

**TOWARDS A PRICING STRATEGY FOR THE SOUTH  
AFRICAN ELECTRICITY SUPPLY AND DISTRIBUTION  
INDUSTRY**

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MSc Dissertation  
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## DECLARATION

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

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**B.R.A Mountain**

Dated at.....this.....day of.....1994

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At the time that I started this dissertation, I subverted a conviction that I would need much more time and effort to complete this work than I had budgeted. In retrospect my conviction was correct and this work could not have been completed in the budgeted time without the support of a number of people. In particular my supervisor, Charles Dingley, is gratefully thanked for his incisive comments and thorough observations. I would like to thank Hendrik Barnard and Andries Calitz, who provided me with opportunities to attempt to maximise the relevance of this work to the electricity industry in South Africa. Sue Cook from the Eskom Library is also thanked for her endless assistance. To Eskom I am indebted generally, for covering all costs incurred in producing this work. Finally, to my wife Roz, gratitude for her patience and perspicacity.

## **ABSTRACT**

**The purpose of this dissertation is to develop a strategy for electricity pricing in the South African electricity supply and distribution industry. To achieve this, the thesis focuses on three specific areas: Electricity pricing theory; past and present electricity pricing in South Africa; and a review of electricity pricing in the United Kingdom, France and Zimbabwe. Using this research as a basis, various thoughts are presented on a pricing strategy for the South African electricity industry.**

**The essence of the strategy is that optimal pricing will occur in a truly competitive industry. The thesis does not seek to prove this hypothesis. Instead a three phase development process is proposed whereby electricity pricing in the South African industry may be transformed from its currently fragmented and decentralised position, to a state in which the force of fair competition will be the prime determinant of the pricing policy of the competing suppliers and distributors.**

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## **CHAPTER 1. INTRODUCTION**

### **1.1 Background and rationale**

Electricity in South Africa has consistently been amongst the cheapest in the world. There are perhaps two main reasons for this. Firstly, South Africa's abundant reserves of cheap coal have resulted in the development of large coal-fired stations which produce electricity very economically. Secondly, as a result of the policies of a previous political dispensation, the industry has largely ignored the electrification of millions of potential customers, whose limited ability to pay would have placed a financial burden on the electricity industry.

One of the consequences of the low cost of producing electricity is that there has been relatively little incentive for the development of economically efficient tariffs. This problem is further exacerbated by an inefficient and fragmented distribution industry in which the structure and level of tariffs are generally influenced to a greater degree by political rather than economic considerations.

However, political changes in South Africa are forcing the industry to face up to some of the realities that have so far been swept under the carpet. The success of the industry in future will depend on a workable solution being found to the problem of serving the needs of the industry's existing customers, as well as providing electricity for many millions of currently unelectrified homes. The way electricity is priced is at the heart of this issue and hence the purpose of this dissertation is to develop ideas on a pricing strategy which will ensure the survival and growth of the South African electricity industry in the context of the severe constraints which it currently faces, and will continue to face in future.

### **1.2 Research on which this thesis is based**

This thesis is based on research conducted principally during 1992 and 1993 during which time the author was employed in the Transmission Economics and subsequently the Electricity Pricing Departments in Eskom. Most of the research was conducted through a desk-bound review of published literature and documentation. However, information and support was obtained from a number of people including: Messrs. Andries Calitz, Hendrik Barnard, Dirk Els, Jac Neushloss and Callie Fabricius (Eskom); Mr Charles Anderson; (Charles Anderson Consulting); Peter Dale; (Power Plan Consultants, Zimbabwe); Mr

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### **1.3 Development of the thesis**

The second chapter presents a theoretical framework to the subject of electricity tariffing. The chapter begins with a paradigm which explains the role of electricity pricing as the mechanism which mediates between the interests of the consumer, the supplier and the State. The chapter then moves through a discussion of various electricity pricing criteria to a specific discussion on various costing and pricing methodologies. As part of the research for this dissertation, an effort was made to gain a theoretical understanding of economic theories of pricing, the purpose of this effort being to explain and interpret aspects of this theory in relation to the problem of electricity pricing. The product of this effort constitutes the greater portion of the second chapter. The substantive focus on economic theory in this chapter is justified in terms of an attempt to develop a holistic treatment of the problem of electricity pricing. It should be noted however, that no claim is made that this work represents a complete discussion on the various theories on electricity economics.

The third chapter presents a history of the development of the electricity supply industry in South Africa. The history is divided into two periods: the period from 1882 to 1948 and the period from 1948 to 1987. After 1948, the supply industry was nationalised and Eskom as a single supply authority became the dominant supplier in South Africa. This chapter attempts to provide a background for the discussion of electricity pricing in South Africa which follows in the next chapter, Chapter 4.

Chapter 4 reviews past and present electricity pricing in South Africa. The significant price increases of the early seventies is the point at which the review of past pricing practices begins. The chapter then proceeds to discuss electricity pricing at present in both the Eskom and non-Eskom distribution industry.

The fifth chapter focuses on electricity pricing in three very different electricity economies in the United Kingdom, France and Zimbabwe. The UK study focuses on the privatisation

and restructuring of the UK electricity industry. The specific pricing mechanisms in generation, transmission and distribution are described and discussed. Finally in this section, some ideas are explored as to how some positive aspects of the UK industry could be applied to the electricity industry in South Africa. France on the other hand, provides an example of electricity pricing in a fully-developed and vertically integrated electricity industry. Here the focus is on describing and analysing the development of electricity pricing in the industry, with specific reference to the applicability of French electricity pricing to South Africa. The focus in the Zimbabwe study is to analyse the development of electricity pricing in the industry in view of the underlying political and economic forces. Zimbabwe electricity pricing contains an irony of particular relevance to pricing in South Africa.

The formative work of the previous chapters is then used in the penultimate chapter which describes a possible vision for electricity pricing in South Africa. The chapter begins with a review of the key issues discussed in each of the earlier chapters. Then the chapter describes a vision for electricity pricing in South Africa. The final section of the chapter proposes a three phase tariff development process which - it is intended - will realise the described vision.

The final chapter draws out the significant conclusions, and discusses aspects of this study.

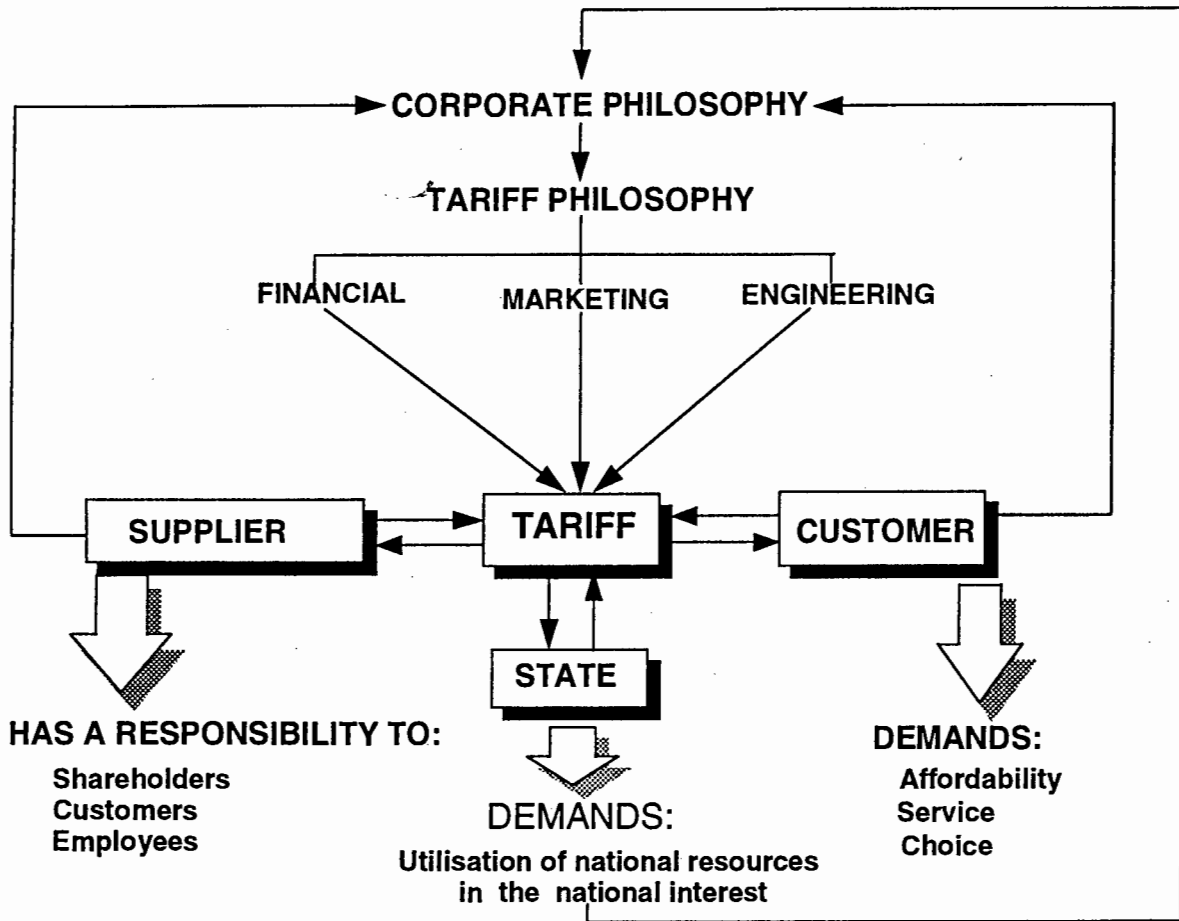
## **CHAPTER 2. A THEORETICAL FRAMEWORK FOR ELECTRICITY PRICING**

### **2.1 Introduction**

This chapter attempts to sketch a broad theoretical electricity pricing framework. The framework is developed firstly by focusing on electricity pricing in general and then progressing towards a specific focus on various aspects of pricing. In the first section a paradigm is developed to explain the role of electricity pricing in the triangular relationship between the State, the electricity supplier and the customer. From there the discussion focuses on various energy and electricity pricing criteria which constitute the different pricing policies adopted or recommended by various international electricity utilities and related institutions. The next section reviews various electricity pricing philosophies. This is followed by an historical review of the development of electricity costing, followed by a review of various cost of supply determinants. Having covered a general discussion of pricing, the next section discusses the embedded costing and marginal costing. This is followed by an analysis of various pricing applications based on marginal costs. The last four sections are then dedicated to four other pricing approaches namely Ramsey pricing, priority service pricing, competitive pricing and non-tariff pricing. The chapter concludes with a summary of the work covered.

### **2.2 An electricity tariff paradigm**

An electricity tariff can simply be seen as a set of prices which a utility charges for the provision of electrical energy. However, through the structure of those prices a utility is able to induce its customers to change the nature of their consumption in terms of, for example, time of use. An electricity tariff is also a mechanism through which the State is able to effect national policy through, for example, redistributing wealth between different types of customers by inducing the utility to cross subsidise between customer classes. An electricity tariff can thus be seen as an entity which represents the interests of the state, the supplier and the customer. This paradigm is presented diagrammatically on the next page.



The **State** is represented as demanding the utilisation of national resources in the "national interest" whatever this can be taken to mean. In "command" economies the State will obviously play a larger role in enforcing "national interest" in the determination of the structure and rate of electricity tariffs than would be the case in market economies.

The supplier has a responsibility to its:

**Shareholders:** Every utility has shareholders. In the case of nationalised utilities the sole shareholder is usually the government. In the case of privatised utilities, the shareholders are private investors. In some utilities such as National Power and PowerGen in England, the shareholders are private as well as government. In private utilities the responsibility the utility owes to its shareholders is usually to provide them with a satisfactory financial return on their investment. In nationalised utilities, the utility becomes an organ of

the government and the utility is thus dictated to by the government. In the case of para-statal utilities such as Eskom or EdF, it is debatable who the utility's shareholders are. The one school of thought is that the customers are the shareholders since they are the reason for the utility's existence. Another school of thought is that the government as well as other stakeholders such as trade unions and customers are joint shareholders. A third school of thought is that the State (as opposed to the government) is the sole shareholder.

**Customers:** The supplier also has a responsibility to its customers. Customer needs can be summarised as follows: The first need is that they be provided with an acceptable standard of service; the second need is that there should be choice of supply options so that the customer is able to exercise his or her choice to his or her perceived benefit; the third need is that the price paid for a specific product is fair.

**Employees:** Since a supplier would not exist without its employees, the supplier has an obvious responsibility to ensure that its employees are adequately provided for.

The demands of the customer, the responsibilities of the supplier and the interests of the State will determine the broad corporate philosophy. The corporate philosophy will influence the tariff philosophy which will, in turn, affect the three disciplines which combine to create the tariff. On *Financial* issues the tariff philosophy will influence the approach to costing, cross-subsidisation, and profitability. On the *Marketing* front, the tariff philosophy will, among other issues, influence the extent to which tariffs will be designed to suit specific markets or specific customers. On *Engineering* issues, the tariff philosophy will influence the choice of solutions to the supplier's generation, transmission and distribution constraints and the customer-metering constraints.

The paradigm is most eloquently summed up in a United Nations report on electricity pricing, as follows:

"A well formulated rate structure can discourage waste and foster the efficient use of national resources of capital, energy and manpower. The skilful use of this tool can thus

benefit not only the enterprise itself but the customers and the national community as a whole" (United Nations, 1972:1).

### 2.3 Criteria for an electricity and energy pricing policy

The previous section described a paradigm which attempted to explain, in the broadest terms, the role of the electricity tariff. This section now attempts to focus more closely on the specific criteria for an electricity pricing policy, and from there to place electricity pricing policy in the wider context of energy pricing policy.

Jeremy Warford in "The Objectives of electricity tariff policy" in Munasinghe and Rungta (eds.) (1984:63), believes an electricity pricing policy can be qualified in terms of five criteria:

1. Generation of revenue
2. Equity or fairness
3. Administrative feasibility
4. Social or political acceptability
5. Impact on consumer behaviour

The five criteria are frequently mutually inconsistent and open to subjective interpretation. For example, newly electrified consumers in a previously disadvantaged township might argue that, on account of past injustices in not having had a right to electricity supply, it is fair and equitable that they should receive a favourable tariff compared to that offered to existing customers. Similarly, existing customers might argue that it is fair and equitable that existing customers should receive favourable tariffs compared to those offered to new customers, since new customers have yet to contribute to the infrastructure necessary to provide their service.

Exactly which objectives of electricity pricing are paramount depends, among other factors, on the politico-economic environment of the specific electricity industry. For example, the Electric Power Research Institute EPRI (1977) in the USA describes the goals of electricity pricing, in the USA, as follows (in priority order):

1. Rates must be *just* and reasonable and they must effect an overall balance between the interests of the owners of the enterprise and the ratepayers.

2. *Equity*: Rates must not be unduly discriminatory, the general constraint being that differentials between classes of service and rates within classes must be based on some notion of cost of service.
3. *Continuity*: Customers have the right to be protected against unnecessarily abrupt changes in the structure of rates.
4. *Simplicity and clarity*: These are considered essential, not only from the standpoint of the customer's ability to understand rates, but also from the standpoint of administration.

It is interesting to contrast these criteria for a developed country against those which Munasinghe in (Munasinghe and Rungta (eds.), 1984:199) recommends for electricity pricing in the context of a developing country:

- " 1. Economic efficiency  
 2. Social subsidy - Basic Needs  
 3. Financial viability  
 4. Comprehension, Metering, Billing  
 5. Price stability, Gradualism  
 6. Other Socio-political Objectives "

In the study described earlier the United Nations (1972:126) somewhat abstractly defines three desirable qualities of electricity tariffs as follows. Electricity tariffs should be:

- " 1. Equitable  
 2. Practicable  
 3. Politic "

*Equitable* is defined as conforming as far as possible to the public view of equity. The point is made that it is unwise to differentiate between one class of consumer and another. This should be noted for its conflict with current tariff thinking - particularly in electricity industries in developed countries - that a primary goal of electricity pricing is cost reflectivity, which demands tariff differentiation between consumer classes.

*Practicable* means that the tariff must take into consideration the prices and availability of competing sources of energy. Practicable in this context is also taken to mean that

"it might be justifiable to subsidise the use of electricity for purposes threatened by competition, using the profits earned on the sale of electricity for other purposes to provide the necessary subsidy" (United Nations, 1972:127 ).

*Politic* is taken to mean that the tariff must encourage growth and economy, i.e. that it should be framed to include incentives and deterrents conducive to those ends.

In the context of electricity pricing in South Africa, significant price increases by Eskom during the 1970's prompted an investigation of the pricing policies adopted in the industry. At the time, a critic of the industry considered that economic viability, economic efficiency, equity and socio-economic objectives should be the most important pricing principles (Herrmann, 1976).

In 1989, Eskom undertook to ascertain the aims and scope of pricing policy, specifically as defined by many of its most significant customers. The result of this survey was the conclusion that, in Eskom's opinion, the most important aims of pricing policy are to

1. Promote total efficiency.
2. Reflect true costs.
3. Promote sound business decisions.

Eskom's current policy is that fairness and equity, though important, should be subordinate to economic efficiency (Eskom 1993(b)).

The analysis of the objectives of pricing policy thus far, has centred on electricity pricing policy. It is now possible to consider *electricity* pricing policy in the wider context of an *energy* pricing policy. In the case of the integrated planning of a country's energy resources, Munasinghe has developed five principal objectives of an energy pricing policy: (Munasinghe, 1990:33)

1. The economic growth objective requires that pricing policy should promote the *economically efficient allocation of resources*, both within the energy sector and between it and the rest of the economy. This means that energy use would be at the optimum level when the price for the marginal unit of energy used reflects the incremental resource cost of supply to the national economy.

2. The social objective recognises every citizen's basic right to be supplied with certain *minimum energy* needs. This may imply subsidised prices - at least for low-income customers.
3. Government should be concerned with *financial objectives* relating to the viability and autonomy of the energy sector. This implies that pricing policies should permit self-sufficiency or a fair rate of return.
4. A pricing policy must take cognisance of the need to conserve energy.
5. A number of additional issues lumped together as the fifth objective are that the pricing policy must provide for price stability and simplicity, and it must take cognisance of socio-political, legal and environmental constraints.

The set of objectives which characterise a particular pricing policy is the starting point on the long and winding road from pricing policy to tariff implementation. This analysis has sought to illustrate that setting pricing objectives requires careful consideration and prioritisation of a number of often mutually exclusive goals.

#### **2.4 Electricity pricing philosophies**

Charles Bonbright in Bonbright, Danielsen and Kamerschen (1988:85-179) distinguishes four different schools of thought on an electricity pricing policy. These are described as:

1. Cost of service
2. Value of service
3. Social pricing
4. Competitive pricing

##### **Cost of service**

*"The price of electricity supplied to customers should be determined solely by what it costs to supply them, without consideration to the value of electricity to the customer, the customer's ability to pay, any secondary benefits to customers or society, or the price of competing energy sources"* (Calitz et al, 1992:20).

From the perspective of the optimal utilisation of resources, in theory at least, the cost of service philosophy is attractive and many utilities are want to claim that their tariffs are

cost-based or cost-reflective. While many utilities are justifiably able to claim that their tariffs are cost-based, when such claims are made it must be noted that they are made in the context of a specific costing methodology. A problem exists in that there is considerable debate as to what the correct costing methodology should be. Some argue that utilities should use shadow costs, while others argue for accounting costs and others still, argue for economic marginal costs. Each of these costing methodologies are briefly described below.

### *Shadow costs*

Shadow costs are what costs *ought* to be and not what they (physically) are. The shadow costs are intended to take into account the effect of distortions in the costing and pricing of goods and services in such a way that using shadow costs will allow the optimal utilisation of resources in the national interest. Some possible sources of distortions may be the value of foreign exchange, the cost of capital, the cost of labour, and "actual" versus "perceived" societal and environmental costs. Shadow costs attempt to get closer to the "true" cost of providing (or not providing) a service. Unfortunately, the highly subjective nature of the elements which constitute shadow costs means that these costs are of more academic than practical value and are thus not known to be used in costing in the electricity industry.

### *Accounting costs*

As will be discussed later in this chapter in more detail, the accounting valuation of costs entails the allocation and apportionment of specific costs to specific units of output. In the accounting cost methodology, costs which can be directly allocated to a unit of output are so allocated. Costs which cannot be directly allocated to a specific unit of output are shared amongst all output. This sharing, or apportionment, can be done in different ways as discussed later.

### *Economic (marginal) costs*

Marginal costs are so called to define the marginal increase in cost given a marginal increase in output. As will be proved later in this chapter, an optimal allocation of resources results when electricity is priced at marginal cost. In practice, in many cases economic marginal costs are used by utilities to derive tariff structures while accounting costs are used to determine price level. This somewhat eclectic approach is a distortion of

the true principle of marginal costs, and in theory means that the utility will not achieve the stated objective of marginal costing, that is, to achieve the optimal allocation of resources.

### **Value of service**

*"The price at which customers are charged is in inverse proportion to their price elasticity of demand."*

Since most customers have more than one use for electricity, the price elasticity of demand (change in quantity demanded relative to a change in price) is not a constant function. Instead, customers will have varying price elasticities of demand, depending on the intended use of the electricity as well as factors such as local custom, prejudice, prosperity, climate and publicity. Furthermore, if the cost variation in tariffs is reflected in a time of use tariff, the price elasticity of demand will also be time variant.

If prices are to be based on the price elasticity of demand, customers with a high elasticity such as domestic customers - particularly those with access to alternative forms of energy - will obviously use less electricity in times when the price rises. Large mines and industrial customers who have limited freedom to use alternative forms of energy other than electricity will be a captive market to the utility which is then able to increase price without losing sales. In this way, the utility is able to use the price elasticity of demand of different customers to effectively cross subsidise between these customers.

Cross subsidisation may be justified as being in the interests of an enterprise. If concessions are made to customers with a high price elasticity of demand considerably more revenue through increased sales can be achieved, than if a similar concession was made to a customer with a low elasticity of demand. In addition, cross-subsidisation based on elasticity of demand appeals to one's sense of re-distributive justice. It would seem fair that customers who do not reduce consumption even if the price increases, should be charged more than customers who do reduce consumption if the price increases.

However cross-subsidisation based on elasticity of demand will achieve fair re-distributive justice only when it is fairly applied, that is, it is only fair to charge a consumer with a higher elasticity of demand, a higher price, when the higher elasticity of demand is due to that customer's extravagance. Unfortunately, a particular customer's elasticity of demand

does not infer the *reason* for that elasticity of demand i.e. it does not distinguish between a high elasticity of demand by reason of a customer's extravagance and high elasticity for other reasons such as the nature of the customer's operations. For example a hospital and an extravagant domestic customer both have a high elasticity of demand. Re-distributive justice will only occur when the wasteful domestic customer and not the hospital pays a higher price. Therefore, for a utility to ensure redistributive justice, it must ensure that it has an accurate record of every customer's price elasticity of demand as well as a record of the reason for each customer's elasticity of demand.

Since it is not possible for a typical utility with more than a million customers to offer customised prices to every customer, the value-of-service philosophy based on price elasticity of demand is, unfortunately, more of academic than practical interest.

### **Ability to pay**

*"Electricity is an essential service rather than a luxury and people of low income should not be deprived of it because they cannot afford to pay the full costs of supply"* (Calitz et al, 1992:21).

There are some strong justifications for a pricing policy based on this philosophy. However, the only way this philosophy can be implemented, given that the electricity supply industry is to be a self-financing industry, is if there is cross-subsidisation between various classes of customers. This introduces a practical difficulty in the fact that the normal classification of customers according to standard industrial classifications, would have to be abandoned in favour of a system of classifying customers between those with the ability to pay and those without the ability to pay. In practice this is almost impossible to do without applying a generalist view that all existing commercial and industrial customers are wealthy, say, and that all existing domestic customers are poor and hence all domestic customers will receive a low price while all industrial and commercial customers will receive a high price. This generalisation will obviously be to the benefit of those customers who are on the "right" side of the generalisation but not to those on the "wrong" side of the generalisation. Hence applying this pricing philosophy to such customers will be defeating the stated objectives. However, the approach will probably be right for about 80% of the customers and hence will find practical application.

## **Competitive pricing**

Almost every electricity utility interested in selling electricity does to a certain extent incorporate competitive pricing into its tariffs. This is particularly the case when the price of alternative energy sources is competitive with the price of electricity. The extent to which a utility will alter the price at which it sells electricity in response to competition is obviously dependent on the goals of that utility.

However, competitive pricing as a tariff philosophy goes beyond the alteration of prices in response to alternative energy sources. Rather, competitive pricing stipulates that price will be determined by the interaction of supply and demand. An example of the competitive pricing philosophy exists in the electricity supply industry in Britain. In this industry, competition exists between suppliers through the operation of a Power Pool in which competing suppliers bid to sell electricity. A particular generator wins the right to generate if his bid is more competitive, price-wise, than a bid from a competing generator. Competition also exists on the distribution side of the industry in that no single distributor is given a monopoly over customers in any specific area. Many distributors may compete, on price and service, to supply a single customer. A fuller description of the privatisation of the UK electricity supply industry is presented in Chapter 5.

The proponents of competitive pricing argue that competition will lead to cost-effective and efficient operations. Detractors of this philosophy argue that suppliers will not enter the market unless a considerable rate of return is possible and that electricity, as a natural resource, should not be subject to profiteering. The arguments between the proponents and detractors essentially mirror the arguments for or against market economies.

### **2.5 Electricity costing: A brief historical review**

Costing for the supply of electricity is complicated by the fact that electricity is a non-storable product. Since not all costs can be directly allocated to a particular unit of output, the way in which costs are shared or accounted for by prices not only affects overall efficiency but also creates incentives or disincentives amongst the utility's customers. The history of the development of electricity costing is an interesting one not least because many of the costing issues grappled with at the start of the industry, are still grappled with today.

As a simplification, an electricity supplier can be thought of as supplying its customers with two services:

1. The energy (kWh) which he or she consumes;
2. The readiness to supply the energy he or she wants whenever he or she needs it.  
This readiness consists of the generation, transmission and distribution infrastructure which has been established in order to supply that consumer.

The cost to the consumer for the first service is entirely dependent on the amount of energy consumed (a variable cost), while the cost to the consumer for the second service is fixed, in the short term, in that this cost is not dependent on whether that particular consumer purchases energy (a fixed cost).

By definition, the variable cost is directly proportional to the number of kWhs supplied. The fixed cost will be largely dependent on the cost of the necessary generation, transmission and distribution equipment. These costs are in turn influenced by the kW capacity of the equipment (generation and transmission) and hence it is reasonable to specify the fixed costs per unit of electrical capacity (kW).

It is interesting to find that the origins of this costing philosophy can be traced back to 1882 when John Hopkinson, in a presidential address to the American Institute of Electrical Engineers, expressed the view that ,

"...the expenses of any undertaking could be divided into two classes, expenses which are quite independent of the extent to which the undertaking is used, and expenses which are absent unless the undertaking is used and which increase in proportion to its use" (Hopkinson, 1892:33 in Hausman and Neufeld, 1982).

Maximum capacity at this time was estimated by the number of installed lights and heaters. It was only in 1896 when Arthur Wright successfully used the ammeter at his Brighton utility, that he was able to meter each customer's maximum demand and hence implement the "Hopkinson Two-part tariff".

However, Wright was later to adapt Hopkinson's principles for the derivation of a tariff which had no customer-specific charge per kW. For the Brighton utility that he directed, Wright calculated that the "running" costs were £2 571 per annum and "standing costs"

were £13 255 pa. After considering the load pattern of his customers, Wright separated costs to calculate a kW maximum demand charge and kWh energy charge in the same way that Hopkinson had proposed. Wright then took the argument one step further by saying that "Theoretically it might be said that the standing charges ought to be divided into amounts proportional to the maximum demand of each consumer at the day and at the very time the maximum load occurred on the mains each year ... however it is impossible to determine in practice and would not necessarily be equitable to the consumers who might or might not have used their maximum demands at the exact moment in question." (Wright 1896:44, in Hausman and Neufeld, 1982)

In a sense contrary to his argument above, Wright made no attempt to differentiate price for those customers whose maximum demand occurred away from the time of the system maximum demand. Wright's argument was that the peak and off-peak consumer were different people whose consumption patterns were not amenable to change and that it would have been unfair to the peak consumer not to charge the off-peak consumer any of the standing cost. He was opposed in this view by engineers from Westinghouse and General Electric, amongst others, who argued that off-peak electricity was essentially a by-product and that off-peak customers should at most be charged only a portion of the fixed charge (Hausman and Neufeld, 1982). Both General Electric and Westinghouse had by this stage developed practical time of use meters which could differentiate between two time periods.

However, Wright argued against the use of these meters saying that the time for which the meters were set would never perfectly correlate with the central station load and hence the tariffs would not accurately reflect costs. "However much Barstow (Engineer at Westinghouse) may modify his time limits for charging full price, unless he alters his time switch every day together with an additional alteration for Sundays, holidays, and thunderstorms, he can never hope to collect the full price for exactly when the peak occurs ... He is therefore driven to the necessity of extending the period of high charge for much longer than is absolutely necessary to cover the fixed cost." (Wright 1898 in Hausman and Neufeld, 1982).

Furthermore, Wright argued that it was the consumer's contribution to the annual peak that caused the utility to incur the expenditure. It was not the contribution to the daily peak that mattered.

In the end, Wright's arguments achieved wider acceptance than the more complicated arguments of the time of use theorists. With hindsight, perhaps many of Wright's objections to time-based tariffs were focused more on principle than on practice. However, it is nevertheless interesting to observe the sophistication of the costing debate at such an early time in the industry's history. This is especially remarkable in view of the fact that it was more than half a century before time of use tariffs were eventually first used in the electricity industry.

## 2.6 Cost of supply determinants

There are a number of factors which may affect the cost of supplying different customers. These include:

1. The quantity of energy supplied
2. The maximum demand of supply
3. The load factor of consumption
4. The diversity between customers
5. The location of the customer
6. The customer's voltage of supply
7. The customer's power factor
8. Time of use
9. The quality of the supply

The first two factors can be thought of as the product which the customer purchases, i.e. the customer purchases energy (kWh) and maximum demand (kW), the maximum rate of supply. The remaining seven factors specify the nature of the product purchased. If any two customers purchase the same quantity of energy and have the same maximum demand but are different in respect of any of the other seven factors, then a truly cost-reflective tariff will reflect these differences in the amount that the two customers pay.

## **Quantity of energy supplied**

The quantity of energy supplied is measured in Watt hours. As discussed in the previous section, the costing methodology first introduced by Hopkinson separated variable (running) and fixed (standing) costs in electricity supply. The variable or 'running' cost represents the total of all variable costs which are incurred in generating energy (kWh). In practice the proportion of these costs as a proportion of total supply costs varies considerably depending on the type of power station used. For example, a large coal-fired thermal station has a much smaller component of variable costs in its total costs than a small emergency gas-fired station, where the high cost of fuel and maintenance and the relatively low capital cost means that running costs are a much larger component of total costs. The cost of *energy* supplied is strictly the variable component of a utility's costs. However, in the pricing policy of many utilities, the fixed capacity charges are sometimes factored into the energy charge.

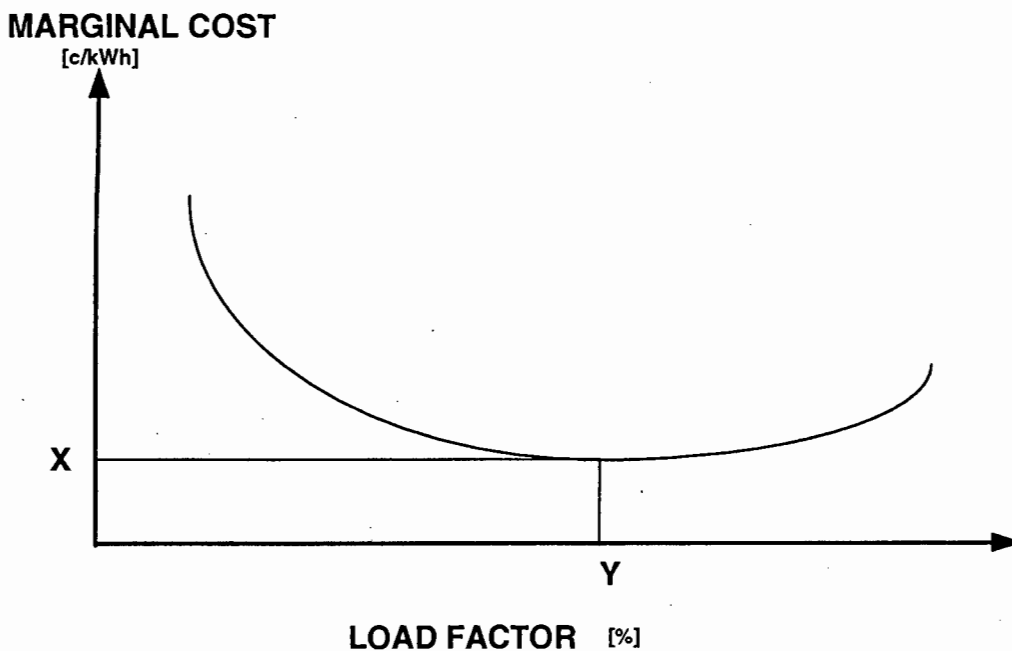
## **Maximum demand**

Hopkinson was the first to assert that the fixed component of costs is directly proportional to the maximum demand of a consumer or class of customers. Maximum demand for tariff setting purposes is the integrated demand over a half-hourly or hourly period and not the instantaneous peak demand. A simple method of allocating costs to the maximum demand was illustrated earlier in Wright's application of the principle to his utility in Brighton. In fact, as will be illustrated in detail later in this chapter, this method of allocating standing charges introduces a high degree of cross-subsidisation between various customers.

## **Load factor**

Load factor is defined as the ratio of average demand to maximum demand. The load factor can be calculated for a number of different time periods. For example, daily, monthly or annually. The system load factor is a measure of the degree of utilisation of the components comprising that system. A utility will be able to minimise the cost of supply (per unit of output supplied) when the cost of operating the system can be amortised over a longer duration of supply. In theory, a system with a 100% load factor will allow for the lowest costs per unit of output. In practice a 100% load factor would not be optimal. Firstly, in a typical power system it is necessary that an enterprise retain a margin of reserve capacity to cover the needs of plant maintenance and unscheduled outages. Secondly, in practice a

power system contains different types of generating plant. A common way of classifying generating capacity is between base-load, mid-merit and peaking power stations. This classification indicates the most economic means of operation, that is, base load plant is plant which is most economically operated when it is operated for a long duration (high load factor) while peaking station is most economically operated for short durations (low load factor). As a result of these two constraints, for a practical system there will be a certain optimal load factor at which the marginal costs (marginal change in cost with a marginal change in output) of operating that system are minimised. This is illustrated in the Figure 2 below.



**Figure 2. Load factor versus marginal cost of supply**

This figure illustrates the relationship between marginal cost (measured in c/kWh) and load factor for a practical power system consisting of several base load, mid-merit and peaking stations. As the figure illustrates, the marginal cost continually decreases until the load factor, Y is reached. At this load factor, the most economical operation of the installed capacity has been reached. To the right of point Y the cost of supply begins to increase since it then becomes necessary to use more of the relatively uneconomical mid-merit and peaking power stations.

It is clear that customers with a high load factor encourage the use of economical base load plant. On the other hand those consumers with intermittent demand (low load factor) cause the utility to construct relatively uneconomical peaking plant. This implies that cost-reflective electricity tariffs should differentiate between customers with high load factors and those with low load factors. In practice this is not always the case.

#### 4. Diversity factor

Diversity factor has been described as, "the most important and elusive of all the factors involved in the assessment of electricity costs" (United Nations, 1972:28). Conceptually, diversity is quite straight forward: It is the ratio of the sum of the maximum demands of all individuals forming a group, to the coincident maximum demand of the group. For a customer with multiple points of supply, diversity exists between those points of supply. Diversity also exists between customers in a particular customer class and finally diversity exists between customer classes. (Here the assumption is made that customers in close geographic proximity and who are fed by a common point of supply are grouped together to form a customer class). Figure 3 illustrates the various levels at which diversity may exist.

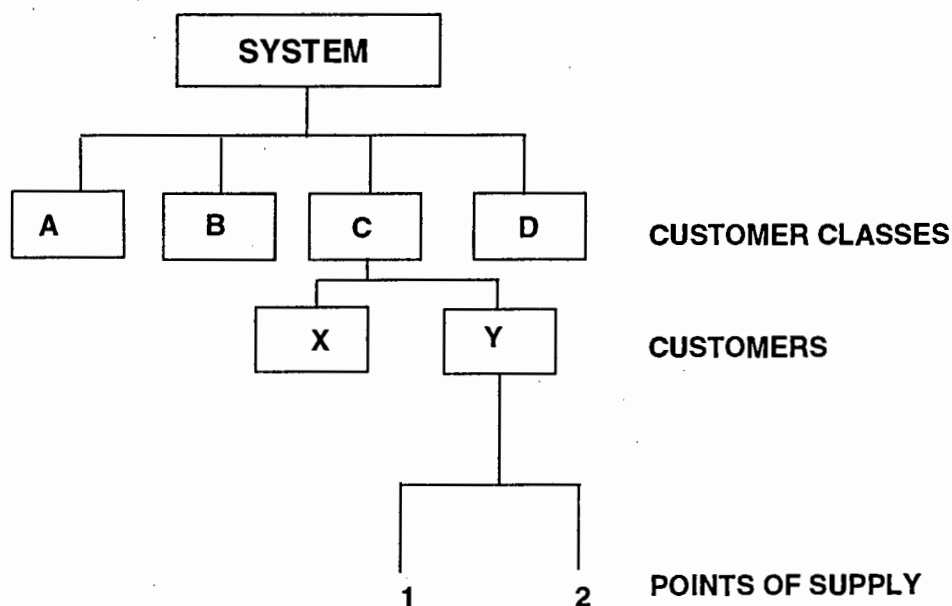


Figure 3. Levels of diversity

The first level at which diversity exists is between two or more points of supply of an individual customer. As illustrated in Figure 3 above, such a customer's actual maximum demand will be the diversified sum of the demand at each separate point of supply. Moving up one level, the customer Y's contribution to the C Customer Class maximum demand will be the diversified maximum demand between customer Y and other customers (in Figure 3 X is the only other customer). Similarly the contribution of customer category C to the system maximum demand will be the diversified maximum demand of all customers classes, A, B, C and D. Cost-reflective pricing requires that if the diversity between the customer class demand and the system demand is high, the contribution of that customer class's demand to the system demand will be low and hence the allocation of fixed costs to that customer class should be low (this is obviously assuming that fixed costs are allocated according to maximum demand). Similarly, if the diversity between the demand of a customer and the customer class is high, the allocation of fixed costs to that customer should be low. This result may not seem intuitively obvious in the case that a particular customer has a high diversity with the demand of the customer class that he or she is in, but yet may have a low diversity with the system. However, it must be remembered that diversity exists at several progressive levels: firstly between the customer class and the system; secondly between the customer class and the individual customers in that class and thirdly between a customer's different points of supply in the case that he or she has two or more.

## **Location**

The cost to a utility of supplying a consumer with electricity will depend to some extent on his physical location. There are two connected, but separate, infrastructures which deliver electricity to a customer's point of supply. The first is the high voltage transmission network. Obviously the more remote a customer is, the longer will be the length of the transmission network necessary to serve that customer. The second infrastructure is the distribution and reticulation network. This infrastructure begins at a major substation in the transmission network and ends with the service connection to the end-user. Once again, the more remote a customer is from the source of energy, the greater will be the size of the distribution infrastructure necessary to serve him.

## Voltage of supply

Customers who are supplied at a higher voltage will not cause the utility to incur the expense of establishing the infrastructure necessary to transform to lower voltages. Furthermore, customers who take power at higher voltages are, in most cases, causing the utility to incur less electrical losses than customers at lower voltages. Most electricity tariffs do carry surcharges for supply at lower voltages.

## Power factor

Both the fixed and variable cost components of supplying electricity will depend upon the power factor at which it is supplied. The power factor is the ratio of kW demand to kVA demand. Low power factor electricity is more expensive than high power factor electricity since electrical loads with low power factors require larger currents than similar loads at higher power factors. A low power factor load thus "wastes" electricity and also causes higher losses (as a result of higher currents) than would high power factor loads. The charge for power factor correction equipment is often factored into electricity tariffs by offering different charges for kW or kVA maximum demand.

The actual methodology of sharing power factor related costs amongst customer classes and finally amongst customers, is a complicated process and will not be discussed further here.<sup>1</sup>

## Time of use

Almost since the beginning of the electricity supply industry, debate has existed as to whether it is fair to allocate costs to customers based on the extent to which a particular customer's demand coincides with the system or aggregate maximum demands. Section 2.5 very briefly detailed the contribution made by the original pricing pioneers to this debate.

Today, incorporating time of use into electricity costing is almost universally accepted as a logical principle and that in the realm of power system economics such allocations are 'fair' and that prices based on such cost allocations are 'cost reflective'.<sup>2</sup> However, time of use

<sup>1</sup> A full description of the process is contained in United Nations 1972, *Electricity Costs and Tariffs: A General Study*, Department of Economic and Social Affairs, United Nations, New York, p55)

<sup>2</sup> Some relevant texts on this subject include:

tariffs may differ greatly in terms of both their derivation and their final form. Some of the issues which may affect a time of use tariff include:

- Whether time of use tariffs should be based on embedded costs or marginal costs ? (This subject is dealt with in section 2.7 of this chapter).
- If the tariff is to be based on marginal costs, should these be short run marginal costs or long run marginal costs? (This subject is dealt with in section 2.7.2 of this chapter).
- How many different rating periods should be used ?
- What proportion of costs should be charged to a time differentiated maximum demand charge and what proportion of costs should be charged to a time-differentiated energy charge ?

These are but a few from a long list of considerations which any tariff designer will have to contend with in the design of a time of use tariff.

### Quality of supply

As with the production of any product, or the provision of any service, the quality of the product or service is directly proportional to the cost incurred in producing the product or delivering the service. In the context of electricity supply, this means that providing electricity with a high degree of reliability and strictly limited voltage and frequency deviations from a standard, is naturally more costly than providing a service which is less reliable and of inferior quality.

Many electricity utilities offer the customer the option of purchasing an inferior product but at a reduced price. An example is an interruptible supply contract where the customer is willing to have his supply interrupted in exchange for a discount on the basic price. Such

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\* Calitz A C and Campbell K J C, 1991. *Consider your verdict: The A to T of Electricity Pricing*, Elektron, Johannesburg

\* *Analysis of various pricing approaches*, prepared for Electric Utility Rate Design Study: Electric Power Research Institute, February 1977, California: Topic 1.3 pg 15 to 27.

\* Calitz A C, 1989. *Priorities for Pricing Policy Development and Time-of-use Electricity Pricing in Eskom*: Internal Eskom Report, Eskom, Sandton, pp 23 -29

\* Mountain B R A, 1990. *An Appraisal of Eskom's Proposed Time-of-use Electricity Tariff and its Effect on the Electricity Costs to a Gold Mine*, Undergraduate Engineering Thesis, UCT, pp 47 -62

\* Munasinghe M and Rungta S (Eds.), 1984. *Costing and Pricing Electricity in Developing Countries*, Asian Development Bank, Manila pp 153 - 171

tariffs are frequently determined, per customer or group of customers, on the basis of the short-term avoided cost of the utility, that is, the costs which the utility could avoid if it did not have to supply those customers.

## **2.7 A discussion on embedded and marginal costing**

The previous sections of this chapter have attempted to identify and explain a wider context against which any electricity costing theory and subsequent pricing philosophy may be viewed. This section now attempts to describe and explain two different costing approaches which are used in the electricity supply industry: embedded costing; and marginal costing. Perhaps one of the biggest debates through the history of electricity pricing has been that of embedded costing (otherwise known as absorption costing or fully distributed costing) versus marginal costing as the basis of price setting. The debate really began in the 1950's when major utilities such as Electricite de France began to implement tariffs based on marginal costs. Today marginal costs are almost universally used as the basis of tariff structures in most major electricity utilities. However, while many utilities today pay homage to marginal costs, in many electricity undertakings, embedded costs are still used in the derivation of their tariffs. In view of the fact that embedded costing has been the basis of electricity pricing for such a long period in the history of the industry, it is constructive to explain the principles and applications of this costing principle.

This section begins with a description and explanation of embedded costing. Two different ways of calculating embedded costs are then described and explained. The next part of this section then attempts to define and explain marginal costs and to describe the proof that marginal costs are economically efficient. Following on from this, the problem of the Second Best in marginal costing is explained. Finally, having established the theoretical basis to marginal costs, the issue of short run versus long run marginal costs is examined.

### 2.7.1 Embedded costing

In the electricity industry, there are some costs such as fuel and water which can be directly allocated to a specific unit of output. Such costs are otherwise known as attributable costs. There are other costs which can not be directly allocated to a specific unit of output. An example of such costs are the capital costs of generating plant, or the capital cost of the Transmission and Distribution network. Such costs are common to all output and thus must be shared amongst the output. Embedded costing, as somewhat abstractly inferred by the name, is a costing methodology through which the cost per unit of output is calculated firstly through the *allocation* of direct costs to specific units of output and secondly through *apportioning* common costs amongst all units of output so that each unit of output has all costs "embedded" into it. Embedded costing is an approach which seeks to determine an *accounting* valuation of costs. As will be discussed later, marginal costing is an approach which seeks to determine an *economic* valuation of costs.

To restate the explanation above of embedded costs, the following formula may be produced

$$\text{Embedded Cost}_i = \text{Directly allocated cost}_i + f_i * \text{Common Cost}$$

Which reads, the embedded cost of producing a specific unit of output,  $i$ , equals the costs directly allocated to that product (attributable costs) plus a proportion of the common cost, given by a factor,  $f_i$ , multiplied by the total common costs. The proportion of common costs to be apportioned among specific units of output is based on the value of the factor  $f_i$ .

There is much debate as to exactly how common costs should be apportioned between units of output and thus how the factor  $f_i$  should be calculated. Two frequently used methods of calculating the fraction  $f_i$  are known as the *Relative Output Method* and the *Attributable Cost Method*.

With the Relative Output Method the fraction  $f_i$  is calculated as

$$f_i = Q_i / (Q_1 + Q_2 + \dots + Q_m)$$

where  $Q_i$  is the quantity of product  $i$  produced  
 $(Q_1 + Q_2 + \dots + Q_m)$  is the total production

Applying the Relative Output Method to costing in the electricity supply industry where, for example, a kilowatt-hour could be distinguished as being produced during the peak period or during the off-peak period, the amount of common costs attributable to a kilowatt-hour produced during the off-peak period will be pro-rata the off-peak kilowatt-hours to the total kilowatt-hours.

Another method of calculating the factor,  $f_i$ , is the *attributable cost method* where the fraction  $f_i$  is calculated as follows

$$f_i = \text{Attributable Cost of product } i / \text{Total Attributable Cost for all production}$$

As stated earlier, the attributable cost of producing product  $i$  is the cost which can be directly allocated to that product. Using the attributable cost method, common costs are apportioned among specific units of output pro-rata with the attributable costs of that output.

Embedded costing in a number of forms including the Relative Output and Attributable Cost Methods, were almost universally used in electricity costing until marginal costs began to gain more popularity. Currently, there is a small minority of electricity utilities in the developed world who use embedded costs. As the theory discussed so far has tried to illustrate, embedded costing is essentially an accounting (as opposed to economic) approach to costing.

The Electric Power Research Institute, in a 1977 Electricity Utility Rate Design Study, (EPRI, 1977) lists several practical objections to embedded costing:

- \* With embedded costing there is no consensus on the cost allocation methodology.

- \* Embedded costs are largely derived from accounting records which do not always reflect true economic depreciation of assets.
- \* The utility's books of account may reflect arbitrary write-offs of plant that are no longer useful and various other adjustments, such as plant acquisitions, customer contributed capital and timing differences between tax accruals and tax payments.

Embedded costs are calculated using the average current costs to the utility based on its historic investment costs, that is to say sunk costs are used in the calculation of future revenues. This is perhaps the single most important argument against embedded costing: Economic theory holds that for efficient resource allocation it is the actual resources used or saved by consumer decisions that are important and not the amount of revenue which must be collected to recover historic sunk costs.

From a review of embedded costing, the discussion now focuses on marginal costing.

### **2.7.2 Marginal Costing**

It was mentioned earlier in this chapter that one of the key debates in electricity pricing has been that between marginal costing versus embedded costing as the basis for costs upon which electricity tariffs should be based. As long as the cost of electricity was continually declining in real times which it was up until the late 1960's there was little controversy over which was the more suitable costing practice. However, from the late 1960's a number of circumstances changed in such a manner as to cause an almost continual real increase in the cost of generation. As a result, the focus of the electricity industry, like that of many other industries, was increasingly drawn towards pricing policies which would optimise the utilisation of available resources.

The application of the theory of marginal cost pricing in the derivation of time of use electricity tariffs was first formulated by Boiteaux in France in the early 1950's and subsequently by Steiner in America, eight years later. Marginal cost based pricing today is widely used in electricity utilities in the developed world.

This section attempts to explain the fundamentals of economic marginal costing. Although this is an engineering dissertation, the principle of marginal costing is of such relevance to electricity pricing that it is felt that more than a lay-mans review of the economic theory of

welfare economics and the theory of consumer behaviour, is necessary. This section begins with the definition of marginal costs. The section then continues to consider marginal costing in the context of the theory of welfare economics. Finally, the concepts of Short Run Marginal Costs and Long Run Marginal Costs are explained.

### *Marginal Costs*

The broadest definition of marginal costs is that they are the cost of society's resources which must be used to produce one additional unit of some commodity. Alternatively, marginal costs are defined as the value of resources which must be used to produce one additional unit of some commodity or the value of resources that would be saved by producing one less unit of that commodity. If price charged is lower than the marginal cost, the value of the last unit of consumption to the consumer is less than what it costs society to produce it and consequently more resources are being devoted to the production of the commodity than is "socially" efficient.

### *Marginal costs and welfare economics*

In 1937 Hotelling first published the idea that prices based on marginal costs would optimise Social Welfare (Crew and Kleindorfer, 1979:25). Before aspects of this proof are reviewed, it is necessary to define the term "welfare economics". Salvatore describes welfare economics as follows, "(welfare economics)...examines the conditions for economic efficiency in the production of output and in the exchange of commodities, and equity in the distribution of income" (Salvatore, 1991:563). As such, welfare economics is concerned with the optimal allocation of society's scarce resources and the optimal allocation of goods among consumers. This is to be clearly distinguished from the everyday usage of the term "welfare".

In welfare economics, the Net Social Benefit is defined as the sum of the producer's surplus (profit) and the consumer's surplus. Further, the producer's surplus is defined as total revenue minus total costs. This is represented by the formula:

$$W = (TR - TC) + S \quad (1)$$

where	W	= Net Social Benefit
	TR	= Total Revenue
	TC	= Total Costs
	S	= Consumer's surplus

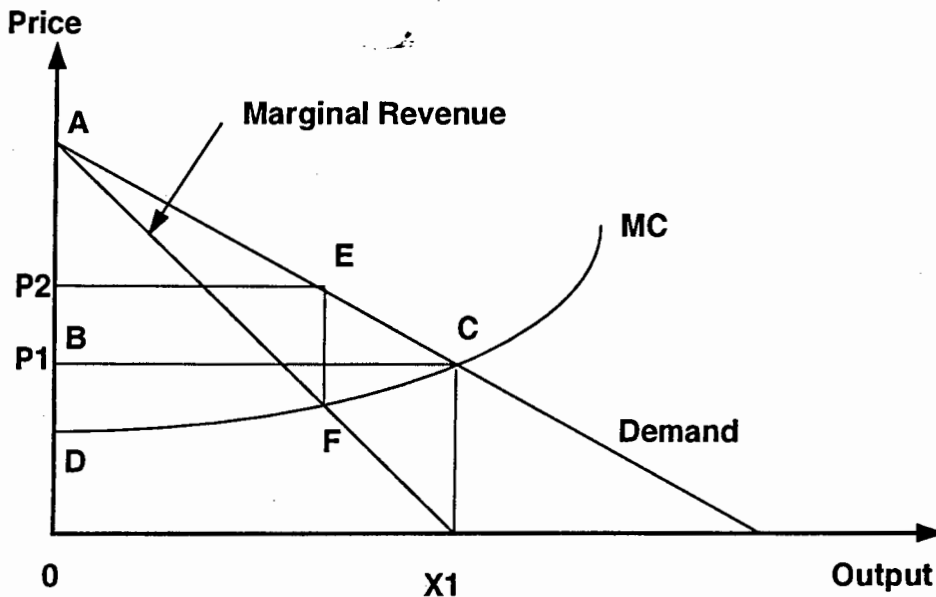
The Net Social Benefit is maximised when the sum of the consumer's and the producer's surplus are maximised. However, since an increase in the consumer's surplus is commensurate with a decrease in the producer's surplus it is necessary to find a level at which the two may be optimally balanced so that the Net Social Benefit may be found. Hotelling proved that this optimal level will be achieved when goods are priced at their marginal costs. In deriving the proof, a number of assumptions were made:

1. The producer produces a single good.
2. The proof assumes a partial equilibrium framework i.e. that the rest of the economy in which the electricity supply industry operates, has already adjusted to marginal cost prices and there is an absence of externalities, or other factors which may distort a state of perfect competition.
3. Consumer surplus is equivalent to the area under the individual's declining demand curve.<sup>3</sup>
4. For any output, profits are measured by the area to the left of the industry's (increasing) marginal cost curve. This requires that there are no fixed costs and that the industry's output is supplied along the marginal cost curve. (See Figure 4)
5. The producer will not sell at a price less than marginal cost.

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<sup>3</sup> A consumer's demand curve maps the relationship between the quantity of a product demanded and the price which a typical customer is willing to pay for that quantity of the product.

Hotelling's proof is illustrated in Figure 4 below.



**Figure 4. Demand and Supply Equilibrium Under MC-Pricing**

Hotelling's contention is that when the producer's marginal cost curve intersects the consumer's demand curve at a price  $P_1$ , the sum of the consumer's surplus (area  $ACB$ ) and the producer's surplus (area  $BCD$ ) is maximised. To prove this, he took a hypothetical price,  $P_2$ , which meant that the consumer's demand would not be met at a price equal to marginal cost. At  $P_2$ , the consumer's surplus is calculated as the area  $AEP_2$  and the producer's surplus is calculated as the area  $P_2EFD$  and hence there is a net loss (a deadweight loss) given by the area  $ECF$ . Hence only at  $P_1$ , when the producer prices at marginal cost, will the Net Social Benefit be maximised.

However, while this proves that marginal costs have to be used to achieve economic efficiency (the maximisation of the Net Social Benefit), there are a number of other important considerations. Firstly, the reasoning behind Figure 4 is restricted to a single point in time and no distinction is made between long-run and short-run costs. Secondly for pricing at marginal cost to be welfare-optimal it has to clear the market (the Net Social Benefit must be positive), and thirdly marginal cost pricing does not maximise the customer's surplus; nor does it enable the industry to maximise profitability. To maximise

profits in theory marginal costs should equal marginal revenues. With reference to Figure 4, such a configuration corresponds to price P2 and thus a welfare loss (area ECF).

That the Net Social Benefit must be positive in order to achieve welfare optimal pricing with marginal costs, deserves closer attention. Teplitz-Sembitzky illustrates this problem as follows: (Teplitz-Sembitzky, 1992:21)

A simplified short-run cost function is given by

$$C(X) = aX + F \quad (2)$$

Where,           a:     Constant unit operating costs equal to marginal costs  
                   X:     Quantity of supply  
                   F:     Fixed capacity costs

In addition, suppose the demand is given by the linear inverse function

$$P(X) = c - dX \quad (3)$$

P(X): Unit price as a function of output  
 c,d: Parameters characterising the demand

Now with reference to equation (1) the "Net Social Benefit" is

$$W = \int_0^x P(X)dx - C(X) \quad (4)$$

which from (2) and (3) yield

$$W = cX - dX^2/2 - aX - F \quad (5)$$

This quadratic has two real roots provided that

$$(c-a)^2/2d > F \quad (6)$$

Now differentiating (5) with respect to X and setting the derivative equal to zero gives

$$X = (c-a)/d \quad (7)$$

which substituted back into (2) says that the *maximum of social welfare occurs when demand is met at a price equal to marginal costs*. However, since pricing at marginal costs does not recoup the fixed cost component, there will be a negative producer's surplus(loss), that is, the market clearing price has not been obtained. Hence investing in production and selling the output will only be welfare-optimal if the net consumers' surplus is greater than the fixed costs. This is a very significant conclusion.

### *The problem of the second best*

The problem of the second best, as it is known in economic parlance, is that in any *real* economy, prices must differ from true marginal cost in order to achieve the maximisation of the social welfare function. Perhaps a more accessible explanation of the problem of the second best is that, in a *real* economy, economically efficient prices are different from true marginal cost. The problem of the second best is of such critical importance that it merits a fuller explanation.

One of the underlying assumptions to the argument of welfare maximisation through marginal costs is that marginal cost pricing for a regulated industry is optimal only when the balance of the economy is competitive, that is, when there is no distortion in prices anywhere in the economy. In practice in a real economy this is not the case. Gordian in (EPRI, 1979:21-7) lists a number of distortionary factors including:

#### 1. Regulatory considerations

One purpose of a regulatory agency is to achieve and maintain an efficient allocation of resources for a particular group or society. This may involve the alteration or distortion of the market equilibrium in order to achieve a specific objective.

## 2. Taxation

Not only do taxes distort the price of labour and capital by their very existence, but their structure is such that they create internal distortions between different types of capital and labour.

## 3. Subsidies

To the extent that they violate marginality conditions, subsidies are a frequent source of distortion.

## 4. Wage regulations

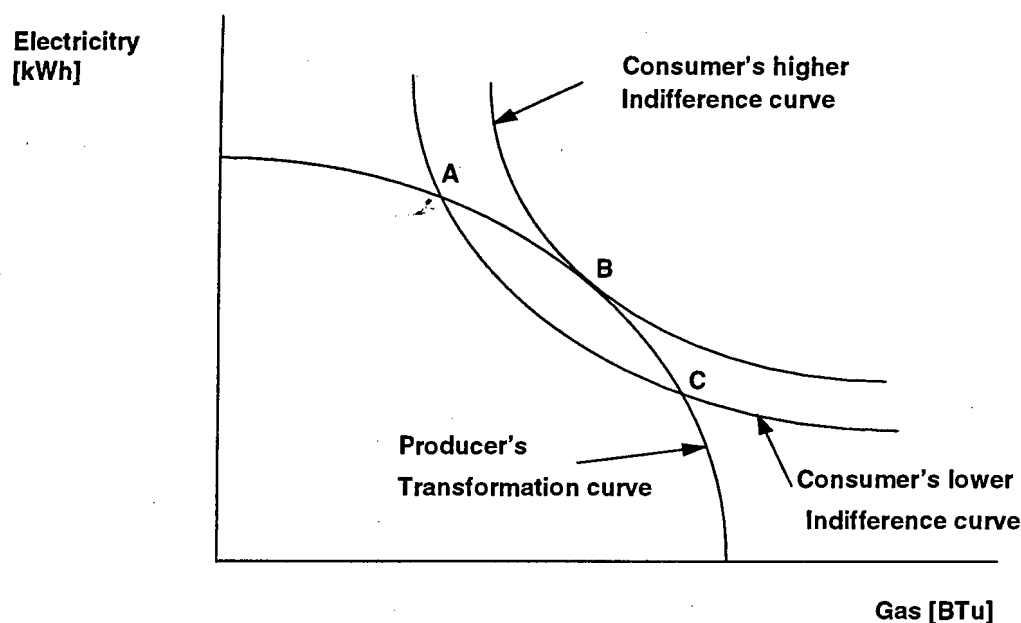
Certain government regulations (e.g. minimum wage legislation) distort the market prices of labour by setting limits on wage levels.

## 5. Public services: monopoly and limited competition

Public services are typically priced at levels that are not necessarily close or related to marginal cost.

The theory of the Second Best is that, as a result these distortionary factors (amongst others) there is zero probability that price will equal marginal cost for commodities. The theory of the Second Best will be explained here through the use of the transformation curve and indifference curves (these are both defined later).

Consider a hypothetical economy in which energy is supplied through either electricity or gas. Figure 5 shows an example of one transformation curve and two indifference curves relating to electricity and gas in this economy.



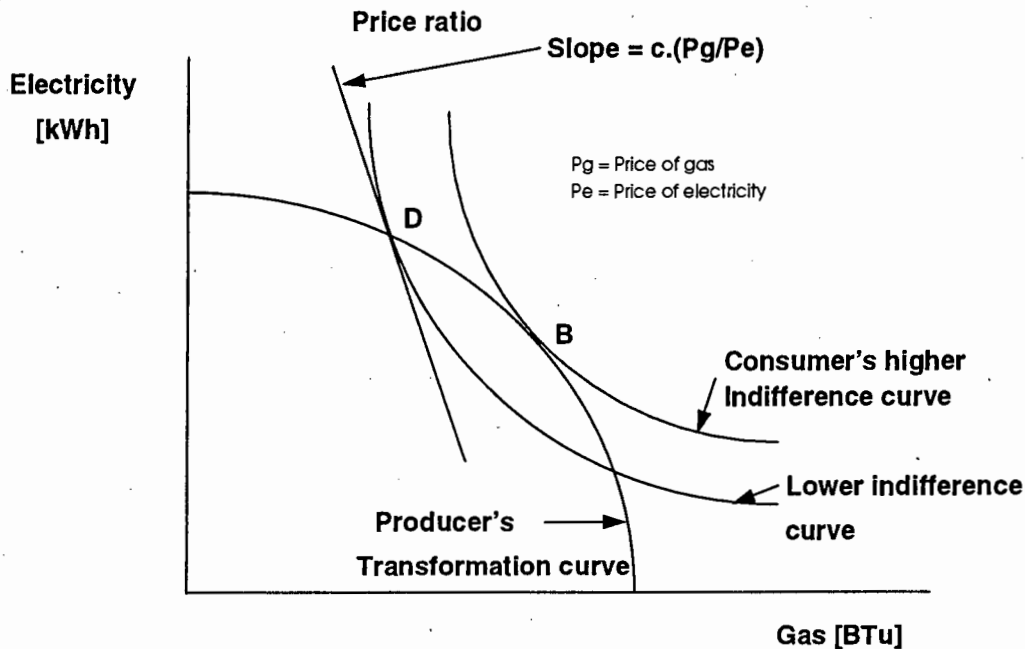
**Figure 5. Producer's possibilities and customers indifference curves**

The producer's transformation curve shows the upper limit of all outputs available to society when all existing resources are being utilised. In figure 5, they show the different combinations of electricity and gas production. For example as illustrated in the curve, it is possible to produce a large amount of electricity but only a small amount of gas at the same time, and vice versa. The indifference curve represents the various combinations of goods which have the same value to the consumer. Since all combinations on an indifference curve offer the same satisfaction, in Figure 5, the consumer is indifferent (to whether to choose electricity and gas), at any two points on the curve. The level of satisfaction of a given consumer can be improved by moving to an indifference curve that represents greater satisfaction, this curve would be further from the origin. In figure 5 at Point A, the consumer is on the lower indifference curve. This is a non-optimal solution since the consumer can substitute gas for electricity to increase his overall level of satisfaction (in figure 5, move further from the origin). Such a substitution leads from point A to point B. If the substitution is carried past point B, the consumer's level of satisfaction will decrease. This is illustrated at point C.

When goods are priced at marginal cost, the economy will rest at point B. This is proved as follows: Under competition, producers seeking to maximise their profits, will produce any two goods until the rate of transformation between the two goods (which is the slope of the transformation curve), equals the ratio of the prices of these two goods (price of gas

divided by the price of electricity). Consumers trying to maximise their individual satisfaction, will allocate their available means so that the rate of substitution on their highest attainable indifference curve is also equal to the ratio of the prices. Under marginal cost pricing, the price ratio is the same for both producers and consumers and point B is attained. At point B, the slopes of the transformation curve and the highest attainable indifference curve are equal to the ratio of the prices of the two goods.

The problem of the second best exists when the optimal allocation of resources is violated through distortionary factors in such a way that the rate of transformation is not equal to the indifference trade-off to the consumer. When this condition arises, as it always does in practice, the cost to produce one more unit of output and what the consumer pays for that additional unit will be different. This difference is denoted by a constant,  $c$ . Given such a distortion, the economy will move to point D as illustrated in Figure 6. below:



**Figure 6** Producers possibility and customers indifference curves

At point D, the objectives of satisfaction maximisation by customers and profit maximisation by producers are met. Yet the condition of welfare maximisation is violated; at society's disposal are resources and know-how sufficient to attain point B, the position of welfare maximisation.

To achieve point D it will be necessary that the distortion in the pricing of the one product, is applied in equal measure to the other product so that the original ratios are restored ( $P_g/P_e$ ) and hence the slope of the transformation curve and highest indifference curve will once again be equal to the prices of the two goods and welfare maximisation will thus occur at point B. This condition is then referred to as second best optimality.

At the beginning of this section it was asserted that the theory of marginal costing is of such relevance to the electricity industry that it merited a review of the theory underlying the justification of marginal costs in the electricity industry. Having progressed from a definition of marginal costs to a review of the maximisation of social welfare with marginal costs and finally an explanation of the problem of the second-best, it is possible to take a step back and question what relevance this has to practical rate making.

An eloquent answer to this question, specifically on the value of the second best theory, is to be found in (EPRI, 1981:23-5)

" ... the fundamentals of second-best theory leads us to the conclusion that the theory is merely an addition to a body of welfare analysis that is itself of dubious relevance for discussing any non-trivial policy problem ... we (are) unable to commend any part of second-best theory to the attention of practical rate-makers or regulators ..."

Perhaps the real value to be gained from this theoretical review of the problem of the second best, is recognition that in practice it becomes difficult to defend marginal cost pricing from the perspective of welfare economics. Rather, it is much easier to defend marginal costing from the perspective that it accords with business-like behaviour (competitive pricing) and that it is *directed* towards achieving the optimal utilisation of resources.

### ***SRMC and LRMC***

Having established the theoretical framework for marginal cost electricity pricing, it is possible to focus on an issue of more practical relevance: the arguments for and against short run or long run marginal costs.

The difference between short run and long run costs is that with short run costs, some costs are fixed while in the long run all costs are variable. In the context of an electricity

supplier, in the short run, the capacity cost of generating plant is fixed while the running costs are variable. In the long run, both the capacity and running costs are variable. Munasinghe distinguishes between short run and long run marginal costs as follows, (Warford and Munasinghe (eds), 1982:23):

"...SRMC may be defined in economic terms as the cost of meeting additional electricity consumption with fixed capacity. LRMC is the cost of meeting an increase in consumption, sustained indefinitely into the future, when needed capacity adjustments are possible."

To explain Short Run Marginal Costs (SRMC) and Long Run Marginal Costs (LRMC) in more detail, consider the following short run cost function for an electricity utility

$$C(X) = c.X + \beta(X).X \quad (8)$$

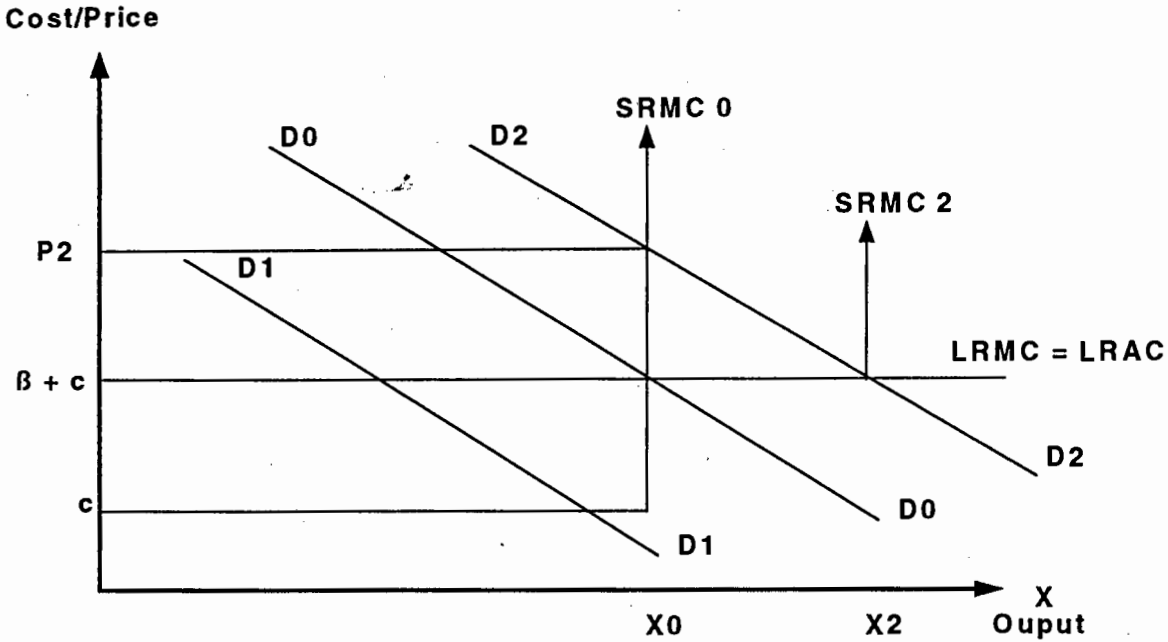
where  $c$  denotes the unit operating costs which are equal to marginal costs, and  $\beta(X)$  denotes the unit capacity costs that vary with the size of the capacity installed and  $X$  is the quantity produced. (Different types of power stations have different unit capacity costs. For example, the capacity cost of a gas-fired power station is much lower, per unit, than the capacity costs of a large coal-fired station)

The long-run counterpart of this function is the first differential of this function with respect to time,

$$LRMC = C'(X) = c.X + \beta(X) + \beta'(X).X \quad (9)$$

where  $C'(X)$  denote the first differential of the short run cost function with respect to time

With sufficient capacity in place, short run costs become relevant to decision making at the margin. This is illustrated in Figure 7, for the case of the demand curve  $D_1D_1$ . In this case the SRMC would be  $c$ . In the special case that demand actually equals the installed capacity, that is, the intersection of demand curve  $D_0D_0$  and  $SRMC_0$ , the short run marginal cost exactly equals the long run marginal cost. In the case that demand exceeds the installed capacity, the short run marginal cost will be the cost that clears the market. In the case of demand curve  $D_2D_2$ , this is at a price  $P_2$ .



**Figure 7. LRM C under Constant Returns to Scale**

In the case that  $SRMC > LRMC$ , investment in additional capacity is warranted. Once the additional capacity has increased the existing capacity to its optimum level,  $X_2$ , welfare maximisation requires that the price be adjusted downwards so that  $LRMC = SRMC_2$ . In an optimally planned system therefore,  $LRMC$  and  $SRMC$  are equal. This is illustrated in Figure 7 as the intersection of the  $SRMC$  and  $LRMC$  curves.

The question remains, should prices be based on  $SRMC$  or  $LRMC$ ? Opinions on this vary. In Munasinghe and Warford (eds) (1982:52) Munasinghe argues that  $LRMC$  will provide a more stable basis in price setting than  $SRMC$ . The principle argument behind this is that demand is volatile and investments in capacity are lumpy and hence  $SRMC$  will result in wide price variations and hence introduce uncertainty in the medium to long term decision making of the utilities. Furthermore, "...the large price fluctuations of  $SRMC$  will be disruptive and unacceptable to customers." This practical problem may be avoided by adopting a  $LRMC$  approach which provides the required price stability while retaining the principle of matching willingness to pay and incremental supply costs.

Teplitz-Sembitzky in (Teplitz-Sembitzky, 1992:27) is somewhat disparaging of this opinion. While he agrees "that the stability argument advanced by Munasinghe looks persuasive since it purports to improve efficiency by providing customers with smoothed

information about future prices", he questions why electricity customers should be protected against volatile tariffs, when in other energy markets (e.g. oil) prices are allowed to fluctuate.

However, although LRMC may fail to accurately recover costs it tends to keep accounting losses at a lower level than does SRMC pricing. This is always true in the case where the utility has excess capacity. However, perhaps the strongest argument against LRMC is that LRMC can only be calculated with any certainty for models which assume a perfectly known future. In practice this is not possible and hence LRMC would appear to have more use in theory than in practice. Teplitz-Sembitzky goes so far as to say that

"...Long Run Marginal Costs are a misleading benchmark for electricity pricing. Unless the power sector invests and operates in a steady-state equilibrium, LRMC cannot be justified on efficiency grounds." (Teplitz-Sembitzky, 1992: v)

On balance between the arguments of Teplitz-Sembitzky and Munasinghe, it would seem that there is no particularly strong case for either method: SRMC comes closer to welfare maximisation but introduces large fluctuations in the price, while LRMC comes closer to the ideal of full cost recovery and will provide stability, but will not, in theory, maximise welfare.

### **Practical perspectives on the theoretical basis underlying marginal costing**

The analysis of marginal costing thus far has discussed this costing methodology in the context of welfare economics. The analysis has also dealt with the theory of the second best and the theory underlying long run and short run marginal costs. It is clear that the derivation of the proof of the maximisation of the social welfare function through marginal costs is based on a number of assumptions that have no basis in reality and hence the proof only has value as the solution to a highly theoretical problem. Further, the problem of the second best was described earlier as "merely an addition to a body of welfare analysis that is itself of dubious relevance for discussing any non-trivial policy problem." This section therefore attempts to provide some practical perspectives on marginal costing.

The first perspective is that in about 100 years since the first centrally controlled electricity power system, marginal costing has only gained widespread acceptance in the last 40 years. The first utility to apply marginal costs to prices was Electricite de France in the late

1950's. Today, American utilities are forced to calculate marginal costs in terms of legislation passed by the Federal Energy Regulatory Commission and organisations such as the World Bank prescribe that tariffs be based on marginal costs so that customers are charged the amount which correctly reflects the value of resources required to supply them (Munasinghe, Gelling and Mason, 1988).

A practical problem with marginal costing is that marginal cost-based tariffs (whether LRMC or SRMC) will not recover total accounting costs in times when the supply authority has an excess of installed generating capacity. The converse is true in times when the installed capacity is not sufficient to meet the customer's demand: In these times the marginal cost will far exceed the average cost and hence pricing at marginal cost will lead to the utility making considerable accounting profits.

Furthermore, marginal costs represent the economic cost of supply and, as illustrated in Figure 7, these vary widely during periods in which a utility has excesses or shortages of installed capacity. Pricing at the short run marginal cost will lead to tariffs with large price swings and hence tariffs based on these costs fail to achieve the desired quality of "rate stability". This problem can (theoretically) be overcome by using long run marginal costs. However as discussed earlier, long run marginal costs can only be calculated with any certainty for models which assume a perfectly known future.

Finally it is impossible to argue that strict marginal costing applied in a real economy would achieve the theoretical objectives it is intended to achieve. However, as a basis to electricity pricing, marginal costing can justifiably claim to be aimed at optimising the utilisation of the producer's and consumer's resources.

## 2.8 Pricing applications based on marginal costs

Having established the theoretical basis to marginal cost pricing, it is possible to review some practical pricing methods based on marginal costs. The two most widely used applications of marginal costs are in time of use tariffs and in deterministic spot pricing

### Time of use pricing

Section 2.5 presented a brief historical review of electricity costing. Part of this review discussed the arguments first put forward by Wright that theoretically "charges ought to be divided into amounts proportional to the maximum demand of each consumer at the day and at the very time the maximum load occurred on the mains each year." His claim was based on intuitive reasoning without any theoretical explanation to substantiate his intuition. The theoretical explanation to prove that marginal cost peak load pricing was welfare-optimal was first proposed by Boiteaux in 1957 in France. Steiner, in America eight years later, published his own contribution to the subject - unaware of Boiteaux's earlier proof (Crew and Kleindorfer, 1979:25). In France, Boiteaux's contribution had a large impact on pricing and was one of the factors leading to France's adoption of marginal cost time of use tariffs in the late 1950's. The Steiner-Boiteaux proof uses the logic of Welfare Economics to prove that pricing according to time of use will maximise the Net Social Benefit. It is felt that reviewing these proofs here will not add value to this discussion. An elementary exposition of the Steiner-Boiteaux model is to be found in Crew and Kleindorfer (1979), while a more detailed exposition is to be found in Teplitz-Sembitzky (1992).

A special case of time of use pricing is known as spot or real time pricing. In essence, spot pricing boils down to continuous-time peak load pricing defined in the face of stochastic demand and supply. Welfare optimal spot pricing will theoretically relate spot market prices to the marginal cost prices of economic theory and in so doing, the Net Social Benefit will be maximised.

Conceptually, the idea of real time pricing has been around for at least as long as the idea of peak load pricing. In 1957, one of spot pricing's present day detractors expressed the idea that, "theoretically, 'the invisible hand' can replicate the allocation of supply in the wholesale market from minute to minute so as to minimise the fuel costs" (Westfield, 1957 in Westfield, 1988). Many years later the same critic wrote "Just as the price of fresh

strawberries in ideal competitive markets (which marginal cost pricing is to stimulate) must at each location be forever changing so as to clear the markets at the point of equality of short-run marginal cost with price, so the rule for the price of electricity must aim to equate at each location short-run marginal cost with price at each moment in time" (Westfield, 1988).

Both of these quotes reveal the essential attribute of spot pricing i.e. it is a method which attempts to continuously relate price to marginal cost. In fact, this is a task not easily achieved mostly because of the highly temporal and stochastic nature of electricity supply and demand. This, amongst other reasons, has resulted in spot pricing being the subject of a considerable amount of controversy. Before the arguments for or against spot pricing are reviewed, it is necessary to present the mathematical basis.

The starting point for spot pricing is the same as for peak load pricing with multiple technology (different types of power stations, for example baseload, midmerit and peaking). This starting point assumes that there is a single public utility which seeks to maximise the Net Social Benefit. This utility owns and operates multiple generating plants and sells to independent customers, who have stochastic demands. From here the model is extended in four ways:

1. Demand and supply are separated from each other by a transmission network.
2. Lines of this transmission network are subject to stochastic outages.
3. Both demand and supply are stochastic.
4. The utility can set and communicate prices instantly, and can set a different price for each customer location at each moment.

Further, assume that demand for electricity,  $X$ , is a function of price,  $p$ , and an independent random variable,  $\emptyset$ . There are constant unit operating and capacity costs, denoted by  $c$  and  $\beta$ , respectively.

From this position the expected total surplus (as in conventional welfare economics) is derived as the sum of the expected consumer surplus and the expected profit (supplier surplus). The expected consumer surplus is given by

$$E(\text{CS}) = \int_{\emptyset} \left\{ \int_0^X p(x, \emptyset) dx - p \cdot X \right\} f(\emptyset) d\emptyset$$

The expected profit (producer surplus) can be expressed as

$$E(\pi) = \int_{\emptyset} \{ [p(X, \emptyset) - c] X \} f(\emptyset) d\emptyset - \beta K$$

(See the definitions of consumer surplus and profit (producer surplus) given earlier in this chapter)

where E =	Expectation operator
$\pi$ =	Profit
X =	The demand for electricity at any time
$\emptyset$ =	Independent random variable (for example temperature)
$f(\emptyset)$ =	Distribution function of theta
K =	Total available capacity
c =	Unit operating costs
$\beta$ =	Unit capacity costs
p =	Price of electricity - which is a function of demand and an independent random variable, $\emptyset$ .

The theoretical treatment of the spot pricing problem is to find prices so that the total expected surplus,  $E(\text{CS}) + E(\pi)$  is maximised. Bohn et al (1982) and Schweppe et al (1988) describe solutions to this problem. It would not be appropriate to review these solutions here.

Moving the discussion from theory to practice, views on the validity of spot prices in the electricity industry are divided. Berrie (1987:335-41), lists the principal advantages of spot pricing as follows:

1. System capacity will be used more efficiently because price will reflect the operating cost of the marginal plant or the market clearing price when demand exceeds capacity. When demand is less than capacity, customers will benefit from the fall in price and will be encouraged to increase purchases.
2. Because price is used to ration capacity, less reserve capacity needs to be held, so

the required capacity investment is lower.

3. Because spot pricing more accurately reflects cost and demand conditions, it can be used as an efficient means of co-ordination in a decentralised system. Efficient merit order running can be achieved without the need for integration of ownership and control. Large monopolistic companies can be replaced by smaller competitive ones, thereby securing the benefits of competition, notably greater efficiency and lower prices.
4. In a less centralised system with spot prices, generating companies will acquire a better understanding of the needs of their customers, which will lead to a better forecasting and investment policy.

Westfield quoted earlier as one of the conceptual pioneers of spot pricing, is ironically now one of its most vigorous critics. Westfield suggests the following disadvantages of spot pricing (Westfield, 1988:378-384):

- " 1. For most customers real time responses to unexpected price changes would be impossible or uneconomic.
2. Those customers whose technology enables them to respond quickly are unlikely to find it worthwhile to do so.
3. Investment in generation and transmission facilities would be less well co-ordinated.
4. The risks associated with competition would lead to smaller units with shorter lives and construction periods, than would be economically efficient, thereby increasing operating costs.
5. The added risks of competition would raise the costs of capital.
6. Environmental costs would be more difficult to accommodate.
7. Fluctuating spot prices would confer windfall gains on investors at the expense of customers, and these gains would not be reclaimed by regulatory procedures. "

A more general criticism of spot pricing levelled by Teplitz-Sembitzky, Littlechild and Westfield is that the spot pricing models have "aimed to determine the policies that would be socially optimal in a static world of perfect information and altruistic authorities" (Littlechild, 1988:398-404). Teplitz-Sembitzky (1992:60) make a more cynical comment, "It seems that ... the concept of real time pricing often serves as a romantic retreat for policy makers and energy planners dissatisfied with the inefficiencies of real world tariffs.

That is to say, one should not become oblivious to the institutional and technical difficulties that are likely to hamper the implementation of efficient spot prices."

A practical discussion of spot pricing is incomplete without a discussion of the kind of structural regime which is most conducive to the emergence of spot prices. For example, if some of the benefits of spot pricing depend upon prices reflecting costs, and if this in turn requires effective competition to achieve, the benefits of spot pricing may be less in a monopoly regime. It is interesting to note Littlechild's conclusions after research into the deregulation of industries in the UK and the USA, that "moves towards deregulation and privatisation in the UK and the USA are more likely to foster the spot pricing of electricity than to discourage it" (Littlechild, 1988:398-404). This conclusion is consistent with Bernstein's study of spot pricing in the Chilean electric power sector (Bernstein, 1988:369-78).

In terms of the applications of spot pricing in the African context, one has to consider several aspects:

1. The spot pricing regime developed will vary considerably depending on the industry structure. For example, in the UK the spot market is designed merely to facilitate trade between largely privately owned concerns. In a monopolist regime, one has to consider that the spot pricing mechanism developed will be subject to the pricing policy of that regime.
2. There are further crucial implementation issues, such as:
  - 2.1 It is necessary to have advanced metering technology and electronic communication capabilities.
  - 2.2 Spot pricing relies on the ability to manage huge amounts of data.
  - 2.3 Part of a spot pricing system is a complex billing system.
  - 2.4 It is necessary to establish a pool of technologically advanced personnel who will be able to meet the design and implementation demands of a highly sophisticated pricing technique.

- 2.5 If necessary, solutions will have to be found to the problem that an unsophisticated customer base might find it impossible, too expensive, or not worthwhile to respond to the signals and service options that spot markets are supposed to provide.

It is interesting to note the advice of Teplitz-Sembitsky in (Teplitz-Sembitzky, 1992:v) "... when many electric utilities in developing countries are on the verge of a financial collapse, pricing policies guided by first-order conditions of global welfare maximisation are misplaced. Rather than requiring the utilities to pine for an *optimum optimorum*, emphasis should be placed on strategies that help restore the solvency of the power sector. For that matter, pricing has to be relieved of sacrosanct efficiency objectives and should come to grips with more mundane and immediate commercial ends." Sioshansi (1988:353-9) also warns against spot pricing, on the basis of political resistance by customers, especially low income domestic customers, who would be exposed to higher prices.

In conclusion, this section has reviewed the application of marginal costs in the development of time-differentiated tariffs. The spot-pricing model in which the price of electricity is based on marginal costs which are recalculated at short time intervals, attempts to maximise pricing efficiency. It is universally agreed that in a theoretically perfect world, spot prices will maximise welfare and thus optimise efficiency. However, although spot pricing has been widely used in several countries specifically as part of pool electricity exchanges, opinion on the practicality and efficiency of spot prices is sharply divided.

## 2.9 Ramsey Pricing

The theory of Ramsey pricing dates back to a 1927 paper by Frank Ramsey in which he showed that tax on a commodity which is inversely proportional to that commodity's price elasticity of demand (change in demand as a result of a change in price) will lead to optimal excise taxation.

In pricing parlance, Ramsey pricing is classified as *Linear Break-even Pricing*. *Linear*, because prices do not vary with the energy produced/sold/purchased and *break-even* because prices are calculated subject to the constraint that the utility will cover its costs. This makes Ramsey Pricing *Second Best*, that is, maximising the Social Welfare Function

subject to the constraint that prices will allow the utility to break even. This compares to the fully optimal, so called first best marginal cost prices which do not necessarily break-even.

The logic of Ramsey pricing can be explained as follows:

Suppose that all prices are set equal to marginal costs. Where a fixed cost exists, as discussed earlier, the firm will fail to break-even. To prevent this situation arising, it is necessary to include a mark-up over marginal costs in such a way that a Pareto optimal<sup>4</sup> solution is obtained (this is the solution to the problem of the second best as explained earlier). To achieve this it would seem reasonable to increase prices in markets in which the price elasticity of demand is low. By following this strategy the markets will be altered as little as possible from the price-equal-marginal-cost equilibrium which, as was proved earlier in this chapter, will maximise the Net Social Benefit and hence provide the first-best solution. In other words,

$$\text{Markup}_i = [P_i - C_i]/P_i$$

Where  $P_i$  is the price in market  $i$  and  $C_i$  is the marginal cost of supplying customers in that market.

Now define the proportionality constant,  $\phi$ , as the constant that adjusts markups in all markets uniformly up to the point where the firm breaks even. Hence,

$$\phi = ([P_i - C_i]/P_i) \cdot \mu_i$$

where  $\mu_i$  is the price elasticity of demand for customers in market  $i$ .

What this formula says is that for any pair of markets served by a regulated firm the percentage deviations from marginal cost, weighted by the price elasticity of demand, should be equal for both markets to the mark-up,  $\phi$ . This is known as the Inverse Elasticity Rule (IER) and  $\phi$  is commonly known as the Ramsey number.

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<sup>4</sup> Vilfredo Pareto was a nineteenth century Italian economist and philosopher who defined "a change that makes one person or group better off at the expense of no one else", a Pareto improvement

Two observations can be made:

1. Ramsey prices, if they exist, will fully distribute a utility's costs across outputs. The allocation of costs is implicitly determined by the Ramsey pricing solution, unlike the formula for apportioning fixed costs as described earlier in the section on embedded costing.
2. In order to deduce the Ramsey solution one has to know the different demand functions and the price elasticity of demand in each of the different markets.

The latter observation is a significant limitation to utilities adopting Ramsey pricing. This is because it is practically very difficult to establish the demand curves of a utility's customers when those customers range from demand inelastic commercial customers to some industrial customers with a high elasticity of demand.

From an organisational perspective, Ramsey pricing can only be rigorously applied in a monopolist or highly regulated industry. It is difficult to imagine that in a competitive industry, a utility would offer prices to a customer based on their perception of that customer's price elasticity of demand. Rather, the prices offered would be based on the firm's own costs and other offers from competitor firms, to that customer.

Leaving these considerations aside, the relevance of the Ramsey-pricing rule has frequently been questioned either because a utility does not seek to maximise the Net Social Benefit (in many cases a utility seeks to maximise profit) or because a regulatory authority which could be required to enforce Ramsey prices has little or no knowledge about the customer's elasticities of demand. Or, as Bonbright puts it, "The problem of determining what surcharges will impose the least serious harm in the form of curtailments and distortions of use of service when the rates as a whole must yield total revenue requirements ... depends on a knowledge of cost functions and of demand functions that practical rate makers simply do not and cannot possess" (Bonbright, Danielsen and Kamerschen, 1988:301).

Furthermore, Ramsey-pricing per se provides no incentive for a utility to cut costs, just as the basis on which it was derived was not to reduce tax but rather to apportion the tax in proportion to the tax payer's ability to pay. Ultimately, Ramsey pricing applied to an electricity utility has been described as "more of a theoretical curiosity than a workable regulatory rule" (Danielsen and Kamerschen, 1981).

## 2.10 Priority Service Pricing

The concept of priority service pricing as an alternative to spot pricing is relatively new. Wilson (1989:1) presents a comprehensive overview of the subject of priority service pricing. Wilson's argument is that spot pricing is rarely used to ration supplies because of "technological limitations and pervasive transaction costs." Wilson develops the theme that a state enterprise can promote substantial efficiency gains by substituting what he called priority service for spot markets.

The idea underlying the priority service pricing approach is that the utility can induce customers to self-select their order of priority in obtaining service, should supply fall short of demand. Hence customers will value reliability by paying a premium depending on the priority ranking they select. Typically the premium is paid in advance, irrespective of whether or not the services have to be rationed. There are two distinct advantages of this scheme:

1. Compared to random rationing in which customers would be cut-off at random should demand exceed supply, with priority service pricing the customer will be better off because capacity is allocated to consumers in accordance with their willingness to pay for service reliability. Customers who would be disadvantaged by an outage would pay a higher premium than those who would not bother about service interruptions (Teplitz-Sembitzky, 1992:87).
2. A public enterprise that offers a *single* service quality (such as Eskom's commitment to meet the demand of every customer) has no direct measure of customers' willingness to pay for capacity increments that improve the quality of service. In contrast, customers' selection of priority service conditions clearly indicate their willingness to pay for quality improvements.

Taken to its theoretical optimum, priority service pricing will result in *ex-ante* (before the event) purchase choices that optimal spot pricing would generate *ex-post* (after the event).

The theoretical rationale of priority service pricing is presented in Teplitz-Sembitzky (1992:87-9) as follows:

Let  $\emptyset$  denote the consumer index that ranks the willingness to pay for reliability. In particular, let  $\emptyset$  represent the value (Rands) that Type- $\emptyset$  customers attach to a unit of output (kWh) supplied with probability  $(1-s)$ , where  $s$  denotes the supply (per unit) that will be available per unit of demand (kW) at some specified instant. (Both  $\emptyset$  and  $s$  are uniformly distributed on the unit interval.) Alternatively,  $s$  can also be interpreted as a service order in the sense that the consumer type  $\emptyset$  will be served first as long as supply exceeds  $s$ ; that is the lower the service order, the higher is the priority in being served. Thus, efficient rationing on the basis of priority service contracts requires that  $\emptyset = 1-s$ .

Now let  $P(s)$  denote the price that customers are induced to pay for service order,  $s$ . If reliability is costless, efficient priority service pricing requires that the class  $\emptyset$  customers' willingness to pay for service order  $s$  is large enough to make up for the outage costs lower priority customers would experience in the event of a shortfall. This condition can be expressed as

$$P(s) = \int_s^1 \emptyset ds = \int_s^1 (1-s) ds = 0.5(1-s)^2 = 0.5 \emptyset^2$$

That is, the premium on reliability increases with the service priority. (This result is intuitively obvious.)

Priority service pricing is offered as a practical alternative to spot pricing. However, attempting to implement priority service pricing as a single pricing principle (as opposed to a pricing option) will be impossible unless the utility is able to have direct control over the power supply to every customer and is able to rank every customer according to a priority service schedule. The logistics of achieving this is formidable and hence the real value of priority service pricing at the moment is to show that in a theoretical optimum the advantages that spot pricing achieves *ex-post* can be achieved with priority service pricing, *ex-ante*.

In practice many utilities use the *principle* of priority service pricing in optional, interruptible tariffs. It is important however, not to confuse priority service pricing with interruptible tariffs. Priority service pricing refers to a pricing principle that governs the setting of tariffs for all the utility's customers. Interruptible tariffs refers to a tariff

technique whereby the marginal cost at certain periods is compared with the customer's willingness to pay that marginal cost. If the willingness to pay is less than the cost, then the customer can enter into an ex-ante contract with the utility to forsake his right of supply at certain times in return for a cheaper tariff from the utility, the savings being shared between the two parties. An interruptible tariff is therefore better defined as an entrepreneurial tariff in a marginal cost environment than as an element of priority service pricing.

## 2.11 Competitive pricing

The revival of the competitive paradigm in electricity pricing has largely been in response to dissatisfaction with the performance of nationalised monopoly electricity industries. The proponents of competition in the ESI argue that:

1. Consumer prices will be brought down by creating competition amongst the suppliers and retailers of electricity.
2. Investment decisions will be made on the basis of competitive market forces and not by bureaucrats.
3. The industry will be governed by competitive forces generated by the market and as such will be free from harmful government intervention.

There is a considerable body of opinion, however, that the electricity supply industry is a natural monopoly and hence attempts to introduce competition will result in the non-optimal utilisation of resources. Before possible means of competitive pricing are explained, it is necessary to focus on the natural monopoly argument.

Put simply, a natural monopoly exists when it is cheaper for a single firm to produce the required output than it is for two or more firms. Teplitz-Sembitzky uses a more rigorous definition to define a natural monopoly: A natural monopoly exists when, "relative to some range of output, the underlying cost function is sub-additive over this output range" (Teplitz-Sembitzky, 1990:14).

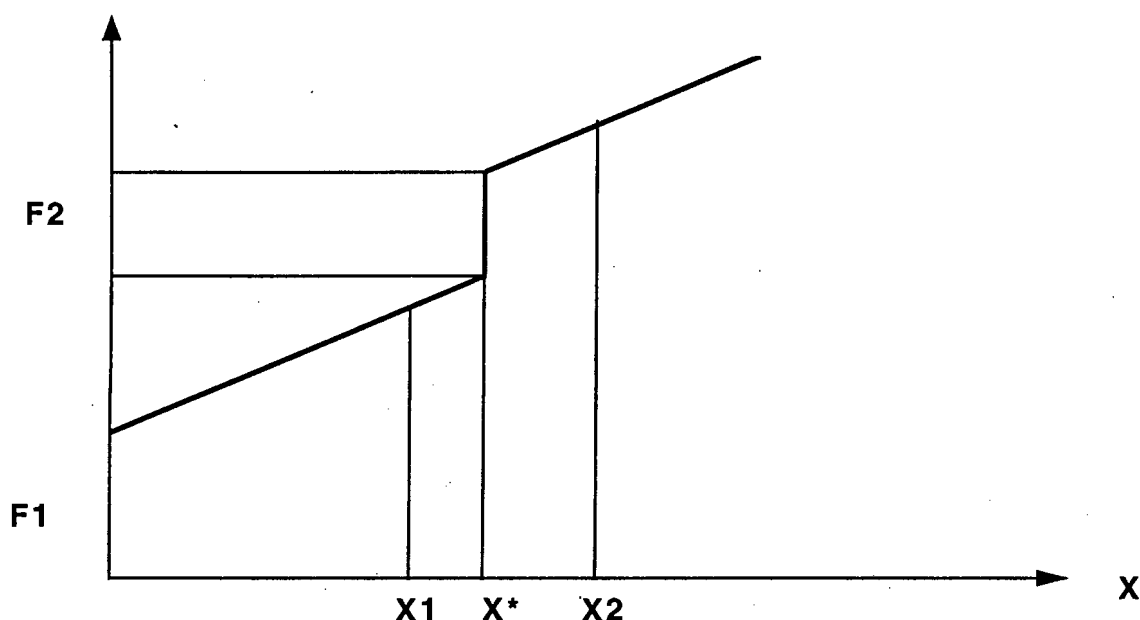
Figure 10 illustrates a sub-additive cost function defined as:

$$C = F_1 + cX, \quad \text{for } 0 < X \leq X^*$$

$$= F1 + F2 + cX \text{ for } X > X^*, \text{ with } F1 > F2$$

where  $F1$ ,  $F2$  are the fixed costs incurred in producing a specific level of output,  $c$  is the variable cost of production and  $X$  is the quantity produced.

**C (Total costs)**



**Figure 10. Sub additive costs**

The cost function is sub-additive over the whole range of outputs since the combined fixed costs of two or more firms, each incurring  $F1$ , exceed the fixed cost of a single producer, i.e.  $\lambda F1 > F1 + F2$ ,  $\lambda \geq 2$ .

In addition to the idea that sub-additive fixed costs define a natural monopoly, in the presence of sunk costs, markets are no longer contestable. In the highly capital intensive electricity industry, the fixed cost element of the cost function is to a large extent, sunk. That is, fixed costs cannot be recovered in the short-to-medium term. These sunk costs erect barriers to entry by subjecting potential entrants to retaliatory behaviour. Consider the distribution, transmission and generation systems:

Investments in distribution systems are almost entirely sunk. The network has no other use than to distribute electricity to customers who are expected to buy electricity. On the other hand, the final consumer has no choice but to buy the distribution services offered by that

system. A distribution system also tends to exhibit strong economies of scale. Thus distribution qualifies as a natural monopoly with a high degree of sunk capital expenditure.

A similar argument applies to transmission. Transmission is locked between power generators and distributors. Given the immobility and almost complete lack of alternative uses, investments in a transmission system are almost entirely sunk, thus constituting a barrier to entry which increases the potential for monopoly pricing as a result of economies of scale.

Sunk costs also play a role in power generation. Power stations are generally highly capital intensive and immobile and as such, investments in generation are largely sunk. Generation also exhibits economies of scale at the unit (larger units are more economical than smaller units) and plant (plants with more generating units are more economical than plants with less units). However certain minimum unit and plant sizes are necessary before scale economies exist. This renders generation, like transmission and distribution, a natural monopoly.

Hence if electricity generation (supply) and distribution is a natural monopoly, there is clearly no point in arguing the case for pricing to be based on competition since, as economic theory maintains, creating competition in a system in which there is a natural monopoly would result in a gross misallocation of resources. For example to create competition in the distribution industry would require that multiple distribution networks be constructed so that independent distributors can compete. It does not require an elaborate economic proof to show that such a situation would be sub-optimal!

If we accept the idea that electricity supply is a natural monopoly and further that the electricity market it is not a contestable market,<sup>5</sup> the question arises whether it is possible to introduce competition in the ESI. To attempt to answer this, possible types of competition in the electricity industry will be described under four headings:

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<sup>5</sup> The Contestable Market Theory says that "if the market served by a multi-product natural monopoly is contestable in the sense that rival firms can enter or exit the market without losing any of their investments, there will be no axiomatic need for price or entry regulation." A key assumption underlying the theory is that there are negligible costs in entering and exiting the market. This hypothesis applied to the electricity supply industry says that price will be regulated by the threat of entry of new competitors to the monopoly market and it is this competitive force which will dictate the price of electricity.

- \* Third-party access competition
- \* Franchise competition
- \* Wholesale competition
- \* Incentive competition

### **Third party access competition**

Third party access competition refers specifically to the situation in which an independent distributor can get access to the distribution and reticulation network which is owned by another party. The distributor using the network would pay the owner of the network an appropriate amount for the use of the network. Since no single distributor has sole right to use the network, the distributor which uses the network is the one that beat other distributors for the custom of a single, or group, of end-users. In this situation, the organisation that owns the distribution network is not material since ownership of the network does not imply sole use of the network.

The distribution industry in the UK is a good example of a competitive distribution industry where competing distributors have the right to use the existing distribution infrastructure. As is discussed more fully in the chapter on pricing in the restructured UK industry, the Office of the Electricity Regulator (OFFER) stipulates very accurately the amount that may be charged by the owners of the distribution network for the use of the network (the wires business). Since all distributors using the distribution network are committed to pay the same amount in respect of the use of the network, there is no competition at this level. The other cost of distribution is incurred in the "supply business" (the supply business refers to the tariffing, marketing, buying and administrative, etc. functions of the distributors). Here the force of competition is used to ensure that the costs incurred in "supply business" functions, is minimised.

### **Franchise competition**

If in view of sunk costs, power markets can not be made contestable there is, at least, the option of competition for the exclusive right to serve the markets. The right is granted on the basis of a well defined contract to perform specific functions, for example, to distribute electricity to a particular area. The principal selection criterion centres on service quality and service variety and the set of prices at which these services will be provided over the

contract period in question. Pricing, in terms of both structure and level in a franchise agreement, will be structured by the competing prospective franchisees in order to win the contract. If after winning the franchise, the franchisee desires to maintain the contract, its pricing will have to be competitive with that of its potential competitors. It is in this sense that franchise competition will regulate the price level and structure. It is obvious that considerable responsibility rests with the franchisor to ensure that correct criteria are set for tariff evaluation.

### **Wholesale competition**

The concept of wholesale competition refers to a system in which utilities will be offered a choice of "independent" power producers from whom to purchase electricity. An example of this is the 1978 Public Utility Regulatory Policy Act (PURPA) in the USA, which stipulated that electric utilities had to buy 3 to 4 percent of total US generating capacity from qualifying co-generation and independent power producers.

The PURPA regulation is ultimately a case of fabricated wholesale competition. A system of true wholesale competition would be one in which there are a number of independent electricity generating companies who compete to sell electricity in a deregulated wholesale market. Such an arrangement presents two possibilities. Firstly the wholesalers are not allowed to enter into contracts with distribution companies or other large end-customers and are instead constrained to sell their full production to a centrally co-ordinated power pool; or secondly, the wholesalers are free to sell power directly to distributors and/or large end-customers.

In the case of the former pool arrangement, the distributors would meet their power needs with purchases from the pool, while on the other side of the pool, the pool authority would have to re-contract power from independent wholesalers. In this case, the price at which the pool would purchase power would be dependent on competition amongst the independent wholesalers. An example of such an arrangement is the UK Power Pool.

In the case of the later, wholesalers/generators have the opportunity to undertake transactions with the distribution systems and end-users. This allows competition between the supplier and the consumer and price between these two parties will be set on the basis of market forces. Teplitz-Sembitzky (1990:67) argues however, that such arrangements are

likely to face pervasive co-ordination problems, be difficult to manage, and will result in vertical integration by contract (i.e. customer/distributor/transmitter/ supplier contracts).

### **Incentive competition**

The final type of competition to consider is artificial competition created through centrally determined incentives. A general problem inherent to the concept of incentive competition is that performance incentives only work on the basis of clearly defined performance targets. This tends to become a preclusive focus i.e. incentives to compete could lead to heavy competition in the area in which the incentive is set, at the expense of other neglected areas.

Incentive competition may be in the form of sliding-scale price regimes, indexing or yardstick competition, amongst others.

#### *Sliding scale price regimes*

Unlike conventional Rate of Return regulation, a sliding scale scheme allows prices to vary if the actual rate of return deviates from the predetermined, comparator rate of return on investment. This approach provides basic incentives for cost-efficient performance but depends on conventional accounting procedures. This means that decisions will be based on embedded costing information. As such, decisions will be based on the wrong economic signals. Furthermore, sliding scale adjustments focus on the average level of prices and therefore fail to distinguish good or bad performance inside of the average.

## *Indexing*

Indexing of utility prices pursues two objectives: It attempts to neutralise the effect of price changes which are not under the control of the utility; and it is designed to create incentives for cost savings. Prices can be indexed with respect to selected, easily monitorable cost items but there is also the option of using broad-based indices such as the Consumer Price Index or Retail Price Index. An example of the later is the RPI - X formula used to index prices in the restructured UK ESI.

Index-based "minus-x" schemes limit the upside on prices by allowing prices to rise no more than a specific price index less X points to allow for efficiency improvements. The advantage is that net revenues are made dependent on the difference between actual and expected efficiency improvements. Thus they provide an incentive to beat expected efficiency improvements in order to realise a profit.

However, efficiency changes provide an incomplete picture of utility performance. For example if customers are willing to pay a higher price for better service, the utility may not be able to charge such higher prices in view of the indexing constraint.

## *Yardstick(benchmark) competition*

The idea behind the yardstick approach is to measure the performance of a particular utility relative to the sector's average performance. This would eliminate many of the deficiencies associated with single-valued performance measures. For instance, if tariffs are set equal to a sector's average costs per unit of output, the individual utility's costs become a choice variable which can be used to influence the individual utility's rate of return. Of course, this discounts any external factors which may be beyond the control of a particular utility.

Yardstick competition is only relevant if there are a number of utilities, relatively comparable in terms of function, regional characteristics, technological standards, accounting principles etc. An example of where yardstick competition could be useful for improving efficiency and hence prices is in the current South African electricity distribution industry. If similar distributors were adjudicated against a common set of benchmark ratios, it would be possible to rank the performance of each distributor against these benchmarks. Favourable variances between the performance of an individual

distributor and the common benchmark would translate into profits for that distributor and visa versa for unfavourable variances.

## 2.12 Non-tariff pricing

The content of this chapter so far has concentrated on tariff principles based, to a greater or lesser extent on rigorous economic analyses. However, it is unrealistic to expect all customers to conform to the strait-jacket of tariffs specified according to their customer category classification. This is particularly the case for large customers who are able to significantly influence the financial viability of the utility. For most electric utilities non-tariff pricing will be an element of their pricing strategy and hence any formulation of a framework for analysing electricity pricing would be incomplete without a review of this pricing technique.

Non-tariff electricity pricing, has been defined as the process of "determining the price parameters for individual customers on a case-by-case individually customised basis" (Calitz, 1991:36). In terms of the various pricing philosophies explained in Section 1.3, non-tariff pricing can be defined as a combination of the cost-of-service, value of service and competitive pricing philosophy: *Cost of service* because the utility offering the customised tariff is unlikely to offer a tariff which will not recover at least its marginal operating costs; *value of service* because considerations of the customer's price elasticity of demand will weigh heavily in the determination of customised contracts; and *competitive pricing* in the case of utilities concerned with market share and competition with other utilities or alternative energy sources.

Calitz (1991:39) describes seven different sources of pressure for non-tariff electricity pricing. Four significant sources are:

### 1. *Surplus generating capacity*

As explained earlier, in times of excess generating capacity, the short run marginal costs are considerably lower than average costs. This leaves a margin between marginal costs and average costs within which the utility can negotiate special deals and still recover its direct costs.

## 2. *Pressures exerted by the customer*

Large customers have called for specially negotiated customised contracts for themselves for large bulk supplies. Utilities, particularly para-statal utilities, have often structured customised contracts in attempts to display customer-focus. However, displays of this kind are limited to those that will at least show some financial return on investment. Most often customised deals are based on mutual economic benefit. An example is Eskom's recent Alusaf contract where Eskom and Alusaf negotiated a mutually beneficial pricing deal.

## 3. *Maturity*

A mature industry requires increased capability to measure costs on individual items and to price accordingly. Maturity implies that customers demand a higher degree of pricing sophistication and will not tolerate tariffs which are not cost-reflective.

## 4. *Pressures stemming from shortcomings of tariffs and competition in the energy market.*

The previous sections in this chapter have attempted to illustrate the various short-comings and advantages of various tariff mechanisms. Some customers may switch to alternative energy sources so as to avoid some of the general short-comings of tariffs applied to specific classes of consumer. This will lead to the utility negotiating special contracts so that this custom will not be lost.

Similarly, competition from alternative sources of energy will lead to pressure for the utility to negotiate special contracts for those customers who have a high price elasticity of demand for electricity.

There are a multitude of different possibilities for customised tariffs such as:

- \* Linking the price of electricity to the price of commodities (Eskom-Alusaf contract).
- \* Avoided-cost-based tariffs.
- \* Co-generation and self-generation based contracts.
- \* Growth incentives - bulk sales discounts.

A common thread in any customised contract is the process of balancing risk and return between the customer and the supplier. Clearly this principle of tariff setting is totally abstracted from the micro-economists' world of analytical tariff theories.

Customised pricing is widely accepted internationally and in South Africa. There is no doubt that it has a place in the pricing strategy of any electricity utility since it would be foolish to ignore requests for customised contracts, particularly if doing so would result in decisions contrary to the national interest. However, customised tariffing - by definition - is an exception to the general pricing practice adopted by any particular utility and as such should not be considered as more than a niche element of a broader pricing philosophy in any particular electricity utility.

### **2.13 Conclusions**

This chapter has attempted to sketch a broad theoretical electricity pricing framework. The chapter began with a description of a paradigm in which the tariff was described as the mechanism which arbitrates between the customer, the supplier and the national interest. In this paradigm electricity pricing is best described as the art of compromise. The chapter then reviewed some views of the criteria which should be used in developing an electricity and energy pricing policy. The specific criteria used in defining a pricing policy will determine the specific philosophy characterising that policy. On this subject, the cost of service, value of service, social pricing and competitive pricing tariffing philosophies were described. Moving from the general to the specific, a brief discussion of what has come to be known as "the first great pricing debate", illustrated some of the key arguments on electricity costing. Since electricity costing is ultimately the basis of electricity pricing, the chapter then focused on nine factors which influence the cost of supplying different consumers. The bulk of the chapter then focused on a critical review of various costing and pricing approaches, specifically: Embedded costing; marginal costing; pricing applications based on marginal costs; Ramsey pricing; priority service pricing; competitive pricing and non-tariff pricing.

## **CHAPTER 3. THE DEVELOPMENT OF THE SOUTH AFRICAN ELECTRICITY SUPPLY INDUSTRY**

### **3.1 Introduction**

Electricity has been a vital part of the development of South Africa for just over 100 years. The purpose of this chapter is to review the development of the electricity industry in South Africa so as to provide a background to the current structure of the industry and the state of electricity pricing in the South African electricity industry. This chapter reviews the history in two periods: the developments prior to the nationalisation of the Victoria Falls and Transvaal Power Company in 1948 and the developments since then. At the beginning of the first period, the generation industry developed in a fragmented and decentralised fashion, reacting to the need for electricity by communities, mines and industries. There was a mix of private and public ownership of the generation and distribution industry at this time. As the generation industry expanded it became progressively more centralised. In 1948 the nationalisation of the Victoria Falls and Transvaal Power Company marked the end of private ownership in the industry and the beginning of a whole new era in the development of the industry. From 1948 onwards the responsibility for generation and transmission rested almost entirely with the Electricity Supply Commission.

### **3.2 The first period: 1882 to 1948**

Reading the history of this period, one is filled with a sense of romance that characterised the pioneering development of the industry. Individuals such as Dr Charles Merz, Dr Hendrik Van Der Bijl, Dr Bernard Price and Sir Robert Kotze are revered as formidable engineers who shaped the development of an enormously significant industry. The flavour of the time is perhaps best conveyed in a letter Dr Van Der Bijl wrote shortly before his death,

"Our inspiration was derived from faith in the future of our country. Still a young and vigorous land in a world grown old and perhaps weary, South Africa possesses abundant resources which her virile people will not leave undeveloped ... it will be our endeavour to play our part not as those who follow where others lead, but as pioneers" (Escom Golden Jubilee 1973).

The nature of the industry Van Der Bijl, (then Chairman of the Electricity Supply Commission) left at his death at the end of 1948, was vastly different from the nature of the industry which he started in, in 1923. Indeed, in the history of the industry from 1882 to 1948 the development of the generation industry was from private ownership to public ownership, from fragmentation to consolidation and from private control to public control. The distribution industry did not mirror these changes and instead became progressively more fragmented.

Kimberly Municipality commissioned its first large scale electricity reticulation system in 1890, Johannesburg followed shortly thereafter in 1891, Pretoria in 1892, Cape Town in 1895 and Durban in 1897 (Escom, 1973). In each province, legislation based upon regulations introduced by the Board of Trade Regulations in Great Britain was created to regulate the new power utilities. This regulation governed the provision of electricity for public purposes. In terms of pricing, the approval of the Administrator of each province had to be obtained for tariffs. By 1905 there were a number of gold mines and a few other industries who had their own generating facilities. In addition there were 24 municipalities who had built their own generation and reticulation facilities. The nine largest, in 1905, are listed in the table below:

Undertaking	Annual Sales [GWh]	Number of Customers
Rand Central, Brakpan	10	28 bulk
De Beers, Kimberly	9	1000 + bulk
General Electric, Germiston	8.6	493 + bulk
Durban Municipality	4.4	3167 + trams
Cape Electric Tramway Co.	3.4	Trams
Johannesburg Municipality	3.3	2420
Cape Town Municipality	1.8	1332 + trams
Pietermaritzburg Municipality	1.1	1068 + trams
Pretoria Municipality	1	1300

**Table 1. Electricity supply in South Africa in 1905\***

\* Source: Christie (1979)

However, in 1905 the price of electricity was very high: The cheapest bulk power tariff in South Africa in 1905 was one penny per unit and the price for domestic customers was as high as a shilling. These prices were considerably higher than in Britain, where the efficiencies of steam turbine generating technology had not yet reached South Africa (Christie, 1979).

Much of this changed with the development of gold mining methods which were more electricity intensive. The increased demand from the mines led to the formation in 1906 of the Victoria Falls Power Company (VFP), as a subsidiary of the British South Africa Company which Cecil Rhodes had established. At the time, the objective of the VFP was to generate electricity from the Zambesi River at Victoria Falls and transmit it to the Gold Mines on the Reef. However as a result of pressure from influential coal barons on the Reef, VFP began to construct large coal-fired plant for the supply of electricity to the gold mines on the Rand. At this point "and Transvaal" was added and the VFP became known as the Victoria Falls and Transvaal Power Company (VFTPC). The VFTPC subsequently purchased a number of strategic concessions, the Rand Central Electric Works and the share capital of the Rand Mines Power Supply Company by 1909. (A fascinating account of the intrigue and "romance" which characterised the formation of VFTPC is to be found in (Christie, 1979)).

At almost the same time as the VFTPC was formed, in 1909 the Earl of Selborne - the Governor-General of South Africa, established a commission "to enquire into the desirability of the establishment of large electric power companies in the Transvaal" (Report of the Power Companies Commission, 1909). The Power Companies Commission as it became known, recommended that large undertakings "should be left to private enterprise" and "private enterprise will for the most part eventuate in the formation of large power companies" (Report of the Power Companies Commission, 1909). However, the Commission also recommended that

"Since the supply of electric power leads to the establishment of a virtual monopoly in a commodity which has become practically a necessity of modern civilisation, it should, while being left as far as possible to private enterprise, at the same time be placed under government control and subjected to regulations which shall secure the equitable supply of power, the public safety and public interests generally"

At the time, the Victoria Falls and Transvaal Power Company Limited and the Rand Mines Power Supply Company, its subsidiary, were practically the only private companies selling power in the country. These companies argued against any form of State control of their businesses. The commission however refuted these arguments saying that companies have "taken steps which have had the effect of eliminating competition within considerable areas, with the result that they are now in possession of what is practically monopolist power. They are thus in a position, if they so desire, to

exercise that power to the detriment of customers and potential competitors and so to the detriment of the state and the community" (Report of the Power Companies Commission, 1909).

The Commission thus requested the government to pass an act which would oblige power companies to obtain a licence from the relevant minister. However, in addition to these requirements, the Act also sought a means of broaching the issue of industry ownership. The Commission had recommended in 1910 that the industry remain in private hands mainly because of the need to attract foreign investment in industry in South Africa and also because the need for State capital for growth meant that the State was simply not in a position to finance the construction of a major power company (Report of the Power Companies Commission, 1909). As a quid pro quo the 1910 Power Act contained a provision for the State appropriation of the industry after a period of 35 years. Setting a limit of 35 years was considered as a long enough time for private investors to obtain a return on their invested capital. The industry fought the issue of 35 years tooth and nail, arguing that experience in Britain had indicated that 42 years was the period of time that was required so as not to deter the investment of capital from electrical enterprise. In the event, the Act settled on 37 years.

With regard to tariff regulation, the commission recommended that "it would suffice if the State have the right of supervising prices, such right to be only sparingly exercised" (Report of the Power Companies Commission, 1909). The recommendation was that "no maximum prices should be fixed, but the price charged should be subject to revision by the government on the application of any 10 customers, or any number of customers taking not less than 5% of the power companies' output. In addition, the Commission recommended that the companies be allowed "to earn a dividend of 10 to 12 percent of the capital invested in remunerative plant" (Report of the Power Companies Commission, 1909). Finally the Act prescribed that undertakings applying for a licence were obliged to submit a schedule of standard prices which the applicant proposed to charge customers. Application was to be made to the Minister of Mines who was obliged to refer the application to the Power Undertakings Board for eventual hearing of the application. The Board was entitled to modify or approve the schedule of standard prices charged by undertakings.

The Transvaal Power Act of 1910 was finally passed three days before the creation of the Union. The Act had made it possible for VFP and Rand Mines Power Company to obtain licenses for their vast new systems. The power industry then surged forward so that by 1915 the VFTPC had already erected four power stations (Brakpan, Simmerpan,

Rosherville and Vereeniging) with a total installed capacity of more than 160 MW. The considerable centralisation of power supply led to large-scale reductions of electricity tariffs so that by 1915 the price had been reduced to 0.525d per kWh (Escom, 1973). At the same time, the VFTPC was able to report increasing profitability (Christie, 1990).

At this stage it should be emphasised that the Power Act of 1910 regulated all undertakings supplying power to others, except the municipalities who were separately regulated by the Provincial Administrations as had been established by the provincial ordinances in 1905. However, the 1910 Power Act also stipulated that municipalities did not have a sole right to supply electricity in their area of jurisdiction. Nevertheless, undertakings applying for a licence to supply within a municipality's area of supply were subject to a veto from either the Governor or the Local Authority Council unless it was a supply in respect of the mines, railways or some government department.

The 1910 Power Act thus marked the end of an era of fragmented and uncontrolled development of the power supply industry, but not of the distribution industry. Furthermore, through the resultant establishment of a Power Undertakings Board, the first regulator had been brought into being. For the moment the principle of private ownership, under benign government control, had been entrenched.

The next significant stage in the development of the industry was driven by the railways. Here the prime focus was to achieve a means of transporting coal from the Natal coal fields, over the escarpment and onto the Reef or from the coal fields to the coast for export. Electric locomotives had by this stage achieved a level of significantly greater efficiency than steam locomotives. The problem the railways thus faced was to obtain a source of electricity to power their electric lines. Various possibilities existed: one was to purchase from municipalities; alternatively power could be bought from a private firm which would be specifically set up to sell electricity to the South African Railways (SAR). With regard to purchasing from private firms, SAR feared that private firms would be subject to strikes and further that the financing requirement would stretch the railways beyond their means. The SAR therefore wanted a state-owned electricity supply institution "to prevent the railways from having to take supply from outside firms" (Christie, 1979). To find a solution to the problem, the Government commissioned Dr Charles Merz, a consulting engineer from London "to study the general question of electric power supply" (Electric Power Supply in the Union of South Africa, 1920).

At the time that Dr Merz began his study (1920) there were more than 58 electricity undertakings in the Union. These included 40 municipalities and 18 private companies of which the VFTPC and Rand Power Supply were by far the largest (Electric Power Supply in the Union of South Africa, 1920). The conclusions and recommendations contained in the Merz report greatly influenced the subsequent development of the electricity supply industry (Morgan, 1993). The Merz report recommendations were inter alia that: (Electric Power Supply in the Union of South Africa, 1920)

1. An act should be passed by Parliament providing for the regulation and unification of the supply of electricity and others forms of power throughout the Union.
2. Priority be given to the development of an electric power supply infrastructure to meet the needs of industry and transport.
3. Dr Merz recommended that an Act should be passed by Parliament to provide for the establishment of a small body of commissioners with a mandate to encourage new schemes for the development of electric power supply, and generally to administer the Act in accordance with the principle explained in his report.

After Dr Merz presented his report to General Smuts (the Prime Minister) in April 1920, a committee under the chairmanship of Sir Robert Kotze, the Government Mining Engineer, was appointed to investigate the implications of Dr Merz's report (Escom, 1973). This committee drew up a draft Electricity Bill, which was introduced into the House of Assembly in May 1922. The Bill was then referred to a parliamentary Select Committee, which took written and oral evidence from various parties. The Kotze Committee, the Select Committee and Dr Merz then considered various alternative forms of organisation in the supply of electricity. The most important were the following: (Board of Trade and Industry Report, 1977)

1. Private enterprise supply companies, without state control.
2. Private enterprise, but subject to publicly administered licensing restraints, to price controls, and to control over the means of financing activities.
3. Supply by municipalities, railways or a Government Department.
4. Supply by a State-owned corporation having its own equity capital, but subject to restrictions over the level of profits.
5. Supply by a state-appointed board or commission, financed by loans and subject to price and other restrictions.

Dr Merz rather ignored the issue of ownership. The thrust of his argument centered on two principles: Firstly, centralised generation was necessary to ensure the efficient operation of the system, and secondly the industry should be regulated by a commission which would control the industry. His argument for the latter principle was as a result of the British Electricity Act (1919) which provided for a commission who were given power to formulate schemes for the establishment of a joint electricity authority in any electricity district (Board of Trade and Industries Report, 1977). Such schemes could require the transfer of electricity undertakings to the joint electricity authority and no new generating station could be established without the consent of the Commissioners.

Sir William Hoy, General Manager of the South African Railways, giving evidence to the Select Committee expressed his opposition to the supply of electricity to the railways by private enterprise (Report of the Select Committee on the Electricity Bill, 1922).

Sir Robert Kotze, Government Mining Engineer, disfavoured power supply directly by the state. His arguments were that, "Private enterprise does work more cheaply and more efficiently than the government, and that is why an attempt is made in this bill to get away from purely government control, and the Commission will be more efficient than a purely government establishment" (Report of the Select Committee on the Electricity Bill, 1922).

Mr Bernard Price, Chief Engineer of the VFTPC argued vehemently against state ownership of the industry and said that in terms of the Transvaal Power Act of 1910, profits generated by the company in excess of a stated return on investment had to be shared in stated proportions between the consumer and the company (Report of the Select Committee on the Electricity Bill, 1922).

Regarding the question of whether the supplying body should be a commission financed by loan money, rather than a corporation financed at least partly by equity capital, the arguments were based upon two successful current examples of commissions, i.e. the Rand Water Board (which gave evidence before the select committee) and Ontario-Hydro which was financed through government secured debt capital. The Board of Trade and Industry Report (1977), in a discussion on the events leading to the 1922 Electricity Act, concluded on these different views as follows:

1. Uncontrolled private enterprise in the electricity industry was not favoured

because electricity, it was believed, should be supplied at cost and cost would in turn be minimised by centralisation. The railways also opposed the intervention of private enterprise in the industry.

2. Controlled private enterprise was not favoured because centralisation was necessary to reduce cost and because the Transvaal Power Act of 1910 had in any case provided for the demise of the VFTPC after 35 years.
3. Municipalities and the railways were not regarded as the ideal vehicle because of the need for centralisation.
4. Government departments themselves were not regarded as providing optimum efficiency in electricity supply.
5. A State Corporation with equity capital was not regarded as necessary, in light of the success which the Rand Water Board and the Ontario Power Commission had enjoyed - both of which had no equity capital.
6. On its own merits and also by elimination, a State-appointed Commission financed by loans and subject to licensing, price and other restraints, operating at cost, was favoured.

The Electricity Act of 1922 concluded the work done by Dr Merz, the Kotze Committee and the Select Committee. The Act repealed the Transvaal Power Act of 1910 and was the first Electricity Act to apply to the Union as a whole. The first chapter of the Act provided for the establishment of a Commission (to be known as the Electricity Supply Commission) consisting of not less than three and not more than five members. Members were selected on the basis of specialist technical expertise "...each member shall be selected for his knowledge and practical experience in business or administration, including, in so far as the Governor-General may deem expedient, knowledge and experience in electricity supply and its techniques" (Section 1(1) of the Electricity Act of 1922). The Commission was established as a body corporate in law and had responsibility for, *inter alia*, the establishment, acquisition, maintenance and workings of undertakings for an efficient supply of electricity; and the investigation of new or additional facilities for the supply of electricity within any area and for the co-ordination and co-operation of existing undertakings so as to stimulate the provision, wherever required, of a cheap and abundant supply of electricity (Section 3(a) and (b) of the Electricity Act of 1922). As such, all undertakings with the exception of the municipalities and South African Railways and Harbour Administration, who wished to supply a sizeable amount of electricity had to apply for a licence to a control board established for this purpose. Again the municipalities escaped the regulatory provisions which applied to the rest of the industry. In deciding whether to issue a licence, the Commission could undertake the supply itself or could permit private undertakers to

supply electricity, the only significant proviso being that any action must be in terms of the "public interest" (Section 6(4) of the Electricity Act of 1922).

With regard to electricity pricing, the 1922 Act stipulated that prices charged were to cover the cost of production (including distribution, maintenance and administration), amounts required for interest on money raised by way of loan, and a reserve fund for the replacement of obsolete plant and machinery. The Act provided for a schedule of standard prices as a condition of the licence granted by the board. In addition, any surplus profits had to be shared between a licensee and its customers as follows: The licensee was obliged within six months after the completion of each financial year of the undertakings, to distribute to the undertakers' customers, pro-rata to their payments, twenty-five percent of the surplus profit of the undertaking for that year (Section 25 (2) (a) and (b) of the Electricity Act of 1922). (This share was increased gradually from 25% to 50% and finally to 70% before 1948.)

With regard to the Commission itself, the Act stipulated that as far as practicable, the Commission's operations should be carried out neither at a profit nor at a loss and as such it was not subject to the regulations described above.

The 1922 Act also allowed licensees to charge prices above or below those in their schedule of standard prices, in any or all of the following circumstances: (Section 26(1) of the Electricity Act of 1922)

- (a) "the amount of electricity consumed" by a customer justified a discount/premium in his/her bill,
- (b) a customer with "uniform or regular demand" was entitled, at the suppliers discretion, to a discount,
- (c) supply could be discounted/surcharged for specific customers based on "the time when, or during which, the electricity is required,"
- (d) "the expenditure of the licensee in furnishing the supply" could be reason for a discount/surcharge,
- (e) any "special circumstances" not included above could be reason for discounts or surcharges.

Finally, the Electricity Act of 1922 also contained the provision that the Governor-General, after obtaining reports from the Commission and the Board, could expropriate

private undertakings. However a period of 38 years had to have expired since the time that the licence was first issued to the undertaking.

In summary, in terms of the trends explained in the introduction to this chapter, the 1922 Electricity Act resulted in a further centralisation of the industry, increasing government control and increasing government ownership. Private ownership was not rejected but it became subject to a higher degree of control and the further expansion of private industry was limited.

After the passing of the 1922 Act the activities of the Commission began a rapid expansion. Only three days after the first meeting of Escom, a conference was held with the Railways and Harbours Administration for the take-over of the Colenso Power Station from the railways. This was followed by the construction of the Congella Power Station near Durban and the Witbank, Klip, Vaal and Salt River Stations.

One of the first disagreements between the privately owned industry and the commission took place in 1923 when VFTPC applied in May 1923 for permission to erect a power station at Witbank to meet the increase in the demands of the gold mines after the Rand revolt. Escom, as it became known, opposed the application. Smuts (the Prime Minister) personally intervened and concluded a compromise whereby the VFP was to build and operate the station, while the commission would finance the project and thus own it. This set a precedent which meant that it was the end of the road for private sector expansion of the generation capacity. It is clear that the Commission intended to become the sole owner of generation capacity in South Africa. An era of private sector ownership of the means of production of electricity had given way to ownership by the Commission, which effectively meant ownership and control by the government (Morgan, 1993).

In the 1930s, with the discovery of new gold fields, the industry headed into a sales boom. Between 1935 and 1936 sales increased by 51% and this was repeated again between 1936 and 1937 (Escom, 1973). The increasing efficiency achieved through more advanced generation technologies meant that by 1940, the price of electricity was 0.1755d per unit (Escom, 1973) This compared to more than 1 shilling per unit sold to domestic consumers in 1905.

Up to 1946 it seemed that the rapidly expanding Escom and the existing private generators had successfully co-existed. Sir Bernard Price, a director of the VFTPC in an address in 1944, spoke proudly of his organisation being an example of "controlled

private enterprise". The essential principle behind the arrangement of supply by the VFTPC was the regulation and control of the profit motive via the sharing of surplus profits on a predetermined automatic basis. Dr Price commented that the arrangement had operated to the entire satisfaction of the mining industry and other customers of the company.

However, Price's attempts to get Escom to leave the VFTPC as a private concern, were to no avail. Hence on 1 July 1948 Escom successfully negotiated a take-over of VFP for 14.5 million pounds. The takeover of the VFTPC provided Escom's Rand Undertaking with a well established power system, able to meet the demands for further development. The year 1948 thus marked the end of any significant private ownership of generating capacity in the industry and the beginning of a new era of public ownership and centralised control under the Electricity Supply Commission.

### **3.3 The second period: 1948 to 1987**

After the expropriation of the Victoria Falls and Transvaal Power Company, Escom became the dominant player in the supply industry. Indeed, from 1950 to 1974, Escom's electricity sales increased by an average of 8.8% per annum (De Villiers Commission of Enquiry, 1984), and between 1945 and 1955, with the purchase of VFTPC, the capacity of Escom's power stations doubled (Escom, 1973).

However by 1957 Escom was still, (defacto), "regulated" by the 1922 Act. In 1958 a new Act, the 1958 Electricity Act was passed, consolidating the amendments that had been made to the 1922 Act. In terms of the new Act, Escom was split into a number of separate undertakings, each of which had to separately account for the costs used to derive the prices they charged. Section 14 of the Electricity Act of 1958 repeated the provisions of the 1922 Act, that the price charged for electricity was to cover:

1. The cost of production, including distribution, maintenance and administration.
2. The amounts required for interest on money raised by way of a loan, redemption of any securities for those loans and other expenditure incidental thereto.
3. The amounts set aside for the Reserve Fund.

In addition, Escom was bound by the constraint that it was to make neither a profit nor a loss.

In 1971, the 1958 Electricity Act was amended to allow the Commission to establish a Capital Development Fund through which appropriations from revenue could be made, in order to decrease the ratio of Escom's debt to its retained earnings. In the same year, a second amendment was approved whereby Escom had the authority to amalgamate the power stations from two or more undertakings and to supply electricity from one undertaking to another. This laid the basis for the establishment of the Central Generating Undertaking on 1 January 1972, which enabled Escom to operate all its power stations and other plants as an integrated system (De Villiers Commission of Enquiry, 1984). The creation of a centrally planned and controlled power industry is ultimately what Dr Merz had recommended in his report in 1922 - "An Act should be passed by Parliament providing for the ... unification of the supply of electricity and other forms of power throughout the Union" (Electric Power Supply in the Union of South Africa, 1920).

The next major development in the history of the industry was the De Villiers Commission of Inquiry into the Supply of Electricity in the RSA. The purpose of this inquiry, following shortly after the Board of Trade and Industry Report in 1977 which was motivated by customer dissatisfaction concerning unacceptably high tariff increases, was to investigate the legislation, structure, cost effectiveness, pricing policy and functions of existing institutions involved in the supply of electricity in the Republic of South Africa. Although not stated as such, it would appear that the continuing extraordinarily high price increases was one of the principle motivating factors for the De Villiers Commission Inquiry.

The most important recommendations of the De Villiers Inquiry were as follows: (De Villiers: 1984)

1. The principle of operating at neither a profit nor a loss should be discarded in favour of a sound assets and income structure complying with certain requirements.
2. The industry should be integrated and production costs (excluding transmission and distribution costs) should be centrally pooled.
3. A permanent Board of Control, whose Chairman should be appointed by the State President, would be responsible for the supervision of an independent Escom management board.
4. The task of the Escom Management Board should be to run Escom properly.

The recommended Board of Control made provision for a high degree of customer representation by agricultural, mining, municipal and commercial customer sectors. For the first time in the history of Escom, customers were comprehensively represented on its controlling body.

Accordingly, the Electricity Act was amended in 1985 and 1986 to effect some of the recommendations of the De Villiers Inquiry. The Electricity Act of 1958 was repealed in its entirety by the new Electricity Act of 1987. Eskom, as it was renamed, was exempt from applying for a licence by the Electricity Control Board, which hence forth only had limited jurisdiction over Eskom's activities.

In terms of tariffing issues, the current control structure ensures that Eskom has jurisdiction over tariff level while the Electricity Control Board has jurisdiction over the tariff structure.

The positive developments in the supply industry did not, however, spill over into the distribution industry. Municipal electricity distributors are still administrated according to provincial ordinances dating back to 1905. This means that the municipal electricity distributors are regulated firstly by their local councils and secondly by Provincial Administrations. This method of control has been effective in ensuring that the local authority electricity distribution industry succeeded in meeting the needs of the white residents who were able to vote for their respective local authority councils. However, with a clear line drawn between the relatively affluent whites and the disenfranchised blacks, the development of electricity distribution in the black areas remained almost totally neglected. These structural defects were exacerbated by the establishment of the Bantu Administration Boards in 1973 and Black Local Authorities in 1982 which took over the supply of services to black townships. Without the industrial and commercial customers which had financed the electrification of white areas, these apartheid creations failed, and in so doing precipitated the current crisis in electricity provision to black areas (Steyn, 1993).

The fragmentation of the distribution industry was exacerbated by the creation of fragmented "Self-Governing" and "National States" each of whom had the right to supply inside their own areas of jurisdiction. In addition, Eskom distributes electricity to most rural areas as well as in many Black Local Authority areas, whose distribution function has recently been taken over by Eskom.

### 3.4 Conclusions

This chapter has reviewed the development of the electricity supply and distribution industry in South Africa. From fragmented and decentralised beginnings at the start of the century, the supply industry became progressively more centralised so that today more than 96% of South Africa's electrical energy is generated centrally in a single organisation. Further, while the supply industry was largely privately owned in the first quarter of the century, progressively larger portions of the supply industry became publicly owned so that by 1948, after the purchase of the Victoria Falls and Transvaal Power Company, almost the whole of the bulk supply industry was publicly owned.

The trend of centralisation in the supply industry was not mirrored in the development of the distribution industry which instead became progressively more decentralised. Today there are a large number of local authorities, Regional Services Council distributors, distributors in the fragmented "Self-Governing" and "National States" as well as Eskom, who are involved in electricity distribution. In addition, distribution is regulated (to a greater or lesser extent) by separate authorities. The implication of these structural defects will be explained in more detail in the next chapter.

## **CHAPTER 4. PAST AND PRESENT ELECTRICITY PRICING IN THE SOUTH AFRICAN ELECTRICITY SUPPLY AND DISTRIBUTION INDUSTRY**

### **4.1 Introduction**

The purpose of this chapter is to review past and present electricity pricing in South Africa with a view to setting a background for a future electricity pricing strategy. The chapter begins with an historical review of electricity pricing in Eskom. This provides a background to the second part of the chapter which discusses electricity pricing policies and practices currently used at each of five interfaces in the industry: Eskom Generation to Eskom Transmission; Eskom Transmission to International Customers; Eskom Transmission to Eskom Distributors; Eskom Distributors to end-customers and non-Eskom distributors; finally non-Eskom distributors to end-customers. Finally the chapter reviews electricity pricing in the non-Eskom distribution industry at present.

### **4.2 A history of Escom pricing and costing policies**

In the first period of the development of the South African electricity supply and distribution industry from 1882 to 1948 as discussed in the previous chapter, the price of electricity was continually decreasing in real terms. This resulted from continually improving plant efficiency, an abundance of cheap coal and labour, a virtually unabated growth in demand and consumption, and cost savings through improvements in economies of scale. To a certain extent this trend continued in the second phase of the industry. From 1950 to 1970 for example, there was only a nominal 3.87 % increase in price (De Villiers Report 1984:5).

This section focuses specifically on pricing in Escom from its formation in 1922 up to the time that it was reconstituted through the Eskom Act of 1987.

As discussed in the previous chapter, Escom was created through the 1922 Electricity Act. Essentially the only provision in this Act relating to pricing by Escom was that Escom should price electricity so as to make neither a profit nor a loss.

Although Escom was created as a single national parastatal corporation, its activities throughout South Africa were split into a number of largely independent regional

undertakings. As Escom developed, it became necessary to define Escom's pricing policy more clearly. To this end, the Electricity Act of 1958 prescribed three principles for Escom pricing as follows:

1. Escom undertakings should not show any surpluses or deficits. (Section 14)
2. Each of Escom's undertakings must be separately taken into account when prices are assessed or adjusted, and separate accounts must be kept for each undertaking, with a fair allocation of overhead and administration charges. (Section 16)
3. One consumer group should not subsidise another. (Section 14)

However, the further development of the Escom power system led to an ever-increasing gap between the costs of generating electricity in the coal-rich areas in the Eastern Transvaal and the cost of generating electricity in other parts of the country. This was one of the contributing factors which led to the establishment of a national transmission network which fully interconnected the previously separated regional undertakings. The development of the national grid thus led to a situation where it was possible to operate Escom's power stations in order of economic merit. Accordingly, all Escom's power stations were transferred to a separate undertaking, namely the Central Generating Undertaking (CGU). All power stations were then operated in a centrally controlled, integrated system.

The establishment of the CGU was authorised in terms of a special permit issued by the Electricity Control Board. This permit stipulated the approved method of allocating the CGU's costs to the distribution undertakings. The basic principle was that the excess generating cost of the power stations previously operated by the Cape Western, Natal and Border Undertakings, compared with the generation cost of the remaining power stations, must continue to be carried by the power stations concerned (Board of Trade and Industry Report No 1889 1977:48). This principle was changed twice subsequently. With the first amendment, the excess generation costs (energy related) arising from the operation of the coastal power stations which had annual station load factors of more than 0.2, was excluded. In the second amendment, the excess generation costs to be charged to the coastal undertakings was limited to the interest and redemption charges of the power stations involved.

The 1958 Electricity Act, as amended, described the method of cost allocation to the different distribution undertakings as follows:

" Prices for electricity should cover the cost of production including distribution, maintenance and administration, (the costs incurred by the Central Generating Unit), and interest on loans, redemption of loans and annual contributions to the Reserve Fund and the Capital Development Fund. "

The permit of the Central Generating Unit prescribed that the costs of generation (or purchase of electricity) including the cost of reserve plant, the cost of interconnection of power stations, investigation and research costs, and overhead and administration charges, should be allocated to the separate undertakings on the basis of kW demand and kWh consumption of each undertaking (Board of Trade and Industry Report No 1889, 1977:48).

The differences in the cost of supply to the different undertakings is contained in Table 1 which lists the 1976 costs per unit of energy (kWh) sent-out, in each of Escom's eight undertakings.

Undertaking	Large Power Users	Small Power Users	Domestic Users
Border	2.77	5.46	4.6
Cape Eastern	3.25	6.8	8.2
Cape Northern	2.04	4.6	3.24
Cape Western	1.95	4.2	3.91
Eastern Transvaal	1.36	3.5	2.46
Natal	1.8	3.7	4.07
Orange River	1.34	5.4	7.4
Rand and OFS	1.31	2.8	2.02

**Table 1. Cost to per kWh sent-out in 1976**

(Source: Board of Trade and Industry Report No 1889,1977:16)

The most important factors causing the differences in costs between undertakings, according to the BTI Report, were as follows:

1. Excess capacity costs

In terms of the CGU permit issued by the Electricity Control Board, the excess generating cost of the power stations previously operated by the Cape Western, Natal and Border undertakings, compared with the generation cost, must continue to be carried by the power stations concerned. (Board of Trade and Industry Report No 1889, 1977:48). As described

above, with the first and second amendment to the original CGU permit the allocation of the excess capacity costs to the coastal undertakings was progressively diminished.

## 2. Location

The 1958 Electricity Act stipulated that costs incurred in the transmission of electricity were to be allocated to the undertaking to which the electricity is transmitted (Section 23(6)(b) of the Electricity Act of 1958, as amended). Expressed in cents/kWh, this cost varied from 0.14 c/kWh for the Cape Western Undertaking, to 0.001 c/kWh for the Rand and OFS Undertaking.

## 3. Age of undertakings

According to the principles of fund accounting which were practised in Escom at this time, each loan could be linked to a specific asset, or group of assets. Hence newer undertakings, or those in which there was significant growth, had assets which had a higher historical cost than that of similar assets which, in the case of older undertakings, had been purchased some time back (and hence had a lower historical cost.)

## 4. Operating expenses

A number of factors such as the regional density of consumers, the size of the supply area and human resources costs amongst others, led to differences in the operating expenses of the different undertakings. The ratio of operating expenses to electricity sold (kWh) for 1976 ranged from 30 in the case of the Cape Eastern Undertaking to 7 in the case of the Rand and OFS Undertaking (Board of Trade and Industry Report No 1889,1977:56).

## 5. Mix of consumers

The mix of consumers, i.e. whether sales are predominantly to a few very large consumers or to a large number of smaller consumers, has an influence on the costs of an undertaking. In the case of those undertakings with low consumption levels per consumer (Cape Western, Cape Eastern and Natal), the cost per unit consumption was naturally higher (Board of Trade and Industry Report No 1889,1977:56).

## 6. Load factor

In the same way that the number and size of consumers has a direct impact on the costs per unit consumption, so the load factor of the undertaking's consumers will have an effect on the cost per unit consumption. That is, the higher the load factor the lower the cost per unit consumption will be, because the fixed costs, i.e. loan charges, transmission costs and generation capacity-related costs allocated from the CGU, are distributed over higher consumption figures. For 1976, the Border Undertaking had the lowest load factor of 0.58 and the Rand and OFS had the highest load factor of 0.75 (Board of Trade and Industry Report No 1889,1977:56).

### *Allocating costs to consumers*

After having determined the full costs pertaining to each undertaking, these costs were translated into service charges, demand charges and consumption charges in a number of specific tariffs. In 1977, Eskom offered three tariffs: Tariff A for large users i.e. those whose demand exceeded 100 kW/kVA; Tariff B generally applicable to loads not exceeding 100 kW/kVA; and Tariff C for domestic customers within a proclaimed residential area.

Tariff A consisted of a monthly service charge to compensate Eskom for consumer-related costs; a fixed demand charge per kVA based on the maximum demand during a particular month - to cover the demand-related costs or part thereof - and an energy charge per kWh consumed.

In 1976, Tariff A revenue accounted for 97% of Eskom's total income (Board of Trade and Industry Report No 1889,1977:61). The method of allocating costs to consumer groups with Tariff A was explained in the BTI Report as follows:

"After determining the total costs of each undertaking, deduct the income expected from Tariff B and Tariff C consumers, income expected from extension charges with Tariff A consumers, and the income expected from the service charge in Tariff A. The remainder is divided into demand-related and consumption related costs."

However, there was also a transfer of some demand-related costs into energy-related costs. This transfer from demand-related costs to energy-related costs was justified on account of the fact that, "high load factor consumers do not contribute much to diversity and

consequently a transfer from demand-related cost to energy-related costs takes place to prevent the overcharging of low load factor consumers who make a larger contribution to diversity" (Source: Board of Trade and Industry Report No 1889, 1977:61).

The transfer of demand-related costs to energy-related costs would appear to be logically correct. However, while the transfer from demand-related to energy-related costs was justified in terms of load factor/diversity considerations as explained above, this justification would appear to be a smoke-screen, since in actual fact nothing was done to determine the relationship between load factor and diversity for the consumers in each of the undertakings. Instead, the extent to which demand-related costs were transferred into energy-related costs was based on a set of subjective factors. The BTI investigation described these factors as follows: (Board of Trade and Industry Report No 1889,1977:63)

- " 1. It may be desirable to set the tariffs of two adjoining undertakings with similar cost structures, but with different load and diversity factors for instance on such a level that average costs per kWh are the same;
2. An excessive bias (transfer of demand-related costs into energy-related costs) in the Escom tariff may raise the tariff energy charge rate to a level above those of the municipalities which are generating themselves; and
3. The higher the bias the lower the incentive to improve monthly load factors. "

One is left with a great sense of disappointment that the considerable amount of work that took place in allocating costs objectively to each of the different undertakings, was all but lost in the end-tariff which allocated costs to the demand and energy charges in Tariff A in a highly subjective manner.

Tariff B (for customers with loads not exceeding 100 kW or 100 kVA) consisted of a service charge for each point of supply to cover consumer-related costs, unit charges at a high rate for the first 500 kWh consumed per month, and unit charges at a lower rate for the balance of kWh consumed. Tariff C for domestic customers was structured in the same way as Tariff B with the exception that the first energy block was actually 300 kWh instead of 500 kWh. The charges for the first block were originally determined at twice those of the second block. However, the BTI Investigation reported that no exact cost calculation was carried out to determine the magnitude of the charges in the first block. As with Tariff A, one is left with a sense of disappointment at the subjective and essentially arbitrary manner in which the final tariffs reflected costs which had been rigorously determined for each undertaking.

The BTI investigation made a number of recommendations of relevance to pricing in Escom. These included recommendations relating to Escom's accounting policy, control over Escom, and possible geographical equalisation of tariffs. These recommendations are explained below:

### *Accounting policy*

The essence of the recommendation on accounting policy was that fund accounting<sup>6</sup> be discontinued in favour of current cost depreciation accounting. The recommendation was made as a result of what had occurred since the Electricity Amendment Act no 49 of 1971 - which gave Escom the authority to establish a Capital Development Fund - had been passed. The percentage of Escom's costs attributable to its contribution to the Capital Development Fund increased from 5.5% in 1972 to 25.8% in 1977 (Source: Board of Trade and Industry Report No 1889, 1977:84). (It increased further to 32.5% in 1979 (De Villiers 1983:205)). The BTI report argued against the existence of this fund since it was a "device for earning profits under the guise of costs." The sharply increasing contributions to the Capital Development Fund had led to a greater proportion of capital expenditure being financed out of retained profits. This meant sharply lower debt/equity ratios than the BTI recommended ratio of not less than 4:1 (Board of Trade and Industry Report No 1889,1977:152) which was advanced as a suitable ratio on account of the fact that Escom bonds were underwritten by the State. In the BTI report a higher debt to equity ratio was also justified in terms of the argument that in the electricity industry, consistent income means that the industry is intrinsically a low risk industry.

### *Control over Escom*

The BTI report also recommended greater government control of the industry through the regulation of profits, and therefore prices, through the Department of Industries (Board of Trade and Industry Report No 1889, 1977:158). In addition, it was recommended that the existing Electricity Control Board, should have control over the generation and distribution of electricity and the tariff structure. The theme of stronger direct government interference in the running of Escom was also supported by recommending "liaison and consultation" between the Department of Finance, the new Capital Projects Evaluation Group (in the Department of Finance) and the Electricity Control Board. It is interesting to note that the report made no recommendations on municipal distributor pricing. Rather it came to a

<sup>6</sup> The accounting concept of creating a fund and then making a specific investment so that the value of the investment equals the value of the fund, is called fund accounting.

timid conclusion that "the different Provincial Administrations should perhaps control the electricity tariff levels of municipalities in terms of profitability in order to prevent excessive surpluses" (Board of Trade and Industry Report No 1889, 1977:151). The BTI Report then referred this recommendation to the Inter-departmental Committee of Inquiry into the Finances of Local Authorities.

### *Geographical tariff equalisation*

As a result of the magnitude of the differences in the costs between Eskom's different undertakings - as shown in Table 1 earlier- the BTI report argued for a greater geographical equalisation of the Eskom tariffs, through greater cost pooling. It was argued that all costs excepting transmission and distribution costs incurred by the distributing undertakings themselves, should be pooled. If this recommendation was to be enacted it would have meant that it would have been necessary to alter Section 14 of the 1958 Electricity Act.

It is uncertain exactly what effect the recommendations of the BTI investigation had on Eskom. Certainly, the high price increases before the time of the BTI investigation continued after the investigation. (The average annual increases in the average selling price from 1977 to 1982 per year, were 48.2%, 16.5%, 6.1%, 6.1%, 12.7% and 22.9% respectively (De Villiers Report 18/1985:36)). Furthermore, the existing legislation was not altered to effect any of the BTI recommendations.

### **The De Villiers Commission**

Continued price increases exceeding the rate of inflation was one of the reasons that the State President appointed a Commission of Inquiry into the supply of electricity in South Africa. The Commission's report heralded a whole new era in the history of Eskom.

The essential recommendation of the Commission was that Eskom should have a two-tier control structure consisting of an Eskom Board of Control (to be known as the Eskom Council) and a Management Board. It was recommended that the function of the Eskom Council would be "to see that the business is managed properly" and the role of the Management Board was to "run the business properly." This process was intended to mirror a similar process that occurs in private corporations through the interaction of shareholders and management. Indeed the type of control structure which the De Villiers Commission had recommended indicated a paradigm shift from direct government control

of key aspects of Escom, as recommended by the BTI investigation, to a situation whereby the State was at arms length with Escom. Furthermore, as a consequence of the De Villiers recommendations, for once in the history of Escom, customers were represented on the controlling body (the Eskom Council).

With regard to electricity pricing there were a number of relevant recommendations in the report of the De Villiers Commission. Firstly it was recommended that "Escom should assume a leading role in the conservation of energy and electricity while preventing prices from rising too rapidly and the generation of electricity from making excessively high capital demands on the economy. Its (Eskom's) objective should be the maximum utilisation of resources and capital in the economy through the optimum use of energy and electricity" (De Villiers 1983:16). In line with this recommendation was the principle that "operating at neither a profit nor at a loss must be discarded in favour of a sound assets and income structure complying with the condition that the interest coverage ratio should be greater than 1.05 and the assets/liability ratio should be maintained at 3:2" (De Villiers 1983:16).

With regard to tariff structure, the De Villiers Commission recommended that the concept of different undertakings within Escom be discarded and that the tariff structure be modified so as to: (Source: De Villiers 1983:16)

1. Distinguish between maximum demand and actual consumption when allocating unit cost.
2. Determine the unit cost of transmission to an agreed reference point and that of distribution from the reference point to the customer, on the basis of the cost per km for various voltages and loads.
3. Allow pooling of costs so that tariffs for individual groups of customers may be built up from mean pooled costs.

In line with the objective of savings and efficiency, was the recommendation that customised price deals and time of use based tariffs should be developed (De Villiers 1983:210).

However, despite this emphasis on efficiency and conservation, the De Villiers Commission argued against the use of marginal costing in the industry (De Villiers 1983:192). This is a subject which merits closer attention since the issue of marginal cost-based tariffing is one which dogs the industry to this day.

The De Villiers Commission recommended the use of the **consumer privileged philosophy** for the following reasons: (De Villiers 1983:192)

- "
1. Historically it has been a policy in South Africa.
  2. The vast majority of countries South Africa has to compete with in the export market pursue this philosophy.
  3. The economy built on this basis will be disrupted by a change in this philosophy. (Tariffs would have to be increased by approximately 35% if a price policy tending to long-term marginal costs were pursued.)
  4. The possible advantages of more efficient appropriation of resources which have been regarded as an important advantage of the consumer-neutral philosophy are vague and uncertain and could in any case be defeated by other stumbling blocks in the South African economy which still differs much from a classical free-market economy. "

It is difficult to see why the first reason justifies the use of the consumer privileged philosophy. Historically, fully-distributed costs had been used in the electricity industry until Steiner-Boiteaux proved that time of use based peak load pricing would result in economically efficient prices. Since then, marginal costs have come to be used in almost every power utility in the developed world. Hence the argument that marginal costs should not be used in Escom because historically it has never been a policy, is hardly convincing.

The second reason provided is factually incorrect: The electricity supply authorities of all of South Africa's major trading competitors have pursued the consumer neutral philosophy for decades.

The third reason is true of a change in any economic policy. Arguing that marginal costs should not be used because changing to marginal costs would disrupt the economy, is an unconvincing argument.

The fourth reason is also incorrect if the experience of marginal cost based pricing particularly in France and Britain is anything to go by. Here the electricity utilities have been able to achieve considerably improved utilisation of resources through the use of marginal costs in their tariffs.

**In summary,**

Since Escom was formed in 1922, pricing has gone through *some* far-reaching changes. Although Escom was initially made up of a number of largely independent undertakings, the industry developed to the stage where its functions could most economically be achieved through the establishment of a national transmission network and a central generation undertaking. As discussed, Escom spent a considerable amount of effort in quantifying the costs which should be allocated to each separate undertaking and the principles underlying the cost allocations were entrenched in law as amendments to the 1958 Electricity Act. Although since 1922 the real price of electricity was continually decreasing, this trend changed during the early 1970s. This resulted in two major investigations: one by the Board of Trade and Industry and one by an appointed Commission chaired by Dr De Villiers. The Board of Trade and Industry, and the De Villiers Commission sought to deal with the problem of excessive price increases in very different ways. The BTI approach was to increase the amount of direct government control whereas the De Villiers Commission's recommendations centred on putting the government at the same arms length that it was at when Escom was created in 1922. The De Villiers Commission also focused on getting much greater customer involvement in the control of the industry. These differences were reflected in the recommendations on pricing policy. Amongst other recommendations the BTI report focused on increasing the degree of direct government control of Escom. The De Villiers report on the other hand focused on economic efficiency and although it rejected the use of marginal costs by Escom it focused on the development of pricing mechanisms, such as time of use and customised tariffs, which would come closer to achieving the goal of "the optimal utilisation of resources". Through the Eskom Act and Electricity Act of 1987, both of which are still in existence today, many of the De Villiers Commission's recommendations took effect.

**4.3 Electricity pricing in Eskom at present**

Having discussed aspects of pricing in Escom's history, it is possible to focus on pricing in Eskom at present. This section reviews pricing at five interfaces: Firstly from Eskom's Generation Group to Eskom's Transmission Group on the Generation Tariff, secondly from the Transmission Group to the Eskom Distribution Group, thirdly from the Transmission Group to International customers and finally from the Distribution Group to both end-consumers and non-Eskom re-distributors.

### 4.3.1 Pricing between Eskom Generation and Eskom Transmission

Electricity is "sold" between Eskom's three conceptually independent businesses: Generation, Transmission and Distribution. The Generation Tariff accounts for sales between Generation and Transmission, while the Transmission Tariff accounts for sales between Transmission and Distribution. Since Eskom supplies more than 96% of South Africa's electrical energy, an examination of these internal pricing mechanisms is vital to an understanding of electricity pricing in South Africa.

The Generation Tariff was first introduced in 1992 with a cryptic description of the objective of the tariff being "to induce the Power Stations to adopt a behaviour which is commercially oriented and consistent with Eskom's objectives" (Eskom 1992(a)). Broadly, the tariff that has been applied is made up of two parts:

- \* *A standby charge* which the power stations charge the Transmission Group for providing capacity (MW) as and when it is required.
- \* *An energy component* which compensates the power stations for energy (GWh) sent out on the Transmission system.

The *standby charge* has a long term component designed to generate one third of the capacity charges budget, and a short-term component designed to recover two thirds of that budget. The *energy component* recovers the production costs of generation.

A new Generation Tariff, yet to be finalised, has been proposed for 1994. Broadly, the Generation Tariff charges for a number of "services" as well as the supply of electrical energy. The monthly bill sent to the Eskom Transmission Group will consist of a number of separate charges:

- \* Capacity and Standby, including bonuses and penalties
- \* Energy delivered, including bonuses and penalties
- \* Start-up costs
- \* Synchronous condenser operation
- \* Primary frequency control, including fixed payments and penalties

The most significant charges are for capacity and delivered energy. The capacity charge is calculated on a specified level of capacity which Transmission contracts from capacity

offered by Generation. This charge is calculated in cents per MW and is the same for all power stations. Penalties are applied if the capacity offered by Generation is not sufficient to meet the capacity demand by Transmission. Similarly, bonuses are applied if the amount of capacity actually required by Transmission exceeds the amount of capacity contracted for.

Energy charges are calculated annually and are split between fixed and variable rates. The energy charge is intended to reflect true production costs plus a negotiated margin. Based on these rates, and keeping in mind the centrally planned production optimisation plans, Transmission can, with limited discretion, increase the load from particular power stations so as to attempt to optimise all costs and risks which are under their control.

To understand the Generation Tariff correctly it is necessary to understand the conflict between the desire for optimisation through competition, and the practical constraint that Eskom is a centrally planned monopoly. On the one hand, the Transmission Economics Department (the Eskom department responsible for the development and maintenance of the Generation and Transmission Tariffs) is attempting to introduce as much competition into the pricing process as possible. On the other hand, Generation in Eskom is structured as a single, centrally planned business. This means that with the Generation Tariff, the capacity charge in cents per kW is the same for all power stations, despite the fact that the two costs (return on assets & depreciation) making up this capacity charge actually varies considerably amongst the different power stations. If there was true competition between individual power stations, the different capacity costs between the different power stations would need to be used.

The only differentiation between individual power stations in the proposed Generation Tariff, is in respect of the energy charge which is made up of a fixed and variable rate. This variable rate, per power station, is based on the variable costs of that station such as the cost of coal and various other operational costs which are affected by that particular station's operational efficiency. With the Generation Tariff, the Transmission Economics Department attempts to induce economically efficient behaviour by maximising the amount of generated energy from those power stations which have the lowest short run marginal cost, and in so doing attempting to get stations to compete so as to minimise their input costs and operational costs. In this too, they are limited since the operation of Eskom's power stations is determined through a centrally planned and pre-determined production optimisation schedule which stipulates the extent to which each power station should be run.

It is meaningful to compare the operation of the UK Power Pool (explained in Chapter 5) in which the principle of pure competition is the driving force, and the proposed future Generation Tariff in Eskom in which there is an attempt to introduce competition into what is a highly controlled and centrally planned environment. Broadly, it can be concluded that the Eskom Generation Tariff aims to reflect the costs of operations - as far as these have been economically ascertained - in an attempt to induce economically efficient behaviour through the creation of limited competition.

#### 4.3.2 Pricing between Eskom Transmission and Eskom Distribution

The Transmission Tariff, which is used to price electricity sales between the Transmission Group and the five Eskom Distributors, was first implemented at the beginning of 1992. At the time, the tariff was similar to the proposed time of use tariff options, T1 and T2, which Eskom offered to external customers. It consisted of four time of use energy charges and a maximum demand charge, which was levied on maximum demand recorded during the peak or standard tariff periods. Each Distributor was billed based on the recorded electricity consumption at each of the Main Transmission System (MTS) substations within the area of supply of that Distributor.

The level of the Transmission Tariff was set so that the total revenue requirements of the Generation Group and Transmission Group could be recovered. The Transmission Tariff recovers revenue from the five Distributors in three ways:

- \* Revenue from "Base Sales"
- \* Revenue from "Budgeted sales to Customer Incentive Scheme (CIS) customers"<sup>7</sup>
- \* Revenue from "Growth Sales"

In calculating the revenue to be derived from Base Sales, the total budgeted fixed costs of the Generation and Transmission Groups for the present year was divided by the total kWhs sold by the Transmission Group for the previous year, to calculate a c/kWh charge.

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<sup>7</sup> Customer Incentive Scheme customers purchase electricity on customised tariffs which differ from standard tariffs in terms of price and frequently also in terms of structure. Most customised tariffs are mutually beneficial to Eskom and to the particular customer. There are approximately 30 CIS customers at present.

This charge was multiplied by the total metered kWh at each MTS substation for the previous year so that a figure for total "Base Sales" revenue could be derived for each Distributor.

For Revenue from Budgeted CIS sales, the charge was based on the short-term marginal costs of Generation and Transmission. This average marginal rate was the same as the marginal rate paid by Transmission to Generation, plus the marginal costs of Transmission's losses. The variable energy rates of the base load power stations were used in calculating the average marginal energy costs for Generation - in 1993 this was 0.93 c/kWh. To account for extra losses, an extra 0.02 c/kWh was added. In addition, for every extra kW of capacity that Transmission purchases from Generation in an hour (standby charge), Transmission pays an extra 1.5 c/kW. The cost of CIS sales to the Distributors was thus calculated to be  $0.93 + 0.02 + 1.5 = 2.45$  c/kWh.

The revenue from "Base Sales" was meant to recover the full budgeted fixed costs of the Generation and Transmission Groups. Hence the tariff for electricity sales above budget (growth) was meant only to cover the marginal variable costs. In calculating the price at which growth sales was to be charged, the price of the CIS sales of 2.45 c/kWh was increased to 3 c/kWh "to give the Distributor an incentive to budget their CIS deals as accurately as possible." (Eskom 1992(b))

Since January 1994, a whole new tariff structure has been implemented by the Transmission Economics Department, which is intended "to be as cost reflective as we can make it on our current level of computational abilities." (Eskom 1993(c)) The tariff structure is relatively complex and consists of three parts as follows:

1. A *network* charge designed to recover Transmission's own revenue requirements.
2. A *time of use* charge designed to recover the total fixed and proportional variable components of the costs of Generation and proportional Return On Assets. This is by far the largest component of the tariff.
3. An *hourly marginal energy rate* designed to recover the proportional variable components of the cost of Generation and Transmission.

The *network charge* is a fixed monthly payment in respect of a point of supply (MTS substation) determined on the basis of the historical relative use of the system by that particular point of supply and the reserved capacity allocated to it. This charge is

calculated to recover Transmission's revenue requirements. The practical calculation of the network charge is a relatively complex process which is based on simulating load flows at various points in the transmission network.

The *time of use charge* is based on the negotiated baseline load for every point of supply. This baseline load for 1993, is defined as the total metered kWh (excluding CIS sales) at all MTS (Main Transmission System) substations during 1992. During 1992, this figure totalled 127 024 GWh. With knowledge of the half-hourly energy consumption for every MTS substation for every day of the previous year, it is possible to calculate the time of use charges for all energy metered at each MTS substation. The charge so calculated is known as the time of use charge.

The *hourly marginal energy rate* is applied to consumption in excess of the baseline load. The rate is made up of two items:

The **marginal cost of supply** which, in turn, is a function of the short-term marginal cost of generation at the short-term marginal power station and the short-term marginal transmission cost up to the point of supply. For each hour in the year, the short-term marginal cost of generation is equal to the variable energy cost of the marginal station for that hour, plus the variable hourly cost of capacity at that station. The marginal station is determined by an economic dispatch procedure that dispatches the stations according to their variable costs, after consideration of the system constraints. The Generation Group deems the marginal capacity cost to be equal for all the stations. This has to be seen as a most unfortunate simplification since the actual marginal capacity cost will vary considerably, based on the type of power station used. For example, a large thermal power station has a much higher marginal capacity cost than a small gas-fired station. Ultimately the fact that the average marginal cost is used, means that the hourly marginal operating cost is a misnomer since the "marginal operating cost" is actually a combination of the *marginal energy* and *average capacity* rates.

The **marginal outage cost** is equal to the loss of load probability multiplied by the value of the unserved energy. It is intended that these rates will be made available initially a week ahead and later on every working day at 14h00.

To evaluate the proposed Transmission Tariff, it is necessary to firstly take a look into the past. Until 1978, there was very little cost pooling between the different regional undertakings, since it was policy that each undertaking should calculate their own

accounts, and price accordingly. The 1977 Board of Trade and Industry Report and 1983 De Villiers Reports both recommended a greater integration of what were then Eskom's eight regional electricity undertakings. However, the present structure of Eskom was determined only in early 1992 when the existing five Distributors came into existence. At the same time that these operations began to function, the Transmission Tariff was created for the pricing of electricity between "Eskom Corporate" and the five conceptually autonomous Eskom's Distributors. The main purpose of the Transmission Tariff is to encourage efficient behaviour, i.e. it is intended as a mechanism to reflect the *cost structure* and not the actual costs of supply.<sup>8</sup>

The initial version of the tariff used in 1992 was very similar to the end-user time of use options, T1 and T2. Since then, in terms of tariff design, the Transmission Tariff has made considerable progress. The latest structure is probably the most sophisticated tariff structure currently used in the South African electricity industry. The degree to which the tariff reflects the costs of supply is commendable. However, the Achilles heel of the Transmission Tariff thus far has been implementation. The most significant problem here is metering problems on the MTS supply points. These problems have so far been dealt with to varying degrees of success.

An important consideration in the current tariff structure is that the tariff is intended to encourage the Distributors to induce their customers to optimise their pattern of consumption so as to minimise the amount that they pay for their electricity purchases, to the mutual benefit of the Distributors and of Transmission. Since the network charge and time of use charge are practically fixed payments, the *hourly energy rate* is the part of the current tariff that allows Distributors the freedom to optimise their operations. However, this freedom is something of a mirage since Distributors do not have freedom in deciding the structure or price level of the external tariffs which they apply and hence their actual ability to alter the consumption pattern of their customers is limited.

#### **4.3.3 Pricing between Eskom Transmission and International Customers**

The import and export of electricity between South Africa and her neighbours currently amounts to a very small percentage (in Eskom terms) of electricity generated. In particular for 1993, total net exported energy is expected to be of the order of 1600 GWh, earning a total sales revenue of the order of R10 million. Eskom's Transmission Group is responsible for all pricing contracts with International Customers. Currently there are contracts

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<sup>8</sup> Dirk Els, Financial Planning Manager: Eskom, personal communications.

between Eskom and ZESA (Zimbabwe Electricity Supply Authority), SWAWEK (Namibian Supply Authority), (EdM) Electricite de Mocambique and (BPC) Botswana Power Corporation.

The philosophy governing the development of some international tariffs at present and all international tariffs in future is that tariff structures and price levels for these customers should be based on a set of pricing principles which are commonly used to conduct inter-utility trade. In this regard, Eskom has a particular interest in the power pools in existence in North America and Europe.

Eskom's Chief Executive, Dr McRae, has long been known for his vision of establishing an inter-connected Sub-Saharan electricity network. The main purpose of such a network would be to inter-connect the coal-fired power stations in Southern Africa with possible hydro-powered stations in Central Africa. The technical arguments that Transmission put forward in favour of establishing such a power pool in Sub-Saharan Africa are as follows: (Source: Eskom 1993(a))

- "1. Power Pools result in improved reliability and quality of supply through mutual assistance when problems arise.
2. Power pools result in the optimised use of existing Generation and Transmission facilities, by generating at the cheapest generating units in the whole pool rather than in each area of control taken individually.
3. Power pools result in greater economies of scale and the development of the cheapest primary energy sources in the whole pool rather than in each area of control taken individually. "

In the Southern African Power Pool, Eskom identify various possible types of transaction: (Eskom, 1993(a))

1. System (Firm) Power

In this transaction, a reliable supply of capacity and energy is provided from one utility to another utility. In this type of transaction, a tariff normally has a large capacity component and a small energy component. Examples of such transactions are the current contracts between Eskom and ZESA for the Beit Bridge inter-connection.

## 2. Capacity Power

Capacity power may be sold between two utilities to replace generation in either system. The direction of the power flow and its load factor will be dependent on the marginal cost of generation of the two systems. Tariffs for capacity power have a commitment charge for capacity and the energy charge will be equal to the marginal cost of generation in the seller's network plus a charge for transmission losses, plus a profit margin.

## 3. Reserve Capacity

Reserve capacity in one system is used to provide the required spinning reserve or operating reserve in another system. Pricing in this mode, in principle, is based on the fixed costs of new peak load plant, but in a competitive situation utilities with reserve capacity may discount the price they charge for reserve capacity.

## 4. Surplus energy

Surplus energy in one system may be dumped at a low price to another system. An example of such a contract is the purchase agreement between SWAWEK and Eskom, in the case that the hydro station on the Ruacana River is spilling.

## 5. Economy energy

Energy may be sold by one utility having a low marginal cost to another utility having a higher marginal cost. Energy sold in terms of an economy energy contract is not backed-up by capacity and as such is interruptible. Normally the contracts split the saving in marginal costs between the two parties.

## 6. Emergency energy

An emergency energy contract describes the sale of electricity to provide short-term assistance to another system which may be experiencing difficulties. The marginal cost of generation of peak load plant, perhaps less a discount, is often used as a price basis to such transactions.

These various methodologies describe a pricing system distinctly different to that which characterises sales between a utility and its end-users. Eskom argues that inter-utility

transactions should not be based on standard tariffs since such tariffs do not make provision for "volatile and frequently large commitments which characterise inter-utility trade" (Eskom 1993 (a)).

### **Matimba-Bulawayo 400 kV line**

The beginning of the proposed power pool (from Eskom's side) is the 400 kV interconnection between Matimba in South Africa and Insukamini (Bulawayo) in Zimbabwe which involves ZESA (Zimbabwe), BPC (Botswana) and Eskom. This line will link Eskom's 23 000 MW network with that of ZESA (1700MW) plus ZESCO (Zambia) (1000 MW) plus BPC (190 MW) plus SNEL (Zaire) (2500 MW). In terms of the agreement for the 400 kV line, ZESA will commit themselves to taking 400 MW of capacity in 1995 and 1996 and 150 MW thereafter. The Capacity Power contract has a two-part structure consisting of a capacity charge and an energy charge. The capacity charge is based on the capital plus fixed operating costs of base load plant in the Eskom system, plus a margin intended to reimburse Eskom for backing the supply with reserve capacity. The capital and fixed operating costs of the new coal-fired plant at Lekwe, was used as a benchmark. The annual levelised costs of Lekwe have been estimated at R254/kW or \$83/kW per annum. The capacity charge negotiated with ZESA is \$87/kW per annum in respect of the firm commitments described earlier. A second part of the agreement is that ZESA has access to capacity in excess of amounts agreed to, but with Eskom's consent. The premium over the basic capacity charge ranges from 5.3% to 44% depending upon the time when capacity is required.

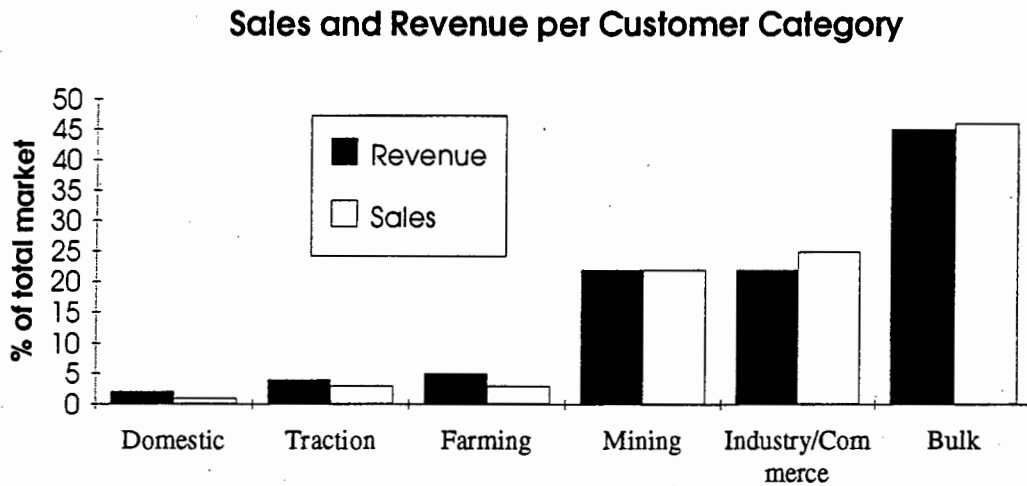
The energy rates in the contract comply with the pool concept that energy should be traded at marginal costs plus a small margin. The rates are set according to the estimated marginal cost of generation plus 3% for transmission losses plus 10% for profit. The charges vary according to time of use in the same way as the end-user time of use tariffs described later.

The uneven distribution of natural resources in Sub-Saharan Africa has meant that South Africa has an immense wealth of coal to power its considerable electrical network. However, her neighbours, by virtue of their hydrography all have the potential to develop considerable hydro-powered generating capacity. The development of a Power Pool to link the independent networks in Sub-Saharan Africa, could thus be mutually advantageous. The success of such a power pool is dependent on the pricing mechanisms which govern the trade between the different participants. The current thinking on this matter has been described above. However, it is important to bear in mind that a power pool in Sub

Saharan Africa such as exists in Nordel in the Nordic countries and Nepool in North America, is still no more than a vision. Turning this vision into reality is perhaps ultimately dependent on Africa's ability to realise the hydro potential which it possesses. If the experience of Hydro-Electrica de Cahorra Bassà thus far is anything to go by, turning the vision into reality may take some time yet.

#### 4.3.4 Eskom Distribution sales to non-Eskom re-distributors and end-user customers

In 1992 Eskom sold more than 75 000 GWh to end-use customers in South Africa, with a further 63 193 GWh to other distributors for redistribution to the end-customers. The revenue from these sales in total was R12.65 billion (Eskom, 1992). The sales per customer category and revenue per customer category are as shown in the bar chart below:



**Figure 1. Eskom Sales and Revenue per customer category**

These sales have been achieved through a number of different standard tariffs and, in the case of a select few customers, through customised tariff agreements. However, before the details of the different tariffs are discussed, it is necessary to review aspects of the pricing policy common to all tariffs. These aspects include, the current regulation governing Eskom prices, the pricing policy which Eskom has adopted, the method of setting the price level and finally, cost pooling.

#### **The 1987 Eskom Act**

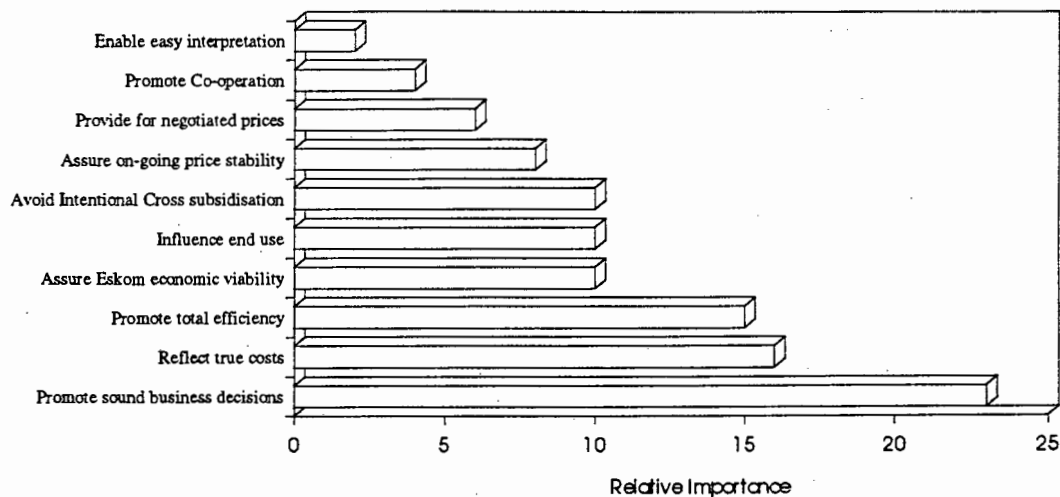
In 1987, the Eskom Act was passed, largely as a consequence of the recommendations made in the De Villiers Commission study into the Electricity Supply Industry. Section 15 of the Eskom Act stipulates the prices to be charged for electricity supplied by Eskom. The Act states that Eskom's tariffs "may from time be revised and amended by Eskom in general in order to ensure a sound financial structure", however this is subject to one condition: "If price amendments result in different price increases to the different 'classes of customers', then such increases shall be subject to the ruling of the Electricity Control

Board, should there be any public objections to such price amendments" (Eskom Act 1987, Section 15 (1) (b) and Section (3)). What this effectively means is that Eskom has discretion over the average price level when it is uniformly applied, but not over tariff structure, where differences in tariff structure would result in differences in the effective price paid.

### **Eskom Distribution pricing policy**

The first chapter examined some international opinions on the criteria of an electricity pricing policy. The work in this section so far has discussed the pricing philosophies which Eskom's Transmission Group apply in their tariffs to International Customers and also to Eskom's five Distributors. The final link in the Eskom tariff chain is that between the Eskom Distributors and the end-customers or other re-distributors. This section will examine the tariff policies at this level.

Perhaps Eskom's most thorough examination of the criteria of an electricity pricing policy, took place during an Electricity Pricing Forum meeting in 1989. This forum was specifically organised "To Determine the Principles of an electricity pricing policy for Eskom and the application thereof" (Eskom, 1989). The forum consisted of Eskom, consultants, the National Energy Council, several large industrial and mining customers and several municipalities. The output from this Forum was a highly qualitative list of criteria for an electricity pricing policy as interpreted by Eskom and some of its major customers. Ranked in order of importance, these criteria are illustrated below:



**Figure 2: Eskom pricing criteria**

At the least, this list of functions illustrates Eskom's customers' perception of what an electricity pricing policy should look like. From this list of issues, Eskom framed the aims and scope of electricity pricing as follows: (Eskom 1993 (b))

1. Electricity pricing must ensure that national economic resources are allocated efficiently, not only amongst sectors of the economy, but also within the electricity industry. This implies that prices that reflect costs must be used to indicate to customers the cost of supplying their specific needs, so that supply and demand can be matched efficiently.
2. Fairness and equity requirements are satisfied by: Allocating costs among customers according to the burdens they impose on the system; ensuring a reasonable degree of price stability and predictability and avoiding fluctuations from year to year; and providing a minimum level of service to customers who may not be able to afford the full cost.
3. Electricity prices must raise sufficient revenues to meet financial requirements. The structure of prices must be simple enough to facilitate metering and billing of customers. Finally, other economic and political requirements must be considered. Such requirements may include, for example, subsidised electricity supply to electrically under-developed areas to catalyse growth.

The actual tariffs which Eskom applies will be discussed in the context of these objectives.

### **Setting the price level of end-user tariffs**

In calculating the price level of the end-user tariffs, Eskom does not see the organisation as being made up of three "independent" businesses, but rather as one vertically integrated business with a single funding requirement in order to recover all forecast expenditure. Hence, the price levels of the end-user tariffs are set by examining the forecast total kWh consumption, the forecast revenue requirements, and hence arriving at an average c/kWh price necessary to recover the forecast required revenue. This average price increase (or decrease) as the case may be, is then factored into the various tariff charges.

## Cost Pooling

Eskom's distribution operations span the length and breadth of South Africa. Ultimately, cost reflective tariffing demands that all costs incurred in generating, transmitting, distributing and reticulating power, per customer, is reflected in the charge to that customer. In terms of geographic tariff differentiation, a farmer in the Karoo, who has caused Eskom to incur considerable cost in respect of transmitting electricity to the Cape from the Transvaal, distributing it to the boundary of his farm and then reticulating it to the point of supply, would pay a much higher cost than a customer in central Johannesburg where the less significant reticulation, distribution and transmission network is amortised by a much larger number of customers. The same argument as pertains at a local level as described, pertains at a regional level. Until the recommendations of the De Villiers Commission report had been implemented, the Electricity Act of 1958 specified that each of Eskom's eight different undertakings were to keep separate accounts. This resulted in considerable differences in the price of electricity amongst the different undertakings. Following the recommendations of the De Villiers Commission, costs in Eskom are centrally pooled, with a minor surcharge for customers far from Johannesburg.

To give some indication of the different profitabilities of the different Eskom operations in South Africa, we will consider Eskom's 54 Districts to be independent business units, which purchase electricity on the Transmission Tariff and distribute it via a range of national external tariffs. It is possible to calculate the "profitability" of these different Districts. Such a study was undertaken by the author in terms of the (NELF) National Electrification Forum's (EDI) Electricity Distribution Industry Database. The Table below contains the results obtained in this study for the profit or loss of 54 Eskom Districts for the 1992 financial year. On account of the way costs are currently centrally pooled, the profitability of the different Districts is affected, to a limited extent by the remoteness of the area, and to a much greater extent by the number and type of customers in the District and the operational efficiency of the District. It must be noted that in terms of the point already made that the Transmission Tariff reflects the cost structure and not the actual supply costs, *these figures for the profitability of different Eskom Districts should be observed for their relative sizes and not for their absolute values:*

District	Profit/(Loss) [R'000]	District	Profit/(loss) [R'000]
Colesburg	(18586)	Kuruman	11159
Empangeni	(6886)	Lichtenburg	(15588)
Ladysmith	(159)	Lydenburg	(433)
Margate	(12966)	Middelburg	62
Newcastle	37258	Midrand	10433
Pietermaritzburg	3889	Nelspruit	3043
Pinetown	29426	Nigel	3526
Bellville	(29718)	Parys	(895)
Benoni	41999	Phalaborwa	6480
Bethal	644	Pietersburg	(6903)
Bethlehem	(13726)	Randfontein	62408
Bloemfontein	(31062)	Rustenburg	13652
Bothaville	(2388)	Sandton	3640
Brits	64636	Senekal	(468)
Carletonville	53813	Swellendam	(10861)
Delareyville	(1876)	Thabazimbe	28908
East London	3690	Uitenhage	19347
George	3417	Upington	9076
Germiston	35095	Vanderbijl Park	12731
Grabouw	(3429)	Vereeniging	(9318)
Grahamstown	(13750)	Vredenburg	3136
Groblersdal	(27656)	Vredendal	(1137)
Harrismith	(664)	Vryburg	379
Johannesburg	(19802)	Warmbad	2307
Kimberly	(12924)	Welkom	59322
Klerksdorp	30069	Wolmaransstad	(2076)
Kroonstad	(5251)	Worcester	(6694)

### A review and discussion on Large Power User Tariffs: Tariffs A, E, T1 & T2

Tariff A is one of Eskom's oldest tariffs. Sales on Tariff A presently account for the greatest portion of Eskom's revenue. The Eskom tariff schedule describes Tariff A as a tariff for large customers with a high load factor of consumption. It is only applicable to customers with a load of greater than 25 kW/kVA. The Rates effective from 1 January 1994 are as follows:

Basic Charge: R143.47 per month

Energy: 5.97 c/kWh

Demand: R32.36/kVA/Month to R28.54/kVA/Month at voltages of supply

K  
T  
W  
e  
J

ranging from 500 Volts to greater than 132 kV, or R34.81/kW/Month to R30.94/kW/Month at voltages of supply ranging from 500 Volts to greater than 132 kV.

The tariff is ideally suited to Gold Mining customers who are able to maintain high load factors. However, most municipal distributors also purchase electricity on Tariff A.

The basic principle behind Tariff A was first introduced by Hopkinson in the previous century. Hopkinson's principle is that capacity-related costs should be charged in proportion to the maximum demand while energy-related costs should be recovered in proportion to energy consumption. The remaining costs may be recovered either through a basic charge or by factoring them into either the demand charge or energy charge or both. In practice however, capacity costs are factored into the energy charge. This is justified on the basis of the load-factor/coincidence<sup>9</sup> factor relationship explained as follows:

" Load-factor is directly proportional to co-incidence factor, i.e. given two customers, if both customers have a high load factor, there is a greater probability that their maximum demands will coincide. Hence high load factor customers do not contribute much to diversity and consequently a transfer from demand-related costs to energy related costs takes place to prevent the overcharging of low load factor customers who make a larger contribution to diversity. "

As discussed earlier in this chapter, until Eskom developed national tariffs in 1986, the methodology of calculating the amount of the capacity charge which should be transferred to the energy charge was driven by practical considerations arising as a consequence of the financial independence of the eight regional electricity undertakings. The magnitude of the capacity cost transferred to the energy charge varied considerably amongst the different undertakings. The transfers expressed as a percentage of demand-related costs before any transfer, were calculated by Eskom as follows: Border Undertaking 8%, Cape Northern Undertaking 30%, Cape Western Undertaking 18%, Eastern Transvaal Undertaking 20%, Natal Undertaking 18%, Orange River Undertaking 28 % and Rand and OFS Undertaking 28% (Board of Trade and Industry Report No 1889, 1977:63).

Revenue recovery between the demand charge and energy charge was determined based on the premise that for a 100% load factor customer, 60% of the revenue should be recovered from the demand charge and 40% of the revenue should be recovered from the energy

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<sup>9</sup> The load factor of a customers demand is a measure of the degree of continuity in his/her demand. The coincidence factor is a measure of the extent to which customers demand patterns coincide.

charge. The amount of the total revenue to be recovered through the demand charge would have a minimum of 60% for 100% load factor customers and this proportion progressively increases as the customer's load factor decreased. This leads to the obvious conclusion that low load factor customers on Tariff A are paying an inordinate amount for capacity and hence are effectively subsidising high load factor customers.

Besides the objection to Tariff A on account of load factor-based cross-subsidies, Tariff A also results in time of use cross-subsidies since the charges in the tariff are based on the average capacity and operation costs of all generation equipment. The time-variation in these costs are not reflected in the tariff at all. Hence customers who have a greater proportion of their consumption at the time of the Eskom system peak periods, are effectively being subsidised by customers who maximise their consumption in the off-peak periods.

Judged against Eskom's stated pricing criteria, i.e. economic efficiency through cost reflective tariffing, Tariff A is therefore a failure! The tariff is applied to a wide range of customers who have varying load factors and since there is a single tariff, the consequence is cross-subsidisation between the different customers. A consequence of this cross-subsidisation was the decision by Cape Town City Council to construct the Steenbras pumped storage station built in 1979 in order to reduce the amount that the Council paid Eskom in respect of the demand charge on their maximum demand. Since the high demand charges of Tariff A did not reflect Eskom's capacity costs, and since Cape Town City Council decided to build Steenbras in an attempt to avoid this charge, Tariff A clearly had a detrimental effect on the industry. The failure of the tariff to reflect cost differences between customers of varying load factor or time of use, has been recognised for some time and has provided impetus for the development of the time of use options currently offered (Calitz et al, 1989). However, Tariff A still remains by far the most significant tariff in terms of sales and revenue. It is most unfortunate that such a primitive tariff mechanism still plays such a significant role in electricity pricing in the industry.

### **Tariff E**

Tariff E is intended for customers who are able to shift load into the off-peak periods i.e. from 23h00 to 7h00.

The tariff charges applicable from 1 January 1994 are as follows:

Basic Charge:	R318.87 per month
Energy charge:	5.97 c/kWh
Demand charge:	R32.36/kVA/Month to R28.54/kVA/Month for voltages from 500 Volts to greater than 132 kV, or R34.81/kW/Month to R30.94/kW/Month for voltages from 500 volts to greater than 132 kV.
Minimum Charge:	If the sum of the revenue from the demand charge and the energy charge work out to be less than 9.57 c/kWh, then a minimum charge of 9.57 c/kWh applies.

Tariff E is ideally suited to large industrial customers, such as the steel and ferrochrome industries, who are able to minimise their load during the period from 7h00 to 23h00.

Tariff E was first introduced in January 1986, in response to recommendations made by the Association of Municipal Electricity Undertakings (AMEU), the De Villiers Commission and Ernst and Whinney (Calitz, 1989). Its introduction coincided with Eskom's use of uniform national tariffs. By the end of 1988, there were 157 large Eskom customers on Tariff E. These customers have a non-simultaneous maximum demand of 3800 MW (Calitz, 1989).

It seems surprising that a utility the size of Eskom with the sophisticated technology at its disposal, took so long to apply Tariff E which is, at best, a hesitant step towards time of use tariffing. In a report first published before June 1986, Eskom argued against the development of an off-peak tariff since the load factor of Eskom's system was extremely high, with an annual load factor exceeding 75% and a daily load factor in excess of 80% (Eskom, 1986). Furthermore it was argued that apparent slack-time<sup>10</sup> is fully utilised by Eskom in carrying out essential maintenance work and any incentives that might lead to still higher load factors through off-peak tariffs could necessitate additional capacity having to be installed to maintain acceptable reserve plant margins (Eskom, 1986).

Essentially the same objections that were raised in respect of Tariff A earlier, i.e. the over-simplified nature of the tariff, means that it fails to reflect the actual cost of supplying the different customers who choose the tariff. Leaving these considerations aside, in view of the fact that mostly large customers have chosen Tariff E, Eskom has been able to effect a

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<sup>10</sup> Times of low demand

significant load shift into the off-peak night time periods hence achieving the desired goal of a high system load factor.

### Tariff T1 and T2

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

**Connections fees:** Tariff T1: R 3500  
Tariff T2: R 1750

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

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

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

The times of the peak and standard periods vary between winter and summer, with the summer having a five hour peak from 7h00 to 12h00 during weekdays, while winters have a three hour peak period from 7h00 to 10h00 and a two hour peak from 18h00 to 20h00 during weekdays.

By the end of 1993, the time of use option had been chosen by more than 270 customers with a total revenue of over R1.5 billion Rands or approximately 8% of Eskom's 1993 income. The largest time of use customer is Durban Electricity which is Eskom's second largest customer after Alusaf.

The subject of Time of use tariffs was addressed by Eskom in earnest for the first time in January 1989 (Calitz, 1989). Up to that time and since 1978, "time of use pricing (had) been addressed repeatedly, without any major progress in that direction" (Calitz, 1989). By the end of 1989 however, the development of a time of use tariff was firmly on the road although the process met considerable resistance en route. Eskom motivated the development of time of use tariffs for three particular reasons: (Calitz, 1991(b))

- " 1. To contribute to the efficient allocation of national economic resources, not only among different sectors of the economy but also within the electricity supply industry.
2. To adequately reflect the cost of supplying electricity in meeting any type of demand pattern so that decisions affecting the use of electricity can be based on the true costs of providing it.
3. To provide customers with incentives to adopt consumption patterns that lead to a more effective use of electricity and thus to reductions in supply costs. "

The time of use tariffs are developed from the marginal cost philosophy described in detail in the second chapter. In particular, the basis of the tariff structure is Long Run Marginal Costing (LRMC) defined in a similar way to that of EdF in their tariff policy. The tariff level however, is established by scaling the marginal cost derived structure so that the revenue generated from the tariff will achieve Eskom's short-term revenue requirements.

The LRMC basis was chosen in preference to (SRMC) short run marginal costs because "it (LRMC) reflects the full costs of supplying extra load on a long term basis, and is thus appropriate to a tariff on which long term decisions will be based" (Calitz, 1991). This contrasts with the use of SRMC in the derivation of tariffs for international customers.

In arriving at the winter and summer charges during each of the respective periods, it was necessary to determine the LRMC of Generation and Transmission for each hour in a typical winter and summer week. These were established by computing the extra cost of supplying an extra unit of load from a generation system having an optimal mix of base, intermediate and peaking power stations. The computation results in a marginal cost in c/kWh for each hour of the week, plus a capital related cost (R/kW) in the hour of peak demand. These costs are used as the basis to the rates for Tariff T1. It should be noted however, that the maximum demand charge in T1 is applied to the peak as well as standard period to reduce the danger of the system peak shifting into what is defined as the standard period.

The rates for T2, which has no demand charge, are calculated by allocating the capacity related costs described earlier, to each hour of the week in proportion to the system Loss of Load Probability (LOLP). Since the LOLP is only really significant during the peak period, this means that the capacity related costs are effectively factored into the peak period only. This is evident in the tariff rates for T1 and T2 which are the same during the off-peak and standard periods but are considerably higher during the peak periods in tariff T2.

During the development of the tariff there was extensive interaction between Eskom and the municipalities, mines, industrial customers and various consultants. Most of these bodies put up considerable opposition to aspects of the proposed tariffs (Calitz 1991). In particular, municipalities opposed the substantial reduction in the proportion of total revenue which was to be derived through the demand charge in the T1 tariff than was derived from the demand charge in the existing A tariff. The municipal opposition was generated because municipalities pay Eskom for their diversified maximum demand while they (the municipalities) are paid for the sum of the individual demands of their customers, and hence through diversity they receive substantial financial benefit. The loss of the diversity benefit with the proposed time of use tariffs, according to the municipalities, placed Eskom in an advantageous position to compete with municipalities in the distribution of electricity. A second concern which the municipal distributors had, was that they would be unable to pass on Eskom's time of use tariff to their own municipal customers because of prohibitive metering costs. A third concern was that because municipal distributors have less control over their load than industrial customers, they should be given a special, more favourable tariff. The nature of these concerns would seem to indicate that the municipalities essentially had no logical opposition to time of use based tariffs. Rather, their opposition indicated their unwillingness to change to a tariff, that in the short-term at least, would not serve their own interests.

There were also concerns, mainly from mining customers, that the proposed tariffs would result in high load factor customers paying more than they would on Tariff A. As explained earlier, the calculation of the demand charge of Tariff A meant that low load factor customers were effectively cross-subsidising high load factor customers. Hence Eskom argued that time of use tariffs do not penalise high load factor customers, but rather charge customers the true cost of supplying their particular type of demand pattern. It would seem that this argument is only half right, since it is impossible for one set of demand and energy rates to accurately reflect the cost of supplying customers of different load factors. The T1 Tariff will recover the correct amount of revenue through the demand and energy charges only for those customers whose load curve matches the forecast system load curve, as used in the calculation of the demand and energy rates in the LRMC methodology (explained earlier). If the tariff is to be cost-reflective, customers with a lower load factor than the forecast system load factor would have to have a greater relative energy component, while customers with a higher load factor would have to have a greater relative demand component. This could only be achieved if there was a range of time of use tariffs with different relative demand and energy charges which the customer could choose from, as is the case with the time of use tariffs offered by Electricite de France.

However this does not detract from the fact that the time of use tariffs, T1 and T2, are light years ahead of the rest of Eskom's external tariffs. Besides the rural time of use tariffs, they are the only tariffs which are based on a costing principle which seeks to achieve economic efficiency. As a result of this, the tariffs have been structured in a manner which it is believed will achieve the optimal utilisation of the customer's and utility's resources by encouraging customers to adopt a pattern of consumption which will minimise Eskom's capacity and operating costs. Furthermore, in developing the time of use tariffs, Eskom took a relatively thorough look at the charges for reactive energy and voltage differentiation in the cost of supply. Hence in T1 and T2, unlike the other large customer tariffs, the charges for reactive energy and voltage are more reflective of the costs which Eskom incur.

A specific problem with the T tariffs which became known after their implementation is that they are not cost reflective when applied to rural customers. This is discussed in more detail in the section on the Ruraflex tariffs.

**A review and discussion on Eskom's Medium power user tariffs: Tariff F and Ruraflex**

## Tariff F

Tariff F was designed for medium sized customers with low load factors and high maximum demands (mainly farmers) and was first implemented in January 1987.

Supply on this tariff is limited to customers with a maximum demand of greater than 25 kVA but whose voltage of supply is in the range from 500 Volts to 22 kV. The charges at 1 January 1994 are as follows:

Basic Charge:	R143.47
Energy Charge:	5.97 c/kWh
Maximum demand Charge:	R32.36 to R31.08 per kVA at voltages of supply from less than 500 Volts to 22 kV.
Maximum Charge:	In the case that the revenue derived from the energy charge and the maximum demand charge exceeds 27.57 c/kWh purchased, a maximum charge of 27.57 c/kWh will be applied.

The charges are the same as Tariff A with the exception that there is an upper limit on the size of the bill to 27.57 c/kWh. The Tariff is offered only at 380 and 220 volts, 11 kV and 22 kV, these qualifying voltages contrived to limit the tariff to large power farming customers only (Barnard et al, 1993).

It is clear that if in Tariff A there was a load factor differentiation in the relative sizes of the maximum demand and energy charges, there would have been no need to develop Tariff F or indeed to specify a maximum price.

### Time of use tariffing for rural customers: Ruraflex

At present 170 rural customers are on Tariff T2. Eskom is under-recovering costs on these customers since no allowance has been made on T2 for the following: (Ligoff and Hager, 1993)

1. Recovery of about R220 of capital already recovered in Tariff D (the tariff generally applied to rural customers).
2. Higher losses associated with rural networks.
3. Higher support costs in rural areas.

The demand amongst rural customers for time of use tariffs has therefore lead to the development of a tariff based on T1 but customised for rural, predominantly farming customers. The tariffs are known as Ruraflex1&2 although the only difference between the two is size of the basic charge. The Ruraflex rates are as follows:

	Ruraflex 1.(≤ 50 kVA)	Ruraflex 2. (> 50 kVA)
<b>Basic Charge [Rands]</b>	274.46	304.95
<b>Energy Charge [c/kWh]</b>		
<b>Winter</b>		
<b>Peak</b>	34.61	34.61
<b>Standard</b>	13.07	13.07
<b>Off-peak</b>	7.6	7.6
<b>Summer</b>		
<b>Peak</b>	31.06	31.06
<b>Standard</b>	11.72	11.72
<b>Off-peak</b>	6.82	6.82
<b>Voltage percentage discount</b>		
<b>500 &lt; V</b>	0	0
<b>500 ≤ V &lt; 22kV</b>	1.86	1.86
<b>Reactive energy charge [c/kVArh]</b>	1.14	1.14

### A review and discussion of Eskom's small power-user tariffs: Tariffs B, C, D, S1,2,3

Like the rest of Eskom's tariffs, the tariffs for small power users - which account for more than 90% of Eskom's total number of customers but for less than 4% of the total revenue - have been shaped by political and economic developments both inside and outside the electricity industry. However, in contrast to large customers where the possibility of improving Eskom's utilisation of resources is possible through changing the consumption pattern of only a few large customers, small power users do not offer the same opportunities. Hence, while cost reflective tariffing is the most important consideration in

large power user tariffs, practical considerations such as metering and implementability are frequently the most important considerations in small power user tariffs since the revenue generated from small users is much smaller in proportion to the cost of metering and administration.

Before the actual tariffs are discussed, the range of small power user tariffs currently offered by Eskom are described below:

	<b>Tariff B</b>	<b>Tariff C</b>	<b>Tariff D</b>
<b>Applicable Customer Categories</b>	Small Urban commercial customers	Domestic consumption with conventional credit meters	Rural, particularly farming customers
<b>Basic Charges [Rands]</b>			
≤ 25 kVA	41.45	-	70.17
> 25 and ≤ 50 kVA	66.95	-	95.64
> 50 and ≤ 100 kVA	114.78	-	143.47
Irrespective of demand	-	34.24	-
<b>Energy charges [c/kWh]</b>			
0-500 kWh	27.57	-	-
500 kWh upwards	15.94	-	-
0-1000 kWh	-	-	27.57
1000 kWh upwards	-	-	15.94
All energy	-	18.62	-
<b>Connection fees [Rands]</b>			
Single phase	450	450	600
Three phase	900	900	1200
<b>Extra</b>	An extra monthly charge will be levied should the connection costs exceed the standard costs already factored into the tariffs.		The connection fee covers the first 200 meters of customer-connection line as well as metering. Amounts in excess of this are recovered through an additional monthly charge.

## S Tariffs

The S tariffs are applicable to single-phase pre-paid supplies. In the design of the S1 tariff, it was intended that the full generation, transmission, distribution, reticulation and service connection charge be factored into the c/kWh tariff. With S2 the customer pays for the service connection, while with S3 the customer pays for the service connection as well as the reticulation costs.

The applicable rates at 1 January 1994 are as follows:

Tariff	S1	S2	S3
c/kWh rate	24.82	21.22	18.62
Connection fee	0	40	Actual costs

### B & D Tariffs

Tariff B and D have a similar structure with the exception that the size of the first energy block in the two block structure is larger in Tariff D (1000 kWh/month) than in Tariff B (500 kWh/month). Tariff B which is now classified as suitable for small urban commercial customers, was always used for rural farming customers until Tariff D was introduced in 1982.

There is an interesting history behind tariff D. The 1977 Board of Trade and Industry Report recorded strong complaints from farmers in regard to the monthly extension charges used with Tariff B. Nothing was changed until 1982 when farming customers once again put pressure on Eskom to do something about the monthly capital charges. This time Eskom developed Tariff D which differed from Tariff B in that the first 800 kWh were now at a high rate instead of only the first 500 kWh. However despite this increase, a decrease in the monthly capital charges allowed an average 40% reduction in electricity costs for all farmers (Krumm 1989). Tariff D was also linked to the Land Act making it compulsory for farmers to change over from Tariff B to Tariff D.

Although the new tariff (Tariff D) was designed to incorporate the capital cost of providing 1 km of line into the tariff's standard charges, last minute representation to Eskom by the South African Agricultural Union and the Minister of Agriculture resulted in the capital costs of 2 km of line being covered by Eskom. To compensate, to a certain extent, for the extra capital costs which Eskom incurred in providing 2 kilometres of line, the high rate units were increased from 800 kWh to 1000 kWh per month and the basic charge was levied at different levels for supplies at 25 kVA, 50 kVA and 100 kVA. Monthly capital charges for new customers were only charged on line lengths in excess of 2 km.

The 2 kilometre factor (as it became known) was however short-lived. In 1988, Eskom investigated the profitability of Tariff D and found that Eskom was not recovering the costs of supplying Tariff D customers. This was because the tariff was designed to recover

supply costs at a consumption level of 1000 kWh per month, whereas the actual average usage was in the region of 750 kWh per month. Further, since the costs of construction had risen drastically the cost of the two kilometre of service connection was not being adequately recovered by the slight alterations in the basic charges. As a result of these problems, a change was made during 1989 to the monthly capital charges structure whereby the costs of only 200 meters of line were included in the tariff's standard charges. For a customer connection longer than 200 meters, a Rands per meter charge was estimated and this charge recovered through a monthly capital charge.

In the meantime, Tariff C - which was never the cause of particular attention - was changed by doing away with the high and low block rates and implementing a single rate tariff with an increased basic charge.

In 1989, Eskom reached the following conclusions on their small customer tariffs: (Krumm, 1989)

- " 1. They provide the farming sector with a cheap source of power.
2. They are understandable.
3. Revenue requirements with some tariffs (Tariff D) are not met.
4. There are cross-subsidies from existing farmers to new farmers.
5. There are cross-subsidies from the large power customers to small power customers.
6. Conservation, wise and efficient use of electricity is not encouraged.
7. The policy is prescriptive, the customer may not select the tariff which is most suitable to his needs.
8. It is administratively complex, three groups of customers in only 4% of Eskom's business."

As an alternative, a new policy was suggested: (Krumm, 1989:14)

- " 1. All small power users should be aggregated together as one group.
2. A range of tariffs applicable to all customers within the group and linked to usage patterns, be developed.
3. Pricing structures would be such as to encourage effective use of electricity.
4. Excess capital costs not catered for in the tariff shall be allocated to the specific customer or customers responsible for such costs.
5. Under-recovery of any tariff within the small power user group will be

supported where it is deemed to be in the long term business interest. "

These recommendations go to the heart of what in EdF tariffing is held as a crucial principle: Within practical limits, customers should have a wide choice of tariffs, so that the tariff that is chosen is the one that will minimise the cost of purchases to the customer and the cost of supply to the supplier.

As valid as these recommendations are, to this day they have not been implemented possibly in view of other, more urgent pressures on small customer pricing, such as the need to provide a pricing structure for application in the electrically under-developed areas, to further Eskom's vision of electricity for all at affordable prices.

This brings the discussion to the development of the single-rate S tariffs. The major obstacle to affordability amongst the lower income sectors was recognised to be the significant connection charges. The aim of the S tariffs was thus to provide electricity at an affordable price while still covering the costs of generation, transmission, distribution and reticulation. Integral to the development of the S tariffs was a simple and affordable prepayment metering system which would allow the metering of energy consumption but not maximum demand.

The original S1 tariff came into effect from 1 September 1989. It was intended to break-even with Tariff C at a consumption level of 355 kWh per month. At the time 355 kWh per month was the expected consumption level of customers who would be supplied on the S1 Tariff. Tariffs S2 and S3 were subsequently developed. The difference between the three tariffs is that: with S1, Eskom finances the capital cost of the bulk supply, reticulation network and service connection; with S2, Eskom finances the capital cost of the service connection or any part of the reticulation up to R1000 per stand; and with S3 the customer finances all of the bulk supply, reticulation network and service connection costs (Barnard, 1992).

Including the Ruraflex tariffs, Eskom presently offers more than 7 different tariffs, each with different structures, to customers classified as small power users. In practice, however, customers have a limited choice. Only pre-payment customers use the S tariffs, only conventionally metered urban customers use the B tariff and only conventionally metered urban domestic customers use the C tariff. It is only fairly large rural farming customers who have a choice between Tariff D and the recently introduced Ruraflex tariffs.

It is suggested here that a better alternative would be to develop two or three generic structures and allow customers to choose the particular tariff which allows the customer to choose the tariff that will allow him/her to minimise their electricity costs. Extra charges in terms of connection fees, transmission surcharges etc. could then be levied separately or integrated into the monthly charges as is done with the S tariffs.

### **Customised pricing**

By recommending that interruptible supplies be offered to some large customers in return for compensatory tariff benefits, the De Villiers Commission had indirectly recommended the development of customised price agreements as an integral part of the electricity pricing policy in the industry. Customised price agreements account for approximately 10% of the total electricity sold by Eskom in 1993. There have been a number of factors which have led to the establishment of customised prices. Firstly, deficiencies in the range of standard tariffs have led Eskom and some of its customers to seek customised agreements which offer both parties benefit. Secondly, considerable excess capacity in Eskom at present has led to an initiative to increase sales as much as possible to recover at least the marginal cost of operating existing facilities. Thirdly, political pressure has led to special deals with some strategic industries. Fourthly, in the case of the municipalities with self-generation capacity, Eskom has offered preferential agreements to municipalities to attempt to induce them to not use their (relatively) more expensive and inefficient power stations. The benefit to Eskom is an increase in sales at a time when Eskom has considerable excess capacity. There also appears to be a "national interest" benefit in the sense that through the customised tariff, the production resources of lowest cost are being utilised.

The customised pricing deals are worked out by negotiating various options with the customer. Some customised tariffs which are currently used include:

1. Commodity linked price increases.
2. Block rate tariffs with customised blocks set at specific rates.
3. Discounts on the maximum demand charge.
4. Modified time of use tariffs.

A list of customers with customised price deals and their 1993 budget energy sales are shown below. Unfortunately confidentiality precludes the publication of the revenue per agreement, but total revenue on customised price deals exceeded R360 million for the 1993 financial year.

<b>Municipal Electricity Distributors</b>	<b>Sales (GWh)</b>	<b>Industrials</b>	<b>Sales (GWh)</b>
Johannesburg Municipality	2012	Siltek	370
Pretoria Municipality	840	Richards Bay Minerals	225
Port Elizabeth Municipality	678	Alusaf	1622
Cape Town Municipality	750	AECI Midland	130
Bloemfontein Municipality	520	SASOL 2	458.8
Kroonstad Municipality	70	Atomic Energy Corporation	2180
Queenstown Municipality	24	Mossgas	220
		Sappi Ngodwana	180
<b>Ferro Chrome Industry</b>		Highveld Steel	240
CCT	394.6	Rand Carbide	106
CMI	167.2	Transalloys	115
Tubatse	80.1	Silicon Smelters	537.5
Ferralloys	8.5	Manganese Metal	50
Ferrometals	157	Other	250
Middelburg	8.5		

It is envisaged that customised pricing agreements will play a progressively larger role in electricity pricing in the industry, even after the existing surplus capacity has been exhausted. It should be noted that in the French and Zimbabwean electricity industries, customised agreements play a significant role in electricity tariffing. In France in particular, all customers on the Green C Tariff have customised agreements with EdF.

From a tariffing perspective, customised pricing forces the utility as well as the customer to examine their own and each others' operations thoroughly so that the electricity tariff agreed to will benefit both parties. This is, after all, the ultimate objective of electricity tariffs and hence the development of customised agreements should have an important role to play in tariffing in the industry.

## 4.4 Electricity pricing in the non-Eskom distribution industry at present

### 4.4.1 Nature of the industry

As stated earlier, the control structure of the municipal electricity distribution industry has remained largely unchanged since the beginning of the industry. The third chapter explained that provincial ordinances which took effect around the start of the century, placed control of electricity distribution in the hands of the local authorities, whose electricity departments were given a monopoly supply right inside their area of jurisdiction. Since only those resident within the area of jurisdiction of the respective local authority have a right to vote for their councillors, these councillors have generally used their respective electricity departments as a political tool in order to meet the needs of their white, mainly domestic, voters.

Before electricity tariffs in the industry are focused on further, it is necessary to give a broad overview of the non-Eskom distribution industry:

- \* In the non-Eskom distribution industry there are a total of just over 300 electricity distributors including separate Black and White Local Authority municipal distributors, some of the Regional Services Councils, the "Self-governing State's" electricity departments and the "National State's" electricity departments. Within the area of jurisdiction of most White Local Authorities there is almost 100% electrification. The break-down of the number of customers and sales to these customers in the electricity distribution sector controlled by the white municipalities, for 1992, is as follows:

	Number of customers	Total GWh Sales
Domestic	1 868 340	17 710
Commercial	140 954	6 830
Industrial	37 412	23 514
Rural	16 124	405

(Source: National Electrification Forum's Electricity Distribution Industry Database)

- \* The regulatory structure is best described as a "tangled mess": White Local

Authority Councils are responsible for the Electricity Departments under their jurisdiction. Similarly, Electricity Departments formed under Black Local Authorities are responsible to their Black Local Authority Councils. Municipal electricity distributors are regulated firstly by their local authority electricity councils and then by their respective Provincial Administrations, although the latter are not known to regulate the activities of municipal electricity undertakings whatsoever. Regional Services Councils and Joint Services Boards are responsible for their own activities as assigned by Provincial Administrators. The electricity supply authorities in the "National States" and "Self-governing States" are accountable to their respective governments. And finally, an Electricity Control Board issues licenses to distributors, "controls" the activities of licensees and can control the Local Authority tariffs to customers outside their proclaimed Area of Jurisdiction. Eskom's tariffs in terms of structure are ultimately regulated by the Electricity Control Board. The level of Eskom tariffs is however within its own jurisdiction.

- \* On account of national political policies since the beginning of the industry, it has become structurally imbalanced with the relatively affluent white domestic customers adequately provided for, but the disenfranchised majority largely ignored. There are currently an estimated 4.2 million dwellings are not yet electrified.<sup>11</sup>
- \* The highly fragmented structure of the distribution industry has led to a multiplicity of different tariffs with essentially no justifiable economic reason for the difference in most of the tariffs offered by the different distributors. This has led to the absurd situation where in some cases two adjacent customers supplied by different distributors are forced to pay completely different prices.
- \* On account of the relationship between most Local Authority Councils and their Electricity Departments, cross-subsidisation between commercial and industrial customers in favour of domestic customers, has been entrenched.
- \* Finally, in the non-Eskom distribution industry there is a real cash flow out of the industry in the form of surpluses generated by the municipal Electricity Departments and paid into the municipal Rates Fund (or similar).

The structure of the industry has had an impact on pricing in the industry and vice-versa. Electricity Pricing in the non-Eskom part of the distribution industry will be dealt with firstly under the heading *Price level* and then under the heading *Tariff structure*.

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<sup>11</sup> Personal Communications, Koos Schoeman, Eskom Electrification Planning.

#### 4.4.2 Price level

All municipal distributors purchase the bulk of their electricity from Eskom. Most of these purchases are on Tariff A, although the largest municipal customer, Durban Electricity, recently converted to Tariff T1. Some municipal distributors including Johannesburg, Pretoria, Port Elizabeth, Cape Town and Bloemfontein have a limited capacity to generate electricity. As a result of excess generating capacity in Eskom at present these municipalities are able to benefit through significant discounts through customised prices designed to displace municipal self-generation. The two-part structure of Tariff A also allows municipal distributors to recover significant amounts of revenue through the benefit of diversity. These factors combined with the inelastic demand of many commercial and industrial customers supplied by the municipalities, allows the municipalities to generate significant surpluses.

Using the National Electrification Forum's Electricity Distribution Industry Database, the figure for the actual surpluses generated in 95% of the non-Eskom distribution industry was R1,270 billion for the 1992 Financial Year. The figure for the surpluses generated firstly as a Rand amount and then as a percentage net mark-up on cost, for some prominent non-Eskom municipal distributors are shown below:

Distributor	Surplus [R'000]	Net mark-up [%]
Johannesburg	215 833	23
Pretoria	178 766	21
Vereeniging	26 208	20
Germiston	25 443	14
Benoni	18 522	17
Boksburg	16 248	13
Durban	114 662	12
Cape Town	92 571	16
Pietermaritzburg	29 559	19
Port Elizabeth	27 028	11
East London	12 351	15
Bloemfontein	19 633	16

In the survey of 16 municipalities as part of the 1977 Board of Trade and Industries investigation into the electricity supply industry, it was found that all municipalities favoured earning surpluses on their electricity distribution service. Some of the arguments put forward in favour of surpluses were, inter alia: (Board of Trade and Industry Report No 1889, 1977:105)

1. Electricity undertakings should make a contribution for the use of roadways,

land and facilities.

2. The rate of return on capital employed in municipal electricity undertakings is substantially lower than those of private undertakings. (At the time of the BTI Report, there were no private electricity undertakings in South Africa. Hence it is assumed that this statement is a comment on private electricity undertakings versus municipal electricity undertakings generally).
3. Indirect rates are necessary to burden all inhabitants and not only the owners of property.
4. Low interest loans are provided to electricity undertakings.
5. City Councils guarantee the deficits of electricity undertakings.

It is difficult to see why any of these reasons justify municipalities using their electricity departments to generate surpluses. Perhaps the real reason that municipalities use their electricity departments to generate a surplus, is because they can, and although they receive some opposition to this practice, this opposition has never been strong enough to cause them to change.

Moving one level down to examine the relative price level of the domestic, commercial and industrial customers, the table presented below expresses the average annual price in cents/kWh for industrial, commercial and domestic customers.

Distributor	Domestic [c/kWh]	Commercial [c/kWh]	Industrial [c/kWh]
Johannesburg	12.9	26.2	17.9
Pretoria	18.3	18.3	12.8
Vereeniging	13.4	21.9	12.3
Germiston	14.5	24.2	15
Benoni	16	27	15
Boksburg	14.2	20.5	19
Durban	14.5	15	13
Cape Town	14.3	19.5	13.7
Pietermaritzburg	12.4	23.9	17.86
Port Elizabeth	12.3	22.6	15
East London	15	17	18
Bloemfontein	11.4	14.7	13.8

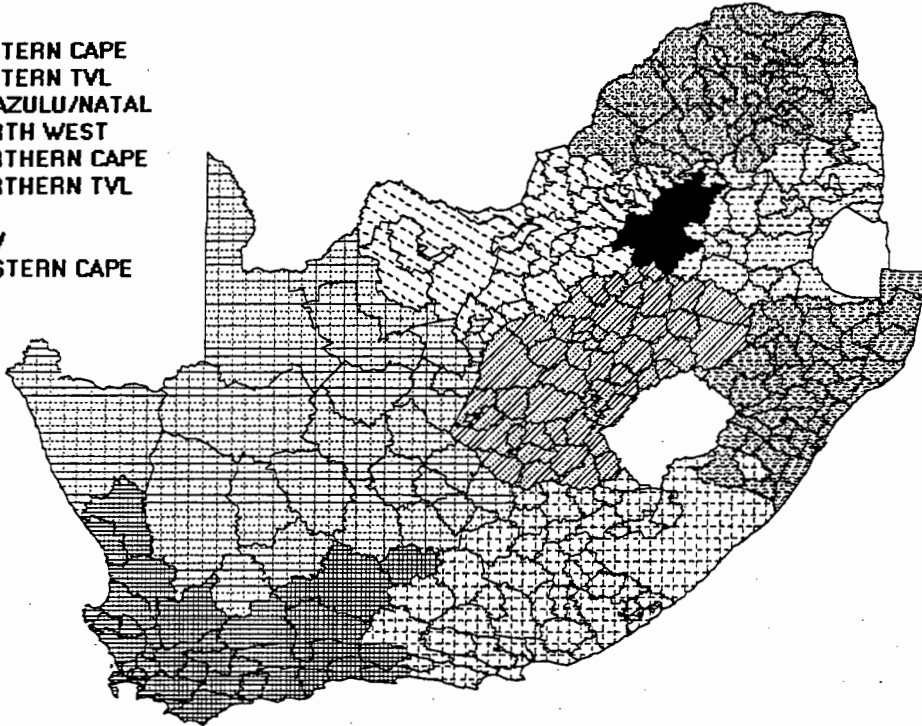
From the figures in this table, it is clear that there is extensive cross-subsidisation from commercial to domestic customers. The inconsistency of the price level amongst customers in the same class but in a different geographical area, is also clear.

Relating to the issue of price level at distributor and customer level, it is pertinent to examine the "wealth distribution" of electricity income throughout South Africa. The map

below indicates the boundaries of the nine political regions recently agreed to at multi-party negotiations at the World Trade Centre.

**Province**

-  EASTERN CAPE
-  EASTERN TVL
-  KWAZULU/NATAL
-  NORTH WEST
-  NORTHERN CAPE
-  NORTHERN TVL
-  OFS
-  PWV
-  WESTERN CAPE



Grouping all non-Eskom distributors according to these boundaries the surpluses, per region, for 1992 would be as follows:

Region	Surplus [R'000]
Eastern Transvaal	37 712
KwaZulu/Natal	163 610
North West	52 353
Northern Cape	19 656
Northern Transvaal	15 695
OFS	62 963
PWV	655 675
Western Cape	183 757
Eastern Cape	71 077

These figures clearly indicate the considerable disparity in the net income of the various regions. Furthermore, considerable electrification potential exists in the Northern Transvaal, Eastern Cape and PWV Regions. It is clear that the net income of the non-Eskom distributors in these areas will be totally insufficient to meet the financial cost of electrifying these areas. Although this section does not attempt to provide answers to this problem, if one assumes that the already excessive cross-subsidisation between domestic

customers and industrial and commercial customers cannot be increased, it becomes evident that unless there is a funds transfer (through whatever mechanism) from the more affluent PWV region to the lesser endowed regions, it will be impossible (unless there are some external subsidies) for the industry in these areas to meet the considerable electrification commitments they need to make.

#### 4.4.3 Tariff Structures

The considerable price level differences between the various distributors is mirrored in the considerable number of different tariff structures which are used.

In the BTI investigation of municipal pricing in 1976, it was found that the most common tariff structures used by the municipalities were the same as the tariff structures used by Escom. Some municipalities also offered limited time-differentiated tariffs, whereby discounts were given if customers agreed not to consume electricity during the time of system maximum demand. However, this was noted to be the exception rather than the rule (Board of Trade and Industry Report No 1889, 1977:104)

Regarding the cost allocations upon which municipal tariffs were based, the BTI investigation reported as follows: (Board of Trade and Industry Report No 1889, 1977:108)

"The majority of municipalities are vague and it appears that sophisticated methods are not applied. A number of these municipalities stated that they follow Escom's policy as nearly as possible without indicating what it means. In two cases, tariffs were restructured about thirty years ago and in one case it was not possible to determine how tariffs were structured. In two further cases where the methods of allocation were described it was stated in the first case that own costs are allocated according to a fixed rule and in the other case that demand related costs are allocated to consumer groups according to their kWh consumption."

As a brief research into tariff structures for domestic consumers at present, the domestic tariffs offered by Port Elizabeth, Boksburg, Johannesburg, Pietermaritzburg, Bloemfontein, Benoni, Germiston, Vereeniging, Pretoria, Cape Town and Durban were examined. From this small list of distributors, the following differences should be noted:

\* Port Elizabeth, Boksburg, and Johannesburg charge for electricity with a flat

monthly c/kWh consumption rate.

- \* Pietermaritzburg has a Rand per Amp monthly fixed charge and a c/kWh monthly consumption rate. In addition, Pietermaritzburg offers a flat rate tariff for customers whose demand exceeds 40 Amps per phase. Finally, there is an optional 3-block declining rate tariff .
- \* Bloemfontein, Benoni, Germiston and Vereeniging have a fixed monthly charge irrespective of the size of the supply, and a monthly c/kWh consumption rate.
- \* Cape Town City Council has a monthly fixed charge plus a declining block structure tariff, with the first block up to 1500 kWh per month and the second block in excess of 1500 kWh per month.
- \* These rates are in respect of a conventionally metered single phase supply of 60 amps.
- \* Different tariffs are generally offered to pre-payment customers where applicable.
- \* In many cases, different tariffs are offered to customers who are outside the area of jurisdiction of the distributor but are supplied by that distributor .
- \* There is considerable diversity regarding the practice of who funds the service connection, reticulation network and distribution network.

### **Commercial Customers**

Unlike domestic customers who, in the tariff schedules of all distributors in this review are specifically defined as such, most small power users who do not meet the criteria for classification as a domestic consumer, are placed on a general tariff intended for small power users. Customers on this tariff are, for the most part commercial customers but may also include small industrial customers or other such customers. Tariff structures to these customers generally mirror those of the domestic customers with the exception that the rates, in most cases, are considerably higher. In some cases, for example Boksburg, commercial customers are also obliged to go on a maximum demand tariff.

### **Industrial Customers**

Like commercial customers, there is no specific tariff for customers who are classified as industrial customers. In Boksburg for example, all customers who are not domestic customers are offered the same tariff. Non-domestic customers are generally classified as large power users, though the majority of customers on this scale have industrial

applications. Large Power User tariffs vary widely. Most tariffs have a three-part structure i.e. demand charge [R/kVA], energy charge [c/kWh] and a basic monthly charge. The structure and applicable rates are largely based on Eskom's Tariff A.

Some municipalities also have time-differentiation in their Large Power User tariffs, in the form of off-peak tariffs, for example: Benoni, Germiston, Vereeniging, Bloemfontein and Cape Town City Councils. In almost all cases, this tariff has the same structure as Eskom's Tariff E.

#### **4.4.4 Summary of the key issues in non-Eskom distribution industry tariffing**

In terms of electricity pricing, the key attributes of the non-Eskom distribution industry can be summarised as follows:

- \* From a regulatory perspective, the considerable number of institutions that are able to regulate the industry leads to the conclusion that price regulation in this sector of the industry is best described as a "tangled mess".
- \* The industry made a surplus of R1,27 billion in the 1992 Financial Year. Most of this was transferred to the municipal Rates Account to subsidise other services.
- \* The surplus is not evenly distributed throughout the country, but rather is concentrated in a few metropolitan areas, notably the PWV.
- \* The average price level to domestic customers, in comparison with industrial and commercial customers, indicates that there is considerable cross-subsidisation in the industry in favour of domestic customers.

## **CHAPTER 5            INTERNATIONAL STUDIES IN ELECTRICITY PRICING**

The purpose of this chapter is to investigate electricity pricing practices in other countries of the world. The approach is firstly to review the pricing structures in each country and then to develop some perspectives on the applicability of pricing strategies in these countries, to the electricity supply and distribution industry in South Africa. Three very different countries (from a pricing perspective) were chosen for this investigation. The first study is of the electricity industry in England and Wales which has recently been through a major restructuring which aimed to establish the force of fair competition as the prime determinant of electricity prices. The second study is of electricity pricing by Electricite de France, a state corporation, which has had a monopoly over all parts of the electricity supply and distribution industry since 1946. The third study is of pricing in Zimbabwe where, for a number of reasons, the electricity industry has been in a state of crisis since 1989.

## 5A PRICING IN ENGLAND AND WALES

### **Part 1: The restructuring of the electricity industry in the UK<sup>12</sup> and electricity pricing in the restructured industry.**

#### **5.1 Introduction**

In 1990 the UK electricity industry was radically restructured from a monopolist State industry to one in which there was extensive private ownership, competition in generation and limited but increasing competition in distribution. The mechanisms setting price in the industry are unique world-wide in the sense that they have developed as a consequence of the stated goal that pricing in the industry should be based on competition and as such should support absolutely no cross-subsidies whatsoever. This chapter examines the restructured industry and postulates possible applications to the South African industry. The chapter is split into two parts. Part 1 focuses on the restructuring of the industry and the price regulatory mechanisms that have been developed in various sectors of the industry. Part 2 focuses on possible applications of the UK system of electricity pricing to South Africa.

The chapter starts with a discussion on the restructure and privatisation as principally a political development. The basic objectives of the privatisation and restructure are then established. The development of the new industry in the generation, transmission and distribution sectors is then discussed. This is followed by a discussion on the creation of a market-based electricity trading market, the development of generator/supplier/customer contracts, and the restructuring process in general. An explanation of the price regulatory mechanisms in the various sectors of the industry concludes Part 1. Part 2 begins with a discussion of private ownership versus competition. The positive principles arising from the UK restructuring are then discussed. This is followed by a discussion of a possible adaptation of the supply side pricing mechanisms in the UK industry to the South African ESI. Part 2 concludes with an analysis of the application of the UK distribution pricing mechanisms to the South African Electricity Distribution Industry.

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<sup>12</sup> While not technically correct, for the sake of simplicity, all reference to the UK in this chapter, should be taken to mean England and Wales only. The electricity industry restructuring in Scotland was separate from the restructuring in England and Wales and is not discussed here.

## 5.2 Political developments leading to the restructuring of the UK electricity industry

The Conservative Party's manifesto for the May 1987 general election contained two pledges of relevance to the UK ESI. The more important of these was to privatise the industry. This pledge came shortly before the fortieth anniversary of the nationalisation of the industry.

During the years of its nationalisation the UK ESI had enjoyed a high degree of stability. What was, prior to the nationalisation in 1948, a fragmented and largely inefficient industry, had become a technologically advanced and stable industry. In addition, by 1990, the industry was enjoying spectacular financial success, financing all its own investment and paying back much of its earlier debt, so much so that at the time of privatisation it was close to debt-free (De Oliviera and MacKerron, 1992).

However, despite this apparent success, the Conservative Government under the firm direction of Margaret Thatcher sought to radically restructure the industry in order to achieve the oft-cited objective of economic efficiency through competition. The idea that the electricity industry could achieve economic efficiency through competition was a radical departure from the commonly held notion that the electricity supply and distribution industry was a natural monopoly.

The restructure was opposed in view of the apparent success of the existing nationalised industry and the fact that the idea of competition in facets of the electricity industry was so radically new and unproven. Indeed it is clear from published literature on the subject, that both during and after the restructure, considerable doubt existed as to whether the new competitive industry would achieve its stated goals any better than the previous nationalised industry had.

However the fact that the momentous restructure did take place is largely accounted for by the political will of Thatcher's government who were as determined to "roll back the frontiers of the state" as the Labour Party had been to "secure for the worker by their hand and brain the fruits of their industry" when, under their government, the industry was nationalised in 1948.

### **5.3 The objectives of the restructuring of the Electricity Supply Industry.**

Two key principles quantify the basic objectives underlying the restructuring and privatisation of the UK ESI. These have been expressed as: (Ruff, 1991:5)

- 3.1. *Economic efficiency, both long run and short run.*
- 3.2. *Competition, rather than regulation, is the best way to accomplish efficiency.*

The White Paper of February 1988 on the Privatisation of the Electricity Supply Industry stipulated these as the core around which a privately owned electricity industry should be based.

These were the principles that were established at the outset. However there was no grand plan which set out the process to be followed or even what the industry should look like at the end of the restructuring.

### **5.4 The restructure**

To the electricity industry in England and Wales, April fool's day in 1990, ironically, was known as Vesting Day, the day on which the restructured industry came into existence.

As explained earlier, two of the significant objections to the restructuring centred on the fact that the existing industry was apparently successful and also that competition in all parts of the electricity industry was a new and untested idea. In fact there were several other obstacles to the privatisation that only came to light as the restructuring progressed. One such problem was nuclear generation which, due to disinterest from investors made it impossible to privatise.

In this section, the restructuring of the UK ESI has been separated into two distinct processes: firstly, unbundling the industry to achieve competition, and secondly, creating a

trading system to facilitate market-based trading. Before the latter process is explained, it is necessary to describe the former.

#### 5.4.1 The unbundling of the electricity supply industry

Since it was nationalised in 1948, generation and transmission was undertaken by the Central Electricity Generating Board (CEGB) while distribution was undertaken by the twelve Area Boards, who had a franchise over all customers in their respective areas. The industry was presided over by the Secretary of State for Energy and there was no competition in the supply, distribution or transmission of electricity.

The crucial issue in the restructuring and privatisation of the Electricity Supply Industry was to create competition in generation and distribution. This has meant unbundling generation and transmission from the CEGB and restructuring the Area Boards. This section focuses on the developments in generation, transmission and distribution in the course of the re-organisation of the industry.

#### Generation

On the generation side, the erstwhile Central Electricity Generating Board, was split into:

1. Two independent power generators, National Power and PowerGen.
2. Nuclear Electric, a commercial operation with 100% of its equity held by the state.
3. A National Grid Company (NGC).

In terms of the generating capacity in England and Wales, the capacity levels in 1991 were as follows: ( Source: Power In Europe, Issue 106, 1991)

National Power	29 445 MW
PowerGen	18 711 MW
Nuclear Electric	8 333 MW
Others*	2 500 MW

**Table 1.**

\* Includes small scale Independent Power Producers as well as pumped storage facilities owned and operated by the National Grid Company.

### *Nuclear Generation*

For the May 1987 General Election, the second of the Conservative Party's pledges, relating to the UK ESI, focused on nuclear generation. In particular they pledged to continue to support the development of civil nuclear power in the private sector (Cheshire, 1992). However, by November 1989, the government had discovered, much to its chagrin, that the decommissioning costs of some of the very old Magnox Reactors as well as exorbitant fuel cycle costs meant that private investors were not interested in the nuclear power stations, and as such it would have been impossible to effect a constructive privatisation of these assets. This was a source of great embarrassment to the Conservative Party and contributed to Cecil Parkinson's replacement by John Wakeham as Secretary of State for Energy.

### *Conventional thermal generation*

As a result of the withdrawal of the nuclear power generators from the privatisation, National Power, which was originally intended to receive 70% of the nuclear plant held by the CEGB (PowerGen getting the other 30%), ended up with only the CEGB's fossil-fired plant in a split of 46% to National Power and 28% to PowerGen. With the creation of two generators with more than 74% of the generation capacity, the potential for duopolist behaviour was created. However, since the government only withdrew nuclear power generation from privatisation on 9 November 1989, there was not sufficient time to consider any alternatives before the flotation of the industry in April 1990. Had it been recognised at a much earlier stage that nuclear power was to be retained in the public sector, the division of the coal-fired generating assets into five or six companies might have been contemplated. The Secretary of State for Energy later admitted that were he starting again, he would have chosen a different structure for fossil fuel generators (Fourth Report of the House of Commons Select Committee on Energy, 1989, in Cheshire 1992).

### *Independent Power Producers*

The category labelled "Others" in Table 1, include Independent Power Producers (IPP's). In 1992 there were no independent power producers, but generators in this category are forecast to increase to 7% of the total capacity by 1995. (Power in Europe, Issue 106, August 1991) Independent Power Producers (IPPs) will enter the market if they are able to

achieve a satisfactory return on their capital investments. The privately owned electricity distributors known as Regional Electricity Companies (RECs), among others, are investing in IPP's through long term contracts on the proviso that the investments in the IPP's will mean that the RECs will be able to access an economic source of power when the plant is commissioned. The majority of these contracts are for Combined Cycle Gas Turbine (CCGT) plant (Power In Europe Issue 126, 1992). The largest Independent Power Producer project yet agreed to, is for a 1725 MW gas-fired plant. This contract is between four RECs, Enron and ICI and is scheduled for completion before 1995.

It was known long before the privatisation of the power industry, that it was cheaper to generate electricity by using gas than by using coal. A lifting of the ban on the use of gas in power generation around the time of the privatisation, resulted in a new focus on gas-fired generating plant. By July 1992, the NGC had signed deals to connect 23 806 MW of gas-fired plant (Power In Europe Issue 126, 1992). By late 1991, National Power and PowerGen were planning to build 4650 MW and 3730 MW of gas-fired plant respectively (Power In Europe Issue 106, 1991).

### **Distribution**

At the time of the privatisation, the then British Prime Minister expressed the conviction that "no-one in the (electricity) industry should regard customers as theirs by right" (Power In Europe Issue 58, 1989). This meant that in distribution it was necessary to create competition by allowing any customer the right to purchase electricity from any supplier that they may choose. This was perhaps the most radical development of the whole restructuring process. The idea that distribution was not a natural monopoly was an idea as yet unchallenged to any significant extent in the electricity industry world-wide. In order to effect competition in distribution it was necessary to ensure that potential suppliers should not be barred from gaining access to the distribution grid and reticulation "wires" to any particular customer.

Although the intention of privatising distribution was to create competition, the process of introducing competition was intended to be evolutionary. The first step was to privatise the existing twelve Area Boards as public limited companies to be known as Regional Electricity Companies (RECs).

The earnings of the newly privatised RECs come almost entirely from the charges that they are able to levy on customers for the use of their distribution assets. The initial licenses issued to the RECs by the Office of Electricity Regulation (OFFER) stipulated that each REC was allowed to price electricity in order to recover from electricity supply charges, the total costs of all electricity purchases plus a margin (limited to 10-20% of total supply costs) to cover administrative and working-capital costs. Hence the return on equity invested in the industry is a function of the expected growth of electricity consumption in each particular geographic area. The RECs in the South and East of England, with the highest flotation values, had the lowest return on equity and the highest price to earnings ratios, in view of the expected growth of electricity consumption in these areas. Conversely, the RECs in the North of England and Southern Wales had the highest returns but the lowest price/earnings ratios because of the expected industrial stagnation in these areas.

The second stage in the restructuring of distribution was to create competition in the industry. Competition can be said to exist when any consumer anywhere in the UK has a voluntary choice as to which distributing company he or she chooses to purchase electricity from. In practice, creating this competition instantaneously was impossible for a number of reasons. The most significant reason was that at the time of privatisation the RECs entered into contract purchases from National Power and PowerGen at rates higher than the pool price since National Power and PowerGen had in turn been forced into three-year contracts to support expensive coal purchased from British Coal. (The pool price mechanism is explained in detail later). These contracts were scheduled to expire on 31 March 1993 by which time National Power and PowerGen would have been able to explore other avenues to obtain cheaper coal. As a *quid pro quo* the RECs had a franchise over all customers with maximum demands below 1 MW until April 1994. However there was open competition above this limit in which National Power and PowerGen had the right to supply electricity directly to large customers. After April 1994, the proposed franchise limit will be set at 0.1 MW thereby opening up a much larger portion of the market to competition. After 1998 it is intended that the distributors have no franchise over customers inside their "area of supply".

The changes undertaken thus far, and the changes proposed have meant a radically changed role for the distributors. The newly created RECs are responsible for acquiring and distributing electricity to their customers at the cheapest possible prices. This does not

mean that they have an *obligation* to supply. Their role is to serve as an energy purchasing agent for any local customer - they must offer to sell electricity as long as any is available in the pool. Similarly, RECs are not under any obligation to extend their distribution network. Previously with the Area Boards a customer was connected to the system on request. In the privately owned industry however, a customer will only be connected if he or she is able to pay the price that competitive suppliers are asking.

Besides the fact that RECs will eventually have to operate in a completely competitive environment, there is also a regulated limit relating to the extent of vertical integration allowable in the RECs. In particular, they are prohibited from owning or controlling generating capacity exceeding 15% of their annual maximum demand. The intention with this is to stop the RECs from poaching customers previously supplied by the generators. In effect however, this is also a limit on the portion of the Independent Power production. Similarly, National Power and PowerGen are prohibited from contracting directly to supply more than 15% of the load in any REC territory. In fact this limit can be modified by the Director General of Electricity Supply at will.

### **Transmission**

The National Grid Division was created within the CEGB, on the 1 January 1989, as a precursor to the formation of an independent grid company. On the 31 March 1990, the CEGB was split up into National Power Plc, PowerGen Plc, Nuclear Electric Plc and the National Grid Company (NGC) Plc.

For the first two, 60% of the equity is privately owned and 40% is state owned, Nuclear Electric is 100% state owned while the NGC is jointly owned by the 12 RECs.

### *Role of NGC*

The NGC has been given responsibility for: (Source: NGC Annual Report 1989/90)

- " The operation, maintenance and development of the high-voltage transmission system in England and Wales.

Making the transmission system available to generators and suppliers to trade

electricity in the new commercial market.

Co-ordinating the operation of major power stations in accordance with a merit order based on bid prices submitted by generators. "

The NGC should not be seen as a state or even para-statal organisation. It is a commercial organisation but closely regulated by the Electricity Act, the Draft Transmission Licence and Draft Articles of Association.

It is a worthwhile endeavour to examine the modalities of the Draft Transmission Licence, the licence governing the responsibilities of the NGC, especially in terms of its relevance to the possible development of a Southern African Grid Company to co-ordinate exchanges in a Southern Africa Power Pool. The NGC Draft Transmission Licence can be defined in terms of the following codes: (Ruff, 1991:23)

- \* Planning Code
- \* Connection Code
- \* Operating Code

The *Planning code* considers the criteria to be applied by NGC in the development of a supergrid system. It stipulates the data requirements vis-à-vis demand profiles for actual and reactive demand including plant generating parameters and items such as excitation control, governor and protective arrangements.

The *Connection code* ensures a non-discriminatory approach for connection of users to the supergrid system.

The *Operating Code* covers a wide range of issues:

- " Demand forecasts: In the period up to eight weeks ahead, estimates of demand are undertaken by the NGC. Aggregated daily load profiles will be assessed and determined for the whole of England and Wales as the basis for plant scheduling requirements.

Operational planning: The objective of operational planning is to co-ordinate generation and transmission maintenance outage patterns over a 3-5 year time scale in order to ensure adequate generation levels throughout the year.

Operating Margin: Here the idea is to determine the necessary operating plant needed as standby to cover demand estimating errors or unexpected failure of plant.

Demand Control: Load management techniques are centrally co-ordinated to ensure stable operating conditions.

Operational liaison: This code relates to the necessary control room interface arrangements of distributors and generators and grid control.

Safety co-ordination: The need to ensure safety across boundary interfaces at power stations and transmission and distribution locations is of paramount importance.

Contingency Planning: This covers emergency arrangements in the event of major system difficulties. It details the black-start procedures.

National Control: In the event of a defined national emergency following a government notification, NGC has the authority to assume control of the system. "

### *NGC influence on capacity*

With the old CEGB system, the type and level of capacity was determined by system planners who would forecast the system demand and then decide on the type of plant necessary to meet the system demand. The political process also determined to a large degree the type of plant to be used. For example, political influence determined that nuclear energy would be used as a means of generation. The Magnox Reactors, dating back to the 1950's were among the first nuclear power plants. The nuclear stations have never been a commercial success, but have kept generating through political persuasion and through a roughly 9% Fossil Fuel levy. Similarly, the State subsidisation of British Coal and the ban on the use of gas, meant that in the old CEGB, coal-fired thermal power stations were the predominant type of generating station.

With the new regime, the intention is that the end market will dictate the type of generation plant which would be the most economical. It is not intended that the NGC have any influence over what the market would have determined as the optimum type and amount of capacity. Rather, the NGC is responsible for forecasting demand, planning the production and determining the operating margin.

## *Transmission Access and Pricing*

Since the NGC is responsible for co-ordinating the power pool, they have to be paid for the services they provide and also for the use of their transmission grid assets. To this end they have devised certain charges: (Source: Ruff, 1991:23)

### *1. Customer Specific Charges*

Any new generator or supplier wanting to use the grid must pay for the necessary connection equipment, plus a share of any system reinforcement costs made necessary by its connection.

### *2. Site-Specific Entry and Exit Charges*

Each grid user pays an annual capacity charge related to the cost of grid equipment that is required to serve that customer at its specific site. (NGC estimates these costs as £ 1.25/kW for generators and £ 4/kW for off-takers.)

### *3. System Service Charges*

Each supplier pays an annual charge (in 1991 it was £3.37/kW ) to cover the cost of a hypothetical "skeletal" grid that would provide the stability and voltage control that all suppliers would need even if they did not use the grid to transport energy from distant generators.

### *4. Zonal Infrastructure Charges*

Each grid user pays an annual capacity and an annual energy charge. These charges are zone dependent but are unrelated to any generator/supplier contracts. There are 11 zones in total. In the South where there is a deficit of generation relative to load, there is no infrastructure charge payable by the generators. This is not the case in the North and charges are levied on generators here. Suppliers in the North and South pay different capacity charges.

## 5. *Transmission Losses and Out-of-Merit Running Costs*

The costs of electrical losses and of running plants "out-of-merit" because of transmission constraints are recovered through the "uplift" charges in the half-hour in which they occur. These charges will be explained in more detail later in this chapter.

### 5.4.2 The creation of market-based electricity trade

Having discussed some of the details pertaining to the restructuring of the generation, transmission and distribution sectors, it is necessary to focus on the creation of market-based electricity trade. As the restructuring progressed, the ideas on the electricity trading market evolved from the initial idea of separate Distributor and Generator Pools, to the idea of a unified single distribution and generation pool. This section explains the operation of the Unified Pool as it is currently used.

The "U-Pool" consists of three parts: (Source: Power in Europe Issue No 58, 1989)

1. An "energy pool" in which power will be bought and sold at a market clearing price, based on offers made half-hourly by the generators.
2. A "Capacity market" allowing for:
  - 2.1 Long-term contracts for power.
  - 2.2 A regulated insurance market enabling small independent generators to buy back-up at reasonable prices.
  - 2.3 Regulated spot-trading of capacity.
3. A registry which will administer and record all transactions.

On 1 April 1990, after having debated and resolved counter proposals from the generators and Area Boards, NGC began to release daily prices for its pooling and settlements system. The prices were published in the *Daily Telegraph* (they are now published in the *Financial Times*) and contain a table of pool prices on the day of publication and final prices for trading on days previously. The value of these pool prices is calculated *ex ante* based on Notional Dispatch. This process is explained as follows: (Ruff, 1991:31)

## *Notional Ex Ante Pool Prices*

Each day the NGC determines the pool prices for the following day, on the basis of generator offer prices and a notional unconstrained schedule of generator operation<sup>13</sup>. The half-hourly pool price depends on the system marginal price (SMP), a calculated loss-of-load probability (LOLP) and an administratively set, value of lost load (VLL)

### *1. Generator Offer Prices*

Each day, each generating unit notifies NGC of the capacity it expects to have available for each half-hour of the following day and the energy prices (p/kWh) at which that station will generate. The generators also notify NGC of the prices at which they will provide various ancillary services such as spinning reserve and reactive power.

### *2. Unconstrained or Notional Dispatch*

NGC determines an "unconstrained" schedule and dispatch, indicating which units would, in the absence of any transmission constraints, be scheduled to run in order to minimise system costs. The offer prices and the unconstrained schedule have no purpose other than to compute pool prices for each half-hour.

### *3. Energy Price*

The system marginal price (SMP) for each half-hour is conceptually the energy offer price of the highest-running-cost plant operating in that half-hour. In practice calculating the system marginal price is much more complex because of plant start-up costs and plant dynamics. Each generator, whatever its offer price, is paid SMP for the energy it is scheduled to generate in the unconstrained dispatch.

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<sup>13</sup>

In this context a "notional unconstrained schedule of generator operation" describes a hypothetically calculated generation operation schedule in which system constraints on the operation of different power stations have been ignored. The purpose of the "notional unconstrained schedule" is to calculate an operational merit order of the different power stations, based purely on the financial cost of operating those stations.

#### 4. *Loss-of-Load Probability*

Generator declarations of plant availability and NGC's forecast of load are used in a probabilistic model to compute a LOLP for each half-hour of the following day. In the context used by NGC, LOLP is defined as a conditional probability, given today's forecasts, that voltage will have to be reduced in a specific half-hour tomorrow because of insufficient generating capacity. Since there is currently an excess of generating capacity in the UK system the day-ahead LOLP is essentially zero.

#### 5. *Value of Lost Load*

Failure to meet load because of a capacity-related voltage reduction is deemed to impose on customers a gross cost-per-kWh-lost called the Value of Lost Load (VLL). The concept of this cost is clear, however the calculation of a value is highly debatable since the value of lost load will vary widely depending on the particular industry that has lost its supply. The NGC has adopted a value of £2/kWh, a figure which had previously been used by the CEBG and which they advance as being broadly in agreement with various studies of consumer attitudes.

#### 6. *Ex Ante Half-Hourly Capacity Value*

Each kW of generating capacity that is declared available for a specific half-hour of the following day, and then *is* available for that half-hour, is paid an amount representing the *ex ante* value of that capacity. This is over and above the value of any energy it may produce. The value of the capacity payment is:

**LOLP\*(VLL - SMP)** for plant that is notionally dispatched

**LOLP\*(VLL - Bid Price)** for plant that is not notionally dispatched

#### 7. *Pool Input Price (PIP)*

The half-hourly SMP's and capacity payments to dispatched plants are combined into a half-hourly Pool Input Price (PIP) in £/kWh as:

$$\text{PIP} = \text{SMP} + \text{LOLP}(\text{VLL} - \text{SMP})$$

PIP is the amount paid by the pool for each kWh actually generated, whatever the generators bid price. However, capacity available but not run in the unconstrained dispatch is also paid a capacity value equal to  $\text{LOLP} * (\text{VLL} - \text{Bid Price})$ . The PIP can then be defined in terms of SMP for all energy produced and a capacity price related to system LOLP, the value of lost load and the SMP.

### *Final Ex Post Pool Prices*

The discussion thus far has explained the determination of the pool prices. In fact the circumstances forecast in the *ex-ante* approach might not eventuate and hence adjustments have to be made *ex-post* to compensate generators for any costs or lost profits resulting from divergence between the forecast and the reality. The steps in this process are explained as follows:

#### *1. Actual Dispatch*

NGC determines an actual dispatch reflecting transmission constraints and using the same generator bids used in the notional unconstrained dispatch.

#### *2. Out-of-Merit Running*

In the actual dispatch, NGC instructs plants to operate differently from the day-ahead, *ex-ante*, unconstrained dispatch, because of either transmission constraints or last-minute changes in system conditions. Generators are required by the pool to take instructions without further negotiation, but are compensated at their individual offer prices for divergences from the unconstrained dispatch. An example of out-of-merit running is the use of PowerGen's Fawley oil-fired plant. Fawley, is a 2000 MW oil-fired plant which does not get onto the notional unconstrained schedule on the basis that it is not competitive, economically, with other available plant. However, Fawley is needed to stabilise the southern transmission grid, and hence is required to generate at a time when more cost-

effective plant is available. Since Fawley runs "out-of-merit" PowerGen receive the full offer price for power generated by Fawley.

### *3. Ancillary Service*

During the actual dispatch, NGC calls upon generators to provide certain ancillary services such as spinning reserve or reactive power. Because the market in these ancillary services may be quite uncompetitive, NGC pays each generator what it bids, but generators have a licence obligation to bid prices for these services at a "reasonable" level.

### *4. Pool Output Price (POP)*

A Pool Output Price is calculated for each half-hour as the Pool Input Price (PIP) plus an uplift. The uplift is the sum, for that half-hour, of all payments NGC makes for available but *undispatched capacity, ancillary services, out of merit running and transmission losses*, all divided by the total kWh sold in that half-hour. All energy taken from the pool at bulk supply points is paid for at the pool output price.

### *5. Ex Post correction of the Ex Ante Pool Prices*

For the reasons explained earlier the ex-ante calculations of the pool prices may not be accurate. Ex post adjustments are made and final payments are made on the basis of the adjusted prices.

This section has attempted to explain the various mechanisms which have been created to stimulate market-based trade of electricity in the supply-side of the industry. In practice however, the heated debate surrounding the alleged collusion of National Power and PowerGen to control the market is evidence that the proposed structure has not exactly worked as intended. This debate is not entered into here, but is instead covered in later in this chapter.

## **5.5 The development of Generator/Supplier/Customer Contracts**

One of the principal strengths of the U.K system is the apparent extent of contractual freedom for the various participants in the industry. Generators, RECs, customers, power

merchants and brokers, even entities with no connection to the pool and totally outside the industry have freedom to enter into any kind of short or long term contract they desire. The secondary contracts market acts as a market for these participants to insure against Pool transactions. During the first year of pool operation, some 95% of all electricity sold was covered by some form of contract (Littlechild, 1991).

In theory, the pool price is directly related to the balance between supply and demand. In practice, barriers to entry and duopolistic collusion will conspire against the absolute functioning of an absolutely free market. Nevertheless it can be asserted that the pool price comes close to a free-market determined balance between the *bids* of a group of buyers and the *offers* of a group of sellers. By virtue of the stochastic nature of electricity supply and demand, this price will be volatile. It is thus natural for the pool to develop a financial tool whereby participants can minimise their exposure to risk. The risk is the considerable uncertainty as to how the pool will perform and what the average pool price will be. The solution to insure against this risk is a series of contracts which would have the effect of fixing the price of electricity independently of the prevailing pool price. These contracts are known as "**contracts for differences**".

All energy contracts are concluded with the Pool in the first instance. Contracts for differences and other insurance tools are not part of the power pool managed by the NGC. In the Pool, Generators are credited at Pool Input Price for energy delivered to the Pool. Suppliers (distributors) and direct customers are debited at Pool Output Price for energy taken from the Pool. Contracts for differences based on the Pool Price are then written to insure the initial Pool contracts. These contracts can work in two ways:

1. Before the electricity is purchased, a consumer, C, contracts to buy firm energy from a generator, G, at a specified, predetermined price, P. After the contracted-for electricity has been delivered, G is paid by the pool at the agreed pool price and hence the only payment between C and G directly is the difference between the actual Pool Price and the price, P, the agreed contract price.
2. C can pay G a fixed annual option fee, in exchange for which C has the

option of buying energy from G at price P. C will only call the contract when the Pool Price exceeds P. G will then meet the call by paying the difference between the Pool Price and P.

Eighty-five percent of National Power and PowerGen's output - which is sold to the RECs is covered by contracts for differences. In 1992, the contracts were negotiated at a pool price of over 3 p/kWh. For the time that these contracts existed, National Power and PowerGen were therefore secure against pool prices being less than this. It is interesting to note that in the second year of the pool's existence there was a reduced number of contracts for differences and coincidentally the pool price began to rise.

A further development in the financial derivatives market is pool price futures, scheduled to be run on the London Futures and Options Exchange(FOX). In this market, investors and speculators can take any positions that they choose. In essence, it should not be any different to a Gold Futures market. The launch of an Electricity Futures market has been scheduled for mid 1993, not long before the three-year contracts for differences between generators and RECs will expire.

## **5.6 A Discussion on the restructure and the development of the Power Pool**

Roughly 18 months after the White Paper was tabled in the House of Commons, electricity supply and distribution in England and Wales had largely been transformed from a public service industry to a commodity industry. The process had been achieved through privatising much of the industry and then creating a framework within which competition between the privatised participants in the industry could be achieved. The resulting system is far from being a definitive competitive industry. However, it is much closer to a system in which the utilisation of resources is determined by competitive forces in a free market, than it is to a system in which the allocation of resources is determined through centralist technocratic planning.

### *Politics as the driving force*

Much of the zeal in creating a liberated ESI in the UK was the result of Thatcher's penchant for "rolling back the frontiers of the state". The Labour Party was naturally firmly opposed

to releasing the ESI to the private sector since it was a Labour government which had determined the structure of the CEGB and the Area Boards 40 years earlier. It is interesting to note that, at the time, the Labour Party expressed the intention to re-nationalise the industry should they win the 1992 General Election. The privatisation and resultant power pool should thus be seen in the context of the political developments in England at this time.

### *The Pool Model*

It is not the intention of this chapter to enter into a discourse on general pool theory, however it is necessary to provide some insight into the reasons for a central pool.

The motivation for a central electricity pool is not immediately obvious. If the intention with the UK restructuring was to create competition, it is not immediately obvious why the industry could not simply have been deregulated altogether, and hence bilateral power exchanges between the generators and the distributors would have been the *modus operandi* of the ESI?

To illustrate why a central market is required consider the following example: A generator, G, enters into an agreement with a customer, C. C pays G a fixed annual payment to take all of G's power. G and C are both getting what they are contracted for, but the system will not be operating efficiently because the nature of electricity supply and demand means that there will be times when other generators could generate more cheaply than G. Economic efficiency would require G to shut down during these times and purchase power from the other (more economical) generators in order to satisfy its contract with C. This reality points to the need for some kind of central market where buyers and sellers can meet to trade and in so doing, determine a price which will balance system supply and aggregate customer demand. Hence the development of a Power Pool which collects decentralised offers to buy and sell and determines market clearing prices and quantities.

### *Compromise*

The 1988 White Paper explained that the fundamental objective of the restructuring of the ESI was to create a competitive, privately owned industry. It did not attempt to detail how

this process should be achieved, these modalities were left largely to the specialists in the ESI. Hence the privatisation has been described as a process "whereby the ESI was thrown in the air and told to sort itself out before it reached the ground" (Ruff, 1991:2). In fact for the 18 months the ESI spent in the air, it became clear that it would not reach the ground in satisfactory condition without a significant amount of compromise.

One of the first areas to be compromised was the Nuclear power sector. Prime Minister Thatcher and Secretary of State for Energy, Cecil Parkinson, had been strong proponents of nuclear generation and were convinced that the private sector would be able to manage these resources more industriously than the public sector. The intention was therefore to split the CEGB into two separate companies, the larger of which would be responsible for all nuclear plant. As explained in detail earlier, it became clear that it would be impossible to privatise the nuclear plant. Hence the decision was that the nuclear plant would not be incorporated into the private sector, but that it should rather be controlled by a public limited company of which the State was the sole shareholder. Nuclear plant was to be dispatched as base-load plant with the highest priority in the generation schedule. Since the privatisation the nuclear sector has in fact recorded its highest output yet. It is clear therefore that the failure to privatise the nuclear sector ensured its survival but at the expense of true competition in generation.

Another area in which there has been compromise is the limitation of the non-franchise sector (the franchise sector being those customers who are forced to buy electricity from their local REC). Part of the reason for this compromise is explained by fixed coal contracts between British Coal and National Power and PowerGen from 1990 and terminating in 1993. Largely because British Coal prices are uncompetitive with international coal prices, the fixed contracts have placed National Power and PowerGen at a competitive disadvantage compared with other generators who would be free to buy coal on the world market. Hence the contract price of electricity to the RECs was set at a level above the forecast pool price in order to recover the necessary funds to subsidise British Coal. The RECs were allowed to pass this cost on to their customers but, as a *quid pro quo*, the RECs were given a monopoly on sites with maximum demands of less than 1 MW, at least until the termination of the coal contracts. In addition RECs are prohibited from owning generation with capacity exceeding 15% of their 1989 maximum demands, and National Power and PowerGen jointly are prohibited from contracting to supply more than 15% of the load in any RECs area of supply. As explained in detail later, in April 1994, it

is proposed that the monopoly will be limited to customers with maximum demands below 0.1 MW, in April 1998, it is proposed that the franchise market should dissolve altogether.

The current compromises are seen as necessary steps in the evolution to a truly competitive industry.

## **5.7 Price regulation in the generation industry**

The focus of the chapter thus far has been on describing the restructuring process and some of the mechanisms which were developed in the restructured industry. The focus is now turns to analysing the mechanisms, equations and structures used to regulate the price of electricity produced by the generating companies.

### *Price regulation in generation*

Thus far, the analysis of the unbundling of the generation sector and the creation of a competitive market in generation has detailed the mechanisms used to price electricity in the "competitive" industry. At the least the pool pricing mechanism can be described as complex. The principal source of the complexity is that the pricing mechanism attempts to set the laws of supply and demand as the basis to the quantity and price of generated electricity. In practice this objective is complicated by the fact that electricity generation, has a whole set of technical dynamics such as voltage, frequency, load flows and power flows which at times act counter to the requirements for least cost production. In the UK the problem is complicated further by the fact that electricity generated from nuclear plant is not subject to the same rules as electricity generated from other plant.

In this section, the issue of the regulation of the price of electricity purchased from generators, by the Pool, will be analysed in more detail. The section begins with an analysis of the problem of having two dominant generators who together share control of most of the market. The analysis then moves to a discussion of the basis of pool price regulation by the Office of the Electricity Regulator (OFFER). Then the components of the Pool Selling Price i.e. System Marginal Price, Uplift and Capacity payments, will be discussed.

*National Power and PowerGen: Allegations of collusion*

Earlier in this chapter the developments leading to the creation of only two generating companies to assume the non-nuclear power stations of the CEGB, was discussed. National Power and PowerGen together currently control about 70% of the generating capacity in the UK. They have been accused by different parties at different times of colluding to drive the pool prices too low and also of colluding to drive the pool prices too high.

In the first case - pool prices too low - PowerGen and National Power have been accused of exploiting contracts for differences to keep the pool price low and in so doing excluding Independent Power Producers. Since more than 95% of pool trade in the first year was covered by Contracts for Differences, it was argued<sup>14</sup> that it was possible for National Power and PowerGen to offer plant at below operating cost and still recover the required revenue through Contracts for Differences. Substantiating this view is the fact that the average Pool Price during the first year was 1.7 p/kWh when Contracts for Differences had pitched the Pool Price at around 3 p/kWh. By keeping the Pool Price low, Independent Power Producers would be faced with a significant barrier in trying to secure investment capital for new plant and hence further entrenching the position of the two dominant generators. However, Professor Littlechild, the Director General of Electricity Supply, dismissed these arguments and expressed the opinion that the low pool prices were to be expected during the settling-down period (Power in Europe Issue No 79, 1990).

In the second case, National Power and PowerGen have been accused of driving the pool prices too high - the average pool prices in April-September 1991 were 29% higher than in the same period in 1990 (Power in Europe Issue No 115, 1992). In total, the Pool Selling Price (PSP) rose from 1.84 p/kWh in the 1991 financial year to 2.42 p/kWh in the 1993 financial year. The potential for National Power and PowerGen to collude in anti-competitive behaviour has always been recognised and for this reason Professor Littlechild recommended at the start of 1992 that new licence conditions be placed on National Power and PowerGen to oblige them to publish information on plant availability and to establish arrangements for ascertaining whether others would be willing to buy stations which they were planning to close.

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<sup>14</sup> This argument was put forward in July 1990, four months after the pool was in operation, by David Porter of the Association of Independent Electricity Producers.

In July 1993, at the time of the fourth OFFER inquiry into significant price increases in the pool, Professor Littlechild, the Director General of Electricity Supply in OFFER released a press statement saying that:

"In a competitive market, customers' interests are paramount. This is not the case in the electricity market. Further steps need to be taken to ensure that customers do come first" (Littlechild, 1993(a)).

The increases in the pool price were mainly attributable to increases in the bid prices of National Power. However, PowerGen's bidding policy also influenced the process. This evidence has led to concern at the perceived ability of the major generators to raise the prices at will, on account of their market power. Should the pricing developments of the major generators prove to be a case of duopolistic collusion, OFFER may refer the major generators or the structure of the generation market to the Monopolies and Merger Commission. However, there is another twist to this whole debate contained in the fact that 40% of the equity in National Power and PowerGen is still owned by the government, who are eager to realise their investment at the earliest opportunity. A referral to the Monopolies and Mergers Commission will significantly harm the government's ability to realise an acceptable return on their investment and hence there is obviously a certain amount of government pressure on OFFER not to institute a referral. To what extent this pressure will force OFFER's hand is yet to be seen. Evidence so far would seem to indicate that OFFER has maintained its independence.

### *Pool Price regulation by OFFER*

If there was a single yard-stick against which OFFER judged the revenues which generating companies obtained from the Pool, it would be the generator's avoided costs.<sup>15</sup> In the 1992 Review of Pool Prices, Professor Littlechild concluded that the average avoidable costs of the two major generators were above their average revenues from the pool in 1991/1992. On that basis he concluded that it was difficult to object to an increase in bid prices from the level obtaining in 1991/1992. However, in 1992/1993 the revenues from the pool exceeded the avoidable costs of the two major generators. (Littlechild,

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<sup>15</sup> Avoided costs are all those tangible costs which a supplier could avoid if it did not produce any output.  
production.

1993(a)) For this reason, Professor Littlechild argued that any further price increase was not justified.

However, explaining OFFER's method of price regulation as a matter of controlling generation costs through control over avoidable costs, does not do justice to the complexity of the price regulation process. To analyse the process it is necessary to analyse the various components of the Pool Selling Price i.e. System Marginal Price, Capacity and Uplift.

### *Pool Selling Price*

Earlier in this chapter, the Pool Selling Price (PSP) or Pool Output Price (POP) was described as the sum of the Pool Input Price (PIP) plus Uplift. PIP was further described as the sum of System Marginal Price (SMP) plus Capacity payments. Hence increases in POP may be due to increases in SMP, Capacity or Uplift. Table 2 below, describes the trend in these pool price components over the last three years: (Source: Littlechild, 1993(a):8)

Pool price components	1990-1991	1991-1992	1992-1993	Apr to Jun 92	Jan to Mar 93	Apr to Jun 93
SMP	1.74	1.95	2.26	2.14	2.26	2.61
CAPACITY	0.01	0.13	0.02	0	0.01	0.01
UPLIFT	0.09	0.16	0.14	0.12	0.13	0.27
PSP	1.84	2.24	2.42	2.26	2.4	2.89

**Table 2. Pool Selling Price**

### *SMP*

According to OFFER, SMP was lower than the avoidable costs of the generators for 1990-1992, but since the start of 1993, the converse was true. The increase in SMP in April 1993 compared to March 1993, coincided with a 10% fall in average demand. All of this increase has come from increased bids by National Power and PowerGen. To understand the reason for the changing SMP it is necessary to understand the pricing policy of the major generators.

National Power says that the objective of their bidding strategy is to ensure that the prices it achieves for its products cover at least the cash costs of each of its generating assets and also provide a reasonable return to shareholders (Littlechild, 1993(a):77). Bids are based on a supply curve and as such there is a trade-off between price and volume.

A System Marginal Price lower than avoidable cost for 1990-1992 was, in National Power's view, a consequence of the coal contracts put in place at Vesting. These contracts stipulated that National Power and PowerGen consume a specified amount of British Coal. However, as a consequence of low market demand and high nuclear output, bid prices during this period were forced down in order not to risk market share and a consequential increase in coal stocks. Furthermore, in parallel with the over-contracting of British Coal, National Power found itself fully contracted in their contracts with RECs and direct customers. This meant that in the short term the net effect of higher pool prices on operating profit was small. This in turn reinforced their reluctance to risk market share in pursuit of higher prices.

In the period following 1 April 1993, at the termination of the coal contracts, National Power considerably increased their bids from between 0.25 p/kWh and 0.5 p/kWh. It is interesting to note that this led to a loss of market share of 7.3%. This was a strategic decision - now that they had freedom to choose how much coal they wanted to buy and whom they wanted to buy it from, they were able to sell less power, obviously (as the figures indicate) with the goal of producing higher profits on lower volume.

PowerGen's pricing policy is different to that of National Power. PowerGen aim to compete in the contract market with the aim of fully contracting its (PowerGen's) forecast output. In the short-term however, PowerGen aim to maximise uncontracted sales through the pool when Pool prices allow. In the longer term National Power seek Pool prices which result in an effective realised price sufficient to remunerate capital and sustain required investment. PowerGen base their bidding strategy on their average avoidable costs. Accordingly, PowerGen based their bids on an annual average SMP of 2.4 p/kWh for 1993. For April 1993, the average SMP corresponding to this price parameter was about 2.45 p/kWh and hence PowerGen increased the prices of its base-load and mid-merit plant in the first quarter of 1993 by 0.05 and 0.15 p/kWh respectively. It is interesting to compare these increases with the increases in National Power of 0.25 p/kWh and 0.5 p/kWh for the same category of customer. The relatively smaller increase in PowerGen's

prices compared to National Power's prices for the period April 1993 to June 1993, resulted in PowerGen marginally gaining market share during this period.

### *Capacity*

Payments for capacity are defined as payments for generating capacity [MWs] that are declared available on a day-ahead production schedule, and then which actually are used. This payment is described by the following formula:

Loss of Load Probability\*(Value of lost load - System Marginal Price).

As indicated in Table 1, these payments have not increased and furthermore they are really insignificantly small.

### *Uplift*

As explained earlier, Uplift is made up of payments for undispached capacity, ancilliary services, out-of-merit running and transmission losses. Of these, the most significant are the payments in respect of undispached capacity. Under the present Pool rules, generators are compensated if plant which would otherwise have been chosen to run is "constrained off" the system. They are paid the difference between SMP and their bid price. PowerGen have said that "constraining off" has had only a limited effect on the output of its plant and on its pool revenues. It did not apply any separate policy when determining the offer prices of plant which might be constrained off. National Power said that it did not seek to gain or lose from constraining off, but that it typically reduced its bid price for any constrained-off plant to the short run avoidable cost of that plant, in order not to benefit or suffer from being constrained off (Littlechild, 1993(a)).

However despite these policies, constrained-off payments reached £40 million in the quarter from April to June 1993. Professor Littlechild expressed the opinion that in view of the high and increasing cost of constrained-off payments, the Pool should consider whether, or under what circumstances and to what extent, it is appropriate to continue making such payments (Littlechild, 1993(a):68).

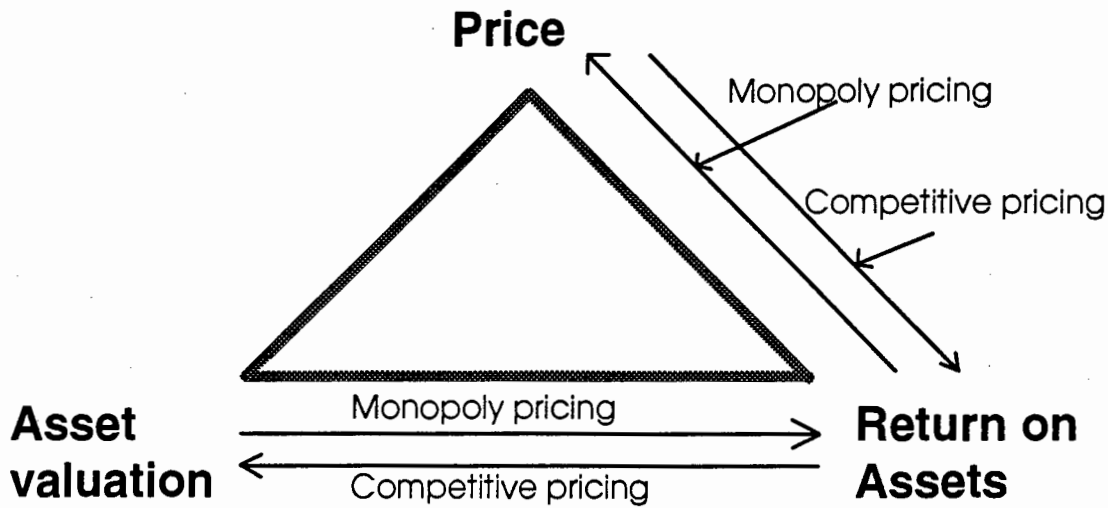
## 5.8 Price regulation in the distribution industry

Having examined the method of price regulation on the generation side of the industry, it is appropriate to examine the price regulatory structure on the distribution side of the industry. The focus of this section is on the regulatory practices in respect of price control in the distribution side of the industry. The section begins with a discussion of a price setting paradigm to explain the difference in *price making* in a monopolistic industry and *price taking* in a competitive industry. The focus then narrows to a breakdown of the costs of serving different types of customers. Finally, the actual price control practices in the distribution and supply businesses will be discussed.

### 5.8.1 Competition: From regulation of profits to regulation of prices

In the UK, if there is one central theme of pricing in the distribution sector, consistent with the restructuring of the generation and transmission sides of the business, it is the conviction that competition should be the prime determinant of the allocation of resources. In the regulation of pricing in the distribution industry, this belief has resulted in a shift in the focus from regulation of profits to regulation of prices. In the UK industry it is believed that in the case of true competition there is no need to regulate the price, since the market determines the quantity and price of goods to be delivered in terms of the balance between supply and demand. Where true competition does not exist, but where the benefits of competition are still sought, it is necessary to set a price as if the market had determined that price.

Diagram 1 below illustrates a paradigm to explain the difference between price making in a monopoly industry and price taking in a competitive industry.



**Diagram 1. A price setting paradigm**

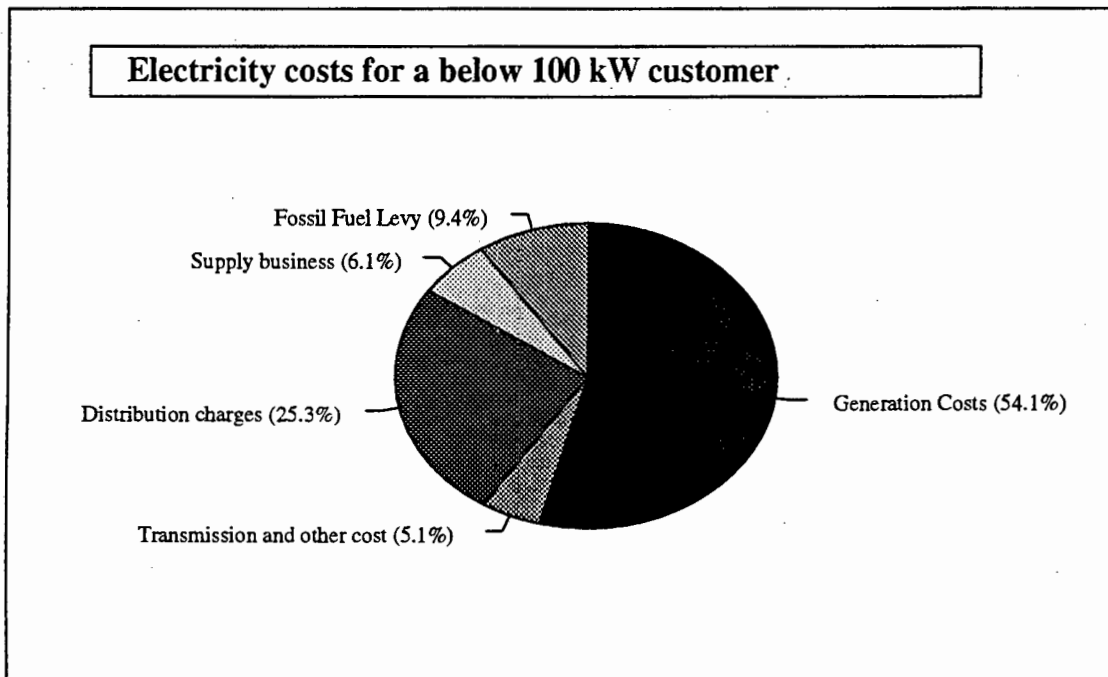
In a monopoly industry, the starting point in determining the price level is the valuation of fixed assets which are used to produce the product which is then sold and generates income. The assets may be valued in a number of ways for example, at historic cost, at historic cost less accumulated depreciation, at current cost or at replacement value. The next step in determining prices in a monopolist industry is to specify the rate of return which must be earned on the assets. A specified Return on Assets is then calculated, and this results in a required price level. In restructuring the UK distribution industry the aim was to reverse this process through allowing the market to determine the price level and the market value of a particular distributor would then be established as the value of future profits discounted to the present by an appropriate rate of return required to cover risk and opportunity costs.

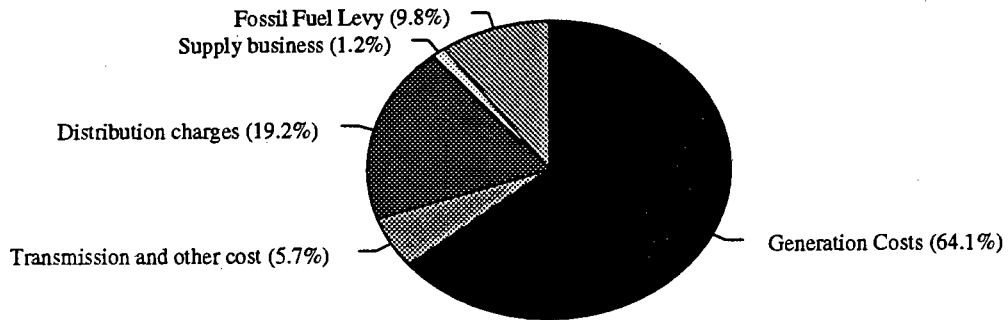
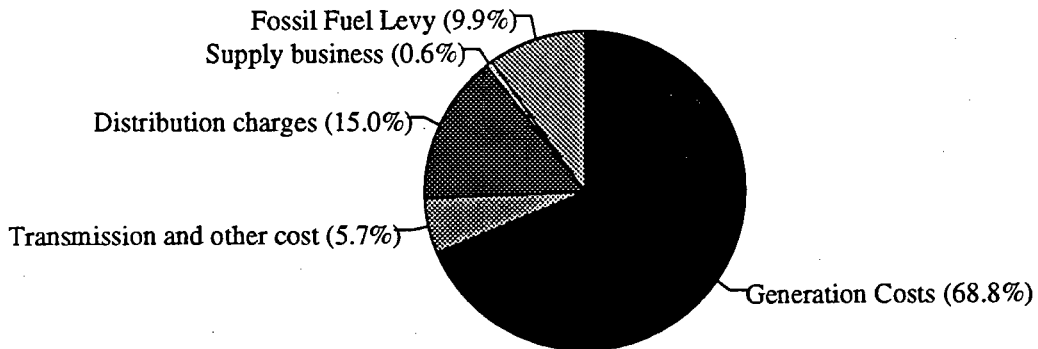
Essentially the method of price regulation in the franchise market of the distribution industry, until 1998, is an attempt to fabricate this process by setting maximum prices which RECs may charge for the "supply" and "distribution" services which they provide. The profit which individual distributors may earn is the difference between the revenue derived through their regulated prices, and their total distribution costs. There is thus an incentive for distributors to minimise costs and optimise operations in order to maximise profits.

It is a combination of the price regulatory structure and the force of private capital seeking to maximise its returns, which has led to tremendous cost consciousness amongst the Regional Electricity Companies.

### 5.8.2 Cost of supply analysis

Most of the 22 million electricity customers in England and Wales buy electricity from the REC in whose area they live (Littlechild, 1993(b):3). Only customers taking above 1 MW are presently free to choose their supplier. In a press release in October 1993, OFFER disclosed that one third of customers in the present competitive market (above 1 MW) now use a second tier supplier. This accounts for more than half the electricity supplied in the market. (Littlechild 1993(c)) This clearly indicates that some RECs have been able to control costs better than others and hence out-compete their fellow RECs for non-franchise customers. To introduce the subject of cost analysis, the following pie charts indicate the respective amounts of the different costs involved in selling electricity to customers of varying sizes (Source: Littlechild, 1993(d):4)



**Cost breakdown for a 100 kW to 1 MW customer****Cost Breakdown for an above 1 MW customer**

As indicated in the above charts, the final price of electricity to customers comprises the cost of electricity purchased from generators, transmission charges, distribution charges, the supply business margin, and a Fossil Fuel Levy (plus VAT). The price regulatory structure in respect of generation and transmission, has already been discussed. The discussion will now focus on price regulation in the supply and distribution businesses.

The supply business, in particular, includes the following activities:

- arranging for the purchase of generation capacity and use of system facilities;
- sending out bills and collecting payment;
- providing service to customers (for example, advice on tariffs, on how to use electricity efficiently and on special services); and
- advertising & marketing

To facilitate competition in supply, each of the RECs is required under its licence to allow other suppliers to use the wires taking electricity from the Grid to its customers' premises. The RECs charge other distributors for the use of the "wires" (distribution and reticulation network) which they own, and they have to charge their own customers the same amount (the "use of system" charge). This part of the companies business is known as the "wires" business or "distribution" business. The next section is concerned with the method of regulating prices in the supply and distribution businesses.

### 5.8.3 Price regulation in the supply business

The objective of the supply price control is to limit the price which a REC may charge in respect of providing the "supply business" services as defined in the previous paragraph. The essence of the regulation is the RPI-X formula. At present (1993) the RECs are allowed to earn revenue for these services based on the number of kilowatt hours supplied. In the price control proposed for 1994, the revenue that RECs may derive for supply services is made up of a fixed allowance (different RECs have different fixed allowances), plus a pence per kWh charge, plus charges in relation to the number of customers connected.

The present (1993) price control governs the prices charged to customers in the competitive market as well as customers in the monopoly "franchise" market. The supply revenue control proposed for April 1994 until April 1998 is that the RPI-X price regulation is only valid for the franchise customers. The non-franchise customers, it is argued, are protected by competition. This has been supported by most of the RECs who have argued that the present all-embracing scope of the price control limits their participation in the competitive market and puts them at a disadvantage compared to their competitors (such as the major generators) who do not have such controls (Littlechild, 1993(b):10). Their argument is that if the costs of purchasing electricity for the competitive market turn out to be higher than expected when signing contracts with customers, they are unable to pass on these higher costs in the competitive market. In contrast, if the costs turn out to be lower, they are unable to keep the difference because the price control requires cost reductions to be passed on to customers.

Professor Littlechild further argues that lifting the price control will also improve the protection for the remaining franchise customers. It will do so by reducing the scope for RECs to cut prices to non-franchise customers at the expense of franchise customers. It will thereby facilitate enforcement of the licence conditions which prohibit price discrimination and cross-subsidy (Littlechild, 1993(c): ii).

The proposed supply regulation is a price control on total revenue in which there is a basic constant term plus an allowance per customer served, plus an allowance per kilowatt hour sold. The last two allowances will be uniform across all RECs. The constant term will vary slightly amongst the RECs in order to reflect the higher costs incurred in serving a

particular customer base, or operating in certain areas. An example of this is London Electricity who put the case to OFFER that certain additional costs of operating in London should be recognised.

The allowance per customer served reflects the differing economies of scale among the different sized RECs. The size of the economies of scale achievable by any REC are obviously dependent on the size of that REC. Since this was determined at Vesting day and since competition will not exist in the franchise market until 1998 it is necessary that the regulatory mechanism take account of these unavoidable differences. Finally, the allowance per kilowatt hour sold is in respect of all costs that are directly proportional to the unit sales.

#### 5.8.4 Price regulation in the distribution business

The 12 RECs in England and Wales, own and operate the lower voltage distribution systems for taking electricity from transmission systems to customers' premises. The distribution price controls are set out in the companies' licenses as public electricity suppliers (PESs). The controls vary from one company to another, ranging from Retail Price Index (RPI) -0.5 to RPI + 2.5. The controls last for five years, until March 1995.

The distribution business has so far proved to be the most lucrative part of the whole industry as Table 3 below shows: (Littlechild, 1993d:6)

Activity	Turnover(£)	CCA Operating profit (£)
Distribution	3209	1042
Supply	12472	154
Generation	7	(8)
Other & Intra-group transactions	(2017)	(53)
Group	13626	1135

**Table 3. Aggregate company accounts for 1992/1993**

There has been some public criticism of the level of profits reported by the RECs. The criticism is levelled at the method of regulation i.e. through the price and not directly through the profits. In this regard it is interesting to note that the controls operating in the regulation of all privatised utilities in the UK are *price* controls. Price control is preferred

to profit control because it gives an incentive to cut costs and achieve efficiency savings during the course of the control, since any extra profit made by so doing will be retained by the company at least until the next price control review. OFFER have expressed the opinion that distribution prices would probably not have been significantly lower had a profits control been used in place of a price control (Littlechild, 1993(d):35).

### **Present distribution price controls**

Ninety percent of distribution business revenues are accounted for by "use of system" charges and are included in the price controls. Just over 10 per cent of the revenue is accounted for by "excluded services", so called because they are excluded from RPI-X price controls. Companies calculate distribution use of system charges using an approach which allocates system costs between major customer groups on the basis of assessments of the long-run marginal costs of meeting each group's demand for use of the system. This means that users connected at a particular voltage level normally only pay for the use of the system at and above that voltage level.

The distribution price control limits the amount of revenue that the RECs are allowed to earn from the distribution business. The control applies an RPI +/- X limit to income per kilowatt hour distributed to all customers, including those outside of the franchise market, connected to HV and LV sections of the distribution network.

The price control formula is expressed as:

$$M_{dt} = (1 + (RPI + X_d))/100 * P_{dt-1} * A_t$$

Where  $M_{dt}$  is the maximum allowed charge per unit in any one year,

RPI is the Retail Price Index

$X_d$  is the X factor applying to the company's distribution business

$P_{dt-1}$  is a base price, and

$A_t$  is a term related to losses.

Each of these terms are explained below:

### **X<sub>d</sub>**

The  $X_d$  term was set by the government when the RECs were formed. Table 4 below shows the  $X_d$  factors for each company (Littlechild 1993(d):12).

Company	$X_d$	Company	$X_d$
Eastern	0.25	East Midlands	1.25
London	0	Manweb	2.5
Midlands	1.15	Northern	1.55
Norweb	1.4	Seeboard	0.75
Southern	0.65	Swalec	2.5
South Western	2.25	Yorkshire	1.3

**Table 4.  $X_d$  values**

At the time it was proposed that positive  $X_d$  factors be used to allow the companies to finance major investment programmes to refurbish their distribution systems. It is clear from reference to Table 3, that the RECs have made very substantial profits with the price regulation established at the time of privatisation.

### $P_{dt-1}$

The base price term  $P_{dt-1}$  is made up of a weighted basket of four component prices. The weights and the component prices differ between the companies depending on their mix of customers connected to the distribution system. The four component elements are:

- LV1, units sold to customers connected at LV at a higher day or peak time price;
- LV2, units sold to customers connected at LV at a lower night or off-peak price;
- LV3, all other units sold to customers connected at LV;
- HV, all units sold to customers connected at high voltage HV.

**Part 2:       The applicability of a UK-style restructuring to the South African electricity supply and distribution industry.**

**5.9     Introduction**

The object of this thesis is to produce some ideas on a pricing strategy for the electricity industry in South Africa. The study of the restructuring of the UK ESI is essentially a study of pricing. However, of necessity, the work has covered a somewhat wider area. The major socio-political and economic differences between the UK and South Africa means that blindly attempting to translate the intricate and highly sophisticated UK system to the South African industry is certainly destined to fail. The focus of this section is rather to draw out some of the key positive attributes of the UK restructure and from there to discuss the application of some of these attributes to the South African industry.

**5.10   Private ownership versus competition**

It is important to distinguish the principle of private ownership from the principle of competition. The essence of the re-organisation of the UK industry was that it aimed at restructuring the industry in order to create competition. Privatisation was seen as a means of lessening the State's investment in the industry while at the same time aiding the process of creating competition. In the White Paper introducing the restructuring, the then Prime Minister Margaret Thatcher was at pains to point out that the focus of the restructure was to create competition in the industry. Private ownership was never seen as an end in itself, but rather as a factor which would enhance competition.

In South Africa at present, the most commonly held view is against private ownership of the electricity industry. It would seem clear that the majority opinion is that there should be a decrease of private ownership. Judgement on whether this is right or wrong will not be passed here. It is clear though, that certainly in terms of ownership it is simply not realistic to expect that any of the UK ideas can find application in South Africa at present.

However, it is entirely realistic to argue that it is possible to create competition inside an industry in which the State alone owns the equity. Indeed the assumption used in this thesis

in applying the lessons of the UK restructuring to South Africa, is that there is only one "owner" of the industry.

### **5.11 Positive principles arising out of the UK electricity industry restructure**

In this thesis it is asserted that competition is a most important ingredient in the operation of an electricity industry. Competition should be enshrined in the structure and expressed in the pricing mechanisms. In this section, some of the positive characteristics arising from competition will be discussed. Later in this section, possible ways of restructuring the South African electricity industry to achieve some of these positive attributes will be discussed.

The study of the UK restructure reveals that some of the positive attributes, particularly from the perspective of pricing, which the UK industry now displays are as follows:

#### **Transparency**

To ensure equitable and fair competition, a necessary precondition is the availability of information detailing the operations of the various players in the industry. In the UK, this precondition is enforced through the creation of the Office of the Electricity Regulator (OFFER) to which every generator or distributor as well as the National Grid Company is required to submit results. Furthermore, should OFFER require additional information, this must be supplied on request.

#### **Accountability**

By splitting the industry into a number of competing enterprises, each of these organisations are directly accountable to their customers. This is further reinforced through the regulatory structure managed by OFFER. Throughout the industry there is a clear customer/supplier link: generators compete to sell electricity to RECs and also to their own large customers, the National Grid Company is responsible to their owners, the RECs - and the RECs are accountable to their customers. A consequence of this accountability is the positive impact on the administration of the pricing mechanisms, from the generator bid prices, to the administration of the Pool, and the price regulation in respect of the supply and distribution industry.

## **Cost consciousness**

Another major impact of the restructuring is the considerable cost consciousness throughout the industry. This is an obvious consequence of competition as well as the method of regulation - which imposes a direct relationship between profitability and the ability to control costs. The earlier analysis of the various cost components in the generation, transmission and distribution sides of the industry clearly indicate the considerable focus on costing. Perhaps one of the most significant aspects here, is the line drawn between "supply" costs and "use of system" costs in the distribution sector. The focus on costing is once again supported by OFFER who stipulate that there shall be no cross-subsidisation in the industry whatsoever. Enforcing this rule in the various parts of the industry has necessitated an accurate and thorough analysis of costs.

### **5.12 The supply-side: Applying a UK-style restructuring to the SA ESI.**

As explained in detail earlier, the transformation of the supply-side lead to the generating capacity of the Central Electricity Generating Board being split between National Power, PowerGen and the fully State owned Nuclear Electric. The purpose of the transformation was two-fold, firstly to privatise previously state-held assets and secondly to create competition in the generation industry. Privatising the South African generation industry will not be explored here since the political will for privatisation does not exist. However, creating competition inside the parastatal ownership structure that exists at the moment is definitely feasible. Before this possibility is explored, it is important to note one significant difference between the supply side of the SA ESI and that in the UK: In the UK, their generating capacity is made up of more than 70 stations the biggest of which has a capacity of just over 2000 MW. In South Africa, as indicated in Table 1, there are no more than 23 stations of which, during 1992, only 11 were used. Furthermore, 6 of these 11 stations are greater than 3000 MW. This difference in the size and number of power stations between the UK and South Africa, has an impact on the nature of the re-organisation that will be necessary in order to create *fair* competition in generation.

To create fair competition in generation it will be necessary to create similarly matched (in terms of size and costs) "generating companies". Table 1 below lists Eskom's current stock of power stations, classified as base-load, mid-merit or peaking/other with their applicable installed capacity ratings.

Base Load	Mid-Merit	Peaking & other
Arnot 2100 MW	Camden 1600 MW	Wilge 240 MW
Duvha 3600 MW	Grootvlei 1200 MW	<i>Pumped storage</i>
Kendal 4116 MW	Highveld 480 MW	- Drakensberg 1000 MW
Kriel 3000 MW	Ingagane 500 MW	- Palmiet 400 MW
Lethabo 3708 MW	Komati 1000 MW	<i>Hydro-electric</i>
Matimba 3990 MW		-Hendrik Verwoerd 320 MW
Matla 3600 MW		- Vanderkloof 220 MW
Tutuka 3654 MW		<i>Gas turbine</i>
Koeberg 1930 MW		- Acacia 171 MW
Hendrina 2000 MW		- Port Rex 171 MW

**Table 1** Eskom Generating Capacity

The different technologies used in these different stations determines the length of utilisation at which these stations are most economically used. In terms of the production plan currently used, the stations are placed in a merit-order in which the most economical stations are used to generate first. In practice, however, there are some special cases where, due to system constraints, it is necessary to interrupt the merit order. During 1992, due to the capacity surplus, all the stations classified as mid-merit were actually in reserve storage.

In creating competition, the station which generates electricity during any hour is the one which bids to sell electricity at the cheapest price. Hence to ensure fair competition it is necessary to ensure that the stations, or group of stations that compete, are able to compete fairly. Using this criteria it is necessary to create a number of competing generating companies who will all have a similar mix of power stations. A proposed means of achieving this is to split Eskom's generating capacity into, say, three "generating companies" each having a mix of base-load and mid-merit station. The hydro, pumped storage and emergency plant could be controlled by a National Grid Company and as such would not be part of the competitive network. One possible split of the power stations currently operational on the grid into three competing generating companies and one national grid company, would be as follows:

Generator A	Generator B	Generator C	National Grid Company
Arnot	Matimba	Tutuka	Wilge
Duvha	Lethabo	Hendrina	Drakensberg
Kendal	Matla	Highveld	Palmiet
Camden	Grootvlei	Komati	Hendrik Verwoerd
	Ingagane		Vanderkloof
			Acacia
			Port Rex

**Table 2. Possible generating companies**

Each of these generating companies would bid to sell electricity to a power pool. The bids would be based on a c/kWh price for the amount of energy offered during that hour. The same structure of payments in respect of constrained-on or constrained-off payments as in the UK, could quite simply be applied here. The hydro, pumped storage and emergency plant, managed by the National Grid Company, would be used to meet sudden changes in load or to maintain the system frequency/voltage and as such would be excluded from the competitive market.

Non-Eskom generating plant such as exists in some of the municipalities, as well as some of the significant co-generators could be considered as Independent Power Producers (IPPs) and would have to bid their energy for sale to the pool in the same way as all other generators.

On the other side of the Pool, a number (say 10) of Regional Electricity Distributors (REDs) would bid to purchase a specific amount of electricity during each hour of the following day. All the mechanisms of calculating the Pool Input Price and the Pool Output Price, as described earlier, can be applied without alteration here.

Another vital aspect of the supply side of the UK industry is the Contract for Differences market where buyers (in the South Africa, the REDs) insure their purchases through the Pool by forward contracting with one of the generating companies or the IPPs for electricity at a certain price. This would insure against the uncertainty in the pool price. Though in the UK the contracts market is actually very complex, it serves a useful purpose

in that it provides an incentive to the RECs to monitor and forecast their load as accurately as possible so as to minimise expenditure on insurance "contracts for differences". This leads to further efficiency in the forecasting and management of load in the RECs. On account of these positive benefits, it is argued here that a similar insurance contracts market should be available to the competitive generators.

As in the UK, the power pool could be managed by a National Grid Company (NGC). The NGC would also be responsible for undertaking to operate the transmission network. The NGC would be "owned" by the Regional Electricity Distributors and as such be answerable to them for their service. Part of its responsibility would be to operate the transmission network efficiently. To achieve this, the NGC would have to develop a transfer pricing mechanism in order to cost for the use of the transmission network. To a very limited extent, Eskom has attempted this already, through the Transmission Tariff, thus far without much success. Since the Pool would use hourly prices, it would be necessary that an hourly costing model for transmission tariffing be developed.

### **5.13 The demand-side: Applying a UK style restructuring to the SA EDI**

#### **Differences in the demand-side between the UK and SA**

Considerable differences exist between the nature of the demand side in South Africa and in the UK. For a start the distribution industry in the UK is funded almost entirely by privately held equity. In South Africa, in the currently highly fragmented distribution industry all the equity is ultimately state-owned, though through a number of different parastatal and Local Authority organisations. In South Africa, there are approximately 3 million customers. A much higher proportion of these customers are very large customers than is the case in the UK. In the UK there are 22 million customers (Littlechild, 1993(b):iv). It has been estimated that more than 70% of these customers have a site specific load of less than 1 MW (Power in Europe Issue No 58 1989). London Electricity alone has more than 1.9 million customers, which is about 60% of the total number of domestic customers that exist in South Africa. Table 4 below reflects the differences in the total consumption in the various electricity market sectors in the UK and South Africa:

Market Sector	UK - 1990	SA - 1991
	Percent of total	Percent of total *
Domestic	34	16
Commercial	25	12
Industrial	37	41
Agricultural	1	1
Traction	1	4
Other	1.7	(Mining) 26

**Table 4: Customer profile in the UK and RSA.**

\* Source: Lane, 1990.

Furthermore, in South Africa there is a considerable distortion in the wealth distribution with the vast proportion of the country's economic activity and people concentrated in a few centres. Finally, in South Africa approximately 70% of the population do not have electricity supplied to their homes. This contrasts with the situation in the UK where the electricity market is fully developed and the wealth distribution is fairly uniform throughout the country. Given such considerable differences it is reasonable to question the relevance of attempting to apply aspects of the UK restructuring to South Africa.

*Applicability of UK distribution price regulation to SA*

It is argued here that despite the fact that there are considerable differences in the respective industries, the method of price regulation used in the restructured UK industry, as explained earlier, provides clear insights as to how to calculate and control the costs of distributing and supplying electricity to the end-users. In particular, distinguishing the supply business from the distribution business has resulted in a clear focus and consequent control over the costs in each of these businesses. This is further reinforced through the two separate price regulatory mechanisms in each of the businesses. The price regulation of the distribution business demands a consistent and reasonable calculation of the costs of using the distribution and reticulation networks. The price regulation of the supply business also provides clear insights as to how supply services should be costed into the electricity sold.

As discussed earlier, the supply price control contains three different components i.e. the fixed allowance, the allowance dependent on the number of customers and the allowance dependent on the number of units sold. These components are used to distinguish differences in the supply costs between RECs in different areas. In the case of London Electricity, the fixed allowance was increased to take cognisance of the higher operating costs inside London. Similarly this structure of supply price regulation could be relatively easily applied in South Africa given a structure in which there are say 10 autonomously independent Regional Electricity Distributors (REDs). Because of the aforementioned structural defects in the South African electricity distribution industry, there will be large disparities between the supply costs between the various regionally differentiated distributors. These disparities can be catered for with the fixed allowance of the supply price control mechanism. The allowance per number of customers and number of units sold may also need to have some regional differentiation.

#### *Transparent Cross-subsidies*

Another admirable feature of the price control in the supply and distribution industry that developed in the UK, is that it developed out of a mandate that there should be no cross-subsidy in the industry whatsoever. Applying this to the South African industry, it will be possible to reflect the actual costs of distributing electricity to the customer. Any cross-subsidy, for whatever reason, between customer types or between urban customers and rural customers, is then immediately transparent.

The final benefit of applying the UK-style price regulation of the supply and distribution business to SA is that it will allow competition in the supply of the very largest customers. In the UK, competition is only being introduced gradually from the largest customers to the smallest customers. There is no reason why similar competition, though for the sake of simplicity initially limited only to the largest customers, can not be put in place in SA. Over time, as the principle of competition becomes accepted and as the industry becomes acquainted with it, competition can be extended to smaller customers.

## **5B PRICING IN FRANCE**

### **Part 1: Electricity tariffing in France**

#### **5.1 Introduction**

A study of electricity pricing in France is a study of electricity pricing in a centralised, mature and stable industry. Following Marcel Boiteaux's design of marginal cost based tariffs in 1949, EdF has had over four decades to evolve its expertise in marginal cost pricing. This has led to the development of highly sophisticated and analytically rigorous pricing applications. The purpose of this study is to review electricity tariffing in France, in principle and in practice. The section begins by focusing on the history of tariffing in France. This is followed by a brief description of EdF's role in the French energy economy. The next section considers the regulatory and financial constraints on EdF pricing. The tariff derivation methodology section then runs through a series of steps that EdF uses in the derivation of their various tariffs. The following section, "from theory to practice" then seeks to analyse how the theoretically derived tariffs are shaped by political considerations. This leads to a review of EdF tariffs, taxation on French electricity and finally a discussion on practical aspects of EdF tariffs. Part 2 focuses on the lessons of EdF tariffing which may be of relevance to pricing in the South African electricity industry. The section begins with a review of the industry structure and price regulatory framework and then it discusses lessons of principle and practice.

#### **5.2 A brief history of electricity tariffing in France**

In 1946, the electricity industry in France was nationalised. The purpose of the nationalisation was, "to endow the country with an efficient electrical power supply system in the post-war reconstruction era" (Roux, 1982).

The new industry took over from more than 1200 private power supply companies, whose policies and methods were extremely diverse. In particular, prior to nationalisation, there were about 15000 separate operating concessions and the new undertaking had to respect the existing prices offered in terms of these often highly disparate concessions.

Beyond this constraint, tariffs were also distorted by the application of rigid indexation formulae. For example, the standing charge in the high-voltage tariff had been set at 165 F/kW in 1936, but had remained unchanged until 1957 whereas it should have been raised to between 5000 and 6000 F/kW to stay abreast of inflation.

Tariffs were thus "giving an inaccurate reflection of production costs and were also wholly inconsistent with commercial considerations" (Forster and Fauconnier, 1988). EdF was concerned about eliminating the inconsistencies of the outdated tariffs.

Progress in reforming the tariffs was relatively slow however. In 1957, the first major tariff reform to high voltage and medium voltage users was undertaken. This resulted in the promulgation of the time of use "Green Tariff."

The second major reform began in 1965 but was not completed until 1972, following the introduction of the Universal Tariff to domestic customers. The initial option proposed two distinct energy rates, in peak hours and in off-peak hours. The universal tariff experienced rapid development and its later replacement, the "Blue Tariff" had nearly 8 million customers (1/3 of EdF's total clientele) (EdF, 1991).

### **1973: The Oil Crisis and the departure from Long Run Marginal Costing**

By 1973, long run marginal costing had been successfully applied by EdF as the basis to their tariffs for more than 15 years. The industry had reached a relatively stable position. Contractual agreements had been entered into with the regulating authorities, whereby EdF was given broader autonomy - including freedom to set tariff levels. As a result, overall revenues and internal cash generation were at satisfactory levels. However, the year 1973 marked the beginning of a world energy crisis, following the first oil price shock. With the oil price trebling between 1973 and 1974, a serious threat had been posed to the existing marginal cost structure: Almost overnight, the production costs of nuclear plant were halved compared with those of oil-fired power stations. As a consequence, EdF halted the development of further conventional thermal stations and accelerated the nuclear program.

However, in 1973 this placed EdF in an invidious position: on the one hand EdF had to bear the burden of a costly capital investment program to change the nature of generation from predominantly coal-fired to predominantly nuclear, while on the other hand the utility

still had to purchase the now expensive fossil fuels needed to keep the conventional thermal stations running.

It was at this point that EdF departed from Long Run Marginal Costs (LRMC) as the basis to their tariffs. The mix of power stations which EdF had at the time of the oil crisis, was such that when oil prices trebled, the marginal cost of generation (for the oil-fired plant) increased from 2.5 centimes/kWh to 7.5 centimes/kWh representing an increase of 5 centimes/kWh. However at this time only two-thirds of total electricity generation was based on fossil fired power stations and one-third on hydraulic and nuclear sources. Hence the average price of fuel only increased by 3.3 centimes/kWh. While, resulting from the increase in the oil price, the short run marginal cost rose dramatically, the long run marginal cost (the cost of nuclear generation - since this was the type of generation which would replace oil-fired generation in the long run) increased to a much lesser degree than the increase in short run marginal costs. This posed a dilemma: basing tariffs on short term marginal costs would have meant that the prices would have had to be increased by 5 centimes/kWh reflecting the increase in the cost of marginal generation. On the other hand, basing tariffs on long run marginal costs would have meant that the tariffs would have had to reflect the increase of nuclear generation, whose marginal costs were considerably lower than that of oil-fired plant.

If at that time, EdF were to have implemented tariffs reflecting the long run marginal cost corresponding to the restructured generation mix caused by the increase in the price of oil, correct investment decisions would have been made but in contravention of operating budget constraints. On the other hand, basing tariffs on short term marginal costs would engender incorrect investment decisions but correct operating budget conditions. The outcome was that EdF opted for a structure derived from short run marginal costs. This is a significant point in the history of EdF tariffing since it represented a departure from the oft-cited LRMC tariffing principles.

### **Changing production systems**

If the tariffs of the seventies were influenced primarily by the oil crisis, the tariffs of the eighties were influenced primarily by changes in the production systems. The trend of electricity production from 1980 to 1990 is contained in Table 1 below: (Source EdF 1992 Annual Report)

Production type	1980	1990
Hydro	23%	14%
Nuclear	7%	79%
Coal & Oil	70%	7%

**Table 1. Trend in production resources: 1980-1990**

Such major changes in the production system led EdF to carry out a complete overhaul of the tariff system from the smallest to the largest customers (EdF 1991). The nature and extent of the changes made to the tariff structures differed according to the category of customer concerned. The changes included:

- " \* Substitution of voltage for demand as a basis for the differentiation of tariffs.
- \* Regionalisation (regional tariff differentials) limited to very large industrial customers.
- \* Reform of tariff structures including new definitions of time-of-day and seasonal headings.
- \* Reclassification of customers within new categories of tariffs, based on subscribed demand.
- \* The development of a wide range of tariff options. "

These changes however, did not alter the fundamental basis to the tariffing philosophy i.e. that tariffs should be efficient, neutral and cost reflective. All the literature reviewed for this study echoed the same underlying principle for electricity pricing in EdF, that is, equality of treatment and economic efficiency. Equality of treatment means that all customers with the same consumption characteristics are offered the same rates. Economic efficiency implies passing on to the consumer the costs that he or she incurs to the power system. Through the realisation of the tariff philosophy, it is intended that each customer is thus encouraged to consume only the kilowatt hours the value of which to the customer is greater than their supply cost. It is interesting to note the directness and rationality of these criteria.

**In summary,**

Since the creation of EdF as a nationalised, vertically integrated industry in 1946, considerable changes have been made to the electricity tariffs within a consistent tariffing philosophy. The basic principles of equality of customer treatment and economic efficiency have not changed. The only change has been in respect of the *application* of these principles from the relatively rigid Green Tariff and Universal Tariff of the 1950's and 1960's to the highly diverse tariff structure which exists today. The evolution has been driven primarily by the need to realise the fundamental principles of equality of treatment and economic efficiency. Customer reaction to tariffs proposed or implemented over the last 40 years, have had a large bearing on the determination of future tariffs. However it is also important to note the role that factors extrinsic to the industry, such the Oil Crisis of the 1970's, have played in shaping EdF tariffs.

**5.3 Electricite De France in the French energy economy**

In 1983 EdF employed 0.5% of the French working population, it contributed 1.8% to the French GDP and it accounted for 5.5% of national investment (Fremaux and Lederer, 1986).

In 1992 EdF's own production of 417 TWh accounted for 95% of electricity produced in France, whereas its sales accounted for 97% of French electricity consumption (EdF 1992 Annual Report). It exported a total of 58.3 TWh, mainly to Great Britain, Switzerland and Italy and had 118 551 staff in full time employment.

Also in 1992, EdF had its anniversary after it was created following the nationalisation of the vast majority of privately owned utilities that then made up the French electricity industry. The law creating EdF as a State Company also granted EdF a monopoly over the transmission, distribution, import and export of electricity. However the law also allowed other companies to own and exploit one or several production units to cover their own electricity needs, provided they sold exclusively to EdF any of their production exceeding their own requirements. However, these companies together only account for 2% of total French electricity production.

#### 5.4 Regulatory and financial constraints in EdF pricing

EdF's relationship with the government is governed by two requirements. Firstly EdF's activities must be consistent with official Public Authority energy policy. Secondly, as a large State body, EdF is inevitably called on by the sponsoring governmental ministries as an instrument to help regulate the country's overall economic equilibrium.

Despite the fact that EdF is a State Company, actual state interference in EdF's operations is very limited. To avoid confusion between the ministries' and EdF's responsibilities, it was agreed that EdF could not perform its task with full efficiency unless it enjoyed a degree of autonomy within a framework of objectives and constraints which were clearly set out and covered a period of several years. It is from this agreement that a "Plan Contract" came into being as the mechanism through which EdF could "buy" freedom from State interference in its operations. In terms of the 1984-1988 contract for example, EdF committed itself to a relative decline in electricity prices by comparison with the general consumer price index, while balancing the utility's accounts and achieving a rate of self-financing of the order of 50%.

The excerpt from the same contract relating to tariff structure reads as follows: (Forster and Fauconnier, 1988:1-32)

- " The tariff structure needs to be in conformity with the following principles:
- The tariff scales will be uniform throughout metropolitan France.
  - Subject to the above, the tariffs should guide customer's consumption choices by reference to the true cost of the energy supplied to them.
  - The tariffs shall respect the principle of equality of treatment between customers with the same characteristics, each customer being allowed to choose between the different options available under the tariffs in force.
  - Within the framework of the general tariff, the tariff structures applicable in offshore and overseas territories will be adapted to suit the special conditions obtaining there.
  - The undertaking shall offer long-term contracts to large industrial users

comprising price guarantees in return for consumption commitments. "

With regard to tariff level,

"The level of tariffs must as a rule be such as to cover the Utility's overall expenditure, allowing for the commercial objectives (described earlier) and for the productivity gains to be made each year. From this standpoint, an increase may take place on the 15<sup>th</sup> February each year, (a) equal to the increase during the previous year in the general consumer price index less 1% and (b) sufficient to maintain an evenly balanced budget, providing no new charges are imposed on the utility affecting its operating accounts."

It is interesting to observe the parallels between the regulation of EdF through the Plan Contracts with the State, and Eskom's current Pricing Compact providing for a decrease in the real price of electricity. This "Plan Contract" regulatory mechanism has allowed arms length regulation in the French industry and is regarded as having achieved the desired objectives.

### **Financial Constraints**

A dominant financial constraint arising from the nationalisation of the industry in the 1940's is that it is illegitimate for EdF to make profits (in the sense of distributable surpluses). In this respect, the tariff level is set so that the average price is sufficient to cover costs.

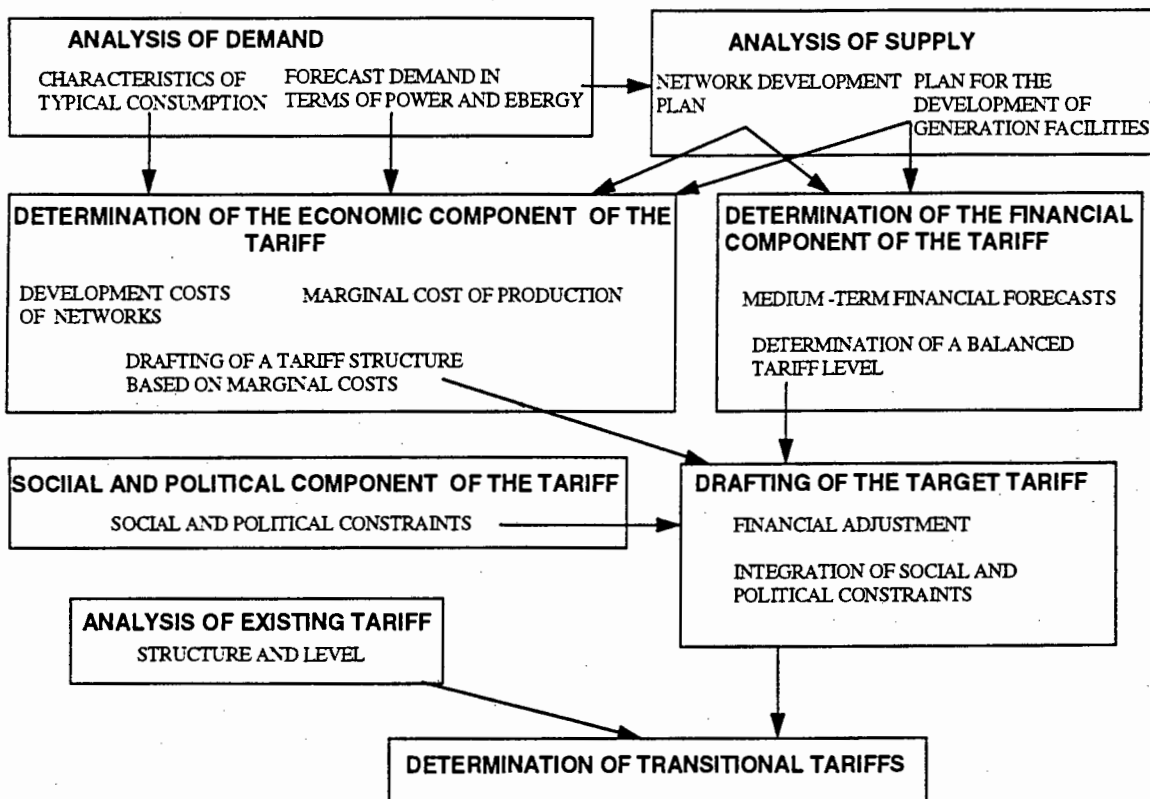
### **5.5 Tariff derivation methodology**

The sections covered thus far, have focused on creating a regulatory and historical background to electricity pricing in France. It is appropriate that the focus now turns to an analysis of the processes used in EdF tariff development.

In the introduction to this section, EdF pricing applications were described as highly sophisticated and analytically rigorous. To support this claim, evidence is available in a number of areas such as the application, in the early 1950's, of the Boiteaux forward-looking marginal pricing principles or the practical application of the Ramsey-Boiteaux

Rules to determine marginal cost prices which reconcile with historical cost-based revenue requirements. In this section, the tariff derivation methodology will be developed by explaining the overall phases of tariff development and also by analysing the calculation of long range marginal costs and the application of the Ramsey-Boiteaux Rules in the calculation of tolls to balance forward looking marginal costs with historical cost revenue requirements.

Forster and Fauconnier (1988: 1-21) explain the tariff design process as follows:



### Step 1. Analysis of demand

The basis of French electricity tariffs is long run marginal costs. This principle was explained in theory in the first chapter and will be explained in practice later in this section. At this stage it is important to notice how the principle of using long run costing places an emphasis on the accurate forecasts of future power and energy needs. The forecasts are based on a number of factors:

- Population and socio-economic data;
- National economic planning with probable development of electricity applications;
- Change in the relative price of other energy sources;
- Sectoral analyses of customers by reference to voltage levels, volume of consumption, etc.;
- Trends observed in previous years.

With regard to trends observed in previous years, an examination of the daily load curves over the weekdays, weekends and public holidays of a year, allows an analysis of capacity needed for the 8760 hours of the year. This analysis ordered on the basis of the duration of a specific level of demanded for a specific period of time, produces a curve known as a Load Duration Curve.

## **Step 2. Analysis of supply**

Having completed the analysis of demand, it is necessary to use these results in an analysis of supply. As explained earlier, EdF is committed to meeting the power and energy demands of its customers and hence developments on the supply side must ensure that forecasted demand levels will be met.

The supply analysis focuses on the development plan for the transmission and distribution network and the development plan for the generation network. The development plan for the transmission and distribution network requires reliable forecasts of the expected demand at the various points on the network. A similar analysis of the generation capacity will result in a generation expansion plan necessary to meet the forecasted demand levels.

The supply-side development plan can then be defined in terms of a schedule of investment outlays over the target time period. This is a vital input in the determination of the capital component of the tariff.

## **Step 3. Determination of the economic component of the tariff.**

### **3.1 Marginal cost of production**

The most crucial aspect of this step is the determination of the marginal cost of production and transmission and the subsequent determination of a tariff structure based on marginal costs. An illustration of how EdF derives these marginal costs, based on the Long Range Marginal Cost theory, is instructive:

Marginal generation costs are calculated as the sum of marginal energy costs and marginal capacity costs. The basis of the calculation of the marginal generating costs are the marginal conditions for least cost operation of the plant mix that is expected to exist during the planning period. The marginal running cost calculation is theoretically made for every level of expected demand on the generating system. The calculation is made as follows: At a particular point in time, the expected generating cost of the least efficient plant that would be loaded onto the system to meet the expected load is calculated. This figure represents the marginal running costs per kilowatt-hour at this time. It is possible to derive these figures for every hour or even-half hour during every day. It is important to note that these marginal running costs will always be greater than the average costs except when only the most efficient plant is running, in which case the marginal running cost equals the average running cost.

The marginal capacity cost for each period of time is calculated by balancing the marginal opportunity cost of capacity (for an optimal system) during that time period, with the marginal cost of shortages, i.e. the costs incurred should the level of capacity not be sufficient to meet the required level of demand. The marginal cost of capacity is based on the cost-minimising conditions that yield an optimal plant mix for meeting an expected load. The optimal plant mix depends not only on the expected peak load but also on the expected load duration curve. Determining the optimal plant mix is a process of determining whether usage levels will be high enough to use high-capital-cost-but-low-running-cost base load plant instead of low-capital-cost-but-high-running-cost peak load plant. The marginal opportunity cost of additional capacity is therefore given by the per-kilowatt cost of capacity, less the fuel savings from displacing plant which has higher fuel costs.

The marginal cost of shortages are simply described as the costs imposed on customers when demand exceeds supply. In EdF tariff practice, the level of capacity that will be installed involves a trade-off between the costs of additional capacity and the expected

marginal shortage costs at any particular level of capacity. Consider the probabilities  $P_1, P_2 \dots P_n$  that demand will exceed capacity in each of  $n$  specified rating periods where each period has a particular number of hours in it ( $H_1, H_2, \dots H_n$ ;  $H_1 + H_2 + \dots + H_n = 8760$ ). Assume that the marginal cost of an outage is given by the value of a constant,  $d$ , in any period. Optimality requires that capacity be expanded up to the point at which the marginal opportunity cost of additional capacity is equal to the expected marginal shortage cost. This is expressed as follows:

$$\text{Optimal capacity} = C_g = (P_1 H_1 + P_2 H_2 + \dots + P_n H_n) \cdot d$$

This expression can be solved for the expected marginal shortage cost in each period.

$$\begin{aligned} \text{Period 1:} \quad & P_1 H_1 \cdot d = (P_1 H_1 \cdot C_g) / (P_1 H_1 + P_2 H_2 + \dots + P_n H_n) \\ \text{Period 2:} \quad & P_2 H_2 \cdot d = (P_2 H_2 \cdot C_g) / (P_1 H_1 + P_2 H_2 + \dots + P_n H_n) \\ \text{Period n:} \quad & P_n H_n \cdot d = (P_n H_n \cdot C_g) / (P_1 H_1 + P_2 H_2 + \dots + P_n H_n) \end{aligned}$$

The expected marginal shortage cost for each kilowatt-hour in each period can be obtained by dividing each of the above expressions by the number of kilowatt-hours in each period.

This complex, and at times confusing, approach to the calculation of marginal capacity costs, has two significant advantages:

Firstly, it explicitly recognises and provides for uncertainty and shortage costs in the electrical system. Secondly, it provides a logical means for assigning some proportion of the capacity costs to several periods according to their relative probabilities of outage and the expected costs of shortage in each period.

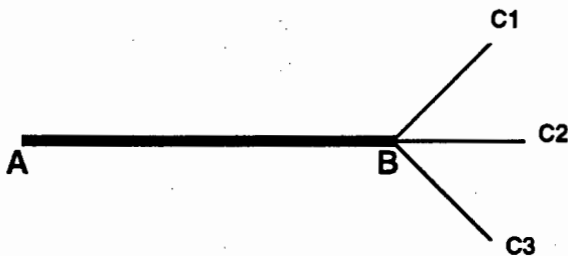
### 3.2 Marginal cost of transmission.

The transmission cost component of long run marginal costs is necessarily related to the location and capacity of the generating facilities. The optimal plant mix and plant location is affected by transmission costs. Unfortunately the problem of solving for the optimal plant mix, optimal plant locations and optimal transmission network simultaneously is extremely complicated. For this reason, in EdF, incremental costs are incorporated using a

relatively simple formula. Firstly, marginal transmission losses should be factored into the costs. To the extent that there are significant variations in transmission losses at different times of day and in different seasons, this should be reflected in charges differentiated by time of day or season. Incremental transmission capacity charges can be calculated at each voltage level as the ratio of the discounted annual investment and operating expenditure to the discounted value of annual peak capacity increases. This results in a measure of the incremental transmission cost per kilowatt.

### 3.3 Marginal cost of distribution

Calculating the differential distribution cost components is a complex problem which, like the marginal transmission cost calculation, is highly simplified in the interests of obtaining some conclusion. The French methodology is based on the principle that some costs, specifically generation and transmission cost are collective costs while distribution costs are more directly correlated with the individual customer's load characteristics rather than the system load characteristics. Consider a simplified distribution system as depicted in Figure 1.



**Figure 1. Simplified distribution system**

C1..C3 are the final distribution points and AB is a line segment serving all of them. The capacity required for each  $C_i$  is determined by that customer's demand and the cost of that capacity should be charged as a demand charge based on that customer's demand. The capacity required for AB will not, in general, be the sum of the capacities required for each of the  $C_i$ 's unless their behaviour is perfectly correlated with one another. While the logic would seem to be intuitively correct it is unclear exactly how EdF incorporates the marginal costs for the line segments B to C1..C3 into its tariffs.

### 3.4 Development of the tariff structure based on marginal costs

Having studied the determination of the marginal generation, transmission and distribution costs separately, it is possible to examine how these are incorporated to determine the actual tariff structure.

The tariff structure is determined by attributing marginal costs to the capacity and energy components:

- The marginal operating costs for generation, as well as the marginal cost of line and transformer losses is fully integrated in the prices per kWh.
- The long run marginal capacity costs as determined in 3.1 are divided between the maximum demand charge and the energy charge as explained below.

The long run marginal capacity costs mentioned above are made up of the capacity costs of generation, transmission and distribution. The distribution of these costs between the maximum demand charge and the energy charge is dependent upon the impact of the consumer's requirements on the specific capacity requirements. To analyse this impact, Boiteaux distinguished three zones of a power system, upstream from a consumer: (EPRI, 1977(b):81)

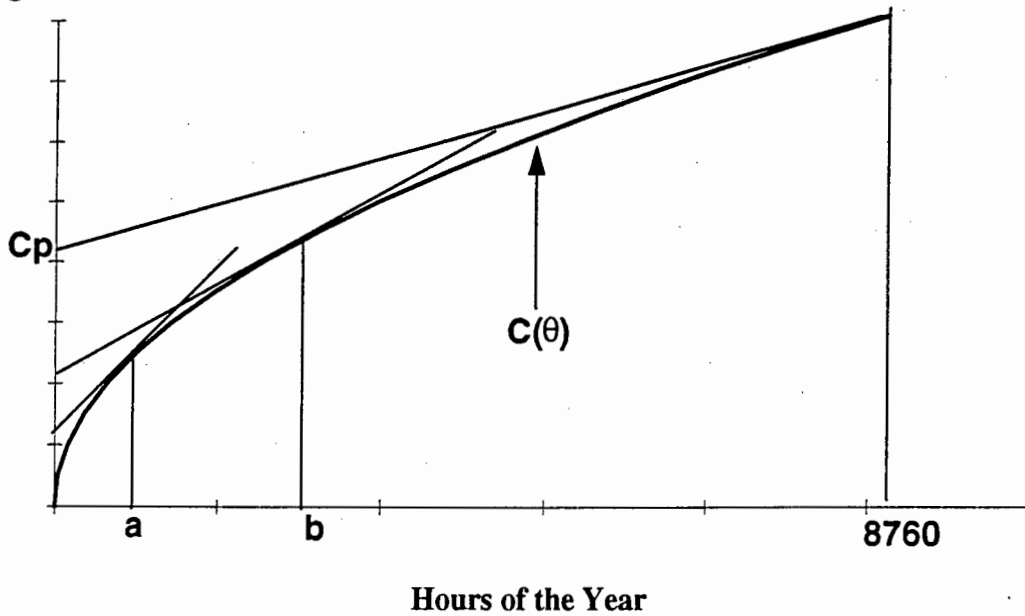
1. The collective network, or the most remote part, where capacity depends above all on the average consumption of customers at the time of the collective peak. Collective system costs are thus assigned to the peak period kilowatt-hours;
2. The "semi-individual network" whose capacity depends particularly on the random conditions of each customer's consumption pattern and hence these costs are apportioned in proportion to the subscribed demand of every subscriber supplied;
3. The individual connection which is directly determined by the personal peak of the customer, who is normally expected to bear the cost of his own connection. "

The explanation for costing in zone 1 as described above, is that at the level of his own insertion into the system, the consumer is entirely responsible for the size of the system serving him. A short way upstream, despite diversity, the consumer's own maximum demand directly affects the required size of the system, partly because people are assumed

to be more like their immediate neighbours than like the system in general. As more and more customers join the system, the consumer's own maximum demand becomes less and less related to the size of the system required to serve him. It thus becomes the customers' *average* demand at peak period which determines system size and hence the assignment of collective system costs to all the peak-period kilowatt-hours.

Another major feature of the determination of the tariff structure in EdF tariffing is the differentiation of tariff structure according to load factor. The reason for this differentiation is that, because of diversity, two customers which register identical peak loads may impose very different capacity costs on the system. Hence the expected system cost of an additional kilowatt of demand varies directly but not linearly with the customer's load duration. In Figure 2 below,  $C(\theta)$  represents the expected "collective" costs imposed on the system per kilowatt of recorded peak demand for customers with different durations of peak demand ( $\theta$ ).  $C_p$  in the figure is the marginal cost of capacity and the slope of the line extending from it is the marginal energy cost ( $C_e$ ) per kilowatt-hour. Only customers with very high load factors impose the full marginal costs of one kilowatt of capacity per kilowatt of recorded individual peak demand. Because of diversity, one kilowatt of additional peak demand recorded on a customer's meter during a broad peak period will cause the system to require less than one kilowatt of additional capacity.  $C(\theta)$  therefore lies below the line extending from  $C_p$  for load durations less than the entire rating period. This is illustrated in Figure 2.

Marginal cost per KW peak demand



**Figure 2. Cumulative marginal cost curve**

EdF then try to make a linear approximation to the actual cost function  $C(\theta)$  at several different load duration levels to allow them to construct a set of two-part, or other, tariffs which more closely matches the rate schedule with cost causality of different types of customers. This is done by drawing lines tangential to the cost function at various load duration levels. The intercept of each line is the demand charge in the rate schedule, and the slope is the energy charge which is always greater than or equal to, the pure marginal energy costs. Examples of this are illustrated in Figure 2 above, at consumption levels *a* and *b*.

#### **Step 4. Determination of the Financial Component of the Tariff**

EdF has to maintain a balanced budget. In step 3, the derivation and application of marginal costs to determine the tariff structure and price level, was explained. It was also explained in chapter 2, that marginal cost pricing will lead to over-recovery of revenue in time of capacity shortages and under-recovery of revenue in times of surplus capacity. Hence given the constraint that EdF has to maintain a balanced budget, it is necessary to modulate the marginal cost derived tariffs so that the total revenue requirement will match

the revenue requirement as stipulated in the historical cost accounting based operating account.

Tolls are used to introduce price differences which guarantee budget equilibrium and yet preserve the principle of marginal costs. These tolls are based on the Ramsey principle: i.e. prices must be closer to the marginal costs, the greater the customer's ability to react to them (this was explained in detail in the second chapter).

To determine the total amount of tolls to be applied to unadjusted marginal costs, EdF has developed a mathematical model, the Medium Term Forecast Study, which enables the financial position to be reconciled.

### **Step 5            Determining the social and political component of the Tariff**

As expressed earlier, EdF's stated tariff principles appear highly rational and scientific, leaving little room for consideration of matters social or political. In the literature reviewed for this study very little mention was made of socio-political considerations in EdF tariff design.

However it should be noted that 12 million of EdF's customers are on a lifeline tariff with a break-even of 2500 kWh per annum (Forster and Fauconnier, 1988:11-6). Furthermore, through regulation of the price through the Contract Plan with the State, the tariffs are inevitably influenced by broad political will.

### **Step 6            The final tariffs**

After proceeding through each of the previous steps, the tariff is ready for implementation. If a new tariff results in drastic changes from existing tariffs, then it is necessary to determine transitional tariffs. It should be noted that EdF pride themselves in building stable tariff structures and that its prices reflect "durable trends of changes in costs" (Forster and Fauconnier, 1988:iv-2).

## 5.6 From theory to practice

One of the key points to be drawn from the analysis of EdF electricity pricing thus far, is the emphasis on economic efficiency and equality of treatment. EdF are far from unique in their emphasis on these two attributes. The restructuring of the UK ESI, studied earlier, was based on the same objectives. However, in contrast with the UK ideology of competition as the *modus operandi* to achieve economic efficiency, the French ideology is that through centralised bureaucratic control (in a tradition dating to Napoleonic days) correct tariffs can be determined to achieve the stated goal of economic efficiency. Such tariffs "contain incentives which, when cumulated nation-wide, generate benefits that enable us to meet the demand at the lowest possible cost" (Bergounoux, 1993:2).

Although this may sound some-what sinister - as if EdF have a grand plan of what constitutes economic efficiency and through their tariffs they seek to realise this goal - in practice this is not the case. To the contrary, EdF define their objective of economic efficiency as follows:

"To satisfy the demand of the users at the lowest possible cost to the community, in a decentralised system where all users can choose, for a given service to be rendered, the solution that is most economical for themselves" (Bergounoux, 1993:3).

This definition of economic efficiency is based on EdF's stated goal of providing tariffs which accurately reflect the customer's cost of supply. EdF frame this goal in terms of *treatment equity* and *tariff neutrality*. Treatment equity means that differences which customers may have with respect to the quantity of energy consumed, time when the connection was first installed, level and regularity of demand, location of point of supply and diversity, must be reflected in the costs which these customers pay for their supply. Tariff neutrality, on the other hand, means that EdF preclude themselves from differentiating between captive customers and competitive customers i.e. there should be no differentiation in the pricing policy offered to these two customers on account of the fact that they differ in respect of their price elasticity of demand. Tariff neutrality as a principle also implies that in principle there is no cross-subsidisation between different categories of customers. While this may well be the case in the construction of the tariffs, the earlier discussion on Ramsey prices in calculating tolls to reconcile economic marginal costs with accounting revenue requirements illustrates that differing price elasticities of

demand are differentiated and hence indirectly there is a degree of cross-subsidisation between customers who are able to shift load in peak period and those that are "captive peak-period" customers. (EdF's use of Ramsey prices was discussed earlier in this section, while the theoretical principles in Ramsey pricing were discussed in Chapter 2).

#### *EdF Pricing: Enhancing customer choice*

The requirement that prices paid are cost reflective is balanced against the pragmatic requirement that the costs of developing, implementing and metering a highly sophisticated tariff does not exceed the cost saved by the utility and the customers using such tariffs. The very large number of different tariff options evidence EdF's attempt to find this balance for its varied customer profile. Indeed, EdF advance the development of tariff options as a solution to reconciling the need for equity, efficiency and practicality.

The tariff options are designed so that each customer selects the option which best reflects the cost of their supply, on the basis that tariff options are designed so that the costs saved by the customer are equal to the costs saved by EdF. As such there is no distinction per se between "good" or "bad" use of electricity. Rather the objective is simply to create a tariff which accurately reflects the cost of supply and leaves the customer to make his own choice. In this respect the common conception of EdF tariffs as "carrot and stick" (Poplewell, 1982) tariffs would clearly appear to be misguided.

#### *EdF pricing and Demand Side Management*

From EdF's perspective, utility efficiency means controlling the total system "to reach an overall optimum for the community as a whole, and to define the most appropriate tariffs and load management schemes by comparing costs (including implementation costs) and benefits for both the supplier (reflecting marginal generation and distribution costs), and the customer" (Lescouer, Galland and Husson, 1988:191-205). On the demand-side, the word "signal" is frequently used by EdF to describe how their tariffs, through reflecting marginal costs, provide an indication to any customer of the effect of their consumption on EdF's total system costs. In all the tariffs there is a clear incentive for customers to be able to forecast and alter their load in a manner which will result in effective savings. This is evident in the subscribed maximum demand charges, the method of charging for reactive

energy, load factor-based capacity and energy charges, and the high degree of time of use differentiation in the structure of the tariffs.

### *EdF pricing and self-generation*

EdF policy on self-generation seems somewhat confused. On the one hand, the Director General of EdF has supported the construction of self-generating plant by EdF customers, if the customer finds that using such plant is more profitable when compared to EdF tariffs.<sup>16</sup> On the other hand EdF have a specific commercial policy: the "phantom incentives" consisting of a subsidy payable to a customer who contemplates installing his own peak generating equipment on condition that he or she agrees to postpone that installation. This incentive clearly conflicts with "tariff neutrality" and "equality of treatment".

### *Excess capacity and "commercial aids"*

Since 1984, EdF has had excess generating capacity. Creating new demand through "commercial aids" has played a large part in EdF tariffing. EdF define a *commercial margin* as the difference between the variable costs of the excess capacity and the total costs of normal capacity. Part of this commercial margin is paid out in the form of an investment subsidy to customers who install new electrical processes. When the excess capacity runs out, the commercial margin will have been absorbed and the system of commercial aids will no longer exist.

The objective of the commercial aid program is to encourage those customers with a high elasticity of demand to consume more, by providing incentives to make electricity more competitive. While EdF has excess capacity, this is a logical program. However, it should be noted that the commercial aid program is in direct conflict with EdF's stated tariffing principle of equality of treatment of all customers, which implies no differentiation of customers on the basis of price elasticity of demand.

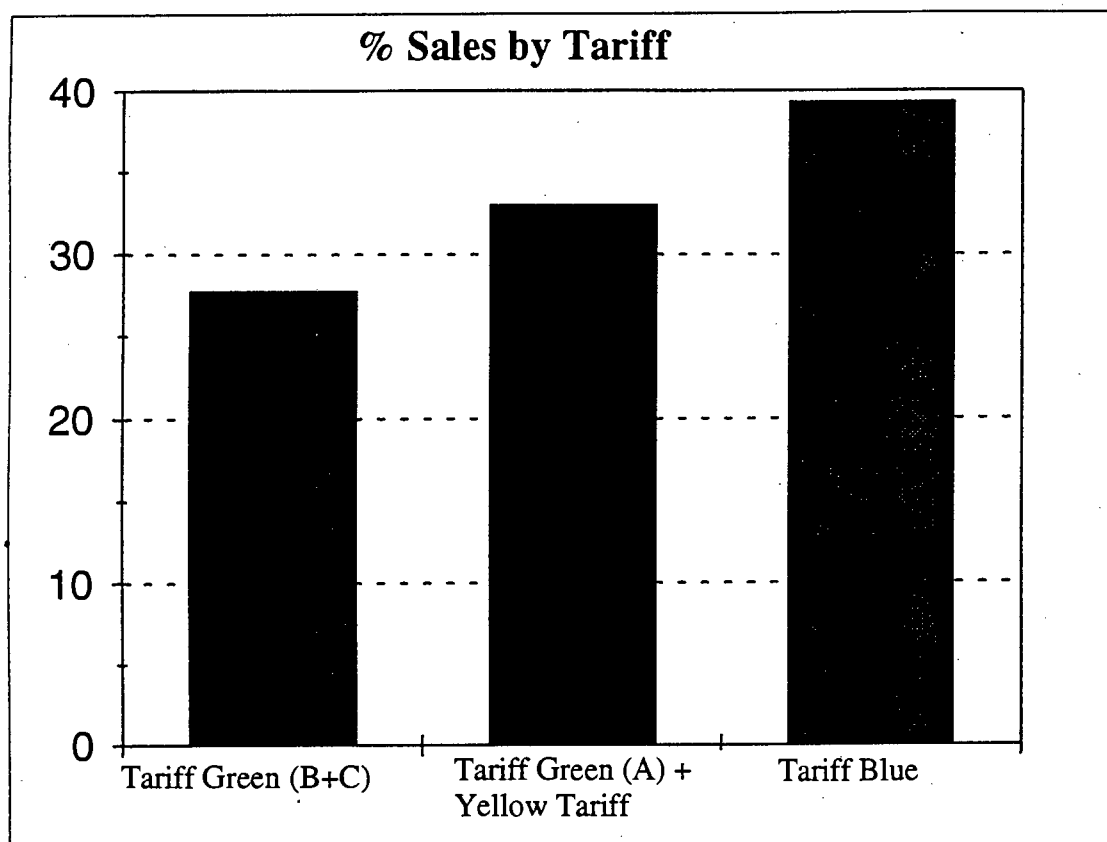
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<sup>16</sup> Director general of EDF quoted at a meeting of regional management personnel on 24 April 1991, in (Bergougnoux 1993:41).

In summary, this section has sought to analyse the principles underlying the tariffs implemented by EdF. EdF advance marginal cost pricing - the mechanism to achieve economic efficiency - as the basis to their cost reflective tariffs. This is supported by the stated goals of equality of treatment and tariff neutrality. (In practice however, EdF has to compete against other energy forms in some markets. The economic reality is that the price elasticity of demand does vary amongst EdF's customers.) Quite justifiably, but in conflict with their stated principle of "equality of treatment", EdF does exploit these differences by charging some customers the full economic cost of their supply, while providing other customers with "commercial aids" to encourage greater consumption or to postpone the construction of self-generation facilities. This discussion does not seek to discredit the policy of commercial aids in any way, but rather merely to illustrate that in respect of this issue there is an inconsistency between EdF's stated theoretical principles and their practices.

## 5.7 A review of EdF Tariffs

EdF have three principal tariffs defined as the blue, yellow and green tariffs. The bar chart below distinguishes the percentage of electricity sales on each of the different tariffs (Source: EdF, 1993(c)).



**Figure 3. Percentage sales by tariff type**

The blue tariff has more than 27.5 million customers, compared to the Yellow Tariff with approximately 180 000, Green Tariff A5 and A8 together with 40 000, Green Tariff B with 400 customers and Green Tariff C with only 70 customers (EdF, 1992). In each of the tariff classifications there are a number of different tariff options. The tariffs pertaining at December 1993 are explained hereafter.<sup>17</sup>

<sup>17</sup> Sources:

EdF, 1992(b). *Prix de Vente de L'Electricite*, EdF, Paris.  
 EdF, 1993. *Bien Connaitre le Tarif vert A5*, EdF, Paris.  
 EdF, 1993(b). *Dossier Electricite*, EdF, Paris.

### 5.7.1 The Blue tariffs

The Blue Tariff is applicable to domestic, agricultural, commercial, civil service and so-called general customers, from very small customers to 36 kVA customers. Different tariffs are offered to domestic and agricultural customers than are offered to "Professional" (commercial and public service customers). This is an aberration in the cost-of-supply basis to pricing and stems from a 1935 Decree. EdF claim that they are gradually minimising the current 10% difference between the average price to customers in these two classes and that by the year 2000, the difference will have been phased out (Bergougnoux, 1993:23).

At present the Blue Tariff is offered in one of three options: Base, Off-Peak and EJP (Peak Day Withdrawal). A notable feature of the Blue Tariff is the number of different tariff variants specifically designed for particular applications. This is illustrated in the tariff structure explained on the next page:

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Pinta J.C, 1989. *Blue, Yellow, Green Electricity Tariffs 1989 - new features*, EdF Paris

Pinta J.C, 1992. *Bleu, Jaune, Vert les Tarifs de L'Electricite 1992 - Les nouveautes et les prix 1992*, EdF Paris.

**Domestic and Agricultural Tariffs:**

Base Option	Fixed Monthly Charge (F)	Energy charge (c/kWh)	
Less than 6 kVA Demand	12.02	67.14	
6	30.53	57.66	
9	61		
12	90.97		
15	120.94		
18	150.91		
Off-Peak Option	Fixed Monthly Charge (F)		
6	57.66	57.66	32.79
9	99.24		
12	141.42		
15	183.6		
18	225.78		
24	342.66		
30	459.54		
36	576.48		
EJP Option	Fixed Monthly Charge (F)	Standard period charge	Mobile Peak charge
12	57.66	36.71	299.83
15	57.66		
18	57.66		
36	225.78		

### Professional and public service tariffs

Base Option	Fixed Monthly Charge (F)	Energy charge (c/kWh)	
Less than 6 KVA Demand	12.02	66.56	
Long utilisation	0	(F 306.12 /annum)	
6	58.78	57.66	
9	99.94		
12	141.1		
15	132.26		
18	223.42		
24	373.72		
30	524.02		
36	674.32		
Off-Peak Option	Fixed Monthly Charge (F)	Peak period charge	Off-Peak period charge
6	94.66	57.66	32.79
9	151.63		
12	208.6		
15	265.57		
18	322.54		
24	601.04		
30	678.54		
36	858.04		
EJP Option	Fixed Monthly Charge (F)	Standard period charge	Mobile Peak charge
12	94.66	36.71	299.83
18	94.66		
36	322.54		

### General use tariffs

The general use tariffs are the same in structure to the Professional and public service tariffs above, but the rates are marginally higher than the rates for the domestic and agricultural tariffs.

## Public lighting tariffs

Option	Monthly maximum demand charge	Energy price (c/kWh)		
Base option	11.65	57.66		
	Fixed charge (F)	Maximum demand charge (F/kVA)	Off-Peak Rate	Peak Rate
Off-Peak option	9.42	14.5	32.19	57.66

### 5.7.2 The Yellow Tariffs

The Yellow Tariff is available to customers subscribing to power between 36 and 250 kVA and to customers subscribing to power of less than 36 kVA, who are not satisfied with the simplicity of the Blue Tariff. The tariff comprises two versions:

- An average usage version for usage of less than 2400 hours
- A long usage version for usage of more than 2400 hours for customers who are able to shift load from the peak to the off-peak periods,

In addition, each of these tariff versions are offered either on the Base Option or EJP Option.

The tariff differentiates two seasonal periods and two time-of-day periods as follows:

Winter (5 months) : November to March inclusive

Summer (7 months) : April to October inclusive

Peak hours : 16 hrs per day, 7 days per week

Off-Peak hours : 8 possibly non-adjacent hours per day, 7 days per week.

Demand is invoiced in terms of apparent power (kVA). In the average usage tariff, a single demand level is possible. In the long utilisation version however, customers subscribe for demand in the peak period but subscriptions for additional power in the off-peak period is also available and is granted the following discounts:

- 50% for additional demand outside the peak periods
- 66% for additional demand within winter low-load periods
- 80% for additional demand in summer

For the EJP Option, there is a discount on the maximum demand charge of

- 65% for additional demand during winter hours
- 80% for additional demand during summer hours

The 1993 rates applicable to the Yellow Tariff are as follows:

Version	Max. Demand charge	Winter		Summer	
		Peak hours	Off-Peak hours	Peak hours	Off-Peak hours
Long usage	338.16	66.92	40.12	20.52	12.6
Average usage	116.04	93.57	54.1	21.99	12.92
EJP Option	338.16	247.81	38.78	20.52	12.6

### 5.7.3 The Green Tariffs

The Green Tariff is offered to Medium Voltage customers between 5 and 30 kV. The tariff offered to any particular customer varies according to that customer's subscribed maximum demand. Tariff A5 is for all customers subscribing to between 250 kW and 10 MW. Tariff A8 is for all customers between 1MW and 10 MW, Tariff B is for customers between 10 MW and 40 MW and Tariff C is for customers taking more than 40 MWs. The Green Tariff A5, is explained in on the next page.

*Base option*

Versions	Fixed charge (F/kW/year)	Energy Price (Centimes/kWh)				
		Winter			Summer	
		Peak	Standard	Off-Peak	Standard	Off-Peak
Very High Usage	781.56	52.79	39.43	28.36	17.4	11.7
High usage	483.96	77.61	51.02	32.14	18.39	11.97
Average usage	301.92	113.82	60.54	35.78	19.72	12.26
Short usage	119.28	158.06	79.25	44.09	20.93	12.55
Reactive energy charge (C/kVArh)		13.23				

*Base Option: Coefficient for calculating the maximum demand charge*

Versions	Tariff periods				
	Winter			Summer	
	Peak	Standard	Off-Peak	Standard	Off-Peak
Very High Usage	1	0.73	0.22	0.07	0.01
High usage	1	0.68	0.26	0.07	0.01
Average usage	1	0.65	0.28	0.07	0.01
Short usage	1	0.62	0.35	0.16	0.01

*Subscribed maximum demand*

With the Green tariff, customers subscribe to a maximum demand level in each of the five tariff periods throughout the year. The applicable annual maximum demand charge is then calculated on the basis of the subscribed demand during each period, scaled by the applicable coefficients and multiplied by the annual fixed charge. An example illustrates the method of calculating the applicable annual maximum demand:

A customer taking electricity on the very high usage tariff has recorded maximum demands in the applicable tariff periods as illustrated below:

Winter			Summer	
Peak	Standard	Off-Peak	Standard	Off-Peak
200kW	220kW	250kW	300kW	350kW

The applicable maximum demand is thus calculated as follows:

$$(200 \text{ kW} \cdot 1) + (220 \text{ kW} \cdot 0.73) + (250 \text{ kW} \cdot 0.22) + (300 \text{ kW} \cdot 0.07) + (350 \text{ kW} \cdot 0.01) \\ = 440.1 \text{ kW}$$

The maximum demand charge would thus be :  $440.1 \text{ kW} \cdot 781.56 \text{ F/kW/Annum}$   
 $= \text{FF}343\,965$

*Penalties for exceeding subscribed maximum demand*

The customer has to subscribe for a level of maximum demand in each of the tariff periods. If this level is exceeded then EdF apply a penalty in respect of the excessive demand. This is calculated as follows:

$$D = k \cdot T \cdot \Delta P \text{ max}$$

Where

D = the penalty amount

k = 10% of the fixed annual charge for the base case of the tariff for very high usage

T is a coefficient applying to particular tariff periods, as illustrated below:

	Winter		Summer	
Peak	Standard	Off-Peak	Standard	Off-Peak
1	0.7	0.23	0.06	0.06

$\Delta P \text{ max}$  is the difference between the subscribed demand and the actual demand for each tariff period.

As an example, a customer subscribes for a maximum demand as illustrated below,

	Winter			Summer	
Peak	Standard	Off-Peak	Standard	Off-Peak	
100kW	300kW	500kW	500kW	500kW	

but the actual demand in the applicable tariff periods was as follows:

Winter			Summer	
Peak	Standard	Off-Peak	Standard	Off-Peak
110kW	320kW	550kW	500kW	600kW

In this case, the penalty, D, would be calculated as:

$$(110-100)*78.16*1 + (320-300)*78.16*0.7 + (550-500)*78.16*0.23 + (600-500)*78.16*0.06 = F 3244$$

The above penalty calculation is used for those customers who have a maximum demand indicator. In the case of more sophisticated electronic metering, the penalty charge is calculated according to the following formula:

$$D = k * [ \sum (\Delta P)^2 ]^{0.5}$$

*Tariff A5: EJP Option*

In addition to the Base option, customers have the choice selecting the EJP option. The EJP option is only offered to average or very high usage customers who are able to reduce their consumption drastically from 7h00 to 11h00 during 22 peak days in winter. These days are not on fixed dates. Rather, every one of these days is determined separately in "real time" by EdF. Customers on the EJP tariff are given short notice, usually not more than one day. The applicable charges in the EJP tariff are as illustrated below:

Versions	Fixed charge (F/kW/year)	Energy Price (C/kWh)			
		Winter		Summer	
		Mobile Peak	Standard	Standard	Off-Peak
Very High Usage	781.56	85.16	30.17	17.4	11.7
Average usage	301.92	209.86	35.7	19.72	12.26
Reactive energy charge (C/kVArh)		13.23			

EJP Option: Coefficient for calculating the maximum demand charge

Versions	Tariff periods			
	Winter		Summer	
	Mobile Peak	Standard	Standard	Off-Peak
Very High Usage	1	0.27	0.07	0.01
Average usage	1	0.35	0.07	0.01

The applicable demand charge and the penalties for exceeding subscribed demand are calculated as in the base case explained earlier.

### Green Tariff A8, B, C

Unlike A5 which has two seasons, and three tariff periods, Tariffs A8, B and C have four seasonal periods and three time-of-day periods. The seasons and time-of-day periods make up eight tariff periods, with a steadily decreasing cost price as indicated below. The hours per year of each tariff are illustrated below:

Position	Tariff Periods	Duration
1.	Peak	249 h
2.	Winter high-load hours	872 h
3.	Mid-season high-load hours	745 h
4.	Winter low-load hours	1039
5.	Mid-season low-load hours	719 h
6.	Summer high-load hours	1870
7.	Summer low-load hours	1778 h
8.	July-August	1488 h

It should be noted that for Tariff C, subscribed demand > 40 MW, EdF only publishes a guide tariff schedule. The special sales conditions for this tariff depend on:

- the location of the customer in relation to the interconnected system
- the possibility of modulating the subscribed demand

### The modulatable option: Tariffs A8, B and C

EdF cost-based tariff philosophy has led to the development of the modulatable option as a further enhancement on the EJP Option to customers on Tariffs A8, B and C. In the modulatable option, four tariff periods are based on a virtually real time basis. The tariff period for which the periods are determined is one week, starting on Tuesday at 7h00. The warning provided is at least 12 hours, i.e. EdF announces the tariff categories for the days of the next week on Monday before 15h00:

- *The moveable peak period, [MP]* 18 hours per day for 22 days, the days being chosen between 1 November and 31 March.
- *The moveable winter period, [MM]* for 9 weeks, all hours which are not moveable peak hours.
- *The moveable mid-season period, [MS]* for 19 weeks, all hours during the seven days of the week which are not moveable peak hours.
- *The variable low-load season, [LL]* for the rest of the year, approximately 24 weeks.

With the modulatable option, the annual maximum demand charge is calculated as the sum, over all tariff periods, of the basic maximum demand charge multiplied by the subscribed demand for each tariff period multiplied by the applicable coefficient of the subscribed demand reduction. The table below contains the 1992 figures for the modulatable option demand charge and applicable reduction co-efficients for the A8 and B Tariff options:

Version	Basic maximum demand charge (F/kW) "A8"	Coefficients of demand reductions			
		MP	MM	MS	LL
Very high usage	774.24	1	0.25	0.08	0.05
Average usage	303	1	0.31	0.09	0.05

In addition to the demand charge rates, the modulatable option also has specific energy rates in each of the four periods.

## 5.8 Taxation in the electricity industry

A notable feature of taxation on the income generated from sales is that all taxes which are raised on electricity sales and which are used to fund activities outside of the electricity industry, are transparent. In particular there are three external taxes:

1. VAT, applied to all electricity sales.
2. A municipal tax, set at between 0 and 8% of the total bill (mainly for domestic customers).
3. A provincial tax, set at between 0 and 4% of the total bill (mainly for domestic customers).

Blue tariff customers are liable for tax on 80% of their bill. Yellow Tariff customers are liable for taxation on 30% of their bill, and Green Tariff customers pay a negotiated amount of tax. A notable aspect of this taxation system is its transparency. A customer's account reflects their total bill, exclusive of tax. Taxes thereon in respect of local, regional and central government are separately calculated and expressed on the face of the account.

## 5.9 A discussion on EdF pricing

The review of the EdF tariffs so far, sets a background against which a qualitative assessment of the tariffs can be made. The discussion begins by focusing on the relationship between customer size and tariff complexity. The discussion then focuses on how supply costs in terms of voltage, power factor, time of use and maximum demand costs versus energy costs, are expressed in the different EdF Tariffs.

### *Complexity versus customer size*

The simplest EdF tariff available is the "long utilisation" Blue Tariff Option which is designed for installations such as fountains, which have a steady and continuous demand. This tariff is simply a single fixed charge in Francs per year or alternatively Francs per hundred kilowatt-hours. The next simplest tariff is the one offered to "petites fournitures" (small installations). This is the EdF equivalent of the lifeline tariff. It should be noted however, that there are more than 12 million of EdF's customers on this tariff (Forster and

Fauconnier, 1988). With this tariff the fixed charge is less than the management and metering costs. However, the energy rate is greater than that in the Base Option. The tariff is thus only applicable to those customers who consume less than 2500 kWh per year.

For the rest of the Blue Tariff, the maximum demand is not metered at all. The only sophistication in the Blue Tariff is the EJP and Off-Peak option where the energy rate differs between mobile peak hours (in the EJP tariff), peak hours in the Off-Peak tariff and standard hours.

The Yellow Tariff is pitched at customers with a capacity between 36 and 250 kVA. In the Yellow Tariff there is a maximum demand charge in Francs per kVA, seasonal differentiation and a choice of Base and EJP Options. There is also differentiation between high usage and average usage customers. The complexity and the resultant increased management and metering costs is justified on account of the size of the Yellow Tariff customers.

#### The Green Tariff

The Green Tariff, in its most sophisticated version is highly complex, with a differentiation between four seasons, two tariff periods in each of those seasons, four levels of load factor differentiation, a separate reactive energy charge and three tariff versions: Base, modulatable or EJP. The Green C Tariff for customers greater than 40 MW has no prescribed prices per se, but rather a list of recommended prices. These prices are then negotiated with individual customers based on the proximity of those customers to the transmission grid and also the ability of such customers to modulate their demand during the peak periods.

#### Cost-based pricing

##### *Voltage*

The Blue and Yellow tariffs are delivered at low voltage. Customers in each of these tariffs are differentiated with respect to their subscribed demand. For the Green Tariff, since changes in 1981, customers are classified according to their demand and not their supply voltage. The voltage of supply is taken into account in determining the different standing

charges (Francs) in the case of the Blue tariff, Franc/kVA charges in the Yellow Tariff and Franc/kW charges in the Green Tariffs.

In the Green Tariff in particular, the following voltage categories are distinguished:

Voltage Category	Actual Voltage Level
MV	1 kV to 40 kV exclusive
HV	40 kV to 130 kV exclusive
225 kV	130 kV to 350 kV exclusive
400 kV	350 kV to 500 kV exclusive

There is no rigid relationship between a tariff and the connection charge. Rather the maximum demand charge is altered based on the actual voltage of supply, thereby enabling all customers to pay the cost price of their electricity. The increases or decreases on the basic demand charge are explained in the table below:

Voltage Category	Tariff category		
	A	B	C
MV	A	B increased	N/A
HV	A decreased	B	C increased
225 kV	N/A	B decreased	C
400 kV	N/A	N/A	C decreased

The increases are applied to the maximum subscribed demand while the decreases are applied to the chargeable demand.

#### *Power factor*

In the Blue tariff there is no charge for reactive energy. Any losses as a result of reactive energy consumption have already been factored into the energy and standing charges. The Yellow Tariff does make provision for some recovery of reactive energy losses, by charging for subscribed demand in terms of kVA. This therefore provides an incentive to

the customer to ensure that the power factor of their operation does not result in excessive payments for subscribed kVA.

In the Green Tariff, an even more sophisticated method of charging for reactive energy is used. Maximum demand is measured in kW and reactive energy is free of charge, together with active power, under the following conditions:

- Up to 40% of the active energy consumed during the peak hours in December, January, February, and during the high-load hours from November to March.
- without restriction during the low-load hours from November to March and without restriction from April to October.

When applicable, reactive energy is invoiced on a monthly basis at the rates stipulated in the price schedules.

#### *Time of use*

Cost variations in respect of time of use receive a lot of attention in the EdF Tariffs. The only tariffs which are not time differentiated are those in the Base Option of the Blue Tariff for customers subscribing to not more than 18 kVA. The Off-Peak option of the Blue Tariff distinguishes between peak and off-peak periods.

The EJP (Peak Day Withdrawal) Option in the Blue, Yellow and Green tariffs is a considerable step towards real time pricing where there is one day's notice for the 22 EJP days during which the unit price is very considerably higher than for the other days. The EJP option is advanced by EdF as an improvement to traditional time of use tariffs which do not account for the additional conditions which affect supply costs i.e. demand and equipment availability. The EJP Option is able to counter for these other uncertainties by determining the EJP days virtually in real time.

As a further enhancement on the EJP Option, with the Green A8, B and C Tariffs, the customer has the choice of going on the Modulatable Tariff. This tariff extends the principle underlying the EJP Tariff by using four determinate tariff periods (with applicable charges). The relevant tariff periods for the week ahead, are announced with one day's

notice. The tariff is still a long way from a true real time tariff but is nevertheless a step towards the goal.

### *Maximum Demand related costs versus energy-related costs*

One of the greatest strengths of the EdF tariffs is that a distinction is made with respect to the level of usage in terms of the relative size of the capacity-related charges and the energy-related charges. The supply-side costing philosophy underlying this was explained earlier in the section on the development of a tariff structure based on marginal costs. The argument for usage-dependent capacity and energy costs may also be made as follows: A customer who has a high load factor uses predominantly base power stations. These stations have a high capital outlay but a low variable operating cost. Conversely a customer with a low load factor, because of the intermittent nature of his demand, causes the utility to invest in peaking plant. This plant has, by nature, a high operating cost but low capital cost. The differing costs which these two customers incur should thus be reflected in the prices they pay. Both the theoretical supply costing argument presented earlier, as well as this more practical perspective, present convincing evidence in favour of load factor differentiation of the tariffs.

### *Conclusions*

It should be borne in mind that the basis of the present tariffs originated almost 40 years ago and electricity pricing in EdF has had a stable and supportive environment in which to mature. From this analysis it is clear that in practice the EdF tariffs are broadly in line with their stated tariffing philosophy. While there is a clear emphasis on equality of treatment and efficiency, this is moderated by the practical requirement that the size of the customer must directly proportional to the tariff's complexity, its accuracy in cost reflection and the number of options available to that customer. Furthermore, with the exception of the very smallest customers for whom a specific tariff is set, the rest of EdF's customers enjoy a wide choice of different tariff options. This choice means that in order for a particular tariff to find acceptance by the customers it has to offer the customers the ability to reduce the size of their electricity bill. While this means reduced revenue to EdF, the tariff has been designed so that any reduction in revenue is at least matched by the reduction in costs. This situation is beneficial to both EdF and its customers.

## **Part 2: Lessons from EdF tariffing of relevance to the SA electricity industry.**

### **5.10 Industry structure and the price regulatory framework**

In respect of generation and transmission, there are a number of parallels that can be drawn between the French and South African electricity industries. In both countries, a single parastatal organisation has had a defacto monopoly of the industry for more than 45 years. In terms of governance of this side of the industry, both have enjoyed a largely arms-length relationship with the regulatory authorities. At the same time, in both countries, the stability of nationalisation and isolation from external interference has facilitated the development of technologically sophisticated industries.

However, on the distribution side of the industry there is a considerable difference between the industry in South Africa and that in France. In this respect, the structure of the distribution industry in SA is best likened to that of France at the time of the nationalisation. In France then, and in South Africa now, the distribution industry is highly fragmented with a large number of independent distributing authorities, each with their own resources having the responsibility for the distribution of electricity within their own areas of supply. As discussed in more detail later, the fragmentation has given rise to an enormous multiplicity of tariffs with essentially little to no effective regulation of the prices which the majority of customers in South Africa pay. By comparison, electricity distribution in France is undertaken by EdF only.

The structure of EdF is often referred to as a feasible possibility for the South African electricity industry. Indeed there are strong lobbies in favour of a national distributor a la EdF. Arguably the most attractive aspect of the French industry is the simplicity of the industry structure. Since the industry has only one supplier the triangular relationship between the supplier, the customer and the State is considerably simplified. The simplicity of the industry structure is further enhanced by the simple but effective regulatory mechanism through which the State and EdF interrelate. In this regard, reference is made to the Contract Plan. With the Contract Plan, EdF is effectively able to "buy" freedom from State interference. This has meant that although EdF is a parastatal corporation it is managed as a business and in practice is essentially largely protected from State interference.

Compared to the confusing and inefficient fragmentation of the South African EDI, it is clear why the structure of the French industry is advanced by some as a possible alternative for South Africa. Therefore, having already focused in detail on *how* electricity is priced in the vertically integrated French industry, the next section will ignore the issue of industry structure in a discussion on the applicability of the principles and practices of EdF tariffing to South Africa.

### 5.11 Lessons of principle

As discussed earlier, EdF claim that their tariffs are built on two fundamental cornerstones:

- \* Tariff neutrality
- \* Equality of treatment

Flowing from the realisation of these two principles, marginal costs came to be used as the basis of EdF Tariffs. It was and still is argued that tariffs based on marginal costs will result in economic efficiency and hence the optimal utilisation of resources. Inherent in this approach, although not plainly stated, is that tariff neutrality and equality of treatment preclude EdF from allowing any cross-subsidies to exist.

It is at this point that possible difficulties in the application of EdF tariffing to SA begin to creep in. The electricity market in France and that in SA are vastly different. EdF's "lifeline" tariff has more than 12 million customers and EdF in total has more than 28 million customers in a country with a population of about 55 million. South Africa by comparison has approximately 2.8 million domestic customers in a country with a population of approximately 40 million. In addition, in South Africa, wealth disparities between different communities severely affect their ability to pay for services such as electricity. Ultimately this means that if the principle of tariff neutrality and equality of treatment were to be applied in South Africa, only those customers who are able to afford the full cost of the service, will be eligible to receive it. The issue immediately becomes political since those who are able to afford electricity are generally those who have, in the past, been favoured by an unjust political dispensation. In the light of such historical analyses, the somewhat theoretical postulations of equality of treatment and tariff neutrality are strongly challenged.

Dismissing the use of marginal costs in SA because of inherent structural defects in the wealth distribution in South Africa may seem reasonable. However this is only one side of the debate. The principle of marginal cost pricing applied to the electricity industry was pioneered by Bioteaux in the 1950s and has been developed to a fine art in EdF. As a result, EdF have saved an enormous amount of money through optimising the utilisation of their generating and transmitting capacity. EdF have successfully proved the value of marginal cost pricing.

One possible solution to explore is the Ramsey pricing theory which allowed for price differentiation based on a customer's price elasticity of demand. Indeed, even EdF claim to use a Ramsey-Boiteaux formulation of marginal costing in their solution to the problem of differences between economic and accounting costs. However, a Ramsey adjustment to the prices paid by different customers is ultimately dependent on the knowledge of those different customer's price elasticity of demand. This becomes a highly difficult problem to solve since it requires an assessment of the wealth of each and every customer in order to determine that customer's price elasticity of demand. Alternatively some generalisation could be made such as: all domestic customers with ripple-control geysers have a lower price elasticity of demand than customers who do not have ripple-control geysers. While this may well be true for most cases, it is not true in all cases and furthermore within the category of those with/without ripple-control geysers there may be an endless number of other subjective possible ways of classifying customers into price elasticity of demand classes.

Perhaps a better solution would be to calculate tariffs based on marginal costs and then, external to the industry, calculate those subsidies or other means of funding which would make it possible to supply those who don't have the means to be able to afford the actual cost of electricity. Funds to allow such cross-subsidisation could be raised through a charge on every kWh sold. The beneficiaries of this funding would receive an account reflecting their actual cost of supply based on marginal costs and in accordance with the principles of tariff neutrality and tariff equality, but there would be an additional entry reflecting the subsidy received. In this way the efficiency-improving qualities of marginal cost based tariffs will be maintained while at the same time transparently allowing cross-subsidisation of specific customers who are not able to afford the full cost of supply.

## 5.12 Lessons of practice

### *Choice*

In EdF tariffs, the degree of tariff choice which a customer has, is directly proportional to the size of the customer. In the case of the largest customers, the principle of choice is taken to its logical conclusion in that these customers are able to negotiate customised tariff deals with EdF. However, even in the case of the smaller customers there are a considerable number of possible options.

In South Africa, as discussed in more detail later, most customers have almost no choice at all. Perhaps this is indicative of the historically entrenched supply-side orientation of the industry. In view of the fact that the customer base in South Africa varies so considerably a very strong case can be made for the development of tariff options, a-la-EdF, in South Africa. In the South African domestic sector for example, there are a number of customers with high consumption and sophisticated uses for electricity. There are also a large and increasing number of customers with very low consumption who would best be classified as "life-line" customers. Both of these customers are in the same tariff category but the nature of their consumption varies considerably. Therefore, by offering such customers a choice of different tariffs, the customer will be able to choose the tariff which best suits their operation and, if they choose to change the pattern of their consumption, will allow them to make the largest savings. If they are properly designed, the tariff options therefore allow a win-win saving shared between the supplier and the customer.

### *Subscribed demand*

All EdF customers, excluding those on the life-line tariff are required to subscribe to a specific maximum demand. For the larger customers this is taken even further in that the customers are required to subscribe to a level of demand during each different tariff period. Demand charges are then calculated on the basis of the subscribed demand and penalties are calculated should demand exceed the subscribed level. This method of charging for capacity has a number of benefits as listed below:

1. On the demand-side, customers are forced to consider their usage of electricity in calculating what the correct subscribed demand level should be. This has particular implications for large customers who have to subscribe for a specific level of maximum demand during each tariff period.
2. On the supply-side, since demand is subscribed for a year in advance, EdF have an estimate of the maximum demand during different times of the year - this has an obvious benefit in the planning process.

Furthermore, the method of getting customers to subscribe to a specific demand level does not require any special administrative effort or special metering technology on the part of EdF. Hence in view of the considerable benefits of subscribed demand, a strong argument can be made that this method of charging for capacity could be profitably applied in the South African industry.

#### *Tariff differentiation based on duration of usage*

All Yellow and Green tariffs differentiate the proportion of the total electricity costs which are recovered through the energy charge and the capacity charge. It was explained earlier that tariffs which differentiate between the relative size of the demand and energy charges based on the variations in the load factor, reflect the costs of different types of generating capacity. The argument in favour of applying load factor differentiated tariffs to South Africa can be made as follows: In South Africa, in the large customer category a significant amount of electricity is sold to the gold mining and ferrochrome industries. The nature of the operation of these two different types of customers results in Gold Mines having high load factors while ferrochrome industries have relatively low load factors. These different customers, because of their different load factors, cause Eskom to construct different types of power station with different relative sizes of capacity and operating costs. At present however, the only differentiation between these customers is in terms of the time of maximum demand (Tariffs A & E) and the time of energy consumption (Tariffs T1 and T2).

#### *Transparency*

In EdF tariffing, transparency is a valued principle. This is reflected in the VAT charges and the levies (calculated on the total electricity price) in support of local and regional government. This contrasts with the situation in South Africa where the actual amount of the electricity price charged by local authority electricity undertakings which constitutes a contribution to the coffers of local government, is not known with any certainty.

The concept of transparency also extends beyond taxation and levies to the calculation of the actual cost of supplying any particular type of customer. Once this has been achieved, any intra-industry cross-subsidies between different consumer classes or even within consumer classes will be publicly known. In so doing, departures from the economically efficient marginal cost prices, in the name of social subsidies, or any other reason for that matter, can be quantified.

#### *Time of use pricing*

In the history of EdF tariffing, time differentiated tariffs were first introduced in the 1950s as a result of the implementation of the Boiteux application of marginal cost tariffs to the electricity industry. Since then, time of use has played a progressively larger role, so that today customers on the Green Tariff have a choice of three different time of use options: The Base Option which is a standard time of use tariff, the Peak Day Withdrawal Option whereby the energy price escalates dramatically for 22 days of the year, or the Modulatable Option whereby four time periods with applicable charges are determined on virtually a real-time basis. The time of use tariffs have been very successful as indicated by a steady increase in the system load factor between the 1950s and the present. By comparison with France, South Africa's first time of use tariff is yet to be promulgated. It is clear that time wasted on rediscovering the wheel can be prevented if EdF's 40 years of experience in time of use tariffing is used in the further development of such tariffs in South Africa.

## 5C PRICING IN ZIMBABWE

### 5.1 Introduction

At the end of 1992, it was forecasted that in the following year, Zimbabwe would lose 57000 jobs and Z\$2.5 billion in GDP through electricity rationing as a result of expected electricity shortages of up to 30% (Robinson and Dale, 1992). In 1993, the newspaper headlines such as "Zimbabwe - the Heart of Darkness" and "Zimbabwe's power crisis causes anger" appeared frequently in the local and Zimbabwean presses.

The Zimbabwean electricity industry is an industry in crisis, in more ways than one. Robinson (1992) presents a very bleak picture of the state of the industry. Some of the issues include:

- \* Inability (of the industry) to supply existing customers with sufficient energy
- \* Inability to redress the backlog of suppressed demand or respond to requests for connections associated with major projects;
- \* Unhelpful political intervention
- \* A continued lack of foreign exchange
- \* A steady loss of trained and experienced staff
- \* Conflicts between the ZESA Board and the Minister of Energy

Zimbabwe's electricity pricing policy - in as far as it fulfils the roles explained in the beginning of the first chapter - has contributed to the current parlous state of the industry. To place a discussion of electricity pricing in Zimbabwe in context, this chapter begins with a discussion of political and economic realities in Zimbabwe. The chapter then discusses the development of the Zimbabwe electricity industry. This is followed by an analysis of the increasing supply/demand imbalance in the industry. The chapter then attempts to explain the role that electricity pricing has played in the industry.

### 5.2 Political and economic realities in Zimbabwe

Independence in 1980 brought an end to white minority rule in Zimbabwe. It also brought an end to 15 years of Unilateral Declaration of Independence (UDI) during which the right-wing Rhodesian Front under Smith, had governed Rhodesia in the face

of strict economic sanctions from Britain and the United Nations. When Robert Mugabe became the first Prime Minister he promised to create a non-racial society, to rebuild rural areas damaged by war and to construct a socialist economy on the principles of Marxist-Leninism (The Economist Intelligence Unit, 1992:1).

At the time of Independence, Zimbabwe had one of the most diversified economies on the continent. On the one hand the economy had a developed and efficient agricultural and mining industry and a manufacturing sector producing a more complex range of products than any other countries in the sub-Saharan region apart from South Africa (The Economist Intelligence Unit, 1992:15). On the other hand there was a highly uneven pattern of income and access to economic assets such as land and housing, and to the key social services of education and health. Its colonial history having initially been dominated by private foreign capital, the Zimbabwean economy was basically capitalist.

The coming to power of a government whose legitimacy and power were based not only on a nationalist and anti-racist platform but also on an explicit commitment to socialism appeared to set an agenda which would seek to correct social, economic and racial inequalities.

In terms of social upliftment and development, Zimbabwe made some impressive progress: Education expansion has been impressive. The expansion achieved a growth in school enrolments greater than anywhere in Africa in the post-colonial period: total enrolments rose from 892 000 in 1979 to 2.96 million in 1989, with the transition rate from the top of primary to the first year of secondary school rising from 28% in 1980 to 66% in 1989. In 1980 Zimbabwe had fewer than 200 secondary schools; by 1989 it could boast more than 1500; enrolments at teacher training and technical colleges trebled and university enrolments increased fivefold. (The Economist Intelligence Unit, 1992 p18) However, while there are now about 200 000 school leavers per annum there are only about 60 000 to 70 000 formal sector job openings (Zimbabwe Structural Adjustment Program (World Bank), 1991:3). In the area of health care, in the 9 years from 1980 to 1989, the percentage of children fully immunised has more than tripled from 25% to 86%; infant mortality has declined from 86 to 61 per 1000 births and life expectancy has increased from 55 to 59 years (Zimbabwe Structural Adjustment Program, World Bank, 1991:2).

However, while it is clear that in the first 10 years of independence, considerable gains were made in the social services, there was a considerable decrease in investment in the productive sectors of the economy. Private sector investment as a share of GDP fell to 8% in 1987 and government took far greater direct control of the business sector (Zimbabwe Structural Adjustment Program, World Bank, 1991:3). In addition to the constraints of a financial nature, businesses experienced price controls, credit controls, wage controls and labour legislation that limited employers' rights to discharge or retrench labour without permission of the ministry of labour. With these came rent controls, interest-rate ceilings for foreign-controlled companies depositing surplus funds, borrowing limits based upon a company's degree of local ownership, dividend remittance restrictions, investment and disinvestment controls, immigration controls and severe restrictions upon the employment of expatriates (Baynham, 1992:108). Generally confrontational attitudes made themselves felt between the business sector and government. These attitudes seem to be of some importance today, with vice-president Joshua Nkomo accusing whites of being disrespectful of Mugabe and of attaching greater importance to the Commercial Farmers' Union and the Confederation of Zimbabwe Industry than they do to the Zimbabwe Government (Saturday Star Newspaper, Johannesburg, August 21 1993).

Another distinct aspect of the first 10 years of independence was the growth of external debt in government and the parastatals (parastatals include Zimbabwe Iron and Steel (ZISCO), Zimbabwe Water and Zimbabwe Electricity Supply Authority (ZESA). In 1981, government debt stood at Z\$ 73 billion, by 1988 this had risen to Z\$ 584,5 billion. Parastatal debt rose from Z\$ 2.7 billion in 1981 to Z\$ 264.4 billion by 1987 (Baynham, 1992). In the case of ZESA, overall foreign debt repayments amount to more than Z\$ 760 million per annum. By comparison, private sector debt was Z\$ 27 million in 1981 and Z\$ 27.9 million in 1988. The huge increase in government and parastatal debt has meant that large amounts of foreign exchange have been channelled into servicing these debts and hence preventing any hope of systematic capital goods replacement in the business sector. Even regular maintenance programmes have had to be abandoned by most companies. In many instances the foreign exchange allocated has had to be used for raw materials almost to the total exclusion of replacement goods. Often because production staff could not be laid off production simply had to continue (Baynham, 1992:71).

It is against the background of the social development successes but the failure to stimulate private sector investment that the Zimbabwe government formulated a

comprehensive program of structural adjustment. The program entitled "A Framework for Economic Reform" was discussed and widely supported by the IMF and World Bank. The program is a departure from pervasive direct controls, to market forces. Its central components are: (Zimbabwe Structural Adjustment Program, World Bank, 1991:3)

- "
1. Fiscal deficit reduction coupled with prudent monetary policy.
  2. Trade liberalisation.
  3. Domestic deregulation.
  4. Measures to alleviate the impact of reforms on vulnerable groups. "

The key objectives of the program are to increase investment and improve efficiency. The cost of the package was estimated at Z\$4 bn by the government and Z\$7 bn by the Confederation of Zimbabwe Industries (The Economist Intelligence Unit, 1992:13).

There are a number of aspects of the structural adjustment program which will directly impact the electricity supply industry. In particular the Structural Adjustment Program (SAP) aims to reduce central government deficits by reducing parastatal subsidies (3.7% of GDP in 1990/1991). These subsidies are expected to fall as a result of comprehensive programs to improve parastatal efficiency, improvements in pricing policy and actions to reduce the size of the parastatal sector. In respect of pricing policy, the World Bank recommends the replacement of administered prices by market determined prices for parastatals operating in a competitive environment and allowing a degree of automaticity and parastatal autonomy for public utilities. Other, sector-wide actions will be taken to improve the economic performance of parastatals. The legal framework within which parastatals operate, will be overhauled to ensure that boards of directors are given sufficient autonomy and responsibility to operate in line with their mandates. The respective roles of ministries, boards of directors and management will be clearly defined.

The key aspects of the SAP relating to parastatals have specific relevance to ZESA which has been noted for the degree of direct government interference and political nepotism which characterised its governance.

### **5.3 A history of the development of the electricity industry**

Electricity was first introduced into Rhodesia in 1897 with the formation of the Bulawayo Electricity Company. This was followed a short while later by the Salisbury

electricity company. After the formation of these electricity companies, construction of municipal power stations - which were all coal-fired - followed progressively. Later as demand for electricity increased steadily, particularly among mining and farming customers, authorities soon realised the need to formulate a proper energy policy which would respond quickly to the country's energy development needs. This led to the promulgation of the Electricity Supply Act which took effect from 1 July 1936 and brought the Electricity Supply Commission (ESC) into being. The Act assigned to the ESC the duties of investigating "new or additional facilities for the supply of electricity within an area, and co-ordinating and co-operating with existing undertakings where required" (ZESA 1991a).

By 1940, in addition to power stations at Gweru, Kadoma and Mutare, the commission had established new stations at Gwanda Munyati and Zvishavane. It was at this stage that the idea of harnessing the Zambezi River at the Kariba Gorge, was conceived. The damming of the river began in 1955 and, after completion in 1958, the Kariba Power Station was officially opened by Queen Elizabeth in 1960. The Kariba station had been built by the Federation of Rhodesia and Nyasaland to serve both Zambia and Zimbabwe, the Federal Power Board, later reconstituted as the Central African Power Corporation (CAPCO) was created to run the power station (ZESA, 1991a).

During the period that the Kariba dam was built, the 330 kV transmission network linking the interconnected system in Zambia and Zimbabwe and joining the towns of Kitwe and Bulawayo was constructed. By the time of its dissolution in 1964, the Federal Power Board had over 1488 km of 330 kV line constructed (ZESA, 1991a).

In the meantime, the ESC had been given jurisdiction for the distribution of power to the whole country excluding the four largest municipalities. In addition, ESC operated Munyati Power Station to schedules set by CAPCO. In the urban areas of Harare, Mutare, Bulawayo and Gweru, the councils had the mandate to distribute power. This was the situation until 1983 when the government approved in principle the amalgamation of electricity utilities in Zimbabwe under one umbrella body (ZESA, 1991a).

The instrument giving effect to amalgamation of the electricity supply authorities in Zimbabwe, the Electricity Act, 1985, was debated in Parliament during the first quarter of 1985 and assented to by the then President Cde Canaan Banana on 5 April 1985. On 24 April 1986, the Act came into legal operation and paved the way for the amalgamation and unification of the five Zimbabwean electricity authorities and the Zimbabwean portion of CAPCO's operations into one organisation - the Zimbabwe Electricity Supply Authority (ZESA). The Act stipulated the functions of ZESA as being: (ZESA, 1991a)

- "
1. To acquire, generate, transmit, distribute and supply electricity;
  2. To investigate new or additional facilities for the generation, transmission distribution or supply of electricity and, to advise the Minister of Energy of the result of such investigations and;
  3. To acquire, control and operate other electricity undertakings within Zimbabwe.
- "

The formation of ZESA heralded a new era in the Zimbabwean electricity industry. From this period onwards the control of the industry was firmly rooted in political hands. In addition to the above-mentioned functions, in terms of the Act a number of key managerial/business decisions have to be referred to the minister for ratification, including: appointment of a General Manager; tariff increases; investment proposals (also to be approved by the ministry of Finance); and the negotiations of agreements with supply authorities in neighbouring states. The move to create ZESA may be seen as being consistent with the government's socialist ideology (Robinson, 1992). As an aside, it is interesting to note the parallels between this regulatory structure of the industry - which ensured a high degree of political control - and the recommendations of the South African Government's Board of Trade and Industry Report (1977) which had recommended something similar for South Africa's electricity supply industry almost a decade earlier.

#### **5.4 Increasing supply/demand imbalances in the electricity industry**

##### *Demand side*

In 1980, per capita power consumption in Zimbabwe was one of the highest in the East Africa region (928 kWh per capita in 1980), largely because of the manufacturing and mining sector which together consumed about 69% of the total electricity produced.

Electricity provided 31.5% of the total energy consumed in Zimbabwe in 1980 (Mian, 1982:5).

Between 1980 and 1990 electricity sales increased by 83.6%. However, this growth was not even throughout the period, with load growing by 56.9% between 1985 and 1986 and only by 12.2% between 1986 and 1990 (ZESA 1990 Annual Report). In 1980, sales to the mining sector accounted for roughly 2.6 times the sales to the domestic and municipal sector. In the same year, sales to industry were 5 times as much as the total sales to the domestic and municipal sector (ZESA 1991 Annual Report). However, mining consumption as a percentage of total consumption decreased by 10.2% between 1960 and 1980, while industrial consumption increased by 3.3% in this period (ZESA 1990 Annual Report).

In 1989, electricity sales to various classes of consumer were as follows: (Source: ZESA, 1992:20)

Sector	Sales %
Mining	17.5
Industrial	48.5
Agricultural	8.2
Domestic & Other	25.8

In 1980 the electricity sector had only about 190 000 domestic customers, which accounted for 16% of all households in Zimbabwe (Mian, 1982:31). In 1990, there was an aggregate total of 267 871 domestic connections. However in the same year there were 176 000 outstanding applications for domestic electricity supply. Furthermore, progress in making new connections appears to be totally inadequate, with the number of connections actually decreasing by 1753 between the 1988 and 1989 financial years (ZESA 1989 and 1990 Annual Reports).

### *Supply side*

In 1981, to determine the least cost generation and transmission solution to meet Zimbabwe's expected demands for power in the country, the government commissioned a Power Development Plan study. This plan recommended the construction of various power stations to meet the forecasted load growth. (Growth rates were based on 7.2% per year for 1980 - 1990 and 6.1% for 1990 -2000. (Actual growth for the period 1980-1990 was less than expected). The least cost development program to meet the expected power demand growth was explained as follows:

Plant	Size [MW]	Commissioning year
Hwange Stage 1	480	1982/83
Hwange Stage II Phase 1	400	1985
Kariba South Extension	300	1987
Kariba North Extension	300	1988
Hwange Stage II Phase 2	400	1989
Batoka Dam and South Bank Power Station	800	1991
North Bank Power Station	800	1994
Mupata Gorge Dam and South Bank Power Station	600	1996
North Bank Power Station	600	1998
Sengwa	600	2000

Most of the projects have not been implemented to date for what ZESA describes as "various reasons, mainly related to the availability of finance, both local and foreign currency" (ZESA, 1992: 22).

The one project, Hwange Power Station, which did eventually come to fruition is, ironically, one which the Smith government initiated in the late 1970s to achieve greater independence from Zambian imports. Smith was unable to complete the power station during the period of UDI since sanctions against Rhodesia made it impossible to acquire the necessary equipment. However, following Independence these sanctions were relaxed and the Zimbabwean government decided to embark on what has been the largest capital development project since independence.

The second phase of Hwange was eventually commissioned in 1987. The station has thus far not had a particularly successful history. Plant has already had to be upgraded in order to achieve design capabilities. Furthermore, difficulties in obtaining foreign exchange have led to incidents where a unit had been taken out of operation for 106 days because of difficulties in arranging foreign exchange to purchase a pump for Z\$ 6000 (Robinson, 1992:3). Today Hwange is not capable of producing greater than 844 MW compared to a design capacity of 920 MW.

Hence, the generating capacity of ZESA at August 1993, consisted of

Plant	Maximum Capacity [MW]
Kariba South	666
Hwange	734
Small Thermals	158

In addition to this generation capacity, there is currently a limited 40MW from Eskom as at January 1993; though this will increase considerably after the completion of the Matimba-Bulawayo 400 kV line.

As a result of insufficient capacity and the resultant excessive usage of the Kariba South power station since 1981, the Kariba Dam became considerably overdrawn. By 1992, the supply crisis reached a head when the Kariba Dam reached its minimum operating level in August resulting in a complete system failure (ESMAP, 1993). The crisis led to the establishment of a quota system to attempt to ration electricity supply.

### **5.5 The contribution of electricity pricing to the current crisis in the electricity industry**

The current state of the Zimbabwe electricity supply industry is the result of a number of different factors, some of which have already been described in this chapter. Electricity pricing in terms of both structure and price level has contributed to the inefficient utilisation of the electricity infrastructure. It has also contributed to undermining the financial viability of the supply industry.

The first issue to be broached in the tariff debate is that of the regulatory structure. Throughout the history of the industry, the regulatory structure of the industry has provided no incentive for economically efficient pricing. This is evident both before and after the creation of ZESA. Before ZESA, the primary supply was undertaken by the Electricity Supply Commission and through the four municipal distributors. In the case of the former, the strong governmental relationship meant that the Commission was used as a tool to attract industry to Zimbabwe through low prices (ESMAP, 1993:5). In the case of the latter, the issue of price level and structure was referred to the local municipal councils who as in South Africa at present, set prices as far as possible to the liking of the bulk of their electorate: the domestic customers. From a pricing point of view the regulatory structure only worsened with the creation of ZESA. In particular the 1985 Electricity Act stipulated that pricing issues in particular were to

be referred to the government for ratification. The concept of arms-length control which is currently seen as a vital aspect of control of the electricity industry had effectively been ignored, and the industry became a tool of the government in the implementation of its social development programs. Evidence of this is clear from the ZESA Chairman's 1990 Annual Report addressed to the Minister of Energy and Water Resources and Development where he expressed the hope that "the Government will seriously address the question of energy pricing in this country, and come up with clear guidelines on pricing, in order to avoid subsidies and promote stable prices and efficient electricity use" (ZESA 1990 Annual Report:1). Evidently these hopes were not fulfilled since, in the 1991 Annual Report, the ZESA Chairman reported with a sense of frustration, the fact that the government's failure to approve tariff increases had resulted in a record deficit (ZESA 1991 Annual Report:4).

Further evidence of the heavy hand of government is to be seen in the average price of electricity as illustrated in Table 1 below: (Source: ESMAP 1993) where the average prices of electricity for the different customers, evidence the high degree of cross-subsidisation of the domestic and agricultural customers. This is clear in view of the fact that the average domestic and agricultural customers are much more costly to supply than the average industrial or mining customer, and yet almost all customers enjoy much the same average price.

Consumer Category	Number of Customers	Total consumption [GWh]	Tariffs (Z \$) Dec 1991
Metered Domestic	145 769	1116.65	
Monthly Charge			12
Energy			
First 300 kWh			0,1085
Balance			0,1266
Average Price \$/kWh			0.1369
Load Limited Domestic	134 245	477.49	
1A			8.7
2.5A			13.05
5A			20.3
7.5A			28.2
10A			45.9
15A			65.81
22.5A			95.06
30 A			128.81
Average Price \$/kWh			0.0951
Commercial, industrial and mining < 300 kVA	32 167	1073.98	
Monthly charge			30
Energy charge			0.1163
Average Price			0.1271
Agriculture < 300 kVA	8531	712.38	
Monthly charge			30
Energy charge			0.1221
Average Price (\$/kWh)			0.1264
Commercial, Industrial & Mining > 300 kVA	1156	2579.16	
Monthly charge			100
MD/KW/Month			30
Energy charge			
Peak			0.0309
Off-Peak			0.0266
Average Price (\$/kWh)			0.1387
Agriculture > 300 kVA	86	110.24	
Monthly charge			100
MD/kW/month			28.9
Energy			
Peak			0.0309
Off-Peak			0.0266
Average Price (\$/kWh)			0.1388
Special customers			
3 Mining and 4 industrial	7	2923	Confidential

**Table 1. ZESA Tariffs at 1 Dec 1991**

Besides the inefficient cross-subsidies between customer classes, a major reason for the current crisis can be drawn back to the fact that between 1960 and 1980 the price of

electricity decreased considerably in real terms. During this period, the largest capital cost was the Kariba South Hydro station commissioned in 1960. In addition, operating costs of the hydro station were very low. Hence based on the historical cost methodologies used to calculate the price, there was no reason to increase the price during the period. However the failure to increase the price meant that ZESA became severely handicapped in its ability to meet the considerable capital costs necessary to expand the supply infrastructure to meet the continually growing demand. As a solution to the problem of the backward looking historical average cost principles, the United Nations/World Bank Energy Strategy Management Assistance Program (ESMAP) stipulated that prices should be based on forward-looking Long Run Marginal Costs. ZESA have supported this in principle. In addition, ESMAP emphasised the need for effective time of use tariffs as part of a demand side management program.

In 1992 ZESA began implementing some radical price increases. However these price increases seem to be based more on basic revenue requirements than on any thorough analysis of Long Run Marginal Costs. Evidence of this is that the price increase to industrial and commercial customers has been in excess of 120% while the increase to domestic customers was around 40 % thereby further aggravating the existing cross-subsidies (ESMAP 1993, Annexure 3).

Perhaps the over-riding impression of the Zimbabwean pricing policy is one of irony. During the colonial era, the government used the Electricity Supply Commission to provide a cheap source of energy to attract and sustain industry and mining. The municipalities, while they had a licence to supply, also used their control to ensure that municipal customers had cheap electricity. Following the formation of ZESA, the Zimbabwe government sought to use the income generated from the industrial and commercial customers to subsidise the domestic customers. At the same time the average price was not increased sufficiently to ensure the long term financial sustainability of the industry. As a consequence, by 1991 ZESA was one of the few electricity utilities in the world known to make a loss. In 1992, there were several power shortages and on one occasion the whole system failed. In addition, at a time when there were more than 176 000 applications for supply outstanding, ZESA was disconnecting existing customers and rationing supplies, costing the country millions. But this was the exact opposite to the desired result: The desired result was one in which a low electricity price supported the social development of the country's people and the economic development of the nation's resources. In this irony, the ZESA study provides invaluable insights.

## **CHAPTER 6 TOWARDS A PRICING STRATEGY FOR THE SOUTH AFRICAN ELECTRICITY SUPPLY AND DISTRIBUTION INDUSTRY**

The objective of this chapter is to present some ideas on a possible short, medium and long term pricing strategy for the South African electricity supply and distribution industry. The chapter begins with a review of the key issues discussed in the preceding chapters. It then briefly presents a vision for optimal tariffing in South Africa. The final section of the chapter then describes a three phase process reflecting different structural phases of the industry and the pricing practices applicable at each stage.

### **6.1 A review of the previous chapters**

#### *6.1.1 Chapter 2: A theoretical framework for electricity pricing*

\* A tariff can be seen as a mechanism which arbitrates between the interests of the customer, the supplier and the State. A well formulated rate structure can discourage waste and foster the efficient use of the national resources of capital, energy and manpower.

\* There are frequently a number of conflicting criteria which need to be compromised in establishing a pricing policy. Economic efficiency, equity, fairness and administrative feasibility are widely held as four essential criteria for a pricing policy. However, the pursuit of a high degree of economic efficiency may be administratively impossible and may contravene the principles of equity and fairness. Similarly, a rigorous pursuit of the latter will compromise the former.

\* Electricity costing has developed significantly from the early days of Hopkinson and Wright. Today it is accepted that for a tariff to be truly cost-reflective it must incorporate charges for the quantity of energy supplied, the maximum demand of supply, load factor, diversity factor, geographical location, voltage of supply, power factor and time of use.

\* The provision of electricity may be costed either according to the principles of absorption costing or marginal costing. In the case of the former, costs which are directly attributable to a unit of output are allocated to that unit. Common costs which are not

directly attributable to a particular unit of output are shared amongst all output. The marginal costing approach seeks to determine costs which will lead to economic efficiency. In the domain of welfare economics, the net social benefit is maximised when demand is met at a price equal to marginal costs.

\* Unless supply and demand is perfectly balanced, marginal costs and accounting costs will differ. Hence if marginal costs are used there will be over or under-recoveries with respect to accounting costs. However, normal business practice does not tolerate wide variances in costs from one period to the next, as results from the use of short-term marginal costs. To a certain extent the tariff instability resulting from short-term marginal costs, can be ameliorated with the use of long run marginal costs. However, as Teplitz-Sembitzky (1990) points out, long run marginal costs can only be calculated with any certainty, in a industry which has a perfectly known future.

\* All electric utilities which apply economic marginal costs, whether they be long run marginal costs or short run marginal costs are ultimately forced to compromise the pursuit of pure economic costing so that accounting costs are consistently stated from one year to the next.

\* Although marginal costs were first applied to the electricity supply industry in the early 1950s, they only gained widespread acceptance after the energy crisis of the 1970s lead to a greater quest for economic efficiency. Today the principle of marginal costing in the electricity supply and distribution industry is recognised world-wide.

\* Competition as a prime determinant of electricity prices is becoming increasingly popular amongst different electricity utilities world-wide. In a truly competitive industry, price is determined by the interaction of supply and demand. In this scenario, complex arguments over marginal costs or fully distributed costs are rendered meaningless since it is ultimately the market which determines the applicable price. However en-route to this truly competitive state, it is possible to simulate competition amongst different suppliers though incentive competition. A commonly used form of incentive competition is to index allowable price increases against a suitable index such as the Consumer Price Index.

\* Non-tariff pricing which is defined as the process of "determining the price parameters for individual customers on a case-by-case individually customised basis" is

playing an increasingly important role in electricity pricing internationally. Non-tariff pricing is of particular relevance to the South African electricity industry where a handful customers account for a very significant proportion of total electricity consumption. By developing customised contracts for such customers, many of the simplifications of conventional tariffs may be avoided.

### 6.1.2 Chapter 3: *The development of the electricity supply industry in South Africa*

\* In the first period of the industry from 1882 to 1948, the trend in the development of the supply industry was from private ownership to public ownership, from fragmentation to consolidation and from private control to public control. The impetus for the development of the electricity industry in South Africa has never been of its own making but rather it has been as a response to the development of industries and communities for whom electrical energy has been a necessary resource. A key turning point in this period was the 1922 Electricity Act which provided for the establishment, acquisition, maintenance and workings of an electricity supply commission which would oversee the efficient supply of electricity. The establishment of such a commission set in place the structures for a centrally controlled supply industry under public control. Furthermore, in terms of the provisions of the Act, the privately owned Victoria Falls and Transvaal Power Company could be expropriated after a period of 38 years. Prices to be charged by the private electricity suppliers were to be regulated through an Electricity Control Board. However, while the supply industry was becoming increasingly centrally controlled, the distribution industry was becoming increasingly fragmented. This is because the influence of the Electricity Supply Commission did not extend to include municipal electricity distributors who were exempted from applying for a licence to supply. Instead, municipal distributors were regulated separately by their Local Authority Councils and respective Provincial Administrators, as had been established by the various Provincial Ordinances at the beginning of the century.

\* The second period in the history of the industry began around the time of the expropriation of the Victoria Falls and Transvaal Power Company which effectively marked the end of any significant amount of private ownership of electricity supply and distribution infrastructure. By this stage there was nothing standing in the way of Escom from becoming the dominant player in the supply industry. Indeed, from 1948 the industry

grew very rapidly with close to double figure annual electricity sales increases, on average, for each year between 1950 and 1974. However, from 1973 onwards, although the industry continued to grow strongly there was considerable customer dissatisfaction concerning unacceptably high tariff increases. This resulted in the Board of Trade and Industry (BTI) Investigation into the Electricity Supply Industry. One of the recommendations of this investigation was that there should be a greater degree of government involvement in the activities of Eskom. The BTI investigation was followed shortly after by the 1984 De Villiers Commission of Inquiry into the Supply of Electricity in the RSA. The De Villiers Commission recommended far-reaching changes to the control and management of the industry. Specifically, the following recommendations were made:

1. The principle of operating at neither a profit nor a loss should be discarded in favour of a sound assets and income structure complying with certain requirements.
2. The industry should be integrated and production costs (excluding transmission and distribution costs) should be centrally pooled.
3. A permanent Board of Control, whose Chairman would be appointed by the State President, would be responsible for the supervision of an independent Eskom management board.
4. The task of the Eskom Management Board would be to run Eskom properly.

Most of the recommendations of the De Villiers Commission took effect through the Eskom Act of 1987 and the Electricity Act of 1987. Through the Eskom Act, the supply industry was largely rationalised and placed at arms length from government control. The respective acts also provided for customer representation at the highest level of the industry.

However, the positive developments in the supply industry did not reach into the distribution industry. Legislation written in the early 1900s provided for a high degree of Local Authority control over their own electricity distribution departments. This resulted in a high degree of fragmentation of the industry and through direct political control by their local authority councils, municipal electricity distributors have largely been used by their

local authority councils to re-distribute wealth from the productive sectors of the economy in favour of their white voters. Furthermore, through the apartheid inspired creations of the Bantu Administration Boards in 1973 and the Black Local Authorities in 1982, the provision of electricity to developing and disadvantaged communities was further neglected. The specific impact which this tangled and structurally defective distribution industry has had on electricity pricing, is reviewed in the next section.

6.1.3 *Chapter 4: Past and present electricity pricing in the South African Electricity Supply and Distribution Industry*

\* The previous section reviewed the circumstances which gave rise to the Board of Trade and Industries and De Villiers Reports on the state of the electricity supply industry in South Africa. The implication of these reports on the structure and governance of the industry was also explained. Relating to pricing policy, the BTI report produced a number of interesting conclusions and recommendations. Specifically, regarding the cost allocations which formed the basis of tariffing in the municipal sector, the report concluded as follows:

"The majority of municipalities are vague (with regard to cost allocations) and it appears that sophisticated methods are not applied. A number of these municipalities stated that they follow Escom's policy as nearly as possible without indicating what it means. In two cases, tariffs were restructured about thirty years ago and in one case it was not possible to determine how tariffs were structured. In two further cases where the methods of allocation were described it was stated in the first case that own costs are allocated according to a fixed rule and in the other case that demand related costs are allocated to consumer groups according to their kWh consumption."

Further recommendations arising out of this report were as follows:

- :- Fund accounting should be dropped in favour of current cost depreciation accounting.

- :- The industry should be allowed to make a profit. However this profit should be regulated by the government.
- :- There should be a greater extent geographical equalisation of the Eskom tariffs, through greater cost pooling.

The BTI report also introduced the idea of marginal costing though without making any specific recommendation that it should be used in the industry. It is interesting to note that at the time of the BTI report, Eskom strongly opposed the use of marginal costs in the industry.

\* The De Villiers Commission of Inquiry in 1983, into the supply of electricity in South Africa, marked a new era in electricity pricing in the industry. One of the central recommendations was that "Eskom should assume a leading role in the conservation of energy and electricity while preventing prices from rising too rapidly and the generation of electricity from making excessively high capital demands on the economy. Its objective should be the maximum utilisation of resources and capital in the economy through the optimum use of energy and electricity."

\* In accordance with the objective of increased savings and efficiency, the report recommended that customised price deals and time of use tariffs should be developed. However, strangely enough, the study argued against the use of marginal costs. Instead it recommended a "consumer privileged" philosophy which promoted the use of embedded accounting costs instead of economic marginal costs.

\* At present, Eskom supplies more than 96% of South Africa's electrical energy. All Eskom energy is "sold" firstly via a Generation Tariff between the conceptually independent Generation and Transmission businesses. The objective of the Generation Tariff at present is to attempt to induce some competition between different power stations in an attempt to induce the optimal utilisation of the generation infrastructure. However this objective is constrained by the centrally controlled production optimisation plan which effectively limits the amount of discretion which individual power stations have to influence their own operation.

\* The Eskom Transmission Tariff is used to charge for electricity sold between Transmission and the five Distributors. The 1994 Transmission Tariff consists of three specific charges:

- :- A network charge designed to recover Transmission's own revenue requirement.
- :- A time of use charge designed to recover the total fixed and part of the variable components of the costs of generation, including a predetermined return on generation and transmission assets.
- :- An hourly marginal energy rate designed to recover part of the variable components of the cost of Generation and Transmission.

The network charge is a fixed monthly payment in respect of each point of supply (Main Transmission Substations). The time of use charge is based on the expected minimum load for every point of supply. The hourly marginal energy rate is applied to consumption in excess of the expected minimum load.

The Transmission Tariff is probably the most sophisticated tariff currently used in the industry but it remains to be seen whether it is administratively workable.

\* A number of bi-lateral agreements exist between Eskom and various international customers. The objective in the structuring of these agreements is to move progressively towards a "power pool" which will operate following the transmission network interconnection of a majority of sub-Saharan countries. It is clear that a considerable amount of work remains to be done in this area not only in terms of the working's of such a power pool but also in terms of the transmission infrastructure which will need to be constructed in order to effect real power flows between the different participants in the pool.

\* The pricing policy governing Eskom Distributor sales to end-user consumers and non-Eskom re-distributors is defined as follows:

1. " Electricity pricing must ensure that national economic resources are allocated efficiently, not only amongst different sectors of the economy, but also within the electricity industry. This implies that prices that reflect costs must be used to indicate to

customers the cost of supplying their specific needs, so that supply and demand can be matched efficiently."

2. The objective of fairness and equity in electricity pricing must be satisfied by allocating costs among customers according to the burdens they impose on the system. The allocation of costs must be such that a reasonable degree of price stability and predictability is maintained. "Fairness and equity" also means that Eskom's prices must be such that a minimum level of service to customers who may not be able to afford the full cost, can be provided.

3. Electricity prices must raise sufficient revenues to meet financial requirements. The structure of prices must be simple enough to facilitate metering and billing of customers. Finally, other economic and political requirements must be considered. Such requirements may include, for example, subsidised electricity supply to electrically under-developed areas in order to catalyse growth. "

\* The profitability amongst Eskom's different regional operations varies quite significantly. Those regions with large industrial or mining customers are generally more profitable than those areas that serve predominantly domestic or rural customers. The profitability in each area depends largely on the cost of purchases on the Transmission Tariff, but it is also dependent on the distribution capital costs and operational costs allocated to customers served in that area.

\* The highly simplified nature of the large power user two-part tariff, Tariff A, renders this tariff a dismal failure when judged against Eskom's stated pricing criteria. Tariff E, the two-part tariff for off-peak users, which is at best a tentative step towards time differentiated pricing faces, similar criticism.

\* The recently developed time of use tariffs seek to address some of the criticisms that are levelled against Tariffs A and E. The time of use tariffs encountered considerable opposition from municipal electricity distributors since these tariffs recover a much smaller amount of total revenue from the demand charge than it does from the energy charge and hence the extra revenue municipal distributors could derive through the benefit of diversity was considerably reduced. Some opposition was also encountered from mining customers who argued that the proposed tariffs would result in high load factor customers paying

more than they would on Tariff A. However this argument was refuted by Eskom on the basis of the fact that the calculation of the demand charge in Tariff A meant that low load factor customers were effectively cross-subsidising high load factor customers.

\* Eskom currently offer a range of five small power user tariffs, specifically tailored to suit different types of small power users. However, in practice, customers are relatively limited in their choice of different tariff options. It is suggested that perhaps a better solution would be to develop two or three generic structures and allow customers to choose the particular tariff which allows the user to minimise their cost of purchases. Extra charges such as connection fees, a transmission surcharge etc. could then be charged on top of the basic tariff.

\* Customised pricing plays a significant role in Eskom tariffing with 30 customised deals earning more than R360 million and accounting for approximately 10% of total Eskom sales for 1993.

\* The salient features of the non-Eskom distribution industry are as follows:

- In the non-Eskom distribution industry there are a total of just over 300 electricity distributors including separate Black and White Local Authority municipal distributors, Regional Services Councils, "Self-governing State's" and "National State's" Electricity Departments. White Local Authorities' Electricity Departments provide an adequate service to their approximately 2 million customers. Within their areas of jurisdiction, these electricity departments have achieved close to 100% electrification. However only approximately 1,8 million of a total of more than 7 million dwellings in South Africa, have electricity. The electrification of these currently unelectrified dwellings is an immediate priority in the distribution industry.
- The regulatory structure is best described as a "tangled mess": White Local Authority Councils are responsible for the Electricity Departments under their jurisdiction. Similarly, Electricity Departments formed under Black Local Authorities are answerable to their Black Local Authority Councils. Municipal electricity distributors are regulated firstly by their local authority electricity

councils and then by their respective Provincial Administrations, although the latter are not known to regulate the activities of municipal electricity undertakings whatsoever. Regional Services Councils and Joint Services Boards are responsible for their own activities as assigned by Provincial Administrators. The electricity supply authorities in the "National States" and "Self-governing States" are accountable to their respective governments. And finally, an Electricity Control Board issues licenses to distributors, "controls" the activities of licensees and can control the Local Authority tariffs to customers outside their proclaimed Area of Jurisdiction. Eskom's tariffs in terms of structure are ultimately regulated by the Electricity Control Board. The level of Eskom tariffs is however within its own jurisdiction.

- \* On account of the relationship between most Local Authority Councils and their electricity departments, cross-subsidisation between commercial and industrial customers in favour of domestic and farming customers, has been entrenched. This is reflected in the average price level to domestic customers, as compared to the average price level to industrial and commercial customers.
- \* The non-Eskom part of the South African distribution industry made a surplus of R1,27 billion in the 1992 Financial Year. Most of this was transferred to the municipal Rates Account to subsidise other services.
- \* This surplus is not evenly distributed throughout the country, but rather is concentrated in a few metropolitan areas, notably the PWV.

## **6.2 A vision for optimal electricity pricing in South Africa**

The long-term vision for electricity pricing described in this thesis is one which has been at the heart of the recent transformations in the Chilean, British, New Zealand, Dutch, Norwegian, and Swedish electricity industries and promises to transform the enormous American electricity industry in the shortly foreseeable future, i.e. that the relationship between price, quantity and quality should be determined by a fair, competitive market. As The Economist succinctly argues,

"In the market system that flourishes when politics and economics are kept apart, decisions about the allocation of resources are highly decentralised. Instead of an explicit organising intelligence, there is spontaneous and unwitting co-ordination - the invisible hand. Instead of planned co-operation, there is competition. This competition extends far beyond the static rivalry of elementary economic theory - i.e. far beyond competition among existing producers and their products. It also encompasses competition among new, would-be producers, ideas for products yet to be invented, alternative means of production and different modes of industrial organisation."<sup>18</sup>

Theoretical arguments for or against competition in the operation of economies have occupied some of the finest minds since the beginning of the industrial age and no attempt is being made here to add to this debate. The fact that the jury on this debate still sits is perhaps evidence of the fact that a verdict for or against competition as the ultimate means of allocating resources, has yet to be delivered. In view of this, the argument here in favour of competition as the basis to electricity pricing amounts to a faith and is thus not argued further.

It should be noted that the argument here is in favour of *fair* competition. If the South African electricity industry were to be restructured to achieve competition in the shortly foreseeable future, millions of currently unelectrified homes would remain unelectrified because the electrification of most domestic dwellings in South Africa is only financially viable in the very long term and would thus not deliver the required rate of return to motivate competing organisations to invest in such electrification projects. Before fair competition in the distribution industry can be established, it will be necessary that the unelectrified market is considerably developed in order to attempt to rectify the current imbalance in the allocation of resources. Furthermore, until the many existing customers who at present are unable to pay the full cost of supply, are able to pay a price in excess of this cost, an effective competitive industry will simply not exist. With the existing wealth distribution, it is clear that a competitive industry created now would only be effective in serving the needs of the developed market. This is recognised at the National Electrification Forum which has rejected competition in the industry at present. It is accepted that for the present, a doctrinaire adherence to the principles of competition, will not achieve the far-reaching structural transformation which is necessary before fair

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<sup>18</sup> The Economist, September 11-17, 1993, London

competition can be created. For this reason, a phased progression directed towards an increasing degree of competition, is envisioned. This process is explained in more detail below.

### **6.3 A three-phase development**

In light of the long-term vision for pricing as described above, the challenge is to develop a pricing strategy which will allow the relationship between price, quantity and quality to be determined in a fair market. In the short-term however, the electricity industry is faced with an enormous challenge to overcome the problem posed by the need to electrify approximately 4.2 million consumers, most of whom are not in a position to able to afford the full cost of their supply.

With the long term vision of competitive pricing, and the short term reality of the need for pricing to facilitate massive electrification, the envisioned pricing strategy is to develop pricing in the industry in three distinct phases during which transformations in pricing practice would coincide with transformations in industry structure. During the first phase, the industry would be centralised. There would be one national distributor. It should be noted that it is not material whether this national distributor is unified with generation and transmission into a single industry, a la EdF, or whether it stands separate from the generation and transmission industry. During the second phase the industry would be gradually decentralised through the creation of a number of autonomous regional electricity distributors and perhaps a number of different electricity generating companies. In the final phase the industry would be open to full competition with a power pool between the generation and distribution sides of the industry and any number of competitive distributors. These distributors would compete in a fair market to sell electricity to the various different end-customers. The three phase process is expanded upon further:

#### **Phase 1: Centralisation and vertical integration**

*Phase 1: Industry structure:*

The currently fragmented industry should be rationalised under one single organisation. Existing distributors would initially be incorporated into the industry on an agency basis with a franchise over all customers in their existing area of supply. Municipal distributors, Eskom Distributors and other such organisations would therefore continue their distribution operations as agents acting for a centrally located Principal (the National Council).

A National Regulator would be appointed by the Government and its powers, duties and functions will be legislated. The National Regulator will be an autonomous, independent, expert body and as such would present recommendations to a National Council representative of the key stakeholders in the industry. The National Council will represent the interests of the customer, the industry and the State.

After the industry has stabilised in this first stage, the initial principal/agent relationship between the National Council and the existing distributors could perhaps reform to one in which the industry becomes more fully integrated by establishing a direct relationship between the erstwhile agents and the National Council. It is argued that the centralisation of the industry would allow the current electricity pricing related problems to be addressed. More importantly however, the immense electrification task, which has to be the industry's most important task at present, would most effectively be addressed in a centralised and homogeneous industry. It is only until the industry has been extensively electrified that control of the industry should be decentralised.

*Phase 1: Pricing policy in the transmission and generation industry*

1. In the first phase, the current structure of centrally controlled generation in Eskom should not be altered. Furthermore, the operation of the centrally controlled high-voltage transmission network would remain unchanged. The progressively developing Generation Tariff and Transmission Tariff should continue to operate. Current non-Eskom power stations should be integrated into the national network, though it is expected that most will be decommissioned on account of their relatively uneconomic operation.
2. International sales agreements which are currently managed by the Eskom

Transmission Group, should remain inside the Transmission function of the new industry. The National Regulator will deliver an expert opinion to the National Council on the effectiveness of these agreements. The National Council will then have the right to accept or reject such agreements.

*Phase 1: Pricing Policy in the Distribution Industry:*

Through the establishment of the agency/principal relationship between the National Council and the existing distributors, it will be possible to change the control structure of the industry over-night without disrupting the physical operation of the industry. From the perspective of control over tariffing in the industry, the agency/principal relationship instantaneously remedies the current regulatory tangle by placing all existing distributors under one common principal. At the same time however, existing distributors would still maintain a degree of autonomy through the agent/principal relationship. At the beginning, the agents should be instructed to maintain their existing tariffs until such time as the National Regulator is able to detail a plan to transform tariffing in the industry.

Tariffing during the first period will be focused on remedying many of the current deficiencies in pricing in the industry. As such the following is proposed:

1. A single national pricing policy will apply to the whole distribution industry.
2. The existing plethora of different tariffs should be rationalised into a set of generic tariff structures for different types of customers, to be applied nationally.
3. The magnitude of the different elements of cost in supplying different customers must be accurately established so that a rational basis is used for tariff differentiation amongst different customers.
4. The principles of accounting used to determine the revenue requirement and hence tariff level, must be common throughout the industry.
5. Economic marginal costs must be used in the determination of tariff structure.
6. The principle of transparency must be established as a key principle in pricing.

This has wide implications: Firstly, the profitability of distribution must be clearly established and widely publicised. Secondly the allocation of distributable profits, if any, must be widely publicised. Thirdly, the determination of strictly cost-based tariffs by the National Regulator must be a transparent process. These tariffs must then be submitted to the National Council for ratification. The National Council, representing the interests of the State, customers and industry, will understandably resolve in favour of social subsidies to sub-economic customers, and possibly surcharges to others. With the imbalanced wealth distribution in South Africa, such deviations from the cost of supply are understandable. However, most importantly, such deviations should be transparently calculated and widely publicised.

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- 7. The size of a customer should be directly proportional to the degree of tariff choice which that customer is offered. It should be the joint responsibility of the National Regulator and the industry to develop a set of tariffs which allow customers to choose the tariff which best suits them.
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- 8. Non-tariff agreements should continue to play a major role in the industry, particularly for very large and nationally significant customers. Such agreements should be open to public inspection.
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- 9. Distribution tariffs should carry a national, regional and local tax. The local tax would be levied to possibly re-imburse the local authority councils for the revenue they would have lost after losing control over their lucrative electricity distribution undertakings. The dynamics of this tax to the industry should however be debated between all the interest groups. The national and regional taxes could be used to contribute to a national electrification fund.
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**Phase 2:                    Regionalisation**

*Phase 2:                    Industry Structure*

After having centralised the industry under a single organisation and in so doing having facilitated the electrification of the industry, it is possible to begin decentralising and creating regional autonomy in the distribution industry. This phase in the development of

the industry is primarily an interim step between the centralised industry and the competitive industry. On the generation and transmission side of the industry, it is envisioned that these operations remain in one single organisation. However, the creation of some sort of generation power pool in which conceptually autonomous generating companies compete to sell to a power pool should be developed, as a precursor to the actual working of a similar structure in the final phase.

On the distribution side of the industry, a number of regional electricity distributors, corresponding perhaps to the geographic regions, should be created. These regional distributors will have a franchise over all customers in their particular area. Day-to-day management will take place through a management board, but political responsibility will rest with a number of Regional Councils, representative of customers, regional government and the regional industry, in the same way as such responsibility rested with a National Council during the first phase. The Regional Distributors will bid to purchase electricity from a power pool managed by a national transmitter. As in the case of the UK power pool, the regional distributors should be able to enter into direct contracts with generating companies. The National Regulator established in the first phase, will continue to play a role as an independent expert body. It will advise a National Council now made up of representatives from the Regional Distributors, national government and the Generation and Transmission industry. The National Council will be the level of ultimate political responsibility for the industry and will have the right to accept or reject resolutions passed at the Regional Council level, as well as govern the generation and transmission industry.

#### *Phase 2: Pricing in Generation and Transmission*

The principle focus of pricing in this sector of the industry, during this phase, will be on establishing a power pool to effect competition in the generation industry. The section in Chapter 5 on the restructuring of the UK ESI, briefly dwelt on the subject of the possible organisation of the existing distribution industry into competitive generating companies. Obviously this subject will have to be extensively debated between Generation, Transmission, the National Regulator and other interest groups before a workable solution will be found. During this phase however, all competing generation companies will remain part of a single organisation and they should not be totally separated until the final stage. A key criterion in the structuring of the competing generation companies, is that no single company has an unfair competitive advantage over any other company. Furthermore, to

recall the experience of the restructuring of the UK industry, it is vital that competing companies are not in a position to collude in anti-competitive behaviour.

*Phase 2: Pricing in Distribution*

As explained, during this phase the regional distributors will have a franchise over all customers inside their area of supply. There will be three challenges to pricing in this sector of the industry: The first is the pool pricing mechanism between the distribution and generation-transmission side of the industry, the second is pricing between the distributors and their end-customers, and the third is price regulation by the National Regulator to ensure that the REDs do not exploit their monopoly status.

With regard to the first challenge, it is envisioned that the regional distributors will bid to purchase electricity from the pool or via the pool, directly from the generation companies. The power pool currently used in the UK would seem to provide a workable example of how this should be done.

In terms of pricing between the distributors and their end-customers, the costing systems developed during the first phase of the industry would form the basis of the tariffs applied by the distributors. However, the national tariffs applied during the first phase will be replaced by tariffs developed by the distributors. The development of these tariffs will be in the context of the franchise which the distributors have, over the customers in their own area of jurisdiction. The urge to abuse their monopoly will be tempered by the threat that in the third and final phase of development, the distributors will no longer have a franchise and hence in order to maintain or further their market base, they will be forced to develop tariffs suitable to their customers. The tariff principles described in the first phase i.e. economic costing, transparency, choice will play an important role in this phase. However, distributors will have discretion over the extent to which their pricing policies reflect these objectives. Ultimately, towards the end of this phase, pricing policies will be driven more by the threat of competition in the final phase than by "an explicit organising intelligence".

The third challenge in pricing in distribution during this period relates to the price regulation, by the National Regulator, of the prices charged by the regional distributors to their customers. As long as the regional distributors have a franchise over their customers, it will be necessary to regulate the tariffs charged. The objective of such regulation should

be to provide an incentive for distributors to minimise their costs so as to make a profit. This can be achieved by regulating the maximum prices to be charged by distributors. These maximum prices may be linked to the annual change in indices, such as the retail price index, to determine the allowable price increases from one year to the next. This methodology of indexed-linked price regulation is widely practised internationally.

The challenge in distributor price regulation will be to reconcile the disparities in wealth distribution, with the need to create an equitably competitive system. It is envisioned that the electrification efforts particularly in the first phase, will contribute considerably towards lessening the highly uneven wealth distribution that currently characterises the distribution industry. However it will take a considerable period of time, if ever, for the geographic distribution of wealth in South Africa to reach the degree of homogeneity evident in the UK for example. This is obviously an impediment, though not an insurmountable one, which the price regulatory system used by the National Regulator will have to address.

Ultimately however, some might argue that the differences in wealth distribution mitigate against the creation of a competitive industry since competitive distributors will not supply loss-making customers and hence much of the lower socio-economic sector - who are not able to pay the full cost of electricity - will not receive a service. This argument is one of the principle reasons for the phased progression towards a competitive system. During the first and second phases, through the electrification and development initiatives, the aim will be to reduce the size of this sub-economic sector. It is accepted, however, that by the time the industry makes the final transition to a truly competitive structure, a reasonably sizeable sub-economic sector may still exist. But, this need not be an insurmountable constraint. One possible solution to the problem is for the State to reimburse competitive distributors for the difference between the cost of supply (plus a reasonable return on assets) and the revenue recovered, in respect of electricity sales to sub-economic customers. The income for this State subsidy could be generated through a c/kWh levy on all electricity sales, for example.

### **Phase 3: Competition**

*Phase 3: Industry structure*

A state of fair competition in generation and distribution characterises the third and final phase. By this stage the experimental power pool and competitive structures developed as part of the second phase, will take final shape. The role of government, where previously it played a guiding hand in the allocation of resources, relinquishes this to the market. The only role of government thus becomes to ensure that the market remains equitably competitive and to ensure that, if applicable, the competitive industry is provided with incentives to undertake electrification projects which may otherwise not be financially viable. The National Regulator then plays the role of ensuring that the rules of the competitive industry are adhered to by the various competitors. Contraventions of the rules will allow the regulator, with government approval, to revoke the licence of the offending competitor.

*Phase 3: Pricing in Generation and Transmission*

In a truly competitive industry, there is no need for a regulated pricing policy. Competitive suppliers will frame their pricing policy in terms of their specific competitive strategies relating to price, quantity and quality. In theory such competition should always be free and fair with the most competitive supplier winning the best advantage both for itself and its customers. In practice, competing suppliers may collude in an attempt to manipulate the market through anti-competitive strategies in order to achieve an unfair competitive advantage. A current example of this is the allegation of duopolistic collusion between National Power and PowerGen in the UK.

In the triangular relationship between customers, suppliers and the State, the role of the State is thus to ensure that the market remains fair. The responsibility for this should rest with the National Regulator. In order to achieve this, the Regulator will have a thorough grip on the costs of supply in order to ascertain if there are any unreasonable deviations between the costs of supply and the prices charged. Whereas the Regulator's role particularly during the first phase and to a lesser extent during the second phase was primarily proactive, in the competitive phase it becomes reactive to the pricing developments initiated by the industry.

Hence, while pricing-related decisions in the supply industry during the competitive phase will be decentralised and largely left to the market, there will still be a strong regulatory framework to ensure that competition in the supply market remains fair.

### Phase 3: Pricing in distribution

Although the essence of the third phase is that competition should be the principle determinant of the price of electricity, there is a fundamental difference in the operation of this competition between the supply industry and the distribution industry. In the supply industry there are a number of existing and possible future power stations which may be grouped in a number of different ways to form a number of different supply companies. New power stations will be built on condition that the present value of future earnings exceeds the present value of the investment. In the distribution industry there is an existing network of wires, switch gear, transformers and cables which are used to distribute electricity from a central network to the end-user. It would be a gross mis-allocation of resources if every prospective distributor were to build their own distribution network in order to supply the same customers. Instead, prospective distributors compete to provide a distribution service to customers, using the existing distribution network.

This service entails firstly, the purchase of electricity from a central pool and secondly the sale of this electricity, via established distribution networks, to a number of customers. The extent to which a particular distributor is able to meet different customers' specific service requirements will determine the success of that distributor. As such, distributors do not have a franchise over the distribution of electricity in any specific area but rather compete with other distributors for the business of existing or new customers.

In this situation, ownership of the distribution networks is not material: the only condition is that distributors who use the distribution networks, pay the owner/s of these networks an amount to cover the costs incurred by usage of the network plus, say, a reasonable return on assets. In the competitive UK structure, in forming the Regional Electricity Companies (RECs), the former Regional Area Boards took ownership of the distribution networks inside their area of jurisdiction. To ensure that the RECs do not overcharge competing distributors for the use of their networks, the regulator determines the costs which the RECs may charge other competing distributors for the use of their networks. Ownership of

the distribution network could, however, just as easily rest with a public corporation which would then charge competing distributors for the use of the network.

With carefully controlled costing and pricing of the use of the distribution infrastructure, the competition created in the distribution industry will maximise the operational efficiency of competing distributors and in so doing will result in a distribution service to the end-user of the highest quality but at the lowest price.

## CHAPTER 7. CONCLUSIONS AND DISCUSSION

This thesis has attempted to analyse pricing theory, discuss the development of pricing in the South African electricity industry, describe and interpret pricing in the United Kingdom, France and Zimbabwe, and finally present some ideas on a pricing strategy for a future South African electricity industry. This conclusion attempts to fit the disparate parts into a unified whole. Following on from this, some ideas are presented on the possible direction of further pricing-related investigation.

The first chapter of the body of the thesis attempted to build a theoretical framework for electricity pricing. In researching the subject of electricity pricing and costing it was found that most of the literature dealt with the subject either from a highly theoretical perspective or from a highly practical, or intuitive, perspective with a clear divide between the two. The theoretical framework presented in the second chapter attempts to bridge this gap so that the link between the intuitive perspectives of pricing and the theoretical basis of pricing may be established. As such, the different pricing theories have only been reviewed as far as they fulfil this objective. Hence it should be noted that the theoretical treatment of electricity cost and pricing in this chapter does not purport to be a rigorous or exhaustive treatment of the subject.

The chapter began by creating a paradigm which described a tariff as a mechanism which arbitrates between the interests of the customer, the supplier and the state. In practice however, the rate structure arises more as a consequence of the relationship between the different players, than as a medium through which the relationship between these players is determined. As such, electricity pricing is, by nature, reactive. It is reactive to socio-political priorities and economic policies and hence to industry governance and, to a lesser extent, industry ownership. It is in this context that the theoretical discussions on a framework for electricity pricing should be viewed. The discussions attempted to get to the fundamental theoretical basis of various costing and pricing theories and from there to consider the application of these principles to real tariffs. However, whether a utility implements tariffs based on marginal costs, embedded costs, Ramsey's rules or according to the principles of competitive pricing or priority service pricing is, as discussed, largely independent of the theoretical merits of the specific approach but rather is dependent on a much wider set of socio-political and economic criteria.

The third chapter on the development of the electricity supply industry in South Africa, described the history of the industry in two periods: from 1882 to 1948 and from 1948 to 1987. The section provides a background to the industry as it exists today. Tracing the history of the industry, one sees the transformation from private ownership to public ownership, the gradual centralisation of the generation and transmission industry and the progressive decentralisation of the distribution industry. Furthermore, the provincial ordinances dating back to the start of the century, the various Electricity Acts and the establishment of the Bantu Administration Boards and Black Local Authorities were discussed with a view to explaining the regulatory tangle which characterises the governance of electricity pricing in South Africa at present.

Using the back-ground developed in the previous chapter, the chapter on past and present electricity pricing in the South African electricity supply and distribution industry, seeks to describe pricing at the various levels of the supply and fragmented distribution industry. The nature of past pricing practices is examined, and as far as possible, reasons for changes in the method of costing and pricing in the industry, have been discussed. From here the chapter discussed electricity pricing practices in Eskom at present. As explained, internal pricing between Eskom's three line functions, Generation, Transmission and Distribution, has developed considerably over the past few years. In particular, the Generation and Transmission Tariffs to price for electricity sold between the Generation business and Transmission business and between Transmission and Distribution respectively, are now certainly the most complex and possibly the most cost-reflective tariffs in the industry. These internal transfer pricing mechanisms will continue to be relevant in view of the impending restructuring of the SA electricity distribution industry since, regardless of the industry structure chosen, to determine cost-reflective tariffs at the end-user level it will be necessary to develop cost-reflective transfer pricing mechanisms from Generation through Transmission and Distribution and finally to the end-user.

In terms of the tariffs which Eskom charges for sales to its end-user customers, there has been a particularly interesting progressive development. Changes in the pricing practices at this level of the organisation have largely been driven by changes in the industry's accounting policy, the extent of geographical tariff equalisation, the extent of direct government control, and the industry's attitude to its customers. At present, Eskom's pricing policy is particularly focused towards the development of economically efficient

tariffs. An example of this is the recent development of time of use tariffs and the considerable growth of customised tariff agreements.

The emphasis on economic pricing in Eskom is, however, not generally evident in the non-Eskom distribution industry. In particular, the non-Eskom industry (excluding the electricity distributors in the "self-governing" and "National States") is controlled at local government level. This has meant that the municipal electricity distributors have generally come to be used as a source of revenue for their controlling local authority councils. Furthermore, most municipal electricity distributors extensively cross-subsidise from their industrial and commercial customers in favour of their domestic customers.

The fragmentation of the distribution industry has led to a situation where, in most cases, there is no logical reason for differences in end-user tariffs offered by different distributors to their customers. Furthermore, the fragmentation and localised control of the distribution industry has severely hampered the development of tariffs. Evidence of this is clear in the myopic attitude to electricity pricing, adopted by most local authority distributors. A recent example of this attitude, as explained earlier, is the initial opposition of the Association of Municipal Electricity Distributors to the implementation of Eskom's progressive time of use tariff options.

Having analysed electricity pricing in South Africa, the following chapter on international studies in electricity pricing set an international background for pricing in South Africa. The first section concentrated on the recent restructure of the UK industry from a monopolist state industry to one in which there was extensive private ownership, competition in generation and limited but increasing competition in distribution. In analysing the restructuring of this industry, it is important to note that it was primarily the consequence of a political dispensation headed by arch free-marketeer, Prime Minister Thatcher. The competitive structures that developed were at the time, without comparison world-wide. However, they have since been applied in New Zealand and Sweden and are gaining increasing credibility in the electricity industry in the United States.

A popular misconception about the restructuring of the UK ESI is that it was primarily an initiative by the government to privatise the electricity industry. Rather, the prime objective of the restructuring of the industry was to create competition. Privatisation was seen as a strategic option by the State to lessen its involvement in the industry and was seen as a

means of aiding the creation of a competitive industry. It should also be noted that the British Government still owns 40% of the equity in the two major generating companies, as well as 100% of the equity in the nuclear generation company. Various ideas on the possible application of aspects of a UK-type restructure to the South African industry were also investigated. Perhaps the central conclusion to this is that while there are aspects of the restructured UK industry that are of immediate relevance to the S.A electricity industry, it is impossible to consider a competitive industry in South Africa while approximately 70% of the population of South Africa does not have access to electricity, and in a competitive regime, will remain neglected unless there is considerable state financial assistance. However, this does not discount the relevance of the restructure of the UK industry to this thesis since, as discussed in the penultimate chapter, in the envisioned final phase of the development of the industry, it is proposed that the SA electricity supply and distribution industry should largely emulate the structure of the current industry.

Perhaps of more immediate relevance to pricing in South Africa, is the current electricity pricing industry in the French electricity industry. There are amazing parallels between pricing in France prior to the nationalisation of the industry in 1946, and pricing in SA at present. In France at that time, as in SA at present, there was a multiplicity of independent distributors operating in a fragmented and decentralised industry. The nationalisation of the industry centralised electricity pricing and allowed the progressive development of pricing in a stable and vertically integrated industry. Pricing in France is the antithesis of pricing in the restructured UK ESI in the sense that the entire pricing function is centrally planned with the relationship between price, quantity and quality determined analytically. The many advantages that the centralisation of the electricity industry in France had brought to that industry, is one of the principle reasons that the objective of the envisioned first phase of the restructuring of the electricity industry in South Africa, is to centralise control.

After the analysis of the successful French industry, the thesis explored pricing in Zimbabwe, where the industry has failed to meet the demands imposed on it. It was explained that one of the main reasons why the industry failed was because the pricing policy adopted as far back as the 1960's, failed to provide for the industry's future growth. Furthermore, despite the hardship suffered by the industry during the UDI period, in the post-independence period, the industry was brought under progressively more direct government control so that by the time the industry was nationalised in 1985, there was direct control of the industry through various ministries. The industry suffered further

during this phase since the government was loathe to increase the price of electricity in view of the effect this might have on the industry's customers and on its social development program. However, by the late 1980s the industry began to collapse under the stress of its enormous interest burden. This paralysed the industry and the resulting major power outages forced a rethink of the pricing policy in the industry. Recently there have been some significant price increases in an attempt to restore the industry to a financially sound state. Perhaps the most relevant lesson from ZESA's experience is that while the industry was forced to support the social and economic development of Zimbabwe through artificially low prices, the policy back-fired and the subsequent failure of the industry has placed severe stress on the Zimbabwean economy.

The four chapters concluded thus far, formed the bulk of the research underlying the development of some ideas for a pricing strategy for the industry. In moving from the analysis of the past and present of pricing to a possible future, the thesis was introduced that in the long term electricity pricing will be optimal when the forces of fair competition determine the relationship between price, quantity and quality. The view is taken that belief in this thesis amounts to a faith and hence no attempt has been made to prove this thesis.

With the underlying faith in mind, and in view of the immense practical challenges that face the electricity industry in South Africa, the idea of a three phase industry and tariff development process was developed. The first phase of the development is to centralise the industry and determine tariffs at a national level. It is argued that this will achieve the objective of developing logical, transparent and accountable tariffs as well as facilitating the elimination of the structural imbalance in the distribution industry, through a centrally co-ordinated electrification program. After having achieved the objectives of the first phase, the second phase will begin. In the second phase, the distribution industry is regionalised. The generation industry is also restructured in order to create competition between autonomous generating companies. The purpose of the second phase is really to prepare the industry for the third and final phase when pricing is totally decentralised in a competitive market. In the final phase, the industry achieves the goal of decentralised pricing in a competitive industry, through the operation of various competitive structures.

However, to reiterate a point introduced in the beginning of this chapter, electricity pricing is by nature, reactive. Obtaining the correct rate structure is dependent on a correctly structured industry. However, since this is a dissertation on electricity pricing and not

electricity industry structures, the problem has been approached from the opposite end, i.e. determine the correct pricing mechanisms and follow this back to determine the correct industry structure. This means that while the industry structures developed in terms of the envisioned pricing development are intended to be optimal from a pricing perspective, all the social, political and economic forces that normally determine the structure of the industry have largely been ignored. In practice the political, economic and social forces which have determined the past and present structure of the South African electricity industry have clearly done so in a manner which, from a pricing perspective, has been sub-optimal. As much as the author would like to believe to the contrary, there is no reason to believe that electricity pricing policy in South Africa has now been elevated to the status of a crucial determinant of electricity industry structure and there is no reason that this should be the case in future.

With this in mind, perhaps a better way to approach the problem of electricity pricing in South Africa, would be to surmise on various possible industry structures and then to develop ideas on optimal pricing in each possible structure. However this too would be unsatisfactory since industry structure is not the sole determinant of pricing policy: Within each possible industry structure, issues such as customer relations, technological capacity; the availability of suitably qualified personnel; amongst others, will also have a considerable impact on the nature of pricing. Furthermore, this dissertation has been written at a time when the South African electricity industry teeters on the verge of a possible major restructure. It is however, highly uncertain exactly what industry structure will transpire and furthermore exactly what affect, if any, national political changes will have on the governance of the industry. With such a high degree of uncertainty in the basic determinants of a future pricing policy, attempting to develop ideas on a future policy which will make the most of one of many possible outcomes, can become a highly frustrating endeavour.

Finally, the envisioned three-phase development process only deals with pricing at a very high level. It is clear that an extensive amount of work needs to be done to quantify the pricing mechanisms during each phase. Another area deserving considerable further research is the role of the National Regulator in setting, adjudicating and enforcing particular pricing policies. The South African electricity industry has never had an effective regulator and it is clear that, regardless of the structure of the future industry, an

independent regulator will have an immensely important role to play in the determination and application of electricity tariffs in the industry.

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