Power sector reforms and regulation in selected Eastern and Southern Africa countries

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Declaration

I, Hieromini Ireneus Shirima, submit this dissertation to the University of Cape Town in partial fulfilment of the requirements for the degree of Masters of Philosophy in Energy Studies. I declare that, unless otherwise acknowledged, this is my own work and that it has not been submitted in this or similar form for a degree at any university.

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Table of Contents

CHAPTER ONE
Introduction

1.0 Background and Rationale

The electricity supply industry (ESI) structures in most African countries are dominated by vertically integrated utilities which are publicly owned and which hold monopoly power over all the core activities of the industry. The utilities of these countries, with the exception of South Africa, are relatively small in size and have different financial and technical capabilities. Their activities are concentrated mainly in the urban areas, and as a consequence there are very low rural electrification rates. At present, national grids of very few countries are fully interconnected. However, in recognition of the potentially cheap power available in other countries and the need to increase reliability, African countries, particularly those in southern Africa, which form the Southern Africa Power Pool (SAPP), are now making a concerted effort to interconnect their grids.

As a result of their fairly similar structures, the power sectors of these countries are faced with problems and challenges of a similar nature. They are characterised by unreliable, inadequate and inefficient power supplies. The sector is plagued by major revenue shortfalls due to non-cost-reflective tariffs and poor revenue collections. Failure to raise funds to finance expansion programmes of the sector, which are necessary to meet the rising demand, has also been a major problem. These, and a number of country-specific factors, are the main driving forces behind restructuring and reforms of power sectors in African countries and also in the rest of the world.

The reforms are expected to bring about an increase in the capacity and provision of reliable and low cost power and will also help governments to avoid incurring further debt in financing the power sectors. Indeed, the World Bank and the International Monetary Fund (IMF) are concerned specifically with this issue of reducing government involvement in financing the power sector. The future of the power sectors of these countries depends entirely on the reforms that will be introduced in this vital area of economic activity.

It is anticipated that these reforms will introduce competition which will in turn create a need for new regulatory bodies/organisations to monitor and ensure fair competition in the sector and also to protect their consumers. In these countries, since their independence, there have been no regulatory authorities responsible for electricity, meaning that the ministries in charge of energy affairs have had to do both the work of policy formulation for the sector and that of regulation of the industry. In some countries, the situation was exacerbated by the fact that electricity utilities were responsible for regulating themselves. Enacting the right legislation will, among other things, offer incentives to

investors as well as promote efficiency in the sector as a whole. Thus, enacting the right legislation is of utmost importance and should be done with great care and forethought. Failure to attract private investments from abroad will result in the total failure of such reforms and the consequences to the already crippled sector will be devastating.

In view of the above concerns, this area needs to be closely studied and analysed to explore and evaluate various options for restructuring and reforming electricity utilities in order to generate a set of focused policy recommendations for improving the performance of the power sectors. The whole process of the involvement of the private sector, the reform of the power sector, as well as electricity regulation, is still fairly new. It is therefore important to ensure that there are communication and feedback between the different parties with regard to policies and strategies on how countries can best handle such processes of reform and transformation.

This research project will enable countries that are in similar situations and are undergoing such reform processes to learn from the experiences of one another thereby helping them to avoid the same pitfalls.

1.1 Thesis Objectives

The objective of this thesis is to undertake a comparative review of the power sector reforms and regulation in seven eastern and southern African countries, namely Uganda, Botswana, Kenya, Namibia, Swaziland and Tanzania[1]. As this objective is a fairly general one, the following questions have been formulated to clarify the more specific objectives of the thesis. The questions are also intended to elucidate the actual research process and to guide the final writing-up and presentation of the research results. The questions are:

Question One:

What is the status of the Electricity Supply Industry (ESI), its restructuring and regulation in the countries under review?

The current trend worldwide is to restructure and set up regulatory frameworks to govern the electricity industry, with the aim of improving its overall performance and creating conditions for its sustainable development. It is postulated that this trend will also broadly apply to the countries under study. One of the objectives of this thesis is thus to explore and describe the current status of the ESI and restructuring initiatives in these countries, as well as the status of the regulatory regimes which have been or are being set up.

[1]A parallel Masters thesis is investigating the same questions in Lesotho, Malawi, Mozambique, South Africa, Zambia and Zimbabwe countries.

Question two:

What are the drivers for reforms in these countries and what are the objectives?

The current efforts on restructuring, privatising and setting up of regulatory frameworks have been triggered by various factors. This research project looked at the different drivers for change in the context of the power industries and the various objectives these countries want to achieve from these reforms.

Question Three

Why are different approaches to restructuring and reforms being adopted in the respective countries, and are they the most appropriate solutions to power sector performance and other policy objectives of these countries?

Depending on the sizes of the various electricity industries, drivers for the reforms and many other factors, which will be discussed in more detail herein, it is likely that each country will have different approaches to restructuring and reforming their own power sectors. The research assessed the existing approaches, their practicality and their expected effects on the power sectors and on their economies as a whole, and has tried to suggest alternative approaches in the case of those which were regarded as inappropriate. With regard to those countries which presently have no plans in place on how they will structure their electricity industries, this research study suggested various suitable approaches.

1.2 Research Methodology

An analysis of the driving forces for electricity supply restructuring, privatisation and regulatory reform, and the nature of the reforms experienced in other countries (outside Africa), which have already undertaken power sector reforms, was conducted by means of a literature survey. Direct contact was also made with experts in the field.

An extensive literature review on the power sectors of the countries being studied was also conducted. The ESKOM Library and SAD-ELEC offices in Johannesburg were visited in order to access annual reports of the utilities and other documents with information regarding the power sectors of these countries. SAD-ELEC has substantial experience of and detailed information available on the power sectors of Southern African countries. Other relevant materials in the UCT libraries and on the websites of the utilities and ministries responsible for energy in these countries were also reviewed. Some utilities and ministries have no websites and those which do, provided insufficient and outdated information. Consequently summary sheets of the power sectors of

individual countries were developed and later sent to the relevant countries for confirmation and for securing hitherto unavailable data.

Questionnaires

Questionnaires relating to institutional structure, performance and the future of the ESI were sent to these countries. The questionnaires were targeted at officials in government departments responsible for energy issues, electricity utilities and regulators, as well as at institutions, boards, or commissions – other than departments of energy – responsible for public enterprises or parastatal reforms.

Discussions and Interviews

In addition to the fact sheets and the questionnaires that were sent out, interviews were conducted with the stakeholders and government officials responsible for ESI reforms to assess the status and direction of the power sector reforms in their respective countries. Personal face-to-face interviews and discussions took place in the researcher's home country, Tanzania, but in the other countries, this was limited to telephonic interviews. A round table discussion with Dr. Xolani Mkhwanazi, Chief Executive Officer of the National Electricity Regulator (NER) – South Africa and Mr. Siseho Simasiku[1], Chief Executive Officer of the Electricity Control Board (ECB) – Namibia, was held in the NER's headquarters in Pretoria. A few NER senior staff members were also present at the said meeting. The discussion centred on the role of the electricity regulatory authorities in the reform process and how the newly formed Regional Electricity Regulatory Association will help to ensure that members of this Association achieve a greater level of autonomy in their respective countries. The reason for this is that in some countries the regulatory authorities experience government interference which makes them unable to perform their duties effectively.

1.3 Limitations of the Study

Actual visits to the countries under study were not made, which limited the research to correspondence and interviews with utility and government officials. As a result, the general public could not be contacted for their views on the issue of power sector reform and regulation. Further, the research was carried out in a dynamic environment. The reforms and the setting up of regulatory regimes are ongoing processes in most of the countries, thus definite information on some aspects of the reforms was difficult to obtain.

[1] Mr Simasiku is the current chairman of the Regional Electricity Regulator Association (RERA)

1.4 Overview of the Chapters

This thesis is divided into nine chapters. Chapter one furnishes the background information to the study, outlining the rationale and the objectives, as well as the research methodology and concluding by indicating the limitations of the study.

Chapter two explores the experiences of power sector reforms in the rest of the world by giving a few examples. It also provides details of the essential aspects and different forms of reforms and regulation in a more general terms.

Chapters three to eight present the case studies of the six Sub-Saharan African countries, namely Uganda, Botswana, Kenya, Namibia, Swaziland and Tanzania. Each chapter covers one country. Each chapter starts by giving background information on the specific country, its location, demography, economy and status of the energy sector. Thereafter it provides more detailed information on the power sector, before providing an analysis and explanation of the sector's reforms and regulations.

Chapter nine is a comparative study of the relevant issues raised in the preceding chapters. It presents observations and conclusions arrived at and puts forward various policy recommendations in general terms.

CHAPTER TWO

Drivers for Change and the Nature of the Power Sector Reforms

2.0 Introduction

Worldwide, the reforms in the power sectors are at different stages of development. These reforms are driven by a number of factors, both general and country specific, and are expected to bring about a wide range of gains such as increased efficiency and capacity and the provision of reliable and low cost power, as well as the achievement of other country-specific objectives. Different countries have chosen different strategies, or patterns, for reforming their power sectors in view of country – specific goals and objectives. However, regardless of the type of strategy adopted by a particular country, in order for the reforms to work efficiently and to achieve all of their objectives, there must be an independent and capable regulator to oversee adherence to market rules and a number of other aspects. This chapter discusses the main driving forces behind power sector reforms in general terms. It also examines expected gains from such changes in the electricity sector, as well as the main elements of the reforms. The need to have autonomous regulatory boards and different forms of regulation is also discussed, as well as the importance of putting in place proper measures to enhance public benefits as the countries embark on reforms.

2.1 Drivers for power sector reforms

The experience of the leading reformers and the benefits which they have so far gained from the reforms, suggest that many other countries will embark on power sector reforms. In fact, countries which are now embarking on reform programmes are seeing the reforms as the only way forward for the development of their power sector. It should be noted that the experience and the benefits gained so far have given further impetus to these reforms. Other countries, particularly developing countries, had to wait until they could see how successful the reforms would be. At present many countries are seriously embarking on these reform programmes. However, one should also expect the developing countries to first stand aside, as history has shown that they normally tend to follow the development models of the developed countries after the models have worked in those countries. Nevertheless, these models may not necessarily produce the expected results in developing countries, and may need to be modified to suit specific conditions. In this regard developing countries are gradually joining the world's movement on ESI reform by embarking on various reform strategies, some of which are substantially different to those implemented in developed countries.

Drivers for changes in the electricity sector may be characterised as:

- The desire to improve allocative and operational efficiencies,
- A desire to widen customer choice,
- Technological change,
- Financing needs,
- Environmental pressure,
- A number of country-specific needs.

2.1.1 The desire to improve allocative and operational efficiencies

Under normal circumstances there are few incentives for the publicly owned utilities to improve efficiencies. This is evident both in the developed and developing countries, though it is even worse in the latter. For instance, the old Central Electricity Generating Board of England, which was regarded as operating with high efficiency, has subsequently (in the new companies) shown marked efficiency gains in a competitive market (Eberhard, 2000:4). In developing countries, most of the state run electricity utilities have recorded poor performance in terms of poor investment decisions, high operating costs, inadequate expansion of access to electricity for the population and unreliable supply. With the aim of improving investment (allocative) and operating efficiency levels, many countries are now introducing a commercial and competitive environment in the power sector through restructuring and by attracting private participation.

2.1.2 A desire to widen customer choice

Previously customers were forced to obtain their electricity requirements from the monopolistic state owned utilities. Consequently these utilities were able to pass on to their customers costs associated with their failure to operate efficiently through tariffs which were set by them. Business and industries for whom electricity is a significant part of their overall costs were the most affected by high costs of electricity. Customers are now tired of carrying utilities' burdens and they are demanding the right to choose their supplier. This has forced many countries to reform their power sectors in order to give customers a right to choose their supplier, thus encouraging industrialisation. Under the reforms, not only will the customers, especially the big customers, be flexible in determining their own terms of electricity purchase agreement, but those who have been allowed to generate electricity for their own use and not allowed to sell will now be allowed to sell the surplus to the grid. This will help them offset capital expenditures on generating equipment which was operating below capacity (African Energy, 2001) The right to choose will also force greater competition and as a result lower prices to customers, which is an important factor for attracting foreign investors to invest in manufacturing industries.

2.1.3 Change in technology

Up to the 1980s, power sector development was seen to require utilities with extensive technical and financial resources. Projects like hydropower and nuclear power, which were extremely capital intensive, were seen as the only means of obtaining economies of scale in the industry. However, recently, developments in generation technologies have made possible a new set of actors in the industry. Private developers, owners of cogeneration facilities and energy services companies have been introduced to the industry and they can compete in the generation portion of the industry. The recent development of combined cycle-gas turbines (CCGT) which can be constructed at lower unit costs (lower capital costs), in much smaller plant size and usually in a short period, has enabled independent private producers (IPPs) to participate in the industry competitively. Development of information and control technologies such as control systems and metering have also influenced the day-to-day operation of the industry and have enormous effects on the types and arrangements of services offered. There are now separate and privately owned companies operating as independent system operators and there are big and small companies competing in retail supplies. However, due to the nature of transmission and distribution technologies, these portions of the industry will remain as natural monopolies (Clark, 2001b:7).

2.1.4 Financing needs

Generally electricity system expansion requires huge investment and it has been one of the sources of the many governments' debts due to the fact that utilities are not able to finance the expansion projects on their own. Furthermore many utilities are no longer credit worthy and have been borrowing under government guarantee. Their failure to pay means that the governments have to pay on their behalf. The governments are now tired of contracting further debts and have more pressing needs, given the limited resources which they have. Moreover, the financiers such as the World Bank and the IMF have now changed their way of financing new power sector expansion projects. The financiers have started to channel their loans through the private sector. For instance in Tanzania, the World Bank is funding a gas to electricity project through the private sector. This has forced the governments to open up their power sectors for private capital, which will make them become self-financing.

2.1.5 Environmental pressure

Currently the world is facing the challenge of expanding and developing the power sector while at the same time protecting the environment. Large nuclear and coal fired power plants, which traditionally played a great role in meeting growing power demands, are now facing huge resistance form the public due to environmental concerns. This has made governments throughout the world

search for alternatives which entail reforming their power sectors to allow private sector participation to invest in new and clean technologies such as gas and renewable energy.

2.1.6 Country-specific needs

There are a number of country-specific needs, which drive the reform agenda. For instance in Namibia and South Africa, there is a specific requirement to widen economic ownership and to promote black economic empowerment (NamPower, 2000:1; Eberhard, 2000:5). In some other developing countries where there is cross subsidisation, reforms are needed to remove these subsidies in the power sector in order to release resources for other pressing public expenditure needs. A desire to raise immediate revenue for the government through the sale of the assets from the power sector has also driven the reform in some countries (Bacon, 2001). In the United Kingdom (UK), the first country to reform, the government wanted to undermine the power of the coal mining trade union, and institutional reform was bound to challenge the old coal contracts and lead to a new reduced reliance on coal as new investments were made in combine cycle gas turbines (Eberhard, 2000:5).

2.2 Main characteristics of the reforms

The drivers for change to some extent differ from one country to another, as do the reform strategies or patterns. Developed and developing countries' power sectors are at different stages of development. Whereas developed countries are embarking on the reforms with 100% electrification rates, in developing countries a lot of work has to be done to widen access and increase efficiency and reliability as well as capacity. Consequently, the reforms which are being introduced tend to follow different paths, although, the ultimate goal is to attain full competition, where technically feasible, in the electricity supply industry (ESI). The fact that one reform path might be more applicable than another, especially in developing countries, is one of the factors influencing reformers to adapt different strategies. Much of the available literature on power sector reforms, such as the writings of Marandu (2000), Eberhard (2000) and Horvei (2001), has highlighted the steps that many countries are following when reforming their power sector. These steps are:

- Commercialisation and corporatisation,
- Restructuring and introduction of competition,
- Privatisation of the unbundled ESI,
- Setting up or change in regulatory framework.

However, Marandu (2000) notes that the steps in the above framework should be thought of as an overall approach to reforming rather than a rigid set of rules to be followed in the same order in each country. This being the case, experience has shown that some countries have leapfrogged over

various stages in structural change while others have privatised aspects of the electricity industry but not chosen to make structural changes (Clark, 2001b: 1). In general, this approach helps in ensuring that important issues are not easily ignored in a reform process.

2.2.1 Commercialisation and corporatisation

Utilities in most developing countries have been performing poorly, are highly indebted and rely heavily on state funding. In many cases, poor performance has been a result of controlled and low tariffs and high levels of government intervention, usually exercised by the ministry responsible for energy. In some countries electricity utilities are treated like a government department and they do not pay taxes or dividends to the government. As an initial stage of power sector reform, many governments are transforming their power utilities into commercial entities with little or no government interventions. In this case a utility's management is granted autonomy in decision-making and is responsible for its own actions. Utilities are now treated as any other commercial enterprise, which must earn a market related return on equity and pay taxes as well as dividends. As regards corporatisation, it involves the formal and legal move from direct government control to a legal corporation with separate management (Clark, 2001b:8). However it has been argued that in order to realise best results, corporatisation is usually combined with commercialisation, as a corporatised utility should be submitted to commercial discipline (Marandu et al., 1999:103).

Often commercialisation and corporatisation in African countries have been introduced under management contract where operation of the utility is delegated to a qualified firm, usually an external firm. The qualified firm signs a contract with the government agreeing on the performance targets to be met over a contract period. Under this arrangement, in return for its service, the contractor receives a fee, which is fixed or indexed to a parameter such as turnover, sales, operating profit or a combination of these. A variation of management contracts is performance contracts between the government and the utility, where remunerations of the utility's employees are related to the success in meeting the targets. Chiwaya (1999) quotes the World Bank as saying that performance contracts are in use in France, Bolivia, El Salvador and Côte d'Ivôire (the Ivory Coast). Commercialisation and corporatisation, whether under management or performance contract, have been considered as a means of creating a level playing field and creating conditions for real competition to take place (Econ, 2000:24).

2.2.2 Restructuring for performance improvement and competition

Restructuring is the cornerstone of the power sector reforms. It is so important and widely used a concept that others use it to refer to power sector reforms or privatisation, which is incorrect. Restructuring is part of the reforms and it entails rearrangement of the organisational structure of a

utility in order to improve performance and create competition. A country may restructure its power sector without necessarily introducing competition or changing ownership of the ESI industry. However, a worldwide trend is to transform the ESI from a state controlled to a market driven sector. The major concepts which are universally considered when countries restructure their power sectors are:- vertical unbundling, horizontal unbundling, single buyer model, wholesale competition model, retail competition model, free entry, open and non-discriminatory transmission system, power pool model, multiple electricity trading market model, a set of trading mechanisms and regulatory capacity. Some of these concepts are discussed in the following paragraphs.

Vertical unbundling

Vertical unbundling often follows the expiring of the management and performance contracts, which were entered into during the commercialisation and corporatisition stage. The traditional vertically integrated utilities are then restructured by splitting generation, transmission and distribution functions to form separate functional units which will trade with one another on a commercial basis. This makes it easier to relate costs to output and to avoid hidden cross-subsidization. It also makes the management triangle shorter and as a consequence decisions are taken quickly and closer to the people who are implementing them. A major rationale for the vertical unbundling is to separate the potential competitive elements of the industry (generation) from the natural monopoly components (transmission and the wires part of the distribution). In order to avoid any shortfall in capacity, which may occur while the newly created entities (particularly the generation segment) are prepared to handle new investment, IPPs may be allowed entry into the market. This will enable the electricity industry to expand as rapidly as possible and at least cost.

Horizontal unbundling

It has been argued that vertical unbundling alone cannot bring the desirable improvement in performance, nor competition, as each newly created entity from vertical unbundling becomes a monopoly at its functional level which might result in higher power prices than that of the integrated monopoly, if not well regulated (Bacon, 1994). Thus there is a need for horizontal unbundling where generation is further separated into a number of competing companies – none big enough to exert market power. O'Neill et al. (2001:1) points out that competition in generation promises large efficiency gains and cost savings to consumers because generation comprises approximately 75% of all electricity costs. For a large country or system where a single national utility was responsible for distribution, horizontal separation to create regional electricity supply companies (Resc) or distribution entities (Discos) may also be adopted. This will bring the utility closer to the customers, thus improving the ability to respond to local needs (Marandu et al., 1999:101). However, since transmission is regarded as natural monopoly, it should continue to be performed by a single

company in order to avoid unnecessary duplication of the systems but should be subject to price regulation.

Single buyer model

During the vertical unbundling stage, some governments may decide to partially unbundle their power sector by leaving transmission and generation together. This means that generation and transmission functions remain to be performed by a single state owned company which purchases bulk power from the IPPs and also sell in bulk to distribution companies or entities. This model is called the single buyer model and has been introduced in many South East Asian countries and other developed countries (Eberhard, 2000:7). One disadvantage of this model is that the ESI may be tied up with undesirable power purchase agreements (PPAs) for a long period of time, and thus unable to lower prices. Moreover, if PPAs are not flexible enough, unexpected economic changes like the devaluation of local currency against major currencies can put extreme pressure on the government finances. This occurs when the state utility is committed to purchase prices denominated in US dollars or UK Pound Sterling while having to on-sell the electricity in its domestic prices. For instance, Indonesia and Pakistan have experienced this problem (Hansen, 2001).

Wholesale competition model

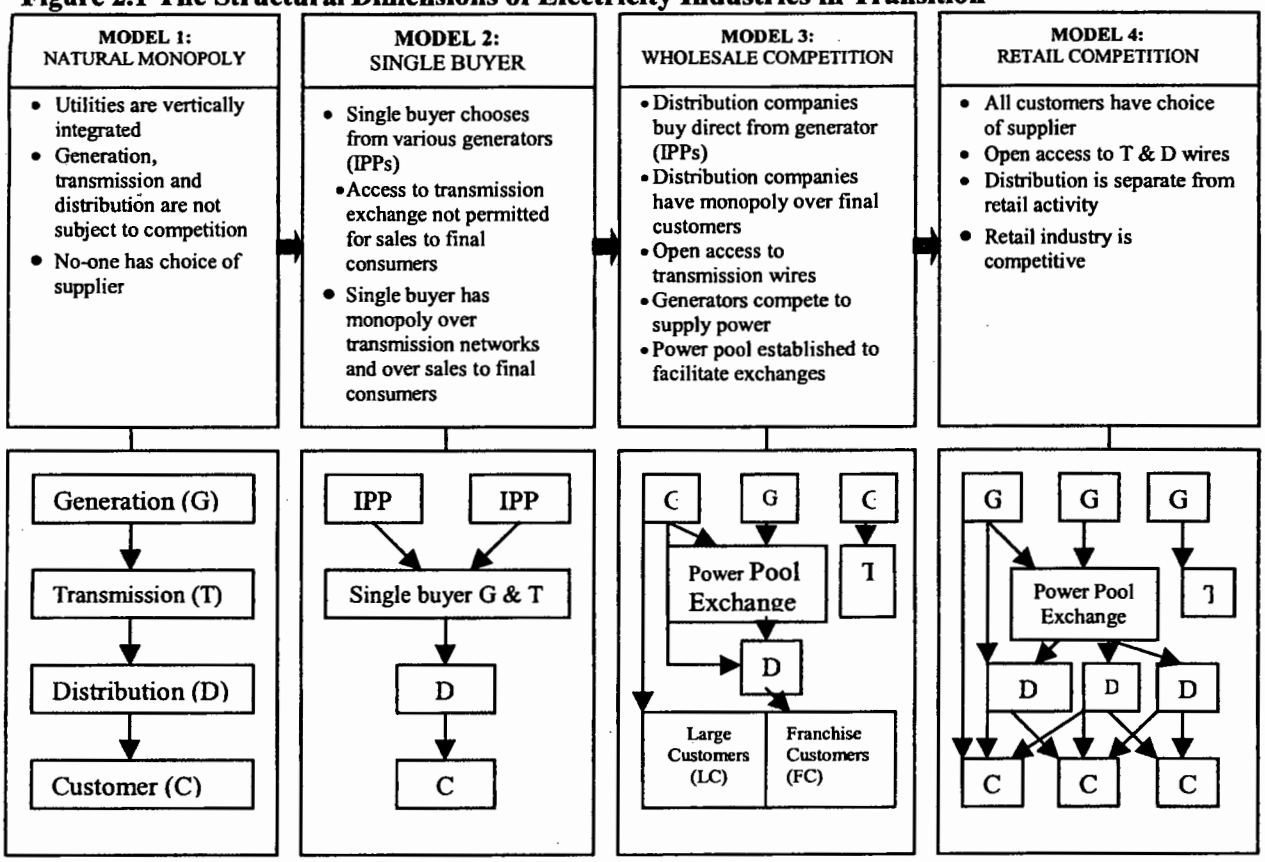
This is an arrangement where the horizontally unbundled power generation entities and IPPs compete in selling electricity in bulk to the distribution companies and large customers. As a result of competition, large consumers are now allowed to buy electricity from lowest cost generators. This forces generators to minimise their cost and hence increase productive efficiency. Allocative efficiencies are also improved for new investment. This system first emerged in the UK. Other countries such as Chile, Argentina and USA have also followed this reform system (Hansen, 2001). However, a requisite for wholesale competition is the open access to the transmission network principle and free entry to the market. Investment in generation and transmission should be freed and left to the market forces.

Retail competition model

The wholesale competition model limits competition to large customers only. However, the introduction of a new participant in the market in the form of energy brokers, commonly known as suppliers, has enabled competition to be extended to all essential consumers. Electricity supply is now carried out by the new participants, and this is termed the retail competition model. Under this arrangement, attained at the mature stage of the reforms, supply is separated from the ownership of the distribution wires, thus enabling small customers to buy their electricity requirements from competing suppliers. The suppliers purchase electricity in the wholesale market and pay a regulated fee to the transmission and distribution companies for the use of their infrastructures. As is the case

with transmission systems, distribution networks should also be under open access for attaining effective retail competition. Countries such as the UK, New Zealand, Australia and Norway have reached this stage, which is regarded as a stage where full benefits of competition in the electricity industry are attained (Fischer et al., 2000). Figure 2.1 below shows structural dimensions of electricity industries in transition.

Figure 2.1 The Structural Dimensions of Electricity Industries in Transition



Source: Adapted from Clark, A.. (2001b)

Electricity trading mechanism

This is another characteristic of the power sector reforms. In order for the competitive electricity market, whether wholesale or retail, to work as required, it requires a set of effective trading mechanisms and instruments. This is in addition to the principles of open access transmission and distribution networks and free entry. As electricity cannot economically be stored in great quantities, its market is rather complicated as sellers and buyers need to interact differently from those dealing with other products. In a competitive electricity market, effective interaction is considered to be facilitated by mainly two market models, namely the power pool model and the multiple electricity trading market model. These models have different sets of trading mechanisms such as a market of bilateral and future contracts, a day-ahead spot market and real time balancing and settlement markets.

Power pool model

Basically, this model involves electricity trading through a power pool which acts as a power exchange.. In this model generators bid their power into a pool and purchasers of power buy their power from the pool. Generators make bids on price and available capacity for a particular period, usually an hour or half hour a day ahead. The power pool operator then uses this information to build a least cost function for the next day's power dispatches. The price that the purchaser of power will pay is based on the bid price of the last dispatched plant, but subject to adjustments to include any capacity payment and costs of system operation and balancing. The system operator is responsible for financial settlement and system balancing and handling any constraints by adjusting the dispatch schedule and ancillary services. Usually a separate price schedule for increase or decrease in generation or consumption is used in balancing markets. Contracts for difference, which are bilateral contracts between generators and purchasers, can be entered into for risk hedging and their payments are done outside the pool. This model was widely used in the UK, Australia and South American countries although it has limited demand side participation which lead the UK to embark on the multiple market model (Fischer et al., 2000; Econ, 2000:27).

Multiple electricity trading market model

Whereas under the power pool model generators are forced to schedule and dispatch all of their power through the pool, under the multiple market model (MMM) generators are allowed to sell their power directly to the consumers. In this model there is a variety of platforms where trade may take place on a voluntary basis, and as a result there is strong demand side participation. Generators and purchasers may enter into long or medium-term bilateral contracts, often far in advance of actual delivery (Fischer et al., 2000; Econ, 2000:27).

2.2.3 Privatisation of the unbundled ESI

Some governments have restructured and introduced competition into their power sectors by limiting private involvement to new entrants in the form of IPPs. This means that all the assets previously owned by the vertically integrated utilities remained state owned even after restructuring. For example, while Norway restructured its power sector but did not privatise the assets, the UK, Chile and Argentina restructured and privatised at the same time (Eberhard, 2000: 9).

However, it has been argued that there is a limit to what the government can do and that certain economic undertakings, particularly industrial enterprises, can be handled more efficiently by the private sector (Chiwaya et al., 1999:300). Governments need to reduce their direct involvement in economic activities and engage in creating enabling infrastructure for more private sector participation for economic growth. Thus, in recognition of the importance of the private sector

involvement in the ESI and in order to attain the full benefits of competition, many governments eventually embark on privatising programmes of publicly owned ESI assets. Privatisation can be introduced in phases, and governments should first decide what parts of the industry are to be privatised and how privatisation is to take place. The most common ways have been through inviting strategic equity partners, auctioning assets, targeted equity sales or an initial public offering.

2.2.4 Change in the role of regulatory oversight

The role of regulation is expected to change as market reforms are adapted to meet the needs of a future competitive electricity industry. Previously, in many countries, particularly developing countries, government departments (in most cases under the ministries of energy) undertook the regulation of the power sector. As reforms are introduced, new regulatory boards, authorities or commissions which are transparent, capable and independent should also be introduced. The role of the new regulatory boards will focus mainly on transmission and distribution, which will remain natural monopolies. There is a need to ensure open non-discriminatory access to the transmission and distribution systems by the generators, customers and retail suppliers. However, for generators and retail suppliers, the role of overseeing proper interactions of the participants to ensure optimal efficiency is now the responsibility of two bodies, the competition body and the regulatory body. These two bodies together have an objective of addressing market failures such as abuse of market power and externalities.

The regulator role will move away from the old "command and control" price settings, which were characterised by government and cabinet approvals, to cost of service regulation or range of conduct or incentive based regulatory mechanisms. Unlike command and control regulation which was characterised by direct operating instructions given to the utilities, the incentive regulation normally uses rewards and penalties to (provide inducements to) motivate the utilities to perform.

Under the reforms there is also a need to have an optimal split in functions between competition authorities and electricity regulators. The competition authority functions could be to look at the structure of the market, control anti-competitive behaviour and to review mergers, which will lead to market power and ensure that such mergers will not happen. On the other hand the electricity regulator functions could be to control monopoly pricing in distribution and transmission systems, to ensure appropriate levels of consumer protection through regulatory mechanisms such as cost of service regulation or incentive regulation and to set and monitor standards. Other functions of the electricity regulator could be to address safety and environmental matters as well as to address public interests such as distribution and equity imbalances. However, the split of function does not mean that the competition authorities and electricity sector regulators work in isolation. The two

boards should work closely together for better co-ordination of the electricity market, thus helping the governments realise their objectives.

2.3 Public Benefit Notion

According to Clark (2001b), the term public benefit refers to social, environmental and developmental "goods and services" that bring about notable social welfare improvements. Specifically in the electricity sector, public benefits include electrification and access programmes, public interest research and development (R&D), public interest energy efficiency, renewable energy, integrated resource planning, customer services (reliability, quality, security of supply, customer support, etc) and environment protection programmes. Societies value all these public benefits, but due to market failures, markets do not provide them adequately. If provided, they can contribute significantly towards sustainable development.

2.3.1 Power sector reforms and public benefits

Electricity has played a critical role in countries' economic development and in raising standards of living of the citizens. As countries are embarking on power sector reform programmes, publicly owned utilities, which were keen on public benefits are now corporatized, commercialised and privatised and are thus required to operate commercially and maximise profits. These reforms will reduce government involvement in the electricity sector. Unfortunately, profit maximisation and public benefits are two conflicting objectives. If public benefits need to be enhanced then proper planning during the reforms must be put in place. Measures which might be adopted to advance them when electricity industries are restructured, should carefully be considered and should be put ahead of the reforms. In developing countries where people live in abject poverty, public benefit goods and services are of great importance, hence the need to advance them rigorously.

2.4 Conclusion

This chapter has highlighted various drivers for change as well as reform strategies which, to some extent, are triggered by the drivers as well as what a particular country wants to achieve from the reforms. However, to achieve the best results, a country needs to evaluate carefully any reform proposal it wishes to follow since each country has a diverse range of economic, social and political structures. Furthermore, the adapted reform pattern needs to be flexible enough, as a reform approach that has worked in one country may not necessarily produce the intended results in another country. In addition to adapting appropriate and flexible reform patterns, the call for change of the regulators' roles to meet the need of the patterns is of great importance. The effectiveness and performance of the regulators in the new patterns will have a critical impact on the expected benefits of these reforms.

CHAPTER THREE
Uganda

3.0 Location and Demography

Uganda is located in the heart of Sub-Saharan Africa and lies astride the Equator. It is a landlocked country, bordering the Sudan to the north, Tanzania and Rwanda to the south, Kenya to the east and the Democratic Republic of Congo to the west. The total area of the country is about 241,000 km^2 of which about 44,000 km^2 (18%) are covered by fresh water lakes and rivers. The country has a population of about 22.2 million with a growth rate of 2.8 % per annum. 86% of the total population lives in the rural areas. With a land area of 197,097 km^2, the population density is about 113 people per square kilometre (World Bank, 2002).

3.1 Economy

The economic reforms, which have been implemented by the present government of Uganda since 1987, coupled with the political stability of the country, have contributed to economic growth rates averaging 7 % per annum in the last decade. This has made Uganda one of the fastest growing countries in Africa. However, in 2000, the real GDP grew by 3.5 % compared to a growth of 7.5 % achieved in 1999. The slower pace of economic growth in 2000 was attributed to a prolonged drought that affected a large part of the country in 1999. However, the manufacturing sector's performance was robust and posted a growth rate of 8.6 % in 2000. As manufacturing is linked to electricity consumption, such robust growth calls for an increase in investment in the power sector. Uganda is thus seeing a shift from the firmly agriculturally based economy of 1986 towards construction, manufacturing and regional trade (World Bank, 2002).

Uganda's monetary policy also ensured that inflation arising from the drought was kept under control and as a result the inflation rate has been maintained below 10 % per annum for the past four years from the record highs of 240 % in 1988. For the year ending December 2001, the annual underlying inflation rate was 3.2 %.

In order to attract foreign investments to complement domestic efforts, Uganda has put in place a fiscal incentive package, whose terms provide for generous capital recovery terms, particularly for investors whose projects entail significant investments in industrial plants and machinery and whose investments are medium or long-term. The incentive package also includes initial allowances, deductible annual allowances and other annual depreciation allowances. Coupled with the incentive package, most of the economic activities are fully liberalised and open to foreign investments. The

foreign exchange market is also wholly liberalised and there are no restrictions on capital amount transfers and in this case no barriers to the remittance of dividends. Uganda's shilling is fully convertible and has remained relatively stable over the last years.

Generally, the country's economic strategy is to modernise its economy by relying on markets. To this effect the government's major role will remain to provide the necessary legal policies and physical infrastructure to enable private investment to flourish.

3.2 Energy Sector

As is the case in most countries in the world, the energy sector is one of the key sectors in the Ugandan economy. Uganda's energy sector is managed by the Ministry of Energy and Mineral Development and is divided into four sub-sectors: - petroleum, electricity, fuel wood, and new and renewable sources. The sector is characterised by a heavy dependence on biomass energy resources, which provide about 94 % of the total national energy needs. Electricity contributes only about 1 % of the total energy consumed, whereas the petroleum sub-sector provides about 5 % of the country's energy consumption requirements. The combined contribution of the new and renewable sources of energy (such as wind, biogas, solar, geothermal, liquid fuels and peat) to the total energy consumed in Uganda is estimated at a mere 1 %.

The Ugandan government has deregulated the energy sub-sectors dealing with electricity and liquid fuels. The government sees its further role in the energy sector as that of elaborating on and implementing energy policies and energy development strategies, as well as in creating the conditions necessary for an improved energy supply. The government's overall policy objectives in the energy sector are the following: -

- To improve the quality and quantity of energy supply through appropriate sector reforms and the establishment of an enabling legislation;
- To promote the efficient utilisation of energy resources and the execution of rural electrification programme;
- To promote private sector participation in the development of both conventional and renewable energy resources in order to expand access to energy services;
- To maximise opportunities for export of power to the neighbouring countries once the internal demand is adequately met (GoU, 1999).

3.3 The Power Sector

3.3.1 Background

The power supply in Uganda is based primarily on hydro, and to a lesser extent, on thermal resources. Uganda, which is one of the sources of the Nile River, has significant hydropower potential on this river, estimated to be in excess of 2,000 MW (GoU, 1999: 8). At present, out of this total potential, only 300 MW capacity has been developed. However, the completion of the proposed Bujagali IPP hydropower project in 2006 will add another 250 MW. Uganda also has great potential for mini-hydros. Twenty-two mini-hydro sites with the capacity range of 0.5 – 5 MW have already been identified (GoU, 1999). Potential sites for large hydropower projects and their estimated maximum installed capacity are summarised in Table 3.1. Studies carried out by Uganda's Department of Geological Surveys and Mines show that Uganda has geothermal resources in the Western Rift Valley estimated at about 450 MW. Uganda also has great potential for solar energy as, by virtue of its location on the Equator, Uganda receives relatively high isolation levels averaging about 5 kWh/m^2/day (GoU, 1999).

Table 3.1 Hydroelectric Potential along the Nile River in Uganda

Site	Potential Capacity (MW)	Potential Generation Capability (GWh)
On Nile between Lake Victoria and Lake Kyoga		
Owen falls Extension	200	500 – 700
Bujagali	250	1,200 – 1,500
Busowoko	230	1,000 – 1,200
Kalangala	225	700 – 900
On Nile between Lake Victoria and Lake Kyoga		
Karuma (Kamdini)	300 – 350	1,200 – 1,400
Ayago North	360 – 400	2,000 – 2,400
Ayago South	230 – 250	700 – 1,200
Murchison Falls (Kabalega)	450 – 550	2,600 – 3,500
TOTAL	**2245 – 2455**	**9,900 – 12,800**

Source: Ruffini, 2000d:29

Although Uganda's power sector heavily depends on hydro (98 %), the fact that the source of the river Nile, Lake Victoria, is situated in Uganda, means that it does not suffer from drought-induced electricity shortages, like its neighbours, Kenya and Tanzania. However, despite such a good resource and the existence of the first hydro power plant, built as early as 1954, only 6 % of the population, in fact, has access to electricity, of which 5 % are found in urban areas and only 1 % in rural areas. The level of electric energy usage in Uganda is extremely low, with an average per capita consumption of only 44 kWh/year. In the rural areas per capita consumption is only 10 Kwh/year. The per capita power consumption is the second lowest in the world, the lowest being

Sierra Leone (African Energy, 2000). However, the remaining 94 % of the population, which as yet has no access to electricity, represents a potential power market, hence the need to increase investments in power generation, transmission and distribution. Private investments are needed to develop the potential hydro resources in terms of mini-hydros and large-scale projects.

3.3.2 Institutional Arrangements

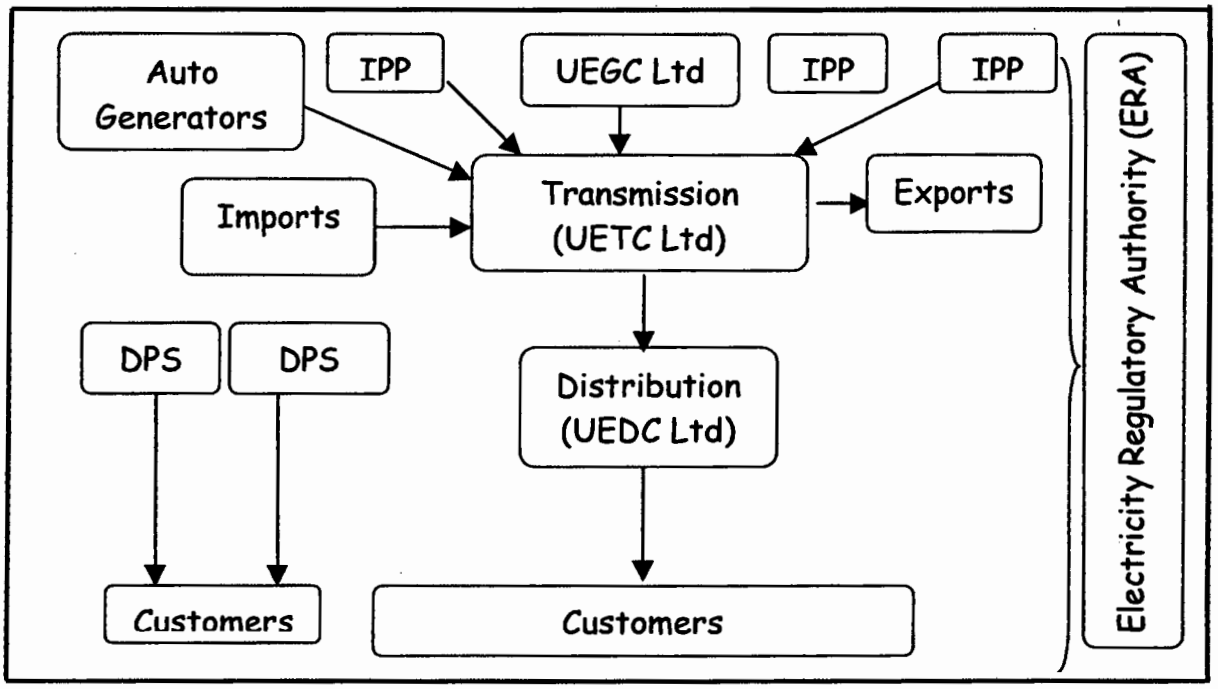
The Uganda Electricity Board (UEB), a publicly owned utility that was formed in 1948 through the Uganda Electricity Ordinance, originally had a monopoly to generate, transmit and distribute electric power throughout the country. The UEB monopoly in the power sector ceased on 31st October 1999 when the new Electricity Act became law, following the approval of a power sector privatisation policy in June 1999. In addition to removing the UEB monopoly, the new Electricity Act also established the Electricity Regulatory Authority (ERA). The objectives of formulating and implementing the new electricity policy were to address the key problems in the power sector, namely very poor financial and commercial performance by the UEB and the need to finance a relatively large investment programme (GoU, 1999: 3).

As a result of the new Electricity Act and the government's objectives and goals for the power sector, as stated in the revised 1999 strategy plan for this sector, the UEB was unbundled into three separate companies. The three companies formed with effect from 30th March 2001, were the Uganda Electricity Generation Company Limited (UEGC), the Uganda Electricity Transmission Company Limited (UETC) and the Uganda Electricity Distribution Company Limited (UEDC). In line with the three limited liability companies, the UEB remains a statutory body that takes care of stranded assets and other unallocated responsibilities. Details of Uganda's power sector restructuring and reform are discussed in Section 3.3.8.

Although the UEB, prior to the new Electricity Act of 1999, had been the only body allowed to generate, transmit, distribute and retail electricity in the country, the old Electricity Act of 1948 had granted the Minister responsible for energy, the power to authorise other private operators without necessarily seeking endorsement by the UEB. There were some institutions, which were generating electricity in small quantities for their own use. For example, Kilembe Mines Company operates a hydroelectric station with a total installed capacity of 5 MW. Another mining company, Kasese Cobalt Company Limited, runs a much bigger plant with an installed capacity of 10 MW. A mission hospital, Kisiizi, operates a generation plant of 0.06 MW capacity, consisting of a single 75 kVa hydroelectric generator. Another hospital, Kogando, also owned and operated a 0.06 MW capacity plant for its own use. Under the new Act, these companies would be allowed to continue generating for their own use and if they should have a surplus, they could inject it into the national grid by

selling it to the UETC or supplying to their surrounding areas. Both Kilembe Mines Company and Kasese Cobalt Company Limited were selling power to the UEB in the past, and now they are selling to its successor, the UEGC. There is also a small hydro power station at Maziba near Kabele town in southwestern Uganda. This plant is connected to the grid and is a standby power station for Kabele town. Figure 3.1 shows the proposed institutional arrangement of the power sector after the reforms have been implemented

Figure 3.1 Proposed Institutional Arrangement of the Power Sector



Key: IPP = Independent Power Producers
DPS = Decentralised Power Systems (Mostly for Rural Electrification)

3.3.3 Supply

Generation

Hydro generation accounts for 98 % of Uganda's total generation capability. The major existing generating facilities in Uganda, the Nalubaale Dam (formerly Owen Falls) with an installed capacity of 180 MW and Kiira Dam (formerly Owen Falls Extension) with an installed capacity of 120 MW, were previously owned and operated by the UEB. These facilities and other UEB-owned generating facilities now fall under the newly formed UEGC – the Uganda Electricity Generating Company Limited. The total combined generation capacity attained at Owen Falls has now reached 300 MW. With three units at Kiira Dam currently operational, work on unit 4 is projected to start soon as funds have been secured from the project's financiers, the World Bank. The UEB had also operated the Maziba Gorge hydroelectric scheme, a three-unit 1 MW (2X250 kW + 1X500 kW) station. The UEB had also been maintaining five diesel generation plants with a total installed capacity of

2.13 MW to supply electricity to isolated upcountry areas. Table 3.2 shows installed capacity of Uganda's electricity generating stations, which now fall under the new Generation Company.

Table 3.2 Installed Generation Capacity

Generation Type	Name of Station	No. of Units	Year Commissioned	Installed Capacity (MW)
Hydro	Owen Falls	18	1954	180
	Owen Falls Extension	3	2000	120
	Maziba Gorge	2X250kV 1x500KV	1993 1993	1.0
Total Hydro Capacity				**301**
Diesel	Arua	3	1989	0.85
	Moroto	2	1989	0.425
	Moyo	1	1989	0.21
	Maziba	1	1990	0.32
	Adjuman	1	1990	0.115
	Nebbi	1	1991	0.21
Total Diesel Capacity				**2.13**
Total Installed Capacity				**303.1**

Source: Compiled from UEB Annual Reports

One of the strategic objectives of the then UEB in managing the existing generating facilities was to maximise the output and achieve 90 % availability of all units. Given this objective and the fact that Uganda's generating capability does not suffer from drought-induced shortages, the plants' performances for the period under review, 1990 – 2001 were generally good, as appears from Table 3.3 below.

Table 3.3 Units Generated and Sent Out (GWh)

Year	Units Generated Hydro	Units Sent Out Hydro	Units Generated Thermal	Total Generation	System Load Factor
1990	736.5	735.7	1.4	737.9	68.6
1991	781.5	780.8	1.1	782.6	65.6
1992	993.3	992.6	1.0	994.3	75.2
1993	976.5	975.9	1.4	977.9	71.0
1994	1,016.8	1,016.5	1.4	1,018.2	72.0
1995	1,056.3	1,056.0	1.5	1,057.8	69.6
1996	1,129.0	1,128.7	1.1	1,130.1	74.1
1997	1,217.3	1,216.7	1.2	1,218.5	77.9
1998	1,232.4	1,231.9	1.2	1,233.6	78.3
1999	1,340.5	1,339.5	1.2	1,341.7	85.1
2000	1,537.9	-	-	1,537.9	67.6
2001	1,556.2	-	-	1,556.2	71.4

Source: Compiled from UEB Annual Report, 1999 and OFPS & UEDCL Corporate Planning

Transmission and Distribution System

Uganda's transmission and distribution system consists of 132 kV, 66 kV, 33 kV and 11 kV lines. The electricity grid extends across the southern part of the country where it covers Masaka, Kampala and Jinja, to the west of Owen Falls Dam, to Tororo in the east, where it connects to the Kenya system and north up to Lira. The interconnection between Uganda and Kenya is via a double circuit 132 kV line. There is also another 132 kV line, which supplies power to Kagera region of Tanzania. However, this region is not connected to Tanzania's national grid, and hence the Ugandan and Tanzanian systems are not actually interconnected.

Some of the transmission and distribution lines in Uganda date back to the 1940s and 1950s. However, much of the new transmission work on the Ugandan transmission system, particularly at 132 kV and 33 kV, was associated with generating station development and the need to upgrade the lines into double circuits for reliability purposes. Table 3.4 shows the development of major transmission and distribution lines in Uganda from year 1991 to year 2001.

Table 3.4 Transmission and Distributions Lines in Uganda (km)

Year	132kV	66kV	33kV
1991	909.2	73.6	2,615.2
1992	909.2	73.6	2,664.2
1993	994.2	73.6	2,696.8
1994	1089.2	73.6	2,715.6
1995	1,225.2	73.6	3,008.6
1996	1,225.2	73.6	3,075.0
1997	1,225.2	73.6	3,120.6
1998	1,313.2	73.6	3,304.0
1999	1,318.1	73.6	3,335.0
2000	1,318.1		3,335.0
2001	1,318.1		3,335.0

Source: UEDCL Corporate Planning

System Losses

Uganda is one of the countries in Africa that experiences very high system losses, both technical and non-technical. The former are due to overloading of some of the feeders well over their design capacity, thus resulting in low supply levels to customers. Another contributing factor is the fact that secondary lines are very long, often resulting in continuously connecting customers on the same line without regard to voltage levels at the end of the lines. Aged transmission lines also contribute to the high levels of technical losses.

As regards non-technical losses, the main contributing factor is the large number of illegal customers who have connected themselves to the grid system. Previously, due to the shortage of meters, UEB was giving some customers an unmetered supply (Mugyenzi, 1999). Illegal connections also flourished, because the UEB took such a long time to connect new customers who had applied for the service, that they were thus tempted to resort to illegal means. However, the new management of the UEB, which was appointed in April 1999, took several measures to reduce both technical and non-technical losses, and to some extent they have succeeded, as is demonstrated by the trend shown in Table 3.5 below. Some of these measures included recruiting more metering staff, improving the meters or issuing replacements, improving the billing systems by using shorter periods of billing, for instance, and physical checking of wiring systems in homes to curb illegal connections (an exercise called "operation see me").

Table 3.5 System Losses

Year	Units (GWh)	Total System Losses (%)
1990	217.5	38.2
1991	128.5	19.7
1992	224.5	31.7
1993	236.8	33.2
1994	276.8	36.2
1995	340.4	39.5
1996	300.4	30.8
1997	346.7	33.1
1998	367.1	34.2
1999	463.5	39.7
2000	442.2	34.4
2001	516.6	36.1

Source: UEB Annual Reports and UEDCL Corporate Planning

3.3.4 Demand

Uganda's peak demand has grown from one year to the next. In recent years, there has been relatively faster growth due to a generally high economic growth in the country. For example, in 1998 the peak demand was 179.8 MW, and it grew to 260 MW in 1999. The electricity demand in Uganda, in fact, comes from two sources, export peak demand and domestic peak demand, which will be discussed more fully hereunder.

Export Peak Demand

A significant market exists for electricity exports to Kenya, Tanzania and Rwanda and to the region at large. Currently, Kenya sources about 4 % of its own electricity needs from Uganda, which exports up to about 30 MW of continuous power. Uganda started to export power to Kenya from

1954 when the Power Supply Agreement, which is due to expire on the 1st January 2008, was signed. Droughts, which have frequently affected Kenya and negatively impacted on its rapidly growing electricity demand, have made it necessary for Kenya to ask Uganda for more supplies. However, Uganda has failed to supply more than 30 MW, due to their own supply constraints, as their domestic electricity demand, too, has increased. Uganda also exports about 5 MW of continuous power (about 20 GWh annually) to Tanzania's Bukoba region, which borders Uganda. There is a possibility for more demand from Tanzania to supply to its proposed mines sites in north-western Tanzania. Apart from supplying these two countries, Uganda also exports about 1.0 MW of continuous power to Rwanda. The total power exported by Uganda amounts to about 300 GWh, for which it earns about US$ 20 million annually.

Domestic Peak Demand

Although Uganda exports power, internally it has been experiencing load shedding almost every day for a long time now. Nevertheless, the problem of load shedding was eased with the commissioning of the new Owen Falls Extension Power Station (now known as Kiira Dam) in May 2000, and since then load shedding has been reduced to once a week. With the commissioning of unit III of the Kiira Dam (Owen Falls Extension) in July 2002, the country now has an installed generating capacity of 300 MW. Table 3.6 shows Uganda's electricity consumption by tariff whereas Table 3.7 shows the system's peak demand.

Table 3.6 Electricity Consumption by tariff

Year	Residential	Commercial	Industrial	Others	TOTAL
1990	274	84	45	5	408
1991	328	100	65	11	504
1992	263	142	73	18	496
1993	272	127	71	3	473
1994	286	116	82	5	489
1995	267	120	98	2	487
1996	367	159	36	2	564
1997	349	194	160	2	705.0
1998	316.6	98.3	289.8	1.2	705.9
1999	429.7	107.2	162.7	2.3	701.9
2000	513.0	121.9	206.2	1.9	843.0
2001	354.4	174.6	381.2	2.5	912.8

Source: UEB Annual Reports and UEDCL Corporate Planning

Table 3.7 System Peak Demand

Year	Domestic Sales (GWh)	EXPORTS (GWh)			Total Sales (GWh)	System Peak Demand (MW)	Number of Customers
		Kenya	Tanzania	Rwanda			
1990	351.7	166.5	-	-	518.2	122.8	103,920
1991	526.6	126.6	-	-	652.1	136.2	95,569
1992	484.8	283.4	-	-	768.6	151.0	110,809
1993	476.4	261.8	0.9	-	739.1	157.2	116,885
1994	487.5	237.1	15.1	-	739.7	161.4	107,595
1995	521.5	175.8	18.3	-	715.6	173.6	101,409
1996	676.7	131.2	19.0	0.9	827.8	174.0	123,047
1997	700.5	148.3	19.6	1.5	869.9	178.6	142,327
1998	705.9	136.3	21.3	1.3	864.8	239.0*	159,205
1999	702.2	152.8	21.1	0.04	876.1	260.0*	164,225
2000	843.0	229.5	21.5	0.1	1,094.3	280.0*	180,234
2001	912.8				1,057.9		200,217

Source: UEB Annual Reports and UEDCL Corporate Planning
**System Maximum Demand in 1998, 1999 and 2000 was established using load studies assuming the Maximum Demand at different substations occurs at the same time, whereas the Maximum Demand in previous years are readings from Owen Falls Power Station (UEB, 2001).*

3.3.5 Tariffs

The electricity tariff system in Uganda has been divided into six main categories with three components, namely an energy charge, a fixed charge per month and a demand charge for some of the categories. The block system is used for the residential tariff to encourage consumers to reduce their consumption. However, although domestic consumers are the major contributors – about 70 % in 1998 – to Uganda's peak demand, a "time of use" tariff is not used. Perhaps this is due to the difficulties in metering customers according to time of use, especially when considering the high technology required for such metering systems.

The latest tariff adjustment in Uganda was made in June 2001. The preceding tariff adjustment had occurred in July 1993, thus no adjustments had been made for almost eight years. Consequently, the latest tariff increases more than doubled the charges in each tariff category. However, according to the Electricity Regulatory Authority (ERA, 2001), the new tariff is, in fact, lower than the 1993 tariff, adjusted for inflation and foreign exchange changes. Under the 1999 Electricity Act, tariff adjustments will now be effected by the ERA. The ERA stated that its general principle in tariff adjustments is that the tariff should reflect the true cost of supplying different consumer classes. In this way it would allow the sector to cover its costs without government subsidies. Tariffs therefore would be adjusted on a quarterly basis in order to reflect fluctuations in demand and exchange rates, as well as annual inflation rates. However, the adjustments of transmission revenue requirement will

be effected on an annual basis (ERA, 2001). Table 3.8 compares the old tariffs (1993) to the new ones (2001).

Table 3.8 Electricity Retail Tariff – 2001

Tariff Code (Old) / (New)	Retail Rate (USh/Unit)		Fixed Monthly Fee (USh/Month)		Maximum Demand Charge First 2000 kVA (USh/kVA)		Maximum Demand Charge Over 2000 kVA (USh/kVA)	
	Old	New	Old	New	Old	New	Old	New
1 (first 30 kWh)	10	20	50	1,000	1,000				
1 (30 to 200 kWh)	10	70	189.8	1,000	1,000				
1 (over 200 kWh)	10	100	189.8	1,000	1,000				
2	10	115	189.8	4,000	1,000				
4.1	20	75	171.6	10,000	10,000	10,000	5,000		
4.2	22	55	99.6						
3.1	30	70	104.4	15,000	15,000	10,000	3,300	8,000	3,000
3.2	32	50	68.3						
5	50	125	176.3	4,000	4,000				

Source: Electricity Regulation Authority

3.3.6 Rural Electrification

Over 90 % of Uganda's 22 million people live in rural areas. At present only about 1.0 % of the rural population has access to electricity. Most of the population with access to electricity in the rural areas does so through such sources as car batteries, diesel generators and photovoltaic systems (PVs). The cost of electricity from these sources is many times that of grid power, i.e. in the order of US cents 250/kWh for the former, compared to US cents 7/kWh for the latter. It is estimated that there are over 200,000 households which are using such sources (Ruffini, 2000a). This shows that there is a potential demand for electricity by Uganda's rural people. As is the case with many utilities in Africa, however, the then UEB concentrated its activities mainly in urban areas and did very little to meet this rural demand.

Since 1995, the government of Uganda has put considerable effort into increasing rural electrification through projects such as the solar PV project, i.e. the Photovoltaic Pilot Projects for Rural Electrification (PPPPRE), which was initiated in 1995. Recently, with the aid of the World Bank, the government of Uganda has committed itself to increasing rural electrification from 1 % to over 10 % by 2012. This will be realised through the Energy for Rural Transformation Programme. The government has just secured US$ 375 million from the World Bank and a consortium of other

donors for this project. Some of this money will be given out as soft loans and subsidies to private investors willing to extend power to rural areas. (Bbumba et al., 2002).

Government's initiatives have also been reflected in the new Electricity Act. The Act encourages private sector-led rural electrification projects. The Act also stated that tariffs would be set so as to ensure financial viability for each decentralised system. This will ensure that the provision of electricity services in rural areas happens on a commercial basis. For less attractive areas 'smart subsidies' in the form of grants will be used to attract developers. Thus in order for the government of Uganda to be able to provide these subsidies, the government is, as part of its reform, establishing the Rural Electrification Fund to replace the subsidy for small consumers. It is because of this seriousness shown by Uganda's government, that the World Bank has selected Uganda as the first beneficiary of the African Rural and Renewable Energy initiatives for the continent (Ruffini, 2000a). This programme, the first of its kind in Africa, was launched on 11th July 2002.

3.3.7 Financial Performance of the then UEB

Before the unbundling of the UEB, the utility was making huge losses, except in 1999. That year the UEB had a significant favourable reversal of financial performance, making a profit of over UShs 4 billion (UEB, 2001). This was achieved through the many changes that the UEB, under new management, introduced that year, such as a new billing system, a new management information system and a large number of retrenchments of employees. Before these retrenchments, the sales and customer per employee ratios had been very low. For instance in 1997 the sales per employee ratio was 291, while the number of customers per employee was 48. These ratios in 1998, after the changes had been implemented, increased to 426 MWh/employee and 79 customers/employee, and further to the even higher ratio of 783 MWh/employee and 148 customers/employee in 2001. The international norm for the ratio of customers per employee is 161 (SAD-ELEC, 2001). The UEB's greatest weaknesses were billing and revenue collection. According to the government's New Strategy Plan and Implementation Plan document, in 1997 the UEB received revenue for only 58 % of the power generated and in 1998 this was even less - around 50 %. Accounts receivable in 1998 exceeded nine months' billing. As a result of poor revenue collection, the UEB was thus unable to contribute significantly to the financing of needed investments, leaving the burden of doing so to the government. Also the UEB had very low, and in some cases even negative, financial performance indicators, as shown in Table 3.9.

Table 3.9 Some Financial Performance Indicators of UEB

Year	Number of Customers	Number of Empl.	Total Sales (MWh)	Sales Per Employee MWh/Empl	Cust. per Empl. Ratio	Total Revenue (UShs'000)	Total Asset Value (UShs'000)
1990	103,920	2,665	518,200	194	39		
1991	95,569	2,913	652,100	224	33		
1992	110,809	2,970	768,600	259	37	22,710,330	
1993	116,885	3,374	735,100	218	35	30,708,262	
1994	107,620	3,155	739,700	234	34	50,204,670	
1995	101,407	3,248	715,600	220	31	51,593,150	
1996	123,047	3,283	827,800	252	37	61,416,080	
1997	142,327	2,993	869,900	291	48	75,771,090	548,880,810
1998	159,205	2,028	864,800	426	79	77,979,163	614,408,825
1999	164,225	2,025	876,100	433	81	87,064,130	704,135,033
2000	180,234	1,903	1,094,300	575	95		
2001	200,217	1,351	1,057,900	783	148		

Table 3.9 Continued

Year	Net Profit/Loss Before Tax (UShs'000)	Average Selling Price of Electricity (Cents/kWh)	Historical Exchange Rate (Average) UShs/US$
1990			
1991			
1992	3,144,530	29.55	
1993	(2,017,511)	41.77	
1994	1,374,098	67.87	
1995	1,247,638	72.10	968.9
1996	401,884	74.19	1,046.1
1997	(13,196,358)	87.10	1,083.0
1998	(26,474,211)	90.17	1,240.2
1999	4,063,654	99.38	1,454.8
2000			1,644.5
2001			1,700.0

Source: Compiled from UEB Annual Reports
Exchange rate figures obtained from CIA World Factbook 2001

3.3.8 Sector Reforms

Uganda has made substantial progress in the process of reforming and restructuring its Electricity Supply Industry (ESI). The reforms of the power sector moreover fall within overall reform initiatives by the government of Uganda to liberalise the economy. In June 1999 the government formulated a comprehensive New Strategy Plan, built on the earlier 1997 Strategy Plan, for transforming its power sector into a financially viable entity. In addition, the new Electricity Act was enacted by Parliament and became law in November 1999. All these efforts were mainly due to the fact that the power sector had experienced a very poor financial and commercial performance,

leading to the failure of the UEB to raise funds to finance new investments. More specifically, the driving forces for this process of restructuring and reform can be articulated as follows:

- First, overcoming the fundamental problems of the UEB, which were:-
  - Very poor supply reliability, characterised by extensive and increasing load shedding and reduction in voltage;
  - Inadequate investment in all parts of the sector during the 1990s and inability to finance future required investments, particularly in distribution;
  - Very poor commercial performance, characterised by collections being received for less than 50 % of the electricity generated;
  - High technical and non-technical losses, exceeding 30 %;
  - High accounts receivables, which in early 1999 were equivalent to about nine months' billings, with around 50 % being due for more than a year;
  - Low productivity, despite the recent retrenchment of around 30 % of UEB's employees; and
  - Poor rate of connection of new customers (GoU, 1999).
- Second, to stop supporting the UEB from the government's budget, hence releasing those funds to finance social sectors such as education and health;
- Third, attracting private capital into the power sector; and
- Finally, the international experience and the benefits which such reforms have so far delivered.

Through the reforms, the government of Uganda wants to achieve the following objectives: -

- To make the power sector financially viable and able to perform without subsidies from the Government Budget;
- To increase the sector's general efficiency;
- To increase the sector's commercial performance;
- To meet the growing demands for electricity and increasing area coverage;
- To improve the reliability and quality of the electricity supply;
- To attract private capital and entrepreneurs; and
- To take advantage of export opportunities. (GoU, 1999)

As previously noted, the implementation of the new strategy plan has led to the breaking/unbundling of the loss-making UEB into three separate limited liability companies: the Uganda Electricity Generation Company, the Uganda Electricity Transmission Company and the Uganda Electricity

Distribution Company. The UEB remained as a statutory company to take care of the stranded assets and other unallocated responsibilities, but the other assets of the UEB were transferred to these three successor companies. The assets of all three companies would remain publicly owned, but would be concessioned out to private companies on a long-term basis.

In concessioning out the existing facilities in generation, transmission and distribution, competitive bidding procedures would be used. New generating capacity would be provided competitively by independent power projects through a process, to be organised by the Transmission Company and overseen by the Electricity Regulatory Authority (ERA). In this case the IPPs' entries will also be through competitive bidding procedures. As regards transmission, the Transmission Company will be a regulated monopoly, but will not be allowed to operate generation and distribution businesses. The Transmission Company will be required to add new transmission capacity as needed, but export lines may be developed, financed, constructed, operated and owned by private investors who will be given entry on a competitive basis as well. The Transmission Company will also be the System Operator (SO) and will be responsible for: -

- Co-ordination of the power supply system to insure balance between generation and consumption of electricity;
- Dispatch of generation facilities;
- Co-ordination of transmission outages;
- Monitoring import and export of electricity;
- Preparation of forecasts of capacity requirements;
- Making rules for dispatch of generation; and
- Publication of standardised tariffs (Electricity Act, 1999).

In additional to the above responsibilities, a "ring-fenced" business entity within the Transmission Company, with separate accounts and its own personnel, has been/will be formed to undertake wholesale market operations. According to African Energy (2001) the unit will be responsible for: -

- Holding power purchases agreements (PPAs) and managing contracts between generators and the Distribution Company;
- Evaluation and planning for least cost system expansion;
- Evaluation of site proposals and recommendations;
- Evaluation of proposals for new generation;
- Development of demand forecast and publication of actual results;
- Conducting least cost dispatch;
- Formulation of wholesale tariffs;

- Providing financial settlement services for the wholesale market; and
- Arranging for system-wide fees to cover generation and transmission capacity.

3.3.9 Regulatory Framework

As part of the overall reform process of Uganda's power sector, the Electricity Regulatory Authority (ERA) was established as a corporate body as required by Article 5 of the 1999 Electricity Act. The main objective of the power sector reform in Uganda is to tap into the benefits of private sector participation and to create competition. The ERA will play a central role in ensuring that the benefits that are expected from the reforms are realised, as well as ensuring the sustainability of the reforms.

CHAPTER FOUR
Botswana

4.0 Location and Demography

Botswana, a landlocked country, is located in Southern Africa. It borders South Africa to the south and east, Namibia to the west, Zimbabwe to the northeast and Zambia to the north. It has a total area of 600,370 sq. km, of which 585,370 sq. km. is land and 15,000 sq. km. is water. 80% of its land area is covered by the Kalahari Desert. Botswana's population is relatively small with about 1.6 million people (World Bank, 2002). Unlike other African countries where the majority of the population lives in rural areas, close to 50% of Botswana's population lives in urban areas with Gaborone, its capital, containing about 42% of the total urban population. It is followed by Francistown with 21% and the mining town of Selebi-Phikwe with 13% (SAD-ELEC, 1996:120).

4.1 Economy

Since its independence, year after year, Botswana's economic growth rate has been one of the highest in the world and its economy is one of the strongest on the continent, after transformation from being the poorest country in Africa when it attained independence. In 2000, Botswana's per capita GDP was US$ 3,300 making it a middle-income country. Although a major attribute to Botswana's economic success is diamond mining, its fiscal discipline and sound management, coupled with a well functioning democratic political system, have also played a major role towards its success. Diamond mining accounts for more than 33% of Botswana's GDP and for about 75% of its export earnings. The tourism sector has also been contributing significantly to the GDP and also the government and service sectors. The manufacturing, agriculture and construction sectors each contributed an average of 5% to the GDP over the last ten years. The contribution from agriculture is small (3.6%) due to the fact that a large part of Botswana's land area is unsuitable for farming. The country also experiences frequent droughts (World Bank, 2002).

4.2 Energy Sector

The energy sector in Botswana is managed by the Ministry of Minerals, Energy and Water Affairs. The national energy balance in 2000 showed that wood contributed about 38.6% of the total final energy consumption. Liquid fuels follow this, mainly in the form of petrol and diesel, of which their total share was 36.5%. Petrol alone accounted for 19% while diesel accounted for 16.5% of the country's final energy consumption. These fuels are mainly used in the transport sector. The other petroleum products used and their shares were as follows:- Paraffin (about 1%) - mainly used for lighting by rural households and as a cooking fuel in some urban and rural households; LPG (1%) –

used in both rural and urban households; Jet A fuel (0.4%) – mainly used in aeroplanes; lubricants (0.4%); Fuel Oil (0.2%); and AVGas (0.2%).

Coal, which is the only main source of electricity in Botswana, accounted for about 12.6% of the country's total final energy consumption whereas electricity's share to the final energy consumption was 9.1%.

4.3 The Power Sector

4.3.1 Background

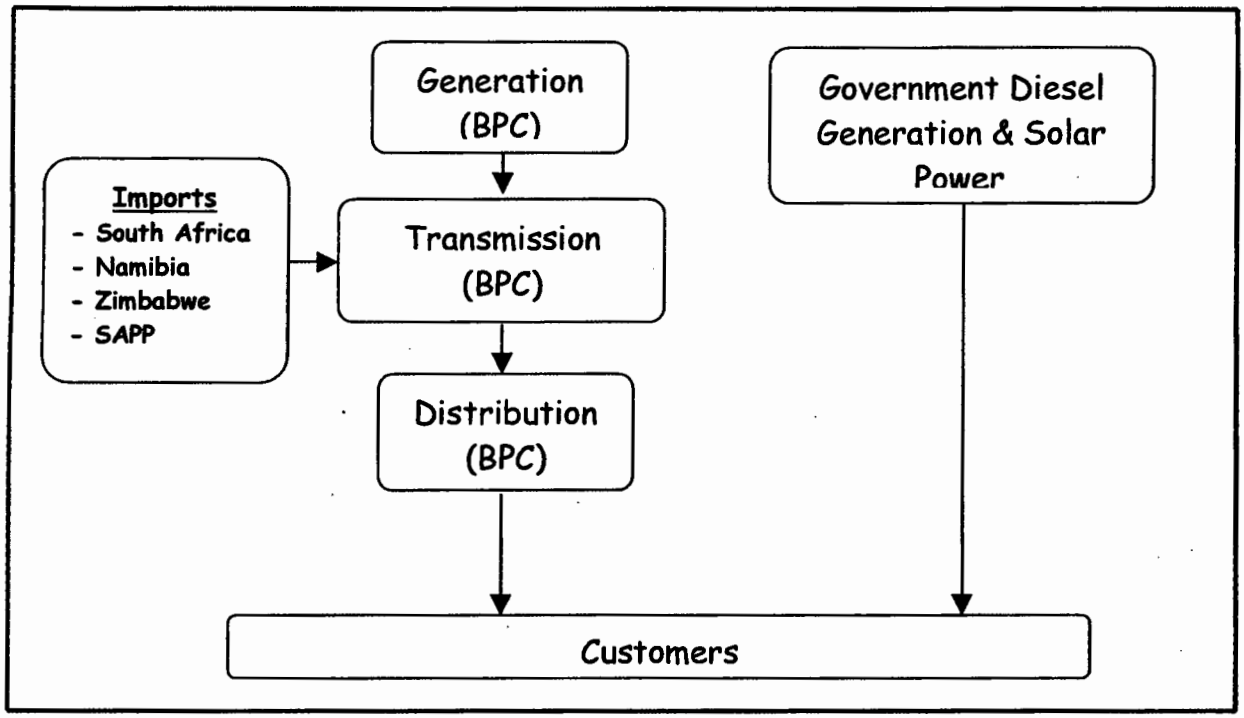
Botswana's power sector has been steadily growing over the last ten years. However, Botswana is a net importer of electricity, with about 55% of the country's total electricity requirements during 2000/2001 being generated beyond its borders. Most of the imports come from South Africa. Other imports come from Zimbabwe, Zambia and Namibia. Although Botswana imports most of its power, it has abundant coal reserves that are currently used to generate the remaining 45% of the country's total electricity requirements, which is used as a base load. The reserves are so huge that they can be used to generate enough electricity to meet all of the country's demand as well as for export. Coal resources are estimated to be in the region of 212 billion tonnes of which 3.34 billion tonnes are measured. According to SAD-ELEC (1996), during 1993 – 96, Botswana carried out studies on a possible 2,400MW export power station. However, nothing has been done so far to implement it.

4.3.2 Institutional Arrangements

The Botswana Power Corporation, BPC, a parastatal utility that was formed in 1970 by an Act of Parliament, has the responsibility to provide electric power throughout the country. It is responsible to the Ministry of Minerals, Energy, and Water Affairs, through the Energy Affairs Division within the ministry. The division was established in 1984 to co-ordinate energy related activities including the management of power development, coal development and energy planning.

BPC is a vertically integrated utility and is responsible for generation, transmission and distribution of electrical power for the nation. In addition, the Department of Electrical and Mechanical Services (DEMS), under the Ministry of Works, operates isolated diesel generators to supply government institutions such as schools, clinics and offices, which are in remote areas. In addition, individual industries generate electricity for their own use subject to a licence being granted by the ministry. Another important institution in Botswana's power sector is the National Rural Photovoltaic Electrification Program (NRPEP), which is responsible for providing Solar Power.

Figure 4.1 Botswana's Power Sector Institutional Arrangements



4.3.3 Supply

Internal Generation

BPC's vision of supplying cost effective electricity caused it to close its Selebi-Phikwe Power Station due to the high per unit cost of generation. The power station was effectively shut down on 31st March 1996. The plant's per unit cost of generation was well above the imported energy from neighbouring countries, particularly South Africa. High costs of coal transportation and the age of the station, including the technology that was being used, were among the factors that contributed to the expensiveness of the generation. As a result of the closure of the Selebi-Phikwe power plant, BPC is currently running only one coal power plant, Morupule, which has an installed capacity of 132MW (4X33MW). Previously the plant could provide up to about 80% of the country's power requirements, but as electricity demand increases the percentage has been decreasing and it can now provide only about 45% of the country's electricity requirements. Despite its decreasing capability in meeting the country's electricity demand, the plant's overall performance over the past ten years has been good, with a load factor of about 89% except for the 1995/96 and 1996/97 period when unit number two was unexpectedly damaged due to overheating (BPC 1997:11).

A study to add two units each with a capacity of 120MW at Morupule Power Station was carried out in 1994 by Blackenridge International of Canada. The expansion would effectively triple the current generation of the station from 132MW to 372MW. Although the study recommended the expansion

to be carried out, BPC deliberately held it back simply because its funding would require borrowing money which would result in increasing the tariffs by 15-20% for the next 15 years. Instead, BPC decided to continue with importation of cheap power from Eskom. However, according to the BPC 2001 annual report, the government has approved that feasibility study to be re-examined to evaluate the proposed generation expansion at Morupule. The study is earmarked to be completed by 2003. If the decision will be implemented, actual construction could also start immediately after in order for the plant to be commissioned between 2004 and 2007.

Imports

BPC depends more on imports than on its own generation for both economic and strategic reasons. Although BPC imports most of the electricity requirements, this is carefully done by constantly weighing up the benefits of importing against its own generation. In particular, there is a criterion, which was set in 1994 for the Corporation's "Import and Generation Policy". The criterion has remained unchanged ever since it was set but operational aspects of the imports have been changing in order to make the operations easier. As mentioned earlier, BPC imports most of its electricity requirements from Eskom of South Africa under a Power Purchase Agreement (PPA), which came into force in January 2000 and expires at the end of 2007. In this agreement Eskom agrees to supply BPC up to 410MW (BPC 2001:17). Apart from bulk electricity imports, there are about 14 towns and villages which are supplied by cross border imports, mainly from ZESCO of Zambia, ZESA of Zimbabwe, NamPower of Namibia and Eskom. Units imported and generated internally and sent out are shown in Table 4.1.

However, the evolution of the Southern African Power Pool (SAPP) plays an important role in meeting Botswana's power requirements and has, in fact, helped Botswana to have a diverse source of suppliers within the region. It can now import electricity not only from countries which it shares borders with but also from any other SAPP member country. BPC's active and strong participation in the SAPP electricity market has already yielded positive results. According to the BPC 2000 Annual Report, a saving of about P7 million on imports was realised over a short period of nine months. It is envisaged that even more savings will be realised using the SAPP's new electricity trading arrangement, the Short Term Energy Market (STEM) through the Co-ordination Centre in Harare.

Notwithstanding such positive results, financially and in terms of the availability of diverse import sources, the government is now concerned with the steady increase of the percentage of imports required to meet the country's fast growing electricity demand. It is expected that by 2007, imports will be supplying up to 70% of the country's total requirements. As noted earlier, efforts are

underway to expand internal generation so as to reduce this over-dependence on imports. The aspects of regional growth and future Power Pool tariffs which Botswana cannot influence have been the main source of the government's concern about its over-dependence on imports.

Table 4.1 Units generated internally and imported

Year	Internal Generation (GWh)	Station Usage (GWh)	Sent Out (GWh)	Imports		Total System Energy
				Units (GWh)	Percentage of TSE (%)	
1989/90	864.9	98.7	766.2	56.0	7	822.2
1990/91	923.7	108.6	815.6	97.4	11	913.0
1991/92	901.0	111.7	789.3	227.6	22	1,016.9
1992/93	1,083.5	132.2	951.3	113.7	11	1,065.0
1993/94	1,014.8	118.8	896.0	225.8	20	1,121.8
1994/95	1,010.5	123.5	887.0	299.6	25	1,186.6
1995/96	1,017.0	123.8	893.2	392.3	31	1,285.5
1996/97	725.4	141.9	583.5	812.4	58	1,395.9
1997/98	834.5	100.7	733.8	809.0	52	1,542.8
1998/99	1,015.5	115.0	900.5	744.0	45	1,644.5
1999/00	1,027.0	115.0	912.0	967.9	51	1,879.9
2000/01	1,034.6	115.0	919.6	1,123.1	55	2,042.7

Source: Compiled from BPC's Annual Reports

Key: TSE = Total System Energy

Transmission and Distribution System

Botswana has a strong interconnected network and it is internationally interconnected to South Africa, Zambia, Zimbabwe and Namibia. The interconnection is through 400kV, 220kV and 132kV lines while the well-developed national power grid consists of 222kV, 132kV and 66kV lines. A recent development on the transmission line was the construction and commissioning of the Sgodtshane – Thamaga 132kV line, the Thamaga Switching Station and the Thamaga – Jwaneng 132kV line. This second 132kV line to Jwaneng mine was commissioned on the 4th August 2002 and was expected to firm up supplies to Jwaneng itself as well as Molepolole and Kanye. Along with spending money on constructing new lines, BPC has been spending money every year on reinforcing the existing system. As a result, system losses, percentage wise, have been at almost single digit figures for the past ten years as discussed below.

The distribution system, which consists of 33kV, 22kV and 11kV lines, has also been expanding over time to cope with the increasing demand from various economic activities as well as from the domestic sector. For instance, during 2000/2001, the distribution system grew by 13% in route length (km) and by some 3% in installed capacity (MVA). Just as with the transmission system, BPC also has given a high priority to the maintenance of its distribution system in order to minimise

unplanned outages (BPC, 2001:15). Total lengths of the different voltage transmission and distribution lines are shown in Table 4.2 below.

Table 4.2 Transmission and Distributions Total Lines Lengths in Botswana (km)

Year	400kV	220kV	132kV
1989/90			
1990/91	-		
1991/92	-	902	407
1992/93	-	902	470
1993/94	-	907	831
1994/95	-	907	920
1995/96	-	1,007	1,243
1996/97	-	1,007	1,243
1997/98	204	1,007	1,243
1998/99	204	1,007	1,250
1999/00	204	1,007	1,250
2000/01	204	1,007	1,385

Source: Compiled from BPC's Annual Reports

System Losses

Botswana is one of the countries in the region with the lowest system losses. This has been the result of the BPC comprehensive maintenance programmes. In 2001 total system losses on the BPC's network were approximately 9.8%. This was less than the SADC average of 13.8% (BPC, 2001:9). A major source of the system losses is caused by customers tempering with meters and illegal connections of electricity which are on the increase, especially in Gaborone and Francistown (BPC, 2001:21). Table 4.3 below shows BPC's network losses from 1990 – 2001.

Table 4.3 Transmission and Distribution Losses

Year	Units (GWh)	Total System Losses (%)
1989/90	50.0	
1990/91	64.1	6.8
1991/92	76.8	6.8
1992/93	74.0	6.2
1993/94	104.2	8.4
1994/95	74.5	6.3
1995/96	88.1	6.9
1996/97	88.7	6.4
1997/98	162.5	10.7
1998/99	143.5	8.7
1999/00	209.2	11.1
2000/01	200.1	9.8

Source: Compiled from BPC Annual Reports

4.3.4 Demand

As is the case in most African countries, the majority of the population lives in the rural areas, but it is the urban areas that form the major electricity demand centres. True to this pattern, electricity supply in Botswana is also confined mostly to urban areas. Recently, however, the BPC, with support from the government, has embarked on a comprehensive rural electrification programme. As a result of the rural electrification programme, the corporation's customer base increased by 12.8 % in 2001.

The above efforts to expand electricity access to the rural population resulted in an increase in the share of domestic electricity consumption from 10% five years ago to the current 13% of the total consumption. The mining sector still consumes the largest share, although it has decreased from 62% to 52% in the past five years. The commercial sector category also consumes a large share and over the past ten years has been consuming on average about 25% of the total sales. Demand from domestic consumer category has been increasing more than other categories as a result of the BPC's efforts to expand access to electricity and rural electrification.

In Botswana, the main electricity load centres are located in the southeastern and eastern part of the country. This is so because the major mining centres are located in these areas and consequently they are also the most populated. The main load centres are thus at Francistown, Selebi-Phikwe with its smelter complex, Gaborone, Orapa, Lobatse and Jwaneng. Table 4.4 shows electricity consumption by tariff category.

Table 4.4 Electricity Consumption by Tariff

Year	Tariff Categories (GWh)				Total Sales (GWh)	Total Number of Customers	System Peak Demand (MW)
	1	2	3	4			
1989/90	65.2	147.1	505.1	54.8	772.2	19,653	144.9
1990/91	78.1	167.0	540.1	63.2	848.4	22,994	159.6
1991/92	94.6	183.6	595.5	66.3	940.0	25,591	179.5
1992/93	109.1	215.8	593.4	72.7	991.0	31,937	193.9
1993/94	122.0	240.9	583.6	71.1	1,017.6	37,471	188.9
1994/95	146.6	278.6	612.4	74.5	1,112.1	44,164	194.7
1995/96	160.5	339.3	618.9	78.7	1,197.4	49,465	204.9
1996/97	173.8	380.2	668.1	85.1	1,307.2	54,440	222.6
1997/98	190.2	382.4	715.2	90.5	1,378.3	60,023	238.5
1998/99	222.6	418.8	753.1	106.5	1,501.0	67,397	256.5
1999/00	280.4	491.8	759.7	138.8	1,670.7	76,380	285.0
2000/01	3336	462.3	899.4	147.3	1,842.6	86,165	316.0

Source: Compiled from BPC Annual Reports
Key: 1 = Domestic; 2 = Commercial; 3 = Mining; 4 = Government

4.3.5 Tariff

The BPC has six tariff categories: home; small business (electricity not exceeding 400 volts and loads not exceeding 35 kW); medium business (electricity not exceeding 400 volts and loads exceeding 35 kW), large business (electricity at or above 11000 volts); government; and water pumping. The tariffs themselves are broken down into three parts: fixed charge per month (administration), energy charge per kWh (production costs) and demand charge per kWh (investment costs).

The tariffs are generally set to reflect the long run marginal cost (LRMC) of supply. The BPC's policy on continuing importation of cheap power against expansion of its own generation facilities has made it possible to restrict tariff increases over a long period. With the aim of co-operating with the government in trying to curb inflation, BPC has a policy of limiting tariff increases to less than 50% of Botswana's inflation rate. However, this is done carefully to ensure a balance against the principle of instituting sound financial policy practices. Over the past eight years average tariff has only increased by 10% in nominal terms – which implies a reduction in real terms after inflation is taken into account.

4.3.6 Access to Electricity and Rural Electrification

This is an area where the BPC has put in much effort in order to increase its customer base as well as to fulfil one of the goals set in Botswana's Energy Master Plan. The goal specifies among other things, " *Make access to electricity and use of electricity affordable. Provide a large number of households with access to electricity.*" In order to fulfil this goal, in October 1995 the government, through the BPC, introduced soft repayment terms for the cost of electricity connections. According to the BPC 1999 Annual Report, the introduction of the soft repayments scheme has increased the demand for electricity to the extent that the BPC in-house and external electrical construction teams have been working to full capacity in order to cope. In 1997 there were five private electrical contractors carrying out construction work to provide power to consumers on behalf of the BPC. This number was increased to seven in 2000. The arrangement of the soft repayment terms was that when it started in 1990, new customers were supposed to contribute 40% of the total connection costs and the balance was paid in equal instalments every month for a period of ten years. During its short period of operation, 1990 – 1995, it proved successful hence the government decided to revise the terms to make them even more attractive. The revised mode of operation requires an individual to pay 10% down payment the remaining 90% being recoverable from the individual over the same period as before i.e. ten years. In April 2000, the payment terms were further relaxed to 5% as down payment, with 95 % recoverable in 15 years.

Rural Electrification

Rural electrification in Botswana is funded by both the government and the BPC. The seriousness of the government and the efforts of the BPC in rural electrification have attracted foreign agencies, in particular SIDA and DANIDA, to assist in funding the rural electrification programme. In 1998, with the Swedish International Agency (SIDA) providing financial and technical assistance, 15 villages were electrified. In the same year another 29 villages were also supplied with electricity from BPC and government funding on a fifty-fifty basis. As mentioned earlier, in 1998/99 70 more villages were expected to be electrified and 14 were earmarked for connection to the national grid.

To take the efforts a step further, the BPC has been trying to make use of other technologies in order to supply affordable service to the low-income rural population. To this effect, in 1998, the BPC started and completed a pilot single wire earth return system (SWER). Consumer uptake on this network has been gradually increasing. The BPC had the intention of adopting the technology to other locations once it proved successful.

The BPC had also investigated the possibilities of establishing solar villages in the country. The utility started a pilot project to electrify Khakhea using photovoltaic solar home systems (SHS). The project was estimated to cost P500, 000, and was expected to be completed in March 1999 (BPC, 1998:16). This project is something that is rarely seen in Africa. However, little progress has so far been made in its implementation, although at the moment BPC is putting in place a new strategy aimed at integrating grid electrification with provision of electricity using PV. So far three villages, namely Motlhabaneng, Kudumatse and Lerolwana have been selected for the implementation of the PV dissemination project (BPC, 2001:21). In the western part of the country, the BPC is planning to use photovoltaics, as grid extension would be quite expensive. Botswana's national grid is concentrated in the eastern part of the country thus leaving the western part without service. Furthermore, in order to minimise supply costs, the BPC has electrified a number of villages near the borders through cross border supply from Zimbabwe, Namibia, Zambia and South Africa. The concept of rural collective schemes is another attempt by the BPC to reduce total costs of supply.

In 1997, before the BPC started using PV, the government had initiated the use of PV for village electrification. Under this programme the government provided loans to customers to purchase solar PV installations through the Rural Industries Innovation Centre in Kanye. Just as it was with electricity connection costs, the customers were supposed to pay 15% of the total cost of the solar installation and the balance was to be paid through monthly instalments over five years. In 1997 – 1998 some 234 solar installations were made. In 1998 the government was evaluating the programme to determine its success.

The BPC's efforts in rural electrification programmes and the programmes of generally widening access to electrification have been successful. The BPC has set targets of the number of new consumers to connect every year and it has been meeting these targets. In fact, it has been exceeding these targets and as a result the number of consumers has more than tripled over the period 1990 – 1999. This has enabled Botswana to achieve a 29% rate of access to electricity, surpassing the SADC average of 17 percent.

4.3.7 BPC Financial Performance

As highlighted by indicators in Table 4.5 below, the BPC's financial performance has been generally good over the past ten years. Over this period, the utility has been realising net profits on an increasing trend, except for the 1996/97 and 1998/99 fiscal years. The decrease in 1996/97 was due to an increase in expenditure on imported energy that resulted from a decrease in internal generation caused by a faulty unit at Morupule power station. That of 1998/99 was mainly due to an increase in depreciation and salaries. One may expect that this overall steady increase of BPC profitability is happening with a corresponding tariff increase but as mentioned earlier, actually there have been no significant tariff increases for the past six years. An important factor behind BPC's good financial performance is the fact that it is making maximum use of the available cheap electricity in the region. The unit cost of imported electricity has been decreasing over the past two years (BPC 2001:9). Its finance charges have also diminished as its debt: equity ratio has improved.

Other financial indicators such as the return on total assets and debt equity ratio have also been generally good. For the past ten years, except for 1993/94, the utility has been exceeding the World Bank set target of 5% for the average return on fixed assets (BPC, 1999:11). Although most of the financial performance indicators have been generally good for the past ten yeas, BPC staffing performance indicators have showed little improvement. For instance, even though the customer per employee ratio has actually increased from 12 to 46, almost four times, the current ratio is still very low compared to international standards which stand at 160 customers per employee (SAD-ELEC, 2001:7). In fact, BPC is supposed to have a high customer per employee ratio because of the fact that it imports most of its electricity in bulk and again it contracts out a significant portion of construction of service line works. Despite that, the BPC, along with Eskom of South Africa and Namibia's NamPower, is rated as one of the most financially viable power utilities in the Southern African Development Community (Ruffini, 1999:11).

Table 4.5 Some Financial Performance Indicators of the BPC

Year	Number of Customers	Number of Employees	Total Sales (GWh)	Sales Per Employee MWh/Empl.	Customers per Employee	Total Revenue (P'000)	Total Asset Value (P'000)
1989/90	19,653	1,614	772.2	478	12	114,058	585,238
1990/91	22,994	1,649	848.4	514	14	140,809	587,113
1991/92	25,591	1,698	940.0	554	15	162,809	724,513
1992/93	31,937	1,770	991.0	560	18	185,603	868,734
1993/94	37,471	1,712	1,017.6	594	22	205,290	1,006,072
1994/95	44,164	1,700	1,112.1	654	26	234,265	1,142,382
1995/96	49,465	1,680	1,197.4	713	29	242,435	1,254,929
1996/97	54,440	1,693	1,307.2	772	32	262,352	1,426,470
1997/98	60,023	1,677	1,378.3	822	36	278,936	1,389,378
1998/99	67,397	1,672	1,501.0	898	40	311,152	1,571,265
1999/00	76,380	1,740	1,670.7	960	44	361,938	1,884,995
2000/01	86,165	1,856	1,842.6	993	46	408,453	2,187,021

Table 4.5 Continued

Year	Net Profit/Loss Before Tax (P'000)	Average Selling Price of Electricity (Thebe/kWh)	Returns on Assets %	Debt/ Equity Ratio	Interest Cover Ratio	Historical Exchange Rate P/US$
1989/99	7,048	14.8	5.3	1.0	1.0	
1990/91	14,876	16.3	6.6	0.9	1.8	
1991/92	23,974	17.3	7.3	0.5	2.2	
1992/93	34,049	18.8	6.7	0.4	2.6	
1993/94	37,048	20.2	3.7	0.3	3.7	
1994/95	60,205	21.1	5.3	0.3	4.7	2.77
1995/96	76,134	20.2	6.0	0.2	4.7	3.32
1996/97	72,392	20.1	5.1	0.2	3.6	3.65
1997/98	95,678	20.2	6.4	0.2	8.2	4.23
1998/99	89,501	20.7	6.0	0.2	5.9	4.62
1999/00	127,645	21.7	7.7	0.1	8.0	5.10
2000/01	165,335	22.2	7.7	0.1	17.0	5.46

Source: Compiled from BPC Annual Reports
Exchange rate figures obtained from CIA World Factbook 2001

4.3.8 Sector Reforms

The process of electricity industry restructuring, privatisation and regulatory reform, worldwide, has been the current trend with the aim, amongst others, of improving the overall performance of the industry as well as creating conditions for its sustainable development. As discussed above the BPC, the sole electricity utility in Botswana's power sector, has been performing quite well to the extent of being able to restrict tariff increases for the past six years. Despite these good results, there is always room for improvement. In recognition of this fact, the government of Botswana approved a White Paper on Privatisation Policy, in March 2000, which earmarked the energy sector as one of

the sectors where liberalisation should be considered. Through the privatisation of the power sector, the government wants to make the BPC more efficient so as to supply electricity at least cost to the economy, in line with the National Development Plan 8. As part of the implementation of this privatisation policy the government has set up an autonomous public entity, Public Enterprises Evaluation and Privatisation Agency (PEEPA), which will evaluate the performance of the parastatals, BPC being one of them, and advise on the commercialisation and privatisation processes.

Following the approval of this White Paper on Privatisation Policy by the parliament, some initiatives in regard to the power sector reform have already been undertaken. Recently, the government of Botswana has floated an advertisement inviting tenders from various consultants for a preliminary investigation on Electricity Supply Industry restructuring. Recommendations of this study will enable the government to make an informed decision on the industry's future. In particular the government wants the consultant of the study, among other matters, to review laws and regulation of the electricity supply industry; review and evaluate models of electricity supply industry restructuring in selected countries; and assess if any of these models suit Botswana and report on the impact of a restructuring of employment and tariffs. The consultant is also required to make recommendations regarding the ESI restructuring, based on the results of investigations, and to advise on how to proceed with the restructuring, if restructuring is the way to go.

4.3.9 Regulatory Framework

In 1970, an Act that established the Botswana Power Corporation and defined its constitutional rights and internal organisation was passed. The legislation gives the BPC all powers necessary or convenient for the performance of its functions and duties, provided it conducts its affairs on sound commercial principles. The BPC was also given a mandate to set out its own electricity tariffs. There is no independent regulatory board but consumers have the right of appeal to the Minister of Minerals, Energy and Water Affairs.

In its capacity as regulator, the Ministry, through the Electricity Supply Act of 1973, issues licences to applicants who want to operate in the ESI. However, the Minister is obliged to consult with the BPC before issuing licences to any applicants and must take into consideration BPC's future plans as well as give precedence to the BPC's interests. However, the government is now committed to distancing itself from regulating the sector and it wants to assign this task to an autonomous body. As part of the tasks to be performed by the consultant who will advise the government on restructuring options, the consultant is also required to recommend whether Botswana should establish a dedicated ESI regulator or a multi sector regulator.

CHAPTER FIVE
Kenya

5.0 Location and Demography

Kenya is located astride the Equator on the East Coast of Africa. It borders Uganda in the west, the Indian Ocean in the east, Tanzania in the south and Somalia, Ethiopia and the Sudan in the north. It covers an area of 583,000 sq. km (225,000 sq. miles). The population statistics in Kenya in 1999 reveal that there were 30.1 million persons living in the country, with 67% of the population living in the rural areas (World Bank, 2002).

5.1 Economy

Kenya's economy depends largely on agriculture, which accounts for about a quarter of the GDP (24.5 % in 1999), and approximately two thirds of exports. Agriculture is complemented by manufacturing (13.2 % in 1999), commerce and tourism (12.5 % in 1999). These last three collectively account for an additional one-quarter of the GDP. Since 1998 Kenya's economy has been slowing down, which has been attributed to various factors including crumbling infrastructure, high interest rates, loss of investor confidence and prolonged droughts that have adversely affected agriculture and the power supply. The growth of the real GDP decelerated from 1.8 % in 1998 to 1.4 % in 1999, and decreased further to –0.3 % in 2000. With the exception of the transport, storage and communications sectors, all other sectors recordered a negative growth rate in 2000. The country's inflation rate has remained at a single digit, averaging 6 % in 2000/2001, and was projected to reduce to 3 % in 2002 as a result of expected improvements in food production (KenGen, 2001a).

In an attempt to reverse the economic decline situation, the Kenyan government has implemented various measures directed at removing structural bottlenecks, improving governance and creating an enabling environment for investment and economic growth. Some of these measures include reforms geared at restoring economic growth particularly privatisation of commercial public sector institutions. With regard to the general economy, this began in the 2000/01 financial year, but in the power sector the reforms actually started as early as 1997.

5.2 Energy Sector

The Kenyan energy sector is managed by the Ministry of Energy, which has always played a very important role in Kenya's economy. As is the case in other developing countries, particularly in Africa, biomass is also the major energy source of Kenya. Kenya's primary energy sources, in

descending order, are as follows: fuelwood dominates (55 %), followed by petroleum (21 %), charcoal (13 %), hydro and geothermal (10 %) and lastly coal (1 %) (Ruffini, 2000b:18).

Since the mid-1990s the Kenyan energy sector has been undergoing restructuring and reforms, particularly in the electricity and petroleum sub-sectors. The Government of Kenya decided to carry out these reforms due to acute power shortages caused by the lack of investment between 1990 and 1996 and the persistent droughts. In its Electric Power Act of 1997, Kenya made a commitment to liberalise and privatise its power sector. As a result, Kenya was one of the first countries in Africa to embark on a power sector restructuring and reform programme, although its actual implementation was slow. The liberalisation of Kenya's energy sector has led to the introduction of private players in both the electricity and petroleum sub-sectors. These private players in the form of Independent Power Producers (IPPs) are now contributing significantly to electricity generation. Restructuring and reforms in the power sector are discussed in more detail in Section 5.4.8 hereunder.

5.3 The Power Sector

5.3.1 Background

Kenya's power sector is relatively well developed, with an interconnected system linking all major towns and cities. The power supply comes from three major sources, i.e. hydro, thermal and geothermal. Most of the hydro developments, five major power stations, are situated along the lower part of the Tana River with water being cascaded from one station to the next. Although Nairobi City is the country's major demand centre, the national grid has been well developed and covers almost the entire country, thus connecting the generation centres to all major load centres.

The existing installed hydropower capacity of 677.2 MW forms about 45 % (so far developed) of the total country's potential hydropower resource, which is estimated at 1,500 MW. An additional installed capacity of 60 MW is set to become available in July 2005 with completion of the Sondu Miriu River Project. About half of the potential is attributed to small rivers. In this regard, to date, 55 river sites have been identified as commercial possibilities for micro hydro plants with a maximum mean capacity ranging from 50 KW to 700 KW (Lore, 2000). However, in contrast to the situation in Uganda, most of this potential is rainfall dependent and as a result the country has been experiencing acute electricity shortages. Kenya also has huge geothermal potential, which can be used to generate electricity at relatively low cost. According to the Kenya Electricity Generation Company (KenGen), 576 MW of additional geothermal energy is planned by the year 2017, which will represent about 25 % of Kenya's power requirements, projected at 2,349 MW. Furthermore, by virtue of its geographical location astride the Equator, Kenya has excellent solar energy sources, with mean solar radiation estimated at 5.5 kWh/m^2/day, which is available for as much as 280 days per annum,

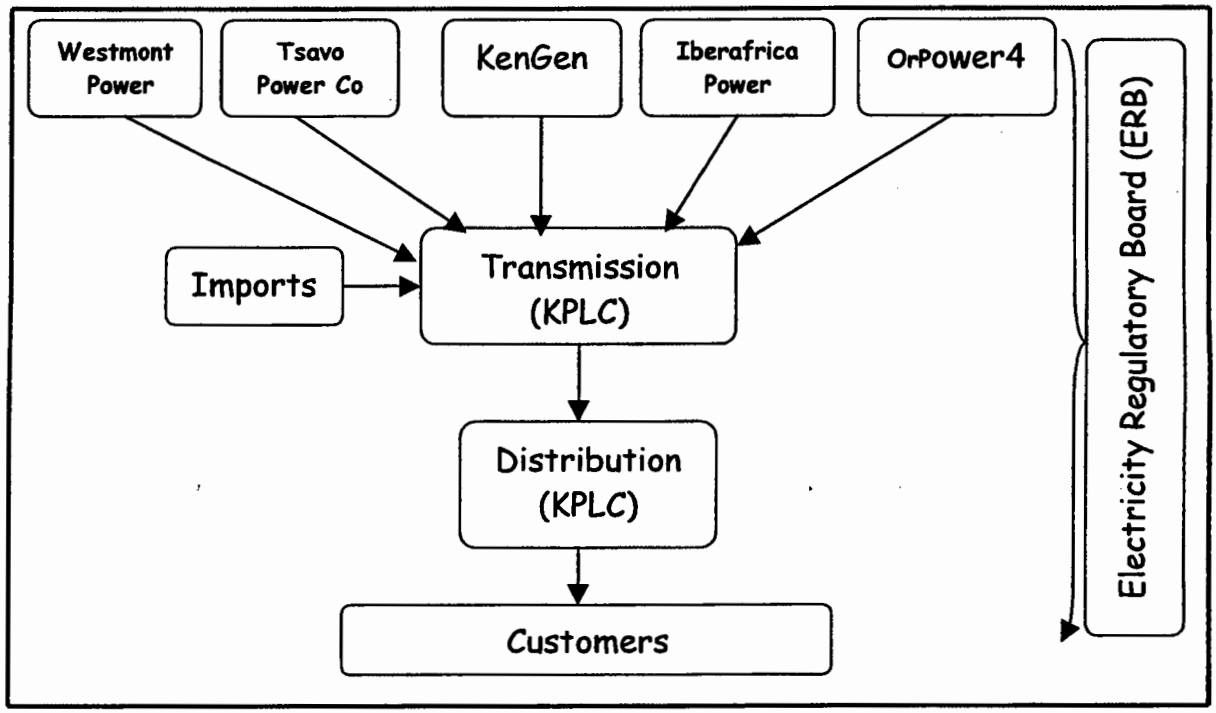
depending on location (Lore, 2000). A good number of solar home systems have already been installed to tap this resource.

5.3.2 Institutional Arrangements

Before January 1997, there were basically two state-owned companies dealing with electricity generation, transmission and distribution in Kenya. These companies were the Kenya Power Company (KPC) and the Kenya Power and Lighting Company Limited (KPLC). The KPC was established and registered as a company in 1954 and was responsible for developing geothermal and other generating facilities, and the sale of electricity in bulk to the KPLC. The KPC was also commissioned to construct the Nairobi–Tororo-Uganda transmission line. Although it was registered as a company, it was, in fact, managed by the KPLC under a management contract. The KPLC was responsible for transmitting and distributing electricity throughout the country.

In January 1997, the functions of the KPC and the KPLC were clearly separated; this included the separation of the KPC management from the KPLC. This occurred as a result of the power sector reforms, which were being implemented by the government at that time. The Electricity Regulatory Board (ERB) was also established and IPPs were introduced as part of the overall reform process. More specifically, the KPC which was re-launched on the 2nd October 1998 under a new name and corporate identity, namely the Kenya Electricity Generation Company Limited (KenGen), took charge of all publicly owned power generating plants. KenGen sells bulk electricity to the new Kenya Power and Lighting Company Limited (KPLC), which owns all the transmission and distribution assets and is responsible for the transmission and distribution of electricity. The KPLC also buys bulk power from IPPs and imports power from Uganda. The four main IPPs are Iberafrica Power (K) Ltd, Westmont Power (K) Ltd, Orpower4 Inc and Tsavo Power Co. Ltd. All these players in Kenya's electricity industry are regulated by the ERB, which also has the responsibility of setting, reviewing and adjusting the tariffs. The Ministry of Energy is now only responsible for formulating the policy for the energy sector and administering the Rural Electrification Schemes. There are also a few private individuals and institutions that generate electricity for their own use and sell the surplus to the KPLC. Figure 5.1 below shows the institutional arrangements in Kenya's power sector, which basically consists of a single buyer model using Power Purchase Agreements (PPAs).

Figure 5.1 Institutional Arrangement of Kenya's Power Sector



5.3.3 Supply

The electricity supply in Kenya consists of power that is generated within the country itself, and power that is imported from Uganda. Each of these will be discussed more fully hereunder.

Generation

Kenya has a diverse electricity generation industry in terms of the players involved as well as the technology used. Kenya's total existing installed electricity generation capacity stands at 1,072.1 MW, with an effective capacity of 889.1 MW. KenGen alone owns and operates 87 % of the total existing installed capacity. The four IPPs together own and operate 175.5 MW capacity as follows: - Iberafrica Power (K) Ltd. (56 MW), Westmont Power (K) Ltd. (43.5 MW), Orpower4 Inc (12 MW) and Tsavo Power Co Ltd. (74 MW). Table 5.1 shows the existing installed generating capacity in Kenya. In 2001, which was a drought year, the peak demand in the country was fairly low, 724 MW. In the preceding ten years the highest peak demand had been 734 MW, attained in 1998/99. Apart from generation from KenGen and the four IPPs, three emergency power producers (EPPs) were contracted in the drought year (2000), to supply 105 MW of continuous power to ease the impact of power rationing. These EPPs were Aggreko (45 MW), Cummins (30 MW) and Deutz (30 MW), and their contracts expired during the May – June 2001 period. The government, with assistance from the World Bank, met the financial obligations of the contracts. In 2001 other power suppliers included Mimias Sugar Company that supplied 2 MW, and various private auto generators who supplied a total of 20 MW (KenGen, 2001a & KPLC, 2001).

Table 5.1 Existing Installed Generating Capacity in Kenya

Generation Type	Name of Station	No. of Units	Year Commissioned	Total Installed Capacity MW	Available Capacity MW
Hydro	Tana	3 2	1940 1953	14.4	12.4
	Wanji		1955	7.4	7.4
	Kindaruma		1968	40.0	40.0
	Kamburu		1974	94.2	84.0
	Masinga	2	1981	40.0	40.0
	Kiambere	-	1988	144.0	144.0
	Turkwel Gorge	2	1991	106.0	106.0
	Gitaru		1978 1999	145.0 80.0	145.0
	Small Stations			6.2	5.4
Total Hydro Capacity				**677.2**	**584.2**
Geo-thermal	Olkaria	1 1 1	1981 1982 1985	45.0	45
	OrPower4[1]			12.0	12
Total Geothermal				**57.0**	**57.0**
Thermal	Kipevu Steam			75.5	23.0
	Kipevu 1 (Diesel)		1999	75.0	70.0
	Kipevu GTs			60.0	60.0
	Fiat – Nairobi South			13.5	10.0
	Garissa and Lamu			3.9	3.5
	REF Stations[2]			5.1	4.6
	IberaAfrica[1]			56.0	56.0
	Westmont[1]			43.5	43.5
	Tsavo[1] (Kipevu II)		2001	74.0	74.0
	Mumias[1]			2.0	2.0
Total Thermal Capacity				408.5	346.6
KenGen Wind Plant – Ngong				0.4	0.4
Total Generation Installed Capacity				**1143.1**	**988.2**
Emergency Power Producers – Thermal – (2001)					
Aggreko[3]				45.0	45.0
Cummins[3]				30.0	30.0
Deutz[3]				24.0	24.0
Total Emergency Power Producers				**99.0**	**99.0**
Uganda Imports				30.0	30.0
Total Capacity (June 2001)				**1,272.1**	**1,117.2**

Source: Compiled from KPLC Annual Reports

Key: [1] Independent Power Producers (IPPs)

[2] Owned and Operated by Government of Kenya

[3] Emergency Power Producers (EPPs) whose contracts ended in June 2001.

The rest (not marked) Owned and Operated by KenGen

As regards the technology used in generation and as shown by the table above, 677.2 MW (about 63 %) of the existing installed capacity is hydropower. As mentioned earlier, most of the hydropower plants are situated on the lower Tana River and all are owned by KenGen. Thermal energy sources with a capacity of 408.5 MW account for about 38 % of the existing generating capacity, with geothermal capacity (57 MW) accounting for only about 4.8 %. The majority of the thermal stations are strategically located at the coast, near Mombassa, both for easy supply of fuels and also to service the Mombassa load, which is the second biggest load centre after Nairobi. To boost the existing generation capacity, KenGen is currently constructing two plants, a 64 MW geothermal plant, Olkaria II, and a 60 MW hydropower plant, Sondu Miriu. These plants are expected to be completed by the end of 2002 and mid-2004 respectively. Another 48 MW Olkaria III plant (IPP project) is also expected to be commissioned in July 2003 (KenGen, 2001a: 13).

Imports

Kenya also imports about 30 MW of continuous power from Uganda. It started doing so in 1954 through a PPA, which will expire in 2008. However, all of Kenya's capacity, both imports and internal generation, is insufficient to meet its total demand, mainly due to the erratic nature of rainfall. As a result of this, Kenya has shifted its dependency on hydropower to the development of geothermal resources and thermal generation, and to an international interconnection and electricity trade. In this regard, as part of the KPLC's strategy to diversify its sources of bulk power, it has signed a new power purchase agreement for additional capacity with the recently established Uganda Electricity Transmission Company (UETC). Under the new agreement Kenya will import up to 80 MW of power from Uganda when the 200 MW Bujagali hydropower project on the River Nile is commissioned in February 2006. The new contract, which will replace the earlier one, will enable Kenya to purchase 50 MW of firm capacity and an excess of up to 80 MW for a period of 14 years (KPLC, 2002a). Table 5.2 shows the total amount of electricity generated in Kenya itself and the amount imported from Uganda.

Table 5.2 Units Generated and Imported

Year	Total Hydro (GWh)	Total Geo-hermal (GWh)	Total Thermal (GWh)	Total Generation (GWh)	Imports		Total System Energy (GWh)	System Load Factor (%)
					Units (GWh)	% of TSE*		
1989/90		298					3,085	68.2
1990/91	2,760	298	110	3,168	134	4.1	3,302	67.8
1991/92	2,775	272	97	3,144	240	7.1	3,384	68.6
1992/93	2,974	272	81	3,327	273	7.6	3,600	69.3
1993/94	3,048	261	160	3,469	264	7.1	3,733	72.6
1994/95	3,104	290	284	3,678	187	4.8	3,865	72.2
1995/96	3,163	390	417	3,970	149	3.6	4,119	72.3
1996/97	3,354	393	405	4,152	144	3.4	4,296	72.1
1997/98	3,259	366	744	4,369	146	3.2	4,516	71.5
1998/99	3,274	390	832	4,496	140	3.0	4,637	72.2
1999/00	2,435	383	1,488	4,306	155	3.5	4,461	71.9
2000/01	1,325	429	2,129	3,683	198	4.9	4,081	64.4

Source: Compiled from KPLC Annual Reports

TSE* = Total System Energy

Transmission and Distribution System

National grid extension was a major priority of the government during the 1980s and as a result the country is well covered. A 220 kV double circuit line connects the country's seven forks hydro complexes located at Kiembere and Nairobi. Other upcountry load centres are connected via 220 kV or 132 kV transmission lines. The system has been interconnected with Uganda's system through a 132 kV-transmission line from Tororo (Uganda) to Nairobi. This line was built in 1954 to transmit the power generated at the Owen Falls Dam near Tororo in Uganda. Studies are now being carried out for a Kenya–Tanzania interconnection. A 250 km 220 kV transmission line will be built from Arusha (Tanzania) to Nairobi. Its completion will interconnect all the East African countries that form the East African Co-operation, namely Kenya, Uganda and Tanzania. At the moment Kenya is pushing the Tanzania–Zambia interconnection so that it can access the Southern African Power Pool (SAPP). However, Kenya is not yet a SAPP member although it has already applied for membership (KPLC, 2001: 17). Table 5.3 hereunder shows the development of the transmission and distribution systems in Kenya from 1991 to 2001.

Table 5.3 Transmission and Distribution - Total Line Lengths in Kenya (km) (As at 30th June)

Year	220 kV	132 kV	66 kV	40 kV	33 kV	11 kV
1991	877	1,980	451	126	3,342	7,870
1992	877	1,980	451	126	3,451	8,309
1993	877	1,980	451	126	3,583	8,613
1994	877	1,980	573	126	3,686	8,838
1995	877	1,980	573	126	3,876	9,250
1996	877	1,980	573	126	3,969	9,372
1997	877	1,997	574	126	4,094	9,616
1998	877	1,997	574	126	4,203	9,671
1999	877	1,997	574	126	4,516	10,029
2000	877	1,997	576	126	4,639	10,397
2001	885	2,032	580	126	4,795	10,593

Source: Compiled from KPLC Annual Reports

With regard to transmission developments, construction of a 140 km 220 kV line from Kiembere to Nairobi is currently underway and its completion will improve the transmission of power from the hydro stations on the Tana River to the capital city. Another 220 kV double circuit line from Olkaria to Nairobi and associated sub-stations is also under construction and was scheduled to be completed in mid-2002. This line, which covers a distance of 110 km, will enable the transmission of power from Olkaria II and Olkaria III power plants to the national grid. As part of the Sondu Miriu hydropower project, a 50 km 132 kV transmission line is being constructed and is expected to be completed in 2004 (KPLC, 2001: 9-13).

System Losses

Previously Kenya had relatively low system losses, both technical and non-technical, but during the 1989/90–2000/01 period system losses have increased steadily, except during the 2000/01 financial year, when they decreased slightly, as shown in Table 5.4 below. This decrease can be attributed to various practical measures taken by the KPLC to reduce both technical and non-technical losses. For instance, to reduce technical losses, the KPLC implemented a number of system reinforcement projects and did maintenance work on the transmission and distribution systems, as well as installing loss reduction equipment on distribution lines. To reduce non-technical losses, the company carried out a countrywide meter inspection exercise in conjunction with a successful customer awareness programme. These measures are expected to be intensified in the coming years. The company set itself a target to reduce the system losses from the current levels to 17.5 % within the next three years (KPLC, 2001: 10). However, even if the KPLC attains its target, the percentage of 17.5 % is still very high by international standards.

Table 5.4 System Losses

Year	Total Units (GWh)	Total System Losses (%)
1989/90	484	14.8
1990/91	511	15.2
1991/92	566	15.8
1992/93	559	15.2
1993/94	598	15.6
1994/95	660	16.2
1995/96	660	16.2
1996/97	695	16.4
1997/98	831	18.6
1999/99	884	19.2
1999/00	957	21.5
2000/01	869	21.3

Source: Compiled from KPLC Annual Reports

5.4.4 Demand

In recent years, the demand for electricity in Kenya has exceeded the supply. In 2001 the total installed electricity generation capacity stood at 1,173.1 MW, whereas the effective capacity was only 988.1 MW. This effective capacity could not meet Kenya's electricity demands in 2000. In an attempt to avoid load shedding the government contracted three emergency generators to augment generation. These generated a total of 587.4 GWh. Despite these efforts, Kenya again experienced a heavy load shedding programme. Since September 1999, Kenya has been experiencing inadequate power in its system due to a lack of rain and delays in the implementation of planned power projects. This has resulted in losses to the economy that are conservatively estimated at approximately US$ 68 million per month (Daily Nation On the Web, 2000). All the major demand categories suffered heavily during this period, with small and large industries registering huge losses of output.

Kenya's peak demand has grown year after year, regardless of the suppressed demand. For instance, over the period from 1989/90 to 2000/01 the highest peak demand was 734 MW during the 1998/99 financial year. Due to power shortages, the system's peak demand dropped to 708 MW in 1999/00 before increasing to 724 MW in 2000/01. The installation of back-up electricity generating units, such as small generators, solar photovoltaics, solar thermal, wind and other renewable energy sources has increased as a result of the unreliability of the power from the national grid and the failure to meet consumer demand. Moreover in rural areas four times as many households have solar home systems than are connected to the national grid, which is the reason why Kenya has one of Africa's most thriving photovoltaic (PV) electricity sub-sectors (Lore, 2000).

With regard to consumption per consumer category, the large commercial and large industrial category has always been the major consumers, followed by the domestic, small commercial and small industrial category. In 2001, for instance, the large commercial and large industry category consumed 1,361 GW, which is about 44 % of the total electricity sold in Kenya (i.e. 3,091 GWh), while domestic, small commercial and small industry consumption was 34 %, (1,064 GWh) of the total. The demand from the latter category has been increasing steadily during the period under review, averaging over 6 % before it decreased to –2% in both 2000 and 2001 due to load shedding. This initial rapid growth occurred because of the expansion of the informal sector, improvements in the standard of living and the increase in human settlement, particularly in urban areas. Nairobi, the major load centre, continued to record most of these increases, followed by Mombasa. In 2001, Nairobi alone consumed about 52 %, while the Coast region, which includes Mombasa consumed about 20 % of the total electricity sold. In 2001 Nairobi's maximum demand was 401 MW, while that of the country was 724 MW. Table 5.5 shows electricity consumption for different consumer categories.

Table 5.5 Sales of Electricity in GWh to different categories of customers

Year	Tariff Categories (GWh)					TOTAL SALES (GWh)	Total Number of Customers	System Peak Demand (MW)
	A	B	C	D	E			
1990/91	823	585	1,178	109	14	2,708	287,012	550
1991/92	877	567	1,198	104	14	2,760	307,135	566
1992/93	927	564	1,281	115	13	2,901	329,081	596
1993/94	977	559	1,326	125	10	2,997	351,647	612
1994/95	1,026	569	1,356	119	18	3,089	370,456	605
1995/96	1,049	618	1,491	100	12	3,269	406,523	648
1996/97	1,116	567	1,536	86	10	3,406	426,500	680
1997/98	1,207	665	1,526	89	11	3,498	452,963	721
1999/99	1,270	680	1,513	92	9	3,564	472,671	734
1999/00	1,158	724	1,398	74	11	3,366	505,951	708
2000/01	1,064	609	1,361	51	7	3,091	537,079	724

Source: Compiled from KPLC Annual Reports

Key:

Tariff A - Domestic, small commercial and small industries

B - Commercial (medium) and industrial (medium)

C - Commercial (large) and industrial (large)

D - Off-peak

E - Street lighting

5.4.5 Tariff

Electricity tariffs in Kenya need to be set at a level that is sufficient to keep its diverse power industry running smoothly. The tariff should make the KPLC financially viable so that it can pay for the bulk electricity it buys from the publicly owned KenGen and the IPPs. According to Gatheru et al., (1998), up until 1994 Kenya's electricity tariff was very low. After a comprehensive study, a new tariff was introduced that almost doubled the average price of electricity. The new tariff was set to recover the cost of both the generation and the distribution companies. It had three components: - a) the basic tariff based on 75 % of long-run marginal costing (LMRC), b) a fuel oil surcharge formula to recover the cost of fuel oil, and c) an exchange rate fluctuations factor on foreign loans. However, in 1999 the tariff was re-adjusted upwards as a result of the increase in fuel oil prices and the devaluation of the Kenyan shilling against major currencies.

The 1999 tariff, although slightly revised in May 2000, is still in use but it is presently under review by a consortium of consultants, the National Economic Research Association (NERA) and a power industry consultant, GIBB (East Africa). The consultants were commissioned by the ERB to do the review and have already issued a draft report in 2001, which indicated that it was necessary to increase the tariff. The consultants recommended that the new tariff proposal be made effective by July 2002 when the KPLC's new financial year (2002/2003) begins. This was recommended in order to ensure that the KPLC remained financially viable. According to the East African Standard (2002), with the existing tariff, the KPLC is completely unable to recover costs and last year – in 2001 - the company reported the biggest operating loss in Kenya's business history, namely Kshs 5 billion. Furthermore, the KPLC owes KenGen in excess of Kshs 12 billion in unpaid electricity supplies. Retail tariff adjustments are now done by the ERB. In future the ERB will from time to time review the tariff to ensure that it is sufficient to allow the power industry to recover all its costs.

With regard to bulk electricity tariffs, which the KPLC pays to its various suppliers, it has been urged that the tariffs are extremely high. For instance, under the existing tariff between KenGen and the KPLC, which was approved by ERB and effected in August 1999, KenGen sells a unit of electricity to the KPLC at Kshs 2.36 (about 3.0 US cents) which is too high (KenGen, 2000a). According to the KPLC (2001: 9), bulk power purchases cost the company up to 92 % of its annual total revenue. It further states that as part of the short-term measures to address the high cost of bulk power purchases, the company was negotiating a review of the bulk electricity tariffs with its suppliers (KenGen, Iberafrica, Westmont and UETC for the imports) in order to rationalise the bulk tariffs with the retail tariff yield. To facilitate the review, a consultant, PB Power of United Kingdom, was appointed by the government to update a tariff study. This was already undertaken in 1998, and the consultant was supposed to produce a final report by January 2002. He was required to recommend appropriate bulk

power tariff levels between the KPLC and KenGen. It was expected that this recommended tariff would be implemented in April 2002. As to the import tariff, the KPLC has already succeeded in negotiating a tariff adjustment with the Uganda Electricity Transmission Company, which will result in an estimated annual saving of Kshs 200 million (KPLC, 2001: 13).

5.4.6 Rural Electrification

Since the early 1960s, Kenya has maintained the Rural Electrification Fund, which is administered by a committee under the Ministry of Energy. Apart from the levy on the electricity sold by the KPLC, donor agencies and the government have been contributing significantly to the Fund. The contributions from the donor agencies have been in the form of grants, very soft loans and interest differentials; while those from the government have come directly from the treasury or as remission from duties and taxes on imported materials. The Fund has made it possible to electrify almost all the district headquarters and a number of other rural schemes.

The power sector reform process has also recognised the task that lies ahead for rural electrification. Under the revised Electric Power Act of 1997, there is a provision of a levy – up to a maximum of 5 % – on the KPLC's total revenue, for rural electrification projects. This is expected to generate funds to continue carrying out the Rural Electrification programmes as per the comprehensive rural electrification master plan which was prepared by the Ministry of Energy with the assistance of the Africa Development Bank. The KPLC is the implementing agency of the rural electrification plan and will be engineering and constructing various rural schemes itself or through subcontracting. However, according to Gatheru et al., (1998), there is no proper institutional framework with regard to the following functions: -

- To administer the Rural Electrification Fund;
- To set procedures and formulate policies for planning, financing and executing the rural electrification programme;
- To set priorities based on maximising economic benefit: cost ratio and to bring about the greatest social benefit to the communities
- To allocate funds on an equal basis to all provinces, on the basis of size, population, economic, environmental and social factors.

5.4.7 Financial Performance of the Utilities

As noted earlier, there are basically two major utilities which operate in the Kenyan power sector. These utilities, KenGen (the electricity generation utility) and the KPLC (the transmission and distribution utility), are supposed to operate in accordance with commercial principles and are required to pay taxes as well as dividends to their respective share holders. After the separation of assets was completed in 2000, each utility now has its own assets. However, for the past two years their financial performance has so far been in direct opposition to each other, in the sense that one realised profits, while the other recorded net losses. While KenGen realised profits before taxation of KShs. 2,475 million and KShs 3,763 million for 2000/2001 and 1999/2000 respectively, the KPLC recorded net losses before taxation of KShs 4,106 million and 4,158 million for the same financial years. Other financial and performance indicators for the loss-making KPLC also deteriorated during the past two years, as shown in Table 5.6. Although the KPLC's total revenue seems to be substantial, there is an amount which cannot be counted as revenue, as it only collects it as fuel cost recoveries, which are passed on directly to consumers. For instance, as per the Income Statement as at June 30th 2001, out of the KShs 28.2 billion collected in 2001, about KShs 12.1 billion were fuel cost recoveries. On the other hand, as shown in Table 5.7, KenGen had very healthy financial and performance indicators. At the same time it should be noted that KenGen's sales per employee ratio is exceptionally high due to the fact that it sells electricity in bulk in contrast to the KPLC. This ratio, however, dropped drastically in 2000/2001 due to a decrease in the units generated, which was caused by drought (KenGen, 2001a & KPLC, 2001).

According to the KPLC (2001:7) three major factors contributed to its lack of profitability, namely: - firstly, high power purchase bulk tariffs with electricity suppliers, which take up 92 % of the total company's annual revenue. Secondly, high technical losses, which, for example, in 2001 caused the company not to realise a total of KShs 1,689 million. It should be noted that the KPLC buys electricity in bulk and in that way it pays also for the transmission and distribution losses. And last but not least is the decline in units sold due to power rationing between May 2000 and January 2001, which was caused by KenGen's failure to supply sufficient electricity to the KPLC. Apart from the non-availability of power from the generation segment, a situation which ended in January 2001 after the country received sufficient rainfall, the decline in units sold was caused by a lower than projected demand for electricity, experienced since January 2001 as a result of a general economic slow-down. Although the KPLC did not mention openly (in the 2001 Annual Report) the fact that some of its customers – and especially the government – were delaying paying their bills, it is likely that these delays also contributed to the KPLC's poor performance. According to East African Standard (2002), by January 2002 the government's pending bills with the KPLC were in excess of KShs 2.5 billion,

which the government had promised to settle, but little has, in fact, been paid. This is a significant amount of money that could to some extent reverse the company's poor financial performance.

The poor performance of the KPLC has far-reaching implications for the Kenyan power sector as a whole. Since the KPLC operates as a middleman between the final consumers and the bulk power suppliers, its performance automatically, in one way or another affects the consumers or the bulk power suppliers. As appears from KenGen's balance sheet as at June 30th 2001, a total of KShs 11.4 billion was owing to them from the KPLC in the form of electricity units sold to them and in the form of a Development Surcharge due. This represents an increase from the amount of KShs 9.3 billion owing as at June 30th 2000. While such a big amount of money was owed by the KPLC, KenGen was struggling to raise money to finance its existing power construction projects estimated at KShs 3 billion (East African Standard, 2002). According to the KPLC (2001:13) the construction work of Sondu Miriu 60 MW hydropower project has been adversely affected due to the government of Japan's delays in realising funding. KenGen has to come up with its share first, before the external financier, the government of Japan, releases his share of the funds. As a consequence of delays in payments, there were also problems with the Olkaria II 64 MW geothermal power project and, in fact, its contractor threatened to abandon the project. If these projects will not be completed and commissioned as planned, Kenya will again experience a major power supply shortage by 2004 (East African Standard, 2002). To reiterate, the ultimate cause of all these problems experienced by KenGen and of the fact that Kenya is on the brink of experiencing another electricity shortage, can be attributed to the poor performance of the transmission and distribution company, the KPLC.

However, in recognising the need for KPLC to perform well in order to salvage the situation, it has put in place some short-term and medium-term measures. These measures included: enhancement of the power capacity, review of the power purchase bulk tariffs, reduction of the technical losses, business and organisation restructuring and improvement of the financial management of the company (KPLC, 2001: 13-14). These measures were developed with the assistance of the government and the consultant. As regards enhancement of the power capacity, it is envisaged that, subsequent to the recently commissioned 75 MW Kipevu II project and an additional 210 MW capacity expected to be commissioned between 2002 and 2005, the recent problem of power shortages will be overcome.

In relation to the review of the bulk power purchase tariffs some steps have already been taken, as discussed earlier under the tariff subheading. Successful implementation of the measure to reduce technical losses, as was also discussed earlier, is projected to yield an additional revenue of KShs 200 million per annum during the first year, which will increase to KShs 600 million per annum in the

third year. As for business and organisation restructuring, the company intended to, *inter alia*, reduce its workforce by 2,000 employees by June 2002. However, according to Oyuke *et al.* (2002), the government and the World Bank, which is sponsoring the business and organisational restructuring exercise, are currently fighting over who should actually finance the project thus standing at a high risk of stalling. Improvement of the financial management entails implementing measures to improve its working capital, such as reduction of electricity debt and debtors (KPLC, 2001: 13-14).

Table 5.6 Some KPLC Financial Indicators

Year	Number of Customers	Number of Employees	Total Sales (GWh)	Sales/ Per Empl. *	Customer per Employee	Total Revenue KShs'000	Total Asset Value (KSh'000)
1989/90	265,413	10,789	2,595	240	25	2,901,840	
1990/91	287,012	10,895	2,708	249	26	3,824,734	
1991/92	307,135	10,880	2,719	250	28	4,556,374	
1992/93	329,081	10,585	2,859	274	31	5,001,004	
1993/94	351,467	10,186	2,997	294	35	9,279,744	
1994/95	370,456	8,864	3,017	348	42	1,2957,798	
1995/96	402,536	8,193	3,269	399	50	14,925,761	
1996/97	426,500	8,279	3,406	411	52	16,893,149	
1997/98	452,963	7,167	3,498	488	63	18,073,232	
1998/99	472,671	7,100	3,564	502	67	18,422,731	
1999/00	505,951	7,095	3,365	474	71	23,564,466	25,501,415
2000/01	537079	6,900	3,091	448	79	28,188,525	28,812,360

Table 5.6 continued

Year	Net Profit/Loss Before Tax (KShs'000)	Average Selling Price KShs/kWh	Average cost of Units Sold (KShs)	Returns on Assets	Debt/ Equity Ratio	Interest Cover Ratio	Average Exchange Rate KShs/US$
1989/90	82,637	1.12	1.05				
1990/91	157,673	1.41	1.28				
1991/92	162,191	1.68	1.49				
1992/93	(261,178)	1.75	1.58				
1993/94	763,136	3.10	2.84				
1994/95	1,499,803	4.29	3.86				51.43
1995/96	1,512,042	4.57	4.27				57.12
1996/97	2,160,099	4.96	4.59				58.73
1997/98	2,005,343	5.17	4.71				60.38
1998/99	1,721,924	5.17	4.64				70.33
1999/00	(2,574,269)	7.00	8.03	-0.13	0.38	4.65	76.18
2000/01	(4,103,984)	9.12	10.27	-0.16	2.08	8.33	78.60

Source: Compiled from KPLC Annual Reports
Exchange rate figures obtained from CIA World Factbook 2001.

Table 5.7 KenGen Financial Indicators

Year	Number of Customers	Number of Employees	Total Sales (GWh)	Sales per Employee	Total Revenue KShs'000	Total Asset Value (KSh'000)
1989/90						
1990/91						
1991/92						
1992/93						
1993/94						
1994/95						
1995/96	1		4,062		3,925,887	
1996/97	1		4,236		2,136,719	
1997/98	1		4,129		3,509,645	
1998/99	1		4,139		7,407,949	21,079,460
1999/00	1	1,620	3,982	2,458	15,574,463	49,335,946
2000/01	1	1,587	2,757	1,737	13,488,013	55,076,574

Table 5.7 continued

Year	Net Profit/Loss Before Tax (KShs'000)	Average Selling Price KShs/kWh	Average cost of Units Sold (KShs)	Returns on Assets	Debt/ Equity Ratio	Average Exchange Rate KShs/US$
1989/90						
1990/91						
1991/92						
1992/93						
1993/94						
1994/95						51.43
1995/96		0.97	5.88			57.12
1996/97		0.50	3.38			58.73
1997/98		0.85	0.85			60.38
1998/99		1.79	1.79		0.61	70.33
1999/00	3,763,000	3.91	2.67		0.78	76.18
2000/01	2,475,000	4.89			0.86	78.60

Source: Compiled from KenGen Annual Reports
Exchange rate figures obtained from CIA World Factbook 2001

5.4.8 Sector Reforms

Power sector reforms in Kenya began in the early 1990s. Kenya is among the first African countries to embark on a power sector restructuring and reform programme. Previously, there were two publicly owned companies, which dealt with electricity generation, transmission and distribution, namely the KPC and the KPLC. As mentioned earlier, the KPC was managed by the latter under a management contract, and it was responsible for developing and running generating facilities. The KPLC was responsible for the transmission and distribution of electric power throughout the country, although it

also owned generating facilities under the Tana and Athi River Development Authority (TARDA), the Tana River Development Company (TRDC) and the Kerio Valley Development Authority (KVDA).

The two entities mentioned above, which for practical purposes was a single entity as a result of one being managed by the other, performed relatively well since their inception up to the early 1990s. From this time, Kenya's power sector started to experience some difficulties, mainly due to an inadequate power supply. This was attributed to three major causes: - a) an over-dependence on hydropower generation, which was adversely affected by the lack of rainfall as well as the poor distribution of rainfall in the main catchment area; b) the high breakdown rates of both thermal and hydro plants, largely resulting from a lack of investment between 1990 and 1996 (Gatheru et al., 1998); and c) more significantly is the fact that none of the 250 MW of generation capacity planned between 1993 and 1997 was actually built (Ruffini, 2000b:32). Lack of investment and the failure to implement planned power generation projects were firstly due to an embargo imposed by donor agencies on the government, and secondly due to the failure of the KPC and the KPLC to finance the projects themselves. This resulted in massive load shedding, which began in 1996 and continues to date, and which has had a severe impact on Kenya's economy.

Drivers for the reforms

The main driving forces behind Kenya's power sector reforms are: -

- the generation shortages which were caused by the three factors mentioned above;
- the government objectives of improving the efficiency of the power sector operation; and
- attracting private investment (international financing) to remedy the situation by investing in power generation.

As a result of these, a new Bill, the Electric Power Act of 1997 was passed by the Kenyan Parliament, becoming law on the 9th of January 1998. Among other things the Act provides for the following: -

- Separation of the policy and regulatory functions exercised by the Ministry of Energy and consequently the establishment of an autonomous Electricity Regulatory Board;
- Separation of the management and other functions of the KPC and the KPLC; and
- Seeking to liberalise the sector by enabling the private sector to participate in power generation and to sell electricity to the grid.

Implementation of the reforms as provided for in the new Bill saw the power sector officially split into two utilities. Thus, the KPC and the KPLC were separated into two companies. As mentioned earlier, the KPC, which was wholly owned by the government, became a separate company with a separate board, management and staff and was charged with the generation of electricity in

competition with IPPs. It sells electricity in bulk to the KPCL. All the generation assets previously owned by the KPC itself and the KPLC were put under the control of the KPC which later, on October 2nd 1998, changed its name to the Kenya Electricity Generating Company Ltd – KenGen. On the other hand, the KPLC, a monopoly, remained responsible for the transmission and distribution of electricity in all the areas of the country. It thus buys power in bulk from KenGen and IPPs under bulk power purchase agreements. The KPLC also started to issue shares to the public, although the government owns the majority of these shares in order to retain control. The process of the separation of the assets between the KPLC and KenGen took almost three years and was finally completed in June 2000 (Daily Nation On the Web , 2000).

While the process of asset separation took so long, the IPPs were allowed to operate even before the new Electricity Power Act of 1997 had been passed, in an attempt by the Kenyan government to ease the power shortage. Early in 1996, the KPLC signed power purchase agreements (PPAs) with two IPPs, Iberafrica of Spain and Westmont of Malaysia, to install 88 MW capacity together. These projects were commissioned in August 1997 (Gatheru et al., 1998). Thus, with regard to private generation, the new Act aimed to attract more investors and raise investors' confidence. As a result of having in place such an Act, two more IPPs were introduced, and there are presently a number of other private power generation projects under construction, some of which will be commissioned in the near future, such as the Kipevu II 75 MW diesel plant.

The reforms also saw the establishment of the Electricity Regulatory Board in June 1998 to regulate the generation, supply, transmission and distribution of electricity. The establishment of the Regulatory Board removed the government's direct involvement in the sector. The government's only task with regard to the energy sector now is policy formulation for the sector and administering the Rural Electrification Scheme.

The reform process is not complete yet. To ensure that the sector attains the optimum levels of efficiency, some other processes need to take place. These include the privatisation of various publicly owned assets and further vertically unbundling the KPLC to separate the functions of transmission and distribution. Distribution may also be horizontally unbundled to allow different distribution companies to service different load centres or zones. To create fair competition on the generation side, the giant and publicly owned KenGen may be divided into several small generating companies and sold to private individuals, although strategically the government may retain ownership of up to 45 %. However, the government of Kenya is still committed to continue reforming the power sector. It has been stated in various government policy documents, such as the Poverty Reduction Strategy Paper (PRSP) that the government is committed to continuing with reforms in the

energy sector. The government has stated its commitment to the restructuring and privatisation of the power sector in order to make the sector more efficient, and also said that it aims to further restructure the KPLC so as to improve its operations and financial management (Daily Nation On the Web, 2000 & KPLC, 2002c).

To fulfil its commitments the government, it is currently carrying out a power market design and pre-privatisation study through a consultant in order to determine an appropriate competitive electricity market structure for the country. In addition, the consultant will recommend effective ways of private sector participation in generation, transmission and distribution. The consultant is supposed to complete the study in 2002 (KenGen, 2001). In October 2000, prior to these initiatives the government appointed a team known as the Restructuring Task Force and a management consultant (Price Waterhouse Coopers) to review the organisational, management and financial structure of the KPLC. The consultant was expected to make recommendations on how the KPLC could be restructured to make it more efficient and how to reduce the operational costs of the company. Some steps, such as reducing the number of the KPLC functional divisions from 15 to 7 and reducing the operational areas from 6 to 4 business regions, have already been taken since then. On the other hand, according to the KPLC (2001: 9) the government is currently preparing a National Energy Policy to make the fiscal, regulatory and legal regime of the sector more investor friendly so as to attract more private investors.

5.4.9 Regulatory Framework

Kenya's Power Act of 1997 provided for the separation of the policy and regulatory functions exercised by the Ministry of Energy by establishing an autonomous regulatory board. Consequently, the Electricity Regulatory Board (ERB) was established in June 1998. Prior to this, the Ministry of Energy was responsible for the functions of both regulation and policy formulation in the electricity sector. The establishment of the ERB was part of the overall reform process of the power sector and it was established to manage the sector and to ensure efficient functioning.

However, according to a study conducted by Nyoike *et al.* (2002: 1), which examined the autonomy of the ERB, it was established that it is not as autonomous as it ought to be. This is because of the fact that the Electric Power Act of 1997 and the State Corporation Act (SCA) of 1986 define the ERB as a state corporation. The study further revealed that the SCA provides for the dissolution of a state corporation, the dismissal of a board member and even the entire board by the executive and that the board was recently replaced in its totality, which confirms the power of the executive over the ERB. As regards the granting, suspension and revocation of licences, the study found that the ERB's role is merely advisory, and that the final authority rests with the Energy Minister who is not bound to accept

the ERB's recommendations. The study recommended, among other things, that instead of ERB members being appointed by the Energy Minister, they should be appointed by the Cabinet, which would reduce their vulnerability and simultaneously increase their autonomy.

CHAPTER SIX
Namibia

6.0 Location and Demography

Namibia is located in Southern Africa. It borders the South Atlantic Ocean to the west, Angola to the north, and Botswana to the east and South Africa to the south. Namibia has a total area of 825,418 sq. km. In 2000 it had a small population, by international standards, of only 1.8 million people, scattered over the entire land area. 31% of this population is considered urban while 69% of the population live in the rural areas (World Bank, 2002).

6.1 Economy

The Namibian economy is heavily dependent on the extraction and processing of minerals. Export of non-fuel minerals accounts for a significant portion of its exports. It is the fourth largest exporter of non-fuel minerals in Africa and the world's fifth producer of uranium (Photius, 2000). Apart from uranium, other minerals exported by Namibia are diamonds, lead, zinc, tin, silver, marble gemstone, copper and tungsten. Namibia is rich in alluvial diamond deposits. The export of minerals makes the mining industry a key sector in Namibia's economy. In 2000, its contribution to the total exports was 50.7% (Bank of Namibia, 2001).

Unlike other African countries, agriculture contributes little to the total GDP of Namibia, an average of 10% in the period 1996 – 2000. However, a large number of the population depends on subsistence farming despite the fact that it is often severely affected by frequent droughts. This results in the majority of the population living in abject poverty due to its over-dependence on subsistence farming and the fact that the country's income distribution is highly skewed (Photius, 2000). Even though agriculture's contribution to the GDP is minor, the country's manufacturing industry focuses on food processing and beverages. In the period 1996 – 2000, the manufacturing sector contributed an average of 14.2% to the total GDP. Namibia furthermore has one of the richest potential fisheries in the world. Its contribution to the total GDP has been significant, about 4.5% on average over the period 1996 – 2000 (Bank of Namibia, 2001).

Namibia's economic policies aim at sustaining an economic growth variety in the productive base and the attraction of foreign investors by offering an attractive incentive package. Among the incentives to foreign investors are that there are no restrictions on them bringing funds into the country or taking out investment capital, interest or dividends. However, dividends are subjected to a 10% withholding

tax while there is no withholding tax on interest. Foreign investors are highly attracted to the economy in order to contribute to Namibia's economic growth which was 4.5% in 2000. This year the GDP, at current prices, was N$23,786 million. The real per capita GDP of N$8,096 (about US$1,153) and the per capita national income of N$9,075 (about US$1,293) in 2000 defines Namibia as a middle-income country (Bank of Namibia, 2001). The government is now reducing its direct involvement in the economy by privatising most of its publicly owned enterprises. Its future role will be to provide an enabling environment for strong private sector involvement so as to stimulate faster economic growth.

6.2 Energy Sector

Namibia's energy sector is one of the key sectors of the country's economy. As in many African countries, Namibia's energy sector is also a key link between poverty and environment. This is due to the fact that wood is the single largest fuel source for the rural households. As mentioned earlier, 72% of Namibia's population lives in the rural areas, thus exerting huge pressure on the forests and the environment. It is estimated that about 93% of rural households depend on wood for their cooking, lighting, ironing and water heating (Utonih, et al., 2001:2). Some poor households are meeting these energy needs by using low quality energy types such as crop waste and dung.

Petroleum products, i.e. petrol and diesel, dominate the energy sector in terms of commercial energy consumed. In the year 2000, they accounted for 63% of the total commercial energy consumed. All the petroleum products consumed in Namibia are imported with 60 – 70% coming from South Africa. Electricity is the second largest commercial energy consumed, accounting for about 17% of the total in 1996. Coal consumption accounts for only about 5% of the total commercial energy consumed with most of it being imported from South Africa as well.

Lying on the same south-west coast with Angola, which has quite a lot of economically exploitable oil reserves, Namibia has yet to experience a commercial oil discovery although extensive explorations have been done and were recently intensified. However, Namibia has ample reserves of natural gas which can be commercially exploited. Policy formulation to guide exploration and exploitation activities of these resources (oil and gas) as well as policy development of the overall energy sector, is the responsibility of the Ministry of Mines and Energy.

6.3 The Power Sector

6.3.1 Background

Before its independence from South Africa in 1990, the power sector in Namibia was developed mainly to supply the urban centres. Since independence, considerable progress has been made in supplying grid electricity to the rural areas and also in widening access to those living in urban areas that previously had not been connected. However, despite all the progress most of the electricity supplied in Namibia is imported from South Africa thus leaving the abundant domestic electricity potential sources undeveloped.

One of the potential electricity sources is natural gas discovered at Kudu in the late 1960s early 1970s when the initial offshore exploration phase took place. Mbendi quotes Namibia's state oil company, Namcor, as saying that the country has sufficient gas deposits to meet its electricity demand for the next century and that proven reserves stand at 1.3 trillion cubic feet (tcf) which justifies the plans for exploitation. There have been plans to exploit the gas for liquefied natural gas (LNG) production for exports, electricity generation in Namibia and piping – over a distance of 700 km to the Western Cape in South Africa. This would make Namibia self-sufficient in power generation for a considerable period in the future.

Apart from natural gas, the country also has a significant hydropower potential mainly on the Kunene River. The potential includes 12 different schemes ranging from 50 to 500MW (MME, 1998:10). Some of this potential has already been developed while studies are going on to determine the feasibility of the others. There are also other rivers with some potential although at the moment the feasibility is not known. The only known site is the 15MW potential on the Okavango River. Namibia is also considered to have plenty of untapped solar power and wind potential due to its location. There is plenty of wind in the coastal areas and currently Namibia is planning to put up a wind turbine farm.

6.3.2 Institutional Arrangements

Namibia has a relatively diverse power sector, different from many African countries where publicly owned monopoly utilities are responsible for generation, transmission and distribution. The power sector in Namibia is different because of the fact that the Namibia Power Corporation Pty Limited, henceforth NamPower, the state owned utility, is responsible for generation and transmission only. It sells electricity in bulk to the distribution entities and to large customers such as mining companies and commercial farms. NamPower was established on 9th December 1964 as the South-West Africa Water and Electricity Corporation (SWAWEK) and became operational in 1973. Later it was

registered as a private company under the Company Act of 1973. It had a monopoly in electric power generation and transmission.

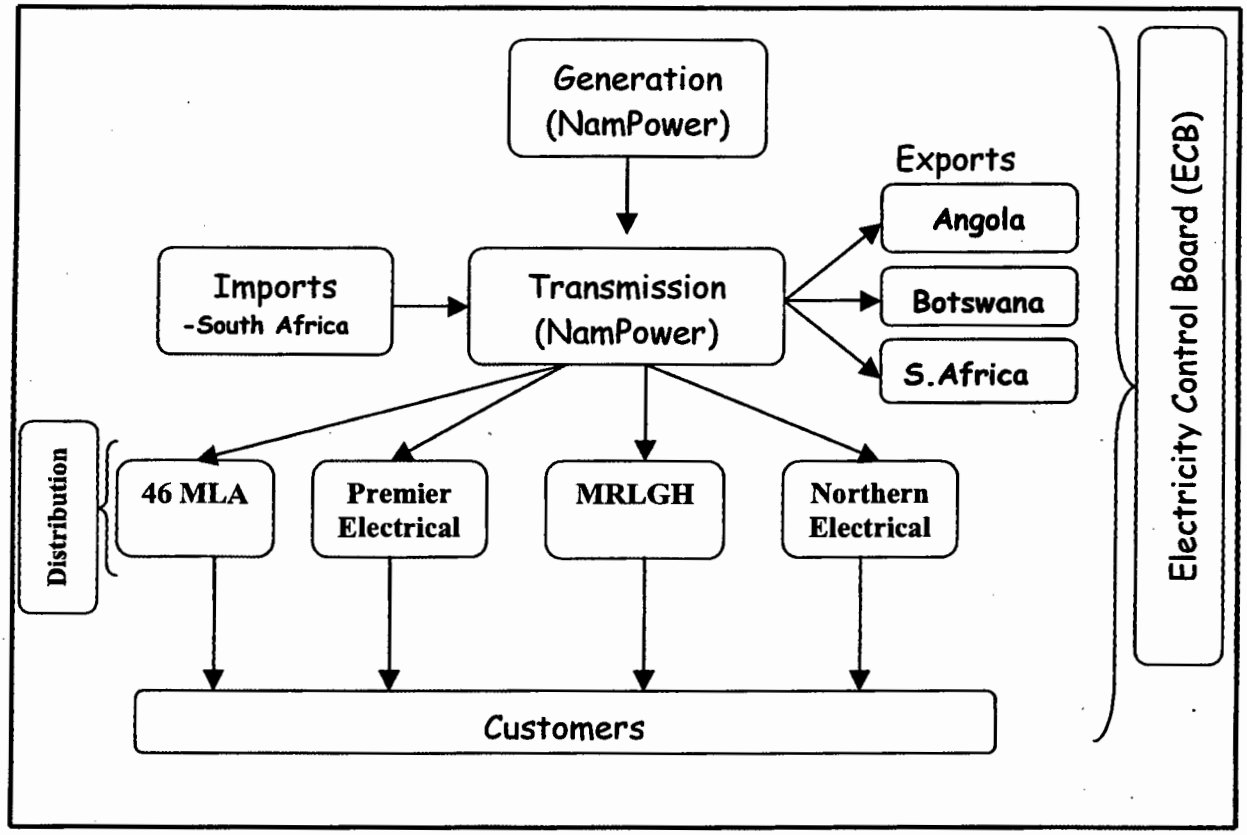
Municipal electricity departments largely undertake distribution of electricity in Namibia. There are 46 municipalities and local authorities supplying electricity to end-users in the urban and peri-urban areas. In the rural areas, distribution is the responsibility of the Ministry of Regional and Local Government and Housing (MRLGH) although NamPower supplies commercial farmers. Other government departments are also involved in the supply of electricity but mainly for government buildings and own use. The Department of Works used to run diesel generators in areas not previously electrified and was supplying electricity to the government offices. It was also responsible for paying all the government energy bills. Recently, individual government departments have had to take budgetary responsibility for many of the Department of Works functions.

Although the MRLGH is the one responsible for rural distribution, electricity supply to some other areas in Namibia have been contracted out to private companies. In the northern part of the country, Northern Electricity (Pty), a private company, distributes electricity. The company started as a revenue collecting agency for MRLGH and also handles supply in rural areas in the regions of Oshana, Ohangwena, Omusati and some districts in the Oshikoto region. However, the assets are still publicly owned by the MRLGH. The company is responsible for operation, maintenance, new connections, revenue collection and payment of NamPower charges but with MRLGH monitoring. NamPower together with the Ministry of Mines and Energy (MME) are responsible for rural electrification. In this case, NamPower is responsible for the main rural transmission and distribution system and direct supply to commercial farmers and users in places where there are no municipalities.

In July 1999, the country's electricity distribution industry was bolstered by NamPower establishing a subsidiary company, Premier Electrical, to engage in electricity distribution. The new company is responsible for distributing electricity to smaller consumers in small towns and municipalities, towns and villages by using both grid and off-grid technologies particularly solar power. In municipal areas, the company has entered into joint ventures with the municipalities to provide reliable and affordable power to the local residents.

Overseeing the activities of all the above institutions in the power sector is the responsibility of the Electricity Control Board (ECB) which was established in July 2000. It controls and regulates the industry in all aspects of generation, transmission, distribution and supply of electricity. Diagrammatically, institutional arrangements in Namibia's power sector are shown in Figure 6.1 below.

Figure 6.1 Namibia's Power Sector Institutional Arrangements



6.3.3 Supply

As is the case in most of the countries which border South Africa, Namibia's electricity supply is made up of internal generation and imports, with most of the imports coming from South Africa.

Generation

Currently all the generation facilities are owned and operated by NamPower. In fact, previously NamPower had a monopoly over generation but now generation has been opened up to competition. Most of the generation facilities, which make up about two thirds of the total country's installed capacity are on the Kunene River at the Ruacana Falls in northern Namibia. The Ruacana hydropower plant, which is a run-of-river power plant, has an installed capacity of 249MW. As a run-of-river hydropower plant, its firm capacity has been highly fluctuating depending on the amount of rain received in a particular year. Utonih and Dlamin (2001:15) quote the World Bank as saying that Ruacana's capacity is reduced to half its rated capacity, 130MW, for much of the typical hydrological year and to as low as 65MW during the driest quarters.

NamPower's other installed electricity generating facilities are: - Van Eck coal plant at Windhoek with a capacity of 120MW and the Walvis Bay diesel plant with an installed capacity of 24MW. However, these thermal plants have been kept on standby mode due to their high per unit cost of generation compared to the substantially low unit price from power trading within the rules of SAPP (NamPower, 2000:11). Table 6.1 shows existing installed electricity generating capacity in Namibia.

Table 6.1 Existing Installed Electricity Generating Capacity

Type of Generation	Name of Plant	Year Commissioned	No. of Units	Installed Capacity MW	Available Capacity MW
HYDRO	Ruacana	1980		240	
Thermal	Van Eck	1972		120	
	Walvis Bay	1979		24	
	Katima Mulilo			3	
Total Existing Installed Capacity				**387**	

Source: Compiled from NamPower Annual Report, 2001

As mentioned earlier, internal generation in Namibia is mainly from the Ruacana hydropower plant and according to the NamPower 2000 Annual Report, in 2000 generation reached an all time record of 1,407GWh. This was attributed to above average water flows in the Kunene River coupled with increased efficiency at the Ruacana plant. However in 2001, generation decreased by 13.4% to 1,211GWh mainly due to less water flow in the Kunene River compared to the flow in 2000. Despite the decrease in hydro generation, the thermal plants continued to be on a standby mode and the difference was sourced from importing more units from South Africa. Generation at the Ruacana plant will continue to be constrained until the Gove Dam in Angola, which was built on the Kunene River to regulate water flow, is repaired. The dam was damaged during the civil war in Angola before it was even commissioned. Perhaps now that there is peace in Angola the dam is going to be repaired and will become operational as originally envisaged.

Imports

Units imported during a particular year depend on the performance of the Ruacana hydropower plant, which, as mentioned, is influenced by the amount of rainfall received. In 2000 internal generation increased and the electricity imported decreased by 11.5%. Namibia's overall dependence on imports then declined to 34.8%, the lowest over the period 1990 – 2001 (NamPower, 2000:14). In 2001 internal generation decreased and the units imported increased to 1,066GWh, which was about 47% of the total units supplied. Table 6.2 shows Namibia's internal generation and imports from Eskom in South Africa. Namibia also imports electricity through a 66kV interconnecting power line from

Zambia. This serves the Eastern Caprivi region which includes the town of Katima Mulilo. Apart from South Africa and Zambia, Namibia also buys electricity from SAPP which sells power on the Short Term Energy Market (STEM) or on Bi-lateral Agreements.

Table 6.2 Units generated internally and imported

Year	Internal Generation (GWh)	IMPORTS		Total System Energy (GWh)	Imports (%) to Total System Energy	System Maximum Demand (MW)
		ESKOM (GWh)	ZESCO (GWh)			
1990	1,149	641	-	1,790	35.8	225
1991	1,368	551	-	1,919	28.7	240
1992			-	1,949		246
1993			-	1,747		279
1994	879	874	-	1,753	49.9	251
1995	1,257	758	-	2,015	37.6	277
1996	873	1,078	-	1,951	55.3	294
1997	630	1,319	-	1,949	67.7	321
1998	1,004	1,192	15	2,211	54.6	326
1999	1,198	869	18	2,085	42.5	298
2000	1,407	766	19	2,192	35.8	317
2001	1,211	1,045	21	2,277	46.8	332

Source: Compiled from NamPower Annual Reports

Planned Generation Development

Currently NamPower is concerned with the over-dependence on imports. Tassel (1999:8), quotes the NamPower Chief Executive Officer, Dr. Leake Hangala, as saying that "it is of concern to be dependent on a neighbour, no matter how friendly that neighbour might be". According to the journal he made the statement when he was commenting on the ability of Eskom to supply power to Namibia. To this effect NamPower has now initiated aggressive efforts to reduce the over-dependence by having on hand plans for the construction of power plants to increase internal generation. A wind power station with a capacity of up to 10MW will be constructed at Lüderitz near Grosse Butch. According to NamPower (2001), its construction will start immediately after securing a licence from the Electricity Control Board.

NamPower's efforts to increase generation and, if possible, to become self sufficient, rests on two possible developmenst, the Epupa hydro plant on the Kunene River and the development of the Kudu gas field. According to NamPower, a combined cycle power plant with a capacity of 750MW was planned. Given the current electricity demand in Namibia, completion of this plant will not only give Namibia enough internal capacity but also a significant export capacity. However, recent wells drilled by Shell have been dry and Shell has withdrawn from the venture. Furthermore, feasibility studies for

a 20 – 30MW hydropower facility at Divindu which will supply the Kavango and Capri regions are scheduled for next year.

Transmission and Distribution System

Namibia's national grid is concentrated at the centre of the country running from the southern to the northern end of the country. The grid system is made up of 400, 300, 220 and 132kV transmission lines. A newly built 900km 400kV transmission line strengthens Namibia's connection to the South African grid. It runs from Aries near Kenhardt in South Africa via Keetmanshoop to the Auas substation just outside Windhoek in Namibia. Of the 900 km, 735 km are on the Namibia side and the remainder are in South Africa. The completion of the line has given Namibia sufficient capacity to meet its power demand for a long period in the future through imports from South Africa and from the SAPP.

The country has a total of 521 km of 330kV-transmission line which connects the Ruacana power station to the country's main distribution station at Omburu near Omaruru. It was built in 1977 and since then there has been no other transmission line built at this voltage level.

Before construction of the 400kV interconnector, power imports from South Africa were via a double circuit 220kV line. This line was first built as a single circuit in 1980 with a length of 740 kilometres. Later, in the late 1980s, this line was upgraded to a double circuit after the building of another 740 km, thus making the total line length 1480 kilometres. Another 125 kilometres of 220kVtransmission line was built in 1995 which connected the town of Oranjemund in the extreme southwest to the town of Ariamsulu in the extreme southeast.

Development of the 132kV line, which was undertaken between 1990 and 2001, included the construction and commissioning of a 156 km line in 1991 to supply power to the Elizabeth Bay diamond mine. In 2000 another 220 km were commissioned to transmit power from the Ruacana hydro power station to Omatando – Okatope. This line was expected to improve the quality and reliability of power supplies and to cater for the expected load demand increase in northern Namibia.

Over the past eleven years, 1990 – 2001, NamPower has been concentrating on widening access to electricity to the Namibian people and as a result the total lengths of the medium and low tension lines, 66kV and below, have increased considerably. For instance, in 2001 NamPower constructed a total of 567 km of 66kV and below lines, as can be seen in Table 6.3 below. The table also shows development of the major transmission lines.

Table 6.3 Transmission and Distribution Total Line Lengths in Namibia (km)

Year	400kV	330kV	220kV	132kV	66kV & below	Transmission Losses (%)
1990	-	521	1,480	790	5,090	10.00
1991	-	521	1,480	946	5,453	10.50
1992	-	521	1,480	946	6,507	
1993	-	521	1,480	946	7,576	
1994	-	521	1,480	946	8,519	11.41
1995	-	521	1,645	946	9,580	11.46
1996	-	521	1,645	946	10,546	11.28
1997	-	521	1,645	946	11,293	12.78
1998	-	521	1,645	946	11,516	13.89
1999	289	521	1,645	946	11,924	10.65
2000	735	521	1,664	1,166	12,656	9.76
2001	735	521	1,664	1,166	13,223	9.97

Source: Compiled from NamPower Annual Reports

System Losses

Unlike other African countries where there is a sole utility generating, transmitting and distributing electricity, figures for system losses given by NamPower do not represent the system losses for the whole country. As distribution of electricity in Namibia is undertaken by many other entities, getting the national figure for system losses entails combining all system losses figures from all the entities in the electricity supply industry. Consequently the figures in Table 6.3 above are only for NamPower transmission losses. NamPower has been able to maintain these losses at below 10% for the past two years.

6.3.4 Demand

Electricity demand in Namibia consists of domestic demand and export demand.

Domestic demand

In the early 1990s, the mining sector was the major electricity consumer in Namibia. During this period, electricity consumed by the mining sector was more than that consumed by the municipalities to distribute to their proclaimed areas. For example, in 1990 mines consumed 736GWh, about 47% of the total while the municipalities in total, purchased 619GWh, about 40% of the total consumption. However, from 1992 demand from the mining sector has been decreasing and in 2001 mines accounted for only 29% of the local electricity consumption. In 2001, electricity consumed by the mining sector decreased to 592GWh from the 1991 high of 757GWh while at the same time demand from municipalities increased to 1,161GWh from 659GWh in 1991. The mining sector electricity consumption declined because of the dormancy of copper mining and processing activities at Tsumeb which historically was one of Namibia's largest consumers of electricity (NamPower, 1999:14)

While electricity consumption by the mining sector was declining, consumption by other consumer categories was increasing particularly, as mentioned, from the municipalities as well as from the rural areas. Increase in demand in these categories was because of commitments to increase access to electricity both in the urban and rural areas. In 2001, rural areas demand increased by 12% although the rural areas electricity consumption accounts for only about 11% of the total consumption.

Exports Peak Demand

Ironically, while Namibia imports most of its electricity from South Africa, it also exports electricity to South Africa and other countries, like Angola and Botswana. NamPower supplies electricity to Katima Mulilo from Zambia through a 66kV transmission line. NamPower also supplies electricity to the Mohombo area in Botswana through a 33kV power line from Omaere, Gobabis in Namibia. Furthermore, NamPower supplies southern Angola from Omatando. The contribution of these cross border supplies to Namibia's 332MW peak demand in 2001 is not significant. Out of the total energy of 2005GWh supplied by NamPower in 2001, exports accounted for only about 3%. In 1992, exports to ESKOM were 204GWh, about 12% of the total system demand, the highest recorded over the period 1990 – 2001. Since then exports to South Africa declined to a record low of only 1GWh in 1997. This was due to the fact that the country experienced devastating droughts during the preceding years which severely affected the performance of the Ruacana hydro power station. Table 6.4 shows electricity consumption by different consumer categories and exports to neighbouring counties.

Table 6.4 Electricity Consumption by Consumer Categories (GWh)

Year	Municipalities	Mining	Rural Areas	EXPORTS			Total Sales
				Angola	Botswana	ESKOM	
1990	619	736	91	-	-	166	1,612
1991	659	757	102	-	-	201	1,719
1992	720	688	102	-	-	204	1,714
1993	750	641	111	-	-	49	1,551
1994	803	606	116	-	-	28	1,553
1995	868	631	139	-	-	146	1,784
1996	913	656	132	-	-	30	1,731
1997	963	596	140	-	-	1	1,700
1998	1,028	668	185	1	1	21	1,904
1999	1,060	562	185	1	3	52	1,863
2000	1,114	560	204	1	4	95	1,978
2001	1,116	592	228	2	5	62	2,005

Source: Compiled from NamPower Annual Reports

6.3.5 Tariff

NamPower, over time, has been maintaining price stability in its sales of electricity – something which NamPower expects to retain during the electricity reforms. Such price stability will foster increased demand among industrial, mining and other bulk electricity users to the benefit of Namibia's economy. In this respect, NamPower is determined to maintain the price of electricity at affordable levels. However, NamPower efforts and determination should be supported by the distribution entities, as the final consumer price depends highly on their performances.

According to NamPower's 2001 annual report, the unit cost of electricity sold to customers over the years has been declining in real terms although it does not reflect the cost of supply. In an attempt to make the prices reflect the cost of supply, tariff adjustments were effected on 1st July 2000. Since then there have been no other adjustments. Last year NamPower proposed to the Electricity Control Board an implementation of a phased move towards fully cost-reflective tariff in each of the areas of generation, transmission and distribution (NamPower, 2001:15).

The consequences, of Namibia's fragmented electricity distribution industry, which has a number of players, is the fact that end-user electricity prices vary considerably throughout the country and between urban and rural areas. The pricing structures and levels of the distribution industry do not reflect the cost of supply, hence they are not conducive to efficient resource allocation (White Paper on Energy Policy, 1998:22). In this policy document (White Paper on Energy Policy), the government states "electricity tariff structures and prices will be based on sound economical principles generally and as a whole reflecting the long-run marginal cost of electricity supply". Implementation of this policy statement was expected to start in 1998 by conducting a tariff study, which would recommend ways in which electricity pricing reforms would be undertaken.

6.3.6 Access to Electricity and Rural Electrification

Access to Electricity

As mentioned earlier, electricity distribution in Namibia is done by many institutions. Consequently widening electricity access by connecting new customers is the responsibility of each of these distribution institutions. As regards NamPower fulfilling this task, in its 2001 annual report, NamPower clearly re-stated its serious commitment to increase electricity access to Namibians throughout the country. Previously NamPower was supplying electricity to only large consumers like mining customers and commercial farms but now, to reflect its commitments, it has established a wholly owned subsidiary company to engage in electricity distribution. The newly formed subsidiary company has already entered into joint ventures with some municipalities and local authorities in

order to foster connections to new customers as well as to provide reliable services in those areas. The NamPower distribution arm is also engaged in electricity distribution in rural areas.

On the other hand, municipalities and local authorities and the MRLGH, which are responsible for connecting customers in their proclaimed areas, have also stepped up efforts to widen electricity access although they are not as strategically positioned as NamPower's distribution company. Their technical and financial capabilities in a way limit them from achieving high connection rates compared to Premier Electric. However, their efforts are evident from the fact that they have, over time, increased the quantity of electricity they purchase from NamPower to distribute to their customers. In 2000 total electricity purchased by municipalities increased by 5.1%, suggesting that the increase of demand came from new customers who have been connected. Furthermore, in an effort to improve electricity supply services including widening access, a privately owned company, Northern Electrical, was contracted in 1996 to operate and manage electricity supply in the densely populated northern regions of Namibia (Utonih et al., 2001:4).

The government is also very keen to widen access to electricity in urban areas and it has given this due attention in the White Paper on Energy Policy, 1998. To this effect the government's policy statement given in the White Paper on Energy Policy is that: "Government will ensure that licenses for distribution of electricity in urban areas under the Electricity Act include provisions, such as electrification targets and a fair structure, that facilitate increased access to electricity among low-income consumers". This seems to be a very well focused policy statement, given the fact that in Namibia only 75% of the urban population has access to electricity (White Paper on Energy Policy: 22). If implemented as planned, Namibia will electrify the remaining 25% and reach 100% access in urban areas within a short period of time.

The policy statement is also concerned with the ability of poor households to use electricity in urban areas. In most of the urban areas in African countries access to electricity by poor households is one problem and using the electricity after getting it is another problem altogether. Poor households use electricity mainly for lighting which is not the aim of all the electrification efforts. Electricity should be used for more than lighting. Other uses like cooking and ironing should also be encouraged and facilitated as they decrease the demand for charcoal and wood, thus saving the forests and preserving the environment. That being the case, making electricity affordable is of paramount importance.

Rural Electrification

Rural electrification is part of NamPower's commitment to increase electricity access to the majority of Namibians. In this regard the government is also very committed, as it is closely co-operating with NamPower, in terms of financing and policy formulation, for the rural electrification programmes. In the White Paper on Energy Policy, the government states the necessity for rural electrification as a way of uplifting social conditions and creating incentives for economic growth in the rural areas and as a means of redressing past imbalances. In an effort to enhance rural electrification, it is included among the items under the performance agreement between the government and NamPower.

Accordingly, NamPower has been meeting the requirements of the performance agreement (NamPower, 1997:20). The performance contract requires NamPower to invest N$ 10 million each year in rural electrification. Perhaps investing in rural electrification had to be put into the performance contract due to the fact that rural electrification investments are not financially viable, not only in Namibia and in this case for NamPower, but everywhere else and for any other utility.

Surprisingly, the government and NamPower have two different targets for rural electrification. In the White Paper on Energy Policy issued in May 1998, the government states its intention to have at least 25% of rural households connected to the national grid by 2010. On the other hand, NamPower states its commitment as giving access to electricity to at least 80% of Namibians within the next 10 years. This was indicated both in the 1996 and 1999 NamPower annual reports. While the government's target is for rural households, that of NamPower is for all Namibians. The targets differ considerably even by computing the access to all by assuming 100% access in urban areas (with 28% of Namibia's population) and 25% access in rural areas (with 78% of the population) set by the government. In other words, if NamPower will attain 100% access in urban areas within the next 10 years, then to attain its 80% target it should attain 42% access to electricity in rural areas which differs from the government's 25% target.

NamPower's rural electrification programme targets both communal areas and commercial farmers in the rural areas. The programmes started in the mostly densely populated central northern regions of the country covering the Omusati, Oshana, Ohangwena and Oshikoto regions in 1991 and 1993. The programmes continued and in 1992 and 1993 the western Kavango Region was electrified, followed by the eastern Kavango region in 1993 and 1994 (Utonih et al., 2001:4). Since then a number of other rural areas have been connected to the grid for the first time thus making the current percentage of rural households with access to electricity rise to 15% (Utonih et al., 2001:4). However, it should be noted that most of the programmes mentioned here were run by the government but with NamPower acting as an implementation agent.

Funding of rural electrification:

The financing of the rural electrification programmes is mainly done by the government, NamPower and the Norwegian government through NORAD. In addition to the N$10 million, which NamPower is required to spend every year for rural electrification; NamPower introduced to Namibia a grant funding component of some N$200 million for rural electrification programmes when it secured international funding for the 400kV Power Project. It was expected that the funds would be allocated to priorities identified by NamPower and the Ministry on completion of the Namibian Rural Electrification Distribution Master Plan in 1999 (NamPower, 1999:19). However, the Rural Distribution Master Plan was completed in August 2000 instead of the planned 1999. Its objective is to provide guidelines and establish priorities for upgrading the extensions of the existing electrical distribution networks in Namibia which will enable NamPower, in conjunction with the Ministry of Mines and Energy, to establish the networks to meet the demands of development in an orderly and cost-effective manner within the 20 year span of the plan (Utonih et al., 2001:6).

Table 6.5 Rural Electrification Funding Received Since 1991

Funding Agency	Time Frame	Total Funds (N$'000)
Norwegian Government (NORAD)	1991 - 1998	84,000
Namibian Government	1991 – 1999	102,000
NamPower	1995 – 1999	42,500
ANNUAL AVERAGE	1991 - 1999	25,400

Source: Utonih and Dlamini, 2001:6

Off-grid Electrification:

In recognition of the role of renewable technologies, particularly solar systems, in supplementing grid electrification, the Namibian government instituted a revolving credit fund for solar home systems (SHS) under a project called "Home Power" in 1996. The fund would help cover the high cost of SHS, especially in areas with dispersed population. This project is managed by the National Development Corporation and it provides loans at low interest rates (5%) to purchase SHS. The loans are payable over a maximum period of five years. To qualify for a loan a customer is required to pay a down payment of 20%. The customer also should be earning a minimum annual income of N$15,000. The project has been implemented in phases and until mid-February 2001, 456 systems had been installed in Namibia (Utonih et al., 2001:5). Premier Electric is also involved in Solar Power Project. In July 2002 the company commissioned the first pre-paid solar system in Namibia.

6.3.7 Financial Performance of NamPower

This section was supposed to discuss the financial performance of all the main players in Namibia's power sector but due to the existence of a large number of entities in the distribution part, it was difficult to obtain their annual reports. The discussion is therefore limited to NamPower's financial performance, as it is the largest player by far. Moreover, many of the distribution entities are not financially viable (NamPower, 1999:9).

In July1996, SWAWEK transformed into NamPower. SWAWEK was a business concern which was always managed in strict observance of business principles without any government interference and as result it was financially very successful. Thus NamPower inherited a stable and sound business which it has enhanced even more as it has been producing favourable financial results year after year. It is one of the largest and most financially sound corporations in Namibia and it fully complies with the principles of generally acceptable accounting principles (GAAP) (NamPower 1998:18)

NamPower's financial performance is characterised by increased profit and high returns on its assets. In 1999 it realised a profit after tax amounting to N$193.2 million which was the highest over the period 1991 – 2001. This was mainly attributed to the high internal generation at the Ruacana hydro power station which followed an above-average water flow on the Kunune River (NamPower 1999:8). Returns on assets have also been very competitive, and so have other financial indicators. Table 6.6 contains key indicators of NamPower's financial performance over the period 1991 – 2001. The financial performance of NamPower during a particular year depends highly on the performance of its Ruacana hydropower plant which is influenced by the amount of rainfall received at the Kunene River catchment area in Angola. This is to say that low internal generation leads to more units being imported from Eskom and thus increased total expenditure. NamPower's sound financial performance has made it a creditworthy entity. It has always serviced its long-term debts without fail, something which most of the other electricity utilities in Africa are unable to do.

NamPower pays both tax and dividends to the government on an annual basis and it has been a major and dependable contributor to the government's revenue (NamPower, 1998:16). It started to pay taxes in 1994 and dividends in 1991.However, in 1993 and 1994 it didn't pay dividends due to the severe drought which Namibia experienced which impacted negatively on NamPower's financial performance. It has also been substantially financing rural electrification.

Table 6.6 Some Financial Performance Indicators of NamPower

Year	Number of Customers	Number of Employees	Total Sales (GWh)	Sales Per Employee MWh/Empl.	Total Revenue (N$'000)	Total Asset Value (N$'000)
1990	866	795	1,612	2,027.7	162,412	577,868
1991	950	801	1,719	2,146.1	187,361	676,741
1992	1,111	778	1,714	2,203.1	226,375	
1993	1,298	768	1,551	2,019.5	234,442	
1994	1,451	749	1,553	2,073.4	256,742	2,507,641
1995	1,662	751	1,784	2,375.5	307,325	2,669,420
1996	1,897	771	1,731	2,245.1	374,829	2,694,198
1997	2,061	814	1,700	2,088.5	449,918	3,150,248
1998	2,219	789	1,904	2,413.2	528,382	3,256,706
1999	2,374	827	1,863	2,252.7	532,141	3,834,627
2000	2,341	831	1,978	2,380.3	541,829	4,132,900
2001	2,723	831	2,005	2,412.8	674,960	4,477,886

Table 6.6 Continued

Year	Net Profit/Loss Before Tax (N$'000)	Average Selling Price of Elect. (Cents/kWh)	Average cost of Electricity Generated	Returns on Assets %	Debt/ Equity Ratio	Interest Cover Ratio	Historical Exchange Rate (Average) N$/US$
1990	38,387	7.60			0.09	684.00	
1991	54,895	8.36			0.07	600.00	
1992		8.89					
1993		9.72		3.79			
1994	9,626	10.98		2.24	0.00	561.56	
1995	52,248	11.68	10.37	3.85	0.00	-	3.63
1996	159,265	13.62	11.11	5.91	0.00	-	4.30
1997	105,493	16.11	15.35	3.35	0.00	-	4.61
1998	172,788	17.40	15.10	5.16	0.00	-	5.53
1999	193,218	18.11	13.74	5.04	0.06	-	6.11
2000	132,820	18.92		3.22	0.13	21.66	6.94
2001	157,067	20.19		3.51	0.18	3.54	7.78

Source: NamPower Annual Reports
Exchange rate figures obtained from CIA World Factbook 2001

6.3.8 Sector Reforms

The current worldwide power sector reforms which are being undertaken have caused most countries to closely examine their power sectors and make important decisions on their future. In this respect, most of the African governments are making efforts to increase the sector's overall efficiency. Likewise, the government of Namibia has stated its intention to reform the power sector. In fact, some initiatives to reform the power sector have already been undertaken. The reforms are intended to liberalise the electricity supply industry and to allow for more effective private sector participation.

Drivers for the power sector reforms in Namibia

As stated earlier, the current structure of Namibia's power sector is made up of NamPower, which virtually has a monopoly in generation and transmission, and a highly fragmented electricity distribution industry. This being the case the sector may be operating at an efficiency level possibly below what is needed to support economic and social developments in Namibia (White Paper on Energy Policy: 21). Rearranging the distribution industry so that it can deliver reliable, quality and affordable electricity is one of the main drivers for power sector reforms in Namibia. According to NamPower (2000:1) other drivers for ESI reforms are:-

- Maximising financial and economic returns to the state through fiscal revenue and debt reduction;
- Widened resource availability and technological change through competitive imports;
- Opportunities for black economic empowerment;
- International environmental concerns; and
- Improved customer service and choice.

On the other hand, the government listed the ESI problems as follows: -

- High import dependency and few sources of supply;
- A large number of supply authorities with widely differing competence and practices;
- Various technical, financial and institutional problems relating to rural electricity supply;
- Electricity prices that in many instances are not cost-reflective; and
- An unclear institutional structure (White Paper on Energy Policy: 20).

Objectives of the reforms

The government has the following objectives:

- Increase sector efficiency;
- Improving access to electricity in a sustainable manner, particularly in rural areas;
- Increase security of supply, while taking into account the risk of stranded investments;
- Promotion and development of the sector as a key vehicle for investment and growth;
- Introducing sector competition;
- Ensuring environmental and socio-economical sustainability;
- Alleviation of resource constraints in the electricity sector; and
- Development of an efficient and appropriate governance framework and structure.

In the White Paper on Energy Policy, the government highlighted different routes it would take to achieve the above objectives and set out its implementation targets. However, prior to the issuing of this policy paper the government had contracted a group of regional and local consultants led by

SAD-ELEC (Pty) Limited of South Africa to carry out a study of different models for restructuring the power sector. The study was launched in November 1997 and was expected to recommend how the fragmented distribution industry would be restructured in order to form an efficient industry, as well as how competition in the electricity generation industry and supply by private sector participation could be introduced.

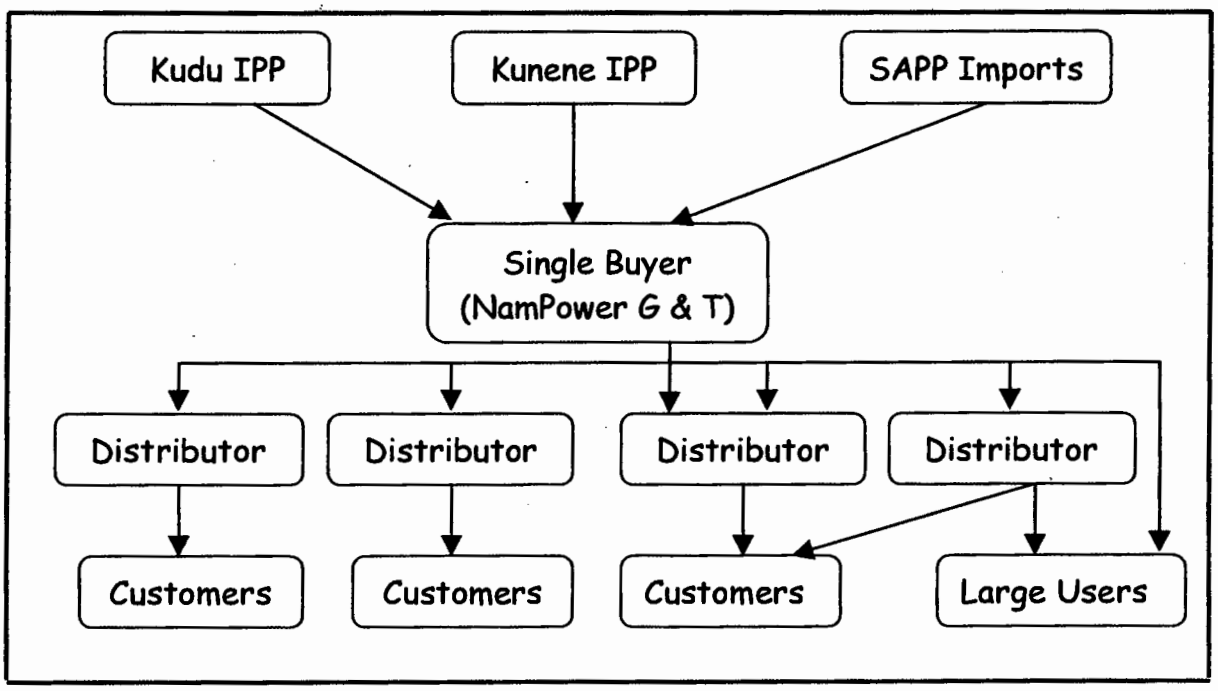
In order to ensure that an in-depth investigation would be carried out, the study was undertaken in three phases. The phase one was completed in March 1998. It investigated in detail the current performance of the ESI and relevant international experience. Phase two evaluated possible restructuring options with particular focus on rationalisation of the electricity distribution. This phase was completed in July 1998. According to SAD-ELEC et al (1999:2), these two phases (one and two) accomplished the documentation of the performance of the Namibia's power sector and reviewed the key issues at stake, from a Namibian perspective. The other functions completed during the two phases were identification of the options for change, with reference to international experience and local conditions and a detailed analysis of a limited set of options for the distribution part of the ESI. After the completion of these first two phases, phase three of the study was undertaken and a draft report submitted in November 1999. The main objectives of this phase were:- first, to make recommendations for the most appropriate market structure for Namibia's power sector and its implications for the generation and transmission component of the industry; second, to finalise recommendations for the restructuring of the distribution industry by focusing on the different parts of the country and the necessary process to facilitate change; third, to develop proposals and recommendations with regard to resolution of key policy issues identified in phases one and two; and lastly to establish proposals for implementation of the recommendations.

On completion of phase three, it was recommended that Namibia embark on a single buyer model with the following key elements:

- Electricity should be traded through the single buyer by all generators and distributors selling and buying power from the single buyer;
- IPPs can export power using NamPower's transmission system;
- Large users with a notified maximum demand greater than 5MW at a single point have the right to choose the single buyer or local distributor;
- The single buyer may waive the right to supply in favour of IPP/imports; and
- Small-scale generators, which are embedded in the local distribution network, need not sell to the single buyer (SAD-ELEC et al., 1999:8).

The study further recommended that on implementation, NamPower's transmission business should perform the commercialisation functions associated with the task of the single buyer, act as a system operator and own and operate transmission infrastructure. To ensure greater transparency and to enable regulation to focus on the aspects of business that should be regulated, NamPower should restructure by separating generation and transmission functions and each should have its own accounting function. However, it was clearly pointed out that the proposed single buyer model for Namibia could be taken as a transitional stage towards a greater degree of wholesale competition. Figure 6.2 below shows Namibia's proposed Single-Buyer Model.

Figure 6.2 Namibia Single-Buyer Model



Source: SAD-ELEC et al., 1999:6

As regards the distribution industry structure, it was recommended that regional electricity distributors (REDs) be established in the North and Erongo regions. For the Central/South region it was recommended that a combination of municipal distributors plus the NamPower distribution Company, Premier Electric, operate rural supplies and some urban areas but with an open-ended future option of combining the assets and the operations to form a RED. A summary of the key features of the proposed distribution structures is given in the following table:

Table 6.7 Key Features of the Proposed Distribution Structure

	North	Erongo	Centre/South
Structure	A move towards an asset-based RED	A phased approach towards a joint venture RED	A combination of municipal distributors plus Premier Electric operating rural supplies and some urban areas.
Ownership	Predominantly stakeholder ownership	Stakeholders ownership	Municipal and NamPower ownership
Private Participation	Part ownership of distribution	Possible involvement in the final stage of establishing the JV RED	Possible part ownership of Premier Electric
Electrification assets	Owned by a company which will be formed (AssetCo) or asset-holding subsidiary of NamPower	In the final stage assets are owned by the JV RED	Owned by Premier Electric or asset-holding subsidiary of NamPower
Governance	Electricity Stakeholders Council plus Board of Directors for RED		Existing municipal controls plus Corporate Governance for Premier Electric
Regulation	All distributors will be subject to Electricity Board licences and price controls		

Source: SAD-ELEC et al., 1999:12

To reflect its commitments, the government started to implement the reforms as recommended in the study by starting with the introduction of a new Electricity Act in July 2000. This Act aimed at levelling the playfield for competition in the sector, broadening the supply base and increasing investments. It also provides for the establishment of an Electricity Control Board to regulate the sector and ensure fair competition and high efficiency levels. It was envisaged that after the establishing of the Electricity Control Board the first round of licensing would take place during 2001.

In line with the government's objectives of creating competition in the sector and with the aim of implementing the study's recommendations, NamPower transformed itself from a monopolistic vertically integrated utility to a commercial energy-related enterprise. In this respect, as stated earlier, in 1999 NamPower formed a subsidiary company, Premier Electric, to serve as its distribution vehicle which will later compete with other distribution companies still to be formed or licensed. NamPower's transformation entailed revising its internal structure. It implemented this through a project called "NamPower Mongula" meaning NamPower Tomorrow (NamPower, 2001:10). Unlike distribution, for which a subsidiary company was formed, NamPower ring-fenced its other business units which are generation, transmission and single buyer – in order to maximise accountability and performance. All of this was done so that they can hold their own and against private competition. NamPower also separated those activities which fall under the auspices of the Electricity Act and the

ECB (regulated activities) from non-core activities (non-regulated) so that it can enter into new commercial opportunities.

6.3.9 Regulatory Framework

The new Electricity Act of July 2000 was enacted to replace the old South African Electricity Act which previously governed the sector. The new Act provides for the establishment of an electricity regulatory board and as a result, the Electricity Control Board (ECB) was established in the same year (2000). The ECB is responsible for regulating the electricity industry, setting electricity prices, issuing licences to all players, including IPP's, as well as offering customer protection. Prior to the establishment of the ECB, the ministry responsible for energy, the Ministry for Mines and Energy, performed both regulatory and electricity sector policy formulation functions, as is the case in most African countries.

CHAPTER SEVEN
Swaziland

7.0 Location and Demography

The independent Kingdom of Swaziland, a landlocked country, lies between South Africa and Mozambique. It shares a border with South Africa of 430 km out of a total of 535 km (80 %), and shares the remaining 105 km with Mozambique. Except for Gambia, it is the smallest country on the African continent with an area of 17,363 sq. km. It has a population of about one million people with a growth rate estimated at about 2.5% per annum (World Bank, 2002).

7.1 Economy

Swaziland's economy is heavily dependent on South Africa for its sustenance. South Africa, which is the region's dominant economy, is Swaziland's paramount trading partner as Swaziland sells about three quarters (75 %) of its exports to, and buys more than 80 % of its imports from, South Africa. The top three export items are mixed manufacturing, sugar and wood pulp. The soft drink concentrate from the large Coca-Cola plant is its largest single manufactured export product. Its major imports include electricity, petroleum products and coal. With a per capita income of US$ 1,500 per annum, Swaziland is ranked among the lower middle-income developing countries (World Bank, 2002).

Since the 1980s, however, the performance of its economy has slowed down. During the year 2000 the economic growth continued this downward trend to an estimated 2.6 % from 3.7 % in 1999 (World Bank, 2002). This was mainly attributed to reduced agricultural production due to floods, leading to a slowing down of agro-processing. The economy is dominated by export-based agricultural and agro-based manufacturing products and is thus highly vulnerable to climatic and other external factors. While the economy is currently characterised by a gradual decline, the population has been growing at a faster rate, 3.4 % in 2000 as against 2.9 % in 1999, and this has led to a decline in the standard of living of the average population.

To reverse this downward trend in economic growth, the Swaziland Central Bank, in its 2000 annual report, issued a number of recommendations to the government. Among the recommendations are that the Swaziland government should make an effort to support existing investors by improving the business environment and that it should continue with its efforts to attract foreign direct investments (FDI). The Central Bank also urged the government to enhance the FDI attraction by upgrading investment incentives so that they compare well with those offered by neighbouring countries.

7.2 Energy Sector

Swaziland's energy sector is managed by the Ministry of Natural Resources and Energy (MNRE). A parliamentary portfolio ensures its proper functioning. Under the Ministry there is an Energy Section, which is responsible for ensuring the sustainable supply and use of energy resources to the optimum benefit of the country. It is also responsible for collecting energy-related data, such as data on energy demand and supply patterns, energy reserves and technologies and on environment-related matters.

The country is a net importer of energy, and depends on energy imports from South Africa. It imports all of its petroleum products and about 70 % of its electricity requirements from South Africa. More than 60 % of the final energy consumption is based on biomass, which encompasses bagasse, woodfuel (firewood and wood waste from sawmills and plantations) and a small amount of agricultural waste and animal waste. In this case biomass is regarded as the backbone of the energy supply system in Swaziland. Bagasse, a waste product of the sugar industries, is used to generate electricity and is the largest contributor, estimated at 33 %, to the energy supply. It is followed by wood fuel and wood waste, which [together] contribute about 26 %. The wood is consumed in households, while the wood waste from the timber industry is used by industries for generating electricity and heating. Coal, which is imported from South Africa, contributes about 13 % to the primary energy supply. Swaziland further has a substantial amount of anthracite and semi-anthracite, which cannot, however, be used in most of the burning appliances and equipment used in Swaziland. These appliances and equipment are imported from South Africa and are designed to use bituminous coal (MNRE et al., 2002).

7.3 The Power Sector

7.3.1 Background

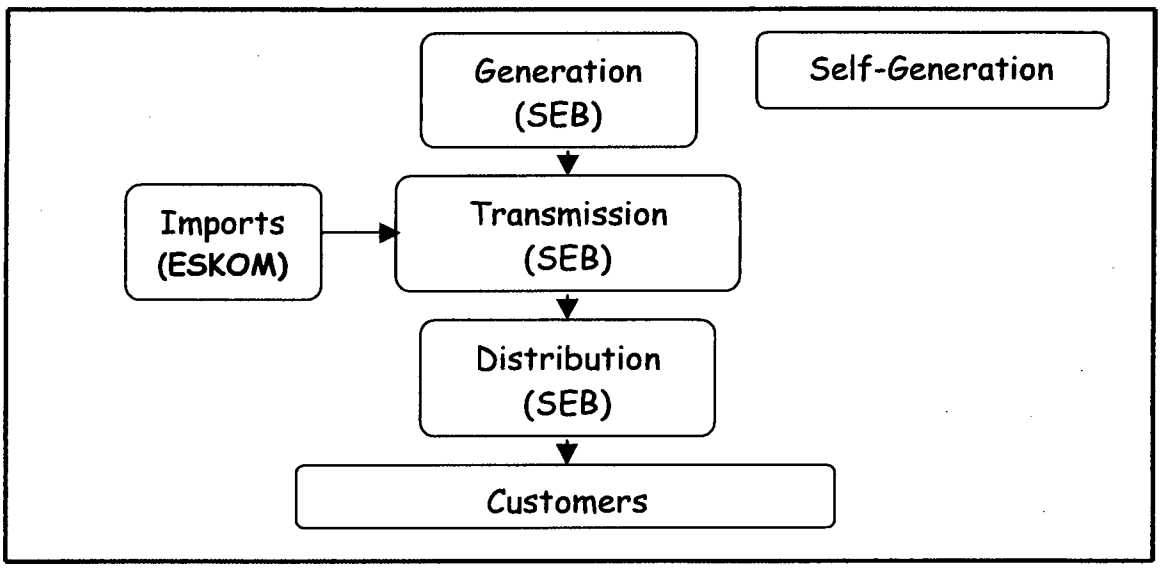
Given the small size of Swaziland both in terms of area and population, its power sector is also relatively small. As mentioned above, the country imports more than 70 % of its electricity requirements from South Africa. However, it does have other potential sources of electricity, such as hydro, bagasse and large reserves of low-volatile and low-sulphur anthracite coal of medium to high quality. This coal is relatively smokeless and thus would be environmentally less harmful, and it is a good source of electricity. Currently, this anthracite coal is mined for export purposes only. The MNRE et al (2000) report quotes the Geological Survey and Mines Department (GSMD) report which states that as of 1998 the probable and potential coal reserves in Swaziland were estimated at 1,017 million tonnes.

Swaziland is the second largest sugarcane producer in Africa and therefore the sugar industry produces substantial amounts of bagasse annually. In 1995, this amounted to some 818,532 tonnes, some of which were used for industrial process heat and electricity generation (MNRE et al., 2000: 9). Further, according to the MNRE et al (2000), there is a substantial amount of excess bagasse, which could be used for electricity generation. Besides the existence of large reserves of coal and excess bagasse, Swaziland also has good potential for hydropower. A number of studies which were conducted concerning hydrological resources, produced preliminary information indicating that Swaziland has a gross theoretical potential of 440 MW, although there is a need to perform a re-analysis of the national potential with new and more up-to-date criteria for site selection (MNRE et al., 2000: 10).

7.3.2 Institutional Arrangements

The Electricity Act of 1963 established the Swaziland Electricity Board, henceforth known as the SEB, to make provision for the exercise and performance of the functions related to the generation, transmission, distribution and supply of electricity, the inspection and testing of electrical plants and the safe use of electricity in Swaziland. Although the Act makes the SEB a monopoly in the power sector, Section 17(2) of the same Act gives the SEB the power to grant licences authorising any person to generate electricity for his own use or to generate or supply electricity for another person's use. In this case therefore, the power sector is divided into two segments, i.e. the commercial supply through the national grid and self-generation. The SEB, which is publicly owned, is responsible for the commercial supply of electricity. It delivers about 70 % of the country's electricity for final consumption. The remaining 30 % is generated by a number of industries for their own use. Figure 7.1 below depicts institutional arrangements of the power sector.

Figure 7.1 Institutional Arrangements of Swaziland's Power Sector



7.3.3 Supply

The electricity supplied in Swaziland thus comes partly from internal generation but mainly from imports from Eskom South Africa. Imports constitute about 80 % of the electricity required for commercial supply, whereas internal generation supplies only 20 %.

Generation

Most of the electricity generated by the SEB for commercial supply is generated at four hydro power stations. About 81 % of the total SEB installed generating capacity is made up of hydro, while the remaining 18 % is diesel. The amount of electricity generated by hydro plants has varied considerably over the past ten years due to poor and unreliable rains. For instance, in 1992 with the same installed capacity the SEB generated only 81.5GWh due to dry weather conditions. In 1999 the SEB generated fewer units too, a mere 189.6 GWh, also due to dry weather conditions, but one year later in 2000, Swaziland received more than adequate rains, which resulted in increased river flows to the SEB's generating system, and as a result the SEB generated 192.3 GWh. Table 7.1 shows the SEB's installed generating capacity in 2000.

Table 7.1 SEB's Existing Installed Generating Capacity

Generation Type	Name of Station	No. of Units	Installed Capacity (MW)
Hydro	Ezulwin	2	21
	Edwaleni Hydro	4 1	10 5
	Maguduza	1	5.5
	Mbabane	2	0.5
Total Hydro Capacity			**42.0**
Diesel	Edwaleni Diesel	2 1	9.5 0.5
Total Diesel			10.0
Total Installed Capacity			**52.0**

Source: Compiled from SEB's Annual Reports

Imports

As mentioned earlier, 80 % of the electricity requirements for the commercial supply comes from South Africa's Eskom. These imports are based on bulk power supply agreements. In 1985 the bulk power purchase agreement was based on a monthly rental for the lines in respect of capital expenditure incurred, a basic rental charge, a capacity charge and an energy charge per kWh. However, this agreement was recently replaced by a new agreement, with retrospective effect from 1st January 2000. Instead of the different charges, now a Megaflex, "time-of-use" tariff is used. It is a three – part time-of-use tariff, which discriminates based on time of day, day of week and month

of year. In this case the tariff has a lower rate during the low demand season, October – March, and a higher rate during April to September. It also has low rates for weekends and holidays. According to the MNRE et al 2000 report, for the SEB to obtain maximum benefits with this tariff, it needs to manage its energy consumption and maximum demand according to Eskom's specified time schedule. 14 % of the time allocated is charged at a peak rate, whilst 36 % and 50 % are charged at standard and off-peak rates respectively.

Understanding the importance of diversifying its electricity sources, the SEB had plans to start trading with other utilities under the SAPP especially after completion of the 400 kV-transmission line. Now the SEB purchases power from the SAPP at an hourly pool price or at contracted prices with any other pool generating members. However, the SEB always ensures that it maximises its internal generation especially from the hydro system in order to minimise its imports from Eskom. This enables it to reduce its bills with Eskom as hydro generation is cheaper than what it would pay to Eskom. For example, the average cost per unit of internal generation in 2000 was Lilangeni cents 7.5/kWh while the cost of the electricity imported from Eskom was Lilangeni cents 12.2/kWh. According to the SEB 1998 Annual Report, it uses the Import Maximum Demand System facility at the National Control Centre to control the imports over internal generation. Since it implemented this facility in 1996, it has been able to make substantial savings on Eskom's electricity bills. Table 7.2 shows electricity generated internally and electricity imported from Eskom and other sources.

Table 7.2 Units generated by SEB and units imported

Year	Hydro (GWh)	Diesel (GWh)	Total Internal generation (GWh)	Imports From ESKOM (GWh)	Total System Energy (GWh)	System Maximum Demand (MW)
1991	163.3	1.7	165.0	387.0	717.0	100.0
1992	166.3	0.2	166.5	427.7	760.7	103.0
1993	81.5	2.7	84.2	555.8	724.2	112.0
1994	125.0	1.1	126.1	546.9	799.1	115.0
1995	109.0	8.4	117.4	597.0	831.8	117.5
1996	118.5	2.0	120.5	583.1	824.1	125.1
1997	191.0	0.8	191.8	598.0	981.6	139.0
1998	192.9	1.5	194.4	605.6	994.4	144.8
1999	189.6	1.4	191.0	639.7	830.7	146.4
2000	192.3	2.4	194.7	652.4	874.1	153.8

Source: Compiled from SEB's Annual Reports

Transmission and Distribution System

The transmission and distribution system of Swaziland consists of 400 kV, 137 kV, 66 kV, 33 kV and 11 kV lines. The bulk supply (imports) from Eskom comes through three 132 kV lines and the newly constructed 400 kV line, which originates from Camden in South Africa and runs across Swaziland and Komatipoort to MOZAL (an aluminium smelter) in Maputo, Mozambique. This 400 kV line is owned and operated by the Mozambique Transmission Company (Motraco), a joint venture between the EDM of Mozambique, ESKOM and the SEB on a 33.3% equity partnership. The completion of this line significantly increased the reliability and quality of the power supply and has provided the SEB with adequate capacity (250 MW) for the next 20 to 30 years. The power from the 400 kV-transmission line is injected into the SEB national grid at Edwaleni II 400/132 kV substation. Table 7.3 shows the growth of the major transmission and distribution total line-lengths in Swaziland from 1995 to 2000.

Table 7.3 Transmission and Distribution Total Line-Lengths in Swaziland (km)

Year	132kV	66kV	33kV	11kV
1995	206	912	90.5	2,669.3
1996	206	912	90.5	2,840.6
1997	206	912	90.5	2,980.8
1998	206	912	104.7	3,082.2
1999	206	912	112.8	3,232.6
2000	206	912	112.8	3,410.2

Source: Compiled from SEB's Annual Reports

System Losses

The percentage of system losses in Swaziland has been declining over the years. This is a result of the SEB's continued intensified programme of identifying the areas where losses occur and reducing both technical and commercial losses. For the past five years system losses were 16.3 %, 15.6 %, 13.0 %, 15.7 % and 14 % for 1996, 1997, 1998, 1999 and 2000 respectively. In 1998 the SEB's target was to reduce the loss level to 13 % by 2001, 12 % by 2002 and 11 % by 2003 and thereafter. However, in 1999 losses increased dramatically as a result of the fact that, although a reduction target had been set, no clear programme had been put in place to manage these losses. Moreover, with the fast growth of the rural electricity network, technical losses tend to increase, largely because of the long line distances.

7.3.4 Demand

As Table 7.4 illustrates, industry utilises more than 50 % of the total electricity consumed in Swaziland. For instance in 2000 it consumed 395.3 GWh, being about 54 % of the total consumption. The industrial category is followed by domestic consumers. Although the irrigation

category is also significant, its yearly consumption varied considerably over the years, depending on the amount of rainfall the country received. During dry years the consumption increased dramatically, while during wet years it decreased. As regards the system's peak demand, it has grown steadily for the past ten years: in 2000 it was 153.8 MW. In 1998, for the very first time, the system's peak demand surpassed the system's peak capacity thus creating an overshot of about 5 MW. However, due to the installation of the power factor correction equipment, load shedding was avoided.

Table 7.4 Electricity Consumption by Tariff Category (GWh)

Year	Domestic	Commercial	Industrial	Irrigation	Other	Total Sales	Total Number of Customers
1995	132.7	54.3	307.6	108.6	-	603.2	25,696
1996	129.2	52.9	317.1	88.1	-	585.0	26,708
1997						671.7	
1998						694.7	
1999	143.7	64.7	366.5	136.5	7.2	718.6	33,718
2000	161.0	73.2	395.3	95.2	7.3	732.0	36,367

Source: Compiled from SEB's annual reports

7.3.5 Tariff

The electricity tariff of any country is the single most important factor that could make its power sector either viable or not. This being the case, Swaziland has been increasing its electricity tariff every year in January with the aim of ensuring the financial viability of the SEB. Tariff revision is done in January because it is also the time when Eskom revises its tariffs for SEB. To this effect the last tariff adjustments were effected in January 2002 with an average increase of 6 %. However, according to the SEB's annual reports, these increases have always been lower than the rate of inflation and as a result meant a reduction in power costs in real terms.

SEB tariffs are divided into six main categories, namely: the domestic tariff, general-purpose tariff, small commercial and industrial tariff, large commercial and industrial tariff, off-peak water heating tariff and irrigation tariff. For all these categories, the three tariff components are the following: - firstly, a fixed (facility) charge per month, which is the same for all. Secondly, energy charges which differ according to the tariff category, being highest for general purposes and lowest for irrigation. The third and last component is demand charge, which only applies to large commercial, industrial and irrigation tariff categories.

The block tariff or time-of-use tariff, especially for domestic consumers, is not used in Swaziland. Its use might encourage consumers to limit their consumption particularly during peak hours.

According to the MNRE et al (2000) report, electricity in Swaziland is not priced at economic rates which means that consumers do not receive the right signals to consume electricity rationally. There is thus a need to review and adjust electricity tariffs in order to ensure that producers receive high returns. In response to this the SEB in 2000 aimed to change the tariff structures to include provisions for both time-of-use and interruptible tariffs. This would allow consumers a wide range of choices on how to use electricity to the best and most economic advantage and at the same time would enable it to fully recover its costs. Besides this, consumers would also be encouraged to reduce their consumption during peak periods, thus reducing national peaks and conforming to the bulk electricity tariff requirements. However, the time-of-use tariff has not yet been implemented. This is because the differences that would result from load shifting were regarded as being too small to justify any load shifting by customers. This option is, however, still being pursued.

As has been mentioned earlier, the SEB buys most (70 %) of its electricity in bulk from Eskom of South Africa. The balance (30 %) is hydro generated, which is one of the cheapest sources of electricity. In this regard, one would expect Swaziland to have reasonably low prices of electricity. This is not the case, however, as Eskom charges Swaziland more for the same units of electricity than it charges its own distributors in South Africa. In addition the SEB has a smaller customer base and thus is lacking the same economies of scale that Eskom enjoys (MNRE, 2000). According to SAD-ELEC (2001), the SEB tariff in US dollar terms for domestic customers who use up to 200 kWh in a month was the highest in the region in 2001.

7.3.6 Access to Electricity and Rural Electrification

In Swaziland an estimated 30 % of the population has access to electricity. Moreover, this supply is concentrated in the urban areas, leaving the majority of the population living in the rural areas unserved. According to Utonih *et al.*, (2001: 25) out of about 26,725 of the SEB's domestic customers in 1998, only 3,000 were rural households. The estimated total number of rural households was about 108,000 meaning that less than 3% had access to electricity. In an effort to increase electrification rates, the SEB established a new Marketing Department. In addition a rural electrification programme is also being implemented at present, jointly funded by the government of Swaziland and the SEB. As a result of these efforts, an annual average growth of +8 % is being realised especially in the domestic sector. However, due to slow economic growth globally, major business concerns closed down in Swaziland, and the SEB lost significant load. The asbestos mine, which was the SEB's major revenue earner, closed down in 2001 along with other major business concerns, which negatively impacted on the utility's ability to finance rural electrification programmes.

Rural electrification programmes are mainly financed by the government, the SEB and grants. In 1999 – 2000 the government and the SEB financed rural electrification programmes at a funding ratio of 60:40 respectively. A two-phase grant finance was received from the Republic of China with R21.7 million received during the first phase in 2001. The second phase of the project has a grant finance of R50 million. Apart from these efforts, a proposal to obtain World Bank finance for rural electrification is being proposed. The Swaziland government has already signed an agreement with the World Bank, but this project will only be implemented once the World Bank mission has approved the funding on the basis of its ongoing feasibility studies.

Currently the country has no rural electrification fund. On a year-to-year basis, the government and the SEB meet to agree on a specific budget for rural electrification projects, which does, however, depend on the availability of funds.

7.3.7 Financial Performance of the SEB

The overall financial performance of the SEB has been generally good during the 1994 – 2000 period. For the whole period the SEB realised profits (surplus). As shown by Table 7.5 below, in 1995 and 1997 profits increased to more than double that of the preceding years. However, it should be noted that the SEB was exempted from paying taxes. Although it is performing relatively well, its future survival is at a high risk, since 2 % of its customers account for 60 % of its sales revenue. For instance and as mentioned earlier, the closing down of the asbestos mine along with other major business concerns in 2001, which were the SEB's major revenue earners, will greatly affect the utility's financial performance.

Table 7.5 SEB's Financial Indicators

Year	Number Of Customers	Number of Employees	Total Sales (GWh)	Sales Per Employees (MWh/Empl.)	Customer per Employee	Total Revenue (E'000)	Total Asset Value (E'000)
1991			493.6			71,923	148,597
1992			523.8			83,071	159,440
1993			552.2			103,079	168,371
1994			545.8			123,500	181,807
1995	25,696	620	603.2	972.9	41	147,118	210,525
1996	26,708	622	585.0	940.5	43	160,876	250,507
1997		678	671.7	990.7		191,878	278,376
1998		719	694.7	966.2		207,877	300,447
1999	33,718	728	718.6	987.1	46	266,724	398,525
2000	36,367	713	732.0	1,026.6	51	240,699	513,382

Table 7.5 continued

Year	Net Profit/Loss Before Tax (E'000)	Average Selling Price of Electricity (Lcents/kWh)	Returns on Assets	Debt/ Equity Ratio	Interest Cover Ratio	Historical Exchange Rates E/US$
1991		14.6				
1992		15.7				
1993		18.0				
1994	7,279	22.3				
1995	16,770	24.4	0.12	0.96	2.76	3.63
1996	15,985	27.3	0.17	0.61	4.35	4.27
1997	35,379	28.6	0.16	0.41	5.30	4.60
1998	30,225	30.0	0.12	0.35	5.76	5.48
1999	37,267	31.6	0.11	0.21	7.13	6.11
2000	32,129	32.9	0.08	0.21	7.10	6.91

Source: Compiled from SEB's Annual Reports
Exchange rate figures obtained from CIA World Factbook 2001

7.3.8 Sector Reforms

Most of the countries in Africa as well as in the rest of the world are now carrying out power sector restructuring and reforms. Not only are they expected to bring about an increase in the capacity and provision of reliable and low cost power, but they will also help their governments to avoid incurring further debts in financing the power sector. In understanding the importance of these reforms, the Swaziland government has also expressed its intention to reform its power sector. In 1998 the government commissioned a consultant, SAD-ELEC, to carry out a study on the future options of the development of its power sector. The consultant recommended, and subsequently the Swaziland government approved, the corporatisation of the SEB with a public/private ownership option. The other two options, which were considered but not adopted, were the commercialisation of the SEB whilst it still remained publicly owned, the unbundling of the SEB and electricity market liberalisation.

The corporatisation of the SEB was adopted due to the fact that the SEB will be converted into a commercial entity which will operate under normal company laws, regulations and taxation. It will be required to be efficient, as it will be subjected to competition. In order to cope with the changes in the business environment, the SEB has decided to undertake internal restructuring whereby its core activities, i.e. generation, transmission and distribution, will be ring-fenced such that costs and revenues are allocated separately and individual accounts are issued for each business (SEB, 1998). This will make the SEB capable of competing with new participants in the industry. Although the government has already approved the corporatisation of the SEB, this will be effected after the necessary amendments to the old Electricity Act of 1963 have been effected. The amendments will also allow the setting up of a regulator to oversee the power sector. In fact, the government has

already completed three draft legislations, which are due to be tabled in parliament this year. These legislations are: -

a) The Regulatory Act, which will bring about the introduction of an energy regulator – its role, functions and responsibilities;
b) The Electricity Act, which will initially be based on a single buyer model – the buyer being the SEB; and
c) The Corporatisation Act, which will make it possible for private sector participation, i.e. to allow for the conversion of parastatals to companies.

7.3.9 Regulatory Framework

Currently, in Swaziland, the Ministry of Natural Resources and Energy performs the tasks of policy formulation and regulation of the power sector. As part of the overall reform process of the power sector these tasks will be separated, and an autonomous regulatory authority/board will be established to oversee the sector. The Ministry will be left with only the task of policy formulation for the sector. The regulatory authority/board that will be formed will play a central role in ensuring that the benefits that are expected from the reforms are realised, as well as ensuring the sustainability of the reforms.

CHAPTER EIGHT
Tanzania

8.0 Location and Demography

Tanzania is located in East Africa on the Indian Ocean coast, between Longitudes $29^0 - 40^0$ East and Latitudes $1^0 - 11^0$ South. It is bordered by eight countries, namely Kenya, Uganda, Rwanda, Burundi and the Democratic Republic of Congo, as well as Zambia, Malawi and Mozambique. The country covers a relatively large area of 942,500 sq.km and has an estimated population of 33.7 million people (World Bank, 2002). This population is concentrated on the periphery of the country, leaving the central part, which is rather dry, relatively sparsely populated. It is estimated that 72 % of the population lives in the rural areas and the remaining 28 % lives in the urban areas (World Bank, 2002). However, for the last few years there has been a high rate of rural – urban migration due to deteriorating conditions in the rural areas, which is expected to increase the percentage of those living in urban areas.

8.1 Economy

As is the case in most Sub-Sahara African countries, Tanzania's economy relies heavily on agriculture, with the main cash crops being coffee, tea, cotton, wheat, cashew nuts, rice, sisal, maize and tobacco. It is estimated that agriculture employs about 90 % of the entire labour force and contributes approximately 50 % of the GDP. In 2000 its contribution to the GDP was 45.1 %. The agricultural sector is characterised by small-scale farming, which depends on weather conditions. Consequently the sector is adversely affected by frequent droughts. For instance in 1998 traditional exports, namely coffee, tea, cashew nuts, cotton, tobacco and cloves, decreased by about 27 % from US$ 107.6 million recorded in 1997 to US$ 78.9 million in 1998. Unfavourable weather conditions during that particular period accounts for the large financial decrease (BoT, 2001:10).

In terms of GDP contributions, the agricultural sector is followed by the commerce and hotels sector, which contributed about 16.4 % to the GDP in 2000. Its real growth rate has been steadily increasing from a low of 0.7 % in 1992 to a record high of 6.5 % in 2000. This has been attributed to the increase in tourism following a decision by the government to liberalize this sub-sector and to privatise most of the tourist hotels. Liberalisation and privatisation in this sector were part of the overall economic reforms, which have also positively impacted on the industrial sector. This sector (industrial) recorded its highest real growth of 8 % in 1998 compared to 4 % in 1992. However, in 1999 the growth rate decreased to 3.6 % before increasing slightly to 4.8 % in 2000. These

fluctuations in the industrial sector's real growth did not affect its share of the GDP, which remained constant at about 8.4 % for the period 1998 - 2000 (BoT, 2001:29).

Although the mining sector's contribution to the GDP is not significant, viz. an average of 2.1 % for the period 1998 - 2000, it is the fastest growing sector of the economy. During 1998 the sector recorded its highest growth rate of 27.4 % compared with a growth of 7.7 % recorded in 1992. As happened in the industrial sector, the growth trend of the mining sector decreased to 9.1 % in 1999 before it increased once more to 13.9 % in 2000. While the general improvement in the performance of the mining sector can be mainly attributed to the economic reforms, the poor performance during 1999 of the mining and industrial sectors can be attributed to electricity shortages as a result of droughts (BoT, 2001:29).

During 1993 the economy recorded its lowest growth over the past ten years – only 0.4 %. However, the improvements in the performance of the important sectors during 2000 saw the overall economy grow at 5.1 %. Implementation of structural reforms, deregulating investments, privatisation, promoting local infrastructures, restructuring of the financial sector as well as implementing a solid fiscal policy, contributed to this high economic growth rate. There was also a significant drop in inflation. It has been declining over time, dropping from the maximum of 33% in 1994 to an all time low of 5.1% in 2001 (BoT, 2002). With a per capita Gross Domestic Income (GNI) of US $ 270 in 2000, Tanzania is one of the poorest countries in the world (World Bank, 2002). Furthermore, it is also one of the "highly indebted poor countries" (HIPC). However, as a result of the successful implementation of sound economic policies, which were initiated in 1996, the country has restored donors' confidence, which in turn, through the Paris Club, has seen a large portion of the debt being written off.

8.2 Energy Sector

The main primary source of energy for most households in Tanzania is biomass in the form of wood and charcoal, which accounts for about 92 % of total energy consumption. Woodfuel is mainly used in rural areas, while in urban areas over 70 % of the households use charcoal for cooking. However, the number of households using charcoal is currently considered to be on the increase, as electricity is perceived as too expensive. The increase in charcoal use and the fact that most of the charcoal is produced in a primitive way with very low efficiency rates, is unfortunately resulting in extensive deforestation, as forests are harvested at a rate faster than their natural rate of regeneration.

As regards commercial energy consumption, petroleum products dominate even though they account for only about 7 % of the total energy consumption. Tanzania is a net importer of petroleum

products, with most coming from oil-producing Arabic countries. They are mainly used in the transport sector, with households using a relatively small quantity of paraffin for cooking and lighting. To date, no oil reserves have been located in the country despite on-going and extensive oil exploration activities. However, modest gas resources have been discovered. Owing to the extremely high costs and risks of oil exploration, this is mainly done by foreign investors. With the aim of attracting more foreign investors to participate in oil exploration and in the development of hydrocarbons, the government has put in place attractive incentive packages such as the facility to negotiate special terms. Currently, foreign investors are also attracted to invest in electricity generation since electricity consumption amounts to only about 1 % of the total energy consumption. Policy formulation to attract foreign investors to the energy sector and all other energy issues are the responsibility of the Ministry of Energy and Minerals (MEM).

8.3 The Power Sector

8.3.1 Background

The power supply in Tanzania comes from hydro (64 %) and thermal (36 %) generation. However Tanzania is considered one of the few countries in Africa with ample hydropower potential, estimated at 4.7 GW of installed capacity or about 3.2 GW of firm capacity. At present, only about 12% (0.56GW) of the total potential has actually been developed. The underdevelopment of the hydropower potential and the fact that a large portion of generation is thermal, burning expensive imported oil, is the result of the high costs associated with hydropower development, which the country cannot afford. Power sector liberalisation will likely further jeopardise the development of hydro projects, as most private investors tend to opt for small units of thermal generation which are easy to construct and have short construction times, and as investments costs are small compared to the far more costly hydro projects. In addition, investors prefer to invest in thermal generation because rainfall particularly in the region is variable and unpredictable (rainfall risk).

Tanzania also has proven natural gas fields, located offshore at Songo Songo Island and at Mnazi Bay near Mtwara. Natural gas reserves at Songo Songo Island are estimated at 736 billion cubic feet (bcf), while those of Mnazi Bay are still uncertain (Acres, 2001: 6-1). A Songo Songo gas-to-electricity project, which will cost about US$295.2 million, financed mainly by the World Bank, is about to be launched. The project entails the construction of a gas pipeline over a distance of 232km, to supply natural gas to the existing 112 MW gas turbines at Ubungo and to a cement factory, both in Dar es Salaam. It is expected that the project will be completed towards the end of 2003. As regards Mnazi Bay, negotiations with a foreign private investor are at an advanced stage; the aim of this project is to generate enough power to supply the southern regions, which are not connected to the national grid.

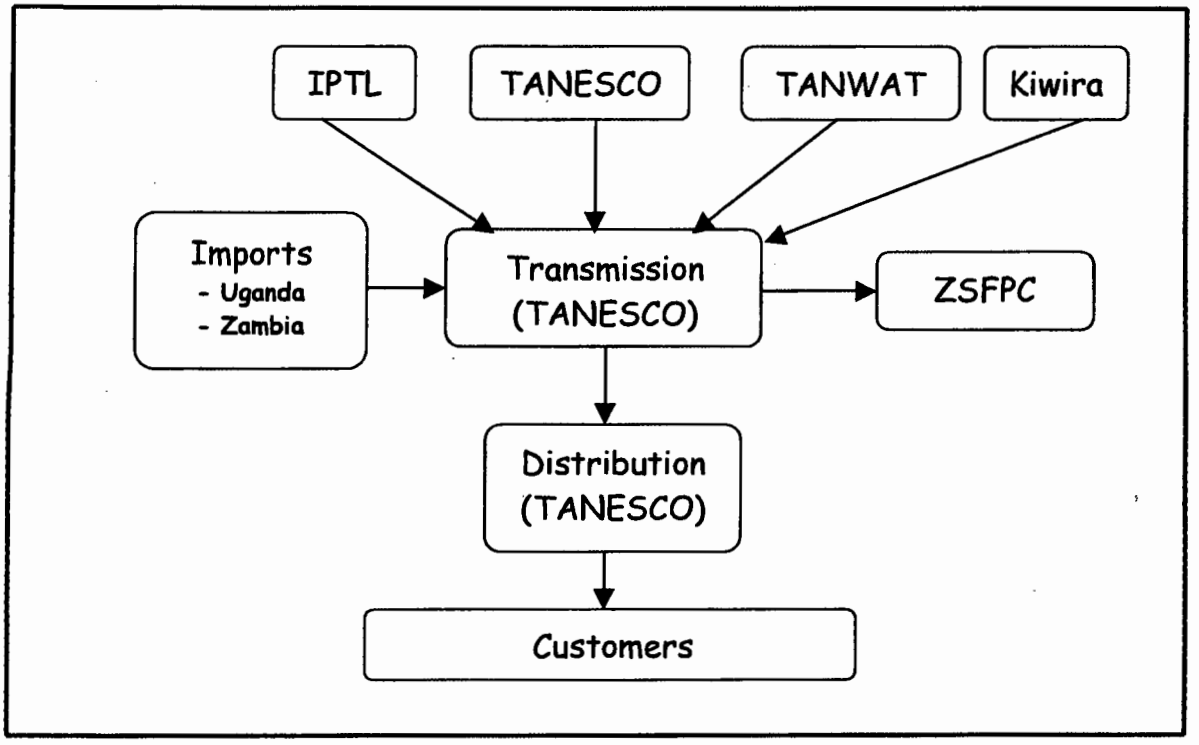
Another indigenous energy resource available in Tanzania is coal. Its reserves are estimated at about 12,000 million tonnes, of which 304 million tonnes may be considered proven. Coal occurrence was first reported towards the end of the nineteenth century but since then very little development has taken place, mainly because the energy markets are not fully developed. Currently coal from the Songwe-Kiwira coalfield is used by the 6MW installed capacity plant to produce electricity for their own use and the surplus is being sold to the national electricity utility. The National Development Corporation (NDC) is also co-ordinating an even bigger coal power project. A coal plant with a staged capacity of 100 MW – 400 MW will be constructed at Mchuchuma coalfield under the Mtwara corridor project.

8.3.2 Institutional Arrangements

The major player in the country's power sector is the Tanzanian Electric Supply Company Limited, (TANESCO) which is responsible for the generation, transmission and distribution of electricity throughout the country. It also sells bulk power to the island of Zanzibar, where distribution of electricity is the responsibility of the Zanzibar State Fuel and Power Corporation (ZSFPC). TANESCO is a publicly owned utility; it was set up in 1964 after a merger of two private utilities, and was nationalised in 1968. Figure 8.1 below shows the current institutional arrangement of Tanzania's power sector.

In 1992, the government decided to end the monopoly power that TANESCO had enjoyed since its inception, thus allowing public and private companies as well as individuals to engage in electricity generation. Consequently a number of companies have already started to generate power, and others are about to begin. In this regard, Kiwira, a coal plant, and TANWAT, a wood residues plant, own and operate 6.0 MW and 2.3 MW respectively. They generate electricity for their own consumption and sell the excess to TANESCO. Another independent power producer (IPP), namely Independent Power Tanzania Limited (IPTL), has recently constructed a 100 MW diesel generation facility at Tegeta Dar es Salaam, which has been selling bulk power to the TANESCO grid system since February 2002. Furthermore a number of industries and large gold mines are generating electricity in small quantities for their own use. The large gold mines which have put up diesel generating facilities for their own use are the Geita Gold Mine (40 MW), Bulyanhulu Gold Mine (15 MW) and Afrika Mashariki Gold Mine (12 MW).

Figure 8.1: Institutional Arrangement of Tanzania's Power Sector



8.3.3 Supply

The electricity supply in Tanzania comes mainly from internal suppliers, but also from a few cross-border suppliers.

Generation

Tanzania's electricity system consists of two parts, namely the national grid system (called the interconnected system) and several dispersed isolated systems. The grid system provides power to the major cities and towns from the country's major generation centres, while the isolated systems provide electricity to smaller towns, which are not connected to the national grid. The generation facilities which currently feed power to the grid system, are mainly hydroelectricity (72 %) and thermal (28 %). In the case of the isolated systems, electricity is provided mainly by diesel generators, but also by cross-border suppliers. The isolated systems supply five regional headquarters, several district headquarters and other areas. However, most of the diesel units in the isolated systems are old and very unreliable. In some cases supplies of diesel to these towns have also been a problem for several reasons; for instance, TANESCO's failure to pay the oil companies in time, which led them to cut supplies, and the fact that during the rainy season some of the roads become impassable. In both systems, generation facilities are owned by TANESCO and a few private companies, as noted above. Of the country's total existing installed electricity generating

capacity, which stands at 902MW, TANESCO owns and operates 796MW (88%), while the remainder is owned together and operated by the three IPPs mentioned above. Table 8.1A below provides details of the hydro and thermal capacity in the national grid, while Table 8.1B shows the existing electricity installed generating capacity for the isolated systems.

Table 8.1A: Installed Generating Capacity of the Existing Grid System

Generation Type	Name of Station	Year Commissioned	No. of Units	Total Installed Capacity (MW)	Effective Capacity (MW)
Hydro	Kidatu	1975/80	4	204	204
	Mtera	1989	2	80	80
	Kihansi	2000/01	3	180	180
	Pangani Falls	1995	2	68	66
	Hale	1968	2	21	17
	Nyumba ya Mungu	1964	2	8	8
Total Hydro Capacity				**561**	**555**
Thermal	Ubungo GT (ABB)	1994	2	40	37
	Ubungo GT (EPP)	1995	2	80	75
	Diesel Generation	-	-	82	35
	IPTL –Tegeta[1]	2002	10	100	100
	Kiwira Coal Plant*			4	4
Total Thermal Capacity				**306**	**251**
Total Installed Capacity of the Existing Grid System				**867**	**806**

Source: Compiled by the Author

Key: [1] Owned and Operated by IPTL

*Owned and Operated by Kiwira Coal Mine, the rest owned and operated by TANESCO

Table 8.1B Existing Isolated Systems Installed Generating Capacity

Generation Type	Name of Station	Year Commissioned	No. of Units	Total Installed Capacity (MW)	Effective Capacity (MW)
Thermal Diesel	Mtwara	'80, 86,94,97,2000	8	4.74	3
	Masasi	1984	3	4.5	4.5
	Kigoma	1973,81, 86, 90	7	4.08	2.66
	Songea	1975,87,,88,95,2000	9	5.67	4
	Lindi	1991, 2000	3	2.28	2.2
	Kilwa Masoko	1977, 1995,1999	3	1.119	0.55
	Ikwiriri	1991	2	0.848	0.848
	Mafia	1991	2	0.848	0.848
	Tunduru	1992, 1993	2	0.7	0.66
	Liwale	1975, 1994	4	0.202	0.12
	Sumbawanga	1983, 87, 89, 91	4	2.14	1.4
	Mpanda	1993	3	1.96	1.3
	Njombe	1991	2	1.28	1.28
	Biharamulo	1991	2	0.848	0.848
	Ngara	1991	2	0.952	0.952
Wood Residues	TANWAT*	1992	2	2	2
Mini Hydro	Uwemba	1989	3	0.843	0.843
Total Isolated Systems Installed Capacity				**35.0**	**28.0**

Source: Compiled by the Author

Key:

* Private Generators, the rest owned and operated by TANESCO

With regard to units generated, in 2001 the total TANESCO grid system generated 2,668.5 GWh, an increase of about 11 % when compared with 2,408.4 GWh generated in 2000. The isolated systems generated about 80 GWh in 2001. As stated earlier, the grid system is hydro-dominated which makes it vulnerable to droughts. Thus, for the past ten years, hydropower generation has been severely affected by frequent droughts, particularly in the catchment areas of the major rivers, which significantly reduced water flow to the major hydroelectricity generating plants. For example, in 1997 the cascaded Kidatu and Mtera hydropower plants on the Ruaha River generated at only about 50 % of their capacity, thus losing about 700 GWh of energy, the worst during the period 1990 – 2001. This led to too much pressure being placed on thermal generating facilities, which could not meet the demands, and consequently TANESCO has had to embark on a more severe load shedding programme. Tanzania first experienced load shedding in 1992 and since then it has recurred several times, as shown in Table 8.6A. The resulting loss to the economy has been estimated as millions of US dollars.

In an effort to reduce the effects of load shedding and to meet growing demand, TANESCO constructed Kihansi Hydropower plant, which was commissioned in December 2000. However, the

plant is currently losing about 15 MW of its capacity daily as a result of the efforts to save a "rare toad species", which is believed to live only in the Kihansi basin. One important feature of these toads is that their reproduction process is unique in that, unlike other toad species, they give birth instead of laying eggs. The effort to ensure their survival entails releasing water to keep the environment at the Kihansi gorge as close as possible to what it was before the construction of the plant. The government and TANESCO on one side, and the environmentalist and international community on the other side, have initiated a study aimed at establishing the minimum amount of bypass flows that should be met by TANESCO.

It should be noted, however, that any amount of bypass flows will significantly reduce the firm energy from this plant. A higher bypass flow at say from 4 m^3/sec may reduce the overall viability of the plant, and actually turn it from a positive investment into a liability. Thus it is up to parties concerned to decide whether priority will be given to the toads or to the electrical power, which is highly needed by Tanzanians for economic development and thus poverty eradication. However, it must be added that this controversy would not have happened if all the necessary measures had been taken during the project's feasibility study stage. One objective of carrying out an environmental impact study, which is currently a worldwide requirement for big projects and especially those financed by donor communities, such as this one, is to ensure that projects will cause minimum harm to the environment. In this case, therefore, one must ask whether such a study was really carried out or not, and if it was, whether it was done properly; further, if it was indeed done properly, did TANESCO ignore the study's recommendations and simply go ahead with constructing the plant without considering the survival of the "rare toad species"?

Imports (Cross-border Supplies)

In addition to internal electricity generation, Tanzania also imports electricity from its neighbours Uganda and Zambia to supply its isolated towns found near the borders with these countries. The existing cross-border supplies are the following: the Kagera region gets its power from Uganda via a 132 kV transmission line from Masaka in Uganda. Others are Sumbawanga town, which gets its power from Mbala Sumbawanga via a 66 kV transmission line, and Tunduma towship in the Mbeya region, which gets its power from Kasumulo in Zambia, via a 33 kV transmission line. Table 8.2 shows units generated in Tanzania and imports for the period 1990 – 2001.

Table 8.2 Units Generated and Imported (GWh)

Year	GRID SYSTEM			Total Isolated Systems	IMPORTS		Total System's Energy
	Hydro	Thermal	Total		Uganda	Zambia	
1990							
1991	1,725.6	24.8	1,750.4	74.6	-	1.9	1,826.9
1992	1,650.0	86.9	1,736.9	81.2	-	1.9	1,819.9
1993	1,697.4	110.5	1,807.9	67.4	0.9	2.7	1,878.9
1994	1,499.4	224.7	1,724.1	66.5	15.1	4.3	1,810.0
1995	1,538.7	243.9	1,782.6	58.0	18.3	2.7	1,861.6
1996	1,747.9	192.1	1,940.0	51.6	15.9	3.1	2,010.6
1997	1,449.2	430.9	1,880.1	56.1	25.4	3.6	1,965.2
1998	2,077.6	25.4	2,103.0	60.3	27.8	4.2	2,195.4
1999	2,161.7	90.2	2,251.9	73.4	21.0	4.9	2,351.1
2000	2,145.0	263.3	2,408.4	70.8	21.5	5.8	2,506.4
2001	2,601.9	66.6	2,668.5	79.9	22.0	6.4	2,776.8

Source: Compiled by the Author

Planned Generation Development

In 1999, TANESCO, assisted by a consultant (Acres International of Canada), completed a long range Power Sector Development Plan for Tanzania for a 25-year period. The plan is continuously updated each year by its Corporate Planning Department. The revised load forecast in both 2000 and 2001 developed two load forecast reference scenarios, one with a "reduced" and the other with a "full" industrial list. These two scenarios were developed due to the uncertainties surrounding the timing of the planned large mining loads. It was difficult to establish whether some of the planned mining projects would indeed take off, and if so, whether they would be using TANESCO's power. For example, a recently established mining company has decided not to use TANESCO's power but has set up its own generation capacity, allegedly in a bid to avoid TANESCO's expensive power. The "reduced industrial list" assumes that some mining loads will not be realised, whereas the "full industrial list" assumes that all the planned mining loads will take off as planned and will be connected to the national grid. Consequently, the 2001 update study recommended two least-cost generation expansion plans for the reduced and full industrial list load forecasts, as shown in Table 8.3 below.

Table 8.3: Least Cost Generation Expansion Plan for the period 2003 – 2026

[illegible]	[illegible]	[illegible]
2003		
2004	1X40MW (UGT5; 1X60MW GT-Oil)	1X40MW (UGT5; 1X60MW GT-Oil)
2005		2x60MW GT – Oil
2006	2X100MW Zambia Imports	
2007		2X100MW Zambia Imports
2008		
2010	4x89.5MW, Ruhudji Hydro Power	4x89.5MW, Ruhudji Hydro Power
2016	2X100MW Coal Plant - Mchuchuma	2X100MW Coal Plant – Mchuchuma
2020	2X100MW Coal Plant - Mchuchuma	2X100MW Coal Plant – Mchuchuma
2023	3x74MW Rumakali Hydro Power	3x74MW Rumakali Hydro Power
2025		
2026	1x60MW GT at Kinyerezi	1x60MW GT at Kinyerezi

Source: TANESCO, PSMP, 2001 Update

Transmission and Distribution System

From the early 1970s TANESCO has made aggressive efforts to extend the national grid, and as a result most of the major cities and towns in the country are now connected to the national grid. At a certain time these efforts were so assertive that the perception arose that they were being done at the expense of adding new generation facilities. The transmission lines, almost all of which are radial single-circuit lines, were built to deliver power to cities and towns from the major generation centres, most of which are found in a single region in the centre of the country. The voltages of the transmission system are 220 kV, 132 kV and 66 kV, which all are alternating current (AC) with 50 Hz frequency. Distribution system voltages include 33 kV, 11 kV and lower voltages supplying different types of consumers, residential, industrial, commercial, agricultural, depending on their electricity demands. Table 8.4 below summarises the route lengths of transmission and distribution lines.

Table 8.4 Transmission and Distribution: Total Lengths of Lines in Tanzania (km)

Year	220 kV	132 kV	66 kV	33 kV	11 kV
1990	1,847.0	1,160.0	36.0	3,136.0	2,720.0
1991					
1992					
1993					
1994					
1995	2,089.0	1,339.0	136.0	5,033.5	3,104.6
1996	2,522.0	1,403.0	136.0	5,293.6	3,119.0
1997					
1998					
1999					
2000	2,658.0	1,420.0	378.0	7,057.0	3,639.0

Source: Compiled by the Author

The Tanzanian national grid is not interconnected with any of its neighbouring countries' grids. However, studies are now being carried out for the construction of a 220 kV line from Arusha (Tanzania) to Nairobi (Kenya), which will interconnect the grids of the three East African countries, Uganda, Kenya and Tanzania. Kenya and Uganda are already interconnected albeit only by means of a fairly low-voltage, 132 kV, double-circuit line from Tororo (Uganda) to Nairobi (Kenya). As shown in the least-cost generation expansion plan, an interconnector with the Zambian grid is also planned for 2006/2007. This will connect Tanzania and the other East African countries to the Southern African countries' grids and to the SAPP. A number of internal transmission lines to transmit power from the planned additional electricity generation plants to the different load centres have also been earmarked for construction. However, according to the 1999 power sector development plan and its subsequent update studies, during the 25 years planning horizon there is no single isolated system which is earmarked to be connected to the grid system, as doing so will not be economically feasible. As an alternative, a recommendation was made to investigate and evaluate other supply options such as local hydro and/or gas resources for the isolated load centres.

System Losses

TANESCO's system losses are well above the international average of 10 – 12 % (Marandu et al., 1999: 94). This is firstly because some of the transmission lines and transformers are very old, and secondly because a significant amount of electricity is lost through illegal connections and wrong billing. As Table 8.5 shows, distribution losses are much higher than transmission losses because they include non-technical losses and have in fact been increasing over the past three years. This increase has been associated with increases in illegal connections, which are due to the following: firstly, TANESCO's failure to speedily connect new customers, and secondly, some customers tamper with and by-pass the electricity meters. For instance, in one region alone, Arusha, out of 12,322 customers whose premises were inspected, 1,251 illegal electricity users were netted. TANESCO's ineffective billing system and non-payment have also contributed to high distribution losses. Table 8.5 below shows both technical and non-technical losses for transmission and distribution.

Table 8.5 System Losses

Year	Total Units Generated (GWh)	Transmission Losses (%)	Distribution Losses (%)	Total System Losses (%)
1990	1,565.0	13.2	6.1	19.3
1991	1,826.9	13.2	8.7	21.8
1992	1,819.9	11.7	13.2	24.8
1993	1,878.9	7.3	16.3	23.6
1994	1,810.0	6.7	12.6	19.3
1995	1,861.6	5.9	8.0	13.9
1996	2,010.6	5.3	5.6	10.8
1997	1,965.2	4.4	6.8	11.2
1998	2,195.4	5.8	8.6	14.3
1999	2,351.1	5.9	12.7	18.6
2000	2,506.4	6.3	12.4	18.8
2001	2,776.8	6.6	20.0	26.6

Source: Compiled by the author

8.3.4 Demand

Electricity demand in Tanzania has been growing steadily over the last 10 years although the demand has been suppressed as a result of load shedding and lack of timeous connections of new customers. The annual average growth rate for the period 1990 – 2001 was about 5.5 %. In 2001, peak demand on the grid system increased from 425.7 MW recorded in 2000 to 464.8 MW, which was an increase of about 9.2 %. Table 8.6A shows electricity consumption in the grid system, sorted by consumer categories, while Table 8.6B shows the same with regard to the isolated systems. As the Tables show, consumer category one consists of residential, commercial and light industrial customers. This followed a decision taken by TANESCO to regroup its consumer categories, as had been recommended by a tariff study, which was undertaken by the consultant, London Economics of United Kingdom, in 1994. Consequently it is difficult to establish amounts of electricity consumed by households in comparison with that consumed by businesses.

Unlike the situation that prevails in Southern Africa, Tanzania's system peak demand has no seasonal variations, mainly due to the fact that there is no winter heating demand, as the country lies near the equator. However, there are two daily peaks, i.e. an evening peak between 19:00 and 22:00 hours, and a mid-day peak between 09:00 and 13:00 hours, with the former being the stronger peak. Although it becomes very hot in summer, particularly in Dar es Salaam and other coastal towns, air-conditioning demand does not influence the peak demand. This is because air conditioners are mainly used in offices, and very few are used in residential areas; this is because residential electricity tariffs are high, and because the air conditioners themselves are expensive in relation to the general income of the households.

Table 8.6A: Electricity Sales by Consumer Categories (GWh) in the Grid System

Year	Tariff Category					Total Sales	Maximum Demand (MW)	Load Shedding Units
	1	2	3	4	5			
1990	575.7	255.4	364.7	6.6	52.0	1,254.4	263.7	-
1991	634.2	279.0	398.5	7.2	56.8	1,375.8	297.8	-
1992	683.0	255.1	365.7	10.1	60.1	1,373.9	302.9	
1993	710.5	247.2	336.6	8.7	68.3	1,371.3	311.2	
1994	762.5	279.3	292.8	9.2	54.0	1,397.8	301.2	198.8
1995	851.4	268.2	329.8	6.4	83.6	1,539.4	332.5	114.1
1996	1,019.1	284.7	325.3	2.8	85.7	1,717.6	337.6	1.4
1997	924.8	343.9	369.7	2.4	95.0	1,735.8	339.0	75.4
1998	974.0	385.2	358.3	1.0	103.8	1,822.4	367.5	0.4
1999	1,112.7	301.5	306.7	3.3	114.0	1,838.1	394.1	0.9
2000	1,158.0	297.5	367.0	2.4	130.2	1,955.2	425.7	29.1
2001	-	-	-	-	-	-	464.8	2.0

Source: PSMP, 2001 Update

Table 8.6B: Electricity Sales by Consumer Categories (GWh) in the Isolated Systems

Year	Tariff Category					Total Sales
	1	2	3	4	5	
1990	40.2	8.0	0.300	0.320	-	48.8
1991	42.8	9.0	-	0.332	-	52.2
1992	52.0	16.3	-	1.149	-	69.4
1993	48.3	14.5	1.557	0.602	-	65.0
1994	51.9	9.5	-	1.279	-	62.7
1995	66.3	16.9	0.069	0.705	-	84.0
1996	62.6	12.4	0.182	0.119	-	75.3
1997	43.2	12.5	0.056	0.041	-	55.8
1998	41.0	17.0	0.007	0.069	-	58.1
1999	62.0	13.6	0.002	0.050	-	75.6
2000	60.1	21.0	0.001	0.044	-	81.1
2001					-	219.3

Source: PSMP, 2001 Update

Key: Tariff 1 = Residential, Commercial and Light Industry

2 = Low Voltage Supply 3 = High Voltage Supply

4 = Public Lighting 5 = Bulk Sales to Zanzibar

Projected demand

The forecast energy and peak demand projections for the reduced and full industrial lists presented in Table 8.7 below, indicate a very strong growth in early years, peaking in 2005. The rapid increase in 2005 is attributed to the maturing of the expected new mining and industrial loads, which are expected to be commissioned in the 2002 – 2005 period. The country's ongoing economic reform

programmes and in particular power sector reforms and privatisation are also some of the factors behind the anticipated faster growth.

Table 8.7 Forecast Energy and Peak Demand Projections for the Interconnected System

Year	REDUCED INDUSTRIAL LIST			FULL INDUSTRIAL LIST		
	Energy (GWh)	Peak Demand (MW)	Energy Annual Growth Rate (%)	Energy (GWh)	Peak Demand (MW)	Energy Annual Growth Rate (%)
2002	2,914	492	6.5	2,914	492	6.5
2003	3,073	524	6.5	3,214	560	10.3
2004	3,332	573	9.4	3,511	618	9.2
2005	3,954	668	16.6	4,186	727	19.2
2006	4,200	710	6.3	4,432	769	5.9
2007	4,782	798	12.4	5,215	908	17.7
2008	5,007	837	4.9	5,440	946	4.3
2009	5,242	877	4.8	5,675	987	4.3
2010	5,486	919	4.8	5,919	1,029	4.3
2011	5,740	962	4.7	6,174	1,072	4.3
2012	6,005	1,008	4.8	6,439	1,118	4.3

Source: TANESCO, PSMP, 2001 Update

8.3.5 Tariff

The average electricity tariff in Tanzania has been increasing steadily since 1990; the increase was particularly large between 1993 and 1995, when it increased by over 62 %. The reason for this dramatic increase was to make tariff levels equal to the long-run marginal cost (LRMC), as recommended by the London Economics tariff study. Tariffs were increased every January and July to adjust to the effects of the devaluation of the local currency, the Tanzanian shilling, against the US dollar, and inflation. Table 8.8 shows the trend of average tariff increases in Tanzanian shillings and in US cents for the period 1990 – 2001. As the Table indicates, the effects of the devaluation of the shilling led to decreases in the average tariff in US cents. This is because the regular biannual increases in tariffs stopped due to the government's reluctance to approve further increases. They feared negative political consequences, as Tanzania's industrial tariff was already the highest in the region (Katyega, 2000:10). According to the existing licence, TANESCO is permitted to increase its tariffs by up to 5 % biannually, while the Minister of Energy and Minerals in consultation with the Ministry of Finance is allowed to raise tariffs by an additional 10 %, and any excess of this has to be approved by the cabinet (Marandu, 2001b:14).

Table 8.8 Average Electricity Tariffs in US cents

Year	Average Tariff (TShs/kWh)	Exchange Rate (TShs/US$)	Tariff (US cents/kWh)
1990	10.50	193.30	5.45
1991	13.49	215.10	6.27
1992	18.38	248.40	6.46
1993	32.43	412.80	7.86
1994	42.97	512.50	8.38
1995	50.20	557.70	9.00
1996	61.37	586.59	10.46
1997	62.77	612.8	10.24
1998	68.76	654.11	10.51
1999	71.06	733.21	9.69
2000	70.43	802.34	8.78
2001	80.00	871.53	9.18

Source: Data for 1990 to 1995, Adapted from Marandu et al., 1999:92
Data on Exchange Rate (mean rate) for 1996 onwards, Adapted from Bank of Tanzania Economic Bulletin, Dec. 2001

Recently, electricity tariffs in Tanzania have been one of the major problem areas of the country's power sector. TANESCO increased its tariffs in order to meet its cost of generation. However, in 1997 the major industrial consumers complained that the cost of electricity in Tanzania was too high compared to other costs of production. Following this, TANESCO took the initiative and actually surveyed twenty industries to compare the costs of electricity and other costs of production. The findings showed that what the manufacturers paid for electricity, in fact, constitutes a very small percentage (less than 10 %) of their total costs of production. Interestingly, between 1999 and 2000 two conflicting statements were made by two top government officials regarding electricity prices. The first one was made by the Minister of Minerals and Energy to Parliament in his 1999/2000 Ministerial budget speech, when he announced that that the government would reduce the price of electricity by 30 % - 60 %. This move was highly welcomed by electricity consumers but a shock to TANESCO, as they were operating under heavy bank overdrafts as a result of insufficient tariffs. After a few months the President made a second statement, telling electricity users that they should not expect electricity prices to decrease. This time it was great shock to electricity consumers, who had been waiting for the tariff to go down as had been promised by the Minister, whereas it was a relief to TANESCO. This is a challenge to TANESCO and the energy sector in general.

Another development was that two investors (in the mining industry) with a total demand of 67 MW decided to generate electricity (using industrial diesel oil (IDO)) for their own use on the grounds that, and as mentioned earlier, TANESCO's power was too expensive, a situation which is extremely frustrating for both local manufacturers and foreign investors, and calls for an immediate solution.

In an effort to attract foreign investors and encourage manufacturing activities in the country, in March 2002 TANESCO decided to reduce its industrial tariffs. This came after a period of some three years since January 1999 during which TANESCO had not adjusted its tariffs. The adjustments were intended to bring to an end the prevailing situation where industrial consumers were subsidising residential consumers. In that way all categories of electricity consumers will pay the actual cost of electricity supplied to them. Other reasons provided for the increase were to compensate for the devaluation of the Tanzania shilling against the US Dollar and to make the utility operate more commercially. In this case the subsidised units (kWh) were reduced from 100 to 50 only. Thus residential customers were required to pay Tshs 25.90 for the first 50 units and Tshs 83.00 for the units above 50. This resulted in many complaints from electricity consumers around the country including legislators who complained even more. As a result of these complaints, on April 16, 2002 the Prime Minister made a statement in Parliament instructing TANESCO to increase the subsidized units from 50 to the original 100 units.

8.3.6 Access to Electricity and Rural Electrification

Access to Electricity

As is the case in most African countries, access to electricity in Tanzania is very low and limited to urban areas, even though still a good number of urban houses have yet to be connected to electricity. Previously TANESCO had been completely unable to cope with the number of customers who had applied for service line connections, resulting in huge customer backlogs waiting to be connected. It also resulted in wasted time and great inconveniences, as customers often had to follow up their applications in person at TANESCO's offices. In 1998 TANESCO had a huge backlog of up to 55,000 applications, which amounted to about 16 % of existing residential connections (Marandu et al, 1999: 84). TANESCO's failure to speedily connect customers to the service line was mainly due to liquidity problems and shortages of distribution line materials and transformers, most of which are imported. Massive devaluation of the local currency also made it difficult for TANESCO to import enough line materials.

However, during 2000 and 2001 TANESCO made extra efforts to acquire the needed distribution line materials, and was thus able to construct so many service lines that almost the entire backlog was cleared. In May 2001, in an effort to sustain this rate of development, and with the Ministry of Energy and Minerals granting approval, TANESCO decided to raise the service line connection charges from TShs 90,000 to 141,000 (about 57 %) for a single–phase connection, and from TShs 180,000 to TShs 180,000 to 584,000.00 (about 224 %) for a three-phase connection. TANESCO's aim was to make the customers pay the true cost of the service line connection. The price hike met with a public outcry that the hike was not realistic and that it would merely ensure that those who

had not yet been connected would continue to use poor energy sources. As a result, the new rates were applied for less than a month before the Minister of Energy and Minerals announced in parliament that TANESCO should immediately revert to the old rates. It should be noted that this was the same government which first approved the price hike and then reversed it so dramatically in parliament. It did not, however, put in place an alternative means to help TANESCO to finance the service line connections, as the reduced rates would negatively impact on TANESCO's financial performance.

Furthermore, all customers in Tanzania are required to meet certain standards by TANESCO for house wiring, which many customers cannot afford. There are no differentiated standards or special arrangements to help urban poor households. These might help a significant number of urban poor to be connected to electricity, as proper house wiring is a big problem for them – quite apart from paying the service line connection charges. The current access to electricity in Tanzania is only 10 %. If the government does not intervene by putting in place polices and mechanisms to increase access to electricity – and to ensure its affordability – it is obvious that, particularly with the planned reforms, the low rates of access to electricity will prevail for the foreseeable future. One way the government could help is by making funds available so that customers can pay the full cost for the service line to TANESCO or its successor but under a soft loan arrangement. The customers could, for instance, be asked to raise about 20 % of the costs, with the balance to be paid in instalments together with their monthly electricity bills for a period of time, such as five years. Such an arrangement has been used successfully in Botswana, and as a result, access to electricity in Botswana currently stands at 29 %, which is the second highest in the region after South Africa.

Rural Electrification

The scope of rural electrification differs according to the level of electrification of a country. In some countries rural electrification means the provision of electricity to rural villages, but in others, it entails the electrification of smaller towns far from the urban centres. In some other countries, where all towns have already been electrified, rural electrification involves connecting remote farmhouses; in Tanzania rural electrification refers to supplying electricity to district townships, agro-based industries and other small industries outside of the regional towns (Kjellstroem et al. 1992). Rural electrification programmes in Tanzania are now concentrating on supplying district headquarters. The target, which was set in 1975, was that by the year 2000 all district headquarters must be electrified by grid extensions or by their own generators. This target has not yet been met and at present only 87% of the target has been reached, i.e. as at 2002, 84 out of the 97 district headquarters have been electrified.

The financing for these rural electrification programmes has come primarily from TANESCO and from the international donor community, mainly Finland, Sweden, Norway, Denmark, Japan, Germany, Spain, the African Development Bank (ADB) and the World Bank. The government neither has a rural electrification fund in place, nor clear policies for rural electrification, although when it has been required to contribute to certain donor-funded projects, it has done so from its own budget. Nowadays most of the rural electrification programmes, as well as other projects in other sectors which are being financed by foreign donors, require recipient governments to contribute a certain percentage, in some cases on a fifty-fifty basis. The issues of non-differentiated house wiring standards and high service line connection fees are also major problems in newly electrified rural areas and generally in all rural areas. The problem is well known to both the government and TANESCO, but so far little if nothing has been done to solve it. In a move made in early 2000, which can be seen as an admission that the connection charges are indeed expensive, TANESCO reduced both single-phase and three-phase connection charges by 50 %. Unfortunately this reduction lasted for only three months, 1st January – 31st March 2000, and was applied only to selected rural areas. Nevertheless, it is likely that a lot of customers took advantage of this reduction.

However, there have been some new initiatives to introduce locally managed electricity supply cooperatives. So far Tanzania has four fully established electricity cooperatives serving about 3,000 people. These are Urambo, Mbinga, Kasulu and Kibondo established in 1995, 1996, 1998 and 2000 respectively. Meanwhile, a number of rural townships are looking into the possibility of establishing power cooperatives. This community participation is currently the best option, as less and less funds are now available from donor countries to finance rural electrification projects. Appropriate studies, however, should be done to identify optimum technology, financing options and institutional arrangements to facilitate these programs.

8.3.7 Financial Performance of TANESCO

TANESCO's financial performance has generally been very poor over the past ten years. As indicated in Table 8.9 below, TANESCO recorded huge net losses before tax from 1992 – 2000, except in 1997. Consequently other financial indicators such as return on assets and interest cover have also indicated a very poor performance. The government's tendency to over-regulate tariff and other operational matters largely contributed to the lack of TANESCO's profitability. Over-regulated tariffs have led to tariffs not being adjusted in line with the devaluation of the shilling and increases in generation costs, thus making revenue fall short of cost in real terms.

As regards operational matters, the utility has also shown great weaknesses in revenue collection. This has adversely affected TANESCO's liquidity. As a result it operates under considerable bank

overdrafts, which bear heavy interest rates. The government's failure to honour its electricity bills has greatly contributed to TANESCO's poor revenue collection. In some cases it is difficult to near impossible for TANESCO to disconnect power from non-paying government departments such as the army and big hospitals, because of their importance to society. For instance, up to May 2002, the government owed TANESCO a total of TShs 42.583 billion. However, the President of Tanzania said that this should not be an excuse for the company management to perform so poorly, as TANESCO also owed the government a total of TShs 150 billion, which is more than three times what the government owes TANESCO (Nyanje, 2002). Nevertheless, this behaviour illustrates an irresponsible behaviour adopted by the government. The Zanzibar State Fuel and Power Corporation (ZSFPC) is also not paying for the bulk of the electricity it buys from TANESCO. TANESCO, again, cannot discontinue supplying power to Zanzibar for political reasons. Reduced electricity generation and consequent load shedding is another factor which contributed to TANESCO operating at a loss. During the dry years TANESCO further experienced reduced generation from its hydroelectric plants, thus leading to load shedding as well as making it spend most of its revenue (up to 40 %) on buying fuel for its thermal plants.

During the period 1990 - 2000, there were, however, some improvements on various staffing performance indicators, such as sales per employee and customer per employee ratios. The fact that TANESCO froze employment in 1995, saw the number of employees decreasing, mainly because of deaths caused by the Acquire Immune Deficiency Syndrome (AIDS) pandemic, but also retirements, resignations and dismissals, while the number of customers have been on the increase. However, it should be noted that although these staffing performance indicators have been improving of late, they are still very low when compared to international norms. According to SAD-ELEC (2001:7) international standard customer per employee ratio is 161.

Table 8.9 Some Financial Performance Indicators of TANESCO

Year	No. of Custusto mers	No. of Employee	Total Sales (MWh)	Sales Per Employee MWh/Empl.	Customers per Employee	Total Revenue (TShs' B)	Total Asset Value (TShs' B)
1990	172,274	6,500	1,303,186.5	200.5	27	13.70	88.12
1991	188,905	6,500	1,427,957.5	219.7	29	21.78	105.16
1992	221,954	6,980	1,443,339.2	206.8	32	26.54	144.02
1993	246,668	7,500	1,436,309.4	191.5	33	47.14	200.62
1994	259,410	7,450	1,460,466.8	196.0	35	63.69	250.92
1995	267,224	7,493	1,623,390.8	216.7	36	85.14	741.57
1996	261,578	7,569	1,792,971.4	236.9	35	110.03	886.25
1997	352,130	7,269	1,791,586.3	246.5	48	106.77	1,102.02
1998	371,233	7,107	1,880,412.3	264.6	52	117.57	1,216.13
1999	396,440	6,950	1,913,767.2	275.4	57	124.20	1,281.49
2000	431,722	6,612	2,036,284.9	308.0	65	130.77	1,254.78
2001	440,431	6,540	2,021,935.4	309.2	67	139.21	

Table 8.9 Continued

Year	Net Profit/Loss Before Tax (TShs' M)	Average Selling Price of Elect. (TShs/kWh)	Returns on Assets %	Debt/ Equity Ratio	Interest Cover Ratio	Historical Exchange Rate (Average) US$/ TShs.
1990	2,665.97	10.52	0.03	0.85	1.86	196.60
1991	1,592.88	15.25	0.01	1.13	1.36	233.90
1992	(9,982.94)	18.39	(0.07)	1.13	(0.78)	335.00
1993	(11,540.93)	32.82	(0.06)	1.22	(0.36)	461.31
1994	(5,131.38)	43.61	(0.02)	1.00	0.43	536.50
1995	(26,441.53)	52.45	(0.34)	0.27	(1.35)	591.65
1996	(3,377.70)	61.37	(0.00)	0.30	0.51	586.59
1997	3,094.87	59.60	0.00	0.23	1.48	612.80
1998	(13,729.80)	62.53	(0.01)	0.28	0.07	654.11
1999	(25,168.21)	64.90	(0.03)	0.33	(0.63)	733.21
2000	(9,082.28)	64.22	(0.01)	0.32	0.35	802.34
2001		68.85	-	-	-	871.53

Source: Compiled from TANESCO Annual Reports
Data on Exchange Rate (mean Rate), compiled from Bank of Tanzania Economic Bulletin, December 2001.

Key: B = Billion M = Million

8.3.8 Sector Reforms

By recognising the importance of having an efficient and effective power sector for the promotion of industrial growth and improving its people's living conditions, the government of Tanzania has also embarked on a programme for liberalising and reforming its power sector. This imperative decision was reached by the government in 1992 and was part of the overall decision to reform and privatise

all the public corporations involved in the provision of services, such as water, electricity, transport (air, water and road), telecommunication, etc. The overriding reason for the government's decision to reform and privatise these corporations was due to their failure to deliver the services as required, coupled with specific sector drivers. (The specific reasons behind power sector reforms will be discussed later in this section). The overall objective was to improve the performance of these enterprises in order to create an environment conducive to good business and to enable them to contribute substantially and meaningfully to the country's economic development efforts.

Following this decision, in 1997 TANESCO was officially placed under the authority of the privatisation commission, the Parastatal Sector Reform Commission (PSRC), in order for the commission to co-ordinate the process of reforming and privatising it. However, the PSRC could not immediately start the process, as there were no policies in place to guide such a process, and as it could not decide on its own how to reform TANESCO. As noted in Chapter Two, there are several different strategies to reform the power sector of a country. A country will embark upon a particular strategy depending on what it wants to achieve from the reforms, and depending on the nature and existing characteristics of its power sector. In addition to this, unlike the privatisation of some other state-owned companies which can even be sold by auction, great care must be taken when reforming and privatising such a vital and technical corporation, since if problems arise during the process, the outcome may be devastating. What happened in California in this regard was a good lesson for new reformers. To this effect, in October 1999, the government issued a new Power Sector Policy outlining the new industrial structure and the government's objectives with regard to power sector reforms. But before discussing these objectives, we must first consider the reasons for the power sector reforms in Tanzania.

Drivers for power sector reforms in Tanzania

Generally, reforms in most African countries are driven by poor performance of the traditional vertically integrated and publicly owned utilities. Tanzania is no exception to this trend. Previously, TANESCO performed well but in recent years it has been performing poorly, recording huge financial losses year after year. Consequently it has failed not only to pay dividends to the government, but also to effectively finance both rehabilitation and expansion of its system. Service quality has also been very poor. In a more systematic way, at a seminar on the privatisation of TANESCO held on 10th November 2001, at the Royal Palm Hotel in Dar es Salaam, the Minister of Minerals and Energy stated the reasons for changes in the government's stance on dealing with TANESCO as the following: -

- Poor service to its customers, as evidenced by substantial complaints from the public;

- TANESCO has continued to record losses in billions of Tanzanian shillings from 1996 to 2000, with the exception of the year 1997 when it realised a small profit. Further, it is failing to repay its internal and external debts, as well as to rehabilitate the existing infrastructure;
- Year after year, the rate at which new customers are connected, as measured by the long list of customers who are still waiting to be connected, is actually decreasing;
- Continuous increases in operating costs instead of decreases, as shown by the customer-employee ratio;
- High technical and non-technical losses, as shown by flourishing electricity theft, and inefficient transmission and distribution systems, as shown by the small revenue collected compared to the quantity of electricity generated.

Besides TANESCO's poor performance, which most of the government officials have stated is the main motivation for the power sector reforms in Tanzania, there is no doubt that external pressures also played an important role in persuading the government to reform its power sector. Evidence, suggesting external pressure, is that recently the World Bank decided to finance a major gas-to-electricity project called Songas, through the private sector, but with the government coordinating the project. The World Bank is also the major financier of the ongoing power sector reform and privatisation process. The reforms have enabled many governments to shift their burden of financing new investments in the power sector to the private vital sector, which in turn has enabled governments to reallocate their scarce resources to other sectors, such as education and health.

Objectives of the power sector reforms in Tanzania

Power sector reforms, both in developed and developing countries, have generally been aimed at improving the sector's efficiency, hence leading to a reduction in electricity prices. However, according to the new electricity sector policy, one of Tanzania's power sector reform objectives is also to increase sector efficiency. However, this is not in order to lead to price reduction, but in order to meet electricity demands and provide for sufficient reserve margins. It is clear from this that different governments have different objectives and goals which they want to achieve from such reforms. According to the policy documents, the Tanzanian government's other objectives are: -

- To accelerate electrification, so as to ensure access to the broadest cross-section of the population and centres of economic activities;
- To ensure the long-term economic viability and sustainability of the electricity industry, so that it can meet the challenges of economic development; and
- To reduce public sector expenditure and debt by transferring to private capital the commercial risks which are inherent in investments in the electricity sector.

Reform strategies

Although these serious efforts were only seen in the past three years, initial reform strategies, had been taken as early as in 1992 when the government removed TANESCO's monopoly by allowing private power producers to produce and sell electricity to TANESCO or directly to consumers. This was a way of alleviating power shortages, which resulted from the 1992 drought that hit the country so severely. As TANESCO's system is highly dependent on hydropower, massive and frequent load shedding was inevitable, thus creating a need for new power generation sources, in which the government and TANESCO were unable to invest quickly enough. The removal of TANESCO's monopoly and the call for private sector participation saw two IPP's, Kiwira and TANWATT, selling power to TANESCO only two years after its monopoly had been ended. A much bigger and significant private power project, a (100 MW) diesel plant in Dar es Salaam, had already been completed in 1999. The project was a joint venture between Malaysian and Tanzanian firms, which formed a company called Independent Power Tanzania Limited (IPTL). Although the project was already completed in 1999, it only started generating in 2002 due to a dispute with the government over allegedly unreasonably high tariffs. The dispute was a result of inadequate legal and regulatory frameworks. It could be said that private sector participation was done in a hurry, perhaps due to the urgent need to solve the power shortage problem.

The reform agenda was developed further in October 1999, when the government approved a new policy and restructuring framework for the electricity industry. In this policy document the government articulated the following strategies, which would be adopted in order to realise the policy objectives of the power sector reforms: -

- To restructure and unbundle the present vertically integrated utility along the functional units of generation, transmission and distribution;
- To introduce competition in the sector where applicable, while seeking to safeguard stakeholders' and consumers' interests through regulation;
- To review the Electricity Ordinance and enact new industry legislation to capture changes in the electricity sector and to allow the private sector to provide public electricity supplies;
- To establish an independent regulatory agency, which will be put in place before the privatisation of major state-owned assets in the electricity sector;
- For the government to continue providing the necessary incentives to encourage private investments in the exploitation of different sources of energy. To encourage the development of electricity generation from these sources, and in so doing to follow the least cost basis of investment programmes, effective demand management and use of up-to-date and cost-effective technologies;

- To make provisions in the regulatory framework for the pricing of those parts of electricity which continue to display natural monopolistic characteristics and to develop a bulk electricity exchange market with the market price to be determined by the system's marginal cost;
- For the government to continue accessing concessionary funds to foster rural electrification programmes; and
- In the short term to improve the efficiency in the distribution system especially in respect of the metering and billing system.

Even though the government clearly stipulated the strategies it intended to follow, it also had to appoint consultants through the PSRC to assist them. It wanted to avoid making the same mistakes which had been made before in other countries, and which would prevent it realising its objectives. In particular, consultants were engaged to advise the government on the following:

- Restructuring and unbundling of TANESCO;
- Developing the electricity trading arrangements and regulatory environment in the electricity sector;
- Developing an approach to improve access to electrification (rural electrification) and to meet universal service obligations; and
- Advising on privatisation transactions for companies, which will be created as part of the restructuring process.

As noted in Chapter Two, often many governments commercialise and corporatise their utilities as the first step in reforming their power sector. However TANESCO is already a body corporate and is required to operate on business principles just as any other entity. Although commercialisation was not mentioned or included as one of the government's strategies in reforming the power sector, in 2002 the government through the PSRC initiated the process to make TANESCO operate along more commercially disciplined lines. The government decided to commercialise TANESCO through hiring an external firm to manage TANESCO under a management contract. The reason given for this was the managerial weakness identified by an external auditing firm. In the process a number of international firms submitted their bids and, on evaluation, Net Group Solutions (Pty) Limited of South Africa won the tender and is now managing TANESCO for a two-year contract period. Eskom Enterprises (Pty) Limited, also a South African company, and ESBI International of Ireland lost the tender.

Looking at the government's strategies for reforming the power sector, it appears that it is following the standard World Bank Reform Model for developing countries. This model entails

commercialisation and corporatisation as a first step, then restructuring by vertically and horizontally unbundling the utilities, including developing of electricity trading arrangements. This step is often followed by establishing a regulatory framework and, lastly, privatisation of the core business units, namely generation, transmission and distribution. However, the government has said repeatedly that it will never privatise sensitive infrastructures and that they will be leased on a long-term concession basis to private firms. In most African countries hiring an external firm to run their utilities before privatisation has become a common strategy of power sector reforms, perhaps due to the government's urgent need to improve sector efficiency and prepare the ground for privatisation (i.e. it is used as an in-between or transitional step). In Tanzania, however, many institutions and individuals challenged the government's decision to hire a private firm to manage TANESCO. They argued that management's failure to deliver prior to the management contractor should not be taken as an indication there are no other individuals in the country who are able to manage the utility as required.

Despite the above criticisms the fact remains that the management contractor will most likely increase the utility's efficiency due to new private management skills which the firm will provide. Moreover, it is likely that during the contract period the government will reduce its excessive interference in management's operations, which will greatly contribute to the success of the management contractor. There will no longer be reluctance by so-called "key government institutions" to pay their outstanding electricity bills. Every institution in the country will be required to settle its electricity bills promptly. Furthermore, usually the fee of the management contractor is fixed or indexed with regard to operating profits or any other parameters. If this also applied to the management firm in Tanzania, it will provide incentives for better performance. However if only a small part of the management firm's remuneration is indexed to profit, then it is likely that the contractor will not resist excessive interference by government, and thus the anticipated improvements will not be achieved.

In the same way that the advent of the IPP generated significant controversy, the process of acquiring the management contractor was a controversy as well. The process was declared by the Minister of Energy himself to have lacked transparency. It is not known why the Minister expressed such reservations on the level of transparency. However, in response to this, the PSRC, which was coordinating the process, issued a press release, denying the allegations by saying that transparency prevailed throughout the process and that top officials from the Ministries of Finance and Energy participated fully in the entire process of evaluating the bids. On the other hand, TANESCO's employees had earlier vowed to prevent the management contractor from entering the offices until the government had signed a voluntary agreement, which would guarantee their welfare. As a result,

the new management had to force its way in with the help of the armed special police force (Field Force Unit); this unit also patrolled outside the utility's head office building for some days to ensure the contractor's security. The government used force after negotiations between the government and TANESCO employees had failed.

All of these are the challenges faced by power sector reforms in Tanzania, which need to be duly addressed by the government. If this is not done, they may outshine the expected benefits of these power sector reforms. One may wonder that, if these small processes, the advent of IPP and the hiring of the management contractor, generated so much controversy, what will happen with the privatisation process, which is much bigger and even more important. However, if transparency prevails and the utility's employees and the public at large are properly educated on the benefits of power sector reforms, it is likely that the government's policy objectives will be achieved. In a bid to show its commitment on the issue of transparency, the PSRC's Chairman, when presenting a paper at a seminar on the privatisation of TANESCO, held on 10th November 2001 at the Royal Palm Hotel in Dar es Salaam, gave the following tentative timetable for TANESCO's divestiture:

Date	Activity
January 2002	Completion of the study on the new electricity sector structure and legislation
February 2002	Government approval on the study's recommendations for the new electricity sector structure and legislation
August 2002	Completion of the new electricity sector structure together with new legislation
October 2002	Legislation presented to Parliament;
March 2003	Completion of unbundling of TANESCO into different companies; New companies to start trading with each other under the new electricity sector structure
May 2003	Hiring a consultancy to advise the government on privatisation of the newly formed companies
September 2003	Completion of the preparation for privatisation of the electricity distribution companies
December 2003	Completion of the privatisation of the electricity distribution companies
	After privatisation of the distribution companies, privatisation of the generation companies will follow in 2004.

8.3.9 Regulatory Framework

As part of the overall reform process, the government is committed to separating its policy and electricity industry regulation roles. The government realises that without an independent and transparent regulatory framework in place, its reform objectives, such as attracting private

investments to the sector, will not be achieved. In fact, as mentioned earlier, if a capable and independent regulatory regime had been in place during the advent of the IPP, the more than three–year long conflict between the government and the IPTL might have been prevented. The conflict saw the country experiencing a heavy load shedding programme, while the 100 MW generating capacity, which could cover the shortage, was standing idle. As a result of load shedding, the economy suffered significant losses, quite apart from the losses suffered by the investor who is still fighting in a court of law to be paid by the government. Moreover it is most likely that this conflict scared away many prospective investors, not only in the power sector but also in other sectors of the economy. The conflict had to be resolved in the international arbitration court and now the government and TANESCO are paying, on a half-half basis, about TShs 3 million (capacity charge) every month over and above what TANESCO is paying for energy charges.

To implement its commitment and to ensure such conflict will not happen again, in April 2001 enabling legislation to establish a multi-sector regulatory agency was passed by parliament. The bill provides for the setting up of a multi-sector regulatory agent to regulate energy and water utilities. In addition to this bill, parliament also passed another bill, which provides for the setting up of another multi-sector agency to regulate surface and maritime transportation. While the energy and water regulatory agency will be named Energy and Water Regulatory Authority (EWURA), that of surface and maritime transport will be named Surface and Maritime Transport Regulatory Authority (SUMATRA). According to PSRC (2001: 6) the issue of regulatory independence is covered under institutional enabling legislation, while regulatory mechanisms will be spelt out in the industry specific legislation, which is expected to be enacted soon. Industry specific legislation will make regulatory provisions to regulate each industry, including electricity, and covering such items as licensing, tariff quality, environment, consumer protection, dispute resolution, etc (Masalla 2001: 30).

At present efforts are being carried out to make these agencies start operating. The Guardian (12. 6. 2002) quoted Bashiri Mrindoko, the Commissioner for Energy and Petroleum Affairs in the Ministry of Energy and Minerals, as saying that the government is in the process of operationalising EWURA. However, no specific date for its launch was given, although it is noted that the project consultant, Stone and Webster, from the United States, is currently working on the institutional and legal requirement before its launch (Ubwani, 2002).

The decision to establish these multi-sector regulatory agencies followed recommendations made in a study, which was commissioned by the PSRC with World Bank financial support. The proposed EWURA is really a multi-sector regulatory agency, as it will regulate the water supply, sewerage

disposal, petroleum, gas pipeline transmission and electricity sectors. Perhaps the main aim of establishing such a multi-sector regulatory agency is to avoid regulatory capture by politicians or the private sector. The fact that its chief executive officer will be working under several ministers could to some extent prevent excessive interference by the politicians.

CHAPTER NINE
Comparative Study

9.0 Introduction

The power sectors of the countries discussed in the preceding chapters vary significantly in terms of issues such as sector efficiency, number of people with access to electricity, performance of the traditionally publicly owned utilities and steps taken so far to reform the sector. Some countries have already initiated power sector reforms and have set up the requisite regulatory authorities, while others are only now considering the reforms. As mentioned earlier the reforms are expected, *inter alia*, to allow for the participation of the private sector, which is desperately needed to invest in expansion of the electricity system to meet demand and widen access to more people. This chapter sums up the findings of the preceding chapters by looking at the status of the ESI of the countries under study in terms of issues such as potential electricity sources, installed electricity generating capacity, electricity supply and demand, as well as performance of the electricity utilities. Then it will move on to discuss power sector reforms by exploring the main driving forces behind the reforms and the precise objectives of the respective governments with regard to these reforms, before examining the different reform strategies adopted by them. And lastly, before presenting the conclusions of the present study, the regulatory frameworks will be discussed.

9.1 Current Economic Situation and Prospects

Although all the countries under study fall into the category of "developing countries", they are in different income groups. Whilst Botswana and Namibia are defined as middle-income countries, the rest are regarded as low-income countries. As regards economic growth in these countries in 2000, this was mixed. For instance, while Tanzania recorded the highest overall growth rate, Kenya recorded not only the lowest but in fact a negative growth rate, as shown in Table 9.1. The effect of such a negative economic growth rate, and for those countries that recorded economic growth rates that are lower than their population growth rates, is that their inhabitants are becoming poorer. To make it possible for these countries to fight poverty, which is widespread, requires higher and sustained economic growth rates. BBC (2002) quotes the New Partnership for Africa's Development (NEPAD) as saying that an annual growth rate of 7% is needed in order to reverse the economic decline in Africa. In view of this, in an attempt to attain these required high economic growth rates, most of the countries have put in place economic policies that foster economic growth and attract foreign investors, such as liberalisation of exchange rates, privatisation of commercial public sector institutions and implementation of solid fiscal policies. If such policies were actually implemented as planned, these countries could succeed, as they are endowed with plentiful natural resources, such as minerals and substantial suitable land for agriculture, including rivers for irrigation. Figure 9.1

shows the GDP per capita for each of the countries studied in 2000 while Figure 9.2 shows percentage of population living in rural areas.

Table 9.1: Some Population and Economic Indicators (2000)

Country	Population (Millions)	Rural Popul-ation (%)	GDP, (US$, billions)	Annual GDP growth rate	GDP per Capita (US $)	1990 – 2000 Average GDP growth	Agriculture Contribution to GDP (%)	Annual Inflation Rate
Botswana	1.6	50	5.3	3.4	3,300	4.7	3.6	11.6
Kenya	30.1	67	10.4	-0.2	350	2.1	19.9	6.8
Namibia	1.8	69	3.5	3.9	1,900	4.1	10.7*	9.5
Swaziland	1.0	74	1.5	2.6	1,500	3.3	16.8	11.7
Tanzania	33.7	72	9.0	5.1	270	2.9	45.1	5.9
Uganda	22.2	86	6.2	3.5	280	7.0	42.5	3.3

*1999 data; *Source: World Development Indicators database, April 2002.*

Figure 9.1: GDP per Capita (2000)

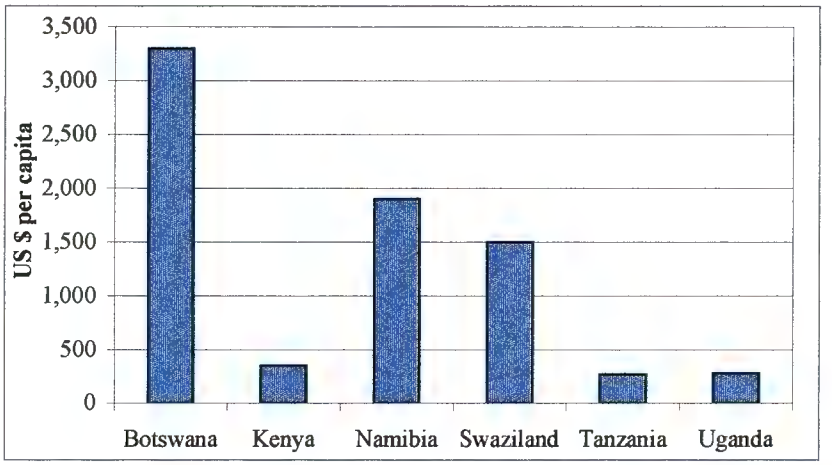
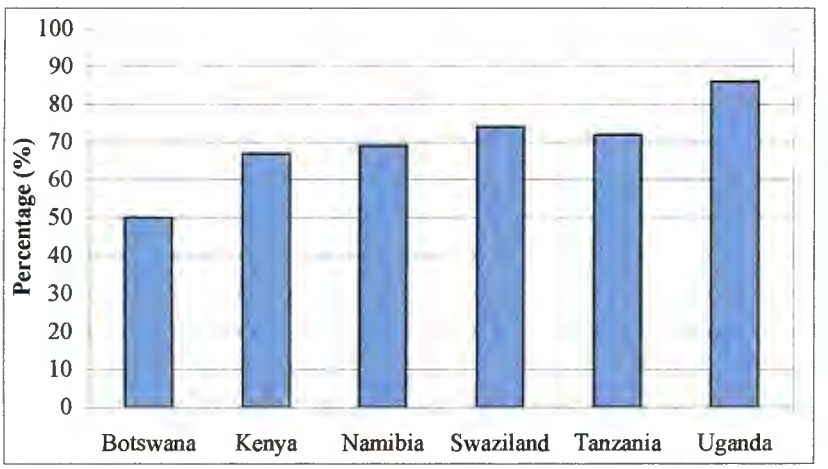


Figure 9.2 Rural Population (2000)



9.2 Resource Potentials for Electricity Generation

All the countries under study are richly endowed with potential sources of electricity, although their resource base varies according to the quantities and types of potential sources available. For instance, some are endowed with as many as three different sources while others have only one. As seen in Table 9.2 below, the total hydroelectric potential of all of them together is estimated at 9.4GW of installed capacity. However, out of this total potential only about 13.4% (1.3GW) has actually been developed. If it were to be developed, this hydropower potential would, in fact, provide enough power to these countries to last for quite a long period of time. Hydropower does, however, require a substantial initial investment cost, which may discourage potential developers. As a result, if financial solutions coupled with government guarantees are not put in place, this potential may remain undeveloped even after the liberalisation of the ESI. The fact that these countries experience frequent droughts, which pose a further substantial risk to hydropower development, may also be a significant deterrent to potential private developers.

As has been the case with hydropower, little effort has been made so far to exploit the other resources. For example, despite the fact that Botswana has 3.3 billion tonnes of measured coal reserves, currently it has only one plant with 132 MW of installed capacity. Botswana's as well as all other countries' failure to exploit the vast energy potentials they possess, while the majority of their people are still using poor energy sources such as fuel wood, is due to undeveloped energy markets in these countries and a lack of financial resources by the governments. In order to increase the current exploitation levels of these potentials significantly, these countries and all other countries in the region will need to open up their markets to each other and to create an integrated plan on an economic basis without undue regard to political boundaries. This will enable the development of big power plants to be carried out in one country, and the power to be sold to other countries. In this way the problem of low utilisation levels of big plants during their first five to ten years of operation due to low electricity demand growth in the individual countries, can be avoided. As a result of this problem most of the proposed large power plant projects have been both economically and financially not viable. In addition to the market reform (integration), proper legislation and regulatory frameworks should also be in place so as to attract private capital. In this regard, the current initiatives and their arrangements to develop the gas resources in Namibia and the Bujagali hydropower project in Uganda provide a good starting point.

Table 9.2: Potential Energy Sources (2000)

Country	Hydro (GW)	Coal (Tonnes – bill)		Gas (Tcf)	Geothermal (MW)	Uranium* (Tonnes'000)	Oil
		Probable	Proven				
Botswana	-	212	3.34	-	-	-	-
Kenya	1.5	-	-	-	576	-	-
Namibia	0.266	-	-	1.3	-	180.5	-
Swaziland	0.44		1.017	-	-	-	-
Tanzania	4.7	12	0.304	0.736	-	-	-
Uganda	2.455	-	-	-	450	-	-

*Total recoverable at less than US$ 130/kg

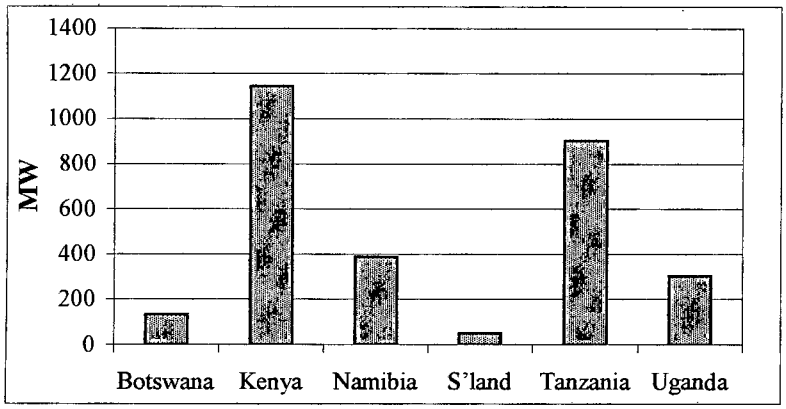
9.3 Current ESI

9.3.1 Generation

Existing Installed Capacity

With the exception of Botswana the installed generating capacity of the countries under study is dominated by hydropower. As Table 9.3 shows, Kenya has more than one third (677 MW) of the total hydropower installed generating facilities, while Swaziland has less than 3 % (42 %). Recently, these facilities have created a lot of problems for the power sectors, as these countries are prone to droughts. During the 1990 – 2000 period, Kenya, Tanzania and to a lesser extent Namibia have experienced electricity shortages several times caused by the failure of their hydropower plants to generate power due to a lack of rainfall. In contrast, while Uganda also depends on hydropower, it does not suffer from drought-induced electricity shortages, as its main river, the Nile, which is where the country's two major hydropower plants are situated, has its source in Lake Victoria. Botswana, on the other hand, has only one electricity-generating plant with an installed capacity of 132 MW. This plant uses coal, and its annual generation has been increasing over time due to improved efficiency. Apart from hydropower and coal plants, most of the countries also have thermal generation plants, which use various types of expensive imported diesel. In some cases the lack of foreign exchange has impacted negatively on the generation from these thermal (diesel) plants and the plants have been one of the major contributors to the utilities' poor performance. For instance, Tanzania's TANESCO, 28 % of whose installed capacity is thermal, has been using up to 40 % of its total revenue to buy fuel during dry years. Figure 9.3 shows existing installed generating capacity for these countries.

Figure 9.3 Existing Installed Generating Capacity (2000)



Units generated

Units generated in 2000 in the countries under study are as shown in Table 9.3 below. As mentioned above there is a heavy dependency on hydropower generation in Tanzania, Uganda, Kenya and Namibia which reduces the available generation in times of drought. Kenya's hydro system, for instance, generated a total of 3,274 GWh in 1999, but in 2000 its generation was reduced to 2,435 GWh, a reduction of 840 GWh (about 26 %). This energy, which could not be generated because of a lack of rainfall in the region, is more than Swaziland's total sales for that same year. Tanzania and Namibia also experienced a substantial reduction in units generated due to drought. In contrast Uganda's hydro system generated fewer units because of a lack of sufficient spares for maintenance, thus leading to a large number of forced outages rates. The poor performance of the hydro systems in terms of units generated led to severe load shedding programmes in Uganda, Kenya and Tanzania. On the other hand Namibia and Swaziland were able to secure their power shortfall by importing more units from South Africa whose system is thermal based – using available cheap coal.

Imports

Most of the countries under study import power to supplement their internal generation. The only countries which do not import power to feed into their grid systems, are Uganda and Tanzania, although the latter does receive several small cross-border supplies from Zambia and Uganda. Whilst Kenya imports 30 MW of continuous power from Uganda, all the other countries under study (i.e. Botswana, Swaziland and Namibia) which border South Africa, rely heavily on South Africa for power imports. In the year 2000, for instance, Botswana and Swaziland imported more than what they generated internally, whereas Namibia imported about 46 % of its total power requirements. However, the amount of power Namibia imports in any particular year also depends on the performance of its Ruacana hydropower plant, which is affected by the amount of rainfall received. With regard to Botswana, the units imported are increasing every year as a result of having only a

single power plant with limited generation capability. In this case the increased demand in a particular year is met by power imports from South Africa.

However, with the exception of Namibia, which has reported a decrease in profits in all the years when it imports more power, the other countries are reported to have greatly benefited from these imports. Nevertheless it should be noted that, despite the decrease in profits reported by Namibia, the country has for a long time now had two power plants which have been on standby because their per unit costs of production are higher than the unit cost of imports. Thus, if there were no imports, then Namibia would have no alternative but to operate those plants, which would greatly and negatively affect the utility's performance and the country's tariff levels. Botswana, on the other hand, has managed for several years to keep on hold the expansion of its internal generation capacity, as it is able to get cheap power from the SAPP and South Africa. It has been established that, if Botswana had invested in its internal generation expansion projects, its tariffs would have increased substantially.

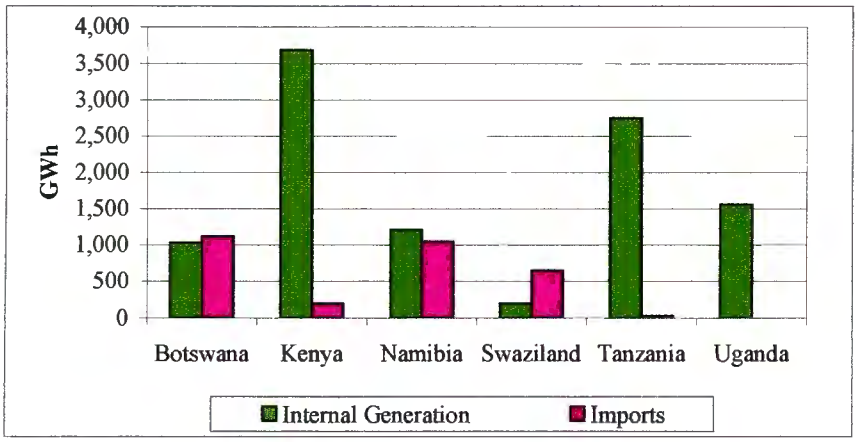
Similarly, the 30 MW of continuous power which Kenya is importing from Uganda, has helped Kenya substantially, and especially so during the drought years, when its hydro system has generated less power. In fact, Kenya and Uganda have recently in 2002 signed a new power purchase agreement, which will enable Kenya to import up to 80 MW of continuous power after the completion of the Bujagali hydropower project in Uganda in 2006. Clearly, such electricity imports have greatly benefited most of these countries. As mentioned earlier, the import and export of electricity is highly needed in the region, to facilitate significant exploitation of the abundant potential electricity resources available in the region. Table 9.3 below shows the installed generation capacity and the units generated and imported by the respective countries in 2000, whereas Figure 9.4 presents graphically the units generated internally, the units imported and the total system's energy, also for the year 2000.

Table 9.3: Internal Generation Performance and Units Imported (2000)

Country	Existing Installed Generating Capacity (MW)				*Total Installed Capacity (MW)	Total Internal Generation (GWh)	Total Imports		Total System Energy (GWh)
	Hydro	Coal	Diesel	Geo-thermal			(GWh)	%	
Botswana	-	132	-	-	132	1,035	1,123	55	2,043
Kenya	677	-	409	57	1,143	3,683	198	5	4,081
Namibia	240	144	3	-	387	1,211	1,045	46	2,277
S'land	41	-	10	-	51	195	652	77	847
Tanzania	562	4	336	-	902	2,748	28	1	2,777
Uganda	301	-	2	-	303	1,556	-	-	1,556

*Total Installed Generating Capacity

Figure 9.4 Internal Generation and Imports (2000)

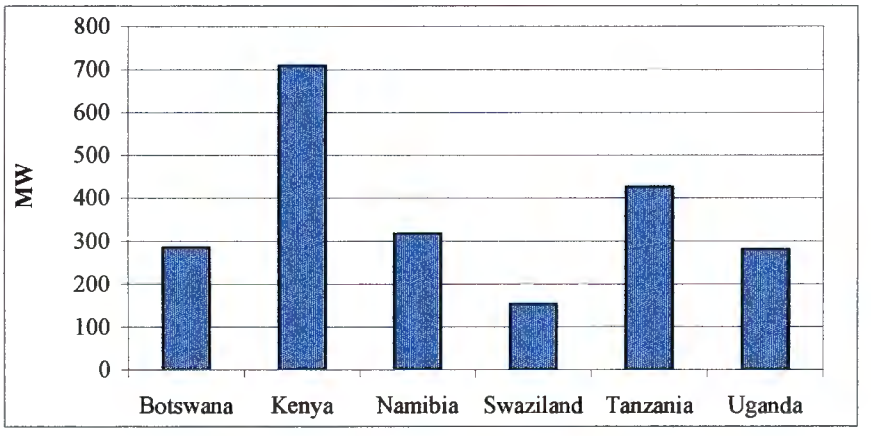


9.3.2 Transmission and Distribution

Maximum demand

As appears from Figure 9.5, the maximum demands of the countries under study are generally low, but also vary greatly from one country to the other. In 2000 Kenya had the highest peak demand, of 708 MW. Although there are 3.6 million more people in Tanzania than in Kenya, Tanzania's peak demand in the same year was much smaller than that of Kenya. Another interesting situation is that of Uganda and Botswana. These two countries' peak demands in 2000 were almost equal, i.e. that of Botswana was 285 MW and Uganda 280 MW. However, their respective population sizes vary considerably, with Uganda having almost 14 times as many inhabitants as Botswana. To equal their per capita peak demand Uganda should theoretically have had a peak demand of 3,990 MW. Further, as in the case of Kenya and Tanzania, Botswana has a larger GDP per capita than Uganda, meaning that Botswana is more developed as also substantiated by its higher per capital income.

Figure 9.5 Countries' Peak Demand (2000)



Exports

Electricity exports as opposed to imports are not common in the countries under study. With the exception of Uganda and Namibia, all the other countries do not export electricity. Nevertheless, although Uganda in 2000 exported a total of 251.1 GWh to Kenya and Tanzania, it did so although it did not have enough power to meet its domestic demand. In other words, it exported electricity and at the same time its local customers were sharing power through load shedding programmes. This situation can be attributed to the fact that Uganda had to fulfil its Power Purchase Agreement (PPA) requirements with Kenya. As mentioned earlier in Chapter 3, the PPA had been signed in 1954, and in terms of this agreement, Uganda was obligated to supply Kenya with 30 MW of continuous power for a period of 50 years. As regards Namibia, the country exports small amounts of electricity to South Africa, Zambia, Angola and Botswana through cross-border supplies. Table 9.4 below shows the electricity exports and total sales for 2000.

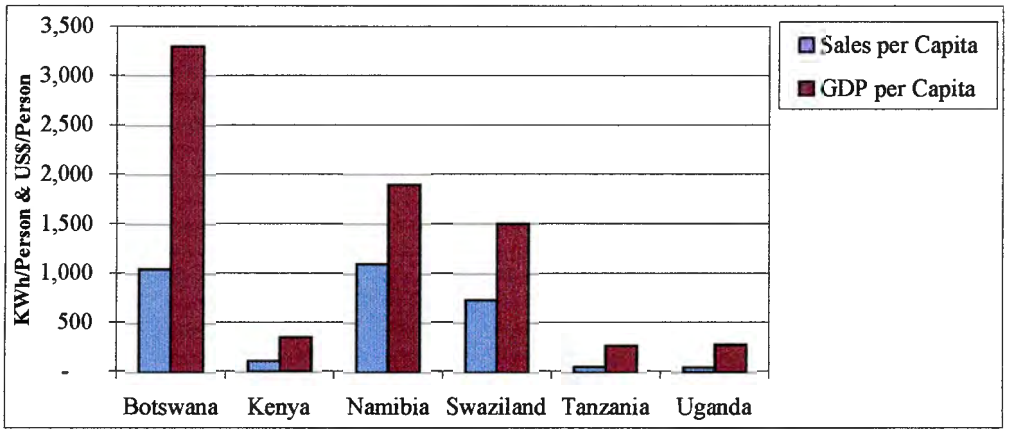
Table 9.4: Electricity Sales (2000)

Country	Electricity Sales (GWh)			Peak Demand (MW)	Number of Customers	Sales per Capita (KWh/Person)	Consumption per GDP KWh/US$
	Domestic	Export	TOTAL				
Botswana	1,671	-	1,671	285.0	76,380	1,044	0.32
Kenya	3,366	-	3,366	708.0	505,951	112	0.32
Namibia	1,878	100	1,978	317.0	2,341	1,099	0.57
Swaziland	732	-	721	153.8	36,367	732	0.49
Tanzania	2,036	-	2,036	425.7	431,722	60	0.23
Uganda	843	251	1,094	280.0	180,234	49	0.18

Sales

Electricity sales in the countries under study vary widely as well. There are great variations both in terms of electricity sales per capita as well as sales per GDP, as shown in Table 9.4 above and Figure 9.6 below. When comparing GDP per capita and electricity sales per capita, it appears that there is a correlation between high GDP per capita and electricity use per capita. Botswana, Namibia and Swaziland which have high GDP per capita also have high electricity sales per capita whereas Kenya, Tanzania and Uganda, which have low GDP per capita, show low electricity sales per capita. This suggests that to a certain extent high income contributes to increase in modern energy (electricity) consumption.

Figure 9. 6 Sales per Capita and GDP per Capita



With regard to growth in demand for electricity in the countries under study, there has been a steady growth over the 1990 – 2000 period. As shown by Figure 9.8 below, Botswana and Kenya experienced a very strong growth in electricity demand from 1994 to 2000, although in 2000 Kenya recorded a decrease due to fewer units generated as a result of drought in the country. Before 1996, the electricity sales in Namibia were more than those of Tanzania. However, since 1996, Tanzania experienced a rapidly growing demand and as a result its sales exceeded those of Namibia. Even though, at present Tanzania's sales slightly exceed those of Namibia, there remains a lot to be done in Tanzania, owing to the fact that its population is 19 times that of Namibia. .

Figure 9.7 Electricity Sales GWh (2000)

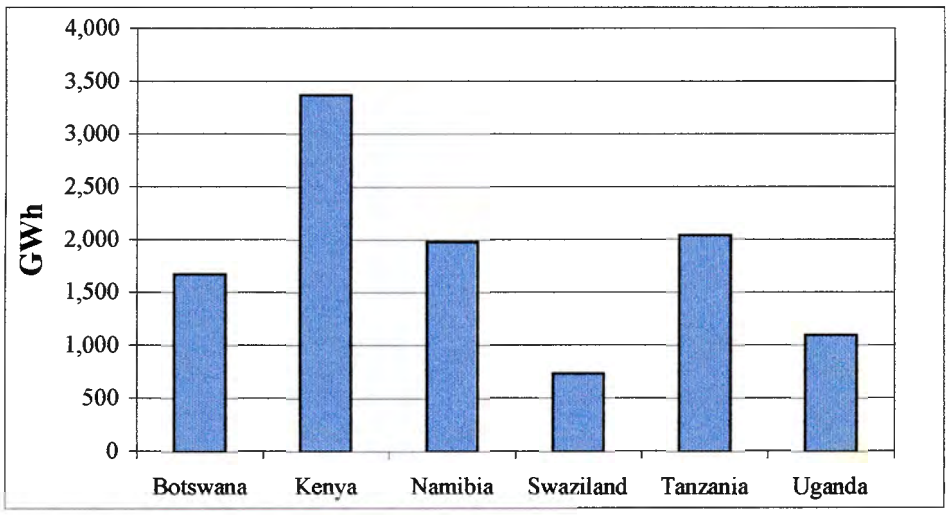
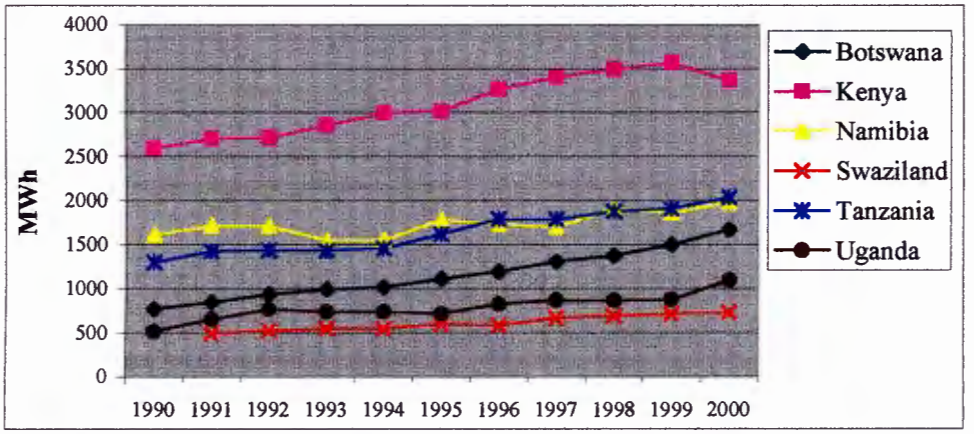


Figure 9.8 Electricity Sales Growths, (1990 – 2000)



Number of Customers

The customer base for all the utilities in these countries is relatively low, with most of the utilities having fewer than 500,000 customers. In comparison with the total population in these countries, the number of customers is very small, which clearly indicates that the utilities, in conjunction with their respective governments, need to look into ways of increasing their customer base. With the exception of Botswana, there is no other country which has in place special arrangements to boost its customer base. Botswana's arrangements of providing loans with soft repayment terms for service line connection should be copied by the other utilities and governments, as this would increase their customer base and improve access to electricity. As discussed earlier in Chapter Four this arrangement in fact allowed Botswana's electricity utility to almost double its customer base within a relatively short period of time (1995 – 2001).

The majority of the people in these countries are poor and cannot afford to pay for the fairly high electricity connection charges and for wiring of their houses. On the other hand, utilities do need to charge connection fees that reflect their own costs so that they will be able to pay for the line materials, most of which are imported. This problem is exacerbated by the rapid devaluation of the local currencies against the major foreign currencies. As a result, utilities find themselves in difficult situations, with no option other than raising their connection fees. As the rates are already on the high side, the further hike in fees makes it impossible for many customers to afford them and thus they continue using inferior energy sources which have additional problems associated with them, such as environmental degradation, etc. Figure 9.9 shows customer growth for the period 1990 – 2000.

Figure 9.9 Customer Growth; 1990 - 2000

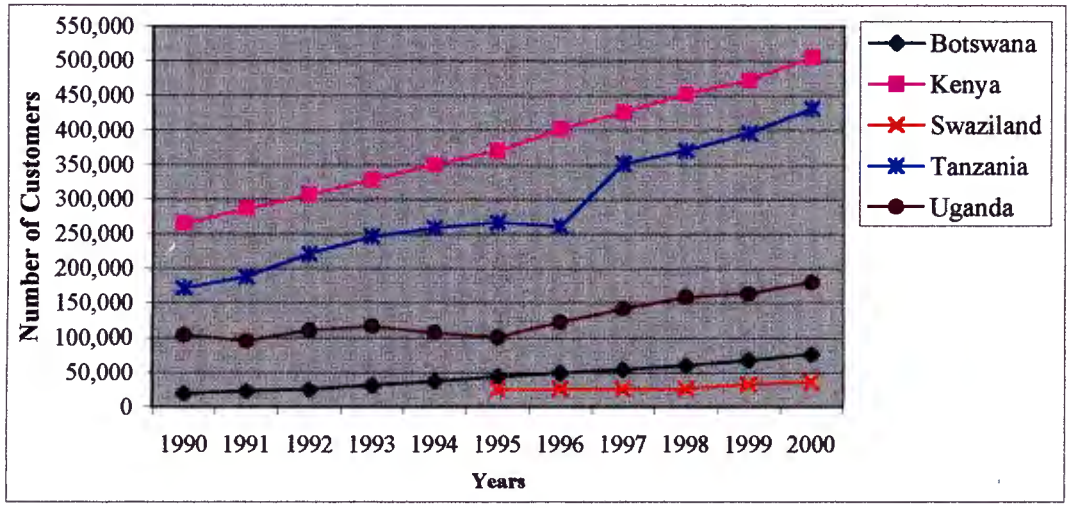


Table 9.5 Percentage increases of sales and the number of customers 1990 – 2000 – (%)

Year	Botswana		Kenya		Namibia	Swaziland		Tanzania		Uganda	
	Sales	Cust	Sales	Cust	Sales	Sales	Cust	Sales	Cust	Sales	Cust
1991	9.9	17.0	4.4	8.1	6.6			9.6	9.7	25.8	-8.0
1992	10.8	11.3	0.4	7.0	-0.3	6.1		1.1	17.5	17.9	15.9
1993	5.4	24.8	5.1	7.1	-9.5	5.4		-0.5	11.1	-3.8	5.5
1994	2.7	17.3	4.8	6.8	0.1	-1.2		1.7	5.2	0.1	-7.9
1995	9.3	17.9	0.7	5.4	14.9	10.5		11.2	3.0	-3.3	-5.7
1996	7.7	12.0	8.4	8.7	-3.0	-3.0	3.9	10.4	-2.1	15.7	21.3
1997	9.2	10.1	4.2	6.0	-1.8	14.8	0.0	-0.1	34.6	5.1	15.7
1998	5.4	10.3	2.7	6.2	12.0	3.4	0.0	5.0	5.4	-0.6	11.9
1999	8.9	12.3	1.9	4.4	-2.2	3.5	26.2	1.8	6.8	1.3	3.2
2000	11.3	13.3	-5.6	7.0	6.2	1.8	7.9	6.4	8.9	24.9	9.7
Average	**8.1**	**14.6**	**2.7**	**6.7**	**2.3**	**4.1**	**7.6**	**4.7**	**10.1**	**8.3**	**6.1**

9.3.3 Performance of the National Utilities

In general, with exception of Namibia's and Botswana's national utilities, the other utilities performed poorly over the last decade. Power interruptions, coupled with insufficient power in the grid systems, which have led to load shedding, have become part and parcel of electricity supply in most of the countries under study. For instance, in Tanzania customers had used all the ways available to them to air their complaints at the frequent power interruptions, many of which happened with no prior notice. Despite this, there have been few improvements and at present customers are urging the government to expedite the process of selling the utility in the hope that the new owners will rectify the situation. Deficient maintenance resulting from a failure to raise the funds needed to buy spare parts and the fact that some of the systems are old, have been the main reasons for the unreliability of the supply. Furthermore the lack of proper maintenance and the use of aged systems have also resulted in high system losses, which in turn significantly reduces the

available capacity that could be used to meet the growing demand.

As shown in Table 9.5 as well as Figure 9.11 on the following page, the utilities' profitability in 2000 was mixed. While Botswana's utility, BPC, recorded the highest profit, equivalent to about US$ 25 million, Kenya's electricity transmission and distribution utility recorded the poorest performance, reporting a loss equivalent to about US$ 34 million. Tanzania's utility, TANESCO recorded a loss equivalent to about US$ 11 million. In the previous year, 1999, TANESCO had recorded a net loss equivalent to about US$ 31 million. Apart from some of the utilities recording huge losses and even for those which realised profits, their asset bases (as also shown in the same table) are relatively small compared to the number of the population they are supposed to service. With such small assets bases these utilities will not be able to operate efficiently or be able to widen their services to cover more customers in all areas, urban and rural, as required.

For some utilities such as Tanzania's TANESCO, apart from having a small asset base, a great part of its equity consists of debt, which means that it carries a large interest payments burden (see the respective ratios in Table 9.6 below). These interest payment obligations in turn reduce the utilities' ability to finance maintenance or new system expansion. All other performance indicators for all utilities as shown by Table 9.6 are far smaller compared to the respective international benchmarks with the exception of system losses for Botswana, which was 11.1 – parallel to the international standard of about 10 – 12%. However, it should be noted that figures for Namibia, which are substantially different, are exclusively those of NamPower, which sells electricity in bulk.

Table 9.5: Some Financial Performance Indicators (2000)

Country	Total Asset Value (US$ Mill)	Total Annual Revenue (US$ Mill)	Net Profit Before Tax (US$'000)	Avg. Price of Electricity Sold (US c)	Return On Assets	Debt Equity Ratio	Interest Cover Ratio
Botswana	369.5	70.9	25,019.6	0.04	7.7	0.1	8.0
Kenya[1]	334.8	309.3	-34,051.2	0.09	-0.13	0.38	4.65
Namibia[2]	595.5	78.1	19,138.8	0.03[3]	3.22	0.13	21.66
Swaziland	74.3	34.9	4,652.6	0.05			
Tanzania	1,563.9	163.0	-11,319.7	0.08	(0.01)	0.32	0.35
Uganda	428.2	52.9	2,471.1	0.06[4]			

[1] Does not include generation

2 Excludes distribution

[3] Bulk Sales

[4] 1999 data

Figure 9.10 Average Price of Electricity in US cents (2000)

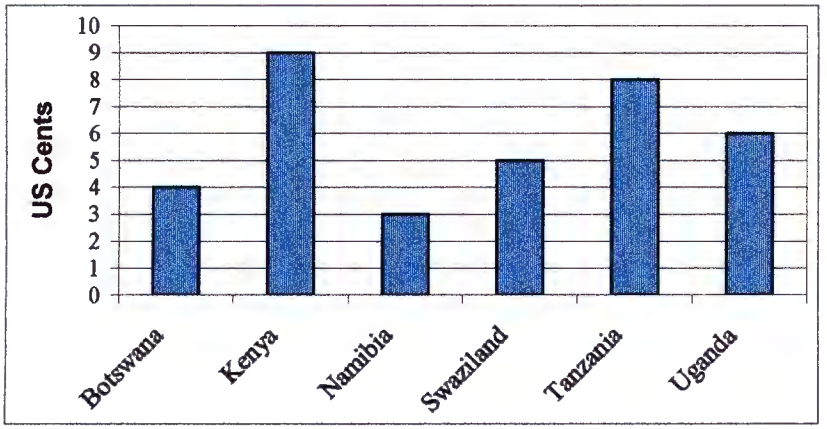


Figure 9.11. National Utilities' Net Profit/Loss Before Tax (1996 - 2000)

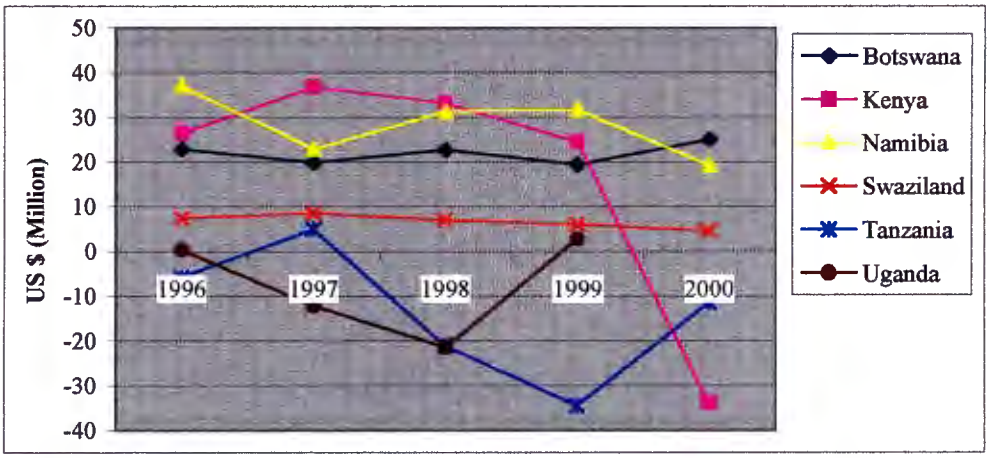


Figure 9.12 Return on Assets (1990 – 2000)

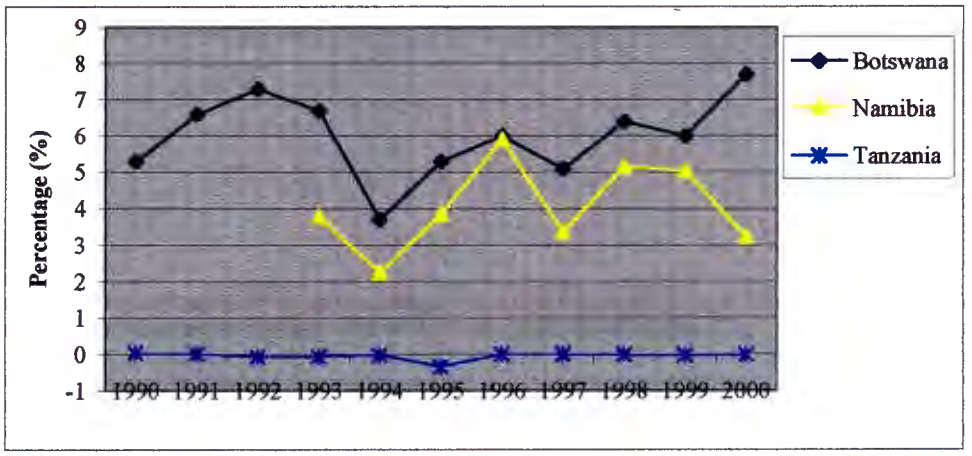


Table 9.6: Other Performance Indicators (2000)

Country	Number of Employees	Customers per Employee	Sales per employee MWh/Empl.	Total System Losses		Access to Electricity
				Units (GWh)	%	
Botswana	1,740	44	960	209.2	11.1	29
Kenya	7,095	67	502	957.0	21.5	9
Namibia*	831	3	2,380	223.1	9.8[1]	27
Swaziland	713	51	1027	115.1	14.0	30
Tanzania	6,612	65	308	471.2	18.8	9
Uganda	1,903	95	575	516.6	36.1	6
International Standards		160		-	10 – 12	80

International Standards adopted from Chiwaya et al. (1999: 337– 338)

*Excludes distribution
[1]Does not include distribution losses.

Figure 9.13 Number of Employees (1990 – 2000)

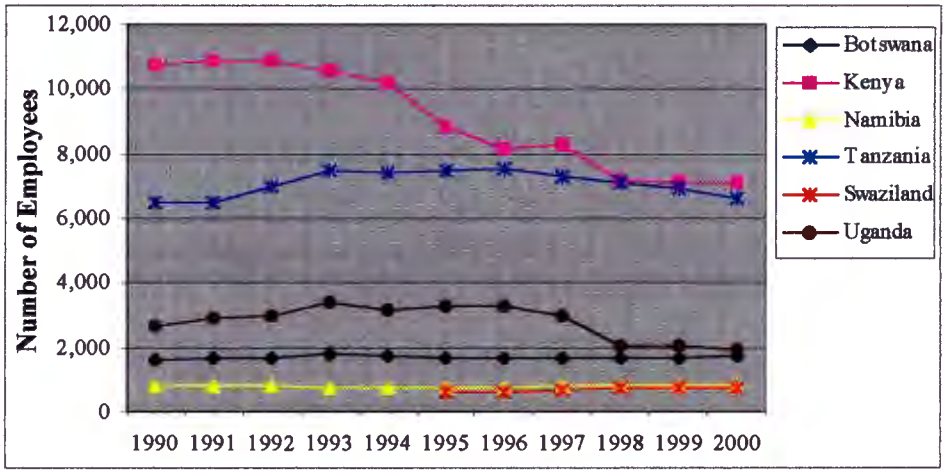


Figure 9.14 Sales per Employee (1990 – 2000)

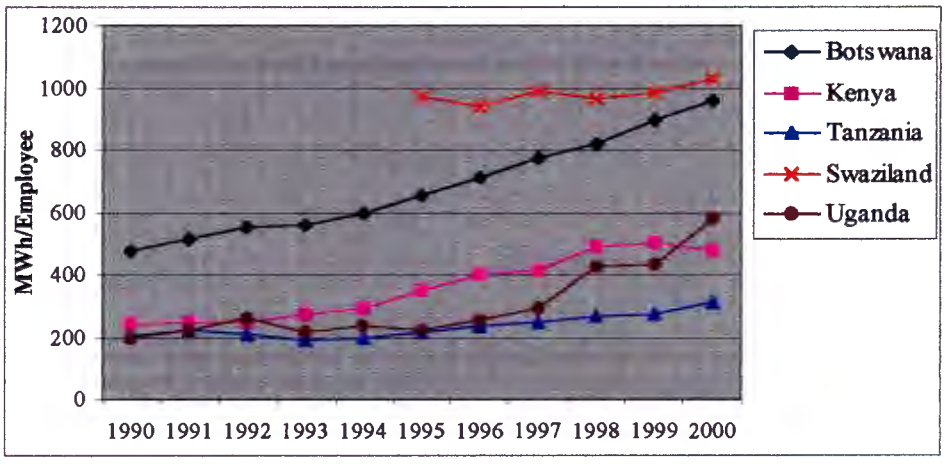


Figure 9.15 Customers per Employee (1990 – 2000)

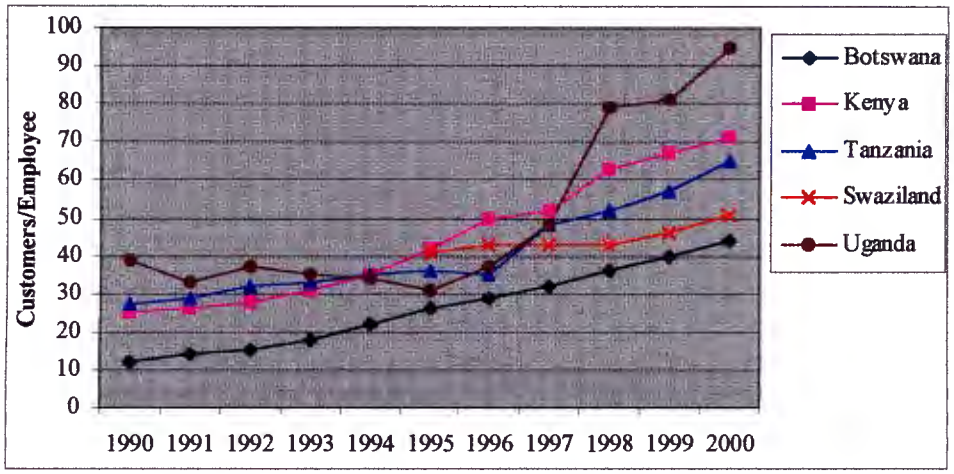
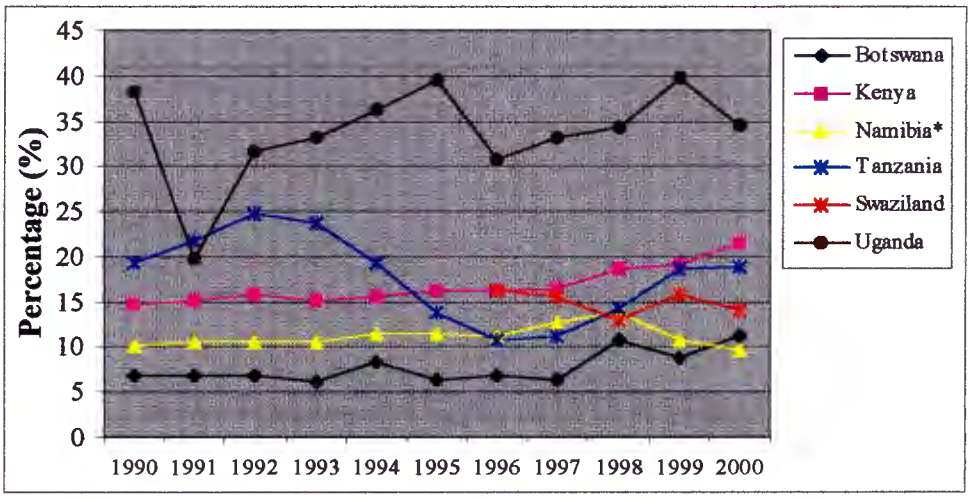


Figure 9.16 System Losses (1990 – 2000)



*Does not include distribution losses

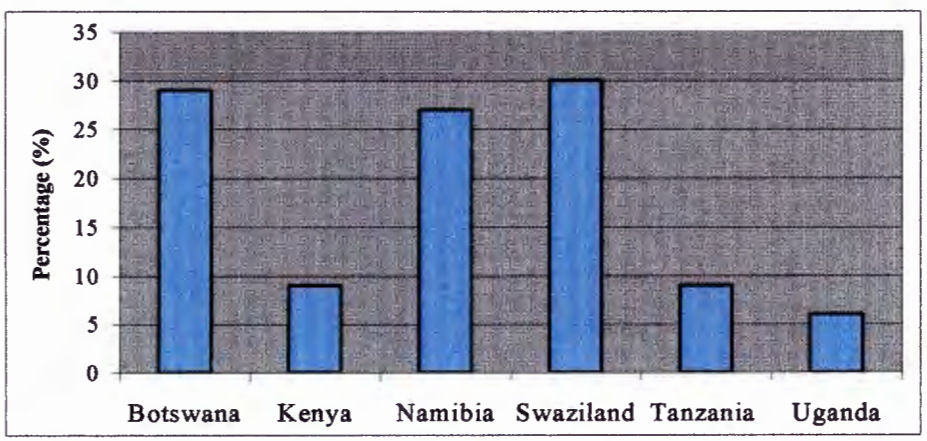
Access to electricity

As Table 9.6 above and Figure 9.17 below show, electrification rates in the countries under study are extremely low with the exception of Swaziland, Namibia and Botswana, which have rates that are encouraging, although, in comparison with the international standards they are still very low. The electrification rates in these countries' rural areas are even worse. The situation in rural areas is worse due to the fact that the utilities' activities are, in fact, concentrated in urban areas, although the majority of the population actually lives in rural areas. Botswana's high electrification rates are a result of the combined aggressive efforts of both the government and the utility. As mentioned before, the soft loan arrangement, which started in early 1990, enabled a good number of new customers to be provided with electricity. In April 2000 the arrangement was relaxed further, and

new customers are now required to pay only 5% as a down payment, with 95 % recoverable in 15 years.

Uganda, which has the lowest electrification rates among the countries under study, has recently also started to put in some more efforts with special emphasis on its rural areas in order to increase its electrification rates. The target set by the government for the coming ten years is to attain 10 % electrification in rural areas. This implies that with 85.8% of its population living in rural areas and given an annual population growth rate of 2.7%, it will take Uganda quite a long period of time (perhaps 100 years) before it can attain a 100 % electrification rate in rural areas. This is a challenge not only for Uganda, but for all other countries in Africa. One major problem with rural electrification is the dispersed nature of the population, which makes grid extension extremely expensive. As a result, even with the pending reforms, very few if any of the private investors will invest in rural electrification. It is therefore the task of the respective governments to carefully plan how they will enhance rural electrification. Initiatives such as establishing rural electrification funds should be considered by all countries and should be well administered if the intended results are to be obtained.

Figure 9.17 Access to Electricity (2000)



9.4 The Reforms

As the movement to reform power sectors is gaining momentum across the world, similarly the countries under study have already started their reform process and, compared to the rest of other African countries, some of them have progressed relatively far. Thus, for instance, Uganda and Kenya have made substantial progress in the reform process, with Kenya being among the first African countries to embark on the power sector restructuring and reform programmes. However, on the other hand, of the six countries under study, Botswana has lagged behind the others in making any step towards power sector reforms, although it recently started to seriously consider such reforms. Likewise, although Swaziland also took time before joining this movement, it is presently

in the initial planning stages, while Tanzania is at an advanced planning stage and has already started to take some key initial reform steps. Namibia has completed the planning stage and is now at an advanced implementation phase. All these reform initiatives have been driven by a number of factors, which are discussed in the following sub-section.

9.4.1 Driving forces behind the reforms

Basically the main driving forces for the power sector reforms in the countries under study are almost identical, except that Namibia has some additional country-specific driving forces, namely black economic empowerment and the need to deal with the problem of the existence of a large number of distribution entities with widely differing competencies and practice. Apart from these country-specific driving forces, others include the following: -

a) Poor technical and financial performance of the traditionally publicly owned utilities (Uganda and Tanzania) as discussed under section 9.3.4 above;
b) Improved customer services and choice (Namibia);
c) Attracting private capital to the power sector subsequent to the government's inability to finance the needed expenditure on the networks' maintenance and expansion (Kenya, Uganda and Tanzania);
d) Generation shortages which was caused by - first, an over-dependence on hydropower generation, which was adversely affected by the lack of rainfall as well as the poor distribution of rainfall in the main catchment area; second, the high breakdown rates of both thermal and hydro plants largely resulting from a lack of investment between 1990 and 1996; and lastly failure to implement generation capacity expansion plan between 1993 and 1997 – (Kenya);
e) External pressure, especially from major lending institutions such as the World Bank and the IMF. These institutions have changed their ways of financing new power sector expansion projects and have started to channel their loans through the private sector, as evident by the Tanzanian example given earlier in Chapter Eight (Tanzania);
f) International environmental concerns (Namibia);
g) Maximising financial and economic returns to the state through fiscal revenue and debt reduction (Namibia);
h) Stop supporting the national utility from the government's budget hence realising the funds to finance social sectors such as education and health (Uganda); and
i) Lastly, the international experience and the benefits which such reforms have so far delivered (All).

However, although the driving forces behind the power sector reforms in these countries are somewhat similar, the pace of the reforms differs considerably. This is mainly due to the fact that the extent of poor performance of the traditional utilities and the resulting problems vary

significantly from one country to another. The more severe the problems of the traditional utility and the power sector at large, the quicker the country embarked on the reforms with expectations that these would provide the necessary solutions; the reverse was true, however. The cases of Kenya and Uganda on one side and that of Botswana on the other side clearly explain this situation.

In the early 1990s Kenya experienced serious generation shortages resulting from, firstly, over-dependence on hydro generation, which was adversely affected by lack of rainfall. Secondly, the government's failure to implement none of the 250MW of generation capacity planned between 1993 and 1997 saw the country being among the first African countries to embark on power sector reforms. Uganda – having excellent hydropower potentials which are immune to droughts and at the same time having a per capita power consumption of only 44 kWh/year, which is the second lowest in the world – embarked on the reforms far earlier than many other countries. Moreover, of the countries under study, Uganda's electricity utility problems were actually far more serious (see Chapter Three). On the other hand as a result of the consistent and relatively good performance of Botswana's utility, (BPC), as evidenced by the fact that the country's electricity levels (29 %) are higher than the SADC average and due to very small market, Botswana was the last country to implement reforms.

9.4.2 Objectives

Since the driving forces behind these reforms are similar, the countries' objectives are also similar. These objectives are: -

a) Increase sector efficiency (Tanzania, Uganda, Namibia, Swaziland, Botswana and Kenya);
b) Attracting private investors in the power sector (Kenya, Namibia, Tanzania and Uganda);
c) Introducing sector competition (Namibia);
d) To make the power sector financially viable and able to perform without subsidies the government budget (Uganda);
e) To reduce public sector expenditure and debt by transferring to private capital the commercial risks, which are inherent in investments in the electricity sector (Tanzania);
f) Increasing access to electricity in a sustainable manner particularly in rural areas (Namibia);
g) To accelerate electrification, so as to ensure access to the broadest cross-section of the population and centres of economic activities (Tanzania);
h) To meet the growing demands for electricity and increasing area coverage (Uganda);
i) To improve reliability and quality of the electricity supply (Uganda);
j) Alleviation of resource constraints in the electricity sector (Namibia);
k) For those countries which are well endowed with potential electricity sources like Uganda and Namibia, the governments want to encourage development of the sector so as to take advantage of export opportunities (Uganda and Namibia);

l) Development of an efficient and appropriate governance framework and structure (Namibia);
m) To increase the sector's commercial performance (Uganda and Swaziland);
n) Ensuring environmental and socio-economical sustainability (Namibia);
o) Promotion and development of the sector as a key vehicle for investment and growth (Namibia);
p) To ensure long-term economic viability and sustainability of the electricity sector, so that it can meet the challenges of economic development (Tanzania); and
q) For those countries that heavily rely on imports and few sources of supply, another governmental objective is to increase the security of supply, while taking into account the risk of stranded investments (Namibia).

One key objective that has been declared as priority number one is to increase the sector's efficiency. Not only has this been prioritised by the countries under study, but also throughout the rest of the world. Developed countries, too, have embarked on power sector reforms with the aim of improving sector efficiency, hence leading to a reduction in electricity prices. In developing countries such increases in sector efficiency, in addition to leading to price reductions are expected to help in meeting the growing electricity demand. Another key and common objective of power sector reforms is to accelerate electrification in a sustainable manner and to widen the area coverage to include rural areas. The number of people that have access to electricity in these countries is extremely low, thus the relevant governments are expecting these numbers to increase if the suitable reform programmes are implemented. Additionally, as most of the governments could no longer effectively finance the required new investments, the governments have formulated the further objective of attracting private investors to participate in all areas of the electricity industry.

9.4.3 Reform Strategies and Progress

Generally, before countries embark on power sector reforms, they first show their intentions by issuing an energy policy or a sector-specific policy, which provides the broad guidelines for the reform programme to be followed, and then enact the required enabling legislation for implementation of the policy. This stage is followed by embarking on reform strategies, which differ somewhat from one country to another. However, experience has shown that a broadly similar model is followed in the developing countries, particularly in Africa. As mentioned earlier, this model entails the following steps: -

i) Corporatisation and commercialisation of the national utilities. In this step the publicly owned utilities are corporatised by transforming them into self-contained entities. The utilities are separated from direct government control and become legal corporations with separate managements and accounts and are required to pay taxes and dividends. Those which are already body corporates are transformed into more commercially viable entities,

as they are required to operate on sound commercial principles, a process which is known as commercialisation;

ii) The second step that often follows is to establish a regulatory authority. This is required at the first stages so that it can work hand in hand with the government in the remaining steps of the these reforms, so as to help avoiding any mistakes and future problems;

iii) The third step entails restructuring the utilities by vertically and horizontally unbundling them to form new separate entities on a vertical and/or horizontal basis. These newly formed separate companies are then required to trade with each other on a commercial basis. At this stage IPPs may also be allowed to enter into the power sector arena, which together with the generation company or companies will sell power to the transmission company. Another sub-step in this third step involves making the transmission company the sole purchaser of power from the generation company or companies and the IPPs, which in turn will sell in bulk to the distribution entity or entities. This sub-step is called creation of a single buyer; and

iv) Lastly, privatisation of the unbundled entities, i.e. the newly formed generation, transmission and distribution companies.

Accordingly, with regard to the countries under study, which have already begun to implement power sector reforms, they all appear to have taken the same steps. Their programmes have been built around this basic model, as discussed below in greater detail.

Enabling Legislation and new ESI Policies

The good intentions of a country to reform its power sector, which are in most cases well presented in a policy paper document, are clearly not enough, as it is required to commit itself through implementing various legislation and laws in order to attract potential investors. According to Marandu (2000: 23), legislation is needed in order to create the legal basis for the regulation, unbundling and privatisation of the power sector. It also introduces credibility to the reform process for investors who know that they can challenge unfair decisions in a court of law.

In view of the above and as Table 9.7 below shows, many governments of the countries under study have already enacted the required legislation and others are underway. On the one hand, Swaziland and Botswana are yet to enact the required new laws to allow for power sector restructuring and setting up of regulatory frameworks. As mentioned earlier in Chapter Six, at present Swaziland has in place three pieces of draft legislation, which are due to be tabled in parliament this year. These include the Regulatory Act, the Electricity Act (which will initially be based on a single buyer model) and the Corporatisation Act (which will make private sector participation possible). As for Botswana, so far the government has only in March 2000 approved a White Paper on Privatisation

Policy, which earmarked the energy sector as one of the sectors where liberalisation should be considered. It is expected that this will be followed by enacting the required legislation, as without supporting legislation the policies, however good they may be, will achieve nothing as far as reforms are concerned.

On the other hand, Kenya, Uganda, Tanzania and Namibia first issued new energy policies or specific electricity industry policies detailing the direction to be taken by the respective governments concerning the restructuring and privatisation of the industry. These policies were followed by enacting legislation to enable changes in structure and ownership to be effected. Kenya was the first to enact enabling legislation with its new Electric Power Act of 1997. Among other things, this new bill provides for the separation of KPLC and KenGen and the establishment of an electricity regulator, as well as allowing private sector participation in terms of IPPs. Uganda followed suit, enacting its new Electricity Act in 1999. This bill provides for the vertical separation of the traditional electricity utility and the establishment of electricity regulator. As for Namibia, the government enacted its new Electricity Act in July 2000 to replace the old South African Electricity Act and provides for the establishment of electricity regulator. Tanzania, too, has in April 2001 enacted the necessary legislation to establish a multi-sector regulatory agency. It is expected that the new legislation to enable effecting new industry structure would be presented and passed by parliament in October 2002. Enacting the right legislation, which will provide assurance to potential investors, is one of the prerequisites for a successful power sector reform programme.

Corporatisation and commercialisation

Following a study, which made certain recommendations that were subsequently approved by the government, Swaziland is intending to start its power sector reforms through the corporatisation of its national utility, SEB. Currently, SEB does not pay taxes or dividends. Through corporatisation it will be converted into a commercial entity, which will operate under normal company laws, regulation and taxation, and it will be owned by public and private shareholders through selling of shares.

On the other hand, all the other national utilities of the countries under study, which are already body corporates, are required to pay both taxes and dividends. However, due to poor management and excessive government intervention, some of these utilities performed poorly and were unable to pay taxes and dividends as required. The utilities that performed poorly were those of Uganda (UAB) and Tanzania (TANESCO). They had been operating at very low efficiency levels and huge financial losses and had also failed to either invest in new capacities or to rehabilitate their systems. Consequently their respective governments had to take some measures to make them operate on more commercial principles and deliver services at an acceptable standard. Commercialisation of

these utilities in these countries occurred by placing them under management contract. This was the best way that these governments could achieve the desired results within the minimum time before the restructuring phase. This is to say that, the aim of commercialisation is to level the playing fields for the new business entities, which are created as part of the restructuring step.

As discussed in Chapter Three, by placing the UEB under management contract, a significant increase in the utility's value and an improvement of its service delivery was achieved during the contract period. Tanzania very recently contracted a private firm to run its utility, but it is expected that at the end of the two-year contract the management firm will succeed in turning the utility into a profitable entity as well as raising its value before the restructuring phase is implemented. On the other hand, Namibia and Kenya bypassed this first step of hiring a firm to manage the incumbent utility on a contract. For Namibia, this is because its utility, NamPower, had performed relatively well for the past ten years. In addition to this, because of the existence of many distribution entities and although some of them were operating poorly, it was not a better option for the government of Namibia to hire private firms to run them. As regards Kenya, which also bypassed this first step, the government decided to proceed straight to unbundling. As mentioned earlier, Botswana is currently considering reforming its power sector. It is most likely that it will also bypass this first step as its utility has been performing well too – earning reasonably increasing profits, although it has not increased electricity tariffs for the past six years, as well as achieving relatively high electrification rates.

Restructuring

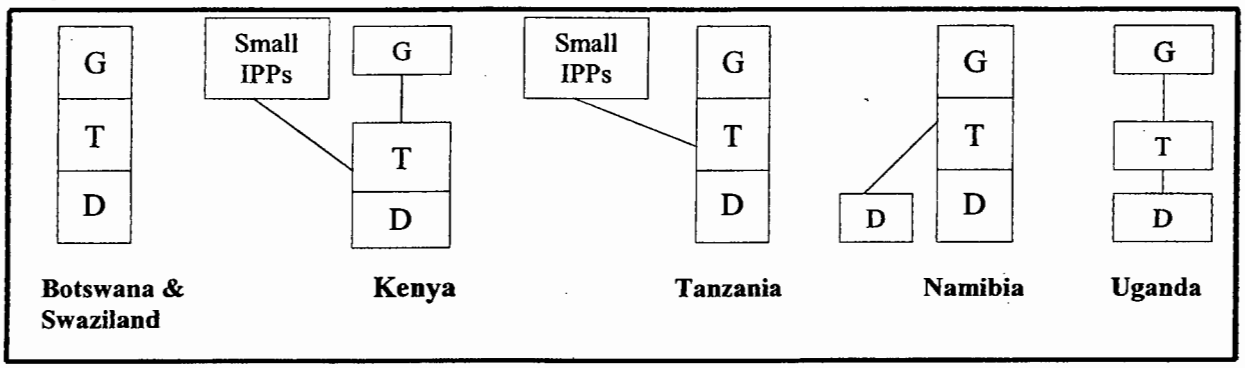
Current Structure and Ownership

Previously, the ESI structure was characterised by vertically integrated and publicly owned utilities with monopoly power in all the segments of the industry, namely generation, transmission and distribution. In most of the countries under study the same trends of ownership and structure still apply, although reforms in some countries have allowed new generators to enter the market. With the exception of Kenya and Namibia, all the other countries have a single utility responsible for the generation, transmission and distribution of electric power throughout the country, although Tanzania has allowed the entry of small IPPs and Namibia does so in principle.

Uganda has just completed unbundling its utility to form three separate entities. In Kenya, following the government's decision to partially unbundle the ESI, there are now two publicly owned utilities, i.e. one responsible for the transmission and distribution of electricity and the other one responsible for generation; together with four IPPs, the latter sells bulk power to the transmission and distribution utility. Namibia is the only country which has a number of electricity distributors. In

terms of utility ownership, all utilities, including the newly formed separate companies in Uganda, are 100% owned by their respective governments, except for the transmission and distribution utility in Kenya, which is partly owned by the government and by private individuals who own shares. The IPPs, which are currently operating both in Tanzania and Kenya, are owned by private individuals, most of them from outside the country, although in Tanzania a joint venture between foreign and local firms owns one IPP and the other two are owned by publicly owned companies. Figure 9.18 shows the current structure of ESI in these countries.

Figure 9.18 Current Structure of the ESI in the Countries under Study



Expected Structure

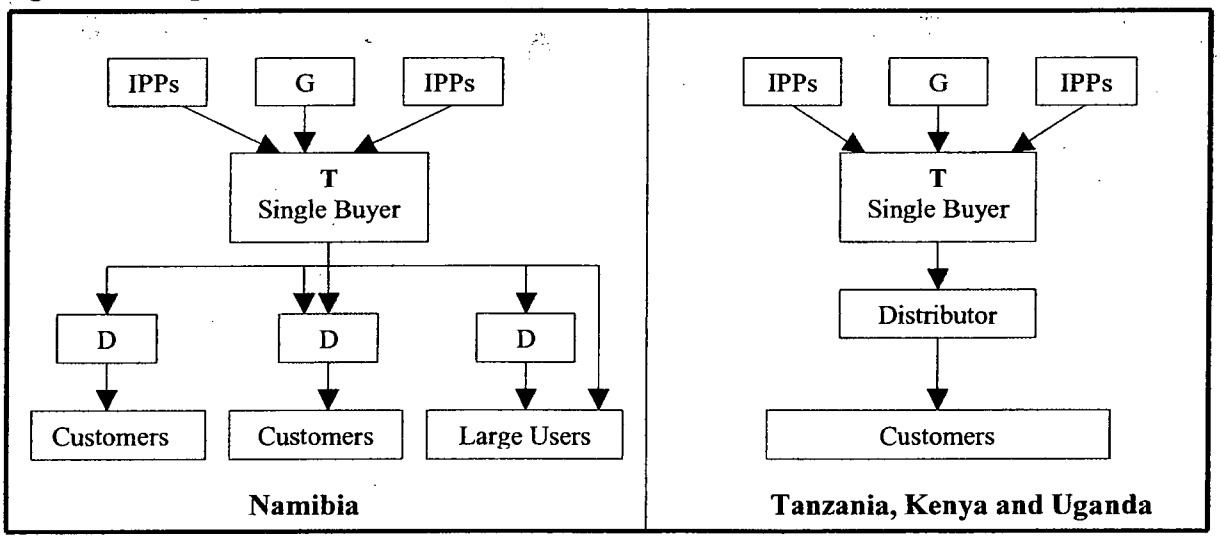
The expected structures of the ESI of those countries under study, which have already undertaken some reform initiatives, seem to be heading to a single buyer model. For instance, Namibia has already embarked on a single buyer (SB) model and is reorganising its distribution industry to form viable regional electricity distribution companies (REDs). In fact, the existence of the highly fragmented electricity distribution industry which has had negative implications on tariff levels and entailed a loss of economies of scale, was the major problem of Namibia's ESI.

Thus Namibia's reform strategy entails NamPower to continue playing an important role not only with regard to generation and transmission, but also in the area of distribution. In the generation sector, NamPower is encouraged to take part in IPP development, which will be introduced in the transmission segment; its transmission business performs the tasks of the single buyer and acts as a system operator albeit with a separate account. As for the distribution industry, NamPower is also allowed to take a key role in the REDs, which will be formed in terms of ownership and operations. After the REDs have been successfully created, the government is committed to looking into further ways of introducing competition so as to be able to pass on to its consumers the full benefits of efficiency gains.

With regard to Uganda, after it had successfully completed the restructuring of its national utility by vertically unbundling it to form three separate companies, it has assigned the responsibilities of single buyer to the newly formed Transmission Company. This is the system operator which, among other things, has the responsibility of co-ordinating the power supply system to insure a balance between the generation and consumption of electricity as well as dispatch of generation facility. In addition the Company will form a "ring-fenced" entity with separate accounts and personnel, which will be responsible for wholesale market operations. On the other hand, Tanzania has announced that when the two-year management contract is finished, it will restructure the utility by vertically unbundling it. It is most likely that the country will also create a single buyer, as currently there are some IPPs, which hold long-term PPAs with the incumbent utility.

As far as Kenya is concerned, as pointed out earlier, the country has partially unbundled its two utilities, which previously existed as one. The unbundling resulted in the formation of two companies, one responsible for generation, i.e. KenGen, and the other responsible for both transmission and distribution, KPLC. The transmission and distribution company buys power in bulk from the generation company and some small IPPs by using PPAs. However, the government of Kenya is committed to further unbundling the two companies to form separate business units in line with the recommendations of the market design study that is currently underway. Due to the existence of several PPAs between the KPLC and the generators, it is likely that transmission functions will be separated from distribution to form a single buyer. It is not known as yet whether the distribution industry will be further unbundled to form several distribution entities. This also applies to Uganda and Tanzania. Figure 9.19 shows the expected structure of the ESI of these countries.

Figure 9.19 Expected ESI Structures



The two separate utilities that were formed in Kenya after the partial unbundling have so far existed and operated as completely independent entities for about three years. As mentioned earlier their business performances for this period have taken two opposite directions, profitability and loss making. In other words, while the generation utility enjoys positive returns, the transmission and distribution utilities experience major problems. For two consecutive financial years, 1999/2000 and 2000/01, it recorded total net losses before tax equivalent to US$ 86.3 million, which is almost enough to construct a diesel generation facility with 100 MW capacity. This substantial amount of money could also have been used to connect electricity to a significant number of consumers. This provides a very good lesson for countries such as Botswana and Swaziland, which are now at the planning stages of their reform programmes.

Kenya's case suggests that the distribution part of the ESI in these countries and in the rest of Africa is the main source of most of the industry's problems. Careful analysis of all the countries under study shows that all these countries had or have major problems with distribution as compared to the generation part of the industry. For instance, as seen in the chapters on the respective countries, Uganda and Tanzania had very poor revenue collection, coupled with flourishing electricity theft by customers, which led to high levels of system losses (36 %). In addition the rates at which new customers were connected to their grid systems were very low, thus reflecting their very low access to electricity rates.

Moreover, the relatively good performance of Namibia's generation and transmission utility and its highly fragmented distribution industry with varying performances, also illustrate this fact. This shows that when countries adopt various ESI reform strategies, they need to pay more attention to distribution, as this appears to be the main source of the industry's problems. In fact, if a country's reform programme will result in a weaker distribution industry, it will in turn significantly deter potential investors in the generation and transmission segments. This would most likely bring about a complete failure of the reforms. This is because potential investors will not be sure of selling their power and being paid accordingly. There is no private investor who would be willing to be owed a large amount of unpaid bills by a distribution company (as was the case with KPLC and KenGen in Kenya – see Chapter Five). Although it could not be established how KPLC was treating the IPPs in terms of settling their bills from the electricity, which the latter supplied to the former in bulk, it is likely that other potential IPP developers are looking at Kenya critically.

Privatisation

As regards privatisation, Uganda is about to complete concessionning out the newly formed generation, transmission and distribution companies. Tanzania has also announced that the privatisation of the new companies will be carried out by concession. As for Kenya, the government

is currently awaiting the consultant's recommendations on the industry's future structure and ownership.

Regulatory Framework

As mentioned earlier, previously, government departments (in most cases resorting under the ministries of energy) undertook the regulation of the power sector as was the case in most African countries. A similar trend was and is also found in the countries under study. As reforms are introduced new regulatory boards, authorities or commissions, which are transparent, capable and independent should also be introduced. So far this has only happened in Kenya, Uganda and Namibia, which have full established and operational regulatory boards. These boards were formed as part of their power sector reforms and are expected to work together with their respective governments in accomplishing the reforms programmes which are still under way. Tanzania, Swaziland and Botswana are yet to establish such regulatory boards, but as was discussed in Chapter Eight, Tanzania is about to operationalise its multi-sector regulatory agency, which will also oversee the electricity sector. As regulators are critical to the smooth functioning of the electricity markets that will be created, by ensuring that prices are pushed to their lowest possible levels, the governments should make sure that the regulators are fully equipped in terms of skilled manpower and that the right laws are in place.

As was mentioned in Chapter Five, there have been some concerns regarding the independence of Kenya's Electricity Regulatory Board. This poses a challenge to Kenya and to all other countries, as the need to have independent regulatory boards or authorities to oversee the sector and ensure its smooth running cannot be over-emphasized. All governments should support the current initiatives to establish both the Regional Electricity Regulator Association (RERA) and the Africa Forum for Utility Regulators (AFUR) as it is only through cooperation and sharing of experience that regulators will be able to work more independently in their respective countries while at the same time maintaining common practices in the region and in Africa at large. Under the auspices of NEPAD, if RERA and AFUR were to be established as planned, it is likely that it will be easier for them to force the respective governments to ensure that the regulators are independent, in other words, that each country has a sound regulatory system.

Table 9.7 Status of the Reforms

	Botswana	Kenya	Namibia	Swaziland	Tanzania	Uganda
Energy Policy	-		1998		1999	-
ESI Reform Policy/Strategy	2000		1998	2002?	1999	1999
Reform Legislation	-	1997	2000	2002?	2002?	1999
Regulator Legislation	-	1997	2000	2002?	2001	1999
Corporatisation	-	-	-	2002?	-	-
Commercialisation						
-Management Contract	-	-	-	-	2002	1999
-Unbundling (Separation of Accounts)	-	-	2002	2002?	-	-
Physical Vertical Unbundling - Gen/Trans/ Distr	-	-	-	-	2003?	2001
- Gen&Tran/Distr.	-	-	1964	-	-	-
- Gen/Tran & Distr.	-	1998	-	-	-	-
Horizontal Unbundling						
- Gen/Gen/Gen	-	-	-	-	-	-
- Dist/Dist/Dist	-	-	-	-	-	-
- Distr. Rationalisation	-	-	2002?	-	-	-
Competition						
IPPS	-	1997	-	-	1992	1999
Competition Possible	-	-	-	-	-	-
Competition Actual	-	-	-	-	-	-
Generation Monopoly	1970	-	-	1963	-	-
Gen. Market Power	-	Yes	Yes	-	Yes	Yes
Single Buyer	-	1998	2002	-	2003?	2001
Wholesale Competition	-	-	-	-	-	-
Electricity Trading	-	-	-	-	-	-
Privatisation						
- Generation	-	-	-	-	2004?	2002?
- Transmission	-	-	-	-	-	2002?
- Distribution	-	-	-	-	2003?	2002?
Independent Regulator - Sector Specific	-	1998	2000	-	-	1999
- Multi-sector	-	-	-	-	2002?	-

Key:

? = Planned

9.5 Conclusion

The study's findings have shown that in these countries there are very few good experiences which could provide good lessons for each to learn from one another and to copy in their efforts to develop the sector. Both in terms of the status of the various ESIs and the initial steps taken so far to reform the industry there have been more problems than good examples and/or successes.

With regard to the status of the ESI, the critical role played by importation of electricity in satisfying a country's power requirements does at least provide a very good lesson, which these countries and the rest of the region should find ways to enhance. Electricity imports might have been one of the simplest solutions to the power shortages faced by many of the countries, if all their power systems had been interconnected with one another. In fact, imports could even be far better than own generation, as evidenced by Botswana, which has been importing more than half of its electricity requirements and yet its utility has been the most successful one overall. Thus an initiative such as the SAPP, which brings together utilities to trade electricity among them, is of profound importance. The SAPP could also help in attracting investors to develop coal, which is plentiful in the southern part of the region, and cheap hydropower, which is available in eastern and central Africa. However, initially SAPP was established with its membership made up of the countries' national utilities. These countries are currently embarking on reform programmes, and ways to widen SAPP's scope to include private sector participation should be sought accordingly in order for the countries to benefit more from an electricity trade under a new industry structure and ownership.

On the other hand, as pointed out earlier with regard to the power sector reform initiatives, which have been taken so far by some of these countries, their results unfortunately cannot inspire other countries. In fact, countries such as Kenya and Tanzania have experienced more problems than before the reform initiatives, a situation which does, however, provide good lesson for others to learn and benefit from, one of which being that careful planning should be done before actually embarking on such reforms. It should also be noted that the problems experienced by Kenya and Tanzania are less a result of the failure of reforms or deregulation, but rather of poor planning and a lack of prerequisite capable regulators. The fact that the government of Tanzania is now paying about US$ 1.5 million monthly to an IPP as a capacity charge, apart from and in addition to what the national utility is paying, is only due to a lack of proper planning. This large amount of money is currently being paid by taxpayers, many of whom are not electricity users (note that only 9 % of Tanzanians have access to electricity). Both the energy charges and all the capacity charges were supposed to be met by electricity users through the utility and not otherwise. Assuming that this particular PPA will last for ten years, the government will pay a total of US$ 180 million, which might have been used in other needy areas such as education and healthy sectors. Clearly these are not the intended results of the power sector reforms and, in fact, their aim is to enable governments

not to finance the sector anymore. Thus countries which are now planning their reform programmes, should ensure that all the necessary prerequisite conditions are already in place before embarking on such reforms.

Due to the small sizes of the individual countries' power sectors, as mentioned earlier, it is likely that most will resort to a single buyer model, just as Namibia did. This entails all generators selling their power to an entity, which in turn will be the only seller of bulk power to distributors and large users of power. This offers a very limited form of competition and involves signing of Power Purchase Agreements (PPAs). As a result, if these countries are not careful enough, the power sectors will be tied up with high-priced and poorly designed PPAs which will have profound implications on the tariffs levels – which are already on the high side in some countries – and thus overshadow the benefits of the reforms. Kenya is experiencing such a situation and is currently trying to revise their PPAs within a short time of operation – again an exercise that could have been avoided if thorough study and care were taken beforehand. In order to avoid such problems when signing PPAs, considerable care must be taken and, most importantly, competition during entry should be ensured and well implemented. As the systems grow and all the necessary conditions are in place, this single-buyer model should be abandoned and further reforms introduced to stimulate more competition. As mentioned previously, competition is the only way to pass on benefits of these reforms to the ultimate electricity consumers. However, competition could bring even more benefits if there were a larger interconnected market.

Although these reforms will not in the short and medium term be able to bring full competition into the ESIs of these countries, as is the case with developed countries, they are nevertheless the only way forward for these countries and for the rest of Africa in trying to solve current power sector problems. For instance, participation of the private sector as a result of these reforms will help these countries in many ways, such as investing in system expansion, which many governments had failed to do, providing quality service with no power interruptions, delays and incorrect bills, etc. Moreover, the governments which previously had to finance the sector would then be able to concentrate on other priority sectors such as education and health, which are also facing many problems. However, for the reforms to be embraced even more, and apart from providing the required additional capacity, they should enable more customers to be connected with electricity. As has been shown in this chapter and in the chapters on the respective countries, access to electricity is extremely low . Ways of increasing electrification rates should be sought during the planning stages of the reform programmes and their implementation should also be well monitored.

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