INVESTIGATING THE FINANCIAL RECOVERY OF EMBEDDED GENERATION IN MEDIUM VOLTAGE DISTRIBUTION SYSTEMS

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In partial fulfillment of the MSc Engineering degree, College of Agriculture, Engineering and Science, University of KwaZulu-Natal

17 October 2013

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No contribution to publications

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ACKNOWLEDGEMENTS

My sincere gratitude and appreciation go to, Professor N. Ijumba and Dr L. Chetty for standing in as main and co-supervisor for this dissertation.

I wish to express my utmost gratitude to my wife and my daughter, whose love, belief and encouragement make me able to achieve my goal of completing my dissertation.

ABSTRACT

Embedded generation (EG) provides many benefits in terms of reduction of system technical losses and increased load carrying capacity. In this study the sustainable EG carrying capacity permutations in a medium voltage distribution system, will be determined. Using these results, the financial investment recovery potential of EG will be studied and the impact on the cost recovery by the Utility as a result of compensating the EG at the current system marginal price, will be analysed.

The study was done to show what capitalisation can be done on a medium voltage distribution system, by the owners of EG plant receiving revenue from the Utility, at the system margin price with the anticipated inflationary increases. The study will also cover the effect on the revenue stream of the Utility as a result of voltage changes caused by the EGs to the loads being supplied.

The electrical system used in the study consisted of a radial system with distributed load and generation. The distributed loads were modelled using the average load capacity supplied by the Utility in medium voltage system. The average volume of sales lost as a result of non-technical losses was included in the load model so that the overall accuracy of the revenue effect by EG on the Utility, could be increased. The amount of capitalisation that is achievable by the owners of the EG was tested against various practical permutation scenarios, including variation of location, system impedance (different X/R ratios), time of operation and changing load volume and type.

The extent of successful penetration of EG into the distribution system was found to be between 20% and 60% of the load carrying capacity of the system. The simulated results revealed “bathtub curve” behaviour for the cost of energy losses and this reconciled with the theoretical analysis of other studies done in this area. Lower volume penetration of EG results in higher investment potential of up to ten million rand per MW with a 5% MARR per year. This is very low when compared to the levelised cost of the expensive renewable energy technologies that are currently available in the market. With higher penetration of EG on low impedance systems, the gross contribution of the Utility is negatively affected which would introduce instability in the SMP yearly increases.

CONTENTS

1. INTRODUCTION

Over the last three decades the effect of high SO_x and NO_x pollution emissions levels as a result of using fossil fuel generation has come under increasing scrutiny in the world. The extent of which is apparent by the penalties and funding conditions applied by investing agencies to this type of generation [1]. The trends for international funding and lending intuitions indicate favouritism towards investment into energy saving practises and technologies rather than capital investment into fossil fuel technology. This is very apparent in the North American and European energy markets where the energy used is kept flat even though economic activity increases [2].

These efficiencies will not resolve the long term global appetite for electricity generation as the world population continues to increase in Africa and Asia where the additional demand for electricity generation represents the largest driver in the demand for energy and hence, economic stability. It is expected that the role of independent power producers will greatly assist the liberalisation of the African energy market especially in the renewable energy sector and the efficiency improvement requirements for the industrial and commercial sectors [2].

In South Africa electricity generation is mainly derived from coal fired power stations which utilise low grade coal as the source of fuel. This type of generation produces high pollution emissions levels and also places stress on scarce water resources. The high average age of the entire generation infrastructure decreases the generation average availability time. This results in increased maintenance costs. The transmission and distribution infrastructure, in African countries, has to also expand rapidly due to growth in economic activity and electrification. The capital required for building new infrastructure is done mainly through long term loans and bonds and this is one of the main contributors to the retail tariff in countries like South Africa, increasing at a much higher rate than inflation each year for the last five years [3].

Embedded Generation (EG) options are being focused on by users of electricity in order to improve energy savings and increase revenues derived from the sale of electricity. Feed-In Tariffs (FIT) are used by Government agencies in countries including, but not limited to, Europe, North American, Australia, and New Zealand, to increase the viability of renewable energy technology [2]. In South Africa, the Department of Energy, has introduced a renewable bid in program based on international experiences, economic studies and localised parameters. The nature of the program is based on price bidding. The average cost of all the renewable energy can only be assessed after the program has been concluded in 2015 [4].

The renewable energy cost recovery by Utilities is done via existing pricing frameworks for cost recovery. This results in an increasing wholesale tariff, which is the average cost of generation. International practise requires that that the wholesale tariff becomes the rate at which power suppliers, outside structured renewable energy programs, be paid [4]. Eventually an economic point is reached where the cost of investing in localised EG, becomes viable at the wholesale rate. This breakeven point varies across the available EG technology spectrum. However, it is possible to calculate the capital investment that can be made by investors, based on the revenues derived from selling power to the Utilities, at the wholesale rate. The wholesale rate is also commonly known as the system marginal price (SMP) [3].

The research hypothesis is that the introduction of EG into a Distribution medium voltage system will improve the overall system load transfer capability by reducing technical losses and displacing existing load but the amount of capital required for investment into EG projects will be limited by the amount of EG penetration, the amount and load pattern usage of the paying and non-paying customers being supplied by the Utility, the electrical parameters of the system and the pricing tariff used for buying the energy from EGs.

1.1. Motivation and objectives

It is by no means easy to give a general view of the current state of research about EG, because of the various emphases of different researches. In the following, a brief review is presented by focusing on the works which concern the financial recovery of EG in medium voltage networks.

As far as the author of this dissertation is aware there has been a lot of technical analysis performed on the penetration and optimal distribution modelling of EG but the question of the level of capitalisation that can be made by investors based on revenues received at the SMP, which includes the recovery of both technical and non-technical losses, needs to be answered.

The objectives of this dissertation are:

- To identify and evaluate the amount of technical and non-technical losses in a generalised medium voltage system. Losses are comprised of technical and commercial (non-technical) components and vary with changes in customer composition, consumption patterns, changes in electrical grid topology and accuracy of customer billing [5].
- Evaluate the impact of EG on these components of losses
- Evaluate the resulting revenue recovered by the Utility in the generalised system.

- A further step is proposed to determine the conditions under where EG changes the revenue recovered in the general MV distribution system.
- Another objective of this dissertation is to give an answer to the following consideration: Can the load loss savings that is classified as either capacity or energy loss savings, be attributed to the EG's and provide a sufficient revenue stream for the investment of infrastructure based on this future earnings potential at the SMP?

The question in the last bullet point listed in the objectives above is answered by investigating the financial relationship between EG and the customer composition profile for a typical (generalised) network. The effect of improving system performance on the revenue recovered as well as the asset creation costs will be taken into account.

The following are the main assumptions adopted for the generalised system:

1) The loads and generators are evenly distributed with the electrical parameters of the generator fixed and based on typical values. The size of the generation per point will allow all load variation permutations up to the maximum full load consumed per point.
2) The composition of the load points is based on the average historic sales volumes.
3) The non-technical loss breakdown used is based on field work done over the last three years by Eskom in Kwazulu Natal.
4) The payment rate for generation will be at the system marginal rate. This rate will be directly impacted by the volume of new generation.

1.2. Outline of the Dissertation

In meeting the final goal of determining the financial effect of embedded generation in medium voltage systems, the requirements to be assessed are listed below. These requirements are to be met in order to ensure that the evaluation of the data, extraction and simulation of information, will allow results and conclusions to be made based on the completion of the dissertation

Following the introduction into the context of the environment in electricity delivery sector given in chapter 1, chapter 2 overviews the methodology of this work, mainly including:

1) Exploring the current research on similar topics within the field of EG in South Africa and internationally
2) The concept and attributes of EG and their impact on system operation in a generalised network
3) The concepts and attributes related to static loads

4) The fixed and variable costs associated to EG's.
5) Determine a suitable tariff model based on tariffs that are available from Eskom and currently in use in South Africa.
6) Determine a suitable model to be used for the calculation of non-technical losses for medium voltage systems.
7) Determine a suitable simulation model to be simulated in DIgSILENT PowerFactory.
8) Determine the load data sets to be used for the simulation models and compile an algorithm for testing multiple variables using DIgSILENT PowerFactory load flow simulation software
9) Detailing the method used to derive the load, electrical system and cost model for the generic system.
10) Detailing the method and techniques used to test the hypothesis and analyse the validity of study
11) Detailing the electrical models used and the parameters that are varied in the simulation model.

Chapter 3 concentrates solely on the results and discussion of the results which are presented and evaluated as follows:

1. The results of the simulations are analysed.
2. The practical permutations of operational flexibility available are determined. This is done by evaluating the configurations of embedded generation that is possible in medium voltage systems.
3. The capital investment limits are determined for the various scenarios based on the overall system limits. The scenarios include the payment options available for different minimum attractive rate of returns (MARR).
4. The discussion of the results and comparison with the theory from the literature review.

Chapter 4 looks at the conclusions and recommendations from the study and will include:

1. Determining the penetration limits of embedded generation in a medium voltage system.
2. Determine the effects of EG on technical losses and the cost of energy recovery for a MV system.
3. Determine the effects of EG on non-technical losses and the cost of energy recovery for a MV system.
4. Determine the capital that can be invested for an EG system based on the income generated from operating with the system limits of the MV system.

5. Determine the effect of using different load models on the MV system with EG and the resulting financial impact.

2. METHODOLOGY FOR DISSERTATION

2.1. Literature survey

2.1.1. Concepts and attributes of embedded generation

Embedded generation (EG) can be defined as generation that is connected to the distribution system (< 132 kV), is generally less than 40 MW units, consists of various technologies and fuel sources, and is not centrally dispatched by the Utility [6]. The medium voltage system which will be used in this study is defined as less than and equal to 33 kV. The typical mixture of EGs to be connected to the MV system in South Africa would consist of wind, small-scale hydro, combined heat and power (CHP), photovoltaic and landfill gas [6]. The variability associated to the energy input required (feed stock) is not covered in this dissertation.

Distribution networks have historically been designed and operated for unidirectional energy flow but with the introduction of EG, energy flows are changed and new systems and processes will have to be introduced to accommodate the change in characteristics of the system. This extends from operation to energy and short circuit level management. With increasing levels of penetration of EG, there will have to be a change of thinking regarding the planning, design and operation of distribution networks in South Africa [6].

Compared to conventional generation, EG usually has characteristics as [7]:

- not centrally planned.
- not centrally dispatched.
- with small capacity.
- usually connected to the distribution system.

And it mainly contributes to [7]:

- reduction of emission levels (mainly CO_2, sulphates and nitrates).
- energy efficiency or optimal use of different energy sources.
- deregulation of supply industry or competition policies enabling overall price changes.
- improvement in diversification and hence reduces reliance on fixed energy sources.
- reduction of land sterilisation.

- quicker plant construction availability times and lower capital costs of smaller plant.
- reduction of power transmission costs and losses.

2.1.2. Overview of embedded generation technology

The concept of EG in Distribution networks in South Africa is new but the currently available EG technologies up to a capacity of 5 MW, used in the EU and America's mainly include [8]:

1) Micro turbines – With the increasing retail cost of electricity, there has recently been increased focus on this emerging technology even though it is currently only available from a few manufactures with the models ranging from 30 kW to 200 kW. Micro turbines promise low emissions but are relatively expensive [8]. The suitability to the South African market will depend mainly on the cost subsidies that are economic available and the feed stock availability to the point of generation.

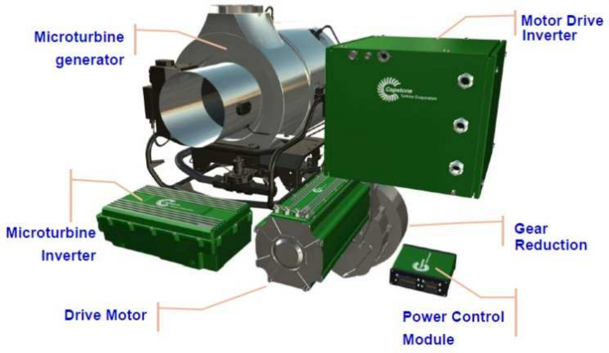


Figure 2-1 Capstone micro turbine generation set block diagram [9]

2) Industrial combustion turbines – In South Africa, this is a mature technology and current available size penetration ranges from 1 MW to over 5 MW. They have low capital costs as they are inherently always part of a combined process; have low emission levels, but also low electric efficiency ratings. In order to increase overall process efficiencies, there is greater focus on using this technology as there is a range of products which suppliers can provide depending on the market offering. This technology is receiving a lot of focus in research into increasing efficiency levels for this widely available technology and finding custom made applications. Industrial combustion turbines are being used primarily for offsetting high retail tariffs in peaking power operation mode and in cogeneration applications when feedstock and product diversity is available [10]. This study will use the parameters of these machines as its

penetration and availability potential in the South African market is high and there are some established applications.

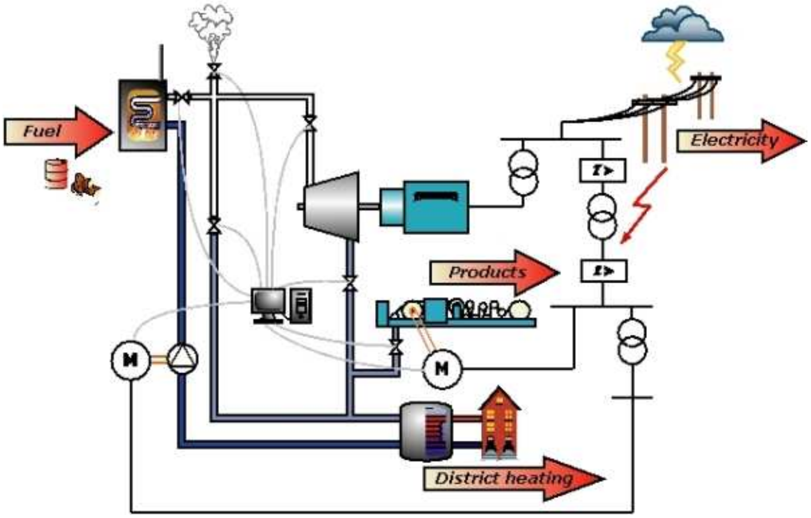


Figure 2-2 Industrial combustion process [11]

3) Fuel cells – Although the first fuel cell was developed more than 150 years ago, this remains a high end cost technology and there are very limited applications for this technology as a result [10]. Although the emission levels are quite low, the combined life cycle emission taking into account manufacture, redundancy, idle time, replacement and disposal could be high and demonstrated reliability remain major problems for its market penetration [10].

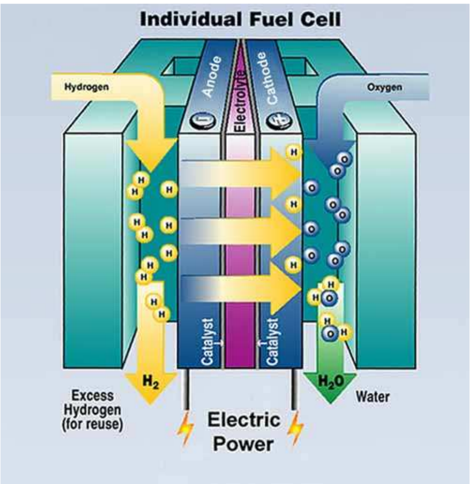


Figure 2-3 Individual fuel cell chemical process [12]

4) Photovoltaic – There are essentially two types of solar photovoltaic (PV) technology, crystalline and thin-film which are both are fairly mature, being developed over 70 years ago and are currently widely available for both commercial and domestic use. The technology is expensive and relies on Government subsidies to reduce installation costs and improve financial viability but improvements in the manufacturing of the technology as well as increased global demand for the technology has resulted in decreasing manufacturing costs of approximately 1.0-1.4 $/Wp in 2010 to 0.7-1.0 $/Wp in 2013 [13]. The modular nature of solar PV means that it be installed for output ranging from a few Wp to several hundreds MWp with higher economies of scale achieved for the larger installations. The infrastructure to support the installation of solar panels is very easy to construct due to the basic design requirements and the actual panels produce no emissions during operation and require minimal maintenance. South Africa has very favourable solar irradiation levels of between 2,000 to 2,600 kWh/m^2 per year on a horizontal plane this is available for all months in the year whereas other countries in the northern hemisphere where the technology has been highly used, suffer from season bias [13]. The low use of water makes this technology suited for Southern African countries where water is limited. This technology is very easy to install, but there are limited manufacturers in South Africa and exposure to exchange rate fluctuations and lack of contribution to local economies, in terms of resources and manufacture, makes this technology extremely costly as demonstrated in Annexure B.

Figure 2-4 Typical PV installation [14]

5) Wind Turbine systems – Are currently available from many manufacturers and are the lesser expensive renewable energy technology to be used [8]. The reliability is variable and the performance requires very specific conditions in order to be effective. The main requirement is that the wind resource needs to be consistent and unidirectional. Variable wind conditions result in poor operational efficiencies and design windows have to be made larger resulting in more costs. The typical cost in South Africa is shown in

Annexure B which was acquired from the Power Generation Technology Data for Integrated Resource Plan of South Africa [4].

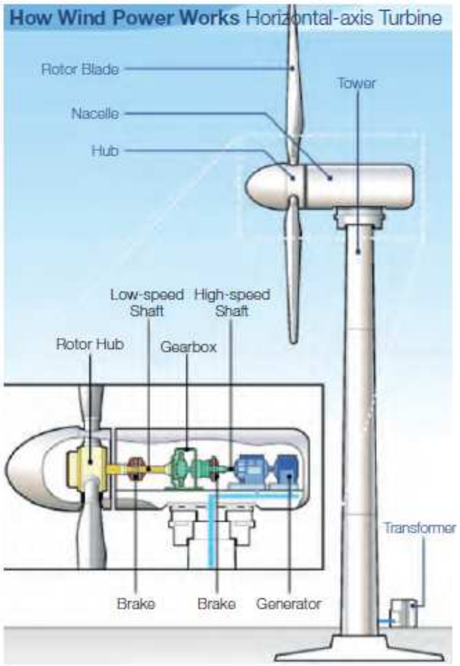


Figure 2-5 Mechanical structure of wind turbine power [15]

6) Small Hydro Turbines – Water resources is South Africa is limited for electricity generation application. The dam infrastructure in South Africa needs to be increased but the cost differential between agricultural and residential requirements is large and subsidies between treated and untreated water is not financially sustainable without very high external subsidy. Run of water system generation is more viable and there are many sites in South Africa for this technology with the power output range from 300 kW to 2 MW with a very high load factor. The operating power range comes from the applications for grid connection that have been received by Eskom over the last three years for hydro generation projects [16].

7) Biomass Generation – This is the largest capacity for generation in KZN. The fuel being wood or wood residue, bagasse (from sugar cane) and tops and leaves from sugar cane. The potential generation range is from 1 MW to 100 MW [2]. Infrastructure upgrade costs would be the highest cost factor. The window of operation would only be for 9 months of the year but with a very high load factor [16]

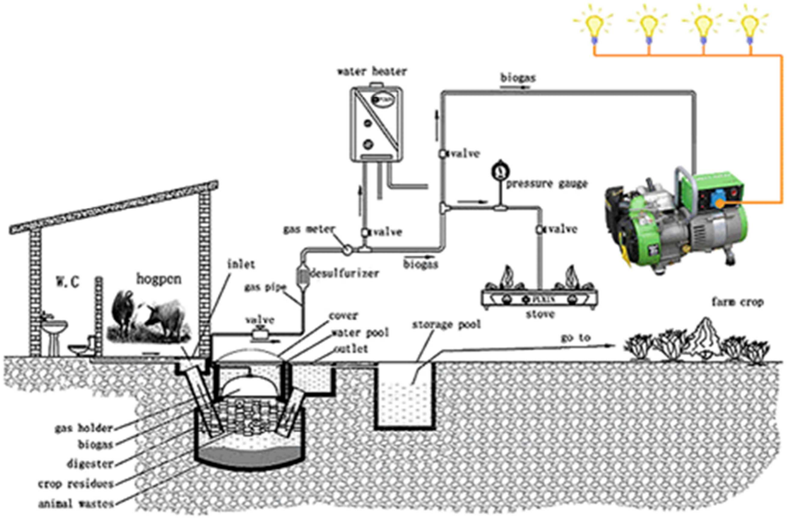


Figure 2-6 Biomass generation process [17]

2.1.3. Impact of embedded generation on power system operations

From a technical aspect, EG poses some impacts on power systems, especially to the operations of distribution systems. They mainly include:

- Voltage rise - The utility must provide electricity to the customers at a voltage within specific limits. However, if the capacity of the connected EG is relatively large or the connection between the transmission and distribution system is relatively weak, the steady state voltage rise may be a problem [18]. This analysis is carried out under both maximum and minimum load conditions. The worst case scenario for voltage rise occurs at minimum load conditions and are created by low load conditions or high EG output levels [19].

- Protection - The connection of EG changes the magnitude, duration, and direction of a fault current, thus requires corresponding adaptations of the existing protection system. The rules of operation in South Africa as per the national published standards for grid interconnection of EG, require that the EG automatically and safely disconnect from the grid in the event of a loss of the grid or as a result of an abnormal condition [20]. An abnormal condition is where there is a change in the system parameters i.e. voltage and frequency limits. Table 2-1 [21] includes a summary of specific protection functions that shall be provided at the point of utility connection (PUC).

Table 2- 1 PUC protection requirements per voltage level

Protection Type	**HV Requirement**	**MV Requirement**
Overcurrent, Earth Fault	Yes	Yes
Sensitive Earth Fault (SEF)	No	Note 1
Phase Under/Over Voltage	Yes	Yes
Residual over-voltage	No	Note 1
Under/Over Frequency	Yes	Yes
Loss-of-Grid	Yes	Yes
Check Synchronising / interlocking (Block dead line charge)	Yes	Yes
Reverse Power	Note 2	Note 2
DC Failure Monitoring	Yes	Yes
Note 1: Depends on neutral earthing philosophy adopted. Neutral voltage displacement protection will be applied on networks where the EG or generator transformer does not provide an earth connection to the Eskom network. Earth Fault and Sensitive Earth Fault protection will be required in the event that an earth connection is provided **Note 2:** Reverse power protection shall be applied in the event that the EG does not plan to, or is not permitted to export power to the grid, but which will be synchronised with the grid.		

- Power Quality – The measurement of the quality of supply at the point of connection would include *"frequency deviations, connection/supply interruptions, voltage variations (including voltage dips), voltage harmonics, interharmonics, voltage flicker, voltage unbalance, voltage swells and transients, undervoltages and overvoltages"* [21]. It is not practicable for the Utility to guarantee that the continuity and voltage quality of the connection will always be maintained under all contingencies. It is therefore incumbent on the EG to take adequate measures to protect the EG facility against any losses and/or damage arising from supply deviations in quality of supply parameters [21]. The national regulatory standard in South Africa (NRS 048 -02) will determine the parameters for the quality of supply conditions.
- Stability - The increase in the incremental capacity of EG as a ratio of overall power supplied from non-EGs, determines that its effect in power system stability analysis be taken into account. Therefore more considerations are required in this aspect and this will place additional pressure to acquire and retain very high resource skill levels and system levels analyse capability [22].
- Security - EG energizes the system via lots of points and thus complicates the policies of isolation and earthing for safety, before maintenance work is undertaken [22].
- Thermal Constraint – The rated current carrying capacity of the lines under design specific conditions must not be exceeded [8]. "*Under standard voltage levels and power factor conditions the rated current of the line can be translated directly into a rated active power for that line*" [8].

- Equipment Rating **-** The combined value of the generation and load must not exceed the rating of the transformer. The manufacturers' specifications for maximum withstand short circuit rating capability for the equipment must not be exceeded. Due regard should be exercised when using fault limiting equipment and the out of service implication of this equipment [23]. Calculations should be done every time equipment is changed out. "*The short circuit ratio (SCR) is the ratio of generator power to the short circuit level*" [24]. This ratio translates directly into the voltage performance as a result of a system abnormality i.e. a fault on the system [24]. If this value is too low, instability when using induction generators could occur. The inverse is also true i.e. with a high SCR, the induction generators on the system will remain stable during faults or loss of feeders [25]. The operation of the EGs protection as a result of instability, will result unplanned outages of the EG and will impact their financial performance.

2.2. Static load model

For medium voltage distribution systems there is a high R/X ratio which means that the types of loads used in simulations will affect the voltage regulation results and hence the electrical losses results. For transmission systems the busbar voltages are regulated by various voltage control devices and lumped constant power loads can be used as the worst case scenario for load flow studies. This is not the case for distribution systems where the V-I characteristics of load are more important for the system load flow studies in order to determine the effect of new load connection and the sizing of LV infrastructure. There are two load models that are traditionally used, static models and dynamic models [26]. The effect of dynamic load models is not important in load flow studies and could require very specific simulation tools [26]. Another reason for not using dynamic load models in this particular study is that dynamic load response changes are not relevant on large lengths of time where the minimum measurable period is integrated over 30 minutes by the energy measurement meters installed. "*Static load models, on the other hand, are relevant to load flow studies as these express active and reactive steady state powers as functions of the bus voltages (at a given fixed frequency)*" [26]. The simulations used in this dissertation will take only static load models into account. The static load models are categorized as follows :

- *"Constant impedance load model (constant Z): A static load model where the power varies with the square of the voltage magnitude. It is also referred to as constant admittance load model"* [26].

- *“Constant current load model (constant I): A static load model where the power varies directly with voltage magnitude”* [26].
- *“Constant power load model (constant P): A static load model where the power does not vary with changes in voltage magnitude. It is also known as constant MVA load model”* [26].

Load modelling has always been a difficult issue because [26]:

- many different types of load are connected to the power system at any period of time
- level of complication and quantity of data is very high at any given moment
- it is hard to predict loads response (behaviour)

There are two mathematical forms that are commonly used in modelling studies: polynomial and exponential load models. Polynomial model is a static model describing relationship of the power and voltage magnitudes as a polynomial equation and can be expressed as [26]

$$P_L = P_0\left[p_1\left(\frac{V}{V_0}\right)^2 + p_2\left(\frac{V}{V_0}\right) + p_3\right] \tag{2.1}$$

$$Q_L = Q_0\left[q_1\left(\frac{V}{V_0}\right)^2 + q_2\left(\frac{V}{V_0}\right) + q_3\right] \tag{2.2}$$

p_1 and q_1 are the constant impedance load parameters

p_2 and q_2 are the constant current load parameters

p_3 and q_3 are the constant power parameters

Note: The frequency variation with the generators on are not going to influence the overall system frequency, hence the frequency sensitivity parameters can be ignored.

When $p_1 + p_2 + p_3 = 1$, $q_1 + q_2 + q_3 = 1$ when $V = V_0$

While the exponential model has the form of [27]:

$$P = P_0\left(\frac{V}{V_0}\right)^{np} \tag{2.3}$$

$$Q = Q_0 \left(\frac{V}{V_0}\right)^{np} \tag{2.4}$$

Setting these parameters to 0, 1, or 2, the load model becomes constant current, power, or impedance.

2.3. Economics of embedded generation

The legal requirements and as well as the technical limits to which both the Utility and the EG must adhere to is covered by a connection and use of system agreement signed between the two parties. Violation of these limits will result in legal action and or the severance of the EG from the grid. The connection and use of system agreement also ensures that all EGs have the same access to the grid and promotes fairness. In addition to this, there would also have to be tariffs that are fair to both loads and generators with an equitable loss allocation policy [7]. In South African the framework for this policy has not been promulgated as yet. It is expected that before the year 2015, Eskom will have such a policy available to recover the investments necessary for a cost effective and sustainable grid. It is anticipated that Utilities will have to create a special generator tariff that will allow the Utility to recover upfront connection costs and any other additional costs required for maintenance, operation, replacement, social subsidies and a reasonable rate of return on the capital [7].

The basis of having the tariff with appropriate connection and running costs would allow the grouping of cost and benefit, thereby allowing for equitable cost allocation to both loads and generators on a year by year basis. The connection costs may alter the cost base of the EG significantly. When EG's connect at higher system voltages there is greater stability to the system but the connection costs are much more significant and this also will contradict the need to have dispersed generation at the local level so as to improve the load carrying capacity and overall reach of the distribution system without additional reinforcement [7]. This conflicting objective can in part be addressed by appropriate regulation and incentives but it needs to be balanced appropriately, and will definitely require an in-depth technical and economic analysis.

"Reactive and/or active power control may be used as a means of controlling the network voltage profile and in particular the voltage rise effect" [7]. This would have to be included in the network tariff structure but it would be very difficult to implement in the current tariff topography as there has to be a commercial framework for the provision of voltage regulation services on a competitive basis. Currently the onus is on the individual to ensure that power

factor is at its optimal. Unbundling cost components in the tariff is complicated and eventually will lead to an averaging principle.

The degree to which upstream costs are recovered from the generator will determine the overall viability of the point of connection. The boundary point at which a Utility attributes cost changes to an EG could be shallow, which only covered the physical connection point or deep, which would cover all reinforcement costs required by the Utility. Both these means of cost recovery are also affected by the Utilities ability to raise capital from the market place.

For EG’s that are presented connected to the system, Eskom recovers all the physical costs related to the direct connection. This cost is recovered as an upfront payment and is the policy favoured by the Utility. It would however put a huge strain on the Utility to recover the costs from borrowings especially in the current climate of economic unbalance should the upstream or deep costs, be very significant in nature and with limited attributable growth in new customers.

There would also be various other levies that would be required for EG in South Africa including electrification and rural subsidy levies and a contribution to network security. In principle EG make a positive contribution towards the security of generation but ultimately the state owned company has to make provisions for all contingencies. It is also expected that the EG on distribution systems will not be scheduled and not dispatched from a central location. This will impact forecasting requirements and the ability to deal with real time network contingencies. The cost for this sophistication will ultimately lead to higher network availability charge. It can be argued that the availability of generation is considered to be significantly lower than the availability of distribution circuits, however in South Africa there are licensing challenges associate to running island networks with customers that are normally supplied from the Utility. This challenge would not be easily overcome.

One of the key drivers to stimulate localisation of EG, is to have a clear and consistent policy on the equity and allocation of energy losses. Some of the policies that are used internationally require the calculation of marginal contribution. This would work if the network remained static, but networks in South Africa are constantly being changed to accommodate the expansion of the system into new areas. If the marginal contribution changes every year, as it would need to, then the revenue streams of the EG would be difficult to predict and deter establishment in areas where capital relieve for reinforcement can be obtained with the introduction of an EG.

The technical and network pricing frameworks therefore have to be done taking into account all levels of economic and social needs and it is vitality important that these frameworks and policies can be implemented in a consistent and fair way.

2.4. Fixed and variable costs for EG

In order to perform a financial analysis of the impact of EG, there is a need to know the cost for constructing and operating a system. These costs are very specific to the type of technology used and the circumstances under which the EG is used. As an example to this, the costs associated to building and operating PV plants vary depending on the UV densities as does the costs for building wind generators in variable wind conditions. Although it is possible to determine average costs per MW per technology, these average costs do not reflect the variability of costs across the whole operations spectrum. It is therefore not the intention of this dissertation to generalise these costs as a fixed cost per unit but rather to use the system marginal price (SMP) as an indicator of what level of fixed and variable capital can be made available in a generalised network.

It is very important to be able to attribute both fixed and variable cost categories to a project so that the overall life cycle cost effectiveness or return on revenue can be determined with a clear risk profile. In all circumstances the costs related to operations and maintenance, are very system specific [28].

The fixed costs include [28]:

- *“The cost for purchase of the equipment, including any taxes, and transportation to the site”* [28].
- Installation costs which broadly consists of [28]
    - Installation licenses, permits and compliance certification
    - Acquiring the required land and the costs related to preparing the land
    - Construction of the buildings and facilities
    - Installation and commissioning of equipment costs
    - Soft costs – This includes the fees related to doing the design work as well as other professional services required for the analytical evaluation, planning and development including documentation and as-built drawings costs. This can be 15%-30% of the total cost.
    - Interest during construction and escalation costs

The variable costs include:

- Operation and Maintenance Costs
  - During the design and construction phase, all aspects of costs related to the decisions of operations and maintenance of large installations will be taken into account. The decision assumptions would need to be covered by appropriate insurance risk migrators, like currency fluctuation risk mitigation. This is not necessarily the case for smaller installations and there are inherent risks that interventions aimed at reducing initial costs may lead to unintended consequences of increasing operational and maintenance costs jeopardising the overall total economic performance levels of the project [10]. The availability of fuel across the time range for which it is needed is the highest cost contributor towards the operational costs. Even when fuel is available as a result of a by-product or waste recovery process, storage and handling costs on the direct profitability of the main product line, is significant. The variability and unpredictability of renewable fuel also leads to high standing costs [10].
  - The running costs for various other consumables, such as lubricating oil, make up water and chemicals, is generally small if there is adequate maintenance and refurbishment policies in place [10].
  - The number of people needed for an operation would be determined by the size of the system together with the extent to which automation is used. The range for medium-size systems is from 10 MW to about 30 MW and for these systems, it will require that the operations are attended to on site and could be controlled by one person with sufficient technical skill. It stands to reason that systems that are larger than this, will need proportionally higher number of resources for operational and maintenance activities. The health and safety regulations in South Africa specify the number of people required for operations if the system includes an exhaust gas boiler. If the fuel is solid in nature then the handling and storage costs need to be taken into account.
  - Where electricity generation is from reciprocating engines and these are heavy-duty engines, these will usually require less maintenance than light-weight engines. The manner in which the system is operated and maintained will determine the overall cost impact [10].
  - The maintenance industry in South Africa is very well established and a company would have access to a variety of maintenance contracts. The contracts are normally negotiated for the period of operation and of such a nature that will pose the least amount of financial and operation risk. The cost

    effect of these contracts can be easily forecasted and taken into account. In order to reduce costs it is possible to install online diagnostic and performance monitoring systems. The maintenance can then be scheduled more efficiently and done when and as required. These types of systems generally decrease maintenance costs but usually the technology system needs to be researched thoroughly before implementation and the all the risks to operation, properly quantified [10].

    - In order to minimise financial operating risks, equipment failure and damage, have to be covered with appropriate short and long term insurance. There may also be cases of extended loss of income due to measures that out of control of the business including but not limited to strikes, safety incidents and other various business interruptions. The appetite for risk and risk mitigation will determine the overall cost of insurance and this will vary depending on a variety of issues including but not limited to, *"the type of prime mover, the equipment performance history, and the system design and operating mode"* [10]. The cost impact is very predictable and in the range from 0.5% to 2% of the operating costs, generally [10].
    - There would also be costs of raising capital in the form of interest on loans as well as costs involved in the general administration of operations, management fees, taxes, interest on loans (if any) [10].
    - In all operations and maintenance, there are fixed and variable costs. Certain fixed costs can be variable over long periods as input costs change due to non-system related issues like wage increase hikes and worker strikes. Detailed logistics and analysis over long periods of time are needed to separate the costs of a particular system into these two categories. Average industry costs could be used as a first investment cost but these costs have to be refined as the project moves from pre-feasibility to concept definition and design phases [10].
- Training and development costs
- Research and development costs

2.5. Load model methodology

In order to model the load profile of a Distribution system in South Africa the energy resulting from both technical and non-technical losses has to be taken into account. This will be an important factor in determining the overall economic effect of EG in a distribution system.

In order to simulate the effect that EG would have on a typical load point, the load type has to be varied. A high component of non-technical losses is made up of constant current type loads. Table 2-2 below shows the energy balanced in KZN for the financial year. The data in the table was obtained from Eskom’s Energy Trading Department in Kwazulu Natal. Kwazulu Natal is one of the nine provinces in South Africa and Eskoms Energy Trading department in each province compile data in similar format for the respective provinces. The data is then combined and are used in the financial results of Eskom but the financial results published by Eskom do not show the Provincial financial statements. Access to the data in Table 2-2 had to be done via the department in Eskom that produces these values.

Table 2-2 KZN Energy Transaction for the financial year 2011-2012

2011_12	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar	YTD
Purchases ER (GWh)	3576	3768	3671	3785	3722	3500	3672	3581	3591	3655	3389	3410	43321
Generation Tongaat Hullett (GWh)	18.62	16.71	18.14	18.44	19.10	16.95	16.44	21.20	22.95	22.55	18.51	20.25	230
Total Purchases (GWh)	3594	3785	3689	3804	3741	3517	3689	3602	3614	3677	3408	3430	43551
Sales ER (GWh)	1808	1880	1800	1915	1886	1801	1894	1834	1804	1862	1855	1904	22243
Sales ER (GWh) Adjusted	1808	1880	1800	1915	1886	1801	1894	1834	1804	1862	1855	1904	22243
Sales KSACS	1590	1625	1628	1581	1558	1497	1572	1538	1615	1602	1373	1307	18487
Sales KSACS Adjusted	1590	1625	1628	1581	1558	1497	1572	1538	1615	1602	1373	1307	18487
Total Sales	3397	3504	3428	3496	3445	3298	3466	3371	3419	3464	3228	3211	40729
Net Exp/Imp (GWh)	-55	-86	-84	-91	-76	-75	-62	-72	-43	-41	-39	-56	-778
International Imports Mozambique (GWh)	0.72	0.82	0.85	0.80	0.88	0.85	0.78	0.81	1.03	1.05	0.43	0.88	10
Net Purchases (Exp/imp)	3540	3700	3605	3714	3666	3442	3628	3531	3572	3638	3370	3376	42783
Total losses	143	196	177	218	222	144	162	160	153	174	141	165	2053
Losses as %	4.04%	5.30%	4.91%	5.87%	6.04%	4.19%	4.46%	4.53%	4.27%	4.77%	4.20%	4.89%	4.80%
Purchases excl 275kV cust													
Total Energy Purchased	3540	3700	3605	3714	3666	3442	3628	3531	3572	3638	3370	3376	42783
Durban 275kV Energy	896	936	930	978	966	911	941	925	931	947	953	985	11299
RBM 275kV Energy	243	246	240	243	249	228	236	225	233	242	223	238	2847
Net Distribution Purchases	2402	2518	2435	2493	2451	2304	2450	2381	2408	2449	2194	2152	28637
Total Sales	2259	2322	2258	2275	2229	2160	2289	2221	2255	2275	2052	1987	26583
Total Losses	143	196	177	218	222	144	162	160	153	174	141	165	2053
Adjusted losses	5.95%	7.78%	7.27%	8.74%	9.04%	6.26%	6.60%	6.71%	6.34%	7.09%	6.45%	7.66%	7.17%

Table 2-3 KZN Customer Sector Classification

Sales Category	Customer class	% Contribution
Key Customers	LPU	46%
Re-Distributors	LPU	43%
Commercial	LPU + SPU	3%
Agricultural	LPU + SPU	2%
Industrial	LPU + SPU	1%
International Sales	LPU + SPU	0%
Mining	LPU	1%
Prepayment	PPU	2%
Publiclights	SPU	0%
Residential	SPU	2%
Traction	LPU	0%
Internal Sales	LPU + SPU	0%
Total Categories		100%

Table 2-4 KZN Energy Sector Classification

Customer class	LPU	SPU	PPU
Total regional Contribution	93%	5%	2%
Contribution without Key Customers	87%	9%	4%

Table 2-5 KZN Meter audit results for 2010-2011

Customer class	Total Audited	Total Problem Meter	Faulty	Tamper
SPU (2009-2012)	48672	8567	6856	1711
% SPU	100%	18%	14%	4%
PPU (2011-2012)	71547	11504	2836	8668
% PPU	100%	16%	4%	12%

The peak, standard and off-peak rates per time-of-use period referred to above are to be applied as follows:

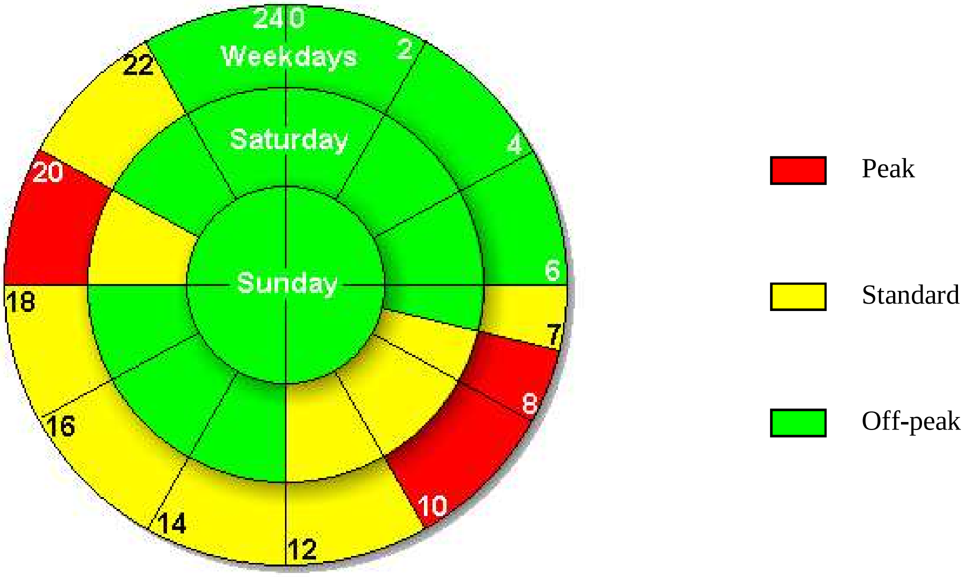


Figure 2-7 Time of use wheel used in South Africa for Eskom supplied customers [29]

The treatment of public holidays will happen as follows: New Year's Day, Good Friday, Family Day, Christmas Day and the Day of Goodwill are treated as Sundays. The rest of the Public holidays are treated as Saturdays unless it actually falls on a Sunday [29].

2.5.1. Non-technical loss derivation

To develop the statistical model for customer spread density for a general MV network, average customer sales in addition to the non-technical losses associated to each customer class will be needed. The energy losses in a system can be broken up into technical and non-technical losses [5].

It is difficult to separate technical and non-technical losses for MV systems because of the customer base composition, metering technology employed and the socio-economic effects [5]. A model is developed to lump the effect of these variables so that the true effect on system performance with embedded generation is developed.

The total losses of a system (KZN) can be calculated very accurately as it is the total purchases measured at the Transmission Station in-feed points minus the total registered sales as can be seen in Table 2-2. The separation of this value into technical and non-technical sales can be done in a number of ways using various simulation packages. The sales values used in these calculations are contaminated as the end loads, (based on sales information), used in the simulations do not have the non-technical losses included resulting in an incorrect non-technical losses derived value. In this dissertation a bottom up approach is used based on three years of field audit data in metered and unmetered installations i.e. the sales in various sales categories are increased based on their historic profile of meter related problems as indicated in Table 2-5 above.

The metering technology employed in the Utility doesn't not register the hourly consumption profile of all customers and therefore it is not possible to reconcile the statistical meter problem rate in the field to an energy consumption rate across a given time period. Customers that are classified as Large Power Users (LPU's) have metering installations that are capable of recording hourly data. LPU's constitute approximately 87% of the customer energy sales base in KZN as can be seen in Table 2-3. The remaining 13% is the sales for energy used by Small Power Users (SPU's) and Pre-paid Power Users (PPU's) as can be seen in Table 2-4. A time of use derivation is required in order to successfully use the bottom up method.

All PPU meters are single phase electronic meters which fail to zero consumption when there is a problem with the installation in the form of a tampered meter or a meter that has gone faulty and not dispensing free energy. The amount of consumption when the energy is free increases so using a linear scaling model of number of problem installations to energy in the system would understate the energy lost.

SPU meters consist of a variety of technologies where the failed state could result in an under read of energy between the levels of 5% to 100%. This means that the number of meters found with a problem in the field doesn't translate directly to an equivalent amount of energy lost. A relationship between these two is needed in order to find the escalation amount that can be used for an average load point.

The instantaneous base case losses for a three phase distribution system can be expressed as [7]:

$$Loss = \frac{rL(P_i^2+Q_i^2)}{3V_p^2} \tag{2.5}$$

"where ***r*** *is the system resistance per unit length, L is the total length of the line,* $\boldsymbol{P_i}$ *and* $\boldsymbol{Q_i}$ *are the real and reactive loads at the* $\boldsymbol{i^{th}}$ *bus respectively and* $\boldsymbol{V_p}$ *the system phase voltage"* [7].

A generic Time of Use (TOU) energy split is used for peak, standard and off-peak energy (as deemed by the Eskom Tariff Structure which is obtained from [29].

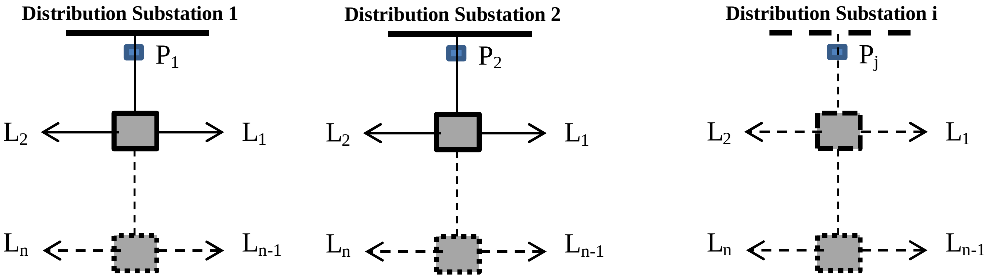


Figure 2-8 Metering diagram depiction for MV systems

For the Figure 2-8 above, Distribution Substation 1 to Distribution Substation *i*, represents the medium voltage busbars, which could be 11 kV or 22 kV. These busbars are connected to the sub-transmission system for KZN. P to P_j represents the total energy metered for all the load points L_1 to L_n and the technical losses associated to the distributed loads L_1 to L_n. The sum of the energy for P to P_j would be the total medium voltage distribution load including distribution technical losses for KZN. The total energy for the subset studied in this dissertation for *i* distribution substations is the sum of all the metered points P_1 to P_j. The load points consist of billed (sales for which the Utility derives an income as a result of electricity units consumed by the customers) and unbilled customers. Unbilled customers are where meter points have become faulty and do no register the actual consumed electricity units, also known as problem meters, or where supply is taken illegally and which is commonly called non-technical losses. The sum of the measured energy P_T for P_1 to P_j would therefore include the technical losses of the wires and MV/LV transformers as well as the non-technical losses for the system.

The total losses (L_T) for the system would be the difference between the total measured energy P_T and billed energy (or sales) for all the load points (L).

The dissertation required that the total energy P_T be split up into the time of use categories as shown in Figure 2-1 above. In order to achieve this split, the methodology described below was used.

P_T = Total energy (kWh) in the system

P_P = Total peak period energy (kWh) in the system

P_S = Total standard period energy (kWh) in the system

P_{OP} = Total off peak period energy (kWh) in the system

Where

$$P_T = P_P + P_S + P_{OP} \tag{2.6}$$

T_T = Total time (hours) in the month

T_P = Total peak time period (hours) in the month

T_S = Total standard time period (hours) in the month

T_{OP} = Total off peak time period (hours) in the month

Where

$$T_T = T_P + T_S + T_{OP} \tag{2.7}$$

The total energy sent out in the system is then separated into the time of use (TOU) categories as calculated below. Using the square relationship of losses to load in equation (2.5):

$$Total\ energy\ density\ = \left(\frac{P_T}{T_T}\right)^2 \tag{2.8}$$

$$Total\ peak\ energy\ density\ = \left(\frac{P_P}{T_P}\right)^2 \tag{2.9}$$

$$Total\ standard\ energy\ density\ = \left(\frac{P_S}{T_S}\right)^2 \tag{2.10}$$

$$Total\ off\ peak\ energy\ density\ =\left(\frac{P_{OP}}{T_{OP}}\right)^2 \tag{2.11}$$

Total Loss Ratio = LR_T; Total Peak loss ratio = LR_P; Total Standard loss ratio = LR_S and

Total Off Peak loss ratio = LR_{OP};

$$LR_T = LR_P + LR_S + LR_{OP} \tag{2.12}$$

$$LR_T = \frac{T_P}{P_T} * \left(\frac{P_P}{T_P}\right)^2 + \frac{T_S}{P_T} * \left(\frac{P_S}{T_S}\right)^2 + \frac{T_{OP}}{P_T} * \left(\frac{P_{OP}}{T_{OP}}\right)^2 \tag{2.13}$$

$$= \frac{P_P^2}{P_T T_P} + \frac{P_S^2}{P_T T_S} + \frac{P_{OP}^2}{P_T T_{OP}} \tag{2.14}$$

$$LR_P = \frac{P_P^2}{P_T T_P} \tag{2.15}$$

$$LR_S = \frac{P_S^2}{P_T T_S} \tag{2.16}$$

$$LR_{OP} = \frac{P_{OP}^2}{P_T T_{OP}} \tag{2.17}$$

Table 2-3 Customer classification breakdown into co-incidental demand

Year 2011-2012										
Classification	Customer Catergory	Total Consumption	No. of Accounts	kWh/Account / day	No. Feeders	Accounts /Feeder	DayKWhavg /feeder	Load Factor	Demand (kW	KW Per Classification
LPU	Agricultural	324,621,890	3,758.50	118.32	909	4.13	978	0.15	136	1,213
LPU	Commercial	1,127,220,947	10,544	293	909	11.60	3,397	0.20	708	
LPU	Industrial	588,322,074	406	3,970	909	0.45	1,773	0.20	369	
SPU	Residential	783,386,394	62,145	35	909	68.37	2,361	0.20	492	628
SPU	Agricultural	324,621,890	3,759	118	909	4	978	0.15	136	
PPU	Prepayment	825,973,117	680,786	3	909	748.94	2,489	0.25	415	415
Total		3,974,146,312	761,398		909				2,256	

The table 2-3 above was derived using the Eskom published energy values [29]. These values however, represent the amount of energy that went through the system in the form of billed energy, or sales. The system has also energy that went through the system as a result of non-technical losses. The equations 2.15 to 2.17 above can now be used together with the process methodology below to derive the demand on the system to include non-technical lost energy.

The simulation requires a single time interval value, which is the demand measured in kW over a 30 minute period. To convert the TOU peak value (equation 2.8) to a demand value to be used for the simulation, it has to be divided by the number of hours in the month and by a correction factor X. The correction factor is an empirical value based on the ratio of the daily peaks for a typical profile for the customer consumption. The value of X in the simulation starts with 0.6 for PPU and 0.8 for SPU.

For this method to work, a closed system, with source metered energy (purchased energy), sales energy and enough field work assessing the amount of unmetered points, must be available. The system chosen for this dissertation was the Edendale – Imbali system. The input values used can be found in Appendix A. Although the total number of customers in this system represents about 6% of the total customer base in KZN, it used in this dissertation as a reflection of the consumption profile of the entire medium voltage supply system in KZN. The basis for this is that the percentage of field meter audit statistics indicates that the unmetered or problematic meter points, where no sales or partial sales (in monetary value) are recovered by the Utility, for the Edendale – Imbali sub-system is worse than that of the rest of KZN. The result of the field audit of the meter condition and performance functionality can be seen in Appendix B. The intention of this dissertation is to reflect the worst case energy recovery scenario, by the Utility, and if the results from Edendale-Imabli are used for the calculation of the average energy in medium voltage systems, then this would represent a worst case scenario.

A more detailed analysis would increase the number of systems being simulated until a level of convergence has been reached, in terms of little change in the values for more systems being added. The increased number of systems would increase the customer base used in the simulations and more accurately reflect the unmetered or problematic metered points, where no sales or partial sales are recovered by the Utility per month.

The basis for the simulation process below is that if the LPU, SPU and PPU average sold energy is known then this can be escalated by the number of known problems found (as a start value). Then energy value is then converted to a demand value. The LPU co-incidental peak can be calculated from the billing information available. The SPU value then can be calculated after a number of iterations. The simulation model will calculate the technical losses for system parameters being used and then the non-technical losses can be derived from the difference between the total losses and technical losses. Escalation factors for the demand per customer category, for metered sold energy can be then obtained, to reflect a system where all energy per customer category can be accounted for.

The process below in Figure 2-9 is then used to calibrate the demand value based on the effect of field fixes in the SPU environment to the actual demand:

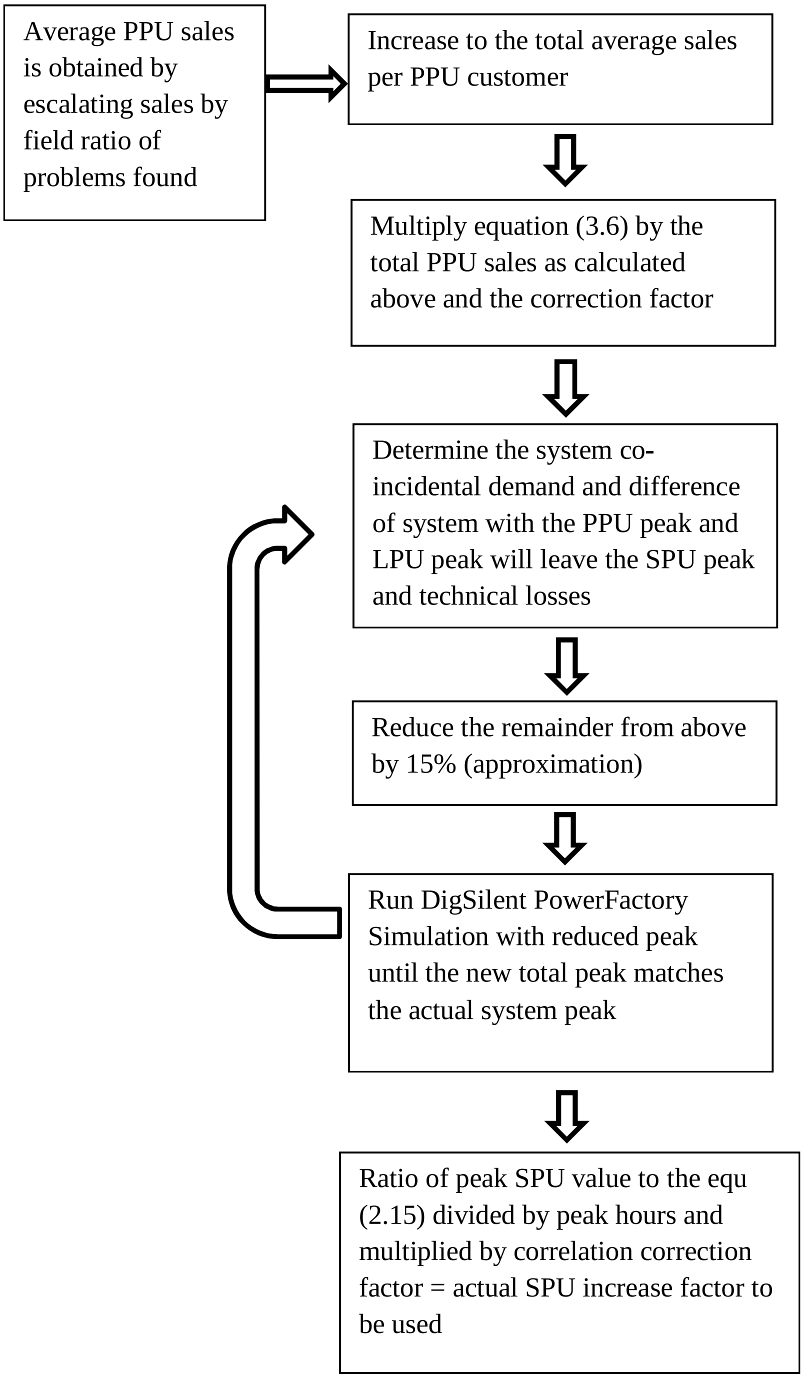


Figure 2-9 Process flow for determining the ratio of peak value to peak TOU value and effect of field audit value

2.5.2. Load point composition

This dissertation will only focus the study on loads and generators that are connected on an MV Distribution Feeder at 22 kV. In Eskom customer are separated in the accounting or billing system according to customer usage and type. The only customer categories that are supplied from medium voltage is Agricultural, Commercial, Industrial, Residential and Prepayment. The other customer categories that are supplied directly from the HV system and are excluded from this study.

Based on the sales per month per category an average kWh consumption per feeder (number of feeders in KZN) is calculated. Using the equations in section 2.1.1 results in values in the table below:

Table 2-4 Energy per point and co-incidental demand per customer category

TOU	Catergory	(kWh/Month)avg/(total feeder	LPU demand (KW)	SPU demand (KW)	PPU demand (KW)	Total Demand
Peak	22kV	281,703	1,213	628	415	2,256
Peak	22kV (Loss adj)	319,596	1,300	757	503	2,559
Std	22kV	275,956	500	259	171	930
Std	22kV (Loss adj)	293,988	808	467	376	1,651
Off-Peak	22kV	44,619	201	104	69	374
Off-Peak	22kV (Loss adj)	61,002	325	188	151	664

The loss adjusted value would be based on the percentage per category calculated in the algorithm in in the process flow details above.

2.6. Electrical system

There are two distribution voltages that are used by Eskom which is 22 kV and 11 kV and 90% of this is done via overhead line.11 kV is predominately used in formal towns and 22 kV is used more for in the rural areas. Currently all new and upgrade networks in KZN are built and insulated for 22 kV specifications so there is no separation in the year end Eskom financial statements to differentiate the length of conductor for the two voltage types. Many 11 kV networks have been upgraded to 22 kV in order to increase network reach and differ capital spend on building additional substations to cater for load growth. There is also an increasing need for standardisation of substation transformer sizes and types. Interconnectivity of networks is required and was one of the key focus areas in Eskom used to improve the time for the measured system average interruption duration index (which from the year end performance results is at 47.5 hours [3]). 22 kV offers more flexibility with regard to shifting loads between networks due to the higher load carrying capacity rating at 22 kV compared to and equivalent conductor that is energised at 11 kV.

Table 2-5 Average feeder length [3]

No. of MV feeders in KZN	Total MV system (km)	Average length of MV feeder (km)
909	29270	32

The table above indicates the total distributed network at 11 kV and 22 kV. There is no information available for the separation for this length into the category for 11 kV or 22 kV specifically. Based on this, the dissertation will cover two length scenarios of 22 kV of total network length 20 km and 40 km. This will serve as the length boundary condition and will provide enough information on the network performance over a wide range from the average length such that conclusions on the performance of distances between the boundary parameters can be extrapolated.

The general electrical network framework to be used for analysis is a 22 kV network with five load points whose composition will be of that described in section 3.1.2. Five generation points will be used in the study and they will be located at the load points. The load points and generation points are used at the same point to represent the generator supplying an average load point i.e. the generator is located in the mid-point in the average load density around it. The five points were chosen to get a sufficient spread of points along the average feeder length.

The load at each of the points will tested for three conditions, which are:

- 0.12 MVA (unity power factor) per load point which is 0.6 MVA total load excluding technical losses. This represents the off-peak load scenario to be tested against the various generator combinations.
- 0.5 MVA (unity power factor) per load point which is 2.5 MVA total load excluding technical losses. This represents the peak load carrying capacity of the system as indicated in Table 2-4
- 1 MVA (unity power factor) per load point which is 5 MVA total load excluding technical line losses. This represents the capacity increase in the system as a result of all generators being in service at the same time i.e. the generators have created enough capacity to double the load demand without changing the net load supplied in the system. The robustness of the extra capacity created on the system will then be tested against the various generator availability combinations.

The maximum size of the generator is kept at the maximum peak load capacity per load point i.e. 0.5 MW and overall net generation capacity on the system is to be obtained by changing the load size. Figure 2-4 below indicates the simulation model used and represents the electrical network framework.

No MV/LV transformers are simulated because the size of generation requires the meters installed for energy measurement of the output power into the grid, be done at MV. This is as per the Eskom planning guideline for connection of embedded generation [21]. The voltage of the synchronous generator units used in the simulation was at 11 kV and 22 kV depending on the study being performed.

An actual distribution system would definitely have many MV/LV transformers connected as well as LV networks. This equipment would contribute to technical losses to the system. The model used in this dissertation takes account of this by using the practical system for loss calibration as described in section 2.5.1 which would include the technical losses of the MV/LV transformers and LV networks.

For the peak load simulation, a value of 100% (22 kV) was used as the busbar voltage and this was assumed to be an infinite busbar. A voltage percentage value of 103% (22.66 kV) was used as the off-peak voltage to take into account the system voltage rise. Fault level changes as a result of the generation switched into operation in the system, beyond the study bus, were not taken into account. The equipment employed in the Utility varies a great deal and this would be out of the scope range of analysis required in this dissertation. As long as the fault levels were within the withstand capability of the distribution system, the cost implications on upstream equipment were ignored in this study.

The conductors that would be used is Fox and Hare conductor [30]. These are typical conductors that are used for Eskoms Distribution system.

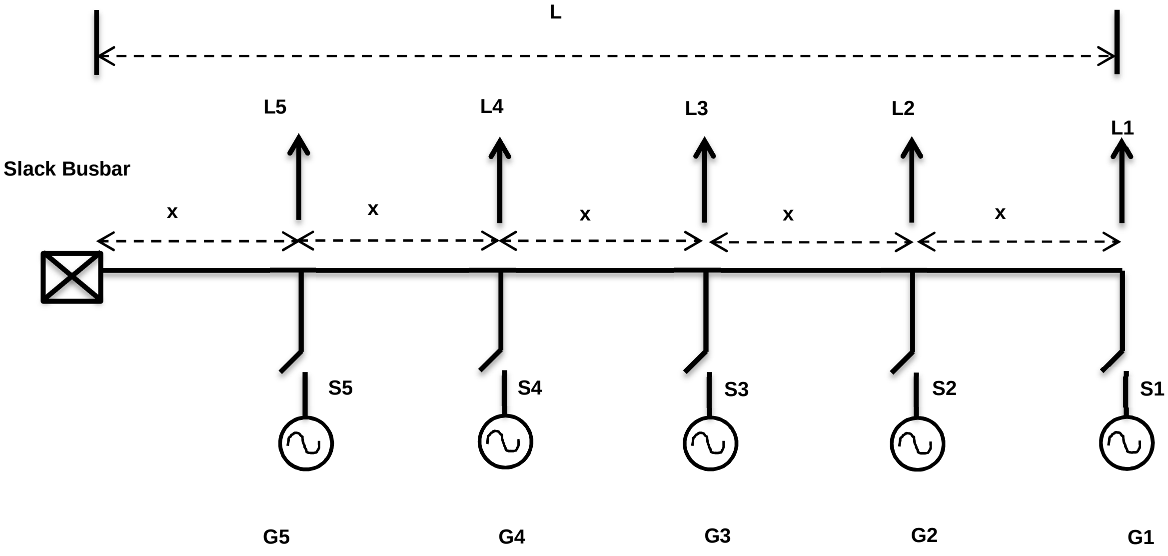


Figure 2-4 General System to be used for simulation model

G1 .. G5 are the directly connected synchronous generators to be used in the system. The reason for using synchronous generators is to because the study is evaluating the cost impact of generator switching configurations on cost recovery. Availability of generation due to fuel or resource limitation would not be a factor for synchronous generators as it would be for other technologies. The use of alternative technologies would require that the study take into account the limitations and variable nature of the renewable or non-renewable resource availability.

L1 … L5 are the loads to be used in the system

S1 … S5 are the switches which is used to switch the generators in or out

x1 … x2 are the fixed distances between the connection points

L is the length of the system in km

The electrical parameters of the conductor of length L is will be simulated for two different types:

Resulting Values	***Unit***	***Fox***	***Hare***
Rate Current	KA	0.151	0.268
Pos Seq Impedance, Z1	Ohm	7.578268	4.039422
Pos Seq Impedance, Angle	deg	24.64418	50.0535
Pos Seq Resistance, R1	Ohm	6.888	2.5936
Pos Seq Reactance, X1	Ohm	3.16	3.0968
Zero Seq Resistance, R0	Ohm	8.08	3.7728
Zero Seq Reactance, X0	Ohm	13.28	14.656

Table 2-6 Line Electrical parameters

The Generator specifications is shown in Table 2-7 below

Table 2-7 Generator Electrical parameters

Results	**Control Value**
Mode of local control	Power Factor
Apparent Power	2.747MVA
Power Factor	0.96
Active Power rating - Max	2.375 MW
Operation limit - Min	0MW
Operation limit - Max	2.375 MW
Synchronous Reactance - xd	2 p.u.
Synchronous Reactance - xq	2 p.u.
Transient Reactance - xd'	0.3 p.u.
Transient Reactance - xq'	0.3 p.u.
Subtransient Reactance - xd"	0.2 p.u.
Subtransient Reactance - xq"	0.2 p.u.

2.7. Cost model parameters

To convert the customer categories into tariffs Table 2-8 and Table 2-9 below was used.

Table 2-8 Conversion factors for customer category to tariff

Tariff Ratio for Rural Feeders					
LPU Tariffs	Miniflex	Nightsave	Rural Flex		Total
LPU Tariffs Ratio	35%	35%	30%		100%
SPU Tariffs	Business Rate	HomePower			
SPU Tariffs Ratio	40%	60%			100%
PPU Tariff Blocks	Homelight Block1	Homelight Block2	Homelight Block3	Homelight Block4	
PPU Block Ratio	40%	35%	15%	10%	100%

Table 2-9: Energy Split ratios

Energy Split per Customer Category		
Total	3,974,146,312	100%
LPU	2,040,164,911	51.34%
SPU	1,108,008,284	27.9%
PPU	825,973,117	21%

Table 2-10 Retail Rates Used (red is for peak Winter Months)

			MONTH											
Tariff	**Unit**	**Charge**	***Apr***	***May***	***Jun***	***Jul***	***Aug***	***Sep***	***Oct***	***Nov***	***Dec***	***Jan***	***Feb***	***Mar***
Miniflex	c/kWh	Peak	70.82	70.82	229.12	229.12	229.12	70.82	70.82	70.82	70.82	70.82	70.82	70.82
	c/kWh	Std	47	47	66.55	66.55	66.55	47	47	47	47	47	47	47
	c/kWh	Off-Peak	26.19	26.19	30.44	30.44	30.44	26.19	26.19	26.19	26.19	26.19	26.19	26.19
	R/KVA/m	Demand	16.28	16.28	16.28	16.28	16.28	16.28	16.28	16.28	16.28	16.28	16.28	16.28
	c/kWh	Elec&Rural Levy	4.57	4.57	4.57	4.57	4.57	4.57	4.57	4.57	4.57	4.57	4.57	4.57
	c/kWh	Enviro Levy	2	2	2	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5
	Rands	Ser & Admin	23143.5	23914.95	23143.5	23914.95	23914.95	23143.5	23914.95	23143.5	23914.95	23914.95	23143.5	23914.95
Nightsave	c/kWh	Energy	32.37	32.37	49.42	49.42	49.42	32.37	32.37	32.37	32.37	32.37	32.37	32.37
	R/KVA/m	Demand	117.4	117.4	193.6	193.6	193.6	117.4	117.4	117.4	117.4	117.4	117.4	117.4
	R/KVA/m	NAC	8.24	8.24	8.24	8.24	8.24	8.24	8.24	8.24	8.24	8.24	8.24	8.24
	Rands	Ser & Admin	23143.5	23914.95	23143.5	23914.95	23914.95	23143.5	23914.95	23143.5	23914.95	23914.95	23143.5	23914.95
Ruraflex	c/kWh	Peak	90.72	90.72	329.55	329.55	329.55	90.72	90.72	90.72	90.72	90.72	90.72	90.72
	c/kWh	Std	54.91	54.91	84.4	84.4	84.4	54.91	54.91	54.91	54.91	54.91	54.91	54.91
	c/kWh	Off-Peak	37.93	37.93	44.37	44.37	44.37	37.93	37.93	37.93	37.93	37.93	37.93	37.93
	R/KVA/m	Demand	11.52	11.52	11.52	11.52	11.52	11.52	11.52	11.52	11.52	11.52	11.52	11.52
	c/kWh	Enviro Levy	2	2	2	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5
Business	c/kWh	Energy	73.05	73.05	73.05	73.05	73.05	73.05	73.05	73.05	73.05	73.05	73.05	73.05
	c/kWh	Enviro Levy	2	2	2	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5
	R/pod/d	Service	20448	20448	20448	20448	20448	20448	20448	20448	20448	20448	20448	20448
	R/pod/d	Network	69210	69210	69210	69210	69210	69210	69210	69210	69210	69210	69210	69210
Home Power & Home Light	c/kWh	Block1	60.83	60.83	60.83	60.83	60.83	60.83	60.83	60.83	60.83	60.83	60.83	60.83
	c/kWh	Block2	75.09	75.09	75.09	75.09	75.09	75.09	75.09	75.09	75.09	75.09	75.09	75.09
	c/kWh	Block3	111.418	111.418	111.418	111.418	111.418	111.418	111.418	111.418	111.418	111.418	111.418	111.418
	c/kWh	Block4	122.206	122.206	122.206	122.206	122.206	122.206	122.206	122.206	122.206	122.206	122.206	122.206
	c/kWh	Enviro Levy	2	2	2	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5

Table 2-11 SMP Rates Used in R/MWh

	MONTHS											
	Apr	***May***	***Jun***	***Jul***	***Aug***	***Sep***	***Oct***	***Nov***	***Dec***	***Jan***	***Feb***	***Mar***
SMP Rates	609.63	609.63	2,257.35	2,257.35	2,257.35	609.63	609.63	609.63	609.63	609.63	609.63	609.63
	362.35	362.35	565.56	565.56	565.56	362.35	362.35	362.35	362.35	362.35	362.35	362.35
	244.83	244.83	288.90	288.90	288.90	244.83	244.83	244.83	244.83	244.83	244.83	244.83

Each tariff has different rates and charges associated to it. In order to get the reflective costs, the energy value per customer category in Table 2-9 has to be multiplied by the ratios shown in Table 2-8. The ratios in Table 2-8 is obtained from data provided by Eskom's Energy Trading Department in Kwazulu Natal. Kwazulu Natal is one of the nine provinces in South Africa and Eskoms Energy Trading department in each province compile data in similar format for the respective provinces. The ratios are the average customer split for the province and this can successfully be used to determine what the typical split would be per network. The charges and energy rates in Table 2-10 is obtained from the Eskom published tariffs [29].

The SPM rate in Table 2-11 is the rate at which the purchase of generation will take place [29]. The rate at which any new generator will get paid will be at the SMP rate. These are standard rates and will be used to calculate the income that the utility can make for the system based on Table 2-10 and the cost to the utility for having the EG as per Table 2-11. The difference between the two values would give the net income that the utility can make from the system taking into account the EG.

2.8. Model of power system component

- The distribution bus is modelled as an infinite bus. The reason for modelling this as an infinite bus is that the revenue calculation comparisons are based on changing system impendences beyond the distribution bus. Successful comparison of the system changes for an MV calculation beyond the distribution bus would require that the Thevenin impedance as seen from the distribution bus, be much smaller than the impedances of the system connected to the distribution bus. Successful relative comparison of different EG operation modes can thus be made. If the study included evaluating the inertia limitations of the distribution bus then reference comparison on the MV system would not be possible without considering the HV effects. It will have to be assumed that the intention of a Utility is not to create HV system limitations. Consequently, the magnitude and angle of the voltage at the distribution bus can be assumed to be constant. With the distribution bus used as an infinite bus, various comparisons can be made regarding the impedances changes to the MV system as a result of EG operation permutations on the MV system.
- The electrical network is modelled for four conditions :
    - Fox conductor with 4 km between nodes
    - Fox conductor with 8 km between nodes

  - Hare conductor with 4 km between nodes
  - Hare conductor with 8 km between nodes
- The load is modelled as a combination of constant power, constant impedance and constant current. The largest component of constant current load comes from the residential customer category as well as the non-technical losses. This is important for the study because with increased nodal voltages the non-technical loss, load, increases and results in greater financial loss on the system. In order to determine the change caused, a comparison is made between residential loads modelled as 50% constant current loads versus the effect of the same amount of load modelled as constant power loads.
- The EG is modelled as a PQ generator because normally it is not controlled but the system operators. The EG is required to have a relatively stable performance.

2.9. Impact of EG on system losses

If the generation and loads are known in system, a power flow calculation will provide all the voltages at all the buses in this system. Once the voltages are known, calculation of the flows in all the buses can be done.

$$S_{Gi} = P_{Gi} + jQ_{Gi} \qquad (2.18)$$

In equation 2.18, S_{Gi} is the complex power supplied by the EG at the ith bus which is equal to P_{Gi}, the active power injection, and Q_{Gi}, the reactive power injection. From this expression, an expression for the current in terms of the injected power and the voltage can be done. The output current from the EG is then shown as equation 2.19 below [7]:

$$I_G = \frac{(P_{Gi} - jQ_{Gi})}{3V_P} \qquad (2.19)$$

The effect on line losses as a result of having a single EG in the system can be broken up into the sum of two parts [30]:

1. Line losses from the source to the location of the EG
2. Line losses from the EG location to the location of load

With the EG exporting current into the grid, the feeder current $\boldsymbol{I_s}$ will be the difference of load current $\boldsymbol{I_L}$ and EG output current $\boldsymbol{I_G}$. Therefore the total line losses with a single EG at “x” distance from the source can be expressed using eq (2.5) as [30]:

$$I_T = \frac{R}{3V_p^2}\left[P_i^2 + Q_i^2 + \left(P_{Gi}^2 + Q_{Gi}^2 - 2P_iP_{Gi} - 2Q_iQ_{Gi}\right)\left(\frac{x}{L}\right)\right] \tag{2.20}$$

"*where, R = rL; total resistance of the line. The instantaneous loss savings (LS) at any point "b" on a feeder is the difference between losses without EG and losses with the EG and can be represented as*" [30]:

$$LS = Loss_{(b)} - Loss_T \tag{2.21}$$

hence [30],

$$LS = \frac{Rx}{3V_p^2L}\left[\left(-P_{Gi}^2 - Q_{Gi}^2 + 2P_iP_{Gi} + 2Q_iQ_{Gi}\right)\right] \tag{2.22}$$

If LS is positive then this indicates that the system loss reduces with the introduction of the EG into the system and if LS is negative then the EG causes higher system losses in the system [13]. For multiple loads, the most amount of loss savings will occur when the EG is equal to the average load and is physically located at the point from the source where the length weighted load point, is located. This is subject to [31]:

$$V_i^{min} \leq V_i \leq V_i^{max} \tag{2.23}$$

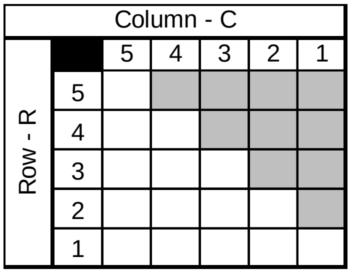
where:

V_i^{min} and V_i^{max} define the voltage limits for the system

2.10 Algorithm for calculating the changes to system with EG

The simulation tool that is used is DIgSILENT's PowerFactory simulation software [32]. The software is used to in the modelling of generation and distribution grids and the analysis of these grids' interactions. The aim of the simulation would be to find the impact that various locations of EG's have on two different system impedances. This algorithm is used to determine the maximum carrying capacity and not the optimisation of the system hence the parameters that will be used, are subject to (2.23) and the boundary conditions are as follows:

- Number of load points: 5
- Start point for load is at the combined customer energy co-incidental point (peak)
- Maximum end point for load is at 2 times the carrying capacity at Peak
- Minimum end point for load is at 0.2 times the carrying capacity at off-peak
- The calculations will be done in descending order connection i.e. the nearest point from the source will be used as per the matrix sequence below:



	Column - C					
Row - R	■	5	4	3	2	1
	5		▨	▨	▨	▨
	4			▨	▨	▨
	3				▨	▨
	2					▨
	1					

Figure 2-9 Switch selection matrix: Cell indicates the switch status to be used where the grey shaded cells are duplicate combinations and not used in the algorithm.

	C1 - 1	C1 - 2	C1 - 3	C1 - 4
R1 - 1	Fox 4km 100% load	Fox 8km 100% load	Hare 4km 100% load	Hare 8km 100% load
R1 - 2	Fox 4km 200% load	Fox 4km 200% load	Hare 4km 200% load	Hare 8km 200% load
R1 - 3	Fox 4km 20% load	Fox 8km 20% load	Hare 4km 20% load	Hare 8km 20% load

Figure 2-10 Input_data_matrix: Each cell contains the data set to be used for the system.

Input_data_matrix is an array that contains the data parameters for the system, for the conditions of:

- Changing conductor parameters
- Changing distances between generator and load nodes
- Changing load as percentage of peak load
- Changing the source voltages

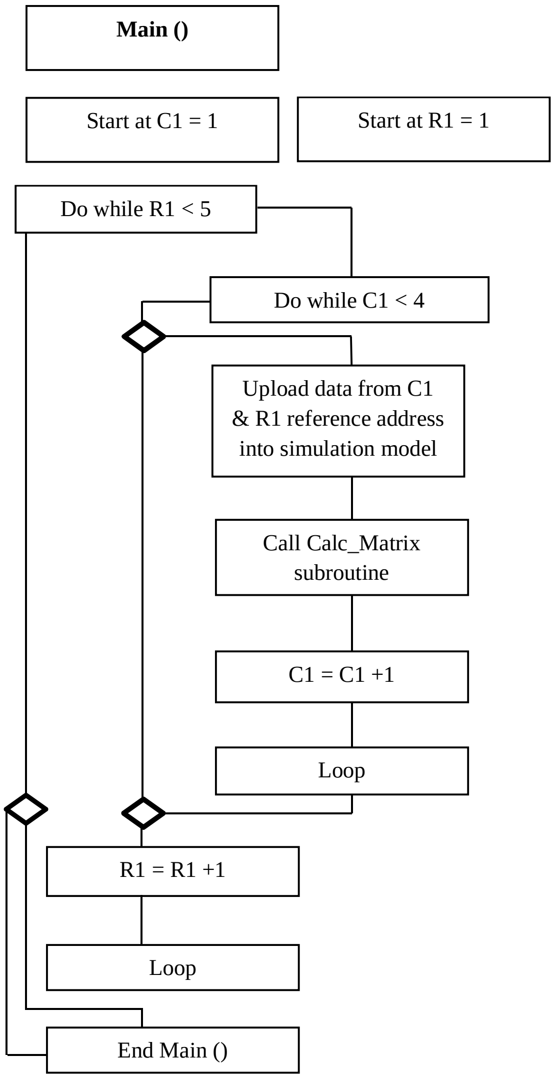


Figure 2-11 Main subroutine: Varying the system parameters

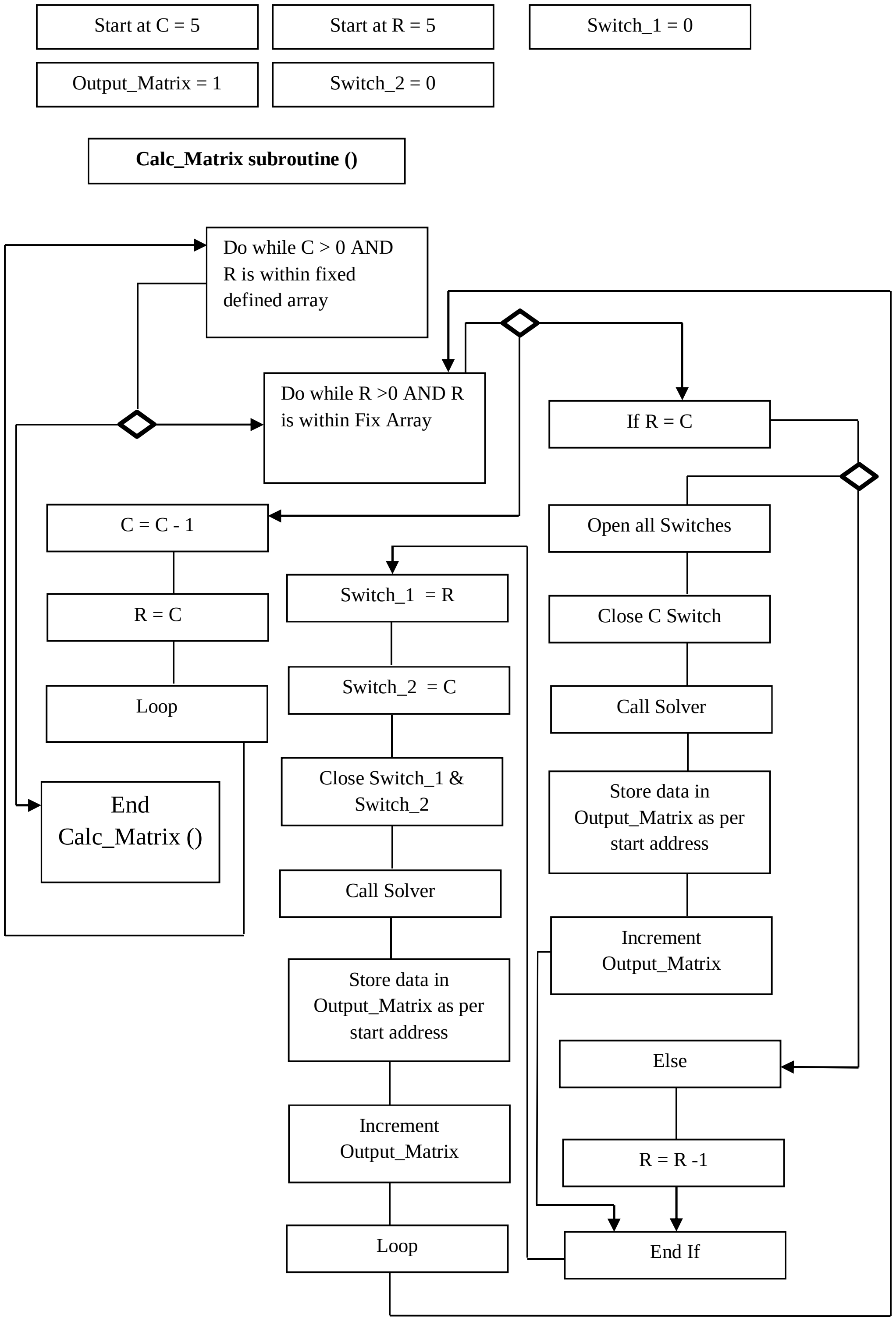


Figure 2-12 Calculation matrix subroutine: Calculate for all permutation of EG operation

2.11 Capital recovery cost methodology

Energy economics is itself a highly specialized and elaborate field with a very large body of knowledge in support, and a full treatment of this field is beyond the scope of this dissertation. This dissertation covers aspects related to the level of capital investment that can be made based on the economics of the energy system in the study case.

There are two important functions of economics is considered in this dissertation. The first is project specific, i.e. the system is scrutinized for cost-effectiveness based on recovery at the SMP. Any project that is economically driven should be able to recover its capital and an acceptable margin of profit with an acceptable risk profile. The market will determine if the technology being invested in goes against the long term social benefits i.e. excessive investment in overly expensive energy projects through Governmental subsidies will lead to higher energy costs for the public, but so will underinvestment in and neglect of the existing stock of energy infrastructure. The margins to which this can be done will be analysed.

The input fields into the study will be as follows [33]:

- Term of the project: This will be expressed as N number of years
- Initial cost: This is a onetime expense incurred in the first compounding period. The constructability of all projects on the medium voltage network will have to be done within one financial year.
- Annuity: An annual increment of cash flow related to a project; which in this case is for the lifetime of the project. Annuities can either be positive (e.g., annual revenues from the sales of energy from a project) or negative (e.g., annual expenditure on maintenance). In this dissertation these values will be shown separately and the analysis will show the costs based on sensitivity values. The specific values per technology are not considered as part of this dissertation.

In this dissertation discounting of cash flow analysis will be used and it starts with the premise that the value of money is declining over time and that therefore values in the future should be discounted relative to the present. Two terms that pertain in particular to discounted cash flow is:

- Interest rate: This is the percentage return on an investment, or percentage charged on a sum of money borrowed at the beginning of a time horizon. In this study the interest is compounded at the end of each year, that is, the unit of 1 year is referred to as the *"compounding period"* [33]. The interest rate will be the current REPO rate of 4%.

- Minimum attractive rate of return (MARR): This is the minimum huddle rate at for which investors and bankers will invest into a project [33].

As a basis for calculating the time value of money, a relationship between the present, annual and future values of elements in cash flow analysis is needed. Given the interest rate, i, time horizon of N years, and a present value P of an amount, the future value of that amount F is given by [33]:

$$F = P(1+i)^N \tag{2.24}$$

To translate a stream of equal annuities forward or backward to some fixed point at present or in the future the equivalent present value P is [33]:

$$P = A\frac{(1+i)^N - 1}{i(1+i)^N} \tag{2.25}$$

Given the same annuity stream and time horizon, the future value F of the annuity at the end of the Nth year is [33]:

$$F = A\frac{(1+i)^N - 1}{i} \tag{2.26}$$

In order to discount a set of non-uniform annuities to its equivalent present worth value PW by treating each annuity as a single payment to be discounted from the future to the present [24]:

$$PW = \sum_{n=1}^{N} \frac{A_n}{(1+i)^N} \tag{2.27}$$

Here A_n is the value of the annuity predicted in each year n from 1 to N [33].

The levelized cost per unit of energy output is one method that can be used as a measure to compare the cost effect across energy technologies [33].

$$Levelised\ cost = \frac{Total\ annual\ cost}{annual\ output}\ \ (in\ units\ of\ R/kW) \tag{2.28}$$

Where [33]:

Total annual cost = annualised capital cost + operating cost + return on investment (ROI)

This study also takes into account the external benefits in the form of direct cost support in the form of subsidies. These subsidy values are known from the existing Government determinations on the renewable feed in tariffs.

3. RESULTS AND DISCUSSION OF RESULTS

3.1. Load flow analysis results

The structure of points of the analysis will occur as per the Table 3-1 below:

Table 3-1: System status of Generators

Condition number	***Status of Gens on***
1	No Gen on
2	Gen1
3	Gen2
4	Gen3
5	Gen4
6	Gen5
7	Gen1&2
8	Gen2&3
9	Gen3&4
10	Gen4&5
11	Gen1&3
12	Gen2&4
13	Gen3&5
14	Gen1&2&3
15	Gen1&2&3&4
16	Gen1&2&3&4&5

The load flow studies were conducted to evaluate the network performance of a one year timespan with the impact of EG assessed for:

- Losses
- Voltage constraints i.e. voltage rise by 5% or decrease by 5%

- Effect on different load models taking into account that non-technical losses are made up of mostly constant current type loads.

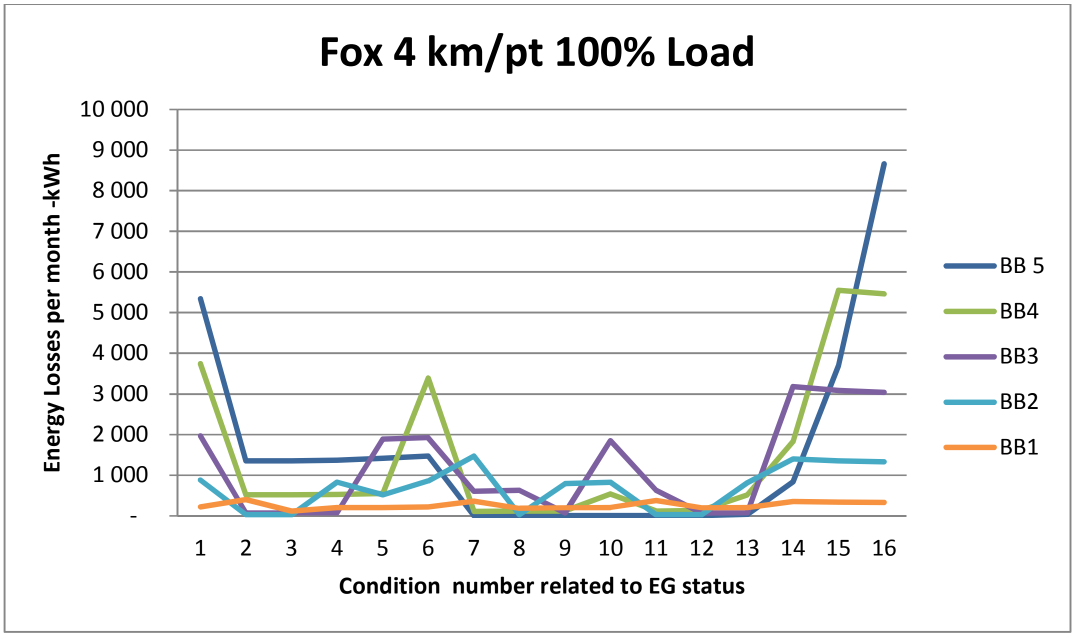


Figure 3-1 Energy Losses profile per busbar for the different generation scenarios – Fox conductor

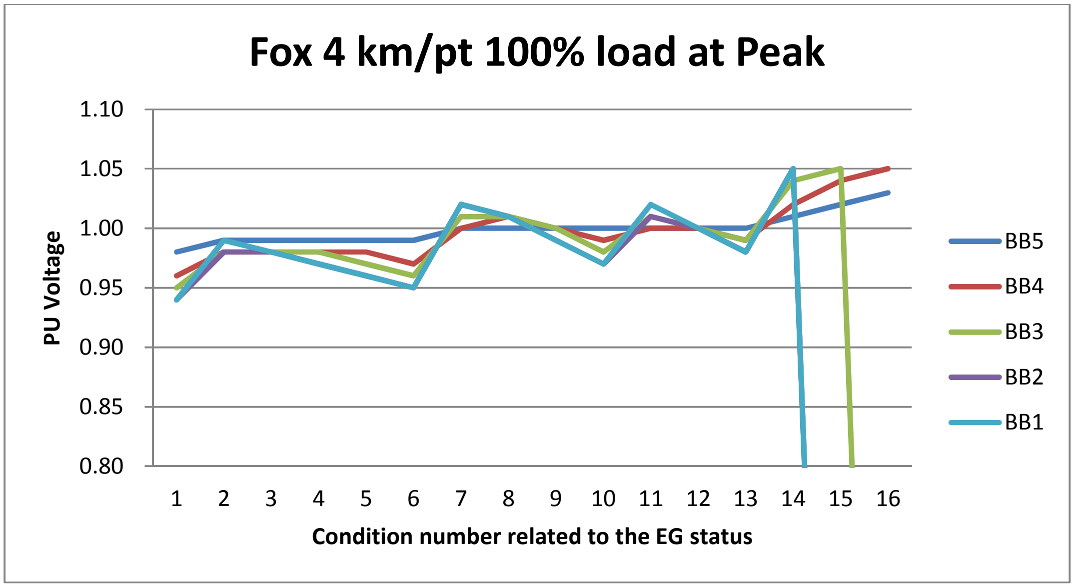


Figure 3-2 Voltage profile per busbar for the different generation scenarios – Fox conductor

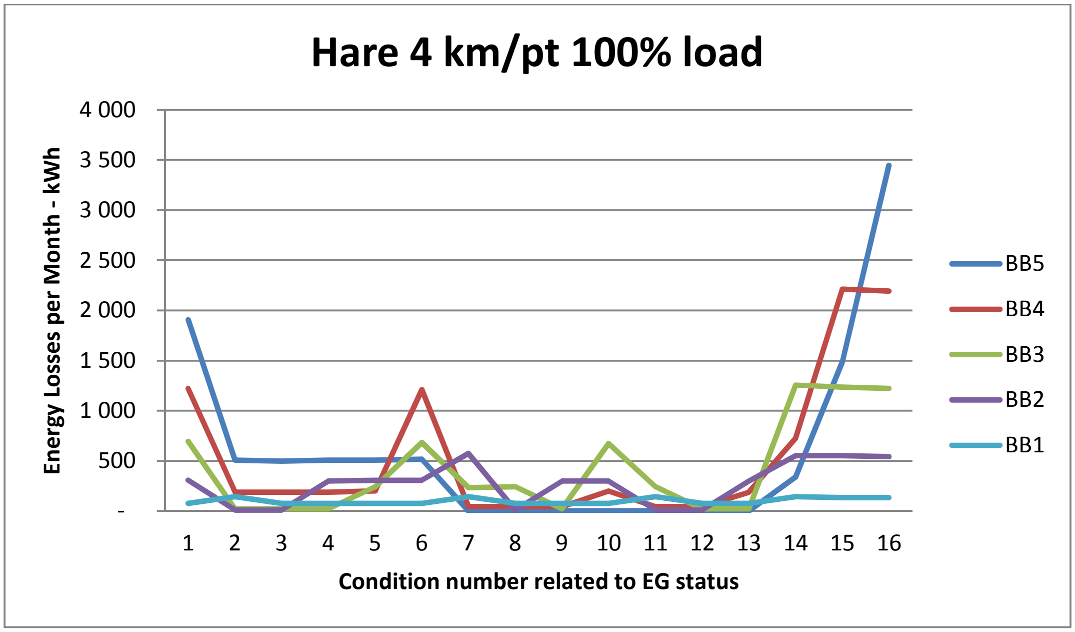


Figure 3-3 Energy Losses profile per busbar for the different generation scenarios – Hare Conductor

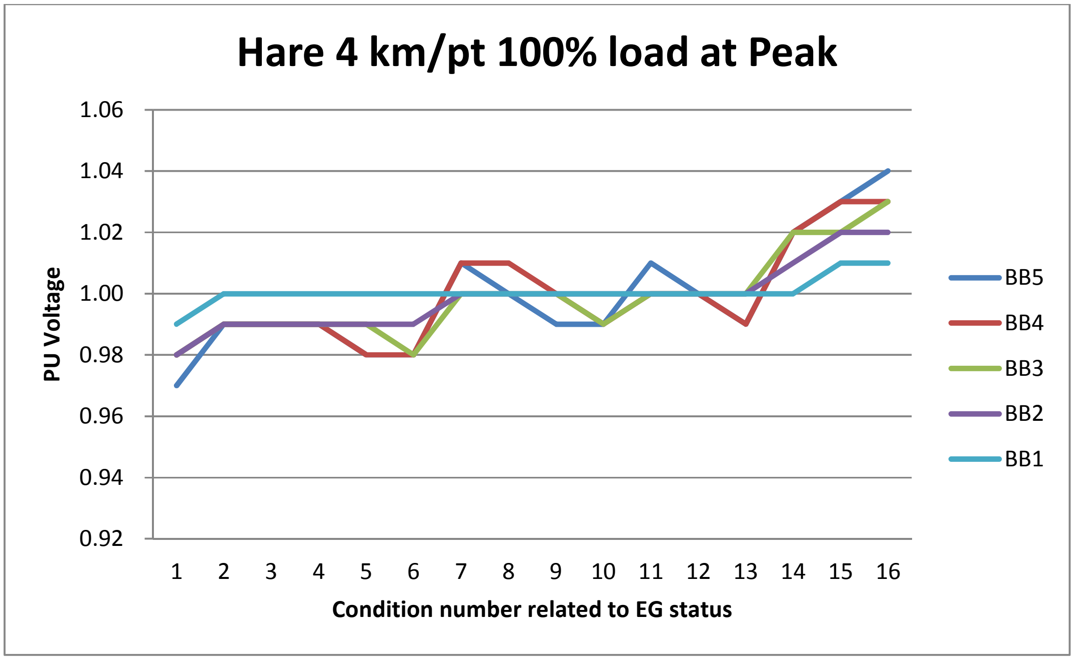


Figure 3-4 Voltage profile per busbar for the different generation scenarios – Hare Conductor

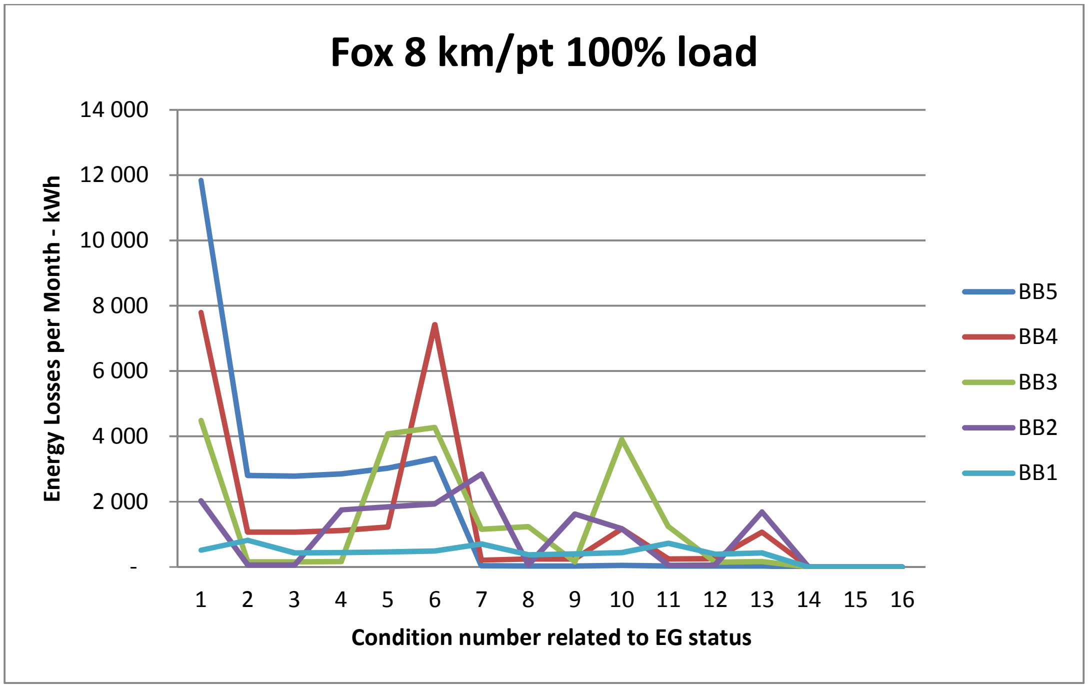


Figure 3-5 Energy Losses profile per busbar for the different generation scenarios – Fox Conductor

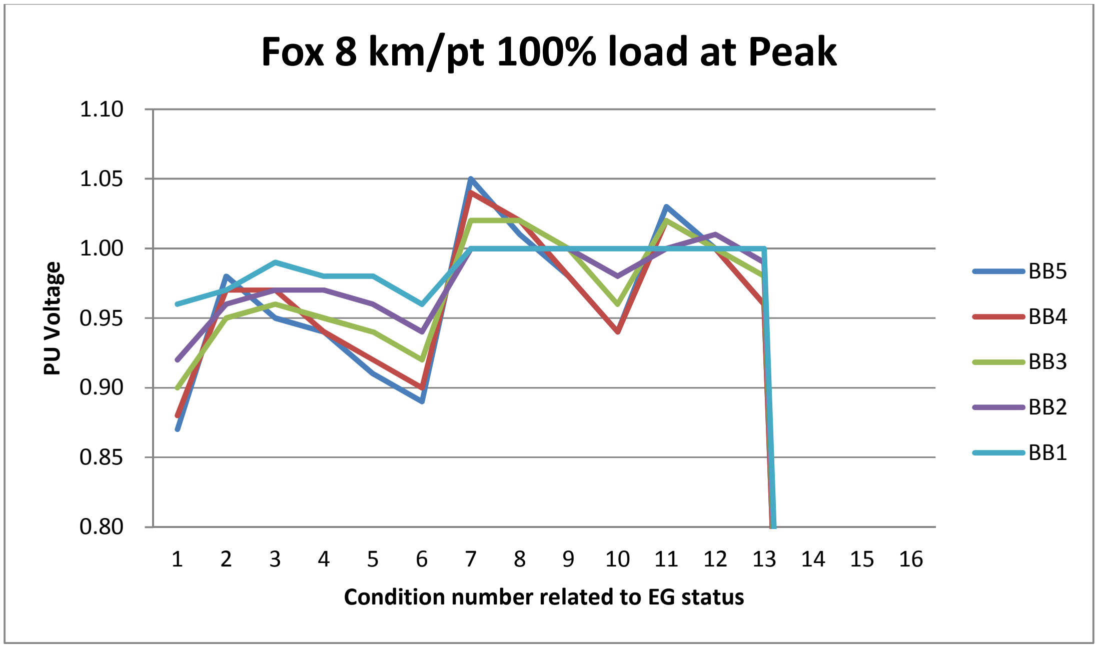


Figure 3-6 Voltage profile per busbar for the different generation scenarios – Fox Conductor

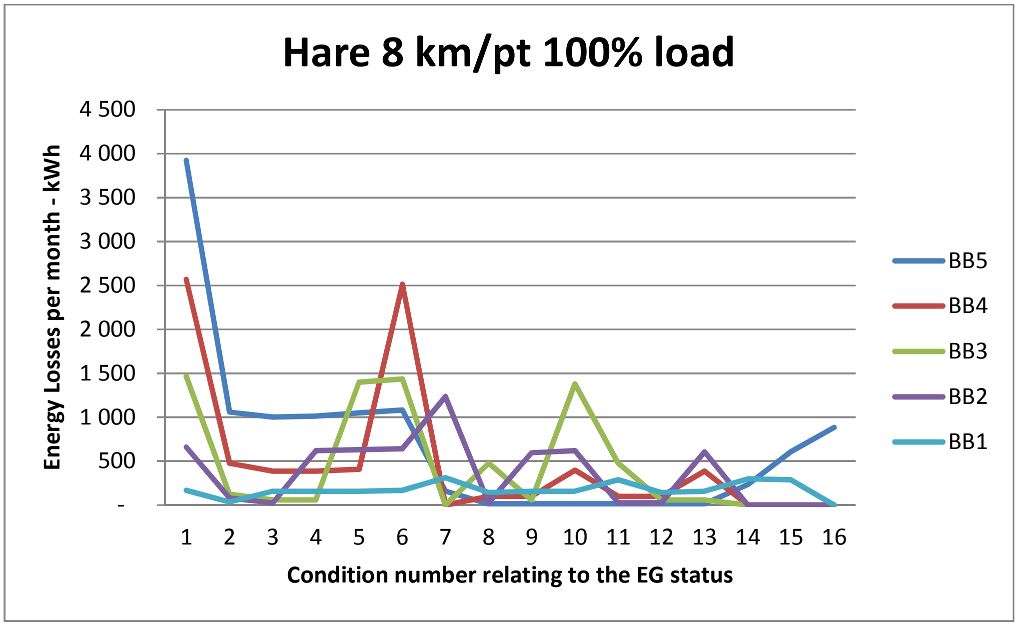


Figure 3-7 Energy Losses profile per busbar for the different generation scenarios – Hare Conductor

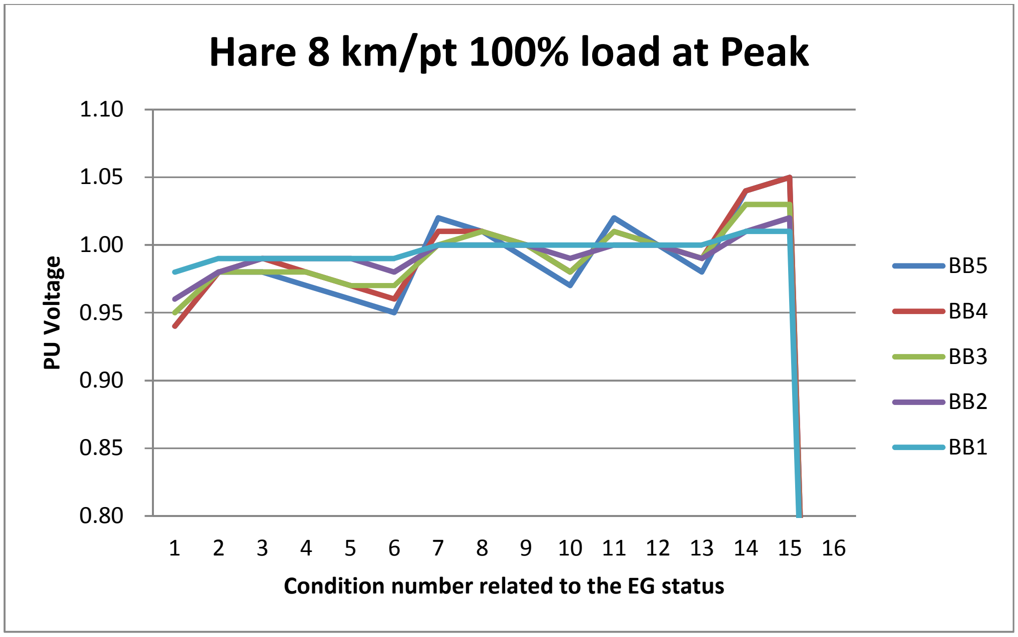


Figure 3-8 Voltage profile per busbar for the different generation scenarios – Hare Conductor

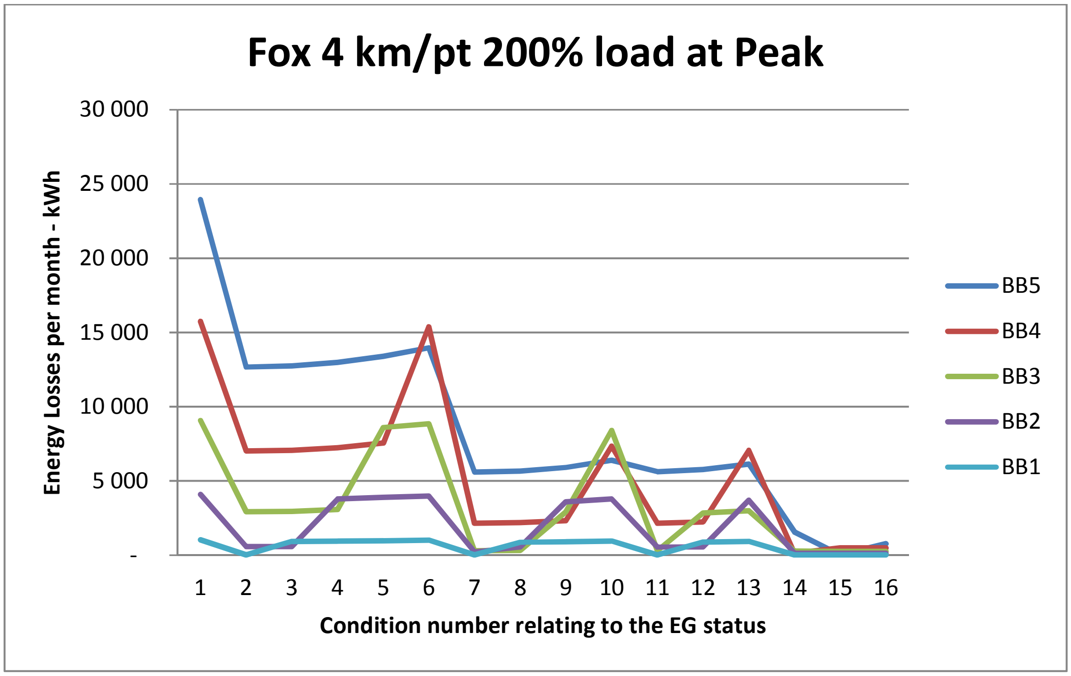


Figure 3-9 Energy Losses profile per busbar for the different generation scenarios – Fox Conductor

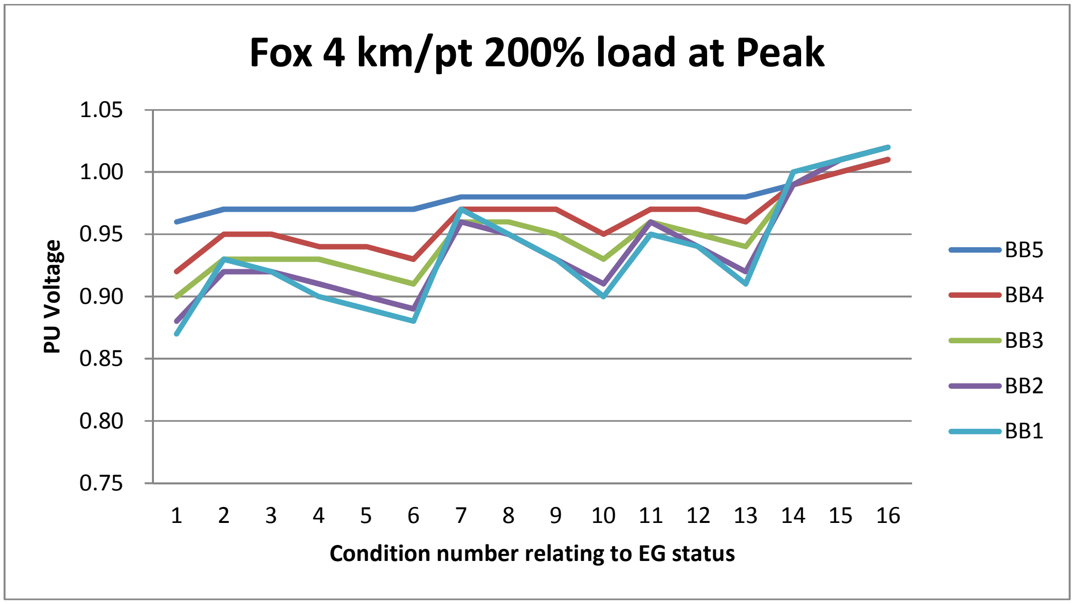


Figure 3-10 Voltage profile per busbar for the different generation scenarios – Fox Conductor

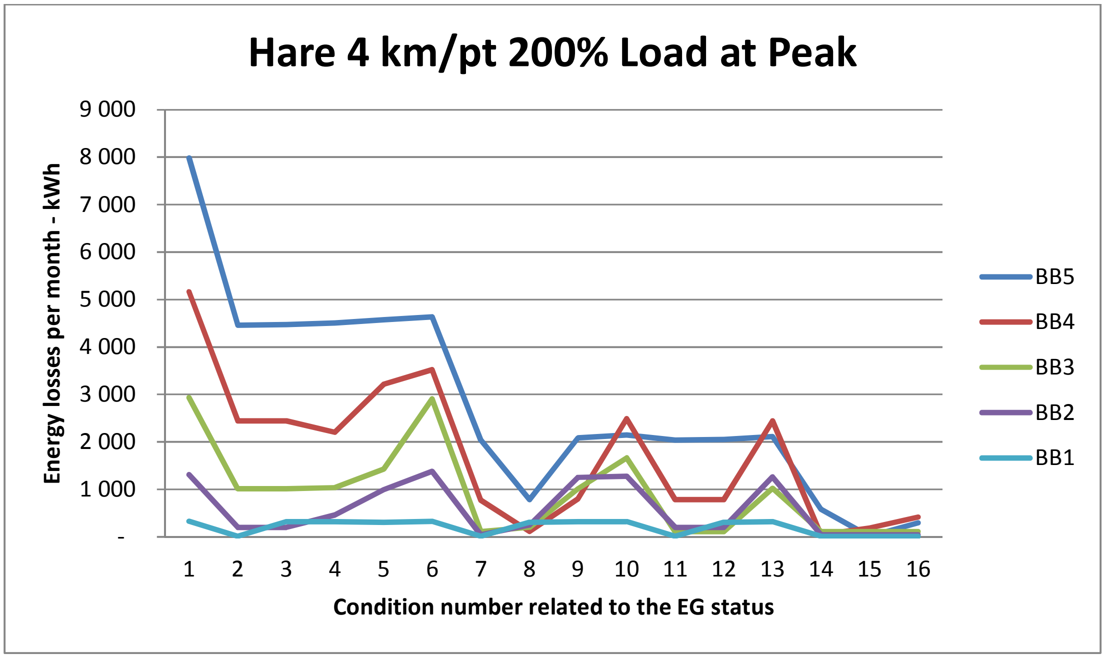


Figure 3-11 Energy Losses profile per busbar for the different generation scenarios – Hare Conductor

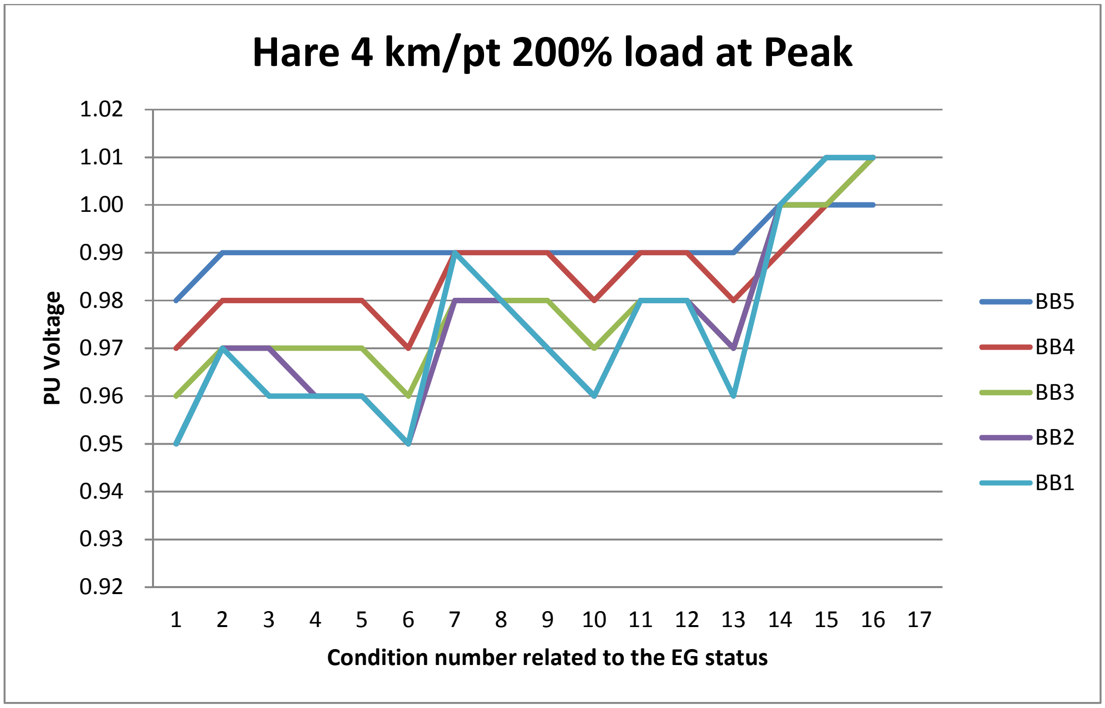


Figure 3-12 Energy Losses profile per busbar for the different generation scenarios – Hare Conductor

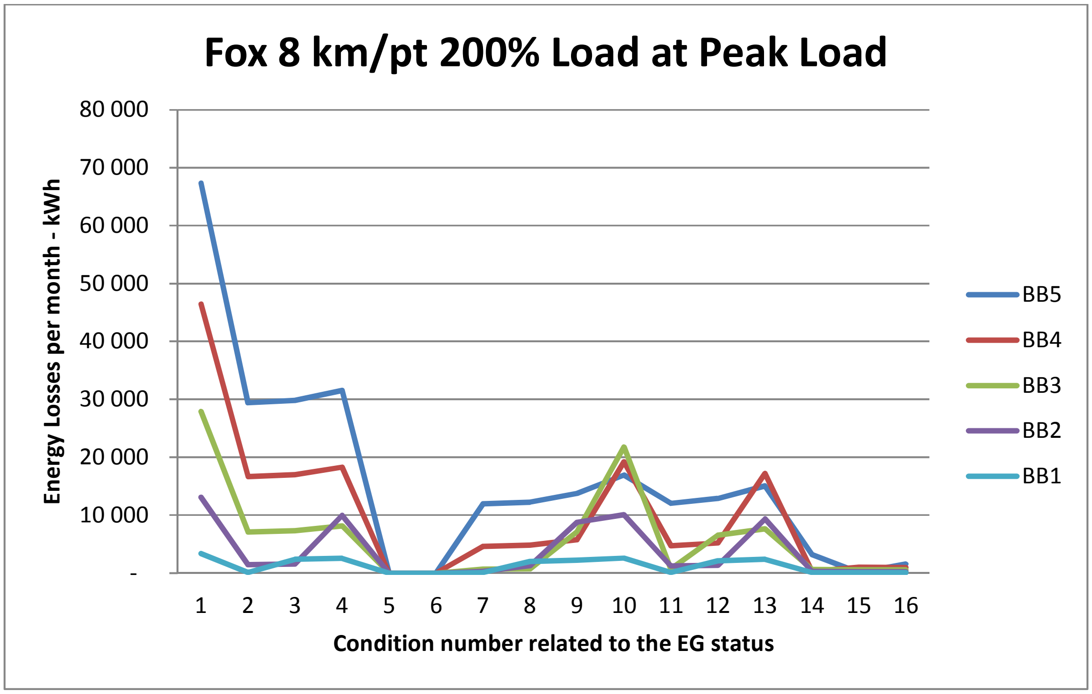


Figure 3-13 Energy Losses profile per busbar for the different generation scenarios – Fox Conductor

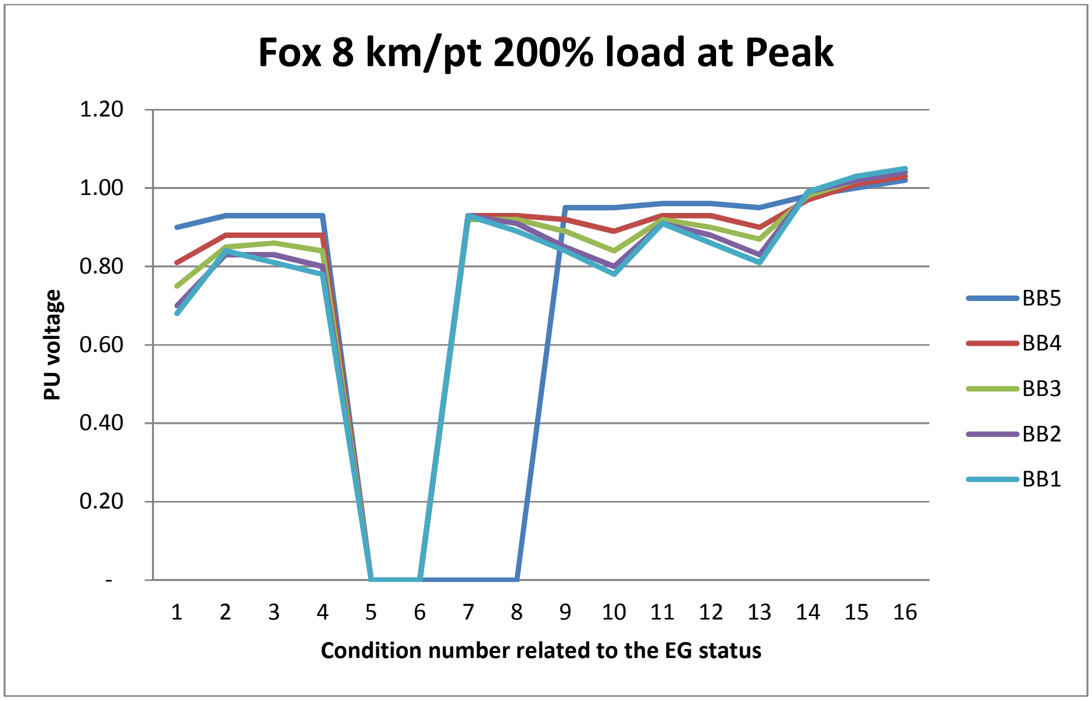


Figure 3-14 Voltage profile per busbar for the different generation scenarios – Fox Conductor

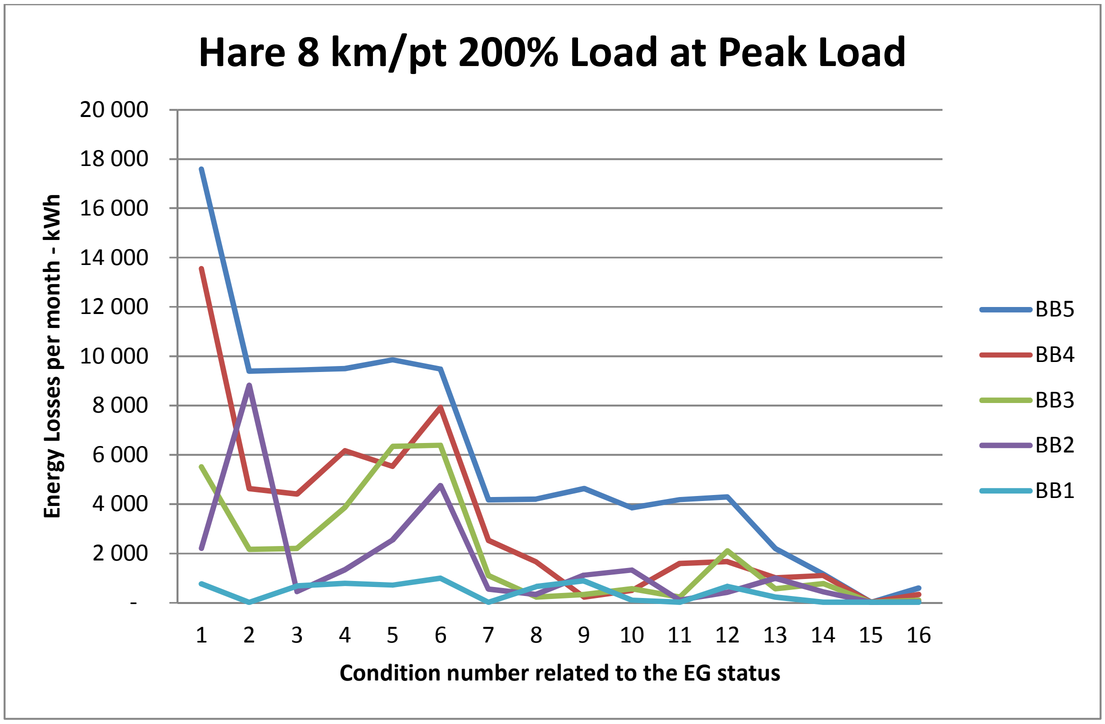


Figure 3-15 Energy Losses profile per busbar for the different generation scenarios – Hare Conductor

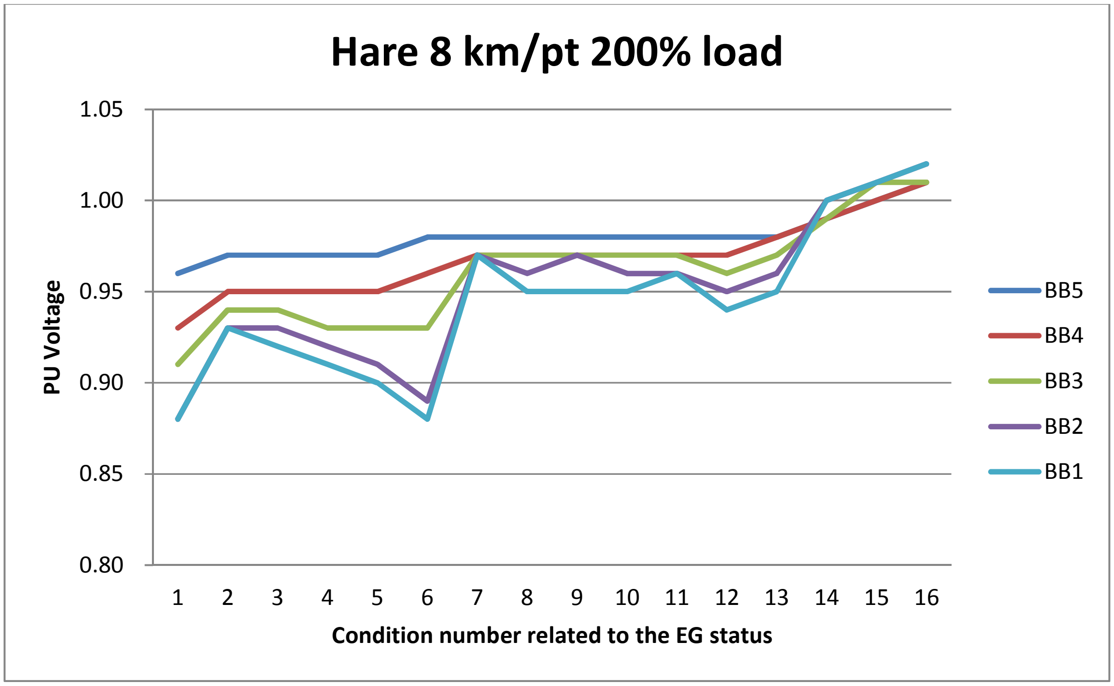


Figure 3-16 Voltage profile per busbar for the different generation scenarios – Hare Conductor

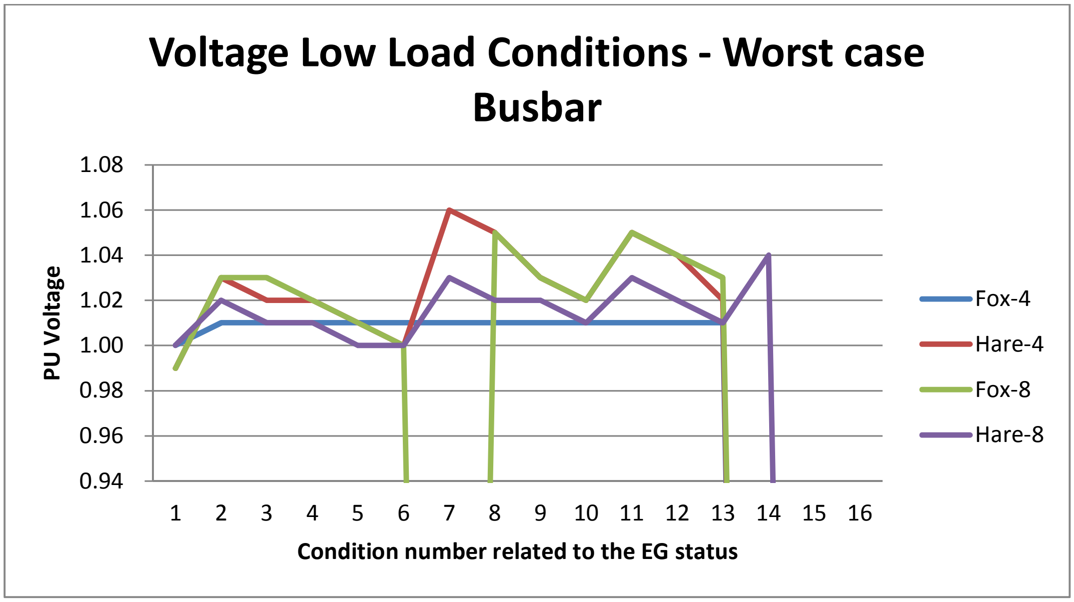


Figure 3-17 Voltage profile per busbar for low load conditions for different conductor sizes and lengths

3.2 Load flow analysis discussion

The NRS 048 specifies that the deviations from the standard or declared voltages provided to customers for greater and equal to 500 V will have a compatibility level not exceeding ±5%. Therefore for this dissertation the study limits of 95% and 105% was used as the voltage boundary conditions.

The combination of EG used per study is depicted in Table 3-1 and indicates that the EG amount (in MW) was varied from 0% to 100% of the load of the system for both Fox and Hare conductor and for both 4 km and 8 km between load points. From Figure 3-1 it can be seen that energy losses on a radial distribution network exhibits “U” type pattern. The reason for this type of pattern is that there is reversal of power flow in the system. The critical point is when the amount of EG on the system matches the distributed load. For system this occurs when there are up to three EGs operating in the system. The ideal system balance occurs when there are two dispersed EGs operating in the system. If the EGs are located beyond 80% of the distance from the source busbar then the losses on the network will decrease. In a system with no EGs the losses in the system increase cumulatively from the furthest busbar to the source busbar. The introduction of EGs into the system effectively reduces the length of the system by displacing the load at the point of generator connection.

The losses in the system will start to increase when the generation capacity reaches 60% of the peak load capacity of the system and is located beyond 40% of the network. At this point the reversal of power flows now means that larger amounts of energy are flowing per section resulting in increasing levels of losses. Figure 3-3 indicates that the voltage on the system improves as the penetration of generators increase. The EGs have the effect of displacing the load on the system and hence the improvement in voltage performance. Once the generation capacity reaches 60% of the peak load capacity of the system, the voltage limit is exceeded. The voltage increases as a result of more power being supplied per point than what the system requires. The greatest improvement in system voltage occurs for condition 6 (Table 3-1), for a single generator located at 20% of the network from the source busbar but the greatest improvement in energy loss reduction is when the generation to total peak load is 40% and the location of the generation is beyond 40% the total length from the source busbar. These improvements are as a result of the reduction of load on the system. When the volume of EG is less than the total dispersed load in the system, this effectively simulates changing load patterns on the system. The effective load that is now distributed in the system results in a change in the energy flow and performance of the system in terms of voltage and energy losses. When the EG volume becomes greater than the load per point of supply, the EGs become sources of power greater than what the system actually needs per point and the overall energy flow in the system increases.

With an improvement in conductor impedance, the overall energy losses is decreased as depicted in Figure 3-3 compared to Figure 3-1. The technical losses that are now available for saving with the EG is reduced approximately 50%. The pattern of loss saving and increase of energy losses as a result of increasing the amount of generation to total peak load is the same as that of Fox conductor. The net energy savings for the generator combinations compared to that without any generators is higher for the higher impedance conductor. This is mainly due to more energy in terms of energy losses that are available to be saved in higher impedance systems. The voltage performance of Hare conductor is far superior to that Fox conductor and that indicates that the EG carrying capacity is higher, with the system being able to be within voltage limits for all generation permutations.

For Figures 3-5 and 3-6, the system is out of voltage regulation limits without any generators in service. For this system the “U” shape for energy losses was not achieved as a result of the system being outside its voltage regulation limits. This system is already in a voltage constrained situation before the introduction of EGs. The power flows in the system are not reversing because the volume of EG is half that of the total load carrying capacity of the system. The best voltage limit improvement is achieved for a single generator that is greater than 80%

of the overall length of the system but the energy loss savings is not as great as other generation configurations. The highest loss reduction occurs when the generation capacity is less than 40% of the peak system load but greater than 20%. The reasons for these changes are similar to what was described for Figure 3-3 above.

For Figures 3-7 and 3-8, the higher impedance, Hare conductor system experiences regulation limit problems without any generation. The improvement in voltage regulation is best when the generation volume is less than 60% of the peak load carrying capacity. Once it is greater than 60%, the voltage regulation is outside the regulation boundary. The maximum energy loss reduction happens when the generation capacity is less than 30% of the peak load. This is the optimal energy balance of the system and is as a result of sufficient load reduction at effective points in the system.

Figures 3-9 and 3-10 are for a Fox conductor system with a 200% increase in load. The system is out of voltage regulation limits with no generation. The minimum requirement to bring the system within regulation is 20% generation. This effectively reduced the total load on the system. The greatest loss savings occur when all the generators are in service and it also results in a far greater overall energy loss savings compared to when the system was run at 100% of peak load. The significance of energy loss savings becomes more material on higher loaded systems that are currently close to their operational voltage regulation limits. This system would also allow for more permutations for generation location and volume. The reason for this is because the overall peak load on the system has been reduced but is still greater than the volume of generation on the system.

Figures 3-11 and 3-12 indicate that the energy losses of the system can only be reduced once the penetration of generation is less than 50% of the total peak load of the system. This was also confirmed with the previous case and the reasons are the same as what was given above. The system is successfully able to deal with generation volume of 50% of peak load and the energy loss saving is greatest for greater than 30% of peak load carrying capacity.

Figures 3-13, 3-14, 3-15 and 3-16, indicate that the system requires at least 20% generation to be within voltage regulation limits. This system has the overall greatest energy loss savings once the system is within regulation limits. This is directly as a result of reducing the power flow in the system as a result of effective displacement or reduction of load.

Figure 3-17 is the voltage conditions for off-peak conditions or low load conditions. None of the system combinations can successfully handle a volume of generation greater than 60% of the peak load carrying condition. For low impedance conductor (Hare), the volume of generation on the system has to be less than 20% of the peak load carrying capacity. The off-peak load value restricts the number or EGs that can be running at their equivalent capacity during peak load conditions. Once the volume of EG exceeds the load in the system, the power flows reverse and the voltage of the system will rise. For low load conditions this happens with very little EG in the system.

In summary of all the load flow results for the various systems discussed above, generation that is further away from the source has a higher effect on the losses. Reversing power flows due to EG lead to an increase in losses. The total losses for low levels of EG penetration, decrease, but with higher penetration of EG, increase the overall losses. At low levels of EG volume penetration where the voltage regulation limits of the network are exceeded without the EG, the penetration of the generation has to be greater than 50% and located at a distance of greater than 20% of the length of the system.

A system is successfully able to be within limits across all time periods as long as the penetration of the EG is located at a distance greater than 40% of the total length of the network from the source busbar, and is less than 20% of the peak load carrying capacity of the system.

A system with a high load factor will allow a higher penetration and volume of EG. If the system does not have a high load factor, operational flexibility of the EG should be used to allow for maximisation of peak capacity creation i.e. varying the use of the EG to match the system load conditions. The financial effect of this type of operational flexibility will be deal with in the next section.

3.3 The effect of different load models

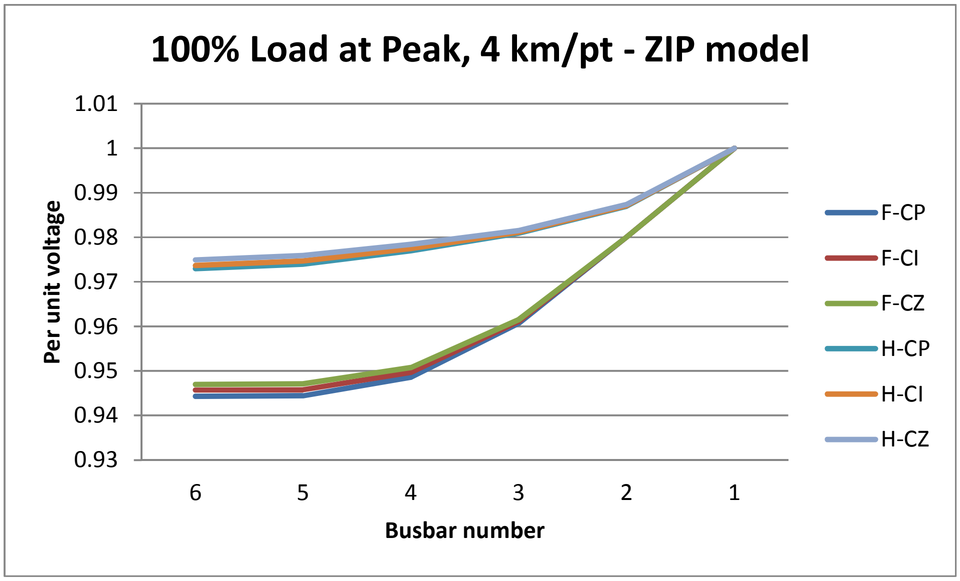


Figure 3-19: Voltage profile per busbar for different load point compositions at peak load

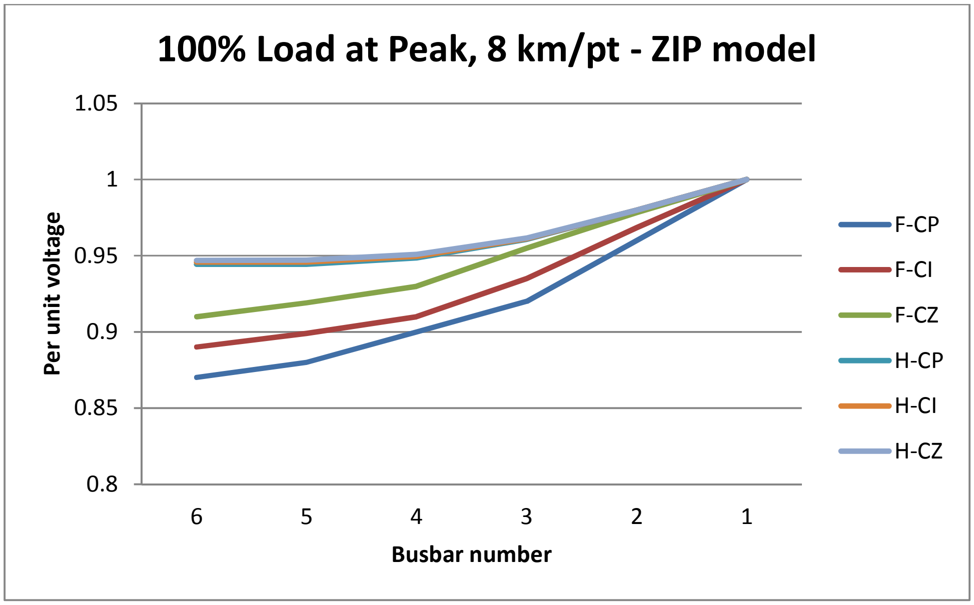


Figure 3-20: Voltage profile per busbar for different load point compositions at peak load

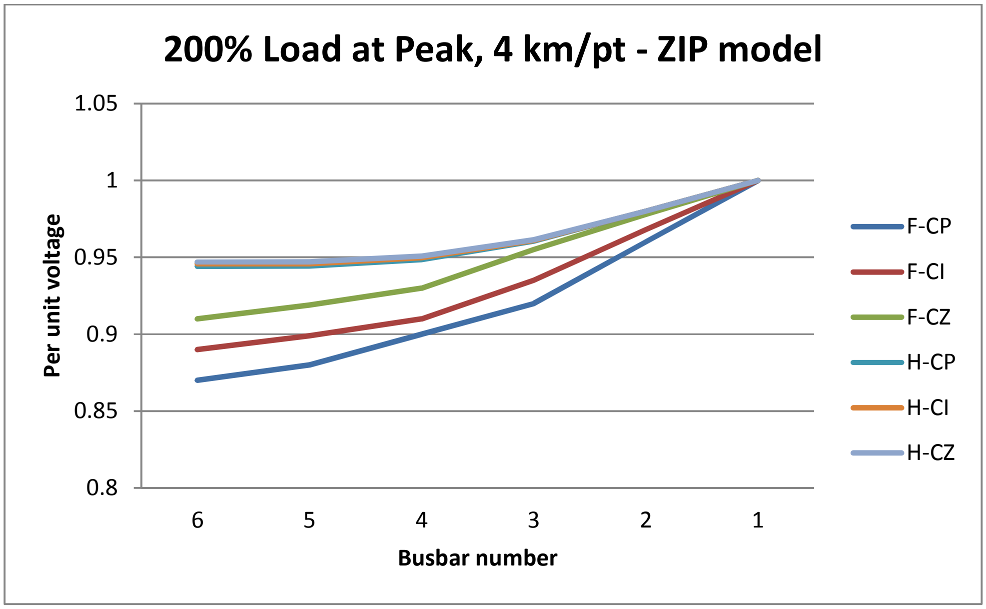


Figure 3-21: Voltage profile per busbar for different load point compositions at 200% peak load

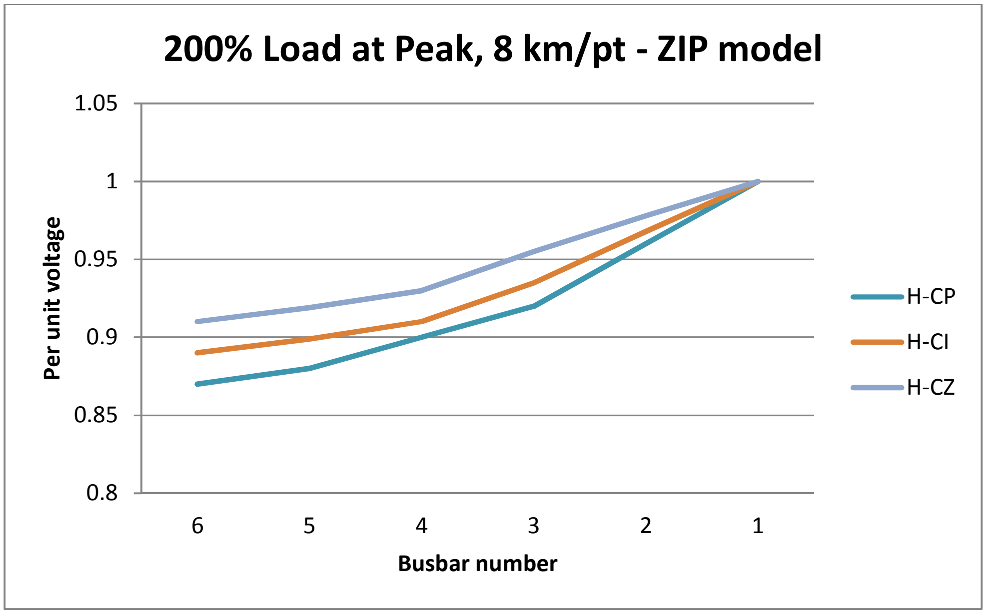


Figure 3-22 Voltage profile per busbar for different load point compositions at 200% peak load

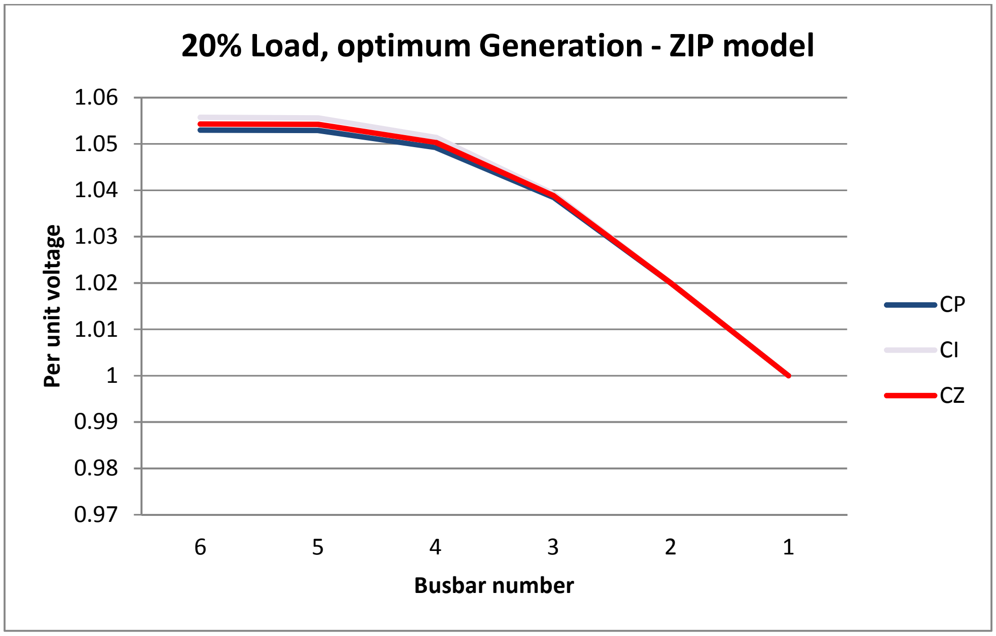


Figure 3-23 Voltage profile per busbar for different load point compositions at off-peak load

The worst case scenario for normal steady state load flow calculations is to model the system using only constant power loads as can be seen from Figure 3-19 to Figure 3-21. The higher the impedance of the conductor (Fox compared to Hare), the more pronounced the effect of the type of load for the study system scenarios further from the main source. This is because the voltage drop across higher impedance conductors is greater.

It is important to factor into the study the off-peak behaviour of various load types. During off-peak conditions shown in Figure 3-22, constant current type loads have the worst effect. This off-peak type condition is relevant because the effect of having EG simulates the off-peak response of the system i.e. decreasing the load per point and improving the voltage. The load composition in the domestic segment in South Africa is mainly made up of constant current type loads and a percentage of this load is not recovered by the tariffs as the customers are not connected legally. This means that if they were a constant current load, the effect on the overall sales losses is less than that if they were modelled as constant power loads. This is a diminishing effect as the loads approach the busbar nominal voltage levels.

In order to simulate the revenue effect of the different load types as a result of the system changes caused by the EG, 50% of the domestic load is modelled as constant current load. The revenue effect between the various time-off-use categories is tabled below, as seen at the source busbar, and is calculated based on an average system voltage change between the number of generators on the system. The location of the generators is not taken into account as the intention is to create an average revenue response change for the various busbars as seen at the source busbar.

Table 3-2: The revenue effect of using 50% constant current for domestic supplies rather than constant power type loads

TOU	Conductor Type (F - Fox, H - Hare), length (4km's or 8km's) and % peak load parameter used for Revenue effect							
	F4-100%	***F4-200%***	***F8-100%***	***F8-200%***	***H4-100%***	***H4-200%***	***H8-100%***	***H8-200%***
Peak	-2%	-10%	-10%	-10%	-1%	-3%	-4%	-5%
Std	0%	0	0	0	0%	0%	0%	0%
Off- Peak	2%	2%	5%	2%	1%	1%	5%	3%

The Table 3-2 above, indicated that average revenue change with the EG generators varies across the system and that the effect is worst when the impedance is highest, either caused by increasing length or type of conductor. This revenue effect is applied to all practical cases where the generation set can successfully fulfil all boundary conditions.

3.4 The sales and cost of sales for the medium voltage system

Table 3-3: Eskom sales made on the Distribution System per tariff category applicable to a typical MV system

Sales (Utility Income) made in the distribution system study case, in Rands per R'1000															
			MONTH												
Tariff	**Unit**	**Charge**	***Apr***	***May***	***Jun***	***Jul***	***Aug***	***Sep***	***Oct***	***Nov***	***Dec***	***Jan***	***Feb***	***Mar***	***TOTAL***
Miniflex	c/kWh	Peak	35.8	35.8	116.0	116.0	116.0	35.8	35.8	35.8	35.8	35.8	35.8	35.8	671
	c/kWh	Std	23.3	23.3	33.0	33.0	33.0	23.3	23.3	23.3	23.3	23.3	23.3	23.3	309
	c/kWh	Off-Peak	13.1	13.1	15.3	15.3	15.3	13.1	13.1	13.1	13.1	13.1	13.1	13.1	164
	R/KVA/m	Demand	6.9	6.9	6.9	6.9	6.9	6.9	6.9	6.9	6.9	6.9	6.9	6.9	83
	c/kWh	Elec&Rural Levy	6.9	6.9	6.9	6.9	6.9	6.9	6.9	6.9	6.9	6.9	6.9	6.9	82
	c/kWh	Enviro Levy	3.0	3.0	3.0	5.3	5.3	5.3	5.3	5.3	5.3	5.3	5.3	5.3	56
	Rands	Ser & Admin	23.1	23.9	23.1	23.9	23.9	23.1	23.9	23.1	23.9	23.9	23.1	23.9	283
Nightsave	c/kWh	Energy	48.7	48.7	74.3	74.3	74.3	48.7	48.7	48.7	48.7	48.7	48.7	48.7	661
	R/KVA/m	Demand	49.8	49.8	82.2	82.2	82.2	49.8	49.8	49.8	49.8	49.8	49.8	49.8	695
	R/KVA/m	NAC	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	3.5	42
	Rands	Ser & Admin	23.1	23.9	23.1	23.9	23.9	23.1	23.9	23.1	23.9	23.9	23.1	23.9	283
Ruraflex	c/kWh	Peak	39.4	39.4	143.0	143.0	143.0	39.4	39.4	39.4	39.4	39.4	39.4	39.4	783
	c/kWh	Std	23.3	23.3	35.9	35.9	35.9	23.3	23.3	23.3	23.3	23.3	23.3	23.3	318
	c/kWh	Off-Peak	16.3	16.3	19.1	19.1	19.1	16.3	16.3	16.3	16.3	16.3	16.3	16.3	204
	R/KVA/m	Demand	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1	25
	c/kWh	Enviro Levy	2.6	2.6	2.6	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	48
Business	c/kWh	Energy	68.1	68.1	68.1	68.1	68.1	68.1	68.1	68.1	68.1	68.1	68.1	68.1	818
	c/kWh	Enviro Levy	1.9	1.9	1.9	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3	35
	R/pod/d	Service	20.4	20.4	20.4	20.4	20.4	20.4	20.4	20.4	20.4	20.4	20.4	20.4	245
	R/pod/d	Network	69.2	69.2	69.2	69.2	69.2	69.2	69.2	69.2	69.2	69.2	69.2	69.2	831
Home Power	c/kWh	Block1	34.0	34.0	34.0	34.0	34.0	34.0	34.0	34.0	34.0	34.0	34.0	34.0	409
	c/kWh	Block2	36.8	36.8	36.8	36.8	36.8	36.8	36.8	36.8	36.8	36.8	36.8	36.8	441
	c/kWh	Block3	23.4	23.4	23.4	23.4	23.4	23.4	23.4	23.4	23.4	23.4	23.4	23.4	281
	c/kWh	Block4	17.1	17.1	17.1	17.1	17.1	17.1	17.1	17.1	17.1	17.1	17.1	17.1	205
	c/kWh	Enviro Levy	2.8	2.8	2.8	4.9	4.9	4.9	4.9	4.9	4.9	4.9	4.9	4.9	52
Home Light	c/kWh	Block1	52.2	52.2	52.2	52.2	52.2	52.2	52.2	52.2	52.2	52.2	52.2	52.2	627
	c/kWh	Block2	45.7	45.7	45.7	45.7	45.7	45.7	45.7	45.7	45.7	45.7	45.7	45.7	548
	c/kWh	Block3	29.1	29.1	29.1	29.1	29.1	29.1	29.1	29.1	29.1	29.1	29.1	29.1	349
	c/kWh	Block4	21.2	21.2	21.2	21.2	21.2	21.2	21.2	21.2	21.2	21.2	21.2	21.2	255
	c/kWh	Enviro Levy	3.5	3.5	3.5	6.1	6.1	6.1	6.1	6.1	6.1	6.1	6.1	6.1	65
Total			680	680	949	959	959	690	690	690	690	690	690	690	9,056

Table 3-4 Eskom cost of sales for a typical MV system

The Cost of Sales in R's as a result of no EG and no non-technical losses												
Energy	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Total
Peak	123,769	137,521	534,677	534,677	560,138	151,274	144,398	151,274	137,521	144,398	137,521	151,274	2,908,442
Std	80,862	88,275	139,884	139,884	145,668	90,970	89,622	90,970	88,275	87,264	83,558	93,329	1,218,561
Off	89,252	87,421	94,245	100,726	96,406	77,809	85,361	77,809	87,421	86,963	74,148	81,700	1,039,261
Fixed	11,539	11,539	11,539	11,539	11,539	11,539	11,539	11,539	11,539	11,539	11,539	11,539	138,473
Realiability	15,437	16,130	15,821	16,259	16,387	15,950	16,259	15,950	16,130	16,260	14,818	16,387	191,787
Total	320,860	340,887	796,166	803,085	830,138	347,542	347,180	347,542	340,887	346,424	321,584	354,228	5,496,524
The Cost of Sales in R's as a result of no EG but with non-technical losses													
Peak	140,418	156,020	606,600	606,600	635,486	171,622	163,821	171,622	156,020	163,821	156,020	171,622	3,299,675
Std	114,861	125,390	198,699	198,699	206,916	129,219	127,305	129,219	125,390	123,955	118,690	132,569	1,730,913
Off	126,778	124,178	133,871	143,077	136,940	110,525	121,252	110,525	124,178	123,528	105,323	116,051	1,476,225
Fixed	13,092	13,092	13,092	13,092	13,092	13,092	13,092	13,092	13,092	13,092	13,092	13,092	157,099
Realiability	20,794	21,653	21,151	21,773	21,892	21,271	21,773	21,271	21,653	21,774	19,789	21,892	256,685
Total	415,944	440,333	973,412	983,241	1,014,324	445,728	447,243	445,728	440,333	446,169	412,915	455,226	6,920,597

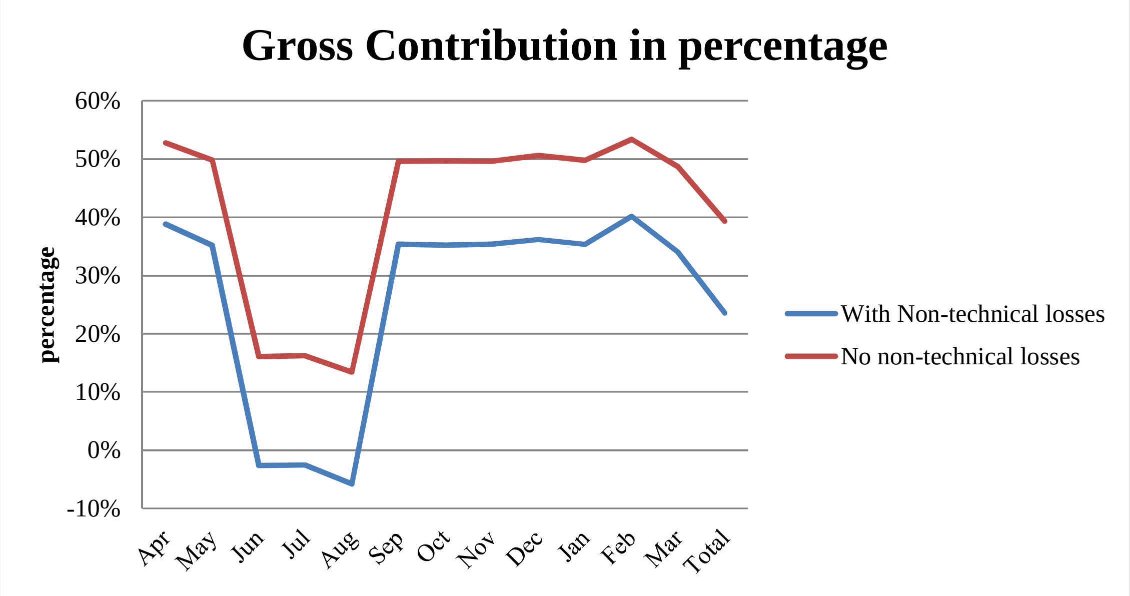


Figure 3-23 Gross Contribution in Percentage

The cost of sales as per the categories for a typical MV system indicates that the gross contribution percentage (sales – cost of sales / sales) in winter with non-technical losses included is negative. There is a 16% change in gross contribution percentage as a result of non-technical losses. The technical loss as a result of non-technical sales is also factored into the calculations. The rate of recovery has to be 24% per year to recover capital costs and increasing operations costs. The capital recovery rate is averaged for the whole of Eskom and Electricity Sales from Distribution is the primary income for Eskom. The average rate of the wholesale cost is 51 c/kWh and the retail rate it is 61 c/kWh. The fuel cost in Eskom is 31 c/kWh which means that at least 70% (fuel and margin between retail and wholesale), of the cost is needed for operations and the 30% used for capital investment for new build. It is noted that the poor load factor and intensity of electricity use for MV supplied customers is not that of the high end Industrial customers. If the penetration of EG's is limited to 20% in MV systems as from the load flow analysis, this means that there is only a 20% decrease in capital required for new build and strengthening in order to cater for the increase in electricity sales, which is currently at 3% per year for Eskom. This directly implies that the Gross Contribution cannot be changed by more than 20% before functionally affecting the sustainable rate of recovery per year i.e. the Gross Contribution cannot drop to less than 19% before the tariffs need to be increased beyond that of the current increases projected by Eskom. This boundary condition will exist due to the difference between the rate of increase of sales demand versus the capacity that is created in the system by EG's.

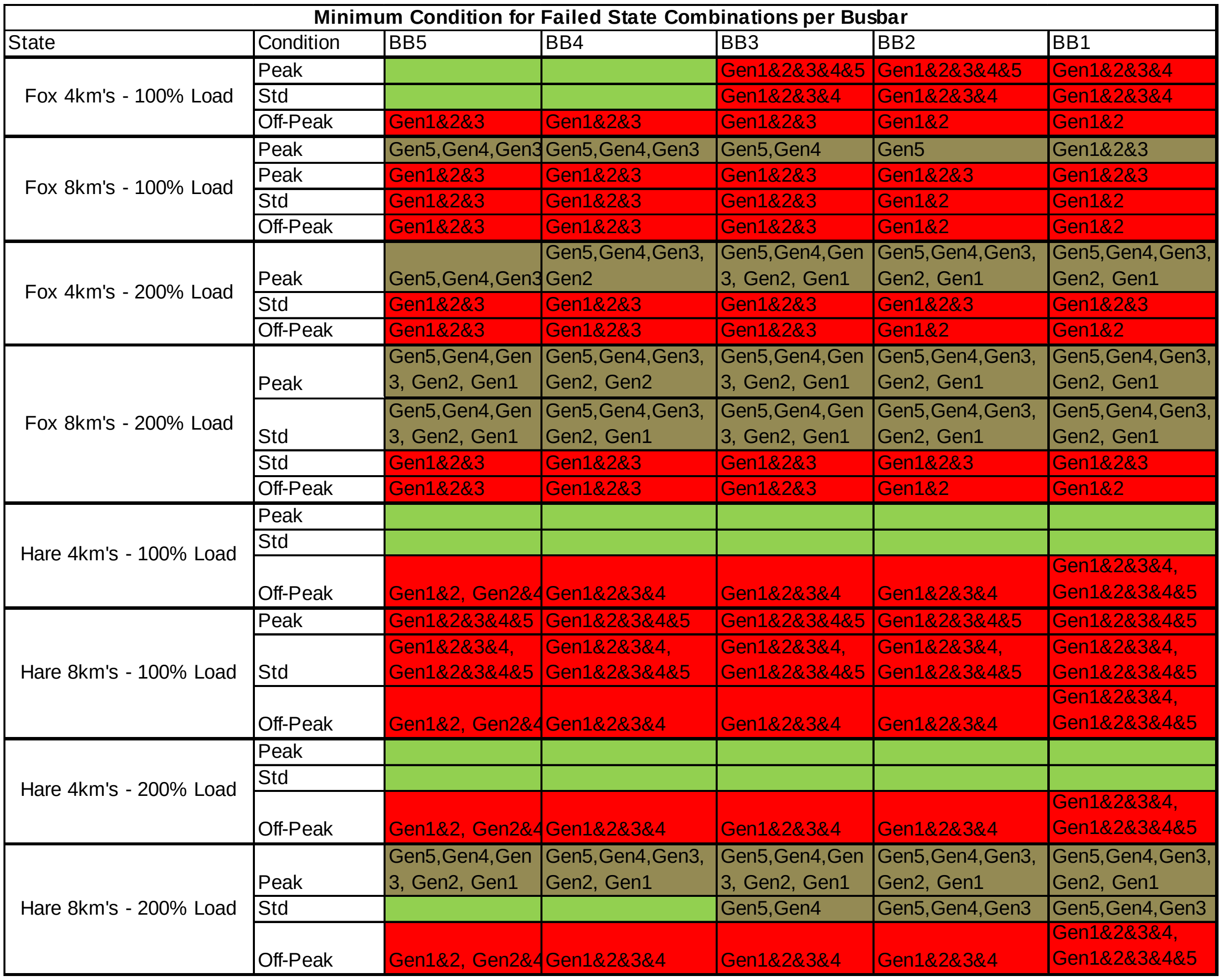
If the rate of capacity creation in an MV system is higher than the rate of sales growth then the cost of paying the EG's will be higher than the requirements by Eskom for capital for new build and operations requirements.

In order to sustainably increase the volume of EG's on the network the non-technical loss has to be converted to sales. If 50% of the non-technical loss can be converted to sales the margin available to without affecting the revenue requirements of Eskom is then changed to a gross contribution of 11%.

3.5 Financial effect of EG

In order to determine the capital that can be recovered by EG's based on the income that they can generate, a correlation is needed to the actual EG combinations that are practical for the MV system. Table 3-5 below details the combinations that is possible based on the load flow results from section 3.2.

Table 3-5 Minimum number of EGs switched in resulting in a failed test condition per busbar



Minimum Condition for Failed State Combinations per Busbar						
State	Condition	BB5	BB4	BB3	BB2	BB1
Fox 4km's - 100% Load	Peak	🟩	🟩	🟥 Gen1&2&3&4&5	🟥 Gen1&2&3&4&5	🟥 Gen1&2&3&4
	Std	🟩	🟩	🟥 Gen1&2&3&4	🟥 Gen1&2&3&4	🟥 Gen1&2&3&4
	Off-Peak	🟥 Gen1&2&3	🟥 Gen1&2&3	🟥 Gen1&2&3	🟥 Gen1&2	🟥 Gen1&2
Fox 8km's - 100% Load	Peak	🟫 Gen5,Gen4,Gen3	🟫 Gen5,Gen4,Gen3	🟫 Gen5,Gen4	🟫 Gen5	🟫 Gen1&2&3
	Peak	🟥 Gen1&2&3	🟥 Gen1&2&3	🟥 Gen1&2&3	🟥 Gen1&2&3	🟥 Gen1&2&3
	Std	🟥 Gen1&2&3	🟥 Gen1&2&3	🟥 Gen1&2&3	🟥 Gen1&2	🟥 Gen1&2
	Off-Peak	🟥 Gen1&2&3	🟥 Gen1&2&3	🟥 Gen1&2&3	🟥 Gen1&2	🟥 Gen1&2
Fox 4km's - 200% Load	Peak	🟫 Gen5,Gen4,Gen3	🟫 Gen5,Gen4,Gen3, Gen2	🟫 Gen5,Gen4,Gen3, Gen2, Gen1	🟫 Gen5,Gen4,Gen3, Gen2, Gen1	🟫 Gen5,Gen4,Gen3, Gen2, Gen1
	Std	🟥 Gen1&2&3	🟥 Gen1&2&3	🟥 Gen1&2&3	🟥 Gen1&2&3	🟥 Gen1&2&3
	Off-Peak	🟥 Gen1&2&3	🟥 Gen1&2&3	🟥 Gen1&2&3	🟥 Gen1&2	🟥 Gen1&2
Fox 8km's - 200% Load	Peak	🟫 Gen5,Gen4,Gen3, Gen2, Gen1	🟫 Gen5,Gen4,Gen3, Gen2, Gen2	🟫 Gen5,Gen4,Gen3, Gen2, Gen1	🟫 Gen5,Gen4,Gen3, Gen2, Gen1	🟫 Gen5,Gen4,Gen3, Gen2, Gen1
	Std	🟫 Gen5,Gen4,Gen3, Gen2, Gen1	🟫 Gen5,Gen4,Gen3, Gen2, Gen1	🟫 Gen5,Gen4,Gen3, Gen2, Gen1	🟫 Gen5,Gen4,Gen3, Gen2, Gen1	🟫 Gen5,Gen4,Gen3, Gen2, Gen1
	Std	🟥 Gen1&2&3	🟥 Gen1&2&3	🟥 Gen1&2&3	🟥 Gen1&2&3	🟥 Gen1&2&3
	Off-Peak	🟥 Gen1&2&3	🟥 Gen1&2&3	🟥 Gen1&2&3	🟥 Gen1&2	🟥 Gen1&2
Hare 4km's - 100% Load	Peak	🟩	🟩	🟩	🟩	🟩
	Std	🟩	🟩	🟩	🟩	🟩
	Off-Peak	🟥 Gen1&2, Gen2&4	🟥 Gen1&2&3&4	🟥 Gen1&2&3&4	🟥 Gen1&2&3&4	🟥 Gen1&2&3&4, Gen1&2&3&4&5
Hare 8km's - 100% Load	Peak	🟥 Gen1&2&3&4&5	🟥 Gen1&2&3&4&5	🟥 Gen1&2&3&4&5	🟥 Gen1&2&3&4&5	🟥 Gen1&2&3&4&5
	Std	🟥 Gen1&2&3&4, Gen1&2&3&4&5	🟥 Gen1&2&3&4, Gen1&2&3&4&5	🟥 Gen1&2&3&4, Gen1&2&3&4&5	🟥 Gen1&2&3&4, Gen1&2&3&4&5	🟥 Gen1&2&3&4, Gen1&2&3&4&5
	Off-Peak	🟥 Gen1&2, Gen2&4	🟥 Gen1&2&3&4	🟥 Gen1&2&3&4	🟥 Gen1&2&3&4	🟥 Gen1&2&3&4, Gen1&2&3&4&5
Hare 4km's - 200% Load	Peak	🟩	🟩	🟩	🟩	🟩
	Std	🟩	🟩	🟩	🟩	🟩
	Off-Peak	🟥 Gen1&2, Gen2&4	🟥 Gen1&2&3&4	🟥 Gen1&2&3&4	🟥 Gen1&2&3&4	🟥 Gen1&2&3&4, Gen1&2&3&4&5
Hare 8km's - 200% Load	Peak	🟫 Gen5,Gen4,Gen3, Gen2, Gen1	🟫 Gen5,Gen4,Gen3, Gen2, Gen1	🟫 Gen5,Gen4,Gen3, Gen2, Gen1	🟫 Gen5,Gen4,Gen3, Gen2, Gen1	🟫 Gen5,Gen4,Gen3, Gen2, Gen1
	Std	🟩	🟩	🟫 Gen5,Gen4	🟫 Gen5,Gen4,Gen3	🟫 Gen5,Gen4,Gen3
	Off-Peak	🟥 Gen1&2, Gen2&4	🟥 Gen1&2&3&4	🟥 Gen1&2&3&4	🟥 Gen1&2&3&4	🟥 Gen1&2&3&4, Gen1&2&3&4&5

For the cells that are shaded in brown in Table 3-5 above, the lower voltage boundary condition was exceeded, with the combination of EGs shown in the cell. For the cells that are shaded in red, the upper voltage boundary condition was exceeded, with the combination of EGs shown in the cell. For each of the failed conditions the minimum number of EGs that cause that state from occurring is determined. Using this table it is therefore possible to then calculate the minimum practical income that is possible.

Table 3-6 Minimum conditions for a failed state per busbar

Combination	**All periods**	**Only Peak**	**Only Std**	**Only off-Peak**	**Peak & Std**	**Std & Off-Peak**	**Peak & Off-Peak**
No Gen	▨	▨	▨	▨	▨	▨	▨
One Gen	🟩	🟩	🟩	🟩	▨	▨	▨
Two Gens	🟩	🟩	🟩	🟩	1 Peak + 1 Std	1 Std + 1 Off-Peak	1 Peak + 1 Off-Peak
Three Gens Combination 1	🟩	🟩	🟩	🟩	1 Peak + 2 Std	1 Std + 2 Off-Peak	1 Peak + 2 Off-Peak
Three Gens Combination 2	🟩	🟩	🟩	🟩	2 Peak + 1 Std	2 Std + 1 Off-Peak	2 Peak + 1 Off-Peak
Four Gens Combination1	🟩	🟩	🟩	🟩	1 Peak + 3 Std	1 Std + 3 Off-Peak	1 Peak + 3 Off-Peak
Four Gens Combination2	🟩	🟩	🟩	🟩	2 Peak + 2 Std	2 Std + 2 Off-Peak	2 Peak + 2 Off-Peak
Four Gens Combination3	🟩	🟩	🟩	🟩	3 Peak + 1 Std	3 Std + 1 Off-Peak	3 Peak + 1 Off-Peak
Five Gens Combination 1	🟩	🟩	🟩	🟩	1 Peak + 4 Std	1 Std + 4 Off-Peak	1 Peak + 4 Off-Peak
Five Gens Combination 2	🟩	🟩	🟩	🟩	2 Peak + 3 Std	2 Std + 3 Off-Peak	2 Peak + 3 Off-Peak
Five Gens Combination 3	🟩	🟩	🟩	🟩	3 Peak + 2 Std	3 Std + 2 Off-Peak	3 Peak + 2 Off-Peak
Five Gens Combination 4	🟩	🟩	🟩	🟩	4 Peak + 1 Std	4 Std + 1 Off-Peak	4 Peak + 1 Off-Peak

Table 3-6 above shows the permutations that were used in order to cover all possible scenarios for the income generated by the EG's per time category.

The following were used as the input parameters into the capitalisation model:

- Eskom is going to increase its tariffs by 16% for the next two years and then will increase its tariffs at CPI of 6%
- The inflationary increase of the EG operational costs is at 6% per year
- The assets can be amortised over 20 years. There will be no salvage value as it will be fully depreciated. A net present value (NPV) of 0 will be used after 20 years.
- Above 90% of the income generated will be for fuel and operations costs expect in the first two years as Eskom is getting above inflationary increases.
- The capital that can be invested in year 1 will be calculated for two minimum attractive rate of return scenarios, 5% and 7%.
- Blanks in the table are regarded as places where the boundary conditions were not fulfilled and no income or capital investment can be calculated for these scenarios.
- The technical losses for single and two generation combinations on the system will vary depending on where the generator/s is/are located. In order to derive the technical losses costs, an average of the technical losses for the different location combinations were used i.e. the technical losses for the single generator located at each of the five locations was averaged to get a single cost and the same principle also applied to when two generators was used.

Table 3-7: Financial effects of all practical combinations for EG in MV system in Rands ‘000

Fox Conductor, 4km's at 100% Peak Load						
One Gen	Eskom Income without Gen	Gen Income	Eskom Income with Gen 100% CP	Eskom Inc. with Gen 50% CP & 50%	Cap Inv - MARR - 5%	Cap Inv - MARR - 7%
All periods	R 34,610	R 7,839	R 26,771	R 26,772	R 14,250	R 12,519
Only Peak	R 16,500	R 2,723	R 13,777	R 13,769	R 4,950	R 4,349
Only Std	R 8,658	R 2,768	R 5,890	R 5,890	R 5,032	R 4,420
Only off-Peak	R 7,393	R 2,348	R 5,045	R 5,053	R 4,269	R 3,750
Peak & Std						
Std & Off-Peak						
Peak & Off-Peak						
Two Gens						
All periods						
Only Peak	R 16,498	R 5,446	R 11,052	R 11,045	R 9,900	R 8,698
Only Std	R 8,655	R 5,536	R 3,119	R 3,119	R 10,063	R 8,841
Only off-Peak						
Peak & Std	R 25,153	R 10,982	R 14,171	R 14,164	R 19,963	R 17,539
Std & Off-Peak						
Peak & Off-Peak						
Three Gens Combination 1						
All periods						
Only Peak	R 16,499	R 8,169	R 8,330	R 8,322	R 14,850	R 13,047
Only Std	R 8,656	R 8,303	R 353	R 353	R 15,095	R 13,261
Only off-Peak						
Peak & Std	R 25,156	R 8,259	R 16,897	R 16,889	R 15,013	R 13,190
Std & Off-Peak	R 16,045	R 7,464	R 8,581	R 8,590	R 13,569	R 11,921
Peak & Off-Peak	R 23,888	R 7,419	R 16,469	R 16,470	R 13,488	R 11,849
Three Gens Combination 2						
All periods						
Only Peak	R 16,499	R 8,169	R 8,330	R 8,331	R 14,850	R 13,047
Only Std	R 8,656	R 8,303	R 353	R 345	R 15,095	R 13,261
Only off-Peak						
Peak & Std	R 25,156	R 8,214	R 16,942	R 16,934	R 14,932	R 13,118
Std & Off-Peak	R 16,039	R 7,884	R 8,156	R 8,164	R 14,332	R 12,591
Peak & Off-Peak	R 23,882	R 7,794	R 16,088	R 16,089	R 14,169	R 12,448
Four Gens Combination 1						
All periods						
Only Peak						
Only Std						
Only off-Peak						
Peak & Std						
Std & Off-Peak	R 16,052	R 9,812	R 6,240	R 6,248	R 17,838	R 15,671
Peak & Off-Peak	R 23,891	R 9,768	R 14,123	R 14,124	R 17,756	R 15,600
Four Gens Combination 2						
All periods						
Only Peak						
Only Std						
Only off-Peak						
Peak & Std						
Std & Off-Peak	R 16,058	R 10,232	R 5,826	R 5,835	R 18,601	R 16,341
Peak & Off-Peak	R 23,897	R 10,142	R 13,755	R 13,756	R 18,438	R 16,198
Four Gens Combination 3						
All periods						
Only Peak						
Only Std						
Only off-Peak						
Peak & Std						
Std & Off-Peak	R 16,064	R 10,652	R 5,412	R 5,421	R 19,363	R 17,011
Peak & Off-Peak	R 23,903	R 10,517	R 13,386	R 13,387	R 19,119	R 16,797

Five Gens Combination 1						
All periods						
Only Peak						
Only Std						
Only off-Peak						
Peak & Std						
Std & Off-Peak	R 16,074	R 12,161	R 3,913	R 3,922	R 22,107	R 19,421
Peak & Off-Peak	R 23,907	R 12,116	R 11,791	R 11,792	R 22,025	R 19,350
Five Gens Combination 2						
All periods						
Only Peak						
Only Std						
Only off-Peak						
Peak & Std						
Std & Off-Peak	R 16,080	R 12,580	R 3,500	R 3,508	R 22,869	R 20,091
Peak & Off-Peak	R 23,913	R 12,491	R 11,422	R 11,423	R 22,706	R 19,948
Five Gens Combination 3						
All periods						
Only Peak						
Only Std						
Only off-Peak						
Peak & Std						
Std & Off-Peak	R 16,086	R 13,000	R 3,086	R 3,095	R 23,632	R 20,762
Peak & Off-Peak	R 23,919	R 12,865	R 11,054	R 11,054	R 23,388	R 20,547
Five Gens Combination 4						
All periods						
Only Peak						
Only Std						
Only off-Peak						
Peak & Std						
Std & Off-Peak	R 16,092	R 13,419	R 2,672	R 2,681	R 24,395	R 21,432
Peak & Off-Peak	R 23,925	R 13,240	R 10,685	R 10,685	R 24,069	R 21,146

Table 3-8 Financial effects of all practical combinations for EG in MV system in Rands '000

Fox 8km's 100% peak load						
One Gen	Eskom Income without Gen	Gen Income	Eskom Income with Gen 100% CP	Eskom Inc. with Gen 50% CP & 50% CI	Cap Inv - MARR - 5%	Cap Inv - MARR - 7%
All periods	R 34,610	R 7,839	R 26,771	R 26,732	R 14,250	R 12,519
Only Peak	R 16,500	R 2,723	R 13,777	R 13,777	R 4,950	R 4,349
Only Std	R 8,658	R 2,768	R 5,890	R 5,912	R 5,032	R 4,420
Only off-Peak	R 7,393	R 2,348	R 5,045	R 5,006	R 4,269	R 3,750
Peak & Std						
Std & Off-Peak						
Peak & Off-Peak						
Three Gens Combination 1						
All periods						
Only Peak						
Only Std	R 8,655	R 8,303	R 351	R 373	R 15,095	R 13,261
Only off-Peak						
Peak & Std						
Std & Off-Peak						
Peak & Off-Peak						
Three Gens Combination 2						
All periods						
Only Peak						
Only Std	R 8,655	R 8,303	R 351	R 373	R 15,095	R 13,261
Only off-Peak						
Peak & Std						
Std & Off-Peak						
Peak & Off-Peak						

Table 3-9 Financial effects of all practical combinations for EG in MV system in Rands '000

Fox 4km's 200% peak load						
One Gen	Eskom Income without Gen	Gen Income	Eskom Income with Gen 100% CP	Eskom Inc. with Gen 50% CP & 50% CI	Cap Inv - MARR - 5%	Cap Inv - MARR - 7%
Three Gens Combination 1						
All periods						
Only Peak						
Only Std	8,655	R 8,303	R 351	R 351	R 15,095	R 13,261
Only off-Peak						
Peak & Std						
Std & Off-Peak						
Peak & Off-Peak						
Three Gens Combination 2						
All periods						
Only Peak						
Only Std						
Only off-Peak	8,655	R 8,303	R 351	R 351	R 15,095	R 13,261
Peak & Std						
Std & Off-Peak						
Peak & Off-Peak						

Table 3-10 Financial effects of all practical combinations for EG in MV system in Rands '000

Fox 8km's 200% peak load						
	Eskom Income without Gen	Gen Income	Eskom Income with Gen 100% CP	Eskom Inc. with Gen 50% CP & 50% CI	Cap Inv - MARR - 5%	Cap Inv - MARR - 7%
Two Gens						
All periods						
Only Peak	R 16,525	R 5,446	R 11,079	R 11,040	R 9,900	R 8,698
Only Std						
Only off-Peak						
Peak & Std	R 25,156	R 10,982	R 14,175	R 14,136	R 19,963	R 17,539
Std & Off-Peak						
Peak & Off-Peak						
Three Gens Combination 1						
All periods						
Only Peak	R 16,531	R 8,169	R 8,362	R 8,323	R 14,850	R 13,047
Only Std						
Only off-Peak						
Peak & Std	R 25,156	R 8,259	R 16,898	R 16,859	R 15,013	R 13,190
Std & Off-Peak						
Peak & Off-Peak						
Three Gens Combination 2						
All periods						
Only Peak	R 16,541	R 8,169	R 8,372	R 8,333	R 14,850	R 13,047
Only Std						
Only off-Peak						
Peak & Std						
Std & Off-Peak						
Peak & Off-Peak						
Four Gens Combination 1						
All periods						
Only Peak	R 16,556	R 10,892	R 5,664	R 5,625	R 19,801	R 17,395
Only Std						
Only off-Peak						
Peak & Std						
Std & Off-Peak						
Peak & Off-Peak						
Four Gens Combination 2						
All periods						
Only Peak	R 16,561	R 10,892	R 5,669	R 5,630	R 19,801	R 17,395
Only Std						
Only off-Peak						
Peak & Std	R 25,166	R 10,982	R 14,185	R 14,146	R 19,963	R 17,539
Std & Off-Peak						
Peak & Off-Peak						

Four Gens Combination 3						
All periods						
Only Peak						
Only Std	R 16,571	R 10,892	R 5,679	R 5,640	R 19,801	R 17,395
Only off-Peak						
Peak & Std						
Std & Off-Peak	R 25,181	R 10,937	R 14,245	R 14,206	R 19,882	R 17,467
Peak & Off-Peak						
Five Gens Combination 1						
All periods						
Only Peak	R 16,581	R 13,615	R 2,927	R 2,927	R 24,751	R 21,744
Only Std						
Only off-Peak						
Peak & Std						
Std & Off-Peak						
Peak & Off-Peak						
Five Gens Combination 2						
All periods						
Only Peak	R 16,586	R 13,615	R 2,971	R 2,932	R 24,751	R 21,744
Only Std						
Only off-Peak						
Peak & Std	R 25,196	R 13,749	R 11,447	R 11,408	R 24,995	R 21,959
Std & Off-Peak						
Peak & Off-Peak						
Five Gens Combination 3						
All periods						
Only Peak	R 16,590	R 13,615	R 2,975	R 2,936	R 24,751	R 21,744
Only Std						
Only off-Peak						
Peak & Std	R 25,206	R 13,705	R 11,502	R 11,463	R 24,913	R 21,887
Std & Off-Peak						
Peak & Off-Peak						
Five Gens Combination 4						
All periods						
Only Peak	R 16,600	R 13,615	R 2,985	R 2,946	R 24,751	R 21,744
Only Std						
Only off-Peak						
Peak & Std	R 25,216	R 13,660	R 11,557	R 11,518	R 24,832	R 21,816
Std & Off-Peak						
Peak & Off-Peak						

Table 3-11 Financial effects of all practical combinations for EG in MV system in Rands '000

Hare 4km's 100% peak load						
One Gen	Eskom Income without Gen	Gen Income	Eskom Income with Gen 100% CP	Eskom Inc. with Gen 50% CP & 50% CI	Cap Inv - MARR - 5%	Cap Inv - MARR - 7%
All periods	34,613	R 7,839	R 26,774	R 26,774	R 14,250	R 12,519
Only Peak	16,499	R 2,723	R 13,776	R 13,772	R 4,950	R 4,349
Only Std	8,656	R 2,768	R 5,888	R 5,888	R 5,032	R 4,420
Only off-Peak	7,382	R 2,348	R 5,034	R 5,038	R 4,269	R 3,750
Peak & Std						
Std & Off-Peak						
Peak & Off-Peak						
Two Gens						
All periods						
Only Peak	16,498	R 5,446	R 11,052	R 11,048	R 9,900	R 8,698
Only Std	8,655	R 5,536	R 3,119	R 3,119	R 10,063	R 8,841
Only off-Peak						
Peak & Std	25,153	R 10,982	R 14,171	R 14,167	R 19,963	R 17,539
Std & Off-Peak	16,037	R 10,232	R 5,805	R 5,809	R 18,601	R 16,341
Peak & Off-Peak	23,880	R 10,142	R 13,737	R 13,737	R 18,438	R 16,198
Three Gens Combination 1						
All periods						
Only Peak	16,499	R 8,169	R 8,330	R 8,326	R 14,850	R 13,047
Only Std	8,655	R 8,303	R 352	R 352	R 15,095	R 13,261

Only off-Peak						
Peak & Std	25,154	R 8,259	R 16,895	R 16,891	R 15,013	R 13,190
Std & Off-Peak						
Peak & Off-Peak						
Three Gens Combination 2						
All periods						
Only Peak	16,499	R 8,169	R 8,330	R 8,326	R 14,850	R 13,047
Only Std	8,655	R 8,303	R 352	R 352	R 15,095	R 13,261
Only off-Peak						
Peak & Std	25,156	R 8,214	R 16,942	R 16,938	R 14,932	R 13,118
Std & Off-Peak	16,037	R 7,884	R 8,153	R 8,157	R 14,332	R 12,591
Peak & Off-Peak	23,881	R 7,794	R 16,086	R 16,086	R 14,169	R 12,448
Four Gens Combination 1						
All periods						
Only Peak	16,500	R 10,892	R 5,608	R 5,604	R 19,801	R 17,395
Only Std	8,658	R 11,071	-R 2,413	-R 2,413		R 17,682
Only off-Peak						
Peak & Std	25,158	R 11,026	R 14,131	R 14,127	R 20,045	R 17,610
Std & Off-Peak						
Peak & Off-Peak						
Four Gens Combination 2						
All periods						
Only Peak	16,500	R 10,892	R 5,608	R 5,604	R 19,801	R 17,395
Only Std	8,658	R 11,071	-R 2,413	-R 2,413		R 17,682
Only off-Peak						
Peak & Std	25,160	R 10,982	R 14,178	R 14,174	R 19,963	R 17,539
Std & Off-Peak						
Peak & Off-Peak						
Four Gens Combination 3						
All periods						
Only Peak	16,500	R 10,892	R 5,608	R 5,604	R 19,801	R 17,395
Only Std	8,658	R 11,071	-R 2,413	-R 2,413		R 17,682
Only off-Peak						
Peak & Std	25,162	R 10,937	R 14,225	R 14,221	R 19,882	R 17,467
Std & Off-Peak	16,042	R 10,652	R 5,391	R 5,395	R 19,363	R 17,011
Peak & Off-Peak	23,884	R 10,517	R 13,367	R 13,367	R 19,119	R 16,797
Five Gens Combination 1						
All periods						
Only Peak	16,502	R 13,615	R 2,886	R 2,882	R 24,751	R 21,744
Only Std	8,662	R 13,839	-R 5,177	-R 5,177		R 22,102
Only off-Peak						
Peak & Std	25,164	R 13,794	R 11,370	R 11,366	R 25,076	R 22,030
Std & Off-Peak						
Peak & Off-Peak						
Five Gens Combination 2						
All periods						
Only Peak	16,502	R 13,615	R 2,886	R 2,882	R 24,751	R 21,744
Only Std	8,662	R 13,839	-R 5,177	-R 5,177		R 22,102
Only off-Peak						
Peak & Std	25,166	R 13,749	R 11,416	R 11,412	R 24,995	R 21,959
Std & Off-Peak						
Peak & Off-Peak						
Five Gens Combination 3						
All periods						
Only Peak	16,502	R 13,615	R 2,886	R 2,882	R 24,751	R 21,744
Only Std	8,662	R 13,839	-R 5,177	-R 5,177		R 22,102
Only off-Peak						
Peak & Std	25,168	R 13,705	R 11,463	R 11,459	R 24,913	R 21,887
Std & Off-Peak						
Peak & Off-Peak						
Five Gens Combination 4						
All periods						
Only Peak	16,502	R 13,615	R 2,886	R 2,882	R 24,751	R 21,744
Only Std	8,662	R 13,839	-R 5,177	-R 5,177		R 22,102
Only off-Peak						
Peak & Std	25,170	R 13,660	R 11,510	R 11,506	R 24,832	R 21,816
Std & Off-Peak	16,051	R 13,419	R 2,631	R 2,635	R 24,395	R 21,432
Peak & Off-Peak	23,890	R 13,240	R 10,650	R 10,650	R 24,069	R 21,146

Table 3-12 Financial effects of all practical combinations for EG in MV system in Rands '000

Hare 8km's 100% peak load						
One Gen	Eskom Income without Gen	Gen Income	Eskom Income with Gen 100% CP	Eskom Inc. with Gen 50% CP & 50% CI	Cap Inv - MARR - 5%	Cap Inv - MARR - 7%
All periods	R 34,609	R 7,839	R 26,770	R 26,776	R 14,250	R 12,519
Only Peak	R 16,499	R 2,723	R 13,776	R 13,760	R 4,950	R 4,349
Only Std	R 8,657	R 2,768	R 5,889	R 5,889	R 5,032	R 4,420
Only off-Peak	R 7,383	R 2,348	R 5,035	R 5,057	R 4,269	R 3,750
Two Gens						
All periods						
Only Peak	R 16,499	R 5,446	R 11,053	R 11,037	R 9,900	R 8,698
Only Std	R 8,657	R 5,536	R 3,121	R 3,121	R 10,063	R 8,841
Only off-Peak						
Peak & Std	R 25,156	R 10,982	R 14,175	R 14,159	R 19,963	R 17,539
Std & Off-Peak	R 16,040	R 10,232	R 5,808	R 5,830	R 18,601	R 16,341
Peak & Off-Peak	R 23,883	R 10,142	R 13,740	R 13,746	R 18,438	R 16,198
Three Gens Combination 1						
Only Peak	R 16,499	R 8,169	R 8,330	R 8,314	R 14,850	R 13,047
Only Std	R 8,655	R 8,303	R 352	R 352	R 15,095	R 13,261
Only off-Peak						
Peak & Std	R 25,154	R 8,259	R 16,895	R 16,879	R 15,013	R 13,190
Three Gens Combination 2						
Only Peak	R 16,499	R 8,169	R 8,330	R 8,314	R 14,850	R 13,047
Only Std	R 8,655	R 8,303	R 352	R 352	R 15,095	R 13,261
Peak & Std						
Std & Off-Peak	R 25,156	R 8,214	R 16,942	R 16,926	R 14,932	R 13,118
Peak & Off-Peak	R 16,037	R 7,884	R 8,153	R 8,175	R 14,332	R 12,591
Four Gens Combination 1	R 23,880	R 7,794	R 16,086	R 16,092	R 14,169	R 12,448
Only Peak	R 16,499	R 10,892	R 5,607	R 5,591	R 19,801	R 17,395
Peak & Std	R 25,155	R 11,026	R 14,128	R 14,112	R 20,045	R 17,610
Four Gens Combination 2						
All periods						
Only Peak	R 16,499	R 10,892	R 5,607	R 5,591	R 19,801	R 17,395
Only Std						
Only off-Peak						
Peak & Std	R 25,157	R 10,982	R 14,175	R 14,159	R 19,963	R 17,539
Four Gens Combination 3						
All periods						
Only Peak	R 16,499	R 10,892	R 5,607	R 5,591	R 19,801	R 17,395
Only Std						
Only off-Peak						
Peak & Std	R 25,159	R 10,937	R 14,222	R 14,206	R 19,882	R 17,467
Std & Off-Peak	R 16,038	R 10,652	R 5,387	R 5,409	R 19,363	R 17,011
Peak & Off-Peak	R 23,881	R 10,517	R 13,364	R 13,370	R 19,119	R 16,797
Five Gens Combination 3						
Peak & Std	R 23,882	R 13,705	R 10,178	R 10,162	R 24,913	R 21,887
Five Gens Combination 4						
Peak & Std	R 23,884	R 13,660	R 10,224	R 10,208	R 24,832	R 21,816
Std & Off-Peak	R 16,040	R 13,419	R 2,620	R 2,642	R 24,395	R 21,432
Peak & Off-Peak	R 23,882	R 13,240	R 10,642	R 10,648	R 24,069	R 21,146

Table 3-13 Financial effects of all practical combinations for EG in MV system in Rands ‘000

Hare 4km's 200% peak load						
One Gen	Eskom Income without Gen	Gen Income	Eskom Income with Gen 100% CP	Eskom Inc. with Gen 50% CP & 50% CI	Cap Inv - MARR - 5%	Cap Inv - MARR - 7%
All periods	R 34,625	R 7,839	R 26,786	R 26,778	R 14,250	R 12,519
Only Peak	R 16,502	R 2,723	R 13,779	R 13,767	R 4,950	R 4,349
Only Std	R 8,663	R 2,768	R 5,896	R 5,896	R 5,032	R 4,420
Only off-Peak	R 7,390	R 2,348	R 5,042	R 5,046	R 4,269	R 3,750
Two Gens						
Only Peak	R 16,500	R 5,446	R 11,054	R 11,042	R 9,900	R 8,698
Only Std	R 8,658	R 5,536	R 3,123	R 3,123	R 10,063	R 8,841
Peak & Std	R 25,158	R 10,982	R 14,177	R 14,165	R 19,963	R 17,539
Std & Off-Peak	R 16,043	R 10,232	R 5,811	R 5,815	R 18,601	R 16,341
Peak & Off-Peak	R 23,885	R 10,142	R 13,742	R 13,734	R 18,438	R 16,198
Three Gens Combination 1						
Only Peak	R 16,498	R 8,169	R 8,329	R 8,317	R 14,850	R 13,047
Only Std	R 8,655	R 8,303	R 351	R 351	R 15,095	R 13,261
Peak & Std	R 25,153	R 8,259	R 16,894	R 16,882	R 15,013	R 13,190
Three Gens Combination 2						
Only Peak	R 16,498	R 8,169	R 8,317	R 8,317	R 14,850	R 13,047
Only Std	R 8,655	R 8,303	R 351	R 351	R 15,095	R 13,261
Only off-Peak						
Peak & Std	R 25,155	R 8,214	R 16,941	R 16,929	R 14,932	R 13,118
Std & Off-Peak	R 25,153	R 7,884	R 17,269	R 17,273	R 14,332	R 12,591
Peak & Off-Peak	R 23,880	R 7,794	R 16,085	R 16,077	R 14,169	R 12,448
Four Gens Combination 1						
Only Peak	R 16,499	R 10,892	R 5,607	R 5,595	R 19,801	R 17,395
Only Std	R 8,655	R 11,071	-R 2,416	-R 2,416		R 17,682
Only off-Peak						
Peak & Std	R 25,154	R 11,026	R 14,127	R 14,115	R 20,045	R 17,610
Four Gens Combination 2						
Only Peak	R 16,499	R 10,892	R 5,607	R 5,595	R 19,801	R 17,395
Only Std	R 8,655	R 11,071	-R 2,416	-R 2,416		R 17,682
Peak & Std	R 25,156	R 10,982	R 14,174	R 14,162	R 19,963	R 17,539
Four Gens Combination 3						
All periods						
Only Peak	R 16,499	R 10,892	R 5,607	R 5,595	R 19,801	R 17,395
Only Std	R 8,655	R 11,071	-R 2,416	-R 2,416		R 17,682
Peak & Std	R 25,158	R 10,937	R 14,221	R 14,209	R 19,882	R 17,467
Std & Off-Peak	R 16,037	R 10,652	R 5,385	R 5,389	R 19,363	R 17,011
Peak & Off-Peak	R 23,880	R 10,517	R 13,363	R 13,355	R 19,119	R 16,797
Five Gens Combination 1						
All periods						
Only Peak	R 16,498	R 13,615	R 2,871	R 2,871	R 24,751	R 21,744
Only Std	R 8,655	R 13,839	-R 5,184	-R 5,184		R 22,102
Only off-Peak						
Peak & Std	R 25,153	R 13,794	R 11,347	R 11,347	R 25,076	R 22,030
Five Gens Combination 2						
All periods						
Only Peak	R 16,498	R 13,615	R 2,883	R 2,871	R 24,751	R 21,744
Only Std	R 8,655	R 13,839	-R 5,184	-R 5,184		R 22,102
Only off-Peak						
Peak & Std	R 25,153	R 13,794	R 11,359	R 11,347	R 25,076	R 22,030
Five Gens Combination 3						
All periods						
Only Peak	R 16,498	R 13,615	R 2,883	R 2,871	R 24,751	R 21,744
Only Std	R 8,655	R 13,839	-R 5,184	-R 5,184		R 22,102
Only off-Peak						
Peak & Std	R 25,157	R 13,705	R 11,452	R 11,440	R 24,913	R 21,887
Five Gens Combination 4						
Only Peak	R 16,498	R 13,615	R 2,883	R 2,871	R 24,751	R 21,744
Only Std	R 8,655	R 13,839	-R 5,184	-R 5,184		R 22,102
Peak & Std	R 25,159	R 13,660	R 11,499	R 11,487	R 24,832	R 21,816
Std & Off-Peak	R 16,036	R 13,419	R 2,616	R 2,620	R 24,395	R 21,432
Peak & Off-Peak	R 23,880	R 13,240	R 10,639	R 10,631	R 24,069	R 21,146

Table 3-14 Financial effects of all practical combinations for EG in MV system in Rands '000

Hare 8km's 200% peak load						
One Gen	Eskom Income without Gen	Gen Income	Eskom Income with Gen 100% CP	Eskom Inc. with Gen 50% CP & 50% CI	Cap Inv - MARR - 5%	Cap Inv - MARR - 7%
Only off-Peak	R 7,402	R 2,348	R 5,054	R 5,067	R 4,269	R 3,750
Two Gens						
Only Peak	R 16,506	R 5,446	R 11,060	R 11,040	R 9,900	R 8,698
Only Std	R 8,673	R 5,536	R 3,138	R 3,138	R 10,063	R 8,841
Peak & Std	R 25,179	R 10,982	R 14,198	R 14,191	R 19,963	R 17,539
Std & Off-Peak	R 16,073	R 10,232	R 5,841	R 5,854	R 18,601	R 16,341
Peak & Off-Peak	R 23,906	R 10,142	R 13,764	R 13,757	R 18,438	R 16,198
Three Gens Combination 1						
Only Peak	R 16,502	R 8,169	R 8,333	R 8,313	R 14,850	R 13,047
Only Std	R 8,662	R 8,303	R 359	R 359	R 15,095	R 13,261
Std & Off-Peak	R 16,051	R 7,464	R 8,587	R 8,600	R 13,569	R 11,921
Peak & Off-Peak	R 23,890	R 7,419	R 16,471	R 16,464	R 13,488	R 11,849
Three Gens Combination 2						
Only Peak	R 16,502	R 8,169	R 8,333	R 8,313	R 14,850	R 13,047
Only Std	R 8,662	R 8,303	R 359	R 359	R 15,095	R 13,261
Std & Off-Peak	R 16,053	R 7,884	R 8,169	R 8,182	R 14,332	R 12,591
Peak & Off-Peak	R 23,892	R 7,794	R 16,098	R 16,091	R 14,169	R 12,448
Four Gens Combination 1						
Only Peak	R 16,498	R 10,892	R 5,606	R 5,586	R 19,801	R 17,395
Only Std	R 8,655	R 11,071	-R 2,417	-R 2,417		R 17,682
Only off-Peak						
Peak & Std	R 25,153	R 11,026	R 14,127	R 14,120	R 20,045	R 17,610
Four Gens Combination 2						
All periods						
Only Peak	R 16,498	R 10,892	R 5,606	R 5,586	R 19,801	R 17,395
Only Std	R 8,655	R 11,071	-R 2,417	-R 2,417		R 17,682
Only off-Peak						
Peak & Std	R 25,155	R 10,982	R 14,173	R 14,166	R 19,963	R 17,539
Four Gens Combination 3						
All periods						
Only Peak	R 16,498	R 10,892	R 5,606	R 5,586	R 19,801	R 17,395
Only Std	R 8,655	R 11,071	-R 2,417	-R 2,417		R 17,682
Only off-Peak						
Peak & Std	R 25,157	R 10,937	R 14,220	R 14,213	R 19,882	R 17,467
Std & Off-Peak	R 16,036	R 10,652	R 5,384	R 5,397	R 19,363	R 17,011
Peak & Off-Peak	R 23,880	R 10,517	R 13,362	R 13,355	R 19,119	R 16,797
Five Gens Combination 1						
Only Peak	R 16,499	R 13,615	R 2,864	R 2,864	R 24,751	R 21,744
Only Std	R 8,656	R 13,839	-R 5,183	-R 5,183		R 22,102
Peak & Std	R 25,155	R 13,794	R 11,354	R 11,354	R 25,076	R 22,030
Five Gens Combination 2						
Only Peak	R 16,499	R 13,615	R 2,864	R 2,864	R 24,751	R 21,744
Only Std	R 8,656	R 13,839	-R 5,183	-R 5,183		R 22,102
Peak & Std	R 25,156	R 13,749	R 11,399	R 11,399	R 24,995	R 21,959
Five Gens Combination 3						
Only Peak	R 16,499	R 13,615	R 2,884	R 2,864	R 24,751	R 21,744
Only Std	R 8,656	R 13,839	-R 5,183	-R 5,183		R 22,102
Only off-Peak						
Peak & Std	R 25,155	R 13,794	R 11,361	R 11,354	R 25,076	R 22,030
Five Gens Combination 4						
Only Peak	R 16,499	R 13,615	R 2,884	R 2,864	R 24,751	R 21,744
Only Std	R 8,656	R 13,839	-R 5,183	-R 5,183		R 22,102
Peak & Std	R 25,157	R 13,660	R 11,497	R 11,490	R 24,832	R 21,816
Std & Off-Peak	R 16,038	R 13,419	R 2,619	R 2,632	R 24,395	R 21,432
Peak & Off-Peak	R 23,881	R 13,240	R 10,641	R 10,634	R 24,069	R 21,146

Table 3.15 Levelised cost for the different system configurations in Rands '000

System Configuration	Statistic	MARR 5%	MARR 7%
Fox Conductor, 4kms 100% Peak Load	Max R'000/MW	R 5,700	R 5,008
	Min R'000/MW	R 1,707	R 3,508
	Avg R'000/MW	R 2,087	R 1,834
Fox Conductor, 8kms 100% peak load	Max R'000/MW	R 5,700	R 5,008
	Min R'000/MW	R 1,707	R 1,500
	Avg R'000/MW	R 2,571	R 2,259
Fox Conductor, 4kms 200% peak load	Max R'000/MW	R 2,013	R 1,768
	Min R'000/MW	R 2,013	R 1,768
	Avg R'000/MW	R 2,013	R 1,768
Fox Conductor 4kms 200% peak load	Max R'000/MW	R 3,993	R 3,508
	Min R'000/MW	R 1,591	R 1,397
	Avg R'000/MW	R 2,080	R 1,827
Hare Conductor 4kms 100% peak load	Max R'000/MW	R 5,700	R 5,008
	Min R'000/MW	R 1,707	R 1,500
	Avg R'000/MW	R 2,232	R 1,929
Hare Conductor 8kms 100% peak load	Max R'000/MW	R 5,700	R 5,008
	Min R'000/MW	R 1,707	R 1,500
	Avg R'000/MW	R 2,283	R 2,006
Hare Conductor 4kms 200% peak load	Max R'000/MW	R 5,700	R 5,008
	Min R'000/MW	R 1,707	R 1,500
	Avg R'000/MW	R 2,232	R 1,929
Hare Conductor 8kms 200% peak load	Max R'000/MW	R 3,993	R 3,508
	Min R'000/MW	R 1,707	R 1,500
	Avg R'000/MW	R 2,127	R 1,850

For a Fox conductor system, the overall network reach is increased with EG but a very high switching configuration would be needed from the generator in order to stick to the times of operation. The times of operation would be split into peak, standard and off-peak as per Figure 2-1. Invariably, the highest volume of generation will always lead to the highest amount of capital that can be raised. However, as per table 3-15, the per unit cost, or levelised cost per MW (rand per MW), indicates that the highest capital can be raised from the least amount of generators operating on the system. In order to have economies of scale benefit, these generator stations should be owned and operated by single entities in order to maximum investment capability. However it is not always practical to have the stations owned by single entities. There would be high competition in becoming the first operator in the system and locking in a contract for as many time periods as possible. Entry of new participants will then see a decrease in the amount of operating time available and hence the amount of seed capital than can be raised. There are currently not enough regulations around these values and significant disputes could arise once operation has begun, without formal network contracting. Multiple generation sets that operate in various time sectors are exposed to network performance issues. The performance of the network was not factored into the calculation but will materially affect the predictability of the profit margin. The yearly planned and unplanned outage performance of the network for the Utility is about 47.5 hours [3] but this could affect operating profit by more than 5%-10% for Fox networks because of the low time penetration of EG. The closer a Fox network is to its operating voltage margin the lower the volume of sustainable generation. Even with the correct operating condition it is still not possible to secure enough capital for a generation scheme and achieve a minimum MARR of 5% when the values in table 25 is compared to the actual values required in Appendix B. This means that it is not possible to fund new generation assets at the Utilities system marginal price and a capital subsidy would be needed in order to make medium voltage EG projects economically viable.

The impact of having a high volume of non-technical losses affects the overall margin that is available to EG's. The cost impact of non-technical losses as a result of modelling some of the load as a constant current load, compared to that if the conventional constant Power load, varies on the time pattern that is used for the EG and the related improvement in voltage parameters. The actual cost impact varies within a small range extending from +R9000 to –R7000 and this can be seen from the difference between columns "Eskom income with generators and 100% constant power (CP)" and "Eskom income with generators and load classified as 50% constant power (CP) and 50% constant current (CI)" in Figures, 3-18, 3-19, 3-20 and 3-21. This impact should also be factored into the apportionment of technical losses savings to the EG. It can be seen from Tables 3-11, 3-13, 3-14 that the income to the Utility goes negative for some combinations, implying that the Utility is paying more money to the EGs than what it is making from the sales of billed customers. There would therefore also have to be a minimum threshold of non-technical losses on the system before a Utility can allow high penetration of EG into an MV system.

The highest number of permutations that are available to the EG's comes from a network that is loaded to its maximum reach in voltage performance. For the Fox network, there were 31/88 (31 out of 88) permutations when it is close to its voltage regulation limit, without any Generators. This is significantly different when the network depends on EG operating, in order for the network to be within its voltage limits. The number of permutations decrease to 7/88 and 8/88 for a network that doubles it length for same load volume and for a network that doubles its peak load value.

For a Hare conductor network the length of time for operation as well as the number of generators that can be added to the network significantly improves from that of the Fox conductor network. When a network is performing higher than its operating voltage limit, it is able to have significantly more number of permutations of EG. The number of permutations varies from 42/88 for a non-optimally loaded system to 29/88 for an optimally distributed load pattern. This means that there can be significantly more stable financial conditions, for capital investment and recovery for a Hare conductor network. The effect of load composition is much greater in a Hare network because of the higher number of permutations of operation. The cost effect of having 50% constant current loads instead of 100% constant power loads results in a maximum and minimum range from R 22,000 to – R 12,000 and this can be seen from the difference between columns "Eskom income with generators and 100% constant power (CP)" and "Eskom income with generators and load classified as 50% constant power (CP) and 50% constant current (CI)" in Figures, 3-7 to 3-14. Improving the system capability for EG, also creates the negative effect on increasing costs related to non-recovery of sales. The technical losses savings as a result of EG is also significantly lower than that of Fox conductor.

Should the spare capacity created by the EG be attributed to new load, with long term fixed operating time contracts for EG, the upper limit of connecting new customers would decrease significantly i.e. there would be a limitation on the amount of new load customers that can be connected. This situation would then warrant the introduction of voltage control devices dispersed in the network. This only becomes relevant when the network is operating at or beyond its voltage boundary condition.

4. CONCLUSIONS AND RECOMMENDATIONS

The primary aim of this dissertation was determining the financial impact of EG on medium voltage distribution systems. This was achieved by first providing a detailed breakdown of the types of loads supplied in power systems and associated tariffs to these loads. Analysis was then performed on the energy losses effect with EG penetration and the level of operational flexibility provided with various EG locations in the networks.

EG does decrease the technical energy losses in the medium voltage distribution system but when the generation amount is greater than 60% of the peak load carrying capacity of the system, the technical losses increase. This is applicable to both Fox conductor and Hare conductor systems. EG improves the overall voltage regulation and load carrying capacity of MV systems. For systems that require at least 10% of EG volume compared to the peak load capacity on the system, to remain within voltage regulation limits, energy losses is only decreased, as long as the EG volume remains lower than 50% of the peak load capacity of the system. The off-peak condition when there is low load available restricts the number, volume and dispersion of EGs that the system can have without going exceeding voltage regulation limits. This limits the operational time and amount of EG that a system can incorporate and reduces the EG financial operating flexibility.

High non-technical losses result in a lower gross contribution percentage which means that there was smaller capacity available for EGs connected to a network and which were not producing significantly lower capital deferral benefits from the capacity created. This contradicts the operational flexibility of the network, in terms of EG permutations available, which has a higher volume available when the network is not operating near to its voltage regulation limit. This contradiction can be addressed by addressing the amount of non-technical energy that is not converted to sales income or by increasing the average tariff for the customer supplied.

The penetration limits of EG can be as high as 60% of the load carrying capacity of the network and dispersion of the EG along the length of the system achieves the best performance in energy loss reduction and voltage regulation in peak period operation. The penetration limit decreases significantly to 20% when the network is near to its voltage limits in normal operation.

The cost of energy losses on radial networks exhibits “U curve” type behaviour where there is a decrease in energy losses for 20% of generation penetration, almost no technical losses for 40% penetration and then an increase in energy losses once the EG volume is greater than 60%. There is a greater energy savings for higher impedance networks or networks that are operating close to its voltage limits, without EG but the number of permutations available to the network is limited. These high impedance networks also exhibit higher energy losses when the power flows are reversed.

The effect of EG on loads that are modelled as constant current type loads, typical for that of non-technical losses, results in very small financial changes for higher impedance systems but larger changes for lower impedance systems. The primary reason for this is that lower impedance systems have much higher time based permutations of generation combinations, available within the voltage limit boundaries. This negative financial effect is a pass through to the Utility which leads to a decrease in the gross financial contribution. Although the negative effect of this is compensated for by reduction in non-technical losses, the most efficient way to maintain financial stability would be to convert the non-technical losses into sales. Without decreasing the amount of non-technical losses the margin that can be attributed to EG's, for load loss savings, is very small. This implies that the higher the penetration of EG, without an increasing customer base, or above inflation tariff increases, or Government subsidies, will result in a material change to the SMP.

Systems, without EG, that are operated very close to the operating voltage limit boundaries have the lowest yield in the number of generation location and time based permutations. Higher yield in the number of permutations that are physically possibly without contravening the system limits, result in higher number of capital investment possibilities i.e. generators can be operated closer to their full capability and for longer periods. The highest yield situation results in approximately R5Million per MW investment potential with a yield of 5% MARR per year. This capitalised value is not sufficient to justify the investment at the system marginal price to install expensive renewable energy technologies. In this dissertation 90% of income derived was spent on operations, maintenance and fuel, but for renewable technologies, this combined cost is not as high as those that need engines and turbo alternators, but even if 10% of the cost was associated to the expenses required for running the technology, it would still not be able to pay for the installation costs of the renewable energy technology. Subsidisation of the tariff received by the independent EGs would be a means to ensure that competition in this sector could be introduced but overall cost recovery mechanisms will result in higher tariffs for load customers. It is therefore critical that the market regulations have to be in place first else unrestricted competition could sterilise the network from new load customer connections. The correction of the system will have to be done with significant capital strengthening investment.

EG results in many positive effects on the network and can be operated in way that results in improvement on system performance and cost efficiencies, however subsidisation with careful and well-structured regulations and management of EG is needed in order to ensure that the system can be operated and managed without negative effects to the customer load base. It is recommended that the best practise regulation for EG should include, but not be limited to, some of the following criteria:

- Simple and transparent rules for connection, cost recovery and incremental energy loss apportionment.
- Only shallow charges to be used as the system average cost recovery is a better method to recover upstream costs.
- Use of system charges need to be developed differentiated by voltage, location and time of use.

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Appendix A: Edendale Imbali metered energy statistics

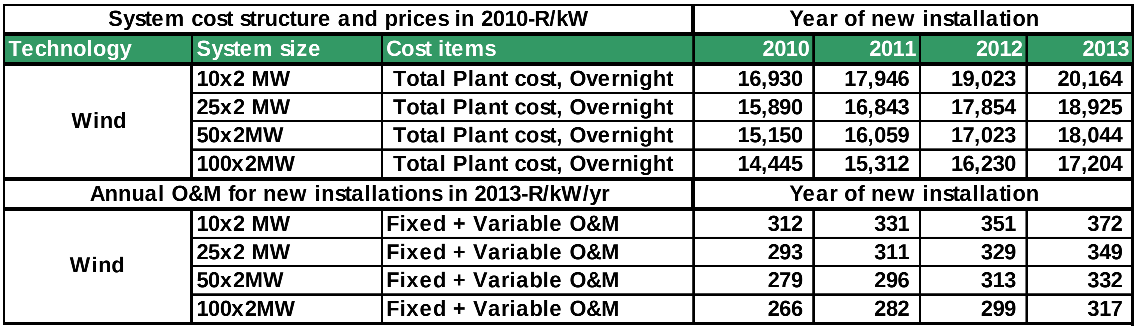
Account Month	Energy Delivered	LPU Cust With kWh	LPU Cust NO kWh	LPU kWh	PPU Cust With kWh	PPU Cust NO kWh	PPU kWh	SPU Cust With kWh	SPU Cust NO kWh	SPU kWh	UNA	Total Sales	Tech Loss %	Tech Loss kWh	ED Less Tech Loss	Non Tech Loss kWh	Non Tech Loss %	Total Cust	Ave PPU c/kWh	Ave Rand Loss
2011/06	24,892,056	9	3	1,525,530	9,138	39,252	2,060,393	2,594	283	2,259,281	953,524	6,798,728	0.10	2,489,206	22,402,850	15,604,122	**62.69%**	51,279	0.6585	R 10,274,794.31
2011/07	27,953,184	10	2	1,790,066	9,295	39,177	2,067,298	2,591	295	2,273,332	671,894	6,802,590	0.10	2,795,318	25,157,865	18,355,276	**65.66%**	51,370	0.6585	R 12,086,337.11
2011/08	25,275,356	10	2	1,862,374	9,507	39,199	2,276,220	2,616	272	2,447,204	643,964	7,229,762	0.10	2,527,536	22,747,820	15,518,058	**61.40%**	51,606	0.6585	R 10,218,124.12
2011/09	20,490,837	11	1	1,747,753	9,512	40,054	1,825,090	2,628	269	2,460,627	873,943	6,907,413	0.10	2,049,084	18,441,753	11,534,340	**56.29%**	52,475	0.6585	R 7,594,978.58
2011/10	21,183,187	12	0	2,678,859	10,220	39,514	2,129,868	2,640	269	2,235,568	799,639	7,843,933	0.10	2,118,319	19,064,869	11,220,935	**52.97%**	52,655	0.6585	R 7,388,611.85
2011/11	19,997,923	12	0	2,549,929	10,818	39,179	2,483,639	2,638	264	2,033,205	890,657	7,957,430	0.10	1,999,792	17,998,131	10,040,701	**50.21%**	52,911	0.6585	R 6,611,467.00
2011/12	17,869,666	12	0	2,314,515	10,790	39,380	2,310,192	2,611	282	1,974,573	984,725	7,584,005	0.10	1,786,967	16,082,699	8,498,694	**47.56%**	53,075	0.6585	R 5,596,106.99
2012/01	17,377,784	12	0	2,442,541	11,209	39,129	2,396,958	2,621	282	2,050,992	916,690	7,807,181	0.10	1,737,778	15,640,006	7,832,825	**45.07%**	53,253	0.6585	R 5,157,654.01
2012/02	17,137,526	11	0	2,592,385	11,322	39,349	2,275,494	2,620	279	1,968,747	906,316	7,742,941	0.10	1,713,753	15,423,773	7,680,832	**44.82%**	53,581	0.6585	R 5,057,572.02
2012/03	18,529,278	11	0	3,221,844	11,681	39,195	2,415,692	2,617	280	1,965,921	966,335	8,569,792	0.10	1,852,928	16,676,350	8,106,558	**43.75%**	53,784	0.6585	R 5,337,898.17
2012/04	19,101,572	11	0	2,331,184	11,601	39,332	2,441,526	2,606	270	2,075,910	966,335	7,814,955	0.10	1,910,157	17,191,415	9,376,459	**49.09%**	53,820	0.6585	R 6,174,085.97
2012/05	21,618,936	11	0	2,557,983	11,727	39,271	2,488,533	2,615	281	2,161,374	926,955	8,134,844	0.10	2,161,894	19,457,043	11,322,198	**52.37%**	53,905	0.7180	R 8,129,338.47
2012/06	25,334,899	11	0	2,435,753	11,797	39,335	2,496,465	2,620	281	2,382,731	963,172	8,278,121	0.10	2,533,490	22,801,409	14,523,288	**57.33%**	54,044	0.7180	R 10,427,720.94
2012/07	25,753,897	11	0	2,357,536	11,919	39,281	2,614,755	2,610	280	2,107,207	897,610	8,017,944	0.10	2,575,390	23,178,507	15,160,563	**58.87%**	54,101	0.7180	R 10,885,284.35
2012/08	25,159,914	11	0	2,606,088	11,855	39,484	2,593,232	2,606	279	2,290,526	938,446	8,428,292	0.10	2,515,991	22,643,923	14,215,631	**56.50%**	54,235	0.7180	R 10,206,822.82
2012/09	22,996,050	11	0	2,457,138	11,917	39,528	2,396,362	2,591	278	2,268,967	936,386	8,058,853	0.10	2,299,605	20,696,445	12,637,592	**54.96%**	54,325	0.7180	R 9,073,790.98
12mma	21,005,053	11	0	2,545,480	11,405	39,331	2,420,226	2,616	277	2,126,310	924,439	8,019,858	0.10	2,100,505	18,904,547	10,884,690	**51.82%**	53,641	0.7180	R 7,815,207.27

Appendix B: Cost per kW for various grid connected technologies [2]

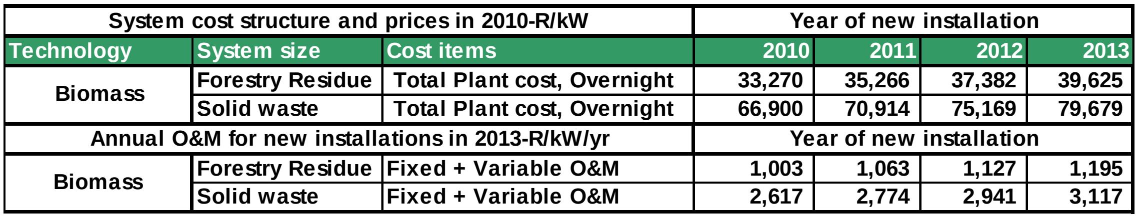
System cost structure and prices in 2010-$/Wp			Year of new installation			
Technology	System size	Cost items	2010	2011	2012	2013
PV Crystalline	0.25 MW	System price	3.58	3.27	2.97	2.74
	1.0 MW	System price	2.89	2.65	2.40	2.22
	10.0 MW	System price	2.81	2.57	2.33	2.16
PV Thin film	0.25 MW	System price	3.23	2.90	2.57	2.41
	1.0 MW	System price	2.62	2.35	2.08	1.95
	10.0 MW	System price	2.54	2.28	2.02	1.89
Annual O&M for new installations in 2010-$/Wp/yr			Year of new installation			
Crystalline and thin film	0.25 MW	O&M	0.036	0.034	0.031	0.029
	1.0 MW	O&M	0.029	0.027	0.025	0.024
	10.0 MW	O&M	0.028	0.026	0.025	0.023
System cost structure and prices in 2013-R/Wp			Year of new installation			
Technology	System size	Cost items	2010	2011	2012	2013
Crystalline	0.25 MW	System price	32.90	30.11	27.32	25.23
	1.0 MW	System price	26.63	24.37	22.11	20.44
	10.0 MW	System price	25.87	23.67	21.48	19.86
Thin film	0.25 MW	System price	29.75	26.70	23.65	22.13
	1.0 MW	System price	24.08	21.61	19.15	17.94
	10.0 MW	System price	23.39	20.99	18.60	17.42
Annual O&M for new installations in 2013-R/Wp/yr			Year of new installation			
Crystalline and thin film	0.25 MW	O&M	0.329	0.309	0.287	0.271
	1.0 MW	O&M	0.266	0.250	0.232	0.220
	10.0 MW	O&M	0.259	0.243	0.226	0.213

System cost structure and prices in 2010-R/kW			Year of new installation			
Technology	System size	Cost items	2010	2011	2012	2013
Pulverized Coal	2x750MW	Total Plant cost, Overnight	16,880	17,893	18,966	20,104
	7x750MW	Total Plant cost, Overnight	16,025	16,987	18,006	19,086
	6x750MW	Total Plant cost, Overnight	15,470	16,398	17,382	18,425
Annual O&M for new installations in 2013-R/kW/yr			Year of new installation			
Pulverized Coal	2x750MW	Fixed + Variable O&M	415	440	467	495
	7x750MW	Fixed + Variable O&M	396	420	445	472
	6x750MW	Fixed + Variable O&M	384	407	432	458

System cost structure and prices in 2010-R/kW			Year of new installation			
Technology	System size	Cost items	2010	2011	2012	2013
IGCC	Two 2x2x1 MW	Total Plant cost, Overnight	24,670	26,150	27,719	29,382
Annual O&M for new installations in 2013-R/kW/yr			Year of new installation			
IGCC	6x750MW	Fixed + Variable O&M	844	895	949	1,006



System cost structure and prices in 2010-R/kW			Year of new installation			
Technology	**System size**	**Cost items**	**2010**	**2011**	**2012**	**2013**
Wind	10x2 MW	Total Plant cost, Overnight	16,930	17,946	19,023	20,164
	25x2 MW	Total Plant cost, Overnight	15,890	16,843	17,854	18,925
	50x2MW	Total Plant cost, Overnight	15,150	16,059	17,023	18,044
	100x2MW	Total Plant cost, Overnight	14,445	15,312	16,230	17,204
Annual O&M for new installations in 2013-R/kW/yr			**Year of new installation**			
Wind	10x2 MW	Fixed + Variable O&M	312	331	351	372
	25x2 MW	Fixed + Variable O&M	293	311	329	349
	50x2MW	Fixed + Variable O&M	279	296	313	332
	100x2MW	Fixed + Variable O&M	266	282	299	317



System cost structure and prices in 2010-R/kW			Year of new installation			
Technology	**System size**	**Cost items**	**2010**	**2011**	**2012**	**2013**
Biomass	Forestry Residue	Total Plant cost, Overnight	33,270	35,266	37,382	39,625
	Solid waste	Total Plant cost, Overnight	66,900	70,914	75,169	79,679
Annual O&M for new installations in 2013-R/kW/yr			**Year of new installation**			
Biomass	Forestry Residue	Fixed + Variable O&M	1,003	1,063	1,127	1,195
	Solid waste	Fixed + Variable O&M	2,617	2,774	2,941	3,117

These costs were obtained from the Power Generation Technology Data for Integrated Resource Plan of South Africa [4] The plan was developed in 2010 and an inflation rate of 6% per year was used to get an indication of present values. The rand to dollar rate of R9.2 to $1 was used for the PV technology.

Appendix C: Definitions of terms

1) ‘Bulk supply’ means a single point of supply to an intermediate distributor
2) ‘Capital cost’ means the expenditure on plant, equipment and other resources required in order to provide capacity.
3) ‘Energy recovery’ means the net change in electrical energy in a system as a result of physical or management changes implemented for that system.
4) ‘F-CI’ means for a fox network and where the 50% of the domestic load is modeled as constant current
5) ‘F-CP’ means for a fox network and where the 50% of the domestic load is modeled as constant power
6) ‘F-CZ’ means for a fox network and where the 50% of the domestic load is modeled as constant impedance
7) ‘H-CI’ means for a hare network and where the 50% of the domestic load is modeled as constant current
8) ‘H-CP’ means for a hare network and where the 50% of the domestic load is modeled as constant power
9) ‘H-CZ’ means for a hare network and where the 50% of the domestic load is modeled as constant impedance
10) ‘LPU’ means large power user where metered data is measured in 30 (thirty) minute integrating periods at the Point(s) of Supply, the user has a demand greater than 25kVA and is on a tariff that classifies the user as a LPU.
11) ‘Maximum Export Capacity’ means the maximum capacity measured in 30 (thirty) minute integrating periods at the Point(s) of Supply notified by the CUSTOMER in terms of Clause 14 and accepted by ESKOM for the transmission of electrical energy between the Facility and the Distribution System.
12) ‘Meters’ shall be the meter(s) and the fittings, equipment, wiring and installations related to the meter(s) at the Point of utility connection.
13) ‘Month’ means a calendar month comprising a period commencing at 00:00 on the first day of that month and ending at 23:59 on the last day of that month.
14) ‘NERSA’ means the National Energy Regulator of South Africa established in terms of the National Energy Regulator Act, (Act No. 4 of 2004), or its legal successor
15) ‘NRS 048’ means the quality of supply specification issued by the South African Bureau of Standards, as revised from time to time or as replaced by a national standard.
16) ‘Point of Utility Connection (PUC)’ means one or more circuit-breakers and associated ancillary equipment (instrument transformers, protection, isolators), entirely independent of any PGC, that connects the Facility to the ESKOM network
17) ‘PPA’ means, if any, the power purchase agreement between the CUSTOMER as Seller and ESKOM as Buyer, in respect of the sale and purchase of metered deliveries of electrical energy generated by the Facility
18) ‘PPU’ means
19) ‘REPO’ means the “discount rate at which a central bank repurchases government securities from the commercial banks, depending on the level of money supply it decides to maintain in the country's monetary system. To temporarily expand the money supply, the central bank decreases repo rates (so that banks can swap their holdings of

government securities for cash). To contract the money supply it increases the repo rates. Alternatively, the central bank decides on a desired level of money supply and lets the market determine the appropriate repo rate. Repo is short for repossession." [http://www.businessdictionary.com/definition/repo-rate.html]

20) 'SMP' means the price at which energy is generated inclusive of all costs necessary for the energy to be produced and delivered.
21) 'SPU' means a small power user, where a meters consumption is read and captured on the billing system for the purpose of generating a bill
22) 'Synchronise' means the act of closing of a circuit breaker so as to bring the Distribution System, and the Facility into synchronism with respect to voltage magnitude, phase relationship and frequency.
23) 'System limits' means the statutory limits for MV system operation
24) 'Tariff' means a combination of charging parameters applied to recover measured quantities such as consumption and capacity costs, as well as an unmeasured quantities such as service costs.
25) 'Time of use tariff' means an LPU TOU tariff with energy charges that change during different time of use periods and seasons
26) 'Technical losses' means the energy losses in an electrical system that occur as a result of the flow of current in that system (copper and iron losses)
27) 'TOU periods' means time blocks based on volume of electricity demand during high, mid and low demand periods and may differ per tariff. The TOU periods typically are peak, standard and off-peak and differ during high and low demand seasons. This is further explained in the main dissertation.