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COAL DEMAND FOR ELECTRICITY GENERATION IN SOUTH AFRICA - ANALYSIS AND CONDITIONAL FORECASTS TO THE YEAR 2020

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I, Anastassios POURIS, submit this thesis in fulfilment of the requirements for the degree of Doctor of Philosophy in Mechanical Engineering. I claim that this is my original work and that has not been submitted in this or in a similar form for a degree at any University.

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ABSTRACT

Coal is one of the most important energy resources in South Africa. It covers 80% of the country's energy needs and provides valuable foreign exchange and employment. The purpose of this thesis is to provide an analytical framework for the examination of the demand for coal for the generation of electricity where more than 50% of the coal produced in the country is consumed.

More specifically, the aim of the thesis is to identify the factors influencing the demand for steam-coal, disentangle their interrelationships, and evaluate their relative influence and importance.

Three factors are identified as determining the demand for steam-coal, and they are analysed. These factors are: (1) the demand for electricity; (2) the efficiency with which the electricity generating utility transforms the chemical energy in coal into useful electricity; and (3) the share of coal-fired power stations in the market for electricity generation.

A comprehensive review of the literature forecasting the demand for electricity in South Africa indicates the lack of research on the effects of price on the demand for electricity. Consequently, the effect of price on the demand for electricity is estimated and a forecasting model incorporating the long-term price effect on the demand is developed. The long-term price elasticity of demand is found to have a value of -0.9

The investigation of the system thermal efficiency (STE) consists of a description and comparison of future technological sources of improvement in efficiency, an analysis of the way with which the STE changes, and a model for forecasting STE in technology importing countries. The model is based on the identification of the speed with which technology is transferred to the home country from abroad and of the adjustment process of the system's efficiency to that of the best plant. The application of the model to South African data shows that under current conditions improvements of the order of 20 to 25 percent over the 1982 STE can be expected over the next 30 years, and that the use of dry cooling technology would restrict the STE to current levels.

The projection of the quantity of electricity to be produced by coal-fired power plants is determined by the availability of resources and the economic merit of the various modes of production. The comparison of economic merit of nuclear and coal-fired power stations indicates that nuclear energy will have an apparent cost advantage over electricity produced by coal-fired power plants by the year 2000.

The thesis concludes with a synthesis of the partial analyses into a forecasting model of the demand for steam-coal. Conditional predictions up to the year 2020 are developed and are compared with official forecasts.

INTRODUCTION

INTRODUCTION

Dwindling supplies of energy pose what may be the most significant problem for the Republic of South Africa in the first half of the 21st century. The nation's response to these shortages could prove to be the measure of its ability to respond to crises in a farsighted manner. Its dependence on energy and raw materials demands the most stringent exercise of management in coping with shortages. Errors in allocating resources and poor judgement in the pursuit of alternative means of using the remaining natural resources will have repercussions that will persist for generations.

Coal is one of the most vital resources in the country. There are few countries in the world that are as dependent on coal as is South Africa. In the early 1980's coal supplied 80 percent of South Africa's energy requirements, largely in the form of electricity, but increasingly as liquid fuel from coal conversion complexes such as SASOL. Additionally, coal provides the country with valuable foreign exchange. The coal's contribution to foreign exchange earnings exceeds that of any other products except gold. In 1983, foreign exchange earnings from coal were 50 percent higher than that of the whole agricultural sector. On the local market, the value of coal sales far exceeds that of any other mineral commodity and coal mining provides jobs for more than 100 000 workers. Taking into account the objectives of the national energy policy for self-sufficiency in energy supply and the oil boycott against the country, the importance of coal for the Republic of South Africa cannot be exaggerated.

Table 1 contains data pertaining to the consumption of coal for the years 1933 to 1984. It is apparent that electricity generation is the largest consumer of coal and that the share of coal consumption for electricity generation in the total inland consumption increased over the period 1933 - 1980. In the year 1940, 36.8% of the total inland coal consumption was consumed for electricity generation, whilst the share was 44.2% in 1960 and 60.8% in 1980. The growth in the demand for coal for liquid fuels (SASOL) has reduced the share of coal for electricity during the 1980's, but coal for electricity is still the dominant market (54.5% of the total inland consumption was used for electricity generation in 1984).

TABLE 1 Sectoral Coal consumption ('000 Metric Tons)

YEAR	ELECTRICITY GENERATION			RAILWAYS	COKE PRODUCERS	COAL GAS PRODUCERS	PRODUCER GAS	MINING	SASOL	INDUSTRY	DOMESTIC	TOTAL INLAND CONSUMPTION
	ESCOM	OTHER	TOTAL									
1933	2306	453	2759	2569	181	16	12	1676		215	1405	8833
1934	2568	579	3147	2713	318	18	30	1811		506	1514	10057
1935	2859	697	3556	3026	363	25	30	1913		496	1623	11032
1936	3251	815	4066	3249	408	36	41	2041		662	1724	12227
1937	3487	933	4420	3688	490	56	41	2067		648	1833	13243
1938	3788	1072	4860	3277	610	62	56	2215		874	1937	13891
1939	4000	1254	5254	3527	660	65	58	2163		900	1846	14473
1940	4197	1345	5542	3727	639	67	56	2190		854	1946	15021
1941	4449	1462	5911	3863	737	71	64	2225		955	2041	15867
1942	4638	1553	6191	4036	1022	79	88	2216		1285	2146	17063
1943	4516	1554	6070	4123	1031	85	111	2157		1591	2244	17412
1944	4685	1645	6330	4278	1054	86	124	2218		1753	2312	18155
1945	4816	1717	6533	4547	1093	93	121	2265		1682	2218	18552
1946	4828	1726	6554	4674	1111	96	139	2629		1912	2284	19399
1947	5443	1999	7442	4939	1186	99	110	2239		1482	2359	19856
1948	5558	1945	7503	5107	1276	106	151	2575		2014	2601	21333
1949	5775	2136	7911	5047	1533	122	207	2298		2708	2679	22505
1950	6323	2308	8631	5066	1610	122	208	2019		2681	2760	23097
1951	6663	2502	9165	5334	1880	121	227	1741		2877	2842	24187
1952	7113	2729	9842	5740	1933	131	313	1461		3920	2994	26334
1953	7394	3021	10415	5769	2015	138	293	1415		3569	2367	26481
1954	8025	3093	11118	5965	2277	142	241	1397	45	2931	2667	26783
1955	9000	3337	12337	6180	2277	143	273	1497	539	3276	2867	29389
1956	9689	3563	13252	6397	2459	143	342	1433	756	4041	2830	31653
1957	10220	3613	13833	6976	2549	154	390	1388	990	4546	2776	33602
1958	10784	3928	14712	7385	2658	151	389	2017	1072	4469	2767	35620
1959	11549	3911	15460	6673	3139	141	333	1415	1170	3772	2966	35069
1960	12513	3929	16442	6567	3275	144	425	1379	1204	4769	2912	37117
1961	12923	4178	17101	6259	3429	138	406	1397	1325	4491	2830	37376
1962	13955	4595	18550	6305	3611	162	461	1216	1377	5033	2712	39427
1963	14721	4629	19350	6265	3674	171	431	1769	1316	4585	2948	40509
1964	15655	4736	20391	6211	4019	158	504	1615	1480	5353	3093	42824
1965	16727	5343	22070	6715	4781	156	535	1306	1537	5615	3583	46298
1966	16983	6016	22999	6235	4899	190	449	1367	1713	4655	3329	45836
1967	18307	6663	24970	5801	5052	249	417	1314	1718	4265	3287	47073
1968	19135	6865	26000	5859	5320	332	491	1365	1787	4968	3170	49292
1969	19983	7614	27597	5118	5156	356	423	1179	1743	4599	3656	49827
1970	21631	7630	29261	5080	5111	1023	570	1179	1440	3688	3573	50925
1971	23416	8248	31664	5111	5465	1269	597	1359	1283	4625	3771	55144
1972	24953	7508	32461	4361	5486	1390	597	1318	1333	4564	3694	55204
1973	27908	7088	34996	3773	5496	1553	587	1093	1463	6296	3594	58851
1974	30891	5740	36631	3351	5713	1960	577	1114	1220	7463	3640	61669
1975	34232	4963	39195	2930	5957	2271	682	765	858	7497	3834	63989
1976	37257	3921	41178	2830	6678	2276	635	816	931	7864	4113	67321
1977	37506	5056	42562	2356	7377	2198	614	1229	1098	9624	3540	70598
1978	39590	4750	44340	2077	7018	2417	636	1136	1349	9429	3880	72282
1979	43265	5036	48301	1880	7264	2992	602	840	1050	10960	3370	77259
1980	46755	2647	49402	1800	7158	3187	599	910	4350	10877	3750	82033
1981	53904	4334	58238	1725	7007	3023	621	1097	7340	11311	4611	94973
1982	55198	8153	63351	1458	6623	3449	524	881	14386	11609	4252	106533
1983	55010	7190	62200	1236	7337	3307	600	787	22248	10458	3864	112037
1984	58704	7727	66431	1112	7682	3493	603	855	23845	12127	5589	121737

SOURCE: D J Kotzé & C J Cooper (1985) "*Energy Projections for South Africa*" RAU Printers, Johannesburg, SA

The objective of this investigation is to obtain a better understanding of coal's role in the electrical generation market which consumes more than 50 percent of South Africa's annual coal production. A better understanding of the numerous variables influencing the industry's demand for coal would be beneficial for policy and forecasting purposes. Specifically, such an understanding could contribute in the endeavours to establish a balanced energy export programme without damaging the country's own future needs and could help in the identification of future energy supply bottlenecks and suggest appropriate preventive actions.

The examination of steam-coal demand cannot be carried out in isolation and the numerous variables influencing directly and indirectly the demand for coal are examined. Because of the broad scope of the study, exhaustive discussion of each variable is not undertaken. An assault on all the details and minor variations of a problem is an investment with dubious or poor returns. An ability to slash away trivia is a necessary condition for better understanding. Consequently, the purpose of the study is not to make an intensive study of a particular variable but to give a better understanding of the relative importance, direction of influence and the interelationships of a number of variables affecting the demand for steam-coal. This in turn, will lead to a better understanding of the major trends expected in the future.

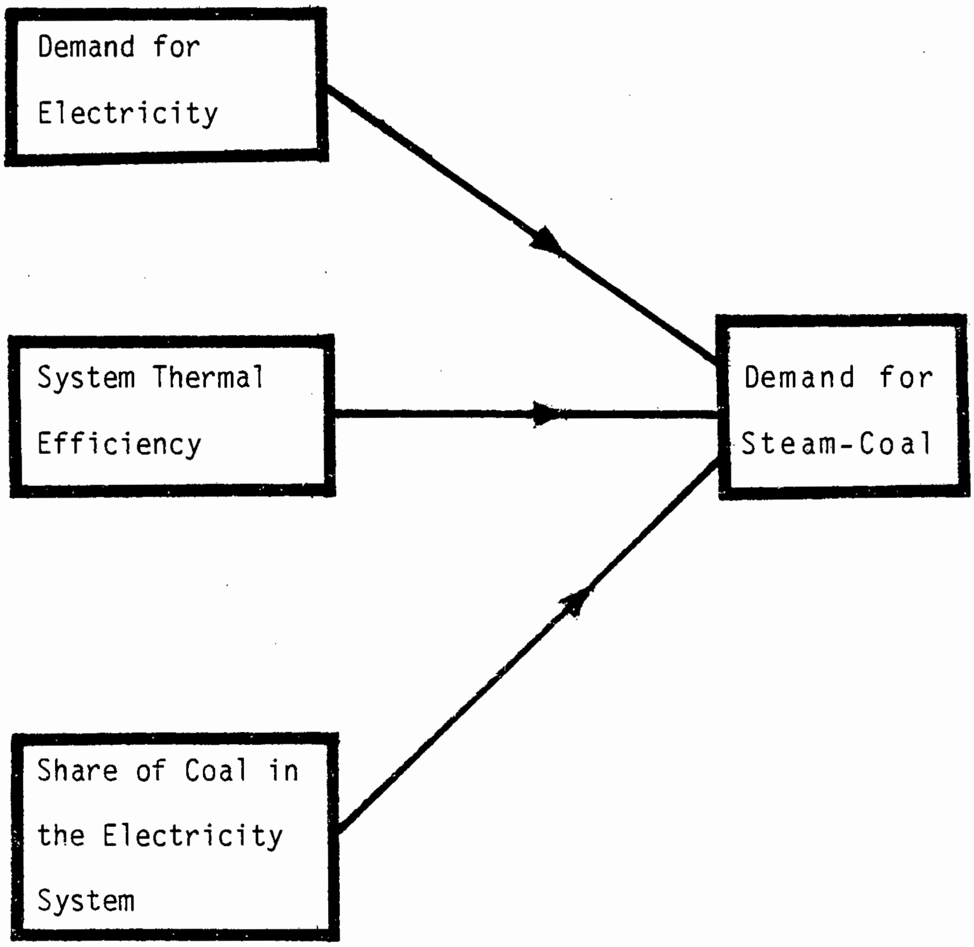
A diagrammatic exposition of the structure of the study is given in Figure 1. The demand for steam coal is considered as a function of the demand for electricity, the system thermal efficiency and the share of coal-fired power stations in the market for electricity generation.

The study consists of 6 chapters. Each chapter is self-contained consisting of introduction, main body and conclusions. The analyses and syntheses presented in each chapter are combined in chapter 6, to provide a comprehensive picture of the interactions and effects of each variable on the demand for steam-coal.

The first two chapters examine the demand for electricity in South Africa. Chapter 1 presents a survey and a critique of the literature that forecasts the demand for electricity in South Africa. The forecasts for the year 2000 are summarised and the assumptions implicit or explicit in the models used, are outlined. Chapter 2 examines the effects of price on the demand of electricity and a model of electricity demand is developed and it is estimated by incorporating the effects of changes on the price of electricity.

Chapters 3 and 4 examine the efficiency with which coal is used for the generation of electricity. Chapter 3 provides a description and comparison of five electricity generating concepts - thermionic conversion, thermoelectric generation, magnetohydrodynamic generation, fuel cell, and gas-turbine generation - which promise to improve the stagnating fuel conversion efficiency of the conventional electric power plants. In Chapter 4, a more holistic view is adopted and the

FIGURE 1 STRUCTURE OF THE PhD THESIS



thermal efficiency of the system is examined. An analysis of the way with which the system thermal efficiency changes is provided and a forecasting model for the electric utilities of technology importing countries is developed. Chapter 5 sets the base for the examination of the proportion of electricity that could be generated by coal-fired power stations. Coal-fired and nuclear-fired power stations are assumed to present the only cost-effective and technologically feasible options for base-load service and their economic merits are examined.

The penultimate chapter provides a model of the demand for steam-coal based on the analyses of the previous chapters and includes conditional forecasts of coal demand for the period up to 2020. Alternative forecasts are presented to indicate the implications of uncertainties about the electricity pricing policies, the break-even cost between coal and nuclear power and international economic and political conditions. A final chapter presents a summary and conclusions.

PART I

THE DEMAND FOR ELECTRICITY IN SOUTH AFRICA

CHAPTER 1

THE DEMAND FOR ELECTRICITY IN SOUTH AFRICA - A SURVEY

INTRODUCTION

Forecasting the demand for electricity and understanding the forces affecting it, are important for planning and policy purposes.

In South Africa, only a limited number of efforts have been recorded despite the importance of electricity as a source of energy and "a factor of development of the country".

This chapter provides a detailed summary and evaluation of the existing forecasting efforts on the demand for electricity in South Africa and it is intended as a comprehensive survey of the literature in this area.

Next, the individual studies are discussed, their methodology is outlined and their forecasts for the year 2000 are indicated. An evaluation and critique of the forecasting efforts follows and the chapter ends with a summary and suggestions for future research section.

ELECTRICITY FORECASTS IN SOUTH AFRICA

Long-term forecasts of the electricity requirements in South Africa are recorded since 1940 (Milton 1947). However, most of the forecasts are subjective estimates or educated opinions (Troost 1956, Fenwick & Torr 1961, Hugo 1955).

The first quantitative forecasting effort was attempted by Straszacker in 1966. Since then, various attempts were made by the staff of ESCOM, various government departments and academics at universities of the country.

The reported forecasts correspond to demands for load on different points in the production-consumption chain of the system and definitions such as electricity generated, electricity sent-out and electricity sold are usually used.

In order to achieve some modicum of comparability and to avoid ambiguity, the suggested forecasts are transformed in units of electricity sold to the consumers.

The ratio of units sent out to gross units generated is assumed to be 0.938 and the ratio of units sold to units sent out is assumed to approach 0.912 (Stoffberg 1975).

The most important forecasting efforts are:-

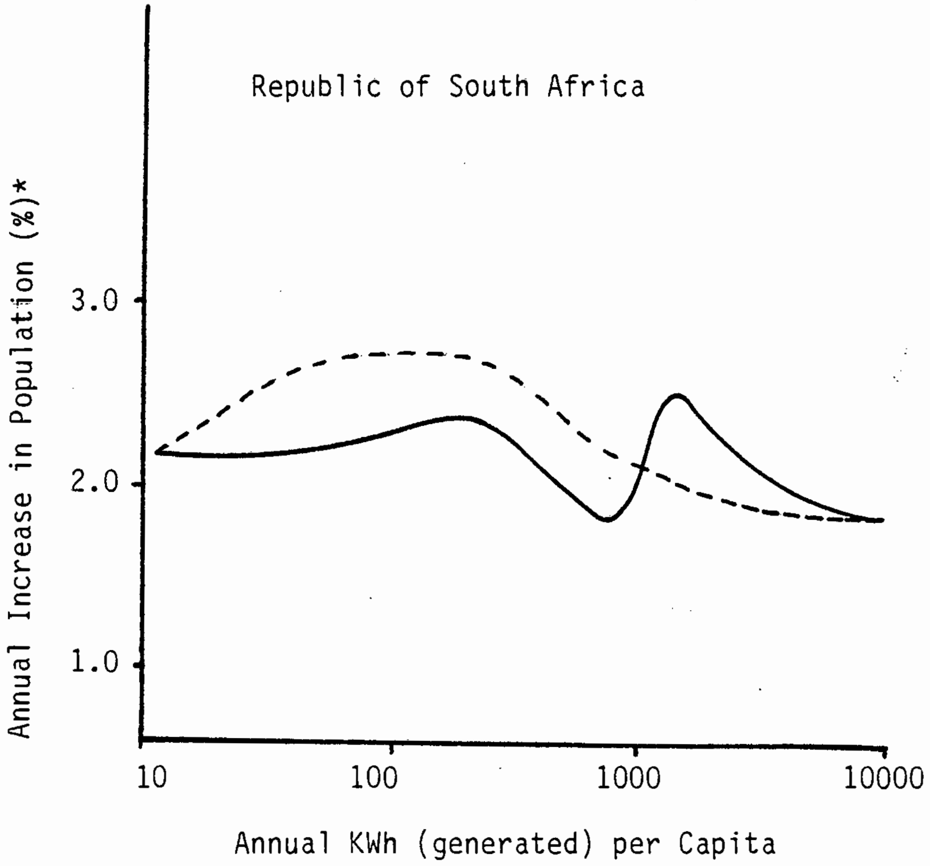
The Straszacker-Felix Forecast

Straszacker (1966) provided a forecast for the demand of electricity in South Africa based on the assumption that most of the countries in the world follow the same development path and therefore by studying the evolution of the energy consumption in countries at a high level of development, it is possible to predict the energy requirements of countries at a lower level of development.

He used aggregate data from 1917 to 1964 in order to develop a functional form relating the growth of "per capita" use of electricity to "population growth". Assuming that the total population in South Africa in the year 2000 will be 37 millions and that the development path of South Africa will not deviate considerably from the media of 153 countries studied by Felix (1964), he concluded that the total generated electricity in the year 2000 will be 300 000- GWh (or on sold basis 256 620 GWh)

Joubert (1971) compared the results derived by Straszacker for South Africa with the media of the 153 countries examined by Felix. He superimposed the curves of the two studies as in Figure 1, and noticed that "between 200 and 700 KWh per capita the South African figures follow the world trend but lie below the world norm. Between 800 and 1 500 KWh per capita, the South African figures increase rapidly to above the world norm".

FIGURE 1 Population - Electricity Relationships by Straszacker and Felix



* Annual rate of population increase during consecutive overlapping 5-year periods

__________ Straszacker

\--------- Felix

He suggested that the take off of electricity generation coinciding with the lifting of the war-time restrictions was mainly due to the development of the Orange Free State gold-fields which supported the industrialization of the country and speeded the urbanization of the South African population.

The Kotzé - Department of Planning and Environment Forecast

The forecast developed by Kotzé (1970) dominated the South African energy forecasting scene during the 1970's. The initial study, a PhD thesis, was written in 1970 and since then two papers with updated data based on the thesis, were presented (Kotzé 1974, 1975), and three booklets on energy demand were published by the Department of Planning and Environment, based on the same work (Department of Planning and Environment 1972,1977).

The study revolves around the relationship between the energy demand and the macro-economy. It has not relied upon large complex models to project energy demand, but it has not just been content to project the relationship between energy and the GNP.

Four sectors are distinguished. The energy demand is analysed in each sector and the shares of the different fuel carriers are estimated through time-series regression.

The sectors distinguished are: industry and commerce, household and agriculture, transport, and mining. The exogenous variables used to project consumption are real value of manufacturing production, real private consumer expenditure and real value of agricultural production, and real value of production of the specific mining group. Only one exogenous variable is used for each sector and the author justifies his decision on the grounds that in this way multicolinearity among the independent variables is avoided.

Two scenarios were developed in the most up-to-date version of the study (Department of Planning and Environment 1977) - low growth and high growth. The low growth scenario assumes a long-term GDP growth of 4.71 percent per year and the consequently implied growth rates in the derived parameters (eg private consumer expenditure). The high growth scenario assumes a real GDP growth of 5.5 percent per year and the appropriate growth for the derived parameters.

The forecasts for electricity for the year 2000, with data from the period 1950 to 1974, are 305 327 and 354 838 GWh (sent-out) for the low growth and high growth scenarios respectively.

In terms of electricity sold, the respective forecasts are 278 458 and 323 612 GWh.

The Trend Extrapolation projects

Joubert (1971) attempted to forecast the demand for electricity in South Africa, up to year 2000, by trend extrapolation.

He argued that trend extrapolation is a feasible solution to forecast electricity demand on the grounds that "technology will not change sufficiently for a significant substitution of electric power to take place, that the economy is at least set on its drive to maturity for long enough for the determinants of demand to have manifested themselves in the growth rate possible and that no catastrophes (war, recession etc) occur".

The forecasted variable was annual GWh sold and the data base contained regional and aggregate data for the period 1940-1970.

Eleven mathematical functions were combined in three different ways to provide forecasts. These eleven functions consist of 3 averaging techniques (simple, simple exponential smoothing, and trend-corrected exponential smoothing), 2 polynomials (linear and parabola), 3 exponentials (simple, log-parabola, and log-linear) and 3 saturation curves (simple, Gompertz, and logistic).

The individual forecasts, through each function, were combined in three different ways to provide combined forecasts. According to the first combining procedure, a weighed mean forecast (W) was developed according to the formula:

$$W_t = \sum_{i=1}^{11} y_{it} p_i^2 \Big/ \sum_{i=1}^{11} p_i^2$$

where W_t is the combined forecast of the annual electricity consumption for the t-period

y_{it} is the forecast consumption of electricity for the t-period by the i function and

p_i is the inverse of the standard error for the number of years forecasted through the i-function.

The second combining procedure calculates a forecast according to:

$$W_t = \sum_{i=1}^{11} y_{it} \;/\; 11$$

with W_t and y_{it} having the same meaning as in the first procedure.

The third procedure initially establishes the same W_t as the first procedure and then in an iterative way rejects all forecasts falling outside one standard deviation until either all forecasts fall within one standard deviation from the mean or more than four are rejected.

The forecasts of all three procedures are smoothed so that the averages for consecutive years lie on a smooth curve.

The forecasts for the year 2000 according to the procedure followed are shown in Table 1.

TABLE 1 Extrapolation forecasts by Joubert for the year 2000 according to different weighing procedures

Procedure	Forecast (GWh sold per year)
1	279 412
2	465 243
3	320 918

The Stoffberg-Ben Yaacov Forecast

Stoffberg (1975) suggested that a stable linear relationship exists between economic growth as it is represented by the Gross Domestic Product, and the total energy consumed in the country, measured in terms of the electricity equivalent of the net energy input.

To support his position he assigned separate economic weights to the electricity component and to the remaining components of the net energy input and examined the energy-economic growth relationship for South Africa, Britain and the United States.

The functional form of his regression is

$$Z = ax + by \tag{1}$$

where Z is the real gross domestic product for a given year measured in the national currency at fixed prices

x is the number of KWh of electricity included in the total national net energy input for the year concerned and

y is the corresponding energy content in KWh of the non-electricity components of the total net energy

a, b are estimated coefficients (0.08 and 0.02 respectively)

Using data for the period 1946 to 1972 for South Africa, 1947 to 1971 for the USA and 1960 to 1972 for the UK, he found that the coefficient a of x coincided for all three countries.

Supported by Stoffberg's foundings of a stable relationship between economic growth and total energy consumed, Ben Yaacov (1977) reformulated Stoffberg's equation expressing the demand for electricity as a function of the real gross domestic product and the electricity component of the net energy input, the latter as a percentage of the total net energy input for the year.

With this equation he estimated the national total KWh of electricity sent out using as independent variables the real gross domestic product for the year concerned in constant Rands, and the electricity component of the net energy input as a percentage of the total energy input for the year.

Assuming that the economy will continue to grow at the same average exponential growth as in the past, and that the electricity growth will follow a saturation curve approaching a level of 75 percent of the total net energy input, the forecast for electricity (sent out basis) is 358 670 GWh, for the year 2000. In terms of electricity units delivered to the consumers, the forecast is 327 110 GWh.

The Silberberg Attempt

Silberberg's (1981) forecast of the demand of electricity stems out of a larger effort to develop an integrated supply-demand model of energy for South Africa.

The model consists of three sections: supply, demand, and integration. However, demand and supply are determined exogenously (eg demand is not constrained by limited supply).

The demand section is based on an analysis of seven energy demand sectors - iron and steel, chemicals, mining, pulp and paper, cement, transport, and household - accounting for approximately 75 percent of the total final demand, and a synthesis attempting to combine the potential future demand of the output of the sub-sectors and the potential effects of technological progress to the demand for energy.

Although the importance of the work lies on the development of the model and not on the correct estimation of future demand and supply, a range of predictions for the year 2000 is provided.

As far as electricity is concerned, three scenarios are reported - high, low and most likely. The forecasted demand for the year 2000 on a sent out basis is :

"high" scenario	302 100 GWh
"low" scenario	171 900 GWh
"most likely" scenario	220 600 GWh

The forecast range is very wide and it is influenced by the assumptions in the growth of output. The low case for example, assumes that the gold production in the year 2000 will be only 52 tons per year and that the cement and iron-steel industries output will expand only by 2.6 and 3 percent per year, respectively. The high case assumes a gold output of 605 tons per year - a reduction in output of 0.05 percent per year for the period from 1980 to 2000, and growth in the cement and iron-steel industries of 4.5 and 7 percent per year respectively.

The high scenario is the most compatible with the assumption of five percent average growth of the economy until the year 2000. The forecast of 302 100 GWh on a sent out basis is equivalent to 275 575 GWh sold.

The Norman Forecasts

Norman (1977, 1982) provided two forecasts of the demand of electricity in South Africa, one in 1977 and one in 1982.

The first forecast is based on Stoffberg's formula, (p 21)

$$Z = ax + by$$

with Z the real gross domestic product

x the electricity included in the total national net energy input and

y the non-electricity components of the total net energy, input in the economy

a,b are coefficients estimated to be 0.08 and 0.02 respectively

in its form used by Ben Yaacov, expressing the demand for electricity as a function of the Gross Domestic Product and of the share of electricity in the total demand for energy in the country.

Norman used up-dated data and instead of using a priori knowledge of the GDP, he fitted GDP data for the 30-year period from 1946 to 1975 to an exponential equation of the type:

$$Z = cd^t$$

where Z is the GDP

and t is the year starting from 1970

a, b are estimated coefficients (0.08 and 0.02 respectively)

This equation forecasts the GDP for the year 2000.

The share of electricity is predicted with the use of the formula with the form:

$$S = 75\ (1 - f^{g-t})$$

where S is the proportion of electricity in the energy input in the country

f, g are estimated coefficients (0.78 and 0.96 respectively)

75 stands for the assumed ultimate saturation value (75%) of the proportion of electricity in the total energy used and

t stands for time in years

The estimated electrical requirement for the year 2000 was given by this procedure as 345 440 GWh on a sent-out basis. In terms of electricity sold the forecast is 315 041 GWh.

The second forecast (Norman 1982) is based on a similar procedure. Future net energy usage is forecast by extrapolating the exponential curve that best fits the historical data (1950-1980) and the percentage of energy supplied by electricity is determined by a logistic formula of the type:

$$F = \frac{0.75}{1 + ab^{n}}$$

where F is the share of electricity

0.75 is the assumed ultimate saturation value of the proportion of electricity on the total energy used and

n is the number of years after 1950

a,b are estimated coefficients (9.08 and 0.957 respectively)

The forecast for the year 2000 is 367 000 GWh on a sent-out basis or 334 704 GWh on a sold-basis.

EVALUATION AND CRITIQUE

The forecasts of the studies reviewed are summarised in Table 1. In the first column the author of the study is denoted, the second column indicates the year in which the study was published, in the third column is shown the approach followed, and in the final column the projection of the demand for electricity for the year 2000 is listed.

A wide range for the forecasted demand for electricity is indicated but when the extreme values forecasted by Silberberg (156 772 GWh) and by Joubert (465 247 GWh) are excluded, the range shrinks to a low of 256 620 GWh and a high of 334 704 GWh. The forecasts due to their convergence seem reasonable, however, their robustness depends upon the assumptions and the methodology that led to them.

The studies by Joubert (1971) and Norman (1982) are based on extrapolation of past trends. The underlying assumption is that the trend curve that fits the past data will be applicable in the future. All factors that theoretically affect the demand for electricity (prices, population growth, economic activity, technology and so on) are assumed to remain unaltered.

TABLE 2 Forecast of Electricity Demand in South Africa

Author	Year	Approach	Forecast for the year 2000 in GWh sold
Straszacker	1966	electricity-population relation	256 620
Kotzé Dept of P & E	1970-1977	sectoral energy-GDP relation	278 458-323 612
Joubert	1971	extrapolations	279 412-465 243
Stoffberg-Ben Yaacov	1975-1977	aggregate energy- GDP relation	327 110
Silberberg	1981	input-output	156 772-275 515
Norman	1977-1982	extrapolations, aggregate energy-GDP relation	315 041-334 704

Stoffberg (1975) and Norman (1977) developed their forecasts through an assumed constant relationship between Gross Domestic Product and energy consumed, and an assumed function which determines the share of electricity in the total amount of energy consumed. Two problems appear in this approach. The first is the assumption that energy and GDP are linked with a constant relationship and the second is the omission of other variables that can affect the demand for energy.

The assumption of a constant relationship between energy and economic growth is questionable on both theoretical and empirical grounds. Stoffberg used in his study 'net energy' which refers to the energy used by the final consuming sectors and thus excludes the energy losses experienced in converting primary energy sources to secondary energy forms. However, that measurement includes losses in the final conversion of energy by the consumer apparatus. In addition, electricity is measured as units sent-out and therefore distribution losses and efficiency of consumers' apparatus are not excluded.

To assume a constant relationship between energy and GDP is to assume that:

1. the efficiency of the electricity distribution system will remain unchanged in the future;

2. the efficiency of the machinery and apparatus used by the consumers will remain constant;

3. energy is a unique input in the production function and cannot be substituted by other factors of production, e g labour; and

4. the mix of ouput contributing to GDP is determined in a way that energy intensive output cannot be substituted by less energy intensive mix.

Clearly, even if useful energy was used instead of 'net energy' in order to avoid the criticism that technology can alter distribution and machinery efficiencies, the substitutions among energy, labour and capital, and the change in the output mix of the GDP would destabilize the relationship between energy and GDP.

As far as empirical evidence is concerned, the most striking and the most popular evidence of the inherent flexibility in energy demand is found in the comparison of the energy utilization patterns in different countries. Countries with similar standards of living use different amounts of energy. For example, energy consumption per million dollars of GDP in the United States was more than 30 percent higher than in Sweden during the year 1974, and both countries had similar standards of living (Sawhill 1974). In addition, it has been found (Darmstadter et al 1977) that on average, approximately 40 percent of the difference in energy utilization between the United States and other countries is attributed to the different mix of activities in different economies - the USA has a larger proportion of expenditures for energy intensive activities. This provides evidence that the level of economic activity does not by itself determine the level of energy demand and that a stable relationship between energy and economy cannot be justified.

It can only be assumed that Stoffberg's findings are due to eclectic sampling procedures and limited examination of the data and the regression techniques used.

Straszacker's appraisal suffers from similar shortcomings. Only one variable, population growth, is assumed to be correlated with the growth of per capita use of electricity. In addition, the existence of a correlation between population growth and per capita use of electricity is suggested not as a causal one but as a way of estimating or predicting the one variable when given the value of the other.

The problem with non-causal relationships is that the detected correlation between the two variables is usually due to a moderate degree of inter-correlation between the independent variable used and various omitted variables. In that case, the detected correlation will be present in the future only to the extent that the independent variable continues to be inter-related with the omitted variables. To the extent that these intercorrelations represent merely sampling phenomena, they will break down and with them the simple relationship between the two variables under examination will disappear.

In order to see the relationship between population growth and per capita use of electricity under another perspective, the case of an effective birth control campaign can be considered. What is implied by the suggested relation is that a successful birth control campaign can influence the demand for electricity! To the extent that improved education is accompanied by improved standards of living, it is possible that population growth is correlated to the growth of per capita use of electricity. When, however, other factors (eg birth control campaign) affecting one of the variables (eg population) are activated, the correlations lose any meaning.

The series of studies based on Kotzé's PhD thesis use a dissaggregate approach. This approach facilitates the use of more appropriate independent variables, as energy in each sector is determined by different factors. However, a serious shortcoming is attached to the approach. The shortcoming derives from the fact that only one independent variable is used to explain the demand for energy in each sector.

The identification of the effect of an independent variable on the dependent is based on holding the influence of all other variables constant and this condition is not observed in the studies under examination. The high correlation coefficients reported are almost always the result of high autocorrelation in the residuals. None, but Kotzé's studies, refer to autocorrelation. The initial study by Kotzé (1970) reports Durbin-Watson statistics in the range 0,6 to 1 which indicate the existence of high autocorrelation.

The existence of autocorrelation not only distorts the R^2 and the t-statistics but also indicates that there is an important part of the variation of the dependent variable which has not been explained.

Finally, Silberberg's input-output approach is plagued by the problems that are common in this sort of model. Input-output models can provide a fairly detailed analysis of energy requirements but long-term forecasting is usually unsuccessful. Important requirements for the model include detailed forecasts of the matrix of technological coefficients, forecasts of the physical output of individual industries and the assumption of zero price elasticity since input proportions are assumed independent of relative prices.

Future matrices of technological coefficients in disaggregated level can be forecast (laboriously) with reasonable precision. Output forecasts of specific products, however, are riskier than forecasts in an aggregate level* and any benefit from precise technological forecasts may be lost by the impression in the output forecasts. The use of input-output models enforces a certain rigidity on the transformation of inputs to output in each industry which make forecasting hazardous.

Silberberg overlooked these problems and used subjective technological coefficients. He assumed no change in the technological coefficients in his high growth scenario and 10 to 30 percent conservation (according to industry) in the low growth scenario. Presumably such an approach can be misleading. Conservation, for example, can be accomplished easier under high growth (as the stock of capital rotates faster and energy efficient machinery substitutes old inefficient stock) than under conditions of low economic growth.

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* Ehrenberg (1975) has argued that social sciences should follow the example of physical sciences. The advances of physical science are to a great extent due to the fact that simple relationships (laws) are attainable because they typically describe the aggregate behaviour of many million entities. This suggests that success in finding laws in the social sciences is most likely in the fields where the behaviour of a large number of objects is being described.

SUMMARY AND SUGGESTIONS FOR FUTURE RESEARCH

The forecasting literature on the demand of electricity in South Africa consists of extrapolations, 'naïve' regressions and some attempts to use input-output models.

The review of the forecasting efforts of six authors shows that the average expected demand for electricity for the year 2000 is 300 000 GWh (± 10 percent) on a "sold to the consumers" basis.

The reviewed studies are criticized on the basis of the hypothesis on which their forecasts are developed.

It is suggested that the studies suffer from spurious correlations, inadequate statistical investigation of the data and mainly restrictive specification of the model.

Forecasts with such defects can serve their purpose only under restrictive assumptions i e in a stable or slowly changing environment. They are inappropriate, however, for energy planning, policy making activities, and forecasting in a fast changing environment.

Energy policy requires the identification of the factors affecting the demand for energy and the estimation of the response of induced or accidental changes in these factors.

With the interest in modification of rate structure as a potential means of controlling energy demand, the role of forecasting models that include price effects becomes increasingly important.

The next chapter is devoted in estimating the long run price effect on the demand for electricity in South Africa and revising the surveyed forecasts accordingly.

CHAPTER 2

THE PRICE ELASTICITY OF ELECTRICITY DEMAND IN SOUTH AFRICA

INTRODUCTION

The term price elasticity of demand is coined by Alfred Marshall (1885, 1890), and refers to the percentage change in quantity demanded divided by the percentage change in price. It is a convenient way of summarising how changes in price or quantity consumed affect each other and it is valuable in a wide variety of applications involving forecasting and pricing decisions. For example, an estimate of the price elasticity of demand would make apparent the effectiveness of an excise tax in reducing gasoline consumption or the necessity to include price as an explanatory variable in a forecasting model.

In the energy field a variety of studies have been published providing estimates of energy elasticities. Bohi (1981, 1984), reviewing more than 80 studies, concluded that energy elasticities in general and electricity elasticities in particular, are different to zero.

In South Africa, electricity forecasts are based on some form of trend extrapolation or on a functional relationship between the demand for electricity and the level of economic activity (Kotze et al 1985, Norman 1977). Such approaches neglect the impact of price on the demand for electricity and as it was argued in the previous chapter are inappropriate for energy planning, policy making activities and forecasting in a fast changing environment.

In this chapter, the long run effect of price on the demand for electricity in South Africa is estimated, and the forecasting and policy consequences are outlined. First the modelling approach and the model specification are discussed. Then the results are presented and the chapter ends with concluding remarks and policy implications.

MODELLING APPROACH

An unconstrained distributed lag model is adopted for the estimation of the effects of price changes on the demand for electricity. In such a model, the independent variable or variables are lagged consecutively up to some preselected number of periods, eg

$$Y_t = b + a_0X_t + a_1X_{t-1} + \dots + a_nX_{t-n} \tag{1}$$

and the coefficients are estimated without restrictions. This model was one of the first distributed lag models to be estimated econometrically. Subsequently, it lost favour because each lagged term uses up a degree of freedom and therefore larger samples are required for reliable estimates. The model came in favour again with Granger's and Sims' (Granger 1969, Sims 1972) works on causality. They suggested that causality between two variables X and Y can be tested by examining the statistical significance of the group of coefficients of the unconstrained distributed models which incorporate lags of either the independent and/or the dependent variables. A variety of causal relationships have been examined with this method and been reported in the literature. Some of the relationships investigated include the relationships between money and prices (Sargent et al 1973), wages and prices (Mehra 1977), wholesale and consumer prices

(Silver et al 1980), exports and growth (Jung et al 1985), etc. This modelling approach therefore provides the first step for a test of one way causality of the effects of price changes on the demand for electricity.

The unconstrained distributed lag model is conceptually preferable to the simple contemporaneous correlation based models that are usually employed to investigate the electricity price-demand relationship. While electricity consumers may adjust the rate of utilization of their electricity using equipment immediately after a change in the price of electricity, (eg. switch off the lights) the bulk of the adjustment will take place sometime in the future depending on the rate of rotation of the capital stock, the success of the price induced innovative activity, the consumers' habits and expectations etc. Contemporaneous correlations ignore such lagged adjustments and consequently provide limited information. The model is also preferable to models using Koyck's (1954) transformation, as it does not require the strong assumption of geometrically declining price impact on the demand neither the largest response to occur in the first period. The Koyck-lag mechanism has gained popularity in electricity demand literature (mainly due to its simplicity) despite its restrictiveness (Grilicher 1967). Among the serious restrictions and shortcomings imposed by Koyck's transformation are: the assumption of identical adjustment elasticities of the independent variables in the model, the introduction of serial correlation in the residuals even if they are independently distributed in their original form and the introduction of bias due to the presence of the lagged dependent variable. Most importantly, researchers (Coghlan

1978, Boughton 1981) have found Koyck's lag mechanism to be partly responsible for the conclusion reached in several studies that the money demand function is structurally unstable. Transferring this finding to the research on electricity demand functions, which also have been criticized as unstable (Dept of Energy 1977, Sutherland 1983), we can infer that Koyck's transformation may be a source of instability in the electricity demand functions as well.

The disadvantages of the unconstrained model are that it requires the estimation of many coefficients, its definition of causality (when it is used as a causality test) is not equivalent to many philosophical notions of causation, and the length of the lag has to be balanced against the number of control variables that are required to be included in the model. If a long lag length is incorporated in the model, the number of control variables is usually restricted in order to conserve degrees of freedom.

As far as the degree of aggregation is concerned, the national level of aggregation is adopted. Such an aggregation would capture the full effect of a change in electricity price on the demand for it. A sectorial aggregation usually hides the more esoteric interactions taking place among different sectors of the economy (Sweeney 1984). Increasing electricity prices can increase the relative price of commodities embodying higher than average electric energy intensity and motivate substitution away from these commodities, thereby reducing electricity demand in the economy. If, however, the substituted and substituting commodities belong to different sectors and are modelled separately, the price induced impact will not be detected as such. An example is the substitution between transportation and telecommunication services. As electricity prices rise, transportation costs may rise relative to telecommunication costs, firms may substitute telecommunication for transportation and overall electricity demand in the economy decreases. If transport and telecommunication are modelled separately, the price effect through the structural change will not be detected. This interaction implies that the sum of the weighted elasticities, of all individual industries or sectors, would be smaller than the elasticity of the entire economy and therefore sectorial analyses will give elasticities for the total economy which are biased downwards (Taylor 1977).

In addition it can be argued that the higher level of aggregation could provide more stable relationships. Ehrenberg (1975) has argued that the advances of physical sciences are to a great extent due to the fact that simple relationships (laws) are attainable because they typically describe the aggregate behaviour of many million entities. This suggests that success in finding laws in the social sciences is most likely in the fields where the behaviour of a large number of objects is aggregated.

Within this framework, the following general model is formulated:

$$E_t = a + \sum b_i P_{t-i} + C_t V_t' + U_t \qquad (2)$$

where E_t is the demand for electricity

P_t is the price of electricity in period t

V_t is a vector of other relevant predictors

U_t is the random error term

a, b_i, C_t are parameters

At this point a decision has to be made concerning the length of the lag (n) to be considered and the predictors to be included in the vector V_t. Inevitably, the decision has to be a compromise between the availability of data and econometric considerations.

Annual averages are the only readily available data on price and consumption of electricity in South Africa. Therefore annual time increments and average prices had to be used. In addition, the credibility of data deteriorates for the period prior to 1950. The Electricity Supply Commission (ESCOM) generated only 71% of the electricity consumed in the country during the year 1950 and the proportion was even lower in the preceding years. The rest of the electricity was produced by individual municipalities and different companies (eg mining companies) and data from these sources are not available. The time coverage, therefore, is restricted to the period 1950-1983 although longer time-series would have been desirable.

All variables were expressed in first differences in order to lessen serial correlation in the residuals. The existence of lags in the regression is expected to cause multicollinearity and therefore the F-statistic would have to be used to detect the significance of the group of coefficients. As the F-statistic is affected by serial correlation in the residuals, it is important that the assumption of serially uncorrelated residuals be accurate.

With these considerations, it was decided to use a lag of 12 years (n=12). A longer lag would be desirable as it has been suggested that the "rate of adjustment to the long-run levels of energy utilization is slow enough for the price changes to have an impact on energy demand for the next twenty years" (Landberg 1980). However, the need to conserve adequate degrees of freedom for the regression led to this decision.[1]

Concerning the explanatory variables to be included in the vector V_t, changes in the Gross Domestic Product, changes in

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[1] A statistical approach in the choice of the length of the lag to be considered, is to use the "Final Prediction Error" (FPE) criterion. The FPE criterion for a total of n lags on the independent and lagged dependent variable is defined as $FPE_{(n)} = [(T + n + 1) / (T - n - 1)] [SSR / T]$ where T is the number of observations and SSR is the sum of squared residuals. If $FPE_{(n+1)} > FPE_{(n)}$, then the n+1 lag is dropped from the model (H Akaike "Fitting Autoregressions for Prediction" Annals of the Institute of Statistical Mathematics pp 243-47, 1969).

However, this technique is also **ad hoc** in the sense that it is not supported by economic theory. There is also the possibility that the FPE criterion will prematurely terminate the selection process just because one lag is not important while subsequent lags are. In addition, if the FPE improves with the incorporation of very long lags the process would have again to be terminated in an **ad hoc** basis in order to conserve adequate degrees of freedom for the regression and estimation of SSR.

On the other hand, in demand analysis it is essential to specify the period of adjustment. "It is vain to search for the elasticity of demand" (H S Houthakker, "New Evidence on Demand" Econometrica 33(2), 1965). Therefore we can specify that the effort in this chapter is to estimate the 12-year elasticity of electricity demand.

weather conditions (temperatures) and changes in the price of fuels competing with electricity are the traditional variables incorporated in the models of electricity demand and were initially considered. The GDP is usually incorporated in this kind of analysis in order to account for the effects of varying economic activity, growth in population etc on the demand for electricity. Gross Domestic Product is preferred to Gross National Product as the former does not include the net factor of income originating in overseas enterprises and investments. Real GDP (deflated) is used in the analysis in order to account for real economic activity net of monetary considerations.

Changes in temperatures are incorporated in studies examining the demand for electricity in order to account for seasonal variation in the demand, mainly for the heating of the residential sector. Variation in temperatures has less explanatory power in studies using annual data from countries with small residential sectors. Obviously there is a larger temperature variation between seasons than between years and industrial and mining electricity demand is less sensitive than residential demand on the variation of temperature. In addition, when aggregate data are used there is the possibility that variation in one sector of the economy is neutralised by opposite variation in other sectors. Lower temperatures, for example, could increase the demand for electricity in the residential sector (eg for heating) but could decrease the demand in the mining sector where electricity can be used to cool underground mining areas (Dept of Planning and the Environment, 1978). In South Africa the residential sector consumes only a small part of the total electricity consumed in the country. It has been reported that the residential and the agricultural sectors combined consume only 17% of the country's total electricity consumption (Venter et al 1986). In addition, the variation of the annual mean temperatures is negligible. The standard deviation of annual mean temperatures has been reported (Weather Bureau 1965), to be 0.76^{0} F (over 100 years) and 0.88^{0} F (over 56 years) for the Cape Town and Johannesburg areas respectively. The average temperatures over the same periods were 62.7^{0}F and 60.2^{0}F respectively. Presumably such a small variation in temperatures cannot explain adequately any part of the variation in the demand for electricity. On these grounds, temperature was dropped from the set of explanatory variables.

The prices of competing fuels are often incorporated in demand functions to account for the rational consumer who observes prices and substitutes one fuel for another. This process assumes that different fuels are substitutes and can easily replace each other. This theoretical conjecture, however, is not easily acceptable in the case of electricity and as Stone (1945) has argued, specific factors, peculiar to a given commodity in a given epoch, and social factors controlling changes in tastes and habits, are of paramount importance. Conjectures stemming from theoretical economics should not blindly be accepted. Doubts about the explanatory value of the price of competing fuels in electricity demand functions have also been cast by Bohi (1981), who, reviewing the relevant literature, concluded that "Cross price effects (of competing fuels) are found to be insignificant, and where significant, are typically small".

The reasons for the insignificant effect of changes in the price of competing with electricity fuels are as follows: Firstly, electricity has unique characteristics. It is the cleanest of all fuels for the end user, it is versatile, easily transferable, susceptible to fractional use, and offers precision of a kind that it is difficult or impossible for fossil fuel processes to match. These unique characteristics cast doubts about the ability of other fuels to replace electricity.

Secondly, rational consumers will observe not only the price of the fuel as such but will also take into account the expenditure to utilize this fuel. Thus the rate of substitution towards or against a fuel is constrained not only by the relative cost of different fuels but also by the relative cost of technologies utilizing different fuels and the availability of such technologies. Since the fuel cost is generally a relative low proportion of overall costs (Thomas et al 1982), marginal changes in the relative price of electricity are unlikely on their own to stimulate a change in production process. A solution would be to incorporate the relative costs of different technologies in the demand function. Unfortunately data availability precludes this solution.

Finally, a peculiarity particular to the South African energy system which weakens the importance of the prices of fuels competing with electricity, is the fact that the price of coal (the most important and the only indigenous primary fuel in South Africa) is in an indirect way legislatively linked with the price of electricity. Most of the electricity in South

Africa is generated by coal-fired power stations (98% in 1983 according to ESCOM's Annual Report) and legislation determines that ESCOM should provide electricity at the lowest possible cost and operate as far as practicable at neither profit nor loss (Electricity Act 1922). As coal cost is approximately 25-30% of the final price of electricity, any variation in the price of coal would be reflected at least partially in the price of electricity. In order to verify this conjecture we estimated the correlation coefficient between the price of electricity and the price of coal over the period 1950-1983. The estimated correlation coefficient was found to be 0.989.

For the above reasons we decided not to use changes in the price of coal as explanatory variable. Instead, the consumer price Index is used as a general surrogate and the price of electricity is expressed in constant (deflated) Rands. The Consumer Price Index incorporates not only changes in the price of coal but also changes in the price of wages, capital, etc. Therefore the index would account for changes in the prices of different factors of production, different fuels and general level of living.

THE ELECTRICITY DEMAND MODEL AND THE EMPIRICAL RESULTS

Based upon the foregoing discussion, the estimated electricity demand function takes the following form:

$$E_t = a + \sum b_i P_{t-1} + C_t W_t + U_t \qquad (3)$$

where E_t denotes the change in the electricity sold from previous year in GWh

P_t denotes the change in the average price of electricity from the year t-1 to the year t in constant 1975 c/KWh;

W_t denotes change in the Gross Domestic Product in millions of constant 1975 Rands.

U_t is the random error term

a, b_i, C_t are parameters to be estimated

Data for the consumption of electricity (GWh sold by ESCOM) and the price of electricity (average price charged by ESCOM) for the period 1950-1983 were obtained from the "Annual Report of the Electricity Supply Commission 1983". The GDP in 1975 prices was obtained from various issues of the "International Financial Statistics" and the Consumer Price Index from various issues of the "South African Statistics". All data are listed in Appendix 1.

The results of the regression are listed in Table 1. A high coefficient of determination (R^2) and a high F-statistic indicate that the group of independent variables have significant explanatory power. The coefficient of determination indicates that 96.5% of the change in the dependent variable is explained by changes in the values of independent variables. The calculated F-statistic is 11.82 with 14 and 6 degrees of freedom and it is significant at the 0.01 level of significance. The serial correlation of residuals is 0.0038. The high F-statistic and the low serial correlation in the residuals indicate that the hypothesis that prices affect the demand for electricity should be accepted.

TABLE 1 Estimated Characteristics of the regression

$$E_t = a + \sum b_i P_{t-i} + C_t W_t + U_t$$

VARIABLE	ESTIMATED COEFFICIENT	STANDARD ERROR	t-STATISTIC
Intercept	3413.61	-	-
P_t	-59.83	3975.99	-0.01
P_{t-1}	1024.22	3846.67	0.26
P_{t-2}	9242.74	5270.94	1.75
P_{t-3}	-4840.07	5723.11	-0.84
P_{t-4}	12526.46	4779.87	2.62
P_{t-5}	-6569.94	4470.28	-1.47
P_{t-6}	-8353.31	8423.26	-0.99
P_{t-7}	22536.23	19749.85	1.14
P_{t-8}	-28092.70	24304.79	-1.15
P_{t-9}	6686.68	24399.06	0.27
P_{t-10}	-19636.93	12449.62	-1.57
P_{t-11}	-22271.68	13283.48	-1.67
P_{t-12}	-10700.66	10065.92	-1.06
W_t	0.71	0.69	1.03

Multiple R	0.9823
Multiple R^2	0.9650
F-ratio	11.82*
Serial Correlation of residuals	0.0038
Degrees of Freedom	[14,6]

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* F-ratio is statistically significant at the 0.01 level.

The large standard errors of the estimated coefficients in conjunction with the high values of R^2 and F-statistic indicate the presence of multicollinearity. This was expected as a variable is likely to be correlated with its lagged values. Multicollinearity precludes obtaining reliable estimates of the individual coefficients but interest here is in the sum of coefficients (long-run elasticity)[2]. As shown by Maddala (1977), the sum of the lagged coefficients is not highly sensitive to the length of lag selected, even though the individual coefficients are highly unstable. The total impact is given by the sum of all coefficients, $b_0 + b_1 + b_2 + \ldots + b_k$. The long-run price elasticity can then be calculated by multiplying the price response by the ratio of the price to the quantity sold (Bohi et al 1984).

The average electricity sold during the period under examination[3] was 52699 GWh and the average real price was 0.976 c/KWh. Therefore, using the response (-48506) derived by regression (3), the 12-year price elasticity of electricity in South Africa is estimated to be -0.90

THE DEMAND FOR ELECTRICITY IN THE YEAR 2000

To show the impact of the estimated elasticity, the demand for electricity for the year 2000 is estimated under two alternative assumptions. The first is that the real price of

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[2] The long run price elasticity of demand has been estimated similarly by Griffin (1974) and Sutherland (1983).

[3] The average electricity sold and the average real price, due to lagged formulation, correspond to 1963-1983 and 1950-1983 periods respectively.

electricity remains unchanged as in the year 1983. The second assumption is that the price increases and becomes 30 % higher, that in 1983, and its full effect materializes by the year 2000.

The forecasting model has the form:

$$Q_t = a \, P^b_{t-12} \, W^c_t \, e^u \qquad (4)$$

or the equivalent:

$$\ln Q_t = \ln a + b \ln P_{t-12} + c \ln W_t + u \qquad (5)$$

where Q_t is the demand for electricity in period t

P_t is the average real price of electricity in period t

W_t is the real Gross Domestic Product in period t

b is the 12-year long-run price elasticity of demand

c is the income elasticity of demand

u is the error term

The GDP is assumed to have a constant growth of 5% per year in real terms and the previously estimated price elasticity of demand is used as an extraneous estimator.

The choice of a growth of 5% is made in order this forecast to be comparable in this aspect with the assumptions of the studies reviewed in Chapter 1, and therefore the price effect could become immediately apparent.

The technique of extraneous estimators is used by economic statisticians in order to overcome the harmful effects of using highly collinear time series observations on regression and correlation estimates, and in order to obtain "structurally" more accurate estimates of income elasticities of demand (Kuh et al 1957).

When multicollinearity makes it impossible to disentangle the relative influence of the various independent variables, the extraneous estimator technique suggests the use of prior knowledge of the size of some of the coefficients in order to estimate the rest of them[4]. In this case the extraneous information is the price elasticity of electricity demand. In order to utilize this prior information, the price elasticity of demand is multiplied by the time series of aggregate price and the product is subtracted from the time series of the annual quantity demanded to form a new dependent variable. The new dependent series is then regressed against the time series of the Gross Domestic Product to obtain an estimate of the income elasticity of demand.

Following Wold (1953), absolute series (not differences) are used, and any trend effects are not removed. Such formulation yields essentially long run estimates (Kuh et al 1957) and therefore the structure is commensurable with the structure yielding the extraneous estimator (long run).

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[4] While a variety of techniques use this concept, the rationale is fully explained in each of the following sources: (i) Durbin, 1953; (ii) Stone, 1954; and (iii) Wold et al 1953.

The regression[5] gives a statistically significant estimate of the long-run income elasticity of demand of 1.64[6] with a multiple correlation coefficient of 0.92 and an F-ratio of 95.

With the estimated parameters of the model, the predicted demand for electricity for the year 2000 are 226 386 GWh and 178 732 GWh for unchanged (as in 1981) and increasing (30 percent higher than 1983) prices respectively. The effect of the price elasticity of demand is obvious from these figures.

CONCLUDING REMARKS AND POLICY IMPLICATIONS

The purpose of this study has been to investigate the effects of price changes on the demand for electricity in South Africa, with emphasis on the long-run impact.

The long-run (12 years) own price elasticity of electricity demand is estimated to be -0.90. Taking into account the fact that more than 70% of the electricity in South Africa is consumed by the industrial and mining sectors, the estimated elasticity is in accordance with Bohi's (Bohi et al 1984)

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[5]

$$\ln Q_t - (-0.9) \ln P_{t-12} = -5.73 + \underset{(9.7)}{1.64} \ln W_t + U$$

where Q_t is the demand for electricity in period t
P_t is the average real price of electricity in period t
W_t is the real GDP in period t
t-statistic in parenthesis

[6] The magnitude of the income elasticity of electricity demand is comparable with the elasticities estimated by Houthakker & Taylor (1970) (1.9), Federal Energy Administration (1976) (1 to 1.63), and Lacy & Street (1975) (1.87), who also used time series analyses.

conclusion (from his extensive review), that the empirical evidence indicates that the long-run elasticity on industrial demand appears to fall somewhere between -0.5 and -1.0. Important implications for South African energy policy formulation and forecasting electricity demand stem out of this finding.

Firstly, price can be used as a policy instrument for the manipulation of demand and promotion of energy conservation. Determining the price of electricity according to its production cost (the current policy) removes a powerful instrument from the hands of policy makers. In addition it is doubtful whether the current policy serves the interests of the consumers. Enforcing the monopolistic utility to sell its product without profits, does not necessarily mean that the consumer pays the lowest possible price. The monopolist can present profits as costs (eg staff benefits, expenses, etc), and inevitably inefficiency builds up in a system where costs are rewarded and profits through savings are not allowed.

A second implication of the non-zero price elasticity of electricity demand concerns the forecasting of, and planning for, the long-term demand. As discussed in Chapter 1, all electricity forecasting models used in South Africa, explicitly or implicitly, assume a zero price elasticity of electricity demand. Such models are deficient in a fast changing environments. For example, with increasing electricity prices, the omission of price from the set of determinant variables will cause the overestimation of the long-term demand by the model. As a result scarce capital would be invested in idle capacity with adverse repercussions for the price of electricity, the utility's financial position and the country's balance of payments. In an environment of falling prices, demand will be underestimated, generating capacity will not be built and black-outs could constrain the country's economic activity and growth. Forecasts which exclude the price effects can only be useful under the restrictive assumption of a stable or slowly changing environment.

PART II

PLANT AND SYSTEM THERMAL EFFICIENCIES

CHAPTER 3

FUTURE SOURCES OF THERMAL EFFICIENCY IN GENERATION TECHNOLOGY

LIMITATIONS IN THE EFFICIENCY OF THE CONVENTIONAL GENERATION TECHNOLOGY

Fossil-fuelled steam-electric power plants have, for a long time, been the mainstay of the electric power industry. Since their inception in 1900, their technological characteristics have changed in an effort to improve their fuel conversion efficiency, that is, the ability to convert the chemical energy in the fuel into useful electricity. In 1900 less than 5% of the energy in the fuel was converted to electricity. Today, the efficiency of the most efficient plants approaches 40%.

Historically, the improvement in the efficiency of the steam-electric generating units was fairly continuous, until 1960, when that progress stopped. The factors contributing to the improvement in the thermal efficiency - temperatures, pressures, reheats and size - not only have stopped increasing, but have regressed as well.

Figure 1 shows the progress in the heat rates (inverse of efficiency) of the most efficient plants in the USA - a technologically leading country in this field - for the period 1925 to 1960, and the period of stagnation since then.

The changes in efficiencies during the 35 years prior to 1960 resulted in the best US plant heat rate decreasing from 15 000 BTU/KWh to around 8 800 BTU/KWh*. Since then, however, the thermal efficiency has remained at that level.

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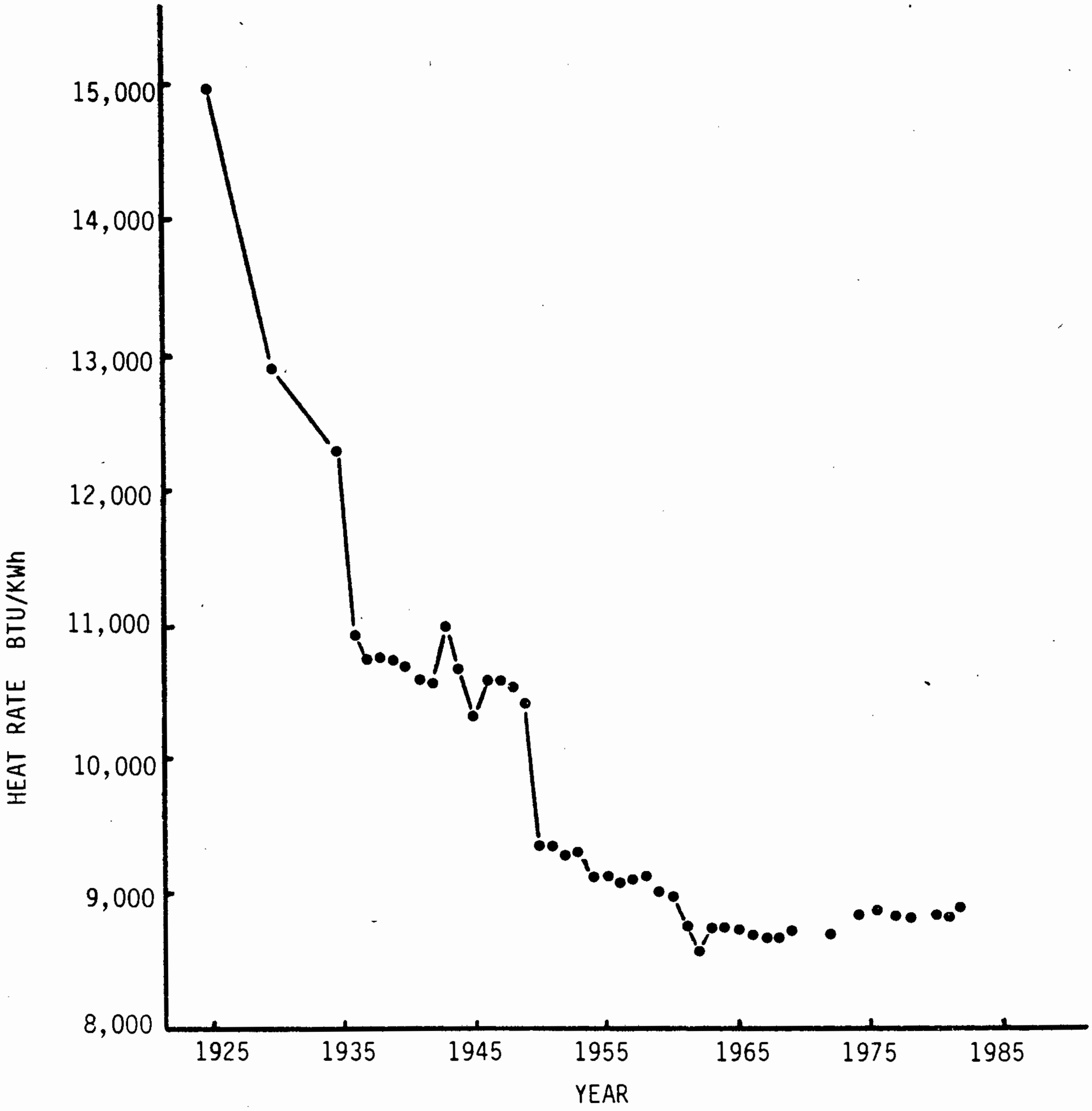
* 1BTU = $1.055*10^3$ J

FIGURE 1 Average annual heat rates of the most efficient coal-only using plants in the USA 1925-1985



SOURCES: - "National Power Survey" A Report by the Federal Power Commission 1964 - US Government Printing Office, October 1969
- "The 1970 National Power Survey" Federal Power Commission, US Government Printing Office, December 1971
- "Steam-Electric Plant Construction Cost and Annual Production Expenses" US Department of Energy, Washington, Annual various

A variety of reasons have contributed to that stagnation. Firstly, temperatures stopped increasing as more costly alloys are required for higher temperatures, maintenance problems are associated with these metals, and boilers utilizing such high temperatures are expensive and not easily available.

Secondly, it is difficult to justify the cost associated with pressure increases. Efficiency varies approximately as the log of the pressure, and therefore equal increments of pressure increases result in smaller and smaller gains in efficiency.

Thirdly, the additional cost of multiple reheats is not always justified by the small increase in the overall unit efficiency.

Fourthly, economies of scale approach their limit as size increases beyond the 500-750 MW-unit range,and availability and flexibility appear to suffer as units increase in size.

Finally, legislatively imposed environmental standards seem to constrain the improvements in efficiency in the conventional steam cycle. Requirements for non-polluting energy producing systems make the retrofitting of additional equipment necessary. This uses energy and therefore reduces the net thermal efficiency of the plant. It has been estimated that simple flue-gas washing to remove 90 percent of the sulphur in a standard 500 MW unit requires so much energy that it reduces efficiency by approximately 3.5 percentage points (Davidson et al 1979).

It is clear therefore, that the practical potential for further development of the conventional steam cycle is very limited and another concept is needed if further improvements in the thermal efficiency of electricity generation are required.

FUTURE SOURCES OF GENERATION EFFICIENCY

Among the new generation methods promising an improvement over conventional fuel conversion efficiency, five appear to have potential as central power generation sources. These are:

1. the thermionic converter;
2. the thermoelectric generator;
3. the magnetohydrodynamic generator;
4. the fuel cell; and
5. the gas-turbine.

A variety of other modes of converting heat to electricity have been suggested - Nernst effect generator, electron convection converter, ferroelectric and thermomagnetic energy converter and others - but have not shown as much promise as the five modes that are discussed in this chapter.

Thermionic Converter

Thermionic generation is based on the phenomenon of electron emission from metals at high temperatures, known as the "Edison effect". The electron emitter (cathode) is heated causing electrons to move through an intervening space to a cooled electron collector (anode). The potential, thus created, causes a current to flow in an external load. The cathode is usually made of tungsten or rhenium and the anode out of molybdenum, nickel or niobium. The heating of the electron emitter can be obtained by different means - nuclear reactors, radioisotopes, concentrated solar energy, fossil-fuel central plants and so on. The cooling of the electron collector is accomplished by the technique of "heat pipe" which works by absorbing heat at one end by vaporization of a liquid, and releasing heat at the other end by condensation of the vapour.

Two different types of large-scale thermionic generators have been suggested. The first is the "in-pile" elements type, fuelled by a nuclear reactor and the second the hydrocarbon fuelled thermionic type. The Federal Power Commission (1964) suggested that the efficiency of thermionic converters may ultimately be as high as 30 to 40 percent and that by using them to top up a conventional steam cycle it would be possible to increase plant efficiencies by as much as 15 efficiency points.

It was noted that the high temperatures required(1650°C), the fabrication of the cathode and the appropriate materials for the emitter, were the main problems.

Engdahl, Cassano and Dowdell (1968) described a thermionic topper for a fossil-fuelled power plant and claimed that the total output power and efficiency of one plant considered increased from 914 MW at 41.3% efficiency to 1 139 MW at 50.6% efficiency, with an increase of only 2% in the fuel consumption.

As far as physically constructed devices are concerned, NASA has sponsored the development of a prototype which is reported to be capable of supplying 185 Watts at 0.73 Volt with an efficiency of 16.5 percent (Angrist 1976).

Further research is under way, mainly for space applications.

Thermoelectric Generation

Thermoelectric generation is based on the principle that a voltage potential difference will be produced when heat is applied to one of the joint ends of two dissimilar conductors (Seebeck effect). The power converted to electricity in this way depends upon the materials used, the temperatures of the heat source and sink, the electrical and thermal design of the thermocouple, and the load on the thermocouple.

Small capacity generators have been used for military and space applications to provide remote unattended power, but with low efficiencies. Theory indicates that all thermoelectric materials appear limited to about a 30% materials efficiency and the Federal Power Commission (1964) suggested that the overall practical efficiency for thermoelectric generation may be limited to 10%. The report concluded that even if the problems of longevity of the thermoelectric elements and of heat transfer were to be overcome, thermoelectric generation would still not be economical, except for special applications.

The present state of the art indicates that the maximum theoretical thermal efficiency for materials over a temperature range of 20 to 1 100°C is approximately 18 percent. The best thermal efficiency of physically constructed devices operating between 20 and 700°C is between 6 and 10 percent. The overall conversion efficiency of hydrocarbon-fuelled generators is 2 to 3 percent; and overall efficiency of radioisotope generators is approximately 5 percent.

Angrist (1976), elaborating on the major problem constraining the development of high efficiency thermoelectric generators, that of materials, concluded: "At present, a materials' breakthrough does not seem imminent, despite tremendous research efforts in this area".

Magnetohydrodynamic generation

Magnetohydrodynamic power is generated when an electromagnetic field is coupled with the flow field of an electrically conducting fluid such as mercury or an ionized gas.

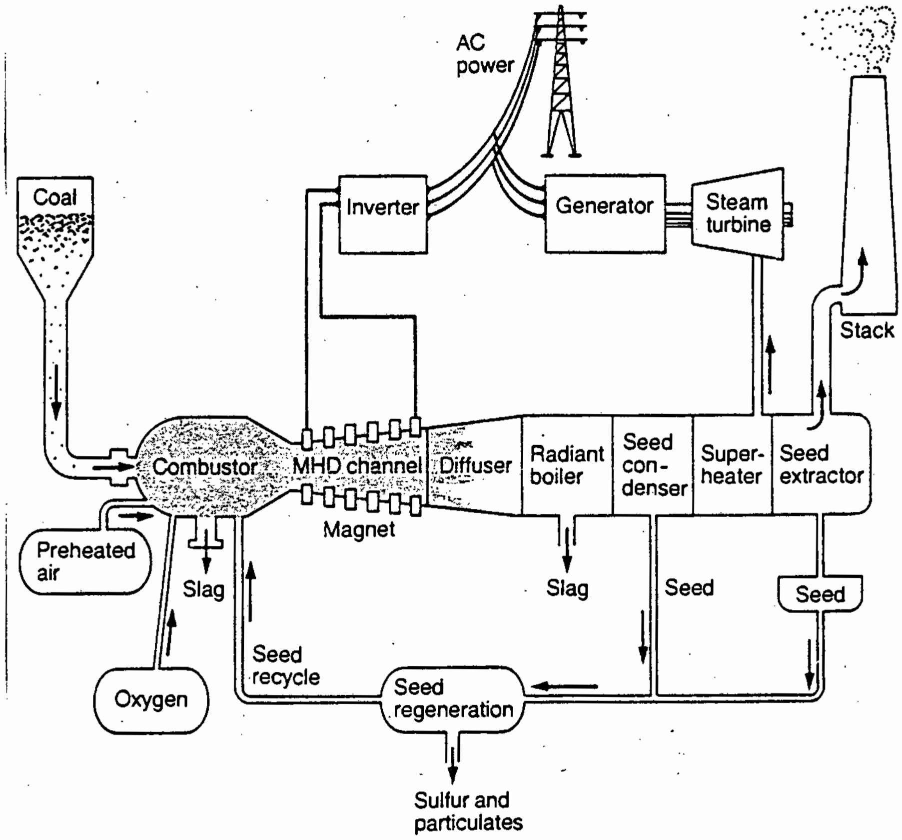
Although the concept "magnetohydrodynamics" (MHD) was originally developed by astrophysicists in order to study stellar phenomena, the underlying principle is the same as the one discovered by Faraday governing power generation by conventional generators with a solid conductor rotating in a magnetic field.

In the MHD generator, the fuel is burnt at a high temperature and the gaseous products of combustion are made electrically conducting by the injection of a "seed" material such as potassium or caesium. The electrically conducting gas travels at high velocity through a magnetic field and in the process creates a flow of direct current.

The gases discharged from the MHD channel have a temperature of 1925°C and can be used to drive a conventional steam-turbine generator, therefore increasing the efficiency with which coal is utilized to produce electricity.

Figure 2 shows a simplified coal-fired MHD plant consisting of an MHD "topping" cycle and a conventional steam-turbine "bottoming" cycle.

FIGURE 2 Simplified coal-fired MHD plant



SOURCE: High Technology 5:76, 1985

MHD promises high efficiencies, 50 to 60 percent, especially in a combined-cycle approach, but a variety of technological and economic problems constrain its development.

Research into MHD generation was on its peak in the mid 60's with major programmes in Japan, USA, USSR, Poland and W Germany (Messerle 1974). Later in the 60's, however, the advent of nuclear power and the rising cost of coal caused a re-assessment of the economics of MHD and major programmes in the UK, France and West Germany were closed down.

At the same time, an MIT study group on MHD (1971) concluded that the fundamental problems in MHD development - gas conductivity, seed recovery, materials, and environmental and fuel constraints - leave little room for enthusiasm. Similarly in 1979 it was reported (Ramaprasad 1979) that "detrimental effects of coal-slag on MHD plant operation and reliability have not yet been satisfactorily solved". The potential problems were identified as:

a) erosion of electrodes;

b) erosion of heat transfer surfaces, refractories and boiler tubes; and

c) the necessity to recover seed from the complex seed-slag mixture.

The major problem appears to be the fact that mineral matter in coal causes serious problems to the MHD gerator and the rest of the power system. The ash constituents, in particular, that get volatalised into the plasma in the combustor condense on the cold channel walls as a potassium enriched slag layer with abrasive effects. The possible solutions are either the development of suitable high temperature materials able to withstand erosive effects of coal-slag or the production of clean fuels from coal ie in gasification.

Some improvements have been made since then, especially in the field of materials science but MHD is further hampered in the western world by the development of the combined gas-turbine-steam-turbine cycle which exhibits efficiencies similar to that of MHD.

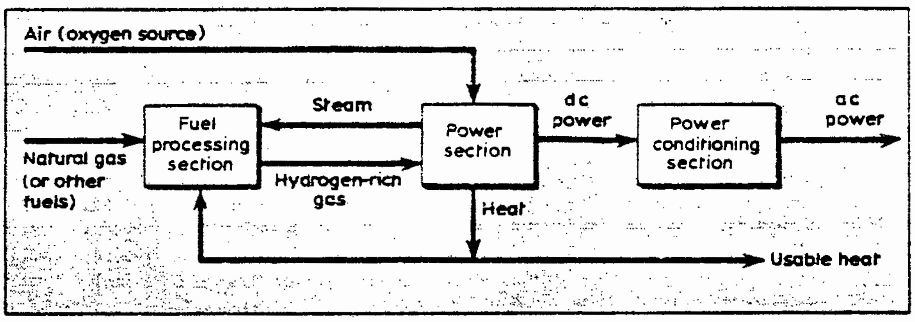
In the Soviet Union, MHD generation research continued and in 1971 a prototype 20 MW type U-25 MHD station started operating at the Institute of High Temperatures at the USSR Academy of Science in North Moscow. After 10 years, the first commercial MHD power station was ordered. The new power station - a combined cycle, 250 MW MHD generator linked with a conventional 300 MW condensing set - is planned to be on stream in 1985.

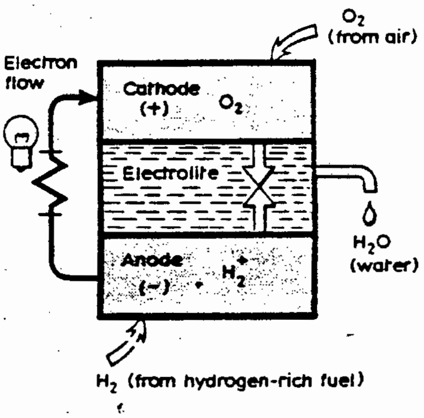
Fuel Cell generation

Fuel cells convert the chemical energy of conventional fuels directly into low voltage direct current. Fuel cells have the basic elements of a battery but they do not store the energy - the fuel and the oxidizing agents have to be supplied continuously and separately.

The engineering concept is straight forward. A cell consists of an electrolyte sandwiched between two electrodes. A fuel processor (Fig 3) turns fuel such as naphtha or natural gas into hydrogen or a hydrogen rich gas stream which is pumped into the anode side of the cell. A catalyst in the electrolyte causes the hydrogen atom to give up an electron, leaving the hydrogen ion in the electrolyte. The electrons travel through an external circuit to provide electricity while the hydrogen ion reacts with the oxygen being passed over the cathode to give water. Hence the only by-products of this form of generation are water and heat.

FIGURE 3 Fuel Processor





SOURCE: New Scientist
p29, 22 March 1984

The US Department of Energy is working on a molten carbonate fuel cell. In this system hydrogen and carbon monoxide produced from coal by gasifiers are supplied to an electrode of an electrochemical cell, and a mixture of carbon dioxide and air is supplied to the other. The chemical reactions at the electrodes create a DC voltage difference capable of directly driving an electric current.

The advantages of fuel cell plants are high efficiency (60 percent or more), essentially no cooling water requirements, minimum air pollution and compactness. Efficiency does not vary with plant capacity and therefore they can meet variable system requirements. An examination of the techno-economic aspects of fuel-cell power plants, by the Institute of Gas Technology (Ng et al 1970), identified the major problem areas as - cell performance, materials of cell components and mechanical limits of size and configuration of the electrolyte brick - and concluded that there is indication that the problems involved in using fuel cells for central stations were not close to solution.

Ten years later, most of the initial difficulties seen to have been resolved although drawbacks still exist. First, because the more advanced fuel cells operate at several hundred degrees centigrade, there are problems with the reliability and lifespan of components. Secondly, cells need catalysts of precious metal to run efficiency; up to now these have been highly expensive. The General Electric Co reporting on the molten carbonate fuel cell (Asher 1980) concluded that the key technical challenge is development of the electrolyte, a ceramic tile matrix holding a mixture of molten lithium and potassium carbonates. So far materials limitations and high required temperatures have held cell life to about 2500 hours as compared with the over 4000 hour needed for a commercial product.

The largest fuel cell plant, a 4.8 MW prototype plant, is being run by the Tokyo Electric Power Company in Japan since 1984. The operation of a twin plant designed to start in Manhattan in February of 1984 was postponed at the last moment and was eventually dismantled because of worries about the dangers of handling volatile fuels at high temperatures in the middle of a highly populated area.

Gas-Turbine generation

The gas-turbine converts fuel to heat and heat to mechanical energy in the same piece of equipment. In contrast with the previous concepts, which transform energy in the fuel directly into electricity, the gas turbine is a heat engine and is constrained by the second law of thermodynamics.

Improvements in air-craft turbines opened the wav to the industrial turbomachinerv. The developement of the industrial gas-turbine has been influenced by, and can be seen as, the blending of technology developed for industrial compressors and steam-turbines and technology applied on the aircraft type gas-turbines.

Differences between the two design philosophies diminished with time and advances in aerospace technology are transferred to and adopted by the turbomachinery industry with consequent improvements in efficiency.

Compared to a steam turbine plant, the present single cycle gas turbine is inefficient (30 percent efficiency), but for the combined gas-turbine-steam-turbine cycle efficiencies up to 60 percent have been predicted (Robson et al 1970).

The combined cycle concept, as its name implies, is a combination of the conventional steam-turbine with another generating system. For example, a modern heavy duty gas turbine with firing temperature around 1 085°C rejects heat at its exhaust at temperatures up to 538°C. The rejected heat can be used as imput in a vapour cycle and the combined gas-turbine and steam system can produce a combined cycle plant efficiency in excess of 45%.

The first plant using the gas-turbine-steam-turbine cycle was the 243MW Horseshoe Lake plant installed in 1963 by the Oklahoma Gas and Electric Company. By the end of 1978, approximately 1 652MW (33 units) of gas-turbine capacity was in combined gas-turbine-steam-turbine cycle operation and more than 13 000MW of gas-turbine capacity for combined cycle plants was on order.

All combined cycle plants utilise the gas turbine firing temperatures associated with present technology. This limits firing temperatures to about 1080°C, where the cooling of blades and nozzles of the gas-turbine airfoils is achieved by bleeding air from the compressor discharge stream. It has been suggested (Broadley et al 1981) that current development work with "air cooling techniques" is likely to permit firing temperatures to be extended to 1150°C - 1260°C. This range of temperatures, however, restricts the combined cycle efficiency to less than 40% For further improvement in efficiency, firing temperatures have to be extended above 1400°C. Such temperatures can be utilised only with the incorporation of advanced materials and/or improved cooling techniques. High technology ceramics and water cooled turbine parts are currently the most promising lines of research. Water-cooled gas-turbines* are estimated to be able to withstand firing temperatures of 1430°C (Broadley et al 1981) while the incorporation of ceramics could increase this limit even further (Sanders 1984).

When gas is not available and coal is the raw fuel in use, a gasifier is added in the above system to create an integrated gasification combined cycle plant (IGCC). In the gasifier coal reacts with steam and pressurised air or oxygen to make a low-heating value gas. This gas is washed and chemically cleaned, and burned in a gas turbine to

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* In the water-cooling system for gas turbine airfoils water is forced through channels in the blades, and is either vaporised or expelled from the bucket tips by centrifugal force, and collected and recycled. This allows a 350°C or more increase in the hot gas temperature, while keeping the maximum metal temperatures 200° to 300°C below current air cooled turbine levels.

produce hot gases as the working fluid in a conventional Brayton cycle. The hot exhaust gas is used to produce steam for use in a second cycle, the familiar steam or Rankine cycle.

Coal gasification has been practiced for nearly 200 years and is still used in many parts of the world to produce "town gas" for residential use or fuel for industrial processes (eg glass manufacturing). When, however, coal gasification is incorporated in a combined cycle plant complexity increases -- as modern gas turbine engines have been designed to operate on clean fuels that do not cause corrosion, fouling, or erosion of the hot turbine section whilst the gases produced from coal are dirty. Earlier attempts to direct fire a gas-turbine with coal were terminated in the early 1960s because of the erosion and fouling that occured. In more recent work on direct firing, coal is burnt in a pressurised fluidised bed* with limestone to fix the sulphur to meet environmental requirements. Two factors limit the future of this approach. The first is that the outlet gas limit the future of this solution. The first is that the outlet gas temperature is limited to 954°C by factors such as clinkering in the bed and sulphur capture efficiencies. The second is uncertainty that conventional cleaning by multiple cyclones will maintain adequate

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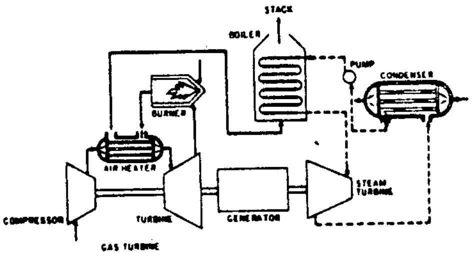
* Pressurised fluidised bed combustion appears to be more promising than combustion under atmospheric pressure. The bed area needed per MW of power is a function of operating pressure and of fluidising velocity. Under a typical fluidising velocity of 2m/s and atmospheric pressure the bed area required is $2m^2$ per MW. Constructing and operating a bed of the order of $1000m^2$ for an atmospheric pressure, a 500 MW unit creates formitable engineering problems, even if the bed is subdivided and stacked vertically. An increase in the operating pressure to 10 atmospheres reduces the bed area to below $0.2m^2$ per MW.

cleanliness on a continuous basis so as to avoid erosion to the gas-turbine. Erosion and corrosion also appear to be a problem. New design concepts (eg adding fins to the tubes) have reduced erosion by a factor of five (Gavaghan 1984). However, even with this improvement the degree of erosion in 250 hours of operation was 12.5 micrometres which is excessive for commercial applications.

An alternative approach to firing a gas turbine with dirty fuels is indirect firing. The gas turbine's compressor discharged air is passed through one or more tubular heat exchangers fired externally by a coal combustor (fig 4). Hence the gas turbine operates on clean air and problems of erosion and fouling are avoided. Critical path analysis of the problem areas revealed that "the heat exchanges to heat high pressure air from 700°C up to the turbine inlet temperature was the critical barrier to the system" (Warel et al 1983).

FIGURE 4 Indirect exhaust coal-fired combined cycle



SOURCE: Ward et al J of Engineering for Power 105:310,1983

The most advanced IGCC plant is the Cool Water project in the USA (Anderson 1986). The project uses a Texaco oxygen-blown entrained-bed gasifier handling 1000 tonnes of pulverised coal a day to supply energy to 90 MW of gas and steam turbines. It has been suggested that the technology could be scaled up to generate 600 MW at a cost competitive with existing technologies. However, the full potential of IGCC systems are expected to be realised only when allowable gas-turbine inlet temperatures reach 1400°C and above (Schmitt 1981).

IDENTIFYING THE SUCCESSOR SYSTEMS

Having identified a set of possible solutions that can satisfy the need for higher thermal efficiency, the question turns to the choice or forecast of the system that will be the first to be developed and commercially diffused.

Technological development and preference for one system over another is based on the decision of the planning groups in industry and governments to spend money, time and effort in one direction. All planning groups, however, base their decisions on the desirability of the product. By identifying and comparing the factors that contribute to the desirability of the product, the system that will receive the most attention and be developed first, can be predicted.

The most important factors determining product desirability, are utility and feasibility. If utility and feasibility could be expressed as single valued quantities, the choice of the most desirable system could easily be made. However, each factor is composed of a number of sub-factors and each one varies considerably with time, as forecasts change and technology improves.

An indication of the relative utility of the different electricity generating systems, discussed in the previous section, can be given by the range of their predicted efficiencies. Table 1 shows the predicted efficiencies of the different concepts for a combined cycle approach (column 1) and a single standing approach (column 2).

TABLE 1 Predicted efficiencies of generation concepts in a combined cycle and single standing approach

Concept	Combined Cycle efficiency	Single Standing efficiency
Thermoelectric generator	N/A	10 -
Thermionic converter	35 - 45	30 - 40
MHD generator	50 - 60	20 - 30
Fuel cell	40*	50 - 60
Gas-turbine	50 - 60	30 - 35

* Re-generative type

SOURCES: Federal Power Commission (1964), Angrist (1976)

The utilities of the MHD generator and gas-turbine for the combined cycle approach and the utility of the fuel cell for the single standing approach (as they are proxied by their predicted efficiencies) are superior to the utilities of the other alternatives. The fuel cell promises an efficiency, in the single standing approach, double that of the other concepts. The efficiencies of MHD generation and gas-turbine, in the combined cycle approach, are almost 50 percent higher than that of the thermionic converter. Moreover, the high value for the efficiency of the thermionic converter is referred to "in pile" type converter used in combination with a nuclear reactor.

The evaluation of the feasibility of the different concepts is more difficult. Different concepts require different technologies and approaches and the difficulties cannot be expressed by a common denominator. The degree of difficulty in developing a porous material with acceptable impurities, impurity levels and uniformity of porosity for the mechanical support of the combined anode-electrolyte-cathode layers of the solid electrolyte fuel cell cannot be objectively compared with the difficulties in stabilizing the flow of plasma through the MHD generating channel. However, all the alternatives discussed require materials that can withstand high temperatures for long time periods. The common constraint of temperature can therefore indicate which generating concept is likely to be developed first.

The MHD generator requires an electron concentration in the gas of about $10^{14}/cm^3$ which requires combustion gases in the range of 2200-2800°C, to exhibit the efficiencies quoted in Table 1. The thermionic converter requires temperatures above 1650°C, the gas turbine can raise the efficiency of the combined cycle system over that of the conventional power system when it works in temperatures around 1100°C, and the fuel cell can function in temperatures ranging from 540°C to 1100°C, depending on the type of cell. Obviously, the concepts least constrained by the need for appropriate materials will be those operating at the lowest temperatures - fuell-cell and gas-turbine.

Flexibility to cope with varying demand and consequent early return on capital investment is another factor that can influence the preference for the development of one concept over another. Fuel cell and combined gas-steam cycle plants are characterised by this unique feature. Fuel cell plants can be built up from a series of modules so plants can expand to cope with demand. Also of importance is that size is not a factor in efficiency and consequently fuel cells may be well suited to a dispersed power system. Similarly, the combined cycle, gas-turbine-steam-turbine, can be installed either as a complete package or separately over a period of years. Capacity additions can be made by first installing the gas-turbines and then, as the system-load increases, the exhaust gas-boilers and steam-turbines can be added. This way the return on investment begins immediately after the gas-turbine is placed in service (DoE 1980).

Another indicator of the concept that will succeed the conventional steam-cycle plants is the stage of development of the different alternative methods. Concepts start their lives as theoretical studies, move into laboratory experiments, small scale prototypes, actual scale prototypes and finally into commercial propositions. Concepts in a more advanced stage of development have a greater chance of becoming viable commercial realities than concepts lower in the hierarchical scale. Moreover, once the gap in the development of two concepts becomes visible, the law of "compulsive sequence" dictates that the development of the most advanced concept will further depress the development of the less advanced. This is because, as the development of a concept progresses, the research and development risk is reduced and resources from the less developed projects go towards the development of the more established one. If the two concepts promise the same return, the possibility that the development gap between the two concepts will close, is remote. In this framework, the gas-turbine concept (in a combined cycle) has a clear advantage over the other alternatives.

The first large size (243 MW) gas-turbine-steam-turbine cycle was tested in 1963 and since then the demand for gas-turbine capacity for combined cycles has increased by an average of 20 percent per year.

The first small scale prototype in MHD generation (20MW) started operating in 1971 and the first large size station is on stream since 1985. Political and language barriers, however, will hamper the diffusion of this generation concept.

The development of the fuel cell concept is at the stage of small scale prototype. In 1984, the first fuel cell prototype plant (4.8 MW) started producing electricity in Japan.

All other concepts are at the experimentation stage of development. In Table 2 the state of the art of the five concepts is summarised.

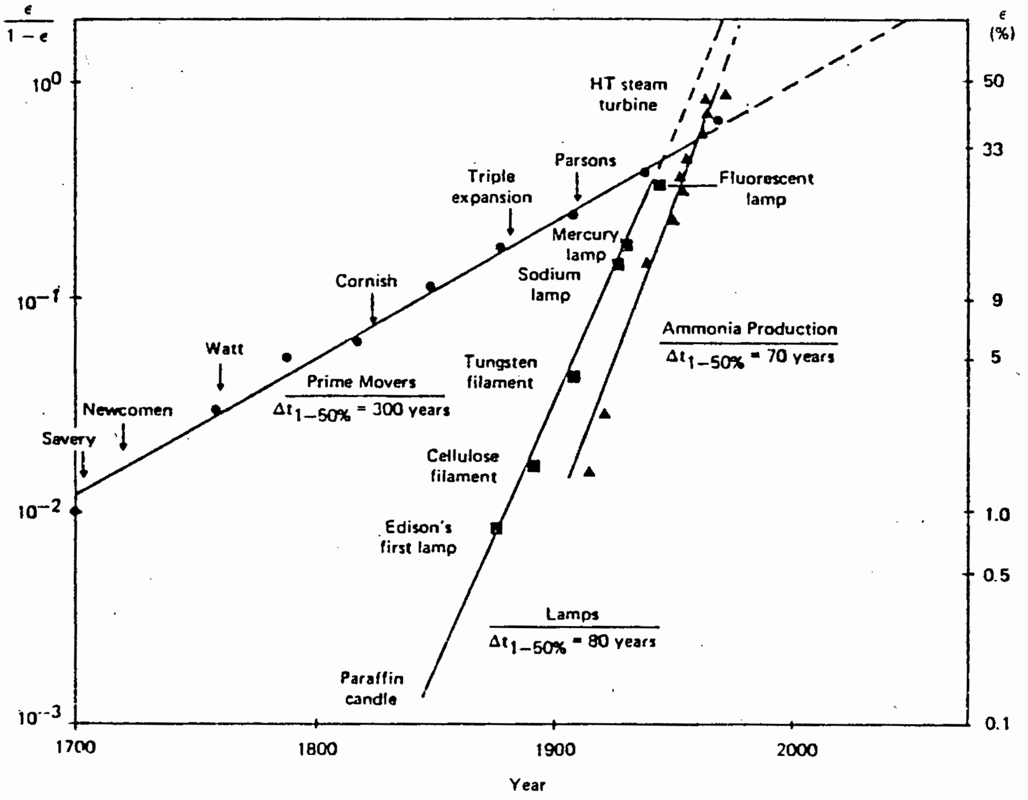
The speed with which the scientific and technological fields, in which the different concepts are examined, move, can also indicate the concept that will dominate in the future. Häfele (1981) examining and extrapolating historical data, argues that chemical processes appear to have faster learning curves or shorter time constraints than do processes for transforming heat into mechanical

TABLE 2 The state of the Art of different generating modes

Thermionic	Experimental prototypes (185 Watts) have been built with efficiencies of 16 to 17 percent
Thermoelectric	Prototypes up to 5 KW have been built with efficiencies of 6 to 10 percent
MHD	The first commercial MHD station (250 MW) is expected to be on stream in the USSR in 1985
Fuel Cell	A small scale prototype plant (4.8 MW) started producing energy in Japan in 1984
Gas Turbine	Well developed technology in the stage of early diffusion. First large scale prototype started in USA in 1963

work. Therefore, chemical processes (fuel cells) will substitute the conventional energy production methods. In Figure 5, it is shown that the time required for the thermal efficiency of mechanical work engines to evolve from one percent to 50 percent was 300 years while the time for two chemical processes (Ammonia production and Lamps) was only 70 to 80 years. On the other had, however, Holliday et al (1984) examining the innovativeness of the industrial sector in the USA for the period 1960-1981, found that the "electrical machinery and communications" sector was rated 2nd out of 16 sectors and it was more innovative than the "chemicals and allied products" sector which was rated 5th.

FIGURE 5 Historical trends in efficiencies. ϵ is second law efficiency; $\Delta t_{1-50\%}$ is time necessary to evolve from an efficiency of one percent to one of 50 percent



SOURCE Adapted from Häfele (1981)

Based on the above finding, it can be argued that development of the chemical components of the fuel cell will be relatively slow and alternative systems researched by the electrical machinery sector will dominate in the production of electricity.

Summarizing, it seems that the three most promising concepts for generation are the gas-turbine, the MHD generator in a combined cycle concept and fuel cells. The combined cycle gas-turbine-steam-turbine is already commercially available and the other two generating concepts do not seem to be able to compete with it in the immediate future. MHD development is isolated in the USSR and fuel cell generation development is at least 20 years behind that of the gas-turbines. However, in the longer term, fuel cells, due to their unique characteristics, have the potential to become the source of further improvements in fuel conversion efficiency.

SUMMARY AND CONCLUSIONS

A variety of factors have contributed to the stagnation of the thermal efficiency of the steam-electric plants in the last 25 years. Since then, however, new energy producing concepts have been developed and are ready to succeed the conventional methods promising higher efficiencies. Five of them - thermionic conversion, thermoelectric generation, magnetohydrodynamic generation, fuel cell and gas-turbine generation - are outlined and their utilization and feasibility are examined.

Gas-turbine and fuel cell generation are equally flexible to adapt to varying load demand but the combined gas-turbine-steam-turbine cycle generation has already taken off while fuel cell generation is just in the small scale prototype development stage. MHD generation is hampered by the fact that its development takes place in isolation in the USSR and that its level of development is between those of the gas-turbine and the fuel cell. In the near future the development of the gas-turbine will depress the development and diffusion of MHD generation technology; while in the long term, fuel cell generation can show much higher efficiencies than the MHD concept. In other words, the argument is that the combined gas-turbine-steam-turbine cycle's current superiority over MHD generation is sufficient to assure supremacy in the near and distant future, while the inferiority of the MHD generation's efficiency in comparison to the fuel cell's suggests that MHD generation will not be advantageous to be diffused widely in the long term.

Improvements in fuel conversion efficiency should be expected to come from the combined gas-turbine steam-turbine cycle in the near future and from the fuel cell generation in the long term.

CHAPTER 4

FORECASTING SYSTEM THERMAL EFFICIENCIES IN TECHNOLOGY IMPORTING COUNTRIES

INTRODUCTION

The system thermal efficiency (STE) refers to a set of fossil-burning power-plants with a common characteristic - belonging to the same company, area, country and so on - and it is a measure of the proportion of the input heat energy (BTU) that is converted into usable electricity (KW). It is determined as the weighted average of the thermal efficiencies of the individual plants which contribute to the electricity output during a defined time-period. The weight for each plant is determined as the ratio of the electricity produced by the individual plant to the total electricity produced by the whole system. The STE is an often quoted indicator of the technical performance of the electricity systems.

Forecasting system thermal efficiencies is of importance for energy, water and environmental planning, because the STE provides the link between demanded output and required input. The energy authorities, for example, can use the STE to derive future fuel requirements from projections for electricity demand. Similarly, the water authorities can use the STE to determine cooling water requirements for power plants (which are of the most voracious users of water), and the environmental authorities to estimate the degree of future thermal pollution.

Previous research on the subject concentrates on predicting the efficiencies of the "best plants"(Downs 1955, Ayres 1968, Floyd 1968 Robson et al 1970, Häfele 1981),especially in technologically leading countries, as an exercise in technological forecasting. When forecasts of the STE are required, naïve extrapolations of past performance (Johnson 1972) or subjective estimations of the degree that the STE will approach the "best plant's" efficiency (Silberberg 1981) are used.

In this chapter, a model for forecasting system thermal efficiencies of technology importing countries is developed and as an application the STE of the electricity supply utility of South Africa (ESCOM) is forecast. It is recognised that the STE is not an independent variable and the intertemporal change of the system thermal efficiency is viewed as a dynamic process with the demand for additional capacity, the speed of technology adoption and the age profile of the plants constituting the system, as the determinant variables.

The structure of the chapter is as follows: Firstly, the way with which the STE changes is analysed. Secondly, the time scale involved in technology transfer and adoption is discussed and the gap in power producing technology between the USA and South Africa is empirically examined. Thirdly, a mathematical description of the change in the STE is given. Lastly, a forecast of the STE for the Electricity Supply Commission (ESCOM) of South Africa is provided and the main points of the chapter are summarised.

BIRTH AND DEATH OF POWER PLANTS AND CHANGES IN THE SYSTEM THERMAL EFFICIENCY

To understand how the system thermal efficiency changes there is a need to recognise the way with which the system evolves and to isolate the strategic influences. Firstly, in a "snapshot" way, the electricity producing system is described and then, the system is dynamised and the way the system thermal efficiency changes is analysed.

Any power producing system consists of a number of plants that produce electricity. Each plant exhibits a different efficiency for a variety of reasons - climatic conditions, fuel quality, degree of utilisation and so on - but the main factor determining the plant's thermal efficiency is the technology embodied in the plant during its construction.

Traditional generation plants produce electricity by converting chemical energy in fuel to heat, then to mechanical energy, and then to electricity. At each stage there are losses which contribute in the reduction of the plant's thermal efficiency. The thermodynamic efficiency of the cycle is concerned only with the efficiency of conversion of heat into work and it is the most restrictive constraint. The efficiency of the boiler is less restrictive whilst almost all the available mechanical energy can be converted into electricity.

An ideal cycle giving the maximum possible thermal efficiency for a cycle operating on selected maximum and minimum temperatures is that of Carnot. The thermal efficiency of the cycle is given by the formula:

$$u_{th} = \frac{T_h - T_c}{T_h}$$

where T_h denotes the highest temperature in degrees Kelvin
and T_c denotes the lowest temperature in degrees Kelvin

Obviously the wider the temperature range the more efficient is the cycle. However, technological and economic factors set limits to both T_h and T_c. The lowest temperature is constrained by the availability of coolant and the economics of the condenser. For example, the coolant media can be water that is available in bulk, and at a temperature of 15°C. Furthermore, if the condenser is to be of reasonable size and cost, the difference between the condensing steam and the coolant should be at least 10°C. Therefore, the lowest economic temperature is in practice around 27°C (300°K). The maximum temperature T_h is also limited by the strength and cost of materials available for the highly stressed parts of the plant, such as the turbine blades, steam chest and casing and the boiler tubes.

From the moment that the above critical temperatures and consequently the materials are chosen and the plant is sited and constructed, the thermodynamic cycle efficiency of the plant is determined for the whole of its operational life. Similarly, the boiler efficiency and the efficiency of the generator are determined during the design of the plant and therefore the plant's thermal efficiency which is defined as the product of the three partial efficiencies is deterministically defined during that time. Efficiency slippage from year to year due to ageing process or efficiency improvements due to substitution of equipments with more advanced counterparts are possible, but their effects are marginal. The plant's thermal efficiency is determined the day the plant is designed.

When a new plant is designed the "best" available technology is applied to it so as to minimise the unit cost of output. The meaning of the "best technology" in this context is taken to mean appropriate. By increasing the capital expenditures of the plant it is possible to decrease the operating costs. With the use of expensive alloys, higher inlet temperatures can be attained and subsequently higher efficiencies, lower fuel requirements and lower operating costs can be realized. However, to minimize the total unit cost of output a balancing approach is required. Future fuel prices and the plants' life expectancy have to be estimated and the additional capital cost has to be justified in view of the reduction in future operating costs.

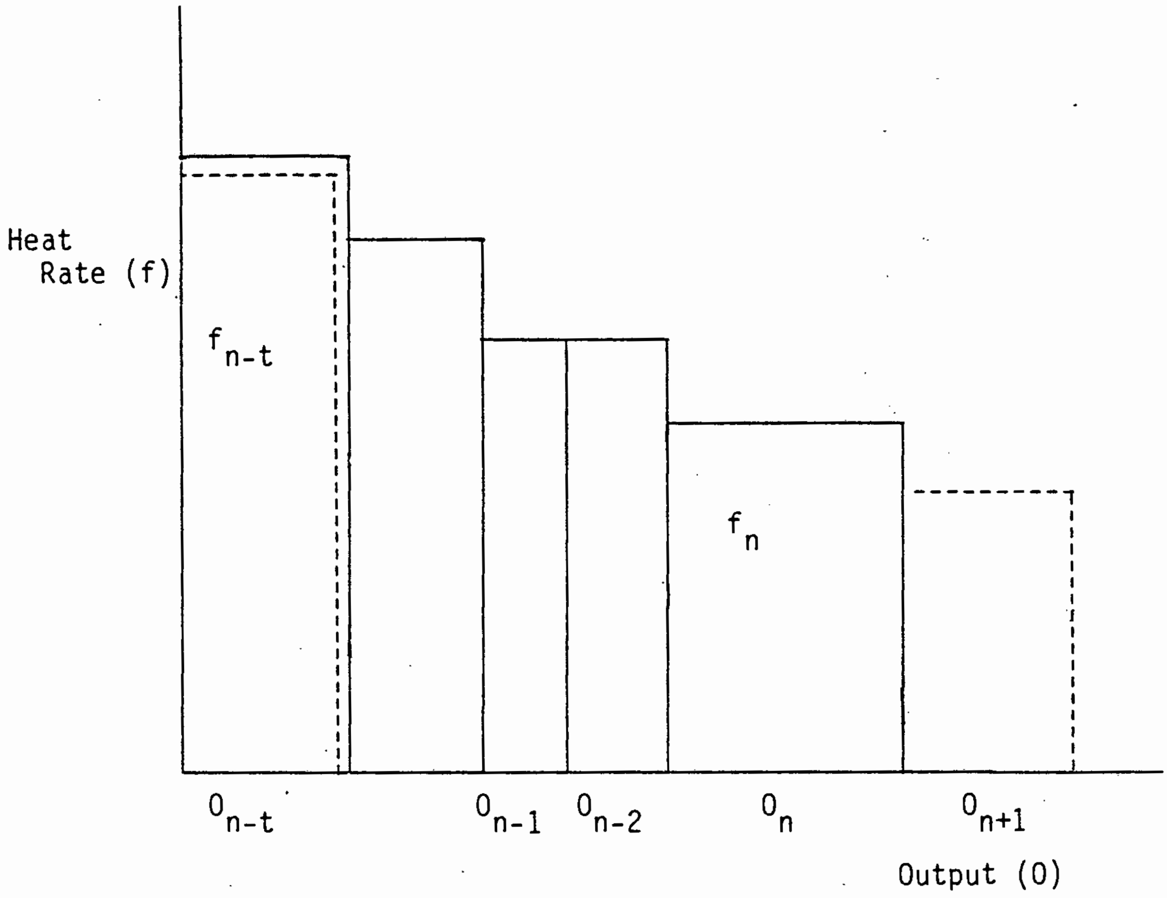
Improved technologies and changed perceptions, as far as the future cost of fuel is concerned, cannot be incorporated into the already existing stock of plants, but they can be embodied in the 'to be built' facilities. As Salter (1969) has observed, "plants are indivisible complexes of capital equipment which embody the best-practice technique of their construction date and cannot be adapted to any other technique".

The power producing plants which constitute a system are constructed at different dates either to replace retired plants or to satisfy increased demand for electricity. Therefore, they have different ages and different technologies are embodied into them. Plants built this year, embody this year's "best" technology; plants built last year embody the technology that was "best" last year. Given a continuous stream of improvements in technology, the plants in existence at any one time show the history of technology over the period spanned by their construction dates.

The time-profile of the plants operating in the system, describe the way that less efficient methods of power production continue into the present to influence the efficiency of the system. If most of the current output is produced by recently constructed plants, then the STE approaches the efficiency of the most recently constructed plants which are supposed to embody the "best" technology. If most of the electricity demanded is produced by plants of older vintage, the gap between STE and 'best' plant thermal efficiency is larger.

In Fig 1 is displayed graphically the relationship between the efficiency of an electricity producing system and the range of efficiencies, and therefore technologies, of the constituent plants. The vertical axis measures heat rates (BTU/Kwh) which is the inverse of thermal efficiency. The horizontal axis measures output. O_n is the output produced by plants built in period n and coincides with their capacity output when the plants are used in full capacity. f_n represents their heat rate. This corresponds to the efficiency of best technology available in the period n. The height of each 'block' represents the heat rate of a group of plants while the width of each 'block' signifies the output they contribute to the total output of the system.

FIGURE 1 The Profile of an Electric Utility



It should be noted that there is no *a priori* reason why younger plants should have lower heat rates than older plants. This is exhibited in the periods 0_{n-2} and 0_{n-1}, where the blocks have the same height. However, it is unlikely (although possible) that modern plants will be less efficient in terms of fuel usage than older vintage plants due to technical progress which encourages progressively greater efficiencies in all activities and due to the economic scarcity of the fuels currently used.

Looking at an electricity producing utility in this way, it becomes clear that the system thermal efficiency, at any one time, is the weighed average of the thermal efficiencies of the individual plants.

The next step is to introduce 'time' in the description of the efficiency of the utility. During a time-period, a new set of plants can be added to the system, a set of plants can be decommissioned, or both, addition and decommissioning can occur simultaneously. Diagrammatically, the construction of a new set of plants is illustrated by the addition of a new 'block' during the period 0_{n+1} (Fig 1) and the decommissioning activity by the deletion of the least changes. Actually these two factors,
changes. Actually, these two factors, namely:

1. the rate at which modern plants are added to the system; and
2. the rate at which outmoded plants are scrapped

when coupled with the rate of improvement of the best plant's thermal efficiency, determine the rate of change of the thermal efficiency of the system.

The decommissioning and commissioning of plants is a continuous process. New plants are built to increase the capacity of the utility in order to satisfy increased demand, or to replace retired facilities. Plants are decommissioned when they end their useful lives or when it is economical to be replaced by new, technologically advanced facilities. In theory, when increasing operating and maintenance expenses together impose costs which exceed the sum of the capital and operating cost of the replacement capacity, the plant is economically "obsolete" and is due for removal. In practice, it is uncertain when old plants will be retired. An old plant may remain in operation at a low plant factor for many years after it has been displaced by newer plants. The cost of removal and disposal of an old plant may be more than the cost of keeping the plant on stand-by for emergency use or to help meet peak demand for electricity. Therefore, plants remain in service until a major discontinuity - major break-down, major maintenance, need for its site and so forth - occurs.

The British Central Electricity Generating Board's big coal-fired stations were re-assessed in 1983 as good for a 40 year life-span (CEGB 1983) while twenty years ago it was forecast that the high complexity of the newer plants would reduce their life expectancy to 30 years, after 1980 (Federal Power Commission 1964). In practice, there are many cases where plants are still in operation after 50 to 55 years.

TRANSFER AND ADOPTION OF ELECTRICITY PRODUCING SYSTEMS' TECHNOLOGY

In the previous section we noted that the rate of change of the system thermal efficiency (STE) is determined by the rate at which modern plants are added at the system and the rate at which outmoded plants are scrapped. It is obvious, however, that the STE will change only if there is a difference in the thermal efficiencies between the plants which are added in the system and the plants which are retired. If all plants have the same efficiency, then addition or retirement of plants leave the STE unchanged.

At a national level, the improvement in the efficiency of the newly added plants is the result of either the development of a new advanced technology or the result of the adoption of a technology developed abroad. In the former case we have a technology leading country while in the latter, a technology importing country. Forecasting the improvement in the best plant thermal efficiency, in a technology leading country, is a subject of technological forecasting and great uncertainty is involved. The task is less risky, within a certain horizon, when the country imports the required technology as the set of the available options is already known.

In this section, the factors affecting the speed of technology transfer are analyzed; the United States is identified as a technology leading country, in the area of electricity from coal technology; the evolution of the best plant's thermal efficiencies in the United States and South Africa are described and by an analysis of precursive events, the speed of technology adoption in South Africa is inferred.

The speed of technology transfer depends on a variety of factors, internal and external, to the recipient country. The decision makers, in the technology importing country have to identify the appropriate technology from the set of the available technologies and try to transfer and adopt it. The type of technology depends on the development objectives and the specific local conditions of the country concerned.

One way to classify the factors affecting the speed of technology transfer is to distinguish them into those constituting the institutional context, those affecting the transfer cost, and those determining the adaptability of the technology.

In the institutional context, we include the preferences of the recipient country to trade only with specific partners for ideological, geographical or any other reasons, governmentally imposed constrains and ownership status of the electric utilities. Trade preferences become constraints only when they exclude the country with the best available technology. Governmentally imposed constraints on technology exports, are not of importance outside the limited area of military hardware and related technology. The ownership status refers to the possible relationship between diffusion and the nature of the ownership. The institutional context usually changes slowly and it can be considered as a factor stabilizing the technology gap between precursor and follower country.

The transfer costs include royalties, consultation fees prior to transfer, costs of transferring engineering information concerning the process, premiums on new technology embodying equipment and materials, wastage due to poor product quality during the period that the workers are learning to utilise the new technology and so on. These costs tend to depend on the age of the particular technology. The newer the technology, the higher the transfer cost tends to be. Newer technologies tend to be less well understood by the transferrer as well as the transferee. With time the transferrer gains experience through the repetitive application of his innovation and operational experience is gained because of the world wide diffusion of the particular technology. Moreover, technologies in their early forms are often highly imperfect and constitute only slight improvements over earlier techniques. With time, subsequent improvements tend to reduce the total cost by an amount greater than the reduction in the cost of the initial invention over the older techniques which it eventually replaces.

The third factor that affects the decision of transferring a technology is its adaptability. The transferred technology must be adapted to the local needs and conditions if it is to satisfy the needs of the recipient. Differences in input prices, size of the market, infra-structure, climate, task and so on make necessary the adaption of the new technology. Again the adaptability of a technology improves with time and experience.

The above classification of the factors affecting the speed of technology transfer is only suggestive rather than exhaustive; the number of variables - economic, technological, institutional, social and legal - which might accelerate or retard the transfer process is virtually limitless. In addition, there are positive and negative feedbacks among the variables which complicate even more the theoretical attempts to identify the speed of technology transfer. De Young and Tilton (1978) in an international comparison of large fossil-fueled generating units, conclude that the diffusion of technology is determined by different factors in different countries. For the purpose of this thesis, an empirical estimation of the speed of the technology transfer is used, although the author is aware of the limitations of the empirical investigations for forecasting purposes.

The first task is to identify the country that is a leader in the particular field of technology. The United States of America seem to qualify for such a role in the field of production of electricity from coal.

The major stimulus to technological growth is need (Isenson 1968) and in the United States of America, the need for improvement in efficiency in any field of activity is what Kuhn (1970) calls a 'dominant paradigm'. Kuhn argues that scientists in any field and at any time, possess a set of shared beliefs about the world and for that time, the set constitutes the dominant paradigm. Improvement in efficiencies was always a <u>sine-qua-non</u> of scientific thought and effort in the United States. Moreover, the USA has the largest market for electricity and coal in the world and any improvement in efficiency is worthwhile as it is magnified by the size of the market. For comparison, it can be noted that the electricity generation capacity in the USA in 1977 was more than double that of the USSR and eight times that of the UK (Table 1). Also, as far as coal is concerned, about one eighth of the world's annual coal production is used to make electricity in the USA (Schmitt 1981).

TABLE 1 Electric Utility Industries

Countries	Installed Generating Capacity, 1977 in MW
USA	557 000
USSR	215 000
UK	67 000
ITALY	34 500
SA (ESCOM)	16 000

SOURCE: Adapted from "ESCOM: The Story of Power - Power 80"

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South Africa, although it enjoys the distinction of being one of the earliest countries in the world to use electric energy on a commercial basis, is a technologically lagging country in this field.

Figure 2 shows the annual heat rates of the most efficient plants in the USA and South Africa for the last 50 years. A remarkable improvement in heat rates is indicated for both countries.

The best heat rates in the USA decreased from 15 000 BTU/KWh in 1925 to around 8 800 BTU/KWh in the 1960's and since then they have leveled off*. Increases in unit sizes, temperatures and pressures accompanied by improvements in equipment design have been responsible for the decrease in heat rates. Since 1960, however, these improvements have tended to be offset by environmental control factors (addition of precipitators and scrubber facilities, use of cooling towers rather than once-through cooling and so on), regression in maximum throttle temperatures, number of reheats and size of units due rather to economic considerations than technical viability.

The regression to lower temperatures, for example, is primarily due to the more costly alloys required for higher temperatures, the maintenance problems associated with these metals and poorer availability of boilers utilising high temperatures.

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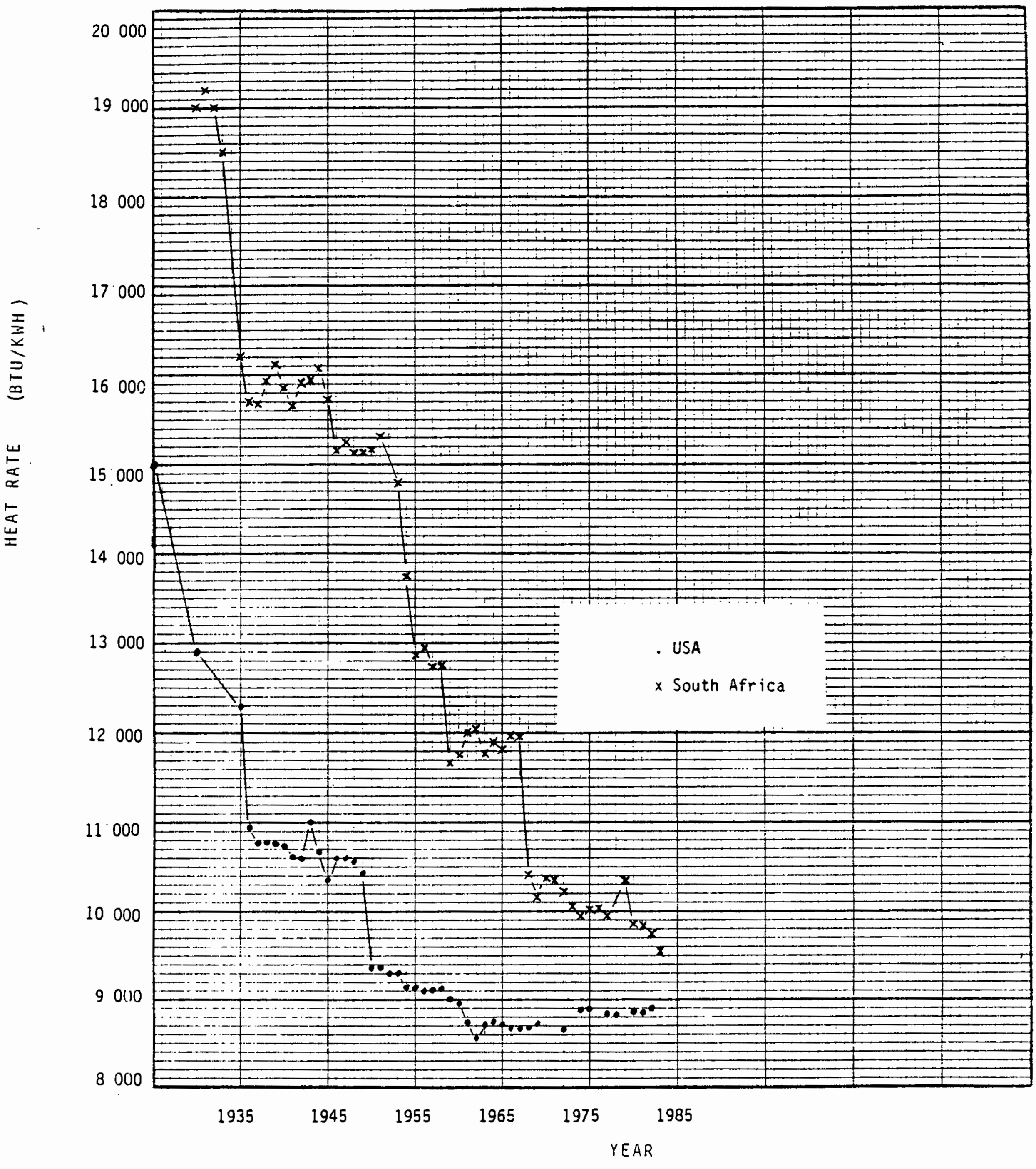
* The best annual operating heat rate was achieved in 1962 (8 534 BTU/KWh) by the Philadelphia Electric Company's 350 MW Eddystone No 1 - a 5 000 psi, 1 200°/1 050°/2050° F double reheat unit.

FIGURE 2 Heat Rates of the 'Best Plants' in the USA and in South Africa (1930-1983)



SOURCES: For the USA - "National Power Survey" A Report by the Federal Power Commission 1964 US Governement Printing Office, October 1969
- "The 1970 National Power Survey" Federal Power Commission, US Government Printing Office, December 1971
- "Steam-Electric Plant Construction Cost and Annual Production Expenses" US Department of Energy, Washington, Annual, various

For the SA - "Annual Report of the Electricity Supply Commission" ESCOM, SA, various

The heat rates of the most efficient plants in South Africa have shown a similar decline but with a time lag relative to the 'best plant's' thermal efficiencies in the USA.

During the 53 years, 1930 to 1983 inclusive, the 'best plant' heat rates improved from 19 000 BTU/KWh to 9 546 BTU/KWh; an improvement of almost 50 percent. The average annual improvement was 178 BTU/KWh. However, from the total improvement of 9 454 BTU/KWh during the 53 years, an improvement of 5 960 BTU/KWh occured with 5 annual leaps larger than 1 000 BTU/KWh. The heat rate improved:

from 18 500 BTU/KWh in 1933 to 16 200 BTU/KWh in 1935
" 14 800 " in 1953 to 13 740 " in 1954
" 12 740 " in 1958 to 11 690 " in 1959 and
" 11 690 " in 1967 to 10 410 " in 1968

If these large jumps are excluded, the average annual improvement in heat rate is reduced to 73 BTU/KWh per year.

It seems that the large leaps occur when a major improvement in technology is available and it is adopted, while the gradual changes happen mainly due to changes in plant utilisation, and improvements and adjustments in the functioning of the plant components.

Turning to the time lags involved in the technology transfer, (horizontal distance between the two curves in Fig 2), Table 2 shows the years of equivalent best plant heat rates in the USA (column 1),

TABLE 2 Years of equivalent 'best plant's' heat rates in the United States of America and South Africa

USA	S Africa*	Gap
1925	1952	27
1930	1957	27
1935	1959	24
1936	1968	32
1937	1968	31
1938	1968	30
1939	1968	29
1940	1968	28
1941	1968	27
1942	1968	26
1943	1968	25
1944	1968	24
1945	1969	24
1946	1968	22
1947	1968	21
1948	1968	20
1949	1968	19
1950	1984-85?	34?

* e g the most efficient plant in South Africa in 1952 had the same efficiency as the 'best plant' in the USA in 1925

in South Africa (column 2) and the time gap in years (column 3). The average time needed for the 'best plant' thermal efficiency in South Africa to reach that of the 'best plant' in the USA is 26 years. The minimum time lag occurred in 1968, when the 'best plant' thermal efficiency in South Africa reached that of the year's 1949 in the USA. Since then, however, the South Africa's 'best plant' has not reached the efficiency reached in the USA in the year 1950. It is estimated that that year's efficiency will be reached sometime during 1984-85 and that will be the longest gap - 34 to 35 years long.

As far as the heat rate gap is concerned, (vertical distance between the two curves in Fig 2), it is noted that it closed with time. The difference in the 'best plant' thermal efficiencies between
the USA and South Africa was 6 100 BTU/KWh in 1930
5 802 " " 1950
1 443 " " 1969
and 676 " " 1983

Assuming that the average improvement in the South African 'best plant' heat rates will be 73 BTU/KWh per year, (the historical average for gradual improvements), the 'best plant' thermal efficiency in South Africa will reach the heat rate of the 1960's 'best plant' in the USA around 1992 with a time gap of 30 years.

MATHEMATICAL DESCRIPTION OF THE INTER-TEMPORAL CHANGE OF THE SYSTEM THERMAL EFFICIENCY

The inter-temporal change in the STE can be considered as the result of two different procedures. The first is the addition of new plants to satisfy increased demand and the second is the replacement of old vintage plants with new ones. The two procedures occur simultaneously and both affect the STE. Their effects are additive. The total change in the STE in any time period is the sum of the change due to addition of new plants in the system and the change due to replacement of some retired capacity.

We estimate first the changes due to addition of new plants to satisfy increased demand and then the changes due to the replacement of the retiring capacity.

Let us define:

$\bar{f}_{n+1}$	the STE in period n+1;
$\bar{f}_n$	the STE in period n;
DI	the projected percentage average increase in capacity for the time span under examination;
f_c	the 'best plant' thermal efficiency during the n period;
a	the annual improvement in the 'best plant' thermal efficiency expressed as a percentage of the 'best plant' thermal efficiency in the n period.

Then the STE in the period n+1 is given by the equation 1.

$$\bar{f}_{n+1} = \frac{1}{1+DI}\bar{f}_n + \frac{DI}{1+DI} f_c\,(1+a) \qquad (1)$$

The equation 1 is derived by the definition of the STE - the STE is the weighted average of the efficiencies of the constituting the system plants. The STE in the period n+1 is the weighted average of the STE in period n and the efficiency of the newly introduced plants. The increased capacity is assumed to be DI (percent) of the existing in period n. Then the portion of the output produced in period n+1 by the new capacity is $\frac{DI}{1+DI}$ and the rest of the system produces:

$$1 - \frac{DI}{1+DI} = \frac{1}{1+DI}$$

The term $\frac{1}{1+DI}$ is used as the weight for the new vintage capacity. The efficiency of the new capacity is considered to be the sum of the 'best plant's' efficiency f_c in period n, plus a percentage increase denoted by 'a'

$$f_{n+1} = f_c\,(1+a)$$

Similarly, for the period n+2, under the assumption that the increase in demand remains the same, DI, and that the new vintage plants have an efficiency $f_{n+2} = f_c\,(1+2a)$, the STE is given by the equation 2:

$$\bar{f}_{n+2} = \frac{1}{1+DI} f_{n+1} + \frac{DI}{1+DI} f_c\,(1+2a) \qquad (2)$$

Substituting equation 1 into 2 we obtain:

$$\overline{f}_{n+2} = \frac{1}{(1+DI)^2}\,\overline{f}_n + \frac{DI}{(1+DI)^2}\,f_c(1+a) + \frac{DI}{1+DI}\,f_c\,(1+2a) \qquad (3)$$

Following the same procedure we obtain for the period n+k :

$$\overline{f}_{n+k} = \frac{1}{(1+DI)^k}\,\overline{f}_n + \frac{DI}{(1+DI)^k}\,f_c\,(1+a) + \frac{DI}{(1+DI)^{k-1}}\,f_c\,(1+2a) + \ldots + \frac{DI}{1+DI}\,f_c\,(1+ka)$$

and rearranging we obtain:

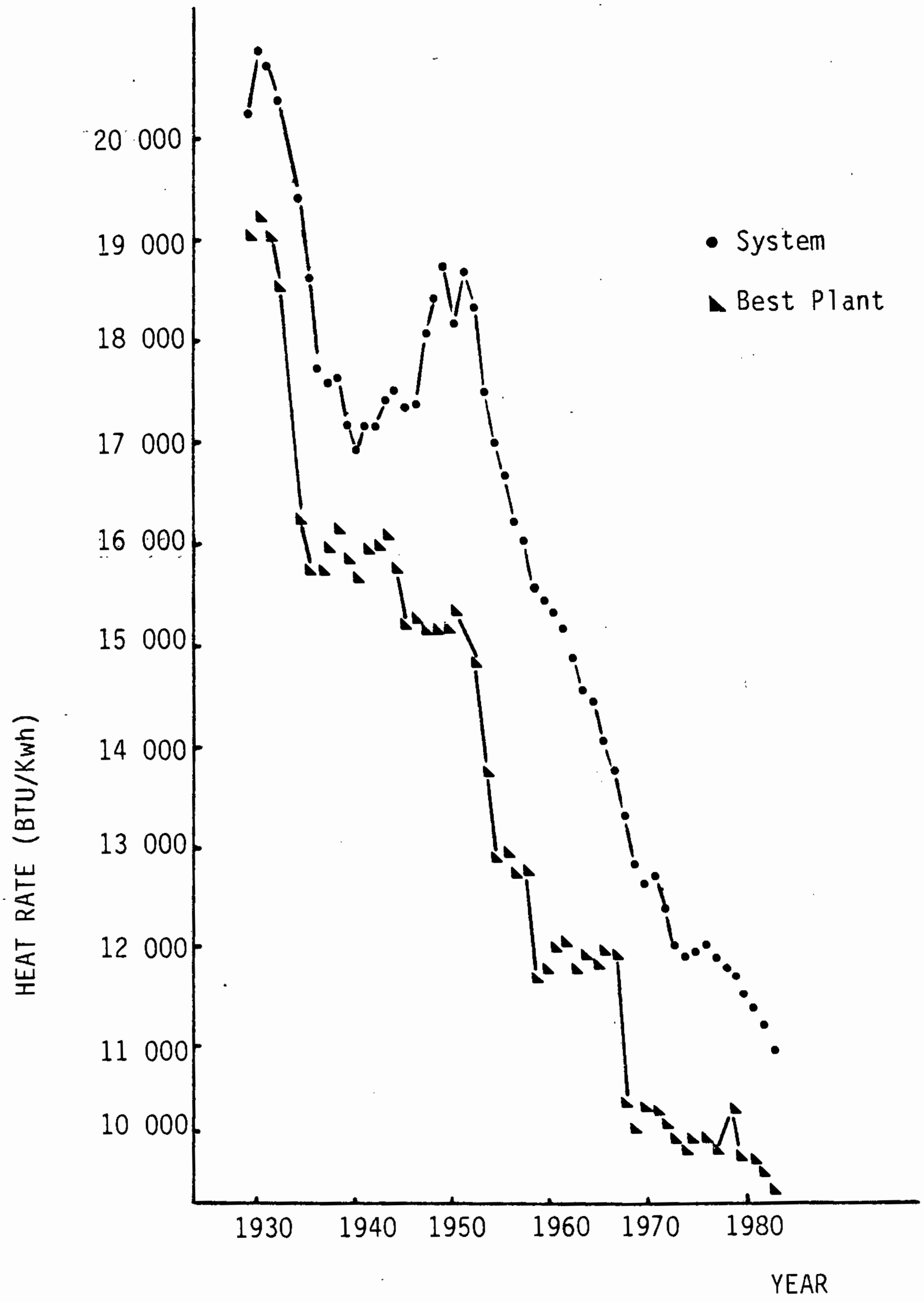
$$\overline{f}_{n+k} = \frac{1}{(1+DI)^k}\,\overline{f}_n + DI\cdot f_c\left[\frac{1+a}{(1+DI)^k} + \frac{1+2a}{(1+DI)^{k-1}} + \ldots + \frac{1+ka}{1+DI}\right] \qquad (4)$$

Equation 4 gives the STE during the n+k period ($\overline{f}_{n+k}$) as a function of the STE during the n period ($\overline{f}_n$), the per period increase in demand (DI), the best plant thermal efficiency in period n (f_c) and the improvement in the 'best plant' thermal efficiency (a).

Equation 4 has been derived analytically and it describes the way with which the STE approaches the efficiency of the best plant. A similar formula can be derived by the use of a bi-variate autoregressive/moving average (ARMA) model. However, the difference is that equation 4 can be used for the development of alternative scenarios and sensitivity analysis while a bi-variate ARMA model always assumes that the key rates of change remain unchanged.

Figure 3 shows the heat rates of ESCOM (system) and of its best plant. The horizontal distance of the two curves indicates the required time

FIGURE 3 Heat-rates of the "Best Plant" and of the system in South Africa (1930-1983)



SOURCE: "Annual Report of the Electricity Supply Commission" ESCOM, South Africa, various issues for the system thermal efficiency to approach that of the best plant's Since 1950, this gap seems to be relatively stable and around 12 years long. Equation 4 could predict adequately the STE during that period because the oldest plants of the system had an age less than 40 years and thus no sizeable retirement occured.

To take into account the effect of the replacement of old vintage plants, a replacement factor (RF) should be added into the equation 4. The value of the RF depends on the percentage of capacity replaced and the difference in thermal efficiency between decommissioned and newly added plants.

Assuming that real demand (real demand = total demand - demand for replacing vintage plants) is zero, the system would change its thermal efficiency only through replacement of aged plants. In that case, the STE in period n+1 is the sum of the STE in period n plus the product of the percentage of new capacity added by its efficiency minus the product of the percentage of the capacity decommissioned by its efficiency; and is given by equation 5.

$$\bar{f}_{n+1} = \bar{f}_n + P_1 \left[f_c \, (1+a) - f_1 \right] \qquad (5)$$

where $\bar{f}_{n+1}$ denotes the STE in period n+1

$\bar{f}_n$ denotes the STE in period n

P_1 denotes the percentage of the capacity to be replaced

f_1 denotes the replaced capacity's thermal efficiency

f_c denotes the best plant's thermal efficiency during the n period

a denotes the percentage per period improvement in the best plant's thermal efficiency

Equation 5 is derived as follows. The STE in the period n is by definition:

$$\bar{f}_n = P_1 f_1 + P_2 f_2 + \dots\dots + P_n f_n$$

Assuming that P_1 percent capacity is replaced in period n, we have:

$$\bar{f}_{n+1} = P_2 f_2 + P_3 f_3 + \dots\dots + P_n f_n + P_1 f_c (1+a)$$

and therefore

$$\bar{f}_{n+1} - \bar{f}_n = P_1 f_c (1+a) - P_1 f_1 \qquad \text{OR}$$

$$\bar{f}_{n+1} = \bar{f}_n + P_1 \left[f_c \, (1+a) - f_1 \right]$$

In the period n+2 the STE is:

$$\bar{f}_{n+2} = \bar{f}_{n+1} + P_2 \left[f_c \, (1+2a) - f_2 \right] \qquad (6)$$

Substituting (5) into (6) we obtain:

$$\bar{f}_{n+2} = \bar{f}_n + P_1 \left[f_c (1+a) - f_1 \right] + P_2 \left[f_c (1+2a) - f_2 \right] \qquad (7)$$

and generalising:

$$\bar{f}_{n+k} = \bar{f}_n + P_1 \left[f_c (1+a) - f_1 \right] + P_2 \left[f_c (1+2a) - f_2 \right] + \dots$$

$$\dots\dots + P_k \left[f_c (1+ka) - f_k \right] \qquad (8)$$

Rearranging the 8 we obtain the replacement factor RF

$$RF = \bar{f}_{n+k} - \bar{f}_n = f_c \left[P_1 (1+a) + P_2(1+2a) + \cdots + P_k(1+ka) \right] - \left[P_1 f_1 + P_2 f_2 + \cdots + P_k f_k \right] \qquad (9)$$

When the k denotes years and it has a value less than the plants' life expectancy, then the P_i, f_i and f_c are known and only the average per year increase in capacity (or modified demand for electricity) and the average per year improvement in the best plant's thermal efficiency are needed to be estimated.

Combining 4 and 9, any change in the STE can be forecast by the following equation:

$$\bar{f}_{n+k} = \frac{1}{(1+DI)^k} \bar{f}_n + DI \cdot f_c \left[\frac{1+a}{(1+DI)^k} + \frac{1+2a}{(1+DI)^{k-1}} + \cdots + \frac{1+ka}{1+DI} \right] + RF \qquad (10)$$

Some variation between predicted and actual STE should be expected as the rate of increase in demand and the rate of improvement in the best plant's thermal efficiency are considered constant over the forecast horizon. Equation 10 can, however, be easily modified to accept any function which describes the rate of change in demand and the rate of improvement in the best plant's thermal efficiency more adequately. Equation 10 can also provide some insight in the dimension of the time gap between STE and best plant thermal efficiency. Under conditions of stagnant demand (DI=0), only the Replacement factor (RF) is active. Then the upper limit in the lag between STE and best plant thermal efficiency is determined by the plants' life expectancy and it is accomplished under conditions of technological stalemate (a=0).

On the other extreme if the plants had an indefinite life and no replacement took place, the size of the gap between best plant thermal efficiency and STE would depend on the demand for additional capacity.

Assuming a technological stalemate (a=0), equation 10 becomes:

$$\bar{f}_{n+k} = \frac{1}{(1+DI)^k}\,\bar{f}_n + \left[1 - \frac{1}{(1+DI)^k}\right] f_c$$

as if the criterion for the STE to approach the best plant's thermal efficiency is the factor $\left[1 - \frac{1}{(1+DI)^k}\right]$ to be 90 percent - that is that $\bar{f}_{n+k}$ consists of 90 percent of the f_c and 10 percent of the $\bar{f}_n$ - then Table 3 gives the time gap as it changes according to demand.

TABLE 3 Time Required for the STE to approach the best plant thermal efficiency according to demand under technological stalemate and indefinite life expectancy for plants

DI	Gap (years)
0.02	116
0.04	58
0.06	40
0.08	30
0.10	24

A FORECAST OF THE SOUTH AFRICAN SYSTEM THERMAL EFFICIENCY

The forecast horizon of the model, developed in the last section is constrained by two factors. The first is the life expectancy of the plants belonging to the system and the second is the size of the time gap involved in the transfer of technology from the leading country to the lagging one. When the forecast horizon is longer than the life expectancy of the plants, then the retirement schedule of the plants to be built in the future is required. Similarly, when the forecast horizon is longer than the time gap involved in the transfer of technology, a forecast of the efficiency of the 'best' plant in the technology leading country is required. The plants' life expectancy can be considered to be 40 to 45 years and the technology transfer gap is extended, as we have seen, up to 35 years. The choice was made to forecast the South African STE of the year 2015, so that the forecast is inside the limits set by the two constraints.

In forecasting the STE of the year 2015, a complication has to be overcome, as the 'best plants'' thermal efficiency in the USA has been stagnant since 1960. Our analysis of the technology transfer gap has shown that the best plant's thermal efficiency in South Africa will approach that of the best plant's in the USA by 1992 and will remain unchanged thereafter, as no new improvements are available to be transferred. Even if new technology in the USA improves the best plant's thermal efficiency, that technology will be transferred in South Africa after the year 2015. To overcome the above complication, the forecasting horizon was broken into two parts. Firstly, the STE of the year 1992 is forecast, assuming an annual improvement in the best plant's thermal efficiency of 73 BTU/KWh and then the STE of the year 2015 is forecast, assuming a zero improvement (a=0).

In order to preceed with the forecast, the demand for additional capacity over the next 30 years, and the retirement schedule of the plants are needed.

The demand for additional capacity is controversial. ESCOM estimates a 7 percent annual growth, while the De Villiers Commission suggests that South Africa has probably entered a long-term phase of low economic growth and predicts that sales of electricity should not grow faster than 4 to 5 percent per year (Financial Mail 1984).

This latter growth in electricity demand is based on an economic growth rate of between 2.5% and 3.0% per annum , which has been derived by taking into account "the whole of the circumstances in the South African economy, the investment patterns, the inefficiency of application of capital and labour and the complete change precipitated in the world economy by the energy crisis" (Commission of Inquiry 1984).

The assumed relationship between economic growth and demand by the Commission of Enquiry is in accordance with the income elasticity of electricity demand (1.64) that was estimated in Chapter 2 and the Commission's assumptions were used in order to predict the system's thermal efficiency (in other words the forecast is conditional on an electricity demand growth of 4% to 5% per year).

As far as future capacity retirement is concerned, a variety of approaches have been used in the relevant literature. One method is to retire an equivalent of a specified percentage of new capacity (e g for every 1000 MW added, retire 100 MW of old capacity). Another approach is to fit a curve to the past trend of retirements and project this into the future. A third method is to retire all plants after a given number of years of operation. The last approach has been suggested and used by Dalsted (1981) and is adopted in our model The life expectancy of the power plants has been estimated to be between 40 and 50 years (Commission of Inquiry 1984, CEGB 1983) and hence we assume that plants are retired after 45 years of operation.

To simplify calculations, the plants belonging to ESCOM were clustered according to their age in 1983 (Table 4) and the capacity with an average age above 45 years (capacity belonging to clusters 5 and 6) was retired immediately. The capacity of each of the rest of the clusters is retired when the average age of the cluster is 45 years. For example, the capacity of the cluster 4 has an average age of 34 and is retired in 1994, the capacity of the cluster 3 is retired in 2004 and the capacity of the cluster 2 in the year 2014.

Setting in equation 10, $\overline{f}_{1983} = 31.10$, $f_c = 35.70$, $DI = 0.04$, $k = 9$ and $a = 0.0097$ (so that the best plant efficiency in South Africa in 1992 will be the same as in the USA - around 8 800 BTU/KWh) (ESCOM 1983), the STE in 1992 ($\overline{f}_{1992}$) is estimated to be 32.116%.

TABLE 4 Distribution of electricity produced by ESCOM in 1983 according to the age of the producing plant

Cl	Age	Fraction of energy produced	Cumulative	Average Th Ef
1	0- 9	0.5093	0.5093	34.80
2	10-19	0.3169	0.8262	31.51
3	20-29	0.1235	0.9498	26.03
4	30-39	0.0350	0.9848	19.36
5	40-49	0.0133	0.9981	17.50
6	50-59	0.0019	1.0000	19.10

Similarly, by setting $\bar{f}_{1992} = 32.116$, $f_c = 38.86$, (for 1992), DI = 0.04 , k = 23 and a = 0, it is predicted that ESCOM's thermal efficiency in 2015 will be 37.95 percent - an improvement of 22 percent over the efficiency in 1983.

If demand for electricity increases by 5 percent per year, the STE in 1992 becomes 33.66 and in 2015 becomes 38.63. The improvement in efficiency over 1983 is 24 percent.

The predicted improvements in the STE for the next 30 years, although sizeable, are only about one third of the gains obtained in the system thermal efficiency during the preceding 30 years.

SUMMARY AND CONCLUSIONS

This chapter identifies and analyses the factors affecting the system thermal efficiency in a technology importing country. It develops an efficiency forecasting model which is used to determine the thermal efficiency of the Electricity Supply Commission of South Africa for the years 1992 and 2015. The factors determining the STE are identified as the speed of the technology transfer from the country of origin to the technology importing country, the rate of demand for additional capacity, and the age profile of the plants belonging to the system.

The forecasting model distinguishes between the changes in the STE due to addition of new capacity to satisfy increased demand for electricity and changes due to the replacement of retired capacity. This approach facilitates the investigation of alternative scenarios - elongation of life expectancy of plants, stagnation in demand for additional capacity and so on - and it can be used for research on the optimum schedule of plant retirement, optimum life expectancy of plants and technology transfer, so as to minimize the total cost of the electricity producing system.

The application of the developed model on the electric utility of South Africa shows that improvements with magnitude of 20 percent over the 1983 STE can be obtained by the year 2015. The implication of this finding is that although electricity demand by the year 2015 is expected to be four times the 1983 level, the coal and water requirements for the power stations will be only three times of that of 1983.

Further improvements in the forecasting ability of the model can be accomplished by research for more accurate predictions on the way utilities retire old plants, on the inter-temporal changes in the demand for electricity and on the time gap involved in the technology transfer in this domain and for the specific country.

PART III

ECONOMIC MERITS OF NUCLEAR AND COAL-FIRED POWER PLANTS

CHAPTER 5

FORECASTING THE FUTURE ECONOMIC MERIT OF NUCLEAR AND COAL-FIRED GENERATION PLANTS IN SOUTH AFRICA

INTRODUCTION

The knowledge of the future mix of electricity producing technologies is important for forecasting and planning a large number of energy related activities. Coal requirements for the production of electricity, labour needs for the mining and power supply industry, capacity requirements of industries like uranium enrichment and railways are some of the issues whose planning requires the knowledge of the future mix of electricity producing technologies.

The usual way of handling this issue in South Africa, is either to assume an a priori mix (Norman 1977, 1982), or to assume that technologies with current merit will be dominant also in the future (Dutkiewicz et al 1985).

This chapter addresses the relative merit of nuclear versus coal-fired electricity generation for plants beginning baseload service in South Africa after the year 2000. Emphasis is placed on the economic merits of the two technologies and environmental and social implications are taken into account only in so far as legislation, security and so on affect the economics of the technologies.

It is assumed that nuclear and coal-fired generating plants will represent the most cost-effective and feasible options for base-load service in the foreseeable future. Sociopolitical considerations and lack of indigenous oil production forbid the use of oil for the production of electricity independently of economic merits. Similarly, the absence of local research on alternative renewable technologies, their stage of development abroad and their current economics limit the possibility of their extensive use in the horizon under examination.

The figure of economic merit used in the study is the "levelized bus-bar* cost" over the life-time of the station. This figure is a representation of the average cost of producing electricity over the assumed life of the nuclear or coal-fired station. The costs are expressed in terms net of general monetary inflation in Rands of 1982 purchasing power. Nominal costs would be larger but the relative results would be the same.

Section 2 of the chapter summarizes the fundamental concepts in bus-bar cost comparisons. Section 3 outlines the basic assumptions, projected costs and sensitivities of coal-fired power stations. Section 4 examines the nuclear costs and section 5 provides observations and conclusions that stem from the results of the analysis.

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* The "bus-bar" point is beyond the generator in the station but prior to the voltage transformation point in the plant switch-yard.

METHODOLOGY

Comparing the future economic merit of different electric generating technologies requires the use of a project appraisal technique and a set of techno-economic projections. In this chapter the project appraisal technique is outlined and the methodology used for the production of the needed set of projections is discussed.

The most commonly accepted methodology for project evaluation is the discounted cash flow technique. Surveys by the Intercompany Comparison Group in 1975 and by the Edison Electric Institute in 1976 and 1977 have found that "virtually all the firms that do any mathematical analysis (in the USA) follow conventional discounted cash flow (DCF) procedures" (Corey 1982).

Under the DCF procedure, the present value of a stream of future expenditures is related to the present value of a stream of future revenues and the project with the greatest net present value is chosen.

Formula 1 shows the mathematical description of the DCF analysis:

$$\sum_{n=0}^{N} I_n \left[\frac{1}{1+r}\right]^n = \sum_{n=0}^{N} R_n \left[\frac{1}{1+r}\right]^n \qquad (1)$$

where r is the annual discount rate

n is the number of time periods (years) before each expenditure is made or recovery obtained. In the case of generation alternatives, costs and benefits are discounted as of the date the plant is scheduled to enter service.

N is the total project life and

$\frac{1}{1+r}$ represents the present value discount factor

The left hand side of the equation represents the present value of the expenditures required and the right hand side the present value of the revenues.

The equation can be solved for the rate of return r (internal rate of return technique) or for the net present value of the project. The net present value (NPV) is the sum of the discounted benefits minus the sum of the discounted costs. The internal rate of return is the rate of discount (r) which will bring benefits and costs to equality so that the net present value equals zero.

A surrogate often used for the present value of a power plant's cost is the "levelized bus-bar cost" (LBBC). The LBBC is obtained by converting the present value of the power plant's cost into a fixed annual charge over the plant's economic life and dividing it by the number of kilowatthours of energy the plant is expected to produce each year. This levelized cost can be seen as the average cost in constant money terms per unit of electricity fed into the grid at which the total lifetime output of the plant exactly balances the costs of the plant, its operating and fuel costs plus waste management and ultimately decommissioning.

Formula 2 gives a mathematical expression of the levelized bus-bar cost of electricity:

$$LBBC = \frac{\sum_{t=0}^{L} (c_t + m_t + f_t) \; / \; (1 + r/100)^t}{\sum_{t=0}^{L} e_t} \qquad (2)$$

where c, m, f the annual real capital, O&M and fuel costs

e_t the net annual electrical output of the plant

L the life of the plant in years and

r a discount factor in %

The validity of comparisons through the levelized bus-bar cost depends critically on two conditions. The first is that the amount of electricity produced is the dominant benefit being considered and the second that the compared generation alternatives are of relatively similar size. If the satisfaction of other criteria (eg reliability) is also required then only a comprehensive analysis of the specified utility system can evaluate the generating options adequately. Similarly if 'LBBC' is used to compare plants of substantially different sizes erroneous conclusions can be reached. For example, if there is no need for all of the energy available from a larger plant, a smaller plant may be better investment, irrespective of what the bus-bar cost suggests.

Instrumental in the DCF procedure is the choice of a discount rate. The discount rate gives an indication of how heavily present costs and benefits are valued against costs and benefits occuring in the future. The relative merits of projects with different pattern streams of cost and benefits are crucially dependent on the value of the discount rate. If, for example, one wishes to evaluate the cost of recovering and processing radioactive wastes currently dumped into the oceans, many years from now, such costs will inevitably appear to be negligible if they are discounted back to the present. The benefits or costs valued at $1000 in one hundred years' time, have a present value of only 7.2 cents, when discounted with a rate of 10% per annum.

Because the choice of the discount rate can influence strongly which public policies can be supported by cost-benefit analysis, and which cannot, it is a matter of concern to politicians as well as policy analysts (Lind 1982). The choice of the discount rate for evaluating public choices is itself a public policy decision that in most cases will be politically determined. As such, it varies from country to country, from agency to agency, and from time to time. The rates used in studies published in international journals, predominantly concerned with conditions in the United States and Britain, vary widely. At one extreme is the view that decisions on programmes should be made on the basis of first year costs and benefits - a procedure which implies a discount rate of 100%, since the future is ignored. At the other extreme is the view that decisions should be based on total undiscounted costs and benefits - a procedure which implies a discount rate of zero, since costs and benefits applicable to, say, the 50th year are treated as being as important as current costs and benefits. In the majority of studies the discount rates used lie in the range of 2 to 13%.

In South Africa there is no official directive for discount rates. In order to determine a suitable discount rate for the comparison of coal and nuclear-fired power plants we follow Lind's (1982) conclusion that the most prominent contenders for the appropriate discount rate for use in public projects are the social rate of time preference and the returns to capital in the private sector.

The social rate of time preference is the rate at which society is willing to exchange consumption now for consumption in the future. The yield of government securities, corrected for inflation, is one indicator of society's preferences between present and future consumption. In Appendix 2 are shown the yields of long term South African bonds adjusted for inflation by the retail price index for the period 1937-1981. The real rate of return fluctuates between -5.4 and 4.15% per annum and the average return for the period as a whole is 0.43%.

The use of the expected or achieved rate of return on capital in the private sector as a discount rate for the evaluation of public investments is based on the argument that the opportunity cost of employing resources in the public sector is not using them in the private sector. Therefore, the appropriate discount rate for public discount rate for public sector investments is the rate which would have been earned in the private sector. The average yields of new issues of company stock debentures and notes in South Africa (Appendix 3) can be used as a proxy for the long-term return on private capital. During the period 1963-1983 the average real yield was 2.48%. We can conjecture therefore that the discount rate for public projects must lie between 0.43 and 2.48% per annum. For the evaluation of nuclear and coal-fired generating plants a discount rate of 2% per annum (in real terms) is chosen.

In order to proceed with the evaluation of the relative merit of nuclear versus coal-fired electricity generation, a set of cost and technology projections is needed. The estimation of LBBC requires the knowledge of the costs involved and the amount of electricity that the individual plants are expected to produce. The cost of generating electrical energy usually includes:

(1) capital-related costs;

(2) fuel costs; and

(3) operation and maintenance costs.

The amount of electricity to be produced depends on the economic life of the plant and the plant's availability*. Generally, power plants are not retired because they wear-out, but rather because they become uneconomic to operate. Selecting an appropriate economic life requires balancing the uncertain future availability of more economic sources of electricity with the residual value of the plant when used in intermittent service or in providing reserve capacity. The material life of the plant stands as the upper limit

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* Plant availability is more appropriate to be used for comparison of different modes of electricity production than load factors (ie when the plants are not used in full capacity). Baseload plants do not always operate continuously at full output even when they are capable of doing so because of total utility system considerations. In defining the benefits offered by each generation alternative its maximum potential electrical energy output should be used and not its expected actual output.

of time that the plant can be operational and depends on the technology used and the way the plant is managed during its operational life.

The availability of a plant is the percentage of time during some time period (say a year) that the plant is available to offer its services. Availability is considered to be a function of the size of the plant and of the complexity of the technology embodied in the plant.

To derive the set of projections needed for this chapter, a multiple-perspective approach has been used. As far as the coal-fired generation plants are concerned, because of inertia, costs are assumed to continue on the trends of the last decade, until the year 1992 when the majority of the plants under construction have been built. Two scenarios are developed for the time thereafter (1992-2000). The first, (low-cost scenario), assumes cost growth similar to that prevailed during the period 1950-1974. The high cost scenario assumes continuation of the trends established during the most recent period (1974-1982). For each scenario sensitivity analysis is employed to examine the effects of exchange rate variation, distance of power station from the coal-mine, cooling mode and environmental control stringency on the levelized bus-bar cost.

The evaluation of the nuclear option relies on a combination of forecasts by the USA Energy Information Administration (1982) for the nuclear content imported in South Africa, and on predictions for the cost of the civil works required, and of the fuel cycle. A high and a low scenario are developed, distinguished mainly by different assumptions for the cost-growth of the fuel cycle and the construction cost. Sensitivity analysis is performed in order to identify the effects of variations in the Rand exchange rate on the total bus-bar cost.

ECONOMICS OF COAL-FIRED PLANTS

The levelized bus-bar cost of electricity produced by a coal-fired plant depends on the capital-related costs, the fuel costs, the operation and maintenance costs, and the units of electricity to be produced during the life-time of the plant.

Capital Related Costs

The capital related cost of an electricity generating plant is its value as capitalised and entered into the plant's asset account of the company's book at the time it goes into commercial service. It includes all expenditures made prior to and during the construction period of the plant for services, equipment, materials, labour, and management, accumulated to the date that commercial service commences. It is conventionally measured in monetary units per MW or KW of capacity installed (R/MW) and it represents the funds and the accrued and compounded interest on the funds invested in the project during its construction period.

In South Africa the capital cost of coal-fired power stations has increased from R77000 per MW of capacity installed in 1950 to R148000 per MW in 1973 and R520000 per MW in 1982 (Commission of Inquiry 1984). This means a growth of 2.9 percent per year during the 1950-1973 period and a growth of 15 percent per year during the 1973-1982 period. In real terms (compensating for inflation) costs declined by 1.1 percent per year during the earlier period and increased by 0.6 percent per year during the latter period.

The 'Commision of Inquiry(1984)' has suggested that some of the reasons for the reversal of the trend in capital costs during the last decade are: higher chimneys, higher efficiency precipitators, and water purifications systems required by anti-pollution legislation; security requirements for more efficient fencing and stronger reinforced structures; longer construction periods and the end of the benefits through economies of scale.

For projection purposes, it is assumed that the trends established during the last decade will continue, because of inertia, until the year 1992. Two scenarios are developed for the period from 1992 up to the year 2000. The first assumes a decline in capital cost of magnitude similar to that of the period 1950-1973. The reasoning is that standardization of the size of sets (Commission of Inquiry, 1984, p182) will bring standardization of parts and eventually economies of scale. In addition, it has been indicated that leadtimes and manpower requirements for coal fired plants have begun to stabilize in the United States (Bowlby et al 1982) and improvements in electricity producing technologies and techniques are transferred to South Africa with a lag. The pessimistic scenario assumes the failure of the efforts to contain the capital cost which continues to increase by 0.6% per year in real terms.

In order to identify the effects of

(1) variations in the exchange value of the Rand;

(2) stringer environmental control enforcement; and

(3) limited water availability,

on the capital cost structure of coal-fired power stations, three "scenariettes" are superimposed on each main scenario. The "scenariettes" are independent of each other and therefore combinations of "scenariettes" are also possible, and are examined.

The first "scenariette" examines the sensitivity of capital cost on the variation of the Rand exchange rate. A widely held view is that exchange rate variations compensate for the difference between the rates of inflation in different countries (purchasing power parity principle). When that is the case, local inflation inflates the price of the local content of the power station while inflation abroad in conjuction with the variation in the exchange rate inflates proportionally the imported content. Hence, when costs are examined in real terms, the variation in exchange rates leaves the end cost unaffected. When, however, exchange rates do not conform to the purchasing power parity principle - and that is the case because of capital transfers, changes in consumer preferences, variations in techniques of production, different rates of productivity and so on - the variation in the exchange rate would increase or decrease the price of imported content disproportionately to the local content.

During the period 1950-1983, the Rand (South African Pound for the period 1950-1961), was fixed to another currency or was adjusted by the authorities in a "managed float" scheme. Examination of the inflation rates and the exchange rates (Appendix 4) shows that the authorities based their efforts to determine the value of the Rand on the purchasing power principle. Therefore, the effects of exchange rate variation on the capital cost of stations during that period do not need special elaboration.

Since 1983 the authorities, undertaking to integrate the South African economy to the international markets, have followed a strategy of liberation of the economy and the foreign exchange market. The Rand exchange rate therefore can be more variable in the future and needs to be considered in the estimation of power station costs.

Presumably, the exchange rate would have a greater influence in the cost when the local content is minimum. Alternatively, if the imported content is zero the exchange rate cannot affect the real cost of power stations. As far as coal-fired stations is concerned, approximately 20 percent of the total capital cost was attributed to the acquisition of components from abroad (70 percent of the turbine and 30 percent of the boiler) in the year 1983. A devaluation of the Rand by 100 percent* below the equilibrium point suggested by the purchasing power parity principle, would therefore increase the total capital cost of a coal-fired power station by 20 percent. In other words, the exchange rate elasticity of capital cost of coal-fired power stations is 0.2.

The second "scenariette" estimates the additional cost occured due to environmental pollution laws which require the installation of scrubbers to prevent sulphur dioxide being released into the atmosphere.

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* eg from $1 = R1 to $1 = R2

Sulphur dioxide is believed to be the primary cause of acid rain and because of the long range effects of emitted gases it is possible that other countries as well could attempt to enforce more stringent environmental controls in South Africa. It is estimated that the equipment of major coal-burning power stations with a scrubber would cost in the region of R300 millions per station (Dutkiewicz et al 1985) in 1982 values. That is translated to approximately R100000 per MW or almost a 20 percent increase.

The third "scenariette" examines the cost of power stations using dry-cooling technology. A primary input in the production of electricity is water, and water is projected to be one of the scarcest resources in South Africa (Science Committee 1983). In order to ease the pressure on the water resources, the Electricity Supply Commission (ESCOM) has started using the dry-cooling technique. Stations employing dry-cooling require 25 to 30 percent of the water used in stations where wet-cooling is employed. Dry-cooling, however, requires redesign in the stations' condensate and cooling water circuit and especially designed and constructed cooling elements. These factors affect the capital cost of the station. ESCOM has suggested (Dutkiewicz et al 1985) that the cost of a station employing dry-cooling is approximately 8 percent higher than that of stations using wet-cooling techniques.

To summarise, the high cost scenario envisages a capital cost for coal-fired stations of R580000 per MW in 1982 Rands in the year 2000 and the low cost scenario a cost of R502000 per MW. The environmental "scenariette" increases these costs to R680000 per MW and R602000 per MW respectively and another R40000 per MW are added for power stations using dry-cooling techniques. A further adjustment of $0.2V_x$ (where V_x is the percentage variation of the exchange rate from the equilibrium price suggested by the purchasing power parity principle with base the year 1982) is warranted to take into account the effects of the exchange rate variations.

Fuel Costs

For coal-fired plants, the fuel cost consist essentially of the costs of purchasing coal from the mining company and transporting it to the power plant site. For the estimation of the levelized bus-bar cost of electricity the thermal efficiency, that is the proportion of the input energy which is converted into usable electricity, is required as well.

The most important factor determining the cost of coal is the method of mining. Coal from underground mines is more expensive than coal from surface mines. In 1982 coal mined underground cost twice as much as coal from open-cast mines (Commission of Inquiry 1984). Other factors such as heat content, ash properties, moisture and sulphur contents also have an effect on the cost of coal.

The average price of coal used by ESCOM has been increasing in nominal and real terms since 1950, to R11.75 per ton in 1982. An average nominal increase of 4.7 percent per year was recorded for the period 1950-1973 and an increase of 19.4 per cent per year for the period 1973-1982. In real terms the increases have been 0.7 percent and 5 percent per year respectively. The steep increase in the price of coal during the period 1973-1982 has tentantively been attributed, by the Commission of Inquiry (1984), to structural changes in the coal mining industry, the end of the monopsonistic coal-market (ESCOM and ISCOR), the growth of exports and the increase in labour cost.

Transporting the coal from the mine to the power station can increase the cost of coal considerably. Transport cost is a relatively unimportant contributor to the total delivery cost when the power station is sited at the pit-head. It is, however, especially important for stations far away from coal-mines. In the South African context, transport cost is relevant for electricity consumed mainly in the Cape Province whose metropolitan areas lay around 1600 km away from the Transvaal and Natal coal-fields.

The coal transport cost has increased from 0.21 cents per ton-km in 1950 to 0.53 cents per ton-km in 1973 and 1.54 cents per ton-km in 1982 (General Manager of Railway and Harbours 1951,1974,1983). This is an increase of 4 percent per year for the period 1950-1973 and 13 percent for the period 1973-1982. In real terms the transport cost of coal remained unchanged during the former period and it fell by 1.4 percent per year during the latter one.

The final factor affecting the fuel cost is the thermal efficiency of the station. Thermal efficiency is a technological factor affecting the fuel cost of producing electricity. A plant with high thermal efficiency needs a smaller quantity of coal to produce an amount of electricity than a plant with a lower thermal efficiency. Increases in unit sizes, inlet steam temperatures and inlet pressures accompanied by improvements in equipment design have improved thermal efficiencies of coal fired stations from 18 percent in 1950 to approximately 35 percent in 1982. The Commission of Inquiry (1984,p179) has noticed that "at current coal prices the improvement in thermal efficiency over the past 30 years enabled ESCOM to save R250 millions per annum on its current coal account". Further improvements, however, are limited. The rate of improvement in ESCOM's units thermal efficiency has slowed down during the 1970's and in any case the limitation in further improvements in thermal efficiency is a world-wide phenomenon. A factor that would affect adversely the future thermal efficiency is water availability. ESCOM estimates that overall thermal efficiency would be reduced from 35% to 30% fpr dry-cooling units. For all practical purposes baring the use of topping devices, a constant thermal efficiency of 35% can be considered for the foreseeable future.

In summary, the continuation of past trends points to a range of real 1982 prices of R28.2 per ton to R20.22 per ton for the high and low scenarios for the year 2000. Transport cost is projected to be between 1.10 cents and 1.31 cents per ton-km in 1982 Rands. Finally, thermal efficiency is assumed to range between 30 and 35 percent depending on the cooling mode used.

Operation and Maintenance Costs

The operation and maintenance (O&M) cost of a coal-fired power plant includes all production expenses excluding fuel costs. Some of the constituent costs are: operators' wages and benefits, maintenance expenses, security, supervision, spare parts, insurance and so on. Part of the O&M costs is of a fixed nature, that is the costs are incurred even when the plant is not in service, and part is of a variable nature, incurred in proportion to the output produced.

The O&M costs have increased from around R500 per installed MW capacity in 1950 to R12758 per MW installed in 1982. A growth of 9.1 percent per year was observed in the period 1950-1973 and a growth of 17 percent per year during the period 1975-1982. The growth in the two periods is not directly comparable because a new accounting system was brought into operation at ESCOM at the beginning of 1975. Nevertheless, the growth of cost within the two periods is indicative of the speed with which the operating and maintenance costs increase. In real terms, the increase in the two periods has been 5.1 percent and 2.6 percent per year respectively.

This gives an O&M cost of R25672 per MW and R30966 per MW for the low and high cost scenarios respectively. Additional O&M cost could occur if power stations have to comply with more stringent environmental standards. Harrer and Niever (1981) examining cost trends for coal units in USA found that O&M cost increases by: 20 percent for every 1 percent increase in sulphur content by weight, and by 2 percent for every 1 percent increased efficiency in the SO_2 removal process. However, they noted that the O&M cost for a scrubber designed and constructed from "bottom up" was around 50 percent cheaper than a retrofitted scrubber. In this analysis it is assumed that environmental considerations would not significantly affect the O&M costs.

Life Expectancy and Availability of Coal-fired Power Stations

The expected life of the power station and its availability over its life for a given capacity determines the quantity of electricity the station can produce. As output increases, the given costs are spread to more units and therefore the cost per unit of output falls.

Perceptions about the life-span of coal fired stations have changed during the last few years. The Federal Power Commission (1964) in the USA had forecast that the life expectancy of big coal-fired stations would be less than 30 years because of their high complexity. Twenty years later, however, the Central Electricity Generating Board (CEGB 1983) in the United Kingdom reassessed the life span of its stations as good for 40 years. Similarly, the Commission of

Inquiry (1984) in South Africa examining the power stations decommissioned since 1970, concluded that "a power station life of 40 years, is a generally accepted figure".

Further improvement in the life span of power stations is attainable. Although the average life of a power station is approximately 40 years, there are stations with ages above 50 years still in operation (Weinberg 1985, Commission of Inquiry 1984). In addition, research in the USA indicates that fossil plants nearing retirement can undergo repair and rehabilitation that "will result in another 20 to 30 years of operation at a fraction of the cost of a new power plant" (Catalano 1984).

Economic considerations also point towards an extension in the life-span of fossil plants. Thermal efficiency improvements in the past had affected the economics of new versus rehabilitated stations, in favour of new more efficient plants. However, as in the foreseeable future efficiency improvement is predicted to be limited, rehabilitating old stations would turn out to be a more economic solution. In this study it is assumed that planners in the year 2000 would estimate a life expectancy of 50 years for fossil-fired plants.

Reduction in availability rates is probably the price the electrical utilities have to pay in order to achieve economies of scale and higher thermal efficiencies. Increase in unit size brought economies of scale and higher thermal efficiencies but it was accompanied by lower unit availabilities. While the availability of a 60 MW unit in its fifth year of operation is 87.7 percent, the availability of a 600 MW unit is only 56.1 percent (Commission of Inquiry 1984, p174)

ESCOM's average availability has been reduced from a peak of more than 85 percent in 1975 to less than 70 percent during 1983. The factors responsible for the reduction in availability have been:

a) the exceptionally high growth of the load and consequently low reserve margins available;

b) the chronic shortage of trained personnel; and

c) the declining quality of coal (Blackmore 1982, Commission of Inquiry 1984).

It is hoped that in the future better maintenance and plant computerization (Dorfmeister 1980) could improve the plant availability. ESCOM has a target to improve availability to 74 percent by the year 1989. In this study an availability of 75 percent is assumed for coal-fired power stations operating in the year 2000.

ECONOMICS OF NUCLEAR POWER PLANTS

South Africa is a new member in the club of countries exploiting nuclear energy for the production of electricity. Its nuclear power station, Koeberg, was ordered in 1976 and the first unit started commercial operation in October 1984. The second unit was connected to the grid a year later, in August 1985. Both reactors are of the PWR type, made by Framatome - France and their designed output is 922 MWe each.

South Africa does not have the technology and industry to produce nuclear reactors and hence it has to import most of the technology and equipment. It is estimated that 70 percent of the capital cost of Koeberg was due to imported equipment and technology.

Attempting to predict the future competitiveness of nuclear power stations in South Africa involves the forecast of the cost of the local content, the price of the imported technology and the technological characteristics of the nuclear technology to be used In this study, the nuclear costs are divided into capital, fuel and operation and maintenance costs. The cost of the imported content is extracted from the relevant literature of nuclear technology exporting countries. Similarly, the O&M costs and technological characteristics are based on the international experience. The fuel cycle cost and the plant construction cost depend on local conditions and are estimated accordingly.

Capital Related Costs

The capital related cost of a nuclear power station sited in a technology importing country, consists of the cost of the locally manufactured content and the cost of the imported parts in the country. In South Africa the local content consists mainly of the construction work and to a smaller extent of the locally manufactured parts of the turbine. The cost of the imported content in local currency units is determined by the price the manufacturer is prepared to offer the nuclear unit and the prevailing exchange rate.

The local content of Koeberg's capital cost is estimated to be 30 percent of the total cost or R278 million per 922 MWe unit. This cost is distributed to construction materials and labour, local services, land acquisition, interest during the construction period and so on. As Koeberg is the first nuclear station in South Africa, there are no other available historical data. For extrapolation purposes, therefore, it is assumed that the cost of the local content will increase up to the year 2000 according to the rate dictated by the rate of increase in the Construction Price Index. The Construction Price Index is a weighted average of a range of construction materials. During the period 1973-1982, the Index increased by 15 percent per year (0.6% in real terms) while during the period 1950-1973 the cost of construction materials and labour increased by 5.4 percent per year (1.4% in real terms)(Dept of Statistics 1982).

Following the methodology developed for the scenarios in the last chapter, it is assumed that the cost of the local content of nuclear power plants will continue to increase by 0.6 percent per year in real terms up to the year 1992. Thereafter, it is assumed that either the same rate of increase will continue, leading to a cost of R308 million by the year 2000 (1982 Rands) or that the rate of increase will accelerate to 1.4 percent leading to a cost of R329 millions. The implicit assumption in this assertion is that the costs of the other components influencing the cost of the local content (eg labour, land etc) will also increase by the same rate as the Contruction Price Index or that their combined effect will be the same.

The imported content consists of the nuclear-steam supply system, approximately 80 percent of the turbine-generator system, and the transferred professional services. For the construction of Koeberg the cost of the imported content is estimated around R650 million (in 1982 Rands) for each unit. For the year 1992, the US Department of Energy (1981) predicts that the cost of nuclear-steam supply system will be 20 percent of the total nuclear capital cost in the USA.

This prediction in combination with the forecast total cost of nuclear plants in the USA (Energy Information Administration 1982) is used to determine the cost of imported content of nuclear plants in South Africa. The Energy Information Administration suggested that "for all regions of the country (USA) average investment costs will continue to escalate. For most regions, costs could rise at a real inflation-adjusted rate of between 4.5 and 7.5 percent per year during the decade, while for the nation, a rate of over 5.1 percent annually is projected". For the year 1990 a total average capital cost has been projected to be US $1545 per kWh. Assuming a continuation of the trend in the increase of costs (5 percent per year), a total capital cost of US $2500 per kWh is projected for the year 2000. In conclusion, the modified projections, of the US Department of Energy, for the year 2000 point towards a cost for the imported nuclear content in south Africa of R500 million (in 1982 Rands and exchange rates) for each 922 MWe unit. This cost is derived by incorporating benefits stemming out of standardisation, serial production and economies of scale due to favourable learning curve available in the nuclear industry (Arthur 1981).

As discussed in the "Economics of Coal-fired plants - Capital Related Cost" section, the cost, in Rands, of the imported content of a power plant depends on the prevailing exchange rate. Seventy percent of the capital cost of a nuclear plant is estimated to be for imports while only 20 percent of the coal-fired power stations' cost are for imports to South Africa. Therefore, it is expected that the exchange rate would have a greater influence on the cost of nuclear stations than on the cost of coal-fired power plants.

To examine the effects of the variation of the exchange rate on the cost of nuclear power stations, it is assumed, initially, that the exchange rate is dictated by the purchasing power principle and the cost sensitivity on a 100 percent devaluation of the Rand below the equilibrium indicated by the purchasing power principle is estimated.

Fuel Related Costs

The cost of nuclear fuel consists of the costs of natural uranium plus the costs of conversion, enrichment, fabrication, and the back-end of the fuel cycle (storage, transportation, and disposal of spent fuel). Historically uranium has represented 25-35 percent, enrichment 30-40 percent,and spent fuel management about 20 percent of the total fuel cycle cost.

South Africa is well endowed with uranium ore and since 1973 has embarked on the research and development of an uranium enrichment process. The Nuclear Development Corporation of South Africa (1984) projects that the technically attainable production of uranium in the year 2025 is around 11000 tU, enough to cover local needs and increase the 1983 level of exports. Similarly, J De Villiers, Executive Chairman of the Atomic Energy Corporation, stated that "South Africa expects to be able to produce its own enriched uranium before the end of the decade"(News Review 1985a). Based on the above information, this study assumes that by the year 2000, South Africa will be able to produce its own nuclear fuel.

The price of U_3O_8 is assumed to range from a low of US$20 per lb to a high of US$50 per lb (in 1982 dollars). The low price scenario is based on the assertion that the average 1982 price will prevail in real terms in the year 2000. The high price scenario is based on the projections by the Energy Information Administration (1982) and by Piran et al (1984).

On the international market, the enrichment costs have been projected to range between US$40 and US$90 per Separation Work Unit in the year 2000 (Pouris 1986). In addition, the operating and total cost of the Advanced Vortex tube technology, developed in South Africa, have been estimated to be (depending on the cost of electricity) US$60 and US$150 per Separative Work Unit respectively. Taking into account that the total cost of enrichment (Pouris 1986) is estimated with an exchange rate of R1 = US$0.5, it is predicted that the South African cost of enrichment is approximately R300 per SWU (total cost). It is assumed that in the year 2000 the same price will prevail for the enrichment service provided by South Africa.

Taking into account that to produce 1 kg of 3 percent enriched uranium at tails assay of 0.2 percent U-235, 6.5kg of U_3O_8 and 4.3 SWU are needed (based on the assumption of 0.5 % material loss during conversion) the cost of acquiring the uranium and enriching it amounts to US$716 per enriched uranium kg for the low price scenario and to US $1445 per enriched uranium kg for the high price scenario. These costs are increased by 20 percent to take into account the back-end of the fuel cycle and fuel conversion and are translated into Rands with the exchange rate prevailing in 1982 (R1 = $1). Therefore, the cost of nuclear fuel is predicted to range between R860 and R1740 per Kg of uranium (in 1982 constant Rands) in the year 2000.

The fuel inventory in the case of 1 GW(e) power reactor is about 90 tons. Approximately one third of that fuel has to be replaced by fresh fuel each year, hence 60 tons of fuel have to be considered as a fixed expense and 30 tons as being of variable nature. In sum the nuclear fuel cost of a 1GW(e) reactor is predicted to range between R25.8 million and R52.2 million per year in the year 2000. In addition, between R50 million and R100 million have to be considered for the initial fuelling of the reactor.

Operating Costs

The operating cost of a nuclear plant represents the labour cost for operating, maintenance, and administrative personnel, and the cost of materials and lubricants necessary for the operation of the plant. Fixed costs normally represent about 80 to 90 percent of the total O&M costs in nuclear power operations. However, in periods of long unplanned outages the proportion of fixed to variable costs can change while the absolute level of O&M expenses may rise significantly.

In South Africa there are no historical data available and hence we resort to information from the USA. The Energy Information Administration (1982) reviewing the historical trends in operation and maintenance costs noted that "O&M costs for nuclear plants have been increasingly nearly 12% in real terms annually since 1975" although "in the past, it had been predicted that O&M costs would remain reasonably stable and the large reactors would experience economies of scale". It was suggested that the increase in equipment size and the complexity of newer, larger reactors caused reduction in plant availabilities and increased the necessary number of qualified personnel. The end result was a real increase in the O&M expenses. The administration has predicted that barring any nuclear accident the O&M cost would stabilize beyond 1995 at around 0.5 cents per KWh.

For the South African nuclear stations it is assumed that an O&M cost of 0.5 cents per KWh would prevail in the year 2000. This assumption is justified on the grounds that equipment and labour used in nuclear plants are of high standards and therefore are competitively valued and arbitraged internationally.

Life Expectancy and Availability of Nuclear Plants

Nuclear reactors attained commercial status in the early 1960's and therefore only limited data on their actual life is available. Currently a life expectancy of 30 to 35 years is assumed for nuclear units. This life expectancy is chosen to coincide with the length of the operating licences being granted for nuclear power plants and/or desires of utility presidents for a fast return on their investments rather than to represent the physical life limit of the nuclear plants.

Most of the nuclear plant is passive and sees no aggressive agents (eg the control system, the buildings and so on). Hence it is only the primary system which could "wear-out" and limit the plant's life time. Moreover, it has been argued (Weinberg 1985) that even the primary system may last much longer than their design life for a variety of reasons:

a) "The neutron embrittlement limit, which requires the fast fluence to remain below ~ 3 x 10^{19} neutrons/cm² can be circumvented by the use of copper-free steel, and better internal shielding of the vessel. In any case, the vessel can, at least in principle, be annealed.

b) Pressure and temperature cycling The primary system is designed to withstand a certain number of pressure and temperature cycles. The number and severity of such cycles is very hard to estimate: the actual number might be very much different (higher or lower) than the estimated number. Should it be lower, then the pressure system will not require replacement.

c) Corrosion The nominal corrosion rate of stainless steel in very hot water is less than 1 mil/year. Thus after 100 years, the average penetration should be less than 0.1 in. Even if localized corrosion occurs, the primary system can be replaced; this has already been accomplished at several BWR s.

d) Radioactive contamination of primary system Better fuel minimizes contamination. Nevertheless, one will probably have to decontaminate old plants periodically." (Weinberg 1985)

The author concluded that "at the very worst, after 30 years, one may be required to replace parts of the primary system" at a cost much lower than building an entirely new plant.

Undounbtedly, as the technology matures, improvements would emerge from research on ways to lengthen the life of reactors. In this study it is assumed that by the year 2000 nuclear reactos would be expected to have a life expectancy of 50 years.

The cumulative load factor (CLF) is another measure of performance similar to station availability. The CLF is the total actual generation achieved by a reactor divided by the generation which was theoretically possible since it began operating.

Examination of historical data (Howles 1985) indicates that current achievement tends to exceed the life-time achievement as the latter includes early operational experience. Pressurized water reactors in Switzerland, Denmark, and Belgium have experienced cumulative load factors or more than 80 percent (during and up to 1984). Similarly, in France, annual availability has climbed to about 80 percent in 1984 from about 65 percent in mid 1983, as a result of better outage organization, the elimination of certain component problems and the use of more sophisticated automatic tooling (News Review 1985). Further improvement in availabilities is possible through advancement in core fuel management techniques (Andrews et al 1985), including increased burn-up and extended refuelling cycles and simpler standardized designs (News Review 1985b). It is expected that after 1990, an availability of 80 percent would be common practice (Carle 1985). Therefore, it is assumed that nuclear plant availability of 80 percent would be considered by planners in the year 2000.

NUCLEAR VERSUS COAL - COSTS AND SENSITIVITIES

In the previous sections the methodology and the assumptions on which this analysis is based were outlined in length. In this section a brief summary of the assumptions and the results of the analysis are presented.

The chapter examines the relative economic competitiveness of coal and nuclear-fired power stations as it could be viewed by analysts in the year 2000. It is assumed that past trends will continue until the year 2000 and then factor substitution and technology induced flexibility will stabilize these trends. Stabilization is taken to mean either constant (in real terms) future costs for both modes of production or proportional changes in nuclear and coal-fired stations' costs. If the economic superiority of one technology can be identified, then by taking into account current relative merits, the effects of the continuation of past trends after the year 2000 can be also assessed.

Two scenarios are developed for the period 1982-2000. The first assumes that production costs due to indigenous content continue to increase with the same speed as during the period 1973-1982. The second scenario assumes that costs increase with the 1973-1982 speed until the year 1992 and thereafter switch to the rates prevailing during the period 1950-1973. The two periods have been characterized as high cost and low cost respectively (Commission of Inquiry 1984). Costs due to imported content are extracted from forecasts by the USA Department of Energy. The two scenarios give two different values for each cost component (capital,fuel, and O&M costs) which contributes to the levelized bus-bar cost of electricity. The high-cost cases are combined to give the total high cost of electricity in the bus-bar and the low-cost cases are combined in a low-cost case.

Table 1 summarizes the levelized bus-bar costs of electricity produced by nuclear and coal-fired stations, in cents per kilowatthour Eight different costs are reported for coal-fired stations depending on the cooling mode used and the availability or not of desulphurization units. It appears that nuclear-fired plants can provide electricity 25 to 45 percent cheaper than coal-fired plants. The last row in table 1 shows the levelized bus-bar cost assuming a 100 percent depreciation in the value of the Rand below the value dictated by the purchasing power principle with base year 1982. The assumed depreciation (100 percent) is an arbitrary quantity used only for indicative purposes. The history of free floating exchange rates is too short to indicate whether such depreciation is possible in the long run. However, the international debt crisis in the early 1980's indicates that countries with financial problems can be forced to devalue their currencies to a large extent, at least in the short-run (eg Brazil has devalued its currency by more than 50 percent below the value postulated by the purchasing power principle over the period 1978-1984). The assumed devaluation affects the capital costs of both nuclear and coal-fired power plants. However, because capital costs dominate nuclear plant

TABLE 1 Levelized Bus-bar cost of electricity in South Africa (1982 values)

Mode Levelised cost (c/kWh)	NUCLEAR		COAL		COAL Dry Cooling unit		COAL Desulphurisation		COAL Desulphurisation and dry cooling	
	High Cost	Low Cost	High Cost	Low Cost	High Cost	Low Cost	High Cost	Low Cost	High Cost	Low Cost
Capital	0.4079	0.3976	0.2800	0.2428	0.2990	0.2625	0.3290	0.2910	0.3480	0.3107
O&M	0.5000	0.5000	0.4709	0.3900	0.4709	0.3900	0.4709	0.3900	0.4709	0.3900
Fuel	0.8564	0.4235	1.4490	1.0390	1.6905	1.2120	1.4490	1.0390	1.6905	1.2120
TOTAL	1.7643	1.3211	2.1999	1.6718	2.4604	1.8645	2.2489	1.7200	2.5094	1.9127
TOTAL *	2.0150	1.5671	2.2460	1.7186	2.5202	1.9170	2.3147	1.7682	2.5790	1.9748

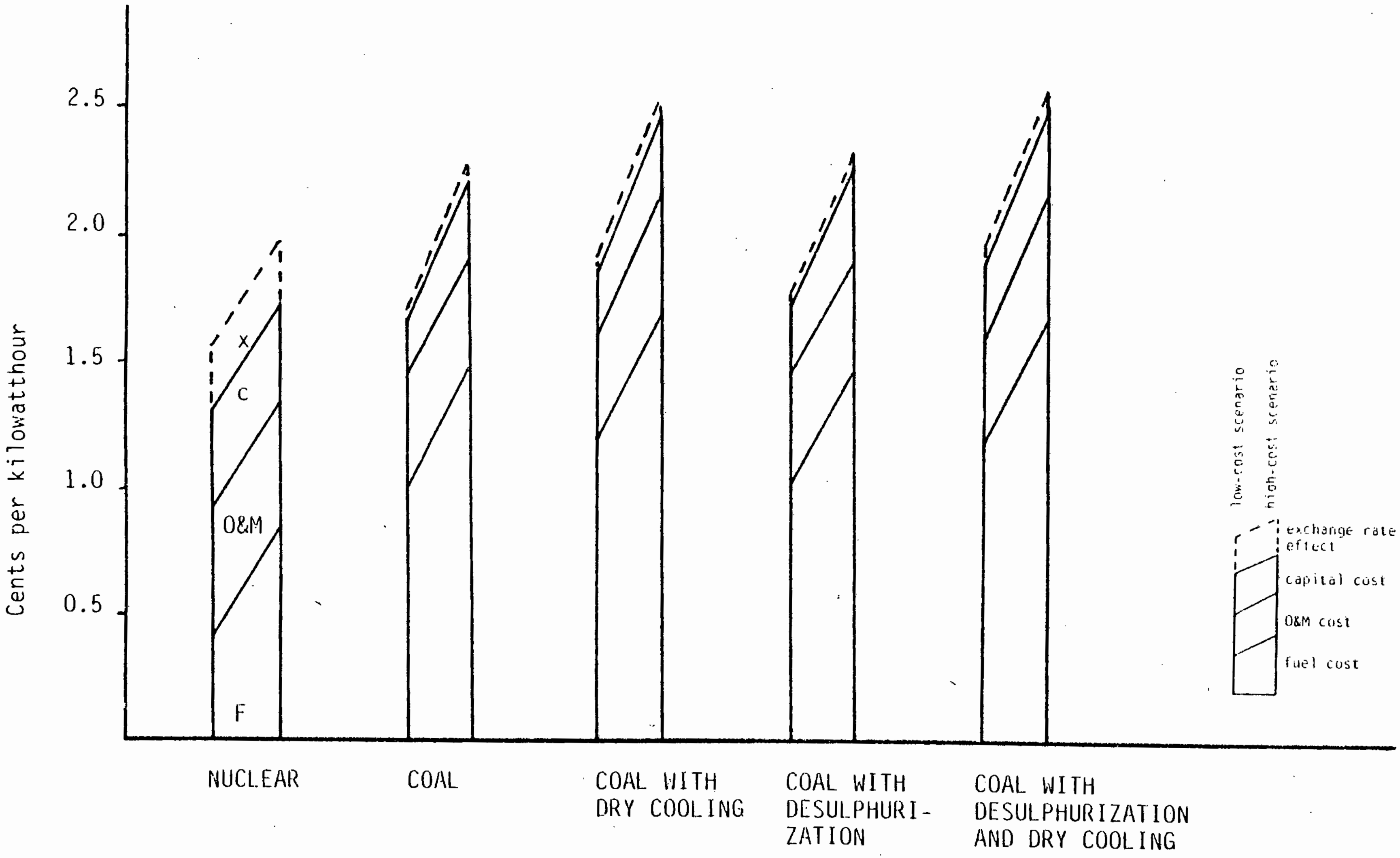
* Total with 100 percent depreciation in the value of the Rand

economics, total bus-bar cost for the nuclear option rises between 14 and 18 percent, while total cost for coal-fired plants rises only 2.5 to 3 percent. Even then, however, the nuclear power plants produce electricity cheaper than coal-fired plants. In Figure 1 the cost components of the nuclear and coal-fired stations, as well as the effect of a 100 percent devaluation of the Rand are illustrated.

The above analysis assumes that the coal-fired power station is sited at the pit-head. Whilst this is the case for most of the coal-fired power stations in South Africa, it is important to be aware that the cost of electricity changes when the coal-fired station is sited far from the colliery. Figure 2 shows the bus-bar cost of electricity produced by a nuclear-fired station, a pit-head coal-fired station and two coal-fired stations sited 500 km and 1000 km away from the coal-mine respectively. While electricity produced by nuclear-fired stations is projected to be on average 35% chaper than electricity from a mine-mouth coal-fired station, the disadvantage for coal-fired stations 500 km and 1000 km away from the coal-mines increases to 45 and 66% respectively.

The major conclusion drawn from the analysis is that the continuation of past trends in the cost of coal and nuclear-fired power stations in South Africa and the realization of projections for the costs of nuclear fired-stations in the United States could reverse the relative economic merit of electricity production technology in the intermediate future.

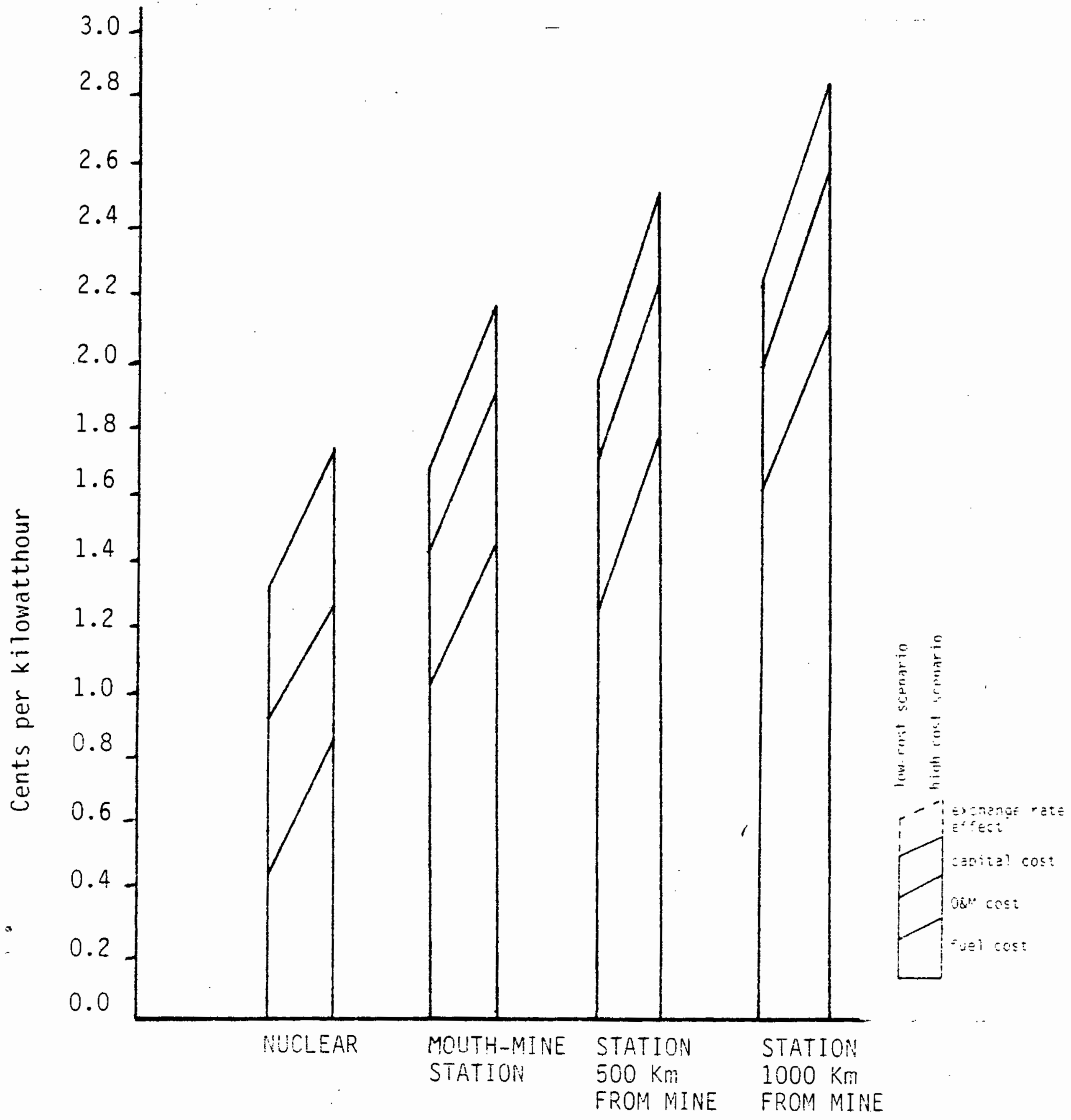
FIGURE 1 Comparison of the cost components of nuclear and coal-fired power stations



x : exchange rate effect
c : capital cost

O&M : Operation and Maintenance cost
F : fuel cost

FIGURE 2 Bus-bar cost of electricity. Nuclear and coal-fired stations in a distance from the mine



The nuclear option is more attractive than coal even under the restrictive assumption that analysts in the year 2000 would assume constant prices for coal, coal-transport, construction materials and labour. If it is assumed that costs continued to increase after the year 2000 with the same speed as in the past, the nuclear option would be even more favourable than the coal alternative.

It should be emphasized, however, that this conclusion is conditional on the underlying assumptions. If past trends in the cost components of coal power stations in South Africa were interrupted or the projections for the costs of nuclear power stations in the United States err by a wide margin, coal generated electricity could keep its economic advantage over the nuclear option.

CHAPTER 6

MODELLING THE DEMAND FOR STEAM-COAL IN SOUTH AFRICA: 1985-2020

INTRODUCTION

Forecasting the future demand for steam-coal is important for planning purposes to electricity supply utilities, to coal-mining industries, and to governmental departments engaged on resource planning. The importance of the issue cannot be exaggerated in the case of South Africa. The country is extensively dependent on coal for its energy needs and more than fifty percent of the coal consumed is for the generation of electricity by the Electricity Supply Commission (ESCOM).

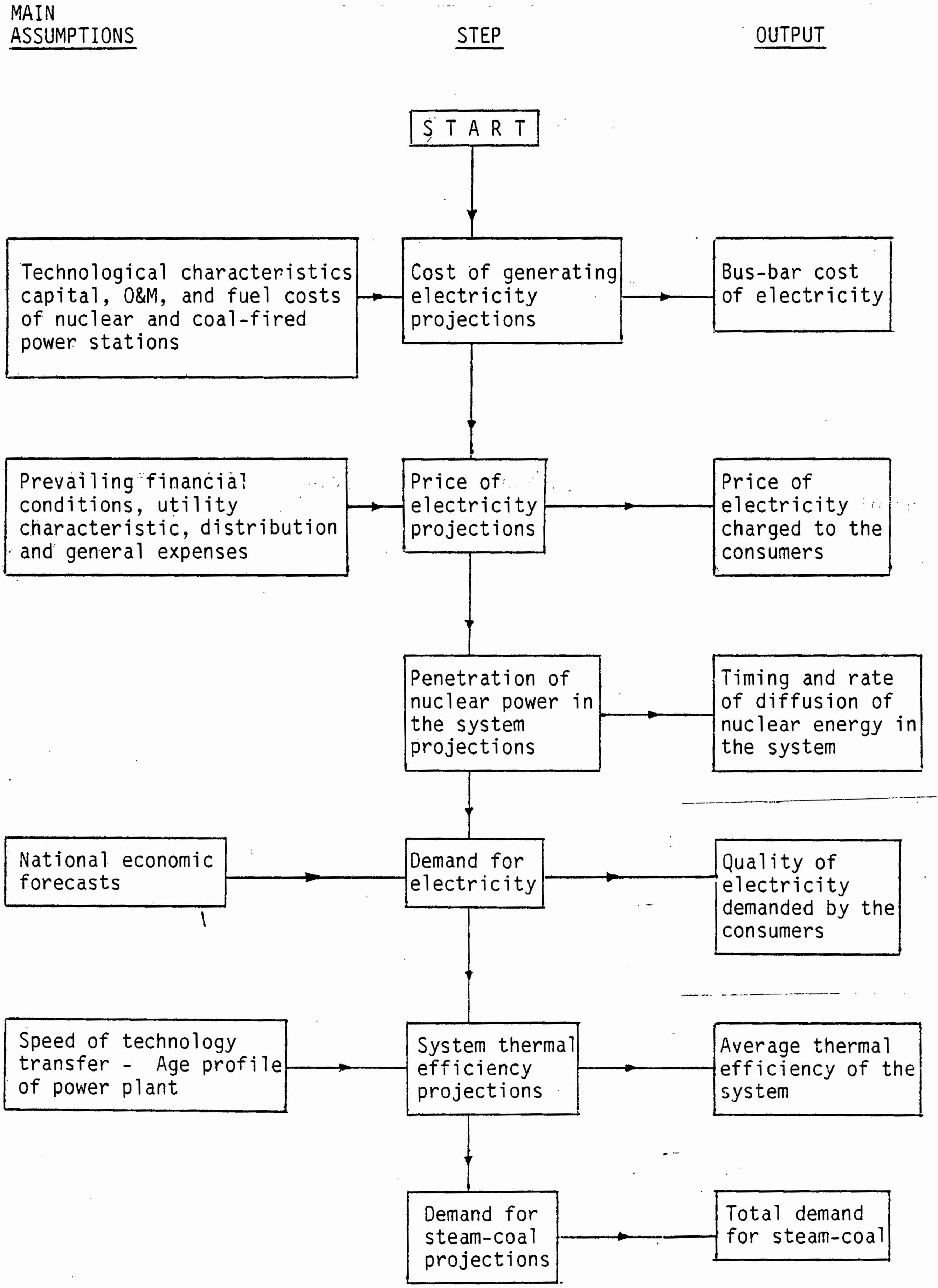
Previous research on the subject (Dutkiewicz 1973, Norman 1977, 1982, Dept of Minerals and Energy Affairs 1984) is based on simple or sophisticated extrapolations which however, implicitly assume that technologies and price paths will exercise the same influence on the demand for steam-coal as in the past. Obviously, such forecasts have a limited value in a changing environment where prices are used for active demand-management and are determined by international politics, and technological improvements reach their limits.

In this chapter a steam-coal demand model is developed. The model is based on the analyses provided in the previous chapters and explicitly recognises the dependence of demand on the pace and direction of technological advance, and on the prevailing economic conditions. The model consists of six modules arranged in a cascade. The output of each module is used as input in a subsequent step. A diagrammatic exposition of the model's structure is given in Figure 1. The first module generates projections for the future cost of generating electricity by nuclear and coal-fired power stations. The second module produces estimates for future electricity prices. The third module estimates the penetration of nuclear power in the South African electricity producing system. The fourth module generates projections for the demand for electricity. The fifth module estimates the future system thermal efficiency and the sixth module gives as output the total future demand for steam-coal.

Depending on the prevailing politico-economic conditions, two scenarios are developed. The first, Normal Conditions Scenario (NCS), assumes business as usual. The second, Boycott Conditions Scenario (BCS) assumes that ESCOM is financially boycotted from the international financial markets and is pushed to raise its tariffs by 30 percent in real terms in order to raise needed finance. Further, "scenariettes" are developed in order to examine the effects of water scarcity and nuclear diffusion in the system on the demand for steam-coal. In the dry-cooling mode scenariette all new power stations after 1992 are assumed to use dry-cooling. In the "nuclearisation" of the system "scenariette", seventy percent of the new demand for electricity is assumed to be generated by nuclear-fired stations, after the year 2005.

Section two treats the conceptual nature of the framework and describes the state of implementation. The chapter ends with a concluding remarks section.

FIGURE 1 Flowchart of steam-coal demand model structure



THE MODEL

The model consists of six modules in a cascade. Each module receives a number of exogenous and a number of internally generated inputs and gives an output (Fig 1). The structure of each module, its inputs and outputs are discussed below. The penultimate module gives as output conditional predictions of the demand for steam-coal in South Africa.

Module 1

The first module is concerned with the cost of generating electricity and provides inputs for the modules 2 and 3 which examine the price of electricity and the penetration of nuclear power in the system, respectively. Two modes of production, ie coal-fired and nuclear generation are considered as the only feasible alternatives for base-load generation in the foreseeable future.

The cost of electricity, as it was discussed in chapter 5, is conventionally divided into three basic components:

1) capital related costs
2) operation and maintenance costs and
3) fuel costs

These cost components have different magnitudes and time patterns of occurrence. Thus, in order to estimate the total cost of electricity these components should be placed in a comparable form. An accepted way to compare cost outlays is to determine the present value of each cost. In the case of power plants, the present value of each stream of costs is firstly converted into a fixed annual charge of the plants economic life and then it is divided by the number of kilowatthours of energy the plant is expected to produce each year to yield the levelized bus-bar cost. This methodology has the additional advantage that makes comparable different generation alternatives.

The levelized bus-bar cost of electricity generated by coal-fired power plants is estimated for the years 1995, 2005 and 2015 and linear interpolation is assumed for the intervening years. The estimation is based on extrapolation of the cost trends established during the period 1950-1982 (-0.62%, 1.9% and 4.5% annual changes, for capital, fuel and O&M costs respectively), and the main assumptions are:

1) plant's life expectancy of 50 years
2) discount rate of 2% per annum in real terms
3) average thermal efficiency of 30% and
4) average load factor of 75%

Elaboration on the cost trends and justification of the assumptions are provided in chapter 5.

Table 1 gives the forecast figures for capital, O&M, fuel, and total cost of electricity for the years 1995, 2005 and 2015. For comparison, the 1982 cost components are also included in the Table. The percentage contribution of the different cost components to the total cost is also shown.

TABLE 1 Future cost of electricity generated in coal-fired power plants in 1982 c/Kwh

YEAR	CAPITAL COST		O&M COSTS		FUEL COST		TOTAL BUS-BAR COST
1982	0.251	22%	0.194	17%	0.705	61%	1.150
1995	0.232	16%	0.343	23%	0.899	61%	1.474
2005	0.218	12%	0.534	29%	1.085	59%	1.837
2015	0.205	9%	0.829	35%	1.307	56%	2.341

It becomes obvious that uninterrupted past trends lead to a doubling in the real bus-bar cost of electricity by the year 2015. It is worth noting that the share of O&M cost doubles from 17 to 35 percent, the share of capital is reduced from 22 to 9 percent, and the fuel cost share is reduced only marginally from 61 to 56 percent.

Estimates of the bus-bar cost of electricity generated by nuclear-fuelled power stations are also taken from chapter 5, "The Future Economic Merit of Nuclear and Coal-fired Generation Plants in South Africa". The predicted cost for the year 2000 is based on predictions for the local and imported content of nuclear power plants, the fuel cost, and the O&M expenses. Using as step-stone the experience gained by the erection of Koeberg, the cost of local content is assumed to constitute 30% of the capital cost and to increase proportionally to the Construction Price Index. The cost of the imported content is extracted from studies by the Energy Information Administration (1982) and the US Department of Energy

(1981). The fuel cost is estimated assuming that South Africa will produce its own enriched uranium and for a variety of prices for ore uranium (Pouris 1986). Finally, the O&M expenses are extracted from forecast by the Energy Information Administration (1982).

Table 2 shows the envisaged total bus-bar cost of electricity generated by nuclear-fuelled power stations and its components. The estimates are derived assuming a 50 year plant life expectancy, 80 percent availability, and 2 percent per year discount rate.

TABLE 2 Projected bus-bar cost of electricity generated by nuclear-fired power stations in the year 2000 (1982 c/KWh)

SCENARIO / COST COMPONENT	HIGH COST CASE	LOW COST CASE
Capital Cost	0.4079	0.3976
Fuel Cost	0.8564	0.4235
O&M Cost	0.5000	0.5000
Total	1.7590	1.3140

The predicted cost in the high-cost case for the year 2000 is similar to the estimated bus-bar cost of electricity generated by Koeberg. The Koeberg's bus-bar cost includes the extra costs occurred due to sabotage in Koeberg and the nuclear embargo of South Africa by the United States.

The cost of electricity generated by nuclear fuelled plants appears to be relatively constant over time in South Africa and therefore nuclear energy plays the role of a back-stop technology setting an upper limit to the cost of electricity in the long-run.

Module 2

The second module examines the electricity pricing mechanism and provides inputs for the modules examining the demand for electricity and the penetration of nuclear energy in the system. The bus-bar cost of electricity provides a floor price and forms a starting point for the estimation of the price of electricity.

A variety of factors affect the pricing mechanism and make the price different from the bus-bar cost. They are:

1) Constraints on financial resources. Electric utilities need to borrow money from the financial markets in order to replace their retiring plants or expand their capacity. In an ideal situation loans borrowed over the construction period of the plant would be amortized and bond-holders paid off over the lifetime of the plant (40 to 50 years). As soon as the plant is amortized, a new loan would be negotiated to pay for the new plant. This ideal situation, however, requires an unlimited, flexible pool of money in the disposal of the electric utility. In reality utilities have to compete with other borrowers in a limited pool of money and negotiate loans with average life to maturity much shorter than the desired. ESCOM has negotiated loans with average life to maturity ranging from 6.6 to 15.2 years during the 1972-1982 period (Commission of Inquiry 1984).

During the same period the average life expectancy of the power plant was 30 to 40 years. Of course, a new loan can be negotiated when an old one matures but as the debt burden increases (especially in expanding utilities) the financial market is reluctant to lend further to borrowers.

2) Distribution cost and general expenses. Price should cover not only the bus-bar cost of electricity but also any general administration costs and the expenses occuring for the operation and maintenance of the distribution grid. During 1982 general expenses and distribution costs constitute 13.83 percent and 1.95 percent of the total electricity cost respectively. It is worth noting that general expenses have been increasing by 4 percent per annum in real terms during the 1967-1982 period.

3) Utility system characteristics. While the bus-bar cost of electricity takes into account the technological characteristics (efficiency, availability etc) of the individual plants, price takes into account the average performance of the whole system. For example, the life availability of individual plants can be 75 percent. However, due to system reliability and fluctuating demand considerations the average load factor of the system would be much lower. Consequently, the plants would produce a smaller number of units of electricity over their life and the cost per electric unit will be higher than it would have been otherwise.

In order to identify ESCOM's pricing mechanism, the levelized cost of electricity is estimated substituting the plant's characteristics for the system's characteristics and the derived figures are compared with the actual figures published by ESCOM.

Table 3 gives the estimated and actual figures.

TABLE 3 Estimated and actual cost components of electricity (c/kwh)

COSTS	ESTIMATES	ACTUAL
Capital Cost	0.251	1.40
Fuel Cost	0.705	0.72
O&M Cost	0.242	0.27
Other Costs	-	0.46

From Table 3 it becomes obvious that while the estimated fuel and O&M costs are good approximations of the actual expenses estimated by ESCOM, the estimated capital cost underestimates the actual figure. The reasons for the underestimation of the capital cost are differences in the discount rate, and in the pay-back periods considered in this estimation and by ESCOM.

To unravel the discount rate and the pay-back period considered by ESCOM*, a trial-and-error method (testing a variety of discount rates and pay-back periods) was used comparing the levelized costs reported by ESCOM with the bus-bar cost derived from the costs of individual power stations commissioned during that period. Figure 2 gives the sub-total levelized capital related costs as charged by ESCOM for selected years and the estimated capital related costs

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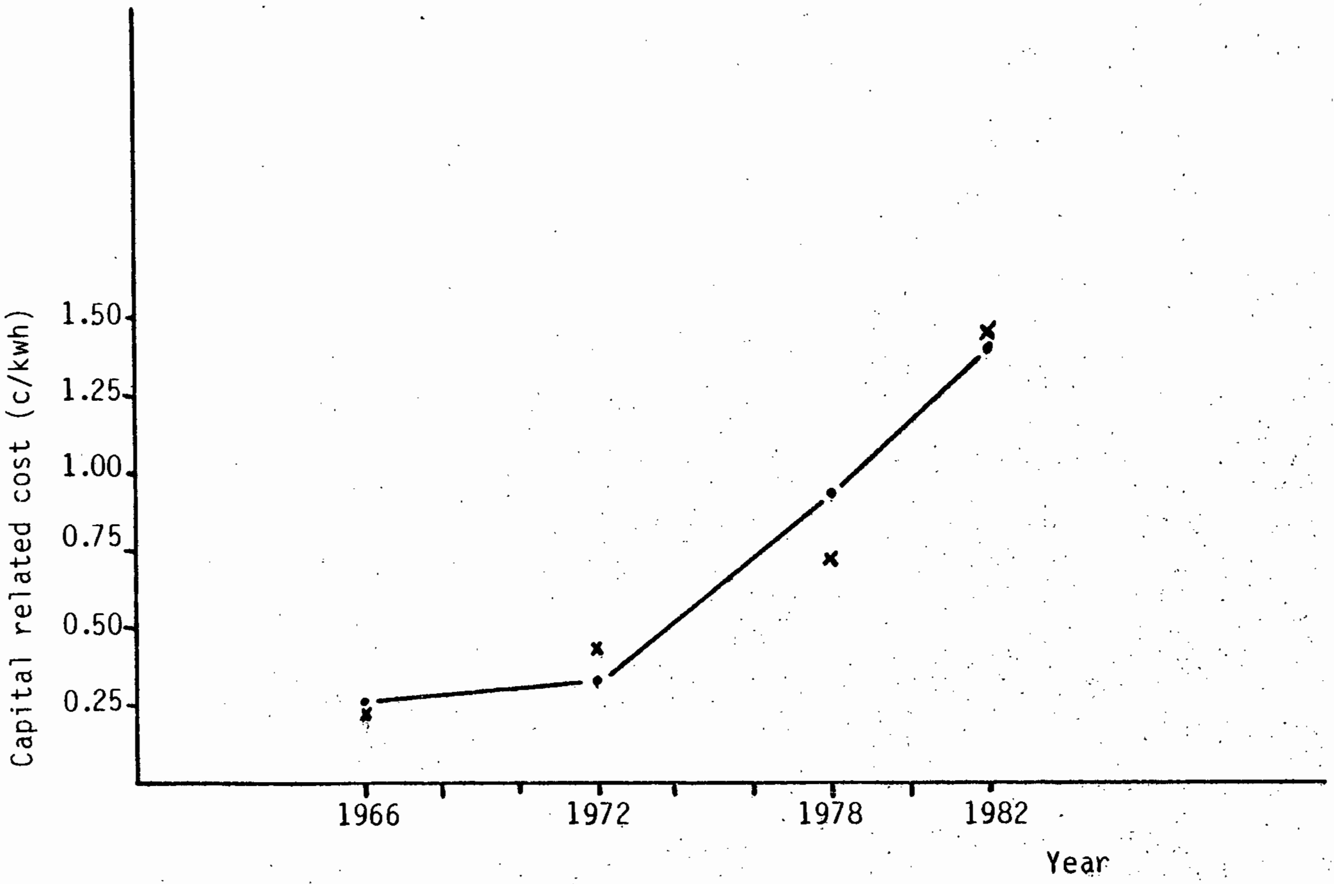
* Discussion with ESCOM's officials revealed that different departments use different discount rates and even in the same department discount rates vary with time and project. As we discussed in Chapter 5, the charge of a discount rate for formulating policy is itself a policy decision that in most cases is determined in order to support specific actions.

FIGURE 2 COMPARISON OF ESTIMATED AND ACTUAL CAPITAL RELATED COSTS OF ELECTRICITY



● Sub-total capital related costs as charged by ESCOM

✘ Estimated capital related costs assuming 10% discount rate and 12-year pay-back period assuming a 10% discount rate and a 12 year pay-back period. The estimated figure represents adequately the actual figure. Hence, it can be assumed that ESCOM in its pricing formula, uses a discount rate of 10% and a pay-back period of 12 years.

It can be conjectured that the high discount rate and the short pay-back period used by ESCOM for its pricing policy is the result of financial constraints usually appearing in fast expanding utilities. ESCOM, having to expand its capacity in order to meet increasing demand, facing a limited local capital market and being unwilling to take the risk of over-expossure in the international capital markets, has to raise capital through its pricing structure. The use of a high discount rate and a short pay-back period effectively increases the price of electricity and provides capital for further expansion.

In order to take into account the effects of financial constraints, the price of electricity is estimated for two different discount rates (2% and 10%) and two different pay-back periods (50 and 12 years). The use of a discount rate of 10% and a pay-back period of 12 years reflect ESCOM's current policy (under financial constraints). The use of a discount rate of 2% and a pay-back period of 50 years reflect normal conditions without financial constraints (the discount rate reflects the cost of capital and the pay-back period the actual life of the investment).

Estimating the levelized capital related costs for a 12 year period with a discount rate of 10 percent and assuming that the past trends underlying the individual cost components of electricity will continue doing so, the average price of electricity for selected years is predicted in Table 4 (column 2).

TABLE 4 Forecasts for the price of electricity for selected years in 1982 c/KWh

YEAR	ELECTRICITY PRICE UNDER FINANCIAL CONSTRAINTS	ELECTRICITY PRICE WITHOUT FINANCIAL CONSTRAINTS
1982	2.847	1.658
1995	3.068	2.240
2005	3.753	2.970
2015	4.754	4.020

The electricity prices estimated for a 50 year pay-back period and a discount rate of 2% (without financial constraints) are reported in column 3. It is obvious that the gap between electricity prices estimated under financial constraints and prices under a capital abundance situation closes as the underlying trends lead to a smaller share for the capital related cost.

Module 3

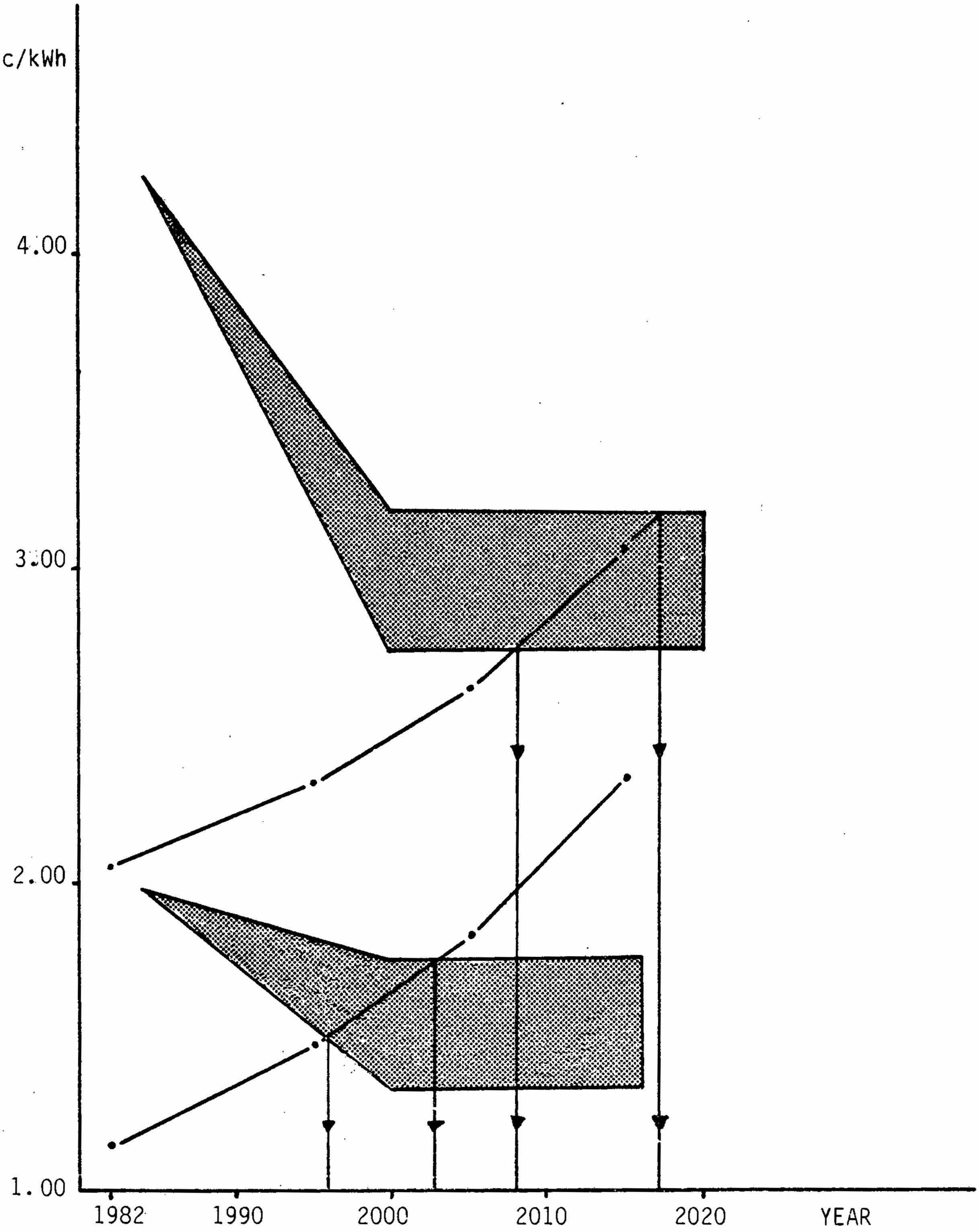
The third module analyses the penetration of nuclear energy into the South African electricity producing system. A variety of factors affect the decision to introduce another mode of production in a system. Conservation of relative scarce resources, independence from labour unrest, experience in a new technology and strategic reasons are some of the most often suggested reasons. Economic merit, however, is the most important factor affecting the decision to introduce nuclear energy. The important questions are:

when will nuclear production of electricity become competitive with coal-fired power stations; and what would be the subsequent relative build-up rate of the nuclear component.

The former question is answerd in Figure 3. Figure 3 shows the predicted bus-bar cost of electricity produced by nuclear-fired power stations (shaded areas) and by coal-fired power stations (solid lines). The top graph is drawn from estimates derived with a discount rate of 10 percent and a pay-back period of 12 years. The bottom graph represents the costs under the assumptions of 50-year pay-back period and a discount rate of 2 percent. Both graphs are subject to the assumptions outlined in the previous chapter. It becomes apparent that nuclear energy becomes competitive with electricity produced by coal-fired power stations by the year 2000 when the two modes are evaluated without taking into account financial constraints. The incorporation of financial constraints delays the introduction of nuclear power plants by approximately 13 years, to 2013. The evaluation of the two modes under financial constraints is demonstrated only for comparative purposes. Investments should be evaluated taking into account all the benefits to accrue from them independently of financial constraints. In addition national electric utilities are in a strong position and if justified they can levy the required sums by increasing tariffs.

The second question is concerned with the build-up rate (relative to the total growth of the demand for electricity) of the nuclear

FIGURE 3 LEVELIZED BUS-BAR COST OF ELECTRICITY PRODUCED BY NUCLEAR- AND COAL-FIRED POWER STATIONS



—— • —— Electricity from coal-fired power stations

Shaded area: Electricity from nuclear power station. Top area is "under financial constraints scenario". Lower area is "without financial constraints scenario".

component. Based on the assumption that there is a load factor at which nuclear power is preferable to other systems, the growth of the nuclear component is contrained by:

1) the unit reliability and size of the system. Nuclear units are economically competitive in high sizes because of economies of scale. If the total system is small in comparison with the nuclear unit to be installed (say less than 10 times the nominal rate of the nuclear unit) the nuclear unit is not justified on reliability grounds. When the unit is out of commission, the whole system will be impaired. Of course in the extreme case in which 100 percent unit reliability could be guaranteed, this constraint would not be binding.

2) The load factor at which nuclear plants break-even with non-nuclear plants. The demand for power over a period is usually represented by the conventional load duration curve(LDC). The LDC is illustrated in diagrams with each point on the absissa denoting the number of time-units in the period during which the corresponding demand on the ordinate is equalled or exceeded. Nuclear plants have the edge over the non-nuclear plants above a critical load factor. Depending on the load duration curve, the rate of nuclear installation may have to be constrained so that nuclear plants do not need to work below the critical load factor.

Both factors however would not constrain the rate of nuclear installation in South Africa, at least for the first 15 years. By the year 2000, when the "nuclearization" of the system is assumed to start, ESCOM will have an installed capacity higher than 50 000 MW (Norman 1982). Therefore, units with size up to 2 500 MW will be acceptable (assuming as a rule of thumb that unit size of 5% of the total system is acceptable).

The break-even load factor is determined by the relationship between nuclear and fossil fuel prices (Levin et al 1985). However, until so much nuclear plants have been installed that the "tail-end" of them operates at the break-even load factor, relative fuel prices play no part in the rate at which nuclear power can be installed. Assuming that the system load duration curve in the year 2000 will have the same shape as in 1982, an installed system capacity of 50 000 MW and a break-even load factor of 80 percent, the constraint of break-even load factor will be binding only after the installation of 20 000 MW of nuclear capacity. In the scenario "system nuclearization" it is assumed that nuclear may take up to 75 percent of all new and replacement plants up to the year 2020. Twenty five percent of all new and replacement plants are assumed to be non-nuclear for operational reasons.

Module 4

Module 4 accepts as inputs the forecast price of electricity and under an assumed value for the growth of the gross domestic product provides predictions for the demand for electricity. An econometric model incorporating the long term effects of price in the demand for electricity is used for predictive purposes. The model (developed in Chapter 2) is based on the assumption that the demand for electricity is a function of economic activity and price.

The forecasting model has the form:

$$Q_t = a\, P_{t-12}^{b}\; W_t^{c}\; e^{\mu}$$

or the equivalent:

$$\ln Q_t = \ln a + b \ln P_{t-12} + c \ln W_t + \mu$$

where: Q_t is the demand for electricity in period t

P_t is the average real price of electricity in period t

W_t is the real Gross Domestic Product in period t

b is the 12-year long-run price elasticity of demand

c is the income elasticity of demand

μ is the error term

The 12-year price elasticity of demand has been estimated to have a value of 0.90 and is incorporated in the model as extraneous information. Estimation of the 12-years price elasticity of electricity demand and justification for the use of extraneous information are provided in Chapter 2. The estimated form of the model with data for the period 1950-1983 is:

$$\ln Q_t = -5.73 - 0.9 \ln P_{t-12} + 1.64 \ln W_t + U$$

With this model the demand for electricity for the years 2000, 2010 and 2020 is estimated. Two scenarios are developed. The first, named Normal Conditions Scenario (NCS), assumes a continuation of price trends (module 2). The second scenario, named Boycott Conditions Scenario (BCS), envisages ESCOM finding difficulties in raising foreign loans. Under such a constraint (occuring in 1987) ESCOM increases its tariffs by 30% (in real terms) to raise the additional capital needed for its expansion.

Assuming a GDP growth of 4% per year, the model estimates the demand for electricity in different years. Table 5 gives the forecast value for selected years for the two scenarios.

TABLE 5 Demand for Electricity (GWh)

SCENARIO YEAR	NCS	BCS
1982	96 135	96 135
2000	152 344	134 967
2010	262 561	207 338
2020	414 202	327 060

The model predicts that under normal conditions the demand for electricity will increase on average by 3.9% per year up to the year 2020. Under boycott conditions the rate of growth is reduced to 3.3% per year. The demand during the period 2010-2020 increases more rapidly under conditions of "nuclearization". Assuming that the price of electricity stabilizes at the 1998 levels the demand for the year 2020 under the NCS and BCS becomes 501 992 GWh and 396 411 GWh respectively.

Module 5

In order to translate the demand for electricity into demand for coal the estimation of the system thermal efficiency (STE) is needed. The STE refers to the thermal efficiency exhibited by a set of power stations and it is a measure of the proportion of the input heat energy that is converted into usable electricity.

The model used to predict the future system thermal efficiency (Chapter Four) identifies South Africa as a technology importing country and recognises the speed of the technology transfer from the country of origin to the technology importing country, the rate of demand for additional capacity and the age profile of the plants belonging to the system, as the STE determining factors. The mathematical formula used to forecast the system thermal efficiency is:

$$\bar{f}_{n+k} = \frac{1}{(1+DI)^k}\bar{f}_n + DI\cdot f_c\left[\frac{1+a}{(1+DI)^k} + \frac{1+2a}{(1+DI)^{k-1}} + \cdots + \frac{1+ka}{(1+DI)}\right] + RF$$

where $\bar{f}_{n+k}$ denotes the STE in period n+k

$\bar{f}_n$ denotes the STE in period n

DI denotes the projected average increase in capacity for the time span under examination

f_c denotes the "best plant" thermal efficiency during the period n

a denotes the per period improvement in the "best plant" thermal efficiency expressed as a percentage in the n period and

RF denotes the replacement factor

The replacement factor depends on the percentage of capacity replaced and the difference in thermal efficiency between scrapped and newly added plants. The formula estimating the RF is:

$$\begin{aligned} RF &= f_c \; [\, P_1\,(1+a) + P_2\,(1+2a) + \cdots + P_k\,(1+ka)] \\ &\quad - (P_1 f_1 + P_2 f_2 + \cdots + P_k f_k) \end{aligned}$$

with f_i, f_c, and a defined as above and P_i denoting the percent capacity replaced in i periods.

The model identifies the United States as technology exporting country and through precursor event analysis estimates the per period improvement in the "best plant" thermal efficiency.

Using the model outlined and the predicted demand for electricity by module 4, the STE is predicted for the different scenarios.

In Table 6 are shown the predicted System Thermal Efficiencies for selected years under a variety of assumptions. The first three columns assume 'normal conditions' and continuation of wet-cooling mode; adoption of dry-cooling after 1992; and 75 percent nuclearization coupled with dry-cooling after 2010 respectively. The last 3 columns indicate the system thermal efficiency under 'boycott conditions'. It is evident that 'boycott conditions' do not affect the system thermal efficiency in contrast with the dry-cooling mode which has a sizeable effect. Of course, that was expected as the best plant's thermal efficiency is reduced by 19% (fc=31.5) when the dry-cooling mode is adopted. Comparing the predicted efficiencies with the gains accomplished over the last 30 years it becomes evident that the future is not promising. Even in the unlikely case of continuation of the wet-cooling mode the predicted improvement for the next 30 years is only a third of the gains accomplished during the last 30 years.

TABLE 6 System thermal efficiency for selected years

	N C S			BCS		
YEAR	Wet-cooling	Dry-cooling	Nuclear-ization	Dry-cooling	Dry-cooling	Nuclear-ization
1983	31.10	31.10	31.10	31.10	31.10	31.10
1993	32.94	32.75	32.75	32.48	32.35	32.35
2000	34.24	32.80	32.80	33.77	32.55	32.55
2010	36.98	32.60	32.60	36.46	32.59	32.59
2015	38.03	32.36	32.53	37.82	32.37	32.53
2020*	38.20	32.19	32.47	38.03	32.19	32.47

Module 6

Module 6 receives as inputs the predicted system thermal efficiencies (Module 5), the predicted demand for electricity (Module 4), and the predicted percentage of electricity generated by coal-fired power stations (Module 3), and estimates the demand for steam-coal. An additional input variable used is the 'heat content of coal' as received by the power stations of ESCOM.

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* In order to extend the forecasting horizon from the year 2015 (Chapter 4) to the year 2020, we assumed that "a" will continue having a value of zero for the 5 years between 2015 and 2020.

The equation estimating the demand for coal is:

$$C = \frac{E * Pc}{STE * HC}$$

where C denotes the demand for coal

STE denotes the system thermal efficiency

HC denotes the heat content of coal

E denotes the sent-out demand for electricity

Pc denotes the percentage of electricity produced by coal-fired power stations.

The heat content of coal is assumed to continue its trend declining by 2.5 per thousand per year. The system heat rates are derived from Table 6 with appropriate modification for unit compatability. The demand for electricity (sent-out) is derived by increasing the predicted demand for electricity (Table 5) by 7 percent in order to take into account distribution loses. Finally, the percentage of electricity generated by coal-fired power stations is derived under the assumption that the possible modes of production are pumped-storage and hydro-electric stations for peaking demand and coal or nuclear-fired stations for base-load. Further, it is assumed that the difference between pumping and generated energy at pumped-storage stations is equal to the energy generated by conventional hydro-stations (Norman 1982). Thus, the energy generated by coal-fired stations is equal to the total electrical energy used in the country less the energy supplied by nuclear stations*. Up to the year 2010, the only nuclear source of electricity is assumed to be Koeberg nuclear power station. After that, under the "nuclearization" scenario, only 25 percent of the additional demand for electricity is assumed to be generated by coal fired power stations.

On these assumptions and for the different scenarios examined, the demand for thermal coal by ESCOM is given in Table 7. A diagrammatic exposition of the normal conditions (NCS) and boycott conditions (BCS) scenarios under dry-cooling and nuclearization are shown in Figure 4.

It becomes evident that increases in the real price of electricity during the 1970's (6% pa in real terms) and improvements in the system thermal efficiency keep the demand for steam-coal relatively low until 1995. Afterwards, however, the small increase in the real price of electricity assumed (1.5% per annum) and the stagnation in the system thermal efficiency increase the rate of change of demand for coal.

TABLE 7 Demand for Coal (000 tns)

	N C S			B C S		
YEAR	Wet-Cooling	Dry-Cooling	Nuclear & Dry-cool.	Wet Cooling	Dry Cooling	Nuclearization
2000	78 000	82 000	82 000	69 577	72 577	72 184
2010	133 000	151 000	151 000	105 208	117 701	117 701
2020	212 000	253 000	167 481	167 481	197 865	151 079

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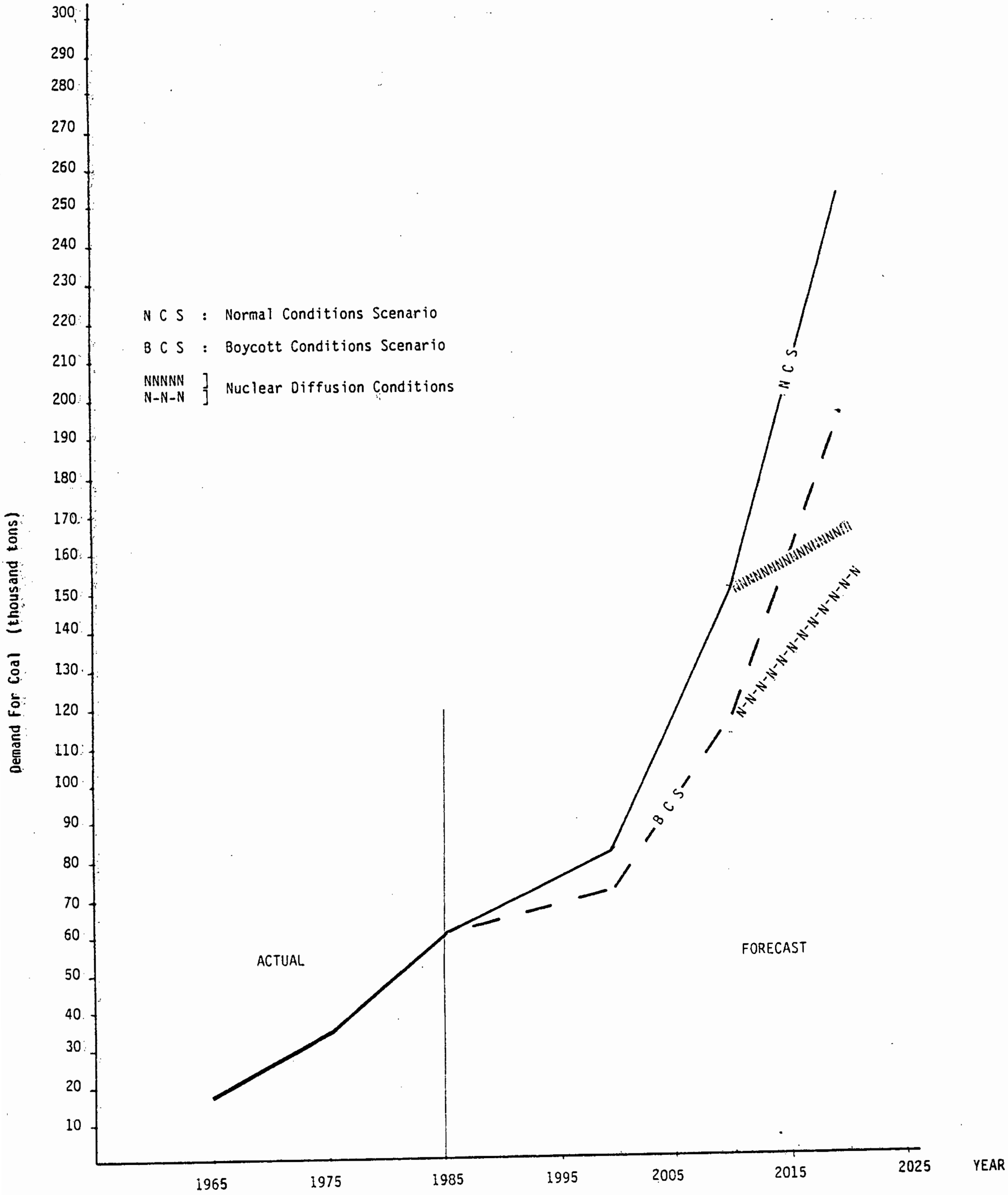
* A further source of electricity is Cabora Bassa. However, political reasons limit its reliability as supply source and for simplicity it has been assumed that electricity imports are minimal.

FIGURE 4 A diagrammatic exposition of the NCS and BCS scenarios under dry-cooling and nuclearization conditions



The demand for coal increases by 2.1% per year during the 1984-2000 period. The growth changes to approximately 6.3% per year during the next period (2000-2010) under the Normal Conditions Scenario (Dry-cooling) and to 5.3% per year during the period 2010-2020. Similar changes appear also in the Boycott Conditions Scenario. Comparing the above predictions with forecasts made by ESCOM (Norman 1982) it appears that forecasts which do not take into account pricing policies and technological evolution tend to overestimate the demand for coal by 30 to 50% depending on the assumptions.

CONCLUDING REMARKS

The analytical framework presented in this chapter represents an effort to examine steam-coal demand projections in a consistent and rigorous fashion. It explicitly recognises the dependence of coal consumption on the technology used for electricity generation and the importance of examining the demand for steam-coal in the context of the prevailing economic conditions. The roles that prices and technology play in influencing steam-coal demand are highlighted in a manner that facilitates sensitivity analysis.

Demand predictions are provided under different scenarios up to the year 2020. The effects of financial constraints and resource scarcities are incorporated in the analysis and the policy decision to diffuse nuclear in the electricity system is outlined. The predicted annual rate of coal consumption is 30 to 50% lower, depending on the scenario, than the predictions provided by ESCOM (Norman 1982). This may be a consequence of the fact that ESCOM's extrapolations do not take into account the effects of changes in electricity prices on the demand for it. The cumulative steam-coal consumption over the next 35 years under the normal conditions, dry-cooling, non-nuclear scenario (under which the highest rate of consumption is exhibited) is approximately 4.7% billion tonnes of coal. This figure represents nearly 8% of the estimated recoverable reserves of 57.5 billion tonnes of coal in South Africa (De Jagger 1982). However, provided that the recoverable reserves would not increase and only 50% of the available coal is allocated for ESCOM the last coal-fired generating plants will be commissioned early in the next century. This is so, because of the shortage of coal needed to support thermal power stations with lives longer than 40 years.

Under the above conditions and assumptions, the last tonne of coal will be burnt to generate electricity after 60 years starting from 1985. If, however, electricity prices increased and nuclear power stations were incorporated in the system as envisaged in the Boycott conditions plus nuclear scenario, the recoverable reserves would last more than 200 years.

An examination of the effects of the adoption of dry-cooling after the year 1992 reveals that 35 years cumulative consumption* (1985-2020) increases by 490 000 000 tonnes over the consumption of the equivalent wet-cooled system in the Normal conditions scenario and by 387 000 000 tonnes in the Boycott scenario. These differences represent 7.5 and 6 times respectively the 1985 annual steam-coal consumption.

The model is built on the assumption that coal and nuclear-fired stations would be the only feasible technologies for the generation of electricity. It is possible that other than coal and nuclear resources would be able to make a sizeable contribution in the production of electricity in the future. However, the current knowledge leads to one robust conclusion. Nuclear power will play an important role in the South African electricity production system during the 21st century. Both, economics and physical constraints

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* Under conditions of exponential growth for N years from a level of annual coal consumption D_1 to a level of annual consumption D_2 cummulative coal consumption is:

$$C = \frac{N}{\ln (D_2/D_1)} * (D_2 - D_1)$$

show that expansion in the system cannot be sustained only with the use of coal. Appropriate strategies have to be developed in order to provide the necessary infrastructure within the context of the desired national energy policy goals.

CONCLUSIONS

CONCLUSIONS

This thesis is a contribution to the debate about the future of coal for the generation of electricity in South Africa. The aim of the research effort is to identify the factors influencing the demand for steam-coal, disentangle their interrelationships, and evaluate their relative influence and importance. In turn, such an effort leads to a better understanding of the major trends expected in the future.

Apart from identifying and determining the quantitative effects of the economic, technological and political factors that affect the demand for coal for electricity, important contributions are made by estimating for the first time the long term price elasticity of electricity demand in South Africa and by providing a mathematical description of the way particular characteristics (eg efficiency) of systems change as new modern units are incorporated and older units are retired from the system. The latter contribution, although it is developed for the analysis and forecasting of the thermal efficiency of systems of power plants, can be applied in many different systems, for example for analysis and forecast of fuel consumption of car fleets.

Three research topics are identified as important for the investigation on the demand for steam-coal for electricity generation. These are: (1) the demand for electricity; (2) the thermal efficiency with which the system of coal-fired power stations transforms the chemical energy in the fuel into electricity; and (3) the share of electricity generated by coal-fired stations.

A comprehensive review of the studies on the demand for electricity in South Africa (chapter 1) shows that the relevant literature consists only of extrapolations, "naive" regressions and some attempts to use input/output models. With the growing interest in the modification of electricity rate structure, the study of the effects of price changes on the demand for electricity is identified as very important.

In order to examine the effects of price on the demand for electricity the price elasticity of electricity demand is estimated (in chapter 2) through an unconstrained distributed lag model and the estimate is used as an extraneous information for the forecast of the demand for electricity up to the year 2020. The main finding is that price is important in the determination of the demand for electricity in the long-run. The price elasticity of electricity demand was found to be -0.90.

The thermal efficiency with which the ESCOM's power stations transform the chemical energy in coal into electricity is the second factor affecting the demand for steam-coal. Chapter 3 examines the possibilities for future improvement in unit thermal efficiency. The comparison of five electricity generating concepts - thermionic conversion, thermoelectric generation, magnetohydrodynamic generation, fuel cell, and gas turbine generation - reveals that further improvements in the thermal efficiency of coal-fired power stations is possible. The combined gas-turbine/steam-turbine cycle is indicated to be the most probable candidate to succeed the conventional electricity generating systems whose thermal efficiency is stagnant. The conclusion of the chapter is that with present day conversion technology, no further significant increases can be expected, although with present day materials, the maximum theoretical efficiency of conversion from heat to work is about 60 percent.

Chapter 4 examines the way that advanced technologies from abroad are transmitted and diffused in the South African electricity generating system. A precursor event analysis indicates that the average time needed for the "best plant" thermal efficiency in South Africa to reach that of the "best plant" in the United States is 15 years. A model describing the way with which the thermal efficiency of the system as a whole changes is also developed. The factors determining the system thermal efficiency are identified to be the speed of the technology transfer from the country of origin to the technology importing country, the rate of demand for additional capacity and the age profile of the plants belonging to the system. Barring the existence of any constraint particular to South Africa, the model conditionally predicts that ESCOM's efficiency in the next 30 years could be up to 20% higher than the 1982 level. The predicted improvement in the system thermal efficiency is only one third of the gains obtained during the preceeding 30 years.

The third factor affecting the demand for steam-coal - the percentage of electricity generated by coal-fired power stations - is examined in Chapter 5. Nuclear and coal-fired power stations are considered to represent the only cost-effective and feasible options for base-load generation and their economic merits are investigated. The comparison of the levelized bus-bar cost of electricity produced by the two generating modes indicates that nuclear power will have an apparent cost advantage over coal-fired power plants by the year 2000. This prediction is conditional on the assumption that cost trends established during the last 30 years are extended in the future.

Sensitivity analysis indicates that a devaluation of the South African Rand by 100 percent below its equilibrium determined by the purchasing power parity principle reduces the advantage of the nuclear mode of production but not sufficiently to make it comparatively uneconomic. The adoption of the dry-cooling mode, stringer environmental controls and coal transport cost appear to widen the cost gap between nuclear and coal bus-bar cost in favour of the nuclear-fired power stations.

In the penultimate chapter the demand for steam-coal in South Africa is modelled and conditional predictions are made covering the time-span up to the year 2020. Sensitivity analysis is performed in order to put into focus the effects of political, resource and policy considerations on the demand for coal. Scarcity of water and the adoption of dry-cooling in power stations is found to have a sizeable effect on the demand for steam-coal. The difference in cumulative demand for coal under the dry-cooling and the wet-cooling scenarios is equivalent to 6 or 7-fold the 1985 consumption rate. Similarly, the adoption of nuclear-fired power stations extends the life of the current estimated reserves from 60 to 200 years.

A comparison of the predicted demand for steam-coal with estimates by ESCOM reveals a difference between 30 and 50 percent. The lower demand predicted by the model is a direct consequence of the analytical framework adopted which recognises the importance of examining the demand for steam-coal in the context of the prevailing economic conditions. The chapter ends with a policy note: energy policy should take into account the economic and physical scarcity of coal and provide, within the context of the desired national energy policy goals, the necessary infrastructure for the successor mode of electricity generation.

APPENDICES

APPENDIX 1

YEAR	ELECTRICITY SOLD BY ESCOM (GWH)	AVERAGE PRICE OF ELECTRICITY (C/KWH)	GROSS DOMESTIC PRODUCT 1975 PRICES (R MILL)	CONSUMER PRICE INDEX
1950	6910	0.2741	7 745	34.4
1951	7456	0.2922	8 585	36.9
1952	8080	0.3115	8 818	40.2
1953	8732	0.3542	9 276	41.6
1954	9676	0.3808	9 895	42.4
1955	10964	0.4139	10 451	43.7
1956	12019	0.4285	10 996	44.5
1957	12763	0.4478	11 483	45.8
1958	13602	0.4733	11 737	47.4
1959	14724	0.4951	12 197	48.1
1960	16094	0.5079	12 605	48.8
1961	17013	0.5155	13 123	49.8
1962	18121	0.5164	13 843	50.4
1963	19500	0.5177	14 959	51.1
1964	21247	0.5101	16 039	52.4
1965	23143	0.5076	17 062	54.5
1966	24554	0.5254	17 857	56.5
1967	26657	0.5467	19 339	58.4
1968	28885	0.5550	20 216	59.6
1969	31505	0.5565	21 528	61.5
1970	34890	0.5545	22 630	64.1
1971	38040	0.5772	23 747	67.7
1972	41648	0.6108	24 038	72.1
1973	46578	0.6484	25 049	78.9
1974	52558	0.6822	26 949	88.1
1975	57869	0.7950	27 370	100.0
1976	63355	1.0360	27 742	111.3
1977	67125	1.5353	27 743	123.6
1978	72780	1.7887	28 366	136.2
1979	80582	1.8980	29 432	154.1
1980	87539	2.0242	31 767	175.3
1981	93844	2.2811	32 044	201.9
1982	96135	2.8038	30 877	231.6
1983	98251	3.3606	30 441	260.2

SOURCES: Electricity Sold and Average Price of Electricity from the Annual Report of ESCOM 1983. Gross Domestic Product from various issues of the International Financial Statistics, IMF, and the Consumer Price Index from various issues of the South African Statistics, Statistics Office, Pretoria

APPENDIX 2

YIELDS OF LONG-TERM GOVERNMENT BONDS IN SOUTH AFRICA 1937 - 1981

Year	Nominal Yield %	CPI Inflation %	Real Yield
1937	3.20	2.3	0.9
1938	3.45	3.6	-0.15
1939	3.70	-0.1	3.8
1940	3.40	3.5	-0.1
1941	3.00	4.6	-1.6
1942	3.00	8.4	-5.4
1943	3.00	6.0	-3.0
1944	3.05	3.5	-0.45
1945	3.05	2.6	0.45
1946	2.94	1.4	1.54
1947	2.57	4.1	-1.53
1948	2.90	5.7	-2.8
1949	3.33	3.6	-0.27
1950	3.63	3.9	-0.27
1951	3.60	7.3	-3.7
1952	4.28	8.7	-4.42
1953	4.50	3.4	1.1
1954	4.46	1.8	2.66
1955	4.33	3.1	1.23
1956	4.73	1.8	2.93
1957	4.75	2.9	1.85
1958	5.13	3.4	1.73
1959	5.25	1.1	4.15
1960	5.29	1.2	4.09
1961	5.78	2.0	3.78
1962	5.41	1.4	4.01
1963	4.75	1.1	3.65
1964	4.77	2.5	2.27
1965	5.60	3.6	2.0
1966	6.25	3.5	2.75
1967	6.50	3.3	3.2
1968	6.50	1.7	4.8
1969	6.50	2.8	3.7
1970	7.15	5.2	1.95
1971	8.38	6.1	2.28
1972	8.35	6.4	1.95
1973	7.83	9.4	-1.57
1974	8.96	11.6	-2.64
1975	9.17	13.5	-3.79
1976	10.38	11.1	-0.72
1977	10.96	11.3	-0.34
1978	10.49	10.9	-0.41
1979	9.69	13.1	-3.41
1980	9.70	13.7	-4.0
1981	12.56	15.1	-2.54

SOURCES: International Financial Statistics (various issues) and
South African Statistics (various issues)

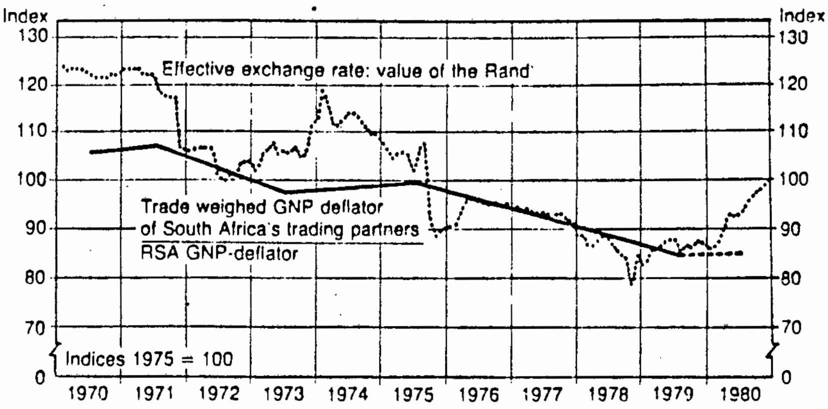
APPENDIX 3 YIELDS OF NEW ISSUES OF COMPANY STOCK DEBENTURES AND NOTES

YEAR	NOMINAL YIELD	CONSUMER PRICE INDEX	REAL YIELD
1963	6.00	1.10	4.90
1964	6.50	2.50	4.00
1965	7.50	3.60	3.90
1966	7.50	3.50	4.00
1967	8.50	3.30	5.20
1968	8.50	1.70	6.80
1969	8.50	2.80	5.70
1970	10.00	5.20	4.80
1971	10.25	6.10	4.15
1972	9.50	6.40	3.10
1973	9.50	9.40	0.10
1974	13.25	11.25	2.00
1975	13.50	13.50	0.00
1976	14.00	11.10	2.90
1977	13.00	11.10	1.90
1978	11.16	10.90	0.26
1979	10.97	13.10	-2.13
1980	12.83	13.70	-0.87
1981	13.75	15.10	-1.35
1982	15.00	14.60	0.40
1983	15.00	12.30	2.70
AVERAGE			2.48

SOURCE: South African Reserve Bank Quarterly Bulletin

various issues

APPENDIX 4 THE EFFECTIVE EXCHANGE RATE OF SOUTH AFRICA AND RELATIVE INFLATION 1970-1980



SOURCE: Mercabank Focus on Economic Issues
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