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THE IMPACT OF DISTRIBUTED GENERATION ON TRANSMISSION PRICES IN SOUTH AFRICA

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DECLARATION

I declare that this thesis is my own, unaided work. It is submitted in fulfilment of the requirements for the degree of Master of Science (Electrical Engineering) at the University of Cape Town. It has not been submitted before for any degree or examination in any other university.

Signature…………………………… Date……………………………

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EXECUTIVE SUMMARY

This research project investigates the impact of distributed generation on transmission prices in South Africa.

The main objective of this research was to predict the effect on the transmission prices in South Africa of connecting distributed generators. The steps towards achieving this objective included obtaining an understanding of the correlation between distributed generation and transmission pricing through an extensive literature survey, identifying existing distributed generators in terms of their nature and size, and assessing the existing and proposed transmission pricing methods in South Africa. These were used in identifying technical aspects of transmission that are likely to change with distributed generation and in comparing the benefits of DG and Eskom's transmission tariffs, to finally predict the impact of DG on the transmission costs and tariff components.

A definition of distributed generation as utilised by various authors was presented in the literature review. Various technologies and applications of distributed generation were identified. The review revealed that DG is emerging today mainly due to regulatory changes, power system deficiencies, price increases, and technology advances. The application of distributed generation leads to benefits to both the utility and the customer. These include increased power reliability, improved power quality, reduced transmission and distribution electric losses, avoided increases in system capacity, peak shaving etc. Regardless of the numerous advantages, a few disadvantages were also identified and potential problems include instability, islanding and reverse power flow in the system.

The common principles on which transmission pricing is based were identified. These include promoting efficient day-to-day operation of the power system, encouraging investment and determining location of generation, compensating owners of the transmission assets, and transparency. The pricing options used in the United States of America (USA), such as postage stamp, contract path, megawatt-mile, and congestion pricing make use of some of these principles. Other pricing methods like open access and bottom-up pricing are also based on these principles. Botom-up

pricing refers to the process of building up transmission prices from each of the cost element. These elements are costs of building capacity including sunk costs, marginal losses, and congestion etc.

The history of the South African power industry shows that before the formation of the national utility (Eskom) in 1923, generation in the electricity supply industry was distributed, with small generators near loads around the country. The expansion of the VFP and formation of Eskom saw the development of central generation, favoured by the economies of scale. The Witbank and Colenso 200 MW power stations are examples of some of the stations that were commissioned in the 1920s. Recent central power stations to be commissioned by Eskom are the 4000 MW Kendal and Majuba thermal and Palmiet pumped storage (2×200 MW) power stations. As much as it was economically viable for Eskom to build central stations, a couple of small generators (distributed generators) are operating in some areas around the country. A good example is that of ten small hydro generators rated less than 20 MW located in the Eastern Cape. These were commissioned in 1979 and 1983.

Today a lot of distributed generation projects exist in the country. This research has listed existing DG installations (including co-generation) of about 1700 MW capacity. Projects still at planning level were not included in the total. Some international trends leading to the development of DG are already evident in South Africa. The main trends include technology advances, power industry restructuring, environmental pressure etc. South Africa also has abundant solar radiation, wind energy, wave and tidal power potential. A number of rivers run across the country, placing it in a better position to develop small hydro stations operating as DG.

The review of the transmission pricing methods used in South Africa since the formation of the Transmission Group in 1991/2 revealed that the development of the transmission pricing models led to a decrease in the price variations between the customers. Initially these models were structured in such a way that the prices sent economic signals related to the cost of supply. Further developments in the pricing methods were centred on sending geographical signals regarding the location of generating sources, need for investments in the transmission system, fairness, and cost of supply. The restructuring of the electricity supply industry also resulted in more changes into the pricing methods used in the country. Two of the changes were the establishment of zonal prices for the network charge and a losses charge components of the transmission price. The entire country comprises eight different transmission-pricing zones with fixed network charges and losses charges.

The research has revealed that the impact of increasing DG penetration on Eskom's transmission tariffs is significant in some components of the tariff. These components are the losses charge, network charge and the reliability services charge. The network charge increases with increasing penetration of DG. This was revealed by an investigation of the effect of increasing DG capacity from 0 – 25% on the network charge in the Eastern Cape. This resulted in increasing network charge with increasing DG capacity, despite the reduction in demand met from the transmission system.

A load flow analysis of the Eastern Cape network (Transkei) with DG connected to the network and DG not connected to the network, showed that the connection of DG near the loads reduces the losses along the distribution feeder and thus the losses charge. It was also found that DG has the potential to provide some ancillary services. Therefore the cost of ancillary services to the Transmission Group would be reduced meaning that the Group can reduce its reliability charge component of the tariff.

Other identified benefits of DG that could be significant in the reduction of the transmission tariffs include deferring transmission and distribution investments, and peak shaving.

Important conclusions are that the increasing penetration of DG in South Africa would lead to an increase in the network charge in areas such as the Eastern Cape located farther away from central stations under the present tariff structure. It was also found that the pricing model used to determine network prices is not consistent with the principles of the pricing method. Therefore raising some questions about its method of operation and allocation and recovery of costs.

It was also concluded that the connection of DG on the distribution network near loads result in reduced losses along the distribution feeder, leading to reduced transmission losses charge. A simulation of the Eastern Cape network with and without DG resulted in loss reduction of about 42%.

Another important conclusion is that DG can be used to provide some of the ancillary services required by the Transmission Group for reliability. The provision of these services mean that the Transmission pays less for ancillary services to Generation, therefore reducing the reliability charge levied to its customers. Finally it was concluded that benefits of DG such as system peak shaving, reliability increases, play a key role in the general reduction of the transmission costs resulting in lower transmission tariffs.

It is therefore predicted that the development of DG in South Africa would reduce the rates of the losses charge, reliability services charge and the connection charge components of the transmission tariff, and increase the network price rate.

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CHAPTER ONE

Introduction

1.1 Background and Objectives

The South African power industry is undergoing a massive structural change. The government is restructuring the Electricity Distribution Industry (EDI), Eskom is currently experimenting with a UK-type power market model to promote competition among its power stations, and a number of distributed generators are operating and more are under construction or at planning level. The implementation of the Eskom power pool and the restructuring of both the EDI and the Electricity Supply Industry (ESI) would mean that Eskom's Transmission Group would operate as a separate unit (monopoly). These changes in the power industry have impact on the power system.

Major changes in regulation in the electric industry, power system deficiencies and price increases, and distributed generation technology advances have led to the emergence of distributed generation (DG) [1]. DG plays a significant part of power supply in a number of countries like Denmark (37%), Netherlands (40%), USA etc. In South Africa, several distributed generators operate in the Eastern Cape and parts of Kwa-Zulu Natal. A wind farm is currently under construction in the Western Cape. The emergence and the connection of more distributed generators could have a major impact on the power system. The present small penetration or proportion of DG is not significant. But increasing DG could be. Much research has been done in assessing the impact of distributed generation in a number of countries with DG [2]. In most cases it was realized that technical and economic effects are site specific and differ with varying cases. The need for an investigation of the technical and economic aspects, which will affect the future connection of DG in South Africa, has come. This is important for understanding markets under proposed new structures. The subject of this thesis is determining the effect of DG on Eskom's Transmission Group's tariffs.

This thesis develops an understanding of transmission pricing so the impacts of distributed generation on Eskom transmission group's tariffs in the future can be assessed. The main objective of this research is therefore, to predict the effects of distributed generation on transmission prices in South Africa.

The steps towards achieving this objective include the following:

- Obtain an understanding of the correlation between distributed generation and transmission pricing through an extensive literature survey.
- Identify existing distributed generators as well as distributed generators that are likely to be connected to the South African grid and clearly describing the nature and size of these DGs.
- Assess the existing and proposed transmission pricing methods in South Africa and other countries.
- Identify technical aspects of transmission that are likely to change with distributed generation and clearly identifying the impact of increasing penetration of DG on the transmission prices.
- Analysing the correlation between the benefits of DG and Eskom's transmission tariffs to predict the impact of DG on the tariffs.

1.2 The Need for the Research

The growth and development of distributed generation around the world and signs of emergence of distributed generation in South Africa led to concerns about changes that might come about in the power industry. Various researchers [2] have revealed that the connection of distributed generation affects the power network. South Africa has cases of existing distributed generators, and the relevant stakeholders such as Eskom are showing interest in DG development. This research concentrates on the impact of DG on transmission pricing. Other research has looked at technical, stability, control, protection aspects of DG in general, and these are concurrent studies looking at the impact in SA, so this research is part of a broader analysis.

This research will provide predictions of the impact of distributed generation on transmission pricing in South Africa. This will give the relevant stakeholders an idea of what to expect as the electricity supply industry changes and the penetration of distributed generation increases. The outcome of this study will be of particular interest to the national utility, Eskom, and the National Electricity Regulator (NER).

The regulator might make changes in the current regulations governing the electricity industry in the country depending on how DG affects the power system. This research will provide these stakeholders with an understanding of the great challenges faced by the electricity supply industry of what the new industry structure will look like with distributed generation and how the national utility can position itself suitably in relation to the inevitable changes that are occurring.

1.3 Key Questions

There are many questions associated with DG:
An understanding of the market mechanisms used for energy trading between Eskom and the existing DGs would help in predicting possible future mechanisms with increasing penetration of DG. Market related questions include the following: What market mechanisms are used in energy trading between Eskom and the existing DG? How is this going to be conducted in the future? Is any compensation provided to South African DG owners and what form should this compensation ideally take? This analysis should include case studies of existing and past schemes.

Will DG provide the most economically efficient solution to infrastructure needs (including peak shaving and other benefits) if the market sends the correct price signals by compensating DG owners for the benefits they provide to the grid?

What impact will a large penetration of DG have on the Eskom Transmission tariff, particularly the effect on the network charge and the transmission losses charge? How much can energy and demand be reduced by an increasing penetration of DG in the country and what impact will this have on transmission tariffs.

Benefits of distributed generation would probably have positive implications on transmission prices. Therefore a clear understanding of these benefits is important as a utility and a customer might have different views about some of these. For example a utility can be expected to see DG as an additional option to meet load growth and relieve transmission constraints. End-use customers will probably view DG as a way to reduce costs and obtain other benefits such as increased reliability and power quality. In SA, what are the views of the utility and how does the purpose of DG affect transmission prices? Also, what would be the negotiating point of view of the DG owner? Is DG sufficiently attractive for a utility like Eskom to consider it a viable option for meeting new demand? Is it sufficiently attractive to a private investor as a business opportunity? If "no" to one and "yes" to the other, is there a deficiency in the pricing signal/tariff?

Finally questions regarding location that would need to be answered in order to obtain an understanding of what would happen in the future are as follows: What is the most suitable location of DG in SA, bearing in mind that the transmission tariff in South Africa is geographically differentiated? Will location of a unit affect its value?

However, in the context of the particular problem addressed in this research, the key questions have been identified as being:

- How are network costs incorporated into transmission prices?
- What effect will an increase in DG in a particular region have on the recovery of network costs through the tariff?
- What impact will transmission tariffs have on the adoption of DG projects?

1.4 Methodology

Most of the research will be conducted through a desk-bound review of published literature and documentation on distributed generation and transmission pricing (local and international). This will be supplemented by information obtained from the various stakeholders through interviews. These stakeholders include the three main divisions in Eskom, i.e. Generation, Transmission and Distribution, and other stakeholders would be the various distributed generators around South Africa. A revision of the operation of existing DGs will be carried out. Necessary load flows for simulations of parts of the system will be done using digsilent power system simulation software. The information obtained would then be used in predicting the effect of distributed generation on transmission tariffs.

The research is configured to the South African application in order to clearly determine the specific effects of increasing DG to Eskom's transmission prices. An alternative configuration can easily lead to results that would probably not be applicable to South Africa. Therefore it is avoided.

The main limitation of this research is that it tries to predict the future using a limited DG history in South Africa.

1.5 Outline of the Thesis

The second chapter presents an extensive literature review of distributed generation and transmission pricing. The chapter is divided into two main sections, with the first section concentrating on distributed generation, its definition, and an explanation of why distributed generation is emerging today. The various distributed generation technologies are briefly described, including photovoltaics, fuel cells, wind energy converters, turbines and engines. The different applications of distributed generation are discussed, together with the benefits and disadvantages of DG.

The second section of chapter two reviews transmission pricing methods. Topics covered in this section include principles of transmission pricing, open access contract design and bottom-up pricing. Bottom-up pricing covers costs of building capacity, recovery of sunk costs marginal losses and congestion. Transmission pricing options in the USA and South Africa are also discussed in this section. Chapter two, therefore, provides a general background against which conditions in South Africa can be evaluated.

Chapter three reviews some cases of distributed generation in South Africa. It begins by a brief history on the development of the supply industry in the country, concentrating on dominance of centralised generation and the later emergence of distributed generators. It then continues by reviewing the amount of distributed generation currently installed around the country. The chapter also looks into the future development of distributed generation in the country based on the key drivers of the development of DG. International trends in DG development are extended to the South African context. Finally the chapter covers the possible outlook for distributed generation in South Africa.

Chapter four covers the development of transmission pricing in South Africa. The chapter reviews a variety of methods that have been in use since the formation of the Transmission Group. A description of transmission pricing from 1991 to 1994 is described. Another pricing method that was used between 1994 and 1998 is described. The development of transmission pricing from 1998 is then explored with particular attention to pricing between the Transmission and Distribution Groups, and the various components of the current transmission tariff. The reasons for changing the various tariffs are also discussed. The chapter also looks into the proposed transmission pricing method for the future. A special example of computing the network charge for the proposed tariff is also shown.

Chapter five presents network-pricing methods used in Australia, England and Wales. The key principles of transmission pricing that are closely looked at from these pricing methods are geographic price signals, cost reflective nature of the charges and the extent of economic signals sent by these charges. These methods are then compared with network pricing in South Africa.

Chapter six presents the details of distributed generation impact on transmission pricing in South Africa. The effect on two main components of the Eskom transmission tariff, network charge and losses charge, are analysed with the increase in DG penetration in South Africa. The impact on the reliability services charge is also assessed in the light of increasing DG penetration and the potential benefits that DG can offer in the country's electricity supply industry. A brief discussion on the connection charge is included, as well as a description of other factors that can influence the prices of electricity.

Chapter seven presents conclusions. These relate to the development of DG and its impact on transmission pricing in SA. Conclusions are drawn on the role of DG in South Africa in the future, the nature of transmission pricing and its components in country, as well as the effect of increasing penetration of DG on these components. A discussion is presented on the implications of the results of the connection of DG to the distribution network, as this will affect the components of transmission prices such as losses and network charges. Areas that specifically require future research are also identified.

CHAPTER TWO

Literature Review

This chapter introduces key concepts of DG and transmission pricing. It also identifies important worldwide trends and practices. Therefore it provides the background for application to South African condition in subsequent chapters. The chapter is divided into two main sections, with the first section describing DG, the various DG technologies and the applications and benefits of DG in particular the effect on the power network. The second section describes transmission pricing, the different types and how they are made up. Transmission pricing principles and methods used in some countries are described. Finally a summary of the chapter is made.

2.1 Distributed Generation (DG)

At present, there is no universal definition of what constitutes distributed generation and how it differs from conventional or central generation. Some definitions include: Distributed generation is defined as small power generation units strategically located near consumers and load centres that provide benefits to customers and support the economic operation of the existing power grid [3]. Ackerman [4], defines DG as an electric power connected directly to the distribution network or on the customer side of the meter. Other authors, such as the Cigre Working Group 37.23 [2], agreed on a more specific definition of DG i.e. Distributed generation is any generator that is: (i) not centrally planned, (ii) not centrally dispatched, (iii) usually connected to the distribution network, and (iv) smaller than 50-100 MW.

DG includes a wide range of technologies for various applications. Technologies that are widely used as DG are: fuel cells, reciprocating engines, gas turbines, photovoltaics, wind, micro turbines etc. DG differs from the traditional central plant model in the sense that it can deliver electrical energy directly to the power distribution network or to where it is consumed, rather than via the transmission system. It also differs in size and the manner in which it is operated. This is an important characteristic for this study because the energy does not flow through the transmission and distribution interface where tariffs apply. DG facilities are smaller than traditional central plants and can be operated remotely [1]. **Table 2.1** shows the annual rate of growth for different energy sources between 1990 and 1998. It illustrates that most traditional generation sources have a low growth rate compared to wind energy and PV. Hence related cost reduction are very limited for traditional generation sources, but significant for DG such as wind and PV. The development of DG will mean that the need to expand the transmission network will be reduced even where loads are growing, as the DG will be supplying from the distribution side.

Energy Source	Annual Rate of Growth (%)								
	1990	1991	1992	1993	1994	1995	1996	1997	1998
Wind	11.6	12.4	15.7	19.1	23.1	31.0	26.9	24.8	35-26
PV	15.7	19.1	4.5	3.8	15.5	13.3	12.7	43.0	20.5-28.2
Geothermal	13.2	2.9	4.6	-6	4.6	10.2	5.5	N.A.	N.A.
Natural Gas	4	1.9	0.7	3.1	0	2.7	4.7	0.5	N.A.
Hydro	1.6	2.2	2.2	2.2	1.7	1.6	0.8	N.A.	N.A.
Oil	0	0.7	0	-0.2	1.8	1.4	2.4	2.4	N.A.
Coal	-1.7	-4.4	1.4	-2	6.4	4.1	2.3	1	N.A.
Nuclear	2.5	-0.9	0.6	2.8	0.6	0.6	0.9	0	N.A.

Table 2.1: Worldwide Annual Rate of Growth of Installed Capacity for Various Power Generation Sources in Percent [14]

2.1.1 Why Distributed Generation Now?

DG is emerging today mainly due to the following three reasons: (i) regulatory changes, (ii) power system deficiencies, and (iii) DG technology advances.

2.1.1.1 Regulatory Changes

Most electricity regulators, such as Australia, England and Wales, and USA, are restructuring the industry to allow customers to competitively select the optimum combination of energy resources to meet their needs [3]. Policy makers in many countries have been seeking to improve the economics of power delivery through a major restructuring of the electric power industry to promote competition, customer choice, greater cost effectiveness, and lower energy prices.

Restructuring promises opportunities for DG solutions. Although the ultimate result (of restructuring in most countries) is not yet clear, industry changes are well under way and some positive trends for DG are already apparent (for example in USA) [1]:

- The opening of retail markets provides customers with choice and has resulted in a large number of competitors offering new products and services, including DG.
- The emergence of performance-based ratemaking provides an opportunity for utilities to deploy DG to improve asset utilisation.
- The unbundling of services and more sophisticated market mechanisms, including real-time pricing, will send price signals that will provide an economic stimulus for DG.

2.1.1.2 Power System Deficiencies and Price Increases

There have been various cases of brownouts, blackouts and equipment failures in a number of places around the world, as a result of high electricity demand and insufficient system capacity. This has been the case especially in California and the North American region [1]. Utility electricity prices are generally high at peak periods when most of the electric energy is in demand. One of the options of meeting the peak load demand is the use of DG. This option offers an additional option to meet load growth and relieve transmission constraints. This has led to the increase in the number of DGs worldwide.

2.1.1.3 Technology Advances

Rapid technological development has led to the improvement of the cost and performance of smaller, modular power generation options. These can be as little as a few kilowatts for individual customers. In the U.S. fuel cells and microturbines have taken advantage of technical advancements in the transportation and aerospace industries and adopted them for stationary power generation applications [1].

Distributed generators have been in existence for a long time. Load growth and energy demands led to the development of large central generating plants which were favoured by the economies of scale. As from the 1970s [1], technology advancements led to the improvements of the distributed generators in existence in that time. In Southern Africa a couple of small generators were commissioned. In Swaziland there are small generators, Lesotho has Muela connected to the South African network and many more (for example Mbashe, Ncora, Mtata First Falls etc) around South Africa. Lately, as a result of technology advances, DGs are seen as an option to combat the load growth, system capacity deficiency and high electric energy prices problem. New developments in small scale power generation technologies have presented an opportunity for innovative solutions.

2.1.2 Distributed Generation Technologies

There is a wide range of distributed generation technologies that energy service providers and consumers can choose from. This section focuses on some of these different technologies, describing and explaining how each operates. Capital and energy costs for DG facilities are shown in **table 2.2**, derived from the Cigre report [2]. As stated, "the values are roughly estimated" and will depend "on the individual conditions", such as load factor, financing costs etc.

2.1.2.1 Photovoltaics

There are two types of photovoltaics, the thermal and the solar photovoltaics. Solar photovoltaics generate electricity when sunlight strikes the solar PV cells and thermal photovoltaics generate electricity by using radiant energy. Thermophotovoltaic (TPV) was first demonstrated at Massachusetts Institute of Technology over 30 years ago [5].

According to the Gas Research Institute (GRI) report [3], the size range of PV ranges from 1 kW to about 5 MW and the range of operation and maintenance cost is between 0.001-0.004 $/kWh. The high costs of these systems make them a niche technology that is able to compete more on the basis of environmental benefits.

PV systems can be connected to the distribution network, even though in most published material on PV systems, they are seen as suitable for remote (grid-isolated) applications. PV systems would be suitable in areas of high sunshine and in extremely sensitive environmental areas.

2.1.2.2 Fuel Cells

Fuel cells produce power electrochemically like a battery. They are smaller, quieter and reliable. A fuel cell is based on phosphoric acid as the electrolyte. Fuel cells consist of an anode and a cathode separated by an electrolyte. It does not run down or need recharging, as long as hydrogen is supplied to the anode and the oxygen to the cathode, it produces power. Fuel such as natural gas goes through a processor, or reformer, to produce hydrogen rich gas, as shown in **figure 2.1** below. Heat and water are by-products of the process [5].

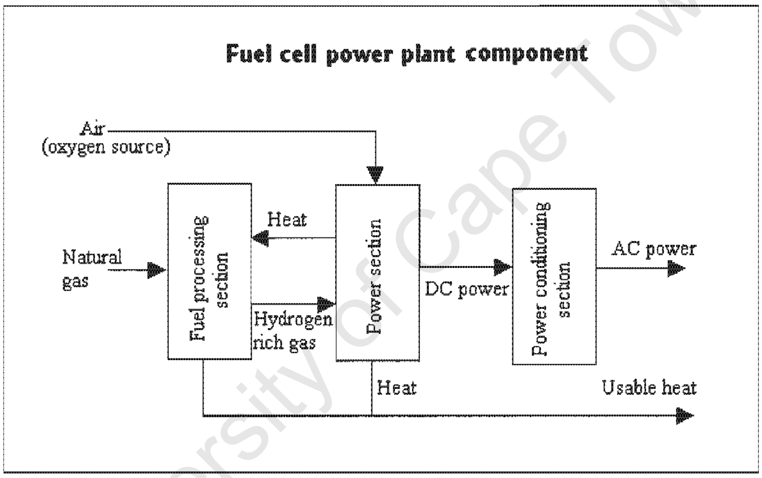

Figure 2.1: Fuel Cell Power Plant Component [5]

Fuel cell efficiency varies from 35-60%, depending on the system used. Fuel cells produce direct current (DC) that must be run through an inverter to get the right frequency alternating current (AC). By making use of power electronics equipment, the power quality can be controlled and the system connected to the grid.

The size of fuel cells ranges from 50-1000+ kW and the operation and maintenance costs vary from 0.005-0.010 $/kWh according to the GRI report [1]. Because of the high costs, fuel cells are best suited to environmentally sensitive areas and customers with power quality concerns.

Technology	Capacity	Capital Costs Euro/kW	Total Costs Euro/kWh
Wind Energy Converters (onshore)	15 MW	900 – 1300	0.04 – 0.09
Wind Energy Converters (offshore)	100 MW	1500 – 2000	0.05 – 0.12
Phovoltaics (PV)	5 MW	6000 – 10000	0.75 – 1
Fuel Cells	5 MW	1100 – 1600	0.08 – 0.1
Micro Generators (Reciprocating engine)	50 kW	600 – 1500	0.07 – 0.15
Micro Generators (turbine)	50 kW	~ 300	0.03 – 0.05

Table 2.2: Capital and Energy Costs for DG Facilities [2]

2.1.2.3 Wind Energy Converters

The technology is mainly determined by the concepts of the rotor and the mechanical electrical energy conversion system. According to Cigre WG 37.23 [2], the rotor is either constructed with variable blade angle (pitch regulation) or in non-variable stall regulation. For the mechanical electrical energy conversion induction or synchronous generators are used. The induction generator is coupled directly to the electrical network. Synchronous generators are usually used for more advanced systems [2].

In most cases wind energy converters are connected to the network injecting only active power and compensating reactive power needed by induction generators locally [2]. There are quite a number of effects of connecting wind energy converters to the grid and these vary from contribution to the short circuit level to the introduction of power fluctuations in the network.

The usual size of wind energy converters, which are connected to the electrical network, is in the range between 30 kW and 1.5 MW [2]. The approximate costs of wind energy converters are shown in **table 2.2**.

2.1.2.4 Turbines and Engines (Micro Generators)

Turbines and engines are usually classified under conventional generators. The two main kinds of these generators, which are mainly used for DG, are combustion turbines and reciprocating engines.

There are two main types of reciprocating engines. These are spark ignition engines and diesel cycle compression ignition engines. Spark ignition engines use natural gas as the preferred fuel but they can be set up to run on propane or petrol. Diesel cycle compression ignition engines can operate on diesel fuel or heavy oil or as dual-fuel configuration. Reciprocating engines offer low first cost, easy start-up, reliability when properly maintained, good load following characteristics and heat recovery potential [3]. The efficiency of the engines ranges from 27 – 34% for natural gas engines and 32 – 38% for dual fuel engines [2].

Combustion turbines are used to power utility and industrial power generators. These turbines produce high quality heat than can be used to generate steam for additional power generation. Maintenance costs per unit of energy output are amongst the lowest of DG technology. The efficiency of the combustion turbines is between 21 – 40% [3].

2.1.3 Applications of Distributed Generation

The application for distributed generation includes combined heat and power (CHP), standby power, peak shaving, stand-alone DG, and grid support. These applications can be designed to meet a wide variety of service requirements such as energy, capacity, reserve, reliability, power quality and backup and standby service. Individual applications are described below.

2.1.3.1 Combined Heat and Power (CHP)

Combined heat and power is the application for distributed generation whereby the power generator creates a large amount of heat in the process of converting fuel into electricity. If the power generation is situated very close to the customers, the heat energy becomes very useful, especially to high thermal customers.

This application for distributed generation reduce global emissions, lower costs and increases the efficiency of energy utilisation. Combined heat and power provides the services mentioned earlier i.e. energy, capacity, system reserve etc. Certain industries in South Africa such as the sugar refineries, SASOL, and the paper industry has some form of CHP in their plants. Some of the industries, including the sugar refineries mentioned, do have capacity and permission to export energy to the grid, and do so on small scale.

2.1.3.2 Standby Power

Distributed generators can be operated as standby generators where they are run when there is an interruption in the electricity service (outages). A lot of customers, sensitive to outages, have standby generators onsite to supply power when outages do occur. These customers include hospitals, elevators and water pumping stations. For industrial customers the installation of standby generators is an economic choice based on extremely high outage costs. Several South African industries and institutions have standby generators for the same reason.

Some utilities recruit customers with standby generation for peak load reduction programs offering payments or rate relief for limited operation during utility peak periods. Standby generation can be part of an optional strategy that minimises power costs and maximises reliability through combinations of firm and interruptible power and onsite capability [3].

2.1.3.3 Peak Shaving

Peak shaving is the process whereby an electricity customer manages the usage of electricity such that his load curve does not peak during peak periods. DG can be used for shaving the peak and by using DG, the customer's overall cost of power would be greatly reduced [3]. The cost of power varies from time to time in a day depending on energy demand. The time of use tariffs (TOU) used for charging for electricity supply are designed in such a way that electricity is very expensive in peak periods. In South Africa a couple of small hydro stations and pump storages are used as peaking stations mainly as a drive to reduce the peak load.

The use of DG for peak shaving could benefit both the customers and the utilities. Customers may find that their DG systems are cheaper than the peak time of use rates. The use of DG in peak periods could reduce the need for utilities to generate or contract to receive and redistribute very high cost power.

2.1.3.4 Stand-alone

Stand-alone DGs are isolated from the grid. In some situations, it is more economic to isolate the DG than integration with the power grid. In some cases, though, customers with CHP systems have separated from the grid due to an inability to negotiate with economic back-up power from their energy service provider [3].

2.1.3.5 Grid Support

Distributed generation offers grid support in a number of ways. These include voltage and frequency support to enhance reliability, transmission capacity release and reactive power control. The use of DG can provide system benefits and reduce the need for investments in other parts of the system. Some of the benefits are [1]:

- Avoidance or deferral of high cost, high lead time T&D system upgrades
- Reduction of line losses
- Reduced central generating station reserve requirements
- Fuel use reduction when solar, renewable, or high efficiency DG is applied in place of central station power
- Emissions reductions from photovoltaics, fuel cells, and clean cogeneration

The application of distributed generation as grid support also provides services such as energy, capacity, system reserve, reliability, power quality and back-up service.

2.1.4 Benefits of Distributed Generation

A considerable amount of work on distributed generation has been published. This has included a wide coverage of benefits of distributed generation. According to A.D. Little [1], customer side distributed generation benefits can be considered from two different perspectives: that of the customer and that of the electric utility.

2.1.4.1 Customer Benefits

Examples often cited for how customers can benefit from distributed generation beyond the electricity cost savings include the following [1]:

- Reduced energy cost for thermal loads (steam, hot water and cooling) – *DG through combined heat and power (CHP) can produce steam or hot water that can be used in manufacturing processes or for space heating and cooling requirements.*
- Decreased exposure to electricity price volatility – *DG can allow customers to take more risks in energy markets or utility rates, since it acts as a hedge on volatile electricity prices.*
- Increased power reliability – *DG can avoid or reduce power outages associated with the grid that can cause operational downtime and health and safety concerns.*
- Improved power quality – *DG can provide very high quality power that reduces or eliminates grid voltage variation and harmonics that negatively affect a customer's sensitive loads.*
- New source of revenues – *DG may allow customers to sell excess power or ancillary services to power markets.*

Some of these benefits are very site specific and application-specific. In addition, some of them might not have any value to the customer. For example, if customers are satisfied with the level of reliability provided by the electric utility, they will place little or no value on the improved reliability that DG can provide.

2.1.4.2 Utility Benefits

The electric utility can greatly benefit with DG at the customers' site. In reference [1], the benefits are outlined as follows:

- Reduced T&D electric losses – *DG avoids electric losses associated with transporting power over T&D system.*
- Avoided increases in system capacity – *DG can provide an additional source of power that could preclude the need to expand the generation, transmission, and distribution system to meet increased demand.*

- T&D upgrade deferrals – *Utilities can use DG to meet growing demands and defer investment in T&D capacity.*
- VAR support – *Some DG technologies can provide reactive power (VARs) that can aid utilities in maintaining system voltage.*
- Transmission congestion relief – *By generating power at or very near the point of consumption where there is congestion, DG can increase the effective T&D network capacity for other customers.*
- Peak shaving – *DG can reduce customer demands from the grid during high demand period.*
- Reduced reserve margin – *By lowering overall demand levels for grid power and providing generation capacity, DG could reduce reserve margins.*
- Improved power quality – *DG can eliminate demand that negatively affects power quality of the grid system.*
- Increased power reliability – *DG can reduce or avoid outages in certain parts of the distribution system.*
- Avoided T&D siting concerns – *By eliminating the need for few transmission and distribution lines, DG can avoid societal concerns over adding transmission lines.*
- Assistance in black start.

It must also be realised that, just like the customer benefits, these benefits are also site specific and that they may not be realised during some time or until some conditions apply. According to A.D. Little [6], utilities maintain that grid side benefits are meaningful only when DG is used as part of utilities' long term T&D planning. Most utilities appear to view DG as a short-term fix to defer T&D investments. Utilities are sceptical about planning system capacity on the basis of peak shaving conducted independently by the customer.

Other benefits of distributed generation include socio-economic opportunities, improved public opinion, and environmental mitigation. These does not directly impact the transmission costs, but their contribution is worthy.

In addition to the benefits DG can bring customers and utilities, there are also additional site-specific costs that must be considered because they affect grid cost such as [1]:

- Standby charges

- Competitive transition charges (CTCs)
- Exit fees
- Additional incremental capital costs for interconnection and permitting.
- The need to equip and manage the transmission and distribution system to handle reverse flows of power.

2.1.5 Benefits of DG Applications

The applications of DG is done in such a way that the customer or the utility benefits. Reliability is one of the major concerns for the customer and most utilities are expected to deliver reliable power. On the other hand distributed generation can be applied as a standby generator or be connected to the grid to enhance reliability.

Distributed generators can be used for peak shaving i.e. operated as peaking stations either to address capacity or high peak energy cost of electricity during peak periods. The application of DG in this case provides the required benefit by both the customer and the utility.

The similarities of the application of DG as combined heat and power (CHP) and the benefit it provides to the customer and utility is that, this application results in reduced energy cost for thermal loads. Energy utilisation efficiency is improved by making use of this application as well.

Some applications such as stand-alone generators provide benefits in their nature. Customers in remote areas that cannot be connected to the power network are supplied this way. Most of the benefits are not directly related to the applications of distributed generators.

2.1.6 Disadvantages of Distributed Generation

Regardless of the numerous benefits of DG to the customers and utilities, there are a number of disadvantages of distributed generation. Most authors omit disadvantages of DG as they mainly concentrate on promoting the development of DG or their ideas on the subject. This section summarises the disadvantages of DG as outlined in reference [7]:

- Matching the generation and demand must be continuously monitored. The control system dispatcher monitors the system at the transmission and sub transmission level, the power fluctuation at the distribution level are not normally monitored.
- With high concentration of DGs on a single feeder there exists the potential of reverse power flow and the possibility of harmonic current distortion, which could affect the power quality.
- Many DG units by their nature are not dispatchable and the system must accept the power whenever it is generated with the potential of overloading cables or transformers.
- Many DG devices and technologies produce power in a form that is not compatible with existing transmission and distribution systems. Specification for interface requirements must preserve system integrity.
- There is a question as to what extent will the utilities be able to control the penetration of DGs and ensure system security during abnormal conditions. Protection and safety must be carefully investigated.
- There are always some risks with new technologies such as DGs, which require market conditioning and assessment of failure. Policies and new regulations may have to be introduced to facilitate pushing DGs into the marketplace.
- Many of the perceived benefits of DGs may not be realised. Some experiences have shown that little benefit has been gained with DGs. Alternative or traditional methods could deliver the same benefits with less cost or proven results [8].
- Distributed generation add to administrative costs. This involves metering, reading and other transactions.

Most of these disadvantages such as the reduction of power quality, overloading of cables and transformers and the careful investigations on protection and safety requirements add to the transmission costs. This leads to increasing costs of transmission, placing DG at a disadvantage.

2.2 Transmission Pricing

This section describes the main aspects of transmission pricing. It begins by identifying the principles of transmission pricing and then describes two approaches of setting pricing, the traditional bottom-up pricing and the more recent open access contract design. This is followed by transmission practice as illustrated by approaches taken in the United States of America and South Africa. Further detail on network pricing (which is a component of transmission pricing) is presented in chapter five.

2.2.1 Principles of Transmission Pricing

Transmission tariffs are designed in such a way that they cover cost related to power transmission from input into the network to the market place. Network owners prepare transmission tariffs based on the following principles [9]:

- Defined connection points where power exchange takes place.
- Provision of revenues to cover costs. Tariffs should provide network owner with reasonable returns on invested capital.
- Tariffs should be defined to stimulate efficient utilisation of the network.

Some objectives of transmission pricing are that the rates should be cost reflective, compatible with time of use tariffs to end-users and should be simple to understand and administer [10].

Other concepts of transmission pricing that need to be considered are transmission constraints and power losses. Transmission constraints can prevent the most efficient plants from operating. These constraints can also determine the location of generation that affect the amount of power losses for transmission. Transmission pricing that considers transmission constraints should encourage the building of new transmission or generating capacity that improves system efficiency.

According to Prete [11] and Shuttleworth [12], in addition to meeting revenue requirements, transmission pricing should ideally do the following:

- Promote efficient day-to-day operation of the bulk power market
- Encourage investment and determine location of generation

- Encourage investment and determine location of transmission lines
- Compensate owners of transmission assets
- Be fair and practical to implement

2.2.2 Traditional Approach: Bottom-up Pricing

Bottom-up pricing refers to the process of building up transmission prices from each of the cost elements. Some of these cost elements are costs of building capacity including sunk costs, marginal losses and congestion. The following sections discuss how transmission contracts should reflect these costs.

2.2.2.1 Costs of Building Capacity

The total costs of projects required to provide additional capacity from one point to another is divided into two elements. The first one is the initial or fixed cost, which includes cost of establishing planning permission and rights of way, hiring contractors, and laying down the basic foundations for providing a transmission link [12]. The second one is the cost of providing the extra units of transmission capacity between two points. Therefore the total incremental cost of a new investment in transmission capacity is the fixed cost (k) plus the cost of providing the extra capacity (bx) i.e. k+bx.

Some network companies have available capacity, which was built years ago. Under cost-of-service regulations such companies would be allowed to charge only the cost of past investment plus accumulated interest (r). In this case, for capacity which was created t years ago, the charge would be $bx(1+r)^t$. In such a situation, it would be sensible for the network company to avoid charging users above k+bx because it would then be economical for users to build their own facilities.

2.2.2.2 Recovery of Sunk Costs

Providing transmission requires long-term investment in capacity. Network companies need to be able to recover its sunk costs. Most utilities are used to operating on the basis of annual tariffs, which are often avoidable by users. Three ways of reconciling this apparent difference between the structure and prices, as outlined in reference [12], are as follows:

- Regulated monopoly network. Allows the network company to recover its sunk costs in annual tariffs, by spreading them over a captive market.
- Long-term capacity contracts. Each user must agree to pay the full cost of investment carried out on its behalf, but in return it receives a long-term right to use any capacity created by its investment.
- Termination payments. Charges paid when quitting a connection are another way of ensuring that network users pay off the full cost of facilities built for their benefit.

The national utility in South Africa, Eskom, owns a regulated monopoly network. The Transmission Group has annual contracts with its customers such as the Distribution Group. Therefore the Transmission Group recovers its sunk costs through these annual tariffs.

2.2.2.3 Marginal Losses (Transmission Losses)

There are two ways to incorporate marginal cost of losses in transmission pricing:

- Charge users the actual, real time marginal cost imposed by their usage.
- Charge the users a fixed kWh price for transmitting energy over the network.

Real time prices must be calculated in a computer model using up-to-date information about actual system conditions. A fixed price may or may not reflect the actual cost of losses very accurately.

2.2.2.4 Congestion

The cost of congestion can be reflected in transmission contracts in three different ways:

- By withdrawing transmission capacity when a constraint occurs, so those network users must adjust their trades in energy.
- By charging an explicit “bottleneck fee” for each kWh that crosses a constraint.
- By including an allowance for the costs of redispatch in the kWh payment for transmission capacity.

2.2.3 New Approach: Open Access Contract Design

The development of power markets, the introduction of competition and open access regulations require a change from the traditional bottom up approach of transmission pricing. This section examines the basis on which an open access contract is designed.

Shuttleworth [12] points out that transmission prices should accurately reflect the cost of the transmission services supplied to any network user. The costs can be identified if the transmission services are adequately described in the contract for transmission access. These services consist of moving energy from one defined point to another, quality of energy supplied to customer, operation of system within certain standards for voltage, power factor and frequency.

Transmission costs depend on the standard of service promised in contract between network owner and user. To understand these standards, the following questions need to be answered:

1. *From where to where:* Generator pays a charge for sending energy to a common point of sale, and each customer for delivering energy from this point of sale.

2. *How much for how long:* Service needs to be defined in terms of a quantity of energy and the period over which the quantity is to be delivered. Network users may have an option over their use of transmission capacity.

3. *Transferable to other network users:* Long-term transmission contracts may become superfluous to the requirements of the network users. It is therefore efficient for network users to transfer some or the entire transmission contract to alternative users. Transfer is encouraged by raising transmission tariffs to ration the available capacity. Network users prefer stable prices. Objectives of efficiency and stable prices can be achieved if the network company offers contracts that are both long term and transferable.

4. *Guaranteed or conditional availability:* Important determinants of the cost of transmission contract are the methods used to reconcile contract commitment

with the actual availability of transmission capacity. The methods used are as follows:

- As available or curtailable capacity: Allow the network company to curtail transactions, so that network users may not schedule flows in excess of available capacity.
- Bottleneck fees: Where capacity is constrained, charging explicit additional tariffs for crossing the constraint rations it.
- Limited interruptibility: When systems provide guaranteed level of capacity, which may be withdrawn for certain number of hours.

Shuttleworth [12] does not mention the other aspects of standard of service such as reliability, voltage regulation etc. But these are also important issues in transmission costs.

2.2.4 Transmission Pricing Options in USA

There is are several electricity transmission pricing options around the world. In this section, four pricing options used in USA are briefly discussed. These are postage stamp pricing, contract path, megawatt-mile pricing and congestion pricing [11].

Postage stamp pricing is the simplest and most common type of transmission pricing. Its rate is a fixed charge per unit of energy transmitted within a particular zone, without considering the distance the energy travels. The postage stamp rates are based on average system costs and may have a variety of rate designs based on energy charges, demand charges or both. In most cases the rates are set as time of use tariffs where by there are separate charges for peak and off peak periods. The charges also vary by season and also depend on time of the week (week day, weekend or public holiday). Transmission services are also generally offered on both firm and non-firm services. Firm service guarantees service subject to constraints while non-firm service is subject to interruption.

Contract path is a traditional pricing mechanism. Its rate follows a fictional transmission path agreed upon by transaction participants. It is usually considered an option to minimise transmission charges and also to avoid transmitting across several utility systems or zones and accumulating utility or zone charges. This pricing option does not reflect actual power flows through the transmission grid.

The megawatt-mile is a flow-based transmission pricing option. The transmission rate reflects the cost of transmission, based on both the megawatts of power flow and the distance travelled by the electrical energy. The cost of transmission per megawatt-mile is the total cost averaged over megawatt miles of usage.

Congestion pricing sets transmission rates to allocate limited transmission capabilities over constrained interfaces to those transmission customers that most value the ability to make power transfers. The increase in electricity demand results in transmission price increases. Congestion costs are either assigned directly to users causing the congestion or shared among all users. [11]

2.2.5 Transmission Pricing in South Africa

The transmission tariff, which is used to price electricity sales between Eskom's Transmission Group and Distribution Group, was first implemented in 1992 (the transmission network belonged to generation before 1992 therefore there was no transmission tariff) [13]. The purpose of the tariff was to create an environment where the operator of the main transmission network could act as an independent broker purchasing energy from generators and selling the energy to the distributors. This can be seen in the South African Electricity Supply Industry (ESI) model in **figure 2.2** below.

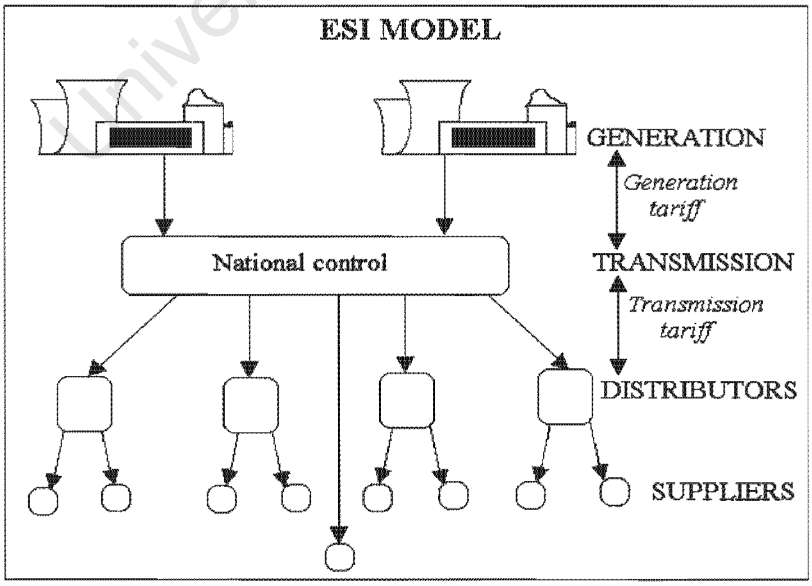

Figure 2.2: Electricity Supply Industry (ESI) Model [10]

The transmission tariff was designed with the hope that it would help the distributors connected to the transmission network to function in a businesslike manner. The tariff rates depended on time of use and were based on optimal long run marginal cost. In 1992, the tariff was similar to the time of use tariff options, T1 and T2 (shown in Appendix one), which Eskom offered to external customers. It consisted of four time of use energy charges and a maximum demand charge, which was levied on maximum demand recorded during peak or standard tariff periods.

Analysis of the weekly load duration curves resulted in a fixed cost in the hour of peak demand and three distinct steps in the variable hourly costs. In allocating the fixed costs, loss of load probability (LOLP) was considered. The level of transmission tariff was set so that the total revenue requirements of the Generation Group and the Transmission Group could be recovered.

The average transmission capital cost per unit of system maximum demand was calculated by dividing the cost of assets by the system maximum demand. A similar calculation was done by using energy as a base to obtain a figure in cents per kilowatt-hour. A distance surcharge similar to the rates used to end customers was used but was not cost reflective. Operations and maintenance costs were recovered by demand charge. The final rates were obtained by adding the components of generation and transmission costs.

The transmission tariff recovered revenue from the distributors in three ways: 1) Revenue from base sales, 2) Revenue from budgeted sales to customer incentive scheme (CIS) customers and 3) Revenue from growth sales.

In calculation of revenues derived from base sales, the total budgeted fixed costs of Generation and Transmission Groups for the present year was divided by the kWh sold by the Transmission Group for the previous year. This resulted in a c/kWh charge. This charge was multiplied by the total metered kWh at each MTS substation for the previous year so that a figure for total base sales revenue could be derived for each distributor.

For revenue from budgeted (CIS) sales, the charge was based on the short-term marginal costs of generation and transmission. This average marginal rate was the same as the marginal rate paid by transmission to generation, plus the marginal costs of transmission losses. The tariff for electricity sales above budget (growth) was meant only to cover marginal variable costs. This was achieved by slightly increasing the price for CIS sales such that the marginal variable costs are covered.

It is not clear why this pricing method was adopted. But it was felt that the method used was not cost reflective and there was a lot of cross subsidisation. A development of a new cost reflective pricing method was considered.

In 1994 the Transmission Economics Department implemented a new transmission tariff. It was intended to be as cost reflective as possible. This tariff consisted of three parts as follows:

- A network charge designed to recover Transmission's own revenue requirements
- A time of use charge designed to recover the total fixed and proportional variable components of the cost of generation and proportional return on assets.
- An hourly marginal energy rate designed to recover the proportional variable components of the cost of generation and transmission. [13]

The network charge comprised of a fixed monthly payment in respect of a point of supply (MTS substation) and the reserved capacity allocated to it. This charge was calculated to recover Transmission revenue requirements. The time of use charge was based on the negotiated baseline load for every supply. The hourly marginal cost rate was applied to consumption in excess of the baseline load. The rate was made up of two items, the marginal cost of supply and the marginal outage cost.

Chapter four focuses on transmission pricing in South Africa. It looks into the history of transmission pricing in the country, the present and the future pricing mechanisms. Therefore more information on this subject can be obtained in chapter four.

2.3 Summary

Distributed generation refers to integrated or stand-alone use of small, modular electric generation close to the point of consumption. Three main trends are the key drivers of the development of distributed generators around the world. These are regulatory changes, power system deficiencies and distributed generation technology advances.

There is a wide range of distributed generation technologies that energy service providers and consumers can choose from. Some of these technologies are photovoltaics, fuel cells, wind energy converters, turbines and engines etc. These technologies can be applied in various ways such as combined heat and power, peak shaving, standby generators, stand-alone generators, and grid support.

Distributed generation provides a considerable amount of benefits to both the utility and the customer. Most of these benefits are very site specific and application specific. Some of the benefits include socio-economic opportunities, improved public opinion and environmental mitigation. Even though distributed generation has plenty of advantages, it does have a few disadvantages. Most of these have negative implications on the transmission costs.

Transmission tariffs are designed in such a way that they cover cost related to power transmission from input into network to the market place. Principles of transmission pricing include defined connection points, provision of revenues to cover costs and stimulating efficient utilisation of the network.

Transmission costs can be identified if transmission services are adequately described in the contract for transmission access. Transmission costs depend on the standard of service promised in the contract between the network owner and the user.

Bottom-up pricing is one of the methods used in transmission pricing. Other methods used around the world, for example in the USA, are postage stamp pricing, contract path, megawatt mile and congestion pricing and have made a big move towards open access pricing.

The tariff used in South Africa was first implemented in 1992. In 1994 a new a tariff was implemented as it was felt that the initial tariff was not cost reflective. The new tariff reduced the variation in electricity prices around the country. The approach is closer to bottom-up than open access.

The literature review has provided a general understanding of transmission pricing that provides the context for developing and using pricing models to investigate the impact of the expected increase of DG on the system.

In chapter three the future potential of DG in South Africa is assessed and chapter four explores the transmission pricing in South Africa in greater detail.

CHAPTER THREE

Distributed Generation in South Africa

The South African power industry has been dominated by large central power stations owned by Eskom since 1949. A conventional large electric power system has been utilised, where large central generators feed electrical power through generator transformers to a high voltage interconnected transmission network. The transmission system is used to transport the power, sometimes over considerable distances, which is then extracted from the transmission network and passed down through a series of distribution transformers to final circuits for delivery to customers. However, recently there have been cases where small generators are connected to the power system at distribution level. A couple of industries are also involved in cogeneration systems. These connected cases are known as distributed generation. This chapter reviews all the cases of distributed generation in South Africa. Issues that are closely looked into are the interconnection voltage level, mode of operation, location, capacity, technology, ownership and planning, and power delivery area.

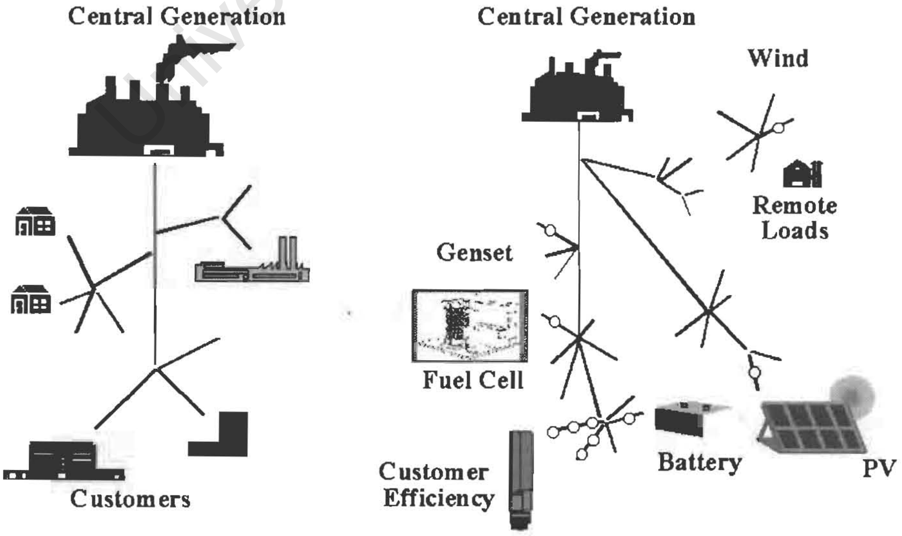

Figure 3.1: Central Generation and Distributed Generation [15]

3.1 Centralised and Distributed Generation

The Electricity Supply Commission known as Escom was established in 1923, but in 1987 the name was changed to Eskom. This is the main utility in South Africa and owns most of the network in the country. The formation of this utility in 1923 saw the development of central generating stations in the country. Witbank and Colenso power stations are examples of some of the stations that were commissioned in the 1920s. These stations were owned by Escom but operated by VFP as part of its network. The discovery of new gold fields to the west of the Witwatersrand and a rise in gold prices increased the development of the electricity supply industry. This led to rapid growth in electricity demand from the gold mines. To meet this demand, Eskom erected another big central power station (Klip power station). More central stations were commissioned immediately after the Second World War. The diagram below shows power stations that were commissioned between 1960 and 1989.

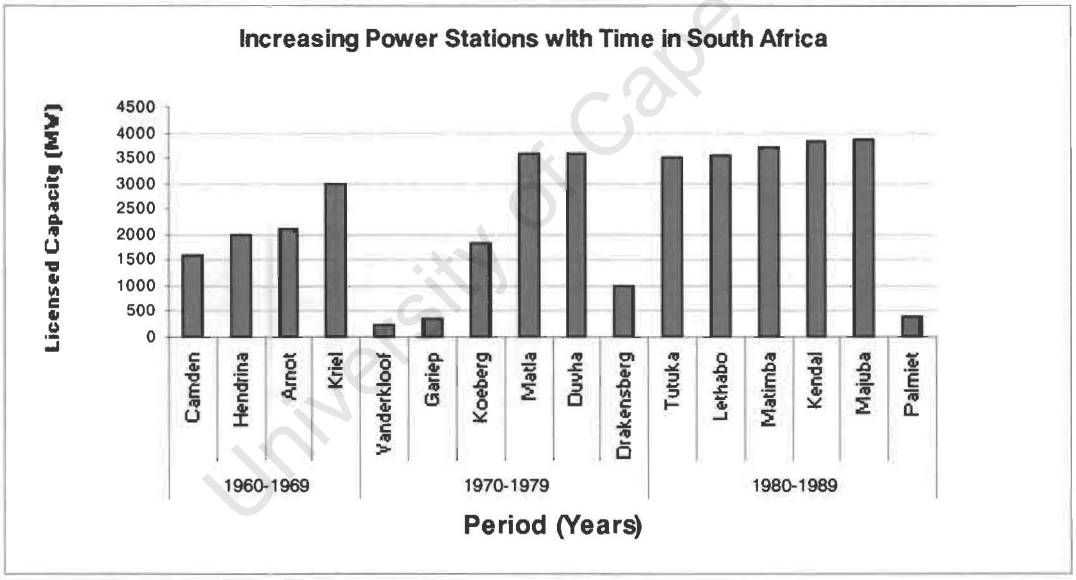

Figure 3.2: Increasing Power Stations with Time in South Africa [16]

A number of the Eskom central stations were constructed to meet the high-energy demand in the country. The economies of scale also favoured the development of central power stations in the country. Some of the central stations were built for peak lopping and for use during emergences as well as reliability purposes on the entire Eskom network. For example Hendrik Verwoerd (re-named Gariep) hydro power station, built as part of an irrigation project, started feeding into Eskom's transmission system in 1971 [16]. Not only did it prove of value in peak load periods and emergencies, but also it strengthened the 400 kV line linking the Transvaal and the

Cape Province. Vanderkloof, a similar hydro power station, was commissioned in 1977 as another feature of the Orange River Project [16]. As much as it was economically viable for Eskom to build central stations, a couple of small generators (distributed generators) were operating in some areas around the country. A good example is that of the small hydro generators located in the former Transkei in the Eastern Cape. These generators were commissioned in 1979 and 1983 [17]. A couple of customers also installed solar panels in their households in order to obtain electric energy. These panels could be combined to operate as DG. Some industries have always generated their own electricity to avoid high Eskom peak prices during peak period. Some of these generators have the potential of generating enough energy for the industry as well as surplus that could be sold to Eskom. Examples of industries that have cogeneration facilities include Sasol, Sappi, and AECI etc.

Central generating stations in South Africa have dominated the Electricity Supply Industry. A few cases of distributed generation, whereby small power generators were built within a localised area of use, have been noticed in the past and more distributed generators are emerging in the South African power industry. The following section focuses on the existing distributed generators in the country.

3.2 How much DG is Installed in SA Today?

The national public electricity utility, Eskom, generates 97% of the electricity consumed in South Africa [18]. However there are customers who still own and operate significant generation. Advances in generation technology, in particular Combined Cycle Gas Turbines (CCGT) makes it increasingly attractive for customers to invest in generation for all or part of their own electricity needs. Many customers are indeed seriously investigating this alternative for meeting their electricity needs.

The potential for non-Eskom Generation has been estimated as 15 400 MW [18]. **Table 3.1** shows a list of most of the distributed generators in the country. Distributed generation is any source of electric power that is interconnected with an electricty supply network at a system voltage level not exceeding 132kV. The generator is not centrally dispatched. It is probably not a trading participant in a power pool but usually responds to a tariff signal. For this research the maximum capacity for DG is 100 MW. Some plants such as Sasol, Sappi, sugar mills and metallurgical industries (shown in **table 3.1)** have more than one generator.

Plant	Size [MW]	Type	Owner
Mtata First Falls	6	Hydro	Eskom
Mtata Second Falls	11	Hydro	Eskom
Mbashe/Collywobles	42	Hydro	Eskom
Ncora	2	Hydro	Eskom
Mantsonyane	2	Hydro	Lesotho
Sasol	728	Coal fired	Sasol
Sappi-Usutu	12	Coal/Black liquor	Sappi
Sappi-Tugela	18	Coal/Black liquor	Sappi
Sappi-Ngodwana	70	Coal/Black liquor	Sappi
Mondi-Richards Bay	35	Coal/Black liquor	Sappi
Mondi-Merebank	145	Coal/Black liquor	Mondi
Tongaat-Hullet Amatikulu	12	Bagasse/Coal fired	Sugar industries
Tongaat-Hullet Darnall	13	Bagasse/Coal fired	Sugar industries
Tongaat-Hullet Felixton	32	Bagasse/Coal fired	Sugar industries
Tongaat-Hullet Maidstone	29	Bagasse/Coal fired	Sugar industries
Transvaal Suiker	20	Bagasse/Coal fired	Sugar industries
Mossgas	90	Gas	Mossgas
Metallurgical industries	200	?	Metallurgical industries
Bloemfontein	102	Coal fired	Municipality
Roggebaai	40	Gas Turbine	Municipality
Athlone	40	Gas Turbine	Municipality
Port Elizabeth	40	Gas Turbine	Municipality
Lydenburg	2	Hydro	Municipality
Piet Retief	1	Hydro	Municipality
Friedenheim	3	Hydro	Private

Table 3.1: Existing DG in South Africa [20]

Eskom, various municipalities and a few private industries own the distributed generators shown in **table 3.1** above. A number of small generators such as solar power and a couple of other electrical energy sources are not listed in the table. The four small generators i.e. Mtata First Falls, Mtata Second Falls, Mbashe and Ncora, currently owned by Eskom, were built by Tescor as local generation in the former Transkei homeland about twenty years ago. These small hydro generators were operated in parallel with the Eskom import. The political changes in South Africa during the early nineties led to the end of the homeland system and homelands like the Transkei became part of the South African government. As a result Tescor was taken over by the national electric utility Eskom in 1994. These generators are connected at distribution voltages of 66, 66, 66/132 and 22 kV respectively.

Some industries, notably pulp and paper and sugar refining, use biomass to raise steam to generate electricity. In pulp mills, the bark from logs and the black liquor from the digestors is burned in boilers for process heat and electricity. In sugar refineries, bagasse (fibres from the sugar cane) is used in the same way. Both the paper and sugar industries have high electrical energy demand for their processes, especially mechanical processes. In order to meet these demands, these industries generate their own electricity by using mainly coal but also waste products as mentioned above. The total generation from paper and sugar industries is 280 and 105 MW respectively as shown in **table 3.1**. The paper mills that generate their own electricity are Sappi Usutu (12 MW), Sappi Tugela (18 MW), Sappi Ngodwana (70 MW), Mondi Richards Bay (35 MW) and Mondi Merebank (145 MW) [19]. The sugar refineries that generate their own electricity are as follows: Tongaat-Hulett Amatikulu (12 MW), Tongaat-Hullet Darnall (13 MW), Tongaat-Hullet Felixton (32 MW), Tongaat-Hullet Maidstone Mill (29 MW) and Transvaal Suiker Ltd (20 MW) [20]. Most of these mills generate energy capacity less than their demand, therefore get extra energy supply from Eskom and also, they do not wheel energy to other mills.

Industries such as Mossgas, Sasol and metallurgical industries also generate their own electricity using mainly steam turbines. These generators are also categorised as distributed generators, cogenerators to be specific. The generation capacities of these small generators are 728, 90 and 200 MW respectively as shown in **table 3.1**.

Various municipalities around the country also own a significant number of small generators. Examples of such generators are the coal station of capacity 102 MW in Bloemfontein, the gas turbines in Roggebaai, Athlone and Port Elizabeth (all of capacity 40 MW), and the two hydro stations in Lydenburg and Piet Retief of capacities 2 and 1 MW respectively [20]. Most of these stations are peaking stations used by the municipalities to supply local loads during peak hours and also to avoid high Eskom peak prices of electricity. Friedenheim hydro power station is privately owned and has a licensed capacity of 3 MW. This indicates that DG can compete.

There are many other examples of distributed generation in the country that are not listed in **table 3.1**. Most of these are isolated and not connected to the grid. Solar energy is widely used in remote areas such as the Eastern Cape. This kind of energy is used mainly in areas far from the electricity grid. Photovoltaics are used for remote radio transmitters and receivers, for rural schools and clinics, and for rural houses. It is estimated that in 1995 South Africa had a total solar photovoltaic capacity of about 5 MWe [21]. None of these is known to be connected to the grid.

There are 7 gas turbine power stations in South Africa, 2 owned by Eskom and 5 by municipalities. Some of these are not classified as DG for example those owned by Eskom such as Acacia and Port Rex (bigger than 100MW in capacity). Most of these stations are small and are not used for base load electricity generation but for meeting load peaks or for standby generation for start-ups or in the event of loss of power from the main plant. They consist of simple gas turbines where the exhaust gases from the turbines go to waste. In South Africa they run on liquid fuels such as paraffin or jet fuel.

Figure 3.3: Photovoltaic Module [22]

The total installed capacity of these plants was just over 606 MWe in 1996 [21]. Their production of electricity was negligible in 1995. **Table 3.1** shows a total of 120 MW and the balance is mainly from Eskom stations such as Port Rex and Acacia. Simple gas turbine generators such as these are quick and easy to start, have low capital costs per kW, high efficiencies (typically 55% and above) and have high running costs. They have no prospect of providing base load electricity in the future. If gas is used for base load electricity in future it will be in Combined Cycle Gas Turbine (CCGT) plants.

It is clear that distributed generation plays a significant role in the current electricity supply industry of South Africa. The reasons behind the construction and emergence of the existing generators in the country vary widely. Some DGs started off as the main energy supplier for certain areas like in the Transkei. This area had a separate government from South Africa, and the power stations were financially viable. Companies such as Sappi, Sasol, and the sugar industry find it cheaper to generate their own electricity other than depending only on Eskom. As a result they constructed their own smaller stations. In fact there might be more reasons for the development of distributed generation in future in the country. The next section closely looks into this subject.

3.3 Development of DG in SA in the Future.

The development of DG in the world has been driven by various reasons. Independent trends - utility industry restructuring, increasing system capacity needs, and technology advancements – have concurrently laid the groundwork for the widespread adoption of DG. Another key driver that is increasingly playing a bigger role in international emergence of DG is the development of more stringent environmental legislation [2]. The development of DG in SA is set to increase in the future. The trends mentioned above together with various other evident reasons will drive the development of DG in the country. These are discussed below.

3.3.1 Technology Advances

New developments in small-scale power generation technologies have presented an opportunity for innovate solutions to address the need for broad-based system expansion. DG nowadays has mature technology that is readily available and modular in a capacity range from 100 kW to 150 MW [2]. This would be one of the main drivers of DG in the country in the future, particularly with the recent high interest in alternative energy sources. Alternative energy sources are abundant in South Africa and the advances in DG technology will lead to an increase in the number of DG in the country. The cost and efficiency of DG technologies is improving dramatically around the world and in SA. This means that energy service providers and consumers in the country can select from a wide range of distributed power generation technologies. With further advances in these technologies, unit prices will be further reduced.

3.3.2 Environmental Pressure

The growing environmental pressure worldwide in response to global warming concerns has accelerated development of non-green house gas emitting technologies. The same is expected to happen in South Africa, where over 92% of the electricity generated is from conventional coal power stations [21]. These power stations are polluting. They produce large amounts of waste, both solid and gaseous. The ash from the coal is made up of a variety of elements. All of these elements end up either in the atmosphere or on ash tips. In South African coal power stations, the only pollutant that is removed from the flue gas are particles (smoke), which are removed with electrostatic precipitators or filter bags. There is no flue gas desulphurisation in South Africa [21]. The other pollutants in the flue gas pass straight into the atmosphere. The increased pressures on utilities to be environmentally sensitive will be a key driver for South African energy providers to consider renewable energy sources, most of which are classified as DG.

3.3.3 Renewable Energy Resources

South Africa is blessed with abundant solar radiation, wind energy, wave and tidal power potential. These free resources can be used, especially with the recent advances in DG technologies. The main South African utility, Eskom, has already shown interest in alternative energy resources, investing in research projects on DG and renewable energy. This shows that alternative energy resources such as renewable energy will play a major role in the development of DG in the country.

An existing project by Technology Services International (TSI), an Eskom Enterprise division, is currently working on installing distributed generators around the country. By 2006 the following technologies will be implemented or in the process of being constructed:

- Large wind farm in the Western Cape
- Concentrating Solar Power Technology in the Northern Cape
- Shore and/or offshore based wave power technology in the Western Cape
- A biopower technology, which harness waste products such as landfill gas around the country.
- A Solar Dish Stirling Project (see **figure 3.4**)

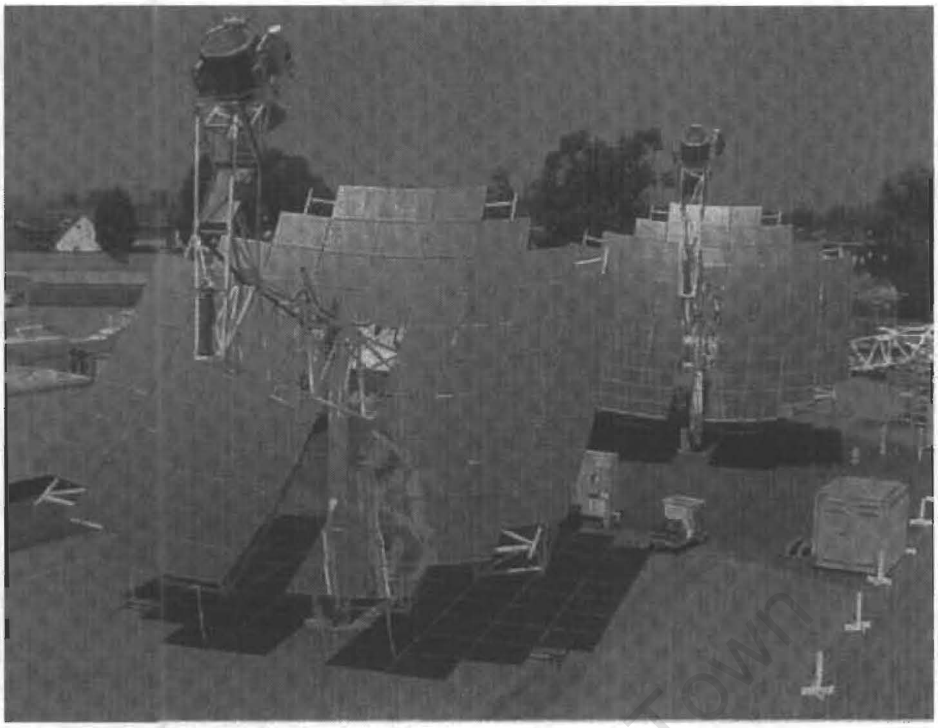

Figure 3.4: A Demonstration of Alternative Energy Sources, the Solar Dish Stirling Project Launched at the Time of the Summit on Sustainable Development in Midrand [39].

Eskom is into DG because it is trying to identify engineering applications for distributed resources and to develop the broad capabilities to incorporate these into technically and economically feasible processes in the electricity distribution business. Eskom is specifically concerned with:

- The assessment of the opportunities and associated business aspects of distributed resources in the distribution network.
- The identification of distributed generation resources capable of being connected to distribution network.
- The technical (where applicable) and economic integration of distributed resources into the distribution network.
- The characterisation of these resources from the perspective of their impact on a distribution network and degree to which they meet customer requirements.

The knowledge gained from the pilot projects mentioned above will provide essential supporting information for the distribution planner and Quality of supply practitioner. These projects will be of great value in Eskom in terms of understanding DG and would also be useful to the development of DG in the country. The viability of DG will be determined through the outcome of these pilot projects.

3.3.4 Political Motivation

In certain countries environmental regulations are politically motivated. High reimbursement tariffs and subsidies are granted for environmentally friendly technologies, or, public service obligations with the aim to reduce pollution. A good example of such countries are Denmark and Germany [2]. This leads to economically favourable conditions for DG development. It is likely that South Africa will do the same in the near future. The above discussion shows that South Africa is already moving towards the development of DG due to global environmental pressures regarding global warming. The National Electricity Regulator (NER) in South Africa is likely to introduce tariff incentives and technical guidelines to stimulate interest and promote new forms of electricity generation, such as distributed generation, especially that which is environmentally friendly. Even if the alternative sources of energy are not affordable, the incentives provided by NER due to worldwide increase of environmental pressures, will stimulate the interest for new forms of electricity generation.

3.3.5 Power Industry Restructuring

Major changes in regulation in the electric industry around the world over the past two decades have led to the development of the concept that is now known as DG. The aim of restructuring is to improve the economics of power generation and delivery through a dramatic restructuring of the electric power industry to promote competition, customer choice, greater cost effectiveness, and lower energy prices. In many countries such as the USA, the final outcome of restructuring is still taking shape, with many states only now beginning to enact legislation. Although the ultimate result is not yet clear, industry changes are well under way and according to A. D. Little [1] some positive trends for DG are already apparent. These are as follows:

- The opening of retail markets provides customers with choice and has resulted in a large number of competitors offering new products and services, including DG.
- The emergence of performance-based ratemaking provides an opportunity for utilities to deploy DG to improve asset utilisation.

- The unbundling of services and more sophisticated market mechanisms, including real-time pricing, will send price signals that will provide an economic stimulus for DG.

The South African power industry is also undergoing a massive structural change. The government is restructuring the Electricity Distribution Industry (EDI). The Electricity Distribution Industry Restructuring Committee (EDIRC) has been requested by the Cabinet to work on the EDI restructuring. The restructuring of the distribution industry forms part of a larger reshape of the supply industry [23]. This will lead to the unbundling of Eskom's Generation and Transmission Groups, the introduction of competition and private sector participation in the longer term. With the electric industry restructuring, unique opportunities exist for new approaches to generating electricity and satisfying on-site customer needs using smaller DG power systems, if regulation allows it. The market for small-scale power generation has the potential to develop in South Africa with the introduction of competition and private sector participation in the local power industry. The formation of Regional Electricity Distributors (REDs) is likely to create this competition and open interests needed to stimulate DG. If REDs stimulate DG, there will be an impact on their purchases from the transmission system. This effect depends on the relative growth of DG and the load. In Chapter six the effect of increasing DG penetration in South Africa is assessed. Eskom is already preparing for the restructuring of the EDI. A provision for impairment of certain classes of property, plant and equipment has been raised. The need for this impairment is influenced by the transfer of assets from Eskom to different companies (REDs) [11].

3.3.6 Customer Choice

Another important factor in the development of distributed generation in the country is that of customer choice. Customers will have to choose how they satisfy their electrical energy needs. The more the customer gets to understand and appreciate the potential benefits of distributed generation, the higher are the chances that distributed generation becomes an option in the future. Internationally, distributed generation is widely used by most customers to provide some or all of their electricity needs. There are many different potential applications for distributed generation technologies. For example, some customers use distributed generation to reduce demand charges imposed by their electric utilities, while others use it to provide clean, uninterruptible, controlled and reliable power (premium power) or reduce environmental emissions. The same is likely to happen in South Africa in the future. A lot of industries require premium power in the country. Electricity price is not a big issue at the moment in South Africa, as a result reducing demand charges is not that significant. But reduction of environmental emissions is very significant and would play a huge role when it comes to customers' selection of power supply, with systems with low emissions, such as most distributed generators getting an upper hand. Customers who are environmentally inclined will purchase green power (power from renewable sources), even if it means paying a higher premium compared to grid based power purchases.

3.3.7 Utility Choice

The demand of electricity is ever increasing in the country and the building of large central power stations is likely not to be the most economical solution to meeting these demands. Economies of scale have been the main driver of cost reduction in the past and it has led to the existing centralised system. Economies of scale, however, have been also an important driver to reduce the electricity production costs of distributed generation. For example in 1985 a 50 kW wind turbine had a rotor diameter of 15m and in 2000 a 4000 kW turbine had a rotor diameter of 88m [14]. Other DG technologies will certainly follow this development. DG has a large potential of economies of scale in comparison to large-scale centralised technologies with their almost exhausted economies of scale. The advances in distributed generation technology means that the prices for these technologies are going down placing them in a better position as a choice in meeting increasing demands of electricity.

A utility such as Eskom will use distributed generation as transmission and distribution deferral. Placing distributed generators in strategic locations will help Eskom delay the purchase of new transmission or distribution systems and equipment such as distribution lines and substations.

The utility can also benefit from distributed generators by obtaining ancillary services. The market for ancillary services is still unfolding internationally, such as in the USA. The same thing can be expected to happen in South Africa very soon. And when this takes place, the penetration of distributed generation will be boosted in the country.

Eskom is currently doing a research on pebble bed modular reactors (PBMR), which have the potential for distributed generation. This research has revealed that this technology has major safety advantages over conventional nuclear plants, and major cost benefits [21]. It is based on a German pilot reactor, the AVR, of 15 MWe capacity, which ran successfully from 1967 to 1989. The proposed South African design will be 100 MWe. The modular design means that units will be built quickly with a minimum of site construction. The smaller units will fit in with an international trend towards smaller power stations (DG) with lower capital costs and quicker construction time. If the South Africa prototype PBMR is successful, it could be exported around the world and would be particularly suited to a niche market where the demand is for a small unit with completely flexible siting. It is possible that PBMR will be operated as DG as the proposed capacity is 100MW for South Africa.

3.4 Possible Outlook for Distributed Generation in South Africa

Even if it were desirable, Eskom would find it difficult to carry out its business in isolation. The electricity supply industry is changing all over the world and customers' electricity demands are becoming more and more based on quality. Distributed generation plays a major role in meeting these demands [14]. As a result most countries are opting for this alternative and the number of these small generators has increased dramatically [9]. A number of key drivers for the development of distributed generation are still evident around the world. Therefore we can say that distributed generation will play a major role in the electricity supply industry around the world including South Africa. **Table 3.2** shows the current and future potential of DG penetration in different countries.

	Today	Future Potential
Australia	3% (2000 MW)	9% (900 MW)
Belgium	10%	Up to 20%
Canada	10% (2900 MW)	75.8% (22 000 MW)
Denmark	37% (1600 MW CHP / 900 MW WEC)	2000 MW CHP, 5000 MW WEC
France	Less than 5%	?
Germany	1260 MW small CHP / 6000 MW CHP / 2400 MW WEC	Up to 35% CHP, >3600 MW WEC
Netherlands	40%	?
Norway	1% (Hydro, low prices)	?
Spain	300 MW	9000 MW WEC, 16000 MW CHP
EU Targets	**9%**	**18% by 2010, theoretical 40%**

Table 3.2: DG Penetration in Different Countries [2]

Eskom is planning a wind project under the auspices of South African Bulk Renewable Energy-Generation (SABRE-Gen) in the Western Cape. An environmental impact assessment is under way and if it is successful construction of the wind project will begin this year (2002). Six to eight wind turbines would be installed with a total capacity of about 10 MWe [21].

Another proposed wind project in the Western Cape is the Darlington Demonstration Wind Farm, an IPP funded by a private consortium, whose first phase would be to install 5 MWe of wind power and whose second stage would install another 5 MWe. It is estimated that the total wind potential in the Western Cape is a few hundred MWe. There is also a greater potential of offshore wind generation in the region.

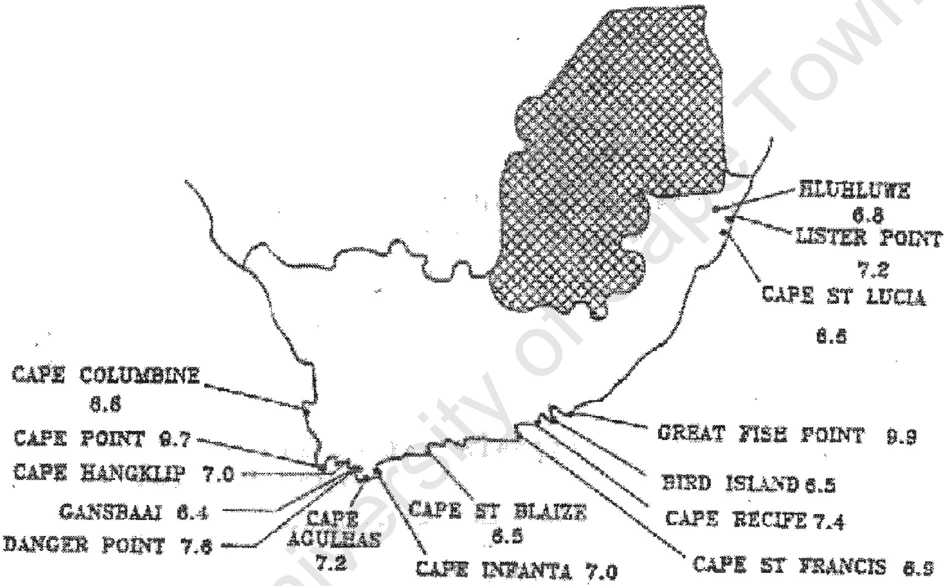

Figure 3.5: Mean Annual Wind Speeds (m/s) in South Africa [41]

South Africa has no natural gas apart from the small field at Mossgas, which is used for making chemicals but it does have coal bed methane especially at the Waterberg field. There is also natural gas in offshore Kudu gasfield in Namibia and the land Pande field in Mozambique. Therefore it is likely that South Africa will build combined cycle gas turbines (CCGT) as DGs, the most rapidly growing technology in Europe. The technology is well proven. Capital costs are low. Construction time is short. It might also become economically viable to import liquefied natural gas (LNG) from fields such Angola, Nigeria, and further away. As a result of the availability of resources as well as the efficiency, low capital cost, and cleanliness, it is likely that (CCGT) distributed generation stations will be built in South Africa before 2020 [21].

They are likely to be in the Northern Cape, Southern Cape, Mpumalanga and Gauteng associated with identified sources of gas and gas utilisation.

Some industries, such as pulp mills and sugar mills, already use biomass to generate electricity for their own use. In future, depending on electricity prices and environmental regulations, some of this electricity from distributed generators could be sold into the national grid. It is unlikely that this kind of electricity generation could play a major role in the contribution to the public electricity supply, as the potential for expansion of sugar cane fields and commercial forests in limited in the country.

Until now South Africa has only made electricity from the sun by photovoltaic panels. Their use is expected to grow rapidly to provide off-grid electricity for schools, clinics and households in remote areas. Eskom and Royal Dutch Shell are now implementing a programme to provide households in the Eastern Cape with photovoltaic panels for lighting and small electrical appliances, and LPG for cooking and heating [21]. PV panel assembly in SA totals about 6 MW per annum [40].
Another quite different principle of solar thermal power, a form of distributed generation, is the heat pipe, where a large vertical pipe, using the chimney effect, draws from under a large, horizontal, heating surface and drives the air vertically up, turning a turbine at its base. This is being seriously considered for the Northern Cape and design work is being undertaken for it at the University of Stellenbosch. It will have a peak capacity of 200 MWe.

Even though the most existing DG in South Africa is hydro, there is little potential for expanding in South Africa except for small schemes in remote locations. Not much is mentioned about new DG projects using hydro.

The different cases of emerging distributed generation mentioned above gives an idea of the possible outlook of South African power industry in the future. Distributed generation would play a significant role and the penetration of DGs will be rapidly increasing in the next 20 years. Eskom supplies approximately 95 % of the country's electricity requirements [23]. This implies that independent power producers supply the remaining 5%, mainly in the form of distributed generation. Distributed generation is estimated to contribute about 25% of energy worldwide by 2010. South Africa can be estimated to have between 20 and 30% or more energy supply from DG by the year 2020. **Table 3.3** below shows a potential of about 30% DG by the year 2020. It is therefore very critical for South Africa to assess the possible impact of increasing distributed generation on the power system.

Various reasons led to the development of DG in SA. These include political motivation for the Transkei generators, cost effective options for the sugar mills, paper mills, Sasol and the various municipalities. Eskom and some municipalities developed DG for peak shaving purposes. Most of the gas turbines are peaking stations. Most of the existing DG systems have been operating well remotely, meaning that the systems were viable. Connection to the grid might increase its viability. In most cases the viability of DG depends on regulation and prices and costs.

DG Type	Location	Future Potential
Wind Power	KwaZulu Natal Eastern Cape Western Cape	150 MW[1] 400 MW 600 MW
Solar power	Northern Cape North West Eastern Cape	50 MW[2] 50 MW 50 MW
Gas (CCGT)	Southern Cape Northern Cape Gauteng Mpumalanga KwaZulu Natal	2000 MW
Hydro	Various parts of the country	6960 MW
Cogeneration	Various industries around the country	3445 MW
Total		**13705 MW**

Table 3.3: DG Potential and Location in South Africa [21] [40]

A wide range of barriers affects the grid interconnection of DG projects [24]. These barriers include direct utility prohibition, exit fees, connection charges, utility operational requirements etc. Resolving barriers to interconnection is a critical step toward achieving the full potential benefits of DG and realising the market opportunities that DG technologies can provide.

The cost of energy production using DG is decreasing meaning that DG will be in a better position to compete with central generation. This is illustrated by the significant DG cost decreases of the Non-Fossil Fuel Obligation (NFFO) achieved in England and Wales. A comparison of the NFFO3 (1994), NFFO4 (1997) and the NFFO5

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[1] Estimated roughly based on the wind speeds of coastal areas and pilot project in the Western Cape
[2] Estimated by using increase rate of PV assembly of about 6 MW per year (up to 2020)

(1998) is shown in **table 3.4**. In South Africa, the various pilot projects around the country and the various world trends will be used to establish indicative costs for DG. Indicative costs for DG are not disclosed in public domain and this is a limitation on the scope of this thesis.

	NFFO3	NFFO4	NFFO5
Large Wind	3.98 – 5.99	3.11 – 4.95	2.43 – 3.14
Small Wind	-	-	3.40 – 4.60
Hydro	4.25 – 4.85	3.80 – 4.40	3.85 – 4.35
Landfill Gas	3.29 – 4.00	2.80 – 3.20	2.59 – 2.85
Waste System	3.48 – 4.00	2.66 – 2.80	2.34 – 2.42
Biomass	4.90 – 5.62	5.49 – 5.79	-

Table 3.4: Successful Bidding Prices in British Pence/kWh [14]

3.5 Summary

The formation of Eskom, the main utility in South Africa, in 1923 saw the development of central generating stations (some were remote grid). The economies of scale also favoured this development. Power quality demands increased in the country. As a result smaller generating units were built to address reliability and some of the power quality concerns. A number of customers opted to own and operate a significant number of small generators. Some of these generators still exist.

Various international trends in the development of distributed generation are witnessed in the country. These trends are seen to be laying the groundwork for the widespread adoption of DG in the country. These trends include technology advances, environmental pressures, and power industry restructuring, renewable energy resources, political motivation, customer choice, and utility choice. Cases of emerging DG are evident in the country. Several local institutions currently do various projects and research projects on distributed generation. The South African government is also involved through the NER in driving the development of distributed generation in the country. It is clear that distributed generation will play a major role in the country's electricity supply industry. South Africa will have between 20 and 30% or more energy supply from DG by the year 2020.

CHAPTER FOUR

Development of Transmission Pricing in South Africa

Eskom formed the Transmission Group, in the South African power industry, in January 1991. The Transmission Group was formed from what used to be the delivery arm of Eskom's Generation Group. Some substation assets that were previously in the hands of the Distribution Group were transferred to the Transmission Group for the transport of electrical energy from power stations to the interface with localised distribution networks. The formation of this group raised the issue of how to fund this operation. The group was formed in an effort to un-bundle Eskom services. This chapter reviews a variety of methods that have been in use and also investigates the proposed transmission pricing methods for the future.

4.1 Principles of Transmission Pricing in South Africa

The principles on which the transmission prices in South Africa were based at the beginning of transmission pricing in the early nineties (transmission pricing did not exist before that in SA) were [13]:

- Transmission prices should be cost reflective: Indicating to the customers the cost of supplying their specific needs.
- Transmission prices should be fair: Allocating costs among customers according to the burdens they impose on the system.
- Electricity prices must raise sufficient revenues to meet financial requirements

The early experience of transmission pricing in the country led to changes in the principles of transmission pricing. Some of the principles that followed in designing transmission prices in South Africa are as follows:

- The prices should signal location advantages for investment in generation and demand.
- Be simple and transparent.
- Compensate owners of the existing transmission assets.

- Signal need for investment in the transmission system.

The pricing methods described in this chapter were developed by Eskom on the basis of the above principles. Some of the principles were realized and some not. Cross subsidization among customers and wide price variations has been the main problem in designing the pricing methods. The following sections describe the various pricing methods utilised in South Africa from the early nineties to date.

4.2 Transmission Pricing from 1991 to 1994

The transmission tariff, used to price electricity sales between the Transmission Group and the Eskom Distributors was first implemented in 1991. The tariff was in line with the concept of a single buyer model. The Transmission group bought energy from the Generation Group (power stations) and sold it to the Distribution Group, including a small mark-up in the unit price, to obtain the revenue requirements for a specific year through this price differential.

The tariff (similar to T1 and T2 shown in appendix 1) consisted of four Time-of-Use energy charges and a maximum demand charge, which was based on maximum demand, recorded during peak or standard tariff periods. Each of the five Eskom Distributors was billed based on the recorded electricity consumption at each of the Main Transmission System (MTS) substation. This tariff recovered revenue from five Distributors in three ways [13]:

- Revenue from Base Sales
- Revenue from Budgeted Sales to Customer Incentive Scheme (CIS) customers
- Revenue from Growth Sales

According to Mountain [13] the revenue derived from Base Sales was calculated by adding the total budgeted fixed costs of the Generation and Transmission Groups for that particular year and was divided by the total kWhs sold by the Transmission Group for the previous year. This gave a c/kWh charge. This charge was then multiplied by the total metered kWh at each MTS substation.

For Budgeted CIS Sales, the charge was based on the short-term marginal costs of Generation and Transmission. The average marginal rate was the same as the marginal rate paid by Transmission to Generation, plus the marginal costs of Transmission losses. The variable energy rates of the base load power station were used in calculating the average marginal energy costs for Generation. For example, in 1993 the average marginal energy cost was 0.93 c/kWh. To account for extra losses, an extra 0.02 c/kWh was added. In addition, for every extra kW of capacity that Transmission purchased from Generation in an hour (standby charge), Transmission paid an extra 1.5 c/kW. Therefore the cost of CIS sales to the Distributors was calculated to be 0.93 + 0.02 + 1.5 = 2.45 c/kWh [13].

The tariff for electricity sales above budget (growth) was meant to cover the marginal variable costs. In calculating the price at which growth sales were to be charged, the price of the CIS sales of 2.45 c/kWh (discussed in the example above) was increased to 3 c/kWh to give the Distributor an incentive to budget their CIS deals as accurately as possible [25].

Variations in the eventual sales to the end customers (compared to budget sales) caused the Transmission Group to over or under recover the required revenue. This meant that the Transmission Group was exposed to full volume risk without much (if any) influence on the eventual volume of sales.

4.3 Transmission Pricing from 1994 to 1998

In the early years of the existence of the Eskom Transmission Group, the Power System Planning Department identified the need to develop a pricing mechanism more in line with the needs of a transmission company. What later developed into Transmission Economics, Market Administration, and eventually Power Pool Operations, initiated a process to develop Transmission Pricing. A literature survey conducted between the formation of the Transmission Group and 1994 managed to reveal some ideas on Transmission Pricing. A methodology from New Zealand, called the "Usage" method was adopted and the Eskom Transmission network was analysed using this method [13]. In 1994 the Transmission Group introduced its first attempt at the pricing of the transmission function separately from the cost of energy, even though it still performed the "Single Purchaser" function as middleman between Generation and Distribution.

In January 1994 a new tariff structure was implemented by the Transmission Economics Department. This tariff was intended to be as cost reflective as possible. This was done by incorporating in the tariff the economic signals related to the cost of supply. No premium was added to earn income for the Group. The tariff was made up of the following components:

- Network Charge
- Time Of Use Charge
- An hourly marginal rate

The network charge was based on the historical relative use of the system by a particular point of supply and the reserved capacity allocated to it. This charge was a fixed monthly payment in respect of a point of supply (MTS substation). This was calculated to recover Transmission's revenue requirements. The practical calculation of the network charge was a complex process that was based on simulating load flows at various points of the transmission network.

The negotiated baseline load for every supply point on the MTS formed the basis of the Time Of Use charge. This baseline load was defined as the total metered energy at all MTS substations. Using the knowledge of the half-hourly energy consumption for every MTS substation for everyday of the previous year, the time of use charges were calculated for all energy metered at each MTS substation.

The hourly marginal energy comprised of two items i.e. the marginal cost of supply and the marginal outage cost. The marginal cost of supply was a function of the short-term marginal cost of generation at the short-term marginal power station and the short-term marginal transmission cost up to the point of supply. The marginal outage cost was equal to the loss of load probability multiplied by the value of the unserved energy [10].

This transmission pricing system resulted in wide variations of the transmission portion of prices across the country (up to a high of about 20 times the average transmission price), applied only to the selling side of the business [26]. Generators did not pay for the benefit of being connected to the transmission network.

4.4 Developments of Transmission Pricing from 1998

Immediately after the implementation of the pricing system for Transmission Group, work started on the development of an improved pricing system. More information was available, and the selection process indicated that price stability would be enhanced by the use of the North American pricing system called the Distribution Factor Methodology (DFM). This pricing system has its roots in wheeling transactions as the MW-Mile pricing system, taking into account volumes as well as distance when calculating prices for electricity wheeling transactions. By changing the system to cater for open access in a utility, as opposed to wheeling through a utility, the MW-Mile pricing system became known as the DFM pricing system.

An analysis of Transmission Group's cost structure and cost drivers indicated that fixed cost dominated the picture for more than 80% of the cost of transmission, and that maximum usage of the transmission network by a customer was an important cost driver. The DFM pricing system was adapted to focus on long-term costs and maximum usage of customers, in order to be in line with the needs of the Transmission Group [26].

In 1998 the DFM based transfer prices were implemented, with the Transmission Group charging 50% of its cost to generators and the balance to loads. This enabled the Transmission Group to send price signals to both sides of the Electricity Supply Industry (ESI).

4.4.1 Pricing Between the Transmission and Distribution Groups

The Transmission Group allocates the sole use of certain capacity, known as reserved capacity, at each point of supply to Distribution. The magnitude of the capacity is negotiated annually between both parties and serves as a basis for calculating the Network Access Payment for the Transmission network. The reserved capacity at each point of supply for the year 2001 is shown in appendix 2 [28].

Distribution provides the Transmission Group with a maximum demand forecast for each point of supply for the following year. This is done on an annual basis and usually before the end of September. This forecast is used in negotiations for reserved capacity for the following year. It is also used by the Transmission Group to plan and implement system additions necessary to supply Distribution. System additions, agreed to and provided by the Transmission Group for ensuring adequate quality of supply standards at specific points of supply attract revised network access payments.

Adequate bi-directional metering equipment, with a metering interval of thirty minutes, measured on the half-hour, combining to loads, for metering the supply at the metering points of each point of supply are installed and kept in good working conditions by the Transmission Group. Energy can also be wheeled between the networks to a third party and the owner of the network used levies charges [28].

4.4.2 Components of the Transmission Tariff

The items that make up the monthly bill sent to Distribution in respect of each point of supply are the network access payment and the energy charge. In calculating the network access payment no diversity benefits are granted to Distribution.

4.4.2.1 Network Access Payment

The network access payment consists of two components. These are the Infrastructure charge and the Reliability Service charge.

Distribution pays a monthly charge for reserved capacity to the Transmission Group at each point of supply. This charge is known as the Infrastructure charge. The charges for 2001 are shown in Appendix 2. The infrastructure charge recovers the annual transmission revenue. It is generally proportional to the usage of the transmission network required to supply a unit of power at each point of supply and the magnitude of reserved capacity agreed between the Transmission Group and the Distribution Group for that point of supply.

The methodology currently used in calculating the network charge can be briefly explained as follows: Firstly, the average network charge is calculated. This is achieved by dividing the total transmission revenue requirement by the total reserved capacity for the year in order to obtain a R/kW/year value. The approximate average network charge for 2001 was R28.88/kW/year. The average network charge is then scaled according to the various concentric regions in the country. The applicable percentage surcharge per concentric region is 0%, 1%, 2%, and 3% as shown in

Figure 4.1. An in depth description of the methodology used in calculating the network charge is covered in the section on Eskom's proposed transmission tariffs.

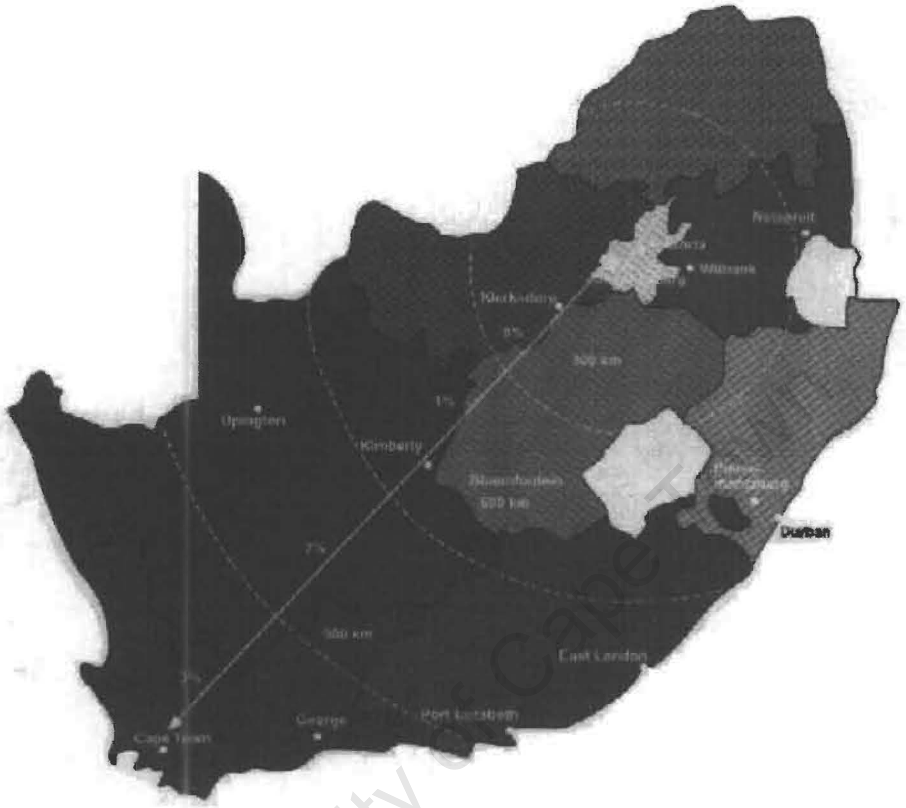

Figure 4.1: Concentric Regions and Percentage Surcharges [29]

Distribution also pays a reliability services charge, which is intended to recover the cost of acquiring ancillary services used to operate the Transmission network according to the quality of supply standards. The Transmission Group purchases ancillary services from the Eskom Generation Group. **Table 4.1** in the next page shows the agreed ancillary services, the associated cost of the ancillary services, the annual payment from Distribution for the ancillary services as part of the reliability service charge and the charge payable for the reliability services. These are approximate figures for the year 2001. Transmission network losses are also viewed as a reliability service.

Ancillary Service	Cost of Ancillary Service (Rm)	Reliability Service cost to Distribution (Rm)	Price Structure	Rate (R/MWh) or Charge [R]
Regulation and load following (AGC)	300.00	143.30	Fixed charge differentiated in R per point of supply	
Network Stability	2.10	1.00	Fixed charge differentiated in R per point of supply	
Reactive Power and Voltage Control (SCO)	24.60	11.80	Fixed charge differentiated in R per point of supply	
Energy Imbalance (Constrained Generation)	175.60	89.90	Fixed charge differentiated in R per point of supply	
Transmission Network losses	546.00	260.90	An average R/MWh for actual off take differentiated per point of supply according to loss factor	89.96
Black Start	17.00	8.10	Fixed charge differentiated in R per point of supply	
Reserves	140.00	66.90	Fixed charge differentiated in R per point of supply	
Admin Fees	115.00	54.90	Fixed charge differentiated in R per point of supply	

Table 4.1: Annual Network Access Payments [28]

4.4.2.2 Energy Charge

The electrical energy supplied to Distribution at the points of supply by the Transmission Group is charged for in accordance with the Eskom Power Pool Rules. According to the Eskom Power Pool Rules [30], the electrical energy price is equivalent to the Pool Output Price (POP). This price is calculated in R/MW/h and is given by the following equation:

$$POP_j = PIP_j + UP_j$$

Where:

POP - Pool Output Price
PIP - Pool Input Price
UP - Uplift Price
j - Hour

The pool input price is equal to the sum of the system marginal price (SMP) for a particular hour and the capacity price for that particular settlement. The uplift price is a constant value, adjusted as required by the Pool Administrator and it consists of costs for Reserve, Available Capacity, Bundled Ancillary services etc.

The price variation across the country is less than with the 1994 pricing system, in the order of up to 10 times the average price. Development work continued and work started on the development of a Wholesale Electricity Pricing System (WEPS) for Eskom. A working group that included the National Electricity Regulator (NER), and various industry representatives, as well as participation from the Generation and Distribution Group was formed to assist and give direction towards the development [27].

4.5 Future Transmission Pricing in Eskom

The development of Transmission pricing in Eskom from the period when the Transmission Group was formed led to the development of a new and better pricing method. The aim of this transmission tariff is to reduce the price variation across the country even further to a maximum variation between zero and twice the average price. This tariff will be applicable to the transport of energy, and will not include a charge for energy at all.

The new Transmission Tariff will only be implemented once the plans for the Regional Electricity Distributors have been finalised. This would be the most appropriate pricing mechanism with the restructuring of the South African Power Industry taking place and the introduction of new pricing methods in the Eskom Power Pool (EPP) i.e. WEPS.

The new tariff proposed by Eskom Transmission Group recovers the cost associated with the running of a transmission system on an annual basis through the transmission tariffs to the users of the transmission system. A few categories of cost exist. Firstly there is the cost associated with building, maintaining and operating a transmission network, the main transmission business. Secondly there are costs to finance transmission assets used to connect specific customers. The third cost relates to the energy consumed as real power losses on the transmission network. Finally there are costs involved with the purchase of ancillary services that would ensure the reliable operations of the transmission network.

4.5.1 Components of the New Transmission Tariff

In the new tariff, all charges are designed to recover 50% of the income from generators and the other 50% from loads. Four components are used to recover the various costs incurred by Transmission Group. These four components are:

- Network Charge
- Transmission Losses Charge
- Connection Charge
- Reliability Services Charge

The network charge and the transmission losses charge are based on a technical analysis of power flows in the transmission system, with maximum demand/installed capacity used for network charge and energy used for the transmission losses charge. The connection charge is based on the cost of assets used for the benefit of a single customer or a small number of customers, and the reliability charge is determined by energy usage and the cost to the Transmission Group to produce ancillary services.

4.5.2 Revenue Requirement for the Transmission Group

The revenue requirement for the Transmission Group is determined at corporate level where the three Eskom line groups are represented and the expected revenue for a year is distributed between the line groups. This annual cost should be sufficient to cover all the core needs of the Transmission Group during that year, for operations and maintenance, for finance costs, for depreciation, for overheads and also for a proper return on investments made in the transmission infrastructure and related equipment. Once the total revenue required for the core transmission business is known, the network charge can be determined.

The cost of transmission losses is equal to the volume of energy consumed as losses on the transmission network, multiplied by the energy tariff (determined by Generation Group). The volume of energy expected to be consumed as losses is estimated by doing load flow simulations, by comparing the results with the figures obtained during preceding years, and by taking into account known factors that affect the volume of losses experienced on the system.

The cost associated with the connection of specific customers and the revenue required to purchase all necessary ancillary services is easier to calculate. The connection costs are easy to identify since the assets used for this purpose are known. Costs associated with new assets used for the sole benefit of a single customer are added together to find the revenue requirements for this category. For the revenue requirement for reliability cost, estimation with reference to previous years and in consultation with System Operations and the suppliers is made during the budgeting cycle.

4.5.3 Calculation for Transmission Tariff Components

The four components of the tariff are calculated as follows:

4.5.3.1 Network Charge

The network charge has the function of recovering the cost of the infrastructure creation and maintenance used for the transport of energy. To calculate network charge, the transmission system database has to be updated annually with the most recent replacement costs for all assets. The system should be correctly configured for the year which prices will be calculated. All assets planned to be commissioned during the year in question should be included in the system model.

Installed capacities from all generators are made available to Transmission Group before the year of calculation. Similarly, for loads, all points of connection between the Transmission system and the Distribution system submit the reserved capacities to Transmission before the year of calculation. The system model consists of eight geographic pricing zones where the generators and loads are located. These zones are shown in **figure 4.2** above.

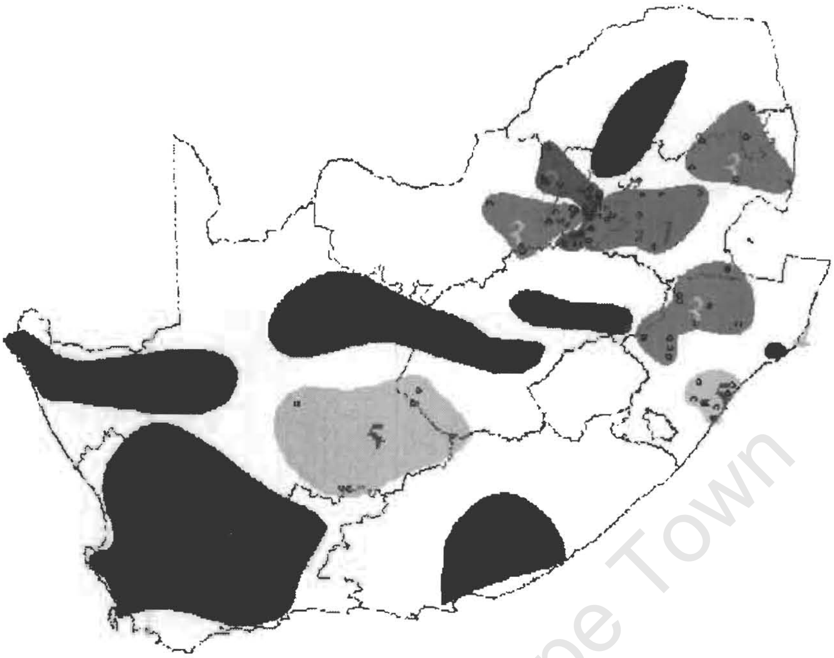

Figure 4.2: Transmission Pricing Zones [27]

A load flow simulation using a DC approximation of an AC system is done. Starting with a case where all loads and generators are on the system does this. Available generation is dispatched in proportion to the installed capacity to match generation and load. The direction of power flow is then determined on every branch in the simulation model. Following this, a load flow simulation is done for each and every generator on its own, connected to all loads, which are reduced in size to the total ratio of its reserved capacity that is equal to the generator's size to total generation. The next step is to do load flow simulations for each and every load point on its own, supplied by all generators simultaneously, but reduced in output to a value equal to its installed capacity times the ratio of the specific load relative to total load.

The output of the above simulation is used to determine the proportion of each transmission asset that is used for the benefit of each load and of each generator.

The total value of transmission assets used for each load and each generator is calculated, as well as the percentage of transmission assets allocated to all users combined. From this the average utilisation factor of the transmission system, based on peak loading is determined.

The different zonal prices are calculated by first allocating the network portion intended for security of supply and for redundancy on an average basis. This portion is calculated as an average charge per kW of demand for loads and per kW of installed capacity for generators. Secondly, the utilised portion of the network is priced. This is done by using the allocated assets for each user, and the prices then reflect geographical location. The prices for the use of the network are then obtained by combining prices for both portions of transmission assets. An example of how to calculate the network charge is done below.

Example

The approximate reserved capacity for all eight loads and the installed capacity for the eight generators for the year 2001 are used and these are shown in **table 4.2** below.

Region Number	Type	MW
1	Load 1	5000
	Generator 1	25000
2	Load 2	15000
	Generator 2	2400
3	Load 3	5000
	Generator 3	1000
4	Load 4	2000
	Generator 4	3000
5	Load 5	1000
	Generator 5	750
6	Load 6	1000
	Generator 6	1*
7	Load 7	3000
	Generator 7	1850
8	Load 8	2000
	Generator 8	1*

Table 4.2: Approximate loads and installed capacity for the eight regions (2001)

The total capacity for all the loads amounts to 34 000 MW and so does the total of the installed capacity for the generators. The amount allocated to transmission from the 2001 budget was roughly R1963 million. **Table 4.3** below shows the capacity of the lines connecting the various geographic pricing regions in the country and the rand values of these capacities. **Table 4.4** shows the actual amount of flow in the assets connecting the regions and the rand utilised value of these.

Asset	Capacity MW	Value R
Line 1-2	16000	2797
Line 1-3	11000	2277
Line 1-4	18000	4802
Line 4-5	10500	1946
Line 5-6	1500	607
Line 5-7	7000	2190
Line 5-8	5000	2254
Total		**16873**

Table 4.3: Network Capacity and Value

Asset	Actual Flow MW	Value R
Line 1-2	12600	2202
Line 1-3	4000	828
Line 1-4	3398	907
Line 4-5	4398	815
Line 5-6	999	404
Line 5-7	1150	360
Line 5-8	1999	901
Total		**6417**

Table 4.4: Utilised Capacity and Value

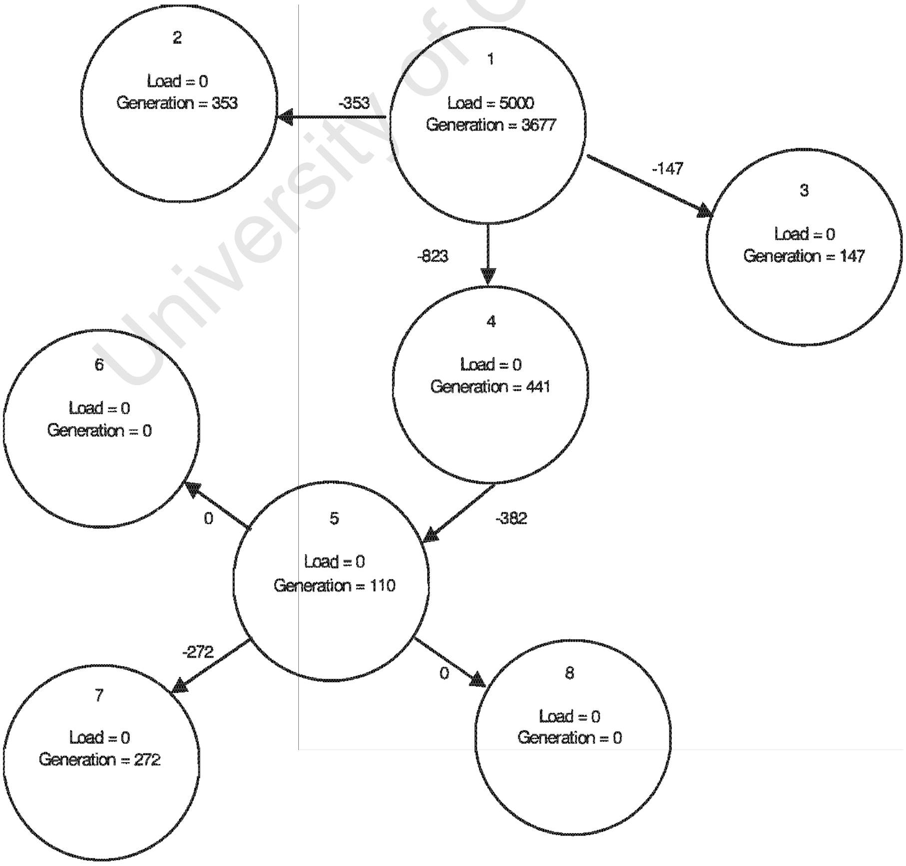

Figure 4.3: Load 1 Model

The total utilised value of assets is about 36% of the total capacity. The value of spare capacity is about 64%.

The network charge for each region (e.g. load 1) is calculated by scaling down all the generators such that they supply the capacity for one load, with all the other loads equal to zero. In this case the capacity of load 1 is 5000 MW as shown in **table 4.2**. The scaling factor for the generators is about 14%, calculated by dividing the total capacity for load1 and the total system load. A load flow simulation is done with all the scaled down generators supplying load 1 and all other loads equal to zero.

The actual flow on the system as a result of supplying load 1 is obtained after the load flow simulation. A model of this is shown in **figure 4.3**. The rand value of the utilised capacity is then calculated. A rental factor is used to calculate the rand value of the capacity used when only load 1 is connected to the system. The rental factor is obtained by dividing the Transmission budget amount by the total utilised value. In this case the rental factor is as follows:

$$rental \quad factor = \frac{Budget \quad amount}{Total \quad utilised \quad value} \times 50\%$$

$$rental \quad factor = \frac{R1963 \quad Million}{6417} \times 0.5 = 15.3\%$$

The rent to be covered by load 1 is obtained by multiplying the rental factor with the total utilised value of connecting only load 1 and the rest of the scaled down generators. In this case the rent is calculated to be:

$$rent = rental \quad factor \times total \quad utilised \quad value = 15.3\% \times -468 = -72$$

A R/kW/year charge is obtained by dividing the rent by load 1 and multiplying by one hundred as follows:

$$\frac{rent}{Load1} \times 100 = \frac{-72}{5000} \times 100 = -14.30 R / kW / year$$

The network charge is found by making an adjustment to the above R/kW/year value by incorporating the average price for spare capacity. The price signal, obtained by making use of the utilised capacity, is added to the average price of the spare capacity, to obtain the network charge for load1. The average price is given by the sum of the rent by all the loads divided by total capacity of the loads times one hundred. In this case this gives 28.88 R/kW/year. The average price for spare capacity is given by multiplying the percentage of spare capacity with the average price. The price signal is given by multiplying the percentage of utilised capacity with the R/kW/year charge of –14.30 obtained in the above calculation. When the price signal and the average price are added together, the network charge for load 1 is obtained. The percentages of spare capacity and the utilised capacity for the year 2001 are 64% and 36% respectively. Therefore the average price for spare capacity and the price signal for load 1 is 18.49 and –5.14 R/kW/year, and the Network Charge for load 1 is the sum of the two, which is 13.34 R/kW/year.

The method used in the calculation of the Network charge for load 1 above is applied in the calculation of the Network Charges for the other loads and generators. **Figure 4.4** below shows the loads and installed capacities for 2001 and the net flow of energy on the transmission network. Also shown in the figure are the approximate network charges to all the loads and generators for the year 2001. These charges are also shown in **table 4.5 and 4.6** below.

	Rent	**R/kW/yr**
Load 1	66.68	13.34
Load 2	344.37	22.96
Load 3	123.67	24.73
Load 4	56.05	28.03
Load 5	38.25	38.25
Load 6	60.54	60.54
Load 7	166.36	55.45
Load 8	126.10	63.05
Total	**982**	

Table 4.5: Charges for loads

	Rent	**R/kW/yr**
Gen 1	850.73	34.03
Gen 2	58.58	24.41
Gen 3	22.63	22.63
Gen 4	58.03	19.34
Gen 5	6.86	9.14
Gen 6	(0.01)	(13.51)
Gen 7	(14.96)	(8.09)
Gen 8	(0.02)	(17.51)
Total	**982**	

Table 4.6: Charges for generators

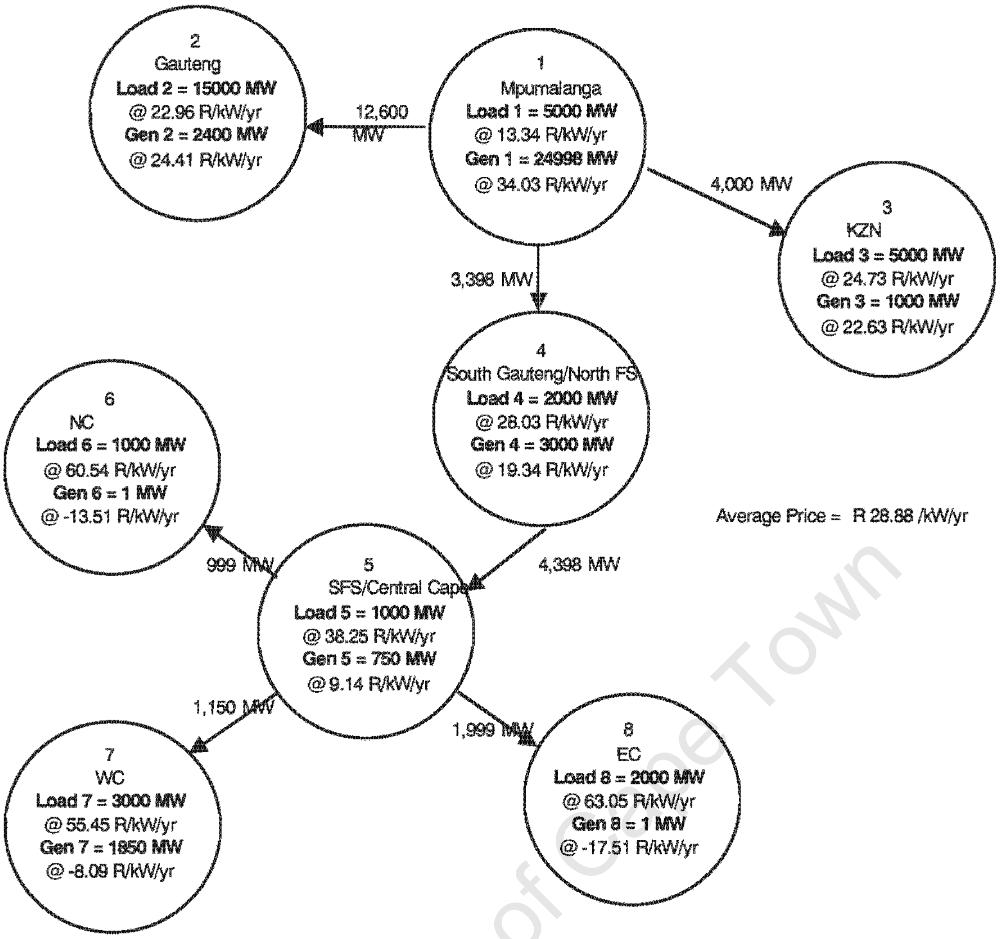

Figure 4.4: Loads and Installed Capacities for 2001

4.5.3.2 Transmission Losses Charge

The Transmission Group only focuses on technical losses. This occurs when more power is measured to be delivered into the transmission network by power stations than is measured to be delivered from the network to re-distributors. The Transmission Group charges both generators and loads a transmission losses charge, reflecting the relative amount of losses associated with a specific position on the network for a generator or load. 50% comes from generators and the remaining 50% from loads.

To calculate transmission losses, an analysis of the actual measured losses during previous years is done first. Then corrections are made for the known factors that have major influences on transmission losses. All future plans regarding these known factors are taken into account for the following year, and the expected percentage of transmission losses can be estimated in this way [28].

When the calculation of transmission losses charge is done, the installed capacities of generators and the reserved capacities for loads are known by the Transmission Group. These values are used in a simulation of the network (using the P/SSE software tool) where the system load is scaled to the average demand of the network, which is total budgeted energy divided by 8760 hours in the year [26].

The standard technique to calculate marginal loss factors is used in the calculation of the loss factors for generators and for loads. For example:

$$\begin{aligned}
&Load \quad A = 1000MW\\
&Planned \quad Energy \quad Delivered = 200274GWh\\
&Hours/year = 8760\\
&\therefore Average \quad Load = \frac{Energy \quad Delivered}{Hours/year} = \frac{200274GWh}{8760} = 22862.3MW
\end{aligned}$$

A load flow simulation is done with reserved capacity loads scaled down to realise a system load of 22 862 MW as explained above. Generators are scaled down in order to supply this load as well as losses. Generation level as well as losses are noted down, say 686 MW in this case (which is about 3% of load). To calculate loss factor for Load A (1000 MW), Load A is increased by 100 MW to 1100 MW. All the other loads are kept constant at their previous values. Total generation is increased by 100 MW using scaling of the generator facility. A new load flow simulation is then done and the losses recorded. If the new losses are 690 MW, this means the losses increased by 4 MW when Load A was increased by 100 MW. Therefore the loss factor would be 1.04 meaning that there is a 4% loss for Load A. If on the other hand, the new losses were 680 MW, then this would mean that losses decreased by 6 MW when Load A increased by 100 MW. Therefore the loss factor is 0.94 meaning that there is –6% losses for Load A.

4.5.3.3 Connection Charge

The connection charge exist in two parts, namely the transformation charge to all users (new and existing) to cover the cost of transforming the voltage from transmission voltages (220 kV and above) to lower voltages (132 kV and below), and a customer specific connection charge to new customers to cover any expenses incurred for the benefit of the new customer [26].

New connections to the transmission network that require minimal investments in transmission assets are connected using the existing network charge, and the connection charge will be calculated as for existing customers, using the transformation charge applicable to the situation. If the customer requests a connection where new assets have to be installed in the substation, the connection charge will reflect actual cost to accommodate the customer's requests.

A new customer connecting to the transmission network will have to pay a connection charge based on the full cost of dedicated assets for the express benefit of this new customer. For transmission assets not dedicated to this new customer, the principles used to calculate the sharing of assets for the network charge will be used to determine the portion of the new assets that has to be paid for, as part of the connection charge. In short this means a load flow simulation has to be done with only the new load on the system, and with all generators supplying this new load, each generator in proportion to it's contribution to total generating capacity. The portion of the new transmission assets used as indicated by this simulation will indicate the portion of the cost of the new assets that has to be included in the connection charge to the new customer.

4.5.3.4 Reliability Services Charge

The purpose of the reliability charge is to earn revenue to pay for the purchase of ancillary services from mainly the generators, but also from industrial customers in certain cases. The total budgeted cost of ancillary services are determined by the relevant Transmission Group officials, and an energy rate is calculated for the reliability charge that would allow the specific amount of budgeted revenue to be collected based on the budgeted amount of energy to be generated and delivered by Transmission Group. It would be beneficial for the Transmission Group to enter into contracts with the bigger players in order to reduce the risk of being caught in the middle if costs of ancillary services spiral and income from reliability services fall short due to lower than budget sales of electrical energy.

4.6 Summary

The transmission tariff was first implemented in 1991 after the formation of the Eskom Transmission Group. The transmission tariff used between 1991 and 1994 was in line with the single buyer model where the Transmission Group bought electrical energy from the Generation Group and sold it to the Distribution Group. The tariff used recovered revenue from the Distributors in three ways, which included revenue from Base Sales, revenue from Budgeted Sales to Customer Incentive Schemes (CIS) customers, and revenue from Growth Sales. The Transmission Group over or under recovered the revenue as a result of the variation in the eventual sales to end customers. Since the Transmission Group was exposed to full volume risk, a development of a better pricing method was initiated.

The Transmission Economics Group in 1994 implemented a new tariff structure. This tariff was made of three components: Network Charge, Time Of Use (TOU) Charge, and an Hourly Marginal Rate. The variations in the transmission prices across the country were wide (up to a high of about 20 times the average transmission price) but better than the first transmission-pricing tariff.

The wide variations in the transmission prices led to a further development in determining a better pricing method. As a result, in 1998 a new tariff was adopted. This tariff was based on the Distribution Factor Methodology, with the Transmission Group charging 50% of its cost to generators and the balance to loads. This resulted in the Transmission Group sending price signals to both sides of the Electricity Supply Industry (ESI). The new tariff consisted of a network access payment and an energy charge. The prices differed and depended on the location of the customers in South Africa. The country was divided into four pricing zones. The price variation across the country was less than that of 1994.

Further developments in the transmission pricing system led to a proposed transmission pricing method to be used in future after the deregulation process is complete. This pricing method involves a change in the zonal pricing method, moving from the four pricing zones to a regional pricing method with eight regions. This method is meant to be in line with the proposed structure for the Electricity Distribution Industry (EDI) and the Electricity Supply Industry (ESI) as well as the implementation of the Regional Electricity Distributors (REDs) and the Wholesale

Electricity Pricing System (WEPS). It is not clear how this will operate, as the proposed REDs comprise six regions whereas the pricing method comprises eight tariff zones. It appears that several REDs will purchase in more than one tariff zone. This shows that this pricing method is not designed in a way that the tariff zone matches the distributor boundaries.

The variations in the Transmission prices across the country would be reduced even further with the implementation of this pricing method. This method has a potential of reducing the prices to a maximum variation between zero and twice the average price. This tariff will also be applicable to the transport of energy, and will not include a charge for energy at all.

CHAPTER FIVE

Network Pricing in other Countries

Network pricing is a vital part of electricity transmission pricing. This chapter reviews network-pricing methods in Australia, and England and Wales. The key principles that are closely looked at are geographic price signals, cost reflective nature of the charges, and the extent of economical signals sent by these charges. A comparison with the South African network charge is carried out towards the end of the chapter.

5.1 Transmission Use of System (TUoS) Charges in England and Wales

The National Grid Company (NGC) operates the transmission grid in England and Wales. The costs of transmission are recovered in two ways. NGC's own costs are met through its charges for connection (to Regional Electricity Companies RECs and generators) and for use of the transmission system by generators and suppliers (transmission use of system TUoS charges). Other transmission related costs are dealt with by the Pool [31].

NGC's charges comply with rules laid down in the company's licence. The licence requires that NGC does not discriminate between any of its customers, and specifies the maximum amount that the company can charge for existing connections, and in TUoS charges [32].

The TUoS charge sends geographical messages. The initial charges divided the country into 11 zones, and set zonal prices for peak demand, registered generation capacity, and energy generated. Generation in London was free; that in the north paid the highest charges, while demand was cheapest in the north and most expensive in London [31]. Demand charges were based on each suppliers triad demand: the amount taken during the 3 half-hours of highest demand that were at least 10 days away from each other. The energy charges for generators were constant proportion of the capacity charges: a station that spent the year without generating would only pay 60% of the bill (per kW) for a station that ran continuously [31]. **Figure 5.1** shows the 1990/1 demand and generation charges in each of NGC's zones.

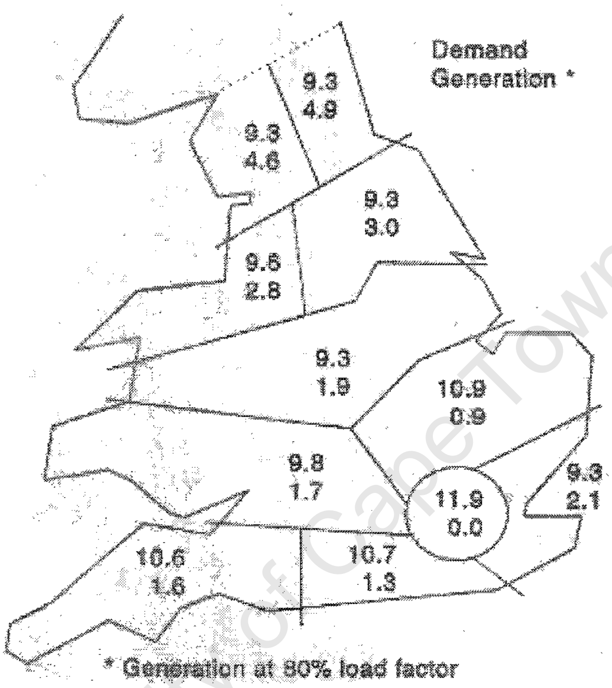

Figure 5.1: The 1990/1 Demand and Generation Charges [31]

In 1992 NGC reviewed its pricing methodology [31]. Several methodologies were considered. A method called Investment Cost-Related Pricing was chosen by the NGC. This method was aimed at producing a more stable message, and which has been calculated in a transparent manner. NGC uses a simple model to asses the cost of expanding the system to cope with additional demand or generation at each node in turn. The model is a linear programme which minimises the MW-km of transport, assuming that electricity flows along the shortest route between nodes with net generation and net demand [31]:

Find x_{ij} *to minimise* $C_{ij} |x_{ij}|$

Subject to ${}_{j}x_{ij}=G_i-D_i$ *for all nodes* i

Where x_{ij} is the flow in MW from node *i* to node *j*, C_{ij} is the distance from node *i* to node *j*, G_i is the generation at node *I*, and D_i is the demand at node *i*. The distances are measured along NGC's existing wayleaves, and increased along those wayleaves where the wayleave only gives permission to an underground line, to reflect the higher cost of those lines. The demand at each node is equal to the forecast peak demand at that node, while the generation capacity at each node is scaled down by the ratio of the forecast level of demand to total generation capacity. (This ensures that the forecast generation equals demand, but does not reflect the likely distribution of actual generation, treating high and low cost stations equally). The model calculates the extra transmission capacity (in MW-km) required by additional demand at each node, which is multiplied by an expansion constant (£24.91 per MW-km in 1996/7) to give the marginal cost of that demand [31]. Northern generation and southern demand increase NGC's costs, while the marginal cost for southern generation is actually negative.

Points with similar costs are grouped into zones, and the transport charge for each zone is based on the average cost of the points within it. NGC demand charges are based on the average triad demands, which is inevitably below the peak demand, and so the raw transport charge is scaled up to reflect this difference [32]. Generation charges are based on registered capacity, rather than output, but the transport charge is no longer adjusted to reflect this. (The exception is where the charge is negative: NGC will only pay generators for an amount of capacity equal to their highest metered output (also on a triad basis) during the winter). Until 1996/7, the same zones (11 at first, then 14) were used for generation and demand charges. From 1997/8, however, NGC has been using different zones for demand and generation. Each REC is now a single demand zone, which greatly simplified the task of organising competition in supply – a supplier need only know which REC's area a customer is in to know the NGC TUoS charge for that customer. NGC also added two more zones for generation in order to reflect its costs better.

NGC estimated that the transport charges for generation and demand would have brought in £148 million if the methodology had been applied in 1992/3, while the company would be allowed to raise £670 million from TUoS charges [31]. To raise the remainder (£522 million in this example), NGC increased all the charges by common amounts (in the example, £2/kW for generation, and £8.30/kW for demand. The figures were chosen to raise three quarters of the revenue from suppliers (continuing the arbitrary split chosen in 1990) while maintaining the geographic message. This message was of much greater differentials than before, and the companies that were to lose out complained. NGC accordingly phased in most of the changes over 4 years, subject to a maximum increase of £2/kW in any year (so that the largest increases, in the southwest, would take 6 years to be fully implemented). **Figure 5.2** shows the charges for 1996/7, when almost all of the differentials had been applied.

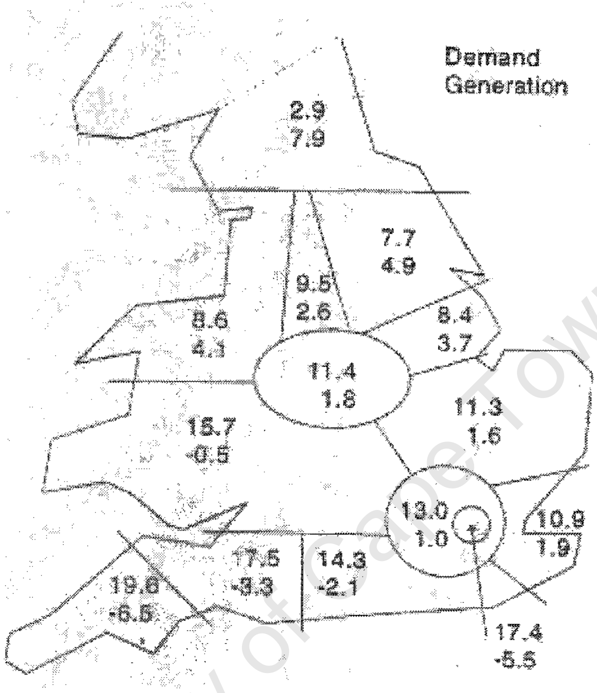

Figure 5.2: The 1996/7 Demand and Generation Charges [31]

The geographical messages are much stronger than before, but they may still underestimate the true cost of electricity transmission. The linear programme used to calculate the cost of expanding the NGC system assumes that electricity will flow by the shortest route, while Kirchhoff's laws imply that power flows would increase on other circuits, increasing the number of MW-kilometres travelled [33]. Furthermore, the expansion constants – the cost per MW-km – assume that the line is being operated at full capacity. The need for system security dictates that the network can function after the loss of any individual circuit, which implies the need for substantial spare capacity on routes, which are served by few circuits. Furthermore, power losses on heavily loaded lines are so high that it is often cheapest to operate a line at little more than half of its rated capacity. NGC's expansion constants might need to be substantially increased to give the true cost of increasing power flows from north to south. In practice, the standard expansion constant includes an allowance for the cost of putting some lines underground, and is nearly 40% higher than the reduced rate used for routes where NGC has substantial spare capacity and uses the cost of overhead lines alone [33]. This might be viewed as an allowance for spare capacity rather than for the cost of underground cables, but would only cover part of the cost. Finally, NGC's charges do not include the cost of losses.

The company sets NGC's charges, and there can be little doubt that they have been designed to recover all of the revenue which NGC's licence allows. These charges do send signals about the appropriate location for new generation and demand as can be seen in **figures 5.1 and 5.2**. The investments cost related prices for transport are determined through a process that involves some simplifying assumptions. One is that Kirchhoff's Law determining flows in electrical networks is ignored. A second is that, instead of simulating a merit order operation, generation at each node is taken to equal generation capacity at that node scaled down in a uniform proportion for all nodes so that total generation equals total peak demand. [33]

5.2 Network Pricing in Australia

The National Electricity Code Administrator (NECA) administers transmission pricing in Australia. The states under NECA's administration are New South Wales, Victoria, Queensland, South Australia, Australian Capital Territory, and Tasmania [35]. The Australian Competition and Consumer Commission provided the network pricing method. This method is known as Transmission Use of System (TUoS) usage charge. The basis of this pricing method is Cost Reflective Network Pricing (CRNP) cost allocation process [34]. This section reviews how this method is applied in determining the transmission network price in Australia.

The application of the network pricing is illustrated by making use of an example. The example system used by Cap Gemini Ernest and Young, which was commissioned by NECA to develop a worked example to illustrate how this method works, is based closely on an example that was used by the Victorian Power Exchange [34]. The example system is shown in **figure 5.3**.

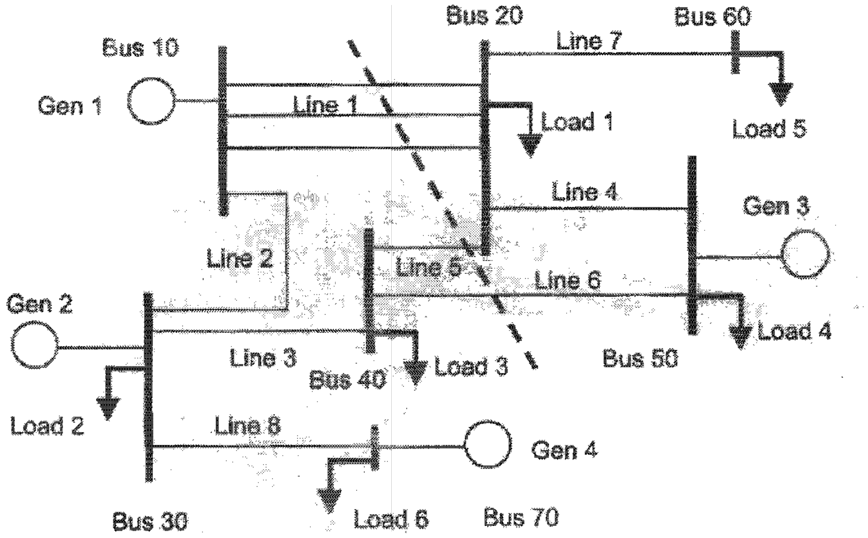

Figure 5.3: Example System [34]

The calculations for network prices require standard matrix manipulations on equations derived from power systems load flow and fault level analysis, including the Jacobian matrix. The relevant generation, loading and line flows are shown in **Tables 5.1 and 5.2**. The calculations that are part of the steps of developing the network pricing in Australia include the fault level matrix, system equation, generation to load allocation matrix and the calculation of the sensitivity matrix. These calculations are quite complex and this thesis does include details of these.

Bus	Generation (MW)	Load (MW)
10	1039.3	
20		400
30	100.0	200
40		250
50	200.0	300
60		300
70	200.0	50

Table 5.1: Generation and Loads [34]

Line	From Bus	To Bus	Flow (MW)
Line 1	10	20	763
Line 2	10	30	278
Line 3	30	40	321
Line 4	20	50	53
Line 5	20	40	-25
Line 6	40	50	48
Line 7	20	60	300
Line 8	30	70	-150

Table 5.2: Line Flows [34]

The explanation of the methodology begins with the participation matrix, which is established from the initial calculations as laid out above. The participation matrix relates the flow components on individual transmission lines to individual loads as shown by the equation below:

$$\begin{bmatrix} \Delta Flow_1 \\ \Delta Flow_2 \\ \Delta Flow_3 \\ \Delta Flow_4 \\ \Delta Flow_5 \\ \Delta Flow_6 \\ \Delta Flow_7 \end{bmatrix} = [p] \begin{bmatrix} \Delta Load_1 \\ \Delta Load_2 \\ \Delta Load_3 \\ \Delta Load_4 \\ \Delta Load_5 \\ \Delta Load_6 \\ \Delta Load_7 \end{bmatrix}$$

This matrix is used to determine the allocated network costs for each load point. This is achieved by multiplying the transpose of the participation matrix [p] by the cost allocated to each of the individual transmission elements to give the Cost Reflective Network Pricing (CRNP). These costs are represented as follows [34]:

$$\begin{bmatrix} C_1 \\ C_2 \\ C_3 \\ C_4 \\ C_5 \\ C_6 \end{bmatrix} = \left[P^T\right] \begin{bmatrix} LineCost_1 \\ LineCost_2 \\ LineCost_3 \\ LineCost_4 \\ LineCost_5 \\ LineCost_6 \\ LineCost_7 \\ LineCost_8 \end{bmatrix}$$

The estimates of these costs are based on the existing asset costs. The ACCC requires that the costs reflect economic pricing signals, ideally as captured through congestion costs. These costs are determined from the augmentation prices associated with each transmission line, adjusted by utilisation. The approach is as follows [36]:

- The cost of the most cost effective augmentation is determined for each individual transmission element, together with the additional capacity that would be provided;
- An incremental (LRMC) price is determined for each element, from the annualised cost divided by the capacity increment;
- For each individual operating condition the price is adjusted by the utilisation of the line;
- The adjusted augmentation price is multiplied by the line flow for the particular operating conditions to arrive at the cost allocated for that line for that condition.

The augmentation costs used for each line and the flow for the example are outlined in **Table 5.3**, together with the calculated price for augmentation of each. This price is used in **Table 5.4** to determine the cost to be allocated based on the actual line flow.

Line	From Bus	To Bus	Flow (MW)	Annual Augmentation Cost ($)	Additional Rating Provided (MW)	LRMC Price ($k/MW)
Line 1	10	20	763	2,000,000	1000	2.00
Line 2	10	30	278	1,000,000	500	2.00
Line 3	30	40	321	2,000,000	500	4.00
Line 4	20	50	53	3,500,000	500	7.00
Line 5	20	40	-25	1,500,000	500	3.00
Line 6	40	50	48	3,000,000	500	6.00
Line 7	20	60	300	0	300	0.00
Line 8	30	70	-150	4,000,000	150	26.67

Table 5.3: Assumed Line Costs [34]

Line	From Bus	To Bus	Flow	Full Augmentation Price ($k/MW)	Utilisation Adjusted Price ($k/MW)	Rating	Allocated Cost ($k)
Line 1	10	20	763	2.00	1.91	1000	1,455
Line 2	10	30	278	2.00	1.39	500	386
Line 3	30	40	321	4.00	3.21	500	1,030
Line 4	20	50	53	7.00	1.55	500	82
Line 5	20	40	-25	3.00	0.31	500	8
Line 6	40	50	48	6.00	1.20	500	58
Line 7	20	60	300	0.00	0.00	300	0
Line 8	30	70	-150	26.67	26.67	150	4,000
TOTAL							7,020

Table 5.4: Allocated Costs for Example [34]

The allocated costs are determined for each location from the following equation [34]:

$$\begin{bmatrix} C_1 \\ C_2 \\ C_3 \\ C_4 \\ C_5 \\ C_6 \end{bmatrix} = \left[P^T\right] \begin{bmatrix} LineCost_1 \\ LineCost_2 \\ LineCost_3 \\ LineCost_4 \\ LineCost_5 \\ LineCost_6 \\ LineCost_7 \\ LineCost_8 \end{bmatrix}$$

$$\begin{bmatrix} C_1 \\ C_2 \\ C_3 \\ C_4 \\ C_5 \\ C_6 \end{bmatrix} = \left[P^T\right] \begin{bmatrix} \$1{,}455k \\ \$386k \\ \$1{,}030k \\ \$82k \\ \$8k \\ \$58k \\ \$0k \\ \$4{,}000k \end{bmatrix}$$

Determining the costs allocated to the busbars completes the allocation of the costs according to the CRNP method. The costs for this example are shown in the equation below:

$$\begin{bmatrix} Bus_1 \\ Bus_2 \\ Bus_3 \\ Bus_4 \\ Bus_5 \\ Bus_6 \\ Bus_7 \end{bmatrix} = \begin{bmatrix} \$0k \\ \$2{,}095k \\ \$995k \\ \$1{,}688k \\ \$1{,}752k \\ \$1{,}571k \\ \$-1{,}082k \end{bmatrix}$$

The total of the allocated costs is $7.02 million and is the same as the total found in **Table 5.4**. The costs associated with each network element are attributed with each busbar. The final step is then to convert the allocated costs into network prices. The first stage here is to make sure that the prices recover all the allocated costs from the connected load. The prices are obtained by dividing the allocated costs by the demand for a specific operating condition. The network prices for this example are:

$$\begin{bmatrix} \Pr ice_{10} \\ \Pr ice_{20} \\ \Pr ice_{30} \\ \Pr ice_{40} \\ \Pr ice_{50} \\ \Pr ice_{60} \\ \Pr ice_{70} \end{bmatrix} = \begin{bmatrix} \$4.23k/MW \\ \$5.238k/MW \\ \$4.975k/MW \\ \$6.752k/MW \\ \$5.841k/MW \\ \$5.238k/MW \\ \$-21.643k/MW \end{bmatrix}$$

5.3 Comparisons with the South African Network Pricing

This section compares the revenue requirements, the geographic signals, and economic signals sent by the various network charges of the three countries.

5.3.1 Geographic Signals

The network charge in England and Wales sends geographical signals of the location of generators and customers. Most generators are located in the North and most demand in the South. Therefore demand was cheapest in the North and most expensive in the South. This is similar to the situation in South Africa whereby the network charges are high for the customers located farther away from the generation-rich Mpumalanga province. Provinces such as the Northern Cape, Eastern Cape and the Western Cape are charged very high network prices. The description of the Australian network price does not emphasize on geographic price signals. However the cost allocated to the busbars is probably distance related as more equipment is used to supply a customer located farther away from the energy source. Therefore, the prices in all three countries can be thought of as sending geographic price signals.

5.3.2 Revenue Requirement

In England and Wales the licence governing NGC regarding TUoS charges sets a maximum charge. This means that the revenue requirement by the NGC for use of its network is limited. In South Africa it is a different case. The revenue requirement is determined by the utility (and approved by the regulator) and there is no set limit. The basis for the revenue requirement is the total network cost. Regardless of how much energy is utilised in a specific year, the required revenue has to be recovered. This means that if the energy delivered decreases, the network charge per unit of energy increases. This method ensures that the total cost of the network is recovered but does not deliver pricing signals to achieve economic efficiency objectives. In Australia the estimates of the network costs are generally based on the existing asset costs, which is similar to the method used in South Africa. However, the cost allocation is modified in order to reflect economic pricing signals. Australia achieved this by recognising congestion costs to represent long run marginal costs, this however is not the only way it can be achieved.

5.3.3 Cost Reflective

All three network-pricing methods are based on cost reflective network pricing. In England and Wales it is highly possible that the charges are designed in such away that they recover all the revenue that NGC's licence allows. In South Africa the network costs are allocated to the various zones mainly based on geographic location rather than congestion. The Australian method is based on CRNP but is modified to reflect economic pricing signals [35]. While the marginal costing approach used in Australia is not the only way to convey economic price signals, the cost allocation approach in South Africa, without recognising congestion, gives an incomplete economic price signals.

5.4 Summary

The network pricing method used in Australia, England and Wales is known as the Transmission Use of System (TUoS) charge. In England and Wales this charge sends geographical messages into the countries' pricing zones. It is also designed to be cost reflective, there is a limit on what NGC can charge its customers. This maximum amount is specified in NGC's licence. Australia's network charge differs from that of England and Wales in that, there is no set maximum charge and it also designed to send economic price signals by considering congestion along the transmission system. Both methods differ from the South African method, which does not have a price cap and does not send economic price signals even though it is cost reflective.

CHAPTER SIX

Impact of DG on Transmission Pricing

This chapter presents an analysis of the impact that DG can have on South Africa's electrical energy transmission costs and tariffs. The transmission tariff used in the country was described in detail in chapter four and distributed generation benefits were discussed in the second chapter. In assessing the impact of DG on Eskom's transmission tariff, these two are linked in this chapter. This is done by unbundling Eskom's transmission costs or rather Eskom's transmission tariff components and analysing the impact of increasing DG on each component. The four components considered are: the network charge, losses charge, connection charge and the reliability services charge.

6.1 Network Charge

The network charge is one of the transmission tariff components. The basis of this charge is the projected revenue requirement for the transmission group. The reserved capacity for all distribution loads, the total installed generation capacity, the capacity of the transmission lines and the actual flow capacity of the lines and rand values of these capacities are used in determining the network charge for a specific load. These form the inputs in the whole network charge calculation. Once these inputs are known, processes such as load flows are performed and outputs leading to the required amount of network charge. The processes include scaling down all generators proportionally and loads for a specific case, and then performing a DC load flow simulation

Using the above information, the rental factor, average price, the average price for spare capacity, and the scaling factor, are calculated. By making use of the scaling factor, all the generators are scaled down proportionally to supply one load. A DC load flow simulation is then done to determine the amount and direction of power flow in the network. This is used to calculate the amount to be paid by the specific load as rent for using the network. The rent is then converted into R/kW/yr. The price signal for the specific load is then calculated and noted. The network charge is then obtained by combining the price signal and the average price.

Based on the benefits of DG identified in section 2.2.4.2 in the literature survey, and the trends in Europe, it is expected that an increase in DG penetration will lower transmission price for a specific region since generation is local. The connection of DG in a specific region comes with a number of advantages to the utility. Reserve margin for the region would be reduced and increases in system capacity would be avoided as DG provides an additional source of power. In certain regions where there is congestion, DG can increase the effective transmission network capacity for other users by relieving the network of congestion. The DG owner could render services to alleviate congestion problems faced by utilities in some parts of their networks. Utilities such as Eskom can use DG to meet growing demands and defer investments in transmission capacity. During high demand periods DG can reduce customer demands from the grid. An increase in DG capacity in a specific region comes with the above-mentioned benefits. If these benefits are meaningful to the utility, the network charge is expected to be affected in a positive way (reduction in network charge) from the customer (distributor) point of view.

6.1.1 Effect of Increasing DG penetration

A study by the Electric Power Research Institute (EPRI) [14] indicates that 25% of new generation by 2010 will be distributed, a study by the Natural Gas Foundation concluded that this figure could be as high as 30%. Considering the abundant DG resources available in SA, as mentioned in chapter three, and the amount of research work done on DG, the same is expected to happen in South Africa by 2020 as illustrated in table 3.3 of chapter three. Assuming that 25% of the total electrical energy in South Africa is from DG and by making use of the 2001 Eskom Transmission Group's budget, reserved capacity, installed capacity, assets, and the eight defined geographical regions as shown in chapter four in figure 4.2, the effect on the network charge for one region is shown in the figure 6.1. This graph shows the impact of increasing DG capacity in the Eastern Cape where the transmission network charge is the highest in the country. This graph was prepared by plotting transmission price rate against the percentage of Eastern Cape load supplied by DG.

The approximate load for the Eastern Cape in 2001 was 2000MW [26]. Therefore the 25% local capacity from DGs would be 500MW. On the basis that some of the load is supplied from local DG, the load on the transmission system would be reduced. If the same network charge allocation method is used the effect of increasing DG capacity from 0 to 25% on the network charge in the Eastern Cape would be as shown by the in figure 6.1. Surely this is the opposite of the expectations with the increasing DG capacity. A similar analysis done for the Northern Cape and the Western Cape produced a similar set of results i.e., the network charge increases with increasing DG penetration. This exercise shows an increase in charge rate.

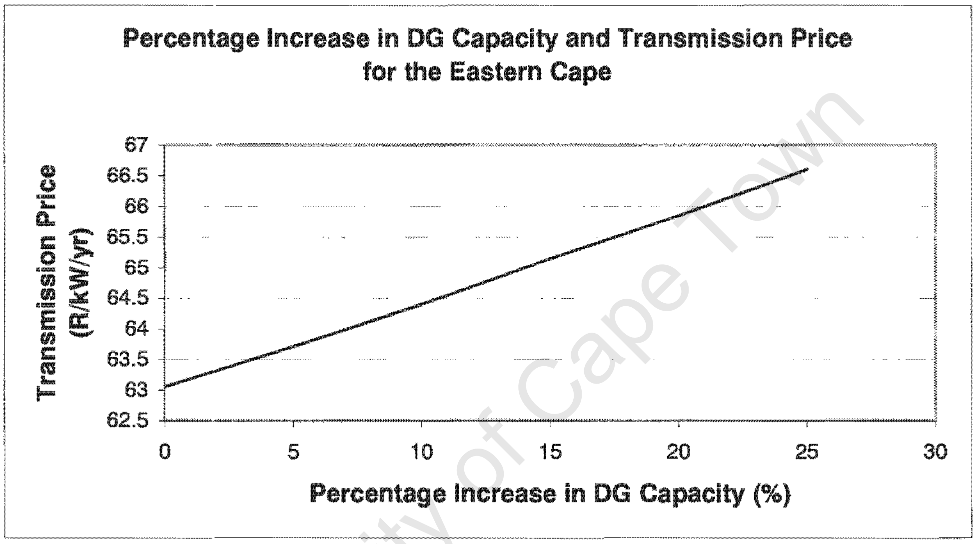

Figure 6.1:Transmission Price According to Proportion (0 to 25%) of Load Supplied by DG

As can be seen in figure 6.1, an increase in DG penetration results in an increase in the network charge rate levied to customers. This means that the expected returns from each region by the transmission group from its customers is fixed for the network charge. If the customers use less network capacity by making use of electricity from local generators such as DG, the Eskom network charge rate automatically increases. The network charges are fixed for a year per region. Therefore the changes on the charges are made when the new price is set on an annual basis. This indicates that the network charge is designed in such a way that it discourages the development of DG. Some customers might view DG negatively as its development results in higher network charge rates. Figure 6.2 shows a graph of the total price against a percentage DG capacity of basic load. The graph shows a contribution of DG between 0 and 100%.

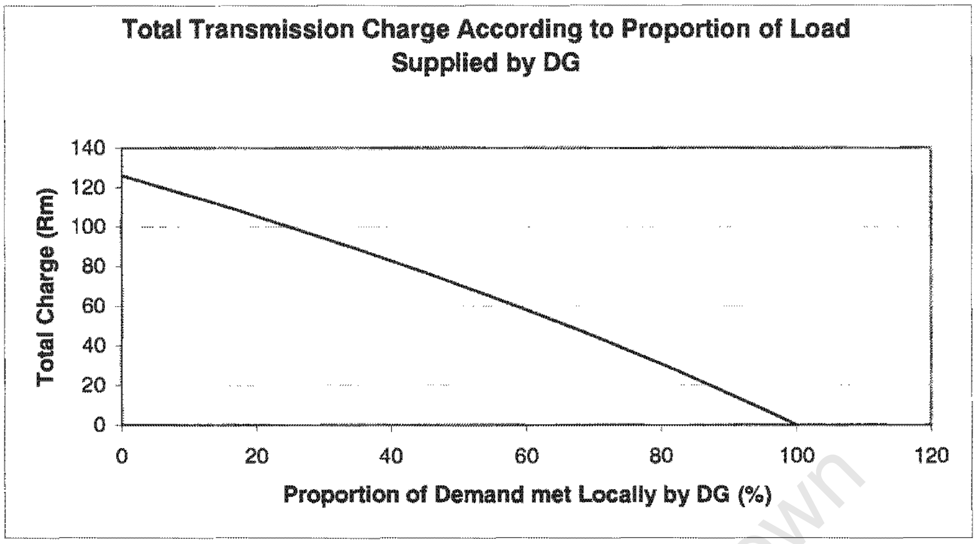

Figure 6.2: Total Transmission Charge According to Proportion of Load Supplied by DG

On the other hand, the increase in network charges can lead to an increase in DG development in the area. The high Eskom network charges might put DG in a good market position to compete with central generation. With Eskom network charges going up, and electricity production costs using DG going down, DG development in South Africa will greatly improve especially in the Eastern Cape, Northern Cape and Western Cape where increasing penetration of DG would result in high network charge rates.

The above results highlight that setting prices by some definitions (in this case by Eskom Transmission) offers no incentives for efficient investment (by DG). The network charge is structured in such a way that, to supply a very remote area like the Eastern Cape, all the generators will contribute towards the demand of the area. Some generators are very far from the Eastern Cape. Therefore a lot of transmission equipment is utilised before the energy reaches its destination. This greatly increases the cost of supplying the area and as a result increasing the network charge for the area. A way of optimising the cost of supplying a customer would be to use the power stations located very close to the customer. This will lead to avoiding the unnecessary usage of some transmission equipment and will result in lower network charges. Unfortunately, this will simply lower the network charges but does not rectify the negative effect the current network pricing structure has on the customers as they invest on DG.

Despite this, the charges do send valid signals about the appropriate location for new central generation and demand. The network charges for regions with lots of generation activity, such as Mpumalanga and Gauteng, are low (13.34 R/kW/yr and 22.96 R/kW/yr respectively). In areas where there is little generation activity, the network charges are high for instance the Eastern Cape and the Northern Cape with charges of 63.05 R/kW/yr and 60.54 R/kW/yr respectively, as depicted in **figure 4.4** of chapter four. DG is treated as a negative load because it was assumed that the Transmission Group treat it the same way. This was based on the fact that from the model used by the Transmission Group for pricing, generators such as the Palmiet Pumped storage station are not treated as central generation. Therefore DG is treated as negative load, not as generation.

An important observation made during the analysis on the impact of DG on the network charge with increasing DG penetration in SA is that, the change in demand or generation capacity of one region, affects the generation capacity of the Mpumalanga region where most central generators are located in SA. The reason for this is that the transmission method used in SA is structured in such a way that generation equals demand. But only the Mpumalanga generation capacity is affected by these changes. A change in generation capacity or demand for any region results in an equal change in the generation capacity in Mpumalanga. This results in changes in energy flowing along the network, which results in changes in the network charges in some of the regions.

In **figure 6.1** the graph shows the resulting network charges for the Eastern Cape with an increase of DG from 0 - 25%. As the region tends to be self-sufficient, the graph would be expected to tend towards infinity. But this is not the case as can be seen in **figure 6.3**, which shows the resulting network charges for the Eastern Cape with an increase of DG from 0 – 100%.

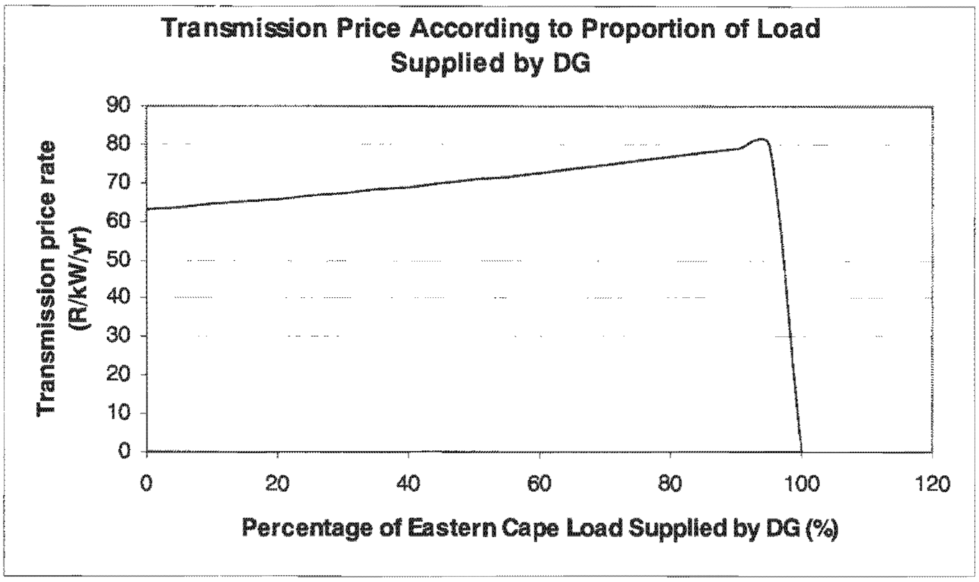

Figure 6.3: Transmission Price According to Proportion (0 to 100%) of Load Supplied by DG

The graph shown in Figure 6.3 indicates that the network charge would be reduced dramatically from the point where DG supplies 100% of the regions' demand.

The dynamics of the pricing method used in SA are unexpected but are a result of the pricing model. The model is complicated and it appears that it cannot be extended for variations in DG. The results of the model do not appear to be consistent with the objectives of the pricing method. However behind this pricing model are decisions regarding the method of its operation and allocation and recovery of costs. These aspects do not appear to be transparent. Questions that arise are: when is generation treated as a negative load and what are the limits of parameters for which the model is valid.

6.1.2 Stranded Transmission Investments

The severe increase of DG results in higher network charges as illustrated in **figures 6.1** and **6.3**. This increase is caused by the fact that some utility infrastructure becomes redundant when customers install DG. This leaves the utility with stranded costs associated with the redundant investments in the power system. Therefore the higher network charges obtained in the previous section can be partly attributed to stranded cost recovery. Utilities such as Eskom expect to receive a fair economic return on their assets. If Utilities are not compensated for stranded costs, either the utility shareholders or the non-DG customers ultimately bear the burden.

In Europe and the Northern America [3], utilities have been allowed to use exit fees and competitive transition charges (CTCs) to be compensated for stranded investments. CTCs are levied to all utility customers and are used to pay for stranded assets that are no longer economic. An exit fee is a form of stranded cost recovery that a utility collects when a customer decides to leave the grid or reduce its load through DG.

Exit fees and CTCs discourage the adoption of innovative energy solutions, such as DG. It is also not likely that the amount of installed DG will outpace demand growth. Therefore can be characterised as Demand Side Management (DSM), including peak shaving and energy saving. In the Eastern Cape, capacity is at its limit and plans for reinforcement are being prepared. In this case DG can be used as DSM and a congestion element in the pricing would reflect economic costs better.

The implementation of this method of stranded cost recovery in South Africa will put DG at a disadvantage without passing the burden to non-DG customers. If DG is completely exempted from any stranded cost recovery, it would hold an economic advantage over alternatives still subject to these charges. The way forward is for South Africa to develop a more balanced cost recovery method where new DG owners are charged an exit fee when the overall DG market penetration meets a certain threshold.

6.1.3 Economic Viability of DG and Associated Savings

At a basic level there are three main elements that determine the economic viability of DG for utility customers. These are:

- Grid cost of delivered electricity
- DG capital charges
- DG operating costs

The relationship between the these elements is as follows:

$$\text{Grid Cost of Delivered Electricity} - \left(\text{DG Capital Charges} + \text{DG Operating Cost}\right) = \text{DG Electricity Cost Savings to Customer}$$

Essentially, if the difference between the DG operating costs and avoided electricity costs is large enough relative to the investment required to meet the customer's investment-return criteria, the project will be viable and would result in savings to the customer.

The first step in evaluating the economics of DG is to understand how the equipment would run and what the potential annual savings to the customer would be. If the Eastern Cape distributor decides to reduce the supply from central generation by 25% ie 500 MW of the 2000 MW. This reduces the Distributors network cost from R126.1 million to R94.575 million, resulting in an annual savings of R31.525 million.

The customer will have additional operating costs to pay, namely for the fuel the DG consumes and for the operation and maintenance (O&M).

$$\text{DG Operating Costs} = \text{Fuel Costs} + \text{O\&M Costs}$$

The fuel costs are a function of the efficiency of the DG and the fuel price. The total annual savings to the customer are found by subtracting operating costs from annual savings in purchased electricity:

$$\text{Total Annual Savings} = \text{Annual Savings in Purchased Electricity} - \text{DG Annual Operating Costs}$$

As the operating cost vary with fuel price, so will the total annual savings. Projects of this type are typically evaluated on simple payback. Simple payback is obtained by dividing the installed costs by the annual saving. Installed costs include equipment costs as well as interconnection, construction, permitting, and engineering costs, for example an installed cost of R126.1m and R7.88m in total annual savings will result in a 16 year payback. It is not possible to quantify the actual savings for the various regions in South Africa as there is no data available (costs associated to DG) in public domain, the method mentioned can be applied to determine savings and viability of DG in South Africa.

6.2 Reduction of Losses

Integration of DG into an existing utility can result in the several benefits identified in the second chapter. This section focuses on line loss reduction. This factor is analysed and quantified and presented in this section for the Transkei network with its DGs and without the DGs. This network was selected because it is part of the Eastern Cape region already analysed.

6.2.1 System Description and Models

A simplified Transkei network is modelled under two different conditions:
(i) System without DG and (ii) system with DG. The ratings and the length of the line are shown in the diagrams representing both models, **figure 6.4** and **figure 6.5**.

6.2.2 Line Loss Reduction Analysis

Electrical line loss occurs when current flows through transmission and distribution systems. The magnitude of the loss depends on the current flow and line resistance. Therefore, reducing either line current or resistance or both can decrease line loss. If DG is used to provide energy locally to the load as is done in the Eastern Cape, line loss can be reduced because of the decrease in current flow in some parts of the network.

6.2.3 Line Loss Analysis for System without DG

Schematic of the system for this analysis is shown in **figure 6.4**. Line loss on a distribution feeder for a three phase system is [37]:

$$Loss = rL\frac{(P_L^{\ 2} + Q_L^{\ 2})}{3V_p^{\ 2}} \qquad (1)$$

The equations for the current absorbed by the load and the load complex power are given by equations 2 and 3 below:

$$S_L = P_L + jQ_L \qquad (3)$$

$$I_L = \frac{(P_L - jQ_L)}{3V_p} \qquad (2)$$

Where:

L = Length of the line [km]

P_L = Real power [kW]

Q_L = Reactive power [kvar]

V_p = Phase voltage [kv]

I_L = Line current [kA]

S_L = Complex powe [VA]

r = resistance [Ω]

The analysis of the power losses for the two cases in the Transkei network were performed using DigSilent power system analysis software. A load flow performed using this software revealed the results shown in **figures 6.4 and 6.5** for the case with DG and the case without DG respectively. The case without DGs has the lines that do not interconnect to the loads removed. The loads for both cases are the same and are shown in **table 6.1.** The real power losses and reactive power losses along the individual lines for both cases are shown in **figures 6.6 and 6.7** respectively. **Table 6.2** shows real and reactive power losses with and without DG on each line as well as the total losses for both cases.

Load	**Size (MW)**
Lamplough	12
Umtata	16
Qunu	4
Paynes Farm	2.5
Sappi	5
Mafini	3.75
Kohlo	1.85
Magwa	4.3

Table 6.1: Sizes of the Loads in the Transkei Network

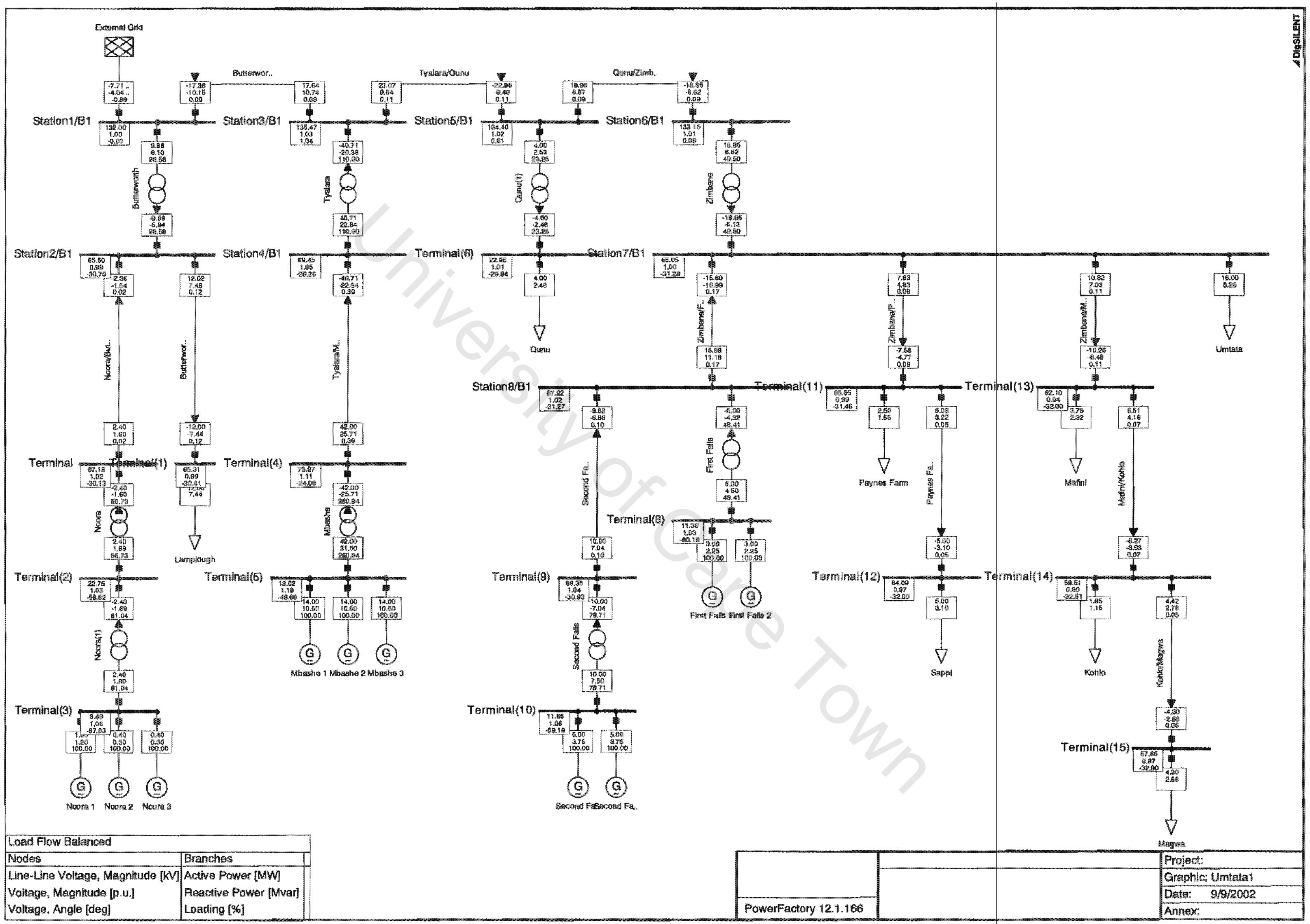

Figure 6.4: Load Flow on Transkei Network with DG

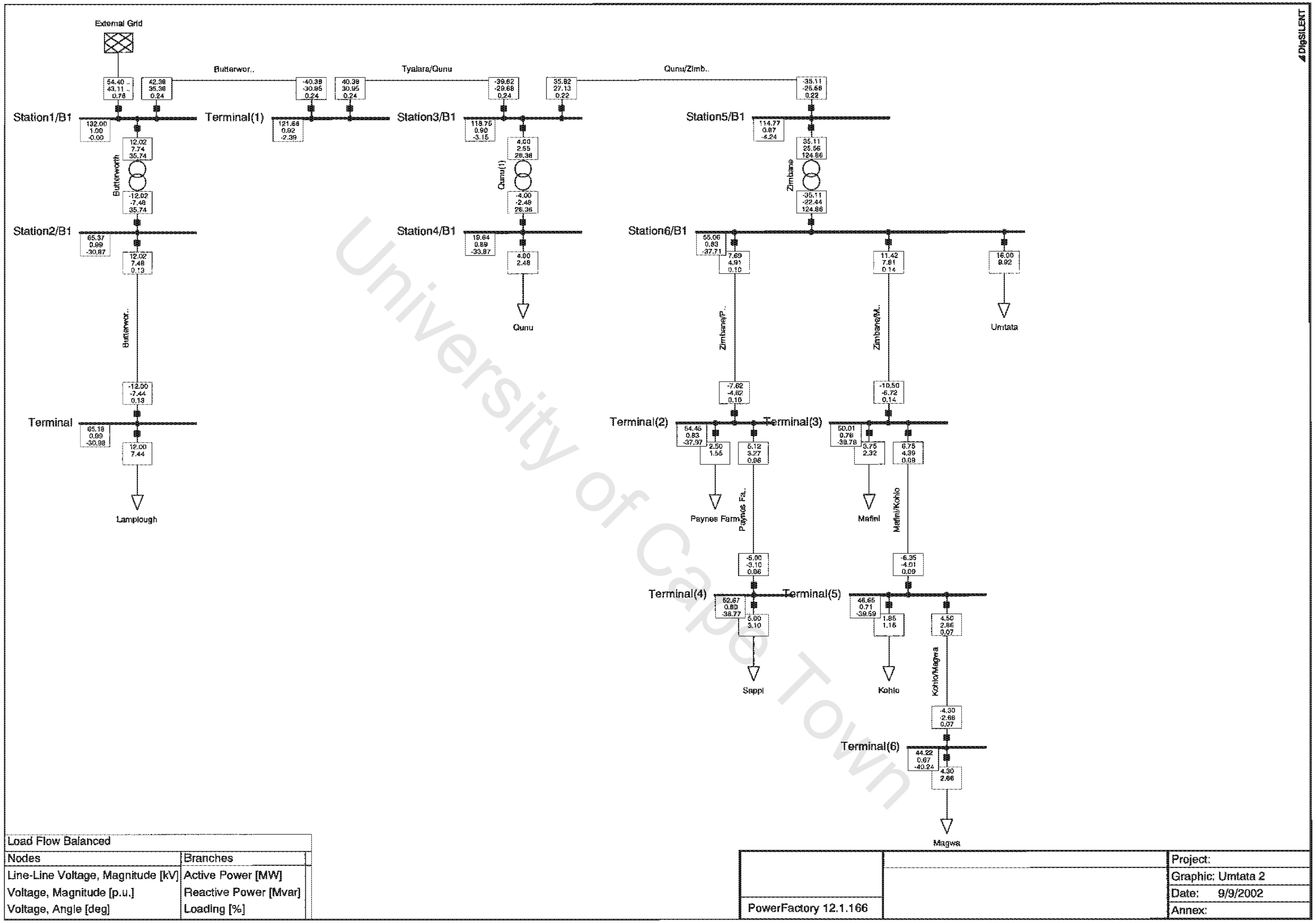

Figure 6.5: Load Flow on Transkei Network Without DG

Line	Losses Without DG		Losses With DG	
	Real Power (MW)	Reactive Power (Mvar)	Real Power (MW)	Reactive Power (Mvar)
Butterworth/Lamplough	0.02	0.04	0.02	0.04
Butterworth/Tyalara	2	4.43	0.16	0.37
Tyalara/Qunu	0.56	1.27	0.16	0.35
Tyalara/Mbashe	0	0	1.3	2.9
Qunu/Zimbane	0.71	1.56	0.17	0.38
Zimbane/Paynes Farm	0.07	0.09	0.04	0.06
Zimbane/Mafini	0.92	0.89	0.58	0.57
Paynes Farm/Sappi	0.12	0.17	0.09	0.12
Mafini/Kohlo	0.4	0.38	0.25	0.24
Kohlo/Magwa	0.2	0.2	0.12	0.13
Total	**5**	**9.03**	**2.89**	**5.16**

Table 6.2: Real and Reactive Power Losses in the Transkei Network with and without DG.

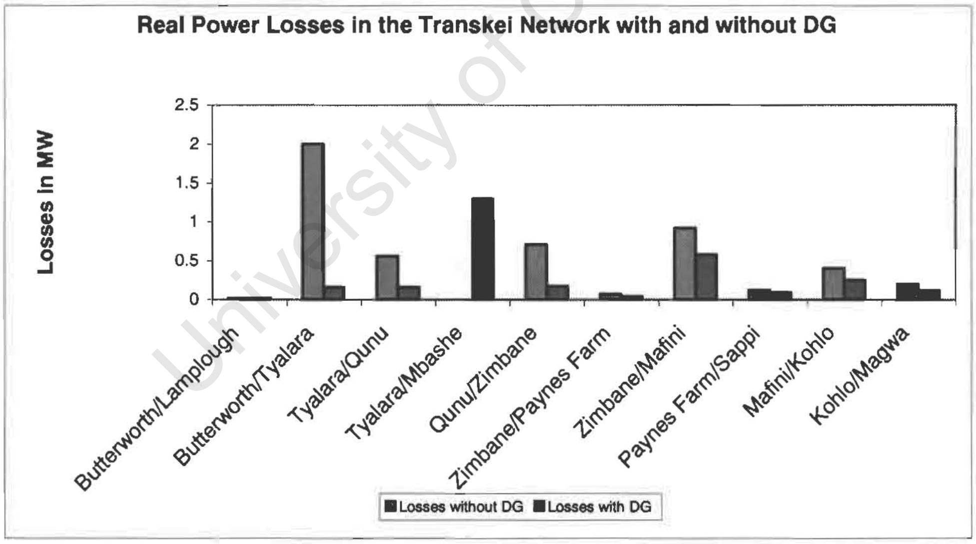

Figure 6.6: Real Power Losses in the Transkei Network

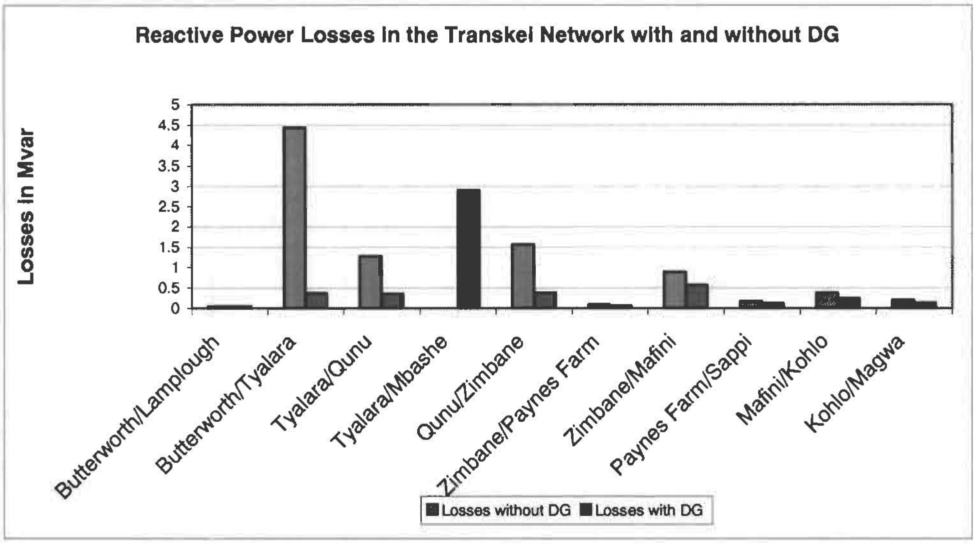

Figure 6.7: Reactive Power Losses in the Transkei Network

A comparison of **figures 6.6 and 6.7** show that the connections of DGs in the Transkei network reduces losses along the distribution lines. This is due to the fact that line current is reduced in some parts of the network as can be seen in **figures 6.4 and 6.5**.

Both **figures 6.6 and 6.7** illustrate that the connection of DG results in losses on the Tyalara/Mbashe line. This is due to the fact that without DG connected to the network, there is no line from the Tyalara substation to the location of the generators. Therefore, no power losses for the case of no DG.

The load flow also revealed that there were small power losses along the Butterworth/Lamplough line for both cases as can be seen in the load flow diagrams and the power losses bar graphs in the above figures. This is due to the fact that the distance of the line is very short (2.3 km) such that the losses are very small.

The load flow results show power loss reduction in all the lines. The total real and reactive power losses are reduced by 42% and 43% respectively, when DG is connected in the Transkei network. Therefore this analysis shows that the inclusion of DG at distribution level near load centres, results in power loss reduction along the lines. These losses can easily be converted to an equivalent value in Rands. It can also be treated as savings to both the Transmission Group and the customers (loads). These savings play a big role in the electricity prices. As the savings increases, the electricity price goes down.

Another important effect of installing DGs at distribution level, apart from the reduction in power losses along the distribution lines, is the avoided power losses along the transmission lines. The fact that power is generated near the loads means that less power is obtained from the transmission network, meaning that fewer losses occur along the transmission lines. This also impacts the losses component of the transmission price by slightly reducing it.

6.3 Reliability Services Charge

The reliability services charge is intended to recover the cost for acquiring ancillary services needed for the operation of the transmission network according to the quality of supply standards. The approximate 2001 costs of ancillary service are shown in **table 4.1** of chapter four. The income for ancillary service is fixed monthly payments (50% from loads and 50% from producers). This is paid regardless of off-take or in-feed levels.

Distributed generation has the potential to provide some of the ancillary services listed in **table 4.1**. In particular DG can serve locally as the equivalent of a spinning reserve and voltage support of the ac bus. Spinning reserve is part of the ancillary services bought by Transmission from Generation. Therefore the Distributor pays for spinning reserve by paying the reliability service charge (the charge for spinning reserve is included in this charge). With DG providing some of the ancillary services, the cost to the transmission group of buying capacity from generation is reduced. Therefore the reliability services charge levied by the Transmission Group to the Distribution Group will be reduced if the charge is cost reflective.

A number of international grid-connected DGs are equipped with power electronic converters as an interface between the generator and the ac grid. The same could be done in SA. These power electronic interfaces can be configured to provide some of the ancillary services. In addition to being available as power reserve, they can be designed to provide reactive power, load balancing, voltage support, and harmonic mitigation.

Distributed generators equipped with rotating converters, either induction or synchronous generators, produce sinusoidal voltages. Therefore some DGs can be viewed as supplying clean power. DG equipped with PWM inverter interface can be used to alleviate power quality problems present on the ac grid. The requirement is to have independent control over the real and reactive components of the power injected into the ac grid. Under these conditions, the distributed generator can be configured to behave as one or more of the following power conditioners or compensators, including [38]:

- Static var compensator (STATCOM) functions: reactive power is injected into the ac grid to regulate the voltage at the point of coupling, reactive power can be controlled to regulate the total plant power factor, reactive power can be used to mitigate voltage flicker. The STATCOM function can also be used to mitigate voltage sags.
- Dynamic voltage restorer (DVR) functions: A series winding, associated with an inverter fed from the dc bus, can be included in the installation to inject the voltages required to support the ac grid voltage at the point of coupling during voltage sags and swells.

DG units that are capable of supplying reactive power, such as synchronous generators, double fed asynchronous generators as well as DC-AC power converters, could be used to control the voltage level within a local distribution network. A reasonable constant voltage level could be achieved by continuously adjusting the reactive power supply according to the voltage variation resulting from the variations in active power generation and load demand. This does not happen in the DGs in the Transkei because the generators are not equipped with the necessary power electronic devices as discussed above. These generators are also not operated as ancillary service providers. The application mentioned above can be used for DGs aimed for providing ancillary services.

Such generation systems could offset the needs for additional voltage regulators and capacitors at substation level and the operator of the distribution network could save significant investment costs. If capacitor banks exist within the distribution network, DG with active power supply as well as with active and reactive power supply can lead to a reduction of the operating time of these capacitor banks. This will reduce operational losses of the capacitor bank. The capital savings of these avoided losses are usually also gained by the operator of the distribution network.

It is evident from the above that DG has a great potential in supplying important ancillary services to the grid, especially when equipped with appropriate power electronic interface. The provision of these services means that the cost of these services to the Transmission Group will be reduced. Thus reducing the reliability service charge paid by customers. DGs that are not equipped with power electronic devices contribute in short circuit faults and usually have low fault clearing times, for example the generators in the Eastern Cape. These faults can be very costly and to avoid this DGs can be equipped with the necessary power electronic devices.

6.4 Connection Charge

The development of DG in South Africa will not play a significant role in determining the connection charge paid by Distributors to the Transmission Group. The existing distributors will probably be still connected to the transmission network even if DG penetration increases dramatically in SA. A possible effect would be a declining rate of increase in the connection charge, since this charge depends on the value of the assets connecting each transmission customer. The development of DG will lead to less transmission investment on the transmission network, as the new demand would be supplied by mainly DGs instead of central generation.

6.5 Other Benefits of DG that can Impact the Transmission Price

6.5.1 Deferring T&D Investment

Local distribution or reticulation networks may become overloaded due to load growth over a period of time. In order to maintain the quality of supply to customers, it would be necessary to strengthen these networks. The cost of strengthening may be very high, compared to the additional revenue to be derived from increased sales. An alternative solution to this problem can be the use of small local generation (DG) that is used to reduce the peak loading of the lines to within their design capacity [14]. The peaks on the local networks are determined by the requirements of the customers served and does not necessarily coincide with the Eskom system peak. The purpose of such generators is therefore clearly not to provide generating capacity, but to relieve local constraints, which may even occur during system off-peak periods. The use of peaking stations to alleviate this problem might result in the reduction in transmission prices. Overloaded and constrained network equipment tends to have a shorter lifespan, therefore costing the transmission owner to replace this equipment. DG relieves the network of such constraints and results in savings to the transmission network company. In considering such savings, the network provider can reduce transmission prices paid by the Distributor. There is no standard method for this.

Distributed generation reduces transmission line construction, maintenance and operational expenses. This means that the transmission price is reduced as some of the costs to transmission are lowered. This changes the both the total price and the transmission price rate.

A utility may or may not be currently constrained in its ability to meet growing customer demand. If the utility is constrained, without enough capacity to meet demand, it must invest in its system. The worst-case scenario in Central Plant option such as Eskom's plants would be generation, transmission and distribution constrained. The costs involved in the investment of such a scenario are the fixed costs for new generation, transmission and distribution as well as the marginal costs for all three groups. To avoid these costs, distributed generators can be used instead of investing on the traditional central plant option. DG would probably be the most cost effective solution to the problem.

A critical factor in quantifying DG benefits is explicit recognition of their highly location specific value. For instance, DG has the highest value in deferring T&D investment when the distribution system is near its maximum capacity. There are also important potential distribution grid side costs of DG, such as the need to equip and manage the distribution system to handle reverse flows of power.

Utilities often also maintain that grid-side benefits are meaningful only when DG is used as part of the utilities' long-term transmission or distribution planning.

6.5.2 Peak Shaving

Utilities are sceptical about planning system capacity on the basis of peak shaving conducted independently by the customer. Utilities are likely to discount customer side DG in their planning unless they have control over the equipment, either through direct dispatch or through contracting. Eskom can do the same in a bid to relieve the network during peak hours and in the same way reducing the prices of electricity during this period.

6.5.3 Reliability

Grid reliability is a significant potential grid-side benefit of DG, especially if price signals in the market encourage increased recognition and utilisation of DG for grid reliability. As mentioned in the section on reliability services charge, the increase in DG can lead to a reduction in transmission prices in South Africa.

6.6. Potential Improvement on Transmission Tariff in South Africa

The results of section 6.1 highlighted the issue of stranded transmission investments and congestion. A practical way of improving the South African transmission tariff would be by addressing the issues of stranded costs and congestion. This can be achieved by adopting a balanced approach of stranded cost recovery where new DG owners are charged an exit fee when the overall DG market penetration meets a certain threshold. Some DG can be characterized as DSM, where DG is used as a means of network congestion relief. Such DG should be exempted from exit fees and instead be recognized for the benefit to the utility.

6.7 Summary

An increase in DG penetration in the in South Africa especially in the remote regions such as the Eastern Cape, results in an increasing transmission charge rate and total transmission prices. The network-pricing model used in SA raises some questions about decisions regarding the method of its operation and allocation and recovery of costs. These aspects do not appear to be transparent.

The connection of DG along a distribution feeder results in reduced losses along that feeder. This is due to the fact that current is reduced along the lines, thus reducing the losses along that line. This results in fewer losses along the distribution network.

Both the customers and utilities know most of the DG benefits but it is very difficult to quantify most of them. Similar benefits are already experienced in the South African power industry, but just like in the rest of the world, quantifying them is a problem. It is clear though that the impact of DG on South Africa's electricity prices could be positive, leading to the reduction in losses charge, connection charge, and the reliability services charge. The network charge is also expected to be reduced, but in South Africa this charge is structured in such a way that an increase in DG penetration results in an increase in network charge or tariff rate.

CHAPTER SEVEN

Conclusions

This thesis has analysed the development of DG in South Africa, and described the transmission pricing in South Africa as well as network pricing in Australia and England and Wales. The impact on Eskom's transmission tariffs of increasing DG capacity in South Africa was assessed and finally some projections were made on how the development of DG in the country might affect the transmission costs and prices. This conclusion attempts to fit these parts into a unified whole. Following this some ideas are presented on possible direction of further DG and transmission pricing-related investigation.

The second chapter of the thesis forms a theoretical framework for distributed generation and transmission pricing. The chapter began by defining distributed generation as small power generation units strategically located near consumers and load centres that provide benefits to customers and support the economic operation of the power grid. However, distributed generation in the South African context was defined as any source of electric power that is interconnected with an electricty supply network at a system voltage level not exceeding 132kV. The generator is not centrally dispatched. It is probably not a trading participant in a power pool but usually responds to a tariff signal. Three major trends were identified as the key drivers in the development of distributed generation around the world. These are regulatory changes, technology advances, and power system deficiences and price increases. This chapter also highlighted the various distributed generation technologies such as photovoltaics, fuel cells, wind energy converters, and turbines and engines. Applications of distributed generation include peak shaving, standby power, stand alone, combined heat and power, and grid support. These applications can be designed to meet a wide variety of service requirements and fulfill the needs of many customers and energy service providers.

South Africa has a number of distributed generators as listed in chapter three. Some DG projects are at a planning stage and others are already implemented. Technology advances, environmental pressure, renewable energy resources, political motivation, power industry restructuring, customer choice and utility choice that led to the development of DG in a number of countries around the world are already evident in SA. This indicates that the development of DG in South Africa is taking place. It is therefore concluded that DG would play a significant role in the future South African power supply industry and that the penetration of DGs will increase rapidly in the next 20 years. It is estimated that electricity supply from DG would probably be in the region of 20 to 30% of the total electrical energy in SA, by the year 2020, based on international predictions of DG development and potential of DG in SA.

Transmission Pricing in Eskom has developed considerably over the past few years. Four transmission-pricing models were described in chapter four. The basis for these models was the following principles: prices should signal location advantages for investment in generation and demand, be simple and transparent, and cost reflective. However, the first model did not follow the principles. Since it was the first model, the main aim was to recover the cost of transmission service but it was realised that this model was too risky as there was a possibility of under recovering the costs, implying that the tariff used was not cost reflective. The second model focussed on economic signals related to the cost of supply. This transmission pricing system resulted in wide variations of the transmission portion of prices around the country, which reflects a bit of cross subsidisation among the customers. Variations in the transmission prices were reduced in the model used from 1998 and for the future pricing model. These models were the closest in identifying with the principles aimed for.

The connection of distributed generation to the power system at distribution level and very close to the load, leads to a reduction in losses along that distribution feeder. The magnitude of current flow along the distribution network is reduced, resulting in lower losses. This was highlighted by the simulation of the Eastern Cape network with and without DG, which resulted in huge loss reduction (about 42%). This implies that the effective cost of losses along that particular feeder decreases. The connection of these DGs at distribution level also means that less energy will be transmitted from central generators; therefore losses will also be reduced along the transmission system. These avoided losses along the transmission system and reduced losses on the distribution network result in savings to the customer if carried through in the tariffs. Thus, it is expected that the connection of DG on the distribution network will result in significant cost savings in cost of losses to the utility and a decrease in transmission losses charge to the customers if the change in cost of losses to the utility is passed on to the losses charge levied to customers (distributors).

An increase of up to 25% of capacity supplied by DG in South Africa will lead to higher transmission network charge rates to the loads located farther away from central generators. This thesis indicates that the Eskom Transmission network charge is structured in such a way that investment on DGs will lead to higher transmission network charges. The utilised tariff does not encourage investment on projects outside the transmission group or that compete with the available central generators. Regardless of how much the customers reduce the amount of energy obtained from the central generators through the transmission network, the fixed revenue required by the Transmission Group from the customers of that particular zone does not change much. This implies that customers have to pay high network prices as they reduce the amount of energy received from transmission supply points.

The decisions regarding the method of operation and allocation and recovery of costs using the Eskom network transmission pricing method does not appear to be transparent. It is not clear how the method is used to determine the prices, as it appears to depend substantially on internal budgets. Not enough information is made available to the public to understand the basis and the method applied in determining the network charges.

The research has revealed that a customer is charged for the proportional usage of the network. These charges are calculated per region and send geographic signals, with customers situated far from the generation centres having to pay more. It was also found that an increase in DG in a region such as the Eastern Cape results in stranded costs for the utility in that region. This forces the utility to incorporate the recovery of the stranded costs into the tariff, which then leads to an increase in the network charge for that region. Therefore an increase in DG penetration in certain regions in South Africa will result in higher network prices. This implies that DG projects will be put at a disadvantage as its development results in higher network prices.

Distributed generation has the potential to increase the reliability of the power network in South Africa. It has a huge potential in providing reactive power, load balancing, voltage support, harmonic mitigation and to be available as reserve power. This would be a big boost in lowering the cost of ancillary services and thus effectively decreasing the reliability services charges levied to the transmission customers (Distributors).

The development of DG in South Africa will not significantly change the connection charge component of the Eskom transmission tariff. However the benefits of increasing DG penetration in the country can play a very important role in the overall reduction of the transmission tariff and promotion of economical alternative methods of power supply. These benefits include system peak shaving, reliability increases, and deferral of transmission and distribution investments.

This research provides an insight on the potential effect of increasing DG penetration in South Africa on the Eskom's transmission cost of supply and charges to its customers. The thesis predicted that increasing DG penetration would result in a decrease in some of the rates of the components of the transmission tariff such as the losses charge rate, reliability service charge rate and the connection charge rate, and an increase for the network charge rate. Future research could involve quantifying the possible DG benefits and locating the strategic positions where these could be utilised for maximum benefit around the country. Greater pricing transparency would be needed to carry out the further research.

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APPENDIX ONE

Tariff T1 and T2

The recently developed time of use tariffs are based on the time of use variation in marginal costs and as such seek to address the time of criticism that was levelled against tariff A. Currently Tariffs T1and T2 are available only on optional/voluntary basis. Tariff T1 is available for customers with a maximum demand of greater than 1 MVA while Tariff T2 is available for supplies from 100kVA to 5 MVA and is furthermore not applicable in rural areas. The tariff charges applicable in rural areas. The tariff charges applicable from 1 January 1994 are as follows:

Connection fees: Tariff T1: R3500
Tariff T2: R1750

Winter: April-Sept	**T1**	**Summer:Jan-Mar; Oct-Dec**
50.74	Basic charge: [Rands]	50.74
R10.82/kVA/Month	Maximum demand charge:	R9.74/kVA/Month
	Energy charges	
19.54	Peak c/kWh	17.58
10.95	Standard c/kWh	9.84
6.29	Off-peak c/kWh	5.65
2.28	Reactive energy c/kVARh*	2.28

∗ Only for reactive energy in excess of 30% of kWh recorded during peak and standard periods.

T2	**Winter: April-Sept**	**Summer: Jan-Mar; Oct-Dec**
Basic charge:	50.74	50.74
Energy charges		
Peak c/kWh	29.79	26.81
Standard c/kWh	10.95	9.84
Off-peak c/kWh	6.29	5.65
Reactive energy c/kVARh	1.14	1.14

APPENDIX TWO

TRANSMISSION PRICES FOR 2001: 0 – 3% VARIATION

Substation	Reserved Capacity	R/kW/yr	R/month	Loss Factor	Reliability Services
ARARAT:88KV	427 MW	27.25	970,192	1.0087	0.2488 C/kWh
ARNOT/RIETKUIL:88/22KV	45 MW	27.25	102,097	1.0087	0.2488 C/kWh
BENBURG:132KV	250 MW	27.25	567,610	1.0087	0.2488 C/kWh
BERNINA:132KV	440 MW	27.25	998,993	1.0087	0.2488 C/kWh
BIGHORN:88KV	419 MW	27.25	951,756	1.0087	0.2488 C/kWh
BRENNER:88KV	400 MW	27.25	908,175	1.0087	0.2488 C/kWh
CAMDEN/UITKOMS:88KV	93 MW	27.25	211,155	1.0087	0.2488 C/kWh
CARMEL:132KV	309 MW	27.25	700,567	1.0087	0.2488 C/kWh
CENTURION:132KV	161 MW	27.25	366,621	1.0087	0.2488 C/kWh
CRAIGHALL:88KV	330 MW	27.25	749,245	1.0087	0.2488 C/kWh
CROYDON:132KV	235 MW	27.25	533,553	1.0087	0.2488 C/kWh
DELTA:275KV	305 MW	27.25	692,484	1.0087	0.2488 C/kWh
EIGER:88KV	325 MW	27.25	737,893	1.0087	0.2488 C/kWh
ESSELEN:132/88KV	550 MW	27.25	1,248,741	1.0087	0.2488 C/kWh
ETNA:88KV	145 MW	27.25	329,214	1.0087	0.2488 C/kWh
EVEREST:132/44KV	441 MW	27.25	1,000,151	1.0087	0.2488 C/kWh
FORDSBURG:88KV	510 MW	27.25	1,157,924	1.0087	0.2488 C/kWh
GROOTVLEI:88KV	40 MW	27.25	90,818	1.0087	0.2488 C/kWh
HENDRINA:132KV	247 MW	27.25	561,534	1.0087	0.2488 C/kWh
HERMES:132/88KV	570 MW	27.25	1,295,126	1.0087	0.2488 C/kWh
INCANDU:132KV	239 MW	27.25	543,194	1.0087	0.2488 C/kWh
INGAGANE:88KV	129 MW	27.25	293,207	1.0087	0.2488 C/kWh
JUPITER:88KV	335 MW	27.25	760,597	1.0087	0.2488 C/kWh
KOMATI:132/88KV	143 MW	27.25	324,854	1.0087	0.2488 C/kWh
KOOKFONTEIN:88KV	200 MW	27.25	454,088	1.0087	0.2488 C/kWh
KRUISPUNT:132KV	390 MW	27.25	886,388	1.0087	0.2488 C/kWh
KWAGGA:275/132KV	801 MW	27.25	1,819,184	1.0087	0.2488 C/kWh
LEANDER:132KV	287 MW	27.25	652,172	1.0087	0.2488 C/kWh
LEPINI:88KV	380 MW	27.25	862,767	1.0087	0.2488 C/kWh
LOMOND:88KV	363 MW	27.25	823,738	1.0087	0.2488 C/kWh
MAJUBA:88KV	4 MW	27.25	55,450	1.0087	0.2488 C/kWh
MAKALU:88KV	45 MW	27.25	556,250	1.0087	0.2488 C/kWh
MARATHON:132KV	49 MW	27.25	566,170	1.0087	0.2488 C/kWh
MATIMBA:132KV	28 MW	27.25	290,360	1.0087	0.2488 C/kWh
MERCURY:132KV	05 MW	27.25	1,147,630	1.0087	0.2488 C/kWh
MERENSKY:132KV	14 MW	27.25	712,350	1.0087	0.2488 C/kWh
MERSEY:132KV	54 MW	27.25	576,610	1.0087	0.2488 C/kWh
MIDAS:132KV	89 MW	27.25	882,620	1.0087	0.2488 C/kWh
NEVIS:132KV	76 MW	27.25	853,680	1.0087	0.2488 C/kWh
NJALA:275/132KV	14 MW	27.25	1,167,150	1.0087	0.2488 C/kWh
NORMANDIE:132/88KV	128 MW	27.25	290,049	1.0087	0.2488 C/kWh
OLYMPUS:132/33KV	350 MW	27.25	794,653	1.0087	0.2488 C/kWh
PELLY:132KV	211 MW	27.25	479,335	1.0087	0.2488 C/kWh
PIETERBOTH:88KV	245 MW	27.25	556,257	1.0087	0.2488 C/kWh
PLUTO:22KV	0 MW	27.25	0	1.0087	0.2488 C/kWh

PRAIRIE:132KV	218 MW	27.25	494,243	1.0087	0.2488 C/kWh
PRINCESS:88KV	263 MW	27.25	597,125	1.0087	0.2488 C/kWh
PROSPECT:88KV	560 MW	27.25	1,271,446	1.0087	0.2488 C/kWh
RIGI:88KV	320 MW	27.25	726,540	1.0087	0.2488 C/kWh
ROCKDALE:132KV	373 MW	27.25	846,942	1.0087	0.2488 C/kWh
SCAFELL:132KV	305 MW	27.25	692,484	1.0087	0.2488 C/kWh
SIMPLON:132KV	169 MW	27.25	382,864	1.0087	0.2488 C/kWh
SNOWDON:88KV	250 MW	27.25	567,610	1.0087	0.2488 C/kWh
SOL:132KV	922 MW	27.25	2,092,990	1.0087	0.2488 C/kWh
SPITSKOP:132/88KV	299 MW	27.25	679,826	1.0087	0.2488 C/kWh
TAUNUS:132KV	715 MW	27.25	1,623,364	1.0087	0.2488 C/kWh
THESEUS:132KV	477 MW	27.25	1,083,113	1.0087	0.2488 C/kWh
TRIDENT:88KV	466 MW	27.25	1,057,763	1.0087	0.2488 C/kWh
VERDUN:88KV	155 MW	27.25	351,918	1.0087	0.2488 C/kWh
VULCAN:132KV	869 MW	27.25	1,972,330	1.0087	0.2488 C/kWh
WARMBAD:132KV	79 MW	27.25	179,751	1.0087	0.2488 C/kWh
WARTERSHED:88KV	315 MW	27.25	714,393	1.0087	0.2488 C/kWh
WESTGATE:132KV	375 MW	27.25	851,414	1.0087	0.2488 C/kWh
WITKOP:132KV	322 MW	27.25	730,525	1.0087	0.2488 C/kWh
ACORNHOEK:132KV	102 MW	27.52	234,359	1.0187	0.2513 c/kWh
ARADNE:132KV	269 MW	27.52	617,557	1.0187	0.2513 c/kWh
ATHENE:132KV	934 MW	27.52	2,142,609	1.0187	0.2513 c/kWh
AVON:132KV	654 MW	27.52	1,499,460	1.0187	0.2513 c/kWh
BLOEDRIVIER:88KV	130 MW	27.52	298,535	1.0187	0.2513 c/kWh
BLOUKRANS:132KV	143 MW	27.52	327,854	1.0187	0.2513 c/kWh
BOUNDARY:132KV	233 MW	27.52	535,334	1.0187	0.2513 c/kWh
DANSKRAAL:132KV	71 MW	27.52	162,530	1.0187	0.2513 c/kWh
FERRUM:132KV	110 MW	27.52	251,374	1.0187	0.2513 c/kWh
FOSKOR:132KV	234 MW	27.52	537,662	1.0187	0.2513 c/kWh
GEORGEDALE:132/88KV	307 MW	27.52	703,582	1.0187	0.2513 c/kWh
HARVARD:132KV	307 MW	27.52	702,917	1.0187	0.2513 c/kWh
HECTOR:275KV	754 MW	27.52	1,728,258	1.0187	0.2513 c/kWh
ILLOVO:132KV	727 MW	27.52	1,666,417	1.0187	0.2513 c/kWh
IMPALA:132KV	486 MW	27.52	1,114,037	1.0187	0.2513 c/kWh
KOMATIPOORT:132KV	79 MW	27.52	180,457	1.0187	0.2513 c/kWh
MERAPI:132KV	134 MW	27.52	307,235	1.0187	0.2513 c/kWh
OLIEN:132KV	95 MW	27.52	218,789	1.0187	0.2513 c/kWh
PERSEUS:22KV	4 MW	27.52	9,310	1.0187	0.2513 c/kWh
RABBIT:275KV	392 MW	27.52	899,602	1.0187	0.2513 c/kWh
SPENCER:132KV	136 MW	27.52	311,890	1.0187	0.2513 c/kWh
TABOR:132KV	160 MW	27.52	367,751	1.0187	0.2513 c/kWh
TUGELA:132KV	150 MW	27.52	344,503	1.0187	0.2513 c/kWh
UMFOLOZI:88KV	64 MW	27.52	147,030	1.0187	0.2513 c/kWh
ARIES:50KV	18 MW	27.79	41,685	1.0287	0.2538 c/kWh
DELPHI:132KV	120 MW	27.79	277,369	1.0287	0.2538 c/kWh
DROERIVIER:132KV	75 MW	27.79	173,689	1.0287	0.2538 c/kWh
GARONA:132/50KV	54 MW	27.79	124,581	1.0287	0.2538 c/kWh
GRASSRIDGE:132KV	574 MW	27.79	1,330,431	1.0287	0.2538 c/kWh
GRDGE. TRACTION:220KV	65 MW	27.79	150,437	1.0287	0.2538 c/kWh
HYDRA:132KV	145 MW	27.79	335,241	1.0287	0.2538 c/kWh
NEPTUNE:132KV	258 MW	27.79	597,049	1.0287	0.2538 c/kWh
PEMBROKE:132/66KV	287 MW	27.79	665,216	1.0287	0.2538 c/kWh
PORT REX:132KV	69 MW	27.79	159,840	1.0287	0.2538 c/kWh
POSEIDON:66KV	45 MW	27.79	103,426	1.0287	0.2538 c/kWh
ROODEKUIL:132KV	128 MW	27.79	296,174	1.0287	0.2538 c/kWh
RUIGTEVALLLEI:132KV	119 MW	27.79	275,018	1.0287	0.2538 c/kWh
ACACIA:132KV	630 MW	28.06	1,473,288	1.0387	0.2564 c/kWh
AGGENEIS:66KV	35 MW	28.06	81,849	1.0387	0.2564 c/kWh
AURORA:132KV	390 MW	28.06	912,035	1.0387	0.2564 c/kWh
BACCHUS: I32KV	315 MW	28.06	736,644	1.0387	0.2564 c/kWh
GROMIS:66KV	18 MW	28.06	42,094	1.0387	0.2564 c/kWh

HELIOS:50KV	20 MW	28.06	46,771	1.0387	0.2564 c/kWh
JUNO:132KV	75 MW	28.06	175,091	1.0387	0.2564 c/kWh
KOEBERG:132KV	115 MW	28.06	268,933	1.0387	0.2564 c/kWh
MULDERSVLEI:132KV	900 MW	28.06	2,104,696	1.0387	0.2564 c/kWh
NAMA:66KV	25 MW	28.06	58,464	1.0387	0.2564 c/kWh
ORANJEMOND:66KV	57 MW	28.06	133,297	1.0387	0.2564 c/kWh
PHILIPPI:132KV	550 MW	28.06	1,286,203	1.0387	0.2564 c/kWh
PROTEUS:132KV	350 MW	28.06	818,493	1.0387	0.2564 c/kWh
TOTALS FOR 2001	**33,007 MW**		**75,416,668**		