated Photovoltaic (CPV) farm in South Africa was funded by a company called Soitec and built as a show case project for the COP 17 Climate Change Conference that was held in Durban in 2011. The CPV plant was officially opened by the President of SA during the COP 17 Conference and the schematic diagram of CPV farm is shown in Figure 3.2.

“The Soitec Hazelmere CPV system incorporates high-performance triple-junction solar cells which are the same solar cells utilised to power satellite systems. Triple-junction cells have the solar industry’s highest conversion efficiency of nearly 40%, double the efficiency of conventional solar cells. The CPV system requires a high precision dual axis tracker. At each moment of the day, the CPV modules have to be perpendicularly aligned to the sunlight in order to concentrate its light directly onto the cells. Dual-axis tracker system follows the course of the sun from east to west and its height above the horizon.” Thirty two CPV units have been installed to produce a 477 kW peak. The electricity produced by the CPV units is routed via DC cables through the tracker controller box. Each CPV unit is fitted with a 15 kW

SMA string inverter which then injects 400 V_{ac} in to a main distribution board. This then connects onto a step up transformer, which then steps up the voltage to 11 kV and inject it into the eThekwini Electricity distribution grid. [34]

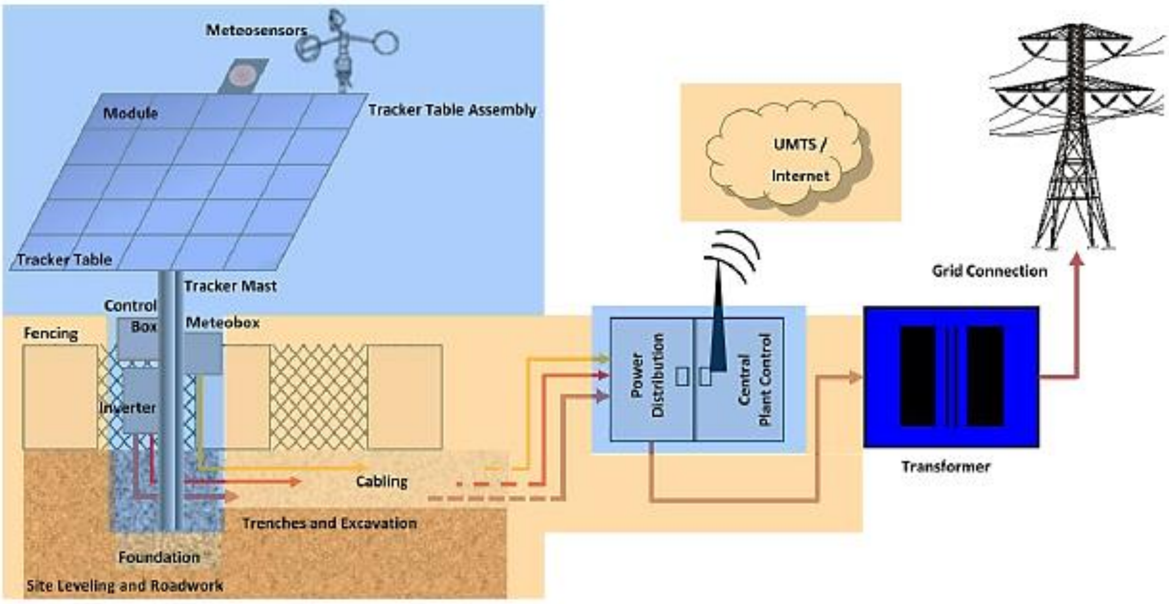
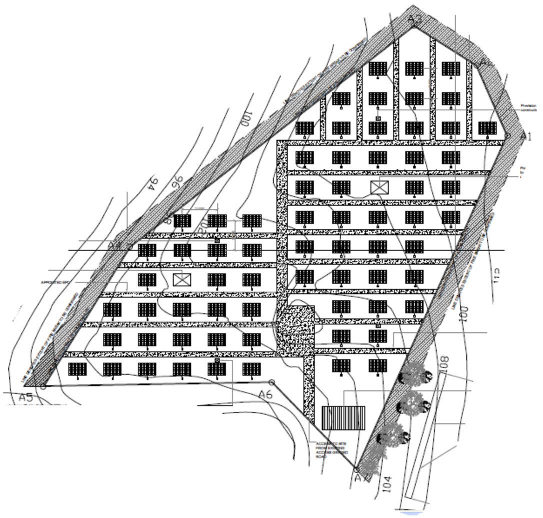


Figure 3.2: Schematic diagram of a typical CPV plant operation [34]

The plant feeds all the generated electricity into the local eThekwini Electricity 11 kV distribution network. The specification of the CPV plant is shown in Table 3.2.

Table 3.2: Technical specification for the Hazelmere CPV farm [35]

Plant Data	
Project Name	Soitec COP17 Solar Legacy Project
	
Plant Size (DC)	477 kWp
Location	South Africa, Verulam, 29˚36́ 43 15″S 31˚03́ 07″E
Altitude	45 m
Site Area in Ha	1
Number of CX – S320 System	32

With the use of the Soitec CPV technology, the advantage is that at least 70% of the power plant area can be used as agricultural land. This was successfully demonstrated in the Hazelmere pilot project.

Figure 3.3: Successful demonstration of dual land use at the Hazelmere CPV farm [35]

The technology used in the Hazelmere CPV farm utilize inexpensive Fresnel lenses to focus Direct Normal Irradiance (DNI) onto small, high efficiency triple-junction solar cells. These high efficiency triple-junction solar cells then convert the sunlight into electricty at twice the efficiency of traditional PV technologies per a square meter. This technology is designed for sunny, dry areas with high DNI. [35]

The technology also uses a dual axis tacking of the sun in order to concentrate the sunlight directly on the solar cell throughout the day, giving a much more constant output power curve. This results in a much more stable production profile when compared to normal thin film PV technology as depicted in Figure 3.4. [35]

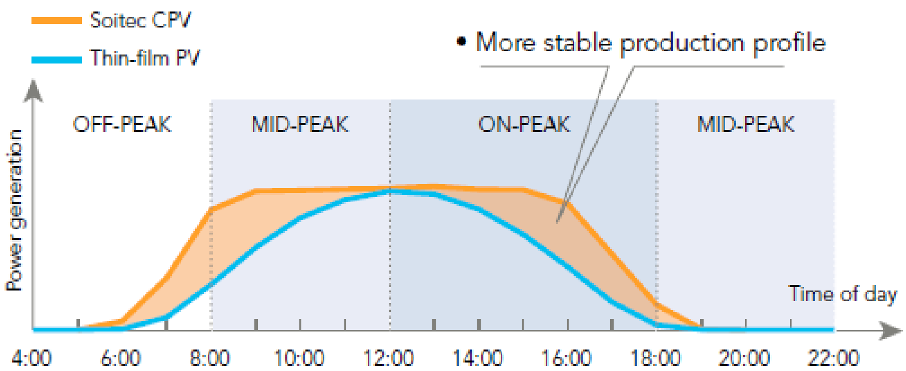


Figure 3.4: Soitec CPV generation profile [36]

3.3.2. Dube Trade Port

Solar PV was installed on various rooftops at the Dube Tradeport in the King Shaka International Airport. The size of the installation for phase one was 762 kWp and made up of four roof top installations. These were 250 kWp on Pack House C, 425 kWp at Farm Wise Packhouse, 84 kWp at Agri House Car Park and 3 kWp at the Pump House. All systems are roof mounted systems made up of Solar World Sunmodule panels and SMA grid tied inverters. The purpose of the project was to supply electricity for their own internal consumption. Figure 3.5 shows the installation on Dube Trade Port pack house at the King Shaka International Airport in Durban. [37]

Figure 3.5: Installation at the Dube Tradeport at the King Shaka International Airport

3.3.3. Man Bus and Trucks

Man Bus and Truck SA Pty Ltd located at 21 Trafford Road in Westmead recently applied to install 2320 of 250 kW solar PV modules mounted on two separate roof structures that will feed into twenty one 25 kW and two 15 kW SMA string inverters. The installation has a potential output of 580 kW. The generated power will be first self-consumed and the excess will then be exported to the eThekwini Electricity distribution grid. [37]

Figure 3.6: Man trucks roof top 580 kW PV installation in Durban [1]

3.4. Proposed PV Projects to be connected onto the eThekwini Electricity Distribution Network

3.4.1. Rooftop PV to be installed on eThekwini Municipality buildings

The eThekwini Municipalities Energy Office was given a R10 million grant to implement rooftop PV on various Municipal Buildings. A tender was awarded to Sustainable Energy Africa (SEA) to carry out a pre-feasibility study on the possibility of installing PV on various Municipal Building. From the initial list of 18 Municipal buildings, 10 buildings were found suitable to install rooftop PV. Table 3.3 shows a list of preferred municipal building rooftops that can be utilised for rooftop PV generation. [38]

Table 3.3: List of preferred sites with potential PV installation sizes [38]

Site	Size of Roof (Horizontal Plane) (m^2)	Estimated Pitch (degrees)	Orientation	Shading	Estimated Norminal Solar PV Size (kWp)	Ratio Max P – Solar to Nominal P - Consumption
1.Metro HQ	1300	0	NNW	Low/items on roof	115	Much smaller
2.Smart Xchange	1475	0	N/A	Low, items on roof, tree	130	Much smaller
3. a Architecture Old Fort Complex - Roofs	2850	30	N	Low, sawtooth roof	250	Similar
3.b Architecture Old Fort Complex - Roofs	3600	0	N/A	None	320	Similar
4.a Loram House roof	54	45	N	Low, roof	5 -10	Larger
4.b Loram House parking	200	0	N/A	Low/medium, buildings	15	Larger
5. Ushaka (office block)	1500	0	N/A	None	135	Much smaller
6.a Moses Mabhida Stadium (MSS) - Arch	20	45	NE	None	2-4	Much smaller
6.b Moses Mabhida Stadium (MSS) – Parking Lot	5600	0	N/A	Low, buildings	500	Much smaller
7. City Library	2850	15	E/W)	None	250	Similar
8.a EWS Customer Services - Roof	510	15	50% N 50% E	Little, trees and buildings	45	Much smaller
8.b EWS Customer Services – Frame Roof	200	0	N/A	Little, trees and buildings	15	Much Smaller
9. MMS Peoples Park Restaurant	870	0	NNE	None	75	Similar
10. City Engineer's Parking Lot	7400	0	N/A	Little, buildings	660	Similar
Total on preferred Sites	**28429**				**2510**	

The following criteria was used for the rooftop PV site selection: size, orientation of roof, possible shading of roof, visibility to the public, estimated maximum size PV that could be installed and the ratio of maximum power production of the solar PV installation to the nominal power consumption of the building. SEA then used a cost of R20/kW installed PV to come up with the required amount of 500 kW that could be installed with the R10 million grant that was given to the Municipality. The list was then shorten down to the 6 sites. [38]

Table 3.4 shows the final selection of municipal building rooftops to be used for the solar PV project.

Table 3.4: List of final roof top PV projects to be implemented. [38]

Installation Name	**GPS Location**	**Building Orientation**	**Roof Type**	**Total Roof Area**	**Utilizable Rooftop Area**
	°N, °E	°		$\mathbf{m^2}$	$\mathbf{m^2}$
Loram House	- 29.504666 31.13480	353°	Pitched, tiles, wood trusses	n/a	162
Metro Police HQ	- 29.505689 31.13058	349°	Flat concrete	2126	857
Moses Mabhida – People's Park	- 29.495542 31.14337	20°	Flat concrete	1589	1257
Moses Mabhida – Sky Lift	- 29.493785 31.15212	19.04°	Flat concrete	n/a	30
uShaka Marine World	-29.52630 31.24027	320°	Flat concrete	1879	1137
Water and Sanitation Building	-29.51773 31.12780	353°	Pitched, metal sheeting, steel trusses	1134	644

Table 3.5 shows the roof of the Metro Police Head Quarters that will be utilised for a proposed 115 kWp rooftop PV installation.

Table 3.5: Metro Police Head Quarters building [37]

Building	**Location and PV System Size**	**PV System Size**
Metro Police Headquarters	29°50'57.05"S, 31° 1'30.66"E	115 kWp

Table 3.6 shows the roof of the eThekwini Municipality Loram House that will be utilised for a proposed 5 kWp rooftop PV installation.

Table 3.6: eThekwini Municipality Loram House Data [37]

Building	**Location and PV System Size**	**PV System Size**
Loram House	29°50'46.74"S, 31° 1'34.82"E	5 kWp

Table 3.7 shows the roof of the eThekwini Municiplaity uShaka Marine World office block that will be utilised for a proposed 135 kWp rooftop PV installation.

Table 3.7: uShaka Marine World office block [37]

Building	**Location and PV System Size**	**PV System Size**
uShaka Marine World office block	29°52'6.07"S, 31° 2'40.43"E	135 kWp

Table 3.8 shows the roof of the eThekwini Municipality Moses Mabhida Statium sky car arch that will be utilised for a 2 kWp rooftop PV installation.

Table 3.8: Moses Mabhida Stadium Sky Car Arch [37]

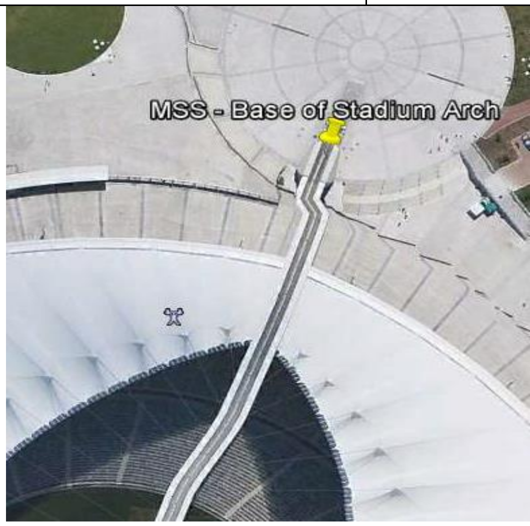
Building	Location and PV System Size	PV System Size
Moses Mabhida Stadium	29°49'38.58"S, 31° 1'51.74"E	2 kWp
		

Table 3.9 shows the roof of the eThekwini Municipality Moses Mabhida Stadium Peoples Park restaurant that will be utilised for a 110 kWp rooftop PV installation.

Table 3.9: Moses Mabhida Stadium Peoples Park Restaurant [37]

Building	Location and PV System Size	PV System Size
Moses Mabhida Stadium – PP Restaurant	29°49'55.29"S, 31° 1'43.42"E	110 kWp
		

Table 3.10 shows the roof of the eThekwini Water and Sanitation Customer Services building that will be utilised for a 45 kWp rooftop PV installation.

Table 3.10: eThekwini Water and Sanitation Customer Services building [37]

Building	Location and PV System Size	PV System Size
eThekwini Water and Sanitation - Customer Services building	29°51'7.74"S, 31° 1'27.72"E	45 kWp
		

3.4.1.1. Intersite Avenue 503 kW Rooftop PV Installation

An application was lodged to install a 503-kWp roof top PV installation at 17 Intersite Avenue in Springfield Park in Durban shown in Figure 3.7. The proposal was to install three module arrays on the roof of the factory. Array one will consist of 1333 of 240 Wp panels producing a power output of 319.9 kWp. Array two consists of 333 of 240 Wp panels producing a power output of 79.44 kWp. Array three consisting of 432 of 240 Wp panels producing a power output of 103.6 kWp. A total of 2096 panels can be installed on the roof at 17 Intersite Avenue which can produce 503 kWp of electricity. The electricity will first be utilized for the factories use and excess will be exported to the grid. [37]

Figure 3.7: PV panel positioning on the roof of 17 Intersite Avenue [37]

3.4.2. Eight kWp installations at Tongaat Secondary School and Temple Valley Secondary School

The Dube Tradeport sponsored two three phase 8 kWp DC PV systems to be installed on both the Tongaat Secondary School and the Temple Valley Secondary School. The Tongaat Secondary School has a three phase 80A connection whilst the Temple Valley Secondary School has a three phase 120A connection. The generated power is to be used up by the schools and the excess will be exported to the grid at times of low usage. Figure 3.8 shows the images of the Tongaat Secondary School and Temple Valley Secondary School.

Tongaat Secondary School **Temple Valley Secondary School**

Figure 3.8: Google Images of Temple Valley and Tongaat Secondary School [37]

The proposal for the schools are to use two strings of sixteen 250W panels each connecting onto an 8 kW SMA inverter as depicted in Figure 3.9. This will then connect via a 63A circuit breaker on to the main distribution board at the school. [37]

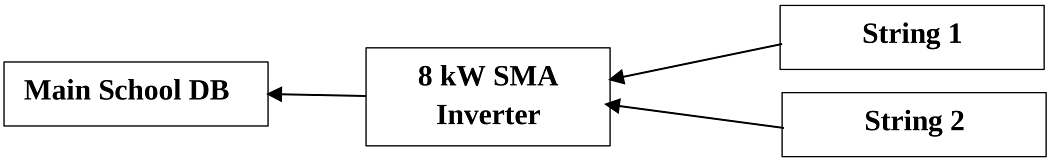


Figure 3.9: Proposed connections diagram for the schools [37]

3.4.3. Eighty kWp installation at Riverhorse Valley

A new factory was been built at the Edstan Business Park in Riverhorse Valley and an application for the installation of 80 kW roof top PV to be operated in parallel with the eThekwini Electricity grid was lodged. The co-ordinates for the location of the site is latitude/longitude: -29.7735972431°/30.9942877293°. The roof top PV system consisted of a 60 kWp crystalline silicon PV panel that was inclined at an angle of 27° (northeast), whilst the awning PV system was 19.285 kWp and inclined at an angle of 5°. The installation utilized Schneider Conext TL three phase grid tied inverters. The purpose of the installation was to provide electricity for own consumption during the week and the excess to be exported to the grid on weekends. [37]

3.4.3.1. 11.52 kWp Rooftop PV installation

An application was made for the installation of a 11.52 kWp roof top PV system at 11 Nattall Gardens in Morningside. The purpose of the installation was for own use for the customer with excess to be exported to the eThekwini Electricity distribution grid. The project was to operate in parallel with the grid and utilized an SMA Tripower inverter. Figure 3.10 shows the simulated kWh to be generated from the 11.52 kW rooftop PV installation. The graph shows the projected generated kWh varying between 1460 kWh in June to 1710 kWh in January. A total of 19 350 kWh is projected to be generated per an annum. These simulated generation output figures by the installer is however dependant on actual weather condition, adequacy of installation, maintenance of the system and the availability of the electricity grid. [37]

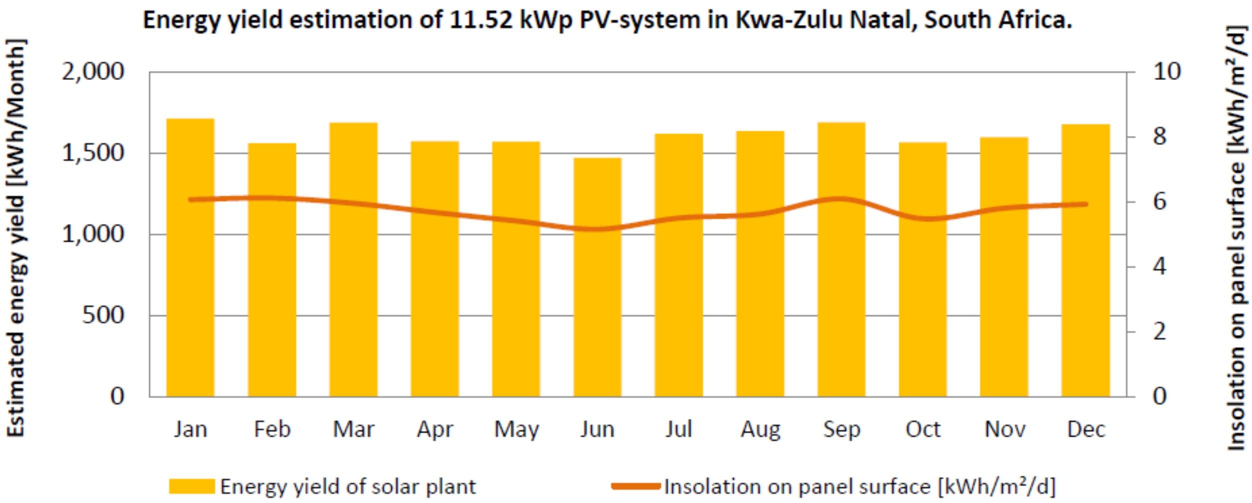


Figure 3.10: Projected kWh figures for the 11.52 kWp PV installation [37]

At the current eThekwini Electricity three phase tariff structure where it costs R1.5878/kWh, if all the electricity is to be utilized by the consumer then he would have saved R30723.93 per annum.

3.5. Potential PV Farms: Installation of Solar PV on old closed landfill sites

For the development of medium to large scale PV farms there need to be large plots of land available that these farms can be built on. These sites need to be located close to the grid in order to keep the grid connection costs to a minimum. We investigate potential plots of land that can be utilized for the installation of PV farms. Large plots of land close to the grid connection is expensive and not readily available in Durban. However there are currently in excess of 20 old landfill sites within eThekwini Municipality that are owned by the municipality. These are large sites which has limited land use options due to the future settlement of the land. This land hence has very low property value and could be leased relatively cheap from the municipality. This provides excellent potential for medium to large scale PV installations. the 9 most suitable sites were selected for further investigation of the 20 potential old landfill sites. The 9 most suitable sites and the PV installation potential is depicted in Table 3.11. Table 3.11 provides the size and generation capacity of at each of the 9 sites selected. This indicates that there is 100 hectares of land available from these 9 selected sites with a generation potential of 53 MWp.

Table 3.11: PV potential from closed landfill sites in eThekwini [38]

Closed Landfill Sites	ZS_ DECIMA	ZE_ DECIMA	Size	Unit	PV Capacity	Unit
La Mercy	-29.62028	31.13528	7.5	ha	4	MWp
Rochdale	-29.79584	30.986211	10	ha	5	MWp
Old Airport	-29.96218	30.965185	9	ha	4.5	MWp
Silverglen	-29.93972	30.92416	10	ha	5	MWp
Umlazi 4	-29.98194	30.90833	8	ha	4	MWp
Umlazi 1	-29.96806	30.91917	3.5	ha	2	MWp
New Germany	-29.79167	30.88528	3.5	ha	2	MWp
Mpumalanga	-29.81083	30.65278	3	ha	1.5	MWp
Bisasar (phase 1)			20	ha	10	MWp
Bisasar (phase 2)			20	ha	10	MWp
Total			**100**	**ha**	**53**	**MWp**

Closed landfill sites offer opportunities for medium/large scale PV installations (>1MWp) because their geotechnical instability prohibits other developments, and the land has therefore no commercial value. In Europe and the US PV installations on closed landfill sites are becoming increasingly common. An example of a PV installation on a closed landfill site is shown in Figure 3.11. [38]

Figure 3.11: Example of a 3.7 MW ground mount PV on a landfill site in Rhode Island [39]

The most prominent landfill site within eThekwini Municipality is the Bisasar Road Landfill in Springfield Park. Half of the landfill site is closed and has settled suffiently for PV installations whilst the remaining half requires about 5 years for initial settlement after closure. [38]

3.6. Availability of Wind Resources in Durban

"One of the key constraints that local South African municipalities face in facilitating the production of renewable energy is the lack of reliable renewable resource assessment within their municipalities to understand what natural resources are available for electricity generation."[38] Hence a wind resource map that was then created for the eThekwini Municipality is shown in Figure 3.12. The wind resource map indicates that there are a number of areas that experience wind speeds between 6.5 and 8.1 m/s and 6 to 6.5 m/s. Wind speeds which exceed 6 m/s are considered to be commercially viable for the installation of wind turbines. Whilst on the residential side, wind speeds in excess of 4 - 5 m/s is considered viable. [38]

Whilst the wind resource in eThekwini Municipality suited in the Kwazulu Natal Province is lower than wind speeds experienced in the Eastern, Western and North Cape, it still has commercial potential for the installation of wind farms. A study was then carried out within the eThekwini Municipality area of supply to identify potential wind farm sites. Ten sites were then identified which supported wind farms sizes between 15 MW and 27.5 MW. These 10 sites can cumulatively support a total installed capacity of 215 MW of wind turbines. The 10 site selections was based on the following factors: [38]

(i) Wind speed needed to be greater than 6.2 m/s

(ii) Close proximity to the grid connection point.

(iii) One landowner for each site selected.

(iv) Urban and suburban areas were excluded.

(v) Wind turbines selected were 2.5 MW.

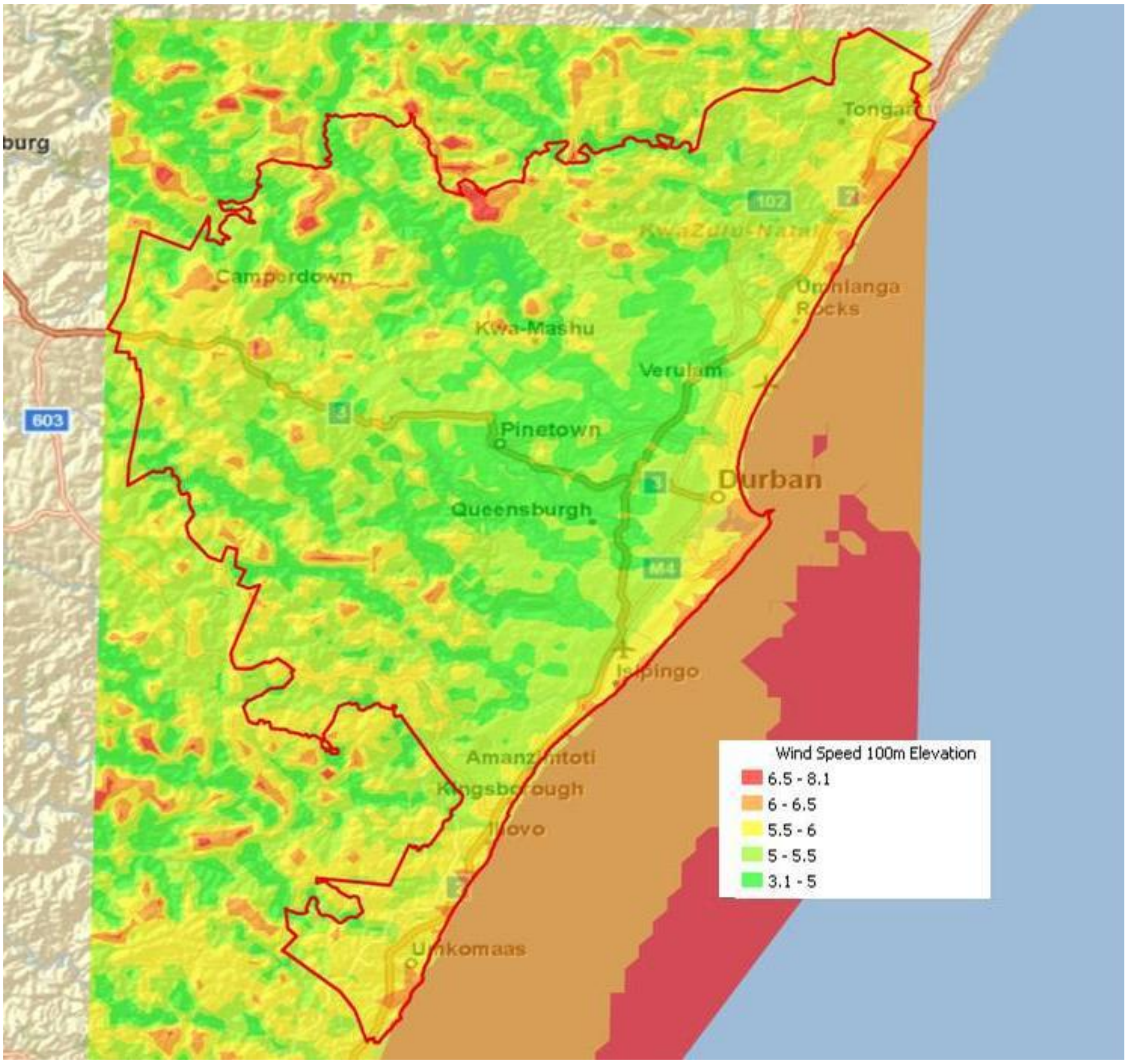


Figure 3.12: Wind map of the eThekwini Electricity area of supply [18]

The following 10 sites in Table 3.12 were identified as potential sites within the exponetial moving average (EMA) that could be considered for further investigation.

Table 3.12: Wind farm potential and locations in Durban [18]

Site Number	GPS Co-ordinates	Number of Turbines	Capacity MW	Mean Wind Speed (m/s)	Area (km^2)	Landmark/Area
Site 1	-29.619459, 30.7238897	10	25	6.5	2.337	Nagl Dam; Valley of a Thousand Hills; Sithumba
Site 2	-29.692687, 30.62732835	8	20	6.2	1.591	Directly south of Nagl Dam; west of MR423
Site 3	-29.6389813, 30.85186955	11	27.5	7.3	2.249	Inanda Dam North
Site 4	-29.7106024, 30.88448335	9	22.5	6.2	1.873	Inanda Dam South East
Site 5	-29.8999154, 30.7152307	8	20	6 - 6.7	1.476	Shongweni Dam South; south of Mr489 Road
Site 6	-29.9283609, 30.80834673	9	22.5	6.2 - 6.6	1.231	Umlazi North West; Inwabi
Site 7	-29.8795165, 30.64369913	9	22.5	6.2	2.153	Shongweni Dam West; directly next to Mr489
Site 8	-29.726814, 30.85641969	6	15	6.2 - 6.6	0.789	Inanda Dam Langefontein
Site 9	-29.7419252, 30.63926058	8	20	6.2 - 6.6	1.158	Camperdown Rural; directly next to N3
Site 10	-29.9361459, 30.67968106	8	20	6 - 6.7	1.324	Nkomokazi; Umbumbulu

3.6.1. Wind Projects – eThekwini Electricity Disaster Recovery Control Centre

The eThekwini Electricity department has built a Disaster Recovery Network Control Centre in Westville. A Vertical Axis wind turbine is installed at this centre. The specification of the wind turbine is shown in Table 3.13. The purpose of the turbine was to assist with the green image of the building.

Table 3.13: Wind turbine specification for the eThekwini Electricity Disaster Recovery Centre [37]

1500 W Vertical Wind Turbine Specification		
	Rated Power	1500 W
	Rated Wind Speed	10 m/s
	Start-up Wind Speed	3 m/s
	Cut – in wind speed	4 m/s
	Survival wind speed	50 m/s
	Rotor diameter	3 meters
	Blade Length	3 meters
	Blade Material	Galvanise

3.6.2. UKZN Westville Campus Wind Repowering Project

Four large 150 kW wind turbines were donated to the eThekwini Municipality by the City of Bremen in Germany in 2011. These turbines were proposed to be installed in the Durban Bluff area as a show case for the COP 17 Climate Change Conference but, due to objections from various bird and bats societies, the installation was stopped. These turbines were 30 meter high with a blade diameter if 23 meters. The major concern was the Bluff area had the largest colony of slit-faced bats. For this reason, other sites were then evaluated and finally the UKZN Westville Campus was selected as the location of choice. Requested studies are currently been carried out at the university campus by Natural Scientists to evaluate the potential impacts to any bird and bats.

3.7. Availability of Gas to Electricity Projects within eThekwini Municipality

3.7.1. Availability of Landfill Gas to Electricity Projects

Landfill gas to electricity technology has been piloted and proven to work at utilities around the world. There are a large number of landfill sites within eThekwini Municipality to deploy this technology for the purpose of generating electricity. Figure 3.13 below indicates the locations of these landfill sites in eThekwini Municipality.

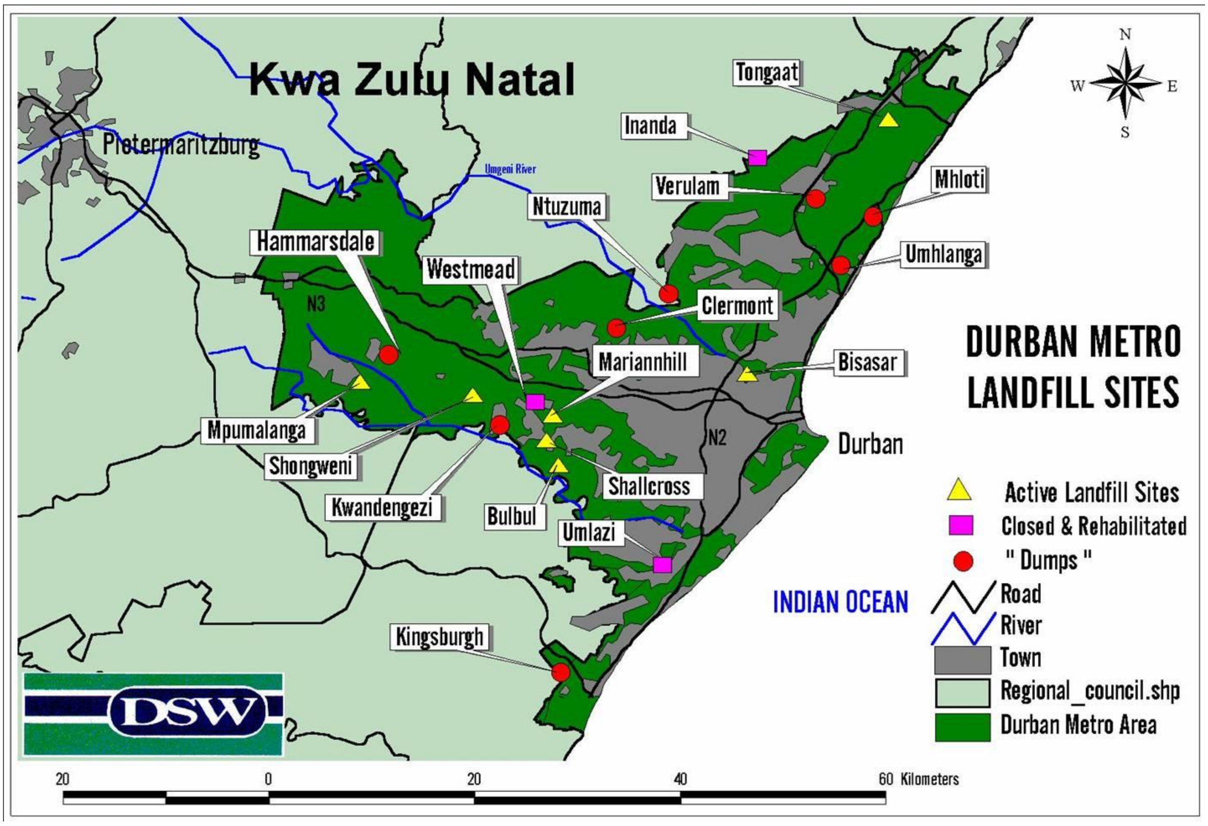


Figure 3.13: Landfill sites in eThekwini Municipality [18]

There is a number of municipal and private owned landfill sites in and around Durban namely Bisasar Road landfill site, Marianhill landfill, Buffelsdraai landfill, Bul Bul drive landfill, Shongweni landfill, etc. These sites produce large amounts of landfill gas made up of a high concentration of Methane gas which can then be captured and utilised to generate electricity with the use of a landfill gas to electricity generators. The process of extracting and using the gas to generate electricity is explained in Figure 3.14.

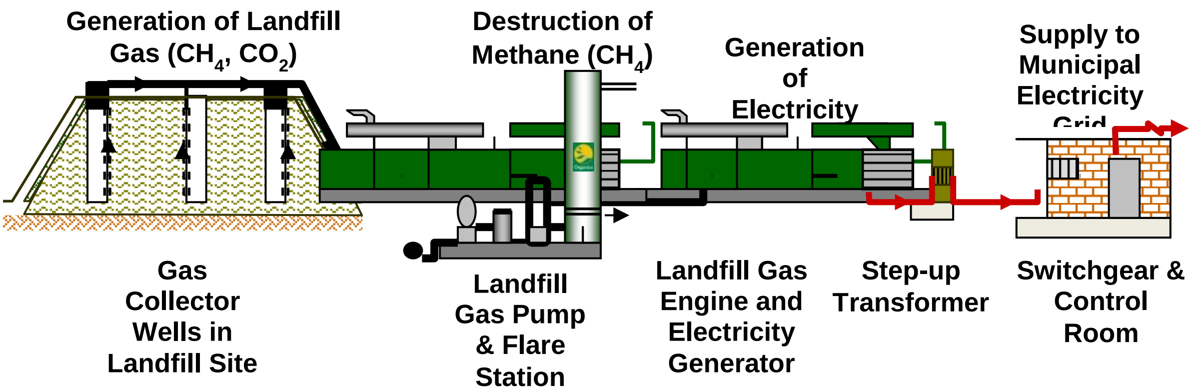


Figure 3.14: Schematic Layout of Landfill Gas-to-Electricity Project [5]

The process required to extract the landfill gas from the site in order to be used it as a fuel for the landfill gas-to-electricity EG units is shown in Figure 3.14 and entails the following process; [41]

(i) “Vertically driven or horizontal extraction gas wells need to be constructed on the landfill site.

(ii) Gas collection pipe works then installed from the extraction wells to the extraction plant from where it is distributed to the electricity generators and the excess to the flare.

(iii) Centrifugal blowers installed for the sole purpose of extracting the gases from the extraction wells and supplying it to the generators and the excess to the flare.

(iv) The landfill gas engines coupled to a synchronous generator then use the extracted gas from the landfill site as a fuel to generate electricity. They commonly available in 1 MW modules (e.g. Jenbacher type 320 engines).

(v) A flare unit is installed at the site to flare of the excess extracted gases that are not utilised by the gas engines.

(vi) Appropriate size cable/lines and switchgear are installed on site to allow interconnection onto the local distribution network. The generated electricity is injected into the closest Distributor Substation within the distribution network.” [41]

3.7.2. Bisasar Road Landfill Site

“The Bisasar Road landfill site was established in 1980 and has a total surface area of 44 hectors with a capacity of 21 million cubic meters. It is said to be the busiest landfill on the African continent accepting a daily average of 3500 to 5000 tons of waste. Gas studies performed at this site has indicated that there will be enough of landfill gas at this site to generate 8 MW of electricity.” [5] The extent of the Bisasar Road landfill site is shown in Figure 3.15

Figure 3.15: The Bisasar Road landfill site [5]

3.7.3. Marianhill Landfill Site

The Marianhill Landfill site is located in the west of Durban and accepts 500 to 700 tons of waste a day. The site was opened in 1997. Gas is extracted and used to generate electricity via a single 1 MW generator. The site has a potential to generate 2 MW of electricity in the future. The generated electricity currently feeds into the eThekwini Electricity grid. [18]

Figure 3.16: Marianhill landfill site gas to electricity project [18]

3.7.4. Buffledraai Landfill Site

The Bufflesdraai landfill site was commission in 2007 and is 100 Ha in size. Meetings held with the eThekwini Municipality Solid Waste Department have revealed that the site has the ultimate potential to generate 10 MW of electricity in the future as the amount of waste starts to increase. This electricity will then be injected into the eThekwini Electricity distribution network. The landfill site has a lifespan of 50 years. [41]. Figure 3.17 indicates the vast extent of the Buffelsdraai Landfill site.

Figure 3.17: Google Image of the Buffelsdraai Landfill site [41]

3.7.5. Availability of Biogas to Electricity Projects at eThekwini Municipality

eThekwini Municipality owns and operates a number of wastewater treatment works in and around Durban. A pre-feasibility study was conducted on a number of these wastewater works with a view of identifying the capacity of biogas produced during the anaerobic digestion of sludge at these wastewater treatment works. The gas produced by the wastewater treatment works have the potential to generate electricity through a gas engine which also produce heat as a by-product. The electricity can be utilised to offset the electricity utilised by the treatment works with the excess exported to the grid whilst the heat produced from the engine can be used to warm the digesters or to dry sludge. The wastewater treatment works included in the prefeasibility study together with the biogas capacity and the electricity generation potential is shown in Table 3.14. [38]

Table 3.14: Wastewater treatment works capacity and generation potential [38]

Name of Wastewater Treatment Works	Capacity	Generation Potential
Durban Northern Wastewater Works	70 ML/d	800 – 1000 kW
Durban Southern Wastewater Works	155 ML/d	+- 2000 kW
Phoenix Wastewater Works	50 ML/d	550 – 650 kW
Amanzimtoti Wastewater Works	22 ML/d	100 – 150 kW
Kwa Mashu Wastewater Works	51 ML/d	550 – 650 kW

In order to harness the biogas from the existing waste water treatment works for electricity generation, the following needs to be taken into account: [42]

- The existing digesters will need to be optimized to ensure that biogas generation is sufficient for adequate electricity generation.
- Gas to electricity engines/generators will need to be installed for electricity generation from the biogas.
- Effective scrubbing of the gas to remove solids, Ammonia, Silicon, moisture and H_2S will be critical to the success of the project as impurities in the gas will result in damage to the gas engines and affect electricity production.
- Depending on the electricity usage at the individual treatment works, excess energy may need to be exported to the grid.
- An effective heat exchange system needs to be installed to ensure that waste heat energy from the gas engines is used to heat the digesters. This in turn will assist in optimizing biogas production and ensuring adequate electricity generation.

3.7.6. Gas Peaking Plant

Meetings were carried out with an IPP who proposed to put up a gas peaking plant in eThekwni Municipality in Durban. The proposal was to use natural gas which will be compressed and stored in tanks and use it to run a gas turbine during peak hours only and if the Municipality required emergency power. The proposed turbine to be installed was 38 MW. According to the IPP, from their feasibility studies done, it made commercial sense to only run the turbine during the peak hours. This was due to the best tariff rates (winter peak rate: R2.5299 and summer peak rate: R0.8251) on the Eskom Megaflex TOU tariff structure that eThekwini Electricity paid larger EG projects to ensure that Eskom avoided costs were paid for any electricity purchased. [37]

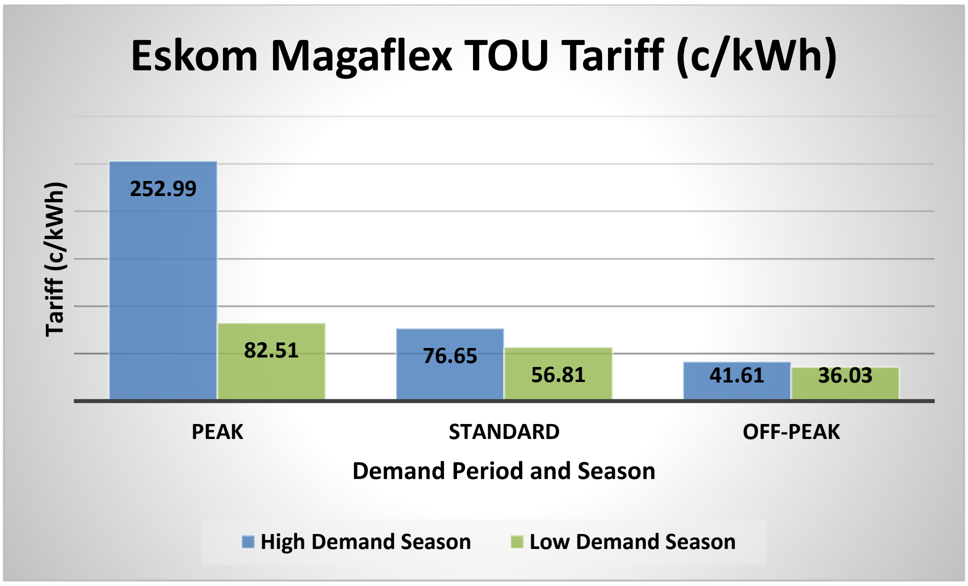


Figure 3.18: Peak, standard and off peak rates for high and low demand season [24]

It is for this reason that the IPP opted to exploit the peak tariff rates and only generate in this period. According to the IPP, the project is financially viable with the calculations done using the winter (3 months) and summer (9 months) rates. The IPP hence proposed that the gas be compressed and stored and generation carried out only during the peak tariff periods. They did offer options to purchase power at any time that eThekwini Electricity required power at a premium negotiated rate. [37]

3.8. Availability of Hydro Generation at eThekwini Municipality

3.8.1. Micro Hydro Generation

Durban is not blessed with any large rivers and dams that will support hydro generation however there are a number of water reservoirs in and around the city of Durban which contains high water pressures on the water inlet pipes to the reservoirs. There is hence a need for pressure reducing valves to reduce the pressures to prevent damages to the inlet pipes. Based on these pressures, the eThekwini Municipality Water Department has looked into the option of installing micro hydro turbines in parallel with pressure reducing valves as shown in Figure 3.19 at the inlet to various reservoirs across the city. It is proposed to insert the turbine in parallel with the pressure reducing valve and only use the valves when the turbine is not operational. The daily flow rates and hence pressure vary on the water pipeline network which will affect the generation output. Five reservoirs were assessed for micro hydro potential at eThekwini Municipality and the results are shown in Table 3.15. Larger reservoirs were selected with higher water flow rates that were situated in close proximity to the local grid. The electricity consumption was also looked at to assist with the project feasibility by offsetting the reservoir usage with the electricity generated. Once commissioned these micro hydro turbines will then feed the electricity needs of the reservoir and export the excess to the municipal grid. [18]

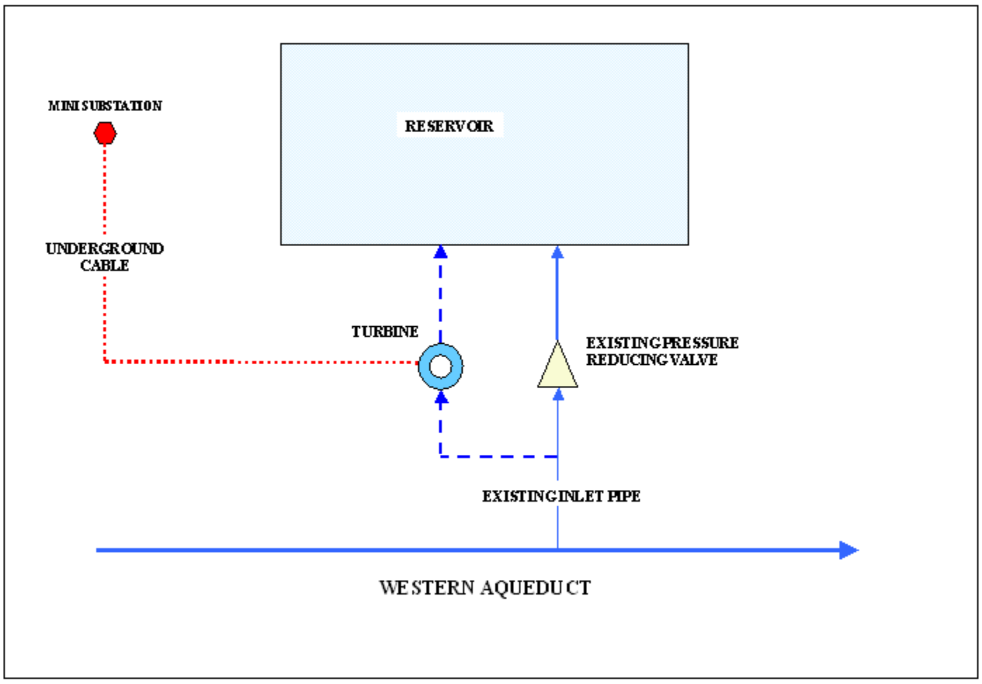


Figure 3.19: Proposed micro hydro turbine installation at reservoirs around the city [18]

Table 3.15: List of reservoirs assessed and generation potential at eThekwini Municipality [18]

Name of Reservoir	**Size of Hydro Turbine**
Theomore Reservoir	71 kW
Stone Bridge Drive Reservoir	104 kW
Umhlanga Rocks Reservoir	Between 26 and 177 kW
Yellowfin and Escolar Reservoir	Between 26 and 177 kW
Avocado and Pomegranate Reservoir	Between 26 and 177 kW

3.8.2. Western Aqueduct Hydro Project

The Western Aqueduct Hydro Project is a water pipeline (aqueduct) project that is been implemented by the eThekwini Municipality Water Department for the sole purpose of transferring water from the Umlass Road reservoir to new and existing reservoirs in and around the city of Durban to meet growing water demands as shown in Figure 3.20. The first phase of the Western Aquaduct covered 19 km from Umlass to Inchanga Station whilst the second phase covered 55 km from Inchanga Station to Umlazi. The project completion is expected in 2017.

During the project feasibility study, it was then realized that there was a need for break pressure tanks to be installed at two sites as calculations showed high water pressures due to the hilly terrain that the aqueduct traverse through. It was at this stage when the thought of installing hydro generators at these two sites with opportunity to generate additional revenue from the electricity sales and possible Carbon credits. Together with the national electricity shortages, recent spate of load shedding and additional revenue generated from selling the Carbon credits from this project, the project soon looked financially attractive and it was then decided that two hydro generators will be installed on route as part of the Western Aqueduct Pipeline Project. Two sites were identified to install hydro turbines. Water flow rate calculations indicated that a 3.6 MW hydro turbine could be installed at the first site whilst calculations showed a 3 MW hydro turbine could be installed at the second site. [38].

Figure 3.20: Pipeline to be installed for the Western Aqueduct Project [38]

3.9. Co-generation

There are many industries that have the potential and opportunity to generate electricity from their existing plant and processes. This can then be used to supply their own electricity needs whilst exporting the excess to the local grid. Durban currently has two companies that have Power Purchase Agreements to sell excess power that is co-generated via their processes.

3.9.1. Tongaat Hullets

The Tongaat Hullets Maidstone Sugar Mill has the capacity to crush 475 tons of raw sugar cane per an hour. This then produces 150 tons of bagasse an hour when the mill is crushing at full capacity. Bagasse is a by-product of sugar cane which can be considered as a free energy resource. The calorific value of bagasse at the Maidstone Mill is 7.7 GJ/ton. Bagasse is currently used as a fuel in the boilers at the Maidstone Mill to produce steam only during the sugar crop season. Sugar Mills across South Africa have historically utilized this bagasse by-produce as a source of fuel to raise their internal steam and electrical requirements. The Tongaat Hullets Mill currently exports about 1 MW of electricity to the eThekwini Electricity grid. [43]

3.9.2. NCP Alcohols

NCP Alcohols is an extra neutral ethanol manufacturer located in Springfield Park in Durban. They currently uses gas fired high pressure boilers to produce steam which then drives a 3 MW steam turbine. This then produces the plant electricity requirements and low pressure steam from the turbine exhaust. The co-generation currently supplies 98% of their electricity requirements whilst the excess is exported to the eThekwini Electricity grid. NCP Alcohols are also planning on converting one of its coal fired boilers to gas which will enable them to generate a further 2.6 MW electricity to export to the grid. [44].

3.10. Network Background

3.10.1. The South African Electricity Grid Background

"Most of South Africa's base generation is thermal coal fired power stations located in the northern and north east regions of South Africa namely Limpopo and Mpumalanga Provinces respectively shown in Figure 3.21 and Table 3.16. A nuclear power station with two 955 MW units is also situated in the Western Cape Province. There are pumped storage schemes at Drakensburg (1000 MW) and Palmiet (400 MW) and to be further supplemented by Ingula (1300 MW) under construction, situated in KwaZulu Natal Province. There is also Open Cycle Gas Turbines (OCGT) providing 2415 MW installed capacity. South Africa is also a net exporter of (2000 MW) and interconnected with five neighboring countries; Namibia at 220 kV and 400 kV, Botswana at 400 kV, Swaziland at 400 kV, Mozambique via two 533 kV DC lines (1700 MW). The 2012 National peak demand was 38 GW. Power transmission voltage levels in South Africa are at 765 kV, 400 kV, 275 kV and 220 kV. The responsibility for distribution of electricity is shared between Eskom, the municipalities and other licensed distributors. About 180 municipalities distribute 40% of electricity sales to 60% of the customer base. Sub-transmission and distribution voltage levels are 132 kV, 88 kV, 66 kV, 44 kV, 33 kV, 22 kV, 11 kV and 6.6 kV." [5]

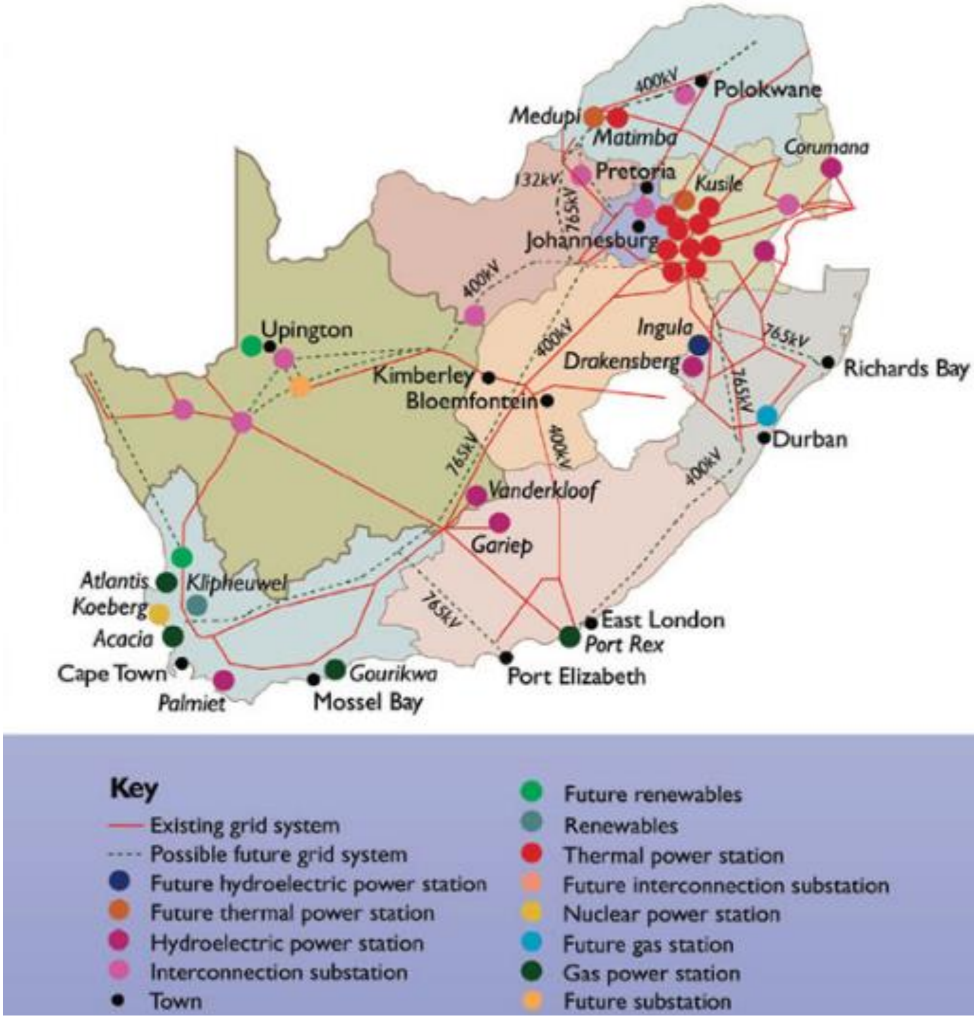


Figure 3.21: Location of Eskom Power Stations [5]

Table 3.16 shows the Eskom's generation fleet in South Africa.

Table 3.16: Break down of Eskoms generation fleet in South Africa [5]

Name of Station	Type of Station	Sets (MW)	Total Capacity (MW)	Commencement of Operation
Arnot	Coal		2100	1975
Candem	Coal		1600	1967
Duvha	Coal		3600	1980
Grootvlei	Coal		1200	1969
Hendrina	Coal		2000	1970
Kendal	Coal		4116	1988
Komati	Coal		1000	1961
Kriel	Coal		3000	1976
Lethabo	Coal		3708	1985
Majuba	Coal		4110	1996
Matimba	Coal		3990	
Matla	Coal		3600	1983
Tutuka	Coal		3654	1985
Koeberg	Nuclear	2 x 960	1920	1984
Gariep	Hydro		360	1971
Vanderkloof	Hydro		240	1977
Drakensberg	Pumped Storage		1000	1981
Palmiet	Pumped Storage		400	1988
Darling	Wind		5.2	2008
Klipheuwel	Wind		3.2	2002
Acacia	OCGT		171	1976
Port Rex	OCGT		171	1976
Ankerlig	OCGT		1338	2007
Gourikwa	OCGT		746	2007
Medupi	Coal	6 x 800	800	2015
Kusile	Coal	6 x 800	-	-
Total installed Capacity		**44832.40 MW**		

The installed generation capacity in SA is 44832.40 MW. Bulk of this capacity comes from base load coal fired power stations. This generation capacity is then distributed to a wide sector of customers all around SA.

3.10.2. Background to the eThekwini Electricity Grid

eThekwini Electricity supplies more than 723 593 customers in an area covering nearly 2 000 square kilometers in and around the city of Durban. In 2014 eThekwini Electricity purchased a total of 11 236 882 178 MWh of electricity from Eskom. The maximum demand peaked at 1 756 MVA. [17] eThekwini Electricity currently purchases just over 5% of the total energy generated by Eskom in South Africa. This is purchased from Eskom at 275 kV at three in-feed points namely Georgedale Major Substation (400/275 kV), Hector Major Substation (400/275 kV) and Avon Major Substation (400/275 kV). This is then fed into the five 275 kV in feed points at eThekwini Electricity namely Durban North Major Substation (275/132 kV), Durban South Major Substation (275/132 kV), Klaarwater Major Substation (275/132 kV), Lotus Park Major Substation (275/132 kV) and Ottawa Major Substations (275/132 kV). [5]

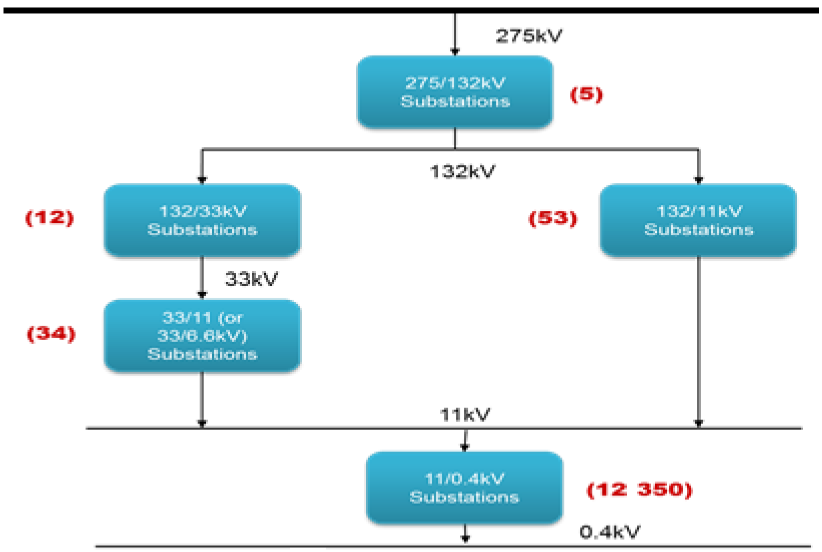


Figure 3.22: eThekwini Electricity infeed and transmission networks (45)

Figure 3.22 and Figure 3.23 shows the eThekwini Electricity transmission (33 – 275 kV) and distribution (11 kV) network. At the transmission level, there is in excess of 100 Major Substations, 650 km of overhead line and 400 km of underground cables. At distribution level, there is in excess of 15 000 substations, 3 500 km of overhead line and 17 000 km of underground cables. [46]

Electricity from the 275kV in feed substations is then transformed to 132 kV which then supply about one hundred and five Major Substations within the eThekwini electricity area of supply. These substations then transformer the voltage from 132kV to either 33 kV or directly to 11 kV. The 33 kV substations then further transformer the voltage to 11 kV. The

11 kV, 400V and 230V is then used to distribute electricity to residential, commercial and business customers. There are a few large industrial customers that purchase electricity at 132 kV and 33 kV. Electricity is currently purchased from Eskom on the Eskom 275 kV Megaflex TOU tariff structure.

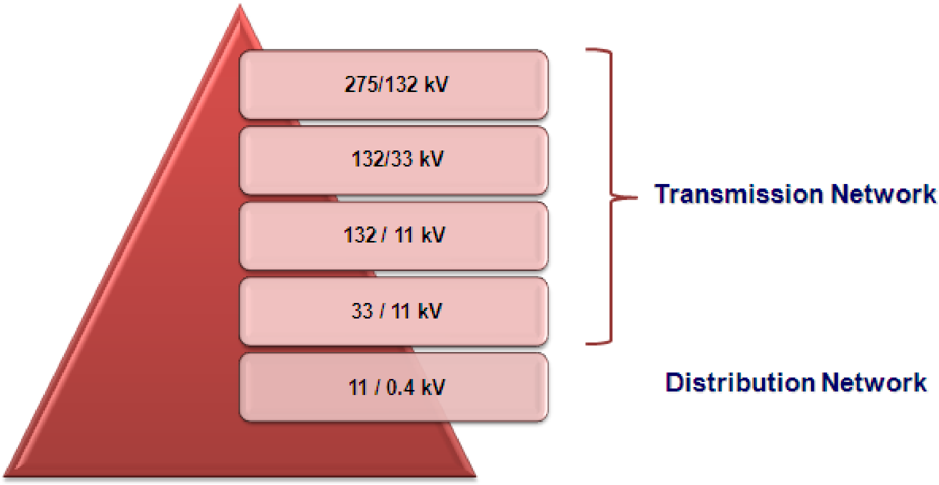


Figure 3.23: Voltage levels at eThekwini Electricity [45]

In order to carry out the required studies, we will utilize a typical 132/11 kV and a 33/11 kV eThekwini Electricity distribution grid to carry out the studies upon. Currently all of the EG connections or proposed connections at eThekwini Electricity is either at 11 kV, 400V or 230V hence the focus area for this study will look at connections at these voltage levels. For larger projects such as wind and solar farm, the connection voltage level will be either 33 kV or 132 kV. The distribution grid selected and modelled for the study will depict a typical MV network at eThekwini Electricity that EG will connect onto. The primary focus of these studies is to understand how the distribution network design and performance will be affected with the increased levels of EG penetration.

eThekwini Electricity currently has 723 589 customers on 15 different tariffs structures as depicted in Table 3.17.

Table 3.17: Breakdown of eThekwini Electricity customer base [24]

Tariff Scales	**Descriptions**	**2013/2014 – Number of Customers**
1	Business and General	40 524
2	Business and General (Two Rate) – Obsolete	1 234
21	Business and General (Two Rate) – Obsolete	258
5	Business and General – Discontinued	865
6	Business and General – Discontinued	98
7	Business and General – Discontinued	14
3&4	Single and three phase credit residential	319 875
8&9	Residential Prepaid	358 411
10	Business and General - Prepaid	1 142
11	Business and General - Prepaid	209
LV3	Low Voltage 3-part – obsolete	132
CTOU	Commercial Time of Use	96
ITOU	Industrial Time of Use	731
Others	Eskom Megaflex TOU	4
Total		**723 589**

The current eThekwini Electricity (EE) residential single and three phase tariffs are R1.5878/kWh. There are presently 319 875 (44%) single and three phase credit residential customers that utilize an average of 700 kWh a month. There are also 358 411 (49%) prepaid customers that utilize an average of 200 kWh on average a month. The relatively low electricity usage can be attributed to many factors including the fact that of the base of pre-paid electricity users, about 100 000 consumers qualify for free basic electricity of 65 kWh per month. These are for electricity users who utilise below 150 kWh a month. Bulk of the pre-paid electricity users are residents from informal settlements, rural areas and transit camps. Their electricity needs and monthly usages are relatively low as they rely on the free basic electricity tokens. Based on their consumption figures, dwelling sizes and income levels, credit customers are most likely to install rooftop PV systems. [38]

Figure 3.24 provides a breakdown of the eThekwini Electricity sales amongst the different category of customers whilst Figure 3.25 provides the revenue distribution amongst the different category of customers at eThekwini Electricity.

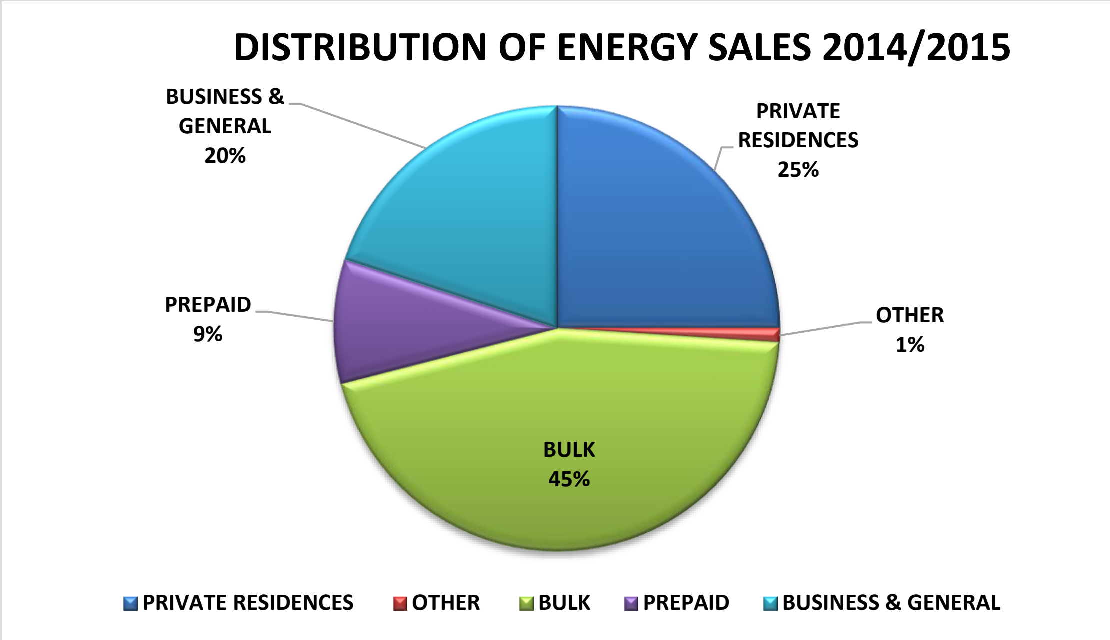


Figure 3.24: Distribution of energy sales for 2014/2015 at eThekwini Electricity [24]

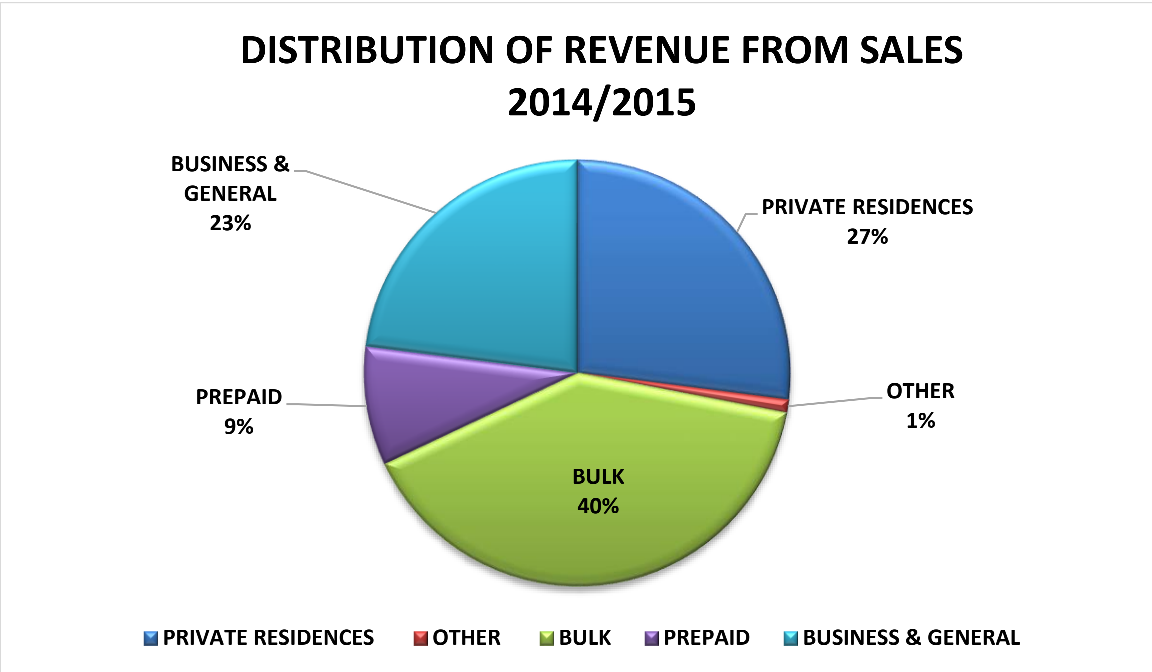


Figure 3.25: Distribution of revenue from total electricity sales at eThekwini Electricity [24]

3.11. Software Packages Utilised for the Studies

Simulation studies are required to be able to predict the behaviour of the eThekwini Electricity distribution network with the introduction of EG. In order to carry out these simulations, a power system analysis tool is required to model the existing electrical networks thereafter various different studies can be carried out to predict the behaviour of the electrical network with the introduction of EG. There are a number of Power System simulation software packages that are currently available on the market and used by universities and utilities. For the case studies selected, various functionality was required from the selected power systems simulations software packages and reasons for the selection of the various packages are detailed below:

1. Landfill Gas to Electricity: needed a software package that support load flow and short circuit analysis. ERACS was selected since this support load flow and short circuit analysis.

2. PV Farm Case Study: needed a software package that supported RMS modelling and analysis. This was functionality was available on Digsilent Power Factory and hence Digsilent was selected for this case study.

3. Residential Rooftop PV: needed a software package that supported single phase AC and unbalance load flow analysis. Low voltage network analysis functionality is supported and available on Digsilent Power Factory.

4. Rooftop PV Projects: needed a software package that could simulate the generation output from these various rooftop PV projects. The software package that supported this was PVsyst which provided accurate site specific generation output data for each site. This package was hence used for the simulations.

Hence the three software packages that were extensively used for this research were Digsilent Power Factory, ERACS Power Systems and PVsyst simulation package.

3.11.1. DigSilent Power Factory Power Systems Simulations Software

Digsilent is an acronym for "**Dig**ital **Si**mu**l**ation of **E**lectrical **Net**works" and is a power systems simulation package that was designed to assist Engineers with network modeling and simulations. It is currently utlised by many utilities in Africa and around the world. [47]

Digsilent Power Factory is a powerful power systems simulation tool that offer various static and dynamic simulation fuctionality. Some of the fuctionality of Digsilent are as follows:

1. Balanced and unbalanced load flow analysis

2. Fault analysis

3. RMS stability functionality for balanced/unbalanced AC/DC systems

4. Electromagnetic Transients stability analysis

5. Harmonic Analysis

6. Protection function analysis

7. Distribution network optimization

8. Low voltage network analysis

9. Reliability Analysis

10. .Optimal power flow (reactive power optimization)

3.11.2. ERACS Power System Simulation Software Package

ERACS is an electrical power systems modeling, simulation and analysis software. "It allows network design and planning engineers to simulate electrical power system networks quickly and easily judge their correct, safe and timely operation under user defined, and sometimes arduous, situations." [48] The software package allows accurate network modelling and simulation of the electrical networks. ERACS software is utilised by eThekwini Electricity and was also utilised for the landfill gas to electricity case studies. The software package that was available supported loadflow and short ciruit analysis which was required for the study.

3.11.3. PVsyst PV System Modelling Package

PVsyst is a software simulation package used for modeling and simulation of PV systems.

The software offers the user three main design options.

(i) "The preliminary design option allows one to evaluate grid-connected, stand-alone and pumping systems, and use monthly values to perform a quick evaluation of system yield. For each project one has to specify the location and the system to be used. The program includes predefined values for locations of different parts of the world but also offers the option to enter the geographical coordinates, and the monthly meteorological information of new locations." [49]

(ii) "The project design option allows one to create full-featured study and analysis of grid-connected, stand-alone, pumping, and DC-grid systems with accurately system yields computed using detailed hourly simulation data. Various different simulation variants, horizon shadings, include detailed losses, and options to add real components to provide economic evaluations. Upon completion of the project, reports are generated by the software.” [49]

(iii) “The tools option includes databases of meteorological information, components, solar toolboxes, and the analysis of real measured data.” [49]

The PVsyst software is used to model rooftop PV systems and the effects of rooftop inclination angles and orientation towards the sun for one of the case studies.

3.12. eThekwini Electricity Distribution Networks to be used for studies

There are currently 105 Major Substations at eThekwini Electricity. Figure 3.26 shows that the breakdown of Major Substations within eThekwini Electricity. The two substations of interest for this study will be the 132/11 kV and the 33/11 kV substations. The distribution voltage levels at eThekwini Electricity are 11 kV, 400V and 230 V, and all of the existing EG p rojects connect at these voltage levels. Similarly, most of the proposed EG projects will connect at these voltage levels except for the case of large wind/solar farms or the 38 MW gas peaking plant.

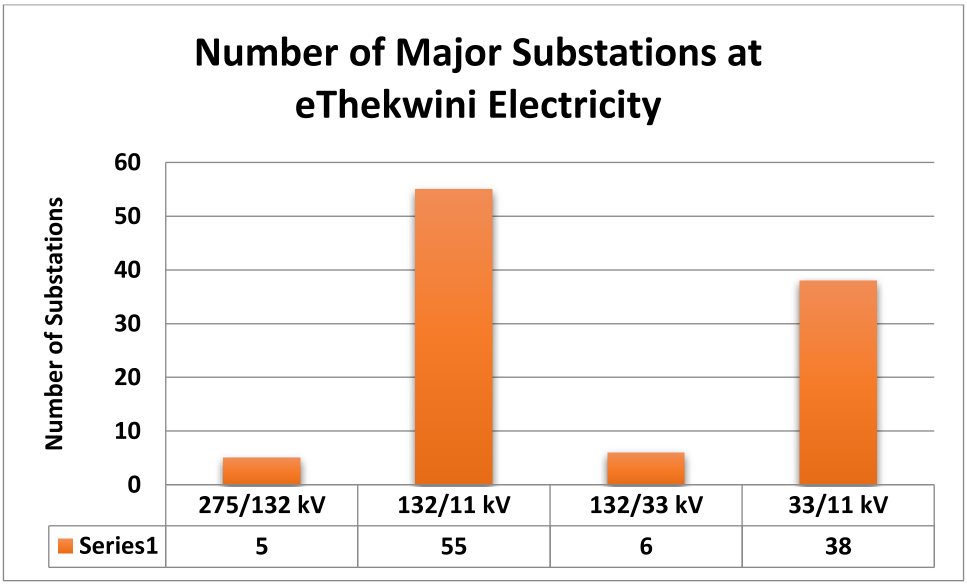


Figure 3.26: Number of different voltage level Major Substations at eThekwini Electricity

3.13. Number of Transformers at each Major Substation (33/11 kV, 132/11 kV)

3.13.1. 132/11 kV Major Substation

eThekwini Electricity design philosophy for 132/11 kV Major Substations is to install four transformers rated at 30 MVA each. In some substations where the load demand is low, two transformers are installed upon commissioning and the other two transformers are added in at a later stage as the area load grows.

3.13.2. Earthing Methods for 132/11 kV Major Substations

The earthing method on the 132 kV side of the power transformer is solid earth whilst the earthing on the 11 kV side of the transformer is earth through a Neutral Earthing Resistor (NER). The NER limits the single phase fault current to 800A. The reasons why this philosophy was adopted at eThekwini Electricity is based on the fact that the most common faults on the 11 kV network at eThekwini Electricity is Earth Faults. Hence it was decided to limit the earth fault to 800A to limit any damages caused by Earth Faults. 800A Earth Fault current limiting NERs was selected to ensure that the current was low enough to avoid damages on the system whilst the fault level was high enough for the protection system to detect. Figure 3.27 shows a typical eThekwini Electricity 132/11 kV Major Substation design layout.

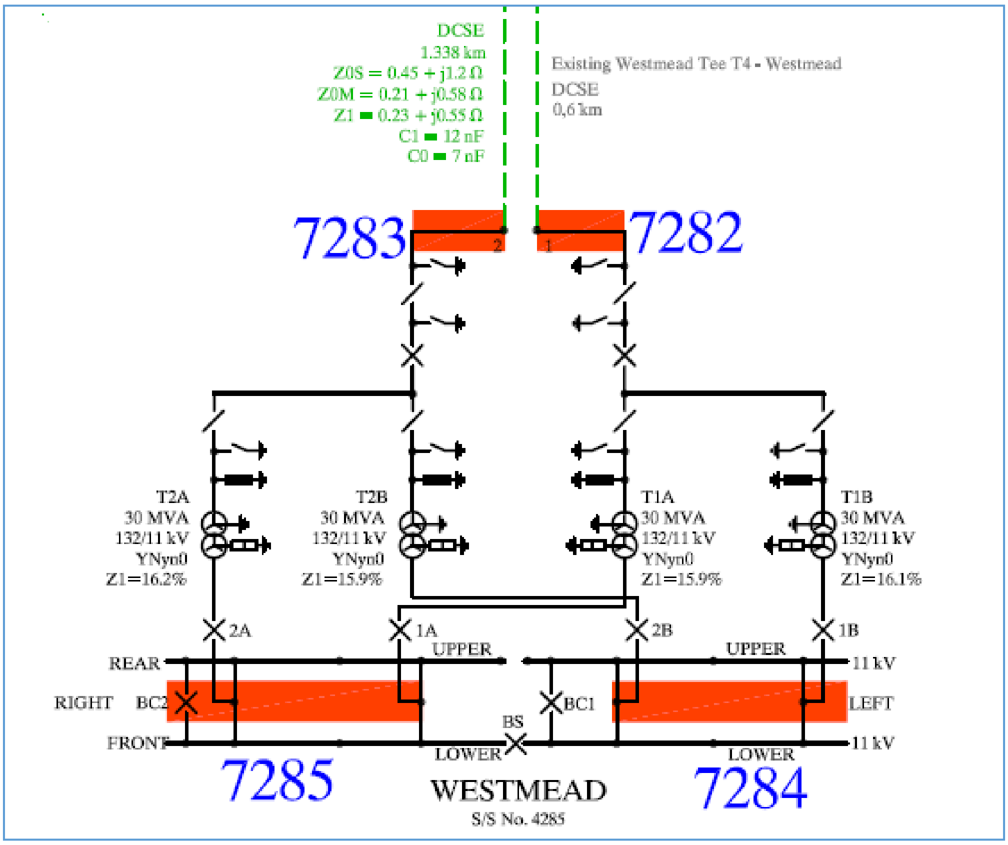


Figure 3.27: Typical 132/11 kV Major Substation layout at eThekwini Electricity [50]

3.13.3. 33/11 kV Major Substation

eThekwini Electricity design philosophy for its 33/11 kV Major Substations is to install two transformers rated at 25 MVA each. The fleet of 33/11 kV Major substations at eThekwini

Electricity is aged. The future plan for eThekwini Electricity is to replace all 33/11 kV Major Substations with new 132/11 kV Major Substations. This then reduce double transformation and losses on the network.

3.13.4. Earthing Methods for 33/11 kV Major Substations

eThekwini Electricity 33 kV side of the power transformers windings are delta whilst the 11 kV side is star which are solidly earth. This philosophy of earthing was historic and eThekwini Electricity has started a program to replace all 33/11 kV Major Substations with new 132/11 kV substations. However there are still 33/11 kV Substations and hence they will be considered for the studies. The three phase fault levels are higher on the 132/11 kV substations whilst the single phase fault levels are higher on the 33.11 kV substations. Figure 3.28 shows a typical design of a 33/11 kV Major Substation design at eThekwini Electricity.

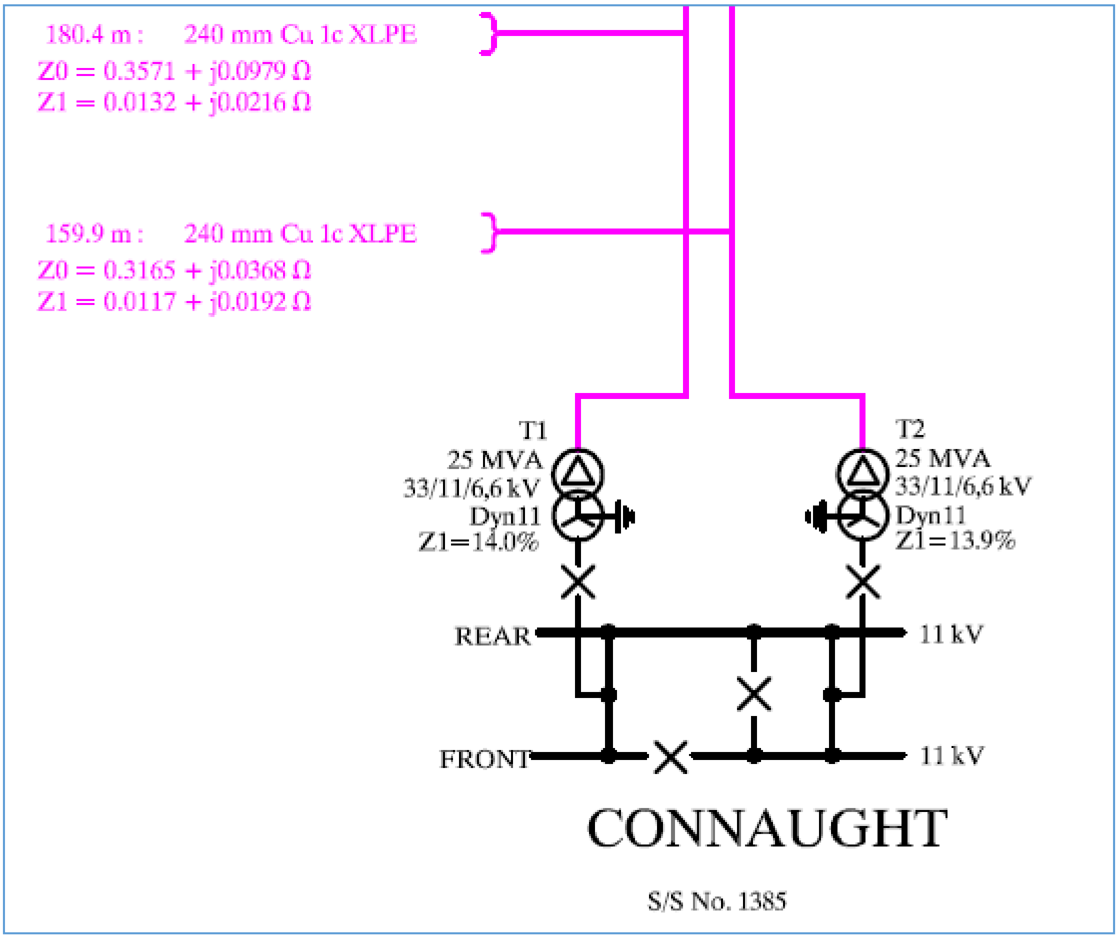


Figure 3.28: Typical layout of a 33/11 kV Major Substation at eThekwini Electricity [50]

3.13.5. eThekwini Electricity Operating Philosophy

eThekwini Electricity operating philosophy is to operate their power transformers at 50% (firm capacity) of the rated capacity (installed capacity). This is to ensure that the substation is designed for N-1 contingency. For a two transformer substation, the substation will be operated up to the maximum rating of a single transformer to ensure that in the event that one transformer faults or is taken out for maintenance, there is no disruption to the consumers as the other transformer will operate at 100% capacity and supply the whole station load. The same applies for overhead line or underground feeds into the Major Substation which is also designed for N-1. This applies to both the 132/11 kV and 33/11 kV Major Substations. Table 3.18 shows the installed vs the firm capacity of 132 kV and 33 kV Major Substations at eThekwini Electricity. All 132/11 kV Major Substations are designed to accommodate 4 by 30 MVA power transformers whilst 33/11 kV Major Substations are designed to accommodate 2 by 25 MVA transformers.

Table 3.18: Installed vs firm capacity of HV Power transformers at EE

Voltage	Number of Transformers	Installed Capacity (MVA)	Firm Capacity (MVA)
132/11 kV	**2 × 30 MVA**	**60**	**30**
132/11 kV	**4 × 30 MVA**	**120**	**60**
33/11 kV	**2 × 25 MVA**	**50**	**25**

3.13.6. eThekwini Electricity 11 kV Distribution Networks

The 132/11 kV Major Substations with two power transformers will typically contain 10 – 12 outgoing 11 kV feeder whilst a four transformer substation will contain 20 – 24 feeders depending on the load type in the area. The 33/11 kV Major Substation contains 10 outgoing feeder. These 11 kV outgoing feeders then feed into Distributor Substations with underground cables at 11 kV from which the power is then further distributed into the network via ring networks. Bulk of the outgoing reticulation network from the 11 kV Distributor Substations at eThekwini Electricity is underground cable networks with a bit of overhead line networks in the rural areas. All of the current and proposed EG generation is injected into cable networks and 11 kV Distributor Substations. Either the same or two different Major Substations will feed a 11 kV Distributor Substations via 11 kV cables (older networks use 240 mm^2 or 300 mm^2 paper whilst of recent there has been an introduction of 240 mm^2 and 300 mm^2 XLPE cables that are used). The secondary outgoing feeder from the Distributor Substation is usually 95 mm^2 paper cables until recently with the introduction of 95 mm^2 XLPE cable to the eThekwini Electricity distribution network. However bulk of eThekwini Electricity's feed from the Major Substation to the Distributor Substation is 240 mm^2 paper cables whilst the secondary feeder cables from the Distributor Substations are 95 mm^2 paper cables. Figure 3.29 provides a simple overview of the eThekwini Electricity distribution network design. The ring networks are operated as two radial netoworks as they will have a normal open point somehwere on the ring. The miniature substation (MSS) then transforms the 11 kV into three phase 400 V, which is then used to feed the three phase and single phase customers. If the consumers apply for a 2 MVA or greater supply then he is required to purchase electricity at 11 kV.

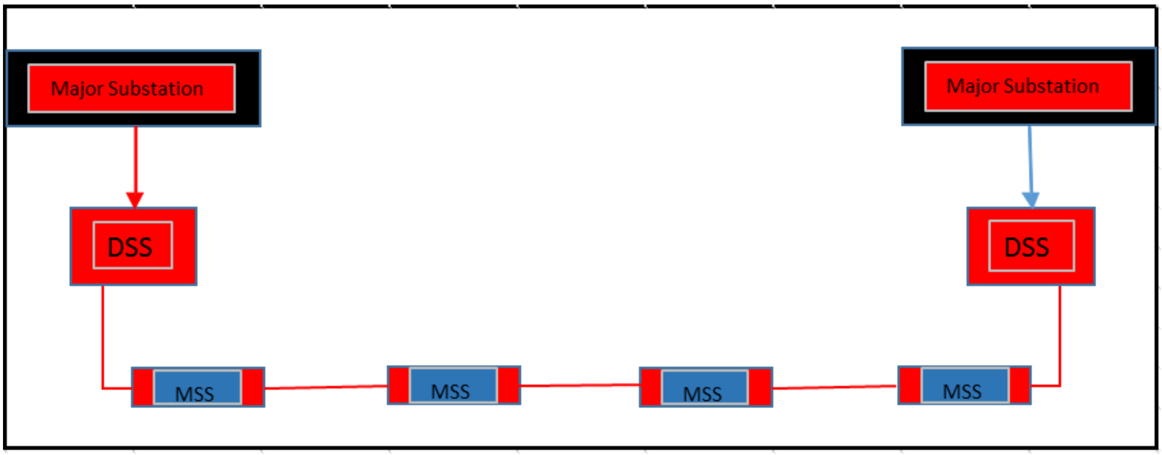


Figure 3.29: Typical eThekwini Electricity 11 kV distribution network design

The cable rating and sizes utilised on the distribution network at eThekwini Electricity is shown in Table 3.19.

Table 3.19: Cable size and rating of cables utilised at eThekwini Electricity

Cable Size	Cable Rating (Amps)	Cable Rating (MVA)	1 second short circuit rating (kA)
95 mm^2 PILC	185	3.5	7.2
150 mm^2 PILC	235	4.5	11.4
240 mm^2 PILC	314	5.97	18.2
300 mm^2 PILC	425	8.1	34.5
95 mm^2 XLPE	225	4.3	8.7
150 mm^2 XLPE	285	5.4	13.8
240 mm^2 XLPE	370	7.0	22.1
300 mm^{2}XLPE	420	8.0	27.6

3.13.7. Network Loading and eThekwini Electricity Current Planning Philosophy

eThekwini Electricity current distribution network planning philosophy is to design the medium voltage (11 kV) networks to an N-1 design. This ensures that there is always a backup feed to any consumer as these networks are designed using the ring network design principle with an open point selected to operate the networks as two radial feeders under normal operating conditions. However at LV level, the radial network design principle is utilized. This has worked well over the years with designing network infrastructure to cater for power flow from the high voltage substations (275 kV, 132 kV or 33 kV) to the medium voltage (11 kV) networks and then to the low voltage (400/230V). Equipment was selected to cater for voltage drops and customer peak loading as the primary concern. Cables and transformers utilised were standardized to ensure competitive prices were received when purchasing bulk and reduce stock levels as opposed to carrying many different types and sizes.

3.14. DigSilent Studies

3.14.1. Final 132/11 kV Grid Model

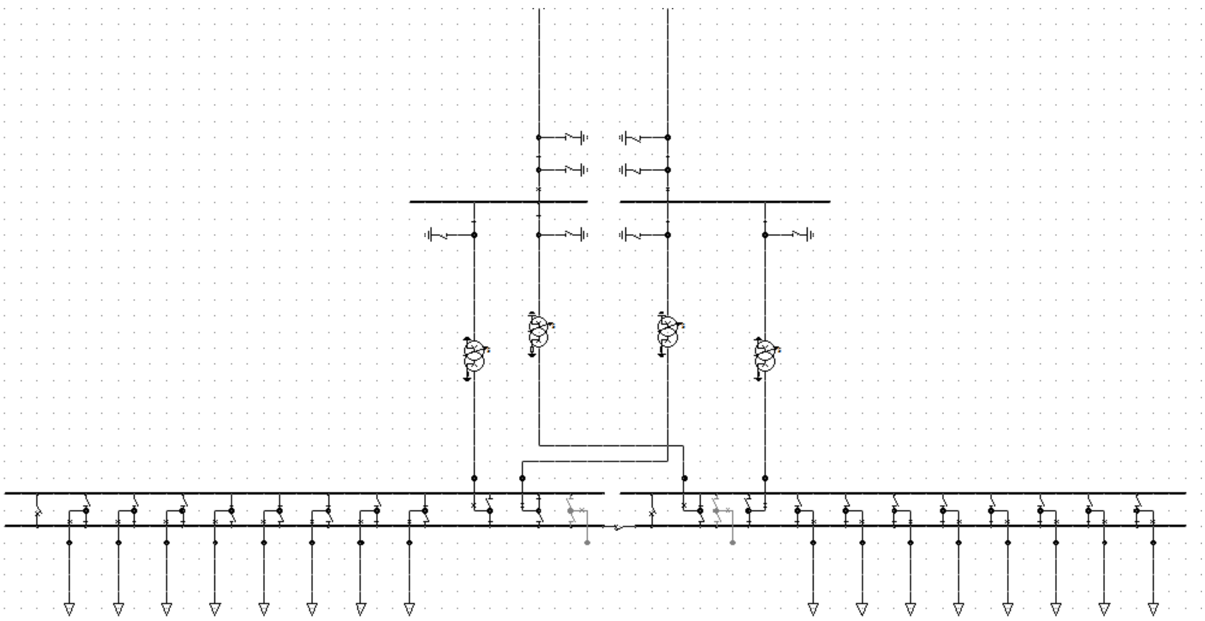


Figure 3.30 DigSilent 132/11 kV Major Substation Model

Figure 3.30 shows the Digsilent model of a typically 132/11 kV Major Substations with four power transformers and multiple 11 kV outgoing feeders. The substation was modelled as a double bus bar with 4 bus sections and 2 bus couplers. This is the standard layout of a 132/11 kV Major Substation at eThekwini Electricity.

3.14.2. Final 33/11 kV Grid Model

Figure 3.31 shows the DigSilent Model of the Connaught Major 33/11 kV Substation that was created.

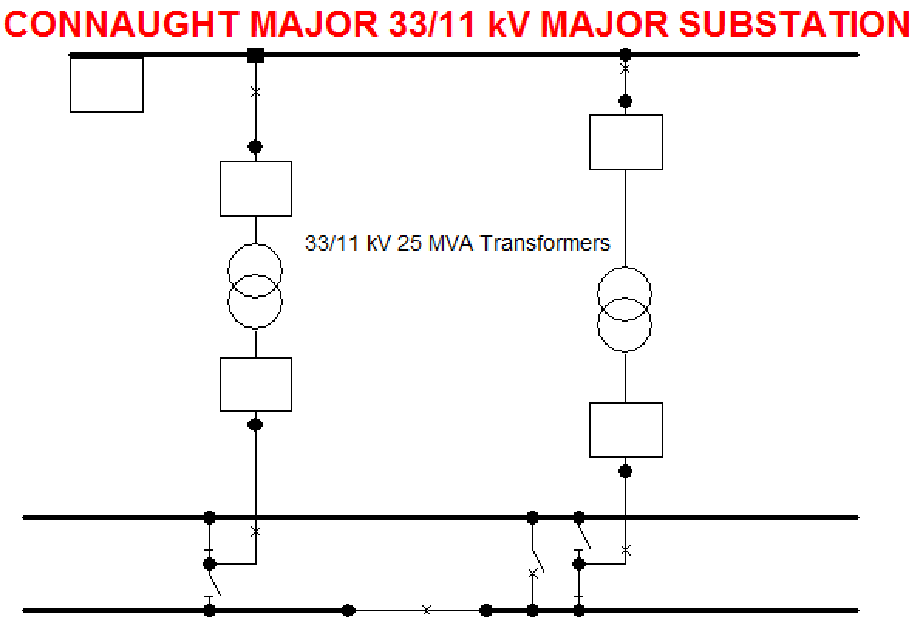


Figure 3.31: Connaught Major Substation modeled in the Digsilent Software

3.15. Case Study Selection

3.15.1. Case Study 1: Gas to Electricity Project

From the list of landfill gas to electricity and bio gas to electricity projects at eThekwini Electricity, the Bisasar Road Landfill gas to electricity project was selected for analysis. Modelling and simulations was carried out studying the impacts of the Bisasar Road gas to electricity project on the eThekwini Electricity distribution network as the generation was increased from 1 MW to 8 MW in one MW increments. This will then cover most of the other gas to electricity projects at eThekwini Municipality as shown in Table 3.20. This case study looks at the impacts of the existing network voltage, single phase fault level, three phase fault levels, generation plant power factor, project feasibility and problem areas identified. The project does not take any regulations and grid codes into account since it was developed prior to the SAREGC and the NRS 097 guidelines.

Table 3.20: Gas to electricity projects at eThekwini

Name of Site	(MW)
Amanzimtoti Waste Water Works	0.15
Kwa Mashu Wastewater Treatment Works	0.65
Phoenix Wastewater Treatment Works	0.65
Shongweni Landfill Site	1
Durban North Wastewater Treatment Works	1
Marianhill Landfill Site	1
Durban South Treatment Works	2
Bisasar Road Landfill Site	8
Buffledraai Landfill Site	10

3.15.2. Case Study 2, 4, 5: Solar PV Proposed

Table 3.21 depicts the list of existing, proposed and potential PV projects in Durban. Due to the high number of proposed and potential PV projects in Durban, it is important for eThekwini Electricity to understand the impacts of these projects. A few of the projects were then selected to carry out analysis and studies to give us a better understanding of the impacts that these projects will have on the grid since it was not possible to analyse every project. The projects analysed will however cover most of the existing and proposed projects and will take into account the NRS 097 guidelines for SSEG and the SAREGC for the larger scale PV plants.

Table 3.21: Existing and potential PV projects in eThekwini

	Project Name	**Project Size (kW)**
1	Mosses Mabhida Stadium Sky Car	4.5
2	Tongaat Secondary School	8
3	Temple Valley Secondary	8
4	Phoenix Secondary School	8
5	Morning Side	11.52
6	Loram house	14.75
7	Mosses Mabhida Peoples Park	27
8	Costal Farmers	40
9	Standard Bank	45
10	eThekwini Water Department	68.5
11	River Horse Valley	80
12	Metro Police Head Quarters	91
13	Ushaka Marine World	114
14	Mr Price Head Office	207
15	Hazelmere PV Farm	477
16	17 Intersite Avenue	503
17	Man Trucks and Bus	580
18	Dube Tradeport	1000
19	Mpumlanga	1500
20	Umlazi 4	2000
21	Umlazi 1	2000
23	New Germany	2000
24	Silverglen Landfill Site	4000
25	La Mercy Landfill Site	5000
26	Rochdale Landfill Site	5000
27	Bisasar Road	10000

The projects is then broken into three categories namely residential, commercial/industrial and PV farms and shown in Figure 3.32 and discussed in Table 3.22. In order to understand the impacts caused by PV in each category, the following analysis will be carried out/studied.

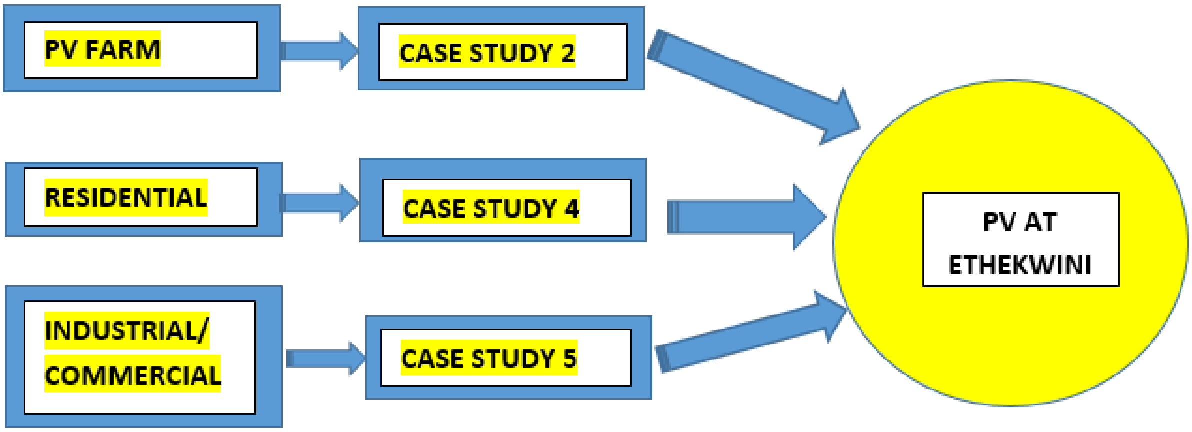


Figure 3.32: PV Case studies to be carried out

Table 3.22: Selected case studies to be carried out for solar PV impacts

Category	**Project Size (kW)**	**Method of Study and Analysis**
1. Residential	Residential (4.6 kW)	Understand factors driving and affecting rooftop PV generation in Durban. Develop a formulae to accurately calculate the payback period of residential rooftop solar PV for Durban to assist to predict when large uptake will occur. Understand factors that will affect the annual generation output of residential rooftop PV in Durban. Case study of residential solar PV with increasing penetration levels. Understand the NRS 097 guidelines for SSEG in South Africa and its applicability in this case study.
2. Commercial/ Industrial	PV on commercial buildings. (14.75 – 580 kW)	Study will look into a project for the installation of rooftop PV on 6 Municipal buildings in Durban. This project will explore a new PV generation option using Solar Edge technology which employs individual optimisers (MPPT) on each panel in five projects and the use of a conventional string inverter will be utilised on the sixth project. The study will analyse the consumer load profile and the simulated PV production from these projects.
3. PV Farms	PV farm on the Bisasar Road landfill site (10 MW)	A study of a 10 MV PV farm installation on the closed portion of the Bisasar Road landfill site. Complete grid code compliance testing will be carried out on a type tested RMS 10 MW PV farm model to understand controllability and operation of the PV farm. This case study will provide a better understanding of the SAREGC for Category B renewable power plants and how its different control functions operate in order to understand how its controllability can be utilised to operate the farm on the eThekwini Electricity network to

		mitigate negative impacts.

3.15.3. Case Study 3: 25 MW Wind Case Study

Based on the winds speeds and potential land availability for wind farm development in Durban, a 25 MW wind farm was selected for this case study to carry out Grid Code Compliance Testing. In order to understand the full requirement of the SAREGC for a Category C RPP, the testing methods and grid code requirements are discussed in this case study. The testing methods were then utilised on a newly developed 25 MW wind farm in South Africa to understand and demonstrate the controllability of the farm as required by the grid code. This then provides us with insight on the plants controllability and how it can be utilised to mitigate negatives impacts on the eThekwini Electricity distribution network. There are a large number of potential Category C wind farm potential in eThekwini Municipality that are predicted to come up in the future based on the studies carried out to identify potential wind farm sites.

This case study demonstrates and provide understanding of the Category C RPP operation and controllability that the System Operator at eThekwini Electricity will have on the wind farm. This case study will also assist in understanding the SAREGC Category C requirements which are the most stringent requirements in the grid code but will assist utilities to deal with increasing penetration of RPPs going forward.

3.16. Summary of Chapter 3

Based on the investigation carried out on the availability of renewable energy resources in Durban, 5 case studies were selected to assist us to investigate our study objectives. Case study 1 will be based on the Bisasar Road 8 MW landfill gas to electricity project, case study 2 will be based on a proposed 10 MW PV farm to be installed on the closed portion of a landfill site, case study 3 will be based on a potential 25 MW wind farm, case study 4 will investigate the residential rooftop PV projects and case study 5 will focus on the impacts of generation source profiles in comparison to the consumer load profile.

CHAPTER 4: CASE STUDY 1: BISASAR ROAD LANDFILL GAS TO ELECTRICITY PROJECT

4.1. Introduction to Chapter 4

Chapter 4 provides an indept background into the landfill gas to electricity extraction and generation process. Thereafter it details an investigation carried out to understand the impacts of increasing penetration landfill gas to electricity generation from 0 MW (with no EG) to 8 MW EG increased in 1 MW increments. Studies are carried out to identify the impacts on the network voltage, equipment loading, single phase fault level, three phase fault level, Power Factor and project feasibility.

4.1.1. Landfill Gas to Electricity Generation

In general, a municipal landfill site consists of waste products from the residential, commercial and industrial sector which then produces large amounts of landfill gas. Landfill gas can be seen to be one of the most important environmental parameters for a landfill of municipal solid waste. Methane (CH_4) and (CO_2) are the by-products of biological degradation under anaerobic conditions and is typically 50 – 60% by volume and have proven to be the major “ingredient” of landfill gas produced at a municipal landfill site. Landfill gas can hence be captured and utilized to generate electricity with the use of a landfill gas engine coupled to a synchronous generator. A study concerning the cost effectiveness of landfill gas was carried out by London Brink Landfill for Hampshire Council provides evidence that landfill gas in the UK has a commercially viable future. [51] The gas can be easily extracted and utilized to generate electricity whilst curbing emissions of Methane gas, a known greenhouse gas. Landfill gas made up 16% of the Methane emmissions in the United States in 2010. [52] South Africa and Africa has an abundance of landfill site, both municipal and privately owned which can be utilized to harness the landfill gas for electricity generation. The eThekwini Municipality was the first in Africa to explore the Methane gas widely available from their landfill sites to generate much needed electricity to assist the country. Landfill gas to electricity technology is not new and has been piloted and proven to work at utilities around the world. This technology serves dual purpose; destroying Methane, a known greenhouse gas, whilst generating electricity. These projects have been driven internationally by environmental concerns, carbon taxes, carbon credits and feed in tariffs. All of which may not be present in the South African context yet. [41]

This live case study was carried out on the eThekwini Municipalities Bisasar Road landfill gas to electricity pilot project to understand the technology better and to evaluate the technical and financial impact of EG (landfill gas to electricity synchronous generator technology) on the existing distribution network. [41]

This case study provides a better understanding on the process to generate electricity from a landfill site, the technical impacts of integrating the Bisasar Road landfill gas to electricity project onto the eThekwini Electricity distribution network, the financial feasibility of the projects to date with methods/options to optimize these projects to improve the viability of potential projects.

4.1.2. Landfill Gas Production Modelling

A landfill gas model is a tool used to project Methane generation over time from a mass of waste. In its simplest form, the model predicts Methane generation or recovery from a single batch of waste, landfilled at a single given point in time. Then the total Methane generation is the sum of outputs from all batches in the landfill. Several methods have been described for modelling landfill gas formation [51]. In general, landfill gas (LFG) formation models are not based on microbiological or biochemical principles, but more on a practical description formation, as it can be observed in laboratory experiments or in full-scale recovery projects. LFG is formed as a result of biodegradation of the organic Carbon in the waste: per kg of organic Carbon that degrades, about 1.87 m^3 of landfill gas normalized to 1 atm and 0° C is produced [54]. Furthermore, although the theoretical quantity of landfill gas from a ton of typical domestic refuse is around 500-600 m^3 at 50% Methane concentration, the conditions within any given landfill site are unlikely to be ideal. The output of a gas model provides the starting point for the development of a project. The quantity and quality of landfill gas production will vary from site to site. In fact, several methods for modelling landfill gas production are possible, such as, Empirical method for calculation of biogas production (considering time), First Order Decay model (FOD), the Triangular model, the Scholl Canyon model, etc. [55]

One such model that can be utilised is the US EPA's Landfill Gas Emission Model (LandGEM Version 3.02). This model can effectively be utilised as a tool to evaluate and project landfill gas production on a site. LandGEM is a Microsoft Excel-based emissions modelling tool that can be used to estimate emission rate for total landfill gas (LFG), Methane (CH4), Carbon Dioxide (CO_2), Non-Methane organic compounds (NMOC), and individual air pollutants from municipal solid waste landfills. The key equation governing this first order decay model is described as follows: [55]

$$Q_{ch\,4} = \sum_{i=i}^{n} \sum_{j=0.1}^{1} kL_{\;0} \left[\frac{M_i}{10}\right] e^{-Kt_{\,ij}} \qquad (4.1)$$

Where:

Qch_4 = annual Methane generation in the year of the calculation (m^3/year)

i =1year time increment

n = (year of the calculation) – (initial year of waste acceptance)

j = 0.1year time increment

K = Methane generation rate ($year^{-1}$)

L0 = potential methane generation capacity (m^3/Mg)

Mi = mass of waste accepted in the i-th year (Mg)

t_{ij} = age of the j-th section of waste mass Mi accepted in the i-th year (decimal years)

Mg= mega-grams mass unit equivalent to 1 ton or 10^6 grams

4.1.3. Chemical Composition of Landfill Gas

To get a better understanding of landfill gas we study the chemical composition of the gas. Landfill gas predominantly consists of Methane gas which has the symbol CH_4 which simply means a gaseous molecule consisting of one atom of Carbon and 4 atoms of Hydrogen. It is always found in a gaseous state at normal temperature and pressure is usually around 50% of the "gas" extracted from a normal city type landfill site. The other 50% is made up of approximately 45% CO_2 and 5% O_2. [41]

In all Hydrocarbon combustion the basic laws of chemistry, i.e. stoichiometric chemical balance must apply i.e.

$$CH_4 + 2O_2 = CO_2 + 2H_20 \qquad (4.2)$$

If everything was ideal and the Methane combined with Oxygen perfectly in the combustion process in the engine we would expect 37.8 MJ of energy released per m^3 of Methane. This is commonly referred to as the Higher Calorific Value and is not used in practice. A more realistic value of 36 MJ/m^3 is used in practice and results from some water already in the mixture which absorbs energy during combustion. From experience on the project, 500m^3 of landfill gas is fed to a 1 MVA generator per hour, where the Methane content is approximately 50% with 45% Carbon Dioxide and 5% Oxygen. Therefore 36 $MJ/m^3 \times 500m^3$ per hour × 50% gives 9000 MJ per hour energy fed into the engine. Using the conversion of 1 kWh = 3.6 MJ we get 2.5 MW power input to the engines as a theoretical maximum. But as we know from the project only approximately 1 MW is delivered to the electrical network so we need to understand that this 40% efficiency is due to a number of factors. The first is that not all CH_4 and O_2 is converted to pure CO_2 and pure H_2O. Some CO (Carbon Monoxide) is also produced which releases much less energy than the 36 MJ/m^3 for pure Methane combustion to CO_2. In addition substantial energy is lost in the flue gases exhausted from the engines. [41]

What is very important for the project is the Clean Development Mechanism (CDM) aspects and requirements which put simply is the total destruction of CH_4 in the process. So exactly what efficiency is achieved in electricity generation is less important than confirmation by a verifiable method that all Methane is destroyed. In a normal commercial generation project where the primary energy (gas or coal) is purchased then overall plant efficiency is very important as it means real net income. In this project the primary goal is the destruction of Methane which essentially is "free"out of the ground, after the capital costs of the gas extraction is paid, which are a sunk cost. [41]

Destruction of Methane can be done by flaring at a temperature above 1000 degrees Celsius or in electricity generation. Having said this it is very important for a CDM project is to accurately "measure" the exact volume of Methane destroyed. One method is to use the very reliable and accurate electricity meters available today, which will give a 99.8% accuracy measurement of the output electrical energy delivered to the grid. [41]

4.1.4. More Chemical Detail

We know from above that:

$$(CH_4) + (2O_2) = (CO_2) + (2H_2O) \tag{4.3}$$

Using the chemical number for each element: C = 12, H = 4 and O = 16 we get

$$\{(12 \text{ x } 1) + (1 \text{ x } 4)\} + \{2(16 \text{ x } 2)\} = \{12 \text{ x } 1 + (16 \text{ x } 2)\} + \{2(1 \text{ x } 2) + (16)\} \tag{4.4}$$

This simplifies to:

$$\{16\} + \{64\} = \{44\} + \{36\} \text{ ie } 80 = 80 \tag{4.5}$$

and dividing by 16 we get:

$$1 \text{ kg } (CH_4) + 4 \text{ kg } (O_2) = 2.75 \text{ kg } (CO_2) + 2.25\text{kg } (H_2O) \tag{4.6}$$

These numbers are important when calculating the tons of CO_2 equivalent destroyed, or not emitted, from this process. For every kg of Methane destroyed 2.75 kg of Carbon Dioxide is emitted but this is effectively equal to only 0.13 kg of CO_2 equivalent or 13% of what would have been emitted had the Methane been allowed to vent naturally to the atmosphere, taking into account that Methane is 21 times more environmentally damaging as a greenhouse gas than CO_2. [41]

4.1.5. The Use of Landfill Gas for Electricity Generation

"The use of landfill gas (LFG) for generating electricity is a promising approach both in terms of conserving energy and also for reducing air pollution. Energy recovery from waste represents an important way to reduce the amount of electric energy to be produced using fossil fuels, which are non-renewable sources of energy. There are many incentives in using LFG in waste to energy conversion systems. In addition to conserving valuable alternative energy resources, direct LFG utilization results in reduced greenhouse gas (GHG) emissions" [55]

The amount of thermal energy generated from the landfill gas could be found using the following equation:

Thermal energy:

$$E_{th\,(MW)} = \dot{m}_{ch_4} X\, LHV_{ch_4} X\, \Re \tag{4.7}$$

where: mch_4 is the flow rate of $CH_4[m^3/h]$

$LHVch_4$ the lower heating value of CH_4 $[MJ/m^3]$

$\Re$ is the recovery rate.

The amount of power could be computed using the electrical conversion efficiency using the equation below:

$$E_{el\,(KWh)} = \dot{m}_{ch_4} X\, LHV_{ch_4} X\, \Re\, X\, \eta_{el} \tag{4.8}$$

Where: ŋel is the electrical efficiency.

4.1.6. Impacts of Landfill Gas to Electricity EG on the Existing eThekwini Electricity Distribution Network

"In 2008, eThekwini Municipality decided to embark on a landfill gas to electricity project at the Bisasar Road landfill site. The Bisasar Road landfill site shown in Figure 4.1 was established in 1980 and has a total surface area of 44 hectors with a capacity of 21 million cubic meters. It is argued to be the busiest engineered landfill on the African continent accepting a daily average of 3500 to 5000 tons of waste. Waste at landfill sites undergoes a methanogenic stage of bio decomposition which produces large amounts of landfill gas typically containing 50 – 60% Methane content. Previously, the Municipality's Solid Waste Department flared the Methane gas from the site to reduce the risk of uncontrolled fires and reduce odours. The municipality subsequently decided to utilise the gas more productively and generate electricity to alleviate SA's energy shortages whilst enhancing the environment by Methane destruction" [5]

Figure 4.1: The Bisasar Road Landfill site [5]

"Gas studies performed at the Bisasar Road landfill site had indicated the site produced in excess of 4000 m^3/hr of landfill gas made up of 52% Methane (CH_4). A 1 MW landfill gas engine requires approximately 500 m^3/hr of landfill gas to produce 1 MW of electricity with a Methane content of 52%." [5] Landfill gas to electricity EG had many advantages over other technologies such as photovoltaics and wind turbines. The main benefit is that landfill gas is produced at a constant rate and the electricity produced when harnessing the gas for electricity production is equivalent to base load generation. This is exactly what the utility required to assist with the energy shortages without the need for expensive energy storage devices. However the landfill gas to electricity EG employs synchronous generator technology which supply the highest fault level contribution when a fault is experienced on the connected network. It also has the ability to operate in leading and lagging power factor mode. The eThekwini Electricity Springfield distribution network and the eThekwini Solid Waste Departments Bisasar Road landfill site was utilised in this case study. eThekwini Electricity mandated a load flow study in order to identify the impacts of connecting this EG project onto the existing eThekwini Electricity's Springfield distribution network. I then carried out the load flow studies to identify the impacts that this project will have on the eThekwini Electricity Springfield Distribution Network into which the generation plant will be injecting power. These studies were then carried out prior to implementation of the project. The landfill generators operated in parallel with the Connaught Major (33/11 kV) substation located in the Springfield area. Electricity prices were low at that stage and eThekwini Electricity offered to pay eThekwini Solid Waste Department the Eskom avoided costs per a kWh for the electricity generated to ensure compliance to the Supply Chain Management (SCM) rules and regulations. The SCM rules stipulated that the utility could not pay more for a product then available on the open market. It was hence decided that a single cable will be utilised to inject the electricity into the eThekwini Electricity Springfield Network. This is opposed to using two cables which would have meant an additional circuit breaker, additional cable and a bus section which would have increased costs. In keeping with reducing the connection costs to the grid and based on the fact that there was no spare circuit breakers at the Counaught Major Substation, it was decided to inject the power at the closest 11 kV Distributor Substation (DSS) to the landfill site which was the New Electricity Department DSS 5374. There was a spare circuit breaker at the New Electricity Department DSS 5374 that was under 500 meters from the generation site. The injection cable used that could carry the total plant generation output was a 300mm^2 Copper Paper Insulated Lead Covered (PILC) cable which had an 8 MVA current carrying capacity. The New Electricity Department DSS 5374 had a 11 kV switchboard with a bus section which was normally closed. Unity Power factor was selected for the studies based on the fact that the Springfield Distribution network was a strong (bus bar voltages in this network was well within the statutory limits) network and hence did not require any import or export of reactive power from the generators. The studies were carried out for the base case (0 MW DG) and thereafter from 1 MW to 8 MW in increments of 1 MW since the generators purchased came in 1 MW containerized units. Containerized units allowed for the units to be moved to other landfill sites when gas levels dropped and also meant that only 1 MW generation production was lost when a unit was maintained. [5]

Figure 4.2 shows “the proposed EG plant layout. The landfill gas to electricity generators were to be procured in containerised units. The generators were 4-pole lap wound synchronous generators (SG) which generated electricity at 400V_{ac}. Each generator was rated at 1MVA and connected onto the 11 kV switchboard via a 1.25 MVA 400/11000 V step up generator transformer. The EG plant was then modelled in the ERACS power systems simulation software.” [5]

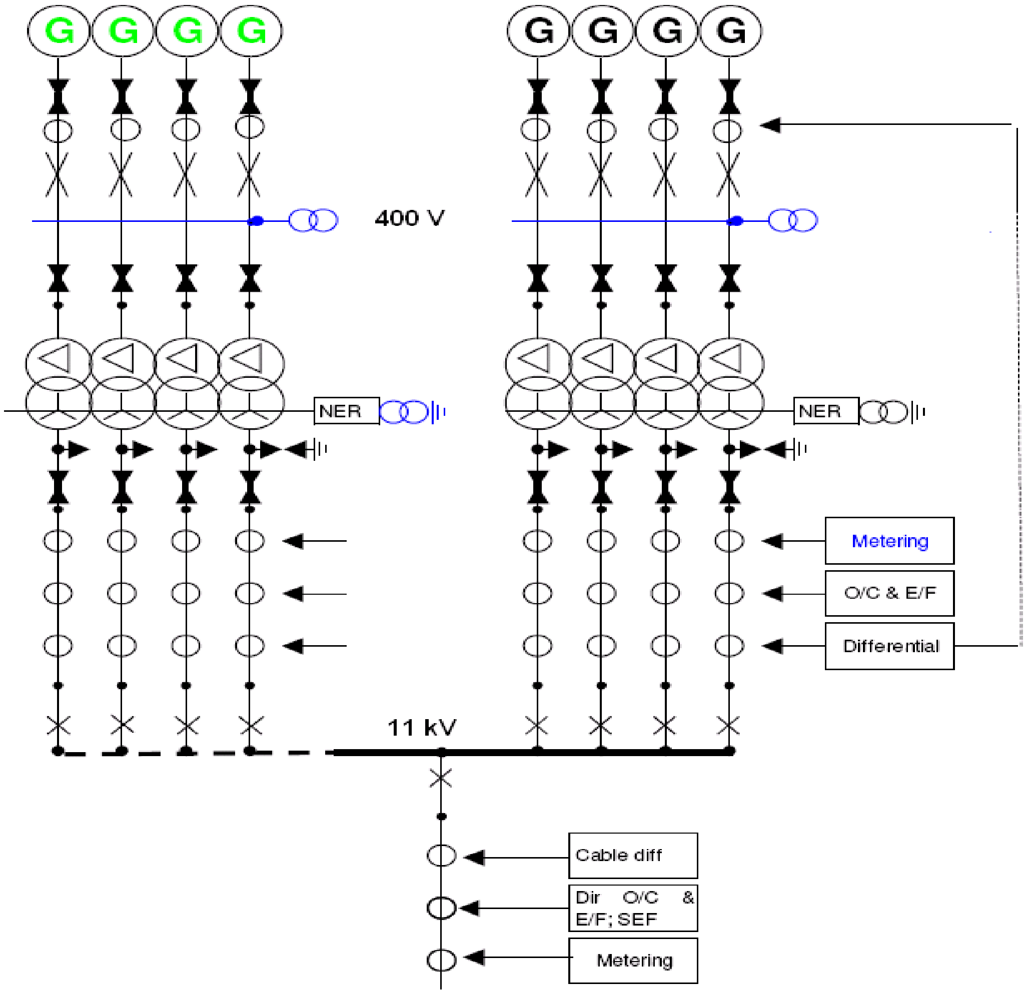


Figure 4.2: Schematic layout of the Bisasar Road Landfill gas to electricity project [5]

4.1.7. Creating of the EG models for the landfill site gas to electricity generators

The data utilized for modeling of the landfill gas to electricity generators are shown in Table 4.1 and Table 4.2. The Spingfield distribution network together with the landfill gas to electricity generators were modelled in the ERACS power systems simulation software.

Table 4.1: Gas to electricity generator parameters [14]

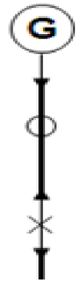
	**Gas to Electricity Generator Parameters**	
	Voltage	400 V
	Rating	1550 kVA, 1064 kW
	Reactance X_d	2.6 pu
	Reactance $X_{d'}$	0.22 pu
	Reactance $X_{d''}$	0.15 pu
	$T_{d''}$	30 ms

Table 4.2: Generator transformer and NER parameters [14]

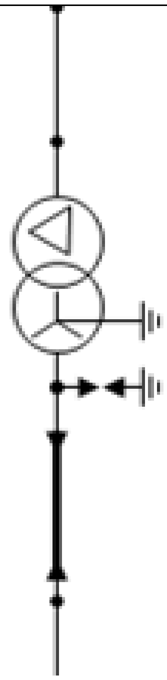
		
	kVA	1250
	Phases/Frequency	3/50
	Secondary Voltage	11 kV
	Primary Voltage	400 V
	Vector Group	dyN11
	Off Load Tap Range	+-2.5%, +- 5% @ 11 kV
	Number of Taps	5
	No Load Iron Losses	2250W
	Load Losses Copper	11 000W
	Impedance	6.5%
	Neutral Earthing Resistor	254 ohms (to limit 11 kV earth fault current to 25 A per transformer)

Figure 4.3 shows the “EG interconnection to eThekwini Electricity Department DSS 5374 located at 11 Electron Road which was then connected to the 1/5 Intersite Avenue DSS 16541 before connecting to the Connaught Major Substation.” [5]

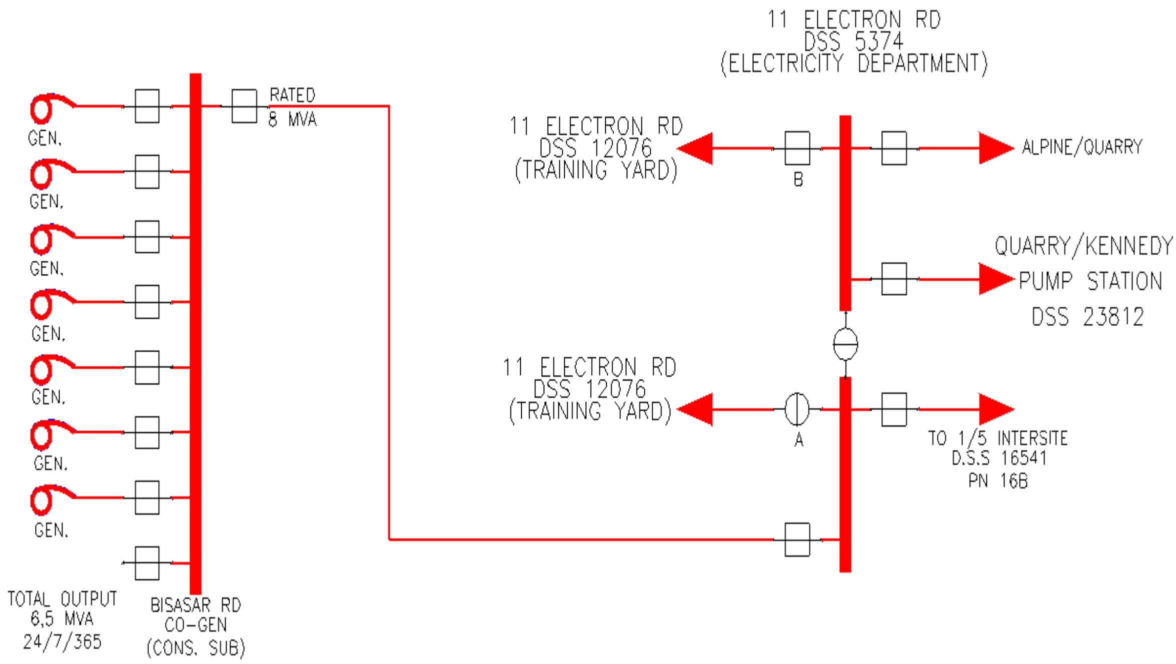


Figure 4.3: Bisasar Road EG plant interconnection to the grid [5]

Figure 4.4 “shows the layout of the Connaught Major Substation. This was a 33/11 kV substation with two 33/11 kV transformers. The 11 kV side of the transformer is solidly earth. The transformers are rated at 25 MVA but operated at maximum 50% rated capacity during normal operating condition. Each transformer fed five of the ten 11 kV outgoing feeders. The load in the Springfield area was predominantly commercial and industrial. Connaught Major was a double bus bar sub-station with the bus coupler normally open and a bus section normally closed.” [5]

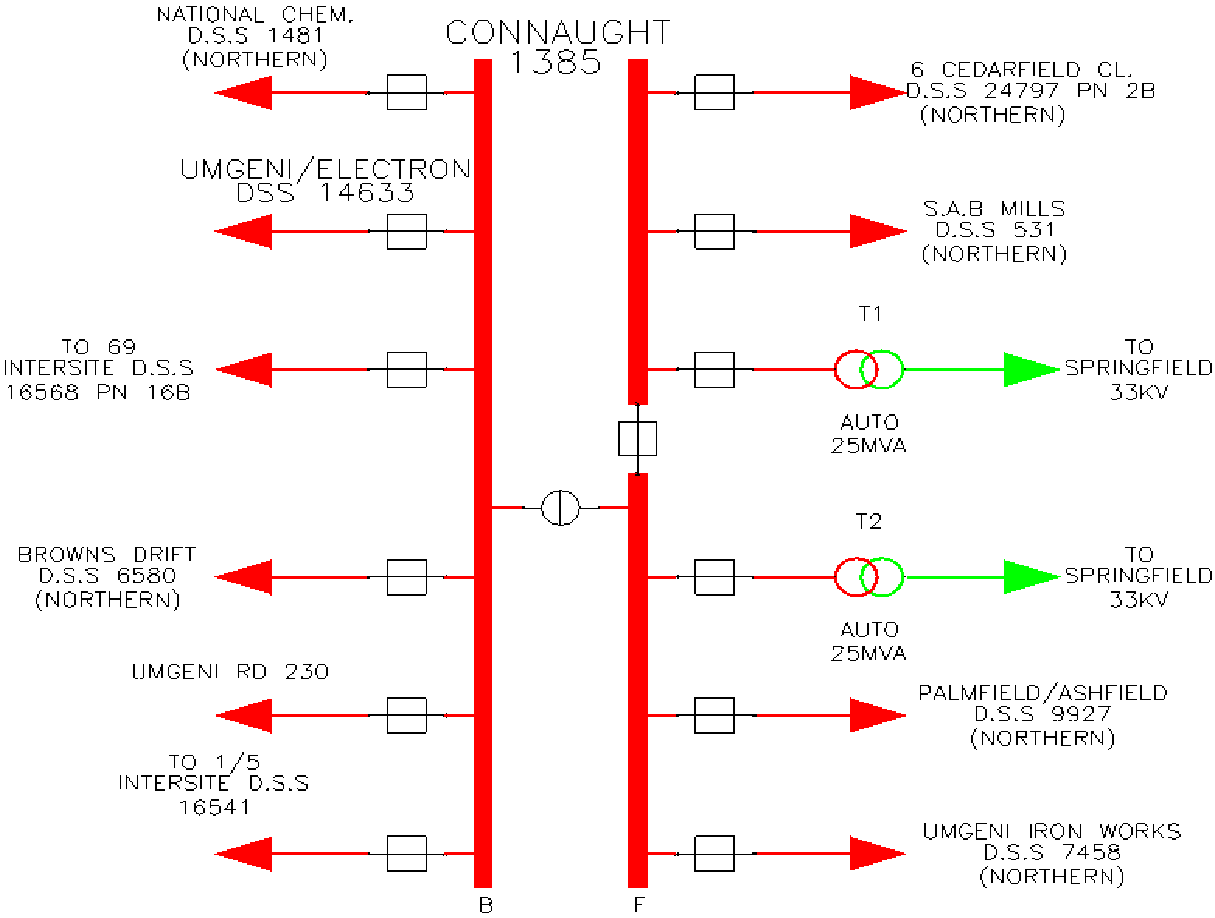


Figure 4.4: Connaught Major 33/11 kV Substation layout [5]

Figure 4.5 shows the data logging results of the peak and off-peak feeder loading at the Connaught Major Substation.

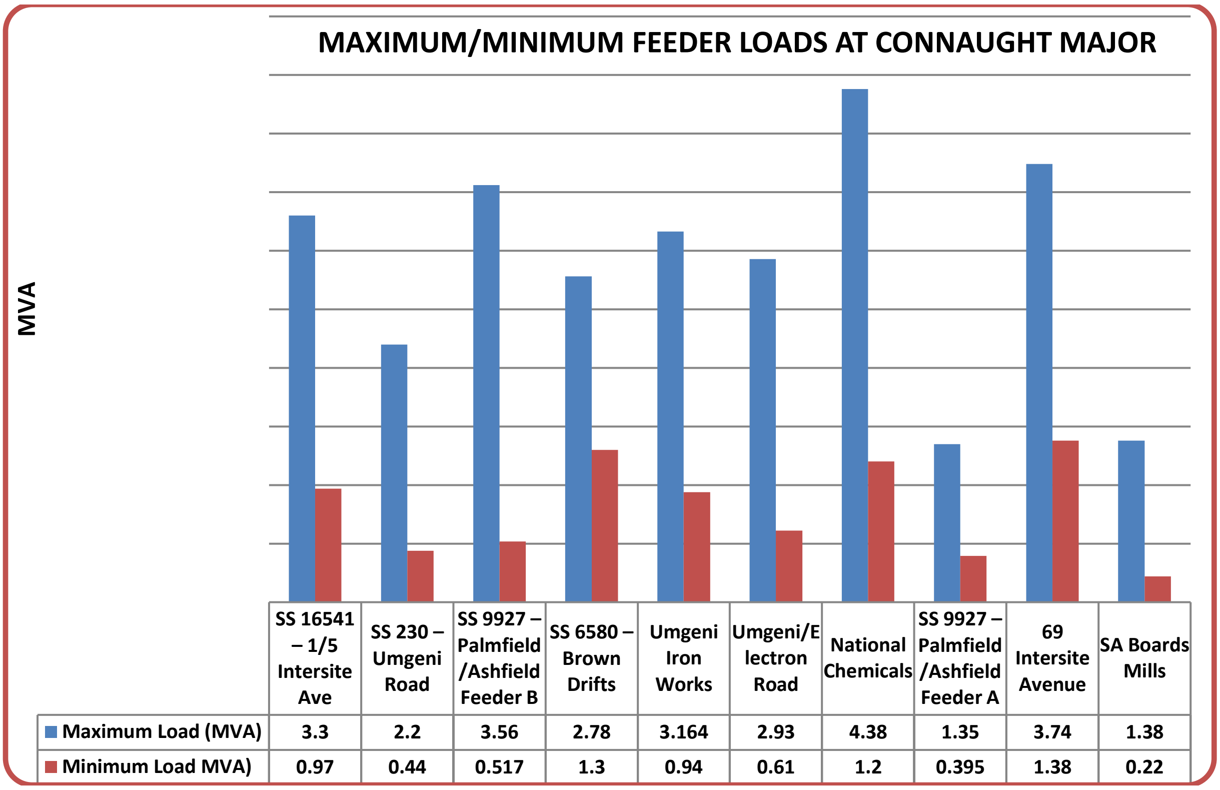


Figure 4.5: Peak and off peak loading at Connaught Major [5]

“The Springfield distribution network and the Bisasar Road landfill gas to electricity EG project was modelled in the ERACS power systems simulation package. The study examined the impact of injecting 0.0 MW to 8.0 MW landfill gas to electricity generation onto the Springfield distribution grid with increasing penertration. The first stage of the project implementation was to install four 1 MW gas to electricity generators.” [5]

4.1.8. Study Results

The case studies carried out assessed the DG impact on:

(i) Voltage
(ii) Cable loading
(iii) Single phase fault current
(iv) Three phase fault current
(v) Impact of power factor on the network

For this investigation, the statutory voltage limits were taken as ± 5% of $V_{Nominal}$ at MV Level (11 kV) and ± 10% of $V_{Nominal}$ at LV level (230V and 400V). This is the acceptable limits in South Africa although in other parts of the world the Medium Voltage statutory limits are sometimes higher. For this study the more stringent ± 5% of $V_{Nominal}$ at Medium Voltage was utilized. [5]

Table 4.3 shows the actual Springfield distribution network bus bar names and the equivalent names used in the ERACS power systems simulation package when the existing network and landfill gas to electricity EG plant was modelled. [5]

Table 4.3: Network Busbar Names [5]

Reference Name	Actual Bus Bar Name
BUS BAR 1	CONNAUGHT MAJOR MAIN REAR BUS BAR
BUS BAR 2	BROWNSDRIFT S/S 6580
BUS BAR 3	6 CEDARFIELD CLOSE DSS 24797
BUS BAR 4	UMGENI & ELECTRON S/S 14633
BUS BAR 5	57 INTERSITE AVE S/S 16754
BUS BAR 6	69 INTERSITE AVE S/S 16568
BUS BAR 7	QUARRY & KENNEDY PUMPS DSS 23812 RHS BB
BUS BAR 8	UMGENI IRON WORKS S/S 7458
BUS BAR 9	UMGENI ROAD S/S 230
BUS BAR 10	ELEC DEPT SS 5874 RHS BB
BUS BAR 11	17 INTERSITE AVE S/S 16441
BUS BAR 12	NATIONAL CHEMICALS S/S 1481
BUS BAR 13	PALMFIELD AND ASHFIELDS S/S 9927
BUS BAR 14	QUARRY & KENNEDY PUMPS DSS 23812 LHS BB
BUS BAR 15	ALPINE & QUARRY
BUS BAR 16	MAIN FRONT LHS BB
BUS BAR 17	ELECTRON ROAD S/S 12076
BUS BAR 18	MAIN FRONT RHS BB11
BUS BAR 19	ELEC DEPT SS 5874 LHS BB
BUS BAR 20	1/5 INTERSITE AVE S/S 16541
BUS BAR 21	SA BOARDMILLS S/S 531
BUS BAR 22	GEN 11kV BUS

"The studies were carried out under normal network conditions where the Electricity Department DSS 5374 bus section was closed and the EG plant was operated at fixed unity power factor during both peak and off peak loading conditions." [5]

4.1.8.1. Voltage Impacts

Figure 4.6 shows the voltage profile on the network as the level of EG penetration increases from 0MW to 8MW during the off peak period. Voltage rise occurs on the network at the injection DSS (Electricity Department DSS 5374) at bus 10 and 19 (Right and Left hand side of the bus section) and the substations (Bus 7, Bus 11, Bus 14, Bus 15, Bus 19, Bus 20) directly connected to the injection point. The voltage approaches the upper voltage statutory limit of 1.05 PU however all voltage levels remain within the statutory limit of ±5% of 11 kV. [5]

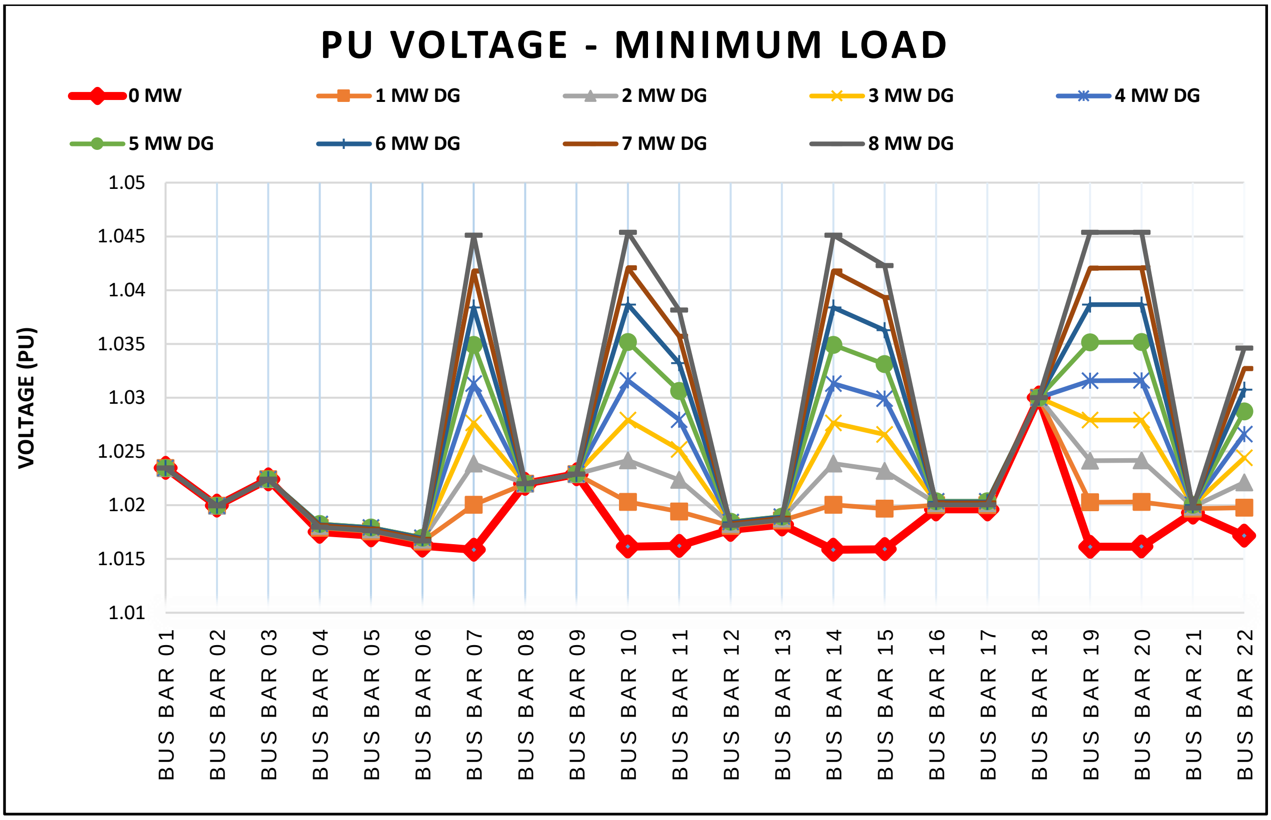


Figure 4.6: Voltage profile during network off peak loading [5]

Figure 4.7 indicates that during the peak loading period, the network bus bar voltages at the injection DSS (Electricity Department DSS 5374) at bus 10 and 19 (Right and Left hand side of the bus section) and the substations (Bus 7, Bus 11, Bus 14, Bus 15, Bus 19, Bus 20) directly connected to the injection point. and the substations directly connected to this substation is supported by the EG plant and improved. All voltages remain within the statutory limits of ±5% of 11 kV. [5]

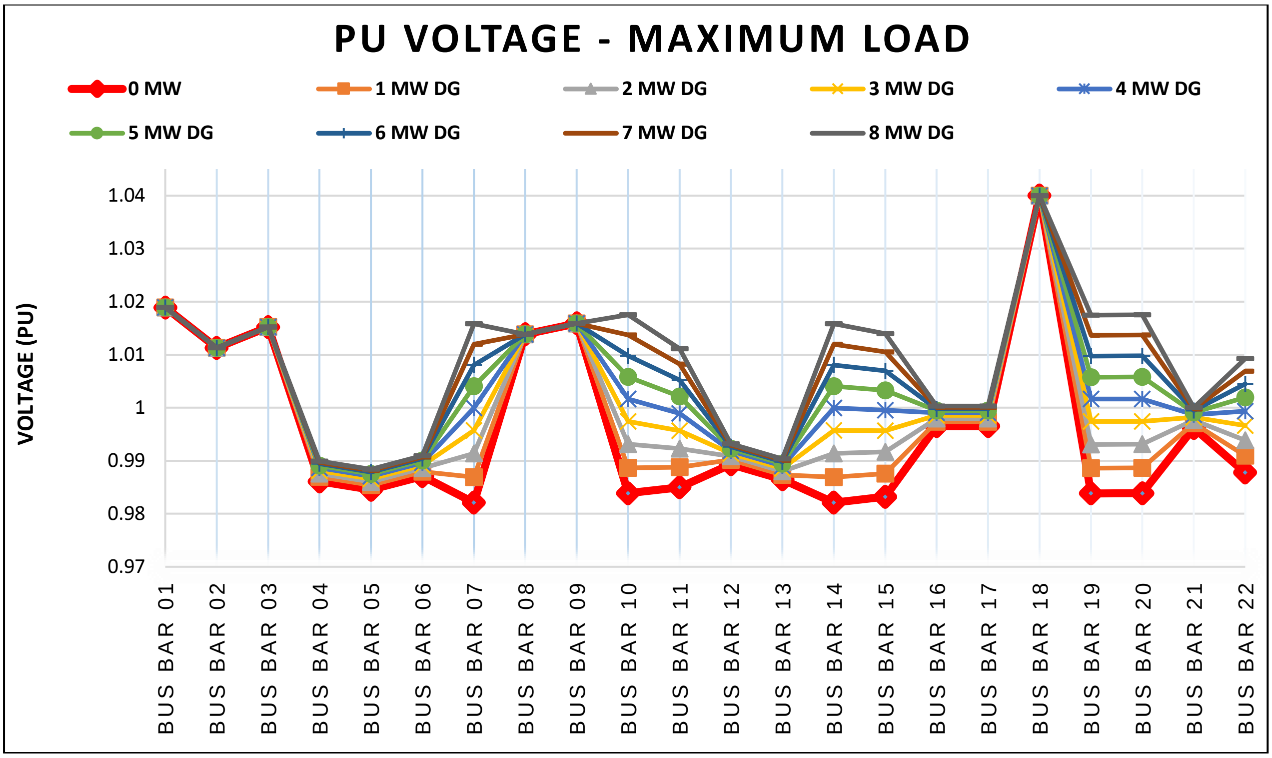


Figure 4.7: Network voltage profile during peak loading [5]

4.1.8.2. Network Cable Loading

The existing Springfield distribution network feeder cables were designed utilizing 240 mm^2 Paper Insulated Lead Covered (PILC) cables which are rated at 5.97 MVA whilst the injection cable from the EG plant to Electricity Department DSS 16541 was a 300mm^2 PILC cable rated at 8.1 MVA. Figure 4.8 shows the network cable loading under normal operating condition during the off-peak loading period. When the EG size increases to 8MVA, the cable feed between Electricity Department DSS 5374 and 1/5 Intersite Avenue DSS 16541 operates at 98.8% of its thermal rating due to low load demand in the off-peak period at the injection point. There is a change in loading on all the feeders surrounding the injection point and linking back to the Major Substation. All other feeder from the Major Substation remains constrant and hence there is no change in their cable loading.

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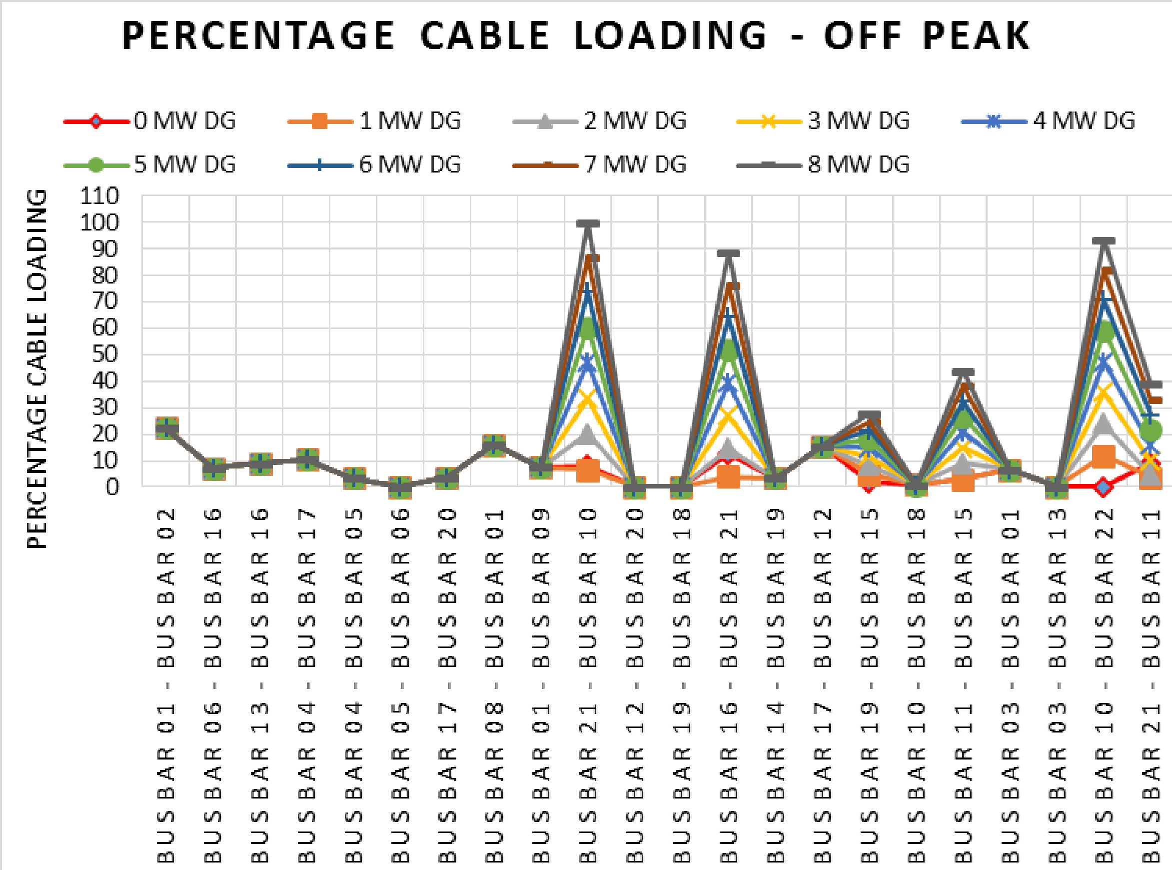


Figure 4.8: Cable loading during off peak loading condition [5]

Figure 4.9 shows the case of a network contingency analysis where the Electricity Department DSS 5374 bus section was opened. In this case with 8MVA EG injection, the cable between Electricity Department DSS 5374 and 1/5 Intersite Avenue DSS 16541 loading increases to 127% of its thermal rating. This is also due to insufficient off peak loading at the injection substation to utilize the generated electricity. The electricity has to be transmitted back to 1/5 Intersite Avenue DSS 16541 and ultimately back to the bus bars at the Connaught Major Substation where it is then distributed to the other feeders. [5]

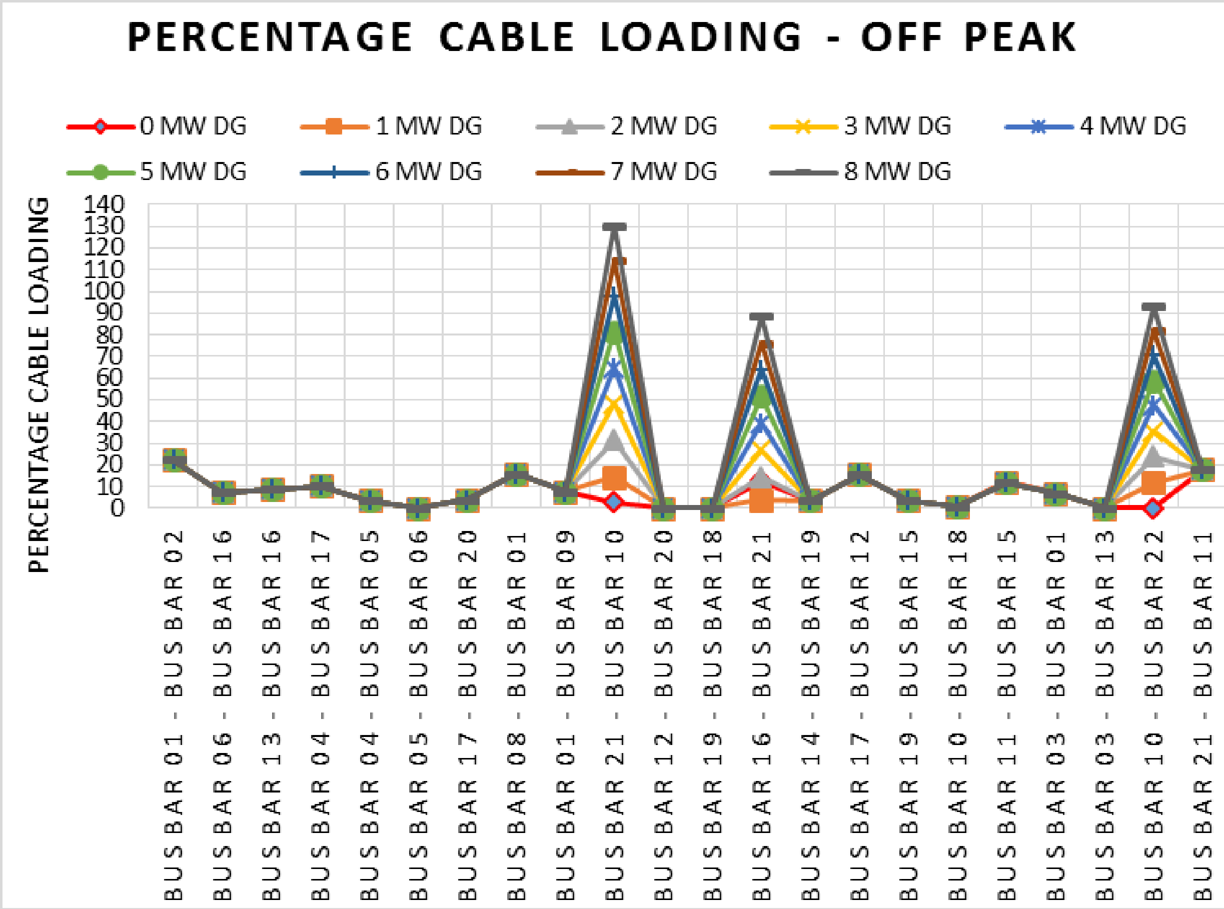


Figure 4.9: Off peak loading with bus section open during contingency [5]

Figure 4.10 shows the cable loading during peak loading condition under normal operating condition indicates that none of the cables exceed their thermal ratings. However, there was a reduction in loading on certain feeders since the load is now supplied from the EG plant as opposed to the grid. [5]

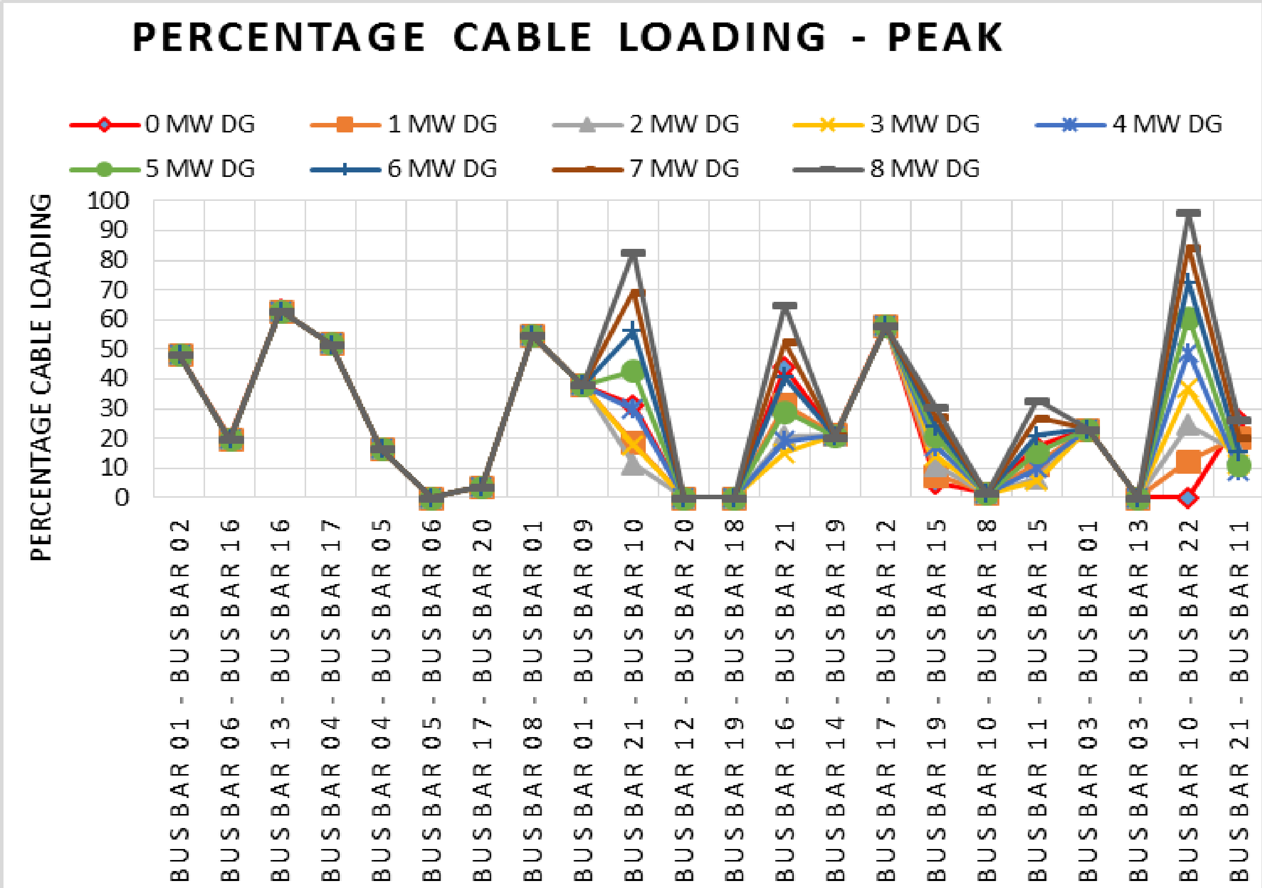


Figure 4.10: Cable loading during peak loading [5]

4.1.8.3. Three Phase Fault Level

Figure 4.11 shows the three phase fault level on the bus bars. The network three phase fault level rose as the number of EG units increase from 1 to 8 units (power output increased from 1MW to 8 MW). This shows the ability of the SG to contribute to a fault on the network. The fault level increase occurred on all feeder bus bars on the network connected to the transformer at the Connaught Major Substation with which the SG plant operates in parallel. Network records indicate that the increased fault levels remained within safe breaking capacity of the circuit breakers on the network which varied from 250MVA for the older circuit breakers to 350MVA for the newer circuit breakers. The new increased three phase fault level of 193MVA occurred at the Connaught Major Substation front bus bar which the 8MW EG operates in parallel with. The highest increase in fault level was 51.623MVA and this occurred at the injection point. This is due to the fact that SGs have the ability to provide fault current up to 8 times its rated MVA capacity. [5]

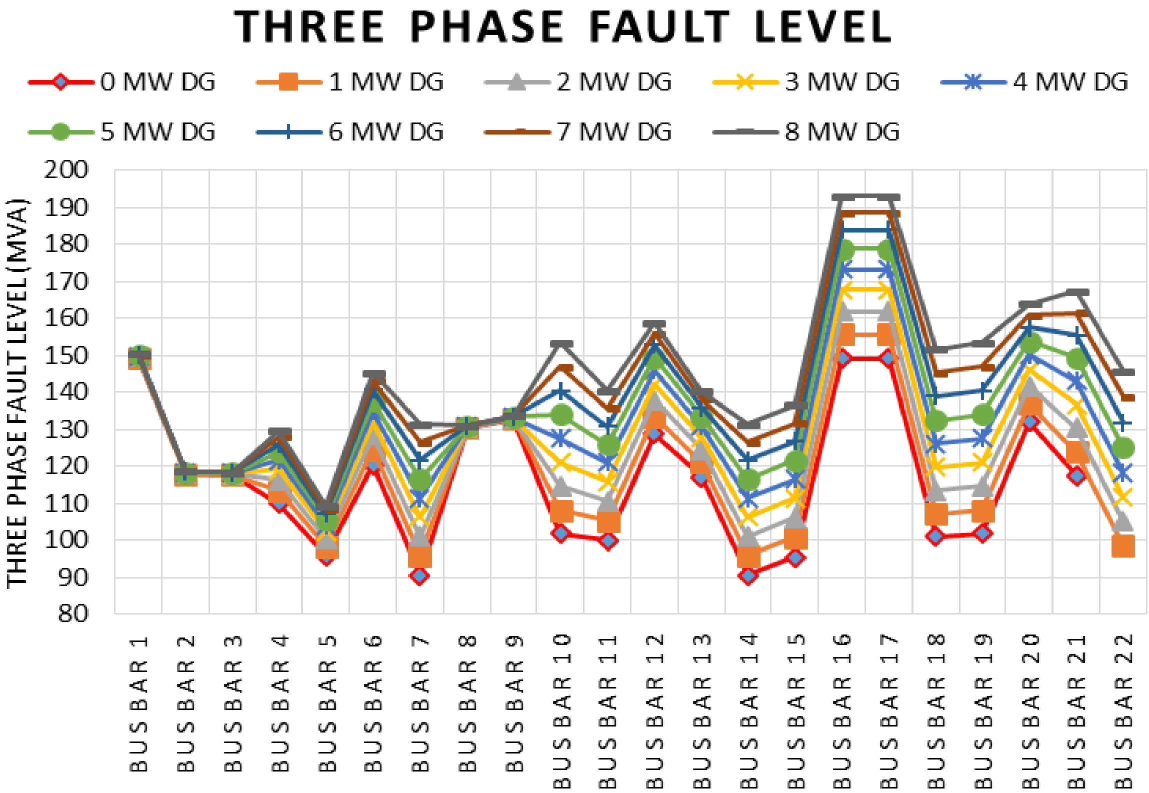
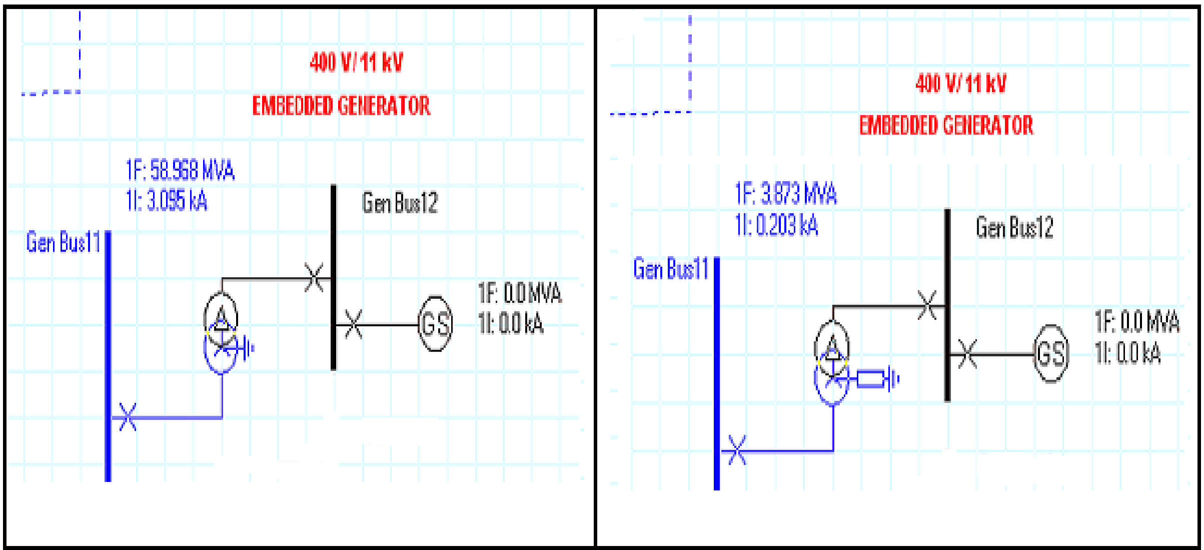


Figure 4.11: Three phase fault level with increased EG penetration [5]

4.1.8.4. Single Phase Fault Current

The earth fault was simulated at the injection point on the grid. Figure 4.12 shows the worst case earth fault current contribution as 3.095 kA by the generation plant 11kV bus bar, however a decision was taken to limit the earth fault current to 25A per 1MW SG. This was achieved by installing a 254-ohm neutral earthing resistor (NER) on the star point of each generator transformers which then reduced the earth fault to 203 A. [5]

Table 4.3 shows the reduction in Earth Fault current with the use of NER's.



8 MW Landfill gas to Electricity DG without NER (Earth Fault Current contribution 3095A from the Generators)	8 MW Landfill gas to Electricity DG with NER (Earth Fault Current contribution 203A from the Generators)

Figure 4.12: Single phase fault current with 8 MW EG at the injection bus bar with/without a NER [5]

Table 4.4 shows the EG earth fault contribution for different EG ratings.

Table 4.4: Earth Fault Current limiting using an NER [5]

EG rating (MW)	Fault Contribution from the EG (A)
1	25
2	50
3	75
4	100
5	125
6	150
7	175
8	200

4.1.8.5. Synchronous Generator Power Factor Varied

An assessment of the impacts of operating 4, 6 and 8 MW EG units at varying power factors from 0.9 lagging to 0.9 leading was carried out. The Bisasar Road Landfill gas to electricity project first stage was proposed to have an installed capacity of 4 MW with the plan to buy an additional two 1 MW engines whilst the site had a total generation potential and was designed for 8 MW. Hence I selected 4, 6 and 8 MW to represent the various potential stages of the project for this study. The impacts of the different power factors on the network voltage during peak and off peak periods were studied. [5]

Figure 4.13 shows the off peak loading and Figure 4.14 shows the peak loading with 4 MW EG. No network violations are experienced.

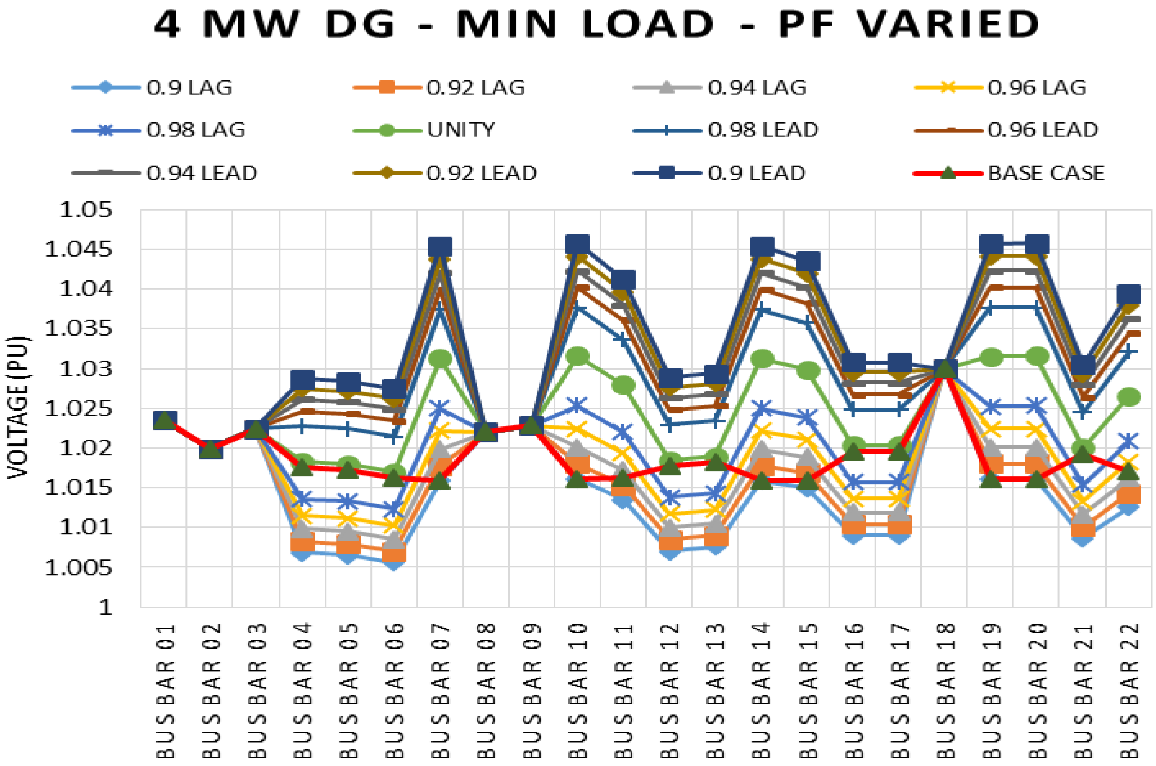


Figure 4.13: Off peak loading with 4 MW EG [56]

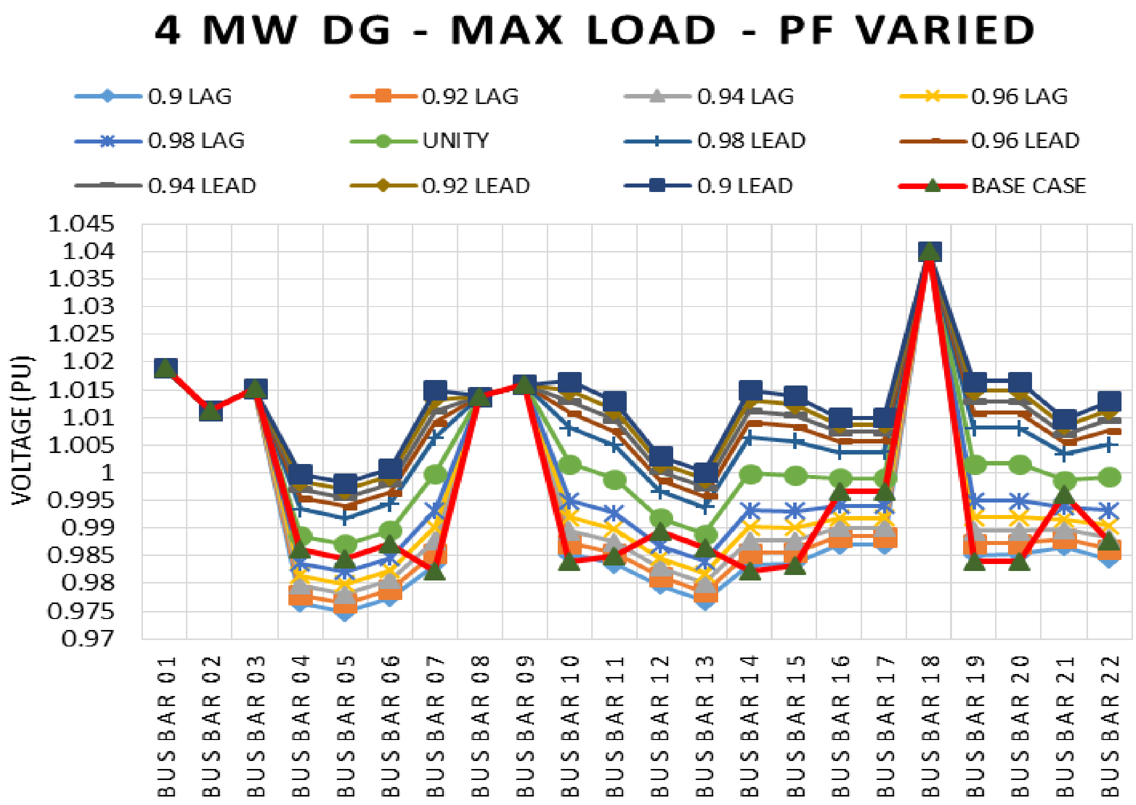


Figure 4.14: Peak loading with 4 MW EG [56]

With the installation of a 6 MW EG to the network, no voltage violations were experienced during the network peak period as shown in Figure 4.15 However voltage violations were experienced during the off peak period as shown in Figure 4.16 when the generator is operated at leading power factor below 0.98. This is due to two factors namely, lower network load demand during the off peak period resulting in a lower voltage drop on the network bus bars and the injection of reactive power from the synchronous generator when operated in leading Power Factor mode causing a voltage rise. It is therefore not advisable to operate the EG in leading power factor mode on the Springfield distribution network. [56]

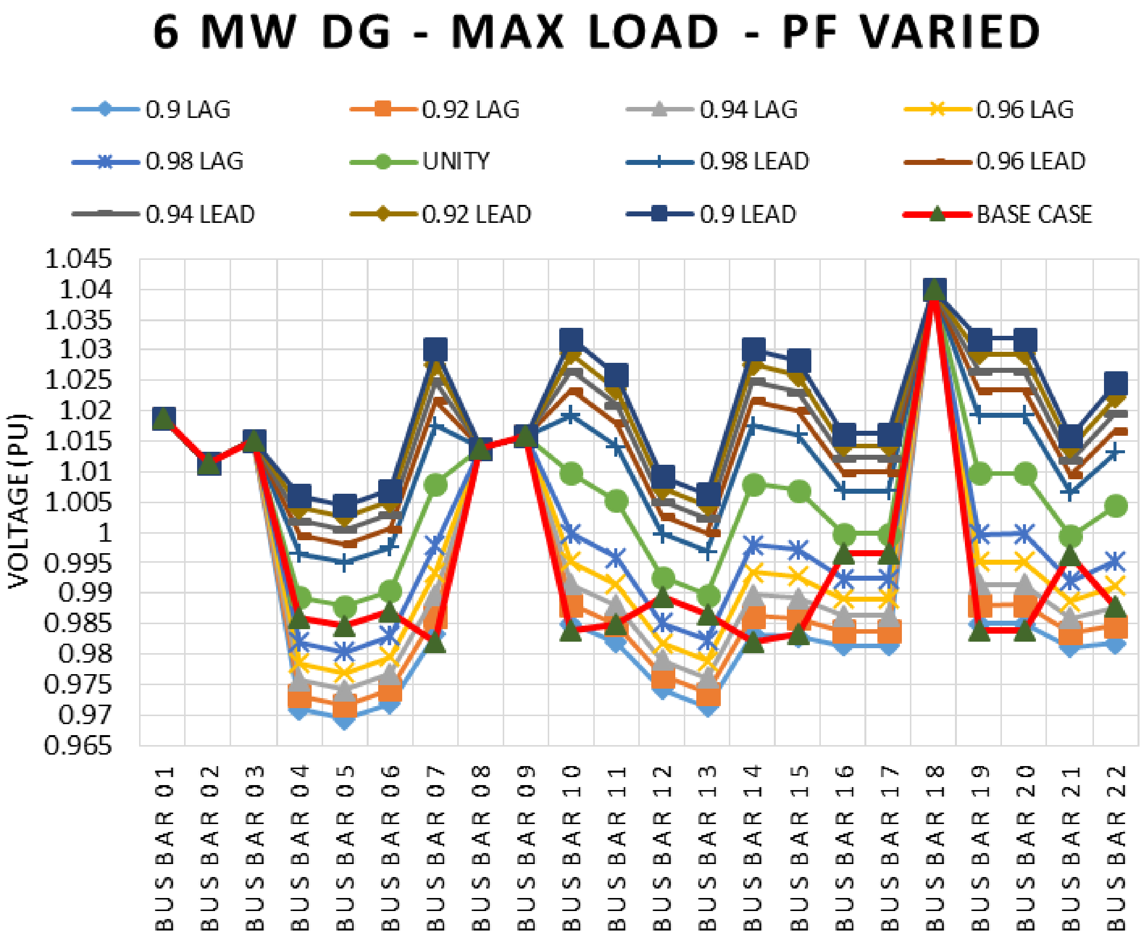


Figure 4.15: Peak loading with 6 MW EG [56]

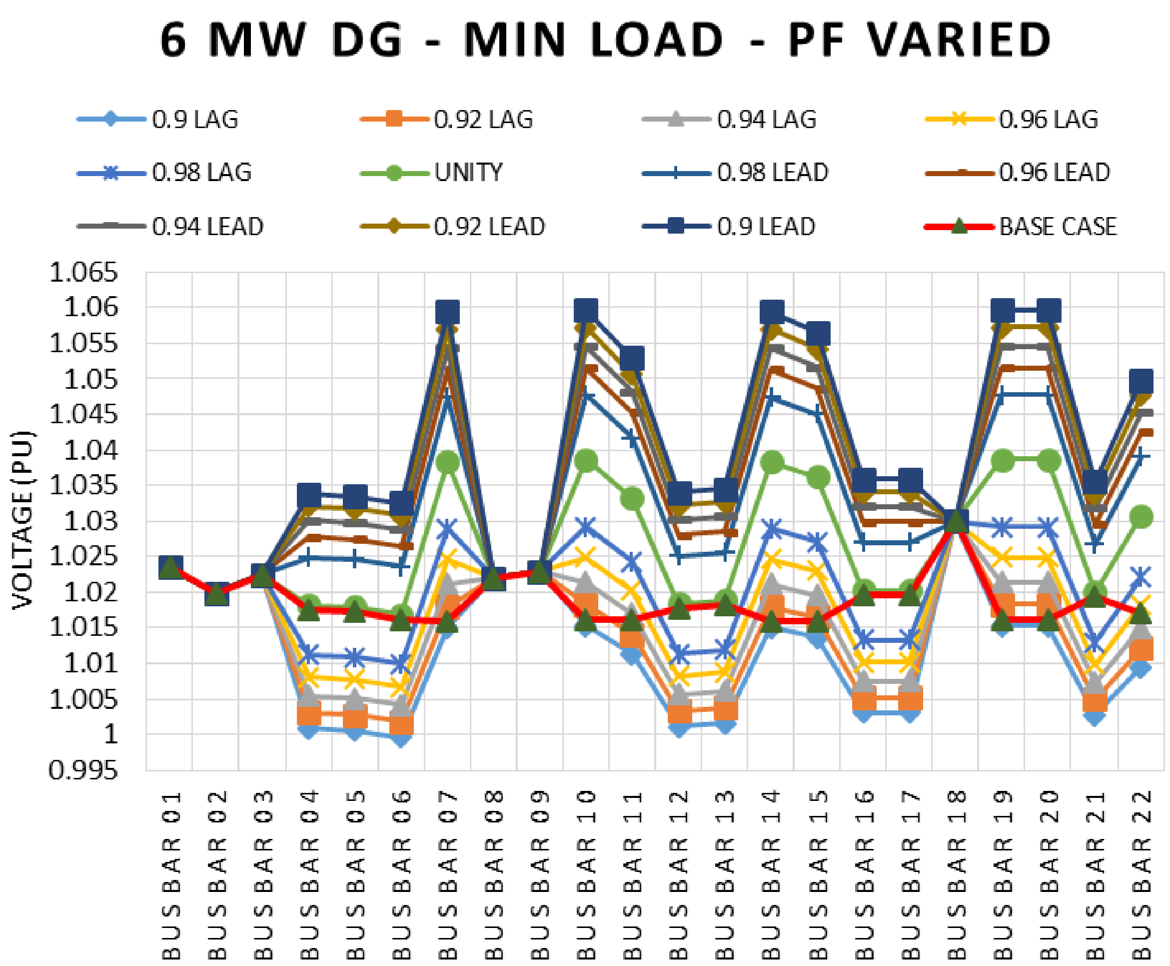


Figure 4.16: Off peak loading with 6 MW EG [56]

With the injection of 8 MW on to the Springfield distribution network, there were no voltage violations experienced during the peak period as shown in Figure 4.17. However, there were voltage violations experienced when the EG was operated at leading power factor during the off peak period as shown in Figure 4.18. This is due to two factors namely, lower network load demand during the off peak period resulting in a lower voltage drop on the network bus bars and the injection of reactive power from the synchronous generator when operated in leading Power Factor mode causing a voltage rise. It is therefore not advisable to operate the EG at leading power factor in the Springfield distribution network. [56]

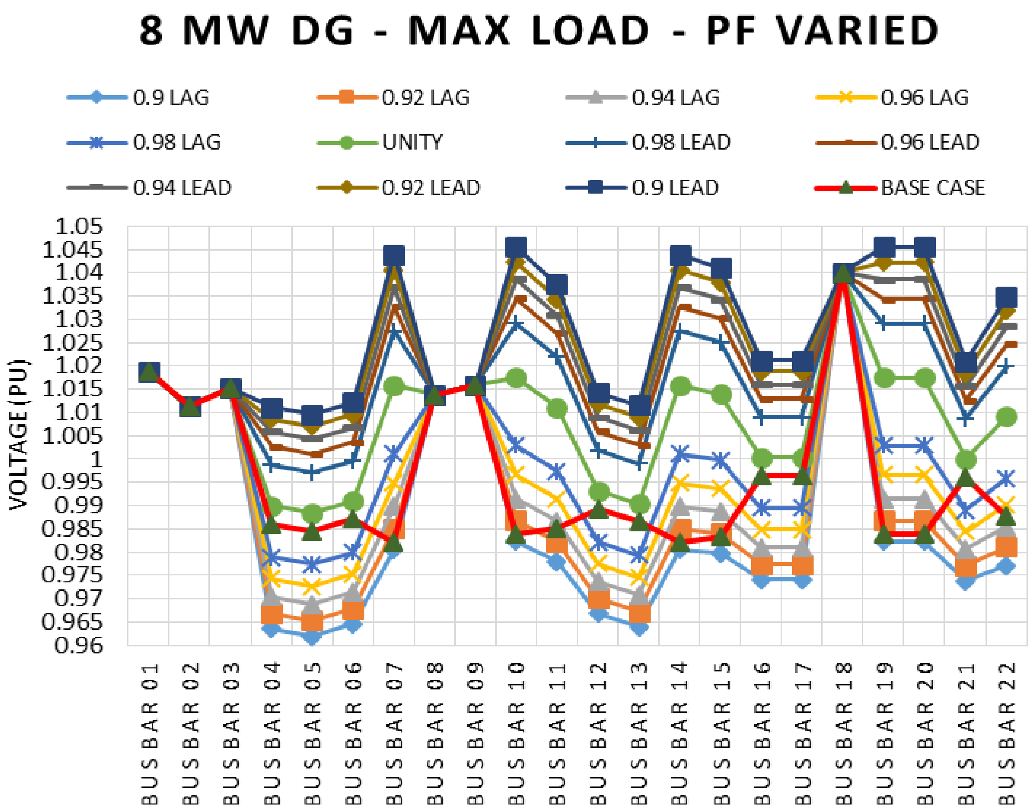


Figure 4.17: Peak loading with 8 MW EG [56]

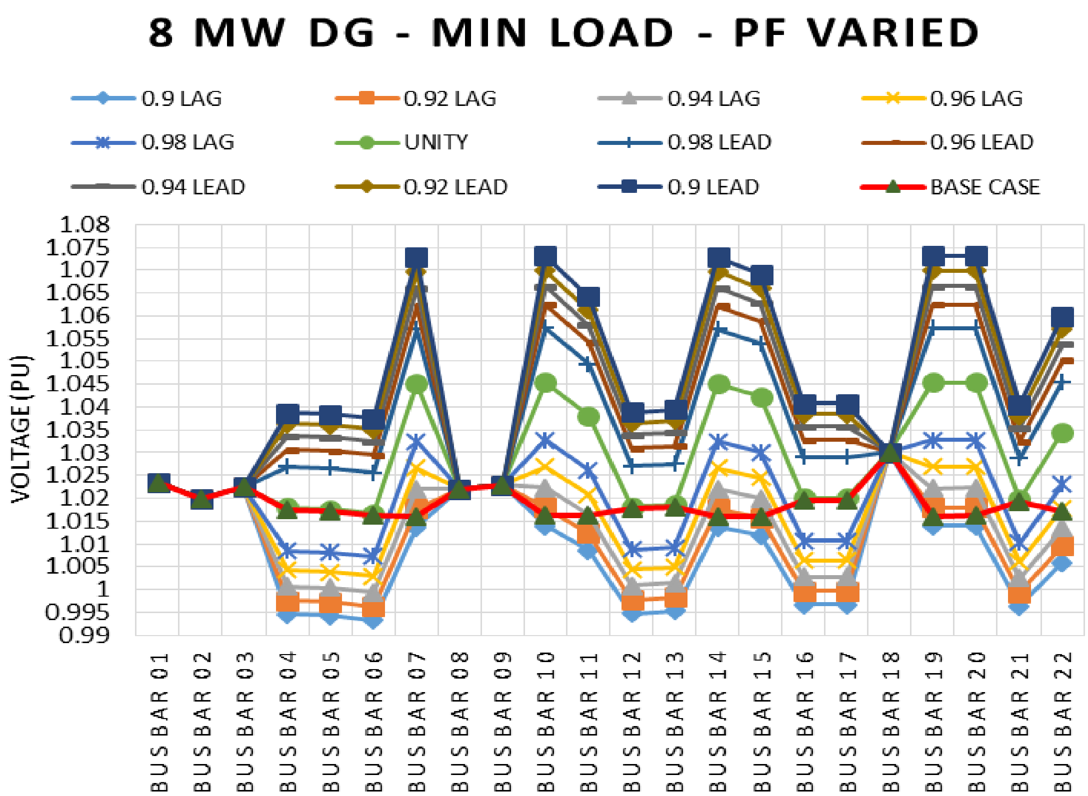


Figure 4.18: Off peak loading with 8 MW EG [56]

4.1.9. Landfill Gas to Electricity Generation Process

The construction of the Bisasar Road landfill gas to electricity project, the largest in Africa at the time then went ahead after receving all environmental clearances and the requred funding for the project. The process of extracting and utilizing the landfill gas to generate electricity is then explained below utilising the Bisasar Road landfill site construction to explain the process. The process required to extract the landfill gas from the site in order to be used as a fuel for the landfill gas-to-electricity generation units is shown in Figure 4.19 and entails the following process;

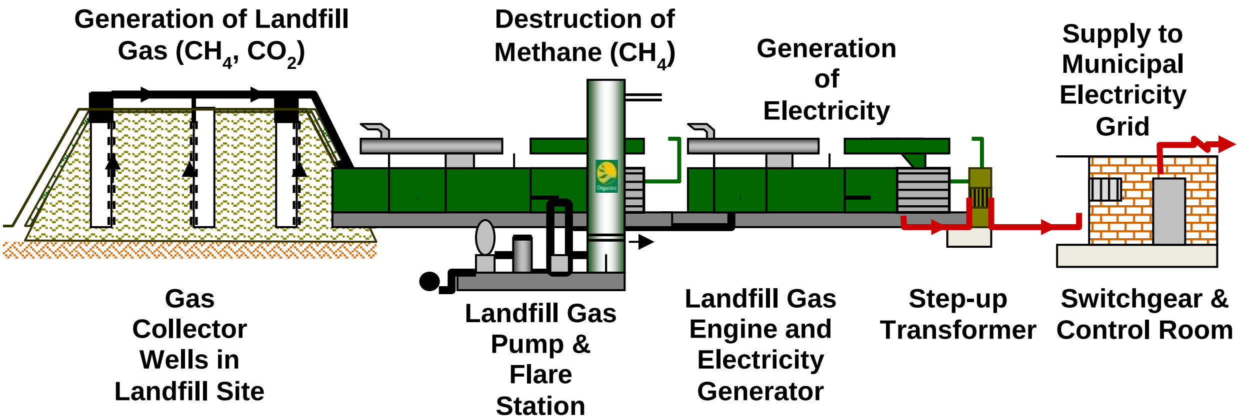


Figure 4.19: Schematic layout for landfill gas-to-electricity [5]

1. Vertical and horizontal extraction gas wells need to be constructed on the landfill site as shown in Figure 4.20 and Figure 4.21. Bisasar Road landfill site has a number of vertical gas wells (VGW) and horizontal gas wells (HGW) constructed.

Figure 4.20: Installation of horizontal gas well [41]

Figure 4.21: Installation of vertical gas wells [41]

2. “Gas collection pipe works are then installed from the extraction wells to the extraction plant from where it is distributed to the electricity generators and the excess to the flare.” [41] Figure 4.22 shows the gas collection pipework.

Figure 4.22: Installation of the gas collection pipework [41]

The Bisasar Road landfill gas management system was designed with a 5000 m^3/hr total flow consisting of two 450mm outside diameter (OD) high density polyethylene (HDPE) (nominal pressure up to 12MPa) which allows conveyance of extracted LFG from the landfill to the generation compound. The plant is equipped with two 2500 Nm^3/hr variable speed drives operated centrifugal blowers that induce a negative pressure (-10 mbars) on the gas field and this is stabilised by a 2000 m^3/hr flare and fed to General Electric Jenbacher (GEJ) spark ignition engine. The pipe work network (better referred to as "fuel carrier") has had careful consideration given to condensate management with knock out pots and attention to pipe grades i.e. in direction of LFG flow allows for minimum 3% whilst in opposite LFG flow direction is typically minimum 5%. "Bisasar Road has to date some 70 vertical gas wells, 100 horizontal gas wells and 70 gas risers which have managed to deliver approximately 4200Nm^3/hr of LFG." [41]

3. "Centrifugal blowers installed for the sole purpose of extracting the gases from the extraction wells and supplying it to the generators and the excess to the flare" shown in Figure 4.23. [41]

Figure 4.23: Centrifugal gas blowers installed [41]

The landfill gas engine is coupled to a SG that uses the extracted gas from the landfill site as a fuel to generate electricity. They generator output from these generatoration modules are commonly available in 1 MW modules (e.g. Jenbacher type 320 engines) or 0.5 MW modules (e.g. Jenbacher type GS – LL 312 engines). Currently the Bisasar Road landfill site has 6 × Jenbacher type 320 engines and 1× Jenbacher type GS – LL 312 engines. The site has a total installed generation capacity of 6.5 MW which was built up in modules over time. Stage one of the Bisasar Road landfill gas to electricity project started with the arrival of the first four gas to electricity engine/generator units shown in Figure 4.24. These engines /generator are in containerised modules rated at 1 MW. The modules contained the engine and generator already assembled except the radiators and cooling equipment which arrived separately and had to be assembled on site. [41]

Figure 4.24: Off-loading of the generator modules [41]

4. A flare unit then needed to be installed at the site to flare of the excess extracted gases and to balance the extraction and generation system.

The flare unit was installed at the Bisasar Road landfill site to balance the extraction and generation system by burning up the excess gas which was not utilized by the engines. This also ensuring that the Methane was destroyed even when some of the engines were out of service. A flare unit of rated capacity of 2000 m^3/hr was installed at the Bisasar Road landfill site as shown in Figure 4.25. [41]

Figure 4.25: Installation of the gas extraction system and the flare [41]

5. “Appropriate size cable and switchgear are installed on site to allow interconnection onto the local distribution network. The generated electricity is injected into the closest 11 kV DSS within the eThekwini Electricity Central distribution network.” [41] Step up generator transformers were installed on site to step up the voltage from the generators. The output voltages from the generators are 400 V which is then stepped up to 11 kV via the generator transformers which was then fed into an onsite substation. Figure 4.26 shows the installation of the step up generator transformers whilst Figure 4.27 shows the 11 kV switchboard installed at the Bisasar Road generation plant. [41]

Figure 4.26: Step up generator transformers installed [41]

Each engine came containerised containing a 20 cylinder gas to electricity engine coupled to 4 pole lap wound synchronous AC generator. Each generator has its own step 0.4/11 kV step-up transformer which then injected the electricity on to a common bus bar on the onsite substation. Then a 300 mm^2 paper insulated lead covered copper cable was then used to inject the power into the local Springfield distribution network. [41]

Figure 4.27: Bisasar Road 11 kV switchboard [41]

4.1.10. Commissioning of the Bisasar Road Landfill Gas to Electricity Project

Since the generator units arrived completely assembled, it took around three months for all the commissioning to be completed and the generators were finally switched on in mid-March 2008. Figures 4.28 and 4.29 shows the generation profiles from the Bisasar Road landfill site during commissioning in March and during operation in June 2008. [41]

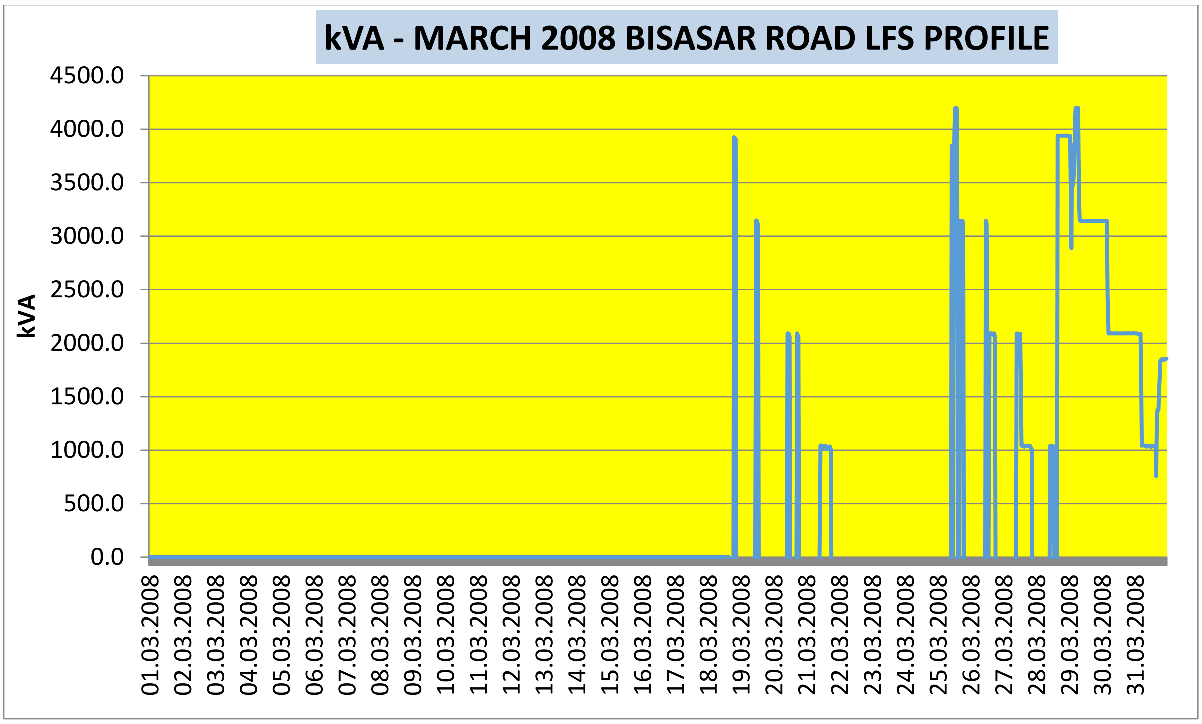


Figure 4.28: Generation profile for March 2008 (Bisasar Road LFS generators switched on during final commissioning tests) [41]

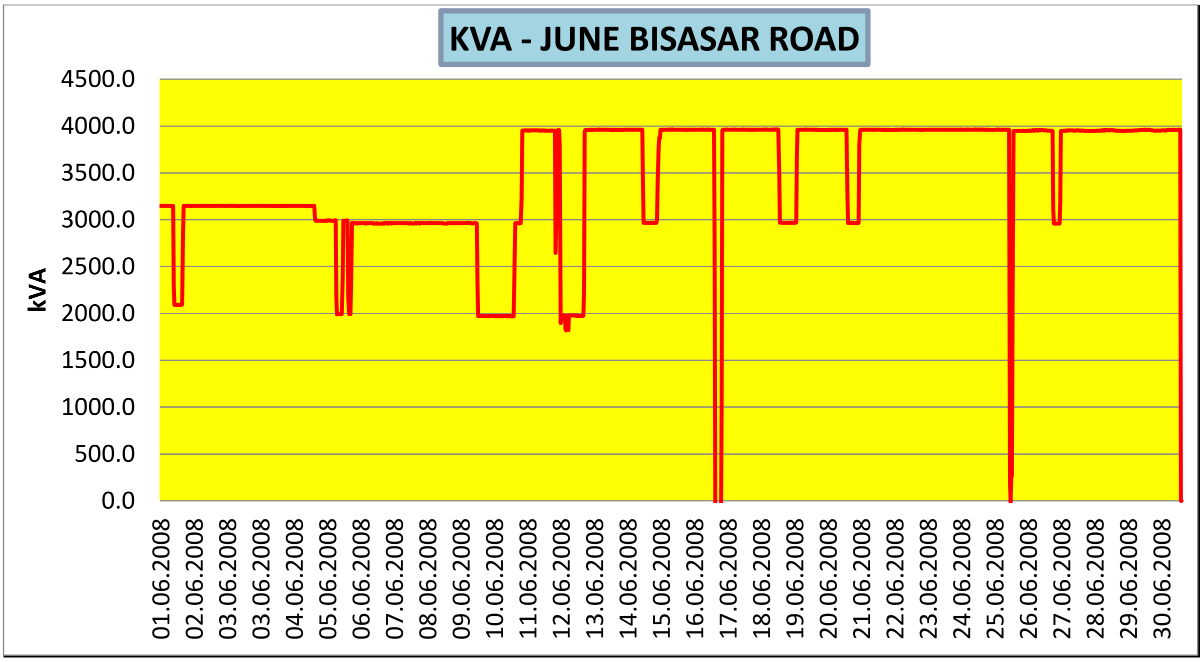


Figure 4.29: Generation profile for June 2008 at Bisasar Road Landfill Site [41]

The generation plant was subsequently increased to 6.5 MVA from 4 MW in August 2009. This was achieved by the purchasing two additional 1 MW gas to electricity generators and transferring a 0.5 MW engine purchased for another landfill site where the gas quality and volumes were very poor. The site currently operates at 6.5 MW. Figure 4.30 shows the generation output when the plant installed capacity was increased to 6.5 MW. [41]

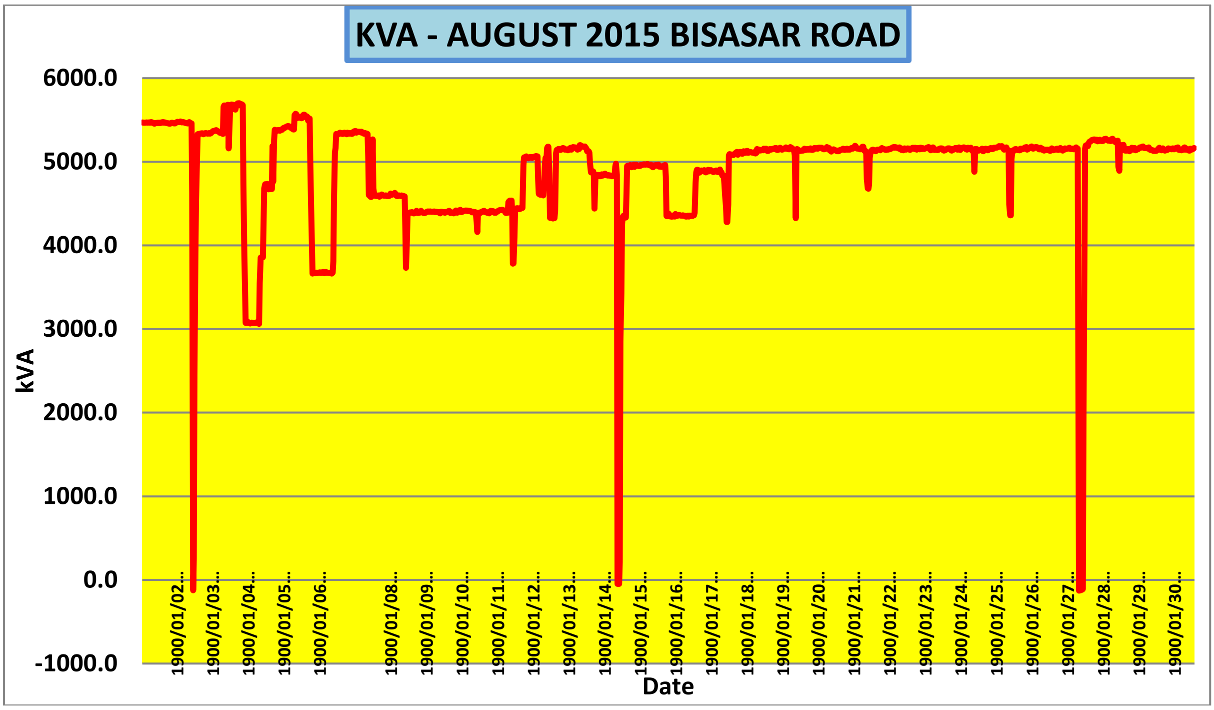


Figure 4.30: 6.5 MW generation profile for August 2015

4.1.11. Feasibility of the Bisasar Road Landfill Gas to Electricity Pilot Project

The Bisasar Road pilot project cost R85 000 000 to construct and commission 6.5 MW of generation. We study the financial feasibility of the project since commissioning in March 2008 to determine whether this technology is feasible to implement in eThekwini Municipality. Figure 4.31 shows the Bisasar Road landfill site and the 6.5 MW generation plant in Springfield Park in Durban. The site has been in successful operation since 2008. [41]

Figure 4.31: Bisasar Road landfill site and generation plant [5]

There was no mechanism in place at the time for the purchase of electricity from a local generator and there were municipal regulations such as the Municipal Financial Management Act (MFMA) which prevented the municipality from entering into any contract greater than 3 years and the Municipal Supply Chain Management Regulation which stated that the Municipality had to purchase any product at the lowest price on the open market. This meant that the eThekwini Municipality Electricity Department could not pay the eThekwini Municipality Solid Waste Department a higher tariff for any kWh of electricity purchased even though the generated electricity was from a more environmentally friendly source. In order to ensure that the project could proceed, a Power Purchase Agreement between the Electricity and Solid Waste Department was signed for three years with the option to renew it at the end of the term. To ensure compliance with the SCM regulations, 4 quadrant bi-directional meters had to be installed at the generation site and programed to record according to a Time of Use Tariff (TOU) structure for both electricity imported and exported. The tariff structure utilized was the Eskom Megaflex 275 kV TOU tariff structure to ensure that they were paid at avoided costs as this was the tariff that eThekwini Municipality Electricity Department paid Eskom for their bulk electricity purchased. [41]

The TOU tariff structure shown in Figure 4.32, Figure 4.33 and Table 4.5 is a complex tariff structure which have different kWh electricity rates dependent on the time of day, day of week and month of year. Eskom is paid utilizing this tariff structure, hence the generation plant was paid using the same structure to ensure avoided costs were paid for electricity purchased.

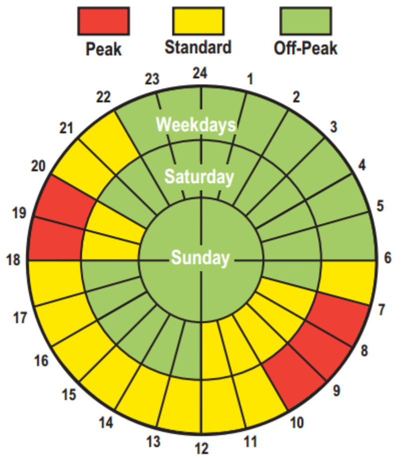


Figure 4.32: Low demand season break down of tariff [24]

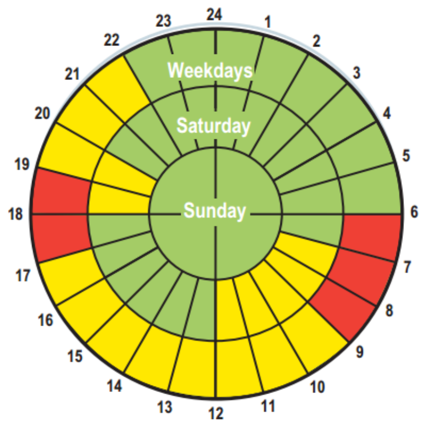


Figure 4.33: Low demand season break down of tariff [24]

Table 4.5: Breakdown of the TOU tariff structure [41]

Low Demand Season (1 September – 31 May)		
Peak	**Standard**	**Off-peak**
76.5c	52.66c	33.4c
High Demand Season (1 June – 31 August)		
Peak	**Standard**	**Off-peak**
234.55c	71.06c	38.58c

We next look at the income derived from this project since commissioning in March 2008 and the average cost per a kWh of electricity sold to the grid. From Table 4.6 it can be seen that at the end of December 2015, 295 309 156 kWh has been generated from the Bisasar Road landfill site gas to electricity project with R130 669 472.21 revenue received. Table 4.6 also indicates that the average tariff paid for electricity in 2008 was R0.20/kWh which has subsequently increase to R0.65/kWh in 2015. The overall average cost paid for the electricity purchased is R0.44/kWh since the start of the project. Since the cost of the project was R85 million and to date R130 million was received from electricity sales which indicates that the project has long paid itself off. However the cost of maintenance was not taken into consideration and the additional revenue received from the sales of Carbon Credits. This proves that landfill gas to electricity projects are feasible to implement at eThekwini Municipality even with avoided costs paid for the electricity generated.

Table 4.6: Generation and financial figures for the Bisasar Road generation plant [41]

Year	**Total kWh**	**Revenue: Electricity Sales**	**Average R/kWh**
2008	21 503 781	R 4 336 602.53	R 0.20
2009	33 464 173	R 7 863 050.94	R 0.23
2010	48 039 123	R 14 947 292.70	R 0.31
2011	41 175 037	R 17 632 774.78	R 0.43
2012	39 646 640	R 20 704 792.56	R 0.52
2013	37 803 728	R 20 604 843.30	R 0.55
2014	36 670 970	R 20 652 877.46	R 0.56
2015	37 005 704	R 23 927 237.94	R 0.65
Total:	295 309 156	R 130 669 472.21	R 0.44

Table 4.7 shows the average prices paid for the South African REIPPPPP. It can be seen that the current rates paid for the generated electricity from the Bisasar Road landfill site generation project is less than those paid for wind and solar technologies on the REIPPPP. [41]

Table 4.7: Average prices for REIPPPP for Round 1 to 3 [41]

Tariffs	**Round 1 Average Bid (Per kWh)**	**Round 2 Average Bid (Per kWh)**	**Round 3 Average Bid (Per kWh)**
Wind	R1.14	R0.90	R0.66
Solar PV	R2.76	R1.65	R0.88
CSP	R2.69	R2.51	R1.46

Even though it has been demonstrated that landfill gas to electricity projects are financially feasible in South Africa, there is still room to improve and optimise potential projects. Methods are discussed below which could be applied to these landfill gas to electricity projects to make the project more profitable/financially feasible based on experience at the Bisasar Road landfill gas to electricity project. [41]

4.1.12. Landfill gas pre – treatment options to improve generation output and reduce engine maintenance.

Unlike natural (clean) gas, LFG is generally saturated with moisture and contains various trace impurities (Sulphur, Silicon, Chlorine, Calcium, etc). These trace impurities do not become noticeable until the gas engine has been in operation for a period of time. In particular, if LFG impurities are not attended to through appropriate gas cleaning systems, it will lead to engine operation and maintenance problems. Although LFG engines are designed on a lean burn system, engine manufacturers are usually protected from warranty claims by providing fuel quality technical specifications with allowable contaminant levels to maintain optimum operating conditions. As a result the onus is placed on the landfill/project operator to ensure the fuel gas meets the engine specifications. The recommended approach would be to undertake regular LFG sampling to obtain detailed knowledge and build a historical database for gas analysis to enable informed decisions on gas operation and reliability. [41]

Pre-treatment of the landfill gas is an option to ensure that the gas meets the engine manufactures input specifications or the alternative will be to accept additional maintenance costs and reduced electricity generation. There are two pre-treatment options namely; primary and secondary categories. Primary pre-treatment of the input LFG reduces moisture/water vapour as well as particle impurities and enhance the performance of the landfill gas engine in terms of reduced maintenance and increased engine output. Whilst secondary treatment options is usually more advanced to remove specific chemical components of the LFG at a higher capital and operating costs. There options are LFG scrubbing, activated carbon, etc. Table 4.8 outlines the common impurities/contaminants, the resulting engine damage and most appropriate gas pre-treatment options. It is apparent that there is more than one appropriate clean up option for any impurity group and the choice of selecting the most appropriate pre-treatment option must be based on technology suitability/back up support, commercial viability of the project and adequacy to site specific requirements. [41]

Table 4.8: Landfill gas pre-treatment options [41]

Impurity/ Contaminant	Type of Engine Damage	Pre-Treatment Options/s	
Moisture	Condensation & formation of acids with available impurities	Knock out pots on pipework	Cyclone Separators
	Corrosion of engine components & metal pipework	Chillers/ Heat Exchange	Condensate Drains
Halogenated Compounds	Formation of Acidic Gas in presence of moisture (HCL, HF, HB)	Membrane Separation	Solvent Scrubbing
	Corrosion of engine components and metal pipework	Water Scrubbing	CO_2liquefaction
Sulphurs	Corrosive in presence of moisture	Dry Scrubbing	
	Wear of piston rings, cylinder linings & valve guides	Water Scrubbing	
	Effect oil quality – Triggers frequent oil change	Solvent Scrubbing	
Siloxanes & VOSC's	Alters oil retaining surface finish of cylinder liners	Activated Carbon (AC)	
	Crystalline SiO_2deposits results in "physical wear" of internal combustion components.	Activated Carbon + Heat Exchange	
	Premature Spark Plug Failure	Activated Carbon + Chilling	
	Effect oil quality – Triggers frequent oil change	In-Line Chemical Injection	

4.1.13. Storage of gas for generation only during peak and standard times only

In the case of a Time of Use (TOU) tariff structure such as the case of the Bisasar Road landfill gas to electricity project it can be seen that it is more financially feasible to generate electricity during the peak and standard periods as opposed to the off peak period. From Table 4.9 and Table 4.10, it can be seen that should the gas be stored and the generators operated only during peak periods in summer, 51.44% (sum of peak and standard generation) gives us 65.01% of the total income whilst in winter, 51. 64% (sum of peak and standard generation) gives us 76.43% of the total income received. The gas used to generate during the off peak period can be stored and utilised to generate during the peak and standard period. Revenue will increase, however cost of the gas storage unit needs to be taken into account as well as the cost of additional engines to allow generation with the excess quantity of gas. This may be a feasible option when the landfill site is closed to new waste and the quantity of gas reduces. The existing installed generators will then be able to generate during the peak and standard period utilising the total gas (produced plus stored). The option has the benefit of a reduction in the maintenance interval as the number of operation hours of the engine and generator reduces by ±48.5%. The plant could also be utilised as a gas peaking power plant with large gas storage facilities. Cost vs benefit analysis will be to be carried out to establish the project feasibility which is based on the tariff structure paid and other incentive schemes offered by the local utility. [41]

Table 4.9: Break down of income during low demand season [41]

LOW DEMAND SEASON ANALYSIS – SEPTEMBER 2015 – NOVEMBER 2015				
Tariff Period	**Total kWh Generated**	**Percentage Monthly Generation (%)**	**Income (R)**	**Percentage Income (%)**
Peak	1385194	14.566036	1059674	23.8189
Standard	3507755	36.885862	1847184	41.5203
Off-Peak	4616806	48.548101	1542013	34.6608
Total	9509755	100	4448871	100

Table 4.10: Break down of income during high demand season [41]

HIGH DEMAND SEASON – JUNE 2015 – AUGUST 2015				
	Total kWh Generated	**Percentage Monthly Generation (%)**	**Income (R)**	**Percentage Income (%)**
Peak	1583317	14.546	3567527.572	43.125
Standard	4038057	37.097	2754377.635	33.296
Off-Peak	5263645	48.357	1950601.036	23.579
Total	10885020	100	8272506.243	100

4.1.14. Perform maintenance during lower tariff periods.

Table 4.11 depicts the percentage saving between the standard and peak period and off-peak and peak period. If plant maintenance can be scheduled and carried out during the standard tariff period as opposed to the peak period, then there will be a saving on 31.16% (during low demand season) and 69.70% (during high demand season) from electricity sales. Should the maintenance be carried out during the off peak tariff period as opposed to the peak tariff period then there will be a saving of 56.34% (during low demand season) and 83.55% (during high demand season). Hence proper scheduling of maintenance can impact the revenue from electricity sales. If maintenance can be avoided during the peak and standard times then there can be substantial savings for the project. [41]

Table 4.11: Typical percentage savings between different tariff periods [41]

Low Demand Season (1 September – 31 May)	
Standard/Peak savings	31.16%
Off- peak/Peak savings	56.34%
High Demand Season (1 June – 31 August)	
Standard/Peak savings	69.70%
Off- peak/Peak savings	83.55%

4.1.15. Utilising a Heat Exchange/Chiller to reduce the inlet gas temperature and improve the gas quality in subtropical regions.

Durban has a sub-tropical climate and at times the gas from the landfill site exceeded the upper limit of 40 °C for the GEJ gas engines. A heat exchange/chiller option was selected and implemented at the Bisasar Road landfill gas to electricity project. This was due to the landfill gas temperature exceeding the engine manufacturer’s specification. The second reason was to remove the condensate from the LFG supplied to the engines to protect it from condensate damage. The heat exchange/chiller did assist and has reduced the inlet gas temperature to below the manufacturer’s specification. Results from the landfill gas analysis before and after the installation of the heat exchange at the Bisasar Road generation project has shown that there is a removal of contaminants (Sulphur (10%), Silicon (14%) and substantial removal of Ammonia (56%) through condensate removal from the landfill gas. There has also been an overall engine operation improvement due to reduced spark plug failures. The condensate removal of the heat exchange has hence further improved the LFG extraction system operations and maintenance. [41]

4.1.16. Maintain high standard of landfill site management as this affects gas produced.

There needs to be proper management of the landfill site and gas fields to ensure that new gas wells are installed as new waste is dumped on to the landfill site. This to ensure that the volume of gas produced at the site is maintained as gas production at old wells reduce, it is supplemented by the new gas wells. This ensures that the gas quantity is sufficient to operate the engines/generators installed on site. [41]

4.1.17. Apply for Carbon Credits for the destruction of Methane in developing countries.

“According to the Kyoto Protocol (December 1997), there are six listed greenhouse gases (GHG) including: Carbon Dioxide (CO_2), Methane (CH_4), Nitrous Oxide (N_20), Hydrofluorocarbons (HFC's), Perfluorocarbons (PFC's) and Sulphur Hexafluoride (SF6)." [41]

"Landfill gas typically contains 50 - 60 percent CH_4. CH_4 has at least 21 times more effect as a greenhouse gas than CO_2. Therefore, CH_4 has got to be a key gas to address in reducing global warming. Reducing CH_4 emissions has over 21 times the effect of reducing CO_2 emissions albeit that there are considerably more CO_2 emissions from industry and transport than CH_4 emissions. European Union countries, and the majority of first world countries, have legislation to control the landfill emissions and combustion of landfill gas. When landfill gas is combusted the CH_4 is converted to CO_2. However, some countries do not have legislation requiring the combustion of landfill gas, and landfill gas vents to atmosphere, with a greater impact on global warming. These countries qualify for the purchase of emission reductions (ERs). At present there is a demand for ERs which exceeds the supply, and the income received from ERs for landfill gas combustion can fund the extraction and utilisation of the gas, with additional income to the authority." [41]

4.1.18. Look at wheeling options to clients looking to purchase clean energy for the company.

There are many companies that are looking at purchasing energy from cleaner sources instead of generating their own green energy. This assists with the companies green image as this plays an important role for their products when exported internationally. The generated power from the landfill site can be wheeled via the municipal electricity network to the potential customer. The tariff and compensation can then be arranged between the company and the generator at higher than municipal tariffs resulting in higher income. Since the landfill gas to electricity generators are synchronous generators, they also have the ability to operate in island mode and could be used to load follow and directly supply a nearby consumer or feed the entire local site loads. [41]

4.1.19. Build the generation plant using containerised units to ensure that should gas quantities reduce, they can be moved to other landfill sites to maintain maximum generation outputs.

There are two options when building landfill gas to electricity plants. Depending on the size, eg. one large 5 MW plant can be built or five one MW containerised modules can be installed. The cost of the one centralised plant will be cheaper than the multiple containerised modules. However the containerised modules provide more operational flexibility, maintenance flexibility and ability to move the modules should gas levels reduce to other landfill sites. The option selected for the Bisasar Road landfill site was containerised units. This has proved well from a maintenance point of view as single generators could be removed from service for maintenance without affecting the rest of the generation plant. This comes in extremely handy when certain components fail on an engine and spare parts need to be flown in from GEJ in Austria. This means only the affected generator is out of service for a prolonged period of time. This will also assist with moving modules to other landfill sites when the Bisasar Road landfill site close for intake of new waste. Figure 4.34 depicts the containerised modules installed at the Bisasar Road landfill site. [41]

Figure 4.34: The Bisasar Road generation plant [41]

4.1.20. Minimise the amount of gas flared to ensure higher generation output

Gas prediction models and accurate measurements need to be carried out prior to sizing of the generation plant and the flare. This prevents the landfill gas from been vented into the atmosphere when the generation plant trips or is shut off for maintenance. However, one factor that must be taken into account is that the flare needs a minimum quantity of landfill gas supplied to it to ensure that it is in operation and does not switch off. This becomes a problem as the quantity of gas starts to reduce at the landfill site and the flare requires a fixed minimum quantity of gas to remain in operation resulting in much less gas for the engines which hence affects the plant generation output. [41]

4.1.21. Requirements for a Power Park Controller

The South African Renewable Energy Grid Code requires that any new renewable generation plant complies with the SAREGC at the point of connection (POC). Where a plant has multiple generation units such as the Bisasar Road landfill gas to electricity generation plant then a power park controller is required to ensure that the plant complies to the SAREGC requirements which are as follows:

(i) Frequency control
(ii) Absolute production constraint
(iii) Delta production constraint
(iv) Power gradient constraint
(v) Reactive power control
(vi) Power factor control
(vii) Voltage control

This cost must be factored in when utilising multiple generating units as opposed to a single large central generating unit. [41]

4.1.22. Use of gas for other purposes

Landfill gas can also be treated and utilised in fleet vehicles which have been modified with gas engines. This has been successfully demonstrated in many utilities around the world. Cost vs benefit analysis needs to be carried out to determine whether this may be a more financially feasible option to that of electricity generation. This will largely depend on the cost paid for the generated electricity which will depend on the local utility, cost of fuel and vehicle modification costs. [41]

4.1.23. Recommendation on Case Study

From the case study conducted, “it was recommended that the eThekwini Municipality Solid Waste Department limit their generation to 6MVA and operate the plant at unity power factor. This will ensure that none of the existing network cable thermal ratings are exceeded during normal and contingency network conditions.” [41] However if the generation was to exceed 6 MVA then the cable between Electricity Department DSS 5374, 1/5 Intersite Avenue DSS 16541 and Connaught Major Substation was to be upgraded from a 240 mm^2 PILC to a 300 mm^2 PILC cable. This will increase the capacity to accommodate the added generation up to 8 MVA during the off peak period. Additional load needed to be added onto the transformer that the EG operated in parallel with, to ensure that no over voltage conditions were experienced during loss of load during the off peak period. “It is also recommended that a 254-ohm NER be installed on the star point of each generator transformers to limit the earth fault current to 25A per 1MW generator.” [41] This will assist in preventing undesirable tripping for out-of-zone earth faults since the generation plant was a source that will feed any faults on the network. In order to allow the earth fault relay on the generation plant injection cable onto the network to be graded with the existing network protection and allow selectivity of the protection scheme to ensure that the correct relay disconnects the faulted circuit, the earth fault current had to be limited to a safe value in order to prevent any possible damage to the generators. This will provide the correct selectivity and sensitivity in the event of a fault and prevent undesirable tripping for out of zone fault earth faults. [41]

The site has since been commissioned and 6 MW EG (six times 1 MW generators) was installed. However due to the closing on another landfill site, a further half MW generator was added at Bisasar Road, bringing the installed capacity to 6.5 MW. This then injects into the Electricity Department DSS 5374 in the Springfield Distribution network. The plant is operated at 6 MW to ensure that the 6 MVA cable back to 1/5 Intersite Avenue DSS and Connaught Major Substation does not overload during the off peak period. [41]

Durbans Bisasar Road landfill gas to electricity project has demonstrated that landfill gas to electricity projects are financially viable at eThekwini Municipality and in South Africa, even at avoided electricity costs (Eskoms current 275 kV Megaflex TOU Tariffs). The feasibility can be further supplemented with registering the project for CDM although this is a complex process that requires very accurate measuring equipment and verifications. To date the site has generated 295 309 156 kWh and received R130 669 472.21 revenue at Eskom avoided costs. The project has also prevented the venting of thousands of tons of greenhouse gasses into the atmosphere and assisted the country with 295 309 156 kWh of electricity. This has proved the feasibility of landfill gas to electricity generation in South Africa, and many other utilities in South Africa and Africa are now exploring this technology. There are plans to roll out more landfill gas to electricity projects including a 10 MW project in Durban and 18 MW of installed capacity projects as part of the REIPPPP in Johannesburg going forward. However the case study has also highlighted the possible negative impacts to the existing distribution network which has to be mitigated to allow successful implementation of landfill gas to electricity projects on to the grid. All future projects need to comply to the SAREGC. [41]

Based on experience from the Bisasar Road landfill gas to electricity projects and research done, a number of methods are then discussed which could optimise and improved the financial viability and operation of a landfill gas to electricity projects. A number of options are discussed for cleaning of the landfill gas to reduce impurities which has impacted on the engine maintenance intervals. Furthermore, should the project be implemented in hot humid sub topical climate then there may be a need for a chiller unit. This unit serves dual purpose from experience at the Bisasar Road landfill site, the LFG temperature is reduced to comply with the manufactures specification and the removal of condensate. This in turn reduces the Sulphur, Silicon and Ammonia content which has a positive impact on the engines. The investigation also discusses the financial benefits when selecting the billing time period to remove engines from service to maintain them and the possibility of storing the landfill gas to generate during higher tariff periods in a TOU tariff structure. The option of utilising the plant as a peaking power plant to assist the utility during peak loading periods are also discussed. There is an added benefit of landfill gas to electricity generation in that the plant can generate electricity at a constant rate and operate as a base load generation station which is not common with other variable renewable energy source such as wind and PV generation. The option of treating the gas produced from the landfill site and utilising this on fleet vehicles with modified gas engines depending on the feasibility based on electricity tariffs, modification costs of the vehicles, capture and treatment cost of the gas and cost of fuel. Landfill gas to electricity projects are viable with many options to optimise and improve the financial feasibility of these projects. These practical options are presented in this case study and can be selected for any potential project for implementation depending on the purpose of the project and aims and objections. [41]

4.2. Summary of Chapter 4

The studies reveals the impacts experienced on the eThekwini Electricity Springfield distribution network with increased penetration of landfill gas to electricity generation. The complete construction process of a landfill gas to electricity project is also discussed based on the construction of the Bisasar Road landfill gas to electricity project. The feasibility of the project and methods to optimise potential projects and improve its feasibility is also discussed in great detail.

CHAPTER 5: CASE STUDY 2: 10 MW PV FARM INSTALLED ON THE CLOSED PORTION OF THE BISASAR ROAD LANDFILL SITE

5.1. Introduction to Chapter 5

Chapter 5 studies the controllability and operational flexibility of a proposed 10 MW PV farm on a closed portion of an active landfill site. An RMS model was created of the PV farm and the farm was tested for grid code Category B compliance according to the SAREGC. The purpose of the test was to understand the operational and control functionality of the PV farm as required by the SAREGC.

5.1.1. Solar PV in South Africa

Based on the number of bids for solar farms in the REIPPPP in South Africa, it can be seen in Table 4.12 that solar farms are set to play a substantial role going forward in the energy sector. In round one of the REIPPPP, 28 successful bidders were selected making up a total of 1416 MW of capacity. In round two, 19 projects were selected making up a capacity of 1045 MW. Whilst in round 3, 17 projects were selected making up a capacity of 1686 MW and in round 4, 19 projects of 2206 MW capacity was selected. Solar PV (2327 MW) makes up the second largest portion of the 6330 MW projects selected under round 1 to round 4 of the DOE REIPPPP. This indicates that solar farms make up 36.76% of the capacity from the total projects selected in the REIPPPP round 1 to round 4 as shown in Table 5.1. [41]

Table 5.1: Selected bidders in REIPPPP: Round 1 to 4 [41]

Technology	MW Awarded Round 1	MW Awarded Round 2	MW Awarded Round 3-3.5	Total MW's Awarded Round 4	Total MW's Awarded Round 1 - 4
Solar PV	632	417	465	813	2327
Wind	634	563	787	1363	3347
Solar CSP	150	50	400	0	600
Landfill Gas	0	0	18	0	18
Biomass	0	0	16	25	41
Small hydro	0	15	0	0	15
Total	1416	1045	1686	2206	6330

The average bid per kWh of energy from solar PV has reduced from R2.76/kWh in round one, R1.65/kWh (60% of round one prices) in round two to R0.88/kWh (32% of round one prices) in round three. The average round three price of R0.88/kWh is highly competitive to the price per kWh that eThekwini Electricity purchases electricity from Eskom on the 275 kW Time of Use (TOU) Megaflex tariff structure.

5.1.2. Potential PV Farms Development in Durban: Installation of Solar PV on old closed Landfill sites

For the development of medium to large scale PV farms there need to be large plots of land available that these farms can be built on. These sites need to be also located close to the grid in order to keep the grid connection costs to a minimum. We investigate potential plots of land that can be utilized for the installation of PV farms. Large plots of land close to the grid connection is expensive and not readily available in Durban. However there are currently in excess of 20 old landfill sites within eThekwini Municipality that are owned by the municipality. These are large sites which has limited land use options due to the future settlement of the land. This land hence has very low property value and could be leased relatively cheap from the municipality. This provides excellent potential for medium to large scale PV installations. The nine most suitable sites were selected for further investigation of suitability of the 20 potential old landfill sites. The selection criteria was based on the locality of the site to the grid, sites with the largest area for PV installation, date of closure of the site, settlement of the site to date and safety and security of the equipment on the closed site. Closed landfill sites offer opportunities for medium/large scale PV installations (>1MWp) because their geotechnical instability prohibits other developments, and the land has therefore no commercial value. In Europe and the US PV installations on closed landfill sites are becoming increasingly common. [38]

5.1.3. Grid Code Requirements from a 10 MW PV Plant

In accordance with the Electricity Regulation Act (Act 4 of 2006) in South Africa, the grid code requirements in the SAREGC shall apply to all RPPs seeking connection to the transmission and distribution system of the respective Network Service Providers (NSPs). The 10 MW solar PV farm falls in Category B of the SAREGC and hence needs to comply with all the requirements for Category B of the SAREGC. Firstly lets identify the differences in the requirements of Category B compared to Category C which is shown in Table 5.2. The comparison will be between the Category B 10 MW PV farm vs the 25 MW wind farm (Category C) which is discussed on the wind farm Case Study in Chapter 6. [16]

Table 5.2: Difference in requirements between Category B and Category C RPPs [16]

Grid Code Requirements	Category B	Category C

Maximum Size	MV connected up to 20 MW	MV & HV Connected > 20 MW
Reactive Power requirements	$-0.28 \leq Q/P \leq 0.28$	$-0.33 \leq Q/P \leq 0.33$
Power Factor Requirements	$-0.975 \leq Q/P \leq 0.975$	$-0.95 \leq Q/P \leq 0.95$
P_{Delta} Requirements (Delta Production Constraint)	No	Yes – Minimum of 3% of $P_{Available}$ except from PV
Voltage Control	Same requirement	
Absolute Production Constraint	Same requirement	
Power Gradient Constraint	Same requirement	
Frequency Response	Only include over frequency response	Includes both under and over frequency response
High Voltage Ride Through Capability	Not required	Category C RPP plants are required to withstand voltage peaks up to 120% measured at the POC for a minimum period of 2 seconds
Low Voltage Ride Through Capability	Same requirement	

The difference in requirements between solar farms and wind farms technology according to the SAREGC is that solar farms do not need to provide P_{Delta} requirements as opposed to wind farms. There is also not High Voltage Ride Trough Capability requirement from Category B RPPs.

For this case study, the RMS model of this 10 MW PV farm to be installed at the closed half of the Bisasar Road Landfill site is modelled and studied for Grid Code compliance. Firstly we need to check for a connection point for the PV farm on the eThekwini Electricity distribution network. The current 6.5 MW Bisasar Road Landfill site gas to electricity project feeds the generated electricity into the Connaught Major Substation. For this project, the generated electricity will be fed into the newly built Randles Major Substation. Load readings taken at the Randles Major Substation indicates that with reconfiguration, it is possible to absorb the generated electricity from the 10 MW PV farm as per Figure 5.1. Since this will be PV generation, generation only occurs during sunlight hours hence this will fit perfectly into the substation profile however should the technology been landfill gas to electricity generation then we would have had problems absorbing the generates electricity at certain times of the day.

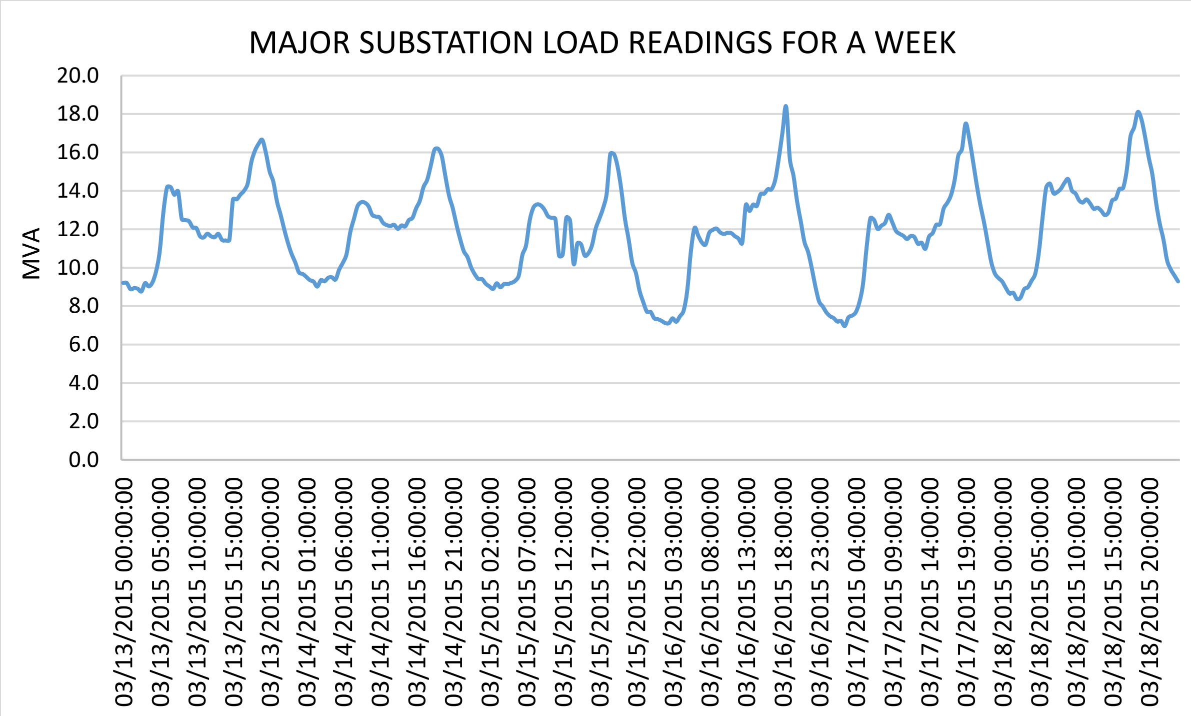


Figure 5.1: Major Substation transformer load readings for one week

5.1.4. Grid Code Compliance Study for the 10 MW Solar PV Farm at Bisasar Road

For the purpose of this case study, a 10 MW PV farm RMS model will be used to check grid code compliance. The purpose of this study is to better understand the SAREGC requirements from a 10 MW PV farm and to understand the control and operational functionality of the PV farm that can be utilised to operate the farm during normal and contingency condition in the eThekwini Electricity distribution network.

Compliance to the SAREGC is mandatory and provides minimum guidelines for RPPs to connect onto the transmission or distribution networks in South Africa. In the case of the proposed 10 MW PV farm to be installed at the closed part of the Bisasar Road Landfill, the grid connection will occur at 11 kV and hence based on the plant size and connection voltage level the plant will fall in the grid code category B as per Table 5.3. The plant will then need to comply with all the requirements of the SAREGC Category B.

Table 5.3: SA Renewable Energy Grid Code Categories [16]

Category	Minimum Size (kVA)	Maximum Size (kVA)	Connections Voltage
B	0	20000	MV connected

The SAREGC provides minimum technical requirements that all RPPs needs to comply with prior to the Network Service Provider (NSP) allowing commercial operation on their grid. In this case the NSP is the eThekwini Municipality. For the purpose of this case study, the focus will be on the requirements for the connection of a Category B 10 MW PV farm on the eThekwini Municipality distribution network. To check grid code compliance, a 10 MW PV farm was built utilising a type tested RMS model of the plant to check how the plant reacts under different network conditions and set points for grid code compliance in the Digsilent Powerfactory power systems simulation package shown in Figure 5.2. The Digsilent RMS model comprise of 7 step up (1360 kVA, 11/0.4 kV) transformers shown as PTR1 to PTR7 on the model. Each transformer is then supplied by two 680 kVA central inverter from the solar farm. Each inverter is then supplied by multiple strings from the solar farm. The farm 11 kV bus bar connects via two cables onto a 11 kV gridbox which has 2 down stream circuits, circuit 1 which feeds 4 transformers and circuit 2 which feeds 3 transformers.

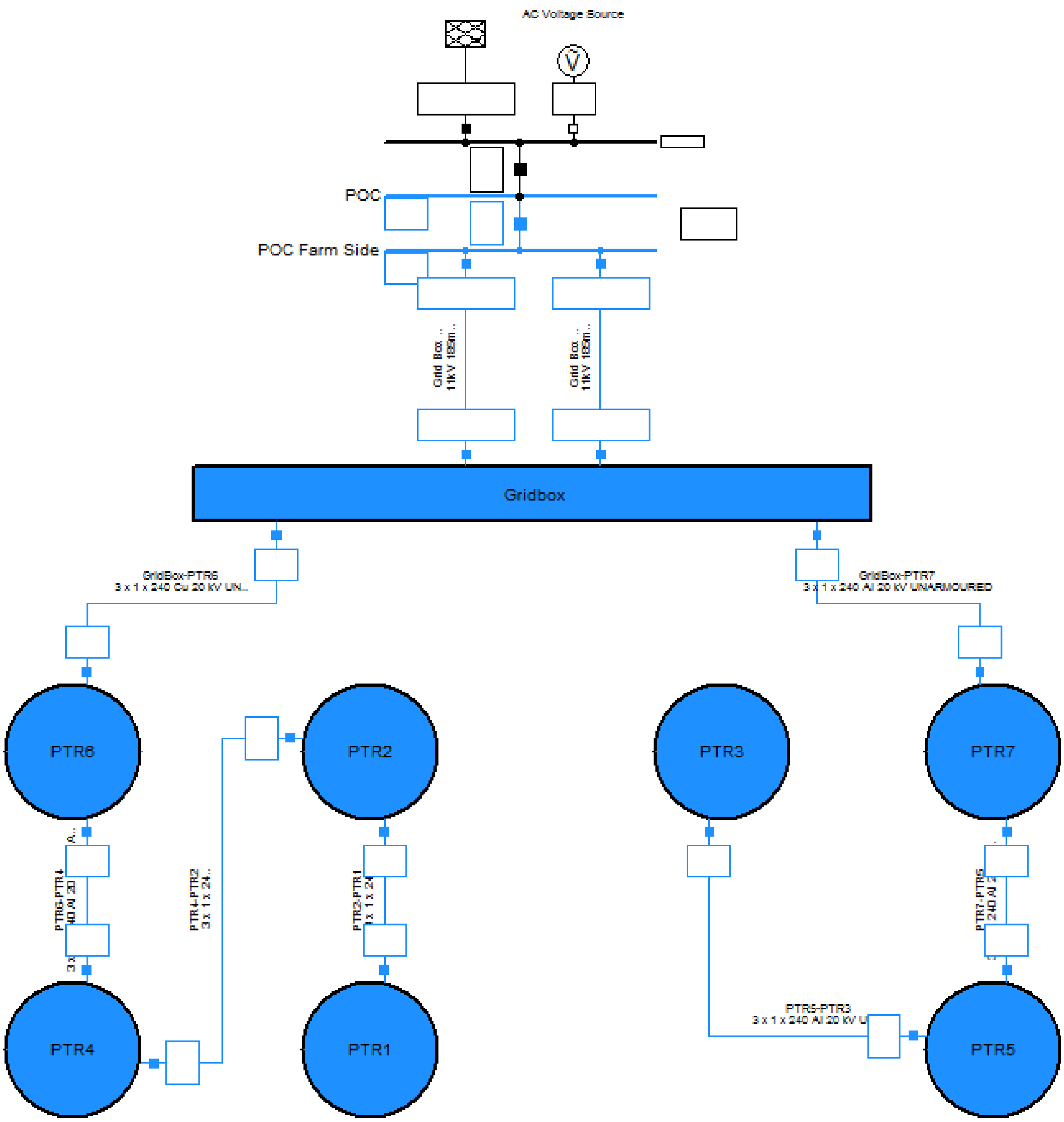


Figure 5.2: Type tested RMS model of PV farm utilised to study Grid Code Compliance

5.1.5. SAREGC RPP Design Requirements

The SAREGC has many design and operation requirements from Category B RPPs which will be discussed in brief detail in this case study with some simplified testing methods which was developed and then utilised to test the proposed 10 MW solar PV farm to check Grid Code compliance.

5.1.5.1. Tolerance to Voltage Deviations

The SAREGC requires Category B RPPs to be designed in order to operate continuously within the POC voltage range specified by U_{min} and U_{max} in Table 5.4.

Table 5.4: RPP continuous operating voltage limits [20]

$V_{Nominal}$ (Un) [kV]	U_{Min} (pu)	U_{Min} (kV)	U_{Max} (pu)	U_{Max} (kV)
11	0.90	9.9	1.08	11.88

5.1.5.2. Voltage Ride Through Capability

The capability of the RPP to be able to ride through voltage disturbances often caused by faults on the network is very important on the local network to ensure that stability of the grid is maintained at all times. Voltage-Ride-Through-Capability (VRTC) assists with preventing loss of generation on the network when a voltage disturbance is experienced on the network. Hence the code requires the RPP to be designed to withstand voltage drops to zero measured at the POC for a minimum period of 0.15 seconds. This ensures that should there be a fault or disturbance on the network, the network protection has adequate time to operate and isolate the problem circuit without the plant shutting down. The required voltage operating capability of the RPP is shown in Figure 5.3 whilst Figure 4.38 shows the reactive power requirements from the RPP based on a function of the voltage. [18]

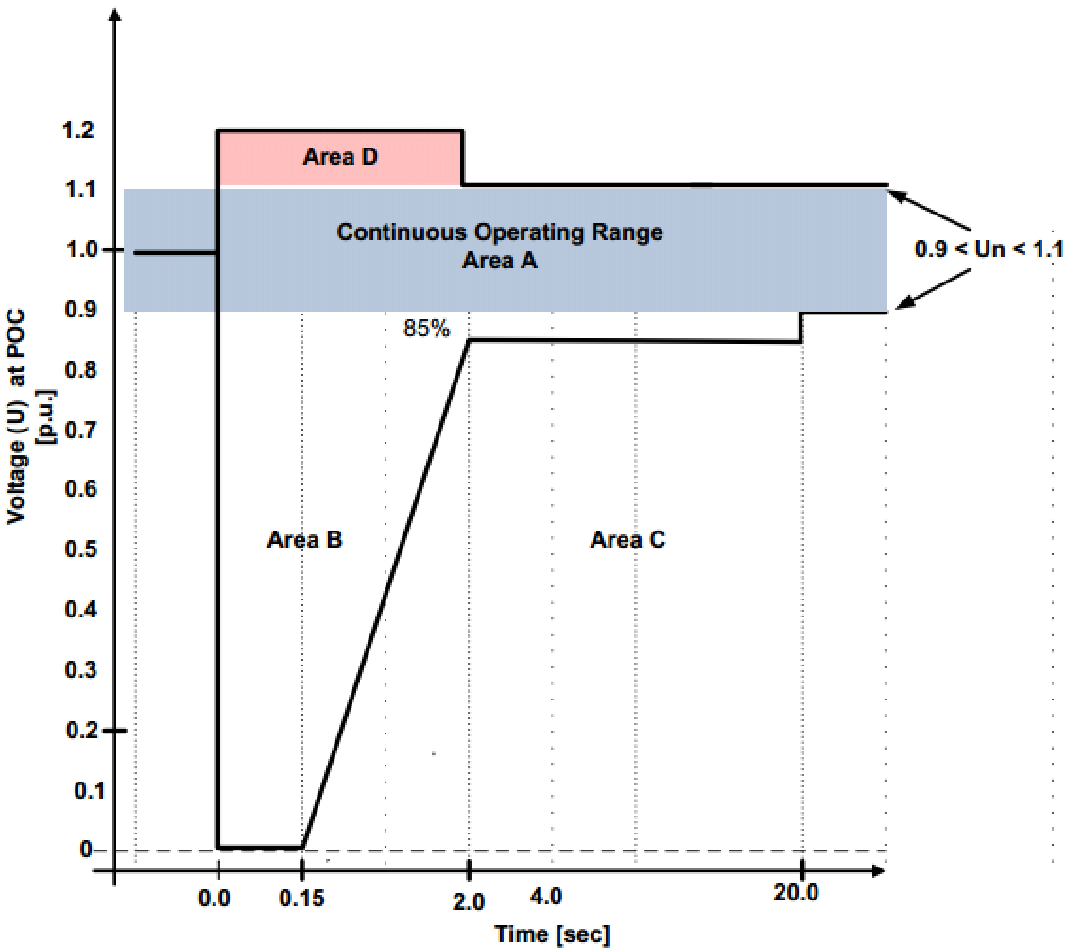


Figure 5.3: VRTC for Category B RPP [18]

The SAREGC requires the RPP to either supply or absorb reactive current based on the function of the POC voltage (LVRT or HVRT) level following a network incident. It looks at two cases, a case of over voltage and a case of under voltage at the POC. The 10 MW PV farm only needs to comply to the LVRT requirements as per the SAREGC. Figure 5.4 shows the Area A which is normal operating area (0.9 ≤V≤ 1.1), Area B (0.2 ≤ V< 0.2), and Area E (V<0.2), where reactive current support is required to help in stabilizing the voltage. [18]

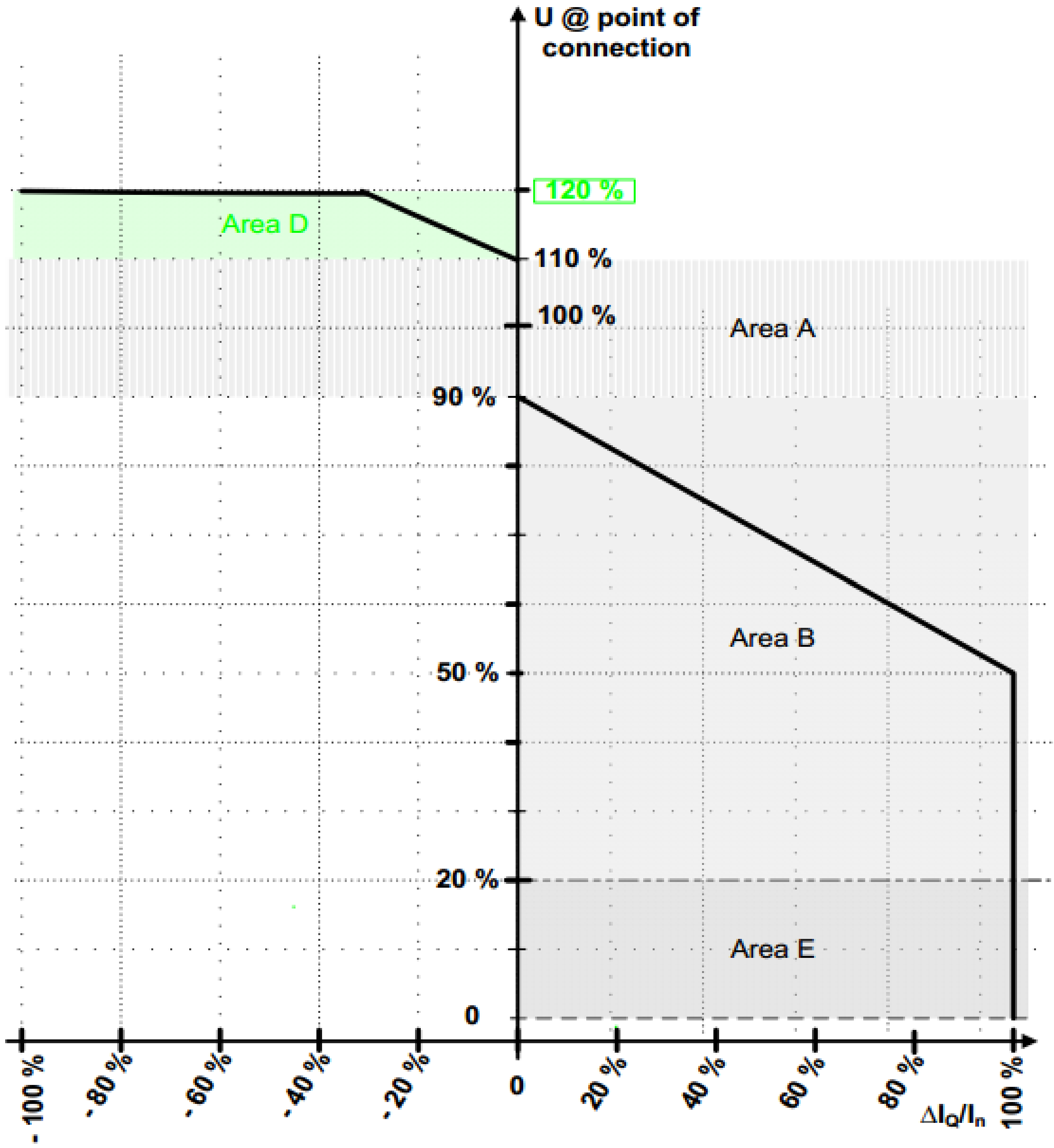


Figure 5.4: Reactive power requirements during voltage drops or peaks from Category C RPP [18]

Low Voltage Ride Through (LVRT) has to be tested via a power systems simulation package such as Digsilent Powerfactory to simulate the appropriate low voltages for the specific duration as per the SAREGC. It is not possible to test this during functionality during site testing. The purpose is to ensure that the plant remains connected to the grid in the event of a disturbance on the network. HVRT is not a requirement from Category B RPPs and will not be considered in this case study. The purpose of the VRTC study is to check if the 10 MW PV farm remains connected to the grid for Area A and Area B in Figure 5.4 whilst it can disconnect in Area C. The applicability, purpose, test procedure and acceptable pass criteria is described in Table 5.5. The tests carried out to prove grid code compliance is shown in Table 5.6. [18]

Table 5.5: Test Criteria for Voltage Ride Through [16]

Parameter	Description
Simulations of fault ride though voltage droops and peaks.	**APPLICABILITY** All new RPPs coming on line and after major modifications or refurbishment of related plant components or functionality. Routine test/reviews: None. **PURPOSE** To confirm that the limits for all power quality parameters specified is met. **PROCEDURE** By applying the electrical simulation model for the entire RPP it shall be demonstrated that the RPP performs to the specifications. 1. Area A - the RPP shall stay connected to the network and uphold normal production. 2. Area B - the RPP shall stay connected to the network. The RPP shall provide maximum voltage support by supplying a controlled amount of reactive power within the design framework offered by the technology, see Figure 5. 3. Area C - the RPP is allowed to disconnect. 4. Area D - the RPP shall stay connected. The RPP shall provide maximum voltage support by absorbing a controlled amount of reactive power within the design framework offered by the technology as required by the SAREGC. **ACCEPTANCE CRITERIA** 1. The dynamic simulations shall demonstrate that the RPP fulfils the requirements specified. Submit a report to the SO, NSP or another network operator three month after the commission.

Table 5.6: VRTC tests carried out on the 10 MW PV Farm [18]

Test	Fault Type	Voltage Dip (pu)	Duration (Seconds)
Test 1	Single Phase	0.00	0.15
Test 2	Two Phase	0.00	0.15
Test 3	Three Phase	0.00	0.15
Test 4	Three Phase	0.20	0.59
Test 5	Three Phase	0.50	1.24
Test 6	Three Phase	0.70	1.67
Test 7	Three Phase	0.85	20.0

For Test 1, the case of a single phase fault is simulated for a duration of 150 miliseconds where the voltage drops to zero pu. Figure 5.5 shows the results of a voltage ride through test done on the RPP. This indicates the plant passing the VRTC test as the plant remains connected to the network during the simulations. The tests also reveal that the plant supplies reactive power as required during a low voltage on the network to try and assist in stabilising the network voltage. In Figure 5.5 to Figure 5.11, the Y axis represent the voltage in pu whilst the X axis represent time in seconds.

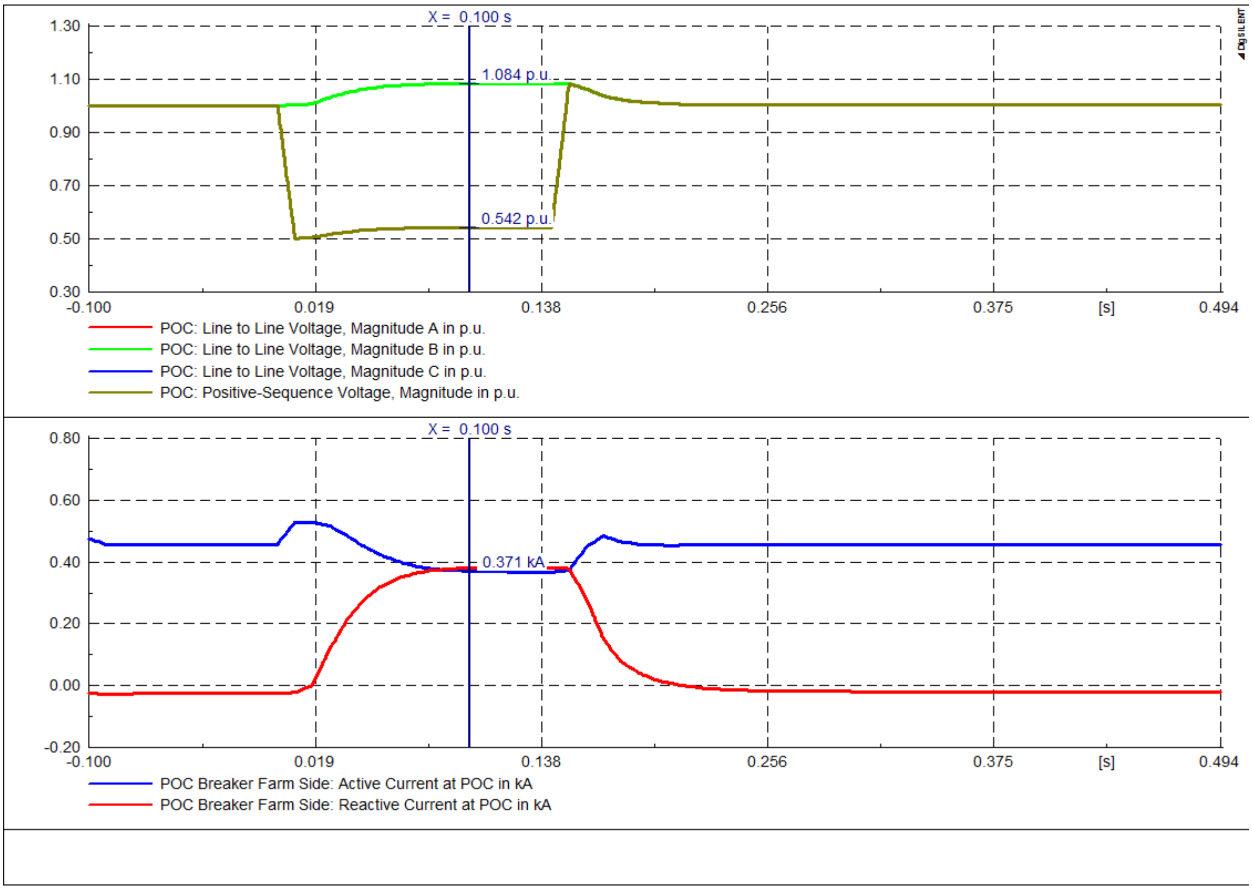


Figure 5.5: Test 1 - Single phase fault with 0 pu LVRT for 0.15 seconds

For Test 2, the case of a two phase fault is simulated for a duration of 150 milliseconds where the voltage drops to zero pu. Figure 4.40 shows the results of a voltage ride through test done on the RPP. This indicates the plant passing the VRTC test as the plant remains connected to the network during the simulations. The tests also reveal that the plant remains connected and supplies reactive power to try and assist in stabilising the network voltage.

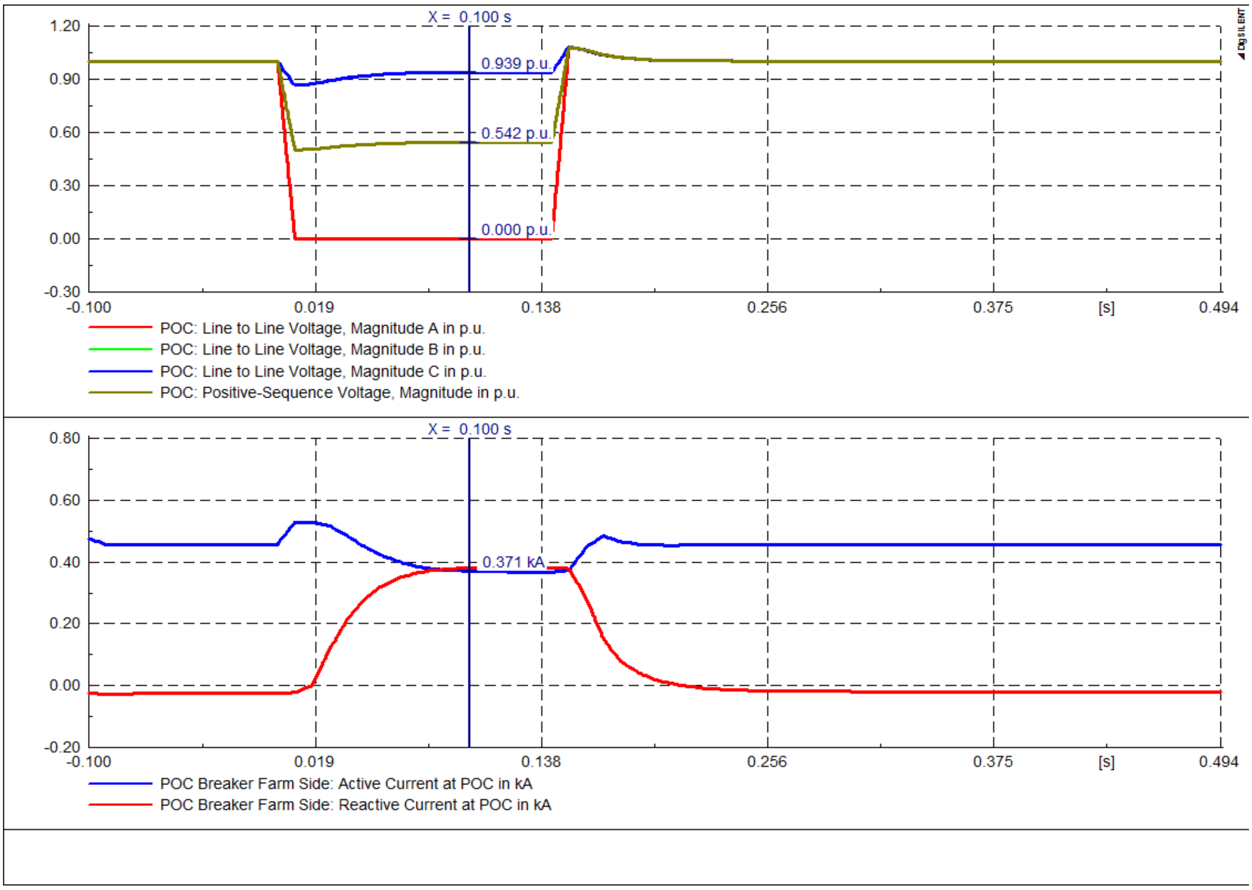


Figure 5.6: Test 2 - Two phase fault with 0 pu LVRT for 0.15 seconds

For Test 3, the case of a three phase fault is simulated for a duration of 150 milliseconds where the voltage drops to zero pu. In this test, the PV farm remains connected to the grid with the POC voltage at 0 pu for 0.15 seconds active power reducing close to zero as shown in Figure 5.7. The plant then supplies maximum reactive power to assist with stabilizing the POC voltage as required as required. The plant hence pass the 0 pu LVRT test.

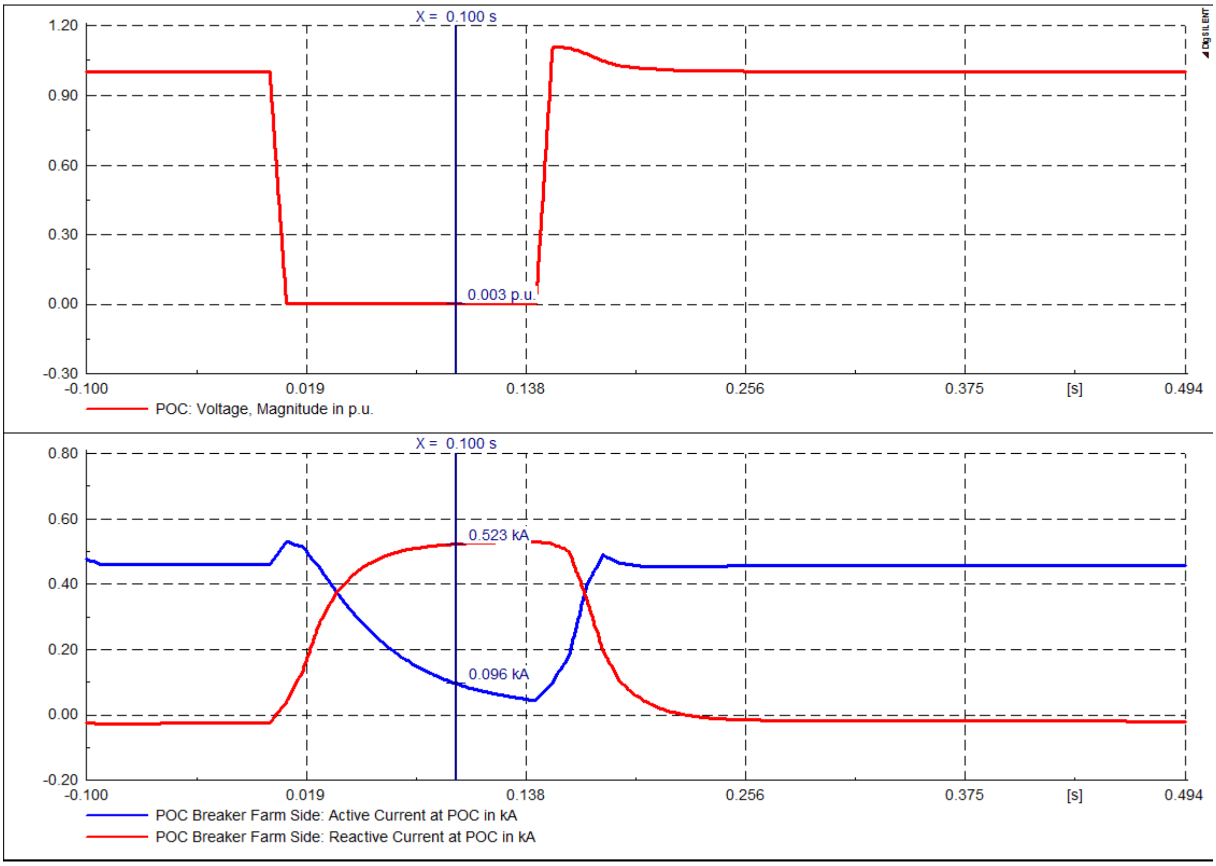


Figure 5.7: Test 3 – Three phase fault with 0 pu LVRT for 0.15 seconds

For Test 4, the case of a three phase fault is simulated for a duration of 0.59 seconds where the voltage drops to 0.2 pu. In this test, the PV farm remains connected to the grid with the POC voltage at 0.2 pu for 0.59 seconds whilst supplying about 20% active power as shown in Figure 5.8. The plant also supplies close to maximum reactive power to assist with stabilizing the POC voltage as required. The plant hence pass the 0.2 pu LVRT test.

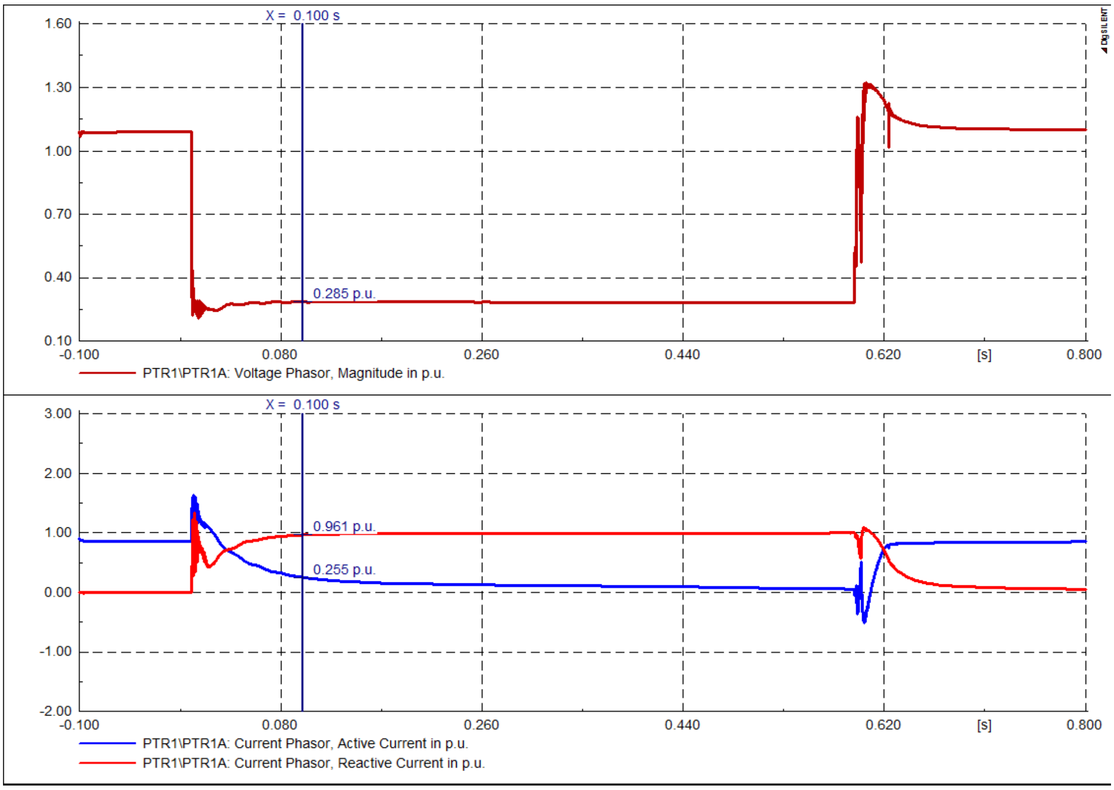


Figure 5.8: Test 4 – Three phase fault level with 0.2 LVRT for 0.59 seconds

For Test 5, the case of a three phase fault is simulated for a duration of 1.24 seconds where the voltage drops to 0.5 pu. In this test, the PV farm remains connected to the grid with the POC voltage at 0.5 pu for 1.24 seconds whilst supplying reduced active power as required as shown in Figure 5.9. The plant also supplies increased reactive power to assist with stabilizing the POC voltage as required. The plant hence pass the 0.50 pu LVRT test.

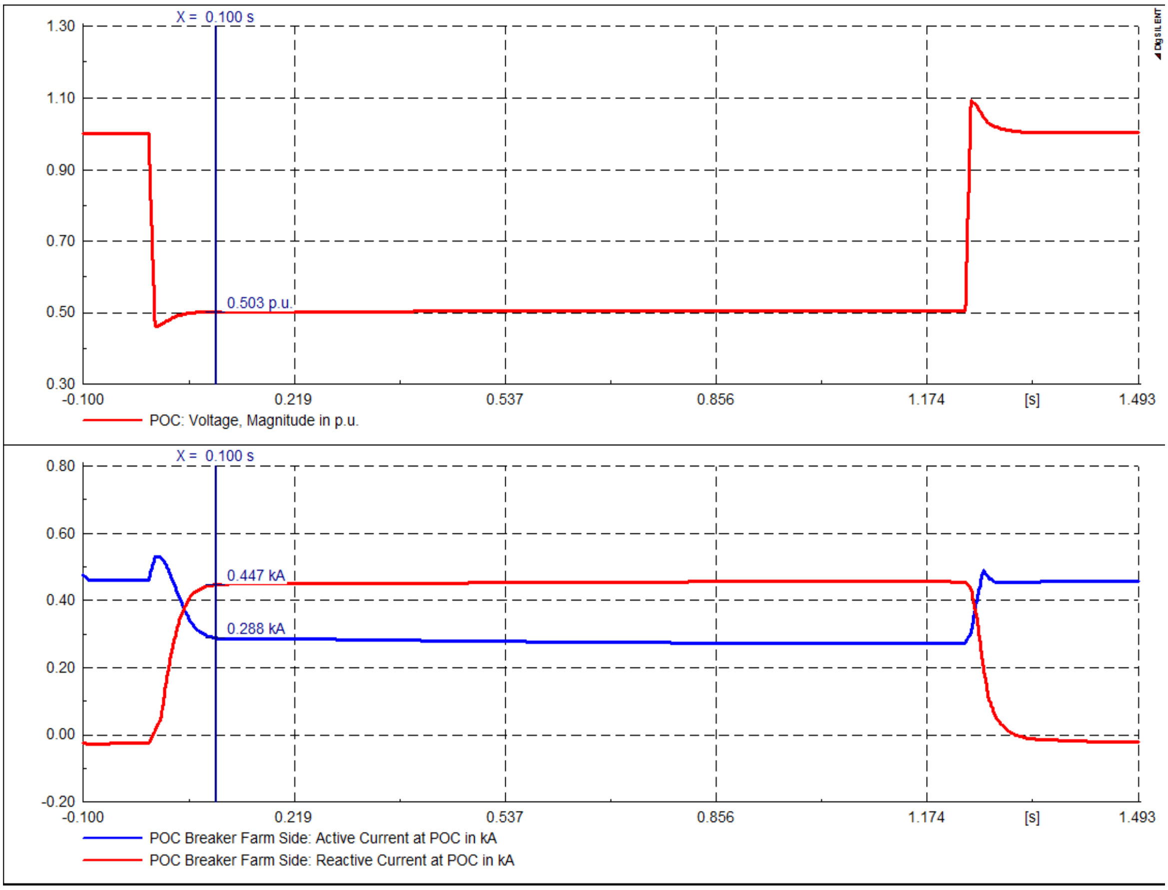


Figure 5.9: Test 5 – Three phase fault level with 0.5 pu LVRT for 1.24 seconds

For Test 6, the case of a three phase fault is simulated for a duration of 1.67 seconds where the voltage drops to 0.7 pu. In this test, the PV farm remains connected to the grid with the POC voltage at 0.7 pu for 1.67 seconds whilst supplying active power as required a shown in Figure 5.10. The plant also supplies reactive power to assist with stabilizing the POC voltage as required. The plant hence passed the 0.70 pu LVRT test.

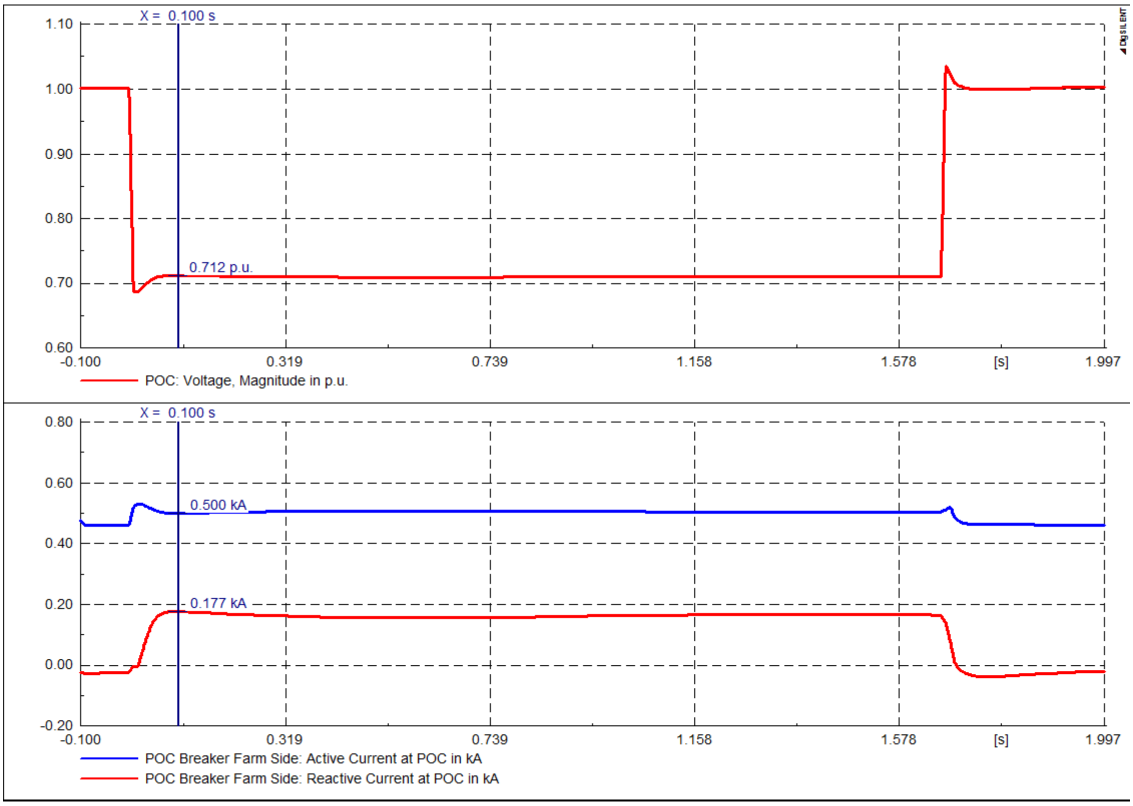


Figure 5.10: Test 6 – Three phase fault level with 0.7 pu LVRT 0.7 pu for 1.67 seconds

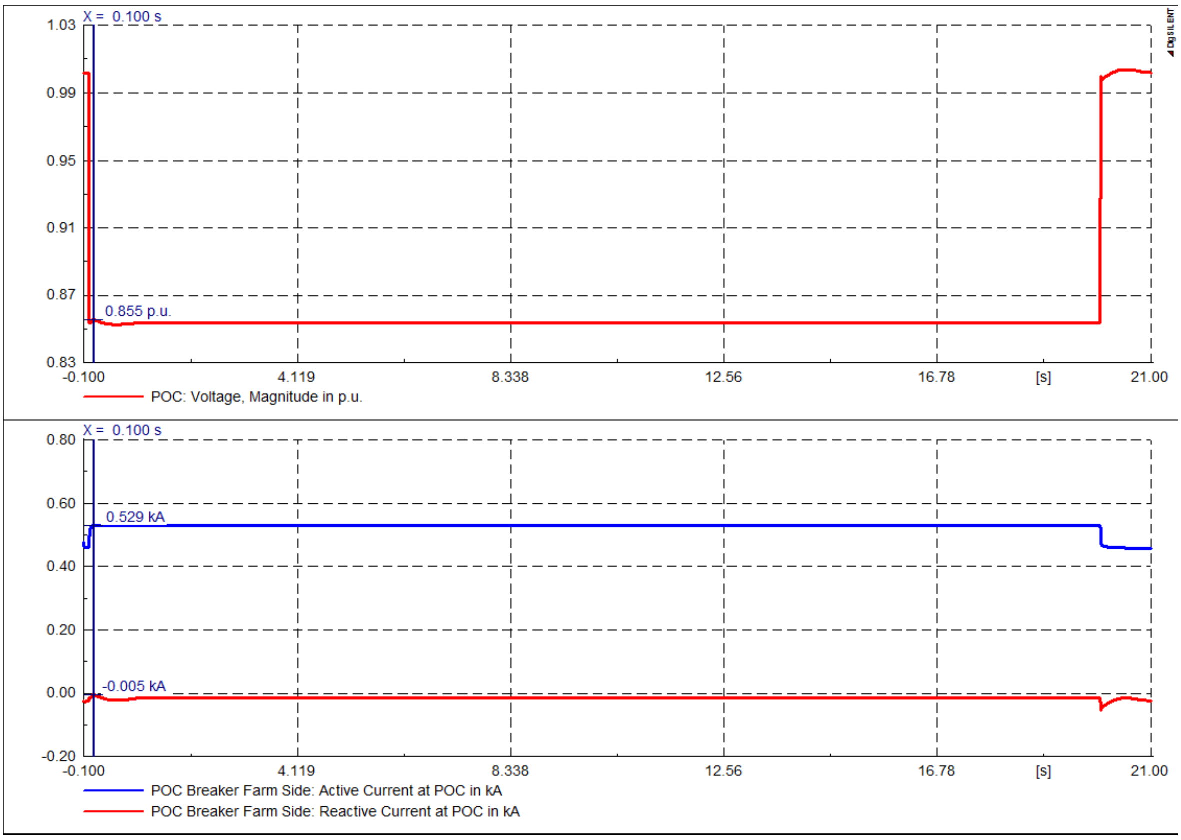


Figure 5.11: Test 7 - Three phase fault with 0.85 pu LVRT for 20 seconds

For Test 7, the case of a three phase fault is simulated for a duration of 20 seconds where the voltage drops to 0.85 pu. In this test, the PV farm remains connected to the grid with the POC voltage at 0.85 pu for 20 seconds whilst supplying full active power. Test 7 results are shown in Figure 4.45. The plant does not supply any reactive power. The plant hence passed the 0.85 pu LVRT test.

5.1.6. Tolerance to Frequency Deviations

The PV farm is required to be designed to operate continuously from 49 – 51 Hz and the plant must be able to withstand phase jumps of up to 20°. However if the frequency is higher the 51.5 Hz for greater than 4 seconds or less than 47 Hz for greater than 200 milliseconds then the plant is allowed to disconnect from the network as depicted in Figure 5.12. This simulates an over frequency and under frequency event on the grid. [18]

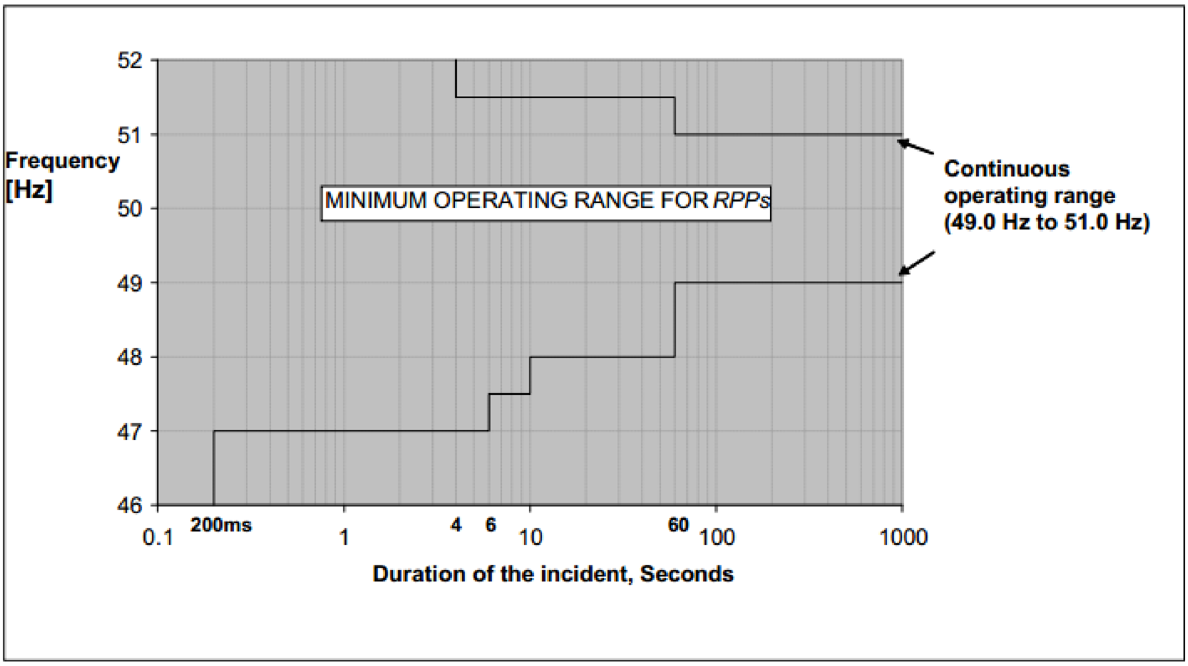


Figure 5.12: Minimum RPP plant frequency operating range [18]

5.1.6.1. Frequency Response Requirements

The requirement from the Category B PV farm is to curtail the active power during an over frequency on the network. The plant is required to provide mandatory active power reduction requirements in order to stabilise the frequency in accordance with Figure 5.13. The PV Farm is required to reduce its active power in accordance with Figure 5.13 when the eThekwini Municipality network frequency exceeds 50.5 Hz. Should the network frequency exceed 52 Hz for more than 4 seconds then the PV Plant is required to disconnect from the network. The reduction in power with regards to change in frequency can be set using a droop setting on the PV farm controller. Calculation of droop is shown in Figure 5.14 and Equation (4.9). Droop is defined “as a percentage of the frequency change required for an RPP to move from no-load to rated power or from rated power to no-load.” [18] All RPPs shall be equipped with frequency controlled droop settings which shall be adjustable between 0% and 10%. During an over frequency event, the network frequency will exceed 50.5 Hz (there is more generation than load on the network), the plant is required to follow the droop setting. This dictates the reduction in power required from the RPP for a change (increase) in frequency. [18]

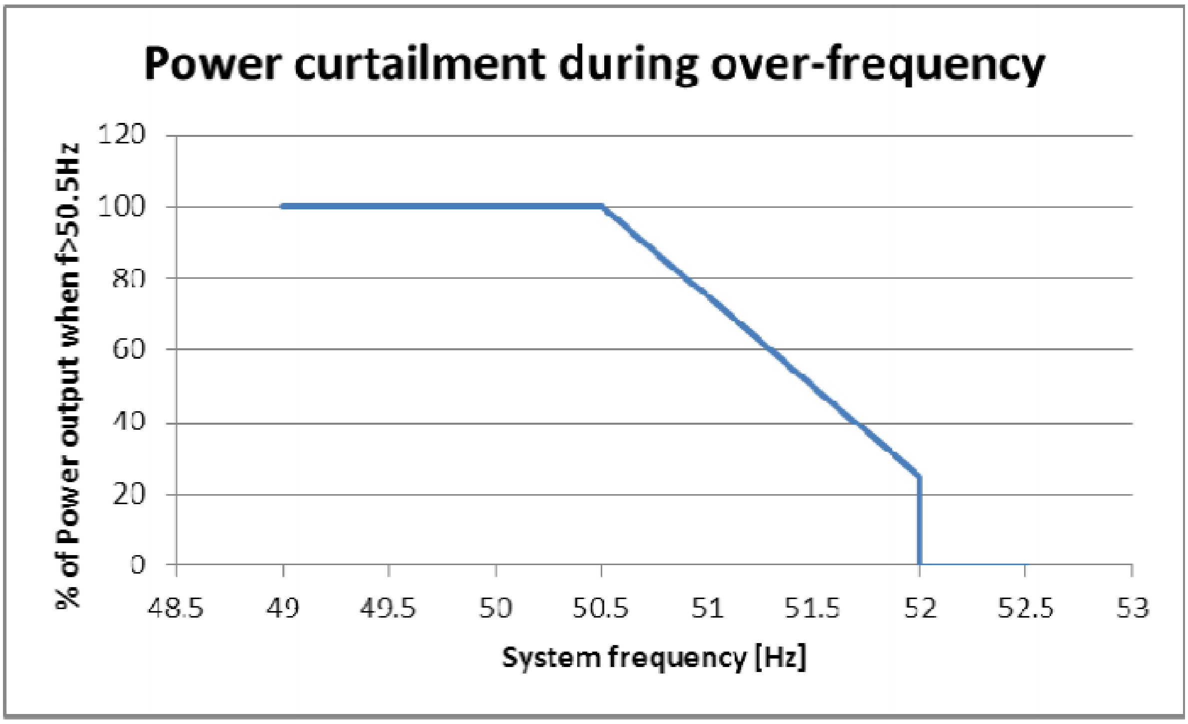


Figure 5.13: Frequency response during over frequency condition for Category B plant [16]

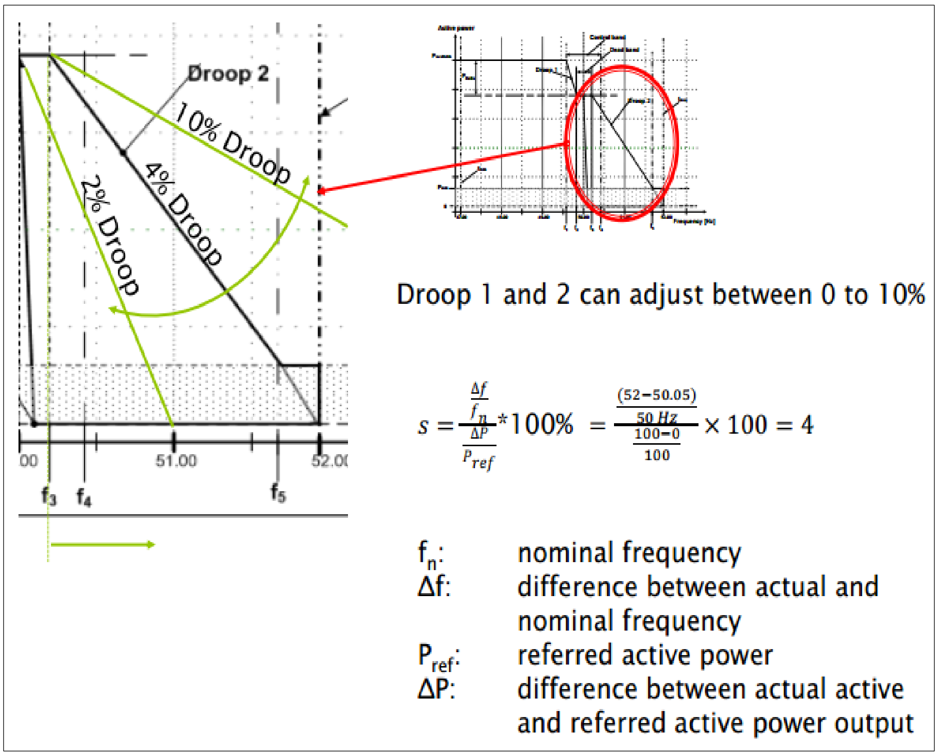


Figure 5.14: Equation for the calculation of Droop [18]

Calculation of Droop Setting for the 10 MW PV Farm:

$$s = \frac{\frac{\Delta f}{f_n}}{\frac{\Delta P}{P_{Ref}}} \tag{4.9}$$

Where: Δf = *difference between actual and nominal frequency*

F_n = *nominal frequency*

ΔP = *difference between actual active power and referred active power output*

P_{ref} = *referred active power*

Table 5.7 shows the set points issued to the 10 MW PV farm and Figure 5.15 shows the PV farm response to an over frequency event on the network. This was achieved by changing the network frequency at the POC and checking the farms response to the over frequency condition. An over frequency condition on the network is experienced when there is more generation then load on the network at that particular point on the network. The plant is hence required to curtail its power output which an increase in frequency from 50.5 Hz to 52 Hz. Should the network frequency exceed 52 Hz for more than 4 seconds then the plant should disconnect from the network. The farm complies with the grid code in respect to power curtailment during over frequency. PV farms are not required to comply with under frequency network conditions as there is no P_{Delta} requirement from PV Farms.

Table 5.7: Over frequency response test on the 10 MW PV Farm

Start Frequency	Set Frequency	Start Time (Seconds)	End Time (Seconds)
50.00	50.00	0.0	10
50.00	50.50	10	20
50.50	51.00	20	30
51.00	51.50	30	40
51.50	52.00	40	-

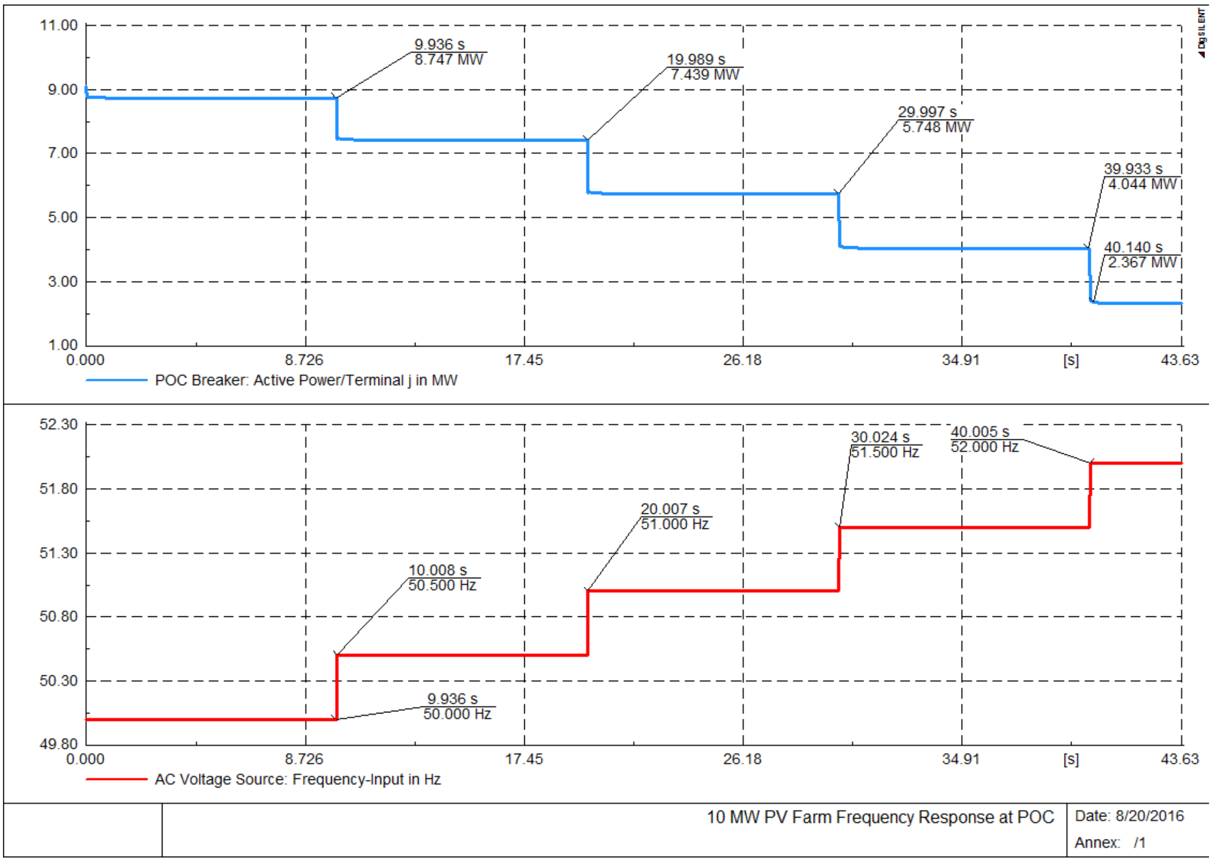


Figure 5.15: Frequency response requirements form the 10 MW PV Farm

5.1.7. Control Function Required from RPPs

The RPP is required to have the following control functions as shown in Table 5.8.

Table 5.8: Control functions required for RPPs [16]

Control Function	Category B
Frequency Control	*x*
Absolute Production Constraint	*x*
Delta Production Constraint	*Not Required*
Power Gradient Constraint	*x*
Reactive Power (Q) Control	*x*
Power Factor Control	*x*
Voltage Control	*x*

5.1.8. Reactive Power Capability

The grid code specify the reactive power requirements from Category B plant [$-0.228 \leq (Q/P_{Max}) \leq 0.228$] measured at the POC. This is shown in Figure 5.16.

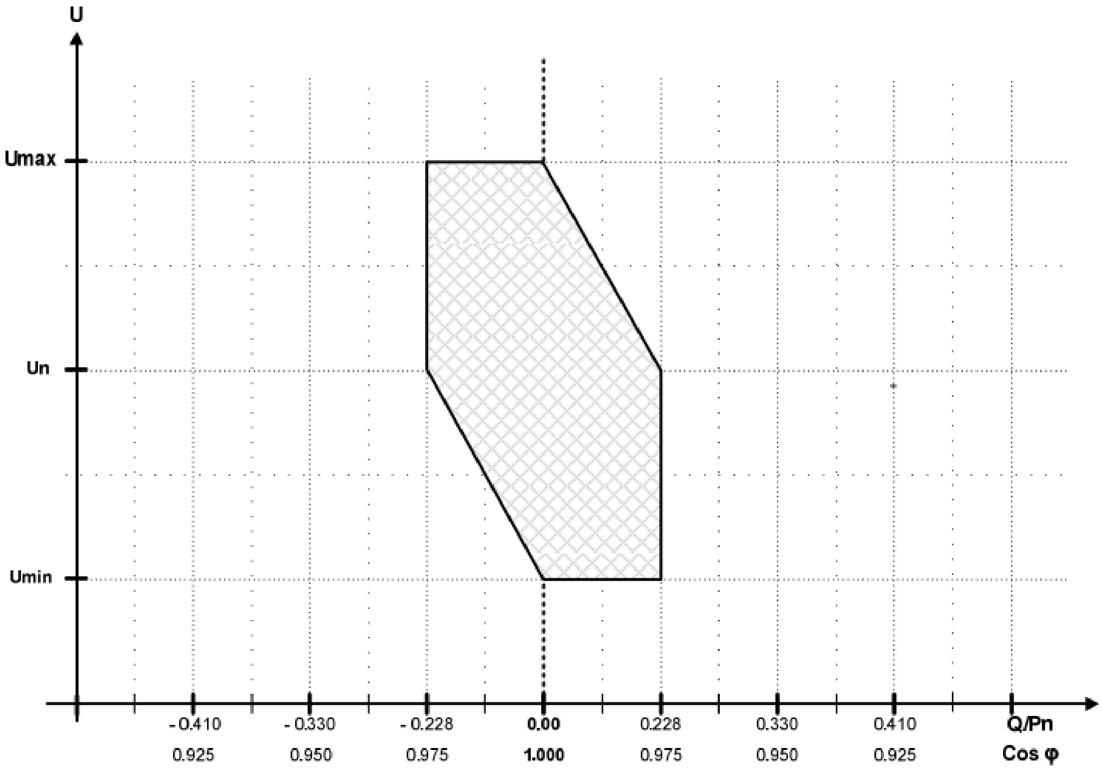


Figure 5.16: Reactive power requirements [20]

To check grid code compliance of RPPs with regards to reactive power requirements, tests and measurements shall be carried out in accordance to the Table 5.9 and Table 5.10 which is for the case of U = 1 pu. If U is not equal to 1 pu then the plant shall operate in accordance to Figure 5.16. The measured values shall be recorded after 30 seconds after receipt of the set point to a measured accuracy to the higher value of either ±2% of the set-point value or ±5% of maximum reactive power. [20]

The reactive power control capability test was then carried out on the PV farm to check the farms response to the reactive power requirement. The test was carried out for $P_{Available} \geq$ 20%. Here we test the farms ability to inject or absorb maximum reactive power when required. Results from the testing is then shown in Table 5.10 and Figure 5.17. From the results obtain, it can be seen that the plant passes the tests as it responds within the required time period (30 seconds) stipulated and accuracy limits (±2% of the set-point value). [20]

Table 5.9: Test Criteria for Reactive Power [16]

Parameter	Description
Reactive power control function and operational range	**APPLICABILITY** All new RPPs coming on line and after major modifications or refurbishment of related plant components or functionality. Routine test/reviews: Confirm compliance every 6 years. **PURPOSE** To confirm that the reactive power control capability specified is met. **PROCEDURE** The following tests shall be performed within a minimum active power level range of at least 0.2 pu or higher 1. The RPP will be required to regulate the voltage at the PCC to a set level within the design margins. 2. The RPP will be required to provide a fixed Q to a set level within the design margins. 3. The RPP will be required to obtain a fixed PF within the design margins. **ACCEPTANCE CRITERIA** 1. The RPP shall maintain the set voltage within ±5% of the capability registered with the SO, NSP or another network operator for at least one hour. 2. The RPP shall maintain the set Q within ±2% of the capability registered with the SO, NSP or another network operator for at least one hour. 3. The RPP shall maintain the set PF within ±2% of the capability registered with the SO, NSP or another network operator for at least one hour. Submit a report to the SO, NSP or another network operator one month after the test.

Table 5.10: Results obtained from Digsilent Simulations of PV Farm at 1 pu Voltage

Start Time (Seconds)	End Time (Seconds)	Setpoint (MVAr)	Results after 30 seconds of set point receipt
0.0	60.0	0.00	0.00
60	120	2.28	2.280
120	180	0.00	-0.005
180	240	-2.28	-2.244
240	300	0.00	0.00

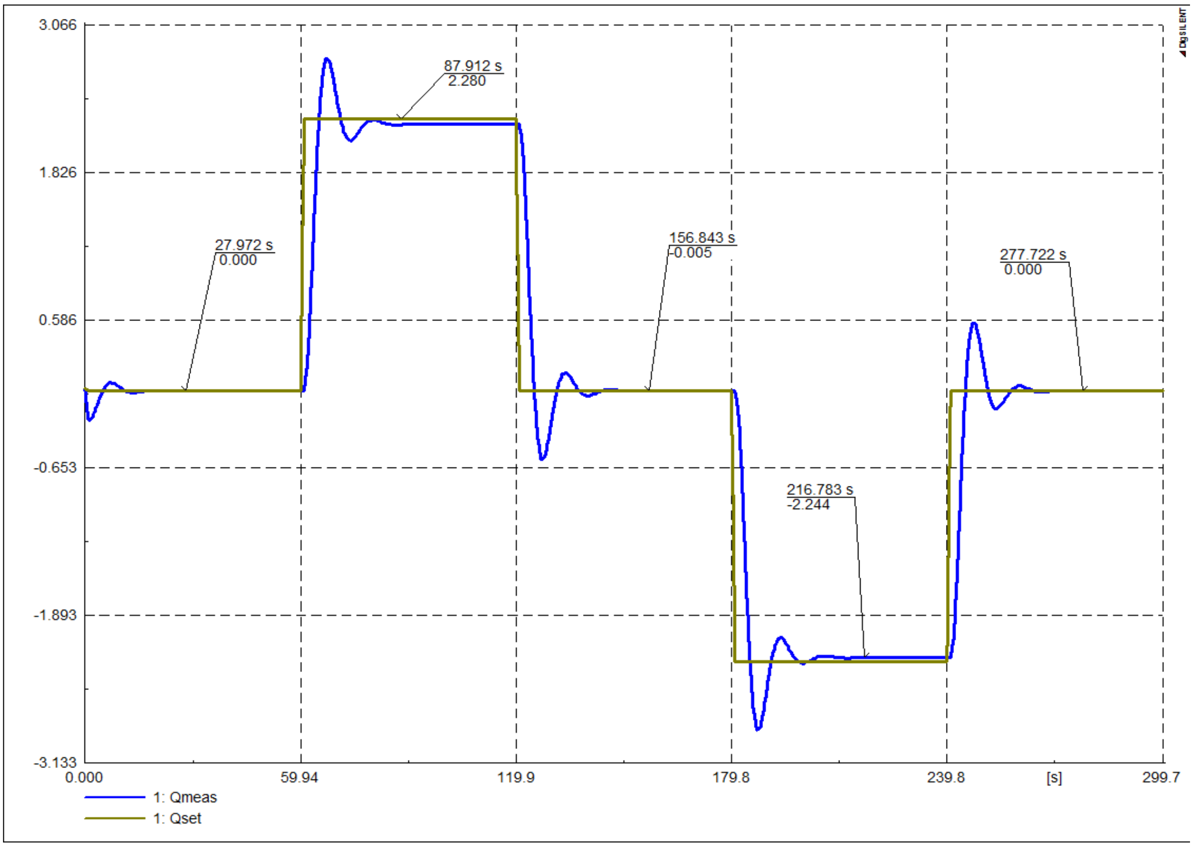


Figure 5.17: Reactive Power Testing of 10 MW PV farm in DIgSILENT Powerfactory at 1 pu Voltage

Reactive Power testing results are shown in Table 5.11 and Figure 5.18 for U_{Min} (U = 0.9 pu). The RPP meets the required set point within the time and accuracy limits.

Table 5.11: Results obtained from DIgSILENT Simulations of PV Farm at 0.9 pu Voltage

Start Time (Seconds)	**End Time (Seconds)**	**Setpoint (MVAr)**	**Results after 30 seconds of set point receipt**
0.00	60.0	0.00	0.000
60.0	120	2.28	2.231
120	180	0.00	0.002

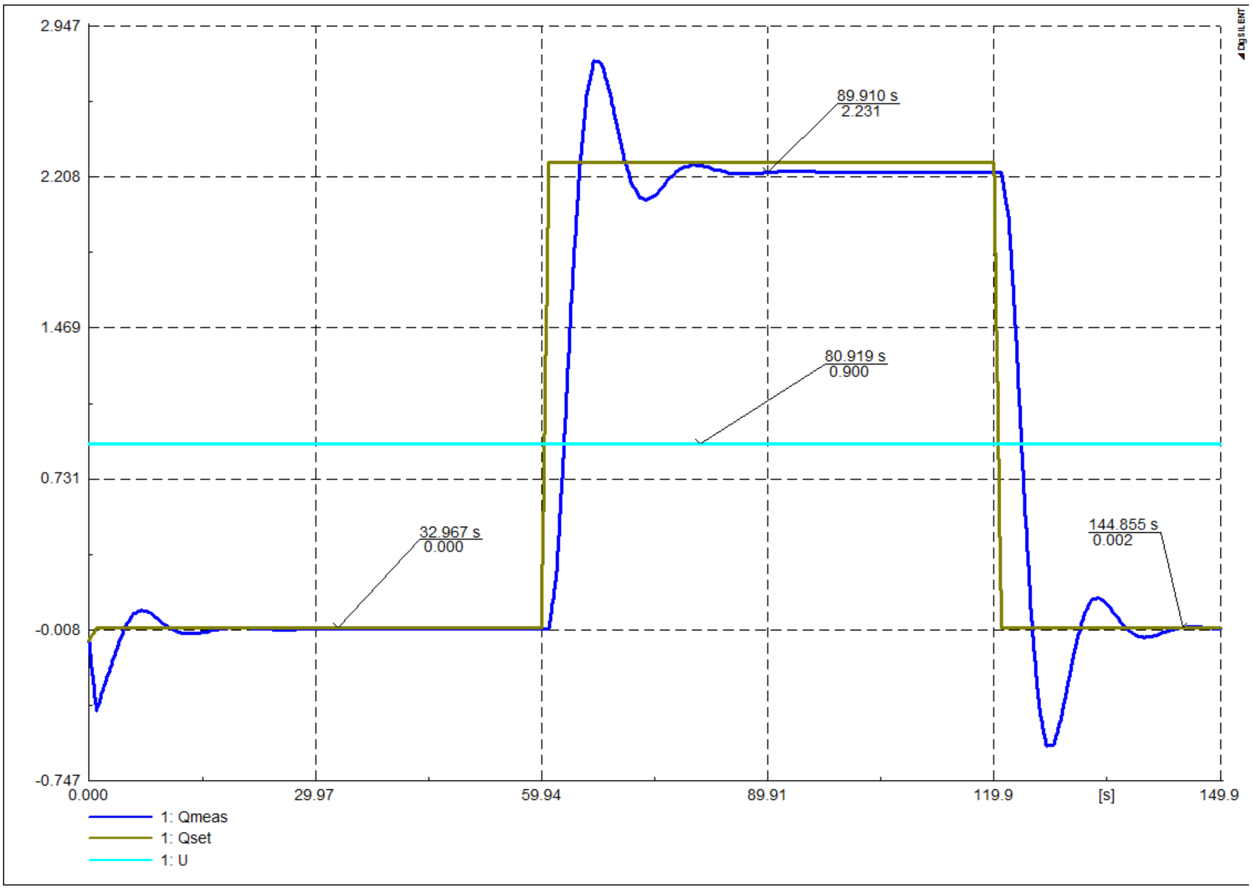


Figure 5.18 Reactive Power Testing of 10 MW PV farm in DIgSILENT Powerfactory at 0.9 pu Voltage

Reactive Power testing results are shown in Table 5.12 and Figure 5.19 for U_{Max} (U = 1.08 pu). The RPP meets the required set point within the time and accuracy limits.

Table 5.12: Results obtained from DIgSILENT Simulations of PV Farm at 1.08 pu Voltage

Start Time (Seconds)	**End Time (Seconds)**	**Setpoint (MVAr)**	**Results after 30 seconds of set point receipt**
0.00	60.0	0.00	0.000
60.0	120	2.28	2.239
120	180	0.00	0.000

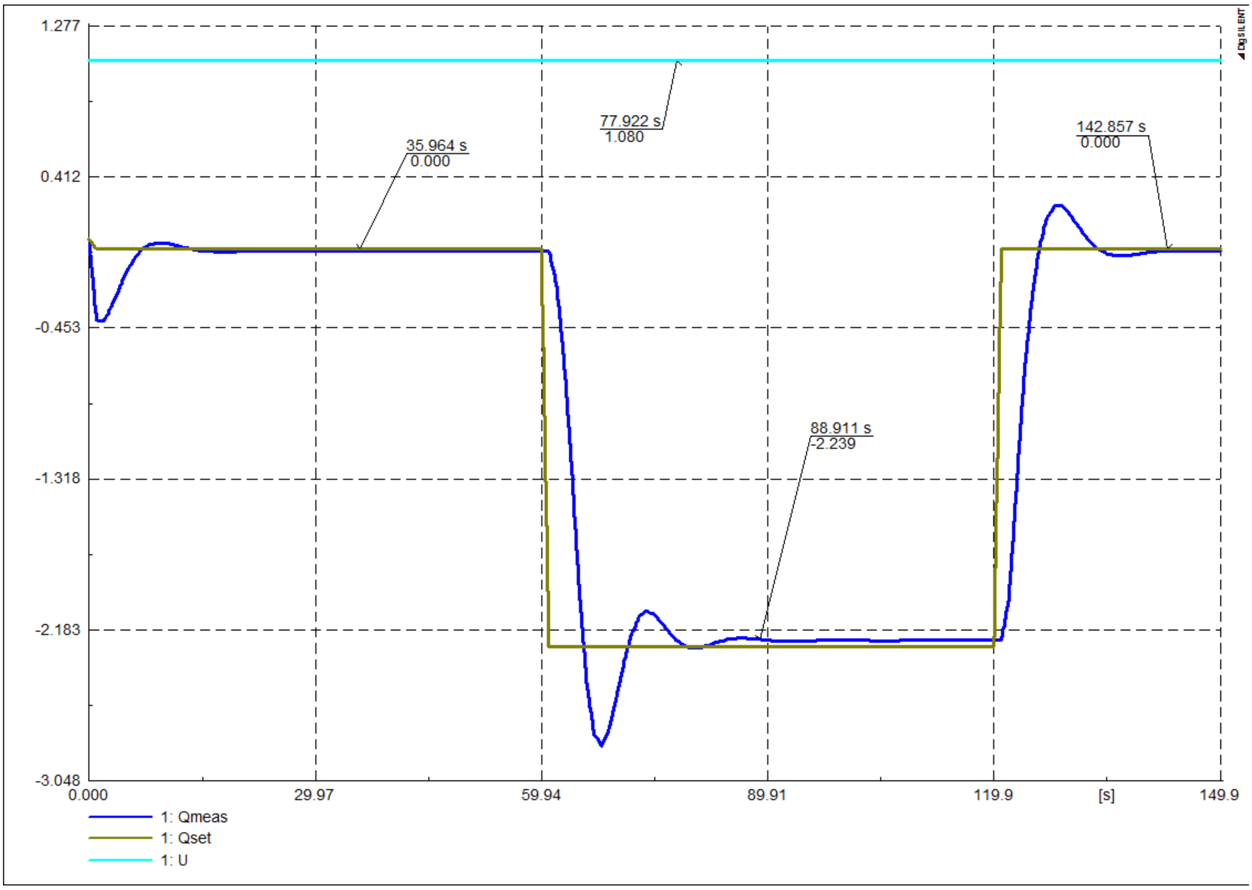


Figure 5.19: Reactive Power Testing of 10 MW PV farm in DIgSILENT Powerfactory at 1.08 pu Voltage

5.1.9. Power Factor Control Function

Category B: Shall be designed to operate from 0.975 lagging to 0.975 leading Power Factor, measured at the POC from 20% and above of the rated power. [20]

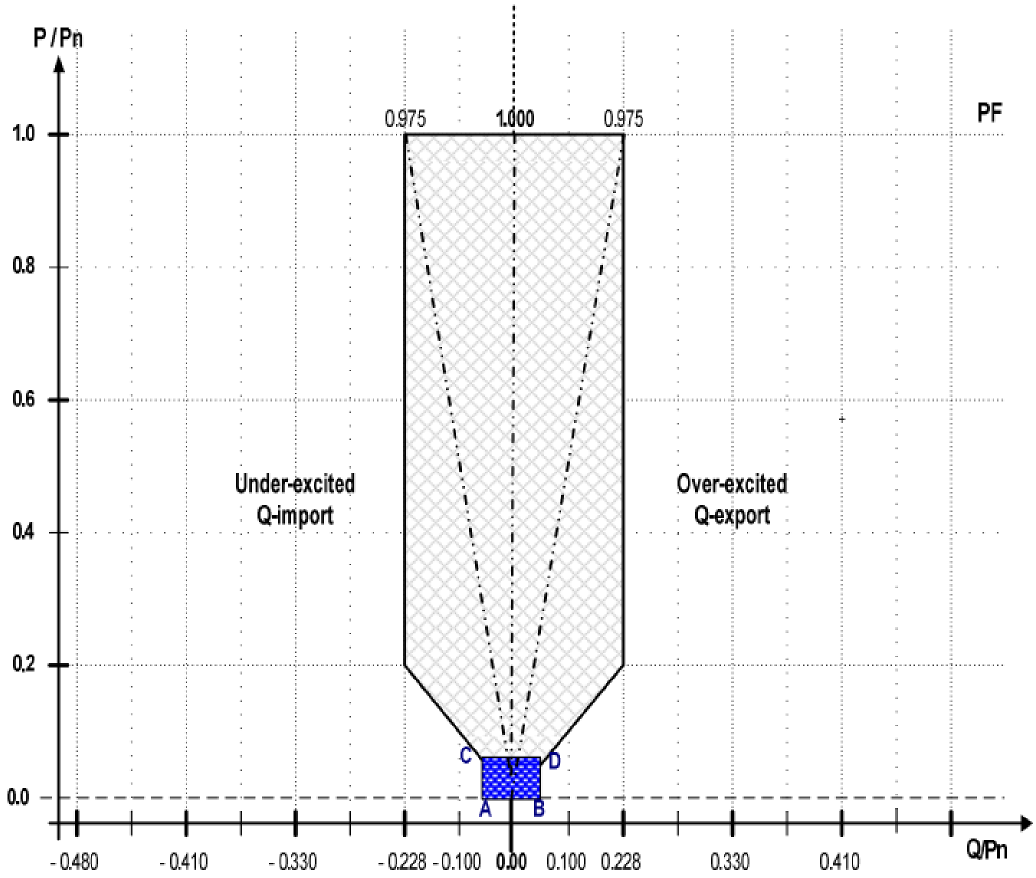


Figure 5.20: Power Factor requirements from RPP [20]

Figure 5.20 shows the test set points that the PV farm needs to comply with. The RPP is required to respond within 30 seconds of receipt of the set point to a measured accuracy of ±0.02 in order to pass the test. A simulation of the test set points that will be issued to the PV farm to check compliance is shown in Figure 5.21. This tests the plants ability to meet the required Power Factor values. The plant must be able to provide the required Power Factor from $P \geq 20\% \ P_{Max}$. [20]

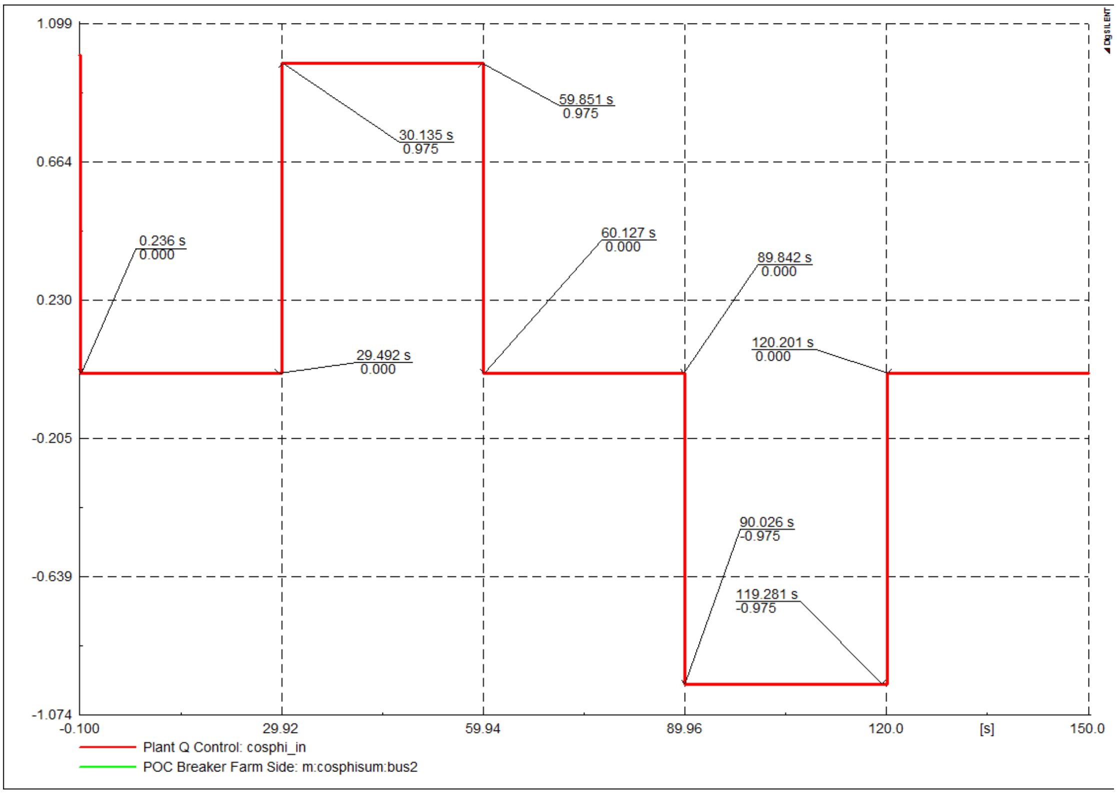


Figure 5.21: Set Points to be issued for the Power Factor Control Function test on the PV Farm [20]

At the start of the test, the plant is operating at unity power factor. At 60 seconds, the 0.975 Power Factor set point is issued and the pant responds to this by increasing its reactive power injected from -0.005 MVAr to 1.552 MVAr to achieve this Power Factor. The POC voltage subsequently increases from 1 pu to 1.017 pu at 0.975 Power Factor as shown in Figure 5.22. At 120 seconds, the plant is issued with a unity Power Factor set point and it then the voltage returns to 1 pu and the reactive power reduces to -0.006 MVAr. The plant hence complies with the Power Factor response test. [20]

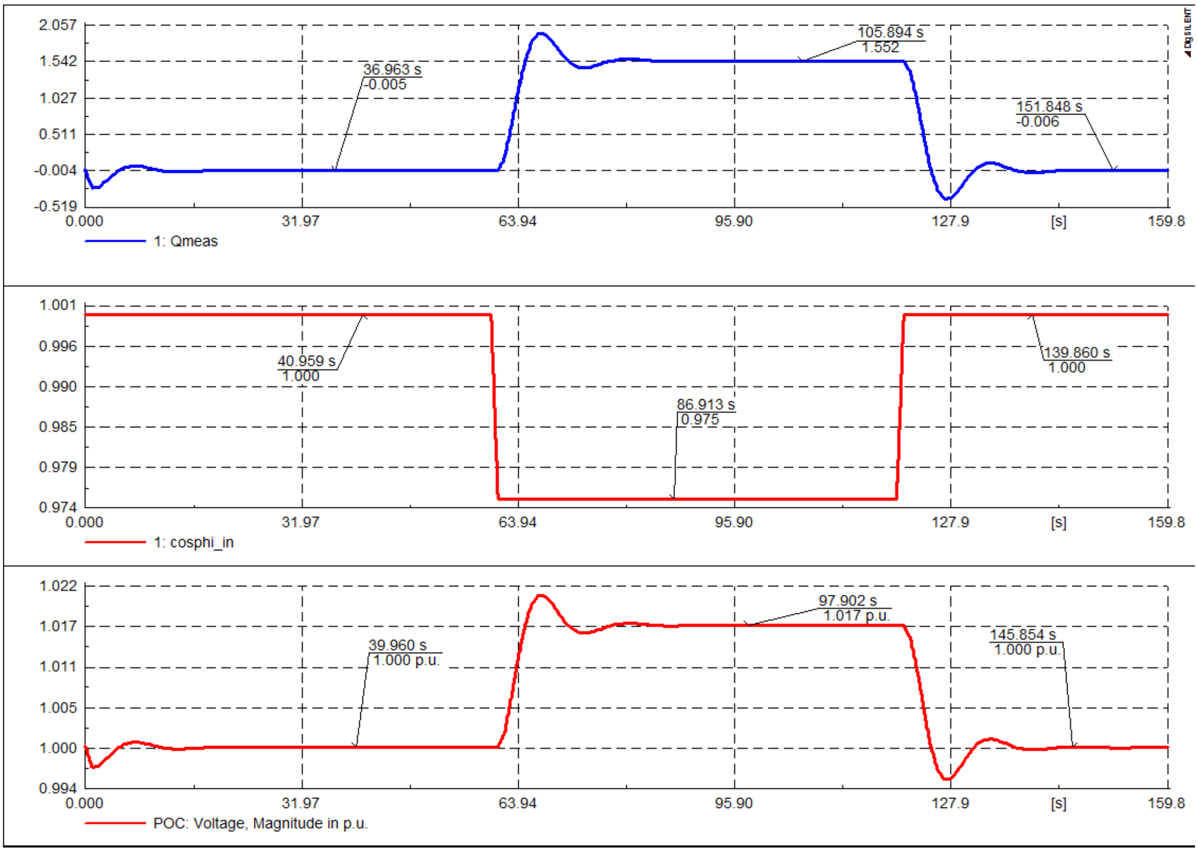


Figure 5.22: PV farm response to Power Factor set point to 0.975 from Unity Power Factor

At the start of the test, the plant is operating at unity Power Factor. At 60 seconds, the -0.975 Power Factor set point was issued and the pant responded to this by absorbing reactive power from the network from -0.005 MVAr to -1.561 MVAr to achieve this Power Factor. The POC voltage subsequently reduces from 1 pu to 0.982 pu at 0.975 Power Factor as shown in Figure 5.23. At 120 seconds, the plant is issued with a unity Power Factor set point and it then the voltage returns to 1 pu and the reactive power increases to -0.007 MVAr. The plant hence complies with the Power Factor response test.

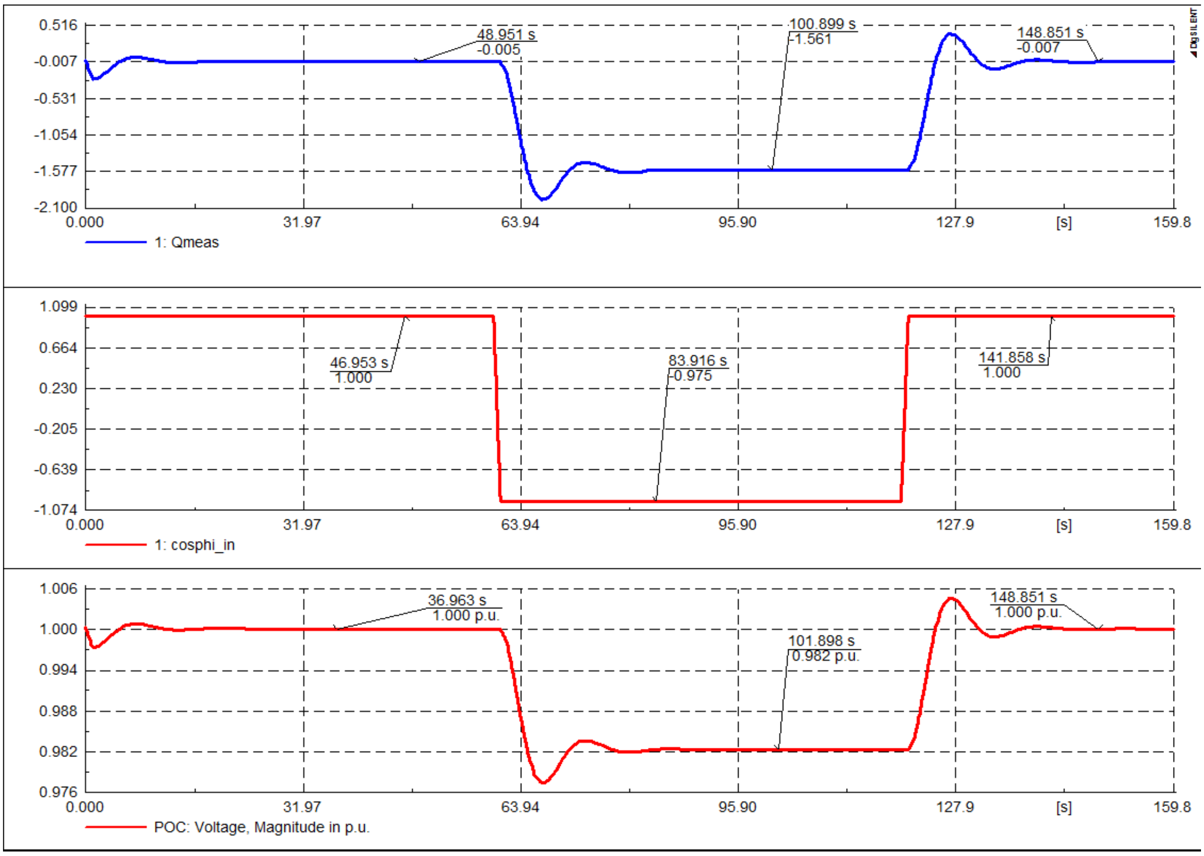


Figure 5.23: PV farm response to Power Factor set point to -0.975 from Unity Power Factor

5.1.10. Voltage Control Functions

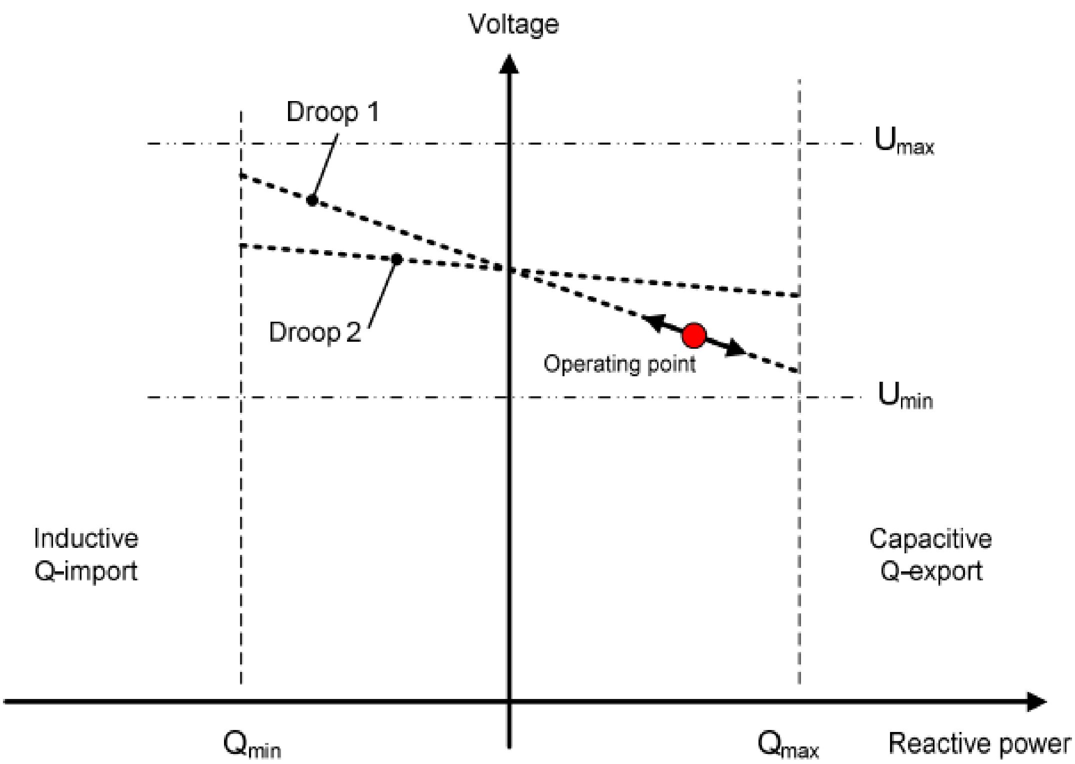


Figure 5.24: Voltage Control for RPPs [18]

The voltage control function for RPPs is depicted in Figure 5.24. If the RPP voltage set point is to be changed, a set point is issued and the change needs to be implemented within 30 seconds with an accuracy of ±0.5% of $V_{Norminal}$ whilst the accuracy of ±2% of the required injection or absorption of reactive power according to the defined droop characteristic. The tests to be carried out are depicted in Table 5.13 and Table 5.14 using 4% and 8% droop.

Table 5.13: Setpoint Values for the Voltage Control Function test on the PV Farm

Start Time	End Time	Start Voltage	Set Point Voltage
0.00	30.0	1.000	1.000
30.0	60.0	1.000	1.020
60.0	90.0	1.020	1.000
90.0	120	1.000	0.980
120	150	0.980	1.000
150	180	1.000	1.040
180	210	1.040	1.000
210	240	1.000	0.960

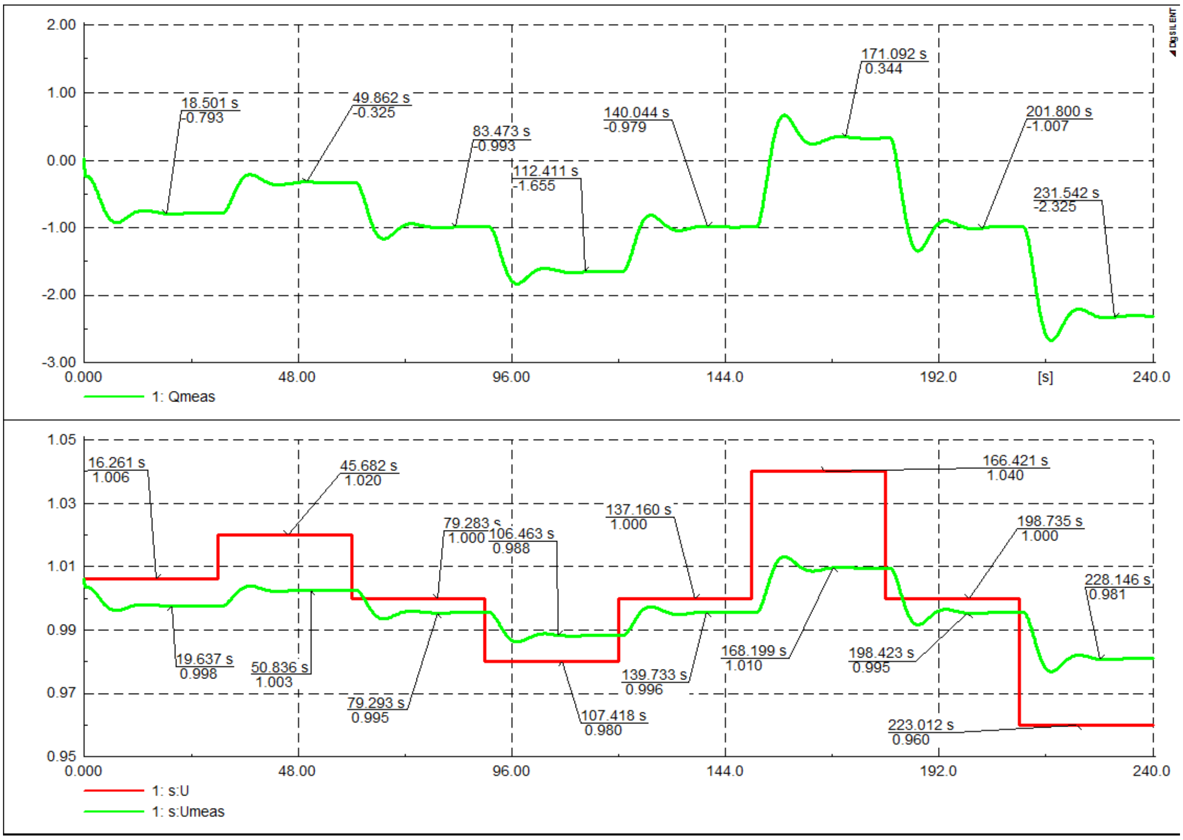


Figure 5.25: Voltage Control Function test results from the PV farm

Table 5.14: Test results from the Voltage Control Test form the PV Farm

Set Point Voltage (pu)	**Voltage Measured (pu)**	**Reactive Power (MVAr)**	**Pass/Fail**
1.000	0.998	-0.793	Pass
1.020	1.002	-0.325	Fail
1.000	0.995	-0.993	Pass
0.980	0.988	-0.1655	Pass
1.000	0.996	-0.979	Pass
1.040	1.010	0.344	Fail
1.000	0.995	-0.1007	Pass
0.960	0.981	-2.325	Pass

Figure 5.25 indicates the farms response to the voltage control function test. The plant does not meet the required voltage set points but the plant responded to the set points by supplying and absorbing reactive power. The only test that the plant passes is the 0.96 pu test where even though the plant does not meet the required set point, it supplies max reactive power according to the requirements of the SAREGC. The plant hence does not pass the voltage control function test. This test can also be verified by on site testing on the farm.

5.1.11. Power Quality

Power Quality is required to be monitored at the POC and the following parameters shall be monitored:

(a) Rapid voltage change
(b) Flicker
(c) Harmonics
(d) Unbalance voltage and current

These Power Quality (PQ) parameters can be checked utilizing the type tested, manufacturer specific model in a Power Systems simulation package prior to the construction of the RPP. Post construction of the RPP, on site PQ meters can be installed to gather the data which can then be utilized to check compliance against values given to the IPP by the NSP. The PQ limits given by the NSP to the IPP are apportioned values which takes the PQ limits given in South African National Rationalisation Standard 048 and apportioned to the upstream contribution together with current and future customers' contribution limits. If the plants violates the PQ limits, then the IPP will need to design filters to be installed to ensure compliance. [18]

5.1.12. Active Power Constraint Function

For reasons of system security, the RPP may be requested to curtail active power output when requested by the SO. Hence the RPP shall have the following active power constraint functions shown in Figure 5.26.

(a) Absolute Production constraint

(b) Delta Production constraint

(c) Power Gradient constraint

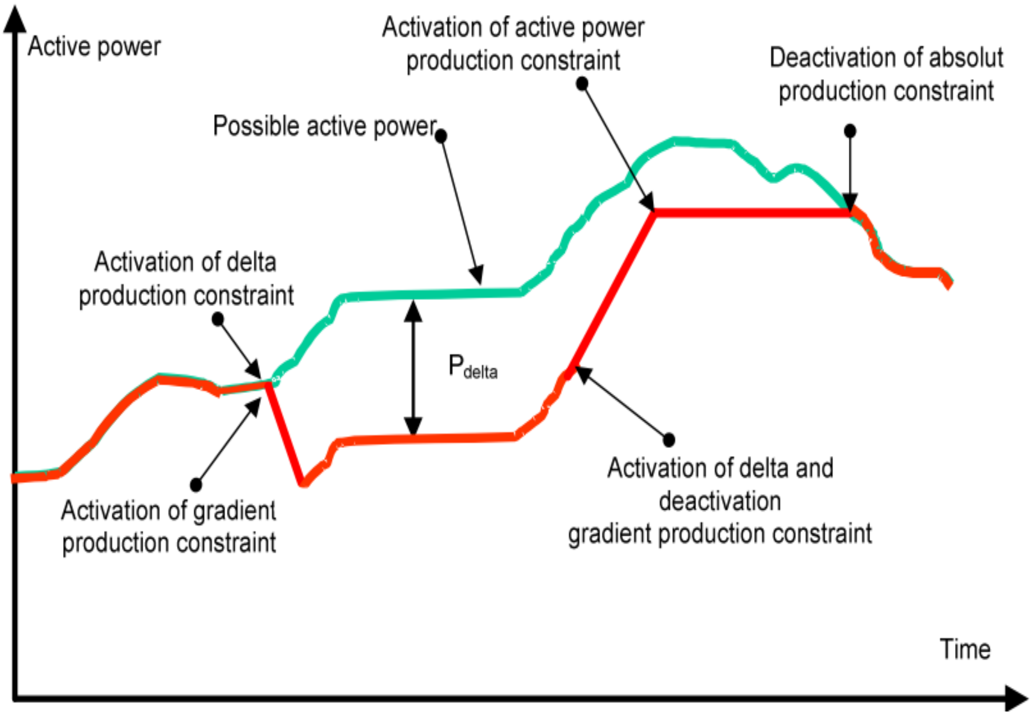


Figure 5.26: Required RPP active power control functions [18]

The purpose and pass criteria for active power constraint function is shown in Table 5.15.

Table 5.15: Active Power Control function and operational range testing as per the SAREGC [16]

Parameter	Description
Active power control function and operational range	**APPLICABILITY** All new RPPs coming on line and after major modifications or refurbishment of related plant components or functionality. Routine test/reviews: Confirm compliance every 6 years. **PURPOSE** To confirm that the active power control capability specified is met. **PROCEDURE** The following tests shall be performed within an active power level range of at least 0.2 pu or higher 1. The RPP will be required to regulate the active power to a set of specific set points within the design margins. 2. The RPP will be required to obtain a set of active power set points within the design margins with minimum two different gradients for ramping up and two different gradients for ramping down. 3. The RPP will be required to maintain as a minimum two different set levels of spinning reserve within the design margins. 4. The RPP will be required to operate as a minimum to limit active power output according to two different absolute power constraint set levels within the design margins. 5. The RPP will be required to verify operation according to as a minimum two different parameter sets for a frequency response curve within the design margins. **ACCEPTANCE CRITERIA** 1. The RPP shall maintain the set output level within ±2% of the capability registered with the SO, NSP or another network operator for at least one hour. 2. The RPP shall demonstrate ramp rates with precision within ±2% of the capability registered with the SO, NSP or another network operator for ramp up and down. 3. The RPP shall maintain a spinning reserve set level within ±2% of the capability registered with the SO, NSP or another network operator for at least one hour. 4. The RPP shall maintain an absolute power constraint set level within ±2% of the capability registered with the System Operator for at least one hour. 5. The RPP shall demonstrate that the requested frequency response curves can be obtained. Submit a report to the SO, NSP or another network operator one month after the test.

5.1.13. Absolute Power Constraint Function

“An Absolute Production Constraint (APC) is used to constrain the output active power from the RPP to a predefined power MW limit at the POC. This is typically used to protect the network against overloading.” [18] In order to check compliance of the RPP to the APC function, the plant shall be tested as per Table 5.16. This test checks the plants ability to comply with different active power constraint set point values that will be issued by the System Operator when the plant is in commercial operation. The measured values shall be recorded after 30 seconds after receipt of the set point to a measured accuracy to the higher value of either ±2% of the set point value or ±5% of the rated power for each set point. If the plant meets the required set point within the time period and accuracy limit, then the plant passes this test. [18]

Table 5.16: Absolute Production Constraint Function test set points and test results

$P_{Reference}$			**4 MW**		
Test	**Percentage of Set Point**	**Time (Seconds)**	**$P_{Setpoint}$ (MW)**	**$P_{measured}$ (MW)**	**Time (Seconds)**
1	100	0.0	4.0	4.000	13.986
2	80	30	3.2	3.198	8.991
3	40	60	1.6	1.584	9.99
4	20	90	0.8	0.773	0.999
5	10	120	0.4	0.430	0.999
6	30	150	1.2	1.179	0.999
7	50	180	2.0	1.989	4.999
8	80	210	3.2	3.198	12.987
9	100	240	4.0	4.000	21.978

Test results from the APC test for the PV farm is shown in Figure 5.27. The PV farm passes the APC test and meets all of the set points within the required accuracy and time limits. This indicates that the SO will be able to issue any APC set point to the farm and it will be able to comply within 30 seconds. This function can also be tested at the farm as part of the onsite compliance testing.

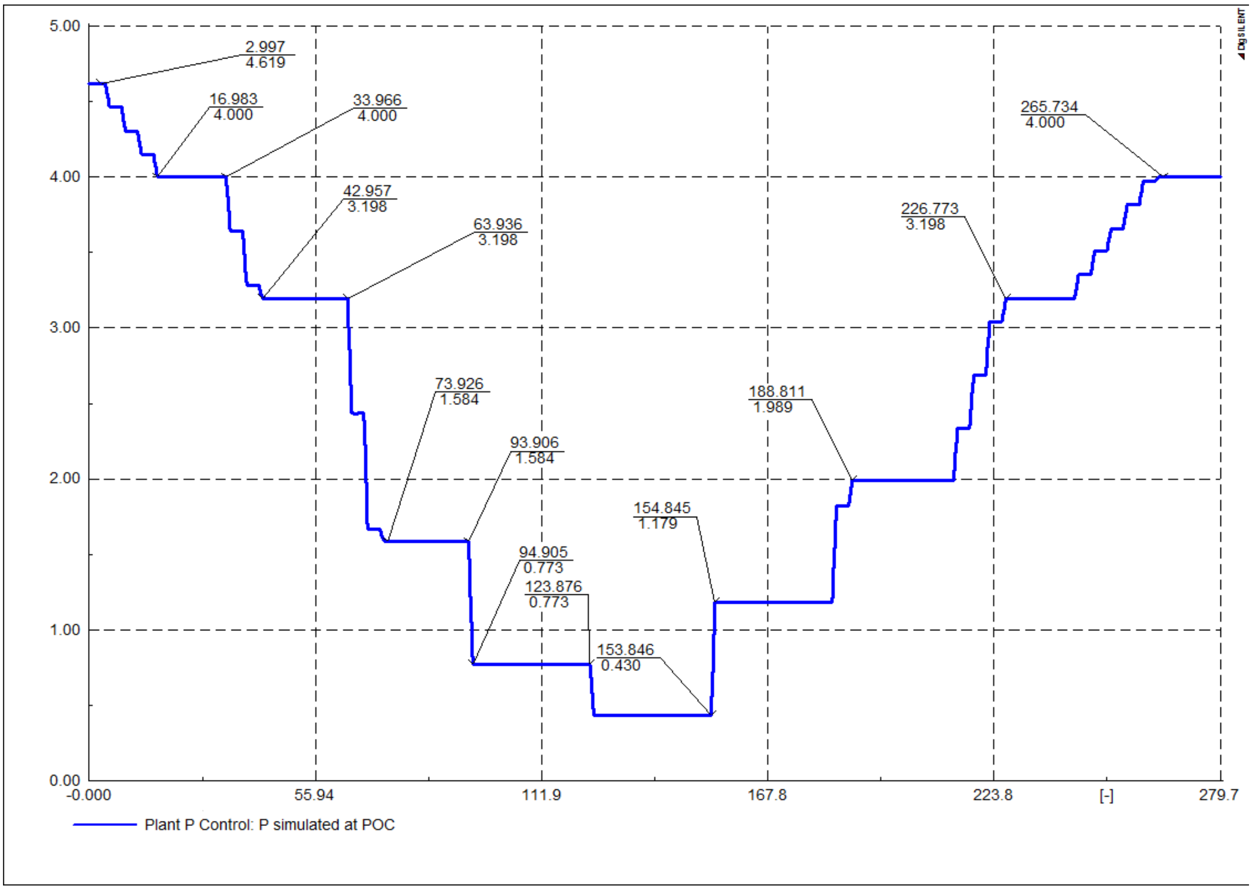


Figure 5.27: Absolute Production Constraint Function test results for the 10 MW PV farm

5.1.14. Delta Production Constraint Function

"A Delta Production Constraint function is used to constrain the active power from the RPP to a required constant value in proportion to the possible active power. It is typically used to establish a control reserve for control purposes in connection with frequency control." [18] This is however not required from PV technology as per the SAREGC.

5.1.15. Power Gradient Constraint Function

"A Power Gradient Constraint (PGC) Function is used to limit the RPP maximum ramp rates by which the active power can be changed in the event of changes in primary renewable energy supply or the set points for the RPP. A Power Gradient Constraint is typically used for reasons of system operation to prevent changes in active power from impacting the stability of the network." [18] The test to check compliance is shown in Table 5.17. The measured values shall be recorded after 30 seconds after receipt of the set point to a measured accuracy to the higher value of either ±2% of the set point value or ±5% of the rated power for each set point. If the plant meets the required set point within the time period and accuracy limit, then the plant passes this test. [18]

Table 5.17 and Figure 5.28 shows the results from the APG constraint function test on the PV farm for a ramp rate of 2 MW/minute. The plant was required to move from 5 MW to 4 MW in 30 seconds and from 4 MW back to 5 MW in 30 seconds. The plant meets the required set point within the specified time and accuracy limit.

Table 5.17: APG constraint function test results for the PV Farm (2 MW/min ramp rate)

$P_{Reference}$		5 MW		Ramp Rate		2 MW/minute
Test	**Start Value**	**Start Time (Seconds)**	**End Time (Seconds)**	**$P_{Setpoint}$ (MW)**	**$P_{measured}$ (MW)**	**Time (Seconds)**
1	5.056	0	30	4	4.048	30.969
2	4.048	30	60	5	4.998	24.945

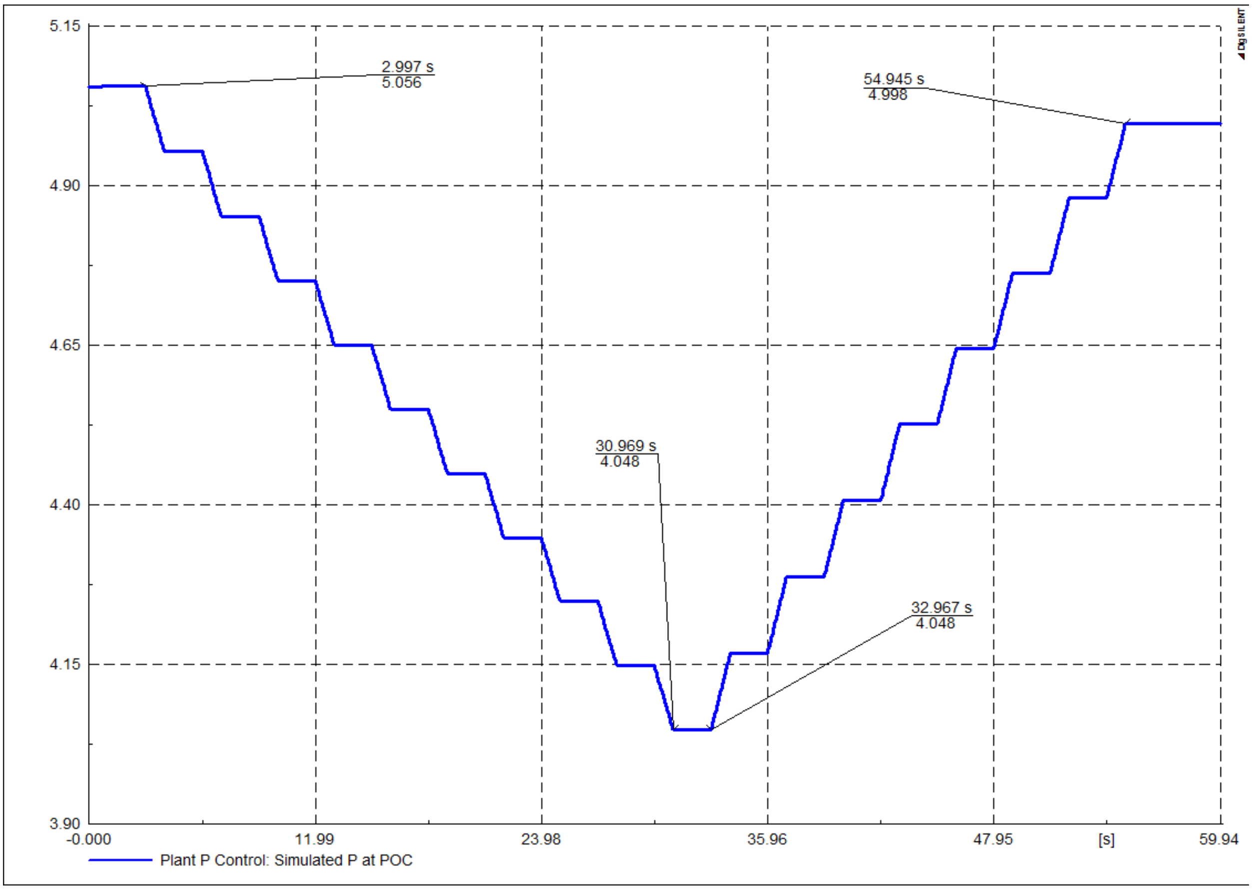


Figure 5.28: Testing of the PV Farm APG Constraint Function at 2 MW/min ramp rate

Table 5.18 and Figure 5.29 shows the results from the APG constraint function test on the PV farm for a ramp rate of 4MW/minute. The plant was required to move from 5 MW to 1 MW in 60 seconds and from 1 MW back to 5 MW in 60 seconds. The plant meets the required set point within the specified time and accuracy limit.

Table 5.18: APG constraint function test at 4 MW/min ramp rate

$P_{Reference}$	5 MW		Ramp Rate	4 MW/minute	
Test	**Start Value**	**Start Time (Seconds)**	**$P_{Setpoint}$ (MW)**	**$P_{measured}$ (MW)**	**Time (Seconds)**
1	5.056	0	1	0.976	57.942
2	0.976	90	5	4.998	53.946

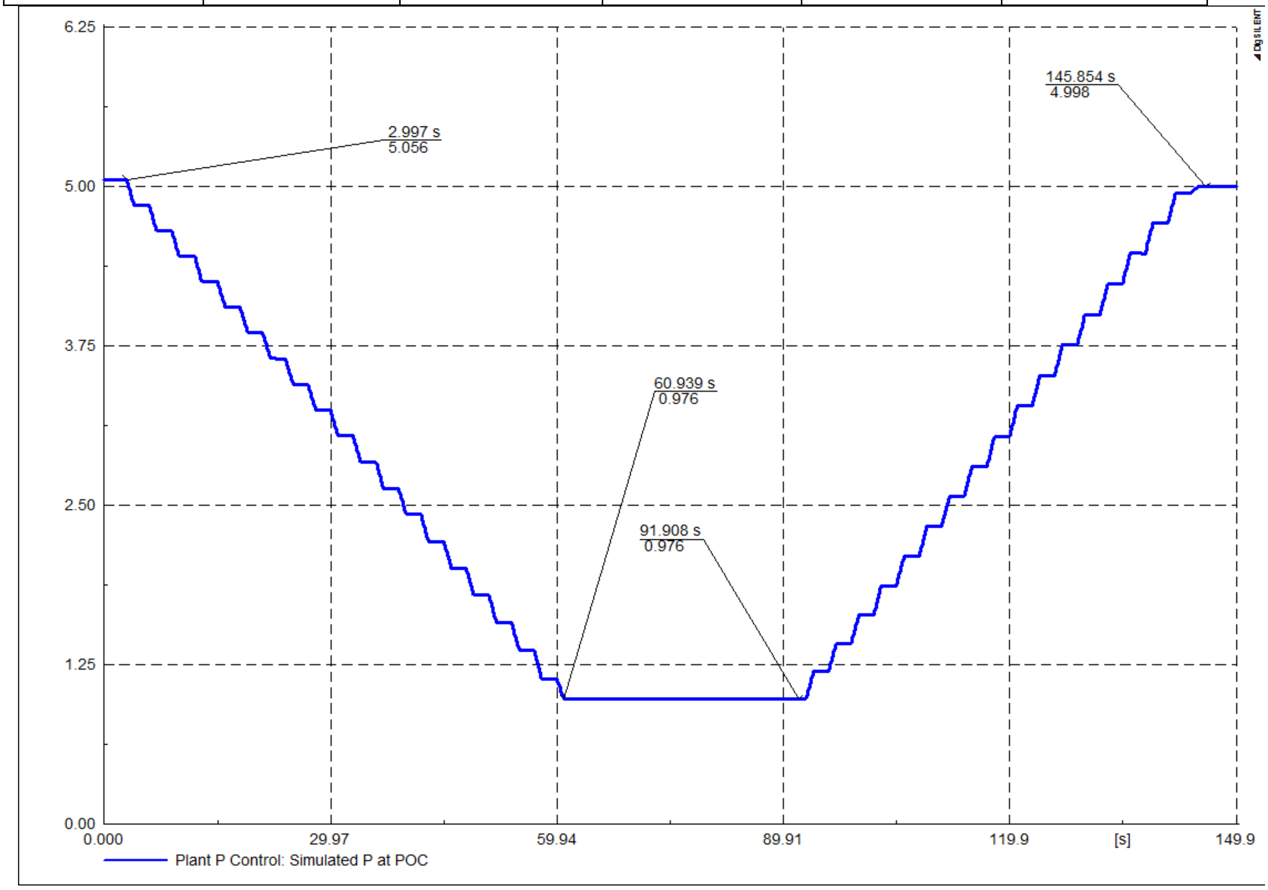


Figure 5.29: Testing of the PV Farm APG Constraint Function (4MW/min Ramp Rate)

Table 5.19 and Figure 5.30 shows the results from the APG constraint function test on the PV farm for a ramp rate of 2 MW/minute. The plant was required to move from 5MW to 1 MW in 120 seconds and from 1 MW to 5 MW in 120 seconds. The plant met the required set point within the specified time and accuracy limit.

Table 5.19: APG constraint function test at 2 MW/min ramp rate

$P_{Reference}$	5 MW		Ramp Rate	2 MW/minute	
Test	**Start Value**	**Start Time (Seconds)**	**$P_{Setpoint}$ (MW)**	**$P_{measured}$ (MW)**	**Time (Seconds)**
1	5.056	0	1	0.976	114.885
2	0.976	120	5	4.998	105.894

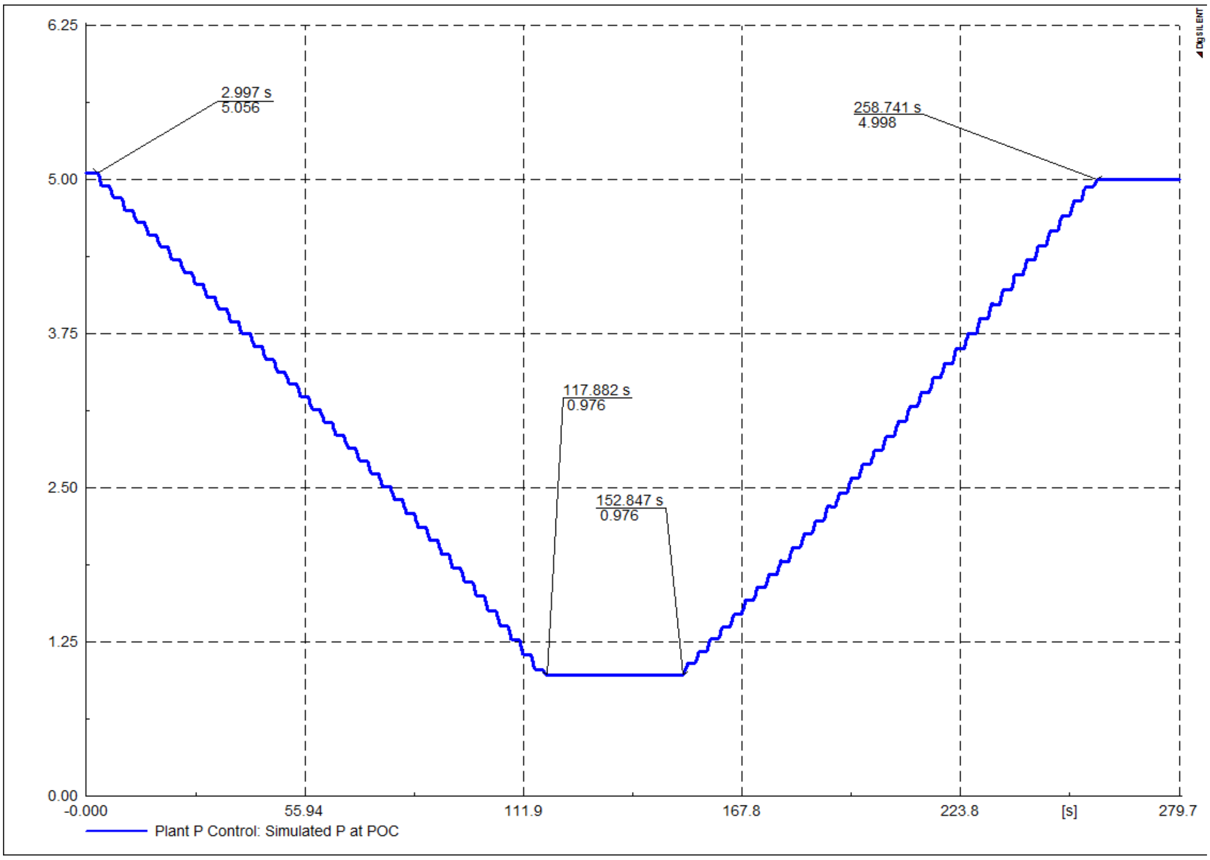


Figure 5.30: Testing of the PV Farm Active Power Gradient Constraint Function (2MW/min Ramp Rate)

5.1.16. Signal, Communication and Control Requirements

Table 5.20 shows the signals that are required from the RPP plant. This will then assist the SO to manage the RPP connection together with the network more effectively. Each signal list is made up of a number of signals.

Table 5.20: Signal required from the RPP plant [18]

Signals List	Description
List 1	General plant data and set points
List 2	RPP available estimate
List 3	RPP MW curtailment data
List 4	Frequency response system settings

List 5	RPP Meteorological data

Figure 5.31 shows a typical screen of signals brought back to the network control room via SCADA from an RPP.

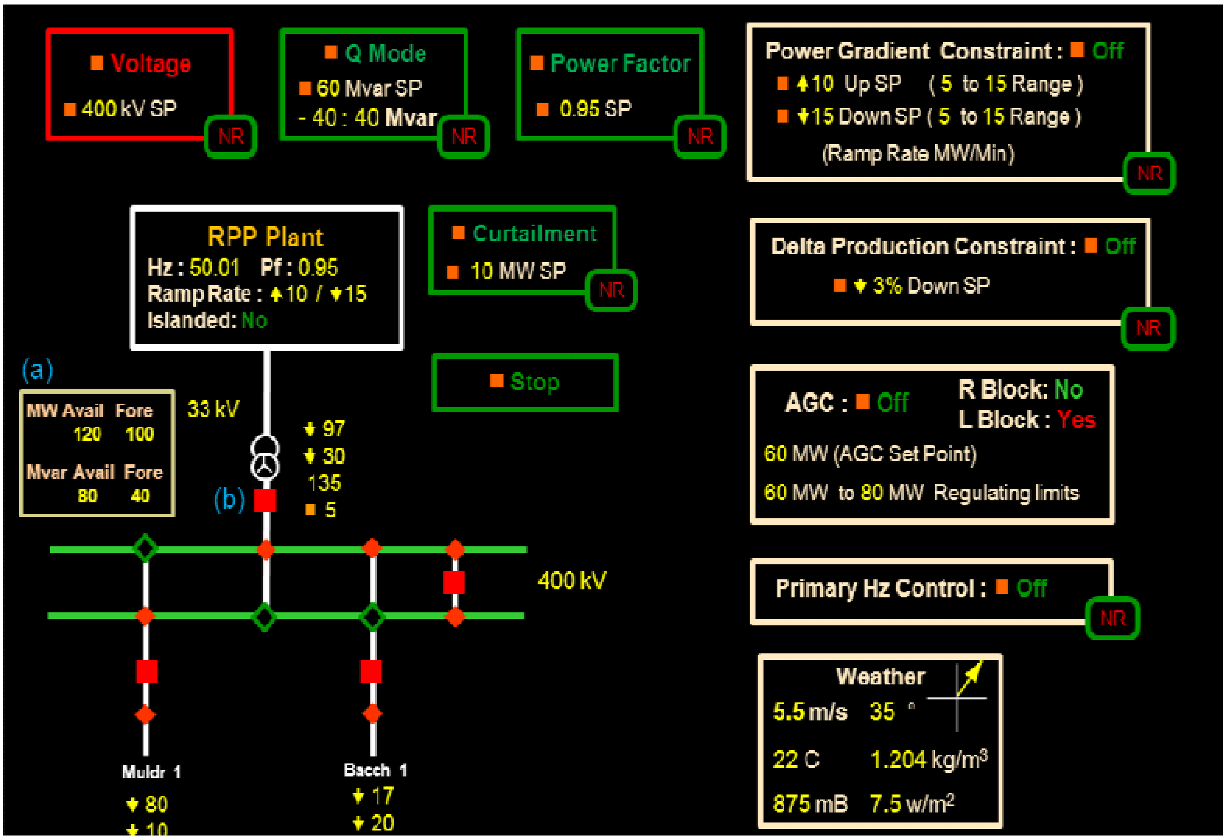


Figure 5.31: Example of signals brought back via SCADA [18]

5.2. Summary of Chapter 5

Results from the case study reveal that the 10 MW (Category B) PV farm has the following control functionality:

1. Reactive Power Control
2. Power Factor Control
3. Voltage Control
4. Active Power Control

This then provides operational flexibility to the eThekwini Electricity SO when operating this PV farm on the network. The SAREGC also requires quick and highly accurate reponses to either set point issued by the SO or events on the network.

CHAPTER 6: CASE STUDY 3: TESTING RENEWABLE ENERGY GRID CODE COMPLIANCE OF A 25 MW FARM

6.1. Introduction to Chapter 6

Chapter 6 provides detailed background information on a wind farm operation and we set out to understand the control functionality of a potential 25 MW wind farm on the eThekwini Electricity grid. This was achieved by testing a new 25 MW wind farm in SA and recording and analysing the results from the study. This will then allow us to understand the wind farm operational functionality. The chapter also provides details on the SAREGC and requirements from international grid codes.

6.1.1. Wind Farm Technology

"Over the past few decades, wind energy has been considered as the most significant and competitive renewable energy resource following the sudden growth in size of commercial wind turbine designs and an increase in their power ratings from a few tens of kW power capacity to megawatts (MW) power capacity" [57] Figure 6.1 shows the growth in the wind turbine size over the years. There has been immense growth in the number of wind farms developed over the past few years in most parts of the world. Wind farms can be both off shore or on shore farms made up of a large number of individual wind turbines. [57]

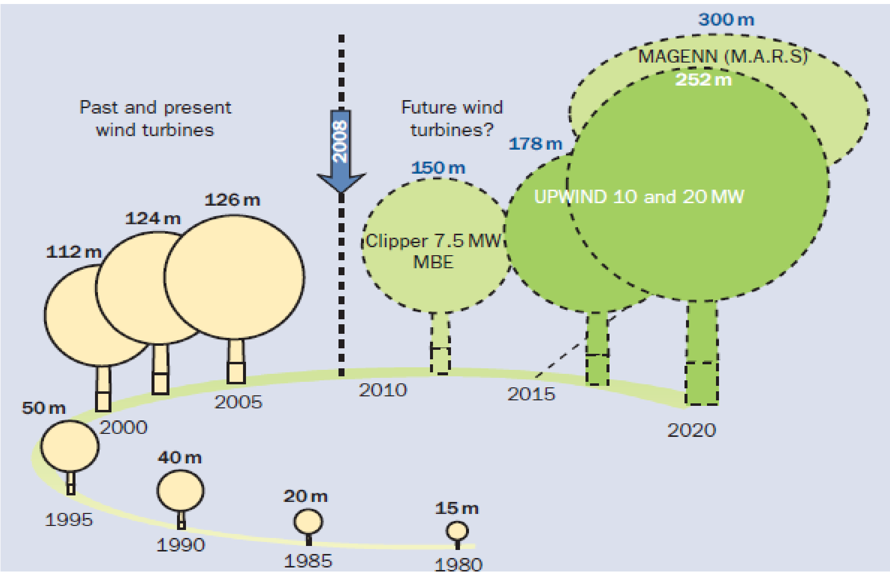


Figure 6.1: Growth in sizes of commercial wind turbine designs[57]

Recent studies have indicated that there is large potential for wind generation at a number of sites around SA. This has been seen in the SA REIPPPP as dipicated in Table 6.1. In round one of the programme, 28 successful bidders were selected making up a total of 1416 MW of capacity. In round two, 19 projects were selected making up a capacity of 1045 MW. Whilst in round 3, 17 projects were selected making up a capacity of 1486 MW and in round 3.5 two projects of 200 MW capacity was selected. Round 4 consisted of 26 projects with a capacity of 2206 MW. Wind (3347 MW) and Solar PV (2327 MW) makes up the largest portion of the 6330 MW projects selected under round 1 to round 4 of the DOE REIPPPP. This indicates that wind farms make up 52.9% of the capacity from the total projects selected in the REIPPPP round 1 to round 4. [18]

Table 6.1: Selected bidders in REIPPPP: Round 1 to 4 [18]

Technology	MW Awarded Round 1	MW Awarded Round 2	MW Awarded Round 3-3.5	Total MW's Awarded Round 4	Total MW's Awarded Round 1 - 4
Solar PV	632	417	465	813	2327
Wind	634	563	787	1363	3347
Solar CSP	150	50	400	0	600
Landfill Gas	0	0	18	0	18
Biomass	0	0	16	25	41
Small hydro	0	15	0	0	15
Total	1416	1045	1686	2206	6330

The average bid per kWh of wind energy has reduced from R1.14/kWh in round one, R0.90/kWh (78.95% of round one prices) in round two to R0.66/kWh (57.90% of round one prices) in round three shown in Table 6.22. The average round three price of R0.66/kWh is highly competitive to the price per kWh that eThekwini Electricity purchases from Eskom. The average round 3 cost from wind generation is currently the cheapest (R0.66) cost per kWh generation from renewable energy sources when compared to solar PV (R0.88/kWh) and CSP (R1.46). This further indicates that generation from wind energy will play a substantial role in the renewable energy generation sector in South Africa going forward. [18]

Table 6.2: Price caps and average REIPPPP for Round 1 to 3 [18]

Tariffs	Round 1 Average Bid (Per kWh)	Round 2 Average Bid (Per kWh)	Round 3 Average Bid (Per kWh)
Wind	R1.14	R0.90	R0.66
Solar PV	R2.76	R1.65	R0.88
CSP	R2.69	R2.51	R1.46

In order to ascertain the potential for wind farms in eThekwini, a study was undertaken to determine potential sites which could support wind farms of 15 MW and greater in Durban.

In order to identify wind farm potential in Durban, “a constraints assessment was undertaken across the eThekwini region in which 10 potential wind farm sites was identified. These sites were identified as being capable of supporting a 15 MW or greater wind farm.” [38]

Table 6.3 indicates the 10 potential sites identified from the constraint assessment.

Table 6.3: Selected wind farm site with capacity of 15 MW and greater [38]

Site Number	**GPS Co-ordinates**	**Number of Turbines**	**Capacity MW**	**Mean Wind Speed (m/s)**	**Area (km^2)**	**Landmark/Area**
Site 1	-29.619459, 30.7238897	10	25	6.5	2.337	Nagle Dam; Valley of a Thousand Hills; Sithumba
Site 2	-29.692687, 30.62732835	8	20	6.2	1.591	Directly south of Nagl Dam; west of Mr423 Road
Site 3	-29.6389813, 30.85186955	11	27.5	7.3	2.249	Inanda Dam North
Site 4	-29.7106024, 30.88448335	9	22.5	6.2	1.873	Inanda Dam South East
Site 5	-29.8999154, 30.7152307	8	20	6 - 6.7	1.476	Shongweni Dam South; south of Mr489 Road
Site 6	-29.9283609, 30.80834673	9	22.5	6.2 - 6.6	1.231	Umlazi North West; Inwabi
Site 7	-29.8795165, 30.64369913	9	22.5	6.2	2.153	Shongweni Dam West; directly next to Mr489
Site 8	-29.726814, 30.85641969	8	15	6.2 - 6.6	789	Inanda Dam Langefontein
Site 9	-29.7419252, 30.63926058	8	20	6.2 - 6.6	1.158	Camperdown Rural; directly next to N3
Site 10	-29.9361459, 30.67968106	8	20	6 - 6.7	1.324	Nkomokazi; Umbumbulu

Figure 6.2 shows the proposed wind farm site 1 which has a potential to install 10 wind turbines.

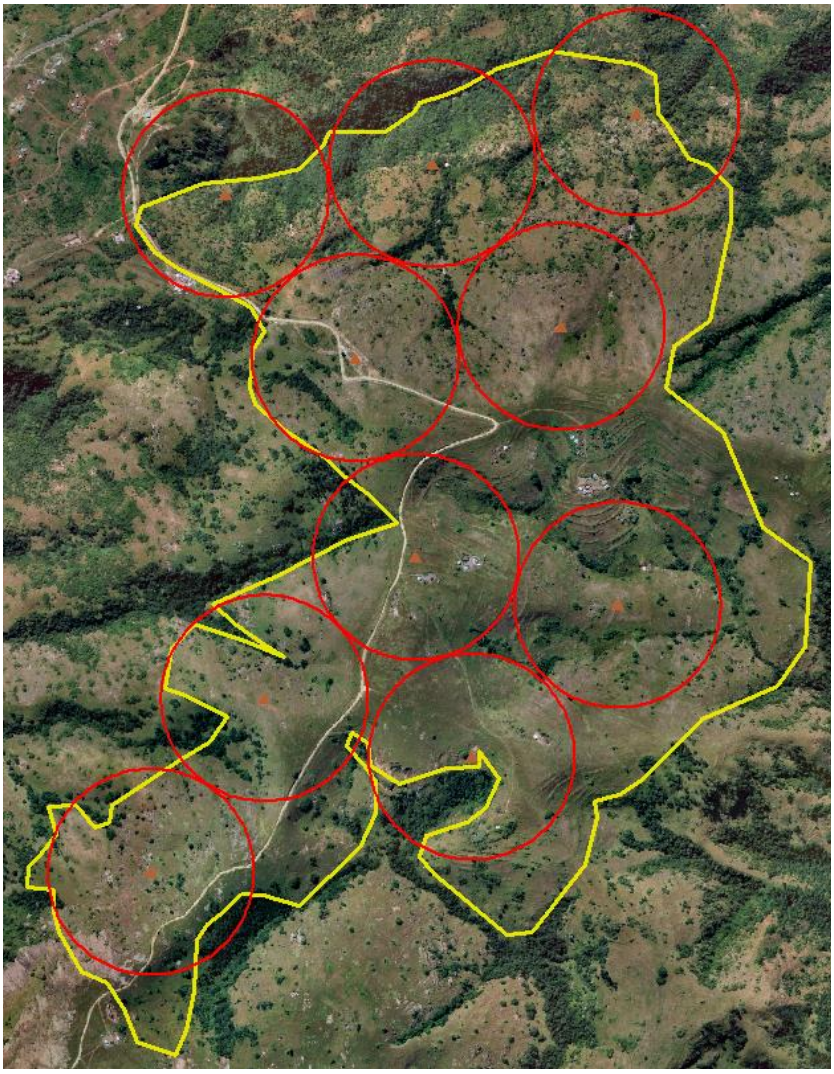


Figure 6.2: Potential 25 MW wind farm at site number one in Sithumba [40]

For this case study, we will utilise a 25 MW wind farm to understand the interaction of the wind farm with the grid. Most of the potential wind farms in eThekwini been 20 MW and greater indicates that these plants fall in the South African Renewable Energy Grid Code (SAREGC) category C. A farm of this magnitude is hence required to fully comply with the SAREGC Version 2.8. Category C grid code compliance has the most stringent requirement in the grid code. In order to understand the interaction of this 25 MW wind farm with the local grid, the SAREGC needs to be clearly understood. This case study was carried out by firstly explaining the requirements from the SAREGC together with the testing method to prove that the wind farm is grid code compliant. Further to that, actually testing was carried out on a newly built 25 MW wind farm in South Africa in order to get results to understand how the actual wind farm behaves under different conditions in the grid code. This will allow us to understand the controllability options that the SO will have on the 25 MW wind farm built in eThekwini.

6.1.2. Wind System Mathematical Modelling

The functional structure of a typical wind energy conversion system is as shown in Figure 6.3.

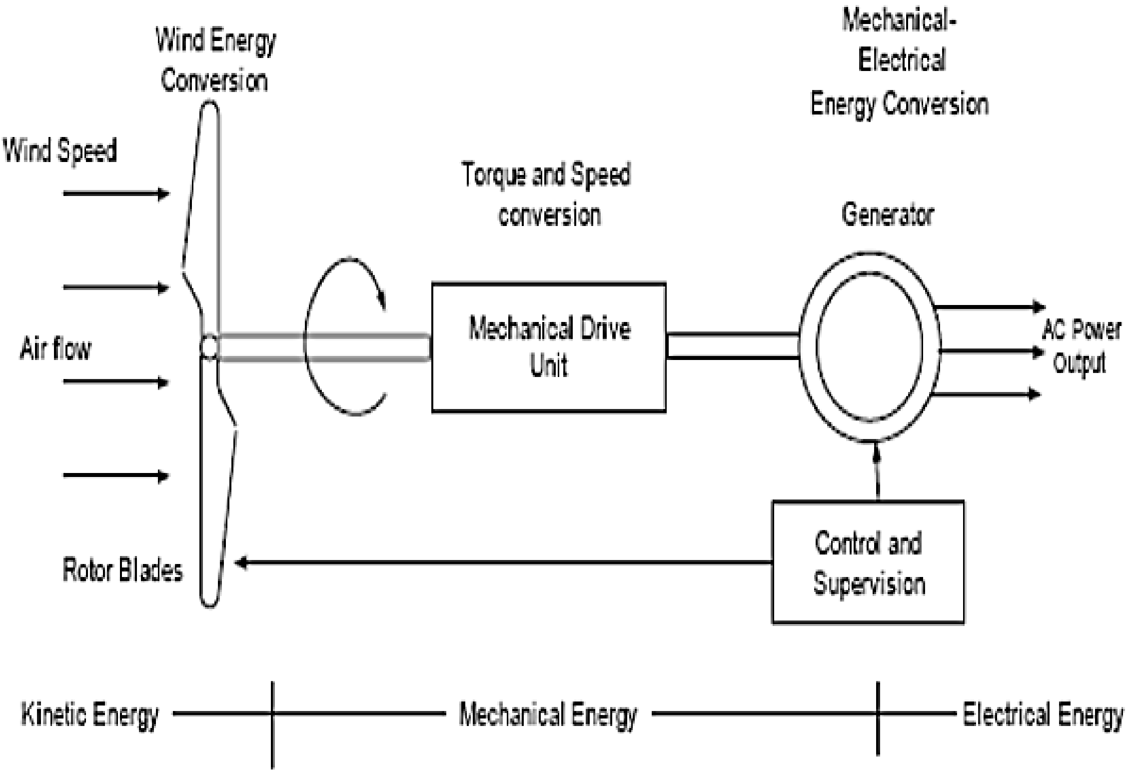


Figure 6.3: Power Transfer in a Wind Energy Converter [58]

"A wind energy conversion system is a complex system converting wind energy to rotational energy and then to electrical energy. The output power or torque of a wind turbine is determined by several factors like wind velocity, size and shape of the turbine, etc. The principle components of a modern wind turbine are the tower, the rotor and the nacelle, which accommodates the transmission mechanisms and the generator. The wind turbine captures the wind's kinetic energy in the rotor consisting of two or more blades mechanically coupled to an electrical generator. The main component of the mechanical assembly is the gearbox, which transforms the slower rotational speeds of the wind turbine to higher rotational speeds on the electrical generator side. The rotation of the electrical generator's shaft driven by the wind turbine generates electricity, where output is maintained as per specifications, by employing suitable control and supervising techniques. Besides monitoring the output, these control systems also include protection systems to protect the overall system." [58]

6.1.2.1. Inputs and Outputs of a Wind Turbine

The inputs and output variables of wind turbine can be broken into the following: [58]

- "The independent input quantity wind speed, determines the energy input to the wind turbine.
- Machine-specific input quantities, arising particularly from rotor geometry and arrangement (i.e. different configurations like horizontal axis or vertical axis turbines, area of the blades, etc.).
- Turbine speed, rotor blade tilt, and rotor blade pitch angle, arising from the transmission system of the wind energy conversion system.
- Turbine output quantities, namely power or drive torque, which may be controlled by varying the above three input quantities." [58]

6.1.2.2. Power Extraction from the Air Stream

"With the identification of the wind turbine's input and output variables, now it is possible to derive an expression relating these two values. The relation between the power and wind speed is derived as follows [58]:

The kinetic energy in air of mass m moving with speed V is given by the following:

$$\text{Kinetic energy} = \tfrac{1}{2} \times m \times V^2 \text{ Joules} \tag{4.10}$$

The power in moving air flow is the flow rate of kinetic energy per second.

$$\text{Power} = \tfrac{1}{2} \times (\text{mass flow rate per second}) \times V^2 \tag{4.11}$$

The actual power extracted by the rotor blades is the difference between the upstream and the downstream wind powers. Therefore, equations (ii) results in;

$$P = \frac{1}{2} \times (\text{Mass flow rate per second}) \times (V^2 - V_o^2) \tag{4.12}$$

Where:

P is the Mechanical Power extracted by the rotor in watts.

V is the upstream wind velocity at the entrance of the rotor blades in m/s

Vo is the downstream wind velocity at the exit of the rotor blades in m/s

Let ρ be the air density in (kg/m^3) and

A is the area swept by the rotor blades in (m^2); then, the mass flow rate of air through the rotating blades is given by multiplying the air density with the average velocity.

$$\text{Mass flow rate} = \rho \times A \times \frac{V+V_o}{2} \tag{4.13}$$

From (4.12) and (4.13), the mechanical power extracted by the rotor is given by:

$$P = \frac{1}{2}\left[\rho . A\left(\frac{V+V_o}{2}\right)\right](V^2 - V_o^2) \tag{4.14}$$

After algebraic rearrangement of the terms we have:

$$P = \frac{1}{2} \times \rho \times A \times V^3 \times C_p \tag{4.15}$$

Where:

$$C_p = \frac{\left[1+\frac{V_o}{V}\right]\times\left[1-\left(\frac{V_o}{V}\right)^2\right]}{2} \tag{4.16}$$

Where C_p is the fraction of the upstream wind power, which is captured by the rotor blades and has a theoretical maximum value of 0.59. It is also referred as the power coefficient of the rotor or the rotor efficiency. In practical designs, the maximum achievable Cp is between 0.4 and 0.5 for high-speed, two-blade turbines and between 0.2 and 0.4 for slow-speed turbines with more blades [58].

From "(4.16)", we see that the power absorption and operating conditions of a turbine are determined by the effective area of the rotor blades, wind speed, and wind flow conditions at the rotor. Thus, the output power of the turbine can be varied by effective area and by changing the flow conditions at the rotor system, which forms the basis of control of wind energy conversion system." [58]

6.1.2.3. Tip Speed Ratio

"The tip speed ratio λ, defined as the ratio of the linear speed at the tip of the blade to the free stream wind speed and is given by the following expression (4.17) and (4.18): [58]

$$VRTSR = \omega\lambda \quad (4.17)$$

$$TSR = \lambda = \frac{\omega R}{V} \quad (4.18)$$

Where:

R is the rotor blade radius in meters
ω is the rotor angular speed in rad/sec
V is the wind speed

TSR is related to the wind turbine operating point for extracting maximum power. The maximum rotor efficiency Cp is achieved at a particular tip speed ratio TSR, which is specific to the aerodynamic design of a given turbine. The rotor must turn at high-speed at high wind, and at low-speed at low wind, to keep tip speed ratio TSR constant at the optimum level at all times. The larger the tip speed ratio TSR, the faster is the rotation of the wind turbine rotor at a given wind speed. High (rotational) speed turbines are preferred for efficient electricity generation. From (4.18), for a particular value of wind speed V, turbines with large blade radius R result in low rotational speed ω, and vice versa. For operation over a wide range of wind speeds, wind turbines with high tip speed ratios are preferred." [58]

6.1.3. International Renewable Energy Grid Code Requirements

The following are requirements in most international renewable energy grid codes.

6.1.3.1. Regulations for Continuous Operation

"Voltage and frequency operating range that renewable power plants must stay connected to the grid and be able to withstand voltage and frequency variation limits established by the grid SO. Voltage range is related to the size of grid transmission system which is characterized by different levels of voltage. Whilst frequency nominal range is determined by electrical characteristics of the power system, such as overall inertia of installed power generation infrastructure as well by the lack of interconnections. Renewable energy generators must also face voltage and frequency deviations outside the conventional range, during a short time period without been tripped." [59]

6.1.3.2. Active Power Regulation

"It is a set power control strategies which gives the SO freedom and flexibility to manage the power output injected into the grid by renewable power plants. Wind and solar generator should comply with this requirement by incorporating internally active power control capabilities as well as allowing plants to be remotely controlled. As the renewable generation is increased, active power regulation requirement will become indispensable on grid codes." [59]

6.1.3.3. Maximum Power Limitation

"This parameter has the purpose to set maximum power output of renewable generator below its rated power. By restricting the maximum amount of power injection, the SO has a way to prevent more instabilities of active power balance due to unpredictable nature of wind and solar resources." [59]

6.1.3.4. Active Power Range Control

"Wind or solar power plants should be prepared to modulate its active power production between a minimum and maximum of its rated capacity." [59]

6.1.3.5. Ramp Rate Limitation

"Limiting the power gradient of renewable power through a set-point can be a very effective way to minimize the impact of sudden rise of renewable energy generation. Ramp rate is defined as the power changes from minute to minute (MW/min). The idea of this concept is to filter faster variations of wind power output by controlling the ramp rate according to changes observed on power demand. If not implemented there is a serious risk that the installed conventional generation may not decrease their power output as quick as necessary, leading ultimately to severe grid frequency problems." [59]

6.1.3.6. Delta Control

"It is a way of securing spinning reserve based on renewable power generation. Power output is artificially lowered, below available power at the moment of generation. The difference is kept as reserve to be used like a conventional generation station does (primary and secondary control). However the curtailed power depends on available natural resources such as wind. Thus the level of reserve is not constant. The curtailed power can be released for frequency regulation, as well as can be used to maintain the voltage of overall system stability through injection of reactive power into the grid." [59]

6.1.3.7. Reactive power regulation

"In recent years wind generators of Doubly Fed Induction Generator (GFIG) type and Permanent Magnet (PM) synchronous generator types have become the standard choice for new renewable installations. Both types are capable of injecting or receiving reactive power at the same time which active power is delivered. This technical capability is also available in solar plants as they share the same power electronics technology interface to the grid. Therefore, performing voltage control at the point of common connection is now available without additional costs. Thus for improving voltage stability, renewable power plants should be equipped with voltage regulation systems. These systems should allow flexible reactive power output within a defined reactive power range. The SO must have control over the voltage regulation system." [59]

6.1.3.8. Power-frequency response

"Frequency response is a grid service performed by conventional generators. An internal power proportional controller allows increasing or diminishing generator power output according to power balance requirements. If the goal is to replace the majority of conventional production by renewable production, frequency regulation needs to be incorporated as a standard service in wind turbine operation. Otherwise it would be not possible to control the system frequency due to sudden change of demand of renewable generation. This capability is required to increase or decrease renewable power output according to system frequency changes. The system acts like the droop operation of conventional generators, decreasing its output proportional to system frequency increase. Above nominal frequency the power is curtailed. When the frequency deviation is below nominal value, the supplementary power delivered to the grid comes from the wind farm spinning reserve." [59]

6.1.4. The SA Renewable Energy Grid Code

"Renewable energy grid codes are basically a set of technical conditions and requirements to be followed when connecting generators to the grid. By complying with these rules the power plant ensures system stability when connected to the grid." [59]

The SAREGC was created in 2010 and provide mandatory minimum guidelines for RPPs to connect onto the transmission and distribution networks in South Africa. The code was developed to help the country deal with the influx for IPP generation sources and to ensure that the grid stability and quality of supply standards were maintained. Table 6.4 shows the different RPP categories in accordance with the SAREGC. Plants are classified according to their size and connection voltage level.

The SAREGC provides minimum technical requirements that any RPP needs to comply with prior to the Network Service Provider (NSP) allowing connection onto their grid. The NSP refers to local grid owner which is either Eskom or the Municipalities in the case of SA. However many utilities are not familiar with the SAREGC requirements or how to go about carrying out grid code compliance testing of these RPPs. For the purpose of this case study, the focus will be on the requirements for the connection of large utility scale (Category C) MV/HV connected RPPs. It must be further noted that the SAREGC requires all testing of RPP compliance to the code to be done at the Point of Connection (POC) and not at the generator terminals as required by certain international codes.

Table 6.4: SA Renewable Energy Grid Code Categories [16]

Category	Minimum Size (kVA)	Maximum Size (kVA)	Connection Level
A1	0	13.8	LV
A2	13.8	100	LV
A3	100	1000	LV
B	0	20000	MV
C	>20000		MV/HV

6.1.4.1. SAREGC RPP Plant Design Requirements

The SAREGC has many design and operation requirements from Category C RPPs which will be discussed in brief detail in this case study with some simplified testing methods which was developed and then utilised to test a newly built 25 MW wind farm to certify Grid Code compliance.

6.1.4.2. Tolerance to Voltage Deviations

The SAREGC requires Category C RPPs to be designed in order to operate continuously within the POC voltage range specified by U_{min} and U_{max} in Table 6.5.

Table 6.5: RPP continuous operating voltage limits [16]

Norminal (Un) [kV]	Umin (pu)	Umax (pu)
132	0.90	1.0985
88	0.90	1.0985
66	0.90	1.0985
44	0.90	1.08
33	0.90	1.08
22	0.90	1.08
11	0.90	1.08

6.1.4.3. Voltage Ride Through Capability

The capability of an RPP to be able to ride through voltage disturbances often caused by faults on the network is very important on the local network to ensure that stability of the grid is maintained at all times. Voltage-Ride-Through-Capability (VRTC) assists with preventing loss of generation on the network when a voltage disturbance is experienced on the network. Hence the code requires the RPP to be designed to withstand voltage drops to zero measured at the POC for a minimum period of 0.15 seconds. This ensures that should there be a fault or disturbance on the network, the network protection has adequate time to operate and isolate the problem circuit without the plant shutting down. Category C RPP plants are required to withstand voltage peaks up to 120% measured at the POC for a minimum period of 2 seconds. Should these over or under voltage violations exceed the voltage ride through time period then the plant may shut down. The required voltage operating capability of the RPP is shown in Figure 6.4 whilst Figure 6.5 shows the reactive power requirements from the RPP based on a function of the voltage.

VRTC, both Low Voltage Ride Through (LVRT) and High Voltage Ride Through (HVRT) is tested via a power systems simulation package such as DigSilent Power Factory to simulate the appropriate low and high voltage durations and scenarios to ensure that the plant remains connected to the grid in the event of a disturbance on the network.

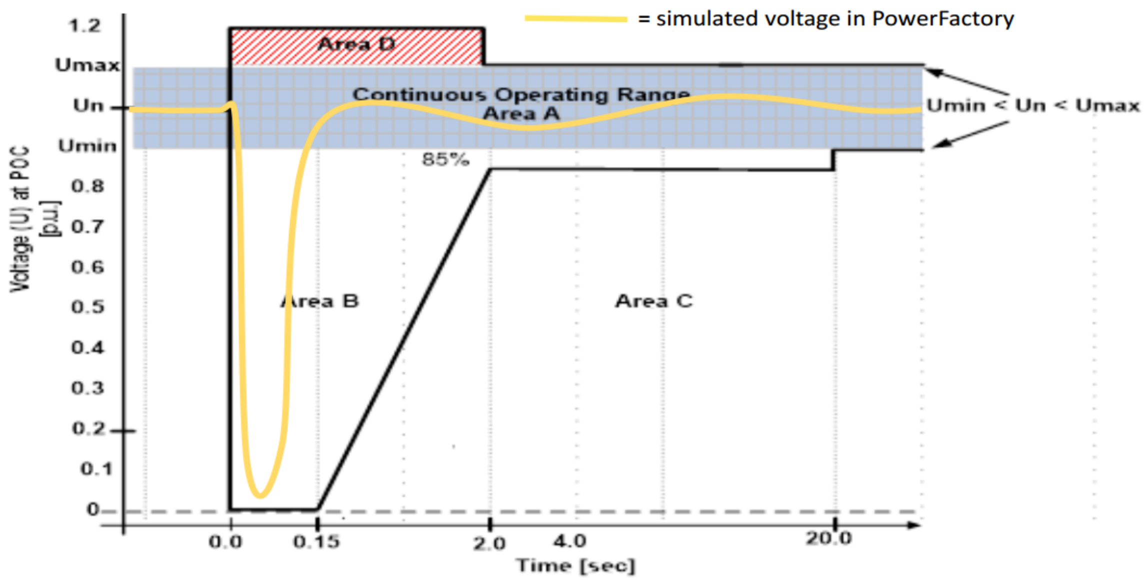


Figure 6.4: Example of VRTC for Category C RPP [20]

To check compliance, the IPP is required to provide the NSP with a type tested, manufacturer specific RMS model of their plant which can then be used to check how the plant behaves for different under and over voltage conditions on the network. Checks need to be done to ensure that no disconnection of the plant occurs as long as the POC voltage remains within the lower and upper limit curve (area A, B and D) in Figure 6.4. Figure 6.4 shows the simulation results for a voltage ride through test.

The SAREGC requires the RPP to either supply or absorb reactive current based on the function of the POC voltage (LVRT or HVRT) level following a network incident. It looks at two cases, a case of over voltage and a case of under voltage at the POC. Figure 4.70 shows the Area A which is normal operating area (0.9 ≤V≤ 1.1), Area B (0.9 <V≤ 0.2), and Area E (V<0.2), where reactive current support is required to help in stabilizing the voltage whilst Area D (V>1.1) requires reactive current absorption to assist in reducing the voltage. [18]

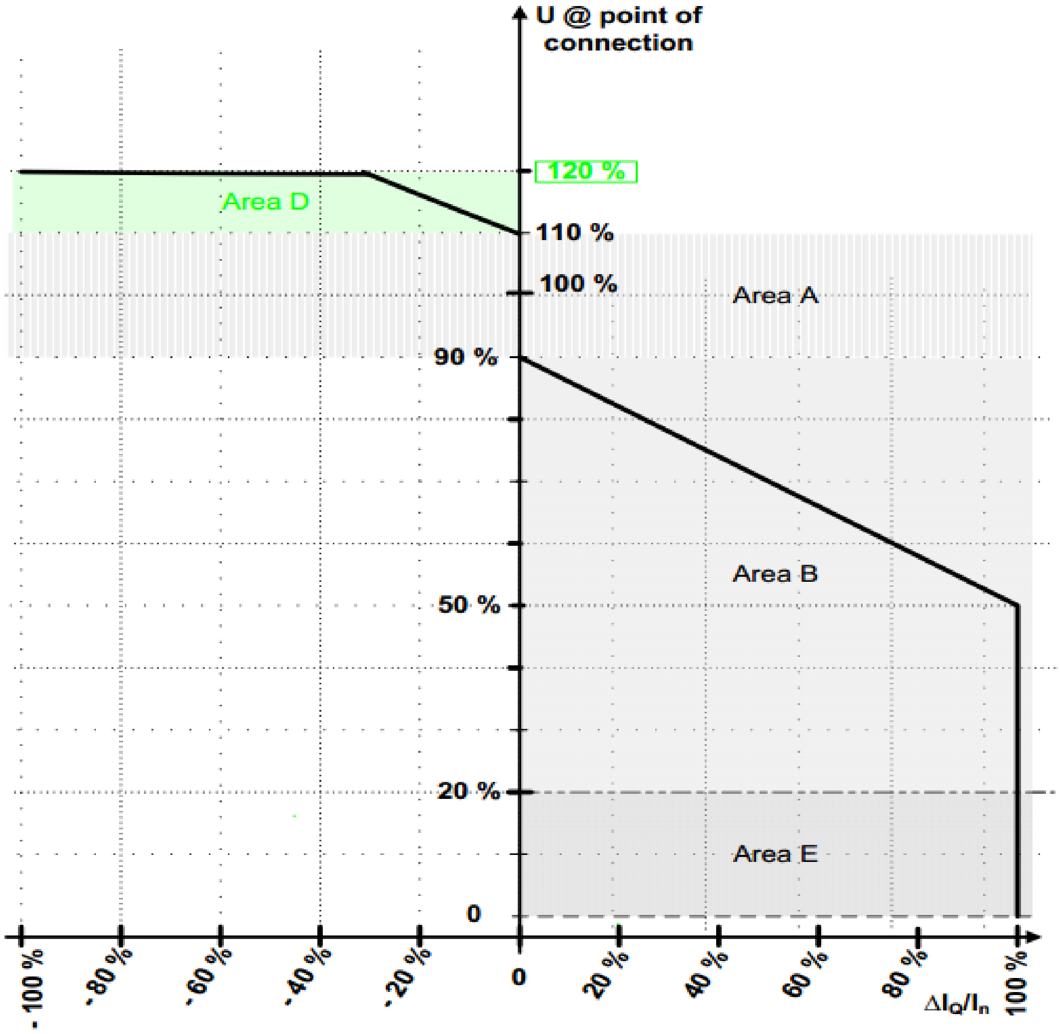


Figure 6.5: Reactive power requirements during voltage drops or peaks from Category C RPP [19]

6.1.4.4. Tolerance to Frequency Deviations

The Renewable Power Plant (RPP) is required to be designed to operate continuously from 49 – 51 Hz and the plant must be able to withstand phase jumps of up to 20°. However, if the frequency is higher the 51.5 Hz for greater than 4 seconds or less than 47 Hz for greater than 200 milliseconds then the plant is allowed to disconnect from the network as depicted in Figure 6.6 This simulates an over frequency and under frequency event on the grid. [18]

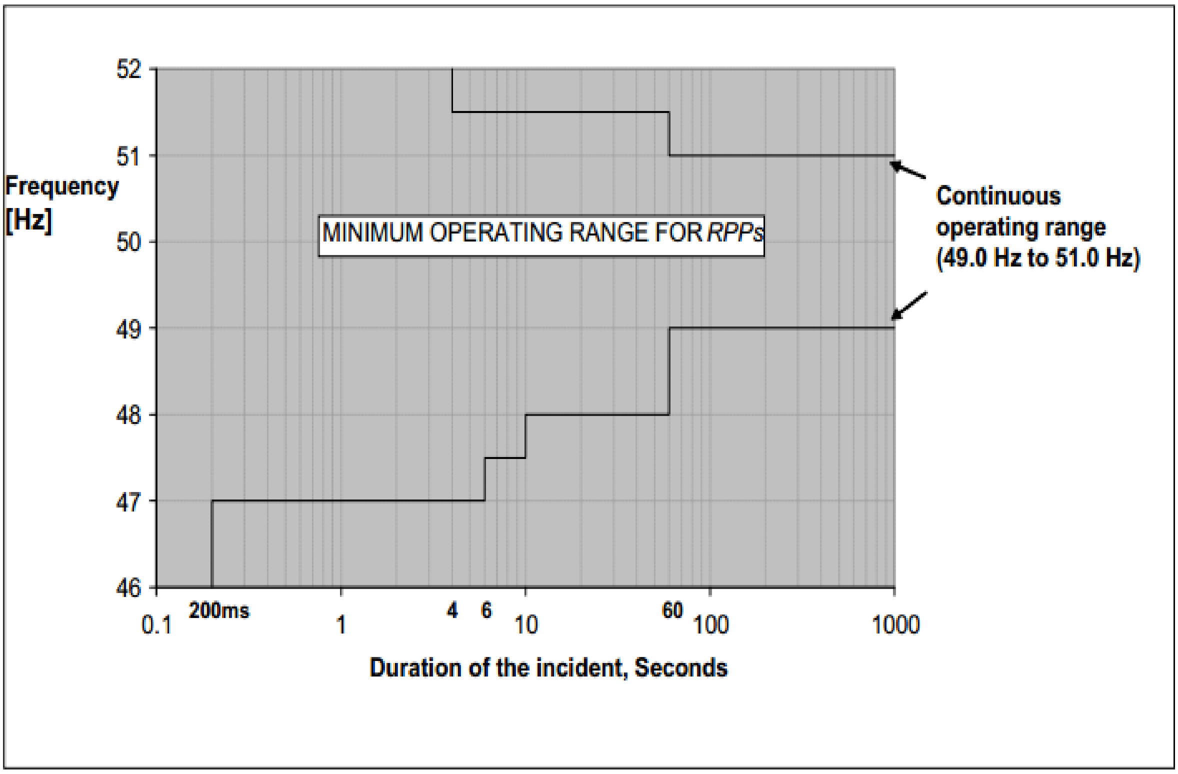


Figure 6.6: Minimum RPP plant frequency operating range [19]

6.1.4.5. Frequency Response Requirements

Figure 6.7 shows that frequency response requirement from a catergory C RPP. Frequency F2 to F3 forms a dead band where there is no requirements from the plant whilst F1 and F4 forms a Control Band. Once the frequency exceed F2, indicating an under frequency event (the load exceeds the network generation) and the plant is required to injected P_{Delta} into the network to assist in stabilizing the frequency. The plant is required to follow the Droop 1 setting on the network. Where droop is defined as “a percentage of the frequency change required for an RPP to move from no-load to rated power or from rated power to no-load.” [18] All RPPs shall be equipped with frequency controlled droop settings which shall be adjustable between 0% and 10%. During an over frequency event, the network frequency will exceed F3 (there is more generation than load on the network), the plant is required to follow the Droop 2 setting. This dictates the reduction in power required from the RPP for a change (increase) in frequency. Figure 6.7 and Table 6.6 indicates the required default plant frequency settings. [18]

Comparing P_{Delta} requirement to international practice, substantial differences can be identified: [59]

(a) Germany: The provision of primary reserves is only required for plants with a rating of 100MW or more, unless otherwise specified. It is not required from wind farms. [59]
(b) UK: Wind farms above 50MW must have the technical capability for providing primary frequency control. The actual provision of primary reserve is paid for as an ancillary service. [59]

In most countries, there is no requirement for the provision of primary control functionality from renewable generators. The main reason for this is that, unlike in conventional plants, limiting the active power does not lead to cost savings (the “fuel” is free), i.e. any limitation of active power (which is required for primary frequency control) is equivalent to unsupplied energy. Hence, as long as it is possible to deliver the required primary frequency control reserve by conventional, fossil fuelled generators, wind farms or solar plants should not be requested to contribute to primary reserves for economic reasons. Primary control reserves from wind farms and solar plants should only be required if the conventional generation cannot provide sufficient primary reserves. However, that would only occur under very high penetration levels of renewable generation. Currently in SA, there is a requirement for P_{Delta} from wind farms and other renewable energy generation sources with the exception of solar PV. RPPs are paid for the P_{Delta} reserve margin. [59]

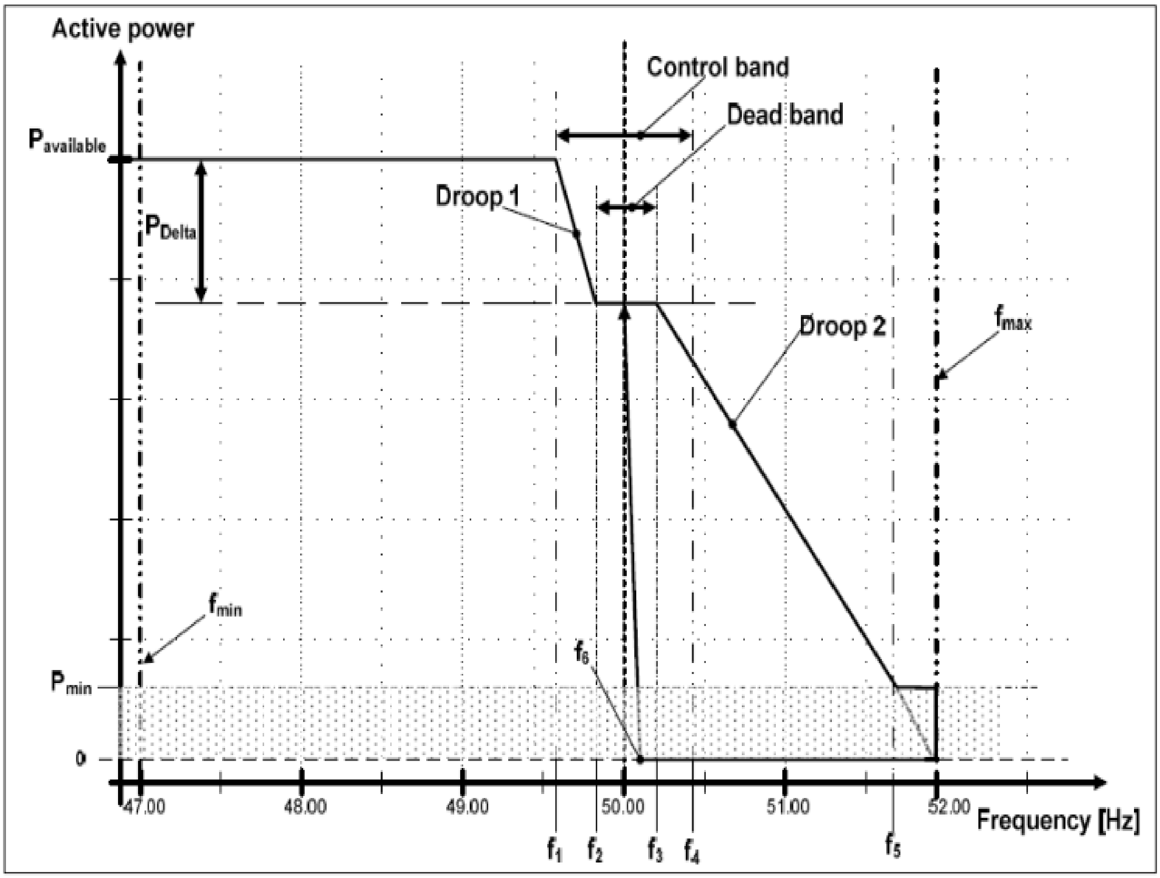


Figure 6.7: Frequency response requirement for Category C plant [19]

Frequencies f_1, f_2 and f_3 shown in Figure 6.7 and Table 6.6 will be set and agreed by the IPP and the SO.

Table 6.6: Required frequency default settings [18]

Parameter	**Magnitude**
f_{min}	47
f_1	As agreed with the SO
f_2	As agreed with the SO
f_3	As agreed with the SO
f_4	50.5
f_5	51.5
f_6	50.2
f_{max}	52

To prove grid code compliance to the frequency response curve in Figure 6.7, a frequency generator is required to inject the frequencies shown in Table 6.6. This is done to simulate an under frequency event on the grid to check if the RPP behaves according to the requirements of Figure 6.7 in an under frequency situation. At the start of the test, select a value for P_{Delta} (P_{Delta} shall be minimum 3% of $P_{Available}$) which is a percentage of $P_{Available}$ and a suitable

Droop 1 and Droop 2 (value range from 0 to 10% although Droop 1 is usually selected at 4% and Droop 2 at 8% for testing purposes). Carry out the 5 tests depicted in Table 6.7 and record the results. “Compliance of the tests is determined if the recorded results after 10 seconds is within ±2% of the set point value or ±5% of the rated power, depending on which yields the highest tolerance.” [18]

Table 6.7: Test for under frequency response [18]

Set value of P_{delta}:		_________% of $P_{available}$
Set value of Droop 1:		_________ %
	Change Frequency	
Test	**From**	**To**
1st test	50.00 Hz	49.85 Hz
2nd test	49.85 Hz	49.50 Hz
3rd Test	49.50 Hz	49.00 Hz
4th Test	49.00 Hz	48.00 Hz
5th Test	48.00 Hz	50.00 Hz

The under frequency testing was then carried out on the wind farm and the results then recorded in Table 6.8 and Figure 6.8. The droop for the test was set to 4% with a P_{Delta} of 10%. Before the test commenced $P_{Available}$ at 50Hz was 20 MW. For the under frequency test, the frequency was dropped from 50Hz down to 48 Hz in steps as stipulated in Table 4.38. Figure 6.8 indicates that during the test, at 49.5 Hz, the plant activates its under frequency response mode and supply P_{Delta} as required in order to try and stabalise the frequency and remains in this mode supplying P_{Delta} until the frequency returns to 50 Hz when it then deactivates. From the result recorded (Table 6.8 and Figure 6.8), the plant performed as required in the under frequency event and hence passed the test.

Table 6.8: Testing of Frequency Control on the 25 MW wind farm with 4% Droop

Set value of Pdelta to	10%	of Pavailable:	2.00MW	Pavailable	20.00 MW		
	Set value of Droop 1:			4%			
	at start; direct before setting			at 10 s after setting the new frequency value[2)]			
Column1	Actual P [MW]	Simulated Grid Frequency [Hz]	$P_{available}$ [MW]	Actual P [MW]	Simulated Grid Frequency [Hz]	$P_{available}$ [MW]	
1st test Frequency from 50 Hz to 49.85 Hz	17.60MW	50.0Hz	20.00MW	19.00MW	49.85Hz	20.80MW	
2nd test Frequency from 49.85 Hz to 49.5 Hz	19.00MW	49.85Hz	20.80MW	19.50MW	49.50Hz	19.70MW	
3rd Test Frequency from 49.5 Hz to 49.0 Hz	19.50MW	49.50Hz	19.70MW	19.80MW	49.0Hz	19.81MW	
4th Test Frequency from 49.0 Hz to 48.0 Hz	19.80MW	49.00Hz	19.81MW	21.00MW	48.0Hz	21.30MW	
5th Test Frequency from 48.0 Hz to 50 Hz	21.00MW	48.00Hz	21.30MW	19.10MW	50.0Hz	20.99MW	

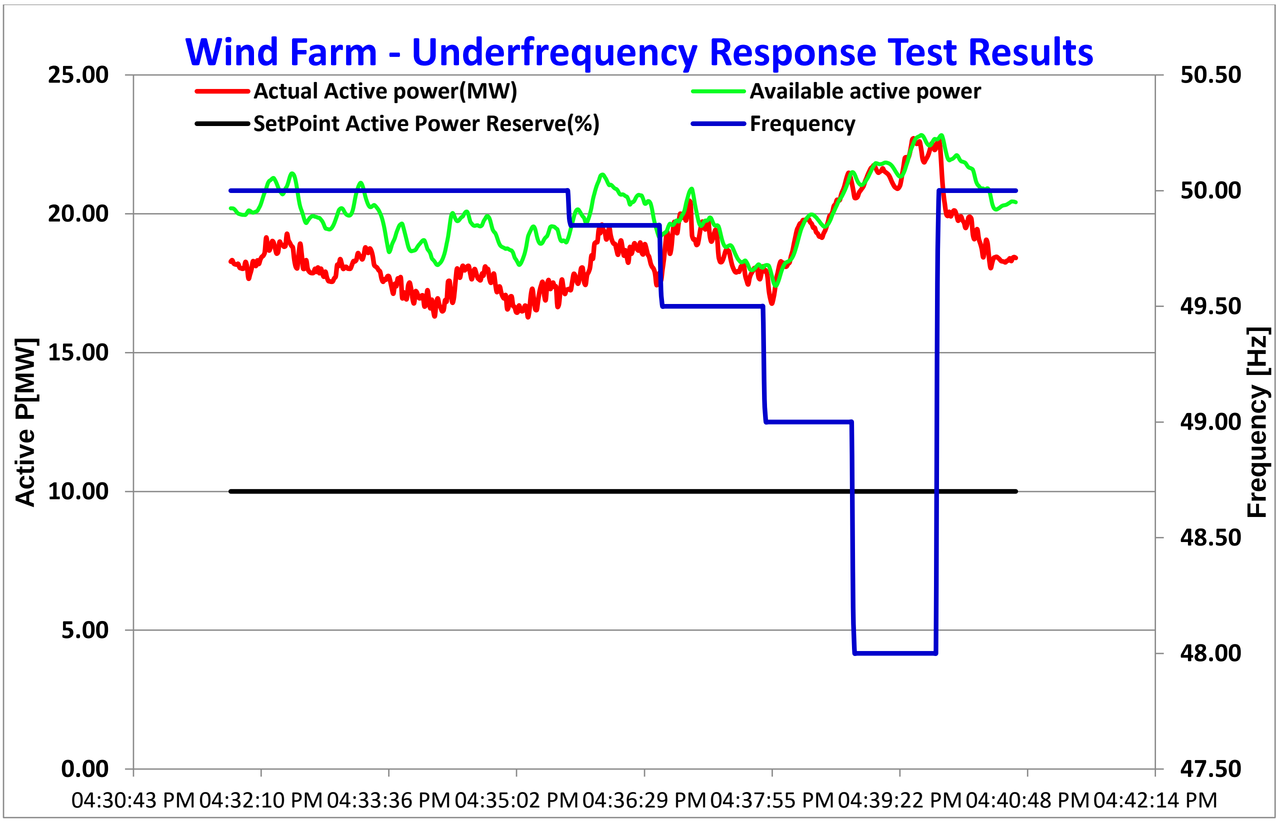


Figure 6.8: Graphical representation of the wind farm under frequency response test results

To simulate an over frequency event on the grid to check if the RPP behaves according to the requirements of Figure 6.7 in an over frequency situation. Select a suitable Droop 2 and use a frequency generator to simulate the frequencies in Table 6.6. This is done by carrying out the 5 tests depicted in Table 6.9 and record the results to ensure that the RPP respond within the required time and accuracy to check compliance.

Table 6.9: Test for over frequency response [18]

Set value of Droop 2:		________%
	Change Frequency	
Test	**From**	**To**
1st test	50 Hz	50.50 - 50.55 Hz
2nd test	51.00	51.05 Hz
3rd Test	51.10	51.20 Hz
4th Test	51.35	51.45 Hz
5th Test	Back to 50 Hz	

The over frequency testing was then carried out on the wind farm and the result obtained from the testing was recorded in Table 6.10 and Figure 6.9. For the test, the frequency was increased in steps from 50Hz to 52 Hz as per the requirements in Table 6.9. The wind farm then managed to reduce its power output with an increase in frequency as required. The plant then shut off at 52 Hz as required and then returned to successful operation when the frequency returned to 50 Hz. Hence the wind farm passed the Frequency Response Test.

Table 6.10: Wind farm over frequency test results

Set value of P_{delta}: 10% and Pavailable =						21.50MW
	Set value of Droop 2:			4		%
	at start; direct before setting			at 10 s after setting the new frequency value[2)]		
Column1	Actual P [MW]	$P_{available}$ [MW]	Frequency [Hz]	Actual P [MW]	Pavailable [MW]2	Frequency [Hz]4
1st test Frequency from 50 Hz to 50.50-50.55 Hz	21.00MW	21.50MW	50.0Hz	21.69MW	21.80MW	50.52Hz
2nd test Frequency to 51.00 Hz - 51.05 Hz	21.69MW	21.80MW	50.52Hz	12.33MW	18.89MW	51.03Hz
3rd Test Frequency to 51.10 Hz - 51.20 Hz	12.33MW	18.89MW	51.03Hz	11.72MW	20.74MW	51.15Hz
4th Test Frequency to 51.35- 51.45 Hz	11.72MW	20.74MW	51.15Hz	8.30MW	20.57MW	51.40Hz
5th Test Frequency back to to 50 Hz	8.30MW	20.57MW	51.4Hz	21.14MW	21.41MW	50.00Hz
6th Test Frequency to 50- 52 Hz	21.14MW	21.41MW	50.00Hz	-0.48MW	0.00MW	52.00Hz
7th Test Frequency 52Hz - 51Hz	-0.48MW	0.00MW	52.00Hz	15.50MW	23.07MW	51.00Hz
8th Test Frequency to 51 Hz- 50.5 Hz	15.50MW	23.07MW	51.00Hz	23.24MW	23.50MW	50.50Hz

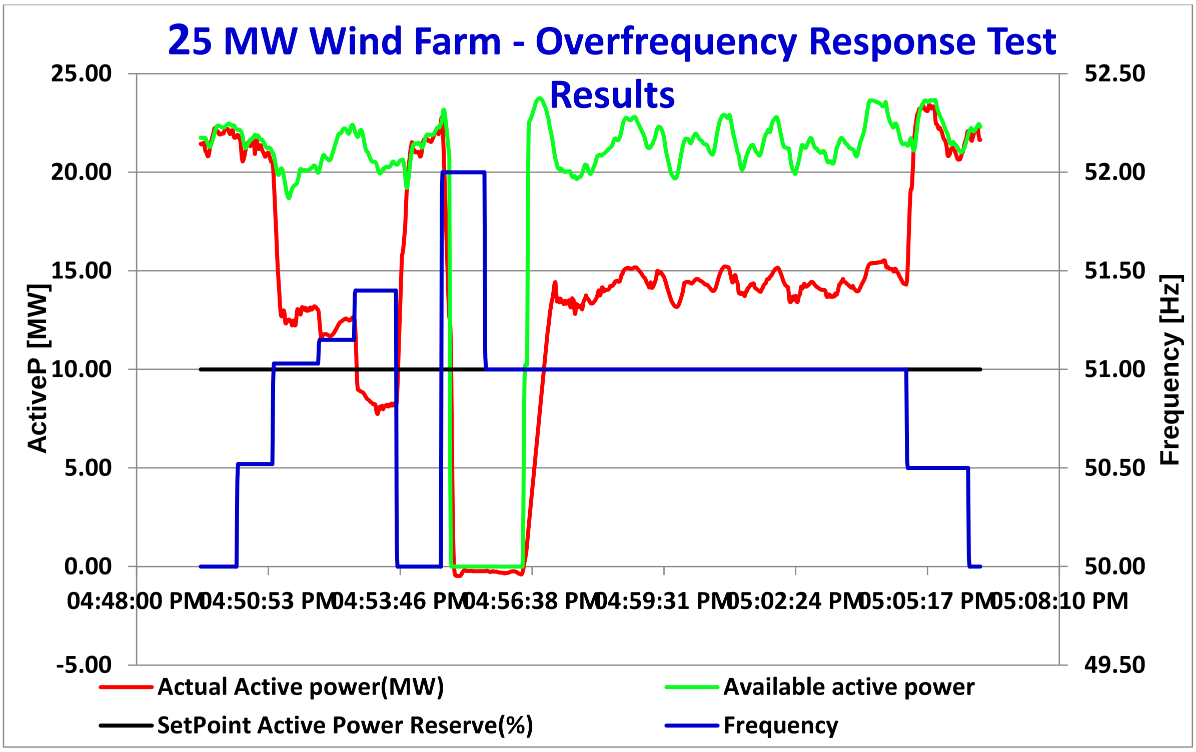


Figure 6.9: Graphical representation of the wind farm over frequency response test results

6.1.4.6. Control Functions Required For RPP

The RPP is required to have the following control functions as shown in Table 6.11.

Table 6.11: Control functions required for RPPs [19]

Control Function	Category C
Frequency Control	x
Absolute Production Constraint	x
Delta Production Constraint	x
Power Gradient Constraint	x
Reactive Power (Q) Control	x
Power Factor Control	x
Voltage Control	x

6.1.4.7. Reactive Power Capability

The grid code specifies the reactive power requirements from Category C plant [$-0.33 \leq (Q/P_{Max}) \leq 0.33$] measured at the POC. This is shown in Figure 4.75.

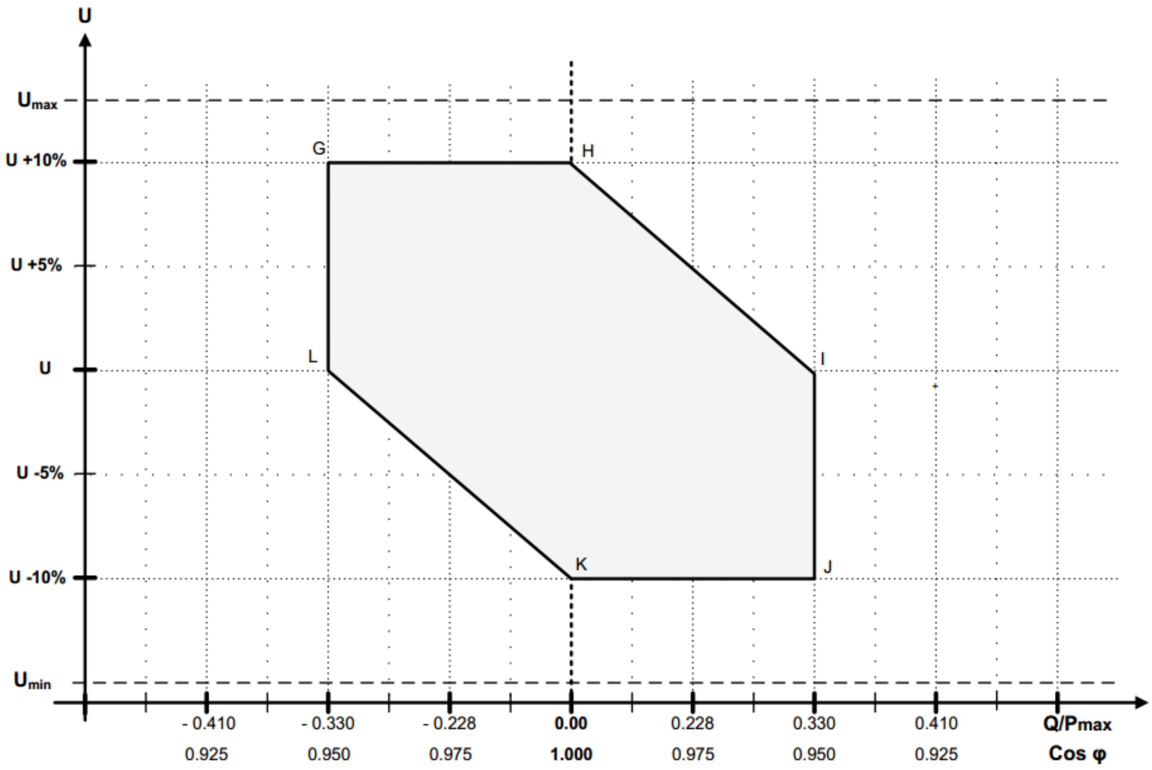


Figure 6.10: Reactive power requirements [20]

To check grid code compliance of RPPs with regards to reactive power requirements, tests and measurements shall be carried out in accordance to the Table 6.12 and Table 6.13 which is for the case of U = 1 pu. If U is not equal to 1 pu then the plant shall operate in accordance to Figure 6.10. The measured values shall be recorded after 30 seconds after receipt of the set point to a measured accuracy to the higher value of either ±2% of the set-point value or ±5% of maximum reactive power.

Table 6.12: Reactive Power Q Control Test at $P_{Available}$ [18]

Reactive Power Control – Fixed Q At $P_{Available}$
$P = P_{Available}$
Q = 0 Mvar
Q_{max}=0.33 P_{max} (overexcited)
Q = 0 Mvar
Q_{max}=0.33 P_{max} (underexcited)
Q = 0 Mvar

The reactive power control capability test was then carried out on the wind farm to check the farms response to the reactive power requirement. The test was first carried out from $P_{Available}$ ≥ 20%. Here we test the farms ability to inject or absorb maximum reactive power when required. Results from the testing is then shown in Table 6.13 and Figure 6.11. From the results obtain, it can be seen that the plant passes the tests as it responds within the required time period and accuracy limits.

Table 6.13 Reactive power capability test on the 25 MW wind farm at $P_{Available}$

Pmax (Plant Rating)	23.28MW		Preference:	18.00MW

SetPoints	Set point Q [Mvar]	Actual Q value	Actual P value	Response time [s]	Measured Accuracy [Kvar]	Accuracy Max allowed [Kvar]	Comments
		Q [Mvar]	P [MW]				
Q = 0 Mvar	0.00	-0.010	18.50MW	30s	10	116.4	Tolerance Acceptable
Qmax=0.33*Pmax (overexcited)	7.65	7.60	18.00MW	30s	50	153	Tolerance Acceptable
Q=0 from 0.33*Pmax (overexcited)	0.00	0.07	16.99MW	30s	70	116.4	Tolerance Acceptable
Qmax=0.33*Pmax (underexcited)	-7.65	-7.64	18.31MW	30s	1.000E+01	153	Tolerance Acceptable
Q=0 from 0.33*Pmax (underexcited)	0.00	0.04	17.88MW	30s	40	116.4	Tolerance Acceptable

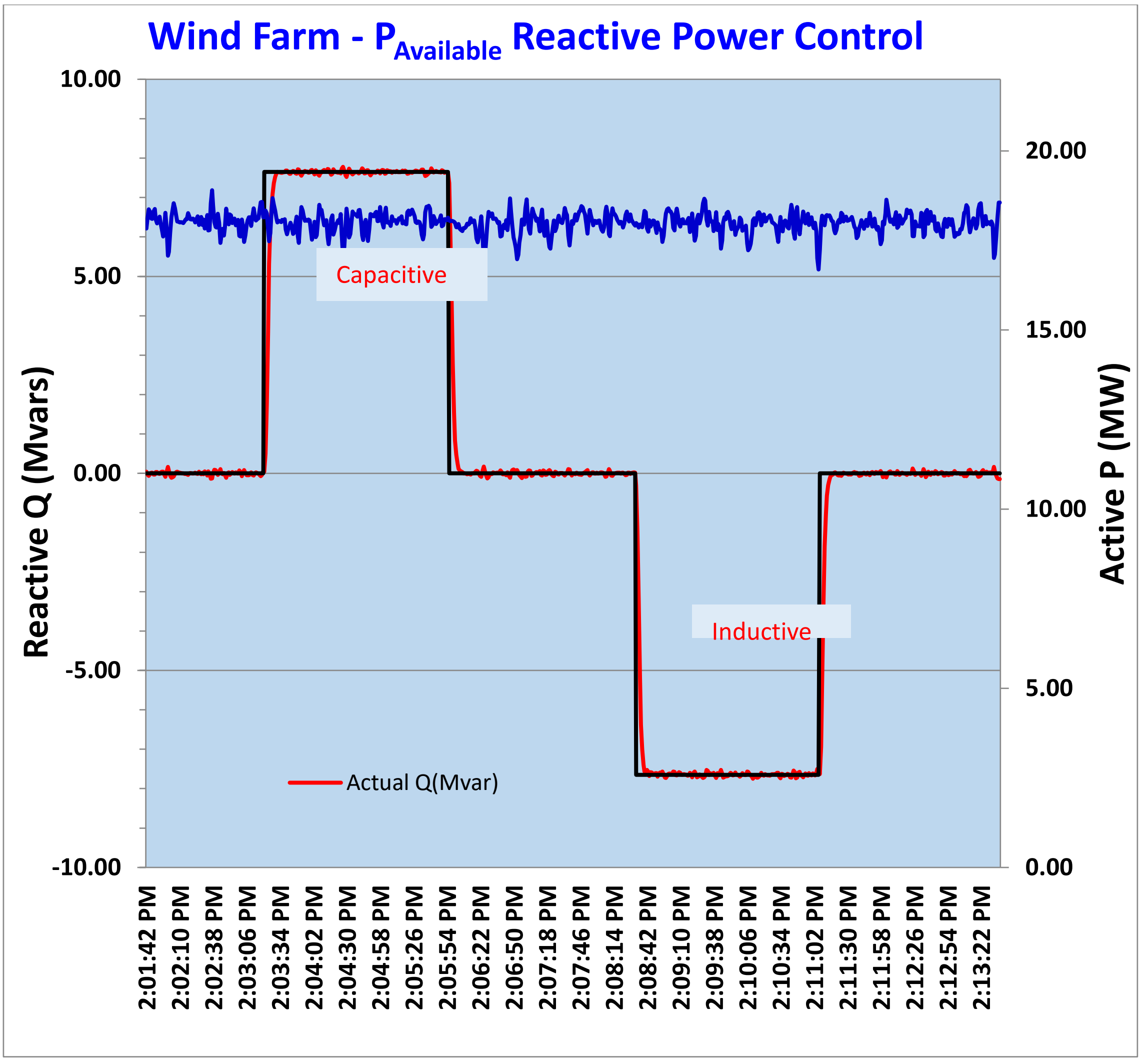


Figure 6.11: Reactive Power Q Control test results at $P_{Available}$

The second test is required to be carried out at 20% P_{Max}. We then check the farms ability to inject and absorb maximum reactive power should this be required by the SO. The set points issued is shown in Table 6.14 whilst the results from the wind farm testing is then shown in Table 6.15 and Figure 6.12. From the results obtain, it can be seen that the plant passes the tests as it responds within the required time period and accuracy limits.

Table 6.14: Reactive power capability test on the 25 MW wind farm at $P_{Available}$ [18]

Reactive Power Control – Fixed Q At 20% P_{max}
Q = 0 Mvar
Q_{max} over excited
Q = 0 Mvar
Q_{max} under excited
Q = 0 Mvar

Table 6.15: Reactive power capability test result on the 25 MW wind farm at 20% P_{Max}

20%	Pmax	4.656

SetPoints	Set point Q [Mvar]	Actual Q value	Actual P value2	Response time [s]	Measured Accuracy [Kvar]	Accuracy Max allowed [Kvar]	Comments
		Q [Mvar]	P [MW]				
Q = 0 Mvar	0.00	0.000	4.66MW	30s	0	116.4	Tolerance Acceptable
Qmax=0.33*Pmax (overexcited)	7.65	7.65	4.66MW	30s	0	153	Tolerance Acceptable
Q=0 from 0.33*Pmax (overexcited)	0.00	0.01	4.66MW	30s	10	116.4	Tolerance Acceptable
Qmax=0.33*Pmax (underexcited)	-7.65	-7.65	4.66MW	30s	0.000E+00	153	Tolerance Acceptable
Q=0 from 0.33*Pmax (underexcited)	0.00	0.00	4.67MW	30s	0	116.4	Tolerance Acceptable

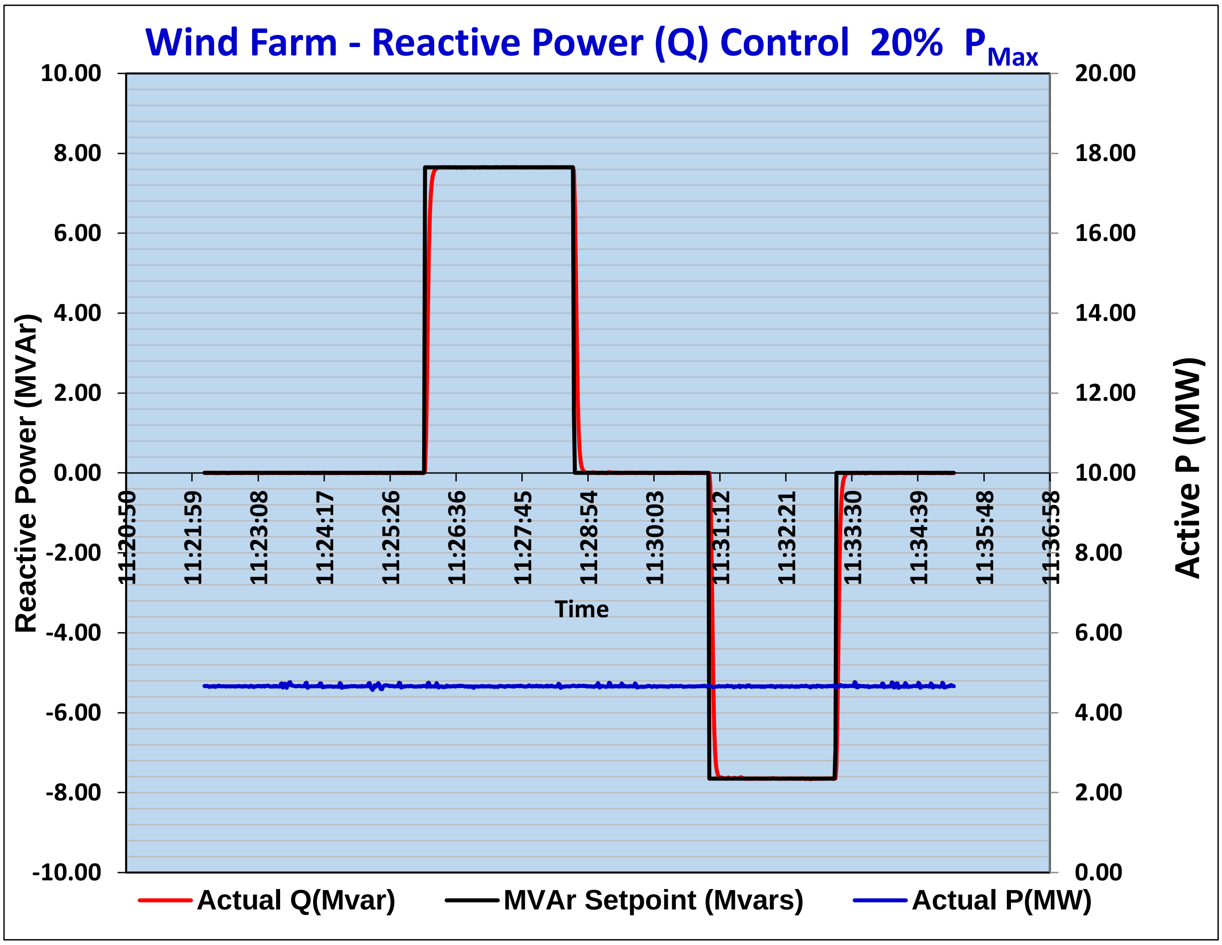


Figure 6.12: Reactive Power Q Control test results at 20% P_{Max}

6.1.4.8. Power Factor Control Function

Category C: Shall be designed to operate from 0.95 lagging to 0.95 leading Power Factor, measured at the POC from 20% and above of the rated power. The RPP is required to respond within 30 seconds of receipt of the set point to a measured accuracy of ±0.02 in order to pass the test. The test that needs to be carried out is shown in Table 6.16 which tests the plants ability to meet the required Power Factor values in Figure 6.13. The plant must be able to provide the required Power Factor from $P \geq 20\% \; P_{Max}$. [18]

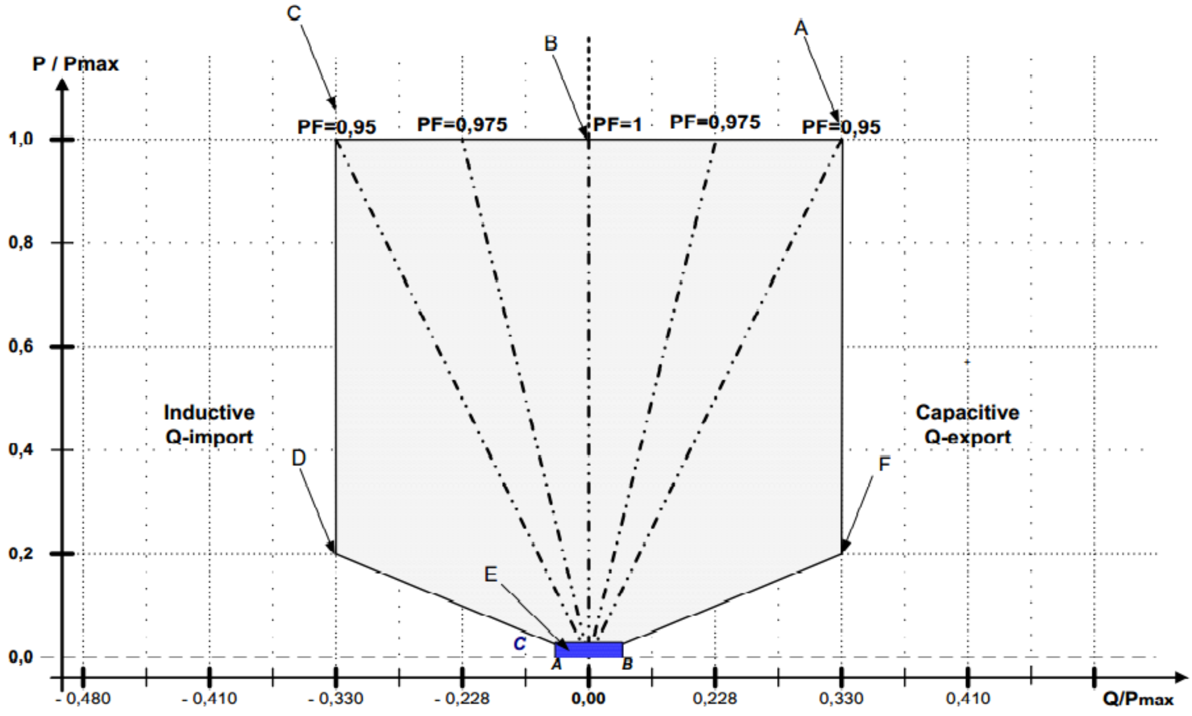


Figure 6.13: Power Factor requirements from RPP [20]

Table 6.16: Power Factor Control function test [18]

Reactive Power Control – Fixed Cos (φ)
Pf Set point
PF= 1
0.95 overexcited (Category C only)
PF= 1
0.95 under excited (Category C only)
PF= 1

The Power Factor Control Function testing was then carried out on the Wind Farm. Table 6.17 and Figure 6.14 shows the results obtained for the Power Factor test on the wind farm. The plant responded and was successful in reaching both the 0.95 inductive and capacitive requirements within the required time and accuracy limits. The farm hence passed the Power Factor Control Function test.

Table 6.17: Power Factor Control function test results from the 25 MW wind farm

Reactive power control – fixed cos (φ) Reactive power testing at different values of displacement factor						
Default value by SO	Actual value Q [Mvar]	Actual value P [MW]	Actual value cos φ	Response time [s]	Accuracy	Calcutated cos φ
PF= 1	-0.04	16.50MW	1	30	Tolerance Ok	1.000
PF= 0.95 underexcited	-6.82	18.83MW	-0.950	30	Tolerance Ok	-0.940
PF= 0.95 overexcited	5.77	17.70MW	0.950	30	Tolerance Ok	0.951

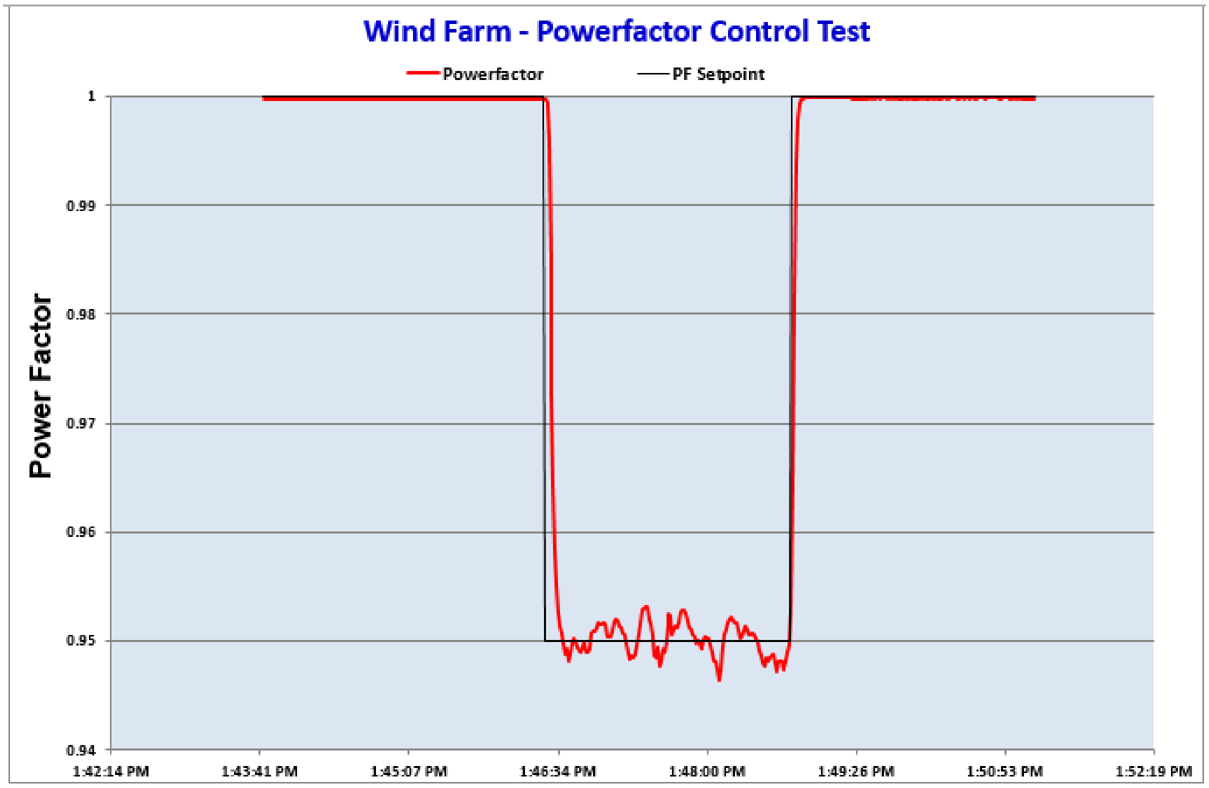


Figure 6.14: Power Factor Control function graphical results (unity to 0.95) from the 25 MW wind farm

6.1.4.9. Voltage Control Functions

The voltage control function for RPPs is depicted in Figure 6.15. If the RPP voltage set point is to be changed, a set point is issued and the change needs to be implemented within 30 seconds with the accuracy of ±0.5% of $V_{Norminal}$ whilst the accuracy of ±2% of the required injection or absorption of reactive power according to the defined droop characteristic. The tests to be carried out are depicted in Table 6.18 and Table 6.19 using 4% and 8% droop.

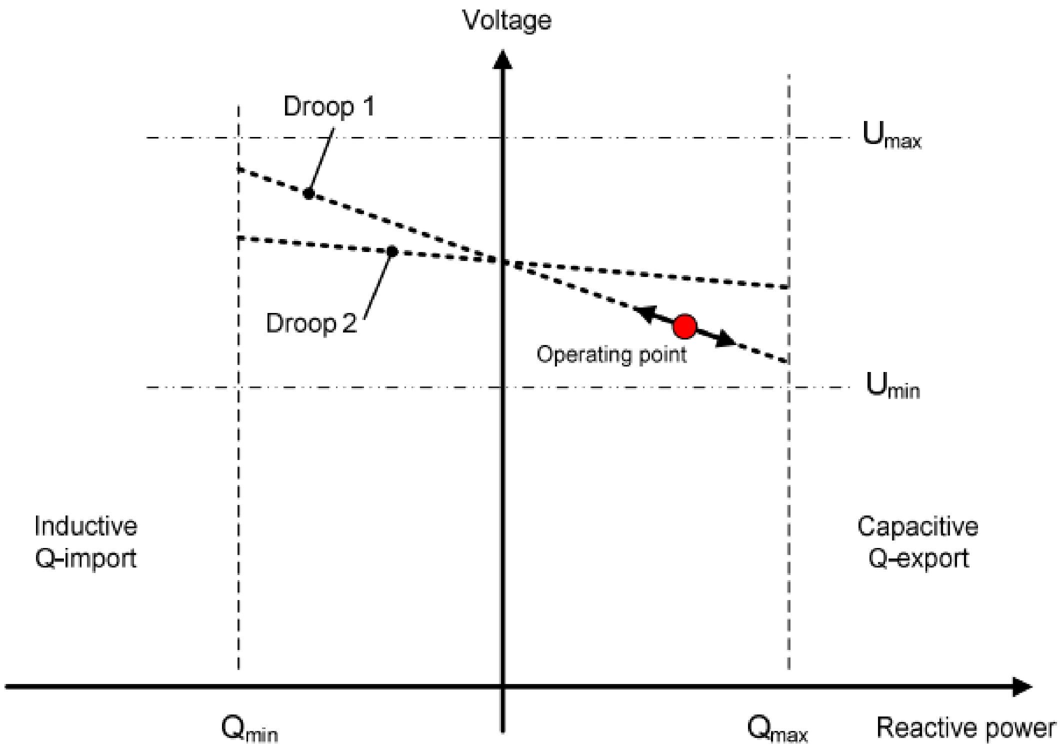


Figure 6.15: Voltage Control for RPPs [20]

Table 6.18: Voltage Control Function Test with 4% droop [18]

Reactive power control – Q(U) characteristic **Test 1:** Set the Droop to 4%: (Q_{max})/4% U_n Reactive power testing at different values of active power
Nominal voltage
1.02 of Un
0.98 of Un
Nominal Voltage

Table 6.19 Voltage Control Function Test with 8% droop [18]

Reactive power control – Q(U) characteristic **Test 2:** Set the Droop to 8%: (Q_{max})/8% U_n Reactive power testing at different values of active power
Nominal voltage
1.04 of Un
0.96 of Un
Nominal voltage

The Voltage Control Function test in Table 6.18 for 4% Droop was carried out on the wind farm and the results were recorded in Table 6.20 and Figure 6.16. The Voltage Control Function test in Table 6.19 for 8% Droop was then carried out and the results recorded in Table 6.21 and Figure 6.17. Upon commencement of this test, the $P_{Available}$ of the farm was at 14 MW. The voltage at the point on connection was already higher (135.6 kV) at 0 MVAr in comparison to $V_{Nominal}$ which was meant to be 132 kV. Hence this affected the tests on the wind farm. The farm could not reach the required set point voltages but it supplied and absorbed the correct amount of reactive power for the voltages that was experienced at the time.

Table 6.20: Voltage Control Function Test results with 4% droop

Test 1						
Set the Droop to 4%: (Q_{max_ue}+ Q_{max_oe})/4% U_n						
4% Droop	1.42Mvar/kV		Calculated Droop	6.48Mvar/kV		
Reactive Power Control – Q(U) characteristic						
Reactive power testing at different values of active power						
Voltage setpoint at the PPC	Set point		Actual values		Response time [s]	Measurement file
	U [kV]	Q [Mvar]	U [kV]	Q [Mvar]		
Nominal voltage	67.80kV	0.00Mvar	67.78kV	0.01Mvar	30	
1.02 of Un	69.20kV	2.84Mvar	68.22kV	2.86Mvar	30	
0.98 of Un	66.40kV	-2.68Mvar	67.28kV	-2.54Mvar	30	

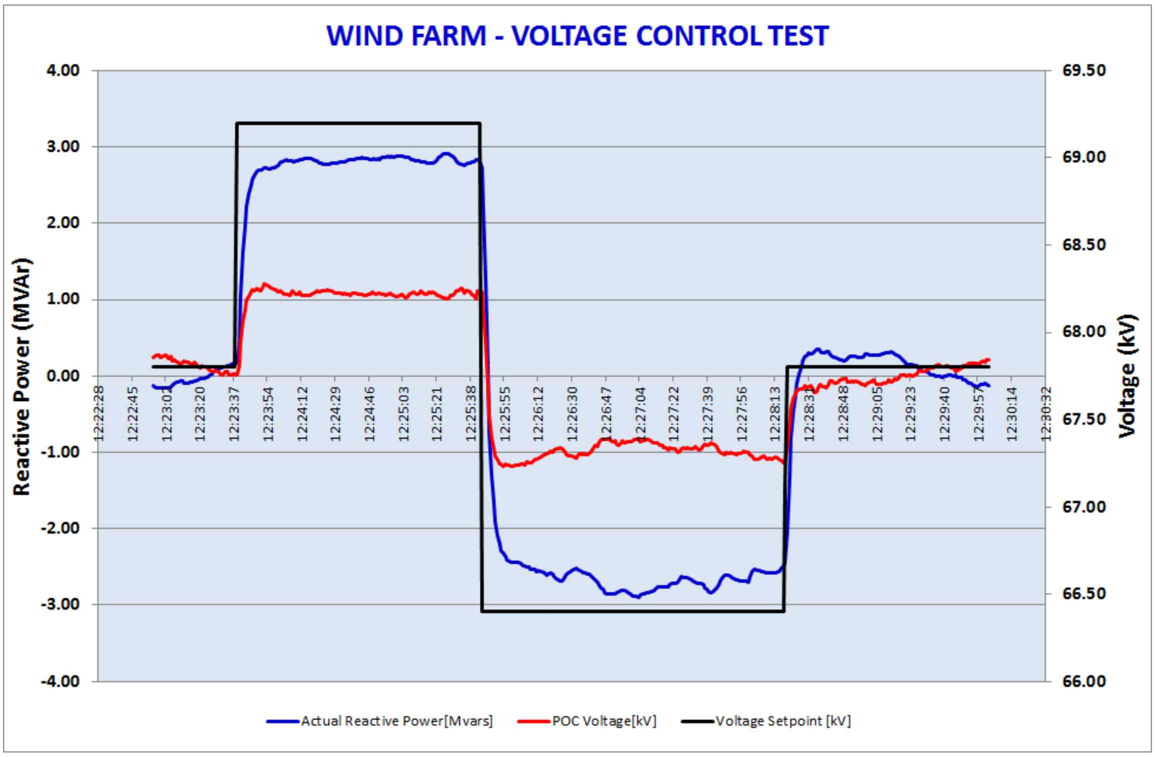


Figure 6.16: Voltage Control Function graphical test results with 4% droop

Table 6.21: Voltage Control Function Test Results with 8% droop

Test 2:						
Set the Droop to 8%: (Q_{max_ue}+ Q_{max_oe})/8% U_n						
8% Droop	0.71Mvar/kV		Calculated Droop	1.73Mvar/kV		
Reactive Power Control – Q(U) characteristic						
Reactive power testing at different values of active power						
Voltage setpoint at the PPC	Set point		Actual values		Response time [s]	
	U [kV]	Q [Mvar]	U [kV]	Q [Mvar]		
Nominal voltage	68.10kV	0.00Mvar	68.14kV	-0.04Mvar	30	
1.04 of Un	70.80kV	2.93Mvar	68.78kV	2.92Mvar	30	
0.96 of Un	65.40kV	-2.20Mvar	66.91kV	-2.17Mvar	30	

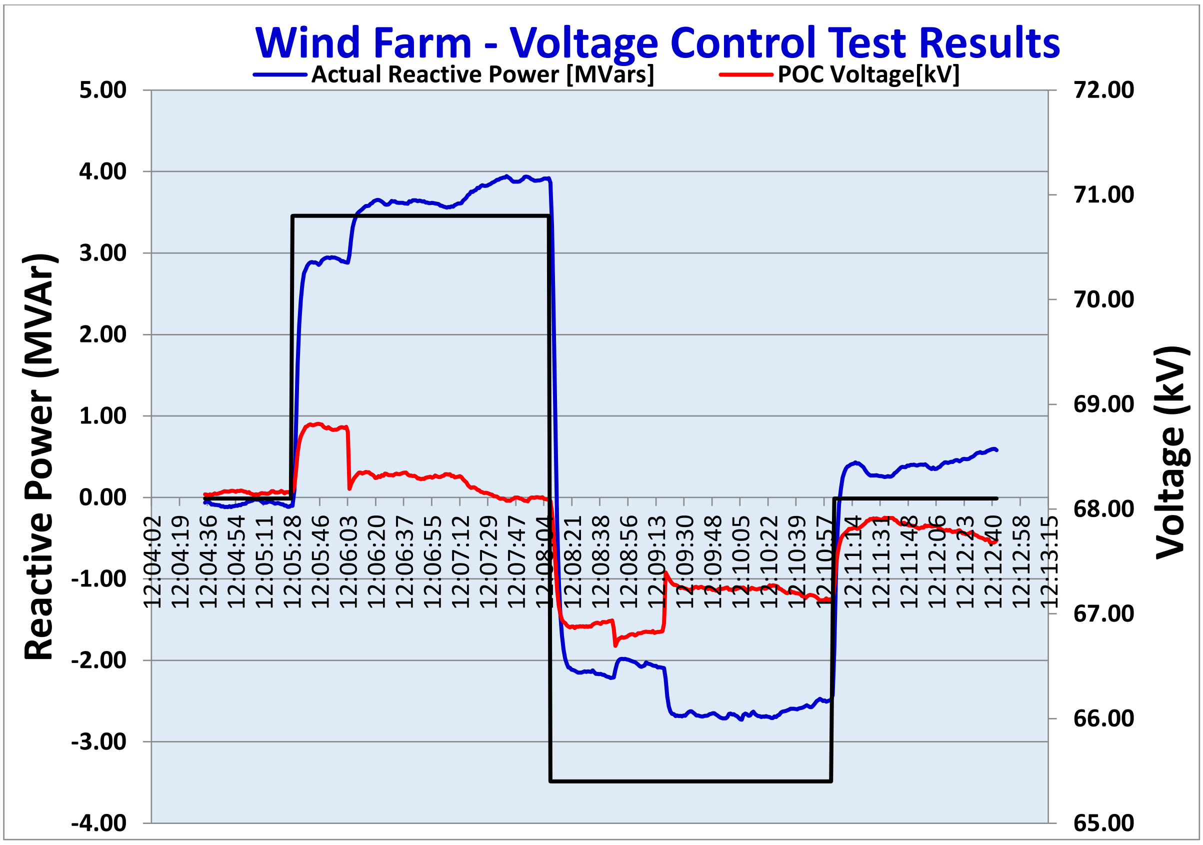


Figure 6.17: Voltage Control Function graphical test results with 8% droop

6.1.4.10. Power Quality

Power Quality is required to be monitored at the POC and the following parameters shall be monitored:

(i) Rapid voltage change

(ii) Flicker

(iii) Harmonics

(iv) Unbalance voltage and current

These Power Quality (PQ) parameters can be checked utilizing the type tested, manufacturer specific model in a Power Systems simulation package prior to the construction of the RPP. Post construction of the RPP, on site PQ meters can be installed to gather the data which can then be utilized to check compliance against values given to the IPP by the NSP. The PQ limits given by the NSP to the IPP are apportioned values which takes the PQ limits given in South African National Rationalisation Standard 048 and apportioned to the upstream contribution together with current and future customers' contribution limits. If the plants violates the PQ limits, then the IPP will need to design filters to be installed to ensure compliance. [20]

6.1.4.11. Active Power Constraint Function

For reasons of system security, the RPP may be requested to curtail active power output when requested by the SO. Hence the RPP shall have the following active power constraint functions shown in Figure 6.18.

1. Absolute Production constraint
2. Delta Production constraint
3. Power Gradient constraint

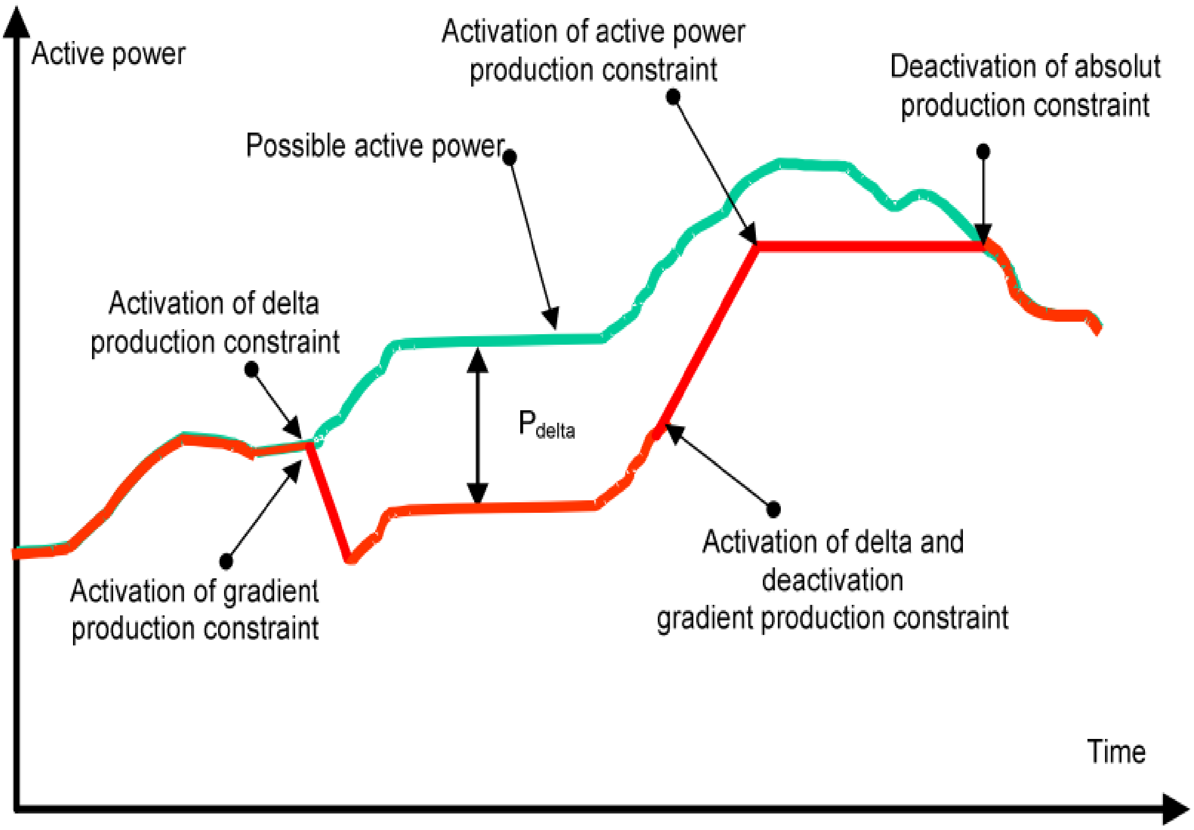


Figure 6.18: Required RPP active power control functions [18]

6.1.4.12. Absolute Power Constraint Function

"An Absolute Production Constraint is used to constrain the output active power from the RPP to a predefined power MW limit at the POC. This is typically used to protect the network against overloading." [18] In order to check compliance of the RPP to the Absolute Production Constraint function, the plant shall be tested as per Table 6.22. This test checks the plants ability to comply with different active power constraint set point values that will be issued by the SO when the plant is in commercial operation. The measured values shall be recorded 30 seconds after receipt of the set point to a measured accuracy to the higher value of either ±2% of the set point value or ±5% of the rated power for each set point. If the plant meets the required set point within the time period and accuracy limit, then the plant passes this test. [18]

Table 6.22: Tests to check operation of Absolute Production Constraint function [18]

Select a $P_{reference}$ value in MW	MW
1st test	$P_{reference}$ to 80% $P_{reference}$
2nd test	80% $P_{reference}$ to 40% $P_{reference}$
3rd test	40% $P_{reference}$ to 20% $P_{reference}$
4th test	20% $P_{reference}$ to 10% $P_{reference}$
5th test	10% $P_{reference}$ to 30% $P_{reference}$
6th test	30% $P_{reference}$ to 50% $P_{reference}$
7th test	50% $P_{reference}$ to 80% $P_{reference}$
8th test	only for responds time: $P_{reference}$ to ≤0%
After the 8th test the RPP shall go back to normal operation	

The Absolute Power Constraint Function test was carried out on the wind farm and the results recorded in Table 6.23 and Figure 6.19. A P_{Ref} value was selected to ensure that the varible energy source doesnot reduce below the P_{Ref} value during the test. Once this was done, the test then starts with the issue of the 1st setpoint value, the results are then recorded after 30 seconds. After recording the results, a 120 seconds settling time period is allowed before the next setpoint is issued. Values recorded in Table 6.23 is the 30 second value recorded after the setpoints were issued. The Y axis in Figure 6.19 represents the MW generation output if the wind farm whilst the X axis represents time. The available power before commencement of the test was 20.9 MW which was curtailed to a more stable active power value of 18 MW. The active power was then constraint in percentages as stipulated in Table 6.22. The RPP was able to reach all the set points within 30 seconds and within the required accuracy limits. The plant was also able to shut down successfully when given a set point of 0 MW and then back to normal operation within 3 minutes when given a set point to return to full production. The plant demonstrated that it could meet all the requirements for the Absolute Power Constraint Function test.

Table 6.23: Actual site testing results for the absolute power constraint function for the 25 MW wind farm

Default value by SO or by the RPP						Preference:		
Before the start, the available power is measured and a reference value must be agreed between the parties: $P_{reference}$:						18.00MW		
Reduction/limit			Set point value P [MW]	Start value P [MW]	Actual P [MW] at 30s after setting the value	Measured Accuracy [kW]	Accuracy Max allowed [kW]	Comment
1st test to:	80%	Preference	14.4MW	18.0MW	**14.44MW**	40.00	400	**Tolerance Acceptable**
2nd test to:	40%	Preference	7.2MW	14.4MW	**7.20MW**	0.00	400	**Tolerance Acceptable**
3rd test to:	20%	Preference	3.6MW	7.2MW	**3.62MW**	20.00	400	**Tolerance Acceptable**
4th test to:	10%	Preference	1.8MW	3.6MW	**1.77MW**	30.00	400	**Tolerance Acceptable**
5th test to:	30%	Preference	5.4MW	1.8MW	**5.38MW**	20.00	400	**Tolerance Acceptable**
6th test to:	50%	Preference	9.0MW	5.4MW	**9.00MW**	0.00	400	**Tolerance Acceptable**
7th test to:	80%	Preference	14.4MW	9.0MW	**14.40MW**	0.00	400	**Tolerance Acceptable**
8^{th} test to	0%	Preference	0.0MW	Available Power	**-0.2000MW**	200.00	400	**Tolerance Acceptable**
After the 8^{th} test the RPP should go back to normal operation			**RPP went back to normal operation successfully**					

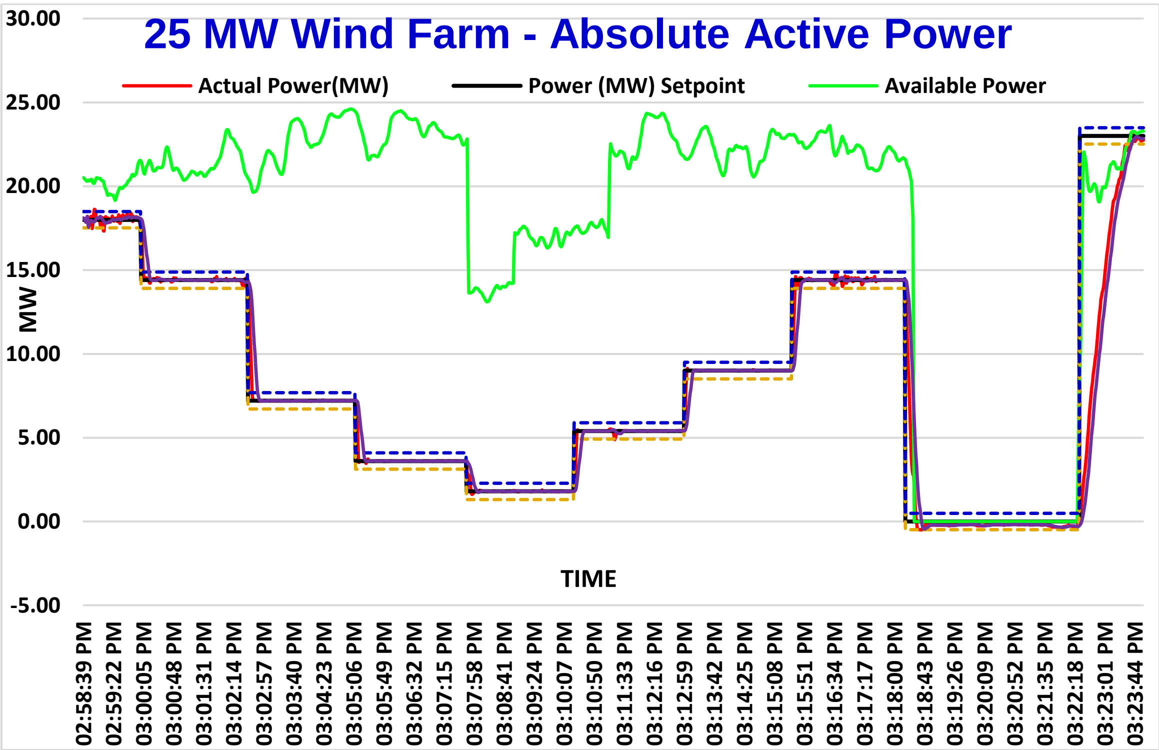


Figure 6.19: Graphical representation of the site testing results for the 25 MW wind farm

6.1.4.13. Delta Production Constraint Function

"A Delta Production Constraint function is used to constrain the active power from the RPP to a required constant value in proportion to the possible active power. It is typically used to establish a control reserve for control purposes in connection with frequency control." [18] To check compliance of the RPP to the Delta Production Constraint function, the plant shall be tested as per Table 6.24. P_{Delta} must be selected as a percentage of $P_{Available}$ which shall be 1 MW or greater. Tests can be carried out only if $P_{Available}$ is greater than 20% P_{Max}. The measured values shall be recorded 30 seconds after receipt of the set point to a measured accuracy to the higher value of either ±2% of the set point value or ±5% of the rated power for each set point. If the plant meets the required set point within the time period and accuracy limit, then the plant passes this test. [18]

Table 6.24: Tests for of delta production constraint function [18]

DELTA CONTROL – ($P_{available}$ >20% of P_{max}) Time for Test: 10 Minutes	
Ref No	**Description**
SETUP	
1.	Check $P_{Available}$ (require at least 20% P_{Max})
2.	Check PPC control ready
TEST	
3.	Check P_{Delta} control enabled
4.	Send ___e.g. 10% of $P_{Available}$ (> 1 MW)
5.	Check if power reduces to set point value on Park controller, SCADA or better measurement system.
6.	Hold for at least 10 min
7.	Further tests as optional. For e.g. longer period if the primary energy do not change during the 10 min test period or other setting like P_{Delta} of 4% would be tested
8.	Disable P_{Delta} control

The Delta Production Constraint Function test was then carried out on the wind farm. The P_{Delta} control was activated and P_{Delta} was set at 10% of $P_{Available.}$ The settings and results from the wind farm is then depicted in Table 6.25 and Figure 6.20. The wind farm met the requirements from the test within the required time and accuracy limits. The farm went back to service upon disabling the Delta Production Constraint Function after 10 minutes. The farm hence passed this test. [18]

Table 6.25: Delta Constraint Function testing on the wind farm

DELTA CONTROL – ($P_{avaiable}$ >20% of P_{max})			
Time for test: 10min			
Ref No	**Description**		**Comments**
SETUP			
1.	Check Pavail at least 20% P_{max}		
2.	Check PPC control ready		YES READY
TEST			
3.	Check P_{delta} control enabled		ENABLED
4.	Send ___e.g. 10% of $P_{available}$ (> 1 MW)	10%	of $P_{available}$
5.	Check if power reduces to set point value on Park controller, SCADA or better measurement system.		OK
6.	Hold for at least 10 min		
7.	Further tests as optional. For e.g. longer period if the primary energy do not change during the 10 min test period or other setting like P_{delta} of 3% would be tested	%	of Pavailable
8.	Disable Pdelta control		

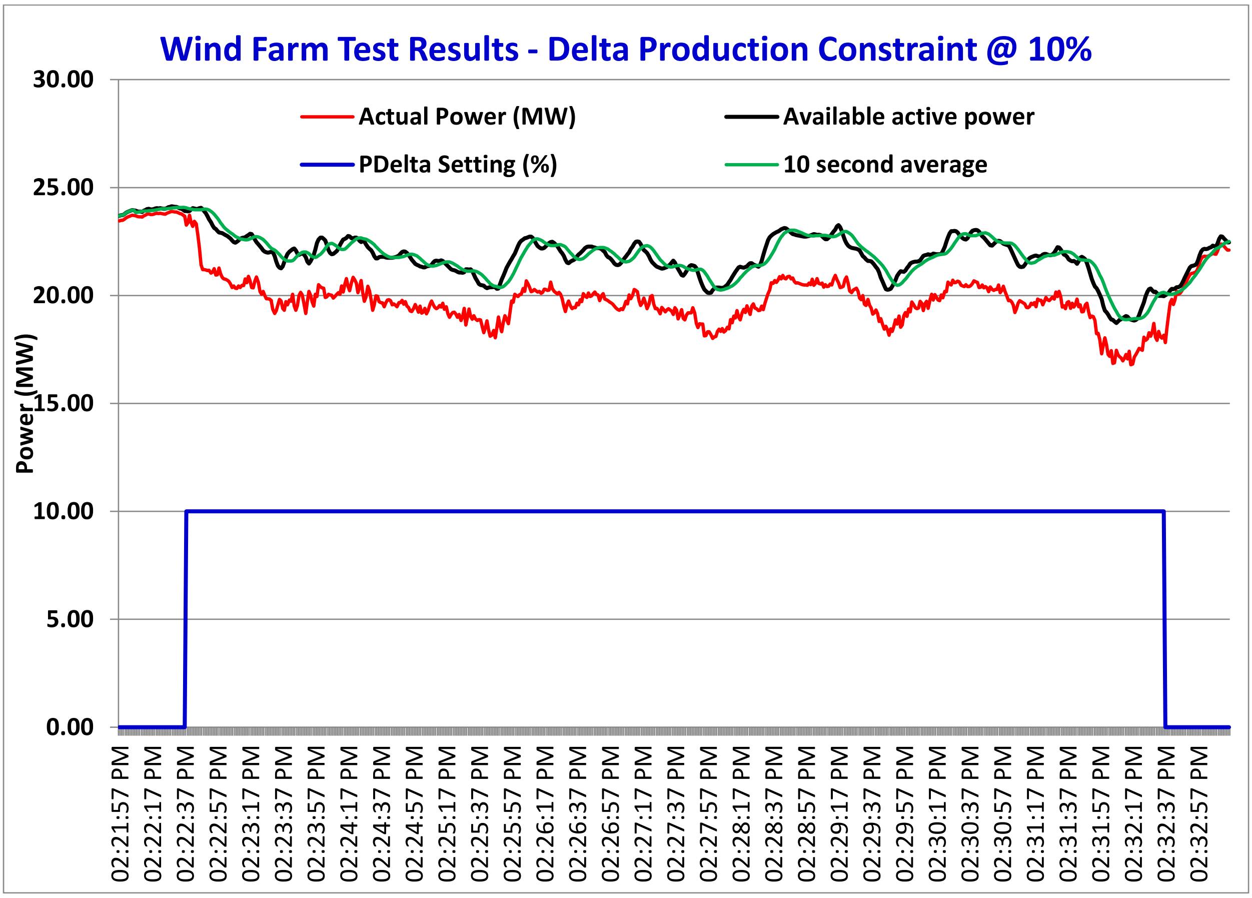


Figure 6.20: Graphical representation of the PDelta Constraint Function Testing on the Wind Farm

6.1.4.14. Power Gradient Constraint Function

"A Power Gradient Constraint Function is used to limit the RPP maximum ramp rates by which the active power can be changed in the event of changes in primary renewable energy supply or the set points for the RPP. A Power Gradient Constraint is typically used for reasons of system operation to prevent changes in active power from impacting the stability of the network.” [18] The test to check compliance is shown in Table 6.26. The measured values shall be recorded 30 seconds after receipt of the set point to a measured accuracy to the higher value of either ±2% of the set point value or ±5% of the rated power for each set point. If the plant meets the required set point within the time period and accuracy limit, then the plant passes this test. [18]

Table 6.26: Test to check operation of constraint function [18]

1st Test: down ramp rate has to be set to: (0.4 x $P_{Reference}$)/min The active power has to set to $P_{reference}$ before the start of 1st test.
1st Test from $P_{Reference}$ to 20% $P_{Reference}$
2nd Test: up ramp rate has to be set to : (0.4 x $P_{Reference}$)/min
2nd Test from 20% $P_{Reference}$ to $P_{Reference}$
3nd Test: down ramp rate has to be set to : (0.2 x $P_{Reference}$)/min
3rd Test from $P_{Reference}$ to 20% $P_{Reference}$
4th Test: up ramp rate has to be set to: (0.2 x $P_{Reference}$)/min
4th Test from 20% $P_{Reference}$ to $P_{Reference}$
After the last test the RPP is allowed to go back to normal operation

The Power Gradient Constraint Function test shown in Table 6.26 was then carried out on the wind farm. $P_{Refrence}$ for the test was set to 16 MW. The ramp rate for the first two tests was set at 6.4 MW/min (0.4 x $P_{Reference}$ /min) and for the last two tests, the ramp rate was 3.2 MW/min (0.2 x $P_{Reference}$/min). The results from the testing on the wind farm was then recorded on Table 6.27, Table 6.28 and Figure 6.21. The farm met both the constraint function ramp rates within the specified time of 2 minutes and accuracy limits.

Table 6.27: Results of the wind farm power gradient control function at 0.4 x $P_{Reference}$ /min

Before the start of the tests the available power is measured and used for all test as reference value as fix value: **Preference =**			**16.00 MW**
1st Test: down Ramp rate has to be set to :	**40%**	x Preference /min	**6.40 MW**
The active power has to set to $P_{reference}$ before the start of 1st test.			
Reduction/limit	Set point value P [MW]	Start value P [MW]	Actual P [MW] at 2 minutes after setting the value[1)]
	20 % of Preference	$P_{reference}$	
1st test from $P_{reference}$ to: 20% Preference	**3.2MW**	**16.0MW**	**3.21MW**
2nd test: up ramp rate has to be set to :		40%	x Preference /min
	$P_{reference}$	20 % of Preference	
2nd test from : 20% Preference to Preference	**16.0MW**	**3.2MW**	**16.10MW**

Table 6.28: Testing of the wind farm power gradient control function at 0.2 x $P_{Reference}$ /min

Reduction/limit	Set point value P [MW]	Start value P [MW]	Actual P [MW] at 4 minutes after setting the value[2)]
Before the start of the tests the available power is measured and used for all test as reference value as fix value: **$P_{reference}$** =			**16.00 MW**
3nd test: down Ramp rate has to be set to :	**20%**	x Preference /min	**3.20 MW**
	20 % of Preference	$P_{reference}$	Actual P [MW] at 240s after setting the value[2)]
3rd test from $P_{reference}$ to: 20% Preference	**3.2MW**	**16.0MW**	**3.40MW**
4th test: up ramp rate has to be set to :	**20%**	x Preference /min	**3.20 MW**
	$P_{reference}$	20 % of Preference	Actual P [MW] at 240s after setting the value[2)]
4th test from : 20% Preference to Preference	**16.0MW**	**3.2MW**	**16.28MW**
After the last test the RPP is allowed to go back to normal operation			

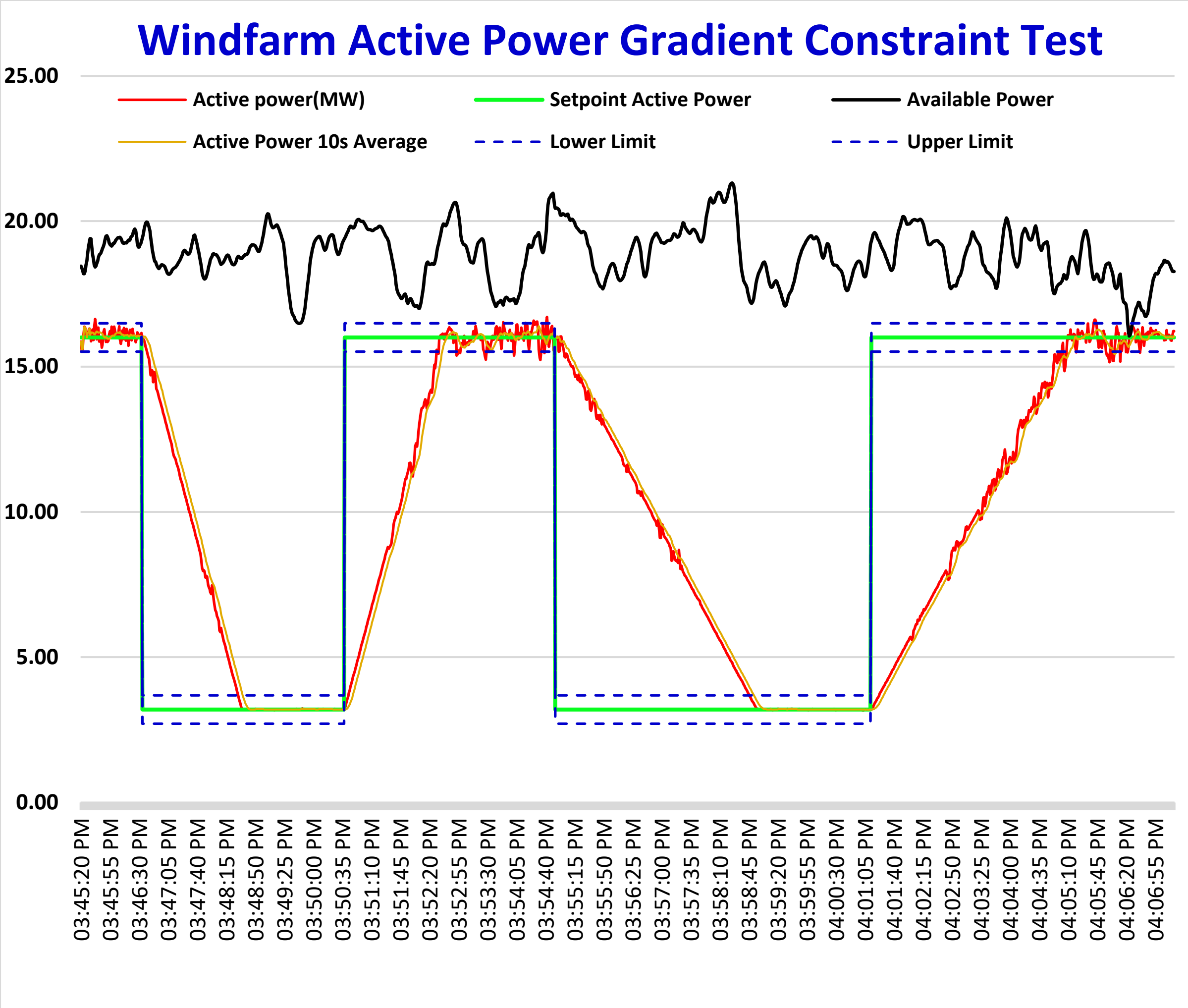


Figure 6.21: Graphical representation of the wind farm Active Power Gradient Constraint Test results

6.1.4.15. Testing of SCADA Compliance

The following tests shall be performed from the Network Service Providers Control Room to the *RPP* Power Park Controller on the day of the grid code compliance tests.

Test 1: Check capability to remotely open the breaker at the *POC* from the respective *NSP* SCADA. Capability to change the mode of operation at the RPP.

Test 2: Check capability to change the set-point in any mode of operation such that the *RPP* adjusts accordingly.

Test 3: Anti-islanding test: The facility shall be subjected to a self-islanding condition to determine the response of the ant-islanding protection function. Following this test, the *RPP's* automated response to the synchronisation function to the network at the POC shall be evaluated. [18]

Should the plant complies with test 1 to 3 then it can be deemed to have passed the SCADA test.

6.1.4.16. Conclusion And Recommendations

The SAREGC will be used to certify grid code compliance of all RPP projects. All plants must comply with the code at the point of connection onto the utility grid in order to operate commercially. With the current electricity shortages and drive towards renewable energy in a country which was dominated by coal fired power stations, there are many opportunities been unlocked to drive the renewable energy. There are many renewable projects that are located all around the country and there is a challenge in utilities with clearly understanding the requirements from the grid code. This is due to the complexity of the code and the tests to be carried out is not stipulated in the code. [18]

If all connected RPP to the grid are Grid Code compliant, it will make operating and managing the network easier for the SO at the Eskom National Control Centre or at the eThekwini Electricity Control Centre. This will ensure that the SO will have both control and visibility of these RPP plants making it dispatchable and controllable. [18]

6.2. Summary of Chapter 6

The study results revealed that in order for a Category C wind farm to comply with the SAREGC, it needs to have a number of control functions and respond to set points issued by the SO and out of bound network conditions within the required time and accuracy limits. This chapter provides a clear picture of the requirements from the plant and the available operational flexibility that the SO will have on these plants to assist with grid events and network contingencies.

CHAPTER 7: CASE STUDY 1: TECHNICAL AND ECONOMIC IMPACTS OF RESIDENTIAL ROOF TOP SOLAR PV AT ETHEKWINI ELECTRICITY

7.1. Introduction to Chapter 7

The Electricity Supply Industry in South Africa has undergone considerable restructuring since 2008 when the National Electricity Supplier (Eskom) had to undergo forced load shedding in order to maintain the stability of the national electricity network. Ever since, the reserve margin between the supply and demand of electricity has been tight with the possibility of rolling blackouts been high. South Africa was historically the cheapest electricity supplier in the world, but this position has evolved over the past 8 years. This is a direct result of constraints in building new generation plants within the country. This has then led to under frequency load shedding and the doubling of electricity prices across the country. With the ongoing electricity price increases, connection of small scale embedded generation (SSEG) on the local low voltage (LV) electricity distribution networks is becoming an increasingly attractive prospect in South Africa. Various EG technologies are entering a period of rapid expansion and commercialization. [21]

Electricity utilities such as eThekwini Electricity are then faced with various concern in understanding the impacts arising from the potential uptake figures of SSEG plants on their existing low voltage networks. This is due to lack of expertise within utilities to ensure the technical and safe integration of these plants on to existing LV networks in South Africa.

This case study further discusses the barriers, drivers of SSEG, available guidelines, heat map developed for evaluating the potential annual output of a roof top solar PV installation in Durban, formulae developed for evaluating the payback period and a case study carried out to determine the impact of residential solar PV on the local eThekwini Electricity distribution network.

7.1.1. Drivers and Potential for Small Scale Residential Embedded Generation

SSEG is defined as less than 1 MW LV connected generation defined as Category A ($0<A1\leq13.8$ kW, $13.8<A2\leq100$ kW and $100<A3\leq1000$ kW) in the SAREGC. The IRP 2010 – 2030 also indicates growth up to 22.5 GW by the residential and commerical sector by year 2030. Even if these estimates are partially correct, this points to a significant level of installed

small scale PV projects in South Africa by 2030. Based on the NERSA research and analysis, solar photovoltaic (PV) is in higher demand in South Africa at the moment than any other technology. This is largely in the under 1 MW installation category. This suggests a demand out there for these systems in South Africa. Given the recent reduction in the cost of PV, it has become probable that residential and commercial customers, as well as some industrial customers will begin installing PV to meet some or all of their electricity requirements. “The adoption of these SSEG schemes have been driven in part by the impact of environmental, regulatory and economic challenges, as well as changing public perception prevalent in the 1990s. The environmental awareness created by the promotion of green energy and energy sustainability following the Conferences of the Parties 17 Climate Change Conference in Durban has prompted an increasing number of residence to reduce their Carbon footprint” [21]

With the introduction of load shedding and the unstable supply of electricity, customers are now more aware of the concepts of electricity usage and continuously seeking for innovative ways to reduce their consumption. Many are turning to energy efficiency projects whilst others are looking into the feasibility of SSEG. With rising electricity tariffs in the country, the pay back periods and viability of small scale generation projects are becoming even shorter and more economically viable. In these SSEG projects, there has been a reluctance to combine expensive energy storage technologies to these systems but rather synchronize and utilise the municipal grid as a virtual battery. Whilst the advantages make synchronization to the grid a logical choice, the municipal network and framework is not designed to facilitate this. “The municipal mandated core function is to procure electricity from Eskom, transform it and distribute it to the end users. Power flow is from Eskom to the end user and all technical, administrative, regulatory and legal aspects are structured to support this unidirectional flow of electric power. The introduction of EG introduces bi-directional power flow on the distribution network. This has an impact on quality of supply, planning, network losses, metering and control of power flow on the existing distribution network.” [21]

“However if the utilities can allow embedded renewable energy generation to feed into their networks, this provides a relatively easy way for private sector companies, institutions and individuals to invest their own resources in renewable generation, without having to undertake detailed own load and storage requirements analysis. The grid will then act as a storage facility. This allows considerable leverage of financial resources into the overall renewable energy generation capacity development process. When national or local government define renewable energy objectives, and decide to financially incentivise these through attractive feed-in-tariffs or renewable energy certificates or similar trading systems, small scale grid connected options will become an important component of the South African renewable energy market.” [21]

7.1.2. The Availability of Solar Resources in Durban

As a developing country with a growing power shortage problem, South Africa is well placed to exploit its abundant solar resources. Figure 7.1 show the world map of global horizontal irradiation which reveals considerable solar resource potential for solar PV power generation all across South Africa. Studies have shown that Durban is well situated and blessed with good climatic conditions and resources to support these PV projects. The climate in Durban, located on the east coast of South Africa is humid subtropical with hot summers and mild winters. There is an average of 2343 hours of sunlight a year with an average of 6.4 hours of sunlight a day. Solar radiation data measured over a year’s period confirms that South Africa has solar energy resources that compares favorably with other global cities where sustainable energy systems have been embraced. [21]

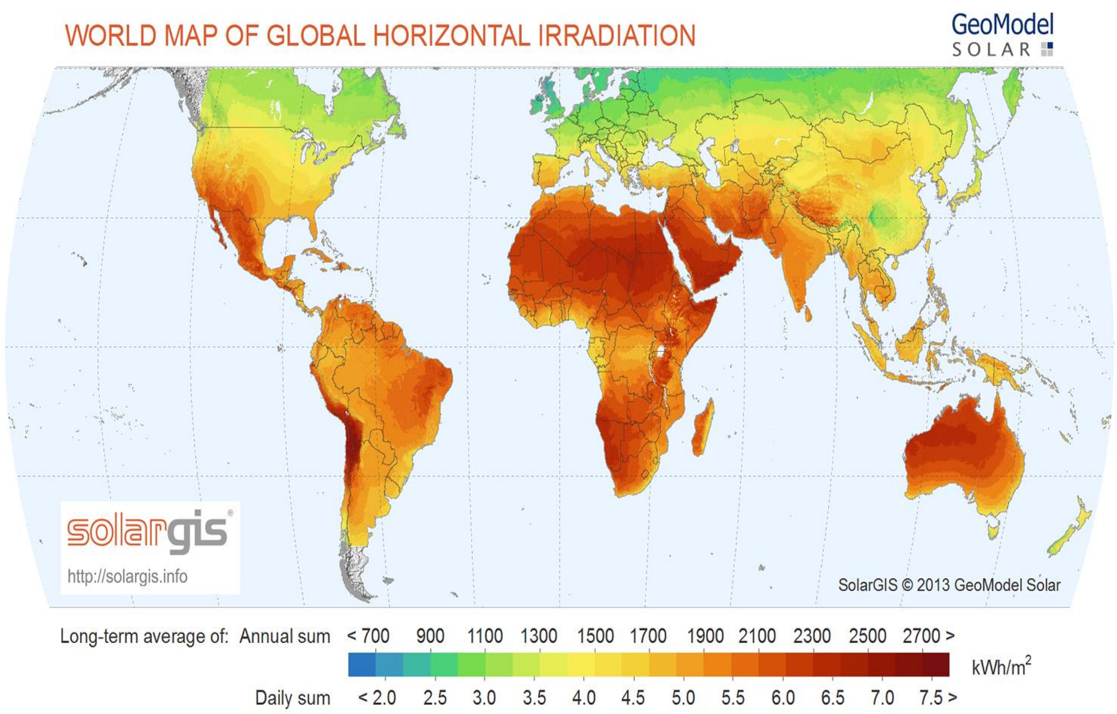


Figure 7.1: World Map of Global Horizontal Irradiation [60]

The direct, diffused and global radiation was measured at 2 sites in Durban and Table 7.1 provides a summary of the current and most accurate data on solar resources for Durban. The average value of the global radiation for Durban is 4.45 kWh/m^2/day as shown in the Table 7.1 which equates to an annual average of 1625 kWh/m^2/year. [21]

Table 7.1: Monthly radiation variation for Durban [21]

Month	˚C	kWh/m^2/d	Ave Sun Rise Time	Ave Sun Set Time
January	24.1	6.39	05:10	18:59
February	24.3	6.14	05:35	18:43
March	23.7	4.77	05:56	18:11
April	21.6	3.86	06:15	17:36
May	19.1	3.64	06:34	17:10
June	16.6	2.81	06:48	17:04
July	16.5	3.17	06:48	17:15
August	17.7	3.71	06:27	17:32
September	19.2	4.1	05:53	17:48
October	20.1	4.07	05:17	18:06
November	21.4	4.85	04:52	18:30
December	23.1	5.93	04:51	18:52
Yearly Average	20.6	4.45		

7.1.3. The Advantage and Disadvantages of Solar PV

Solar PV offers a number of benefits over other renewable energy technologies. Some of the advantages and disadvantages are shown in Table 7.2. The main advantages are the system is simple, it is modular, has a long life, short installation lead times and generation is from an infinite renewable energy source. The disadvantages is the generation is variable, influenced by many factors, large surface area is required for the PV modules, may lead to power quality problems on the network and cost of PV systems is still high.

Table 7.2: Advantages and disadvantages of a PV system [21]

Advantages	Disadvantages
Simple – there are no moving parts, no water is required and no regular maintenance is required.	**Variability –** no generation during the evening. Shading from clouds, trees, etc dramatically reduces output. Power is also unable to be scheduled.
Modular – capacity can be easily increased through the addition of extra panels and inverter capacity.	**Area –** relatively large area needed to generate relatively small amounts of power due to low cell efficiencies.
Long Life – panels typically have a 25 years lifespan whilst inverters have an average 10 year lifespan.	**Polysilicon –** may become rare or expensive as demand increases.
Short Lead Time – systems can be installed very	**Power Quality Issues –** including steady state

quickly.	voltage rise.
Renewable – effectively infinite energy source.	**Cost –** still higher per kWh than coal and gas.

7.1.4. Study of the Market Barriers for Solar PV in eThekwini Electricity (Durban) area of Supply

A study was carried out in 2013 by the eThekwini Municipality to identify the barriers regarding solar PV installations in the eThekwini Electricity area of supply. An electronic survey was undertaken on 174 households. The survey however in no way represents the views of all the household in eThekwini but provide good insight into the potential barriers. [21]

In the residential category, the majority of the householders surveyed lived in either 3 or 4 bedroom houses with 4 individuals on average per house. The house size provides an idea of the available roof space to install rooftop PV. In order to ascertain affordability of PV, the household monthly income levels were classified in which 43.8% households had an income of greater than R50 000, 21.2 % earned between R20 000 and R40 000, 19% between R40 000 and R50 000 and 5% below R10 000. The monthly electricity bill for the households surveyed indicated 41.7% spent between R1000 and R2000, 31.1 % between R2000 and R9500 and 27.2% spent between R100 and R1000. This helped to provide an indication of the potential monthly saving based on the current spending on electricity. 6.7% of the households surveyed had already invested in solar PV. Whilst of the 93.3% who had not invested in solar PV, 34.5% indicated that they were considering investing in solar PV. 34.5% of the consumers who were considering solar PV installations, the main drivers cited was money saving and care for the environment. The 65.5% consumers who had not considered investing in solar PV, 65.9% indicated that they believe the technology is too expensive, 17.6% indicated that they did not understand the technology and the other reasons included aesthetics, believed the technology did not work, its ugly and unreliable. When the 65.9% who indicated that the technology was too expensive was asked whether they will invest in solar PV if the technology was less expensive, 47. 01% fully agreed whilst 31. 34% agreed. [21]

The important aspects that were highlighted from the survey are as follows:

(i) More accurate information on solar PV is required by the customers.

(ii) Customer need to understand the environmental benefits of solar PV.

(iii) Consumers need to accurately understand the payback period (financial feasibility) of installing roof top solar PV.

7.1.5. PV Information made more readily available to the citizens of eThekwini Municipality

In order to provide the citizens of Durban readily available information on the potential benefits of rooftop solar PV, the eThekwini Municipality created a tool that will help both residence and installers of solar PV to determine the amount of solar PV that can be installed on a rooftop and the high level costs and potential savings. The purpose of the tool was to empower the consumers from various sectors to get a feel for the costs vs benefits of installing rooftop solar PV. This approach was adopted from the United States of America which has a similar program called Solar America Communities Program. The purpose of the program was to help accelerate the adoption of solar energy technologies for a cleaner, more secure energy future. [21]

The web tool created allows the residents to input their home address and the map zooms to their property as shown in Figure 7.2. They can then select the roof area of the house and the tool then gives them the potential amount of PV that can be installed, costs and the amount of electricity the system will save per an annum as shown in Figure 7.3. This is a rough tool to give the residence an indication of the potential benefits of installing rooftop solar PV. Information given by the website (http://www.durbansolarmap.co.za) is indicated in Figure 7.3. [21]

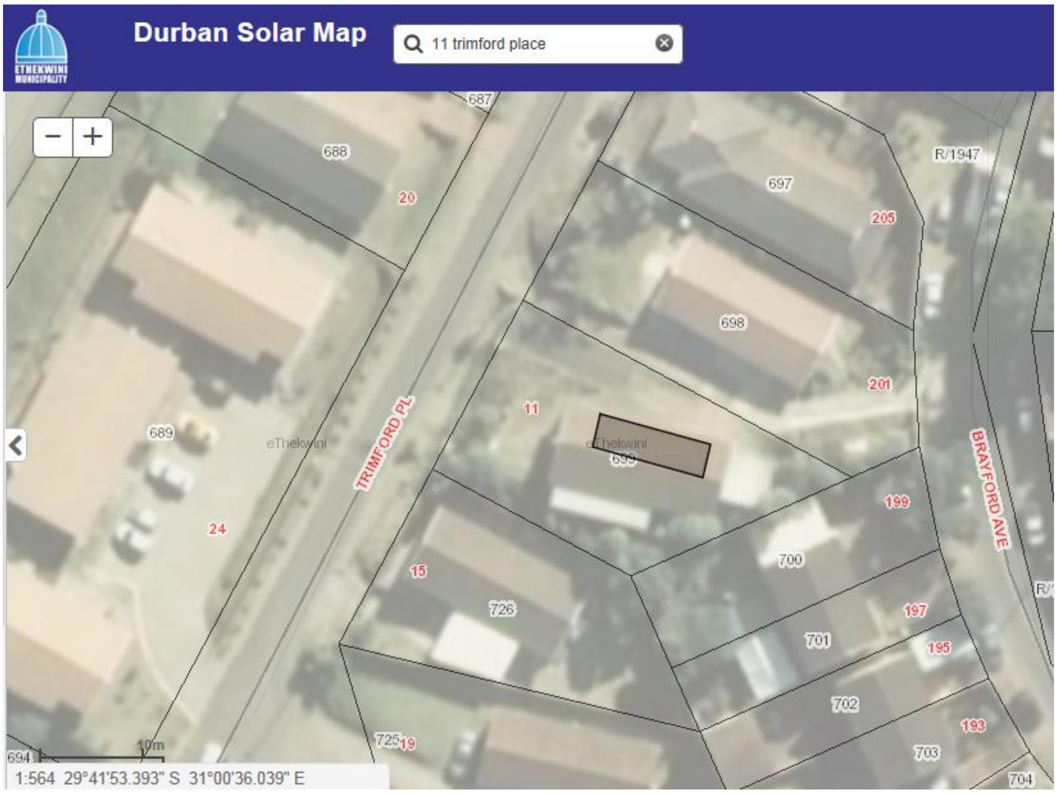
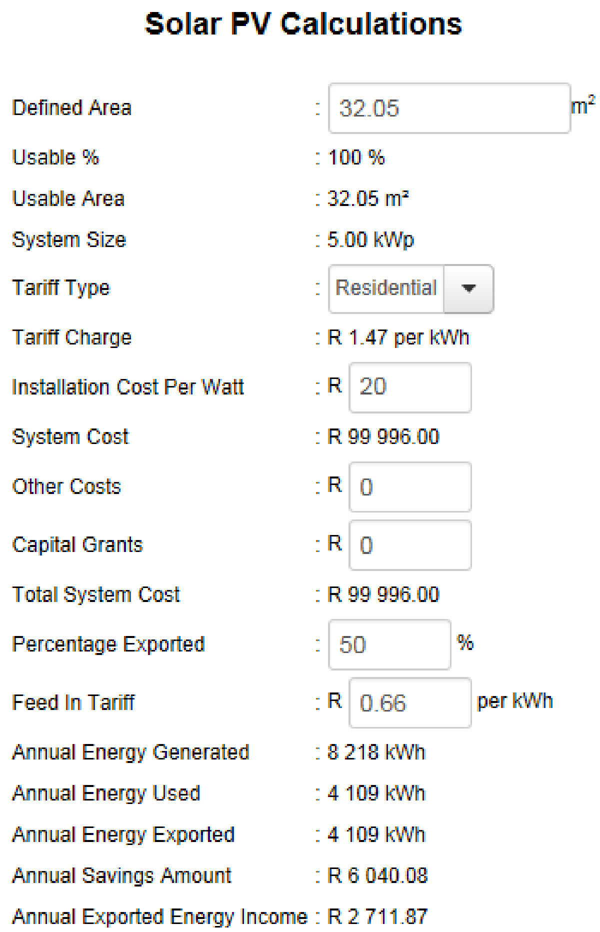


Figure 7.2: Screenshot of the Durban Solar Map [21]

However the tool does not take into account the orientation and inclination of the roof, cost of loans, subsidies, changing electricity tariffs, PV panel performance degradation over time, etc. This may give the consumer inaccurate information on roof top solar PV. We will then attempt to refine the payback period calculation of rooftop PV to take into account all the above factors to give us a more accurate payback period in this case study. [21]



Solar PV Calculations

Defined Area	: 32.05 m²
Usable %	: 100 %
Usable Area	: 32.05 m²
System Size	: 5.00 kWp
Tariff Type	: Residential
Tariff Charge	: R 1.47 per kWh
Installation Cost Per Watt	: R 20
System Cost	: R 99 996.00
Other Costs	: R 0
Capital Grants	: R 0
Total System Cost	: R 99 996.00
Percentage Exported	: 50 %
Feed In Tariff	: R 0.66 per kWh
Annual Energy Generated	: 8 218 kWh
Annual Energy Used	: 4 109 kWh
Annual Energy Exported	: 4 109 kWh
Annual Savings Amount	: R 6 040.08
Annual Exported Energy Income	: R 2 711.87

Figure 7.3: Information that is given by the website [21]

7.1.6. Environmental Concerns/Benefits

An important driver of residential solar PV is the environmental concerns since bulk of the electricity generated in South Africa is from coal fired power stations. The reduction in the environmental impacts and cost of electricity utilised from the grid largely depends on the size of the PV system and the amount of electricity generated from the PV system. The installed size and the amount of electricity generated from a PV systems is affected by numerous factors. [21]

Some of the factors that may affect roof top solar PV installations include [21]:

- Roof size
- Roof structural integrity
- PV panel orientation
- PV panel shading (trees, chimneys, etc)
- Angle of the roof pitch (0°, 30°, etc)
- Soiling

- Carbon tax offset
- Suitable Feed in Tariff (FIT)
- Net Metering Schemes
- Net Billing Schemes
- Generation Export Tariffs
- Carbon footprint reduction
- Inverter losses
- Cloud cover in area
- Pollution
- Temperature
- Cable losses
- Subsidy/incentive schemes
- Grid electricity tariffs
- Performance reduction on PV panels over time
- Inverter losses
- PV panel mismatch
- Reflection
- Irradiance
- Wiring losses

7.1.7. Minimum Roof Area Required to install Roof Top Solar PV

The average dimension of a 250W solar panel is 1.6 by 1 meter. Hence the minimum roof space required for a 1 kW PV system is (1.6×1×4) is 6.4 m^2. Typically for a 5 kW roof top PV system the minimum area roof space required will be 32 m^2. However installers may allow spacing between PV panels to allow cooling of the panels to prevent temperature rise which will reduce the panel effiency which may hence increase the overall roof space required. [21]

7.1.8. Environmental Benefits of Roof Top PV

Equation (4.19) to (4.24) allows for the environmental impacts a avoided to be calculated when generating 1 kWh of electricity from a renewable energy source as opposed to using 1 kWh of electricity generated from the Eskom power stations. The figures calculated are based on total electricity generated by Eskom. This includes electricity from Eskom’s coal, nuclear, pumped storage, wind, hydro and gas turbines power stations. [21]

The simple total Carbon reduction formulae per an annum can be calculated using the following formulae [21]:

Total Kgs $CO_{2\ \text{emissions}}$ = TKG × 0.99 (4.19)

Where: TKG = Total kWh generated from a PV systems

Equation (4.19) then gives us the Total Kgs of CO_2 emissions that will be reduced from venting into the atmosphere. This information is essential for a company or individual that wants to achieve Carbon neutral status. [21]

For every kWh of electricity generated from solar PV, the following impacts are further avoided based on the potential impacts that would have occurred if the kWh of electricity was to be generated from the Eskom power stations. [21]

Coal utilized to produce 1 kWh = 0.54 kg

Kgs of Coal Saved = TKG × 0.54 (4.20)

Water utilized = 1.37 liters

Liters Water Utilised = TKG × 1.37 (4.21)

Ash produced = 155 grams

Reduction in grams of Ash Produced = TKG × 155 (4.22)

SO_x emissions = 7.93 grams

Reduction in grams of SO_x emissions = TKG × 7.93 (4.23)

NO_x emissions = 4.19 grams

Reduction in grams of NO_x emissions = TKG × 4.19 (4.24)

7.1.9. Feasibility of Small Scale PV Projects

The feasibility of SSEG projects are largely dependent to three factors, namely: the cost of the PV installation, the annual kWh of electricity generated and the electricity import/export tariffs. Since the start of load shedding in 2008, there have been large increases in the electricity tariff year on year. Figure 7.4 shows the residential tariff increase for the eThekwini Municipality who purchases its electricity from the Eskom and then distribute it onto its customers. “The residential electricity tariffs have increased by an average of 14.5 percentage over the past 7 years.” [1]

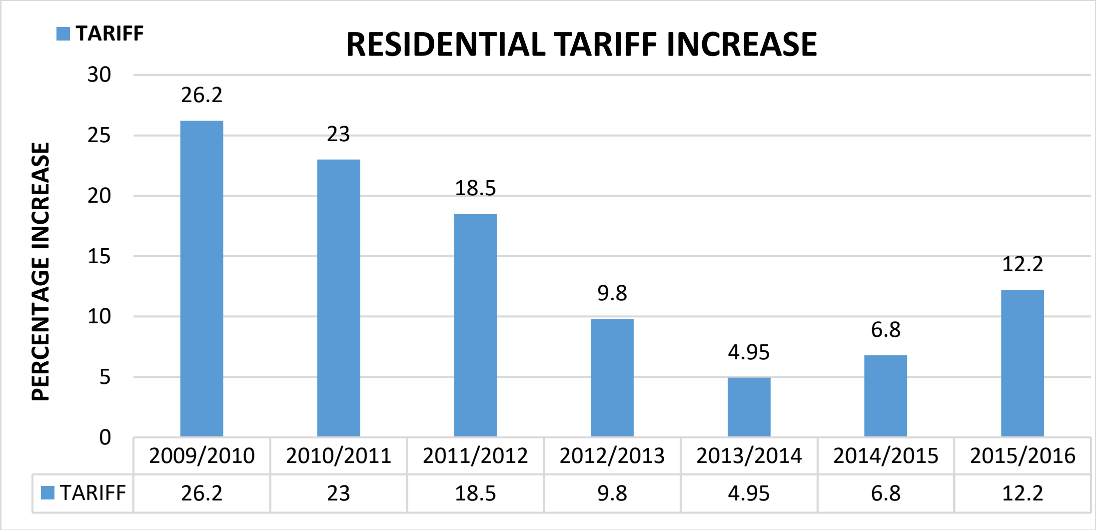


Figure 7.4: Rising Municipal electricity tariffs [1]

The current eThekwini Electricity (EE) residential single and three phase tariffs are R1.58/kWh. There are presently 319 875 (44%) single and three phase credit residential customers that utilize an average of 700 kWh a month. There are also 358 411 (49%) prepaid customers that are made up of rural, RDP and informal dwellings that utilize an average of 200 kWh on average a month. Based on their consumption figures, dwelling sizes and income levels, credit customers are more likely to install rooftop PV systems. [1]

To evaluate the feasibility, there is a need to estimate the electricity tariffs going into the future. Figure 7.5 shows the predicted eThekwini Electricity residential tariff increases projected for 8% (low growth scenario), 11.5% (medium increase scenario) and 14.5% (high increase scenario) increase from 2015 – 2025. The bases for the selection of the 8% tariff increase for the low increase scenario is from the Multi Year Price Determination 3 (MYPD3), which was approved by the National Energy Regulators of South Africa for 8% until 2018. Eskom has, however, applied to the National Energy Regulator to allow for additional increases above the approved 8%. The basis for the high increase selected was derived from the average residential tariff increase over the last 7 years, which was 14.5% at eThekwini Electricity. The medium increase scenario was selected in-between the high and low increase scenario. [1]

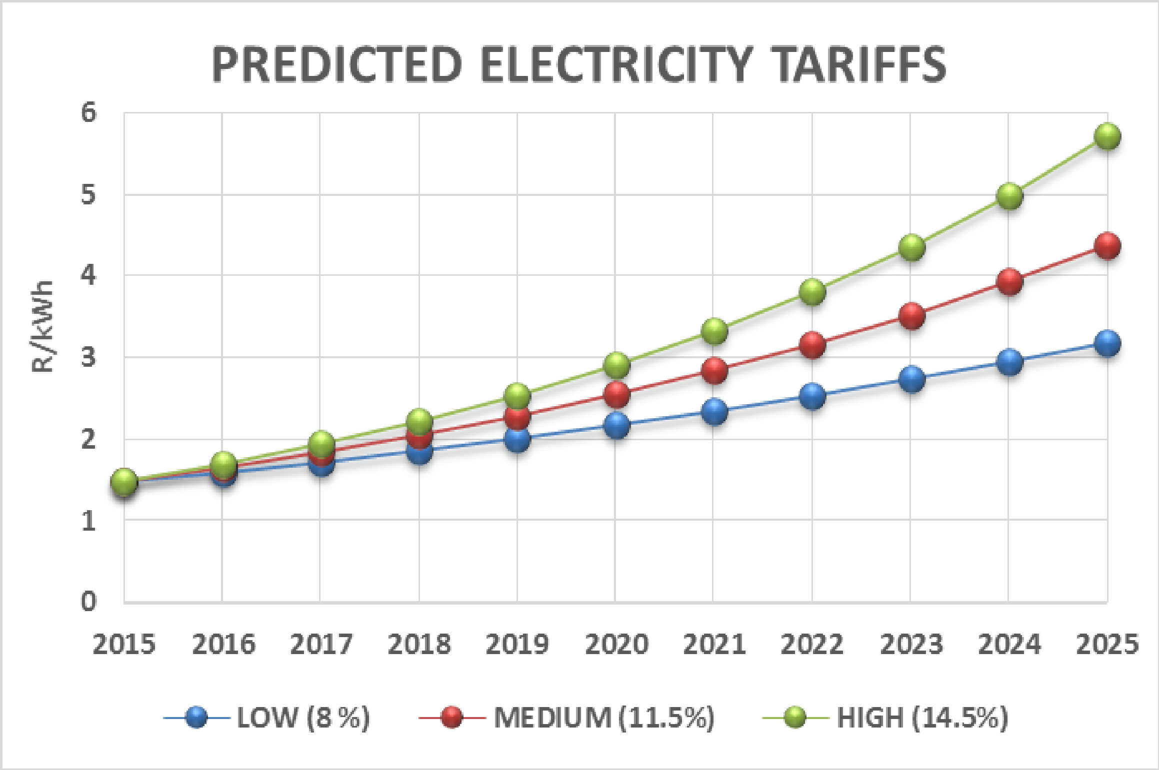


Figure 7.5: Projected Electricity residential tariffs [1]

As it can be seen from Figure 4.91, the electricity price increase in 2020 could vary from 216.72 c/kWh to 290.28 c/kWh and between 318.44 c/kWh to 571.27 c/kWh in 2025. Together with the reducing prices in the PV sector, this makes residential PV a lucrative option and hence it is projected to see an increase in PV installations going forward. [1]

7.1.10. Case Study 1: Payback of a residential 5 kW rooftop PV

The feasibility of a rooftop PV system depends on a number of factors namely [1]:

- Import electricity tariff
- Cost of PV installation
- Positioning of the PV panels
- Shading effects
- Export or Renewable Energy Feed in Tariff (REFIT)
- Life span of the inverter
- Percentage of generated electricity utilised
- Degradation rate of the PV panels (generation output)

The problem with residential PV in comparison to the residential load profile is that during the PV generation peak, which is around noon, the electricity usage by the household is low resulting in excess electricity being exported to the grid. With the municipalities currently not offering any payback (export tariff or REFIT tariff), the feasibility of these projects depends largely on the amount of electricity utilized and the savings received from electricity not purchased from the grid. [1]

We investigate the payback periods of rooftop PV by carrying out a few payback period calculations to look at the payback period of rooftop PV assuming that 50%, 75% and 100% generated electricity from the system was utilised. This assumption is due to the fact that a typical residential load profile is depicted by morning and evening peaks while a rooftop PV system is characterised by a midday peak. This often results in a mismatch between the generation and load demand except in the case where the PV system was sized to ensure that all generated electricity was used. For this feasibility study, we looked at a few realistic scenarios in which 50%, 75% and 100% of the rooftop PV generation was utilised by the household. The actual figures from an existing rooftop PV project in Kloof was utilised shown in Figure 7.6. This PV system parameters are shown in Table 7.3. The calculations utilised the cost of R20/Watt installed rooftop PV obtained from quotations received from PV installers in Durban for the equipment shown in Table 7.3.

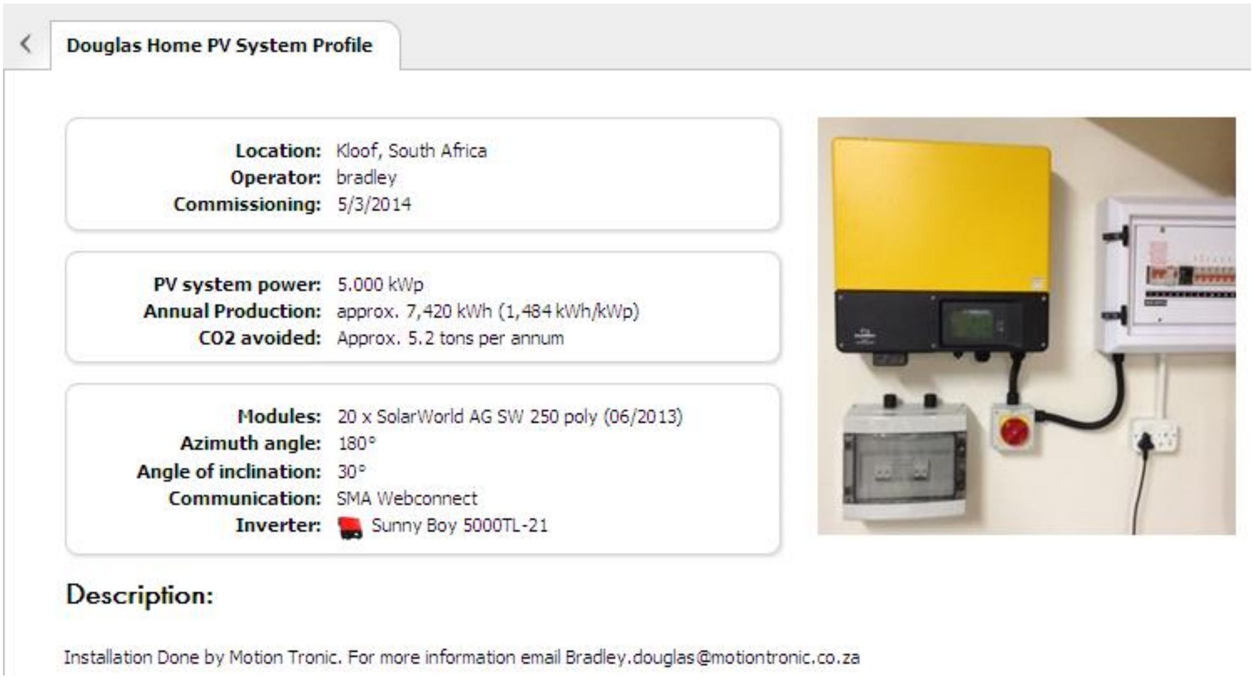


Figure 7.6: Technical details of a 5 kW system installed in Durban [1]

Table 7.3: Five kW rooftop PV details [1]

Location	Kloof, Durban
PV System Power	5 kWp
Annual Production	7420 kWh (1.484kWh/kWp)
Modules	20×Solar World AGSW 250 Poly
Angle of Inclination	30°
Inverters	SMA Sunny Boy 5000TL – 21

Figure 7.7 – 7.9 provides a simple simply payback period taking a few factors into consideration such as the municipal energy costs and the amount of generated electricity used to off set the customers bill. This simple method did not take into consideration any export tariff paid and other factors that would affect generation production. The payback period varies between 8 and greater than 10 years for a PV system which has a lifespan of around 20 to 25 years (according to the PV panel manufacturer the guarantee is 20 – 25 years whilst the PV inverter will require changing during the life of the project). The calculations do not take into account any export tariff paid to the consumer (currently eThekwini Electricity does not pay for exported energy) for excess energy exported to the grid. However this is an ideal case where panel degradation and inverter failure/replacement or capital cost of borrowing to finance the system is not taken into account. It is assumed that the resident pays for the system on his own and no panel degradation takes places or inverter replacement occurs for the period of these calculations. [1]

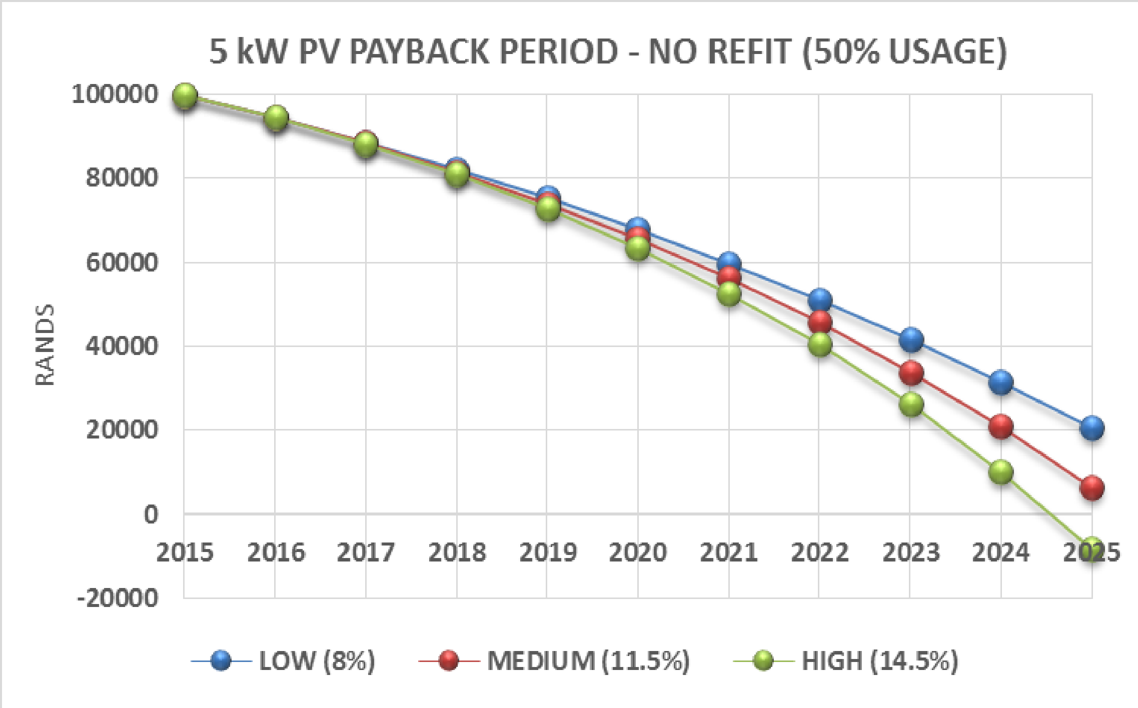


Figure 7.7: Roof Top 5 kWp PV payback period with 50% usage [1]

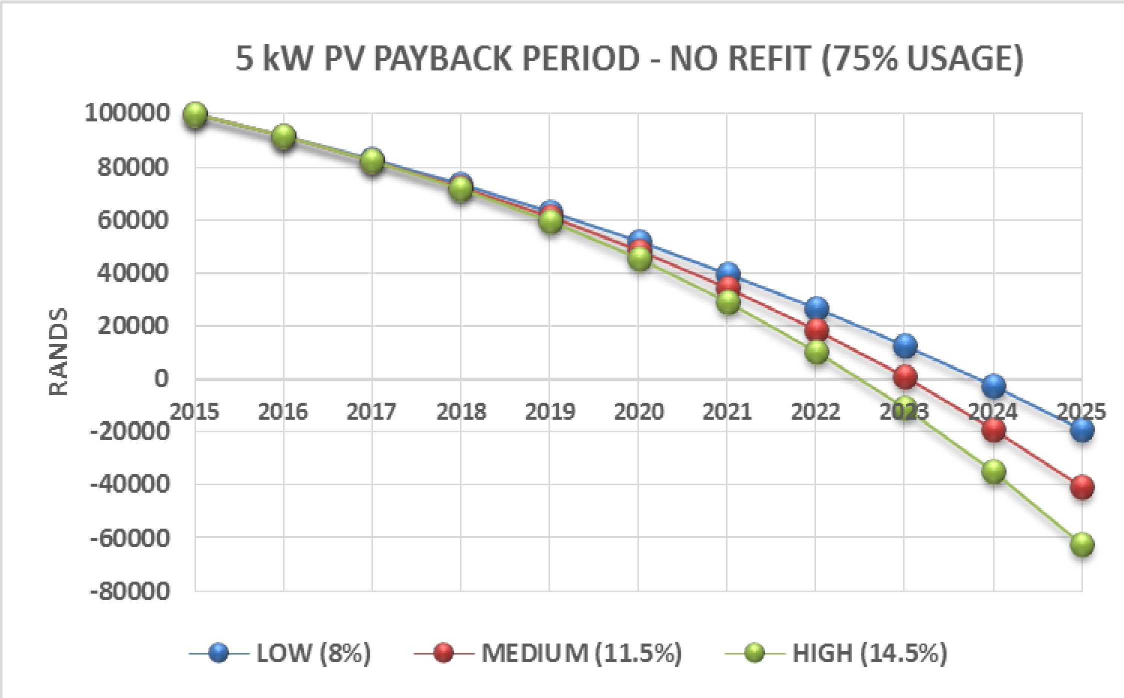


Figure 7.8: Rooftop 5 kWp PV payback period with 75% usage [1]

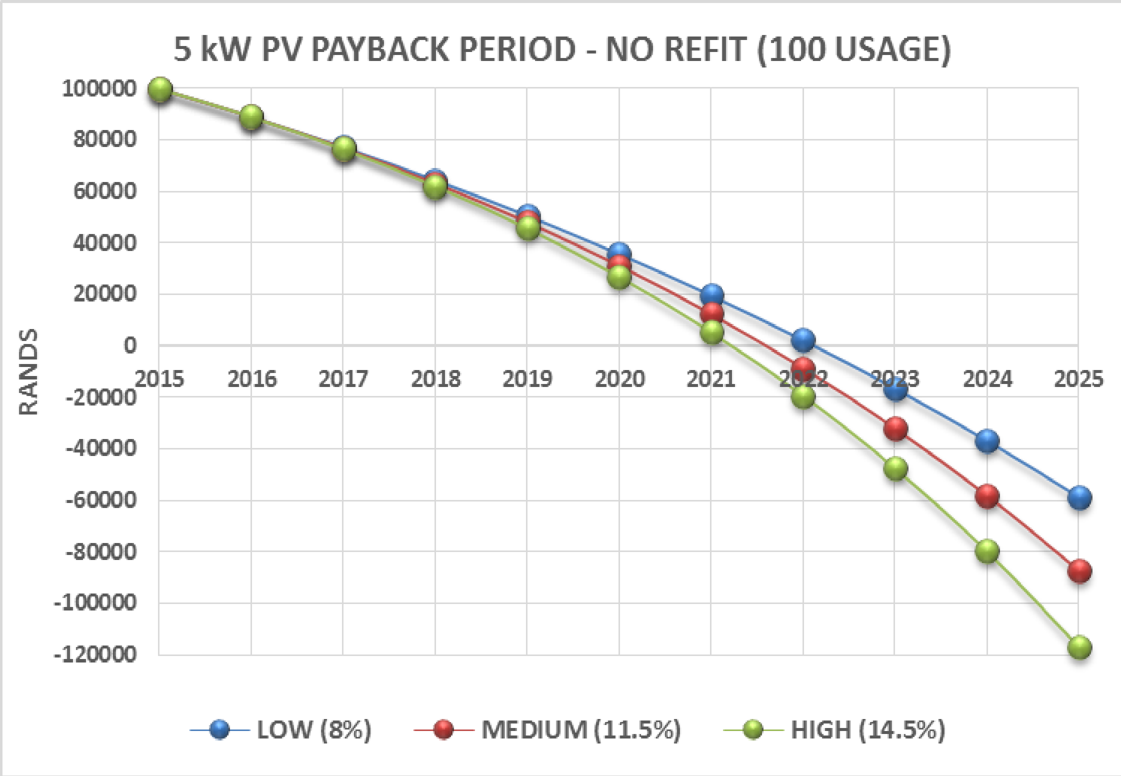


Figure 7.9: Rooftop 5 kWp PV payback period with 100% usage [1]

Table 7.4 provides the payback period for the 5 kW PV system for different tariff increase scenarios and generated electricity usage.

Table 7.4: Summary of rooftop PV payback periods [1]

Payback Period – No REFIT			
	50% Usage	**75% Usage**	**100 % Usage**
Low (8%)	> 10 years	9 years	9 years
Medium (11.5%)	> 10 years	9 years	8 years
High (14.5%)	10 years	8 years	8 years

7.1.11. Potential Renewable Energy Feed in Tariff

Most residential and small customer tariffs are not cost-reflective as they do not reflect the fixed costs associated with the management, operations and maintenance of the grid and the retail related costs to serve the customers. If the electricity tariff supplying a customer is not cost reflective and EG is installed, it means that there will be loss of revenue to the utility. This loss will need to be recovered from other customers as there is no commensurate reduction in the fixed costs. Most residential tariffs comprise of a variable c/kWh charge only and no fixed charges to recover the fixed costs. This implies that if consumption decreases due to own generation, the utility loses revenue that is not commensurate with a reduction in costs. From the utility perspective, revenue loss is a major concern as EG reduces their sales and revenue. A mechanism needs to be determined to facilitate the development of SSEG in South Africa while mitigating a potential negative impact to the utilities revenue. [1] Utilities are currently awaiting guidelines from NERSA for rules and guidelines on creating these tariffs that will be acceptable to the regulator.

In the case of the Municipality, the potential feed in tariff has to be in line with the Eskom 275 kV Megaflex time of use tariff structure which electricity is currently purchased from Eskom on. This is to ensure compliance to the Municipal Financial Management Act which prohibits the Municipality from paying more for a product then what is available on the open market. We look at the possibility of the municipality paying a reasonable export tariff and look at how this will improve the payback period since this is what drives these schemes in other countries. In order to remain compliant, the municipality will at best be able to pay avoided costs (equal to the Eskom 275 kV Megaflex Time of Use tariff) for any energy not purchased from Eskom. [1]

However, currently eThekwini Electricity (EE) residential customers pay a flat rate per a kWh purchased and EE pays Eskom on a TOU tariff. The Eskom 275 kV Megaflex TOU tariff structure is a complicated tariff structure which has different rates for different times of the day, days of the week and different demand season as shown in Table 7.5. We need to then work out the average cost per a kWh of electricity from the Megaflex rate to a single flat rate. This could then be the bases for a potential generation/REFIT tariff. In order to work out the tariff as a single flat rate tariff, we assume a flat load profile. Using this, we then calculate the flat rate tariff shown in Equation (4.25 – 2.27). [1]

Table 7.5: Break down of the Eskom 275 kV Megaflex Tariff structure [1]

	Peak (Hours)	Standard (Hours)	Off-Peak (Hours)
Week Days	5	11	8
Saturday	0	7	17
Sunday	0	0	24
Total Hours/Week	25	62	81
Percentage	14.88	36.9	48.21
Season	**Duration**		**Months**
High Demand	1 June – 31 August		3
Low Demand	1 Sept – 31 May		9

Eskom 275 kV Megaflex Time of Use Tariff			
High Demand	234.55	71.06	38.58
Low Demand	76.50	52.66	33.40

Average High Demand Period Cost = Peak + Standard + Off-peak (4.25)

Where:

Peak = (0.1488×234.55) = 34.90 c/kWh

Standard = (0.369×71.06) = 26.22 c/kWh

Off-peak = (0.4821×38.58) = 18.60 c/kWh

Total High Demand Period Cost = 34.90 + 26.22 + 18.60 = 79.72 c/kWh

Average Low Demand Period Cost = Peak + Standard + Off-peak (4.26)

Where:

Peak = (0.1488×76.50) = 11.38 c/kWh

Standard = (0.369×52.66) = 19.43 c/kWh

Off-peak = (0.4821×33.40) = 16.10 c/kWh

Total Low Demand Period Cost = 11.38 + 19.43 + 16.10 = 46.91 c/kWh

Overall Average Cost = (0.25×Average High Demand Period Cost)

+ (0.75 × Average Low Demand Period Cost) + Other Charges (4.27)

Where:

Other Charges = Ancillary Service Charge + Electrification and rural subsidy charge

Other Charges = 0.29 + 6.39 = 6.68 c/kWh

Overall Average Cost = (0.25 ×79.72) + (0.75 × 46.91) + 6.68

Overall Average Cost = 62 c/kWh

Hence the average flat rate cost per a kWh of electricity from Eskom is 62c. We then look at the possible increases in this flat rate tariff going forward for the low, medium and high tariff increase scenario. The flat rate Eskom tariff will vary between 91.09 c/kWh to 122.01 c/kWh in 2020 whilst it will vary between 133.85 c/kWh to 240.13 c/kWh in 2025 as depicted in Figure 7.10. [1]

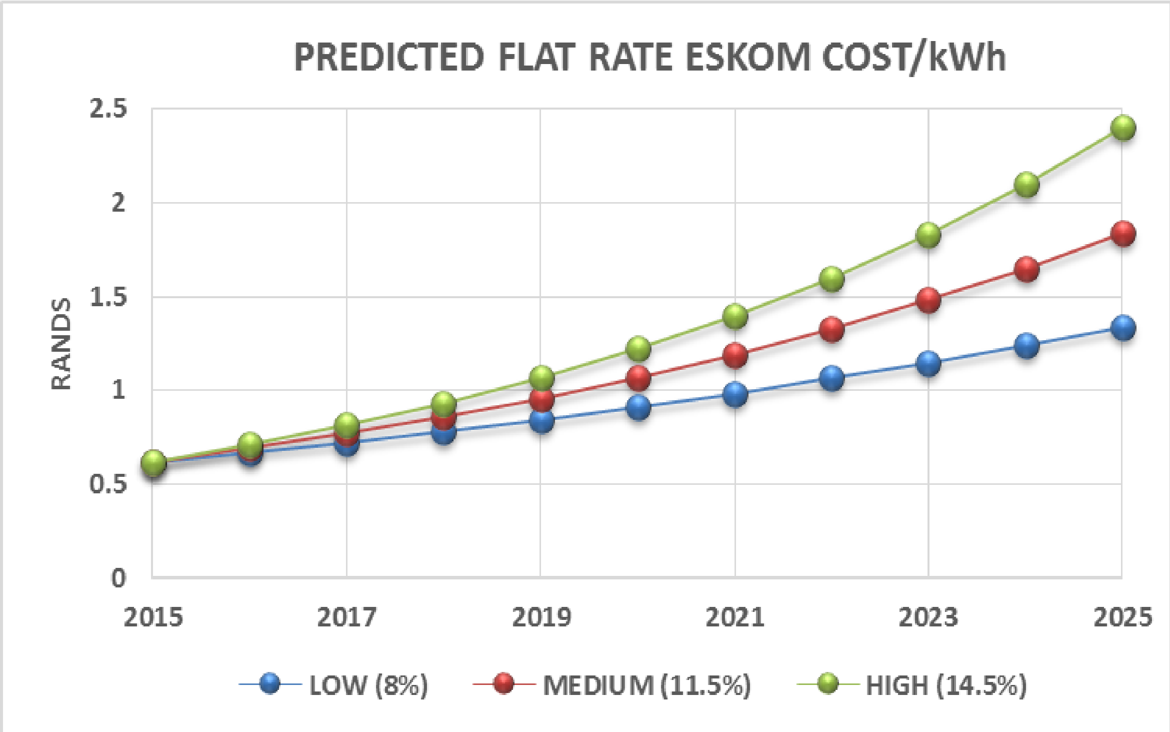


Figure 7.10: Predicted flat rate Eskom costs [1]

7.1.12. Case Study 2: Payback of a residential 5 kW rooftop PV with REFIT

We then utilize the potential REFIT and then recalculate the payback period with the introduction of this generation tariff which is equal to the Eskom avoided costs. With REFIT, the payback period of the 5 kW PV system now ranges between 7 and 10 years as shown in Figures 7.11, 7.12 and Table 7.6. There has clearly been an improvement in the payback period with the introduction of the REFIT tariff as oppose to the case study with no REFIT. [1]

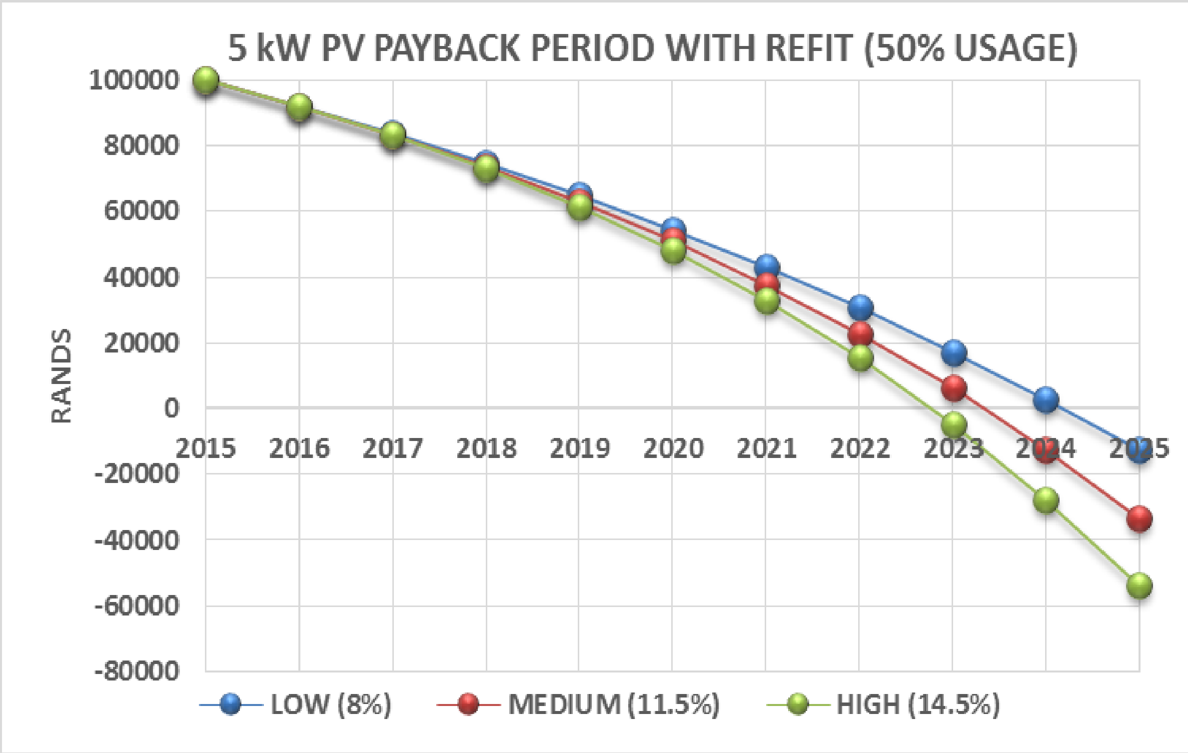


Figure 7.11: Payback period (50% usage) with REFIT [1]

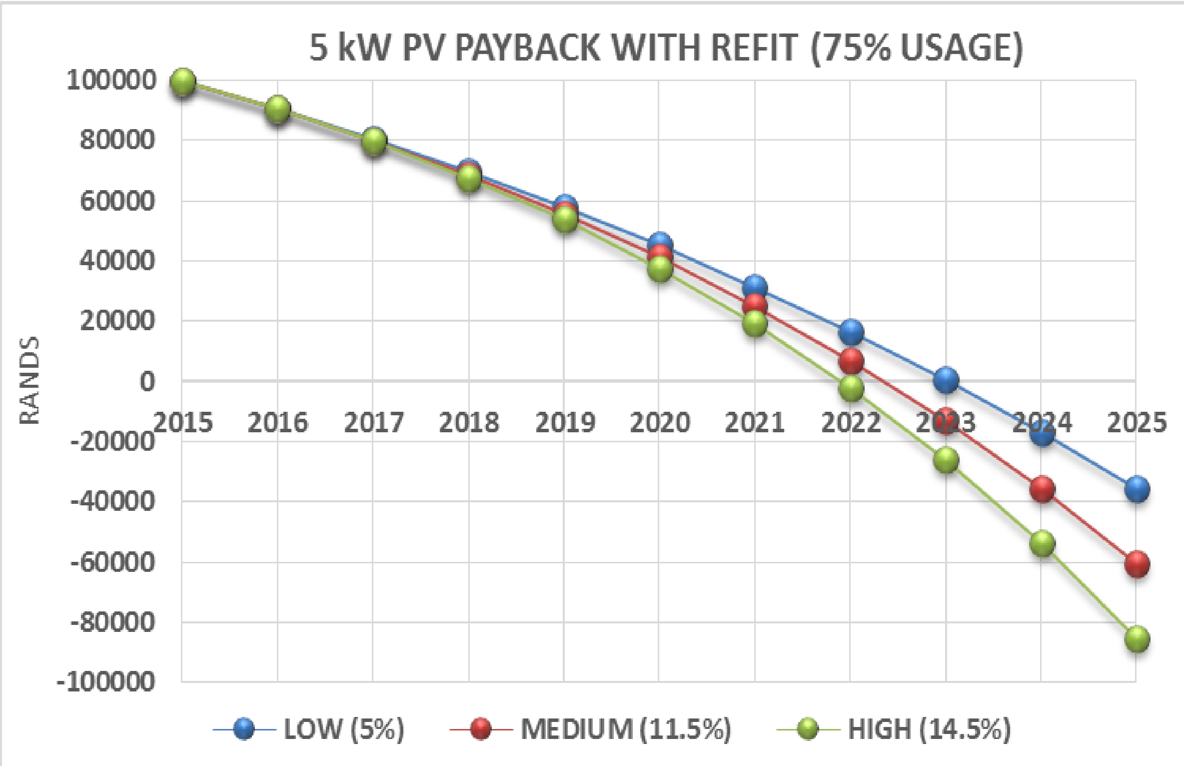


Figure 7.12: Payback period (75% usage) with REFIT [1]

Table 7.6: Payback period with REFIT [1]

	Payback Period with REFIT		
	50% Usage	**75% Usage**	**100 % Usage**
Low (8%)	10	9	Unchanged
Medium (11.5%)	9	8	Unchanged
High (14.5%)	8	7	Unchanged

7.1.13. Ideal PV Panel Inclination and Orientation

As a consumer, it is essential to predict the correct total generation output from a PV system prior to purchase and installation in order to accurately determine the feasibility of the PV system and the payback period. The inclination of the solar panels on a building roof and its orientation towards the sun influences the total annual kWhs that can be generated from the PV system. This then affects the payback period of the PV system. Cloud cover and shading of the panels further reduce the output of the PV system. The effects of shading can be mitigated when designing the rooftop installation by avoiding the installation of panels on parts of the roof that will be affected by shading. Whilst cleanliness on the surface of the PV panels also affect the overall generation output from the PV system. This is influenced by the amount of dust, sand, and wind experienced in the area coupled with the amount of rainfall experienced in the area. Cleaning of the surface of PV panels installed on an inclined roof may be assisted by rain. The effects of pollution, soling and dirt of the panels can be mitigated by regular cleaning of the panel surfaces. [21]

PV payback periods and environmental impact savings are dependent on the total kWhs per an annum that can be generated from the rooftop PV system. Since Durban is located in the Southern Hemisphere and as such the north facing slopes (or topography of roof-tops) receive better quality sunlight. Better quality being more direct (closer to being perpendicular to the sun). However not all residential roof tops in Durban are north facing and further the inclination angles vary between houses making it more difficult to calculate accurately how much electricity can be generated from an installed PV System. The site specific total kWhs generated can be calculated accurately using expensive or complex simulation software packages such as PVsyt, PVSol, Solar Edge, Helioscope, etc. This requires extensive meteorological data, knowledge of electrical and solar systems which is limited to few specialist in this field to use accurately. We then tried to create a simple yet accurate method to calculate the potential kWhs from a PV System in Durban without the use of these expensive and complex software packages. [21]

PV panel inclination and orientation play a major role in the annual generation production from a rooftop PV system. In order to understand how will rooftop orientation and inclination angle affect the potential output of a roof top PV system, simulations where carried out in the PVSyst simulation software for different orientation and inclinations as depicted in Figure 7.13. From the figure it can be see that the best generation production for a roof top PV system in Durban is a 30-32° inclination roof that's orientated north. This is depicted by 100% generation or maximum annual generation output. Worst case scenario will be a 22% of maximum output which will be on a 90° inclination angle south facing installation. [21]

		Orientation																								
		South			South East			East			North East			North			North West			West			South West			South
		-180	-165	-150	-135	-120	-105	-90	-75	-60	-45	-30	-15	0	15	30	45	60	75	90	105	120	135	150	165	180
Inclination	90°	22	24	28	33	40	46	52	57	60	62	64	64	64	64	64	62	60	57	52	46	40	33	28	24	22
	80°	26	28	32	39	46	53	59	64	68	71	73	74	75	74	73	71	68	64	59	53	46	39	32	28	26
	70°	32	33	37	44	51	59	66	71	76	79	82	83	84	83	82	79	76	71	66	59	51	44	37	33	32
	60°	38	39	43	50	57	65	71	77	82	86	89	91	91	91	89	86	82	77	71	65	57	50	43	39	38
	50°	45	46	50	56	63	70	76	82	87	91	94	96	96	96	94	91	87	82	76	70	63	56	50	46	45
	40°	53	54	57	63	69	75	80	86	90	94	97	99	99	99	97	94	90	86	80	75	69	63	57	54	53
	32°	60	61	64	68	73	78	83	88	92	95	98	99	100	99	98	95	92	88	83	78	73	68	64	61	60
	30°	62	63	66	69	74	79	84	88	92	95	98	99	100	99	98	95	92	88	84	79	74	69	66	63	62
	20°	72	72	74	76	79	83	86	89	92	95	97	98	98	98	97	95	92	89	86	83	79	76	74	72	72
	10°	80	81	81	82	84	86	87	89	91	92	93	94	94	94	93	92	91	89	87	86	84	82	81	81	80
	0°	87	87	87	87	87	87	87	87	87	87	87	87	87	87	87	87	87	87	87	87	87	87	87	87	87

Figure 7.13: Percentage of annual generation production for a rooftop PV system [21]

In order to accurately calculate the output of a roof PV system, the follow factors were calculated utilising the PVSyst software using the 30° north facing roof as the ideal case having a K Factor of 1 (100% or maximum annual generation production). The maximum yield of a roof top PV system is produced from 30-32° north facing PV panels. This will be used as a base to determine the fraction of the total yield that other potential roof orientation and inclination will yield. The K Factor will range from 0 – 1 where one represents a North facing orientation roof that's inclined at 30° to the sun as shown in Figure 7.14. [21]

	Orientation																								
	South			South East			East			North East			North			North West			West			South West			South
	-180	-165	-150	-135	-120	-105	-90	-75	-60	-45	-30	-15	0	15	30	45	60	75	90	105	120	135	150	165	180
Inclination 90°	0.22	0.24	0.28	0.33	0.4	0.46	0.52	0.57	0.6	0.62	0.64	0.64	0.64	0.64	0.64	0.62	0.6	0.57	0.52	0.46	0.4	0.33	0.28	0.24	0.22
80°	0.26	0.28	0.32	0.39	0.46	0.53	0.59	0.64	0.68	0.71	0.73	0.74	0.75	0.74	0.73	0.71	0.68	0.64	0.59	0.53	0.46	0.39	0.32	0.28	0.26
70°	0.32	0.33	0.37	0.44	0.51	0.59	0.66	0.71	0.76	0.79	0.82	0.83	0.84	0.83	0.82	0.79	0.76	0.71	0.66	0.59	0.51	0.44	0.37	0.33	0.32
60°	0.38	0.39	0.43	0.5	0.57	0.65	0.71	0.77	0.82	0.86	0.89	0.91	0.91	0.91	0.89	0.86	0.82	0.77	0.71	0.65	0.57	0.5	0.43	0.39	0.38
50°	0.45	0.46	0.5	0.56	0.63	0.7	0.76	0.82	0.87	0.91	0.94	0.96	0.96	0.96	0.94	0.91	0.87	0.82	0.76	0.7	0.63	0.56	0.5	0.46	0.45
40°	0.53	0.54	0.57	0.63	0.69	0.75	0.8	0.86	0.9	0.94	0.97	0.99	0.99	0.99	0.97	0.94	0.9	0.86	0.8	0.75	0.69	0.63	0.57	0.54	0.53
32°	0.6	0.61	0.64	0.68	0.73	0.78	0.83	0.88	0.92	0.95	0.98	0.99	1	0.99	0.98	0.95	0.92	0.88	0.83	0.78	0.73	0.68	0.64	0.61	0.6
30°	0.62	0.63	0.66	0.69	0.74	0.79	0.84	0.88	0.92	0.95	0.98	0.99	1	0.99	0.98	0.95	0.92	0.88	0.84	0.79	0.74	0.69	0.66	0.63	0.62
20°	0.72	0.72	0.74	0.76	0.79	0.83	0.86	0.89	0.92	0.95	0.97	0.98	0.98	0.98	0.97	0.95	0.92	0.89	0.86	0.83	0.79	0.76	0.74	0.72	0.72
10°	0.8	0.81	0.81	0.82	0.84	0.86	0.87	0.89	0.91	0.92	0.93	0.94	0.94	0.94	0.93	0.92	0.91	0.89	0.87	0.86	0.84	0.82	0.81	0.81	0.8
0°	0.87	0.87	0.87	0.87	0.87	0.87	0.87	0.87	0.87	0.87	0.87	0.87	0.87	0.87	0.87	0.87	0.87	0.87	0.87	0.87	0.87	0.87	0.87	0.87	0.87

Figure 7.14: K factors for annual generation production of a rooftop PV system [21]

Using the PVSyst software, we then simulate the output from the PV system that's for a 30° north facing roof. This gives us the maximum annual yield for the typical system size as depicted in Table 7.7.

Table 7.7: Typical annual PV system output for 30° north facing roof in Durban [21]

Month	**3 kW PV System (kWh)**	**4.6 kW PV System (kWh)**	**13.8 kW PV System (kWh)**
January	482	730	2189
February	453	687	2060
March	508	769	2306
April	458	694	2083
May	445	673	2020
June	429	650	1949
July	453	686	2057
August	468	709	2127
September	434	657	1972
October	448	678	2035
November	434	657	1970
December	475	720	2159
Total	**5487**	**8309**	**24927**

Table 7.7 indicates the ideal roof top PV system output for different size PV systems installed on a north facing roof inclined at 30 degrees. This value can be attributed to TKG in the Equation derived to evaluate the environmental benefits of renewabke energy and the payback period of roof top PV.

7.1.14. Favourable Roof Top Orientation in Durban for Solar PV

In order to understand the potential roof top orientation in Durban, a study was carried out to understand the favorable rooftop orientations in and around the city that will provide good solar PV generation output. [21] The output and observation from the study indicated the following:

1. Based on the methodology followed, including the reduced study area, the following estimates are made:

a. There is 50.12km^2, of residential rooftop in the study area. 3.5km^2 (7%) of this amount face North, 13.98km^2, (28%) face North-East or North-West and 17% is flat. [21]

b. Commercial rooftops total 6.74km^2 in the study area. 1.12km^2, (17%) face North, 5% face North-East or North-West and 1.68km^2, (25%) is flat. [21]

c. There is 20.39km^2 of industrial rooftop in the study area. 24% face North, 3.15km^2 (15%) face North-East or North-West and 0.7% is flat. [21]

This indicates that there are significant favorable rooftop orientations to support PV installations in Durban. [21]

7.1.15. PV Panel Degradation

Another important factor that needs to be taken into consideration if we want to accurately calculate the annual energy production from the roof top solar PV system is the PV panel degradation over time. In order to understand the extent of the potential degradation of the PV system, we study the warranty offered by the PV panel manufacturer and utilized this as the worst case scenario degradation. We use the manufacturer's performance warranty for the Yingli Solar PV panels to understand the worst case production degradation per a year as shown in Table 7.8. From the performance warranty it can be observed that we could lose up to 5.3% production in year 5 and 8.8% in year 10 whilst production reduces by 15.8% in year 20. Depending on the manufacture of the PV panel that the resident envisage to purchase, the data sheet of that specific panels needs to be looked at to understand the potential production loss over time in order to more accurately work out the payback period of the roof top PV system. [21]

Table 7.8: Yingli Solar PV Module performance warranty over a 25 year life span [21]

Period in Years from Warranty Start Date	Minimum Scheduled Performance Value (%)	Period in Years from Warranty Start Date	Minimum Scheduled Performance Value (%)
0	100	**13**	89.10
1	97.50	**14**	88.40
2	96.80	**15**	87.70
3	96.10	**16**	87.00
4	95.40	**17**	86.30
5	94.70	**18**	85.60
6	94.00	**19**	84.90
7	93.30	**20**	84.20
8	92.60	**21**	83.50
9	91.90	**22**	82.80
10	91.20	**23**	82.10
11	90.50	**24**	81.40
12	89.80	**25**	80.70

In order to incorporate the PV module production degradation over time into the PV system payback period, we divide the module performance warranty by 100 in order to obtain a "P" factor which we will use in the payback period equation that we derive. This "P" factor represents production over time and will have to be calculated from the PV module manufactures warranty for the PV panel utilized and is shown in Table 7.9. [21]

Table 7.9: Calculated P factors for Yingli Solar PV Module performance over 25 years [21]

Period in Years from Warranty Start Date	Minimum Scheduled Performance Value (%)	Period in Years from Warranty Start Date	Minimum Scheduled Performance Value (%)
1	0.975	**14**	0.884
2	0.968	**15**	0.877
3	0.961	**16**	0.87
4	0.954	**17**	0.863
5	0.947	**18**	0.856
6	0.94	**19**	0.849
7	0.933	**20**	0.842
8	0.926	**21**	0.835
9	0.919	**22**	0.828
10	0.912	**23**	0.821
11	0.905	**24**	0.814
12	0.898	**25**	0.807
12	89.80	**25**	80.70

7.1.16. Payback Period Calculator of Roof Top Solar PV

Large uptake of the residential PV market is expected when the payback period reduces to 5 years and below. This was confirmed in a survey done on a number of customers in South Africa who indicated that they will invest in rooftop PV when the payback period reduces to 5 years and below. This will make obtaining finance from banks and suppliers more accessible prompting greater growth in this sector. [21]

Prior to the installation of a roof top PV system, a consumer needs to be able to accurately work out the payback period of the rooftop PV system. An equation (4.28) was then derived to identify the payback period to achieve the breakeven point of the PV system. The equation takes into account the capital cost of the PV system with any interest accumulated for loans taken to purchase the system per annum, repair and maintenance costs, savings from avoided electricity usage from the grid at the utility residential tariff, panel degradation, panel orientation and inclination angle, payments obtained from any incentive schemes offered by the utility for any generated electricity exported to the grid and also taking into account of any subsidy offered by the utility or government. The breakeven point is obtained when the results obtained from the equation is equal to one. The values can be worked out over a number of years which is equal to i in the equation. [21]

$$\alpha = \sum_{N=1}^{N=i} \frac{A+B-E}{C-D} \tag{4.28}$$

Where:

$$A = [IT(1+\frac{PI}{100})^{N-1} \times (\frac{PU}{100}) \times K \times P \times TKWG]$$

$$B = [ET(1+\frac{PI}{100})^{N-1} \times \{\frac{(1-PU)}{100}\} \times K \times P \times TKWG]$$

$$C = [TCOI(1+\frac{M}{100})^{N}]$$

D = SV

E = AMARC

Table 7.10 defines the symbols used in Equation 4.28.

Table 7.10: Symbols used in payback period Equation 4.28

Description	Symbol
Total Capital Cost of Installation	TCOI
Export Tariff	ET
Total kWh generated from system over a period of one year	TKWG
Average Annual Percentage increase in tariff	PI
Percentage electricity utilised by the consumer from the PV system	PU
Number of years	N
Percentage interest rate of loan obtained for installation	M
Total number of years	i
Annual percentage degradation in output	PD
Factor for different orientation and inclination rooftop PV installations	K
Import Tariff	IT
Annual Maintenance and Repair Costs	AMARC
Subsidy Value	SV
Deviation from maximum generation based on orientation and inclination angle	K
PV Module production over time (years)	P

Equation (4.28) can be simplified as follows [21]:

Term B = 0, if the utility does not offer any compensation scheme for electricity exported to the grid such as a generation export tariff or Renewable Energy Feed – in – Tariff. [21]

Term C can be simplified to C = TCOI, if no loan was taken for the purchase and installation of the PV system. [21]

Term D = 0, if there is no incentive or subsidy scheme offered by the utility or country. [21]

Term E = 0, if there is no maintenance costs or costs incurred to replace damaged panels and inverters and cost of cleaning. [21]

The barriers of residential solar PV include [21]:

- No payment schemes for exported tariffs
- Lack of clear guidelines and standards from the regulator

- Revenue loss concerns by the utilities
- Lack of expertise within utilities to deal with generation
- May introduce quality of supply problems to the grid
- Municipal systems and networks were not designed to accommodate EG
- Utilities unable to offer long term Power Purchase Agreements due to Municipal Financial Management Act
- Customers meters are not designed to measure bi-directional power flow
- Lack of policy on SSEG from the National Energy Regulator of South Africa
- Battery technology is still very expensive
- High capital cost of PV systems

From Equation (4.28), it can be seen that there are a number of factors that can influence the payback period of rooftop PV. The uptake of residential solar PV can however, still be influenced by the following factors: [21]

- Reduction in the cost of a PV installations
- Higher FIT
- Higher annual increases in the residential electricity tariff
- Government or utility Subsidies incentive schemes
- Generation export tariffs
- Net metering schemes
- Easier and cheaper financing for these projects by banks
- Introduction of Carbon taxes
- Third party ownership of rooftop PV installation/renting of roof schemes
- Improvement in the efficiencies of PV systems

7.1.17. Current Standards and Guidelines

Utilities are currently awaiting guidelines from the NERSA to create and approve tariffs for exported energy to the grid as it has a major impact on the utilities revenue. The utilities have however to date been proactive in the creation of the simplified guideline for the connections of SSEG. This will drastically help the utilities in South Africa to safety and technically limit the amount of SSEG on their existing networks whilst still ensuring that the network parameters are not violated. [17]

To date there has been limited standards and guidelines in South Africa to govern the connection of these small scale generation projects on to the local distribution networks. Local utilities required assistance in devising guidelines that will assist them when allowing connection of SSEG on to their existing networks. To facilitate this, a working group was set up. The working group was made up of members from various utilities around South Africa and Eskom was set up to create more detailed guidelines for small scale (LV connected) EG. I was fortunate to represent eThekwini Municipality on this workgroup. SSEG requirements was not covered in fine details in the SAREGC as the MV/HV plants were. The NRS 097 guidelines was developed to cater for the growing number of existing and proposed SSEG projects which is predicted to increase over the next few years. [17]

This working group created a guidelines called the National Rationalization Standard 097 (NRS 097) which provided more detail and focus on the minimum requirements for small scale LV connected EG plants from 0 to 1000 kW. The NRS 097 was broken down into Part 1 to Part 4 focusing on different aspects as described Table 7.11. [17]

Table 7.11: Status and focus area of the NRS 097 guidelines [17]

NRS Document	Focus Area
Part 1	Utility Interface
	Covers all technical requirements of the embedded generator to connect onto the utility distribution network.
	First published in 2010, currently under review.
Part 2	Embedded Generator Requirements
	Standard to cover type testing requirements of generation plant and equipment to certify compliance to NRS 097 Part 1.
	Currently under development
Part 3	Simplified Utility Connection Criteria for low voltage connected generators
	A simplified criterion was developed to safely connect small scale EG plant to LV networks.
	Developed and approved in May 2014
Part 4	Procedures for implementation and application
	Standard still to be developed

A brief summarized version of the NRS 097 – 2 -3 (Simplified utility connection criteria for LV (230/400V) connected generators) is discussed in Table 7.12 and Figure 7.15 outlining the main points of the guideline. The purpose of the guideline was to assist the local South African utilities, many of whom did not have technical expertise to approve the connection of

SSEG plants on their local distribution networks. This criteria was drawn up by the NRS 097 working group of which I was a member after carrying out many case studies which indicates that an individual limit of 25% of the customer Notified Maximum Demand (NMD) will safely support a penetration level (percentage of customers that install a generator) of 30% to 50%. This is considered a reasonable and acceptable compromise between restricting individual sizes versus restricting penetration levels. The further assumption is that the design After Diversity Maximum Demand (ADMD) is unknown. [17]

Table 7.12 shows the simplified connection criteria for LV connected EG. [17]

Table 7.12: Generation connection limits on MV/LV feeders [17]

LV dedicated feeder	**LV Shared Feeder**	**MV Feeder**
Maximum EG ≤ 75% of NMD.	Maximum EG ≤ 25% of NMD.	Total EG ≤ 15% of the MV feeder loading.
Multi-phase supplies: > 4.6 kVA shall be balanced.	EG > 4.6 kVA shall be balanced 3 phase.	
Single-phase supplied: maximum generator size is 13.8 kVA.	Total shared EG shall be ≤ 25% of the transformer rating.	
	Allowed maximum individual limit is 20 kVA.	

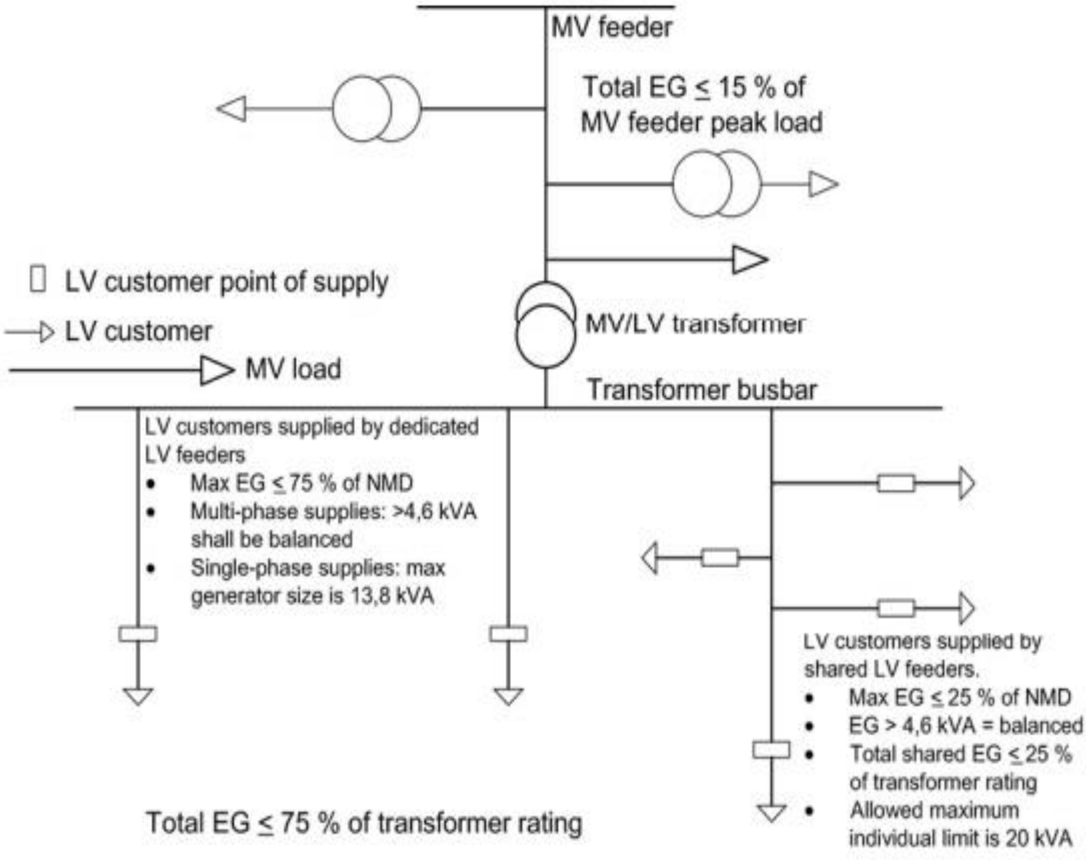


Figure 7.15: Summary of the simplified connection criteria [17]

The technical limits that constraint generation are as follows [17]:

(i) Thermal ratings of the lines and cables.

(ii) LV voltage regulations (±10%).

(iii) The maximum change in LV voltage is limited to 3%.

(iv) Islanding of the utility network is not allowed.

(v) The fault level at the customer point of supply shall be greater than 210 A or the minimum fault level at which the generator is rated.

The application of the limits then gave rise to the following proposed criteria [17]:

(a) Voltage rise on the LV feeders should be limited to 1% (to ensure compliance to NRS048 voltage limits, MV voltage control practices and the MV/LV transformer voltage ratio and tap settings).

(b) The maximum generation connected across the MV/LV transformer is limited to 75%.

(c) The individual customer limit on a dedicated feeder is limited to 75%.

(d) The dedicated LV feeder minimum size is based on a maximum voltage rise of 1%.

(e) The individual customer limit of 25% of a shared feeder will typically support penetration levels of 30 – 50%.

The total generation connected to an MV feeder is limited to 15% of the MV feeder. (This value of 15% is informed by practices in the United States and Europe and is based on the ratio of maximum to minimum feeder loading for a typical consumer load profile. A 15% limit also ensures low probability of reverse power flow into the MV source thereby preventing voltage rise on the MV feeder). [17]

The flow chart in Figure 4.102 shows the method in which the utility will go about utilizing the simplified connection criteria. This criteria is limited to sizes less than or equal to 350 kVA and LV connected. Any generator above 350 kVA is assumed to be connected onto the MV network or should it be connected onto the LV network then detailed studies need to be carried out. It utilizes the generation size limit discussed in Figure 4.101. If the generator meets all of the criteria in Figure 7.16, then the utility can safely allow the connection of this generator onto the network. However if the criteria is not met, then it offers solutions or suggest that detailed studies be carried out before allowing the connection onto the network. This criteria is now utilized by most utilities in South Africa when approving EG connections on to the local distribution networks. [17]

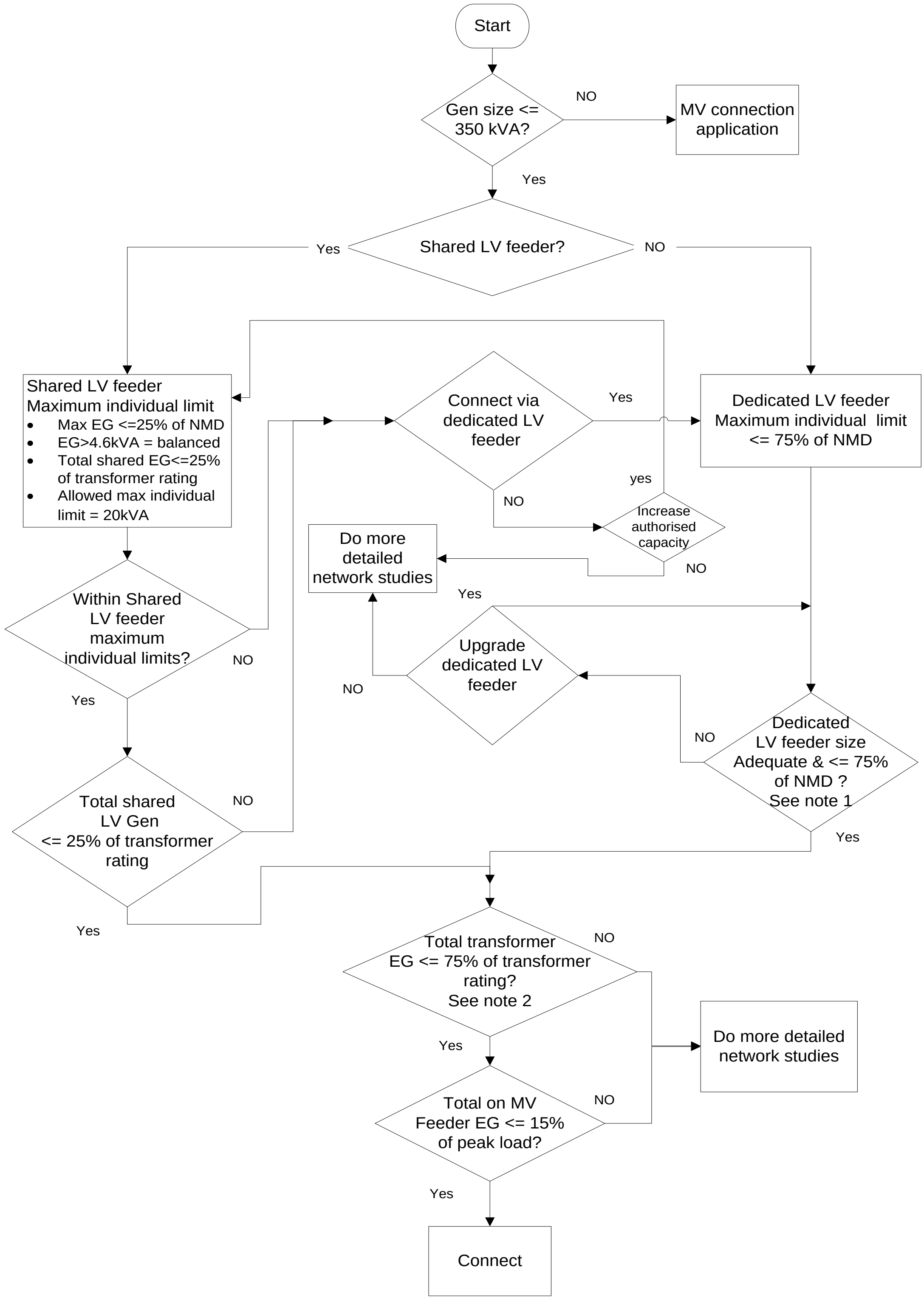


Figure 7.16: Flow chart of simplified connection technical evaluation criteria [17]

7.1.18. Case Study: LV Network impact with increased EG Penetration Background

In order to determine the impact of residential solar PV, a case study was carried out utilising the eThekwini Electricity distribution grid. A new housing development in Durban was utilised for the case study. The development consisted of 90 new medium/high income homes with requests and potential for PV installations based on the energy efficiency requirements for this ecological estate. The site was fed from a 500 kVA miniature substation which was dedicated solely for the development. The electrical layout of the development is show in the Figure 7.17. For the purpose of this case study we modelled the development to consist of three circuits with 30 consumers per a circuit and 3 consumers per a customer distribution unit.

The site was fed from two distributor substations, namely: 192 Underwood Road DSS and 10 Robin Road DSS. These DSS are fed from the Underwood Road Major Substation and Northdene Major Substation. Table 7.13 shows the estate internal reticulation which was designed to ensure that all phases were balanced for the purpose of this study. The case study compared the base case network (with no rooftp solar PV) to that of different levels of PV penetration in order to ascertain the potential impacts of residential solar PV should the penetration levels increase. The network voltage level depicted in Figure 7.17 is at three phase 400V on the LV side of the local substation transformer and up to the Consumer Distribution Unit, thereafter each of the consumers are supplied with single phase 230V.

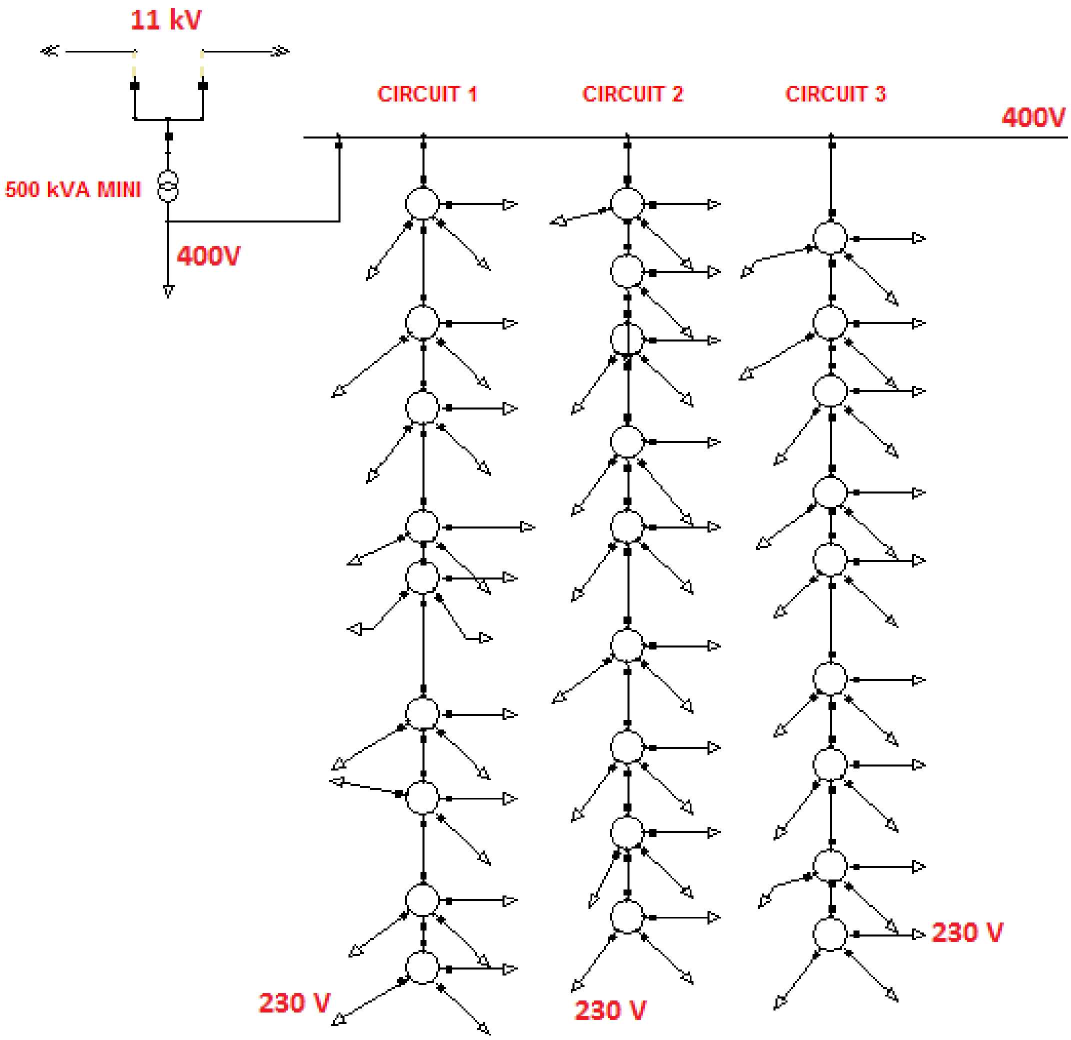


Figure 7.17: LV network model in DIgSILENT PowerFactory

Table 7.13: Circuit feeder layout used for the simulations

CDU NUMBER	CIRCUIT 1	CIRCUIT 2	CIRCUIT 3
	Number of Customers	Number of Customers	Number of Customers
1	3	3	3
2	3	3	3
3	3	3	3
4	3	3	3
5	3	3	3
6	3	3	3
7	3	3	3
8	3	3	3
9	3	3	3
10	3	3	3
TOTAL	30	30	30

To study what impact cable sizes will have on the distribution network, we utilise the 3 different size cables that are utilised for LV reticulation at eThekwini Electricity as shown in Table 7.14. Circuit 1 will be modelled using a 95 mm^2 cable, Circuit 2 will be modelled with a 150 mm^2 cable and Circuit 3 will be modelled with a 240 mm^2 cable.

Table 7.14: LV cable ratings utilised by eThekwini Electricity

Circuit Number	Cable Size ($mm^{2)}$	Cable Rating (A)
1	95	172
2	150	249
3	240	399

7.1.18.1. Assumptions

(i) All customers are single phase customers.

(ii) All PV installations are single phase 4.6 kW systems (maximum PV installation size as per the requirements of NRS 097 Part 3).

(iii) Existing LV loads were balanced.

(iv) Due to the short cable length (< 5 meters) between the CDU and customer meter box which was on the boundary, this was left out to simply the simulations.

(v) Electricity consumption for street lighting was not considered.

(vi) The National Rationalization Standards 069, is used widely standard in South Africa by utilities and consultants when determining loads for new developments. This data is then used to correctly size the distribution network components such as cables/lines and transformers. Table 7.15 is an extract from the standard and gives us the kilovolt-ampere zoning After Diversity Maximum Demand for urban areas at the transformer LV bus. Since the dwellings fell under “Domestic normal”, an ADMD of 4.6 kVA was selected.

Table 7.15: ADMD standard for different urban categories [61]

	Type of Development	kVA/stand (individual)
1	Domestic Electrification	0.2 - 1
2	Domestic low income	1- 3
3	Domestic normal	3 – 6
4	Domestic upmarket	6 – 8
5	Domestic luxury single phase	8 – 12
6	Domestic luxury three phase	> 12

7.1.18.2. Typical PV generation profile vs typical residential load profile

The typical residential load profile is characterised by the morning and evening peaks as shown in Figure 7.18. Whilst the typical PV generation profile is characterised by the start of generation from sunrise to sunset with peak occurring around noon as shown in Figure 7.18. In the residential households there is usually a mismatch between the PV generation and load demand which usually result in export of the excess generated electricity.

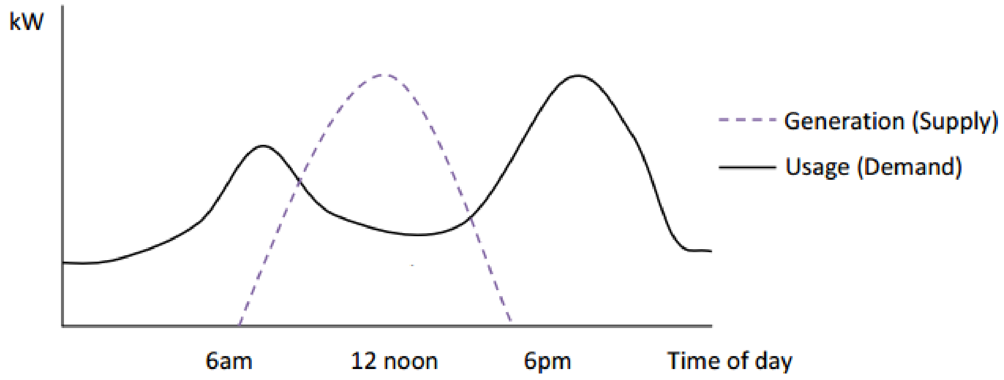


Figure 7.18: Typical residential load profile vs PV generation profile [1]

7.1.18.3. Case Study

The following were taken into consideration in the case study:

- Study the network parameters under 25%, 50%, 75% and 100% of the maximum individual load (4.6 kVA).
- Look at PV penetration levels from 0, 50% and 100%.
- Look at the NRS 097 criteria.
- Look at the impacts of utilizing 95 mm^2, 150 mm^2 and 240 mm^2 low voltage cables.
- Study at the impacts of voltage rise and losses on the network under different network loading and PV penetration levels.

7.1.18.4. Case Study Results

7.1.18.4.1. Roof Top PV Case Study 1: Base Case: No PV Generation

Table 7.16 shows the beginning and end of feeder voltage drop on the low voltage network with no roof top PV installed. From Table 7.16 it can be seen that Feeder 1 and Feeder 2 experience voltage drop problems during peak loading periods. Hence the feeder will have to be designed using a 240 mm^2 cable to ensure that all the feeder voltages remain within the statutory limits.

Table 7.16: End of the feeder voltage drop (nominal tap)

Percentage Load	Start Feeder Voltage (pu)	95 mm^2 (Circuit 1) End of Feeder Voltage (pu)	150 mm^2 (Circuit 2) End of Feeder Voltage (pu)	240 mm^2 (Circuit 3) End of Feeder Voltage (pu)
25%	1.019	0.984	0.995	1.009
50%	1.002	0.940	0.961	0.985
75%	0.985	**0.892**	0.924	0.959
100%	0.966	**0.840**	**0.885**	0.931

7.1.18.4.2. Case Study 2: 50% PV Penetration

With the installation of 50% roof top solar PV, all of the consumer voltages remains well within the ±10% statutory limits as shown in Table 7.17.

Table 7.17: End of the feeder voltage with 50% PV

Percentage Load	Start Feeder Voltage (pu)	95 mm^2 (Circuit 1) End of Feeder Voltage (pu)	150 mm^2 (Circuit 2) End of Feeder Voltage (pu)	240 mm^2 (Circuit 3) End of Feeder Voltage (pu)
25%	1.026	1.044	1.037	1.028
50%	1.011	1.055	1.006	1.006
75%	0.995	0.963	0.972	0.982
100%	0.977	0.918	0.936	0.957

7.1.18.4.3. Case Study 3: 100% PV Generation

With the installation of 100% roof top PV installed, the feeder voltages all remain within the required statutory limits of ±10%. Even with the use of smaller cables (95 mm^2 and 150 mm$^{2)}$ no violations are experienced as shown in Table 7.18.

Table 7.18: End of the feeder voltage with 100% PV

Percentage Load	Start Feeder Voltage (pu)	95 mm^2 (Circuit 1) End of Feeder Voltage (pu)	150 mm^2 (Circuit 2) End of Feeder Voltage (pu)	240 mm^2 (Circuit 3) End of Feeder Voltage (pu)
25%	1.032	1.091	1.070	1.045
50%	1.018	1.055	1.040	1.023
75%	1.003	1.017	1.009	1.001
100%	0.986	0.975	0.976	0.977

7.1.18.4.4. Feeder Losses: Base Case: No PV Generation

Table 7.19 shows that with the kW losses experienced on the LV feeder for different percentage loading with no PV generation. From Table 7.19 it can be seen that as the percentage of load grows, so does the losses on the network with the greater losses on the smaller feeder cables. Using the 95 mm^2 cable yields 473% more loss (compared to the losses experienced on the 240 mm^2 cable) whilst the losses on the 150 mm^2 cable yields a 285% loss (compared to the losses experienced on the 240 mm^2 cable) under a 100% of ADMD load scenario.

Table 7.19: Feeder losses (kW) with no roof top PV

Percentage Load	95 mm^2 (Circuit 1) (kW)	150 mm^2 (Circuit 2) (kW)	240 mm^2 (Circuit 3) (kW)
25%	0.34	0.21	0.08
50%	1.06	0.66	0.24
75%	2.3	1.42	0.5
100%	4.21	2.54	0.89

7.1.18.4.5. Feeder Losses: 50% PV Generation

Table 7.20 shows that there is an increase in the losses on the network for the case with 50% PV generation and 25% of ADMD load on the network. This is a result of excess generation on the network. However there a drastic reduction in losses on the network when the percentage load to ADMD increases to 50% and greater, then we see a drastic reduction in the losses on all three feeders. This is due to the load been supplied by the local generation as opposed to the utility. The reduction in losses for the case of 100% of ADMD percentage load with 50% PV generation on the network with the use of a 95 mm^2 LV cable is 3.56% whilst its 3.54 % for the use of the 150 mm^2 LV cable and 3.37% with the use of the 240 mm^2 LV cable in comparison to the losses on the base case network results in Table 4.78.

Table 7.20: Feeder loading with no roof top PV

Percentage Load	95 mm^2 (Circuit 1)	150 mm^2 (Circuit 2)	240 mm^2 (Circuit 3)
25%	1.37	0.86	0.31
50%	0.54	0.34	0.13
75%	0.15	0.09	0.04
100%	0.12	0.08	0.03

7.1.18.4.6. Feeder Losses: 100% PV Generation

Table 7.21 shows that there is an increase in the losses on the network in the case of 25% of ADMD loading with 100% PV generation on the network. This can be attributed to there been excess generation on the network in comparison to the load on the local network. There losses reduce when compared to the base case in Table 7.19 with no PV generation once the percentage load is 50% and greater.

Table 7.21: Feeder loading with no roof top PV

Percentage Load	95 mm^2 (Circuit 1)	150 mm^2 (Circuit 2)	240 mm^2 (Circuit 3)
25%	1.11	0.74	0.28
50%	0.62	0.41	0.16
75%	0.4	0.26	0.1
100%	0.51	0.33	0.12

7.2. Summary of Chapter 7

The case studies investigating the feasibility of an ideal inclined small scale residential PV system shows that the minimum payback period is currently 8 years and greater. This reduces to 7 years and above with the implementation of a REFIT based on Eskom avoided costs. This is unlikely to attract huge patronage of residential solar PV as predicated by many especially with no REFIT tariff for excess energy exported to the grid. The take-off of the residential PV market is expected when the payback period reduces to 5 years and below in South Africa. This can be achieved by the introduction of subsidies which will assist in reducing the payback period. This was confirmed in a survey done on a number of customers in South Africa who indicated that they will invest in PV when the payback period reduces to 5 years and below. This will make obtaining finance from banks and suppliers more accessible prompting great growth in this sector. [21]

The mismatch between the PV generation profile and the residential load profile affects the payback period of a roof top solar PV installation. However it is possible by performing load shifting to try and utilise electricity household equipment during the solar PV operating times. This could mean operating items such as the pool pumps, dish washers, washing machines, etc during the day to allow greater usage of the generated electricity from the solar PV system. Utilities and government can offer subsidies to residents which will assist to reduce the PV payback period and hence act as a catalyst together with utilities offering the consumer a generation tariff for electricity exported to the grid from these PV systems. The derived breakeven point formulae will assist a consumer in accurately determining the payback period prior to installing a roof top PV system relatively easy without the use of expensive complex computer software for different roof orientation and inclinations. South African utilities applying the NRS 097 standard will ensure that power quality problems such as voltage rise can be avoided. For a greater penetration level of solar PV, more detail and accurate software simulation studies need to be carried out. The case study also shows that cable size affect your network impacts and by increasing the LV cable size it is possible to avoid voltage rise impacts. [1]

PV system generation output can be further improved by taking into account the shading effects, cleaning of panels and spacing panels when installing to reduce temperature rise. [1]

CHAPTER 8: CASE STUDY 2: GENERATION PROFILES FOR EXISTING AND PROPOSED GENERATION PROJECTS

8.1. Introduction to Chapter 8

This chapter sets out to investigate the renewable energy generation profiles in comparison to the customer load profiles for various new and existing projects in Durban. The study focuses on the new Municipal building rooftop PV project in Durban but also looks at the profiles from a few existing PV and co-generation projects.

8.1.1. Background: Solar PV Projects

A study was carried out in 2013 by the eThekwini Municipality to identify the market barriers regarding solar PV installations in the eThekwini Electricity area of supply. “An electronic survey was undertaken on 15 individuals representing small and medium businesses and 9 individuals representing big businesses. The survey in no way represents the views of all the household and business in eThekwini but provide insight into the potential barriers.” [21]

In the business category, “15 businesses who undertook the survey were found to be pro-environmental with just under the majority currently measuring their Carbon footprint with two-thirds having a strategy in place to reduce their Carbon footprint.” [21] 78.9% of the companies surveyed exported less than 50% of their products, 15.8% exported more than 50% of their products and 5.3% did not know if they exported any products. “Literature suggests that more proactive companies are more likely to invest in green technology versus those that have no environmental orientation of the surveyed companies. Only 47.4% of the companies owned the property in which the business was located. This is an important factor in solar PV investments due to the longer return on investment time period.’ [21] Companies quoted their monthly electricity usage ranging from a couple thousand rands to R100000. The companies were on various tariff structures ranging from Business and General, Commercial Time of Use or Industrial Time of Use. 7.1 % of the businesses had already invested in solar PV and 30.8% indicated that they were looking to invest in solar PV in the future. The major drivers were care for the environment and thereafter money saving. [21]

“In the industrial category, 10 large industrial customers were surveyed, of which 90% measured their Carbon footprint and 80% had strategies in place to reduce their Carbon footprint. The industries all had large electricity bills ranging from R2 million to R7 million and 100% owned their premises which suggest a potential saving from PV investments. The number of employees in the industries reviewed ranged from 150 to 7500. This gauged the potential size of the business, which gives an indication of electricity usage and company size. 80% of the industries indicated that they exported less than 50% of their product. None of the industries had any solar PV installed. 30% of the industries indicated that they were considering investing in solar PV in the short term whilst 70% indicated that they were not considering solar PV installations. The main driver for installing solar PV was care for the environment as the primary reason and to save money as the secondary driver." [21]

8.1.2. Favourable Roof Top Orientation Available in Durban for Solar PV

In order to understand the potential commercial and industrial roof top orientation in Durban a study was carried out to understand the favorable rooftop orientations in and around the city that will provide good solar PV generation output. The output and observation from the study indicated the following: [21]

Based on the methodology followed, including the reduced study area, the following estimates are made:

(a) Commercial rooftops total 6.74km in the study area. 1.12km, (17%) face North, 5% face North-East or North-West and 1.68km, (25%) is flat.

(b) There is 20.39km of industrial rooftop in the study area. 24% face North, 3.15km (15%) face North-East or North-West and 0.7% is flat.

This indicates that there are significant favorable rooftops to support PV installations in Durban. [21]

8.1.3. Types of PV Inverters Available

As part of the municipal building roof top PV project, it was decided to investigate the use of the new leading solar technologies as part of the project. There are a number of inverter technologies currently available on the market. The purpose of the inverter in a PV system is for DC to AC conversion and, in most inverters, Maximum Power Point Tracking (MPPT). Inverter technologies currently available on the market include:

1. **String Inverters:** These are the conventional inverters. A string made up of a number of panels connect to the inverter. The Maximum Power Point Tracking (MPPT)

function is built within the inverter and is used to optimise the generation output of the panels. Typically used in residential and commercial applications.

2. **Micro Inverters:** Each panel will contain a micro inverter which performs the DC to AC conversion.
3. **Central Inverters:** These are large capacity inverters used for solar farm applications where multiple strings connect to a single inverter.
4. **Solar Edge Inverters with Individual Optimisers:** This technology differs from conventional inverter technology by having the MPPT installed on each panel as opposed to the inverter. This technology offers many advantages which will be investigated and studied from the installations. Some of the major advantages that the Solar Edge technology offers over conventional inverter technology are addressing of the problem of shading of panels, safety, etc. Table 8.1 shows the benefits of the Solar Edge technology.

Table 8.1: Traditional PV system vs Solar Edge PV system [62]

Traditional System		**Solar Edge System**
Energy Loss	Module mismatch (3-5%)	Solar Edge technology solution overcomes all energy losses providing up to 25% more energy.
	Partial Shading (2 – 25%)	
	Dynamic MPPT Loss (3 – 10%)	Monitoring at individual panel level is possible.
System Drawbacks	No module level monitoring	String voltages are 1 volt per an optimizer seen at the inverter terminal when AC voltage is lost.
	Limited roof utilization	
	Safety hazards (high voltage DC)	12 year warranty on the inverter and 25 year warranty on the optimizer.

5. Smart Inverters: Smart inverters have the functionality to control the voltage by either absorbing or supplying reactive power and ensuring that it remains connected for incidence on the network.

For the purpose of this case study, we will investigate the simultated outputs from the 6 municipal building rooftop projects and compare the generation size to the building load profile.

8.1.4. Solar PV Performance Ratio

"The performance ratio (PR) of a PV installation is defined by the difference between the actual energy yield of a site (production energy) and the expected energy of the site, based on the module type and environmental sensor measurements. The PR value ranges between 0 and 1 and is used to evaluate the PV system performance: A high PR indicates a properly operating site. PR ratio can be utilized to compare the performance of several systems in different locations, monitor a site's performance over time and check if a site is meeting its energy production targets." [62]

8.1.4.1. Performance Ratio Calculation

Performance Ratio (PR) "is the ratio between the actual and the expected energy stated as a percentage" and is calculated using Equation (4.29): [62]

For a PV system with a single orientation:

$$PR = \frac{Production\ Energy}{Expected\ Energy} \tag{4.29}$$

The "production energy is the measurement of the site output in kWh

The expected energy is calculated by multiplying the sensor readings by the peak power (the nominal site output at Standard Test Condition)." [62]

8.1.5. Rooftop PV to be installed on eThekwini Municipality buildings

The eThekwini Municipality Energy Office was given a R10 million grant to implement PV on various Municipal Buildings. A tender was awarded to Sustainable Energy Africa (SEA) to carry out a pre-feasibility study on the possibility of installing PV on various municipal building. From the initial list of 18 Municipal buildings, 10 buildings were found suitable to install rooftop PV. The following criteria was used for the rooftop PV site selection namely size, orientation of roof, possible shading of roof, visibility to the public, estimated maximum size PV that could be installed and the ratio of maximum power production of the solar PV installation to the nominal power consumption of the building. SEA then used a cost of R20/kW installed PV to come up with the required amount of 500 kW that could be installed with the R10 million grant that was given to the municipality. From this the list was then shorten down to the 6 sites. [21]

8.1.6. Impacts of Commercial/Industrial Solar PV on the Customer Load Profile

8.1.6.1. Case Study: Roof Top Solar PV - EOS Solar Project at eThekwini Municipality

In order to lead by example and encourage renewable energy projects at eThekwini Municipality, the Municipality went out on tender for a Municipal Building roof top PV project. The project will look at the implementation of roof top solar PV on 6 Municipal building roof tops and will serve to provide learnings to the Municipality. We will study the PV installaiton in comparison to the building load consumption. These buildings typically represent the case case of commercial and industrial buildings where the size of the PV systems is typically installed to reduce the building consumptions as opposed to export excess to the grid. For each of the buildings, we will study the building load profiles and in comparison to the PV installation size. We will also look at the simulated generation output from the proposed PV system.

8.1.6.2. Case Study 1.1: Moses Mabhida Stadium Sky Car

The Moses Mabhida Sky Car arch location is shown in Table 8.2 and the proposed installation shown in Figure 8.1 which was selected for a PV installation size of 4.5 kWp. This typically represents a residential installation.

Table 8.2: The Moses Mabhida Stadium arch location

PV System Size	PV System Location
4.77 kWp	29°49'38.58"S, 31° 1'51.74"E

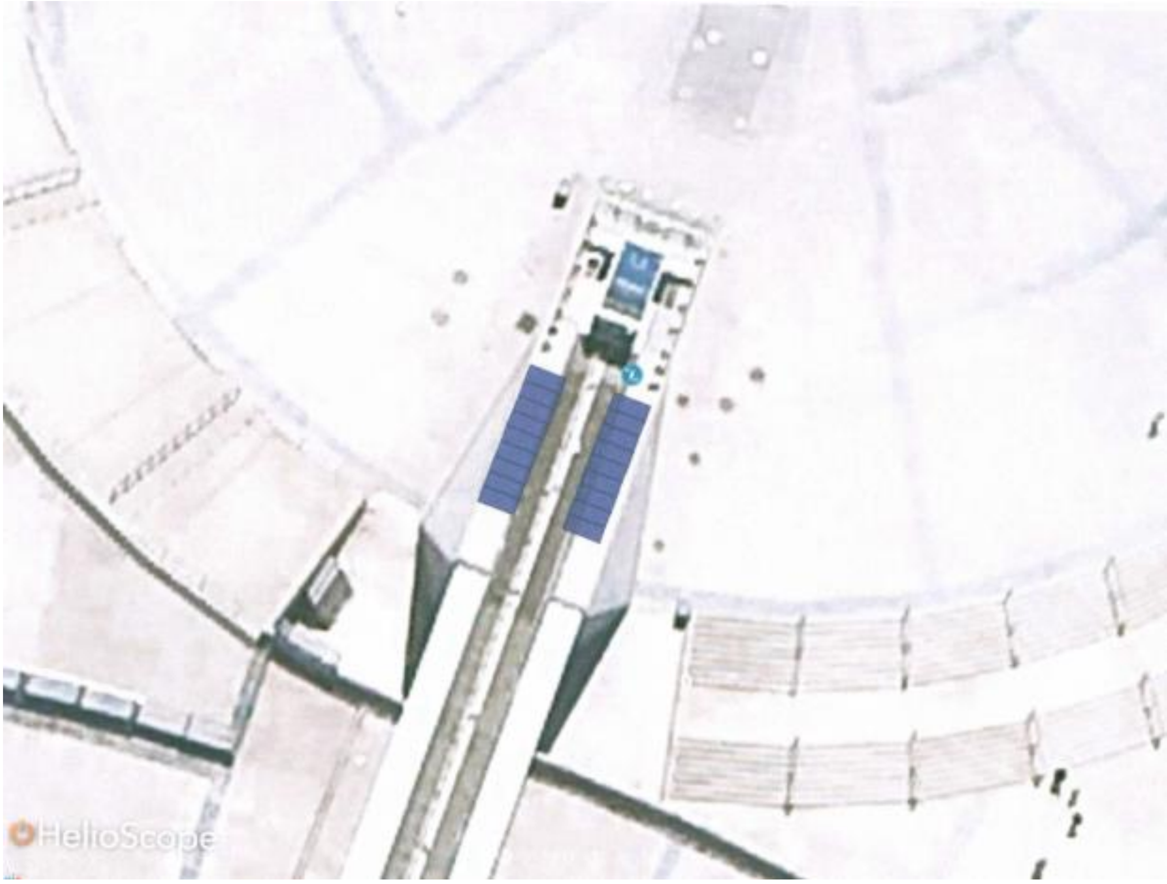


Figure 8.1: Moses Mabhida stadium arch proposed PV installation [63]

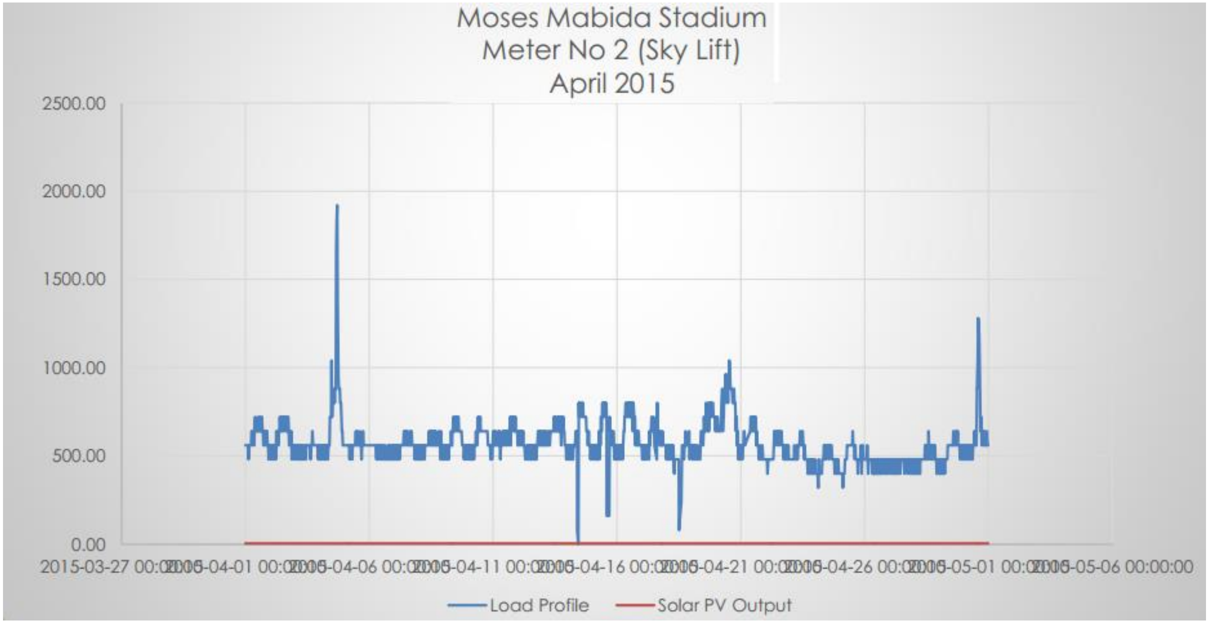


Figure 8.2: Load profile data for the Moses Mabhida Stadium in comparison to the PV installation [63]

Figure 8.2 shows the load profile data for the Moses Mabhida Stadium in comparison to the PV installation on the sky car arch. The Moses Mabhida Stadium has a base load consumption of around 500 kVA with consumption increasing to around 2 MVA for events at the Stadium. Figure 8.2 shows that the PV system size (4.77 kW) is negligible (1%) compared to the base load (500 kW). Table 8.3 shows the equipment to be installed at the Moses Mabhida Stadium. [63]

Table 8.3: Equipment to be installed at Moses Mabhida Stadium sky car [63]

	Solar Edge Inverter	**Canadian Solar Panels**	**Optimizers**	**System AC Size**	**System Production**
	5 kW	**265 W**	**P300**	**kW**	**MWh/year**
MMS Sky Car	1	18	18	4.77	6.841

The simulations result in Figure 8.3 indicates that with the proposed total annual energy generation yield estimate is 7403 kWh.

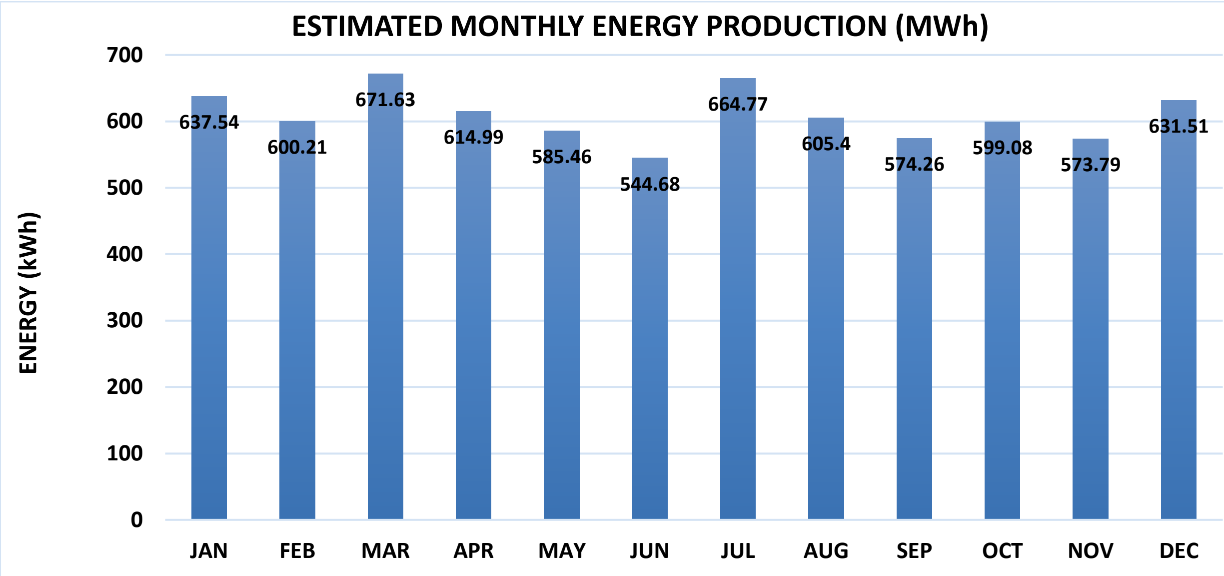


Figure 8.3: Energy yield simulation for Moses Mabhida Stadium sky car [63]

8.1.6.3. Case Study 1.2: Metro Police Head Quarters Building

The Metro Police Headquarters building location is shown in Table 8.4 and the proposed installation shown in Figure 8.4 which was selected for an PV installation size of 92.75 kWp. This typically represent a commercial PV installation.

Table 8.4: Metro Police Headquarters building location

Building	**Location**
Metro Police Headquarters	29°50'57.05"S, 31° 1'30.66"E

Figure 8.4: Proposed PV installation at the Metro Police Head Quarters Building [63]

The proposed PV installation size makes up a substantial (almost 50%) part of the building load demand as shown in Figure 8.5. This will affect the building load profile that will be seen at the meter point by the Electricty Department.

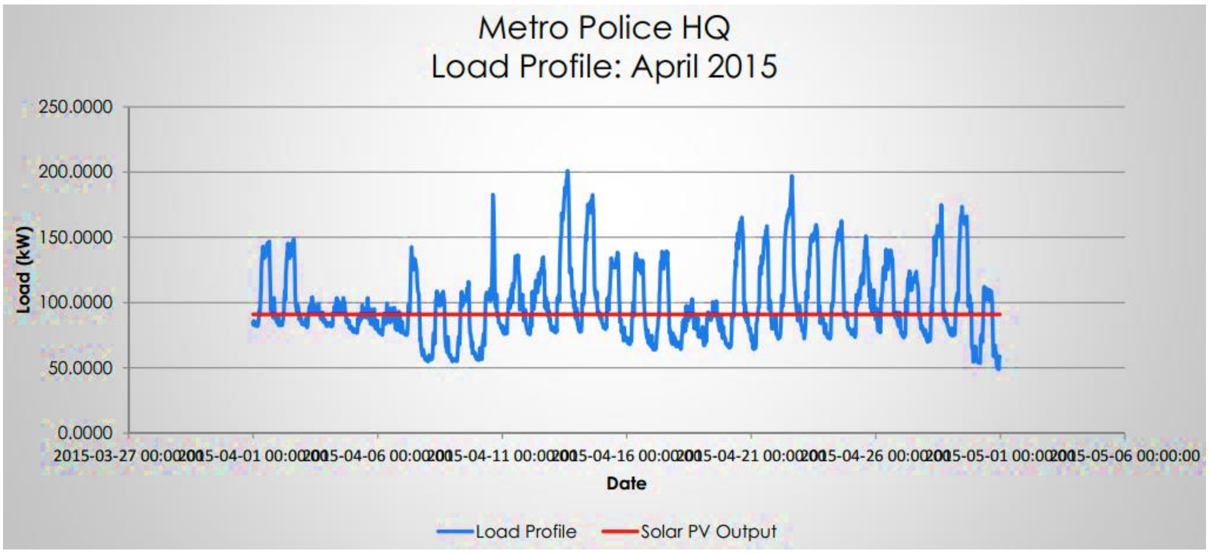


Figure 8.5: Metro Police Head Quarters building load profile in comparison to the installed PV capacity [63]

The Metro Police Headquarters building installation will consist of 350 solar panels, 175 optimizers and 3 inverters. The simulation results reveal that upon commissioning, the installation will produce 141.6 MWh per annum as shown in Table 8.5 and Figure 8.6. Estimated annual energy generation yield is 141.6 MWh.

Table 8.5: PV equipment installed at the Metro police Head Quarters building [63]

	Solar Edge Inverter	**Canadian Solar Panels**	**Optimizers**	**System AC Size**	**System Production**
	27.6 kW	**265 W**	**P600**	**kW**	**MWh/year**
Metro Police HQ	3	350	175	92.75	141.6

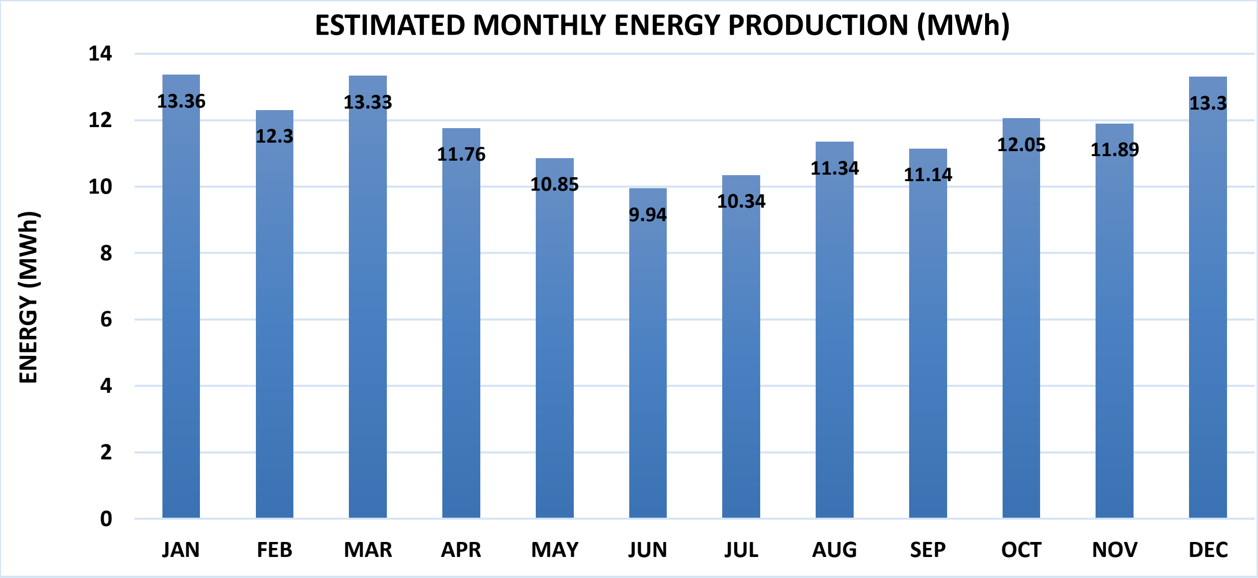


Figure 8.6: Energy simulation for Metro police Head Quarters Building [63]

8.1.6.4. Case Study 1.3: Moses Mabhida Stadium Peoples Park Restaurant Roof Top PV Installation

The Moses Mabhida Stadium Peoples Park restaurant location is shown in Table 8.6 and the proposed installation shown in Figure 8.7 which was selected for a PV installation size of 24.91 kWp. This typically represents a small commercial installation.

Table 8.6: Moses Mabhida Stadium Peoples Park restaurant location

Moses Mabhida Stadium – People's Park restaurant	29°49'55.29"S, 31° 1'43.42"E

Figure 8.7: Proposed rooftop PV installation at People's Park Restaurant [63]

The installation size was selected such that bulk of the generation will be used up by the restaurant with minimal export to the grid as shown in Figure 8.8. Table 8.7 provides a list of equipment to be installed at the Peoples Park restaurant. This is typically how a consumer will select his installation size to get maximum benefit from saving on KWh used from the grid at avoided costs. This installation will change the customers load profile.

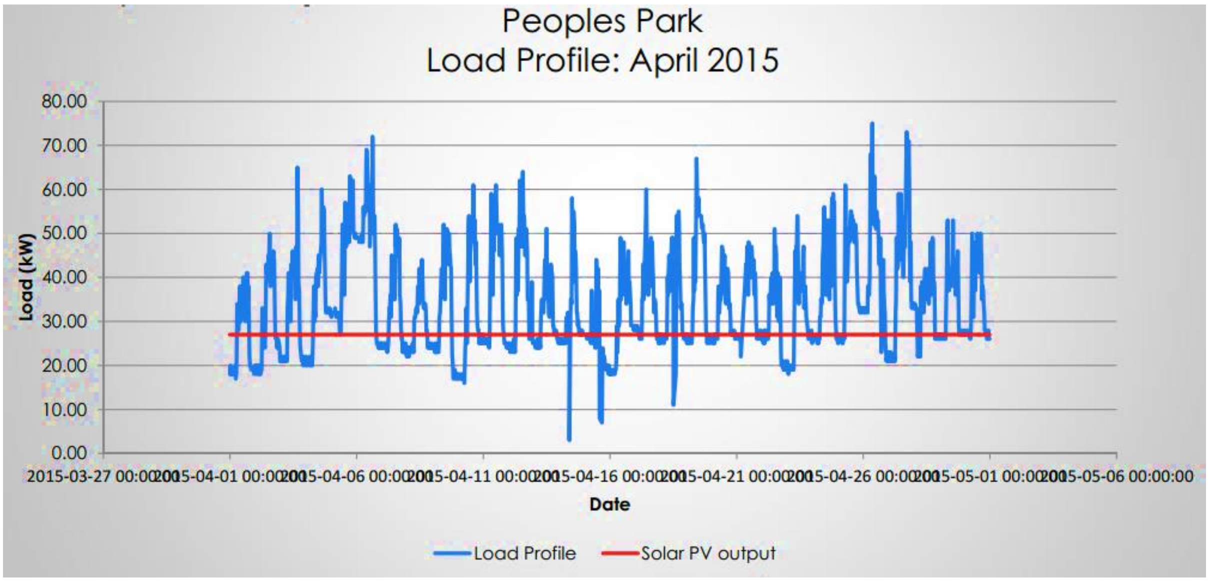


Figure 8.8: Peoples Park load profiles compared to the proposed peak PV generation [63]

Table 8.7: Equipment installed at the Peoples Park Restaurant [63]

	ABB Inverter	**Canadian Solar Panels**	**Optimizers**	**System AC Size**	**System Production**
	33 kW	**265 W**	**P600**	**kW**	**MWh/year**
Peoples Park Restaurant	1	94	None	24.91	40.43

8.1.6.5. Case Study 1.4: Ushaka Marine World Roof Top PV Installation

The uShaka Marine World Administration building location is shown in Table 8.8 and the proposed installation shown in Figure 8.9 which was selected for a PV installation size of 110.8 kWp. This typically represents a commercial/industrial installation.

Table 8.8: uShaka Marine World office block location

uShaka Marine World office block	29°52'6.07"S, 31° 2'40.43"E

Figure 8.9: Solar PV proposed installation layout at Ushaka Marine World office block [63]

The PV installation size is with respect to the total load consumption at the uShaka Marine World is relatively small. This will see no export to the municipal grid and have minimal inpacts to the customer load profile see at the meter point. The simulation on the annual PV generation production in 165.4 MWh. Figure 8.10 shows the Ushaka Marine World load profile compared to the proposed PV installed capacity.

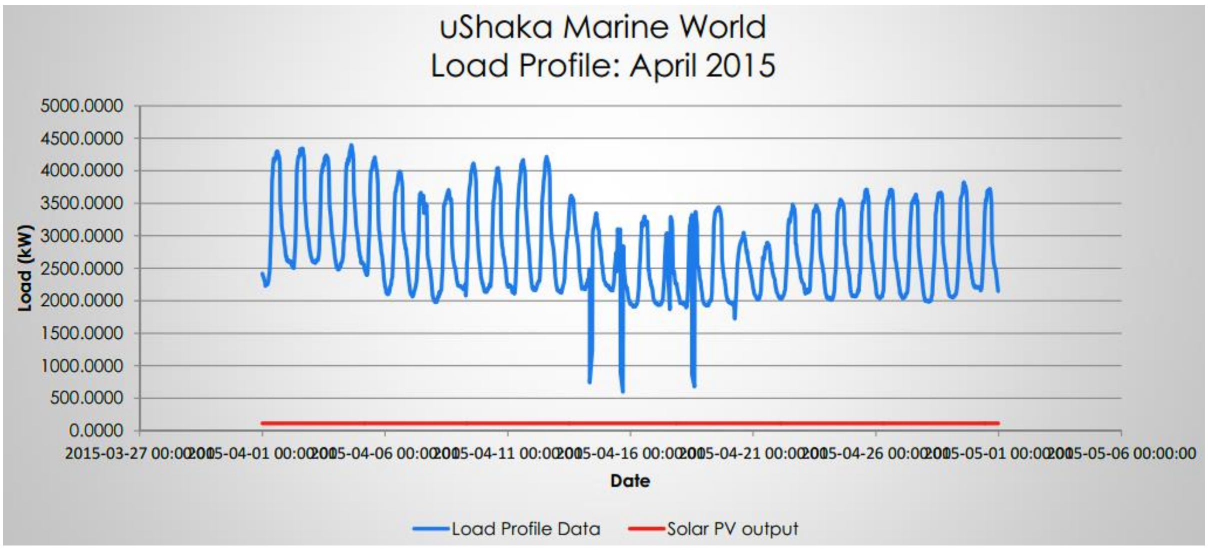


Figure 8.10: uShaka Marine World load profile compared to the proposed PV installed capacity

Table 8.9 indicates that the uShaka Marine World installation will consist of 420 solar panels, 210 optimizers and 4 inverters to make up a 110.8 kWp installation that will produce 165.5 MWh per annum as shown in figure 8.11.

Table 8.9: Equipment to be installed at uShaka Marine World [63]

	Solar Edge Inverter	Canadian Solar Panels	Optimizers	System AC Size	System Production
uShaka Marine World	**27.6 kW**	**265 W**	**P600**	**kW**	**MWh/year**
	4	420	210	110.8	165.4

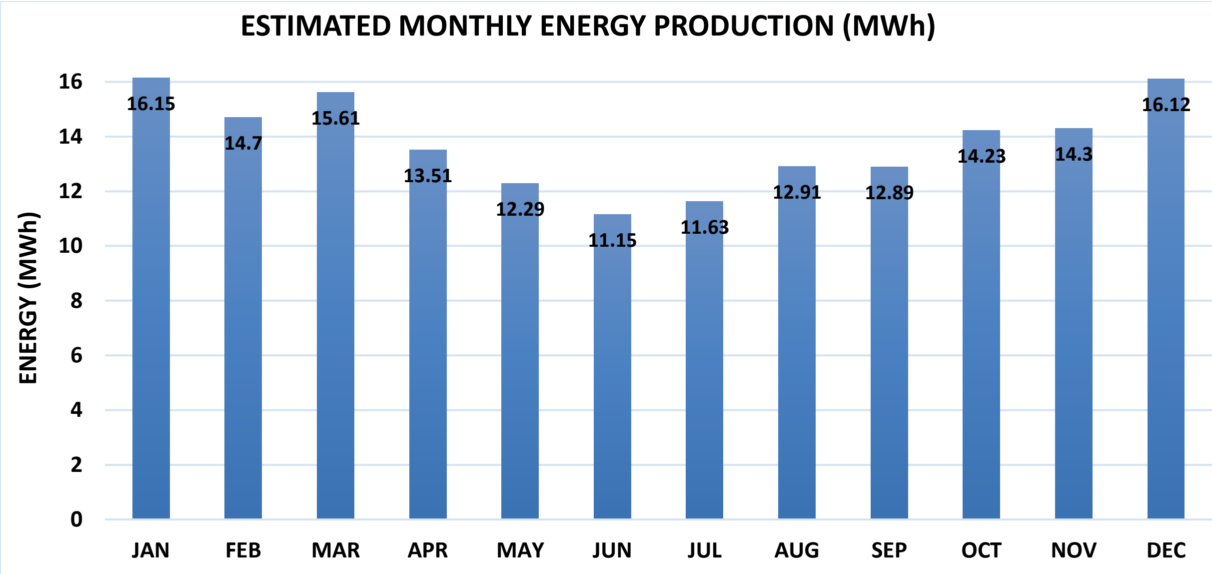


Figure 8.11: Estimated annual energy generation yield is 141.6 MWh [63]

8.1.6.6. Case Study 1.5: Loram House roof Top PV Installation

Loram House location is shown in Table 8.10 and the proposed installation shown in Figure 8.12 which was selected for a PV installation size of 15 kWp. This typically represents a small commercial installation.

Table 8.10: Location of Loram House

Loram House	29°50'46.74"S, 31° 1'34.82"E

Figure 8.12: Proposed rooftop PV installation at Loram House [63]

The PV size is substantial in terms of the building load demand and from Figure 8.13, there will be energy export to the municipal grid during times of low load demand and a change to major change to the customers load profile seen by the Electricity Department at the meter point.

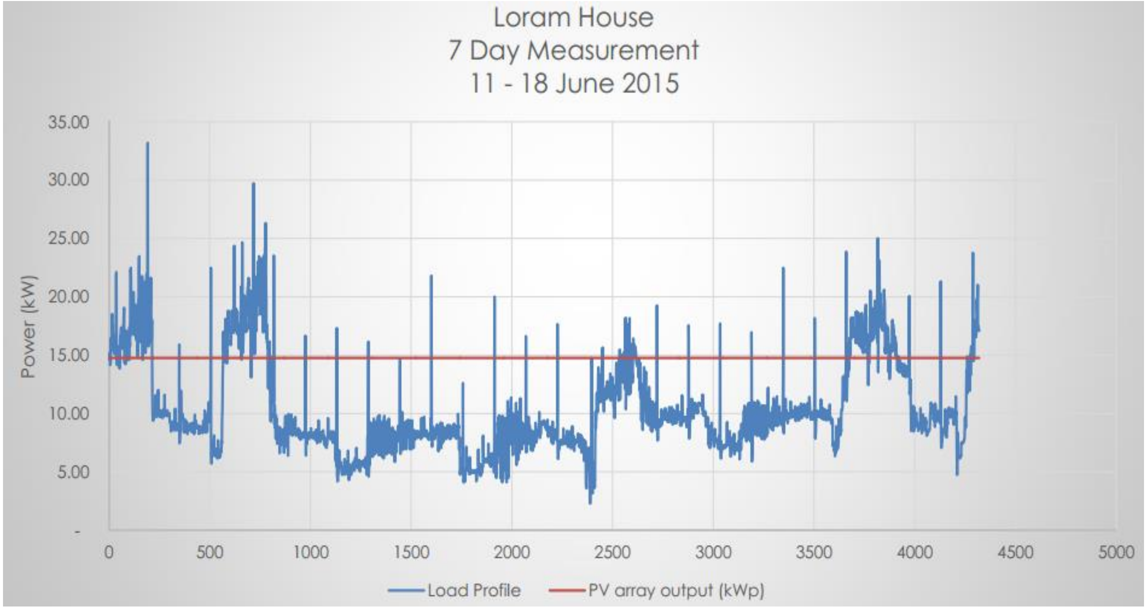


Figure 8.13: Load profile measured at Loram House in comparison to the proposed PV installed capacity

The proposed Loram House rooftop PV installation will consist of 57 PV panels, 57 optimizers and 1 inverter as shown in Table 8.11. Simulation results in Figure 8.14 indicate that the annual yield will be 22.28 MWh.

Table 8.11: Equipment to be installed at Loram House [63]

	Solar Edge Inverter	Canadian Solar Panels	Optimizers	System AC Size	System Production
	17 kW	**265 W**	**P300**	**kW**	**MWh/year**
Loram House	1	57	57	15.105	22.2

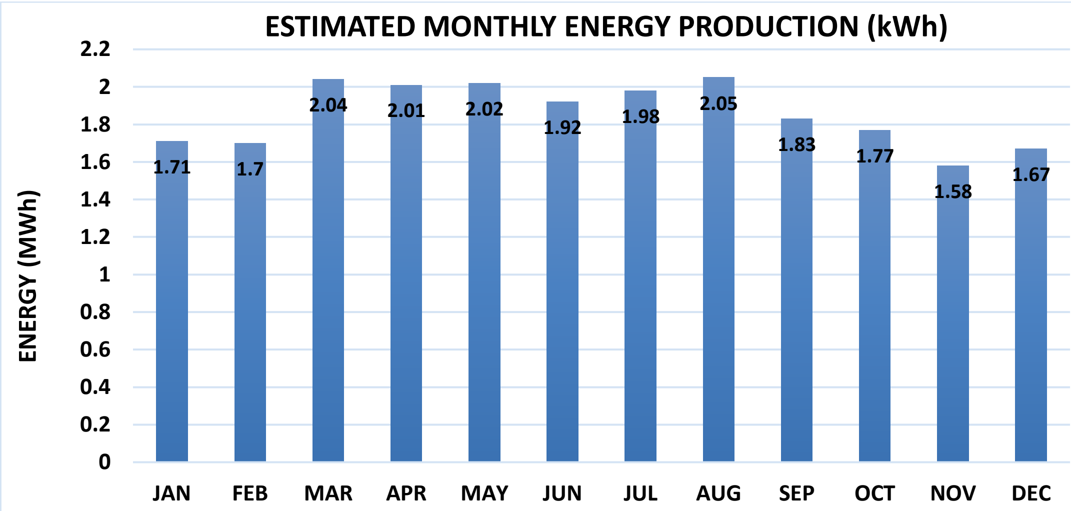


Figure 8.14: Simulated monthly generation yield at Loram House [63]

8.1.6.7. Case Study 1.6: eThekwini Water and Sanitation Building Roof Top PV Installation

The eThekwini Water and Sanitation Customer Services Building location is shown in Table 8.12 and the proposed installation shown in Figure 8.15 which was selected for a PV installation size of 38.16 kWp. This typically represents a commercial installation. Figure 8.16 shows the PV installation with respect to the load profile at Water and Sanitation.

Table 8.12: Water and Sanitation Customer Services building location

eThekwini Water and Sanitation - Customer Services building	29°51'7.74"S, 31° 1'27.72"E

Figure 8.15: Water and Sanitation Customer Services building rooftop PV installation [63]

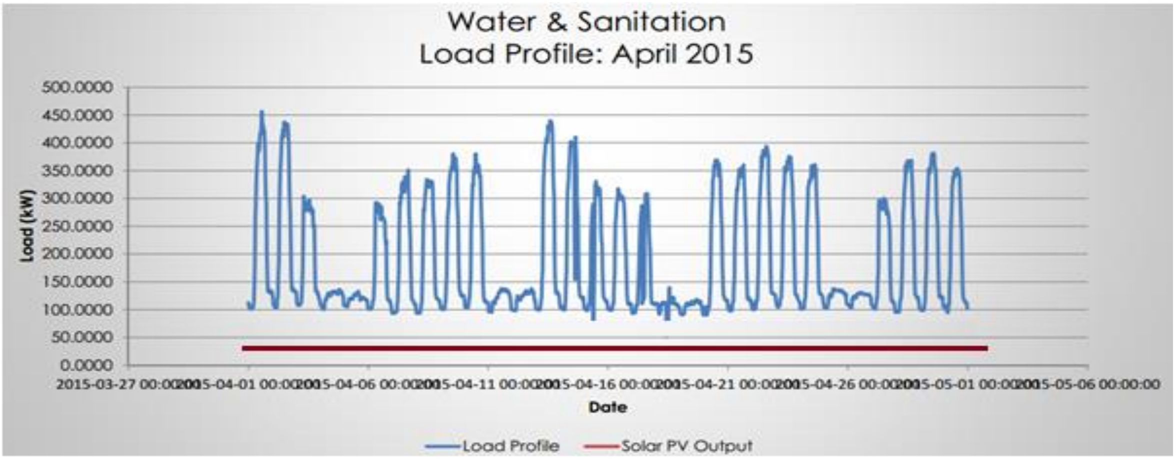


Figure 8.16: Water and Sanitation load profile compared to the proposed PV installed capacity

Table 8.13 shows the equipment to be installed at the Water and Sanitation building which will consist of 114 PV panels, 72 optimizers and 2 inverters. The simulated annual energy yield is 54.59 MWh, whilst a breakdown of the monthly energy yield is shown in Figure 8.17.

Table 8.13: Equipment to be installed at Water and Sanitation building [63]

	Solar Edge Inverter	Canadian Solar Panels	Optimizers	System AC Size	System Production
	17 kW	**265 W**	**P600**	**kW**	**MWh/year**
Water and Sanitation Building	2	144	72	38.16	54.59

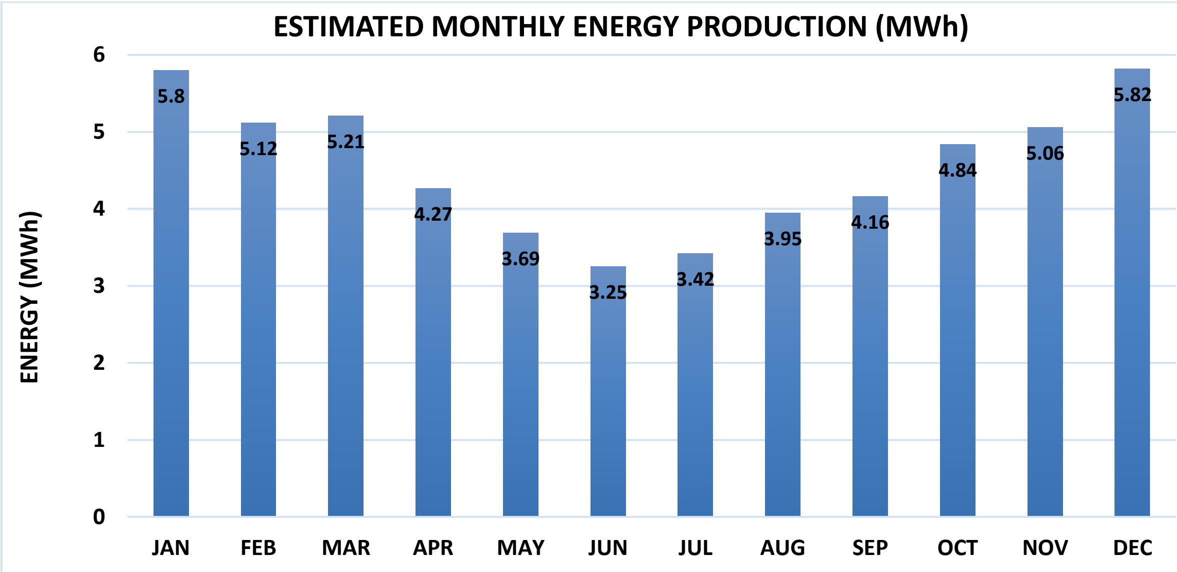


Figure 8.17: Simulated monthly energy generation yield at Water and Sanitation building [63]

8.1.7. Commencement of construction of the rooftop PV projects on the eThekwini Municipality buildings

The construction of the PV installations on various eThekwini Municipality buildings across Durban has begun and Figure 8.18 to Figure 8.22 shows progress on the construction of the PV installation. Figure 8.18 shows the construction at the Moses Mabhida Stadium Peoples Park restaurant whilst Figure 8.19 to Figure 8.22 shows the construction process from beginning to end at the uShaka Marine World administration building rooftop. Completion of construction and commissioning is expected in early 2017.

Figure 8.18: Construction commencement on the Moses Mabhida Stadium Peoples Park restaurant

Figure 8.19: Installation of the PV mounting structure studs at Ushaka Marine World

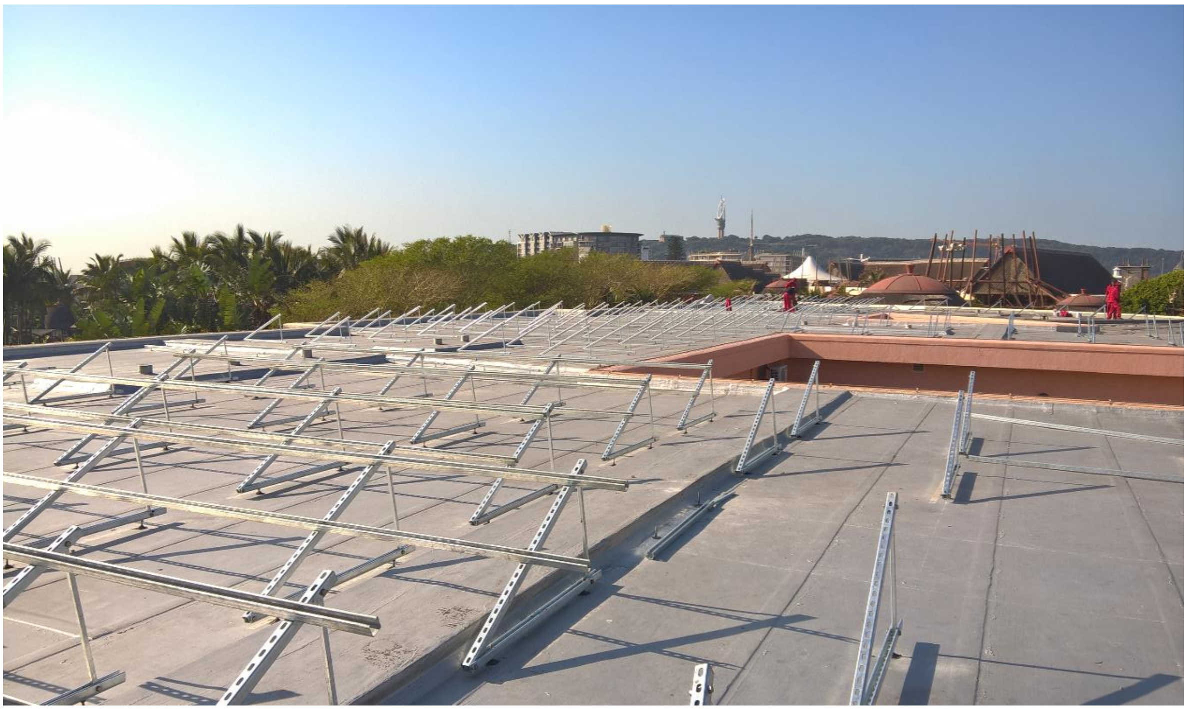


Figure 8.20: Installation of the PV panel mounting structures at Ushaka Marine World

Figure 8.21: Mounting of the PV panels at Ushaka Marine World

Figure 8.22: Completed rooftop PV installation at Ushaka Marine World

8.1.8. Case Study 1.7: Man Bus and Trucks Rooftop PV Installation

Man Bus and Truck SA Pty Ltd, an industrial consumer at eThekwini Municipality located at 21 Trafford Road in Westmead recently installed 2320 of 250 kW solar PV modules mounted on two separate roof structures that feeds into twenty one 25 kW and two 15 kW SMA string inverters. The installation has an installed capacity of 580 kW and is shown in figure 8.23. The generated power will be first self-consumed and the excess will then be exported to the eThekwini Electricity distribution grid.

Figure 8.23: Man Bus and Truck 259 kW rooftop PV installation in Westmead [38]

The current electricity maximum demand for Man Truck and Bus obtained from the eThekwini Electricity billing system is shown in Figure 8.24. The PV installation size exceeds the maximum load demand from the network resulting in export to the eThekwini Electricity grid.

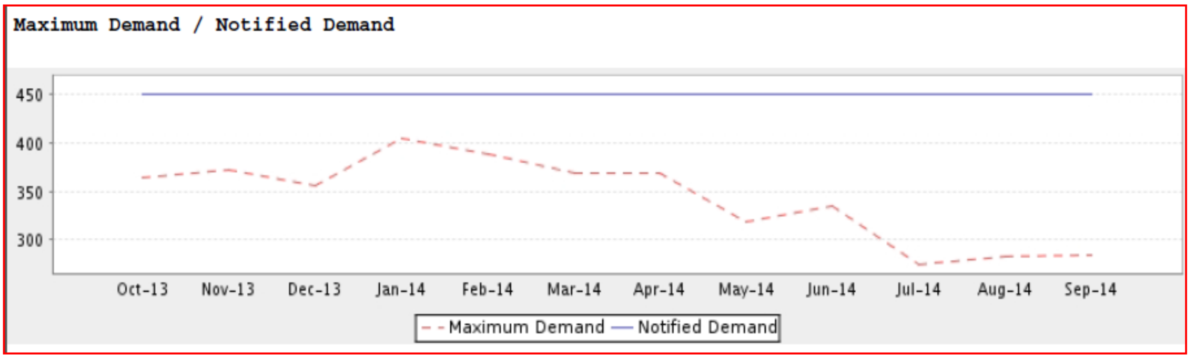


Figure 8.24: Man Trucks electricity maximum demand from EE billing system

The eThekwini Electricity billing system indicates that the current maximum demand for Man Trucks is between 300 and 400 kVA with a Notified Maximum Demand of 450 kVA. Whilst Figure 8.25 shows the rooftop PV generation profile. The generated electricity will first be utilised for their internal load and then the excess exported to the municipal grid. This then changes the load profile for Man Trucks that the municipality will see at the meter point.

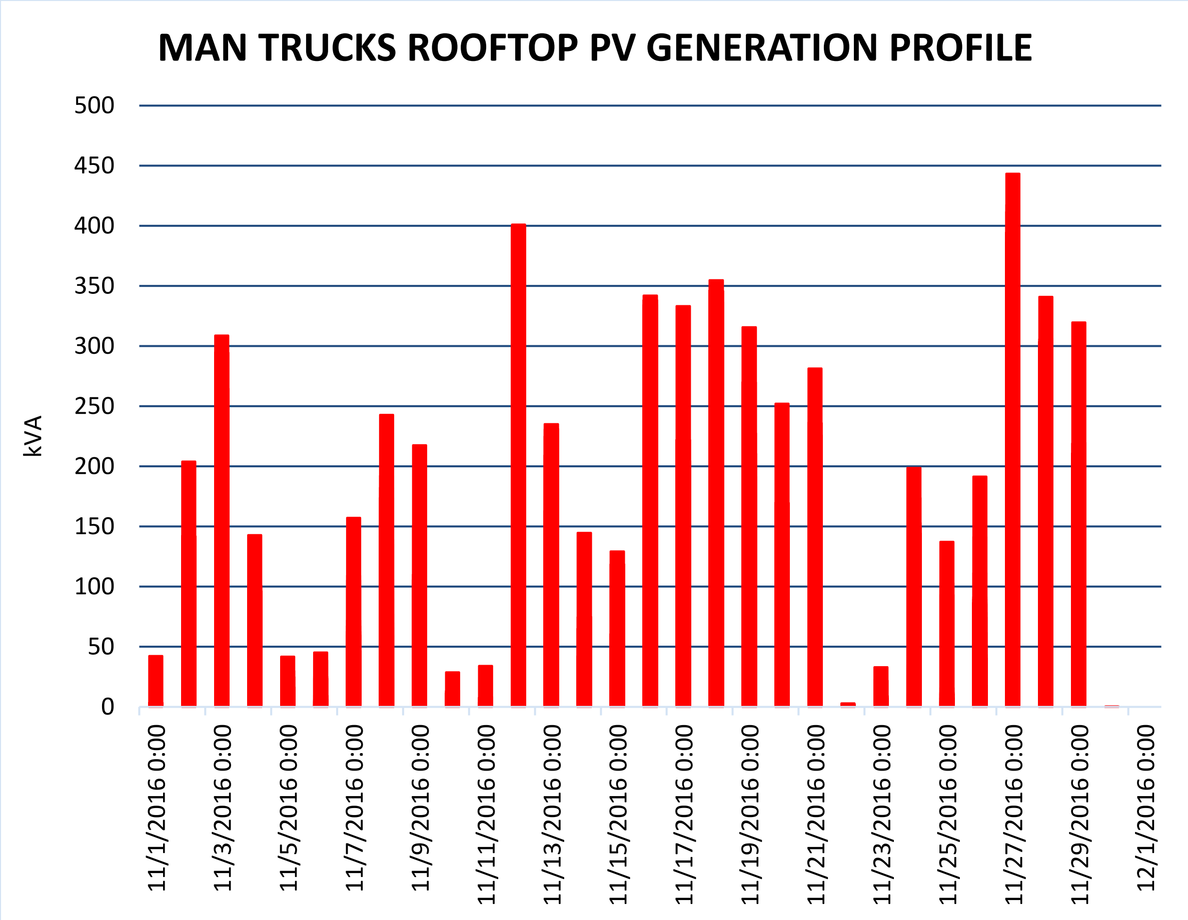


Figure 8.25 Rooftop PV generation profile from Man Truck and Bus rooftop PV

8.1.9. Hazelmere CPV farm Generation profile

The Hazelmere Concentrated Photovoltaic farm monthly generation profile is shown in Figure 8.26 The plants daily peak generation varies depending on the available sunlight, cloud cover, etc. The plant was subsequently decommissioned. Figure 8.26 indicates that daily generation peak can vary from 0 kVA to 372 kVA.

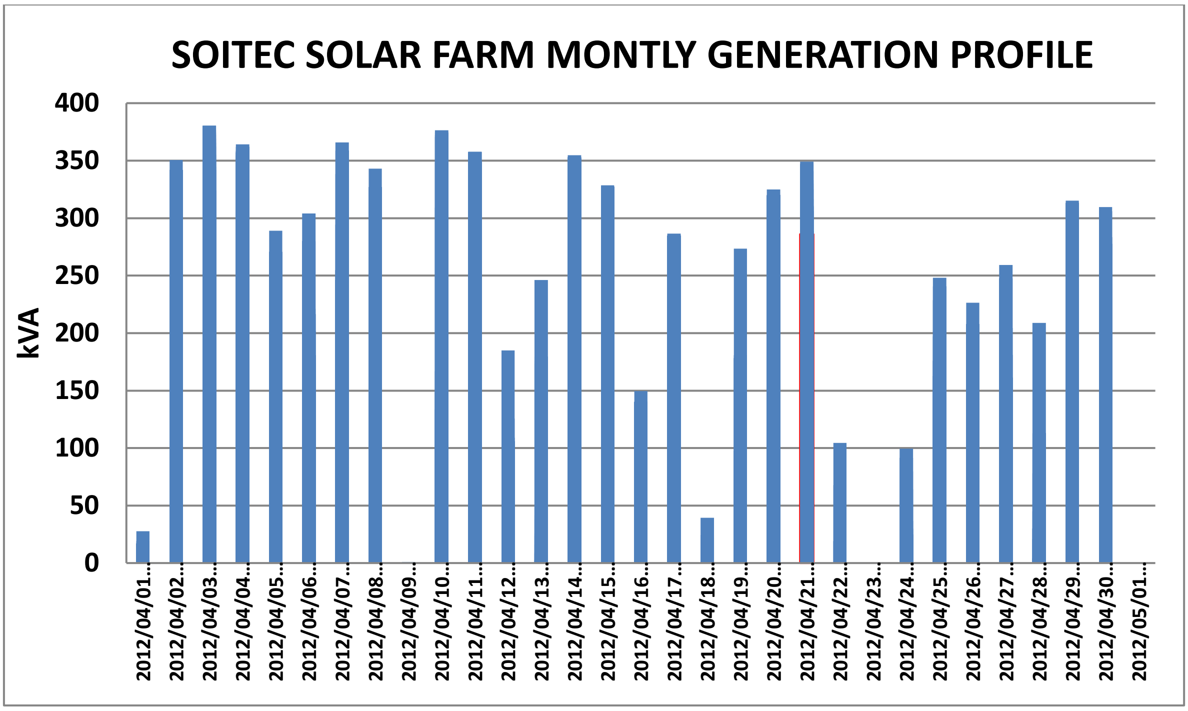


Figure 8.26: Generation profile for the Hazelmere CPV farm

8.1.10. NCP Alcohols Co - Generation

Figure 8.27 shows a typical monthly co-generation export profile from NCP Alcohols into the eThekwini Electricity grid. Only excess power that is generated is exported to the grid as and when not required by NCP Alcohols. There are days with no export to the grid and there will be days where the generation plant is off for maintenance and plants full electricity consumption is required from the municipal grid.

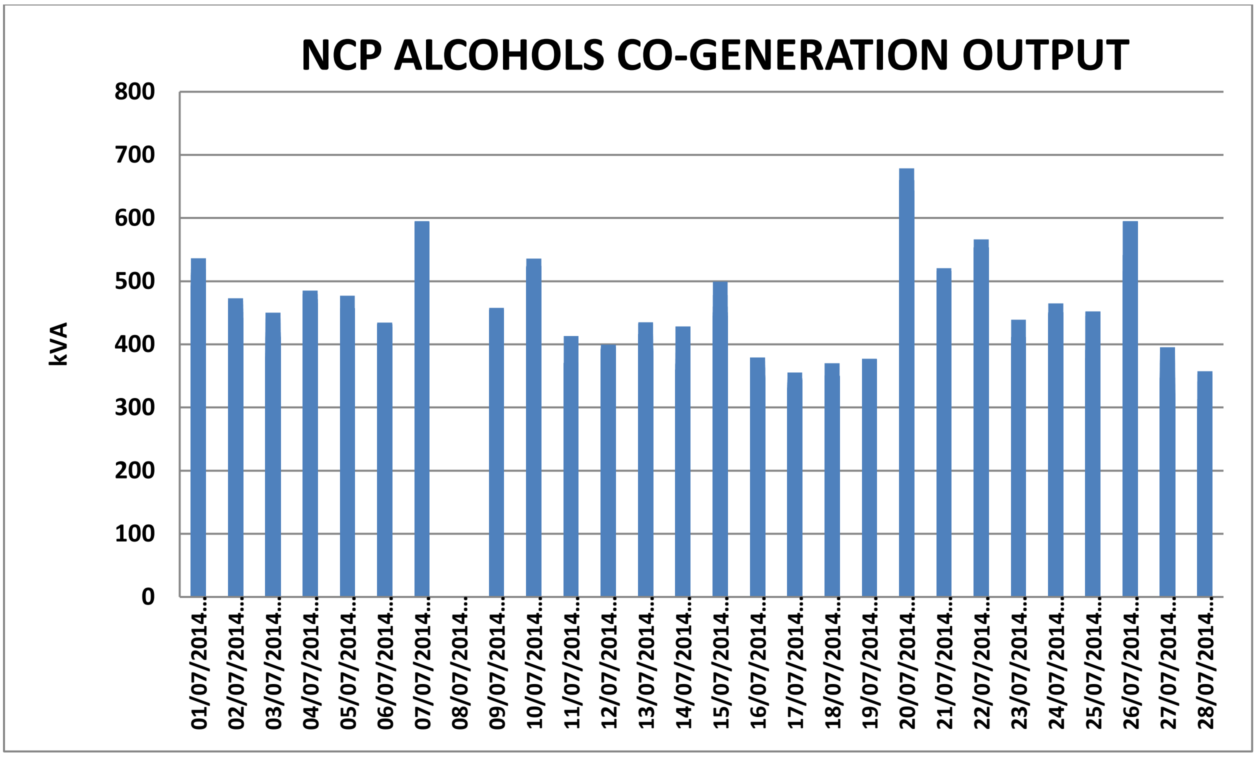


Figure 8.27: NCP Alcohols co-generation output figures

8.1.11. Proposed Gas Peaking Plant

There was a proposal for a gas peaking plant with the sole purpose of exploiting the higher tariff rates on the Eskom Megaflex 275 kV Tariff structure that eThekwini Electricity purchases electricity from Eskom on. The Eskom 275 kV Megaflex Tariff rates are shown in Figure 8.28 and the proposed peaking plant generation profile is shown in Figure 8.29.

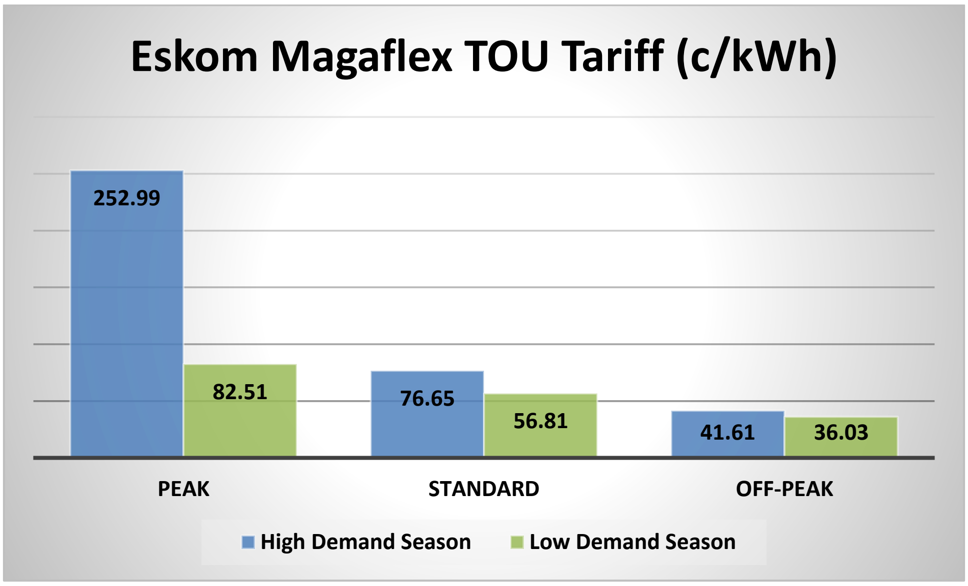


Figure 8.28: Eskom Megaflex Tariff Structure [24]

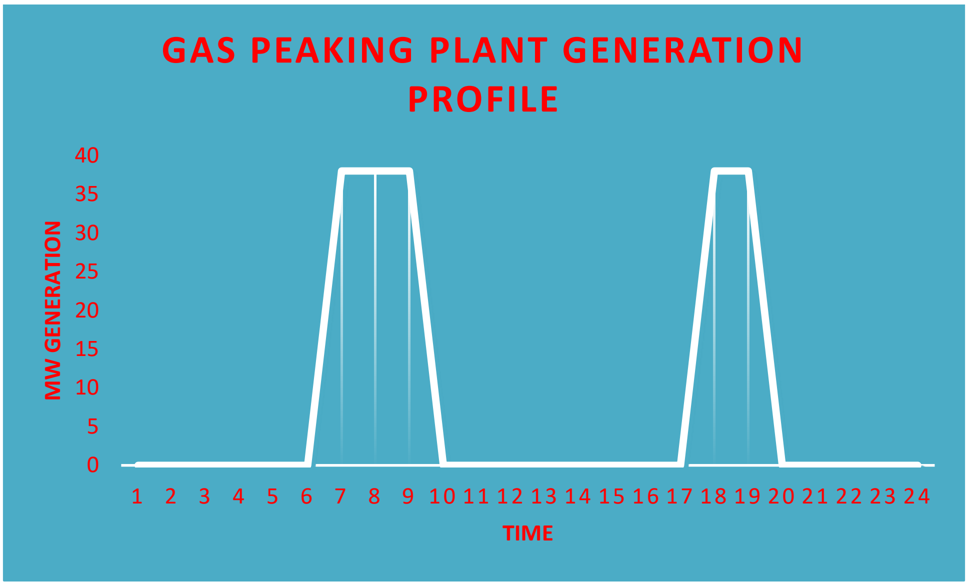


Figure 8.29: Proposed gas peaking plant generation profile

8.2. Summary of Chapter 8

This chapter provides us with greater details on PV generation in comparison to the customers existing load profile. Generation profiles were also obtained from other existing PV and co-generation projects in Durban. Discussion were also provided on the new Municipal rooptop PV project with simulated monthly generation profiles and system size vs the building load profiles.

CHAPTER 9: DISCUSSION AND CONCLUSION

9.1. Discussion

Under-frequency load shedding, rising electricity tariffs, environmental concerns and delays in construction of new power stations has led consumers and municipalities to explore various energy generation options to meet their electricity demands. Renewable energy technologies with its short lead times have become an attractive alternative for the country and hence led to the South African Government calling upon the country to explore renewable energy generation options. Subsequently, the IRP 2010 set a target of 17 800 MW (equivalent to 42%) of new electricity generation capacity to be derived from renewable energy sources. [18]

Currently the level of EG penetration at eThekwini Electricity is under 1% but this level of penetration is set to drastically increase with the number of proposed/potential projects increasing to about 20% of the eThekwini Electricity 2015 maximum demand. This figure includes all existing, proposed and potential projects at eThekwini Electricity taking into account the uptake of the residential solar PV market going forward. From the list of projects, there seem to be a lot of interest in landfill gas to electricity projects, waste water treatment works gas to electricity projects and PV projects. From the proposed list of projects, it can be seen that there are various sizes and technologies that will be connecting onto the eThekwini Electricity distribution networks in the near future. Many of these sources have variable output generation profiles directly influenced by their fuel sources which will produce outputs based on the fuel source availability such as wind and the sun. This is further complicated as most of the consumers who install these EG will firstly utilize the generated electricity for their own needs and then export the excess to the municipal grid as and when not required. This then changes their load profile seen by the utility. However with these variable source generation, provisions need to be made by the network designers to cater for the consumers load when these generation sources are not producing any electricity or reduced amounts of electricity. This makes it difficult to predict the impacts of increased EG penetration on the existing distribution network and planning of the distribution networks going forward. The impacts of EG affects the distribution network design and performance and it is crucial to understand these impacts as the level of EG penetration drastically increases especially on common distribution network. The study outcomes that were set out to be achieved in 1.4 is then discussed.

9.1.1. Understand the drivers of EG in eThekwini Municipality

The drivers of medium/large scale EG is discussed in 2.4 whilst the drivers of SSEG is discussed in 2.7 and the international drivers of EG is discussed in 2.8.

9.1.2. Understand the available renewable energy resources within eThekwini Municipality

This was investigated and discussed extensively in Chapter 3 where the the availability of the various sources of renewable energy projects were identified within the eThekwini Municipality. Based on my investigation carried out to identify available renewable energy resources within eThekwini Municipality, a summary of the available resources identified is shown in Table 9.1.

Table 9.1: Available Renewable Energy Resources at eThekwini Electricity

Resource	**South African Renewable Energy Category**				
	A1 (0 – 13.8 kVA)	**A2 (13.8 – 100 kVA)**	**A3 (100 – 1000 kVA)**	**B (0 – 20 MW)**	**C (>20 MW)**
Solar PV	X	X	X	X	
Wind	X		X	X	X
Gas to Electricity			X	X	X
Bio – Mass			X	X	
Hydro	X	X	X	X	

9.1.3. Investigate the feasibility of residential rooftop solar PV in Durban

Chapter 7 covers in great detail the feasibility of residential rooftop PV in eThekwini Municipality.

9.1.4. Identify factors affecting residential rooftop solar PV feasibility in Durban

This is covered extensively in Chapter 7 and a number of factors affecting residential rooftop PV in eThekwini Municipality is discussed.

9.1.5. Investigate the feasibility of municipal landfill gas to electricity EG projects

Chapter 4 discusses the Bisasar Road landfill gas to electricity project in Durban and use this project to study the feasibility of landfill gas to electricity projects in eThekwini

Municipality. It was established from the study that it is financially feasible to implement land gas to electricity projects in Durban.

9.1.6. Proposed methods to improve operational and financial viability of landfill gas to electricity projects in Durban

Based on research and the practical experience on the Bisasar Road and Marianhill landfill gas to electricity project, a number of methods were proposed to improve the operational and financial feasibility of landfill gas to electricity projects in Durban. This is discussed extensively in Chapter 4.

9.1.7. Study the impacts of increasing EG on the eThekwini Municipality distribution network design and performance

Chapter 4 identifies the impacts of increasing MV connected EG on the existing eThekwini Electricity MV distribution network whilst Chapter 7 identifies the impacts of increased penetration of residential rooftop solar PV on the LV distribution network. A summary of the impacts identified as is as follows: [5]

(i) Voltage impacts
(i) Single phase fault level
(ii) Three phase fault level
(iii) Cable loading
(iv) Impacts to the customers load profile
(v) Impacts to the municipal revenue
(vi) Impact of network losses

9.1.8. Understand the local NRS 097 guidelines on small scale EG

The NRS 097 guidelines for SSEG is discussed in 4.4.18.

Application of the guidelines to the eThekwini Electricity distribution network is discussed below.

9.1.8.1. Maximum Penetration Level of EG on an existing LV Distribution Network: (0 – 1000 kVA LV connected – Grid Code Category A)

To eliminate the negative impacts on the design and performance of the existing distribution network with increased penetration of EG we created a criteria in selecting the correct penetration level of EG on the existing eThekwini Electricity low voltage distribution networks. In order to ensure that the negative impacts to the eThekwini Electricity distribution network is avoided, we identify a selection/limitation criteria that can be used on the eThekwini Electricity low voltage distribution network to limit the penetration level of EG on the existing distribution networks.

The bases for the LV selection criteria will be the NRS 097 guideline, the drafting of which I was party to with other South African utilities as part of the NRS 097 workgroup. This was done in order to facilitate a simplified connection criteria for utilities to utilize when allowing EG penetration on their LV networks. This criteria was created in order to prevent problems of voltage rise and cable overloading, etc on the existing low voltage networks. Figure 9.1 shows a summary of the simplified connection criteria.

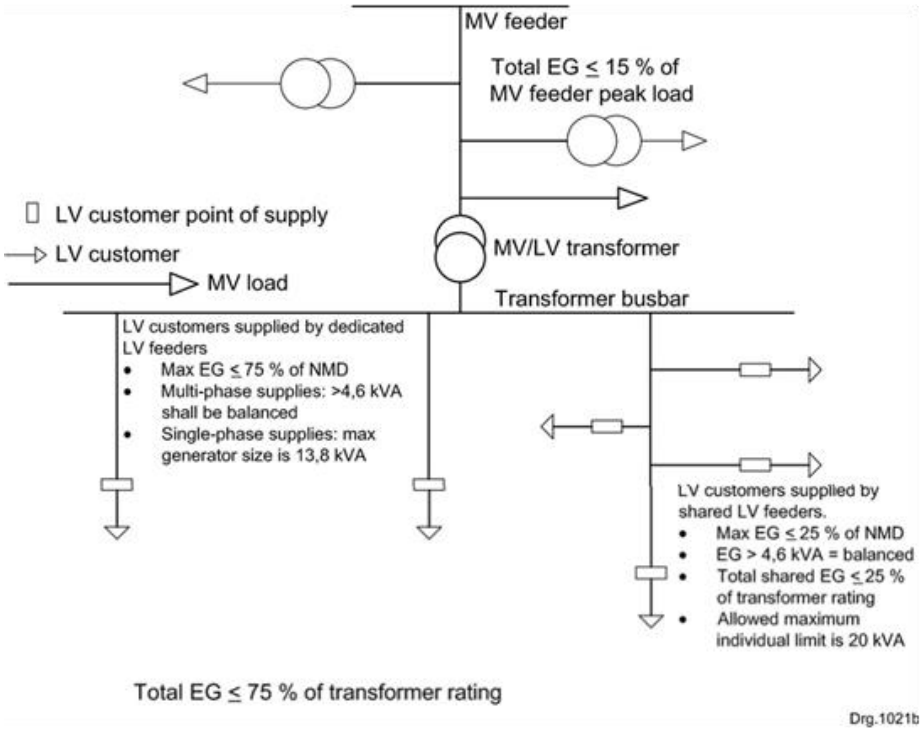


Figure 9.1: Summary of the simplified connection criteria [1]

We then adapt the criteria in Figure 9.1 for application in eThekwini Electricity. This should typically safely allow a penetration of 30 - 50 % rooftop PV penetration. Hence if we stick with the NRS 097 limit of 30 – 50% penertration then we should not experience any quality of supply problems. Even this will take a long to reach this penetration level and should the penetration level exceed 50% then detailed studies can be carried out to check and ensure that no network parameters are violated. In the case study carried out in Chapter 7, even with a 100% PV penetration level, there were no negative impacts experienced. However this may vary on other network factors depending on load types, customer ADMD, network cable rating, phase balacing, etc which may require a more detailed study of the particular network as the penetration level exceed 50%.

9.1.8.2. Maximum Limit on the MV Feeder

Table 9.2: NRS 097 simplified connection criteria [1]

MV Feeder Maximum Limit
Total EG ≤ 15% of the MV feeder loading.

Based on the NRS 097 simplified connection criteria for LV connected EG shown in Table 9.2, we look at the worst case scenario where we assume that the feeder loading is the same as the maximum feeder rating shown in Table 9.3. This then allows us to calculate the maximum penetration of EG that we can allow on a transformer at the Major Substation as shown in Table 9.4.

Table 9.3: Worst case maximum EG penetration rating with respect to maximum feeder rating

Cable Size	**Cable Rating (Amps)**	**Cable Rating (MVA)**	**NRS 097 - 15% Limit (MVA)**
95 mm^2 PILC	185	3.5	0.525
150 mm^2 PILC	235	4.5	0.675
240 mm^2 PILC	314	5.97	0.8955
300 mm^2 PILC	425	8.1	1.215
95 mm^2 XLPE	225	4.3	0.645
150 mm^2 XLPE	285	5.4	0.81
240 mm^2 XLPE	370	7.0	1.05
300 mm^2XLPE	420	8.0	1.2

Table 9.4: Maximum penetration of EG assuming all feeders operating at their thermal limits

Transformer Details	Number of Feeders	Feeder Size	Maximum Possible EG Penetration (MVA)	Percentage of Maximum EG Penetration to Transformer rating
33/11 kV 25 MVA	5	240 PILC	4.4775	17.9 %
132/11 kV 30 MVA				14.9 %
33/11 kV 25 MVA	5	300 PILC	6.075	24.5 %
132/11 kV 30 MVA				20.3 %
33/11 kV 25 MVA	5	240 XLPE	5.25	21.0 %
132/11 kV 30 MVA				17.5 %
33/11 kV 25 MVA	5	300 XLPE	6	24.0 %
132/11 kV 30 MVA				20.0 %
132/11 kV 30 MVA	6	240 XLPE	6.35	21.2 %
132/11 kV 30 MVA	6	300 XLPE	7.2	24.0 %

Table 9.4 shows that by using the NRS 097 simplified connection criteria and assuming worst case scenario where the we assume all out going feeder at operating at 100% of their thermal rating, the maximum percentage of EG to the transformer size is 24%. In reality however, should the six 300 mm^2 cable be operating at 100% of its thermal limits then the transformer will be operating at 36 MVA which exceeds its 30 MVA rating and is not possible. The maximum that the 132/11 kV transformer will be operated at under normal operating condition on the eThekwini Electricity distribution network will be 15 MVA hence (41.7% of the 36 MVA) the EG penetration with the transformer operated at 15 MVA will be (41.7% of 24%) 10% or 1.5 MVA. This should be set as the threshold for the maximum LV EG penetration using the simplified EG connection criteria. The penetration level will however increase under contingency conditions where open points are changed on the network bringing in additional customers and their EG.

Table 9.5 shows the NRS 097 guidelines developed for limiting dedicated feeder customers. Bulk of eThekwini Electricity customers are on shared feeder with only a few on dedicated feeders. Table 9.6 shows all the customers on shared feeders and their maximum allowed size of EG connection.

Table 9.5: NRS 097 limiting factor for dedicated feeder customers [1]

LV Dedicated Feeder
Maximum EG ≤ 75% of NMD.
Multi-phase supplies: > 4.6 kVA shall be balanced.
Single-phase supplied: Maximum generator size is 13.8 kVA.

Table 9.6: Maximum LV dedicated feeder EG limits

Cable Size (mm$^{2)}$	Cable Rating (A)	Cable Rating (MVA)	NRS 097 Limits (3 Phase) (kVA)
95	172	119	89
150	249	172	129
240	399	276	207

Table 9.7 shows the NRS 097 shared feeder limit whilst Table 9.8 shows maximum allowed individual limits by single and three phase customers on shared feeders.

Table 9.7: NRS 097 individual customer size limits for shared feeders [1]

LV Shared Feeder
Maximum EG ≤ 25% of NMD.
EG > 4.6 kVA shall be balanced 3 phase.
Total shared EG shall be ≤ 25% of the transformer rating.
Allowed maximum individual limit is 20 kVA.

Table 9.8: eThekwini Electricity individual customer EG size limits

Consumer Supply Size		kVA	Limit (kVA)
Single Phase	80 A	18.4	4.6
Three Phase	80 A	55.36	13.8
Three Phase	115.6 A	80	20

9.1.9. Provide methods to assist with selecting the EG sizes on an existing eThekwini Electricity distribution network

In order to allow a greater level of EG penetration on the eThekwini Electricity distribution network I created a criteria for the maximum size selection of the EG on the eThekwini Electricity distribution network. The case study results reveal that with any EG (IPP or utility owned generation source) installed on to an existing distribution network results in impacts to the distribution network design and performance. The impacts vary from voltage rise/decrease, increase/decrease in cable/conductor loading levels, increase in fault levels and other impacts which directly affects the existing distribution network design and performance. The impacts are however not only negative in nature but some of them are positive such as bus bar voltage support on heavily loaded feeders and load reduction in over loaded cables. From the study it is clear that the negative impacts emanate as the penetration of EG increases. Hence if the correct size EG (could be one generator or multiple units summed up to give us a total output) is selected for an application then bulk of the negative impacts to the distribution network design and performance can be eliminated. If the incorrect sized EG is however selected (EG size and location selected by an IPP due to the available renewable energy resource) for an application then major network design changes may need to occur such as uprating switchgear, uprating cables, changing network operating points and adding fault limiting devices to allow the EG unit to connect safely onto the existing distribution network. From the research/case studies and experience on EG installations, it can be seen that EG offer the utility a number of benefits (positive impacts) and also negative impacts at the same time.

In order to increase the penertration level of EG at the HV substation transformer level, we then derived a couple criteria that could be used for maximum EG size selection, methods to reduce network negative impacts and the EG operating fuctions to mitigate against negative impacts.

There are a large number of medium scale potential projects that are available in the eThekwini Municipality. Hence prior to selecting of an EG size for an installation on an MV distribution network, a detailed load profile of the entire distribution network that the EG is to be installed in needs to be carried out. The key item of interest is the load profile of the network during off peak loading. Even though there may be up to 4 power transformers (4×30MVA) at an eThekwini Electricity Major Substation, the operational philosophy only allows each transformer to be operated up to 50% of its rated capacity (firm capacity). The Major Substations are also operated with the bus section and bus couplers open to ensure that no transformers are operated in parallel during normal continuous operating condition. In order to increase the EG penetration level on the eThekwini Electricity distribution network, we treat each transformer separately and do not look at the total capacity of the Major Substation but rather the loading on each transformer when connecting EG onto feeders fed of that specific transformer. Based on the off-peak load data on each transformer, we can then decide on the maximum size EG (could be made up of multiple EG units but connecting to the same transformer at the Major Substation) that we can connect onto the network with no negative impacts (all network parameters remain within the required statutory limits). It also needs to be decided on the level of security of supply that is required from the EG plant. If a very high level of security of supply is required from the EG unit (example in the case of a green energy EG plant where Carbon Credits can be claimed for the conversion of renewable energy to electricity) then we may need to use double injection cables, double bus bar generator substation and also choose an EG size that is less than or equal to N-2 times the number of feeders connected to the transformer/bus bar at the Major Substation that the EG operates in parallel with. If an average security of supply is required then we can use a single bus bar generator substation, single injection cable and even choose an EG size of N-1 times the number of feeders connected to the transformer/bus bar at the Major Substation that the EG connects to. In the latter case the loss of the highest rated off peak feeder must be assumed to be the one that is lost in the event of a contingency and further to that the generator Power Factor must be selected such that if that feeder is lost the network parameter still remains within the statutory limits. However if a second feeder is lost then there is a large chance that the EG unit will trip hence it comes down to the amount that the IPP/utility is willing to spend on the security of supply of the EG plant. Also if a large generator plant is used then we may need to inject the generated power at a higher voltage level substation onto the network since a common 33/11 kV substation has transformers commonly rated at 25 MVA with a firm capacity of only 12.5 MVA, whilst a 132/11 kV substation has transformers commonly rated at 30 MVA with a 15 MVA firm capacity and a 275/132 kVA substation has transformers rated at 315 MVA with a firm capacity of 157.5 MVA. Hence for example if a 25 MVA wind farm needs to be connected onto the grid then it can only be accommodated at the 275/132 kV substation with no negative impacts. Depending on the generation source, the transformer off peak loading which is influenced by the customer type will dictate the maximum amount of EG that can be connected with the exception of solar PV (example a solar farm) where the minimum loading during 6am to 6pm can be considered. However if the EG is made up of different generation sources then the off peak loading must be considered.

Keeping the above in mind one then need to choose an injection point onto the distribution network. The following needs to be kept in mind when selecting an injection point: [14]

(a) Depending on the EG unit size, for a SSEG unit (EG unit rated lower than the cable from the Major Substation to the injection DSS) it will often be easier to injection the power into the 11 kV DSS that is in close proximity of the generation plant with a link back to the Major Substation. This will reduce the grid connection costs and prevent using up all the feeders breakers at the Major Substation. Also providing the opportunity for the generation to be consumed by the local load. [14]

(b) For a large scale EG plant (EG unit rated higher than the cable from the Major Substation to the Injection DSS) it must be injected directly onto the Major Substation bus bars to minimize the negative impacts such as cable overloading, etc. [14]

(c) For very large scale EG units, the power then needs to be injected into a higher voltage substation e.g. A 275/132 kV substation and not the local Major Substation to minimize the negative impacts. The power can however be injected onto the 132 kV side of the substation bus bar which will have a link back to a secondary side of a 275 kV substation if the transmission distance from the EG plant to the 275 kV substation is large. This will typically be required in the case of wind farms, large solar farms or gas peaking plants. [14]

Once the level of EG security and the injection point is selected together with the EG size which may be dictated by two factors namely: [14]

(a) The amount of fuel available at the site or the level of security of supply required. If the fuel source is dictated by the EG size then we will need to concentrate on the injection point and the voltage level at which we want to inject the power to minimize the negative impacts.

(b) Whilst if the level of security of supply is of primary concern then we need to look at the EG size which should then be less than or equal to (N-2) or (N-1) times the number of feeders connected to the transformer that the EG operates in parallel with at the Major Substation.

Once the EG size and injection point is established, a plot of the EG operated at different Power Factors needs to be simulated. The plant Power Factor should range between (0.975 leading to 0.975 lagging for MV connected EG units under 20 MW). Units above 20 MW need to be connected at the HV network and needs to operate between 0.95 leading to 0.95 lagging Power Factor. Depending on the type of EG unit used either Synchronous, Asynchronous or Converter technology will dictate the operating Power Factor which can only be lagging for the case of an asynchronous generator or either leading or lagging power factor for a synchronous generators and converter technology. However the SAREGC requires the EG plant to operate at both leading and lagging Power Factor hence excluding certain types of technology. A load flow of the base case network (with no EG installed) voltage profiles indicates whether the network needs reactive power (voltage support) if it contains long heavily loaded feeders and the voltages in the network lies close to the bottom statutory limit (95 % of $V_{Norminal}$) or if the network is very lightly loaded or operating very close to the upper statutory limit (1.05% of $V_{Norminal}$) then it may be required to import reactive power to the generator by running the EG at lagging Power Factor. Figure 9.2 and Figure 9.3 shows the network bus bar voltages during peak and off peak loading with a 6 MW EG unit operated at various leading and lagging Power Factors. This shows the influence of power factor on the network bus bar voltages hence it is important to select the correct power factor to operate the generator/generators on the network to ensure that the voltages remain within the required ±5% statutory limit. [56]

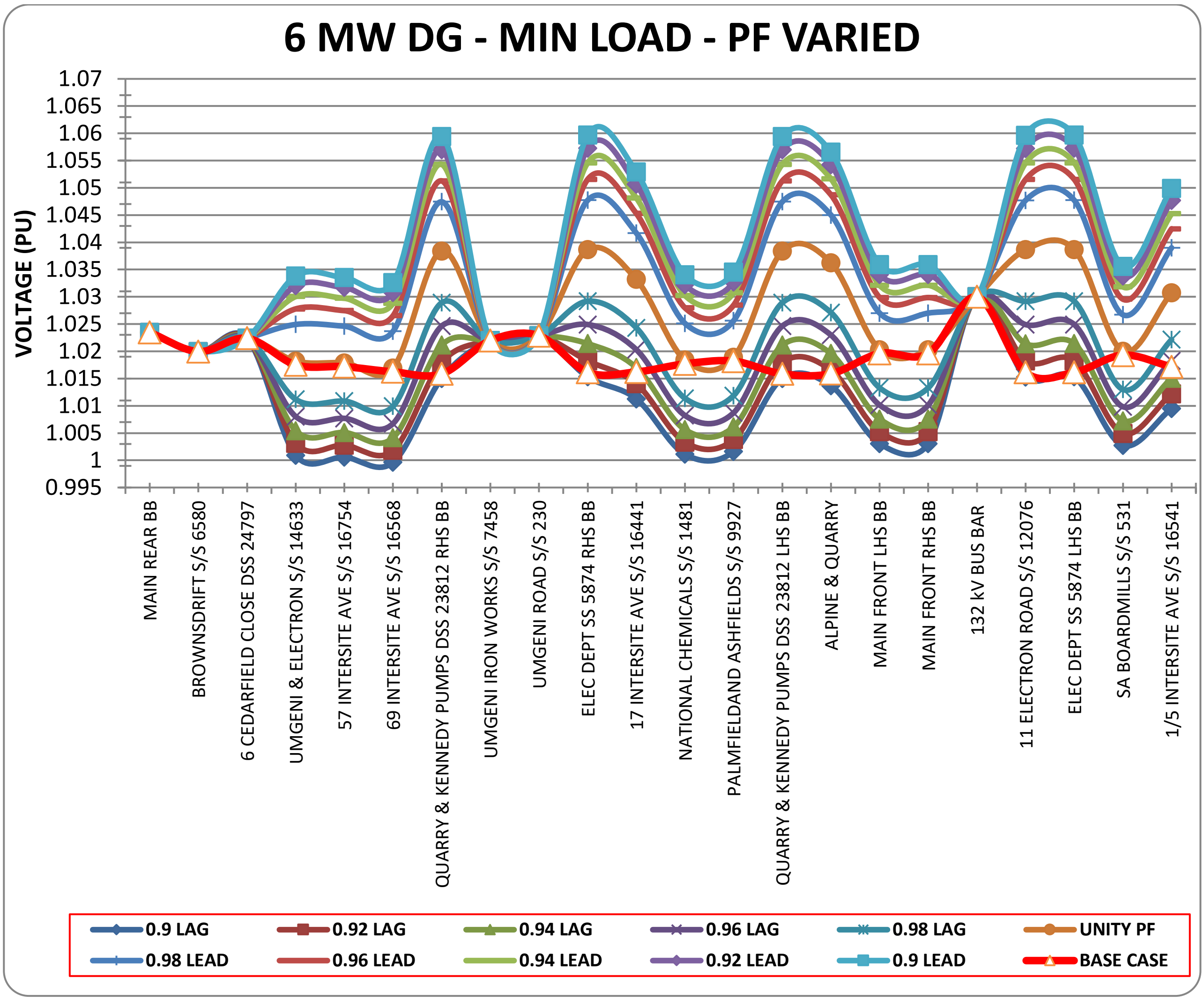


Figure 9.2: Power Factor varied for minimum network loading [56]

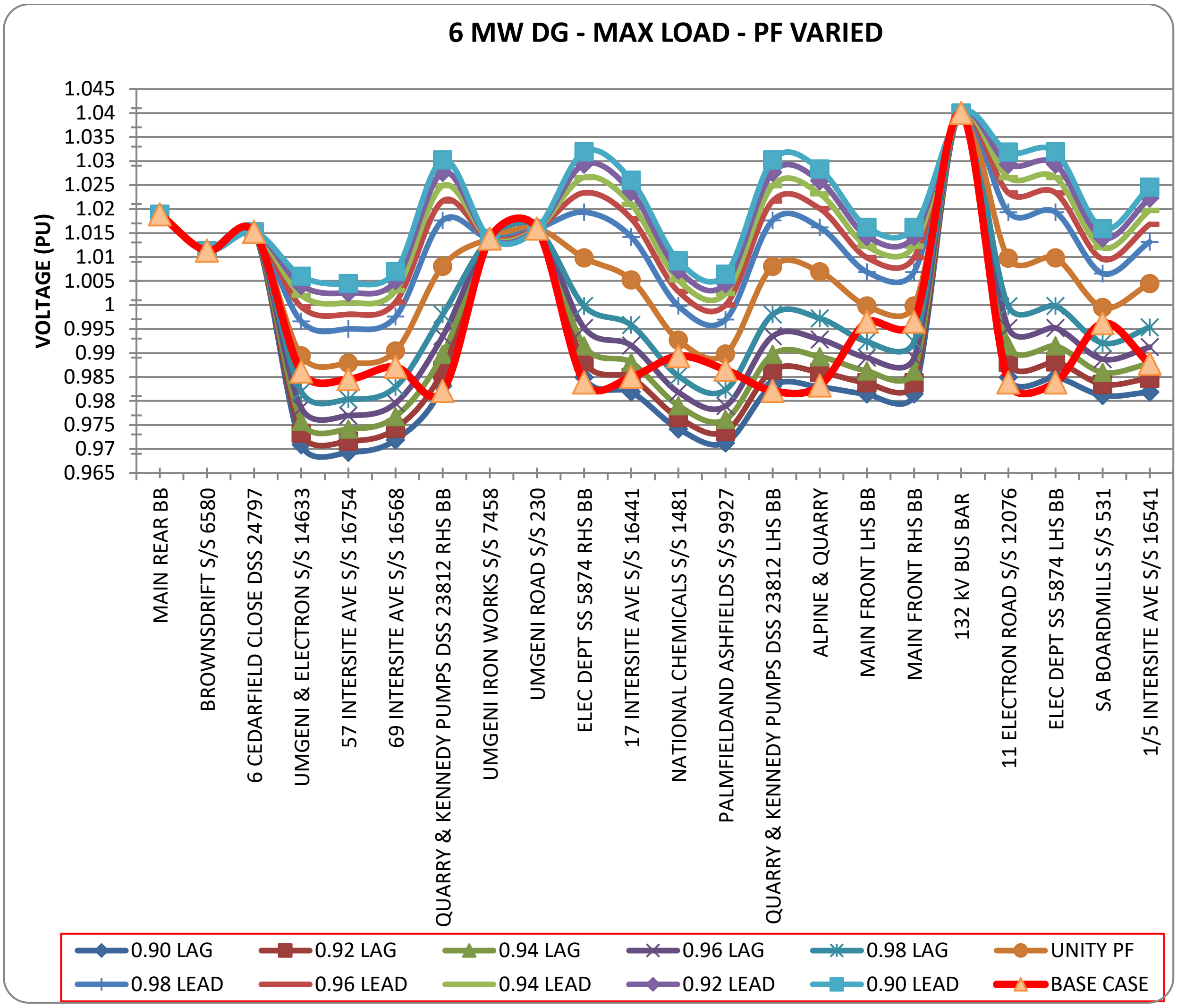


Figure 9.3: Bus bar voltage profile for different DG power factors during peak loading [56]

If the EG is connected to a strong distribution network (bus bar voltages are within the statutory limits) then it would be advisable to operated the EG unity at unity power factor with no import or export of reactive power to the network. As one decreases the generator power factor the impacts become greater as shown in Figure 9.2 and Figure 9.3. With leading power factor problems of over voltage can be experienced and at lagging power factor problems of under voltage can be experienced. It is therefore inadvisable to operate the generator at a low leading or lagging power factor if we want to minimise/elliminate negative impacts. We also need to ensure that the EG power factor (in the case of one unit or multiple units) selected keeps the bus bar voltage within the required statutory limits during network contingencies (either (N-2) or (N-1) loss of feeders) depending of the level of security of supply selected. [56]

The other critical aspect that needs to be then studied is the rise in fault levels caused by the EG unit. Since all distribution equipment have a rated fault current that piece of equipment can safely handle, a plot of fault level/current at each point in the network will give a good indication as to what EG size can be accommodated without any network reconfiguration or fault current limiting devices having to be installed or switchgear needing to be up rated in the network. All existing EG units connecting to that specific transformer on the Major Substation needs to be included in the simulations as they will contribute to the fault levels on the network. [56]

Figure 9.4 and 9.5 indicate that with an increase in the EG size, the three phase fault levels can rise drastically especially in the case where synchronous generator technology is employed. Hence care must be taken to ensure that none of the equipment ratings are exceeded especially in distribution networks which has older equipment that have lower fault current ratings than the newer equipment. This can also be used as a criterion that can help identify which equipment ratings will be exceeded and design changes in the network that will be required such as upgrading switchgear, network reconfiguration or installation of fault limiting devices. In simple terms, if one or two old circuit breakers in the network ratings are exceeded, then it would be more feasible to replace them instead of installing fault limiting devices. But in the event that all the circuit breakers in the network ratings are exceeded then fault limiting devices need to be installed to safely limit the fault current. Network reconfiguration is also an option, where parallel circuits can be split to increase the impedance and lower the fault current, although if this is done then care must be taken to ensure that during contingencies the network is not reconfigured back to parallel circuits resulting in the switchgear safe operating levels been exceeded, compromising plant and personal safety. [56]

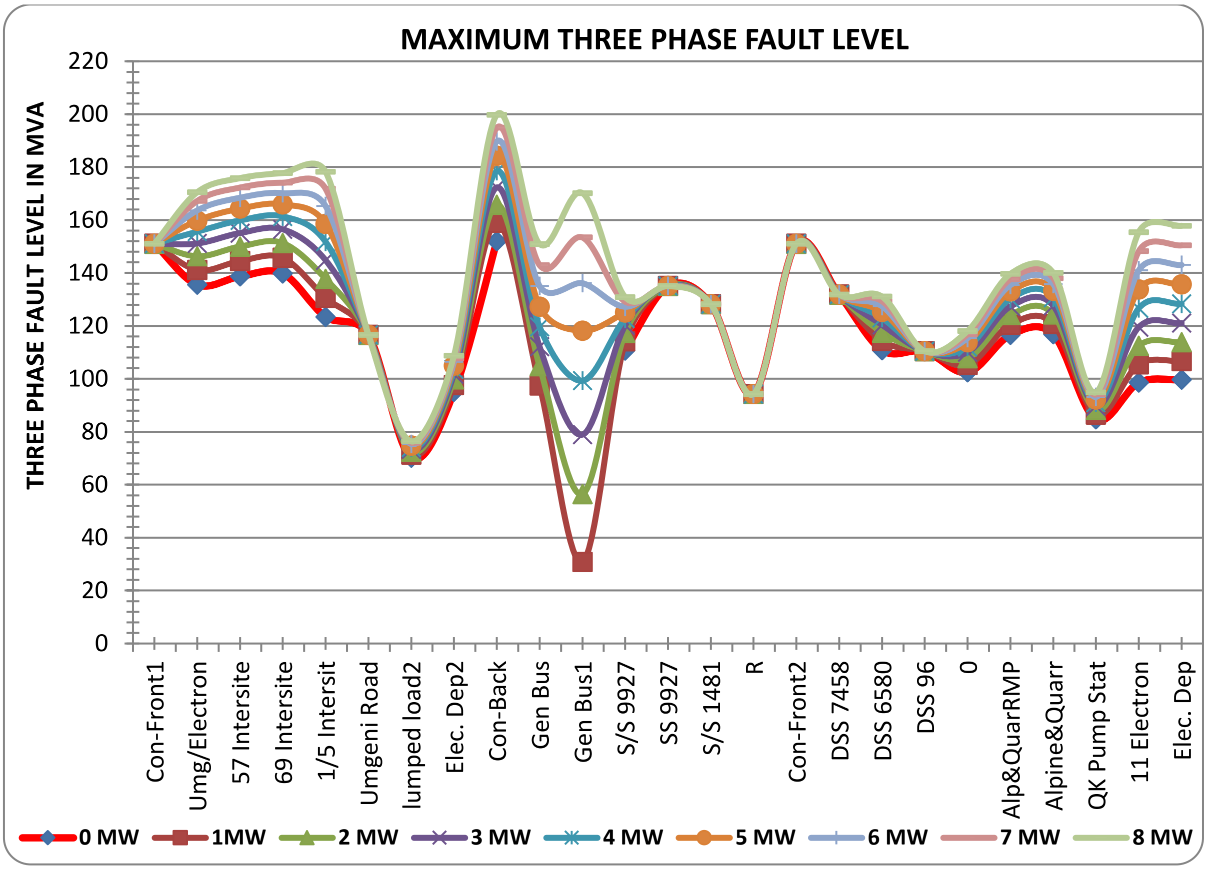


Figure 9.4: Maximum three phase fault level at different EG power outputs [14]

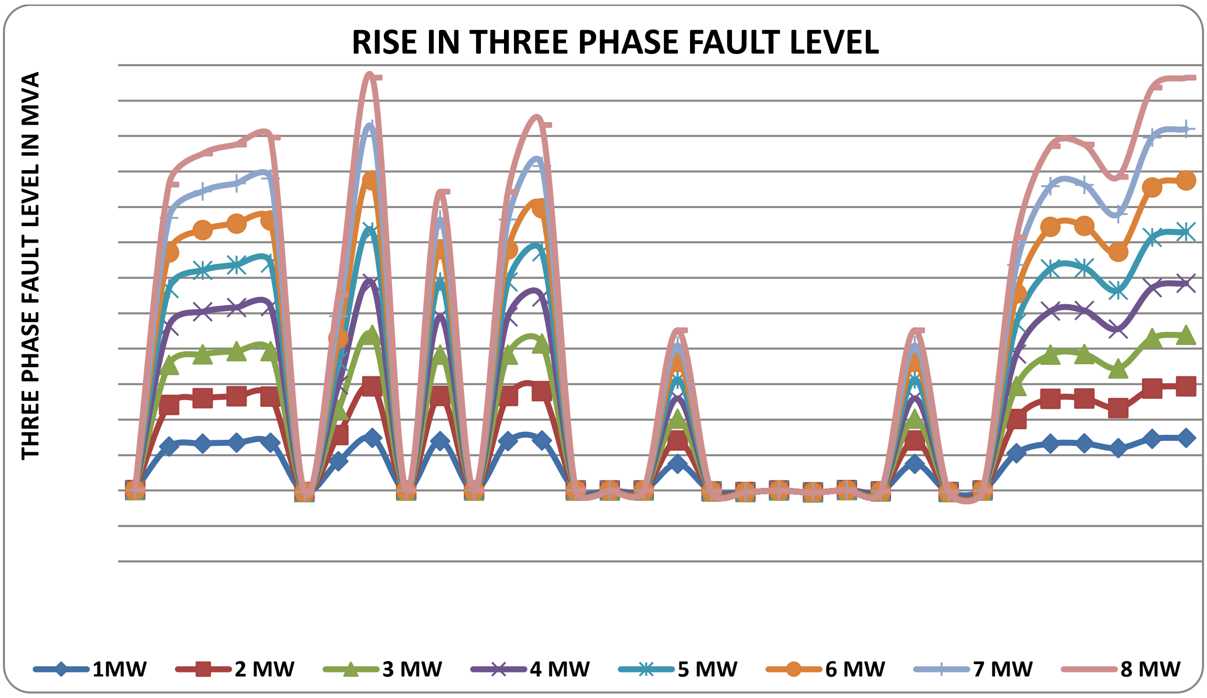


Figure 9.5: Increase in three phase fault level with increase in EG power output [14]

With the installation of an EG unit irrespective of the size selected results in an increase in the earth fault current on the network. Figure 9.6 indicates the impacts on the existing distribution network with the addition of a EG unit with no earth fault limiting devices used. In the case of multiple EG units on the network, the simulation must take into account the contribution from all the units.

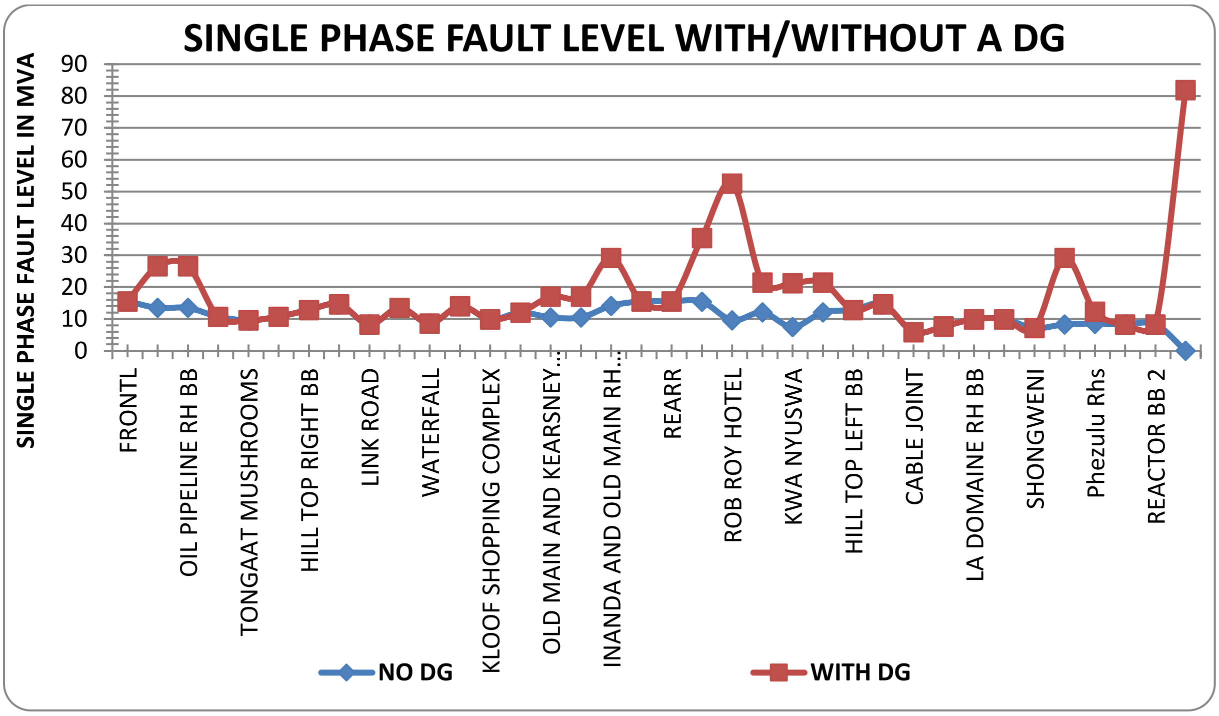


Figure 9.6: Change in earth fault current with the addition of an EG on the distribution network [14]

Earth fault current values with the EG added to the network is often below the network switchgear ratings but from experience it would be best to limit the earth fault current with the use of an NER. Research and practical experience has shown that when the generated power from the EG is injected into the existing distribution network via a cable which is common practice at most municipalities, the injection cable is then requiring to be protected. This is often done by means of an earth fault relay. Often when the earth fault current is not limited, the EG injection cable earth fault relay trips for out of zone earth faults causing nuisances tripping of the EG unit as experienced in the past by eThekwini Electricity. This problem is easily overcome with the earth fault current being limited and the tripping time increased on the EG injection cable relay to that greater than the other relays in the network. The limited earth fault current prevents damages to the EG plant during the extended tripping time in the event of an out of zone earth fault. The common practice at eThekwini Electricity is to limit the earth fault current to 25 A per a 1 MW EG unit at 11 kV as done on the Bisasar

Road landfill gas to electricity project. This has worked well for eThekwini Electricity although research has shown other utilities limiting the earth fault current to 36 A without any problems as well. The best option would be to use a protection simulation package and model the network protection in the vicinity of the EG plant or plants and study the effects on grading and fault current experienced at the EG plant under study. This is to ensure that the correct size NER is selected for that particular network and a balance between grading and fault limitation at the EG plant is achieved which will not result in any damage to the EG plant or infrastructure on the distribution network. [14]

The other important factor that needs to be studied is how the EG size would affect your cable/conductor loading limits especially during your minimum network demand period where the cables are required to carry excess power further into the network away from the injection point. A simple plot of your cable loading for different size EG (or a combination of EG units) would be able to tell you whether you would experience problems or not. A simple rule of thumb that can be used is to compare the ratings of the cables connected to the injection point to the size of the EG maximum power output. If the EG maximum power output is greater than the cable ratings then this will require the cables to then be replaced or up rated to a rating that either match the EG maximum power rating or exceed it to avoid any possible overloading of the cables during operation. [56]

Figure 9.7 gives a good indication as to which cables would experience problems of over loading and exceeding its thermal limits. The most common cable that would experience overloading if rated lower than the EG maximum power output would be the link cable from the injection DSS to the Major Substation. This criterion can be used for strengthening of the network or reinforcing the existing network if the EG size selected is greater than the cable/conductor ratings in the surrounding network. If the EG size exceeds the cable rating between the Major Substation and the injection DSS then injecting directly onto the Major Substation bus bars are also an option depending of the availability of spare circuit breakers at the Major Substation and its location with respect to the EG plant/plants. If the excess power (difference between the EG maximum power output and the cable rating between the Major Substation and injection DSS) can be absorbed at the injection DSS then injecting at the DSS should not be a problem during normal operation however problems can occur during contingency conditions on the network. However if a high level of security of supply is required from the EG plant and loss of load at the injection DSS may compromise the security of supply of the EG unit by tripping the cable between the Major Substation and the injection DSS on overload during contingencies resulting in the generator then tripping on loss of mains protection then this method cannot be used. In this case it is required to inject directly onto the Major Substation bus bars to reduce the risk of the EG plant tripping. [56]

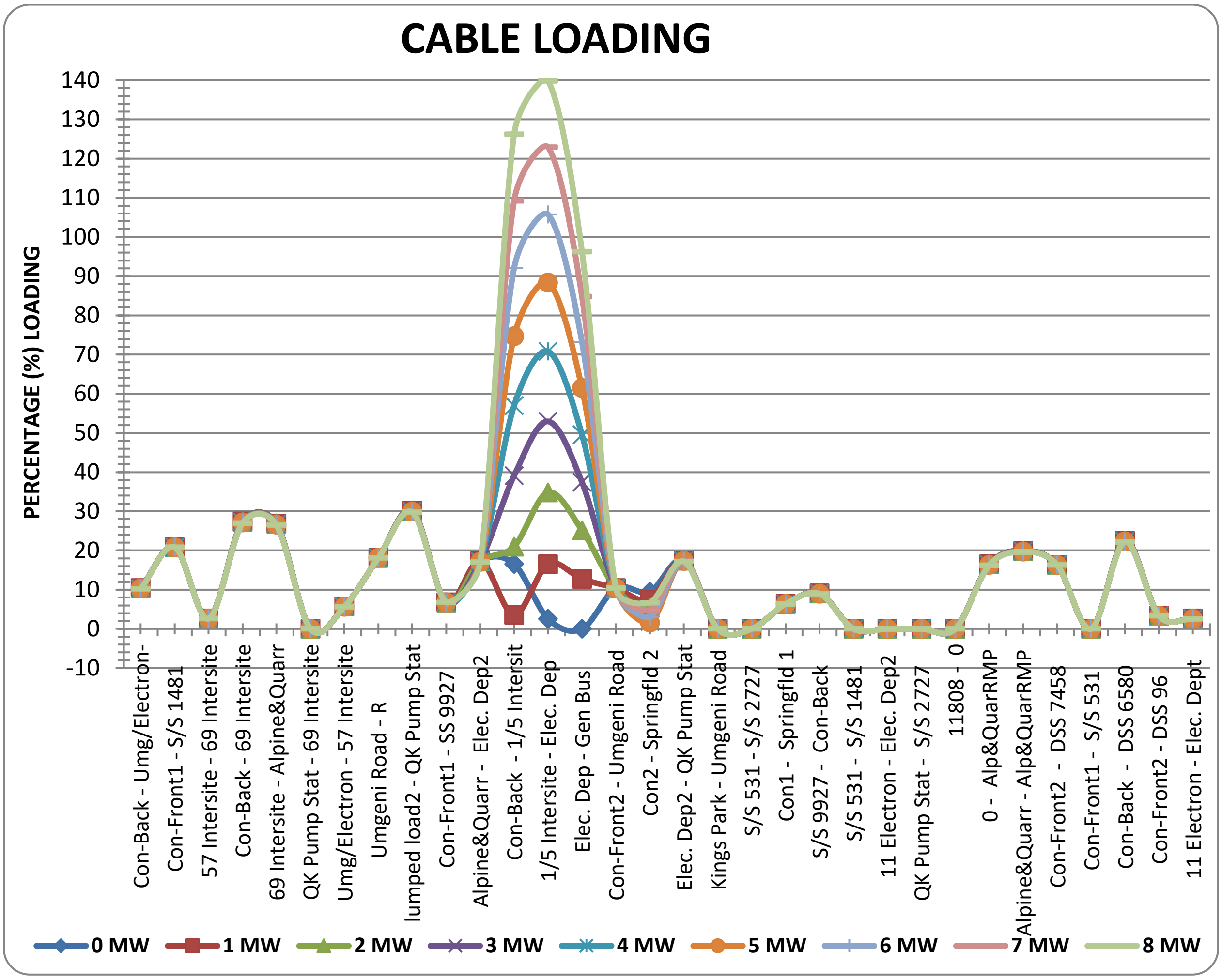


Figure 9.7: Increase in cable loading limits with increasing EG penetrations on the network [14]

Table 9.9 provides a summary of the EG size selection criteria to minimize MV network impacts.

Table 9.9: Summary of EG size selection criteria to minimize network impacts [56]

Generator Size	Generator Power Factor	Three Phase Fault Level		Single Phase Fault Level	Cable/Line Loading
If EG size is dictated by the fuel source/sources then check the injection point and voltage level for injection	Dependant on:	Check if network fault level > network equipment ratings		Check if exceed network equipment ratings	If maximum EG power output > cables surrounding injection point
If not then decide on the required level of security of supply:	Base case network requirement of reactive power and;	If rating > few pieces of equipment	Change equipment	Install NER/fault limiting device	1. Uprate cables
If high then select a EG size up to N-2 times the number of feeders connected to the transformer at the Major Sub that the EG connects to.	Type of generator chosen: 1. Synchronous/Inverter –operates at both lagging and leading PF	If bulk of the gear in the network rating is exceeded	Install fault limiting devices		2. Add additional loads to injection point
If security of supply required is lower than select N-1.	or				3. Inject directly onto the Major substation bus bars
	2. Asynchronous – operates only at lagging power factor				

9.1.10. Mitigation Measures to minimize the impact of EG (IPP owned) on the existing distribution network design and performance

Most of the criteria's outlined in table 9.9 assume that the Municipality has a part in the selection of the EG size. This may not always be possible in the future with the introduction of IPPs to the Power Markets together with the location of the EG plant which may be governed by the availability of pockets of renewable energy sources all around the municipal distribution networks. The study of the available renewable energy resources in the eThekwini Electricity distribution network has shown that there are pockets of difference renewable energy fuel sources scatted all around the eThekwini Electricity distribution network.

In the event that the utility does not have a choice in the selection of the EG size or location eg. an IPP is the owner of the EG plant at a remote landfill site and has selected a generator size based on the landfill gas availability which exceeds some of the criteria's derived in 9.4 on selecting the correct size EG for that specific network/application. This criteria then provides recommendations that will provide mitigating factors that can help the utility to operate the EG plant safely within statutory limits. Some of the mitigating factors that have been identified during research, practical experience on EG projects and case studies carried during my MSc and PhD dissertation studies are as follows: [56]

9.1.10.1. To accommodate the EG during the off peak periods

(i) Firstly identify the renewable energy technology that is going to be used taking into account that technologies such as solar only operate during sunlight hours, landfill gas and bio gas technology without storage operates 247 whilst with storage, it can be dispatched as and when required whilst technologies such as wind is less predictable and it should be assumed worst case scenario where maximum wind generation occurs during the network off-peak loading. Reconfigure the network and add loads that have higher off-peak loading e.g. industries which operate 24 hours a day, ensuring a higher off peak loading and hence the ability to accommodate a larger EG unit onto the existing distribution network. [56]

An example is shown in Figure 9.8 where the maximum and minimum feeder loads out of the Connaught Major 33/11 kV Substation is shown with 5 feeders connected to each of the two transformers at the substation. The substation is a double bus bar substation with the bus coupler normally open. We can add the 5 feeders with the highest off peak (minimum load) loading to the transformer that the EG unit will operate in parallel with. This also then needs to be made as the normal network configuration with the staff at the Network Control Room so that it is not changed back to the old configuration. In this case since we are using 1/5 Intersite Avenue SS 16541 as the injection DSS we can also connect Browns Drift SS 6580, Umgeni Iron Works, National Chemicals and 69 Intersite Avenue onto the same bus bar/transformer at the Major Substation. This will then allow for a larger EG unit such as wind and gas to electricity to be connected onto the Springfield Distribution Network.

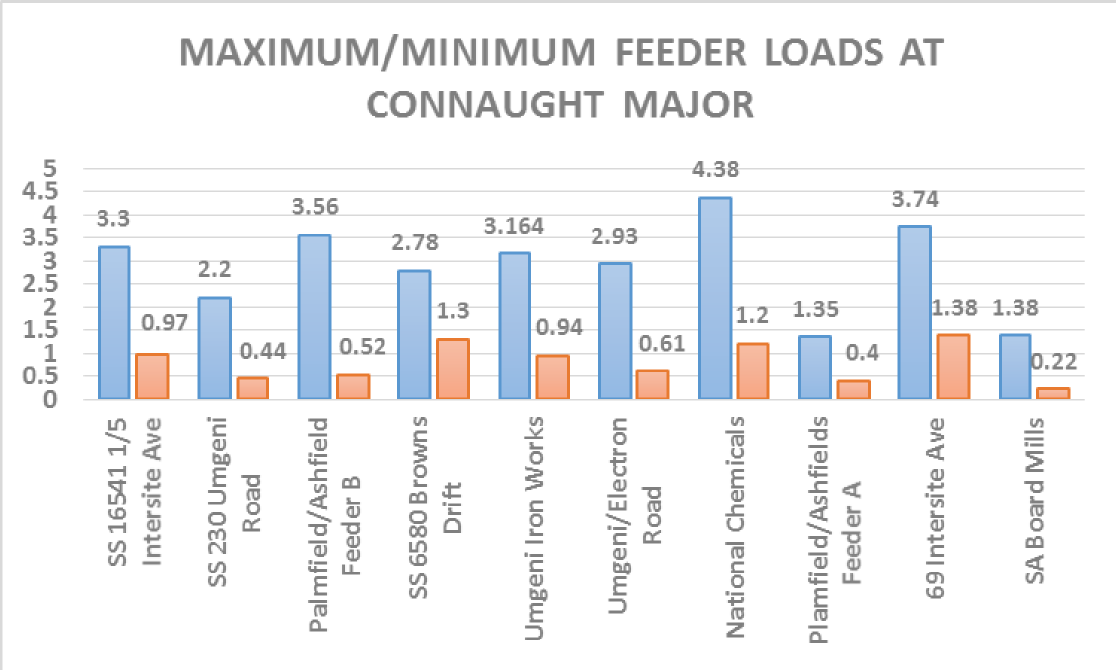


Figure 9.8: Peak/off-peak loading at the Connaught Major Substation [38]

In the event of multiple generation units on a site or the on the same distribution network feeder connecting to the same transformer at the Major Substation eg. eight 1 MW units on a landfill site as shown in Figure 9.9, the onsite substation can be designed such that the generators connect onto a bus bar with a bus section which can be left open and two separate cables or lines used to inject the power into different DSS fed from different transformers or Major Substations such that the generation does not exceed the off peak network demand of either transformer/substation. The common problem that occurs is that although an EG may operate in parallel to a Major Substation that has 4 transformers, it will only operate in parallel with a single transformer (as the bus section and bus coupler are normally open at the Major Substation and each transformer feeds a portion of the bus bar only) and hence the size of the EG unit is dictated by the off peak loading of the feeders connected only to that transformer.

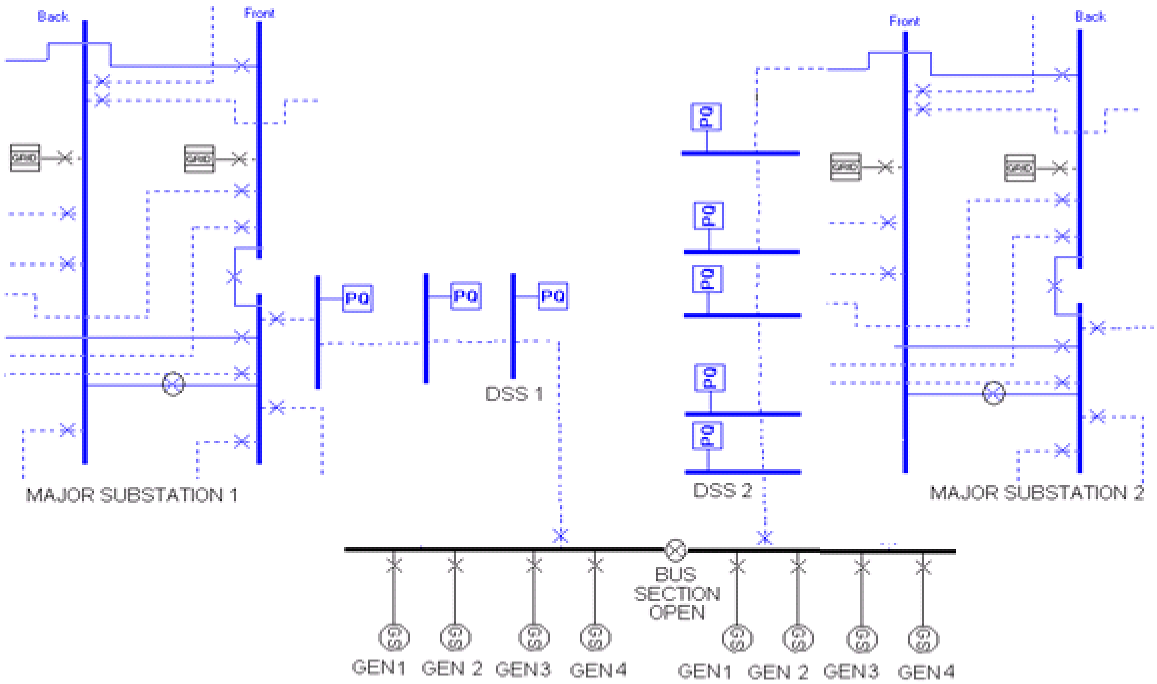


Figure 9.9: Alternate EG connection methods to cater for larger/multiple EG power outputs by injecting onto different Major Substations [14]

9.1.10.2. To reduce network voltage rise/reduction

(i) If the EG is a synchronous generator/converter technology then problems of voltage rise can be mitigated by operating the generator at lagging power factor (importing reactive power whilst exporting real power) or if voltage reduction is a problem (network bus bar voltages reside closer to the bottom statutory limit during the peak loading period) then the generator can be operated at a leading power factor (exporting real and reactive power) to provide voltage support. [14]

Figure 9.10 indicates the effects of the generator power factor on the distribution network bus bars. If problems of voltage rise is experienced on the network bus bars then this could be countered by operating the EG at lagging power factor that will then ensure that the voltages remaining within the required statutory limits. However the studies carried out need to ensure that the selected generator power factor ensures that the voltage remains within the ±5% statutory limit during peak, off-peak and contingency conditions on the network.

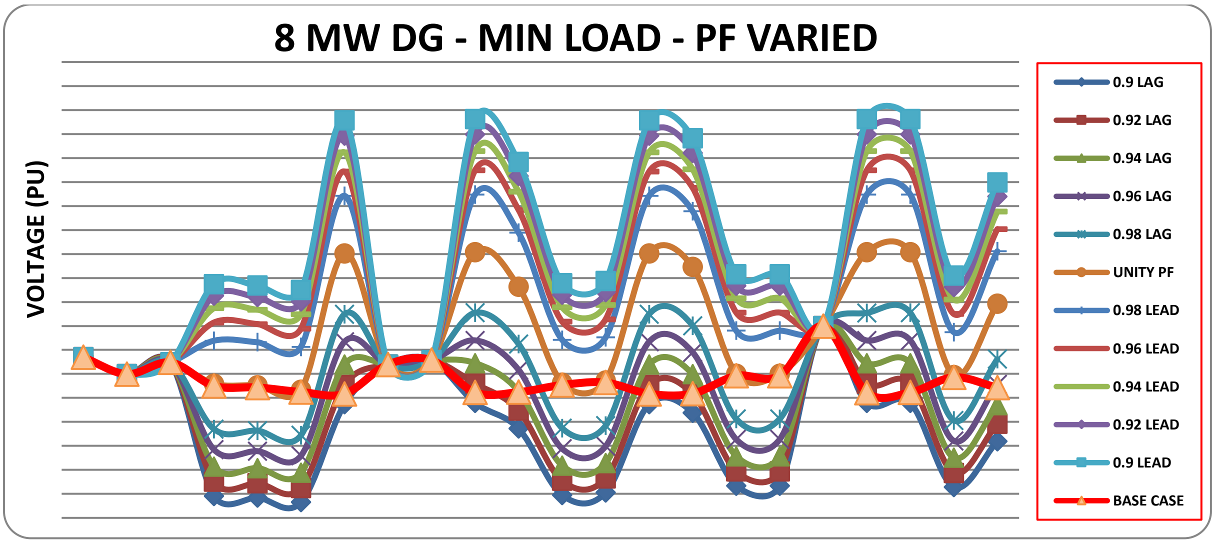


Figure 9.10: Impacts of generator power factor on the distribution network bus bar voltages [56]

(ii) Another voltage rise mitigation factor that can be considered is to reduce the Major Substation bus bar voltage since this is generally set higher than the nominal network voltage to accommodate for the voltage drops in the network ensuring that the voltage at all points in the network remains within the statutory voltage limits. Depending on the size and location of the EG units it may be possible to reduce the Major Substation voltage level to a level that may be derived from a load flow study of the existing distribution network. This is done to ensure that with the voltage reduced at the Major Substation none of the consumers in the network falls outside the voltage statutory limits during both the maximum and minimum network demand period with and without the EG unit/units. [56]

Figure 9.11 shows the effects on the network bus bar with the EG connect with and without the Major Substation bus bar voltage reduced. In this case study the Major Substation voltage was reduced from 1.03 pu to 1.02 pu.

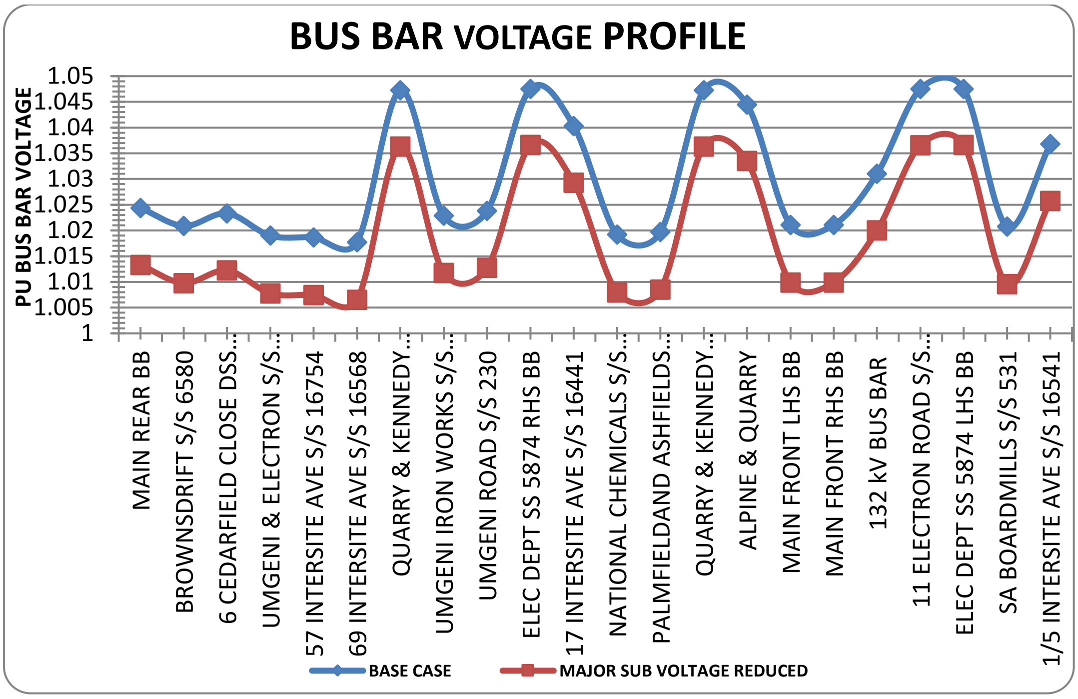


Figure 9.11: Impacts on the network bus bar voltages with/without the major substation bus bar voltage reduced [14]

(iii) Use of an Auto Transformer: by using an autotransformer one is able to regulate the voltage from its primary to secondary side and this measure may be used as a means to ensure that the voltage impact (rise or reduction) with the addition of the EG unit is counted and the network voltage remains within the statutory limits. This measure will assist when multiple EG units are used on the same distribution network. [56]

(iv) Use a generator transformer with a tap changer. This can help deal with over/under voltage problems. The generator transformer can be set at the appropriate tap depending on whether over/under voltages are experienced at the injection point. This will assist greatly on a network with multiple generation units at different points on the distribution network. The tap settings must be selected after carrying out the load flow studies of the network with all generation units in operations. [56]

(v) Reconfigure the network and add additional load to the injection DSS and its surrounding DSS by closing bus sections, moving open points on the network, etc. [56]

Figure 9.12 shows the effects on the eThekwini Electricity distribution network bus bar voltages before and after network reconfiguration. Network reconfiguration in the above case included closing the injection DSS bus section, changing the open points on the outgoing feeders at DSS to add additional load to the injection DSS and its surrounding DSS. This then ensured that bulk of the injected power is then utilized at the injection DSS and its surrounding substations instead of been transmitted back to the Major Substation for further distribution. This exercise however needs to be carried out with all network loading conditions, contengency and should include all generation units. [56]

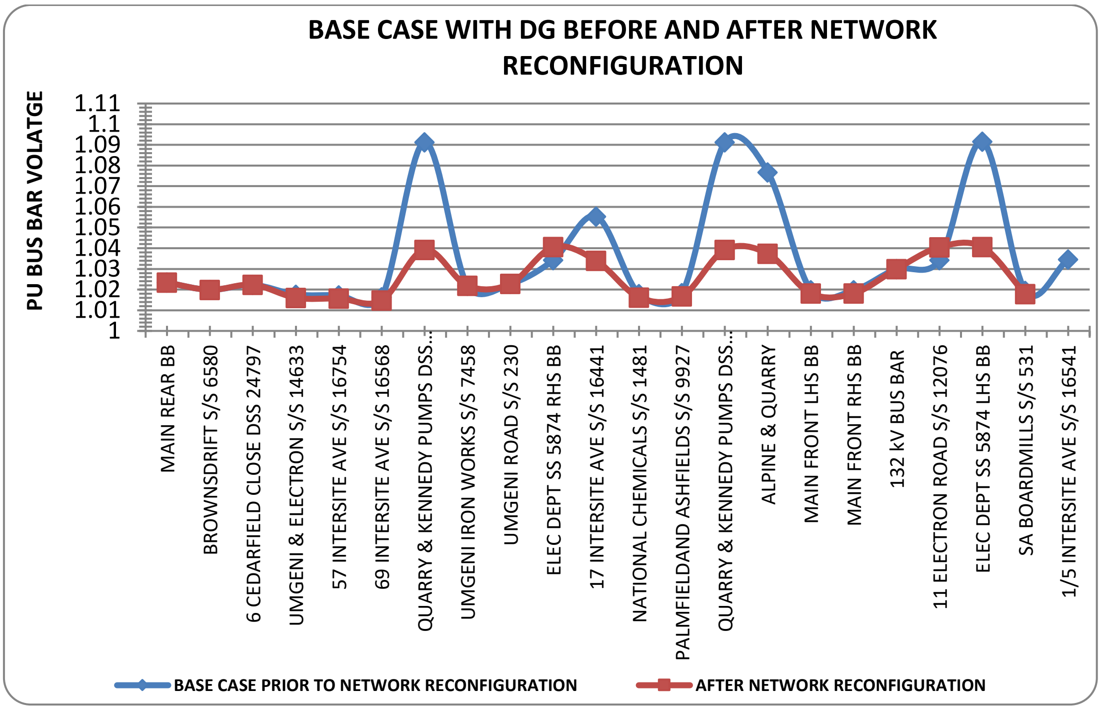


Figure 9.12: Distribution network bus bar voltages before and after network reconfiguration [14]

9.1.10.3. To prevent cable/conductor overloading

(a) The existing conductors that would exceed or are close to exceeding their thermal limits can be replaced with larger higher thermal rated conductor/cable or provide other means of network reinforcement such as adding additional cables/conductors to reinforce the network. [56]

Figure 9.13 indicates that with the addition of the EG unit to an existing distribution network results in few of the network cables been overloaded around the injection DSS during the off peak loading period where the generated power is required to be carried away into the network through the cables. To solve this problem we can up rate the over loaded cables and in this case study we change the 240 mm^2 (6 MVA) aluminum cables to 300 mm^2 (8 MVA) copper cables at 1/5 intersite to New Electricity Deptment and Main Front Bus Bar to 1/5 Intersite Avenue. The cable between the Electricity Department and the 11 kV gen bus was a 300mm^2 (8 MVA) copper cable and in this case the best option was to use a double cable box at both the ends and ran two 300mm^2 copper cables in parallel terminating at the same circuit breaker. This was done since spare circuit breakers were not always readily available at substations in existing distribution networks. This then reduce the existing cable loading by 50%. [56]

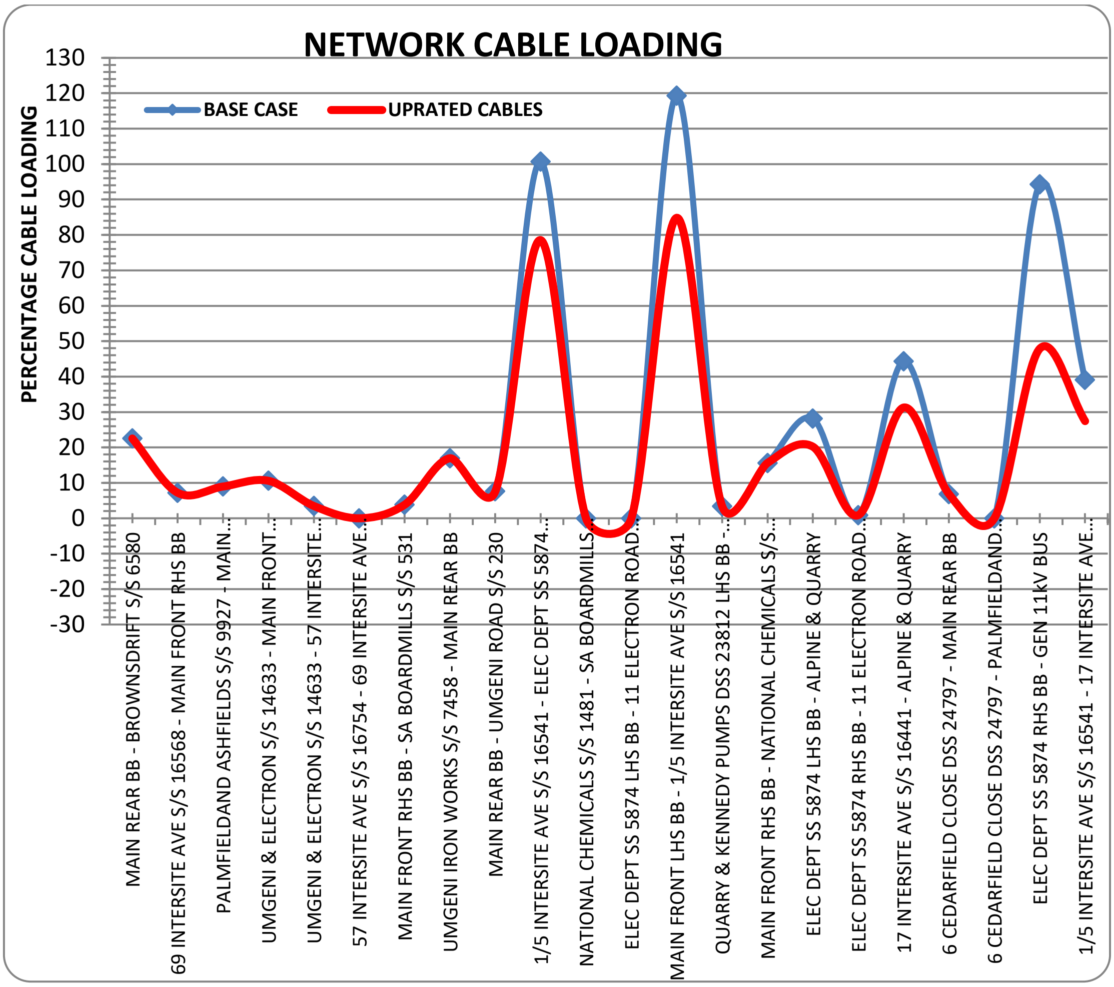


Figure 9.13: Cable loading before/after the network cables were uprated [14]

(b). Add additional loads to the injection substation when the EG plant is rated higher than the cables in the surrounding distribution network such that the difference in the maximum EG power output and the outgoing cable rating is utilized by the total connected load at the substation during the off peak period. [56]

If 7 MVA was injected into a DSS (National Chemicals DSS) which is normally fed from the Major Substation via a 240 mm^2 Aluminum PILC cable rated at 6 MVA as shown in Figure 9.14. If the cable between the Major and DSS is over loaded with the EG connected then we can change the open points on the network fed from the injection DSS to ensure that the loading at the DSS is always over 1 MVA especially during the off peak period. [14]

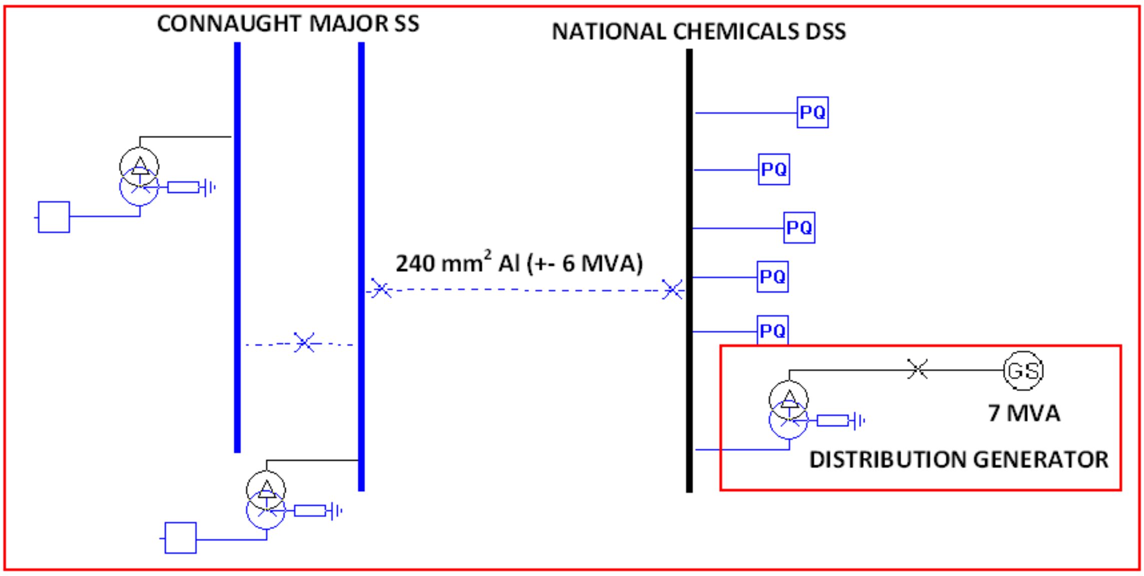


Figure 9.14: 7 MW landfill gas to electricity EG injection into National Chemicals DSS with a 6 MVA link cable between Major Substation and injection DSS [14]

Figure 9.15 shows the DSS load profile after additional loads were added by changing the open points on the network. The off peak loading is always greater than 1 MVA hence implying that the cable back to the Major Substation will not be overloaded under normal operating condition. However a maximum of 1 MW power curtailment may be required from the EG during contingency network conditions.

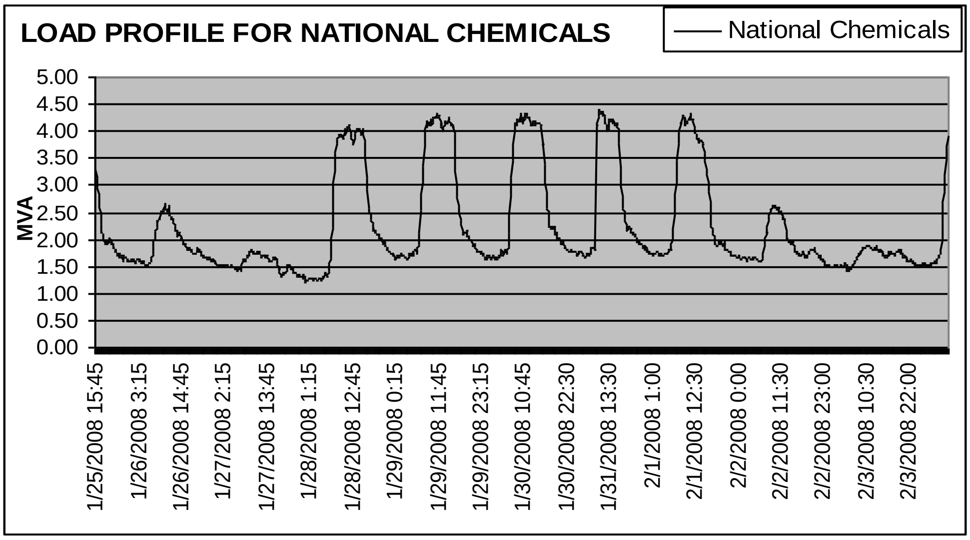
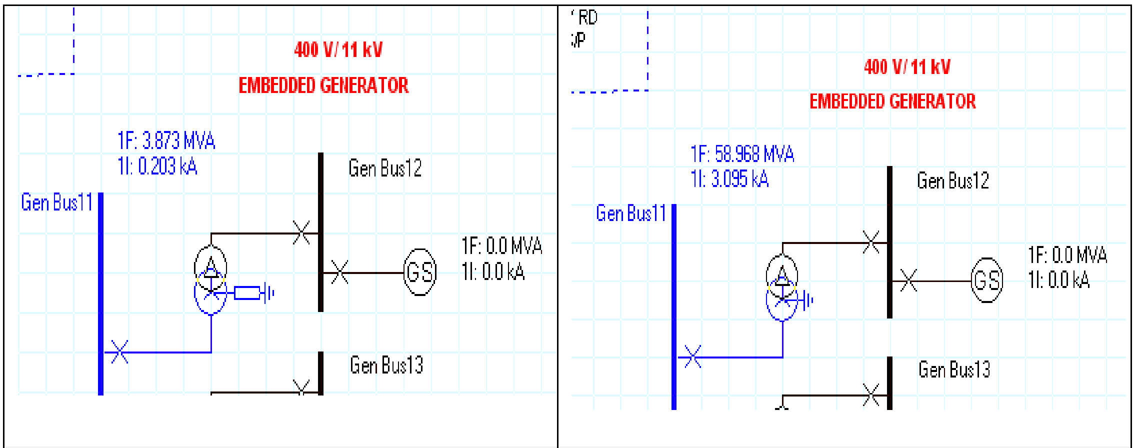


Figure 9.15: Load Profile of National Chemicals DSS after adding additional load [14]

9.1.10.4. Accommodating/Limiting Fault Levels in the network

(i) Single phase fault current can be easily reduced to any required value with the addition of a neutral earthing resistor (NER) installed on the star point of the generator transformer (the generator transformers are generally step up delta/star transformers). [56]

In Figure 9.16, a 254 ohm NER was installed on each of the eight 1 MW generator transformers limiting the single phase fault current to 25 A per a 1 MW generator. This then reduced the erath fault current from 3.095 kA to 203 kA. [56]



8 MW Landfill gas to Electricity DG with NER (Earth Fault Current contribution 203A from the Generators)	8 MW Landfill gas to Electricity DG without NER (Earth Fault Current contribution 3095A from the Generators)

Figure 9.16: Effects of adding an NER on the star point of the generator transformer to limit the earth fault current contribution to a specific value [56]

(ii) Parallel circuits in the network can be split up thus increasing the effective impedance of the network and reducing the fault current levels. [56]

(iii) Current Limiting Reactors (CLR) can be connected in series with the network to help reduce the fault current but care must also be taken to ensure that the additional reactance added by the CLR does not degrade the network voltage profile beyond its statutory limits. This needs to be checked using a load flow package to ensure that the network voltages remain within its required statutory limits. If voltage problems are experienced with the addition of the CLR then the EG power factor may need to be adjusted accordingly to ensure that the voltage remains within the statutory limits. [56]

(iv) In some events the limiting factor that prevents a certain size EG plant from been installed in a network is a few pieces of older equipment with lower fault current rating than the newer equipment and the simplest solution would be to replace these few pieces of old equipment with new equipment of higher fault current ratings. This then allows for the network to accommodate a larger size EG unit. Commonly a few pieces of older switchgear exists in most distribution networks which are rated lower than the new switchgear. [56]

Table 9.10: Summary of Mitigation Measures to minimize the impact of EG (IPP owned) on the existing distribution network design and performance [56]

Generator Size	Voltage	Three Phase Fault Level	Single Phase Fault Level	Cable/Line Loading
To accommodate a larger EG unit to an existing distribution network :	To reduce voltage rise/reduction on the network bus bars:	Reduce Three Phase Fault Current:	To limit single phase fault current:	To prevent cable/conductors from been overloaded:
1.Reconfigure network	1. Synchronous generators can be used at lagging powers factor to prevent overvoltage at the bus bar or used in leading power factor mode for voltage support.	1. Split up parallel circuit	Install an NER	1. Replace with higher rated conductors/cables.
2. If multiple generation units are used then use a bus section and feed different substations on the network.	2. Reduce the voltage level at the Major Substation.	2. Use Current limiting Reactors.		2. Add more load to the injection substation to absorb the excess power that will overload the cable/conductors.
	3. Use Auto transformers	3. Replace older equipment with low fault ratings		
	4. Get a generator transformer with a tap changer.			

9.1.11. Understand the South African Renewable Energy Grid code

The SAREGC is discussed in great detail in Chapter 5 and Chapter 6 where the compliance to the code was carried out on a 10 MW (Category B) PV Farm and a 25 MW (Category C) Wind Farm. The SAREGC compliance on the PV Farm was carried out using the farm model in a software study whilst the compliance to the SAREGC of the wind farm was tested physically on site.

9.1.12. Provide controllability options to manage EG plants on the existing distribution network in eThekwini Municipality

Further to the criteria given in Table 9.9 and Table 9.10 to minimize the negative impacts of EG interconnection onto existing distribution networks. Table 9.11 provides the operation features that is now made mandatory for all new RPPs connecting onto SA distribution networks at MV level. This then provides the Network SO with further operational flexibility, visibility and controllability of the plant. The stringent times specified in the SAREGC requires the RPP to comply within 30 seconds after issue of the set point for voltage control, power factor control and reactive power control. This means that should there be problems on the network due to contingency, the SO has flexibility of changing the plant operating setpoint to ensure that the local network parameters remain within statutory limits during contingency. Also under network contingencies such as trip of feeders and loss of load, the RPP active power output can be curtailed within 30 seconds by the SO. Table 9.11 provides a summary of the controllability of the the EG plant that the SO has visability and controllability to allow operational flexibility of the network during contingencies from Categorgy B RPPs.

Table 9.11: SAREGC Operation requirements from RPPs [16]

Grid Code Requirements	**Category B**	**RPP accuracy and response time to set point**
Maximum Size	Up to 20 MW	Connected onto the MV network
Connection Voltage Level	MV Connected	In most Municipalities MV is 11 or 22 kV
Reactive Power requirements	$-0.28 \leq Q_{Max}/P_{Max} \leq 0.28$ For 20% or greater P_{Max}	The RPP must respond to the set point issued within 30 seconds upon receipt to a measured accuracy to the higher value of either ±2% of the set-point value or ±5% of maximum reactive power.
Power Factor Requirements	$-0.975 \leq Q/P \leq 0.975$ For 20% or greater P_{Max}	The RPP must respond within 30 seconds of receipt of the set point to a measured accuracy of ±0.02
Voltage Control	The plant needs to have two Droop settings that's adjustable between 0 and 10%. Eg: 5% Voltage Droop = $(Q_{max})/5\% \, U_n$	The plant needs to implement the set point within 30 seconds within the accuracy of ±0.5% of $V_{Norminal}$ whilst the accuracy of ±2% of the required injection or absorption of reactive power according to the plant droop characteristic defined.
Active Power: Absolute Production Constraint (APC)	APC is used to constrain the active power output from the RPP to a predefined power MW limit at the POC. This is typically used to protect the network against overloading.	The RPP shall comply within 30 seconds after receipt of the set point to a measured accuracy to the higher value of either ±2% of the set-point value or ±5% of the rated power for each set-point.
Active Power Gradient Constraint (APGC)	PGC function is used to limit the RPP maximum ramp rates by which the active power can be changed in the event of changes in primary renewable energy supply or the set points for the RPP.	The measured values shall be recorded after 30 seconds after receipt of the set point to a measured accuracy of the higher value of either ±2% of the set point value or ±5% of the rated power for each set point.

Figure 9.17 shows the use of the reactive power control function to provide reactive power support to the grid from a PV farm in South Africa. This demonstrates that the control functions which all medium and large scale RPPs are equipped with can be utilized to assist in the grid operation under network contingency conditions.

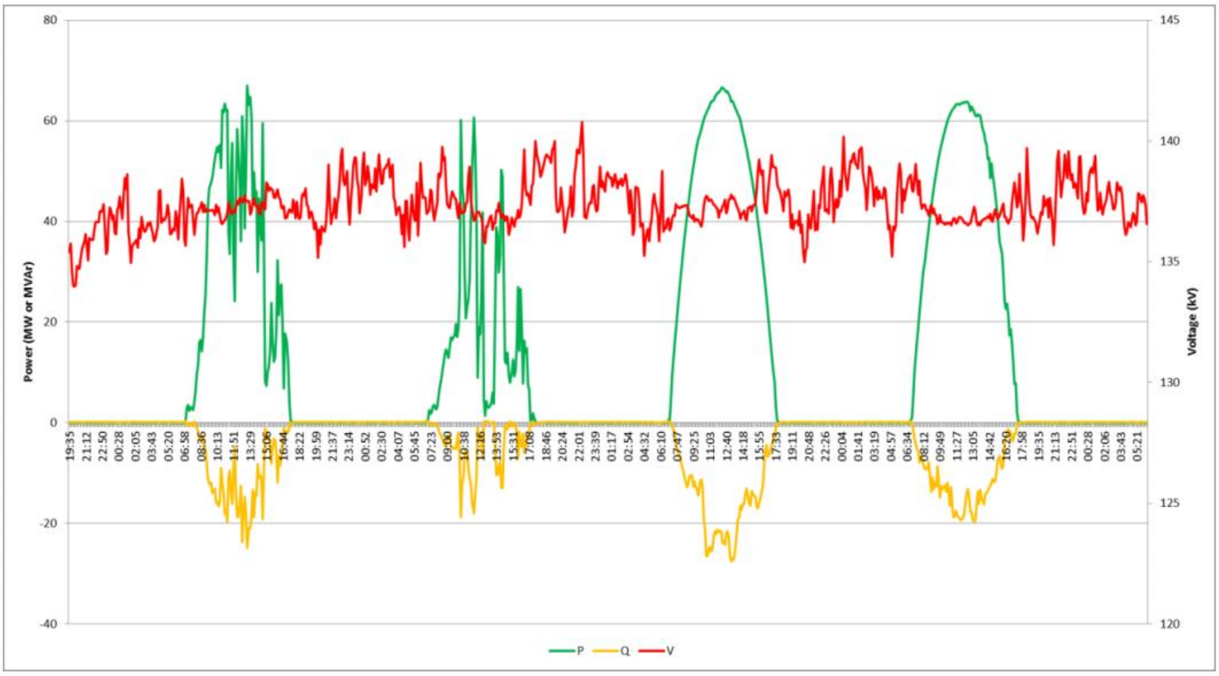


Figure 9.17: Real example of a PV farm providing voltage control over 4 days

9.1.13. Loss of Revenue Impact from Embedded Generators in South Africa

Most residential and small customer tariffs are not cost-reflective as they do not reflect the fixed costs associated with the management, operations and maintenance of the grid and the retail related costs to serve the customers. If the electricity tariff supplying a customer is not cost reflective and EG is installed, it means that there will be loss of revenue to the municipality. This loss will need to be recovered from other customers as there is no commensurate reduction in costs. Most residential tariffs comprise of a variable c/kWh charge only and no fixed charges to recover the fixed costs. This implies that if consumption decreases due to own generation, the utility looses revenue that is not commensurate with a reduction in costs. From the utility perspective, revenue loss is a major concern as EG reduces their sales and hence revenue. A mechanism needs to be determined to facilitate the development of SSEG in South Africa while mitigating a potential negative impact to the utilities revenue. [7]

The main issues for a utility related to the connection of SSEG installations are: [7]

(a) SSEG causes a reduction in sales and where tariffs are not structured to recover all fixed costs through fixed charges, there will be a negative revenue impact due to loss of sales.

(b) Customers may be net zero consumption customers, but still need the grid as a backup to variable energy resources.

(c) Even though consumption might be lower or even zero, customers may still require the infrastructure to draw the same demand affecting the grid and generation capacity as customers that do not have own generation – typically those installing PV.

(d) There remains a cost to connect and use the grid as a backup and to consume when needed.

(e) This cost is not recovered if fixed charges are not cost-reflective and there is a net-metering/billing or net-FIT tariff scheme.

(f) It constitutes variable avoided cost of supply (fuel and variable operating costs).

(g) Most tariffs for residential and small customers do not have cost reflective network charges.

(h) Customers that do not have SSEG could subsidise the tariffs of customers with SSEG, unless the consumption tariffs and the export tariff are made cost reflective.

(i) The customer should be aware that they will not be getting a credit based on current tariffs, that credit should be related to the total utilities avoided cost.

(j) The customer's avoided cost could therefore only be related to costs that are avoided by EG and this needs to be factored in by the customer when investing in such equipment. [7]

In order to resolve the revenue loss concern for residential consumers who generate 27% of eThekwini Electricity's revenue, the utility has two options:

(i) Move all residential customers to a residential TOU tariff structure (eThekwini Electricity currently purchases electricity from Eskom on a TOU tariff structure). In this way the consumer can be charged a demand and network/grid excess charge. This ensures that even if the customer utilizes zero kWhs of electricity, the municipality still recovers the fixed costs. However, the present installed electricity meters do not support the complex TOU tariff structure. This option can however be implemented in the near future after the roll out of smart meters at eThekwini Municipality as part of the smart grid deployment project.

(ii) Unbundle the residential and business flat rate tariff structures for consumers wanting to install EG such as rooftop solar PV. That can be achieved by implementing an interim SSEG tariff structure by creating a simple buy back mechanism for generated electricity.

However in providing an electricity supply to any residential consumer, eThekwini Electricity levy charges by means of a tariff structure to recover costs incurred in providing such a service. There are a variety of costs, however for the purpose of simplicity within the context of this thesis, the cost can be viewed as follows:

1. The bulk electricity costs refer to the costs that are paid to the national generator of the electricity which is Eskom.

2. Whilst the network costs refer to the fixed costs incurred by eThekwini Electricity which includes costs such as repairs and maintenance, salaries, meter reading and related costs.

The SSEG tariff structure will have an import and export tariff component. This tariff structure will then allow residential customers to consume electricity from the grid as well as export excess generated electricity to the grid. As a result of not implementing such a mechanism, the municipality currently runs the risk of a financial loss. If the customer generates as much as he consumed, then the payment to the municipality is zero. To ensure no free riding on the network and the risk to the municipality is limited, a network recovery charge is needed. The current tariff recovers the network charge as electricity is consumed. Whilst this is not 100% cost reflective, it is workable and will be successful in recovering the network charge. To ensure consistence and equal treatment amongst the residential sector, it was proposed that consumers who install a rooftop PV system be moved on to a SSEG tariff structure that is made up as follows; a fixed netwrok usage charge, an export cost/kWh charge and an import cost/kWh charge.

Stemming from the above, it can be concluded that there are fixed and variable costs associated with a supply point, irrespective of the direction of power flow. Residential users currently pay for both costs via a single rate energy charge (per a kWh). The workable proposed EG tariff structure for flat rate electricity users should be broken into three components as flows to ensure business sustainability and prevent revenue loss at the Municipality:

1. Charge a fixed monthly service charge.

2. Charge the customer the current rate for electricity (R/kWh) for electricity imported from the grid.

3. Pay the customer for the excess electricity exported to the grid at a flat rate average purchase price from Eskom similar to the flat rate charge calculated in Chapter 7.

In this tariff structure, simple bi-directional meters are required with two registers (one for imported energy and one for exported energy) is required. The billing system can then calculate the consumers monthly net bill as follows:

Net bill = Monthly fixed charge + Total imported energy charges – Total exported energy charges

In this method, the consumer is compensated for exported excess energy to the grid whilst the reduction in consumption/revenue from the customer is compensated by the monthly fixed charge. This will ensure sustainability in the municipal electricity sector which is often the revenue making unit of the municipality where the revenue received is utilized to cross subsidise other non-revenue generating service units within the municipality.

9.1.13.1. Commercial and Industrial Customers

Revenue loss is not an issue due to the design of the commercial and industrial customer tariff designs, which is in line with the Eskom TOU tariff structure. These customers can purchase imported electricity from the municipal grid at the eThekwini Electricity TOU tariff structure and be paid for electricity exported to the grid at avoided costs (Eskom 275 kV TOU Tariff structure). The TOU tariff structure caters for network demand and network access charges to compensate for the use on the municipal grid.

9.1.14. Provides methods to assist the distribution network designers when designing distribution networks with increasing EG

In the case of the LV connected residential customers, we utilize an After Diversity Maximum Demand value (ADMD) where ADMD is the LV network demand that is aggregated over the number of customers on the network when planning for consumer connections. ADMD values vary from different sectors of the customers and in South Africa we currently use the NRS 069 guideline when selecting ADMD values. However where measured network data is available, this could be calculated by the network planner for a more accurate ADMD values and utilized for the network design. The research investigation into the typical technologies to the deployed in the eThekwini Municipality residential sector was rooftop PV systems without battery storage equipment. This may not affect the ADMD values as the PV generation is very low or close to zero during the morning and evening residential peaks in Durban. Due to the erratic nature of PV generation which is influenced by many factors such as cloud cover, high temperature, shading, dirty panels, rainy days, etc, it is recommended that the network planner plan for the consumers full load supply and stick to the ADMD values used to design in a non EG installed network. This will ensure that during spates of raining or cloudy days, the consumer's full load is supplied and no network loading problems are incurred. This will also assist in switching back the consumers after an outage on the distribution network and all the PV systems are switched off. The network will need to carry the full consumer load until these systems are back in service or during the early morning and late evening peaks when there is not PV generation. This then further justify the need to unbundle the residential flat rate tariff to include a fixed network access charge to make the network available when the consumer needs to draw electricity. In simple terms, the consumer uses the network as a large battery to either draw electricity or charge into the battery.

The impacts to traditional network planning techniques where we assumed unidirectional power flow ie. electricity purchased from Eskom at high voltage, transmitted and transformed and feed to customers has changed. Hence the traditional planning methods need to be modified to ensure that correct network planning is carried out with increased EG installations. The problems with most EG technologies is that they are embedded within the customers network and when the customers load profile is taken at the meter point, the net result of the customers load and generated electricity is seen and shown in Figure 9.18.

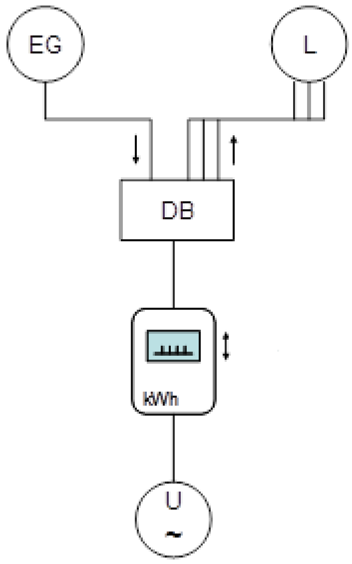


Figure 9.18: Typical traditional customer metering installation [15]

This is due to most MV customers load demand being much greater than their EG generation profile. However in the case of large customer EG installations, there may be times of the day where energy is exported to the grid. This even further distorts the customers load profile and the distribution network load readings taken at the DSS outgoing feeder. This may result in the network planner adding in more customers on to the network since the outgoing feeder load profile shows that there is available capacity. However load problems will be experienced when the EG plant/plants are not generating due to maintenance or lack of renewable resource such as sunlight on that particular day. To some extent the forecasting requirements for RPPs in the SAREGC will assist the SO with forcasting generation but we still need to cater for worst case scenario where there is no generation or minimal generation (due to maintenance, faults, break down, lack of natural resources, etc). In order to assist the planner to continue with his traditional planning methods, the following metering configuration can be implemented to measure the customers load and generation separately as shown in Figure 9.19.

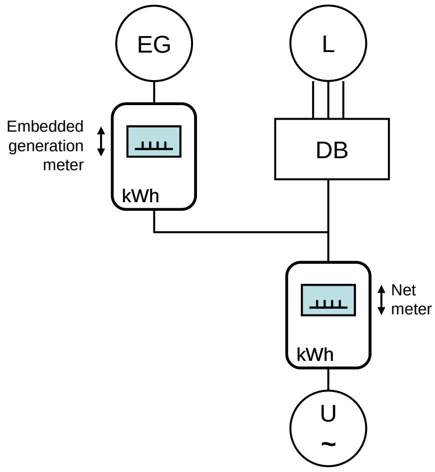


Figure 9.19: New metering configuration to measure EG output [15]

The proposed metering installation will now allow the planner to sum up the EG meter generation profiles with the customer meter load profile to recreate the customer original load profile (without EG) which can then be utilized in the traditional planning method.

In the case of pure generation plants such as landfill gas to electricity projects where all generated electricity is exported to the grid, the site metering data can be used.

In the case of larger (>1 MW MV connected EG), the SAREGC make provissions for the generation data to be brought back in real time to the Control Room. The data can then be stored for future plannings reference purposes.

A practical example demonstrating the re-creation of the load profile on a 33/11 kV 25 MVA transformer for planning purposes at the Connaught Major Substation using metering data at the generation site is shown in Figure 9.20. As discussed, the eThekwini Electricity operating philosophy is to operate the Major Substation transformers at 50% capacity which will be 12.5 kVA on each of the two transformers at the Connaught Major Substation. Transformer 1 feeds 5 outgoing feeders and operates in parallel with the Bisasar Road 6.5 MVA landfill gas to electricity generation project. By using the metering data at the generation plant summed up with the load profile data of the transformer, we see that the transformer exceeds its firm rating. However had the network planner not taken into account the EG plant in the network, it would have been seen that there is still capacity available on the network to connect more customers. The real concerns will then arise when there is a problem on the network (cable fault on one of the 2 incoming 33 kV cables or one transformer is off), the second transformer will need to take the full load of the substation. This works well under normal network condition but should the generation plant trip or is out of service for some reason then the entire network will trip on overload leaving a large number of customers off in the peak time. Hence it is important for the network planner to take any generation on the network into account and make provision for it during network planning and design. The other factor that complicates EG output is that a lot of these EG plants depend on resources such as wind, solar, bio-gas, landfill gas, hydro, etc to generate electricity. These resources may vary and fluctuate resulting in changes to the generation output at different parts of the day and night.

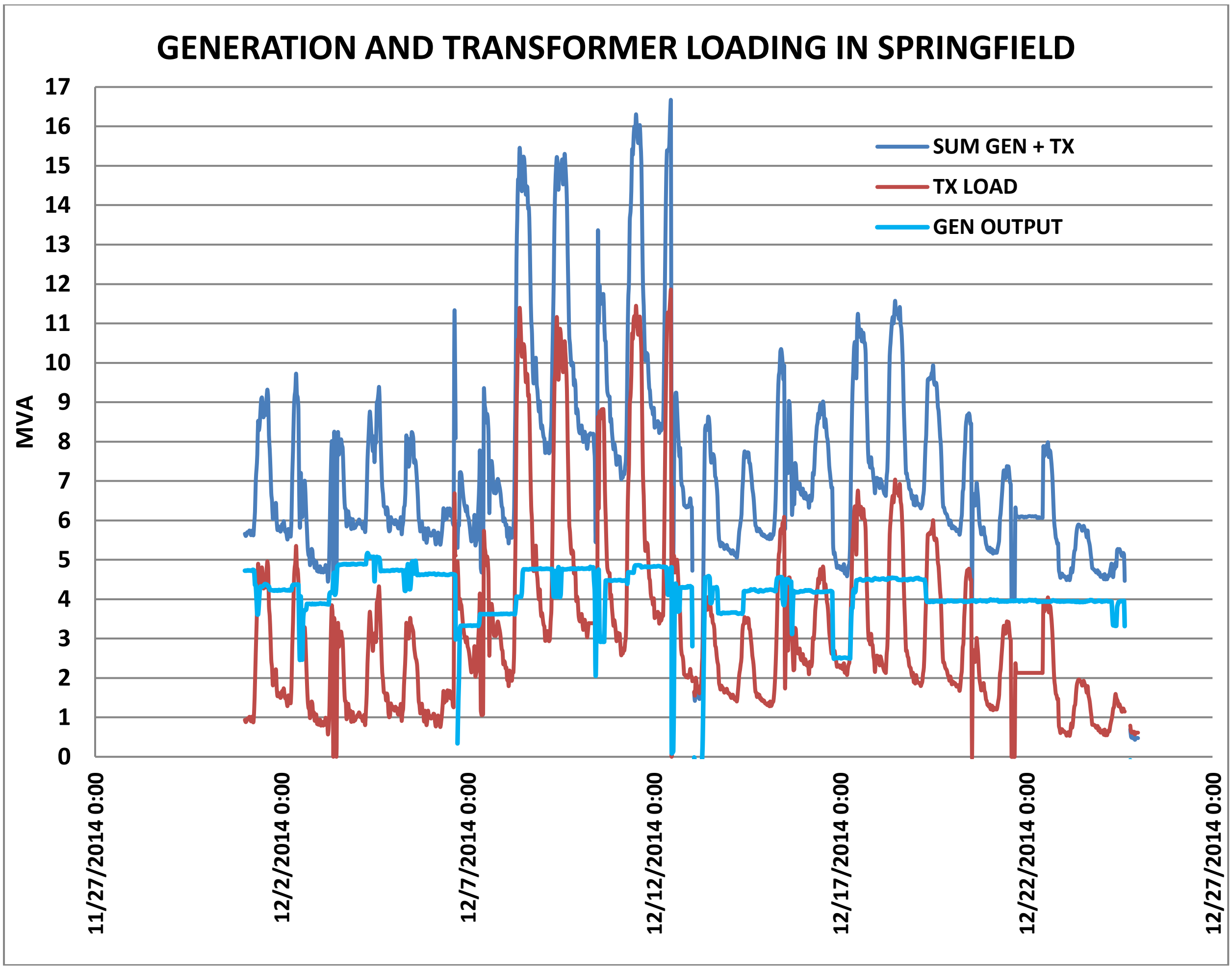


Figure 9.20: Major Substation Transformer Loading vs Generation plant output

9.1.14.1. Generation Resource Table for eThekwini Electricity

An assessment study on the availability of renewable energy resource at eThekwini Municipality is shown in Table 9.12. This indicates the different sources of generation expected at eThekwini Electricity over the next few years. This table will assist network planners to understand the dependency on the generation output from each type of generator and also the type of energy conversion technology utilized. This will assist with network planning especially on networks with multiple generation sources.

Table 9.12: Generation resource table for eThekwini Municipality

Resource	Source	Dependency	Type of Conversion	Generation Output
Wind	Natural - Anytime	Wind speed	Doubly fed induction generator, full converter generator	Variable
Solar	Natural – During sunlight hours	Sunlight, cloud cover, temperature	Inverter	Variable depending on weather conditions and cloud cover – predictable in the sense that generation only occurs during sunlight hours.
Landfill gas	Landfill sites – 247 unless contains storage facility	Waste type and volume, number of gas wells	Gas to electricity engines coupled with synchronous generator	24/7 unless there is storage facilities
Natural gas	Pipeline gas – depends on storage and contract	Contract with supplier	Gas to electricity engines coupled with synchronous generator	Depending on contract and availability of storage facility.
Biogas	Wastewater treatment works – 247 unless contains storage	Storage, volume of wastewater treated	Gas to electricity engines coupled with synchronous generator	Depending on storage facilities.
Bio - mass	Bagasse – seasonal	Seasonal	Steam turbine coupled to a Synchronous Generator	Available during sugar cane harvesting season only and dependent on consumer load demand.
Co - generation	Steam – excess steam from process - variable	Availability of excess steam from process	Steam turbine coupled to a Synchronous Generator	Variable and dependent on consumers own load demand.
Hydro	Aqueduct - water flow rate dependent	Water flow rate	Synchronous generator	Dependent on water flow rates which varies dependent on customer demands.
Hydro	Reservoir Outlets – Water flow rate dependent	Water flow rate	Synchronous generators	Dependent on water flow rates which varies dependent on customer demand and reservoir electricity demand.

9.1.15. eThekwini Electricity's Smart Grid Journey

eThekwini Electricity is currently embarking on the implementation of a smart grid project to mordernise the grid. Part of the smart grid initiatives include the implementation of smart meters. The Advanced Metering Infrastructure (AMI) programme as part of the smart grid initiative is responsible for the implementation of smart metering, associated equipment such as communications modem, Customer Information Units (CIU) and Data Concentrators (DC) as well as Multi-Vendor Master Stations (MVMS) and Meter Data Management System (MDMS). Integration of all these components will ensure a seamless end-to-end bi-directional communication flow. This initiative will enable eThekwini Electricity in its effort to achieve their broader objective of implementing smart grid in their areas of electricity supply. AMI will also ensure consistency and optimisation of similar metering initiatives within eThekwini Electricity. The AMI programme will align to the overall eThekwini Electricity's smart grid objective that entails a sustainable and medium to long term strategy. This strategy is also an essential part of eThekwini Municipality overall vision of creating, among other priorities, a safe, accessible, environmentally sustainable and economically sustainable city by eventually achieving a smart city objective. [25]

The smart meter that was procured has the following features which will further assist with the management and implementation of increased EG connections onto the eThekwini Electricity distribution network as shown in Table 9.13. Some of the key features of these smart meters that will assist with increased EG penetration implementation is as follows:

A. **Supports Pre-paid and credit meter functions**: This assist with implementing an EG tariff for export energy to the grid as the present prepaid meter does not support reverse power flow and hence compensation of exported energy to the grid.
B. **Import/Export Metering function**: The meter supported bi-directional power flow which allows the accurate measure of exported and imported energy to and from the grid.
C. **Daily readings**: The current municipal credit meters are manually read once in three months whilst estimates are utilized in months where readings are not taken. This makes implementing the EG tariff difficult and requires modems to be installed on all bi-directional meters to have accurate import and export meter readings at the end of the month for billing purposes. The smart meter supports daily meter readings and these readings can be downloaded from the meter as and when required since with the implementation of smart grids, there will be communication links to all smart meters on site. This will provide up to date accurate data for billing purposes.
D. **Outage Detection**: This will flag an alarm at the Control Room when there is a loss of supply which will enable a quicker response time from the Maintenance crew as opposed to waiting for the consumer to report the fault through the municipal Call Centre. This function will also enable the dispatcher to determine whether it is a local fault at the consumer or if the entire area is off enabling him to dispatch the either a Faultsman or the Depot crew.

E. **Load limiting**: EG customers are required to automatically shut down their generation plant with the loss of grid. This becomes a problem in SA due to the constant need for load shedding during network generation constraints in order to balance the electricity generation with demand. Each municipality is required to curtail 10% or their electricity consumption during Stage 1 of load shedding and these percentage increases as we move up to Stage 4. Instead of the current method of rotational load shedding where Major Substation are put together in a block and switch off for a 2 hour period per a block depending on the Stage of load shedding. With this feature, the municipality can then curtail the customer supply to make up the required percentage saving and this will enable the customer EG unit to remain on and continuing to generate. This will assist rooftop PV generation as load shedding is mostly implemented during the day when the load demand is high.

Table 9.13: Key features of the smart meters that was procured by eThekwini Electricity [25]

	Meter Feature	**Description**
1	Support pose paid and prepaid mode	Meters are able to operate in prepayment mode and are capable of receiving STS compliant credit tokens
2	TOU Prepayment	Prepaid meters manage money or currency tokens whereby prepaid monetary credit according to the different TOU rates
3	Two way communications	Bi-directional communication between a meter, concentrator & AMI Master Station. The concentrator and meter is able to receive commands from the AMI Master Station and respond that the command was successful. This includes remote disconnect and reconnect instructions, software updates and remote diagnosis of the meter.
4	Interval data reading	Meters register consumption in 30 minute intervals. The interval data is sent to the concentrator every 30 minutes (for Concentrator solution).
5	Register data only	Ability to produce and store register reading to be used for billing
6	Import/export (Net metering)	Energy Balancing is the ability to measure both positive and negative energy flows. This is particularly applicable in cases where the customers has installed PVs or any form of energy source. This is the ability for the meter to measure energy that the customer is supplying to the grid.
7	Daily reading	Ability to produce daily register and interval readings which are sent back to the Master Station
8	Remote Connect/ disconnect	Ability to connect and disconnect a meter remotely for both prepaid and conventional customers
9	QoS – Blinks and outages, sags and swells	Ability to store status alarms, supply outages, over voltage and under voltage events on the meter and to retrieve this data through remote communication with the meter.
10	Load Control	Ability to switch loads remotely (e.g. Geysers) according to a schedule. This can support the TOU tariff (also known as appliance control)
11	Outage detection (meter loss of supply)	A loss of supply at a mini-sub level can be detected immediately as an event that occurs on the concentrator. Meters can also store loss of supply data as events which are communicated less frequently to the backoffice
12	Load Limiting (Supply capacity control)	Ability to limit the supply or load at the customer’s premises on an ad hoc basis. Customers can be allowed consumption below a threshold without disconnection

13	Leading/Lagging Reactive power	Meters capable of indicating inductive or capacitive power
14	Customer Portal	Ability for Customer to view consumption and customer trends
15	Mobile interface	Customer's mobile to act as a Customer Interface Unit

9.1.16. Additional Benefits of Smart Grid Implementation

Traditionally, the power grid is the infrastructure which transports electricity from where it is generated (in remote areas like power plants) to homes, businesses and industries where it is consumed. The grid being largely analog and electromechanical in nature. However over the past few years, a new concept in how the power grid is managed has emerged. This concept is referred to as Smart Grids. The added benefits of a smart grid implementation is shown in Table 9.14. One of the benefits will be the bi-directional power/data flow and opportunity for consumers to sell electricity to the grid. Part of the project also entails the roll of the SCADA to LV feeders and mini substations to bring back data which was previously not available to the network SO and planner. [25]

Table 9.14: Smart Grid Benefits [25]

Area	Utility	Consumer	Society
Improved Economics	a) Opportunities to leverage its resources and enter new markets b) Increased revenues as theft of service is reduced c) Improved cash flow from more efficient management of billing and revenue management processes d) A flatter load profile will reduce operating and maintenance (O&M) costs	a) Downward pressure on energy prices and total customer bills b) Increased capability, opportunity, and motivation to reduce consumption c) Opportunity to interact with the electricity markets through home area network and smart meter connectivity d) Opportunity to reduce transportation costs by using electric vehicles in lieu of conventional vehicles e) Opportunity to sell consumer produced electricity back to the grid	a) A more robust transmission grid will accommodate larger increases in wind and solar generation i.e. green energy. b) Downward pressure on prices — through improved operating and market efficiencies c) Creation of new electricity markets — enabling society to offer its electricity resources to the market and creating the opportunity to earn a revenue stream on such investments as demand response, distributed generation, and storage
Improved	e) Increase asset utilization	f) Increased capability,	d) Deferral of capital investments

Efficiency	f) Reduction in lines losses on both transmission and distribution g) Reduction in transmission congestion costs h) Reductions in peak load and energy consumption leading to deferral of future capital investments i) Increased asset data and intelligence enabling advanced control and improved operator understanding j) Extended life of system assets through improved asset "health" management k) Improved employee productivity through the use of smart grid information that improves O&M processes l) Improved load forecasting enabling more accurate predictions on when new capital investments are needed m) Reduced use of inefficient generation to meet system peaks	opportunity, and motivation to be more efficient on the consumption end of the value chain g) Increased influence on the electricity market	as future peak loads are reduced and more accurately forecasted through the combined efforts of consumers and delivery companies e) Reduced consumption of kWh's through conservation, demand response, and reduced transmission and distribution (T&D) losses
Improved Environment	n) Increased capability to integrate intermittent renewable resources o) Reduction in emissions as a result of more efficient operation, reduced system losses, and energy conservation p) Opportunity to improve environmental leadership image in the area of improving air quality and reducing its carbon footprint q) Increased capability to support the integration of electric-powered vehicles r) Reduction in frequency of transformer fires and oil spills through the use of advanced equipment failure / prevention technologies	h) Increased capability, opportunity, and motivation to shift to electric vehicle transportation i) Improved opportunity to optimize energy-consumption behaviour resulting in a positive environmental impact j) Increased opportunity to purchase energy from clean resources, further creating a demand for the shift from a carbon-based to a "green economy"	f) Reduced CO2 emissions g) Improved public health

9.2. Conclusion

The following outcomes and key contributions were made to the body of knowledge, which was achieved in this research investigation/thesis, namely:

- An understanding of the drivers of EG in eThekwini Municipality.
- Evaluation of the available renewable energy resources within eThekwini Municipality.
- The feasibility of residential rooftop solar PV in Durban.
- Identified factors affecting residential rooftop solar PV feasibility in Durban.
- Assessed the feasibility of municipal landfill gas to electricity EG projects.
- Developed and propose methods to improve operational and financial viability of landfill gas to electricity projects in Durban.
- Provides results showing the impacts of increasing EG on the eThekwini Municipality distribution network design and performance.
- Developed methods to assist and enable distribution network designers when designing distribution networks with increasing EG.
- Developed a methodology for selecting EG size on an existing eThekwini Electricity distribution network.
- Provide methods to minimise the impacts of preselected size of EG given that the municipality has no control over the size selection which may be dictated by the IPP.
- An understanding of the local South African guidelines on small scale EG, and the South African Renewable Energy Grid code requirements.
- Provide controllability options to assist manage EG plants on the existing distribution network in eThekwini Municipality.
- Understand the operation and effects of different EG sources available within eThekwini Municipality.

The research investigation was successful in that all of the study objectives set out were achieved.

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