ELECTRICITY IN SOUTH AUSTRALIA: COST, PRICE AND DEMAND 1950-80

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DEDICATED to the Memory of

My Father who Inspired Me to Read
and to
My Teachers Who Taught Me to Read
With Judgement.

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GLOSSARY

TERMS AND ABBREVIATIONS USED IN THIS STUDY

ABS	=	Australian Bureau of Statistics.
ASIC	=	Australian Standard Industrial Classification.
DME	=	Department of Mines and Energy.
DNDE	=	Department of National Development and Energy.
ETSA	=	Electricity Trust of South Australia.
NEAC	=	National Energy Advisory Committee.
SAGASCO	=	South Australian Gas Company
SASEC	=	South Australia State Energy Committee
Kwh	=	Kilowatt hour (i.e., one unit of electricity).
Mwh	=	Megawatt hour (One Mwh = 1,000 kwh).
Gwh	=	Gigawatt hour (One Gwh = 1,000 Mwh)
Kw	=	Kilowatt (one Kw = 1,000 watts. A watt is the unit of power or rate of doing work).
MW	=	Megawatt (One MW = 1,000 KW).
PJ	=	Petajoules = (10^{15} joules).
GJ	=	Gigajoules = (10^{9} joules).
MJ	=	Megajoules = (10^{6} joules).

Capacity Factor $= \dfrac{\text{Mwh Generated in a Year}}{\text{Maximum Dependable Capacity (MW)} \times 8760}$

where 8760 is the total number of hours in a year.

Peak Demand — The maximum load (MW) which can occur (even for half an hour) throughout the year.

Installed Capacity — The total nameplate rating (MW) of the currently installed generating plant.

Load Factor	Defined as the ratio (expressed as a percentage) of (a) the number of units sent out to the supply system during a given period to (b) the number which would have been sent out had the maximum demand on the system been maintained and supplied throughout the period i.e., $\text{Load Factor} = \frac{\text{Energy in kwh}}{\text{Max. Demand in KW x 8760}}$
Demand Factor	The ratio of the maximum demand for any system to the total connected load of the system.
Diversity Factor	The ratio of the sum of the maximum power demand of the subdivisions of any system or parts of a system to the maximum demand of the whole system or of the part of the system under consideration measured at the point of supply. For instance, if 10 houses have a maximum demand of .36 KW each, the maximum demand at the supply point may not be the .36 x 10 = 3.6 KW unless all 10 houses happen to have identical time of their use of electricity. Thus if maximum demand at the supply point is say, 1.8 KW, then the diversity factor is $\frac{3.6}{1.8} = 2$.
Transmission and Distribution	Transmission means transporting of electricity at high voltage from Power Stations to Major Load Centres (MLC) and distribution means delivery of power to consumers at lower voltage from MLC and/or intermediate load centres (ILC).

SUMMARY

ELECTRICITY IN SOUTH AUSTRALIA: COST, PRICE AND DEMAND 1950-80

The unprecedented rise in oil prices since 1973 was considered by many economists and other social scientists to be the beginning of an era of sluggish economic growth (and hence the situation has been termed an energy crisis). One reason for this fear is the tacit assumption that has long prvailed in the economics literature that substitution possibilities between energy and non-energy inputs are negligible. It has also been generally assumed that energy's bilateral substitutability with any one the remaining inputs such as capital, labour or materials is the same for each type of input. Interfuel substitution was also considered to be the same for each energy type. These assumptions in part explain the absence of energy inputs from previous studies relating to production functions. Intuitively however, they seem implausible. Recent debates have attempted to clarify the importance of energy substitution possibilities, but the evidence put forward so far is inadequate and conflicting.

Nowhere in the economy does the issue of input (energy) substitution appear more important than in the electricity supply industry (ESI). This industry not only produces the most important secondary energy source but is also a large consumer of primary energy sources. While the possibility of energy substitution in the rest of the economy will affect the future demand for electricity, the prospect of input substitutions will affect its cost of generation. An important question before the ESI is then whether the spectacular growth rate

observed in this industry since the early twentieth century will be diminished due to rising energy prices.

In order to address this question, the ESI has to ascertain how seriously the cost of generation is likely to be affected by increases in individual input prices. That is to say, the ESI must have some idea of the elasticities of substitution between inputs (including energy types) and of the cost elasticities with respect to individual input prices. More importantly, the factors responsible for the historical reduction in the per unit cost of supplying electricity must be clearly understood. The importance of increasing scale, of load factor and of technological changes need to be expressed in quantitative terms, so that the policy makers can look at the alternative measures available to minimise cost.

Equally important is an assessment of the determinants of electricity demand and the relative magnitudes of their impact. The role of the price variable in determining demand for electricity is of particular interest.

Quantitative knowledge of the importance of all these variables are prerequisite for an estimate of how much electricity is likely to be demanded in future or how much capacity needs to be built. The issue of whether demand for electricity is highly responsive to price changes also affects policy decisions such as the appropriate proportion of internal funding for capacity expansion.

The crucial issue in answering these questions is not only to identify a proper demand function for electricity but also to estimate the likely impact on load factor of the changing pattern of demand.

The present study is addressed to the above questions in the particular case of the Electricity Trust of South Australia (ETSA). Some of the findings of the present study are summarized below.

Production of Electricity and System Average Cost

Energy and capital in ETSA appear to be substitutes but energy and labour, and labour and capital are complements. Though the impact of technological change on cost reduction could not be separated from scale effects, ETSA seems to have been enjoying substantial economies of scale. This enhances the case for treating it as a natural monopoly. It was also observed that improvements in the load factor can substantially reduce the cost of electricity in South Australia.

Adoption of conventional production functions such as those assume constant returns to scale or unitary elasticity of substitution seems to be misleading in the case of ETSA.

Marginal Cost of Electricity Supply

Conventionally, marginal cost has been assumed to be the same, regardless of to whom the product is supplied. Hence the possible application of Pigouvian Third Degree Discrimination or Ramsey prices has typically been confined to cases where demand elasticities differed between customers. No attempt was made to consider price differentiation based on differences in marginal costs. The present study has found that, for the market supplied by ETSA, marginal costs attributable to different sectors do differ. This provides a basis for evaluation of pricing practices in ETSA, taking into account variations in both sectoral demand elasticities and sectoral marginal costs.

Energy Consumption

The scope for substitution between different fuel types has been estimated for the industrial, residential and commercial sectors of South Australia. In all these sectors, electricity and oil appear to be substitutes, as are oil and gas. The substitution possibility between electricity and gas, however, was not found to be significantly different from zero. This is in sharp contrast with the conventional view, though exceptions to the above general observations were found among individual groups of industrial customers.

Sectoral Elasticities

Contrary to the generally held view, the own price elasticities of demand for electricity in all three sectors of South Australia (namely residential, industrial and commercial) were found to be significant though its relative importance varied from sector to sector. Unlike many previous studies therefore, the present study suggests that the price variable cannot be ignored in forecasting demand for electricity. Moreover, it has been observed that price can be used as an important device for allocating electricity to different sectors.

The elasticity of demand for electricity in all three sectors and the pattern of relative elasticities were found to be variable over time and over the levels of the dependent and the independent variables. The constant elasticity model that has been widely used in recent literature is, therefore, considered inappropriate in the present case.

Pricing Practices in ETSA

Information about the changing pattern of elasticities in different sectors under ETSA together with differences observed in the estimated sectoral marginal costs was used to evaluate pricing practices in ETSA. It has been shown that ETSA did not appear to follow any pricing rule consistent with its objectives, as far as these objectives can be discerned from the historical perspective of the ETSA Act 1946. It has been recommended that ETSA can better fulfil its objectives by adopting Ramsey rules of pricing.

Demand Forecast

It has been possible to present a reasonably reliable demand forecast on the basis of this study's findings and by incorporating estimates of expected changes in the explanatory variables for electricity demand at the customers' end and load demand at the supplier's end. It appears that consumption of electricity as well as load demand will continue to increase (though at a diminished rate) despite an expected rise in electricity prices in real terms.

RESEARCH DECLARATION

I solemnly declare that this thesis contains no material which has been accepted for the award of any other degree or diploma in any University and that, to the best of my knowledge and belief, it contains no material previously published or written by another person, except when due reference is made in the text of this thesis.

I further declare that I have no objection to the thesis being made available for photocopying and loan, if accepted for the award of the degree.

Signature of the Candidate

A.A. Ali Ahmed Rushdi,
Dated 18. 5. 1984

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INTRODUCTION

Experiments in the generation of electricity were first conducted as early as 1600 A.D.[1] However, it was 1882 when the commercial use of electricity commenced with the world's first steam operated generator set up in the city of New York. The growth of the electricity supply industry (ESI) has historically been associated with the growth of the economy as a whole. But the rate of growth in the ESI apparently has been faster than any other industry throughout the world.[2] This occurred because of the versatility of its use in almost all branches of an economy, especially the residential, industrial, commercial and agricultural sectors; and because of the significant increasing returns to scale and improved technology obtained in the industry, with a resultant decline in its relative price.

In South Australia, legislation regarding the establishment of the ESI was enacted as early as in 1882.[3] For the first fifteen years of this enactment, electricity was supplied by a number of small private generators. The South Australian Electric Light and Motive Power Company was formed in 1897 and for the first time, in January 1899, some of the Port Adelaide streets and flagships were lighted by electricity.

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1 Dr. William Gilbert first coined the term electricity from "elektro" the Greek name for amber, a substance from which electricity could be generated by friction.

2 In the U.S., the electricity supply industry expanded at pace nearly twice that of the overall economy, doubling roughly every 10 years. See National Power Survey, U.S. Federal Power Commission, Washington, 1964, p. 9. See also NEAC, (1983), p. 1.

3 See Electricity Supply in South Australia, ETSA, August 1959.

In September 1899, the original company changed hand at a profit nearly twelve times higher than its share capital - $4,000. In 1904, the Adelaide Electric Supply Company Limited (AESC) was formed, which took over the Adelaide and Port Adelaide systems from its parent company at a purchase price of $324,000.[4] The abnormally high profit obtained by the industry generated a series of interesting debates about whether the public interest could be better served by public ownership of the industry. Following a Royal Commission Report in 1945, the State Government acquired the ownership of the AESC in 1946 under the name of Electricity Trust of South Australia (see Section 8.1). Small independent supply authorities (ISA) were gradually taken over by ETSA, though some of them still remained independent in the countryside (see Section 2.2.4). However, electricity supplied by the ISA in 1980 was only 1.6 per cent of the total electricity demand in South Australia.[5]

Electricity sales in South Australia more than doubled in each decade from 1926 to 1946 and almost quadrupled in the first decade of public ownership of the industry. The increase in the next two decades from 1956 to 1976 was less spectacular but it was still considerably higher than the growth rate of aggregate industrial output. The sale of electricity almost trebled from 1956 to 1966 and doubled again by 1976.[6] However, the rate of growth has declined significantly in recent years. The growth rate was 4.8 per cent in 1978, 3.3 per cent in 1979 and 1.6 per cent in 1980. In the residential sector, demand declined in

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4 See ETSA, (1971), The Electricity Supply Undertaking: The Leigh Creek Coal Field, p. 1.

5 Calculated from the unpublished data from ETSA.

6 The real value added in manufacturing industries in 1976 was only 2.5 times larger than that in 1956, see S.A. Year Book 1982, p. 630.

1980, by 1.2 per cent.

The growth rate of electricity sales in South Australia, decomposed by various customer groups, is presented in Table 1. The substantial growth rate in the total sale of electricity is attributable to significant increases in both the number of customers and the consumption per customer. The number of customers increased from 118,260 in 1946 to 216,350 in 1956, 431,430 in 1971 through to 551,290 in 1980. However, although the increase in the number of customers was substantial during this period, the number per transmission mile declined significantly. This occurred because one of the primary objectives of ETSA was to extend electricity supply to the rural areas of South Australia and as such it has had to build up an extensive transmission and distribution network throughout the state. (Further discussion of this is to be found in Chapter VIII). The ratio of the number of customers to transmission miles declined from 103 in 1946 to only 55 in 1956 and 19 in 1971. The ratio increased to 31 by 1980. The fall in the ratio is likely to have introduced some diseconomies in the transmission sector but as we shall see, this did not outweigh the large economies obtaining to the system as a whole.[7]

During this period, considerable reductions occurred in labour requirements per Gwh sold. In 1926, the number of employees per Gwh sold was 19.6. It came down to 7.3 in 1946 and to 4.5 in 1956. By 1970, it declined further to 1.61 and to 1.16 by 1980.[8]

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7 The cost of transmission and distribution in the ETSA system did not exceed 13 per cent of total cost in any year since 1950.

8 Note that the actual number of workers in 1980 was not available from ETSA. The estimated number of 6,730 was obtained by dividing the ETSA wage bill in 1980, by the average wage level in the manufacturing industries in that year.

TABLE 1

Compound Annual Growth Rates of Electricity Sales in South Australia

	Total	Residential	Industrial	Commercial
1950 - 1960	13.5	14.0	13.0	11.0
1960 - 1970	10.6	9.0	10.2	12.5
1970 - 1980	5.2	5.5	3.4	10.0
1950 - 1980	9.4	9.5	8.0	11.0
1979 - 80	3.6	-1.2	5.5	7.7

Source: ETSA, Annual Reports. Computations are the author's.

The decline in labour requirement per Gwh sold was closely associated with significant improvements in the load factor, increases in electricity sales and increases in the size of generating plants. The system load factor rose from 40 per cent in 1926 to 42 per cent in 1946, 57 per cent in 1960, and 61 per cent in 1977. However, the load factor has since then declined to 56 per cent in 1980.[9]

In 1946, the largest generator in use was of 15 MW at Osborne; in 1956, it was of 30 MW; and by 1976, the maximum size had increased considerably to 200 MW (at Torrens Island). This increase in size undoubtedly had its impact in reducing the cost of generating power but it seems that at no time did ETSA avail itself of the opportunity of installing the largest available generator. The 200 MW steam turbine which ETSA installed in 1980 was available in the market as early as

9 These calculations are based on information given in ETSA, Annual Reports and for earlier years, 10 Year Review, ETSA, 1957, pp. 10-14.

1950. By contrast, the average capacity of generators installed in Victoria and New South Wales in the 1970's was 500-660 MW (see Brian and Schuyer, 1981, p. 116). However, the economies of larger size have to be viewed against the diseconomies of the outage necessary for maintenance and also against the risk of shortage in the event of any breakage or disruption. The largest generator in each of the above systems was around 10 per cent of the system capacity.

The present structure of the installed capacity of ETSA is presented below.

TABLE 2

Installed Generating Capacity: ETSA 1982

	Plants	Capacity MW
Torrens Island	4 x 120 MW Steam Turbine	480
	4 x 200 MW do	800
Thomas Playford	3 x 30 MW do	90
	4 x 60 MW do	240
Osborne	6 x 30 MW do	
	1 x 60 MW do	240
Dry Creek	3 x 52 MW Gas Turbine	156
Snuggery	3 x 25 MW do	75
Port Lincoln	2 x 2.5 MW Steam Turbine	
	1 x 3 MW Diesel Generator	
	6 small Diesel Generators	9
Total		2,090 MW

Source: ETSA, Annual Report, 1982, p. 6.

Conventionally defined economies of scale do not merely result from bigger sized generators. Economies in operation and maintenance, construction and supervision costs may be obtained even if a number of small plants are installed at the same place. ETSA seems to have captured these economies quite successfully. The following table reveals not only that the per unit cost in ETSA was the lowest among the mainland systems in 1972-73 but also that the decline in its cost since 1952-53 was the largest but for Western Australia. Detail discussion of cost conditions in ETSA is to be found in Chapter Two.

TABLE 3

Comparison of Per Unit Cost of Supplying Electricity in Australia at Constant 1952-53 Prices

	1952-53 ¢	1972-73 ¢	Index for 1972-73 (with 1952-53 = 100)
New South Wales	2.12	1.06	50
Victoria	1.83	1.14	62
Queensland	2.21	1.21	55
Western Australia	2.72	1.24	46
Tasmania	.51	.46	90
South Australia	2.21	1.04	47

Source: Adapted from McColl (1976), pp. 36-51.

It appears that the growth in production and consumption of electricity in South Australia has been associated with a significant decline in the unit cost of electricity, especially when considered in relation to the persistent rise in the general price index in the post war period. This may be seen in the following table.

TABLE 4

Price of Electricity and Quantity Sold: South Australia

	1926	1936	1946	1956	1966	1976	1980
Electricity Sold in Gwh	48.6	101.4	235.5	893.3	2498.4	4710.7	5798.5
Total Revenue Million A$	-	-	-	18.3	46.3	123.0	214.8
Nominal Price* (cent per kwh)	2.7	1.7	1.4	2.00	1.9	2.6	3.7
Real Price (c/kwh) in 1966-67 Price	-	-	3.9	2.6	1.9	1.4	1.3

Source: Annual Reports and 10 Year Review, 1957, Calculations are the author's.

* The small change in nominal average price between 1956 and 1966 is due to structural changes in demand.

In the immediate post war period, the price of electricity rose moderately in nominal terms but fell in real terms. Between 1952 and 1971 the nominal price was constant. In 1971 the price of electricity was raised by 5.5 per cent, followed by rises of 11 per cent in 1973, 12.5 per cent in 1974, 10.5 per cent in 1975, 10 per cent each year from 1977 to 1979 and 12.5 per cent in 1980. Despite these price rises, the average real price of electricity (in 1966-67 prices) continued to fall from 3.4 cents per kwh in 1950 to 1.3 cents in 1980 (see Table 4).

Despite indication that substantial economies might have been obtained over time, it is surprising that no quantitative analysis is available of the factors responsible for this decline in cost and price. There has been no study as yet to estimate the cost elasticity with respect to quantity of electricity produced (sold) by ETSA. Important issues involved in planning, such as economies of scale, substitution of inputs and demand elasticities have not been given any attention either.

Historically, the increased consumption of electricity in South Australia, as in many other places, has been closely associated with increased economic growth and industrialisation. The rate of growth in real disposable income was substantially higher than the rate of growth in population, so that the per capita disposable income more than doubled during the period from 1950 to 1980. Real value added in the manufacturing industries in 1980 was 3.62 times as much as in 1950. However, the rate of growth in electricity consumption was more than four times higher than that in either real disposable income or industrial value added.

Viewed from this historical perspective, it is not surprising to find it said that

> "any reduction in the amount of electric power available is likely to result in a relatively greater reduction in GNP, until equilibrium is restored at a lower level. And since as much as 70 per cent of electric power consumption is for commercial and industrial purposes, a forced reduction in the availability of this vital form of energy will have an adverse effect on employment". (Electrical World, July 6, 1970, p. 32).

Also "electricity supply constraints, by reducing the rate of economic growth, are likely to act as a disincentive to investment ... (and) to reduce employment opportunities" (Niall, *et al*., 1982, p. 73).

The above statements, reflecting anxieties created by the unprecedented increases in energy prices since 1970, are based on empirically unsubstantiated beliefs that energy (electricity) is a complementary good and there is no close substitute for it. If, however, electricity is substitutable for other forms of energy and energy for other factors of production (e.g., capital and labour), then any reduction in energy availability is less likely to cause a decline in economic growth and employment. Moreover, in a dynamic situation, where economies of scale exist, the necessary increases in the price of electricity is likely to be less (if demand grows).

No proper planning and no reliable prediction can be made without a fair knowledge of factor substitutability and economies of scale both within ETSA and in its customer classes e.g., industrial, residential and commercial. Such knowledge seems to be seriously wanting in the case of ETSA.

For the first time since 1952, the rate of increase in the average and marginal prices of electricity in South Australia during 1981 was higher than the rate of inflation.[10] The reason for this, according to ETSA, was that

> "with lower rates of load growth, the effects of economies of scale are diminishing and are being offset by rapidly rising fuel costs, substantial increases in the cost of new generating plant and high interest rates on borrowing as well as continuous increases in labour costs. Because of these factors, electricity tariffs are now increasing in real terms ... and this trend can be expected to continue for the next few years at least". (ETSA, Annual Report, 1981, p. 4).

Another reason why the cost of electricity is expected to rise seems to be the need for building generating capacity to meet future demand. The installation of the proposed local coal fired station in South Australia is likely to be delayed and ETSA may have to import costlier black coal from New South Wales (see The Advertiser, April 28, 1983). Further discussion of likely price changes is in Chapter Ten.

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10 Electricity price rose by 19.8 per cent in July 1981 and again by 16 per cent in May 1982.

In view of the above and as a result of the socially and technically imposed constraints on the expansion of nuclear electricity, it now seems that the real price of electricity may rise in future above the present level. Whether the rising price will produce a different elasticity of demand than the falling price observed in the past is a question that needs immediate attention.

In the absence of any careful study, it is not known how elastic or inelastic is the demand for electricity in South Australia. It seems that ETSA believes the demand to be highly inelastic so that the proposed 'increase in tariffs to provide a higher level of internal funding' (ETSA, Annual Report, 1981, p. 4) will not significantly alienate some of its customers or reduce the intensity of use of the existing appliances.

To the extent that demand is elastic, such a method of raising funds may be risky. Under such circumstances, not only will the proposed capacity be redundant but also it may reduce the existing Load Factor with an adverse effect on cost. It may also reduce the total revenue coming from the existing customers.

If ETSA is facing an elastic demand and enjoying any economies of scale, the economic wisdom lies in a reduction of price. The American Energy Consumer has rightly concluded that

> "among the most important studies that should be undertaken soon is one that would show the impact of price changes for electricity ... in different economic groups - that is a rigorous statistical analysis of the price elasticity of demand" (George, 1979, p. 31).

An important question before the planners is, therefore, what would be the most likely demand for electricity in the near future and how sensitive is the demand forecast to any change in the level of the determinants of demand. It is also important to know the relative significance of the different explantory variables and the likely change in their relative significance.

This thesis is aimed at providing a more reliable forecasting model than the adjusted trend models currently used in many places including South Australia. No serious study has yet been made in South Australia of demand for and/or supply of electricity, though a number of studies have been made elsewhere.[11]

As we shall see in the literature review given in Chapter Three, the variation in the coefficients estimated in previous studies (mostly in the U.S.) are so wide that the basic question as to whether the demand for electricity is elastic or inelastic with respect to a particular variable remains in doubt. The root of this variation in results can be traced to differences in the periods of study, selection of samples, geography and methods. Moreover, the data used in these studies are mostly of an aggregative nature, so they reveal nothing about the differences (if any) in the demand elasticities and the functional forms with respect to various sectors. However, intuition as well as empirical evidence suggest that they are likely to be different.

In the U.S., the service area covered by a utility often extends beyond the boundary of a state and states served by more than one utility are not uncommon either. The existence of inter-regional differences in alternative fuel availability, environmental

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11 The only demand study available on South Australia, to my knowledge, is the one made by the Department of National Development and Energy. We shall discuss this in Chapters Three and Nine.

restrictions, growth rates of population, taste and temperature as well as differences in real personal income plus the limitations of the empirical methods used, limit the validity of the results obtained in such studies as a guideline for planning purposes in a specific region.

The present study addresses itself to a specific region, South Australia, with only one utility, ETSA, and incorporates recent data disaggregated over sectors, in analysing changes in demand for electricity. This is in sharp contrast with the practice of the recent literature, where the data used are either a single cross-section , a pooled time series of cross sections, or a time series of a large number of utilities (see Chapter Three). Aggregation across firms with different tariff schedules makes it extremely difficult to ascertain whether any single price is representative of the tariff schedule facing the typical consumer. Thus the estimated elasticities are at best aggregates of elasticities which may often be inapplicable to individual utilities. The fact that our study is concentrated on a single utility is expected to yield more precise information on price-quantity relationships than the results obtained from the multi-utility studies. Also our use of more recent data is expected to provide estimates of regression coefficients which can be used more confidently in forecasts of demand for electricity.

In Chapter Three, a summary of the functional forms and results obtained in some of the previous studies is presented. It can be observed that most of the studies used a constant elasticity model. The present study uses a variable elasticity model, hypothesizing that the elasticity of demand changes over time with changes in the levels of explanatory variables. The constant elasticity model, which assumes a hyperbolic demand function, will also be examined.

A corollary hypothesis of the variable elasticity model is that the inter-class differences in the elasticities of demand (residential, industrial and commercial) are changing too. The present study tests these hypotheses and examines the pattern of changes over time. This provides scope for evaluating the historical price differences among various classes of consumers.

To examine more rigorously the extent to which the present pattern of price discrimination by ETSA affects the allocation of resources and to prescribe a possible way of distributing the cost burden among the consumer classes, an attempt is made in the present study to estimate the marginal cost of supplying electricity pertaining to each of the major consumer classes. Attempts to estimate class marginal costs in the past could not be successful due to lack of appropriate data. In the present study, however, the necessary data are available from ETSA, the South Australian Energy Council, the Department of Mines and Energy, SAGASCO, the Department of National Development and Energy (DNDE) and the Australian Bureau of Statistics (ABS).

It is well known that the marginal cost of any product is affected by the cost elasticity, which in turn reflects returns to scale. Thus in estimating marginal cost we are also able to estimate economies of scale in ETSA.[12] These estimates are helpful in predicting the future cost of electricity in South Australia.

It may be worth noting here that the long run marginal cost of electricity supply is greatly influenced by the expected demand. A reliable estimate of demand is, therefore, a sine qua non of a reliable

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12 Difficulties in separating the scale effect from that of density and technology will be discussed in Chapter Two.

marginal cost estimate. At the same time, a reliable estimate of demand has to be based on the expected future cost. The future cost may change not only due to changes in factor prices but also due to changes in the share of various groups of customers in the total demand, changes in the system load factor and/or changes in the generation mix as the system grows in size, where economies of scale are obtained. Tables 5 and 6 give the structural changes from 1950 to 1980.

TABLE 5

Structural Changes in Electricity Demand in South Australia

	Percentage of Total Consumption		
	1950	**1970**	**1980**
Residential	40	40	41
Industrial	43	41	34
Commercial	14	14	21
Others	3	5	4
TOTAL	100	100	100

Source: ETSA, Annual Reports. Calculations are the author's own.

TABLE 6

Generation Mix in Per Cent of Total Gigajoules used

	Gas	Coal	Oil	Others	Total
1950	–	97	3	–	100
1960	–	80	14	6	100
1970	9	60	25	6	100
1980	67	31	2	0	100

Source: ETSA, Annual Reports. Calculations are the author's own.

Major Contributions of the Present Study

The major contributions of the present study are:

1. Estimation of economies of scale obtaining to ETSA.

2. Estimation of the marginal cost and the inter-class differences in marginal cost of supplying electricity.

3. Estimation of substitution elasticities between energy and other factors of production in ETSA and those between electricity and other forms of energy in manufacturing industries as well as in the residential and commercial sectors in South Australia.

4. Identification of the major determinants of demand for electricity in South Australia and the relative importance of these determinants in the short run and in the long run.

5. Evaluation of the existing inter-class price differentials vis-a-vis Ramsey Pricing, Second Degree Discrimination and Third Degree Discrimination.

6. Identification of strategies for future pricing of electricity in South Australia.

7. Provision of a forecast of the most likely demand for electricity in South Australia for the 1980's.

Plan of the Study

The thesis is divided into four parts, dealing respectively with costs and production; demand; pricing; and forecasting. Each part contains a survey of relevant literature, together with one or more chapters presenting the estimates of parameters derived in this study and discussing the implications for ETSA.

The results generated in the first three parts are, in effect, brought together in Part Four, through the development of a forecasting model based on the results derived in earlier chapters. The future pricing strategies for ETSA, and its capacity decisions, are analysed within an integrated framework that provides an unambiguous indication of the value of the detailed investigation of ETSA and its market undertaken in this thesis.

P A R T   O N E

COST AND PRODUCTION

CHAPTER ONE

A SURVEY OF THE LITERATURE ON THE COST OF ELECTRICITY SUPPLY

The cost of supplying electricity comprises not only the cost of generation but also the cost of transmission and distribution to customers. Though transport and distribution costs are not unique to the ESI, the necessity for synchronization between production and consumption significantly adds to the high capital cost in the ESI and is largely responsible for an average capacity utilisation far below that typically observed in a capital intensive industry.[1] This phenonenon can be present even in the face of an accelerated growth of demand for electricity, because, in order to meet a growth in peak demand, the ESI has to build up additional capacity even though the duration of the peak is only short lived.[2] (The problem of peak load pricing is discussed in Chapter VII). That is why Dr. John Hopkinson (1892) divided the cost of electricity supply into two categories: standing cost - the cost of being ready to supply current; and running cost - the cost of actually supplying it. Under standing cost, Hopkinson put capital cost, most of the labour cost and that part of the energy cost which was necessary to keep the steam in readiness to supply current. The running cost was simply the difference between total cost

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1 Note that though transmission and distribution cannot be technically separated from generation, the commercial separability or separation of ownership is not ruled out.

2 It is an interesting aspect of the ESI that the acceleration principle holds good even in the presence of excess capacity. See Billes, F.V., An Econometric Study of Investment Behaviour in the Electric Power Industry, an unpublished Ph.D. Thesis (1974), at the University of California.

and the standing cost.

Taylor (1907) and Parsons (1939) followed the same practice as that of Hopkinson in defining the cost of supplying electricity.

A fundamental weakness of almost all the previous studies on the cost of electricity supply is that they did not consider the whole costs pertaining to the firm (industry) but instead concentrated either on generation or on operation and maintenance costs.

The earliest study on the estimation of a cost function in the ESI seems to be that of Taylor (1907). Taylor tried to estimate the effects on per unit cost of an increase in the quantity of electricity produced. He fitted a linear function and the estimates were as follows:

$$C = 782{,}000 + 3.33\ K \tag{1.1}$$

where C = coal consumption in pounds, and

K = kwh of electricity generated.

A linear relationship between coal consumption and electricity generation was also reported by Parsons (1939). His estimates were:

$$C = 5{,}000 + 1.23\ K \tag{1.2}$$

Though these estimates do not reveal anything about the total cost conditions in the ESI, one can infer from these findings how important technological improvement was between the period 1907 to 1939 in reducing both marginal and average coal consumption in electricity generation.

Byatt (1979) reports that the average costs in the U.K. were about 6d/kwh in 1890, 4d/kwh in 1900 and 1½d in 1911. He claims that this reduction in per unit cost of electricity was the direct result of the exploitation of economies of scale. He quotes two studies (Hobart and Addenbrook) which show that the cost per KW of generating plant declined substantially as the plant size increased. The following table is reproduced from Byatt (1979, p. 131).

TABLE 7

Cost Per KW of Various Sizes of Generating Plants in the U.K. (1909) in Pound Sterling

Size of Plants (MW)	Hobart (£)	Size (MW)	Addenbrook (£)
1.5	25	2.5	24
3.0	21	5.0	20
6.0	18	10.0	17
12.0	16	20.0	15
24.0	15	40.0	14
48.0	14		

Source: Byatt (1979, p. 131).

Evidence of economies of scale is not rare in the post war period either. Golding (1967) records that the cost per KW of Diesel plant reduces to one fifth if the plant size increases from 10 KW to 100 KW. He also mentions that economies of scale exist in the transmission of power. It can be seen in the following table that the transmission cost is a direct function of the distance from the station and an inverse function of the maximum demand. The table is based on the assumption of

30 per cent annual load factor, 20 per cent voltage drop in the line and a 15 per cent (nominal) rate of return per annum on the capital invested in the line.

TABLE 8

Cost in Pence Per KWH for Different Transmission Distances

Maximum Demand KW	50 Miles	100 Miles	200 Miles	300 Miles
500	2.3	4.7	9.7	15.0
1,000	1.2	2.5	5.6	9.5
1,500	0.8	1.7	4.0	6.0
2,000	0.7	1.4	3.1	5.0
2,500	0.5	1.2	2.5	4.0

Source: Golding, E.W., Power Supplies, The Overseas Development Institute, London, 1967, p. 36.

The reduction in cost per kwh as the maximum demand increases rests on the assumptions of given load factor and voltage drop in the line. Any reduction in cost per KW due to an increase in the size of demand may be offset (at least partly) by a drop in load factor. Thus, the extent to which an ESI will, in practice, enjoy economies of scale cannot be determined from the figures given by Byatt (1979) or Golding (1967).

Moreover, in a modern grid system, since plants are operated in merit order, the output chosen for one plant is not independent of the output chosen for others belonging to the same grid. Thus per unit cost taken from the observed data may conceal the impact of capacity utilisation (load factor) and other relevant influences on cost. An economic comparison of one power station with another on the basis of their unit generating costs is valid only if each plant performs an identical service on the grid to which each of them belong. In order to determine the effects on cost per kwh of the size of plants, one has to include other relevant variables in the equation so that the estimates do not suffer from any misspecification.

In a cross-section study of operation and maintenance costs in the ESI, Lomax (1952) finds that such costs are a decreasing function of the capacity of generators and load factor. While the Lomax study does not give us a full picture of the industry, it has highlighted the importance of the rate of utilization of the existing capacity, which was found more important in reducing cost than the size of plants. His results were as follows:

$$Y \propto X_1^{-.12} X_2^{-.41} \quad \text{for North West Region of U.K.} \tag{1.3}$$

$$Y \propto X_1^{-.15} X_2^{-.70} \quad \text{for South East Region of U.K.} \tag{1.4}$$

where $\propto$ is a sign of proportionality;

Y is operation and maintenance cost per kwh generated;

X_1 is capacity of generators in KW; and

X_2 is the load factor.

Though Lomax used cross-section data of 37 plants in 1947-48, the ages of these plants differed substantially. So the decreasing cost in his study cannot be attributed solely to economies of scale. It is possible that improvements in technology were partly responsible for the reduction in cost.

As regards technological improvements, Komiya (1962) concludes that "the fuel and capital requirement of a generating unit of a given size changed considerably from the pre-war to post-war years but in the post-war years they changed only insignificantly" (Komiya, 1962, p. 156). In this study of 235 plants, Komiya had included only new plants in each of the four periods he studies i.e., 1930-45, 1946-50, 1951-53 and 1954-56. His findings provide indication of significant reductions in cost due to technological improvements. One of the interesting findings in Komiya's study was that reduction in cost was realised not only with respect to average size of generating unit but also with respect to the number of units in each plant. Thus he was able to separate out operational economies from scale economies.

Komiya estimated the following three functions, where he assumed full capacity operation. The possibility of variation in load factor is not considered, and so its importance in reducing the cost of generation remains obscure in his study.

$$F = A\ X_1^{\alpha} \tag{1.5}$$

$$C = A\ X_1^{\alpha}\ X_2^{\beta} \tag{1.6}$$

$$L = A\ X_1^{\alpha}\ X_2^{\beta} \tag{1.7}$$

where F = Fuel input per generating unit when operated at capacity level in terms of BTU per hours;

C = Capital cost of equipment in constant 1947 dollars per generating unit;

L = Average number of employees during the year per generating unit;

X_1 = Average size of generating unit in MW;

X_2 = The number of generating units in the same plant.

The estimated values for α and β are significantly less than one, implying that fewer resources are necessary per unit of output with increases in the size of generating units and number of units in a power station.

Komiya did not reduce the labour variable to number of hours worked. Number of employees in his study thus does not reflect the true resource cost unless it can be assumed that the number of hours per worker was the same in all cases. Moreover, his data refer to full capacity plants, whereas the ESI, in practice, can hardly operate at a level of higher than 60 per cent capacity.[3]

The existence of economies of scale is also reported in studies made by Barzel (1964), Ling (1964), Galatin (1968) and Olson (1970). Olson's study covered the period from 1956 to 1965. He fitted a cost function as follows:

$$\log C = \sum_i \beta_i \log X_i \tag{1.8}$$

where i = 0, 1, 2, ..., 12;

C = average generating cost;

X_0 = constant;

X_1 = size of generating units;

X_2 = number of units per plant (Power station);

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3 There are variations in customers demand and load factor. Some plants are to be put on spinning reserve and some are operated only as standby.

X_3 = reciprocal of plant utilization i.e. $\frac{\text{capacity in KW X(8760)}}{\text{output in kwh}}$;

$X_4 - X_{12}$ = dummy variables representing dates of installation.

Olson finds cost elasticities with respect to X_1 and X_3 as represented by β_1 and β_3 to be 0.156 and 0.705 respectively and thus lends supports to the view held by Lomax that load factor was more important than size of plants in reducing cost. But the values of β_2 and $\beta_4 - \beta_{12}$ were not significant in his study, indicating that economies of scale occur more on unit level rather than at the level of the unit of generating equipment and that the impact of technology was not significant either.

Like Komiya, Olson also included both coal and non-coal generators in the study but his period of analysis was from 1956 to 1965. Thus his conclusions support the view held by Komiya that technological effects were insignificant in the post-war period but unlike Komiya he finds number of units per plant as insignificant.

Barzel used pooled cross-section data for the period from 1941 to 1959. His findings were similar to Komiya's i.e., average cost falls as plant size and load factor increases. He also finds that the decrease in cost was greatest for labour followed by fuel and capital respectively. Barzel considered only the generation cost and as such, his study is also subject to the same criticisms as the others. He did not reduce the nubmer of employees to number of hours worked nor did he consider the type of fuel used. The impact of technology also remained obscure.

Ling's (1964) study, which used time series data for 1938 to 1958, was based on data from ex ante engineering estimates which were not checked with ex post data. He did not consider the effect of technological change on cost either.

Galatin, who used time series data for the period from 1938 to 1953, reports that economies of scale existed in the ESI and technological improvement resulted in fuel savings over the years he studied.

None of the above studies seem to have taken note of the possibility of factor substitution in the ESI, which in turn might have affected cost. Some studies, such as Johnston (1960), justified this neglect with the opinion that "men are a poor substitute for coal in the generation of electricity and vice versa", without, however, submitting any evidence (Johnston, 1960, p. 51). It is also impossible to know from these studies how sensitive is the cost of electricity to changes in individual factor prices. As we shall see in later chapters, substitution possiblities between energy and other factors of production cannot just be assumed away.

It is worth reporting the attempt made by Johnston (1960) to separate the effects of new technology on costs from that of output. His study covered the period from 1927 to 1947. He first deflated the cost by a suitable factor price index to separate the price effect from the output effect. Then assuming technological improvement to take place in a linear fashion he used time (T) as an additional regressor along with output where the dependent variable is the cost. His regression results were:

$$\hat{Y} = 18.3 + .889\ X - .639\ T \tag{1.9}$$

where $\hat{Y}$ = estimated costs;

X = output; and

T = time

The large negative value for the coefficient of T suggests that technology was an important source of cost reduction over time. Johnston then computed actual deflated cost i.e., cost that would have been without the influence of technology as

$$\hat{Y} + .639\ T = Y^* \tag{1.10}$$

(where Y^* = actual deflated cost), and attributed the difference $Y^* - \hat{Y}$ to improvement in technology.

Like many previous studies, however, Johnston's model ignores the possibility of substitution between inputs and he did not recognise the possible collinearity of X and T (see footnotes 21-22, Section 2.2.4).

Nerlove's (1963) study is much more interesting in the sense that he tried to estimate the elasticity of substitution between factors though he found it difficult to estimate from the available data (Nerlove, 1963, p. 174). Although his main function involved the generation side of the firm, he provided an appendix showing that the prevalance of economies of scale in generation does not guarantee the same for the firm as a whole. However, he finds that

> "there is evidence of a marked degree of increasing returns to scale at the firm level; but the degree of returns to scale varies inversely with output and is considerably less, especially for large firms, than that previously estimated for individual plants". (Nerlove, 1963, p. 186).

Nerlove used cross-section data for 1955 when plants were smaller than those available today. Though his study was the pioneer in recognising the importance of estimating elasticities of substitution between factors and cost elasticity pertaining to the firm as a whole, Nerlove abstracted from the question of technological change. The impacts of capacity utilization, type of fuel and geographical locations were not considered either. However, his results are similar to those reported by Dhrymes and Kurz (1974) and Seitz (1971). Both these studies indicate that the magnitude of economies of scale diminishes as one moves from the smallest to largest and from the oldest to the newest plants. Again these studies did not recognise the importance of load factor in reducing cost and did not consider the firm as a whole.

It may be mentioned here that in a single plant study Nordim (1947) finds that marginal cost was an upward sloping straight line in a sample of 541 shifts in six months of 1941. His estimates were:

$$Y = 16.68 + .125\ X + .00439\ X^2 \qquad (1.11)$$

where Y = fuel cost for an eight hour period;

X = eight hours total output in per cent of capacity.

Nordim's study was concerned with one plant only and as such is not of much relevance to the modern grid system. Nevertheless, his study indicates that it is not always the case that fuel costs decrease as output increases. Lansing (1948) finds that the long run marginal cost of electricity generation was equal to long run average cost, thus implying constant returns to scale. Similar results were also reported by Johnston (1960).

A more recent cross-section study by Christensen and Greene (1976) finds that in 1970, only 34 per cent of electricity generated in the U.S. was produced by firms having substantial additional scale economies available and a number of firms were in a position where further expansion would cause diseconomies.

Christensen and Greene did not use load factor as an explicit variable in their model. The size of plant in their model was represented by quantity of electricity sold. To the extent that load factor and the number of plants per firm varied widely from firm to firm, their estimates of economies of scale are blurred by the impact of capacity utilisation and operational economies as distinct from scale economies. They did not estimate the marginal cost of electricity generation, probably because they were more concerned with the existence of scale economies than with pricing problems.

Christensen and Greene used the translog cost model pioneered by Christensen, Jorgenson and Lau (1973). This model will be discussed in detail in Chapter Two. Suffice it to say at this stage that this model is capable of explaining factor substitutability in an industry and of testing hypotheses such as constant returns to scale, concavity and homotheticity.[4]

Among the Australian studies on cost of electricity, McColl (1976) provided a comprehensive survey of unit cost in different states of Australia. The following table is reproduced from his Table 1.2 (McColl, 1976, p. 5) which represents the aggregate picture for Australia.

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4 The importance of the substitutability between energy and other inputs has been reinforced in the recent past by the growing concern about the future economic growth rate due to the oil price increase of 1973 and its aftermath. See Hudson, E.A. and D.W. Jorgenson, "U.S. Energy Policy and Economic Growth, 1975-2000", Bell Journal of Economics, Autumn, 1974, pp. 461-514.

TABLE 9

Average Unit Cost of Electricity, 1953-54 and 1972-73

Component of Costs	1953-54	1972-73 Current Prices		1972-73 1953-54 Prices	
	Cents	Cents	Index (1953-54 = 100)	Cents	Index (1953-54 = 100)
Fuel	0.64	0.23	36	0.12	19
Other working expenses	0.70	0.85	121	0.45	53
Sub-total	1.34	1.08	81	0.57	43
Interest	0.25	0.50	200	0.26	104
Depreciation allowances, etc.	0.21	0.39	186	0.21	100
Total	1.81	1.97	109	1.04	57

Source: McColl (1976), p. 5.

This table, as well as other tables which McColl presented with respect to individual states, is based on the accounting costs reported by the supply authorities. Extreme caution is required in comparing costs pertaining to different utilities or comparing those of two periods pertaining to the same utility. Not only do different utilities have different criteria on the basis of which depreciation, interest and other charges are deducted, but also cost is likely to be different at different load factor for an individual plant as well as for the system as a whole. Moreover, the types of generators used by different utilities differ widely because of local variations in availability of resources and environmental conditions (e.g., hydroelectricity in Tasmania, higher grade coal in New South Wales and lower grade coal in South Australia).

Nevertheless, McColl's findings clearly indicate that the

Australian ESI had substantial economies of scale over the time period considered (1953-72). The following table, which is based on his table 3.1, (p. 31) shows that despite the significant rise in general price level, cost per KW of generating equipment declined remarkably over the period from 1953 to 1976 as the size of new plant increased.[5]

TABLE 10

Capital Cost of Generating Stations: South Australia

	Size of Units MW	Total Capacity MW	Date of Commission	Cost per KW ($)
Playford A	30	90	1954-57	233
Torrens Island B	200	400	1976	125

Source: Adapted from McColl (1976), p. 31.

5 Apart from the difficulty of separating the impact of embodied technology from that of size, the mere reduction in cost per KW does not guarantee in itself the same reduction in cost of electricity supplied per kwh. Whether labour and fuel required per kwh is the same as before and more importantly, whether the system load factor improves or deteriorates with installation of a larger plant has also to be considered.

A summary of the econometric results discussed is tabulated below.

TABLE 11

Summary of Econometric Estimates of Cost Elasticities in the Electricity Supply Industry

	Cost		Elasticities Quantity/ Plant Size	Load Factor	Units Per Plant
1. Lomax (1952)	Operation and Maintenance		-.120 -.150	-.410 -.700	- -
2. Johnston (1960)	Generation		.890	-	-
3. Komiya (1962)	Generation:	Fuel = Labour = Capital =	.852 .606 .846	- - -	- .263 .095
4. Nerlove (1963)	Generation		.342 to .592	-	-
5. Barzel (1964)	Generation:	Fuel = Labour = Capital =	.896 .626 .815	.848 .169 .116	- - -
6. Ling (1964)	Generation		-.169	-1.183 to -1.314	
7. Galatin (1968)	Generation*:	Fuel = Labour = C/N =	$25087.1\ X^{-1}$ $.837\ X$ $137.8\ X$	$96591.2\ (CU)^{-1}$ $.33\ (CP)^{-1}$ -	- 20.644N α**
8. Olson (1970)	Generation		.156	.705	-
9. Christensen and Greene (1976)	Generation		.649 to .924	-	-

* For 1945-50 only,
Fuel = BTU/kwh;
X = Size of turbine in MW;
N = Number of unit per plant;
C = total capital cost of the plant in $1,000;
CU = capacity utilization per unit (turbine) in per cent;
CP = capacity utilization per plant in per cent.

** $\alpha = (5372.9\ N - 3437\ N^2 + 462.7\ N^3)$

The question of whether or not an ESI in a particular area is enjoying economies of scale cannot readily be answered without empirical investigation. Moreover, though an ESI may enjoy scale economies in one of its operations, it cannot be concluded that the industry enjoys the same in its overall function of supplying electricity. None of the above studies has examined the cost conditions of the ESI as a whole, which is very important in the evaluation of the pricing policy of the industry.

In Australia, no study has yet been made on the factor substitutability in the ESI nor any study on the cost elasticity with respect to factor prices. Estimation of class marginal cost of electricity supply has remained totally unexplored. It is felt that the identification of differences in marginal cost of supplying electricity to residential, industrial and commercial customers is too important to be left unattended. An attempt is made in this study to narrow this gap in knowledge, so that proper evaluation of inter class price differentials in ETSA can be made.

In the following chapter, we shall present our cost estimates for ETSA.

CHAPTER TWO

ECONOMIES OF SCALE, MARGINAL COST AND FACTOR SUBSTITUTION IN ETSA

SECTION ONE: THE MODEL

Introduction

The determination of scale economies in the electricity supply industry (ESI) is important for at least two reasons: first, the natural monopoly argument for public regulation or ownership of the ESI is based on the assumed existence of substantial scale economies; and, second, in the wake of the world-wide energy price rise in the early seventies, it seems to have been generally accepted that electricity prices are likely to follow the same upward trend. But the extent to which prices need to be revised upward and/or output to grow in order to capture further scale economies depends on the existing unexploited economies of scale in the industry. It also depends upon the cost elasticity with respect to fuel prices (factor prices). This last factor, depends, inter alia on the substitutability between energy groups, between energy and labour and between energy and capital. Clearly, the greater is the possibility of substitution between energy and other inputs, the higher will be the ESI's price elasticity of demand for fuel and the lower will be the impact of fuel price changes on its total cost. It is therefore important to explore the possibility of substitution between energy and other inputs in the ESI of South Australia.

Scale economies and marginal cost of supply are interdependent. The determination of marginal cost, especially the interclass differences in marginal cost, is very important in an evaluation of pricing policy.

As discussed in Chapter One, previous studies are inconclusive as regards the presence and the extent of scale economies in the ESI. Although a considerable literature exists on the substitutability between energy and other inputs in the industrial sector as a whole, studies relating to the ESI in particular are few and far between.

The pioneering attempt to estimate factor substitutability in the ESI was that of Nerlove (1963). He considered the model suggested by Arrow, Minhas, Chenery and Solow (AMCS, 1961) to be superior to the generalised Cobb-Douglas form since the former is not restricted to unitary elasticity of substitution as is the latter. But he obtained the same elasticity of substitution between any pair of factors (i.e., labour-capital and fuel-capital) - a result with which he was not satisfied (Nerlove, 1963, p. 174).

Among the few other studies, that of Christensen and Greene (1976) is noteworthy. They used the translog cost function pioneered by Christensen, Jorgenson and Lau (1973) to estimate economies of scale and factor substitution in electricity generation in the United States in 1955 and in 1970. Other studies using the same form of cost function are by Griffin (1977) and Halvorsen (1978). However, these two studies concentrated on the substitution possibility within the energy group rather than between energy and other inputs.

The translog cost function is superior to either that developed by AMCS (1961) which presupposes constant returns to scale, or Cobb-Douglas which presupposes a unitary elasticity of substitution between any pair of factors. These restrictions are not necessary in the translog function which we, therefore, prefer to use in the present study.

In the following section, the translog model is presented. This will be followed by discussion of the data used and the results obtained.

2.1 The Model

In formulating our cost function, we shall follow Christensen and Greene's (1976) translog functional form. The fundamental proposition of this model is that corresponding to any production function such as

$$Q = f(K, L, E) \tag{2.1}$$

where Q = quantity of output produced; and

K, L, E represent capital, labour and energy inputs

there exists a cost function which represents the essential characteristics of the production technology. Thus the above production function can be represented by:

$$C = C(P_K, P_L, P_E) \tag{2.2}$$

where C = total cost of production; and P = input price.

This dual relationship between the cost and the production function was first demonstrated by Shephard (1953). The translog cost function "represent the production frontier by functions that are quadratic in the logarithms of the quantities of inputs and outputs" (Christensen, Jorgenson and Lau, 1973, p. 28). The function is assumed to be non-negative, non-decreasing and positively linear homogeneous.[1] It is concave in factor prices for each given produceable output vector, and positive for non-zero output with continuous first and second degree derivatives. Note that this is a long run cost function in which capital input is free to vary to produce the required output at minimum cost.

Though we use Christensen and Greene's model, our cost equation is substantially different from theirs. Christensen and Greene used U.S. cross section data for the years 1955 and 1970. The present study uses time series data for one utility only-ETSA. Moreover, we estimate the total cost for all different phases of electricity supply - that is the sum of generation, transmission and distribution costs - rather than for generation alone. We also estimate marginal costs for all three major consumer classes namely residential, industrial and commercial. Further, we have introduced load factor in an attempt to separate the impact on cost of the level of output (size of plants) from that of intensity of use.

Christensen and Greene specified their model as given below:

$$\log C = A + \Sigma\, \alpha_i \log Y_i + \tfrac{1}{2} \sum_{i=1}^{m} \sum_{j=1}^{m} \alpha_{ij} \log Y_i \log Y_j \qquad (2.3)$$

where C = cost of electricity generation;

Y = explanatory variables measuring electricity output or a factor price i.e., $i = 1, 2, \ldots, m$ and $j = 1, 2, \ldots, m$.

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1 The cost function is homogeneous of degree one in factor prices. That is, for a fixed level of output, the total cost must increase proportionately when all prices increase proportionately. See Christensen and Greene (1976), p. 660.

Our cost function is given by:

$$\log C = \alpha_o + \alpha_q \log Q + \alpha_r \log R + \alpha_w \log W + \alpha_f \log F + \alpha_\ell \log L$$

$$+ \tfrac{1}{2}\alpha_{qq} \log Q \log Q + \alpha_{qr} \log Q \log R + \alpha_{qw} \log Q \log W$$

$$+ \alpha_{qf} \log Q \log F \log F + \alpha_{q\ell} \log Q \log L$$

$$+ \tfrac{1}{2}\alpha_{rr} \log R \log R + \alpha_{rw} \log R \log W + \alpha_{rf} \log R \log F + \alpha_{r\ell} \log R \log L$$

$$+ \tfrac{1}{2}\alpha_{ww} \log W \log W + \alpha_{wf} \log W \log F + \alpha_{w\ell} \log W \log L$$

$$+ \tfrac{1}{2}\alpha_{ff} \log F \log F + \alpha_{f\ell} \log F \log L$$

$$+ \tfrac{1}{2}\alpha_{\ell\ell} \log L \log L + U \qquad (2.4)^2$$

where C = total cost of supplying electricity;

Q = quantity of electricity generated (or sold);

R = index of capital rentals;

W = index of wages in the ESI;

F = index of fuel prices;

L = load factor; and

α_o, α_i, α_{ii} and α_{ij} are parameters to be estimated,

where i, j = q, r, w, f and ℓ.

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2 A time trend representing technological change was introduced initially but subsequently dropped due to the problem of multicollinearity between Q and T. Further discussion on this is to be found in Section 2.2.4. The variation in number of generating units per power station has not been significant in ETSA. The operational economies (diseconomies) arising out of any such variation are assumed to be represented by the time trend.

The function is a second degree approximation. Partial differentiation of the above function reveals the following symmetry conditions:

$$\frac{\partial^2 \log C}{\partial \log P_i \log P_j} = \alpha_{ij} = \alpha_{ji} \qquad i,j = r, w, f \tag{2.5}$$

This reduces the number of parameters to be estimated and thus increases the number of degrees of freedom.

Further, the assumption of linear homogeneity with respect to input prices required for a well-behaved cost function implies the following restrictions:

$$\sum_{i=r}^{f} \alpha_i = 1 \tag{2.6}$$

$$\sum_{i=r}^{f} \alpha_{ij} = \Sigma\, \alpha_{ji} = 0 \tag{2.7}$$

for i, j = r, w and f.

The cost function specified above is non-homothetic and may have non-constant returns to scale (Q). We shall call this model A. It is distinct from studies such as Uri (1979, 1982) and William and Laumas (1981) in which a homothetic cost function is assumed. These studies also implicitly assume constant returns to scale.

A homothetic cost function means not only that all the factor prices are separable among themselves but also that the factors and output are separable.[3] Thus an additional parameter restriction

$$\alpha_{qi} = 0 \tag{2.8}$$

would be required. On the other hand, the constant returns to scale (homogeneity) restriction can be imposed by additionally assuming

$$\alpha_{qq} = 0 \tag{2.9}$$

In order to examine whether the assumption of homotheticity and that of constant returns to scale are realistic in the present case, we impose restriction 2.8 without and with 2.9 on top of those given in equations 2.6 and 2.7 and call them models B and C respectively.

The restrictions for unitary elasticity of substitution between factors can be imposed by assuming:

$$\alpha_{ij} = 0 \tag{2.10}$$

so that the function is Cobb-Douglas. The function with restriction 2.10 along with models A, B and C will be called AD, BD and CD respectively.

Whether models B and C represent the cost conditions in ETSA can be

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3 The separability may be of three types: global, strong and weak. If the coefficients of all the cross terms are zero i.e., the function is Cobb-Douglas, the separability is called global. Strong separability requires that the cross terms of the individual inputs be equal to zero. A necessary and sufficient condition for two inputs to be weakly separable is that the marginal rate of substitution between them is independent of the quantities of other inputs. See Turnovsky and Donnelly (1982) and Berndt and Christensen (1976).

examined by estimating model A and looking at the significance of the coefficients obtained for the cross terms of Q with input prices and with Q itself. If the cross terms appear to be insignificant then the models are B or C accordingly. Similarly, one can examine whether the function is Cobb-Douglas by looking at the t-statistics for the coefficients of cross-price terms. If they are insignificant, the models are AD, BD or CD according to whether the function was non-homoethetic and non-constant returns to scale, homothetic and non-constant returns to scale or homothetic and constant returns to scale respectively.[4]

The above hypotheses (restrictions on model A) can also be tested by estimating models B, C, AD, BD and CD and then employing the likelihood ratio or SIGMA test which is given by:

$$-2 \log \lambda = N(\log |\hat{\Omega}_r| - \log |\hat{\Omega}_u|) \qquad (2.11)$$

where $\hat{\Omega}_r$ and $\hat{\Omega}_u$ are the estimates of the restricted and unrestricted disturbance covariance matrix and N is the number of observations. These statistics are asymtotically distributed as Chi-square with degrees of freedom equal to the number of independent restrictions being imposed (Pyndick, 1979, p. 171). If the estimated value of equation (2.11) is greater than the theoretical value of Chi-square, the hypothesis is rejected at some significance level.

The restrictions 2.8 and 2.10 are considered to be severe on the Allen partial elasticity of substitution between pairs of inputs. Under

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4 It should be recognised, however, that t-statistics may appear insignificant purely because of measurement error.

these assumptions, the elasticity of substitution between energy and labour and between energy and capital must be the same. Nerlove (1963) and Magnus (1979) among others consider this to be 'highly implausible'. However, the evidence on this issue seems to be inconclusive. Berndt and Wood (1975), Hudson and Jorgenson (1974), Duncan and Binswanger (1976), Fuss (1977) and Magnus (1979) found energy and labour to be substitutes and energy and capital to be complements. On the other hand, Griffin and Gregory (1976), Pindyck (1979), Halvorsen and Ford (1979), Ozatalay (1979) and Turnovsky, Folie and Ulph (1982) found energy and capital to be substitutes.

Because of this conflicting evidence, the use of the translog model seems to be appropriate, because it permits an examination of the hypotheses concerning returns to scale and elasticities of substitution.

A Hicks-neutral technology is assumed, implying that the share equations are not affected by technological change, which, therefore, can be ignored (see Magnus and Woodland, 1981, p. 8). This does not seem to be an unrealistic assumption in the context of the present study.

Despite the fact that the differences in energy requirement per unit of electricity generated (from all three sources: oil, gas and coal) remained by and large the same, the share of coal in total generation by ETSA came down from 97 per cent in 1950 to 60 per cent in 1970 through to 31 per cent in 1980. The share of oil fell from 25 per cent in 1970 to only 2 per cent in 1980. In contrast, the share of gas rose from almost nil in 1970 to 67 per cent in 1980 (see Table 6). Its share further increased to 75 per cent in 1981 and to 80 per cent in 1982 (see ETSA, Annual Report, 1982, p. 2). It is important to note that this switch over to gas from coal is not due to any technological change in favour of gas. The type of steam turbine (fuelled by gas) installed by ETSA in 1980 was available in the market as early as in 1952. Moreover, the cost of coal fired plants is almost the same as oil fired plants (Brian and Schuyer, 1981, p. 118) and does not exceed the cost of gas fired plants by more than 25 per cent (Griffin, 1977, p. 757). Thus the choice among various forms of energy apparently reflects ETSA's response to changes in the relative price and availability of alternative fuels rather than to technological change which favours one fuel relative to others.

In the next sub-section, we shall discuss the modus operandi of determining shares of various inputs in the total cost of supply. This is important, since we are interested in the cost elasticities with respect to particular input prices and in the possibility of substitution between inputs.

2.1.1 The Cost Share Equations

Shephard (1953) demonstrated that the share of an input in the total cost of production can be determined in the same way as its share in the total product. This is known as Shephard's Lemma.[5] The Lemma states that

$$\partial C/\partial P_i = X_i$$

5 "Part of the duality between cost and production functions is based on the equality between derivatives of the cost function with respect to price and factor demands conditional on output". D.W. Jorgenson in Forward to the R.W. Shephard's book, Cost and Production Function, (1953), reprinted as Lecture Notes in Economics and Mathematical Systems, Springer-Verlag, New York, 1981.

where P_i is the price for input X_i.

Applying this to the translog cost function, we get:

$$\frac{\partial \log C}{\partial \log P_i} = \frac{\partial C}{\partial P_i} \cdot \frac{P_i}{C} = \frac{X_i P_i}{C} = S_i \tag{2.12}$$

where S_i is the share component of input X_i.

Thus we have a system of n cost share equations corresponding to the translog cost function in equation 2.4 above.

From equation 2.4 one can easily determine the ratio of a particular cost component with respect to the total cost. Thus the ratio of capital cost to total cost (S_r) can be read from the elasticity of cost with respect to capital rental (R):

$$S_r = \frac{\partial \log C}{\partial \log R} = \alpha_r + \alpha_{qr}\log Q + \alpha_{rr}\log R + \alpha_{rw}\log W$$

$$+ \alpha_{rf}\log F + \alpha_{r\ell}\log L + U \tag{2.13}$$

The ratio of labour cost to total cost (S_w) will be given by:

$$S_w = \frac{\partial \log C}{\partial \log W} = \alpha_w + \alpha_{qw}\log Q + \alpha_{rw}\log R + \alpha_{ww}\log W$$

$$+ \alpha_{fw}\log F + \alpha_{w\ell}\log L + U \tag{2.14}$$

The share of fuel cost in the total cost (S_f) will be given by:

$$S_f = \frac{\partial \log C}{\partial \log F} = \alpha_f + \alpha_{qf}\log Q + \alpha_{rf}\log R + \alpha_{wf}\log W$$

$$+ \alpha_{ff}\log F + \alpha_{f\ell}\log L + U \qquad (2.15)$$

The parameter restrictions for linear homogeneity for the above three equations as well as in equation 2.4 will be as follows:

$$\alpha_r + \alpha_w + \alpha_f = 1 \qquad (2.16)$$

$$\alpha_{qr} + \alpha_{qw} + \alpha_{qf} = 0 \qquad (2.17)$$

$$\alpha_{rr} + \alpha_{rw} + \alpha_{rf} = 0 \qquad (2.18)$$

$$\alpha_{rw} + \alpha_{ww} + \alpha_{wf} = 0 \qquad (2.19)$$

$$\alpha_{rf} + \alpha_{wf} + \alpha_{ff} = 0 \qquad (2.20)$$

The above restrictions imply that for a given quantity of electricity produced (sold) the total cost must increase proportionately with increases in the factor prices.

The parameters of the cost function can be estimated more efficiently if the cost function and the share equations are estimated jointly. Because the share equations are derived from the cost function, they add no new parameters to be estimated. Further, joint estimation permits imposition of the restrictions that a given parameter has the same value in the cost function as well as in the share equation. The use of this restriction is particularly important in maintaining concavity with respect to input price for the cost function. It should be noted that the assumption of linear homogeneity in factor prices for the cost function establishes a linear dependence among the share equations, i.e.,

$$\sum_{i=1}^{n} S_i = 1 \tag{2.21}$$

Since the cost shares necessarily sum to unity, the sum of the U's in equations 2.13 - 2.15 must be zero at each observation and the disturbance covariance matrix is singular. Thus one equation must be dropped from Zellner's system (Halvorsen, 1978, p. 79). Studies have shown that it does not matter which share equation is dropped (see Barten, 1969). It is also evident from equations 2.18 - 2.20, that the parameters of any dropped equation can be estimated from the remaining equations. Thus, if we decide to drop equation 2.15, the remaining two equations can be rewritten as follows.

Re-arranging equations 2.18 - 2.20,

$$\alpha_{rr} = - \alpha_{rw} - \alpha_{rf}$$

$$\alpha_{ww} = - \alpha_{rw} - \alpha_{wf} \tag{2.22}$$

Equation 2.13 may be rewritten as

$$S_r = \alpha_r + \alpha_{rq}\log Q + \alpha_{r\ell}\log L + \alpha_{rw}(\log W - \log R) + \alpha_{fr}(\log F - \log R) + U \tag{2.23}$$

Equation 2.14 can be rewritten as

$$S_w = \alpha_w + \alpha_{wq}\log Q + \alpha_{w\ell}\log L + \alpha_{rw}(\log R - \log W) + \alpha_{wf}(\log F - \log W) + U \tag{2.24}$$

Thus a system of three equations can produce the parameters of all the equations including total cost and cost shares.

2.1.2 Economies of Scale

Scale economies can be determined from the cost elasticity with respect to the quantity of electricity generated (supplied). If the first derivative of equation 2.4 with respect to quantity of electricity is less than one, then scale economies exist; diseconomies of scale exist when the first derivative exceeds one; and when the elasticity is equal to one, there are constant returns to scale. The formulae for scale economies for models A-D are presented in Table 12.

TABLE 12

Scale Economies for Models A to D

Model A and AD	$= 1 - (\alpha_q + \alpha_{qq}\log Q + \Sigma_i \alpha_{qi}\log P_i)$
Model B and BD	$= 1 - (\alpha_q + \alpha_{qq}\log Q)$
Model C and CD	$= 1 - \alpha_q$

It should be noted, however, that defining scale economies as above suppresses the distinction between reduction in cost due to the use of a larger plant and that due to other factors such as improved technology or density of customers. More discussion of the problems associated with the estimation of scale economies is to be found in Section Two.

The estimation of scale economies is directly connected with that of marginal cost which we discuss in the following sub-section. The issues raised in connection with the estimation of marginal cost are also relevant for scale economies.

2.1.3 Marginal Cost of Supplying Electricity

The marginal cost of supplying electricity can be determined from the elasticity of cost with respect to quantity times the average cost. This is given in the following equation:

$$\frac{\partial C}{\partial Q} = (\alpha_q + \alpha_{qq}\log Q + \alpha_{qr}\log R + \alpha_{qw}\log W$$

$$+ \alpha_{qf}\log F + \alpha_{q\ell}\log L)\ (C/Q) \tag{2.25}$$

It should be noted that the quantity of electricity supplied is not the same as the quantity generated. Strictly speaking the marginal cost should refer to the quantity supplied, to account for the quantity lost in transmission and distribution. But the fuel price is relevant only to the quantity generated, as the transmission and distribution do not require any fuel. A way out of this difficulty would be to estimate the marginal cost of generation, transmission and distribution separately and use the relevant variables for the respective spheres of activities. Unfortunately, no such disaggregated data are available. We are forced, therefore, to use the cost figures aggregated over all phases of activities, namely generation, transmission and distribution. However, the cost of transmission and distribution constitute only a small fraction of the total cost and in the ETSA system they did not exceed 13 per cent of total cost in 1980. They were a little over 12 per cent in 1950 and 11 per cent in 1960 (see ETSA Annual Reports). Under these circumstances, it seems reasonable to assume that the results obtained on the basis of aggregated cost figures will not be much different from those of the disaggregated data.[6] Marginal cost in the present study is computed separately on the basis of both quantity generated and quantity sold.

One needs to be cautious, however, in interpreting the term marginal cost in the ESI, since a small variation in quantity of output (kwh) may not change the total cost at all (thus implying MC = 0). Once a plant is in operation, certain costs have to be incurred irrespective of the quantity sold. To the extent that demand falls short of capacity production, a quantity of electricity is wasted. Thus though a unit of electricity (in terms of kwh) is important for revenue purposes, it is not so important for cost purposes. However, the ratio of peak demand to average demand in a system determines the system load factor and the capacity factor at which a plant is operating.[7] A higher capacity factor is associated with a higher heat rate, implying lower energy requirements per kwh generated. Further, a higher system load factor

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6 Ling (1964) concludes that "since transmission costs in general, amount to only 10 per cent of the investment cost ... variation of the transmission cost ... is unlikely to have material effects on the general contour of the cost function for generation and transmission combined" (p. 83).

7 See glossary of terms for definition of capacity factor and load factor. Recall that the capacity of generating plants is measured in terms of MW (or KW). A one MW plant will generate 1,000 kwh in one hour, if operated at 100 per cent capacity. Normal capacity factor is around 50-60 per cent (see McColl, 1976, p. 55).

means that individual plants run at full capacity for longer time. It also determines the need for future capacity build-up against a given rate of growth for electricity demand. It is in this way that these two factors affect the cost.

Moreover, if demand is skewed over a particular point of time it may be necessary for the utility to bring some of its inefficient plants back into operation, thereby raising the marginal cost.

Thus, though the cost is not affected by a small change in quantity generated (say, a few hundred kwh), it is certainly influenced when the change is significant. In our model, we define Q as million kwh (gwh), (total cost also is expressed in millions of dollars), so that the marginal cost we estimate is the marginal cost averaged over a million kwh.

The results are given in sub-section 2.2.1. Before we reach that point, however, discussion of the methodology for estimating elasticities is appropriate.

2.1.4 Factor Substitutions

Uzawa (1962) has shown that the Allen partial elasticity of substitution between two inputs can be estimated from the following equation:

$$\sigma_{ij} = \frac{C\,C_{ij}}{C_i C_j} \qquad (2.26)$$

where $$C_{ij} = \frac{\partial^2 C}{\partial P_i \partial P_j}$$

and $$C_i = \frac{\partial C}{\partial P_i}$$

For the translog cost function this is given by:

$$\sigma_{ij} = \frac{\alpha_{ij} + S_i S_j}{S_i S_j} \tag{2.27}$$

where $i \neq j$ $\quad$ $i, j = r, w, f$; and

$$\sigma_{ij} = \sigma_{ji}$$

The cross price elasticity is given by:

$$\eta_{ij} = \sigma_{ij} S_j = \frac{\alpha_{ij} + S_i S_j}{S_i} \tag{2.28}$$

where $\eta_{ij} \neq \eta_{ji}$

The own price elasticity is given by:

$$\eta_{ii} = \sigma_{ii} S_i \tag{2.29}$$

where $\quad \sigma_{ii} = \dfrac{\alpha_{ii} + S_i^2 - S_i}{S_i^2}$

It should be noted that in the Cobb-Douglas production function where the elasticity of substitution between two factors is assumed equal to one, the α_{ij} in equation 2.27 is restricted to zero.

With the above delineation of the mathematical tools, we are now in a position to estimate the marginal cost of supplying electricity, scale economies and factor substitutability in the ESI of South Australia. In the next sub-section, we shall consider the data to be used in the above equations.

2.1.5 The Data

We require data on the total cost of supplying electricity, the quantity of electricity generated, and prices of capital, labour and the primary sources of energy used. The time span considered for ETSA is 31 years from 1950 to 1980.

Among the four sets of data required, the estimation of the price of capital and the share of capital in the total product is by far the most difficult and controversial. In measuring the capital stock for the present study, we have followed the widely accepted perpetual inventory method pioneered by Goldsmith.[8] The method is represented by:

$$K_t = I_t + (1 - d)\ K_{t-1} \qquad (2.30)$$

where K_t = capital stock at the year t;

I_t = volume of investment during year t;

d = depreciation rate.

The main difficulty with the perpetual inventory method lies in measurement of the original capital stock. However, if one can go back far enough, any reasonable amount of stock is sufficient to start with. This is because the starting stock is ultimately irrelevant because of depreciation. Fortunately, since ETSA was established in 1946, an annual balance sheet showing the value of fixed assets minus depreciation and the provision for depreciation are published each year in the annual reports. However, it appears that in making deductions for depreciation, ETSA has not followed any particular rule and the

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8 See Garland and Goldsmith (1959), pp. 323-64.

percentage deducted in any year is apparently unsystematic.

One difficult issue concerns the appropriate rate of depreciation. The problem is even more complex in the electricity supply industry where the merit order of generating equipment (to operate at base loads) changes continuously. As the generating equipment ages and becomes relatively inefficient, it is removed from baseload generation and is used to meet either peak load demand or intermediate loads. This equipment is discarded as soon as it is no longer needed to meet the expected peakload demand.

An important question in this regard is 'what does the depreciation account for'? There seems to be an agreement among economists that it accounts for the lost capacity of the equipment used in production. Economists are also unanimous in the view that the depreciation must be in real terms i.e., the changing prices of equipment must be taken into consideration (see Clark, 1970, p. 450). Thus the depreciation should be on the 'replacement cost accounting' basis rather than on the historical cost basis. However, the economically useful life of an asset depends, among other things, on the rate of technological innovation, which is very difficult to assess <u>ex ante</u>. It also depends on the scale at which a system has to operate.

Thus the determination of the depreciation rate is most complicated, the appropriate rate being decided by the collective experience of economists, accountants and tax officials. While agreement is not forthcoming, there seems to have emerged three recognised principles for depreciation. They are: straightline depreciation, diminishing balance and one horse depreciation. Under the first method, a uniform amount is deducted in each year of the assumed lifetime of the asset. The second method applies a uniform percentage reduction each year to the diminishing balance and the third refers to a method whereby the asset is assumed to retain its entire capacity throughout its lifetime and then suddenly disappears (Clark, 1970, p. 451).

For the purpose of the present study, two depreciation rates are assumed: one following Clark (1970) and Hawkins (1977) at 12 per cent and another, following Magnus (1979) at 6 per cent. In both cases, the diminishing balance method is followed (see also p. 76). The use of two depreciation rates will provide scope to examine the sensitivity of results to differences in the rate of depreciation.

The price of capital service has been estimated on the basis of the formula employed by Christensen and Jorgenson (1969). The method has gained wide acceptance because it is based on the current price of the investment goods rather than on the actual price paid for the capital assets. It is assumed that the investment price of an asset is equal to the present value of its expected future service. The formula is reproduced below:

$$PK_t = (P_{it-1})\, r + (P_{it})\, d - (P_{it} - P_{it-1}) \qquad (2.31)$$

where PK_t = price index of capital service at time t;

P_{it} = price index of investment goods at time t;

r = discount rate;

d = depreciation rate.

The last term of the right hand side of the above equation stands for capital gains, if any. Whether enterpreneurs anticipate capital gain when they consider purchasing capital equipment is an empirical question. But it seems unlikely in the case of a public monopoly such as ETSA. It is, therefore, assumed in the present study that ETSA ignores capital gains when they decide to purchase a capital good and this term is dropped in calculating the value of capital service in ETSA.

We have assumed two different depreciation rates and as such we have two different data sets for the value of capital service (PK) and the share of capital in the total cost (SK). We have denoted these data sets as set one and set two. However, in these two sets the discount rate is given by equation 2.32 as described below.

The determination of an appropriate rate of discount is very difficult and contentious. The appropriate rate may vary from country to country and from time to time.[9] A compromise rate may be determined by multiplying the social time preference rate by the prevailing rate of inflation. But then, it is very difficult to determine what is the correct social time preference rate. Magnus (1979) has chosen a constant 3 per cent time preference rate for the Netherlands over the period from 1950 to 1976.

If we assume the same rate for ETSA, the discount rate may be worked out by applying the following formula.

$$(1 + r) = (1 + i)\ (1 + \dot{p}) \qquad (2.32)$$

where i = time preference rate (assumed constant over time at 3 per cent);

$\dot{p}$ = inflation rate in South Australia;

r = discount rate for period t.

9 A good summary of discussion on this may be found in McColl (1976, pp. 91-93).

In the case of ETSA, however, a 3 per cent real rate of interest seems to be too high. From 1950 to 1980 the mean difference between the marginal rate of interest paid by ETSA and the rate of inflation in South Australia appears to be not significantly different from zero.[10] Thus it seems that an assumption of a nominal discount rate equal to the rate of inflation would not be unrealistic for ETSA. If we calculate equation 2.31 on the basis of this last assumption along with a depreciation rate equal to 12 per cent (Clark, 1970; Hawkins, 1977) and 6 per cent (Magnus, 1979) as assumed earlier, we have two more data sets for PK and SK which we call data sets three and four.

The price index for investment goods has been obtained from the Australian Bureau of Statistics and for earlier years from Haig (1966). Haig reported the prices of private fixed investment for the period from 1948-49 to 1959-60 both at current and constant prices. The constant price was given at 1953-54 prices. The ABS produced price data for the period from 1959-60 to 1974-75 at current as well as constant 1966-67 prices. Since 1974-75, the ABS reported prices at 1974-75 prices. All these prices were converted to 1966-67 prices and it is this series which is used in the present study.

The share of wages in the total cost (SL) is the total wages and salaries bill of ETSA plus the employer's contribution to superannuation. These are estimated from the ETSA Annual Reports. A wage index for ETSA was then constructed taking the ratio of SL to the number of persons employed. The ETSA's wage index so constructed was compared with the general manufacturing wage index. Both indices appeared to be moving at similar rates.

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10 The marginal rate is the highest rate of interest paid by ETSA in any year for new borrowings.

Another important matter which deserves attention is the aggregation problem. By aggregating all categories of labour into one measure, man-years of labour, we are inviting criticism on two separate counts: differences in quality are ignored and the existence of the conditions for proper aggregation of factors is called into question. Regarding the former, Griliches (1957, pp. 14-15) observes:

> "Higher quality labor will be usually associated with larger capital inputs, because it will increase the marginal productivity of capital ... Also, it is plausible that quality is a substitute for quantity, and that holding capital constant, firms with higher quality labor will use less 'labor' as it is conventionally measured. Hence it is plausible ... that we shall overestimate returns to capital and underestimate returns to labor".

However, if we can reasonably assume that the wages paid to employees reflect the labour productivity in ETSA, then the problem will not be as acute as it appears at first sight, given that we are estimating cost function rather than production function directly.

Among the conditions for proper aggregation of input variables are:

(i) that the rate of substitution between the different types of factors being aggregated is independent of the quantity of other factors used with them; and

(ii) that the marginal rate of substitution between any two types of the factors being aggregated is constant (Nadiri, 1970, p. 1144).

It is questionable whether these conditions are met in practice and here again, the solution lies in more and better data.

The fuel price index that has been constructed for ETSA requires elaboration. The price for individual fuels paid by ETSA may seem inappropriate except for petroleum products, because the South Australian coal fields are owned and operated by ETSA and the major portion of the coal produced is consumed by ETSA itself in its generation of electricity. Thus the imputed price for coal may not reflect the resource cost. Moreover, the natural gas burned by ETSA since 1970 is purchased from the Cooper Basin field (Santos Ltd.) under a long term contract. Since ETSA purchases about 70 per cent of gas piped to Adelaide, its role was critical and it is doubtful whether the pipeline to Adelaide would have been built without this source of demand. Under these circumstances, it is not unlikely that ETSA enjoys some monopsony margin in its consumption of natural gas. These distortions in the input market raise some doubt about the applicability of our model to the cost conditions of ETSA. This is because the fundamental assumption of our model is cost minimisation which is supposed to exist in the environment of a competitive market for inputs.

Under competitive conditions, the inputs are used in such a way that the ratio of their marginal products is equal to that of their prices. This ensures the duality between cost and production functions (equation 2.12). If the entrepreneur can manipulate one or more input prices, then the changes in prices will not exactly represent the changes in the input combination. However, an entrepreneur with monopoly elements will not necessarily be indifferent to the cost minimization principles. Moreover, it is doubtful whether the local coal used by ETSA at the mine's head could fetch any price more than the value imputed by ETSA. These are low grade coals the economic use of which can be obtained only at the mines head with especially built burners for them. It can therefore, be assumed that the imputed price of coal does represent the resource cost. In spite of the presence of monopoly elements, ETSA has always responded to the economics of the relative price of fuel, at least in the long run. For instance, despite its monopoly interest in the Leigh Creek coal, the Torrens Island Power station of 1280 MW built in 1967 was originally designed to use oil because oil was cheaper than coal at that time. Later, the project was re-designed to use natural gas when a relatively lower price was offered. The structural changes over time in the fuel demand of ETSA have been presented in Table 6. It appears from the table that there has been substantial inter-fuel substitution in ETSA since 1950 and the proportion of a particular type of fuel seems to have largely been determined by market forces.

The prices of individual fuels used by ETSA are not available. The fuel cost index for the present study has been constructed from the total cost of fuel and the total quantity of fuel (in joules) given in the ETSA annual reports. It is assumed that the cost per gigajoule (GJ) of energy incurred in a year is the outcome of long term planning to minimize cost.

In the absence of individual fuel prices paid by ETSA, the elasticity of substitution between energy types can only be estimated by using individual energy price indices for Australia as a whole. However, the validity of such an exercise depends on whether the energy input can be considered separable from other inputs. As we shall see later, the separability assumption is not valid in the present case. However, this does not affect the validity of our estimates of the substitutability between energy and other inputs.

The data on the total quantity of electricity generated and quantity sold were obtained from the ETSA Annual Reports.

The total cost used in our equation is the sum total of the shares of capital service, labour and fuel used by ETSA. The statistical characteristics of the data sets used are presented in Table 13. The estimated results are presented in the next section.

TABLE 13

Statistical Characteristics of the Data Used in the Translog Cost Model

	Mean*	Standard Deviation
Total Cost (1)**	58.11	55.09
Total Cost (2)	61.30	62.36
Total Cost (3)	54.88	52.57
Total Cost (4)	56.37	57.99
Quantity of Electricity Generated (gwh)	3,064.00	2,017.40
Quantity of Electricity Sold (gwh)	2,600.30	1,791.00
Residential Consumption (gwh)	1,084.60	735.05
Industrial Consumption (gwh)	947.00	594.89
Commercial Consumption (gwh)	422.00	368.87
Residential Customers ('000)	294.59	110.17
Industrial Customers ('000)	16.21	9.85
Commercial Customers ('000)	35.28	9.88
Price Index of Capital (1)	.26	.18
Price Index of Capital (2)	.19	.14
Price Index of Capital (3)	.22	.16
Price Index of Capital (4)	.15	.13
Price Index of Labour	3.56	2.85
Price Index of Fuel	.30	.13
Load Factor	.54	.04

* Total number of observations 31.

** Figures in the parentheses indicate data sets 1, 2, 3 and 4.

SECTION TWO: EMPIRICAL ESTIMATES AND THEORETICAL DISCUSSION

2.2 A Theoretical Discussion

Before we present the empirical results obtained by estimating the translog cost model described in the previous section, it is appropriate to briefly outline the *a priori* expectations as regards signs and magnitude of the estimated parameters.

Though the standard theoretical presumption is that substitution is possible, at a practical and empirical levels however, economists do not agree on the possibility of substitution between inputs in the ESI. Komiya (1962) suggested that the factors in the ESI are used by and large in fixed proportions and that the possibility of substitution was meagre. Nerlove (1963), on the other hand, suggests that such possibilities are significant at the firm level. Christensen and Greene (1976) found labour-fuel substitution to be about one and a half times greater than that for labour-capital substitution using 1955 data but the former was only one fourth of the latter while using 1970 data.

The *a priori* expectation regarding signs and magnitude of such parameters is that the scope of substitution between labour and capital and between labour and fuel in the ESI is very limited. Thus, the signs of the parameters are expected to be either negative (implying complementarity) or positive with very small magnitude.

This expectation is a direct result of technological conditions in the ESI, where "men are a poor substitute for coal (energy)" (Johnston, 1960, p. 51). Nevertheless, there are some possibilities for substitution between labour and capital and between energy and capital "by using older and less efficient plants more intensively or by using a large number of small plants rather than a few large ones" (Nerlove, 1963, p. 173). It needs to be stressed, however, that the possibility of substitution of labour for capital in such cases is limited since the inefficient and smaller plants are normally operated at peak hours and shut down during off peak hours. It is unlikely that labour is contracted to work just at the peak hours on an hourly basis. Rather, it is more likely that labour, once employed, is paid on a basis which includes peak and off peak hours. Nevertheless, small scale substitution may take place as the operation of small and older plants will necessitate increased cost for operation and maintenance, a sizeable part of which is likely to be labour cost. In the case of ETSA, the possibility of substitution between labour and capital may show up due to its recent practice of producing some of its capital equipment such as transformer, gear or electricity poles in its own factory and thereby raising labour cost relative to capital cost. However, this possibility (of so called substitution) is likely to be insignificant, as this constitutes only a small fraction of total costs incurred by ETSA. It is, therefore, unlikely that the magnitude of the labour-capital substitution parameter will be significant even though it may have a positive sign.[11]

The sign of the parameter denoting capital-fuel substitution is,

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11 Note that the substitution may be positive even though the sign for α_{ij} is negative. Since substitution elasticity equals

$$\frac{\alpha_{ij} + S_i S_j}{S_i S_j},$$

a negative substitution would require $-\alpha_{ij} > S_i S_j$ where S_{ij} are shares for inputs ij.

however, expected to be positive and its magnitude is expected to be significant. In addition to capital-fuel substitution in peak hours as described above, there may be other avenues through which substitution may take place between these two factors. The thermal efficiency of gas turbines can be substantially improved by using combined cycles and incorporating heat recovery steam generating plant instead of single cycles. This saves energy at the cost of extra capital. Installation of appropriate capacitors, powerful transformers and high resistence transmission and distribution lines to limit the energy losses are some other examples of how a trade-off can take place between capital and energy.

The sign of the own price elasticity (for each input) is expected to be negative on the basis of the law of demand that more of a particular commodity (input) is demanded when its relative price falls and vice versa.

It follows from our concavity hypothesis that the sign of the parameter for an individual factor price will be positive and the homogeneity hypothesis restricts the individual values to less than one so that the sum total of factor price parameters is equal to one.

The sign of the cost elasticity with respect to Q is expected to be positive, implying that total cost will increase as quantity (generation) increases. However, the magnitude of this elasticity cannot be ascertained before hand. It may be above, below or equal to one depending upon the size of economies of scale.

The sign of the cost elasticity with respect to load factor is expected to be negative. Moreover, the coefficient for the cross term of quantity (Q) with load factor (L) is also expected to be negative since an increase in load factor is expected to have a favourable impact on cost reduction.

It is important to recall that the cost function to be estimated in the present study is a long run cost function, where all costs, including capital, are variable. Moreover, the cost refers not only to the quantity generated (or supplied) at any time but also, to some extent, to the quantity expected to be supplied in the near future. Because of the long gestation period in the ESI, capital projects typically start at least ten years before the expected date of commissioning of a plant. Thus a portion of the interest and wage bills paid today is, in fact, a payment against consumption ten years later. Note also that ETSA is paying an exploration levy on gas supplies to enable the South Australian Oil and Gas Corporation to carry out additional exploration to secure long term assurances of supply.[12]

Thus the cost function we are estimating is a long run cost function and as such has greater flexibility than in the short run. This includes the wider possibility of factor substitution, and technical change (and/or learning by doing) through 'a dynamic adjustment process moving from one equilibrium to another'.[13] Long run cost minimization may also be pursued by delaying or advancing the installation of a plant, thereby affecting the present value of cost to be incurred.

Advancing the investment of C_i (capital good) by ΔT_i (time) will incur an increase in both capital and operating cost of:

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12 Formerly, this rate was 3.74¢ per gigajoules (GJ). Currently, it is 7.44¢ per GJ. See ETSA, Annual Report, 1982, p. 2.

13 Edger, *et al.*, (1971), p. 20.

$$C_i(r + P)\ \Delta T_i$$

where r = interest rate;

P = operating cost as a fraction per annum of the capital cost.

The present value of this incremental cost is

$$PV = \frac{C_i(P + r)\ \Delta T_i}{(1 + r)^i} \qquad (2.33)$$

With these possibilities of long run cost minimization, the magnitude of the scale economy as we have defined in Table 12 is likely to be very significant. Recall, that such 'scale economy' will represent a 'catch all' for all the above forces and X-efficiency etc., rather than those arising from scale alone. Separation of pure scale economies from other effects is always recognised as a great problem. We return to this problem again in sub-section 2.2.4. Meanwhile, let us examine the results given below.

2.2.1 The Empirical Results

The translog cost model as outlined in Section 2.1 together with the share equations described in sub-section 2.1.1 have been simultaneously estimated using Zellner's Seemingly Unrelated Regression. The data used are those described in sub-section 2.1.5. For reasons discussed earlier (equations 2.22 - 2.24) the fuel share equation was dropped from the system.

The estimated parameters for Model A with data sets one, two, three and four (for convenience we call them Models A.1, A.2, A.3 and A.4) are presented in Tables 14 and 15 for quantity generated (GQ) and quantity

TABLE 14

Regression Results of the Translog Cost Function: ETSA 1950-1980

Parameters	Models with GQ A.1 d = 12%	A.2 d = 6%	A.3 d = 12% r = INF	A.4 d = 6% r = INF
α_q	.505 (24.23)	.429 (26.13)	.491 (24.36)	.384 (23.91)
α_{qq}	-.002 (-.90)	.003 (1.39)	.003 (1.13)	.011 (4.67)
α_{rq}	.023 (2.43)	.051 (7.15)	.023 (2.55)	.056 (8.61)
α_{fq}	.028 (5.16)	.003 (1.65)	.039 (7.42)	.016 (3.24)
α_{wq}	-.051 (5.70)	-.054 (6.45)	-.062 (-5.91)	-.072 (-8.60)
$\alpha_{\ell q}$	-.179 (3.89)	-.195 (4.02)	-.163 (3.44)	-.187 (4.02)
α_r	.562 (13.39)	.481 (16.19)	.548 (14.68)	.413 (16.65)
α_w	.218 (5.39)	.192 (10.83)	.292 (4.58)	.298 (9.88)
α_f	.220 (8.85)	.327 (9.43)	.160 (11.42)	.289 (13.18)
α_ℓ	.781 (3.44)	.820 (3.89)	.850 (2.90)	.830 (3.00)
α_{rw}	-.126 (-6.10)	-.137 (-8.94)	-.125 (-6.49)	-.139 (-10.22)
α_{rf}	-.051 (-5.35)	-.061 (-8.44)	-.052 (-6.02)	-.058 (-8.63)
α_{wf}	-.084 (-10.32)	-.065 (-7.18)	-.097 (-11.42)	-.084 (-8.49)
α_{rr}	.177 (12.52)	.198 (23.66)	.177 (9.33)	.197 (20.75)
α_{ww}	.210 (8.43)	.202 (13.94)	.222 (11.24)	.223 (16.16)

TABLE 14 (continued)

Parameters	Models with GQ			
	A.1 d = 12%	A.2 d = 6%	A.3 d = 12% r = INF	A.4 d = 6% r = INF
α_{ff}	.135 (17.42)	.126 (14.09)	.149 (15.76)	.142 (14.20)
$\alpha_{\ell\ell}$	.060 (5.27)	.062 (5.52)	0.064 (5.66)	.061 (5.22)
$\alpha_{r\ell}$	.003 (.96)	.005 (1.11)	.004 (1.04)	.006 (1.25)
$\alpha_{w\ell}$	.008 (.88)	.007 (.87)	.006 (1.98)	.005 (1.91)
$\alpha_{f\ell}$	.011 (1.02)	.012 (1.39)	.010 (1.11)	.009 (1.25)

* Figures in the parentheses indicate t-statistics.
** d = depreciation rate, r = discount rate, INF = rate of inflation.

TABLE 15

Regression Results of the Translog Cost Function:
ETSA 1950-1980

Parameters	Models with SQ A.1 d = 12%	A.2 d = 6%	A.3 d = 12% r = INF	A.4 d = 6% r = INF
α_q	.568 (25.61)	.468 (26.58)	.561 (26.34)	.440 (25.11)
α_{qq}	-.007 (-2.58)	.0003 (0.13)	-.003 (-1.36)	.006 (2.48)
α_{rq}	.017 (1.80)	.050 (6.91)	.015 (1.62)	.052 (7.96)
α_{fq}	.031 (5.26)	.006 (1.25)	.038 (6.55)	.018 (3.19)
α_{wq}	-.048 (6.19)	-.056 (-6.26)	-.053 (5.05)	-.070 (-8.36)
$\alpha_{\ell q}$	-.163 (3.04)	-.179 (3.65)	-.146 (4.03)	-.179 (3.60)
α_r	.559 (13.09)	.423 (14.98)	.538 (14.20)	.382 (15.55)
α_w	.242 (4.90)	.246 (9.81)	.216 (4.59)	.313 (9.10)
α_f	.199 (8.68)	.331 (9.53)	.246 (10.33)	.305 (12.16)
α_ℓ	.850 (3.32)	.820 (2.58)	.791 (3.02)	.782 (2.44)
α_{rw}	-.106 (-5.48)	-.127 (-8.72)	-.096 (-5.34)	-.124 (-9.56)
α_{rf}	-.051 (-5.21)	-.059 (-7.86)	-.052 (-5.82)	-.057 (-8.35)
α_{wf}	-.087 (-10.42)	-.071 (-7.71)	-.098 (-11.21)	-.087 (-8.64)
α_{rr}	.157 (9.07)	.186 (16.32)	.148 (9.96)	.181 (20.24)
α_{ww}	.193 (8.08)	.198 (9.55)	.194 (10.84)	.211 (10.44)

TABLE 15 (continued)

Parameters	Models with SQ			
	A.1 d = **12%**	**A.2** d = **6%**	**A.3** d = **12%** r = **INF**	**A.4** d = **6%** r = **INF**
α_{ff}	.138 (16.49)	.130 (15.53)	.150 (17.92)	.144 (17.14)
$\alpha_{\ell\ell}$	.051 (4.48)	.054 (4.49)	.053 (4.67)	.058 (4.02)
$\alpha_{r\ell}$	.003 (.89)	.008 (.79)	.003 (.87)	.003 (.86)
$\alpha_{w\ell}$	.009 (.97)	.007 (1.25)	.004 (1.66)	.005 (1.01)
$\alpha_{t\ell}$	.010 (1.01)	.003 (1.39)	.005 (1.54)	.006 (1.29)

* Figures in the parentheses indicate t- statistics.

sold (SQ) respectively. The results are by and large insensitive to which equation is dropped. The coefficients for the cross terms of individual input prices with load factor ($\alpha_{r\ell}$, $\alpha_{w\ell}$ and $\alpha_{f\ell}$) were found not significantly different from zero in any of the models estimated.

It may be recalled that the cost function is homothetic if and only if $\alpha_{qi} = 0$ (equation 2.8, p. 39). For constant returns to scale, it is required that the parameters $\alpha_{qi} = 0$, $\alpha_{qq} = 0$ (equation 2.9) and for unitary elasticity of substitution, a further restriction that $\alpha_{ij} = 0$ is required, (equation 2.10). In model A the question whether the function is homothetic, constant returns to scale or Cobb-Douglas is decided by the significance test of t-statistics and by the likelihood ratio test (equation 2.11, p. 40). It may be observed that the t-statistics of the estimated parameters of non-homotheticity (α_{qi}), non-constant returns to scale (α_{qi}, α_{qq}) and those of substitution parameters (α_{rw}, α_{rf}, α_{wf}) are large enough to suggest that models B, C and D are not consistent with the data sets used. This view is confirmed by the likelihood ratio test. The relevant statistics are presented in Tables 16 and 17.

Table 16 presents regression results of models B, C, AD, BD and CD using data set one. These models have also been estimated using data sets two, three and four. While the results are not reported in the text, the results of their likelihood ratio tests are given in Table 17.

It appears from table 17 that the computed χ^2 of all the restricted models are higher than the theoretical value of Chi-square thus rejecting the null hypotheses for homotheticity, homogeneity and for unitary elasticities of substitution. It appears that only model A with non-homotheticity, non-constant returns to scale and non-unitary elasticity of substitution is statistically acceptable. It should also

TABLE 16

Regression Results of the Translog Cost Function: ETSA 1950-1980

Parameters	Models GQ B	C	AD	BD	CD
α_q	.636 (31.78)	.553 (124.06)	.417 (27.69)	.760 (67.66)	.690 (338.70)
α_{qq}	-.009 (-4.28)	-	-.010 (-4.65)	-.009 (-7.36)	-
α_{rq}	-	-	.029 (9.41)	-	-
α_{fq}	-	-	-.055 (-17.86)	-	-
α_{wq}	-	-	.026 (8.25)	-	-
$\alpha_{\ell q}$	-	-	-.177 (3.65)	-	-
α_r	.542 (21.15)	.456 (28.71)	.176 (7.38)	.401 (118.12)	.396 (119.37)
α_w	.139 (23.92)	.199 (14.87)	.193 (6.74)	.354 (98.33)	.360 (102.76)
α_f	.318 (6.15)	.345 (26.21)	.631 (27.90)	.244 (87.33)	.244 (87.14)
α_ℓ	.788 (3.15	.810 3.49)	1.080 (3.25)	.664 (2.51)	.665 (2.58)
α_{rw}	-.049 (-5.02)	-.016 (-2.67)	-		
α_{rf}	-.067 (-10.46)	-.061 (-9.76)	-		
α_{wf}	-.044 (-8.35)	-.051 (-10.03)	-		
α_{rr}	.116 (10.17)	.077 (9.19)	-		
α_{ww}	.093 (8.53)	.067 (8.64)	-		

TABLE 16 (continued)

Parameters	**Models GQ** B	C	AD	BD	CD
α_{ff}	.111 (12.41)	.112 (13.38)	–		
Log $\mid \hat{\Omega} \mid$ =	-20.6544	-20.6156	-18.3971	-18.3199	-17.2923

* Parameters $\alpha_{\ell\ell}$, $\alpha_{r\ell}$, $\alpha_{w\ell}$ and $\alpha_{f\ell}$ were found not significantly different from zero.

TABLE 17

Test Statistics for Homotheticity, Homogeneity and Unitary Elasticity of Substitution Between Two Factors of Production: ETSA 1950-1980

Models	No. of Restrictions on Models A.1 - A.4	Critical Value of $\chi^2_{.01}$	Estimated χ^2
B.1	2	9.21	24.97
B.2			17.91
B.3			30.44
B.4			22.17
C.1	3	11.35	26.17
C.2			16.68
C.3			32.35
C.4			22.44
AD.1	3	11.35	94.95
AD.2			122.10
AD.3			94.57
AD.4			125.24
BD.1	5	15.09	97.34
BD.2			133.31
BD.3			95.48
BD.4			150.45
CD.1	6	16.81	113.69
CD.2			135.05
CD.3			105.09
CD.4			141.01

be noted that the differences in results from data sets one, two, three and four are not statistically significant. In other words, the results are insensitive to the rate of depreciation and the rate of discount assumed. Based on this model, estimated elasticities are presented and discussed in the following sub-section.

2.2.2 Elasticities

The methods of estimating elasticities of substitution between factors, cross and own price elasticities have been discussed in Section 2.1.4.

In Tables 18 and 19, we present elasticities of substitution, cross-price and own price elasticities estimated on the basis of parameters reported in Tables 14 and 15, respectively. It appears that the signs and magnitude of the estimated elasticities are consistent with *a priori* expectations. While capital and fuel appear to be substitutes in all the four models, the substitution possibilities between labour and capital and between labour and fuel seem to be insignificant.

The signs of own price elasticities for capital, labour and fuel are plausible though their magnitudes are not large. Looking at the estimated t-values, however, the price elasticities of demand for labour do not seem to be significant.[14] This is also confirmed by the fact that the possibility of substitution of labour for either capital or fuel is not important either.

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14 The measurement problem as referred to in Section 2.1.5 may be responsible for this.

TABLE 18

Estimated Elasticities from Translog Cost Functions: ETSA 1950-1980 for Quantity of Electricity Generated

Elasticity at Means	A.1 d = 12%	A.2 d = 6%	A.3 d = 12% r = INF	A.4 d = 6% r = INF
		Models with GQ		
Elasticities of Substitution				
σ_{CL}	.079 (.52)	.027 (.24)	.082 (.58)	-.043 (-1.34)
σ_{CF}	.511 (7.37)	.422 (8.39)	.463 (5.38)	.410 (5.61)
σ_{LF}	.030 (.31)	.153 (1.31)	-.001 (-.01)	.159 (1.60)
Cross Price Elasticities				
η_{CL}	.027 (.53)	.009 (.25)	.030 (.63)	-.016 (.43)
η_{LC}	.032 (.52)	.012 (.25)	.030 (.54)	-.015 (.42)
η_{CF}	.132 (5.64)	.101 (6.28)	.121 (5.76)	.111 (5.63)
η_{FC}	.207 (5.61)	.186 (6.30)	.170 (5.03)	.148 (5.63)
η_{FL}	.008 (.23)	.049 (1.31)	.000	.059 (1.59)
η_{LF}	.010 (.40)	.037 (1.33)	.000	.043 (1.59)
Own Price Elasticities				
η_{CC}	-.158 (-4.54)	-.110 (-5.79)	-.151 (-2.96)	-.093 (-3.58)
η_{LL}	-.040 (-.54)	-.049 (-1.09)	-.030 (-.57)	-.027 (-.68)
η_{FF}	-.218 (-7.23)	-.235 (-6.30)	-.169 (4.69)	-.204 (-5.51)

* C, L, F are capital, labour and fuel respectively.

** Figures in the parentheses are t-statistics.

TABLE 19

Estimated Elasticities from Translog Cost Functions: ETSA 1950-1980 for Quantity of Electricity Sold

Elasticity at Means	A.1 d = 12%	A.2 d = 6%	A.3 d = 12% r = INF	A.4 d = 6% r = INF
	Models with SQ			
Elasticities of Substitution				
σ_{CL}	.247 (1.78)	.094 (.91)	.100 (.60)	.023 (.22)
σ_{CF}	.490 (4.90)	.404 (5.16)	.570 (7.83)	.423 (5.87)
σ_{LF}	-.012 (-.12)	.197 (1.84)	.021 (.74)	.180 (1.91)
Cross Price Elasticities				
η_{CL}	.089 (1.85)	.033 (.90)	.030 (.60)	.008 (.60)
η_{LC}	.100 (1.78)	.037 (.90)	.037 (.61)	.008 (.23)
η_{CF}	.121 (4.90)	.101 (5.18)	.191 (7.79)	.121 (5.84)
η_{FC}	.198 (4.89)	.160 (5.18)	.209 (7.84)	.145 (5.87)
η_{FL}	-.003 (-.09)	.069 (1.82)	.006 (.22)	.066 (1.89)
η_{LF}	-.004 (-.17)	.049 (1.83)	.007 (.23)	.052 (1.92)
Own Price Elasticities				
η_{CC}	-.207 (-4.84)	-.134 (-4.65)	-.229 (-5.65)	-.129 (-4.96)
η_{LL}	-.097 (-1.41)	-.087 (-1.48)	-.051 (-.85)	-.060 (-1.11)
η_{FF}	-.194 (-5.72)	-.230 (-6.87)	-.307 (-12.32)	-.211 (-7.25)

* Figures in the parentheses are t-statistics. Calculations are based on the formula, e.g., $(Var(\sigma_{ij}) = Var(\alpha_{ij})/(S_i S_j)^2$. See equation 2.27.

The pattern of relative elasticities for all the models estimated appears to be the same. The assumption of a Cobb-Douglas production function for ETSA may also be misleading. The lack of substitution between labour and capital, between labour and fuel and a substitution elasticity less than one between capital and fuel limits ETSA's capacity to keep the cost escalation less than proportionate to the rise in factor prices, especially in the case of wage rises. It also limits the possibility of favourable effects on cost of any non-neutral change in technology. Nevertheless, it appears that the cost of production need not rise in proportion to any rise in factor prices since ETSA seems to be enjoying sizeable economies of scale (density or other cost advantages) which are discussed in the following sub-section.

2.2.3 Scale Economies and Marginal Costs

Though economies of scale and marginal cost can be estimated with respect to all the eight models (four for quantity generated and four for quantity sold) from the results given in Tables 14 and 15, we prefer to report the estimates for the quantity sold (SQ) only. For reasons discussed below, attention is further confined to models A.1 and A.3. In these two models, the depreciation rate has been assumed to be 12 per cent on a diminishing balance. This leaves the diminished balance at 1.89 per cent of the original capital at the end of 35 years, which is the normal life of a thermal generator (McColl, 1972, p. 149). On the assumption of a scrap value for any plant of not more than 2 per cent of the original,[15] the 12 per cent depreciation rate seems to be more realistic than 6 per cent (models A.2 and A.4) which leaves the

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15 Recall that the second hand market for generators is almost non-existent.

diminished balance at 13 per cent of the original capital at the end of 35 years.

Another reason why models A.1 and A.3 are preferable is that the average costs per kwh calculated from these two models are closer to the actual average cost obtained by dividing the total accounting cost (as reported by ETSA) by the total quantity of electricity sold. This may be seen in the following table.

TABLE 20

Average Cost in Cents per kwh: ETSA

	1950–1970	1970–1980
Accounting	1.67	2.23
Model A.1	1.77	2.46
Model A.3	1.66	2.33

* Calculated at the Mean.

It may be remembered that whereas in model A.1, the discount rate is calculated assuming a 3 per cent real rate of social time preference (see equation 2.32, p. 54), in A.3 the real rate was assumed to be zero. That is, the discount rate was equated with the rate of inflation. The assumption of two different rates provides a sensitivity test.

The scale economies pertaining to ETSA are estimated using the formula given in Table 12 for model A and marginal cost is estimated using equation 2.25. Note that the cost elasticities estimated with respect to quantity generated and quantity sold are not significantly different from each other. The estimated marginal cost and scale economies are presented below. The estimates are for quantity sold, which are more relevant for evaluating pricing practices in ETSA (see Chapter Eight).

As may be seen in Table 21, the cost elasticity with respect to quantity of electricity sold by ETSA is estimated at .501 and .526 for models A.1 and A.3 respectively. This means that with each increase in quantity sold, the total cost of supply increases but at a rate less

TABLE 21

Estimated Economies of Scale and Marginal Costs in Current Prices: ETSA 1950–1980

Models	Cost Elasticity $\partial \log C/\partial \log Q$	Economies of Scale $1-[\partial \log C/\partial \log Q]$	MC At means	AC At Means
A.1	.501 (33.27)*	.499 (33.27)	1.124 (33.47)	2.234
A.3	.526 (23.51)	.473 (23.51)	1.114 (26.18)	2.114

* Figures in the parentheses indicate t-values.[16]
** Q = quantity of electricity sold.
MC = marginal cost; AC = average cost.

16 The variance of cost elasticity was obtained by using the following formula. If $\beta = f(\Theta)$ is some function (elasticity) of a parameter vector Θ and $\hat{\Theta}$ is its estimate and Σ its variance co-variance matrix, then the variance for $\hat{\beta} = f(\hat{\Theta})$ is

$$\sigma^2 = \frac{\partial f}{\partial \Theta}(\hat{\Theta})\ \hat{\Sigma}\ \frac{\partial f}{\partial \Theta}(\hat{\Theta})^T$$

I am indebted to Professor Alan Woodland for pointing this out to me.

than the rate of increase in the quantity (a one per cent increase in quantity implies a .53 per cent increase in cost).

As defined earlier (Table 12), returns to scale are increasing, constant or decreasing as the cost elasticity is less, equal or larger (the ratio of average to marginal cost is larger, equal or less) than unity. However, this definition conceals the difference between economies of scale and economies of scope. The cost of producing electricity in peak and off-peak hours by one firm may be less than that by two firms. This is referred to as economies of scope which may coincide with a non-decreasing average cost for each firm separately (see Baumol, et al., (1982), p. 71). Since its inception, ETSA has taken over a number of independent supply authorities. It is, therefore, likely that the cost condition in ETSA is an outcome of both size and scope.[17] Moreover, in the scale economies as reported in Table 21, the impacts of technology, desnity and location of customers as well as the composition of demand are not distinguished from the pure scale effect. Note further, that economies of scale is primarily associated with the expansion of the supplying industry, ETSA, and as such, is a long run phenomenon. It should not be confused with economies resulting from spreading of overheads, which is a short run phenomenon. In the next sub-section, we briefly outline the problem of separating scale effects on cost from other effects.

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17 However, the economies of scope, in the present case, is likely to be represented by the system load factor which we used explicitly in our equation. Thus the scope effect is separable from the scale effect in the present case (see equation 2.35).

2.2.4 Problem of Isolating "Pure" Economies of Scale

As mentioned above, the observed decline in average cost cannot be attributed to scale alone. The separation of other influences on cost from that of scale is important in an examination of the question whether or not ETSA is a natural monopoly. An industry is classified as natural monopoly only when its cost function is subadditive over the entire relevant range of outputs: that is, when

$$C(q) < C(q_1) + \ldots + C(q_K) \tag{2.34}$$

where $q_1, \ldots, q_K$ are an output vector that sums to q and C is the cost function. If the decline in cost is due to technological improvement or any factors other than pure scale economies, then the community may be served equally well by more than one firm.[18]

The cost functions of economic theory are timeless abstractions and specific to a given set of factor prices and a given state of technical knowledge (see Johnston, 1960, p. 54). In the long run cost-output relationship, any attempt to separate the influence on cost of all other factors from that of output is an intricate problem. As Salter (1966) says "these two sources of increased productivity (economies of scale and improved technology) are difficult to separate, for newly discovered economies of scale are a very important aspect of improving technology".[19] Again, it is difficult to identify the form in which technical improvement takes place. This is particularly true in the

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18 For details see Baumol, (1982), p. 9. Note also that for a natural monopoly it is not necessary (as opposed to the traditional view) to have decreasing costs. See Panzar and Willig, (1977), p. 7 and Bornbright (1961) pp. 14-15.

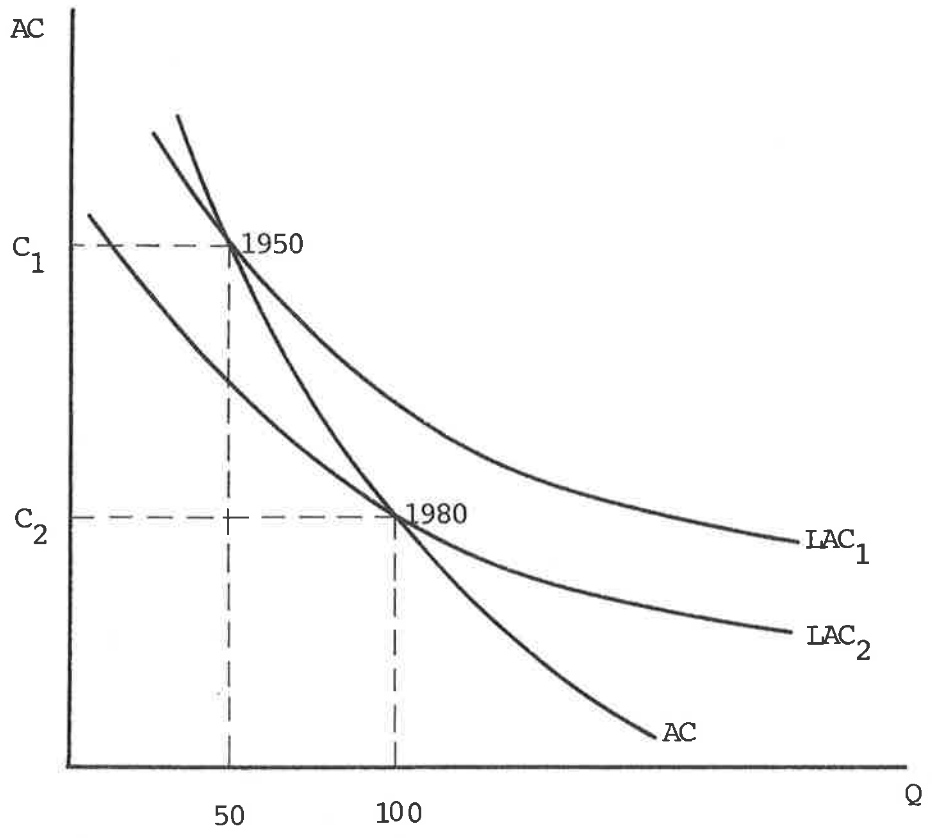
19 Salter, W.E.G., (1966), Productivity and Technical Change, Cambridge University Press, London, 1966, p. 133.

case of ESI, where the system is operated through an integrated grid and as such efficient load dispatching plays a significant role in reducing cost.

The problem of separating other influences from that of output is illustrated in Figure 1.

As we move from quantity 50 (in 1950) to 100 (1980), the average cost comes down from C_1 to C_2 along the observed average cost curve (AC). But whether this decline is due to scale alone or due to other factors (such as technological improvements and factor price changes) so that the cost curve has shifted down over time (from LAC_1 to LAC_2) is not known. In addition, it may be evidence of increased X-efficiency.[20]

FIGURE 1



20 See Leibenstein, H., (1966), "Allocative Efficiency vs. X-efficiency", American Economic Review, June 1966, pp. 392-415.

Given this problem of specifying technological impact on cost, one approach is to assume linear technical progress that can be represented by time.[21] On further inspection, however, T appears to be highly correlated with quantity sold (SQ) and a problem of multicollinearity seems to be unavoidable.[22] Thus an attempt to separate the influence of T from that of SQ, in line with Johnston (1960) (see equation 1.10, p. 26) would be misleading in the present case.

Nevertheless, an attempt was made to estimate equation 2.4 (p. 37) using time as an additional regressor along with others but the results were unsatisfactory. Though the coefficient of T has a negative sign implying reduction of cost over time, the use of T reduces the value of the parameter for SQ, which is not theoretically plausible.[23]

The question of technological progress, therefore, remains largely open and the question whether ETSA is a natural monopoly remains unresolved. The fact that per unit cost in ETSA is far below that in the independent supply authorities (ISA)[24] is not a sufficient evidence

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21 Although the plants installed by ETSA were not technically the most sophisticated currently available, nonetheless, they have updated some of their equipment over time. Moreover, reasonable expenditures were made on training of staff from year to year. Thus the assumption of linear technical progress may not be unrealistic.

22 The simple correlation coefficient between T and SQ (in log form) was calculated as .99 and the R^2 of SQ when regressed with T was .97.

23 If T could capture the impact of technological improvement, then cost reduction due to expansion of SQ alone would have been less.

24 Though we do not have any comparable statistics, it can be inferred from the fact that a subsidy at the rate of 34¢/kwh is being given to the ISA to enable them charge a tariff not exceeding 10 per cent of the tariff charged by ETSA. Further, the fuel requirement per kwh generated by ETSA is significantly lower than that by ISA. This is true even if the comparison is restricted to oil fired stations only.
Source: ETSA and DME, Personal Contact. For amount of subsidy to ISA, see ETSA Annual Report 1982, p. 16.

for subadditivity. Because of the demand pattern in the market served by the ISA, the technology available to them (ISA) is not the same as that to ETSA. It is conceivable that the high cost in the ISA is an outcome of the government's policy of state ownership rather than a reason for it. ETSA's policy of cross-subsidisation (urban versus rural) has confined the ISA to serving only those small and remote places where ETSA is unwilling to go. It is not known what would have been the cost if those places were to be served by ETSA. Apart from the fact that, given the small size of the market, the ISA may not afford a better technology (size and technology is often interwoven), it is also conceivable that they do not attempt to install more efficient plants since they fear an ultimate takeover of their enterprises by ETSA.

Thus the problem of separating technological impact on cost from scale effects is a formidable one. Nevertheless, looking at the size and types of generators used by ETSA (see Introduction, pp. 4-5), one can probably assume that the degree of technical progress in ETSA was rather small. Previous studies such as Komiya (1962) and Olson (1970) also suggest that technological improvement in the post-war period was insignificant. To the extent that this is true in the case of ETSA, the natural monopoly argument is reinforced.

The problem of separating the factor price effect on cost from the output effect appears to be less formidable. Many economists (such as Johnston (1960)), have attempted to solve this problem by deflating cost by a factor price index. The procedure is valid only under the assumption of there being no substitution between factors. A more appropriate method is to use a translog cost model. In our case, the cost elasticity with respect to quantity (Q) is given by

$$\frac{\partial \log C}{\partial \log Q} = \alpha_q + \alpha_{qq}\log Q + \alpha_{qr}\log R + \alpha_{qw}\log W + \alpha_{qf}\log F + \alpha_{q\ell}\log L \tag{2.35}$$

Thus the price effects on cost are reflected through the values of the third, fourth and fifth terms and the quantity effects through α_q and α_{qq}.

Likewise, the impact of load factor on cost elasticity with respect to quantity of output (Q) is reflected through the last term. Since both $\alpha_{q\ell}$ and log L are negative, the product becomes positive implying that the lower is the load factor (the higher is log L) the higher will be the cost elasticity.[25] The scale economies (amalgamated with technical progress and other effects but net of price effects) measured this way are given in Table 22. The results given in Table 21 are also reproduced.

It appears from the table that, out of so called scale economies of .499 and .473 in models A.1 and A.3 respectively, .114 and .124 can be attributed to the economies arising out of ETSA's responses to price changes. The scale economies net of price and load effects as reported below could not be segregated further, though such segregation is desirable, for analytical purposes. However, for the practical purposes

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25 This is not the same as cost elasticity with respect to load factor which can be estimated by differentiating equation 2.4 with respect to L:

$$\frac{\partial C}{\partial L} = \alpha_\ell + \alpha_{q\ell}\log Q + \alpha_{r\ell}\log R + \alpha_{w\ell}\log W + \alpha_{f\ell}\log F + \alpha_{\ell\ell}\log L.$$

From the values given in Table 15 (SQ) the elasticity is estimated to be −.347 indicating that a one per cent improvement in load factor will reduce cost by 0.35 per cent.

of estimating marginal cost and concomitant evaluation of pricing practices, it is not necessary.

TABLE 22

Economies of Scale in ETSA

	Price Effect & Load Effect Included*	Price Effect Excluded	Price Effect & Load Effect Excluded
Model A.1 (SQ)	.499 (33.27)	.385 (26.97)	.485 (17.51)
Model A.3 (SQ)	.473 (23.51)	.349 (55.03)	.439 (22.03)

* Reproduced from Table 21.

It is these amalgam cost elasticity estimates which are used for estimating class marginal cost in the next sub-section.

2.2.5 Changes in Marginal Cost

Recall that the results reported in Table 21 are based on the elasticity with respect to quantity of electricity sold. As the cost function is in logarithmic form, the estimated elasticity is constant over the sample period (1950-80). But, in practice, it is likely that the elasticity would have changed over time, especially after the very high rise in the input prices during the 1970's. The logarithmic form of the equation is advantageous because it permits an easy interpretation of the results. We have already seen that other available forms are not good for examining the factor substitution possibilities in the industry.

One way to retain the logarithmic form yet to examine the possibility of changes in cost elasticity (if any) is to divide the sample period into two appropriate sub-samples. The year 1970 is chosen as a dividing year for two reasons: first, the natural gas which now constitutes about 80 per cent of the primary source of energy to ETSA was not available before 1970 and second, with the energy price increase of the early 1970's, it is possible that the cost structure took a shape different from that of the previous two decades. In Table 23 we present the results for the above two sub-periods. The difference in the estimated cost elasticities appears to be not significant at the 95 per cent confidence level. The marginal costs are different due to changes in the level of C/Q (see equation 2.25, p. 47).

It may be noted that the MC reported in Table 23 are in current prices so the apparent rise in the MC is mostly a reflection of underlying inflation in the factor market. The MC in both the models are far below

TABLE 23

Estimated Marginal Cost for ETSA for 1950-1970, 1971-1980 and 1950-1980

	Model A.1		Model A.3	
Period	$\frac{\partial \log C}{\partial \log Q}$	MC**	$\frac{\partial \log C}{\partial \log Q}$	MC
1950-1970	.447 (6.48)*	.794 (6.46)	.445 (11.65)	.744 (11.69)
1971-1980	.515 (21.46)	1.274 (21.34)	.483 (43.71)	1.134 (43.46)
1950-1980	.501 (33.27)	1.124 (33.47)	.526 (23.51)	1.114 (26.18)

* Figures in the parentheses are t-statistics.
** Marginal cost in current price.

the AC, thus implying increasing returns to scale (see Table 21). The estimated marginal costs using 1966-67 constant prices are presented in Table 50 (Chapter VIII).

In the following sub-section, we shall attempt to determine the marginal cost of supplying electricity to each of the three major consumer classes namely residential, industrial and commercial customers in South Australia.

SECTION THREE: CLASS MARGINAL COST OF ELECTRICITY SUPPLY

2.3 Theoretical Consideration

In the previous section, we have presented the estimates of marginal cost of supplying electricity for the aggregate demand confronting ETSA. Our purpose in this section is to build up some techniques whereby we can apportion the long run marginal cost of electricity supply to various classes of consumers. This apportioning is necessary to evaluate the rationale of class differences in electricity price. The cost of electricity supply differs substantially with variation in the quantity of power demanded at a particular time, location of the consumers and voltage level at which power is transmitted and distributed. Provision of the service to individual customers requires connection to the service, installation and reading of meters and sending bills. The costs of these activities per customer differ substantially from one class to another.

The capacity required for generation and transmission depends greatly on the maximum demand at a point of time. The load curve or profile of demand over time will determine the type of generator purchased. Because of the variation in demand by time of day, some generators are used only for a short period of time. Such capacity has typically high operation cost and low capacity cost. On the other hand, base load capacity normally has low operation cost but high capacity cost. Location of the service affects activities associated with both number of customers and quantity demanded. Density of customers affects the distribution cost and the distance between demand centres and generating stations affects the transmission cost. As loss of energy in transportation is inversely related to the voltage at which it is dispatched, costs of transmission and distribution also vary with the variation in the voltage required. As different consumer classes differ widely in the above characteristics, the cost of their supply also differs.

Normally, industrial demand is more stable over time as firms seek to maintain utilization rates on expensive electricity-powered equipment.[26] Thus the industrial consumption normally has a higher load factor in comparison to residential and commercial consumption. Besides, residential and commercial users generally take their power at low voltage while industrial and bulk users take it at a high voltage level. Apart from the higher line losses associated with low voltage distribution, appropriate transformers are required to step down to low voltage, which involve additional capital cost. For these reasons, the marginal cost of industrial electricity is likely to be less than that in the other two sectors.

Certain customer-related costs such as reading meters and sending bills are quite insensitive to the quantity of electricity demanded but sensitive to the number of customers. For ETSA, the industrial sector has the highest consumption per customer of the three sectors, followed by the commercial sector. Thus, to the extent, that customer-related costs influence the marginal cost, it is likely to be highest for the residential sector and lowest for the industrial sector.

Marginal cost, by definition, relates to increases (decreases) in

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26 That is the industrial demand is likely to vary less from day to day and from month to month than demand in the other two sectors especially in the residential sector.

total cost due to any increase (decrease) in quantity. Thus in determining marginal cost for each sector, it is not the absolute share of a particular sector in total demand which is important, but rather its contribution to the change in demand. In the presence of excess capacity in the system, the higher is the contribution of a sector to the increase in total demand, the lower is likely to be its marginal cost. This is so because a higher contribution to the increments means, ceteris paribus, a higher contribution to the greater utilization of the existing capacity, which is likely to lower the average cost. However, higher contribution to increments may actually be responsible for higher marginal cost if the increased demand occurs in the peak period, which may require further expansion of capacity. Also if the increased demand arose from a large extension of the services, then the marginal cost pertaining to a sector where such extensions were large is likely to be large.

One can generalise these issues by referring to consumption per customer in a sector. A higher consumption per customer in any sector is likely to represent consumption for more hours in a day and more days in a year. This in turn is likely to improve the system load factor and thereby reduce the need for additional capacity. The opposite would happen in the case of a decreased consumption per customer.[27] Again, a decline in per customer consumption in association with an increase in total consumption can happen only through increased numbers of small customers, thereby increasing the customer-related cost. Thus the marginal cost in a sector with falling consumption per customer is likely to be higher than that in a sector with constant or increasing

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27 Further discussion on this is to be found in Section 10.2.2.

consumption per customer.

The shares of various sectors in the total consumption of electricity in South Australia have been presented in Table 5. The contributions of individual sectors to the incremental consumption are presented below in Table 24. The changes in per customer consumption are also presented in this table.

TABLE 24

Structural Change in Electricity Consumption in South Australia

	Ratio of No. of Customers in 1980 to that in 1950	Consumption Per Customer in GWH			Shares in Increased Consumption	
		1950	1970	1980	1950-70	1971-80
Residential	3.78	1.17	3.93	5.06	.40	.40
Industrial	17.19	90.69	62.60	66.49	.41	.28
Commercial	2.76	2.88	11.71	24.45	.14	.30
Others	-	-	-	-	.05	.02

Source: ETSA, Annual Reports: Calculations are the author's own.

It appears from the table that the contribution of industrial demand to the increase in total consumption has fallen sharply to 28 per cent from 41 per cent in the previous two decades. As against this, the share of commercial consumption increased remarkably. To assess the impact on costs, it is more appropriate to look at the change in consumption per customer. It appears that the rise in per customer consumption was greatest in the commercial sector.

From 1950 to 1970, consumption per commercial customer more than quadrupled and again by 1980, more than doubled. In the residential sector, the rise was substantial but not as great as in the commercial sector. In the industrial sector, though consumption per customer continued to remain far above that in the other two sectors, it declined sharply from 90.69 Gwh in 1950 to 62.60 Gwh in 1970, though rose slightly to 66.49 Gwh in 1980. During this time, the number of industrial customers increased by 17.19 times, residential customers by 3.78 times and commercial customers by 2.76 times.[28] Under these circumstances, it is quite likely that considerable economies were obtained in the commercial and in the residential sectors, whereas in the industrial sector some diseconomies (or diminished economies) might have occurred.

2.3.1 Methodology for Estimating Class Marginal Cost

The class marginal cost could best be obtained from a cost function disaggregated over generation, transmission, distribution and administration phases. In general, relative class marginal cost differs among these service phases, so that some relevant information for the individual phase is lost in using an aggregate model. Unfortunately, no such disaggregated data (for ETSA) are available. We are, therefore, forced to use the data aggregated over all phases as described in Section 2.1.5. The data are, however, disaggregated over sectoral consumption and sectoral number of customers.

In estimating marginal cost pertaining to each consumer class, we

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28 In 1950 the number of customers in the residential, industrial and commercial sectors were 124,520, 1,740 and 18,250 and in 1980, rose to 470,920, 29,920 and 50,430 respectively (see ETSA Annual Report).

have re-estimated equation 2.4 with a slight modification. Instead of using one quantity (SQ) variable we used three variables RQ, IQ and CQ namely consumption per customer in each of the major three sectors under study. The total value of the parameters pertaining to each of these variables has been restricted to be equal with the estimated cost elasticity with respect to SQ (see Table 23). Thus the individual parameters of RQ, IQ or CQ represent only a fraction of the cost elasticity reported in Table 21 and 23.[29]

The cost elasticity with respect to one unit of electricity pertaining to a sector will be obtained by dividing the parameter of say, RQ by the contribution of RQ to the total change in consumption. As usual, the marginal cost pertaining to a sector x can be estimated by multiplying the cost elasticity with respect to sector x with the average cost (aggregated over all the sectors).

2.3.2 The Estimated Class Marginal Cost

The estimated marginal costs pertaining to different sectors under ETSA are presented below in Table 25.

It is evident from this table that the increase in the marginal cost of industrial electricity in the sub-period 1971-80 over the period 1950-70 was disproportionately higher than that in the other two sectors. The primary reason for this seems to be the substantial decline in the contribution of the industrial sector to the increase in total demand for electricity in South Australia (see Table 24), and also to the decline in consumption per customer as discussed earlier. The

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[29] That is, the elasticity estimated with respect to one unit of electricity aggregated over all the sectors.

TABLE 25

Marginal Cost of Electricity Supply (in Current Prices): ETSA
(In cents)

	Model A.1		Model A.3	
	1950-70	1971-80	1950-70	1971-80
Residential	1.31 (8.04)	1.44 (7.66)	1.25 (9.39)	1.35 (12.39)
Industrial	.35 (2.46)	1.24 (12.32)	.33 (3.54)	1.17 (4.86)
Commercial	1.10 (4.46)	1.04 (3.92)	1.06 (2.48)	.94 (3.50)

* Figures in the parentheses indicate t-values.
** See Appendix I for calculation.

opposite was true in the other two sectors. The largest contribution to the total increment in demand was from the commercial sector. This as well as substantial increase in per customer consumption in this sector explains why the marginal cost of commercial electricity declined over time.

The difference in the estimated class marginal costs are important findings of the present study. These will provide us with a basis for evaluation of pricing practices in ETSA, to which we turn in Chapters VII and VIII.

2.4 Conclusion

A translog cost function was fitted to the data pertaining to the Electricity Trust of South Australia from 1950 to 1980. The results obtained suggest that the translog cost function is superior to other available models (e.g., ACMS, GCD) in explaining factor substitution in an industry. A model assuming non-homotheticity, non-constant returns to scale and non-unitary elasticity of substitution between inputs seems to give the best results in the case of ETSA.

In the present case, capital and labour appear to be complements, as are labour and energy. However, capital and energy appear to be substitutes. All the regression parameters have plausible signs and magnitude and, with the exception of the substitutability between capital and labour, have support from other studies in Australia, such as Turnovsky and Donnelly (1982), and Turnovsky, Folie and Ulph (1982).

The estimated economies of scale for the period from 1971 to 1980 were not statistically different from those for the period from 1950 to 1970. The economies of scale and the marginal costs pertaining to transmission and distribution of electricity could not be separated from those with respect to generation, since data segregated over these phases are not available. Though the impact of technological improvement could not be separated from scale effect, ETSA does seem to be enjoying considerable economies of scale. This supports the view that there are cost advantages in retaining ETSA's monopoly position. The existing economies of scale and the high degree of substitutability between energy and capital imply that a rise in energy prices may not affect the cost of production significantly, provided other factor prices do not rise at the same rate and provided demand for electricity grows. Further, it has been observed that improvement in load factor can significantly reduce cost.

The marginal costs estimated in the present study involve aggregation over peak and off-peak hours and over rural and urban areas. No further disaggregation was possible due to lack of data.

The marginal cost is less than average cost and as such a policy of pricing electricity equal to marginal cost would make it necessary to subsidise (or cross-subsidise) the industry. The estimated marginal costs pertaining to different consumer classes are significantly different from one another. Whether the actual price differentials between consumer classes under ETSA conform to the marginal cost differential will be examined in Chapter Eight. Before that the following four chapters (Part Two) will be devoted to the estimation of demand for electricity in South Australia.

P A R T   T W O

DEMAND

CHAPTER THREE

A SURVEY OF LITERATURE ON DEMAND FOR ELECTRICITY

Introduction

This chapter is divided into two sections. In Section One, we review the major studies on demand for electricity. In Section Two, we deal with some special issues such as the simultaneity problem, and the use of marginal as compared with average price in analysing the demand for electricity. However, first we present, in brief, the basic economic theory on demand analysis.

The Demand Function

The presentation of a demand function in a mathematical form was first attempted by Cournot in his "Researches" (1838).[1] Later, Marshall (1890) presented what is now known as the "law of demand".

Mathematically, the Marshallian demand curve is not different from that of Cournot and is valid only on a ceteris paribus assumption. This theory has been further developed by Walras, Pareto, Hicks and others. It is worthwhile to recapitulate some of the basic economic ideas to which reference will be made in the remainder of this thesis.

It is well known that, subject to a budget constraint such as

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1 A. Cournot, Researches into the Mathematical Principle of the Theory of Wealth, 1838, Translated by Bacon, N.T., Macmillan, New York, 1938, p. 47.

$$\Sigma p_i x_i = y \tag{3.1}$$

where p = price; x = commodity; y = income; and i = 1, 2, ..., n

a consumer's utility $U = U(x_1, \ldots, x_n)$ is maximized when:

$$\frac{MU_{x_i}}{MU_{x_j}} = \frac{p_i}{p_j} \tag{3.2}$$

i.e., the ratio of marginal utilities derived from any pair of commodities is equal to the ratio of their prices. Doubling of prices and income (spending) must leave quantities consumed unchanged. That is, the demand equation must be homogeneous of order zero.

By Euler's theorem, then, we have:

$$\Sigma p_j \frac{\partial x_i}{\partial p_j} + y \frac{\partial x_i}{\partial y} = 0$$

or

$$\Sigma \frac{p_j}{x_i} \frac{\partial x_i}{\partial p_j} = - \frac{y}{x_i} \frac{\partial x_i}{\partial y} \tag{3.3}$$

This implies that "the sum of elasticities and cross elasticities of demand for any good with respect to prices is equal to minus the income elasticity" (Pearce, 1964, p. 49).

It follows from the budget equation 3.1 that:

$$\frac{\partial x_i}{\partial y} = p_i^{-1} \tag{3.4}$$

i.e., the marginal propensity to consume any commodity is inversely proportional to its price. But if x_i is superior to x_j, then the marginal propensity to consume x_i will be greater than that of x_j, other things being equal.[2]

From equation 3.1, it can also be deduced that:

$$\Sigma \; p_i \frac{\partial x_i}{\partial y} x_j = x_j \tag{3.5}$$

and

$$\Sigma \; p_i \frac{\partial x_i}{\partial p_j} = - \; x_j \tag{3.6}$$

Adding 3.5 and 3.6, we get:

$$\Sigma \; p_i \left[\frac{\partial x_i}{\partial p_j} + x_j \frac{\partial x_i}{\partial y} \right] = 0 \tag{3.7}$$

The bracketed expression in equation (3.7) is known as the substitution effect and shows the rate of change in consumption of the i^{th} good due to change in the price of the j^{th} good when real income is held constant. Expressing substitution effects as σ_{ij}, we may re-write equation 3.7 as:

$$\Sigma \; p_i \; \sigma_{ij} = 0$$

or rearranging:

$$\frac{\partial x_i}{\partial p_j} = - \; x_j \frac{\partial x_i}{\partial y} + \sigma_{ij} \tag{3.8}$$

The first part of the RHS of equation 3.8 gives the income effect which "measures the change in demand for the i^{th} good due to loss (gain) in real wealth incurred by the rise (fall) in the j^{th} price (Pearce, 1964,

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2 Thus, if electricity is considered superior to other forms of energy, its income elasticity is likely to be greater than others.

p. 51). Equation 3.8, thus illustrates how the responses to price changes can be split-up into an income effect and a substitution effect. This is the result first obtained by Slutsky (1915) and later developed by Hicks and Allen (1934). The Hicksian analysis has proved that the substitution effect is always negative and usually stronger than the income effect which is "normally very small" (Hicks, 1956, p. 65).

The demand function was further developed by Moore and Schultz (1938). They introduced population and time as variables, thus giving a dynamic form to the function. In practice, however, other systematic and non-systematic factors have to be considered when the demand for a particular product is examined. Systematic factors are those which consistently influence the demand for a product, as for example, the average air temperature in the case of electricity demand. Non-systematic factors are those which have a sporadic influence upon the demand or occur only once, as for example, war, political events or natural calamities.

Aggregate Demand Functions

The theory of demand enunciated in the previous sub-section was originally developed as a theory of individual preference.[3] In the real world, however, data on such micro behaviour are rarely available. More often than not, we are faced with group data, e.g., average consumption,

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3 By individual it is often meant the individual household consisting of all individual persons subject to joint financial decisions. Thus much of the interesting problems of how the household reaches its decisions through intra-family conflicts are ignored. See Lipsey, R.G., Langley, P. and D.M. Mahoney, Positive Economics for Australian Students, Weidenfeld and Nicolson, London, 1981, p. 65.

average income or average price. The question, then, arises whether the theory of individual behaviour is relevant for interpretation of aggregate data and if so, to what extent and in what sense.

Views on this question differ widely. At the one extreme, there are views that "given individual shares of money income, community choice is determined by prices and community income in precisely the same way as for individuals" (see Pearce, 1964, p. 109). At the other extreme, this view has been termed as "entirely unrealistic" (Phlips, 1974, p. 99) because the implication for individual behaviour would conflict with observed aggregate behaviour. However, most economists and econometricians are of the view that the aggregation problem can be ignored. It is suggested that behaviour of a 'representative consumer' is likely to reflect average behaviour of the population though it may not reflect the behaviour of actual persons (Phlips, 1974, p. 100). This procedure is, to some extent, analogous to accepting the household in place of the individual as a basic decision maker. The aggregation error involved in the procedure is not considered important (Houthaker and Taylor, 1970, p. 200). The present study adopts this approach, though attempts are made to disaggregate electricity demand by consumer classes.

SECTION ONE: ECONOMETRIC STUDIES ON DEMAND FOR ELECTRICITY

Our review of econometric studies on demand for electricity may be grouped accordingly to whether they are aggregate, residential, industrial or commercial, though one group may overlap with another in respect of functional specification. A summary of the results reported in recent studies is to be found in Table 26.

3.1.1 Aggregate Demand Studies

A large number of studies have related the growth of demand for energy in a country with that of the GNP. Recent studies, however, revealed that this relationship is not rigid. Kral (1978), for instance, has shown that countries with higher per capita income were not necessarily higher in per capita consumption of energy. In some countries, the major part of the GNP still comes from the non-electrified sector of the economy.

Some recent studies attempted to use other variables in an aggregative model. One such study is Donnelly and Saddler (1982). They studied retail demand for electricity in Tasmania and used own price, price of heating oil, income and temperature as regressors. They used a double log functional form which implies constant elasticities over time and over levels of explanatory variables. This may not in fact, be the case. Secondly, they used aggregate consumption as the dependent variable, thus the elasticities they obtain are the aggregate elasticities for all classes of consumers. To the extent that functional forms and specification of demand in different sectors are different and to the extent that price pertaining to different consumer classes changed at a different rate, the pattern of changes in class elasticities of demand cannot be reflected in an aggregative model.

Another aggregative Australian study which uses GDP, price of electricity and price of oil as independent variables is DNDE (1981). The study suffers from the same shortcomings as discussed above. (Further discussion of this model is to be found in Chapter Nine).

This type of aggregate model cannot explain the idiosyncracies of a particular class of consumers and/or of a region. The assumption underlying the aggregate models is that underestimation or over-estimation in one sector tends to be cancelled out by the reverse situation in the other. But the differences in electricity coefficients with respect to production and the differences in price and income elasticities in various sectors may be very high and in view of the disproportionately high percentage of electricity consumption by one or two sectors in the economy, the risk of over or underestimation persists in the aggregate models.

The problem of the diverse coefficients in various sectors represents a risk of special dimensions in the electricity supply industry (ESI). Unlike the output of many other industries, electricity cannot be stored in an economic way before consumption.[4] Generation, transmission and distribution have to take place simultaneously with consumption. Thus generation capacity has to be built to meet the peak demand even though the capacity will remain idle at off peak hours. This brings us to the concept of load factor (see Glossary of terms) which plays a very important role in determining the total load

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4 It is possible, however, to pump water during off peak hours to run small hydro stations during peak hours. But generation under such arrangements in any system may constitute only a very small proportion of the total demand.

demand.[5] Load factor in various sectors differs very widely, and the aggregate model cannot cover these variations.

Under these circumstances, a disaggregated model incorporating various determining factors especially relevant to a particular class and chosen in the light of past experience and survey is likely to give us better results.

There may, in fact, be a large number of variables influencing the level of demand for electricity. But it is very hard to measure those influences quantitatively unless the number of variables are limited to only a few. Some economists perferred to limit their number of regressors to only two variables, namely price of electricity and disposable income, which appeared to be the most prominent among all theoretically plausible regressors.[6] One such function has been adopted by McColl (1976) to estimate demand elasticities.

McColl's work is probably the only study which is comprehensive enough to consider demand for electricity in each of the states of Australia separately. It, therefore, deserves a relatively extensive discussion. McColl estimated two separate demand equations, one for residential electricity and the other for industrial and commercial combined.

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5 Engineers use the word 'demand' to mean 'load demand' which is synonymous with total generating capacity minus station loss and expressed in KW or MW. The economist's demand for electricity is the consumption in terms of kwh, which the engineers call 'energy'. One of the reasons why estimation of future energy consumption is so important is to provide a basis from which to estimate load demand. Further details are to be found in Chapter Ten.

6 See Wold, H. and L. Jureen, Demand Analysis, Wiley Inc., New York, 1953, pp. 115-116. "In empirical demand analysis it is customary to work with real prices and income".

3.1.2 Studies of Residential Demand

For residential electricity, McColl estimated two different linear models: one in which personal income alone is used as the regressor and the other in which the price of electricity is also included. The coefficient of income in the case of South Australia falls from 4.19 to 0.90 when price is added in the equation. Thus the income elasticity which he reports to be 1.52 for South Australia seems to be subject to (substantial) upward bias. McColl's estimation for Tasmania has a "wrong" sign for the coefficient of price. The explanation he gives is that

> "the low price of electricity may have influenced consumers to purchase electric appliances in earlier periods, and by making competition from other fuels relatively unimportant, continued to deter consumers from switching to appliances using other fuels even when there was some real increases in the price of electricity". McColl (1976), p. 21.

The argument suffers from at least two flaws. First, customers, being committed to the type of appliance already purchased, may not switch over to other types of appliances but this does not explain why the customer should consume more electricity when its price rises. In this situation, we would expect the consumer's response to price to be insignificant. But in McColl's study for Tasmania, the customer's positive response to price changes appears to be highly significant. Secondly, the number of customers had increased from 89,000 in 1953-54 to 126,000 in 1972-73 (McColl, 1976, p. 18) and as such the explanation of customers being 'committed' does not seem to be convincing. What seems to be a more probable explanation is that the price and income data might have the problem of multicollinearity and as such their individual influence on the demand for electricity could not be separated. The same is true for his results obtained in the case of industrial and commercial demand for electricity in New South Wales.

The relative price of electricity and alternative forms of energy, in McColl's model, seem to be playing only a limited role in determining the levels of household consumption of electricity. In his view, these prices "play some role ... mainly by influencing the type of appliances purchased by consumers" (McColl, 1976, p. 15).

Further, McColl did not include prices of substitutes for electricity in his equations. Notwithstanding the fact that electricity is produced by using gas, coal and oil, and that these primary sources of energy also use electricity in their production, it is widely recognised that for some of its usage, electricity faces competition from gas, coal and oil. Thus prices of these substitutes need to be explicitly included in the demand function. Moreover, though he recognises the influence on demand of stock and types of appliances purchased by customers, McColl did not attempt to measure the impact of stock and applicance prices.

A model that explicitly recognises the short run dependency of electricity consumption on the household stock of appliances is the 'utilization model' first used by Fisher and Keyson (1962) and later developed by Wenders and Taylor (1975). In order to examine the long run elasticities, Fisher and Keyson extended their investigation by inclusion of new variables such as moving averages of real personal income, the price of gas, the ratio of electricity consumers to population, the number of marriages and the price of the 'white goods' concerned.

Fisher and Keyson identified the short run residential demand with the rate of utilization of electricity using appliances or "white goods". Their data were for each of 47 states (U.S.) over 1947-1957. In general, more mature states had a smaller price elasticity of demand, which led them to conclude that "as the economies of all states mature short run household electricity demand will become even less price sensitive than it now is" (Fisher and Keyson, 1962, p. 3).

In the long run, they identify "nearly no effect for price of electricity and a relatively small effect for appliance prices" (Fisher and Keyson, p. 5).

It should be noted, however, that the data available to the authors were, by their own admission, inadequate. Their significant variables were those whose first derivatives were included in the right hand side of the following equation. The cause of insignificance of some variables is apparently the fact that they are expressed in current period levels and not as differences between years.

$$W'_{it} - W'_{it-1} = A_i + \alpha_{i1}(Y^{E'}_t - Y^{E'}_{t-1}) + \alpha_{i2} Y'_t$$

$$+ \alpha_{i3} E'_{it} + \alpha_{i4} G'_{it} + \alpha_{i5}(H'_t - H'_{t-1})$$

$$+ \alpha_{i6}(F'_t - F'_{t-1}) + \alpha_{i7} M'_t + \alpha_{i8} P^{E'}_t$$

$$+ \alpha_{i9} V^{E'}_t + U_{it} \tag{3.9}$$

where ' is for log;

W = white good stock;

α_{ij} = series of coefficients to be estimated;

Y^E = moving average of real personal income per capita;

Y = real personal income per capita for the period;

E = price of the white good concerned;

G = price of gas;

H = number of electricity customers per capita;

F = population;

M = number of marriages during the period;

p^E = expected real price of electricity (measured by means of a three years moving average);

v^E = a three year moving average of gas price;

U = a random error term.

As an analogy one can view the above function as a consumption function specified with a flow variable on the left hand side and stock variables on the right hand side. Clearly, a proper specification should have the independent variables expressed as flows.

Although Fisher and Keyson mention that the size and composition of stock in year t should be expected to be influenced by an average of past income and of past prices, their model explicitly uses current income and current price, on the assumption that the current income and price would tend to be highly correlated with moving averages of their respective past values.

They also believe that "the rate schedule tends to remain fairly constant while the price index shifts through time". Perhaps this assumption is valid when applied to 1950's. But it cannot be expected to hold good at present or in future especially in the light of the recent experience where not only is the average price going up but also the rate schedule is being frequently changed.

Among other studies that recognised the importance of the stock of domestic appliances are Houthaker (1951), Anderson (1971) and Chichetti, Gillen and Smolensky (1977). Aigner (1975) in a recent study relates electricity consumption not only to the stock of appliances but also to their vintages. Whereas long run selection of a particular vintage with a certain energy coefficient is likely to be influenced by the price of electricity, the prices of appliances themselves may be important determinants of the size of the stock and therefore, the level of electricity consumption. Thus, in the short run, while the stock of appliances remains constant, the price elasticity of demand for electricity is expected to depend on the intensity with which appliances are used. In the long run, it is expected that the size of the stock of appliances would vary inversely with changes in their prices and in the price of electricity and directly with changes in income.

Fisher and Keyson used a double log functional form which presupposes that elasticities remain constant over time and over various levels of the explantory variables. This seems to be implausible and cannot be true for all commodities in general.[7]

However, despite its defects, especially that of non-additivity,[8] this functional form is considered without rival as regard goodness of fit and immediacy of interpretation (Houtheker, 1965, p. 278).

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7 Bridge, J.L., Applied Economics, Amsterdam, 1971, p. 99. Recall that from our budget equation 3.1 $\Sigma P_i x_i = y$, one can derive that

$$\frac{\partial x_i}{\partial y} \cdot \frac{y}{x_i} = 1$$

Now if goods have constant elasticity of demand, as income increases, consumers will spend more on those goods with high income elasticities and less on those goods with relatively low elasticities. However, with constant elasticities for all commodities, this will require that the above equation increases to more than one which is not possible under equation 3.1.

8 Houthaker, (1960), pp. 249-252.

Though their model appeared misspecified in respect of variables used, Mount, et al. (1973) attempted to retain the above advantages by estimating a variable elasticity model in the double log form. This model is represented below:

$$\log Q_t = \alpha + \sum_{i=1}^{n} \beta_i \log X_{it} + \sum_{i=1}^{n} \delta_i / X_{it} + \varepsilon_t \qquad (3.10)$$

where Q_i = quantity of electricity demanded at time t;

X = level of i^{th} causal factor;

α, β_i and δ_i are unknown to be estimated; and

ε = error term.

This specification is a simple generalization of the constant elasticity model implying that each elasticity varies as the level of the corresponding factor varies.

The elasticity of i^{th} factor is given by

$$\gamma_i = \beta_i - \delta_i / X_i \qquad (3.11)$$

where γ_i is the elasticity of demand with respect to i^{th} factor. A level of X_i must be specified when evaluating the elasticity since the value changes as the ratio δ_i/X_i changes. As the value of X_i increases, the elasticity approaches β_i asymtotically, and as X_i approaches zero, the elasticity approaches negative infinity.

One of the interesting findings Mount, et al. report is that the price elasticity of demand was directly related to the price level: demand becomes increasingly elastic as price rises. However, they did not explicitly use the prices of close substitutes such as coal and oil in their model. Further, the price variable they used is aggregated over utilities. Thus the coefficient of price in their model may not reflect the sensitivity of demand to price changes in an individual utility. Their model will be further discussed in sub-section 3.1.3.

In a cross-section study with 1971 data, Hawkins (1975) separately estimated residential, industrial and commercial demand for electricity in New South Wales and the Australian Capital Territory (ACT). In estimating residential demand, Hawkins used both oil and gas prices as substitute variables for customers having both electricity and gas connections and used oil price only (as a substitute variable) in the cases where gas connections were not available.

Looking at the t-statistics reported by Hawkins, it appears that in the case of residential demand none of his explanatory variables except own price and household size is significant. Further discussion of his model will follow in the next sub-section.

Another Australian study is Donnelly, Groneratne and Turnovsky (1982) on the "Residential Demand for Electricity in the ACT". They used a double log functional form which suffers from the same criticism as before. Moreover, a vital piece of information - the influence of the number of customers on total demand for residential electricity - is missing in their model. It seems that the model could have been substantially improved by expressing quantity of electricity demand per residential customer.

Among the explanatory variables used to estimate residential demand for electricity in addition to the variables already discussed, Wilson (1971) has used an index of temperature; Anderson (1971) tried the influence of average number of persons per household and an urbanisation index on the demand for electricity; Halvorsen (1978) has used the percentage of the rural population connected with the utility and the percentage of multi-unit housing structures; while Lyman (1976) has introduced distribution of income as an additional variable.

Among the multiplicity of explanatory variables used, the influence of variables other than own price, income and prices of substitutes seem to have been relatively insignificant in the case of residential demand.

3.1.3 Studies of Industrial Demand

Studies on industrial demand for electricity separately from other types of demand are relatively fewer than those on residential demand. A brief discussion of these studies is presented below and a summary of important findings is given in Table 26.

Although some economists consider the nature of the industrial demand to be similar to that for the other two sectors (Mount et al., 1973, Griffin, 1974), the majority of economists believe that the problem of non-homogeneity of industries with respect to size and energy intensity can only be dealt with by using industrial output as an explicit independent variable for electricity demand (see e.g., Baxter and Rees, 1968; Hawkins, 1975; Chern, 1975). Other explanatory variables considered by most of the writers are price of electricity and prices of substitutes such as oil, gas and coal.

The statistical evidence on the responsiveness of industrial electricity demand to the changes in relative price in the short run seems to be inadequate to draw any positive conclusions (see Taylor, 1975, Hawkins, 1975). Nevertheless, it may be assumed that in the long run, the structure of industry and technical advances themselves are influenced by the relative price, which in turn influences the industrial demand for electricity.

The price effect as reported by Baxter and Rees (1968) is ambiguous. The mean elasticity for 16 industry groups was -1.54. However, the coefficient for nine of these was not significant at the 95 per cent confidence level (see Baxter and Rees, 1968, p. 290). Although they reported the existence of autocorrelation and multi-collinearity, they concluded that output growth and technological change are the most important determinants of the growth in the industrial demand.

While Baxter and Rees (1968) and Chern (1975) used industrial value added to represent industrial output, Griffin (1974) and Hawkins (1975) used respectively GNP and number of persons employed as proxies for industrial output. It is, however, doubtful whether GNP can adequately represent the effect of industrial output on demand for electricity, since the composition of GNP and the composition of industrial output itself may vary sigificantly from year to year and from state to state. The number of persons employed can represent industrial and commercial activities only under the restrictive assumption that the relation between persons and hours of work as well as labour productivity is similar across states.

Hawkins expressed his dependent variable in terms of consumption per customer for all three sectors namely, residential, industrial and commercial. Whereas uniformity of customers' behaviour may be a reasonable presumption in the case of the residential sector, it may not be so in the other two sectors, since the size and nature of consumption varies widely in these two sectors e.g., some industries are more energy intensive than others, and some may operate at a very small scale and some at a very large scale. Moreover, neither Griffin nor Hawkins examined the influence of competing fuels on industrial demand for electricity.

Both Griffin (1974) and McColl (1976) considered industrial and commercial demand combined, a procedure which is subject to criticism. Since the purposes of electricity use in these two sectors are not the same, their responses to price or income changes are likely to be different. For the same reason, McColl's use of the value of factory production (F) as the regressor for commercial electricity is also questionable.

Mount, et al. use the same explantory variables to estimate demand for residential, industrial and commercial electricity in the U.S. The variables used in their study are population, income, price of electricity and price of gas. It is doubtful, however, if income and population are valid regressors for industrial demand for electricity, which is more directly influenced by industrial output.

Population can be taken as representative of industrial output only on the restrictive assumptions of fixed labour-output ratio and a fixed industrial labour to population ratio. This seems to be very unrealistic. In South Australia, manufacturing workers as a percentage of total population declined from 11 per cent in 1950 to 10 per cent in 1970 and 8 per cent in 1980. Real value added per worker, on the other hand, increased from $2,758 in 1950 to $5,577 in 1970 and $7,300 in 1980. Thus population does not seem to be an appropriate proxy for industrial output.

Similarly, in a country like Australia, where the contribution of manufacturing industry to the GNP is less than in most industrial countries, personal income may go up even when industrial output goes down. Under such conditions, income seems to be a poor regressor for industrial demand for electricity.

3.1.4 Studies of Commercial Demand

Very few writers have so far dwelt upon the factors influencing the commercial and other demand for electricity. One reason for this may be the relative insignificance of the proportion of electricity consumed by these sectors.[9] Another explanation may be that factors determining consumption in these sectors are not very different from those determining the total demand for electricity and as such no separate attempt to identify the factors has been made. But the most important reason seems to be the lack of clear cut definition of commercial and other (e.g., agricultural) demand for electricity: in some countries they have been branded together under the head of 'miscellaneous'; while in others the term rural energy encompasses agricultural as well as other categories of consumption in the countryside. Electricity consumption in dairy farms, rice mills, flour mills, cold storage etc. is sometimes defined as agricultural, sometimes as commercial and sometimes as industrial. Again, electricity consumption in hospitals, education institutions, public and private offices are sometimes defined as commercial and sometimes as miscellaneous.[10] Fortunately, a consistent demarcation of classes has been maintained in South Australia throughout the sample period, though lately the commercial consumption

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9 See, Energy Forecasting Methodology, Department of Energy, Energy Paper No. 29, London, HMSO, 1978, p. 23.

10 Hawkins (1975) also views that "the main reason for the lack of interest (in commercial demand) appears to be the poor quality of the data generally available", p. 6.

has been put under a 'general purpose' sub-heading.

It is understood that the determining factors in the case of the general purpose group are not different from those determining total consumption of electricity. However, in order to incorporate local idiosyncracies, it is advisable to disaggregate consumption by consumer class as far as possible and to fit a demand function for each class even though with the same set of independent variables. This facilitates the identification of differences in the estimated coefficients applying to a particular class, especially when there is a trend change in the structure of the economy (e.g., in Australia, manufacturing has been declining and services rising).

Mount et al. (1973) and Hawkins (1975) have estimated commercial demand for electricity separately from other sectors. Their findings are summarized in Table 26. Mount et al. used in their model both population and income as explanatory variables, which are likely to be collinear (see Section 4.2.1). The use of income per capita would have been more appropriate.

In Hawkins' model, commercial demand for electricity seems to be insensitive to changes in the price of electricity, the average number of employees in the commercial enterprises and the sales per retailer (S). But when the wage level (PL) in commercial enterprises is used as an additional variable, the first two variables as well as PL appear to be significant. Hawkins rejects this latter formulation because of the possible collinearity between PL and S. However, with exclusion of PL, the only significant variable in Hawkins' equation appears to be the dummy variable (see Hawkins, 1975, p. 13). Thus the sensitivity of commercial demand for electricity remains unresolved on the basis of this work.

3.1.5 Some General Observations

Two further points need to be clarified before we complete this general review of the literature on demand for electricity. First, a number of studies, such as Houthaker and Taylor (1970), Houthaker et al. (1973), expressed the dependent variable in terms of consumption per capita. This functional form presupposes a unit elasticity of demand with respect to population, thus ignoring any possibility of economies arising out of shared use of appliances. The model also ignores the possible differences in elasticities in different sectors.

Secondly, some studies (e.g. Wilson 1971, Halvorsen 1978) obtained a theoretically inconsistent sign for the coefficient of income. Wilson attributes the negative income elasticity to the correlation between low income areas and Federal Power Projects and their associated low wholesale rates. He also explains a negative sign for climate as "these projects occur in regions with mild climates". These explanations are ex post rationalisations and do not seem to be very convincing. Though he did not indicate the existence of any inter-correlation between average size of housing units and income, it is possible that the wrong signs are due to multicollinearity between these two variables.

We have discussed above the major studies of the determinants of demand for electricity in three consumer classes: residential, industrial and commercial. A summary of the major findings of these studies is presented in Table 26, followed by a brief discusion of some of the major issues especially relevant to the demand for electricity.

It appears from the summary of results presented below that estimates of own price elasticity of demand for electricity in the residential sector range from -0.06 to -2.00, implying that one per cent

3.1.6 Summary of Results

TABLE 26

Summary of Econometric Estimates of Elasticities of Demand for Electricity with Respect to Own Price, Income/Output and Cross Price

	Authors	Data Used	Price Variable Used	Elasticities* Own Price	Income	Cross** Price
	(1)	(2)	(3)	(4)	(5)	(6)
RESIDENTIAL DEMAND						
1.	Cutler (1941)	Both Time Series and Cross Section data for 1913-40, 1936, 1937, and 1939.	average price (AP)	-1.00		
2.	Houthaker (1951)	Cross-section of 42 provincial towns of U.K. in 1937	lagged marginal price (MP)	-.89	1.17	.21 (G)
3.	Fisher & Keysen (1962)	Pooled annual Time Series of 47 states for 1946-57	AP	-.15	0.10	
4.	Nelson (1965)	Studies 33 communities in Nebraska for 3 separate years 1948, 1954, and 1958. Used cross-section data.	AP		negative	
5.	Kline (1969)	Used log linear equation and Time Series data for 1950-65 (U.S.)	AP	n.e.	.88	.69 (G)
6.	Moore, T.G. (1970)	Cross-section data for 407 utilities in 1963 (U.S.)	AP for 250 kwh bill	-1.02 (LR) to -1.49	appeared negative so dropped	insign-ificant

TABLE 26 (continued)

	Authors (1)	Data Used (2)	Price Variable Used (3)	Elasticities*		
				Own Price (4)	Income (5)	Cross** Price (6)
7.	Houthaker & Taylor (1970)	Time Series of aggregate U.S. data for 1947-64	AP	-.13 -1.89 (LR)	.13 1.94 (LR)	-
8.	Houthaker, Verleger, & Sheehan (1973)	Pooled Cross section of states for 1961-71	3 levels of marginal price (MP)	-.09 -1.02 (LR)	.14 1.64 (LR)	not sign-ificant
9.	Wilson (1971)	Cross section of 77 U.S. cities for 1963-64	AP for 500 kwh bill	n.e. -2.00 (LR)	n.e. -.46 (LR)	.31 (O)
10.	Anderson (1972)	Cross section of states in 1969 (U.S.)	AP	n.e. -0.91 (LR)	1.13 (LR)	.13 (O)
11.	Halvorsen (1972)	Pooled Cross section of 48 states for 1961-69	AP	- -1.15	.51 (LR)	.04 (O)
12.	Bonneville Power Admin. (1973)	Both Cross section and Time Series data of U.S. for 1960-70	AP	- -.59[e]		
13.	Mount, Chapman & Tyrrell (1973)	Combined cross section and time series data for 48 states for 1946-69	AP	-.14[c] to -.35 -1.20[c] (LR) to -1.23 (LR)	.19[c] .18	.13[c](G) 1.9 (G)

TABLE 26 (continued)

	Authors	Data Used	Price Variable Used	Elasticities* Own Price	Income	Cross** Price
	(1)	(2)	(3)	(4)	(5)	(6)
14.	Griffin (1974)	Simulation model based on annual time series, 1953-71, U.S.	AP	-.06 -.52 (LR)	.88	not significant
15.	Joscow & Baugman (1975)	Cross sectional observation for 1968-72 in U.S.	AP	-.13 -1.31 (LR)	.08 .52	-
16.	Hawkins (1975)	Cross-section data: New South Wales and Australian Capital Territory, 1971	AP	-.55	.93	-
17.	Lyman (1976)	Pooled annual cross section of 31 utilities for 1960-68 (U.S.)	AP	-.44 to -1.1 -.45 to (LR) -.18	very low	not significant

Notes:

* LR for long run elasticities, otherwise the figures are short run elasticities.

** G for gas price, O for oil price and C for coal price.

	Authors (1)	Data Used (2)	Price Variable Used (3)	Elasticities Own Price (4)	Income/ Output (5)	Cross** Price (6)
INDUSTRIAL DEMAND FOR ELECTRICITY						
1.	Fisher & Keysen (1962)	Cross section of 10 manufacturing industries and 6 extractive industries for 1956 & 54 respectively in U.S.	AP	n.e. zero to -2.6 (LR)	.50 to 1.10	
2.	Baxter & Rees (1968)	Quarterly time series of 16 industry in U.K. for the period from 1954 to 1964	AP	-1.54 (LR)	.16 to 2.57	
3.	Wilson (1969)	Cross section of 15 two digit industry for 1963-64 (U.S.)	AP	-1.01 to -2.23 (LR)		not significant
4.	Anderson (1971)	Pooled cross section of metal industries in 30 states for 1958 & 1962 (U.S.)	AP	-1.94 (LR)		-.46 (G)
5.	Mount *et al.*, (1973)	Combined cross section and time series for 48 states for 1946-69 (U.S.)	AP	-.21 -1.64 to -1.72 (LR)	.43 to .54	.06
6.	Bonneville Power Admin. (1974)	Cross section of 48 states for 1970 & 1973 (U.S.)	AP	-1.04 (LR)		
7.	Griffin (1974)	Simulation model based on annual time series of post war U.S, (1953-71)	AP	-.04 -.51 (LR)	.89	
8.	Chern (1975)	Pooled national cross section of 16 three digit SIC industry for 1959-71, U.S.	AP	-.61 -1.98	.97	.53 (G) 1.62 (O)
9.	Hawkins (1975)	Cross-section for 1971, New South Wales and Australian Capital Territory	AP	-	.85	-

Authors (1)	Data Used (2)	Price Variable Used (3)	Elasticities* Own Price (4)	Income (5)	Cross** Price (6)
COMMERCIAL DEMAND FOR ELECTRICITY					
1. Mount *et al.*, (1973)	Combined Cross section and Time series data for 48 States for 1946-69	AP	-.16 -1.24 (LR)	.87 (LR)	.04 (G)
2. Bonneville Power Admin. (1974)	Both Cross-section and Time series data of U.S. for 1960-1970	AP	-1.07 (LR)		
3. Hawkins (1975)	Cross-section for 1971 New South Wales and Australian Capital Territory	AP	-	.79 (S)(LR) -1.03 (M_r) .99 (M_r + M_o)	-

Notes:

c Elasticity of demand for the state of California.

e Elasticity of demand for Bonneville Power Administration Trust.

S Retail sale per commercial customer.

M_r Number of employees in retail and wholesale trade per commercial customer.

M_o Number of employees in transport and storage, communication, finance and business services, public administration and defence, community services, entertainment and recreation.

change in price will cause a change in the demand for electricity possibly as low as .06 per cent or as high as 2 per cent. The estimated responsiveness to the change in income varies from nearly zero to 1.94; while the estimated price elasticity of demand for industrial electricity varies from zero to -2.6. Obviously, such wide variations in the estimated results raise serious doubts about the validity of the specifications used and/or the accuracy of the data.

It should however, be noted that comparison of separate industrial studies are not valid unless the classification of industries is the same. It may be recalled that Mount et al. used total industrial demand, Anderson analysed primary metals and Chern used three digit industries. As such, the findings of these studies are not directly comparable.

One fundamental criticism which applies to most of the studies is the aggregative nature of the data used, which ignores the idiosycracies of different consumer classes. Another criticism is the use of a constant elasticity model. This imposes constant elasticity values over time and as the magnitudes of the dependent and independent variables alter.

As mentioned earlier, the results obtained from these studies cannot serve the specific purposes of evaluation (or prescription) of inter-class price differentials or load demand forecasts for the future. However, one concensus which does emerge from the above review is that variables other than own price, income (or industrial output) and prices of substitutes are not very important determinants of the demand for electricity.

SECTION TWO: SOME SPECIAL ISSUES IN THE ANALYSIS OF DEMAND FOR ELECTRICITY

Introduction

Frequently, analysis of the demand for electricity encounters the problem of simultaneity in estimation and the question whether the marginal price or average price of electricity is the more appropriate independent variable. Moreover, whether the estimated parameters reflect short run or long run elasticities is also an important question. In this section, we present the issues involved and outline the way they will be treated in the present study. We deal first with the problem of measuring short run and long run elasticities of demand.

3.2.1 The Measurement of Short Run and Long Run Elasticities of Demand

The short run demand elasticity is defined as the responsiveness of demand when the stock of (electricity-using) equipment remains constant. When the stock of appliances is allowed to change, the estimated parameters will give long run elasticities.

There are at least three methods of incorporating this distinction into the demand model. The first is to include a stock variable in the demand equation; the long run effect may, then, be determined by estimating the stock equation; the second is to use a lagged dependent variable in the demand equation; and the third is to estimate cross-section models which, under the assumption that the market is in equilibrium, is supposed to pick up long run effects.

Although Fisher and Keysen (1962) and Anderson (1971) estimate separate stock equations, only Houthaker explicitly includes a stock variable in his model indicating that the measures were short run, though he does not mention this. Fisher and Keysen included a stock variable in their theoretical model but the estimated model was a simplified version wherein the stock effect was included in the constant term. By these procedures, they endeavour to measure short run effects in their demand equations and long run effects from the stock equation.

Anderson uses a cross-section model. He measures long run effects in both his stock equations and his electricity demand equations. Wilson (1971) uses a cross-section of cities and Halvorsen (1978) uses a cross-section of states.

Studies that used distributed lag parameters are Houthaker et al. (1973), Mount et al. (1973), Baxter and Rees (1968), Griffin (1974), Chern (1975) and Lyman (1976). All these studies except Griffin's used a Koyck transformation which assumes a geometrically declining response as reflected in the weights of the lag distribution.

Halvorsen comments that his dynamic structure made no significant difference in the estimation of coefficients though he thinks that his price elasticity of demand was likely to have been overestimated by his static model (Halvorsen, 1973, p. 157). Other studies did not test alternative specifications.

Griffin used an Almon polynomial distributed lag because it placed fewer constraints on the lag structure and conserved degrees of freedom. It is worth noting that Griffin's price elasticity of demand is the lowest among the studies mentioned above. Whether this resulted from his choice of lag structure is an interesting question.

For our purposes, a lagged dependent variable has been selected as the most appropriate method by which to distinguish the long and short run responses. The reasons for this choice are discussed in Chapter Four. They are in brief as follows:

1. Data on the stock of appliances are rarely available and those data which do exist are likely to be of uncertain quality. The stock variable, to be meaningful, has to be expressed in terms of KW capacity, the computation of which would be very costly in terms of money and time. Given the availability of alternative estimates - this effort would be hard to justify.

2. The price charged by ETSA is uniform throughout the state of South Australia. Data on regional (or individual) consumption, income and other variables are not available either. In these circumstances no cross-section study to estimate the elasticities can be carried out.

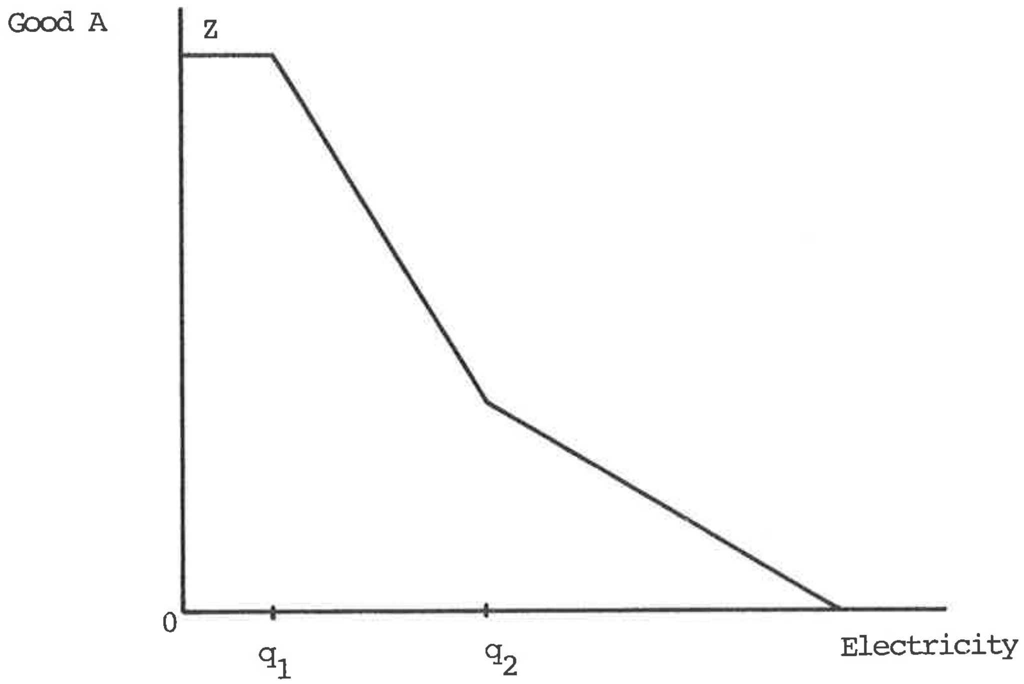
3. In the case of industrial demand for electricity, where industrial value added will be used as an explanatory variable, it is expected that this variable will account for changes in the stock of capital equipment as well as in the intensity of capital use.

In the next sub-section we deal with problems arising from the nature of the price variable used in the demand equation.

3.2.2 Problems with the Price Variable in the Demand Equation

One of the major problems encountered by almost all studies of the demand for electricity is the existence of a declining block rate structure of prices in the ESI. Under this system, the consumer faces not a single price, but a schedule of prices similar to what Pigou termed Second Degree Discrimination (SDD).[11] As a consumer consumes more and more, he finds himself in a lower price block and as such his budget line has kinks. Taylor (1975, p. 76) has demonstrated this phenomenon in the following figure.

FIGURE 2



Any change in the block prices or in the fixed charge represented by the horizontal segment of the curve (z) may lead the equilibrium point to switch from one section of the budget line to another. Because of the discontinuous nature of the budget constraint, ordinary calculus is incapable of deriving a demand equilibrium. While equilibrium may be discovered by applying mathematical programming, the resulting demand function is not obtained from the solution of first order maximization conditions.

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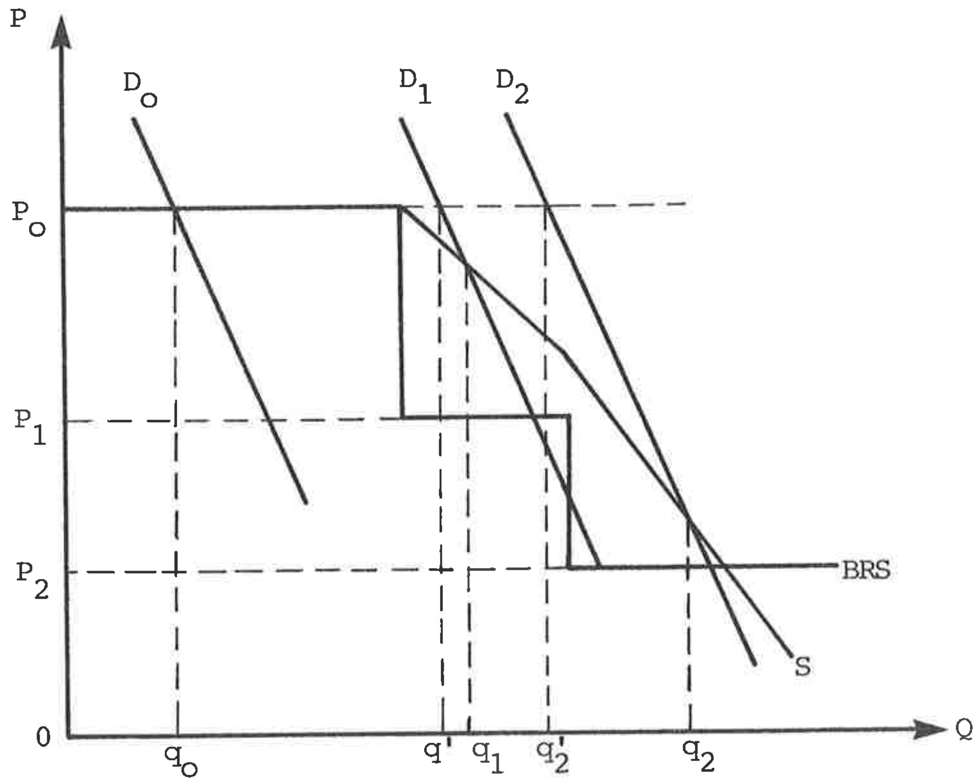
11 See Chapter Seven for further details.

Another problem that block rate pricing gives rise to is the problem of identification. This may be illustrated in the following figure.

FIGURE 3



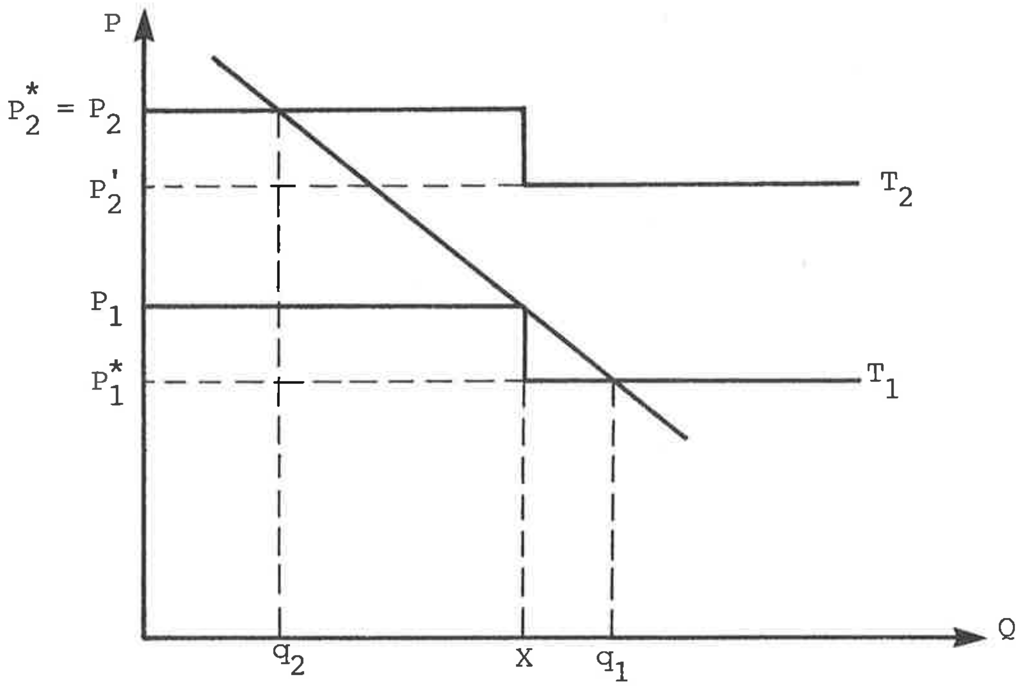
Because of the existence of a block rate schedule (BRS), a consumer faces an average supply curve like SS in the above figure. The shifts in the demand curve from D_o to D_1 to D_2 may be due to changes in income, population, taste etc. At the original price OP_o, these shifts would have been to q_1' and q_2' respectively. But if the shifts are to q_1 and q_2, then there are price effects too. To differentiate between price and non-price effects requires specification of the supply function as well. Until quite recently, it was believed that the price effect was insignificant and the negative relationship observed between price and quantity was explained away as the effect on price of shifts of the demand curve arising from the existence of the BRS, and not the effect of price on the quantity demanded. We treat this problem separately in sub-section 3.2.4.

Yet another problem encountered with the BRS is the divergence between average price and marginal price as shown in the diagram. At a point of time, different consumers will consume at different blocks, so that the data on marginal price would be very difficult to obtain. The basic question is, however, which price in the BRS is the best approximation to the demand relation. Most of the previous studies believed the marginal price was the most appropriate one. Halvorsen (1972, p. 4) says "a purchaser of electricity like any monopolist should base his decision on the marginal price and this is the relevant price variable to include in the equation". Mount _et al._ (1973, p. 6) comment "in economic theory consumers decisions are based on marginal prices". Despite the desirability of using marginal price the problem remains as to which marginal price and how to extract it from the data. The marginal price that refers to the last block is relevant only when the consumer takes from that block. Moreover, the method would require the use of individuals as the unit of observation. Aggregation of individuals would transform the marginal price into an average price unless a single tariff schedule is applicable to all customers who happened to be in the same block.

A way out of this problem may be to use the _ex ante_ marginal price. But the _ex ante_ marginal price is not often the price most relevant to the demand decision.[12] It is important to note that in some studies where ex ante prices were used results vary significantly with variations in the choice of margins. For instance, Houthaker, et al. find long run price elasticity of demand at -.44 for the marginal price of 250-500 kwh but a comparatively very large elasticity of -1.02 for the marginal price of 100-500 kwh. Similarly, Wilson (1971) estimated long run elasticity at -2.00 based on Typical Electric Bill (TEB) for 500 kwh, while Anderson (1972) finds it -.91 for 500-1,000 kwh.

Griffin (1974, p. 531) observes that the use of marginal price may lead to an upward bias of the estimated price elasticity of demand. This is illustrated in the following figure:

FIGURE 4



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[12] Ex ante price is the price specified independent of the sale volume as opposed to ex post price i.e., price actually paid which is determined only after the sale level is established. It should be noted, however, that the use of ex ante marginal price in Houthaker's (1951) article was not irrelevant to the demand decision in the sense that in the U.K. at that time a two part tariff consisting of a fixed charge and a constant marginal charge was in practice, so that marginal price did not vary with the quantity consumed.

At P_2, the consumer's demand is such that he cannot avail himself of the opportunity given by lower block price, P_2'. But when the price comes down to P_1, he can take from lower priced block, so that the actual price he pays is P_1^*. The price elasticity of demand from the observed price changes is given by

$$E_p = \frac{q_2 - q_1}{q_2} \cdot \frac{P_2^*}{P_2^* - P_1} \tag{3.12}$$

But the true price change is $P_2^* - P_1^*$. Since $P_1^* < P_1$, so $E_{p^*} < E_p$, where E_{p^*} represents actual price elasticity of demand.

Taylor (1975, p. 80) recognises this problem of upward bias in the presence of a declining block rate schedule where either marginal price or average price is used separately. To overcome the theoretical problem, Taylor advocates the use of both average and marginal prices as predictors in the demand function. The marginal price to be included should represent the cost of electricity in the last block, while the average price should refer to the average price per kwh of the electricity consumed up to but not including, the final block. Taylor considers that an increase in the customer's charge (Segment Z in Figure 2) or an increase in the intra-marginal price are equal in the sense that they give rise to income effects but not to substitution effects. "But marginal price yields both an income effect and a substitution effect" (Taylor, 1975, pp. 79-80).

This approach was tried by Lyman (1976) with 'implausible results'. Roth (1981, p. 377) using this approach finds his results to be "anomalous because it contradicts most existing empirical studies of electricity demand" and "acceptance of these findings requires a willing suspension of disbelief" (p. 383). The reason why this approach is not satisfactory is that generally only one of the price variables is statistically significant (see Acton et al., 1976). Secondly, the multicollinearity between the two prices (marginal and average) may also decrease the precision with which the coefficients of other variables are estimated.

Wilson (1971), Halvorsen (1978) and Lyman (1976) tried both average price and typical electric bill (TEB) separately for the residential class but did not find any significant difference in the results. Halvorsen showed that in the case of a double log function the use of average price affects only the constant terms.[13] It seems, therefore, that the use of average price provides substantial convenience without significant loss of efficiency. Moreover, to use marginal price is to neglect all rate blocks except one. George (1979, p. 2) concludes "evidence ... suggests that, at least from a practical standpoint, much of the controversy regarding price specification ... is unfounded". Mount et al. (1973, p. 6) conclude "there is no empirical evidence that either the use of marginal prices or the consideration of simultaneity gives results that conflict with those obtained with average prices and single equation models".

3.2.3 Proposed Price Variable in the Present Study

As opposed to the use of marginal price, most of the studies employed average price calculated as the ratio of total expenditure to quantity consumed. In the present study, we shall use the average price for the following reasons:

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13 See Halvorsen (1978), p. 11. See also Uri, Energy Economics, 1979, p. 15.

1. It is felt that this is the most relevant price which the customers take into account for long run decision purposes;[14]

2. From the results obtained in the previous studies, it remains inconclusive whether average price underestimates or marginal price overestimates the elasticity of demand;[15]

3. Data on average price are more easily available;

4. The rate structure is likely to be varied with average price in mind to maintain a balance with average cost;

5. Moreover, it can be shown that in the case of a multiplicative functional form, the estimated parameters based on average price will be identical to what would be obtained with marginal price. Recall that the relationship between average price, P_a and marginal price, P_m is given by

$$P_a = \frac{P_m}{1 - \frac{1}{e}} \tag{3.13}$$

where e = price elasticity of demand; P_a = average price; and P_m = marginal price.

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14 George (1979) quotes Parti and Bawman (1977) concluding that "consumers estimate the current price of electricity by comparing their bills in the previous month with total kwh consumed that month", p. 28.

15 Using ex ante marginal price, Taylor et al., estimate the own price elasticity at -0.8 for residential demand. See Taylor et al., (1976), Residential Demand For Electricity, Report to the Power Research Institute, June 1976. This they claim to be substantially lower than -1.00 obtained from several other studies using average price. However Griffin (1974) using average price and a polynomial lag formulation obtained an elasticity as low as -0.5. Thus a higher elasticity obtained from other studies using average price cannot easily be attributed to the biases of using average price. See also Table 26, where elasticities using marginal prices are not the largest.

Now our demand equation with P_a as an explanatory variable such as

$$Q = AP_a^{\beta} \tag{3.14}$$

can be written as:

$$Q = A\left(\frac{1}{1 - \frac{1}{e}}\right)^{\beta} P_m^{\beta} \tag{3.15}$$

Equation 3.15 shows that using marginal price in place of average price affects only the constant term in the equation.

6. In South Australia over 90 per cent of residential customers buy from the 3rd block i.e., 300-2,700 kwh per quarter. The average consumption also falls in this block. Thus the marginal and average prices are expected to give similar results for most customers.

3.2.4 Problem of Simultaneity

Two problems of simultaneity may arise because of our decision to use ex post average price. First, as price and quantity are jointly determined by demand and supply functions, from the quantity sold and ex post price we may arrive at either the demand or the supply curve. Thus simultaneous equations may be necessary. Secondly, with declining block rates, the price paid by the customers itself is a function of quantity demanded. The question arises, therefore, whether there is any problem of simultaneity peculiar to the presence of a block rate schedule (BRS).

The first thing to look at is whether a simultaneous equation is necessary. The standard demand and supply functions may be represented by:

$$Q = f(X_1, X_2) \tag{3.16}$$

$$X_1 = f(Q, X_3) \tag{3.17}$$

where Q = quantity of electricity demanded;

X_1 = supply price;

X_2 = a vector of all other causative factors of demand;

X_3 = cost of inputs.

Thus X_2 and X_3 are exogenous variables and X_1 and Q are simultaneously determined. Equation 3.16 is estimated by eliminating X_1 from the structural equations, thereby producing a combined reduced form equation.

Two situations may make the simultaneous equations unnecessary for the purpose of identifying the demand function. The first is if there are no shifts in the demand curve, which may happen if income and other variables are assumed constant, so that

$$Q = f(X_1) \tag{3.18}$$

In this case, the estimated function will be the demand function. The second is if supply is infinitely elastic, then

$$X_1 = f(X_3) \tag{3.19}$$

and X_1 is completely determined exogenously. In this case, the system equation is recursive.

The basic question is whether Q and BRS are jointly determined or whether BRS is entirely exogenously determined. If BRS is modified in response to changes in the actual level of demand, then simultaneity exists.[16] Mount et al. (1973) and Chern (1975) assume that the demand curve is identified, because the existing regulations in the ESI require that the desired quantity is supplied at the regulated price and the price cannot be changed quickly in response to changes in cost. As such, BRS can be taken as an exogenous variable (see Cramer, 1971, p. 213). This is more true in the case of a public enterprise such as ETSA which is not a profit maximiser.[17] Price setting in such enterprises normally involves more complex procedures than are frequently observed in the case of private enterprises.[18] This makes the simultaneous equations unnecessary. It may also be noted that simultaneous equations used by Halvorsen (1973) and Anderson (1972) produced very little difference in the estimates from those produced by single equations assuming no identification problem (see also Mount et al., 1973, p. 6).

Under such circumstances, the present study takes the view that the prices in ETSA are likely to be exogenously determined and the problem of identification can, therefore, be ignored. We prefer to use a single equation model, for the empirical convenience it offers.

It may, however, be argued that if ETSA works on a no loss - no

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16 Further discussion on this is to be found in Section 4.2.4.

17 "The Trust's primary function is not to make profit but to provide a service to the Community", ETSA Annual Report, 1969, p. 16.

18 Price changes in publicly owned enterprises sometimes involve inter-ministerial arguments and counter arguments and sometimes even lead to debates in the parliament.

profit basis, this implies a link between average cost and price. If there are significant economies (or diseconomies) of scale, average cost will vary with quantity. This implies a link between quantity and price, and as such a simultaneity problem can not be ruled out. We, therefore, supplement our single equation estimates by those of simultaneous equations to examine the differences, if any (see Section 4.2.4 and also Section 5.1.1).

CHAPTER FOUR

RESIDENTIAL DEMAND FOR ELECTRICITY

SECTION ONE: THE MODEL

Introduction

Many economists agree with Professor Forrester that "in formulating a model of a system we should less exclusively depend on statistics and formal data and make better use of our vast store of descriptive information".[1]

Such an approach would perhaps explain adequately the behaviour pattern in the ESI but cannot be expected to produce a precise quantitative prediction. Marshall said "qualitative analysis tells the iron master that there is some sulpher in his ore, but it does not enable him to decide whether it is worthwhile to smelt the ore at all, and if it is, then by what process. For that purpose he needs quantitative analysis which will tell him how much sulpher there is in the ore".[2]

In the present study, an attempt will be made to bridge the gap between qualitative and quantitative analyses by bringing some of the behavioural characteristics together with prediction-oriented models of demand for electricity. In what follows, I shall first briefly outline

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1 Forrester, J.W., Industrial Economics, MIT Press, 1961, p. 54.

2 Marshall, A., "The Old Generation of Economists and the New", The Quarterly Journal of Economics, Vol. 11, No. 2, January 1897, p. 123.

the theoretical model adopted for estimating demand for residential electricity in South Australia and then present the empirical results.

4.1 Specification of the Residential Demand Function

In the Introduction of the previous chapter we have briefly discussed the development of demand theory for the individual consumer. It was observed that, though market data do not exactly represent the behaviour of an 'individual consumer', they may very well represent a 'representative consumer'. In Section 3.1, a survey of recent studies on electricity demand has been presented. It has been observed that residential electricity demand is expected to be a function of both economic and non-economic variables. Relevant economic variables include the price of electricity, the prices of substitutes and complements and the level of income. Among non-economic determinants of electricity demand are climate, demographic variables and the characteristics of the housing stock.

It should be noted that consumers' behaviour in the residential sector can be approached from two view points. One postulates that each consumer wants to maximize utility subject to a budget constraint and that utility is a function of goods and services consumed. The other assumes that "consumption is an activity in which goods, singly or in combination, are inputs and in which the output is a collection of characteristics" (Lancaster, 1966, p. 133). One formulation of this latter approach is to consider the households as producers who determine the optimal uses of inputs by minimizing costs for a given level of output - the level of output being determined by the budget constraint. When the Kuhn-Tucker conditions are solved for, each model renders the same outcome. That is, the individuals in maximising utility (minimizing cost) would equate the marginal rate of substitution between two commodities with the ratio of their prices (see equation 3.2, p. 98).

Given this behavioural condition, it was shown in equation 3.3 that the sum of price elasticities for any good would be equal to minus the income elasticity. Thus the change in an individual demand for any commodity can be explained in terms of its elasticities with respect to own price, cross prices and the consumers' income (see Bridge, 1971, p. 29). That is

$$dQ = \eta dP + \gamma dY \qquad (4.1)$$

where Q = quantity demanded;

P = price;

Y = income;

η = sum of price elasticities of demand (own price and cross prices)

γ = income elasticity of demand.

Since the prices of all goods and services may influence the changes in outlay or share of income spent on electricity and (hence the elasticities) and it is not possible to either know all such prices or use them in a single equation (because of inadequate degrees of freedom or the problem of multicollinearity), they are conveniently expressed in the form of the consumers' price index (CPI). The CPI is then used as a deflator of individual prices and income to express them in real terms.

Among the price variables included in the present study are the price of electricity, prices of oil and gas and a price index of domestic appliances. Price of coal is not included since almost no coal is used for domestic purposes in South Australia.[3] The problem of selecting the appropriate price variable has been discussed in Section 3.2 and will be further discussed in Sections 4.2.4 and 5.1.1. Suffice it to say at this stage that we are using average price since about 96 per cent of the residential customers in South Australia take electricity from a single block and as such the marginal price for the majority of customers is not likely to be much different from the average price. We expect, therefore, that the results given by the average price will be similar to those from use of marginal price.

Equation 4.1 represents the demand function of a (typical) individual customer. Total demand for electricity is likely to be influenced by the number of customers, population and the number of dwellings in an area served by the utility.

Other variables such as air temperature, number of marriages and interest rates (which affects the capital rental for appliances) may also affect the demand for electricity. In a preliminary test, however, these variables appeared to be insignificant regressors in the present case.

Finally, the time trend is used in an attempt to represent those time-related variables which could not be introduced explicitly into the regression equation. It is assumed that these factors have a constant rate of change per unit of time. We expect the time trend to account for changes in such factors as consumers' tastes, technology and distribution of income and to absorb the influence of others such as the number of dwellings and population which show a strong inter-correlation

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3 See, Report of the South Australia State Energy Committee Report, 1976, p. 58.

and which do not appear explicitly in some equations.[4]

4.1.1 The Functional Form

Economic theory merely tell us that quantity demanded is a function of certain variable(s). It does not tell us the actual functional form of the relationship e.g., is the relationship linear, log linear or exponential? This is something we have to decide on the basis of the data used.

Linear equations give variable elasticities and log linear equations give constant elasticities. The latter form represents a hyperbolic relationship between demand for electricity and the independent variables. It has been observed earlier (see footnote 7, p. 109) that a constant elasticity model for all commodities in the consumers' basket is inconsistent with the budget constraint hypothesis.

In an attempt to test the nature of the relationship between the dependent and independent variables, we have fitted a number of scatter diagrams which appear to be more amenable to a linear relationship than to any other form. The pattern of the relationship over the entire sample period (1950-80) appears to be the same. The Chow test as well as the Gujarati test confirm this view.[5] On the basis of the economic, econometric and statistical criteria set out in Appendix III, the results obtained from the linear model appeared more plausible than those obtained from the double log, semi-log or exponential models

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4 See Shultz, H., The Theory and Measurement of Demand, Chicago, 1938, p. 10.

5 See Dutta, M., (1975), pp. 173-178 for Chow Test and Gujarati (1970), pp. 18-21 for Gujarati Test.

attempted.

Note that a demand function such as equation 4.1 assumes no adjustment lags in demand due to any change in independent variables. However, Nerlove (1958) has shown that such lags may sometimes be important. Hence two different models, static and dynamic, are estimated to see the differences (if any) between the short run and the long run elasticities.

The Static Model

The static model used in the present study is presented in equation 4.2.

$$Q_t = \alpha + \beta X_{it} + U \tag{4.2}$$

where Q_t = quantity of electricity demanded at time t;

X_{it} = explanatory variables;

i = 1, 2, ..., n

U = error terms assumed to be normally distributed and uncorrelated with included variables; and

α and β's are parameters to be estimated.

The Dynamic Model

It is assumed that the full influence of the explanatory variables are realized only in the long run. That is, the full impact of an independent variable depends on its past as well as present values, the weight being successively diminished as we go further back in the past. Thus the estimated coefficients of the (current) observed variables reflect the short run variations (demand elasticities) only.

On the assumption that the percentage of the total impact realized in each period has a geometric distribution, Koyck (1954) has shown that an equation like 4.3 below can be transformed into a more simple equation like 4.4 which requires only one observation to be lost. According to the Koyck transformation, equation 4.2 would appear as follows:

$$Q_t = \alpha + (\beta_o\lambda^o)\ X_t + \beta_1\lambda^1(X_{t-1}) + \beta_2\lambda^2(X_{t-2})\ \ldots\ \beta_n\lambda^n(X_{t-n}) \qquad (4.3)$$

Here β (= $\Sigma\beta_i$) is the total or long run effect and λ's ($\lambda > 0$ for any period and $\Sigma\lambda^i = 1$) indicate the percentage realized in each period. In order to eliminate the infinite sum, Koyck lagged Q_t by one period, multiplied equation 4.3 through by $(1 - \lambda)$ and then subtracted this lag transformed equation from equation 4.3 to obtain the following equation.

$$Q_t = \alpha\lambda + (1 - \lambda)\ Q_{t-1} + (\beta_i\lambda_i)\ X_{it} \qquad (4.4)$$

The property of the geometric distribution of the weight given to the succesive past values of the explanatory variables makes the above expression in terms of the lagged dependent variable possible. The main attraction of this transformation is that the researcher is not required to know the past values of the explanatory variables. He or she can also avoid the trouble of estimating a large number of parameters when the weights of the parameters extend far into the past. Further, one can save a large number of degrees of freedom by using the lagged dependent variable. The value of λ can be obtained from the regression coefficient of Q_{t-1}, which then can be used to find out the values of the β's from the coefficients of X_{it}.

However, the Koyck transformation is not an unmixed blessing. Koyck's assumption of a geometric lag distribution is sometimes considered to be rather restrictive. In reality, there is no reason why it should always be geometric. For instance, due to habit, income in the previous period may have a larger impact on consumption than does income in the current period. Moreover, the impact of an independent variable may not continue ad infinitum in the past. A flexibility in the lag distribution can be incorporated into the mdoel by using the Almon polynomial.[6] In the present study, different values of the polynomial and year lengths were tried but the results were not plausible. We therefore concentrate our attention on the Koyck model.

The nature and the sources of the data used are discussed in Appendix II. In Appendix III, we briefly outline the economic, econometric and statistical tests on the basis of which regression results are assessed.

4.1.2 Theoretical Expectations of Signs and Magnitudes of the Estimated Parameters

Before proceeding to the estimation of our equations, we may make a few a priori comments on the signs and magnitudes of the regression coefficients.

As far as the signs of the coefficients are concerned, economic theory postulates the signs for own price and prices of electric appliances to be negative and those with respect to prices of

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6 See Almon, S., "The Distributed Lag Between Capital Appropriation and Expenditure", Econometrica, January, 1965, p. 178.

substitutes, income and the other variables used to be positive. The sign for the coefficient of time (T) may however, be positive or negative. If it happens that over the sample period, consumers' tastes and habits and the technology which T represents, undergo changes in favour of more electricity consumption, then the parameter for T will have a positive sign. On the other hand, if the new technology is energy saving, then a negative sign may be obtained.

Parenthetically, it should be emphasised that the sign for the price coefficient is expected to be negative even if the commodity concerned (electricity) is considered to be an inferior good.[7] While the substitution effect of any price change is negative and the income effect is positive, the income effect is normally weaker than the substitution effect (see Hicks, 1956, p. 65). Thus the former outweighs the latter and the net effect is a negative sign for the price coefficient. Only in exceptional circumstances will the income effect outweigh the substitution effect, thus producing a positive sign for the price coefficient. It presupposes that the commodity is an "inferior" one, that a considerable proportion of the income must be spent on it and finally, that the substitution effect must be small. A negative price elasticity is expected in our case since electricity does not satisfy the first two properties.[8]

As far as the magnitude of the price elasticity is concerned, it can be reasoned that as the consumption of electricity claims only a

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7 Consistency requires that if the own price coefficient is positive, the income coefficient would be negative.

8 The total revenue from the residential sector in 1980 amounted to A$83.134 million. This is roughly 1 per cent of the total household disposable income in 1980, i.e., A$7750.43 millions.

small proportion of one's budget and falls in the category of necessities, so the price elasticity of demand is expected to be low. Further, in the short run consumers are locked into using existing appliances. Hence the elasticity is expected to be lower in the short run than in the long run.

Another reason why the long run price elasticity is expected to be larger is that as income rises, people tend to possess more appliances which provide similar services but use different types of energy. These provide them with a wider scope for controlling the intensity of use of a particular type of appliance.[9]

As far as the income elasticity of demand is concerned, according to economic theory, one can generally expect an increase in electricity demand whenever there is an increase in income. This means that a positive sign is expected for the coefficient of the income variable. However, a negative sign, though unexpected, is not implausible. With the rise in per capita income, people may tend to buy more outside leisure, thus reducing residential consumption of electricity. Halvorsen (1978) reports negative income elasticities in 27 out of 48 states of the USA he studied (see Halvorsen, 1978, p. 148).

The magnitude of income elasticity is expected to be high in the early period of economic development. Over time, as the stock of appliances approaches the saturation level, the income elasticity tends to decline.

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9 In South Australia it appears that most of the households have duplicate heating arrangements and a substantial number of households have more than one refrigerator. See ABS, National Energy Survey: Household Appliances, Facilities and Insulation, November 1980, Table 1, p. 3.

The cross price elasticities are likely to be positive and larger in the long run than in the short run.

It may be noted here that South Australia did not have natural gas prior to 1968-69. However, domestic customers were supplied with manufactured gas, the energy content of which was less than half that of natural gas.[10] Since the attributes of gas were different in the periods before and after natural gas was introduced, its price, though expressed in terms of a common denominator (GJ) may not offer the same degree of competition with electricity. The difference (if any) in the quality of gas available since 1969 may be represented by introducing a dummy variable (equal to zero for the period from 1950 to 1968 and equal to 1 thereafter) and interacting that dummy variable with the gas price. It is important to note, however, that the competition from gas has remained virtually confined to the traditional areas of cooking and heating. Even in these areas the mobility and portability of electric heaters and the innovation of a large variety of electric kitchen equipment (such as electric kettle, grinder, food processor, sandwich maker, microwave, dishwasher etc.) limits the potential for gas to compete.[11] The South Australian statistics on gas consumption also lend support to this view. Per capita household and commercial consumption of gas in 1970 was only 66 per cent of that in 1960 and did not go above

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10 Manufactured Gas = 18.6 GJ/cm, Natural Gas = 39.1 GJ/cm, where cm = cubic meter. See <u>S.A. State Energy Committee Report</u>, 1976, p. 78.

11 The decline in the family size over the years seems to have made these small electric equipment more attractive than the usual gas equipment. This view has supports from an ABS <u>Household Survey</u>, See <u>Domestic Energy Consumption and Expenditure on the Adelaide Plains</u>, by P.J. Walsh, DME, 1984.

the 1960 index until 1974.[12]

The reason for this low profile of gas consumption is not our main area of investigation. However, it seems clear that the drive by ETSA to make electricity available to every household in the state and to popularize electricity by introducing an appliance hire system has not been matched by any similar drive from SAGASCO. Whereas almost a hundred per cent households in South Australia have electricity connection, only 44 per cent of them have gas connections. Moreover, only 40 per cent of the residential electricity is consumed for cooking, water heating and room heating which have direct competition from gas. The entire gas consumption in the residential sector is for the above purposes.[13] Thus it seems reasonable to believe that the influence of gas price on household demand for electricity in South Australia over the sample period may not have been important.

Electricity for lighting is virtually without rival whenever it is available. Modern household amenities such as refrigerators, television, irons, radios, videos, washing machines, air conditioners and fans can be operated only by electricity. Thus the demand for electricity for these purposes is not likely to be influenced by any change in gas or oil prices. However, oil heaters seem to have been a special market in South Australia. Unlike in many other places, the domestic consumption of heating oil in this area has been on the

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12 See S.A. State Energy Commitee Report 1976, pp. 52-54.

13 See SAGASCO, Annual Reports, 1979-80. ABS, Cat. No. 8208.4, Domestic Appliances and Energy Usage, South Australia, April, 1979, p. 13. Also ABS, Population and Dwellings, LGA 1961-76.

increase since 1960.[14] Thus the oil price is likely to be a significant regressor but its coefficient may be small in magnitude, since its sphere of competition with electricity is restricted mainly to space heating.

In the following section, we present the empirical results.

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14 S.A. State Energy Committee Report 1976, p. 54, see also Demand for Primary Fuels, Australia: 1976-87, DNDE, April 1978, p. 33. The growth of demand for heating oil was at the rate of 36.93 per cent per annum from 1960-61 to 1975-76 and thereafter up to 1980 at the rate of 6.5 per cent per annum.

SECTION TWO: THE EMPIRICAL ESTIMATES

4.2 Introduction

In the previous section, we have discussed the model for residential demand for electricity. We have also discussed the theoretical expectations as regards signs and magnitudes of the demand parameters. It has been observed that given the data conditions, a linear model (variable elasticity model) appears to be the most suitable model for the present study. The model is represented below.

Static

$$Q = \alpha + \beta_1 PE + \beta_2 PO + \beta_3 PG + \beta_4 PA + \beta_5 RC + \beta_6 YD + \beta_7 D + \beta_8 N + \beta_9 T + U \tag{4.5}$$

Dynamic

$$Q = \alpha\lambda + (1 - \lambda)Q_{t-1} + \beta_1\lambda_1 PE + \ldots + \beta_9\lambda_9 T + U \tag{4.6}$$

* For definition of variables see Appendix II.

** For the simultaneous equation and systemwide models see Sections 4.2.4 and 4.2.5 respectively.

Before we present the empirical results, it may be worthwhile to discuss the problems encountered in estimating our demand equations. We begin with the problem of multicollinearity.

4.2.1 The Problems of Multicollinearity, Autocorrelation and Heteroscedasticity

On the basis of the simple correlation coefficients between two independent variables and on the basis of the Klein's rule (see equation R.6, Appendix III), it appeared that the number of residential customers (RC) and the number of dwellings (D) are highly intercorrelated. The simple correlation coefficient between these two variables was as high as .998. D is also highly collinear with per capita income (YD) and population (N). A regression of D with these variables gives an R^2 of .998 which is equal to the R^2 obtained for the dependent variable (Q).

In order to explore the severity of intercorrelation, we have run regressions with and without D in the equation and found that inclusion of this variable leads to little change in the R^2 but to a large increase in the standard errors of other variables. The coefficient of variable D was not significant either. We have, therefore, concluded that the number of dwellings may be a significant variable in itself but its effect on the total residential demand for electricity cannot be separated from those of other variables. No other study, to my knowledge, has reported demand elasticity with respect to number of dwellings.

Sometimes, the use of the Pooling Technique is suggested to get rid of the problem of multicollinearity, though its application may be questioned on the ground that the measurement of a variable in one period (cross-section) may not correctly represent its overall relationship with the dependent variable over time. However, in the present case, the null hypothesis of parameter stability could not be rejected on an analysis of covariance.[15] But a more serious objection to the use of the Pooling

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15 See Kuh, Edwin, (1963), Capital Stock Growth, Amsterdam, 1963, pp. 118-136.

Technique is that the cross-section analysis presupposes some behavioural uniformity between households of different income levels: that is, if household A with a higher income than household B spends X amount on electricity, then household B, when it reaches the same income level as that of A, will spend X amount on electricity. In practice, however, this may not be true. Each household's behaviour is likely to be influenced by not only its present income but also by its past and expected future income.[16]

Nevertheless, we estimated the income elasticity of demand on the basis of the ABS, Household Survey 1975-76 in an attempt to isolate the influence of dwellings on residential demand for electricity in South Australia. The income elasticity was estimated to be .35, which is close to that (.32) reported by Powell (1966, p. 672) for gas and electricity combined. This parameter was used to estimate the residential electricity consumption that would have occurred without the influence of income changes. The transformed quantity (dependent variable) was then regressed with the independent variables (with necessary transformations as discussed below) including the number of dwellings. The coefficient of D appeared to be insignificant as before but its inclusion or deletion from the equation did not change any of the remaining parameters. Thus we may conclude that whatever influence on electricity demand the number of dwellings has individually, that influence is represented by RC and the precision of all other parameters is not affected by its absence.

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16 See Ando and Modigliani, (1963), "The Life Cycle Hypothesis of Saving, Aggregate Implication and Test", in American Economic Review, March 1963, pp. 55-84. Also Modigliani and Brumberg, (1954), "Utility Analysis and the Consumption Function: An Introduction of Cross-Section Data", in Kurihara, K.K. (ed.), Post Keynesian Economics, Rutgers University Press, 1954, pp. 388-436.

Further, it has been observed that RC is also highly collinear with N and YD. Though the collinearity between YD and T was not found to be severe on the basis of Klein's rule, it appeared to be severe on the basis of the Farrar-Glauber set of tests. The estimated Farrar-Glauber χ^2 and F-statistics for YD and T and t-statistics for the partial correlation between YD and T were larger than the theoretical values with appropriate degrees of freedom and levels of significance (see equations R.7-R.9, Appendix III).

Thus it seemed advisable to express the dependent variable either per capita or per customer and to drop the respective variable from the list of independent variables. Experimental runs with per capita and per customer consumption as the dependent variable provided no basis on which to choose between them. The R^2, t-statistics and other statistical tests are closely comparable. However, on an a priori basis, per customer consumption seems to be the more appropriate dependent variable as the customers or the households are the basic decision makers and the services given by domestic appliances are consumed jointly by all persons living in a house. Moreover, the use of per capita consumption as the dependent variable implicitly assumes a unit elasticity of demand with respect to population, which may not always be correct.

With the dependent variable expressed in terms of per customer consumption, the way population can affect the results is by a change in the size of households. Thus the population variable (N) has been replaced by the number of persons per household, which appears to have no significant influence on the dependent variable. It should not, however, be inferred from this result that population has no effect on total demand for electricity. Obviously, the number of residential customers will depend, inter alia, upon the size of the population in an area. The impact of population on total demand for electricity will be further discussed in Chapter Ten. Suffice to say at this stage that the influence of population has not been removed altogether since the income variable in our equation is expressed in per capita terms. Thus the impact of population on electricity demand per customer is likely to be reflected through its effect on per capita disposable income (YD). This approach was felt advisable since YD and N were also found highly collinear.

With the above transformation of the dependent and the independent variables, the collinearity between YD and T appeared no longer severe.

One of the snags with the choice of per customer consumption as the dependent variable is that as the total number of customers increases, the marginal customers are likely to consume less than the average, because their stock of appliances is likely to be less than that of the existing customers. Thus with the increase in the total number of customers, the average consumption is likely to fall which in turn may introduce a downward bias in the estimated parameters. However, in practice, its adverse effect is unlikely to be severe for two reasons. First, the marginal customers at any point of time are a small proportion of the total, hence the influence of their consumption on the size of the average will be minimal. Second, the old customers were not always old: as "new" customers are being added to the total, some of the existing customers are becoming "old" in a continuous process through time. Thus the problem of averaging the old and new customers arises only if the rate of growth increases. Since the rate of growth of RC in South Australia appears to be declining over time (i.e., the ratio of new customers are becoming less and less every year), it seems to pose no problem in the present study.

With the necessary adjustments discussed above, only the following explanatory variables remain in our equation: price of electricity (PE), price of gas (PG), price of oil (PO), price of appliances (PA), per capita disposable income (YD/N) and time (T).

On a stepwise regression PG, PA and T were found too insignficant to be included in the equation.[17] Their inclusion or deletion did not significantly change any of the summary statistics such as R^2, DW-statistics, residual variance or standard errors of other variables. In other words, they appeared to be superfluous and were therefore dropped from the equation in the final run.

Parenthetically, it can be observed that the non-significance of the above theoretically plausible variables in our case is not surprising. As mentioned earlier, the sphere of competition from gas is confined only to cooking and heating and this in less than half (44 per cent) of the total households in South Australia. Since gas is not available to a large section of the residential customers (RC), the insignificance of its price as an explanatory variable is not unexpected. The variation in the relative price of electric appliances and changes in technology in the residential sector do not seem to have been large enough to have any impact on demand for electricity in this sector. The fact that T appears important when total demand (as opposed to demand per customer) is used as the dependent variable may be due to the collinearity between RC and T.

Further, the dummy variable used to examine the shift in the intercept and/or change in the slopes (if any) appeared insignificant.

In order to test whether the assumption of homoscedasticity is true

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17 However, T appeared significant when total quantity (Q) was used as the dependent variable.

in the present case, we have used the Spearman Rank Correlation and Glejser test (see Appendix III, pp. 334-35). No significant heteroscedasticity was observed.

As discussed in Appendix III, the d-statistics or the H-statistics are considered to be important tests for detecting autocorrelation in the presence of which the significance of the estimated parameters cannot be judged from the computed t-statistics or standard errors. In the present study, serious autocorrelation was observed when the constant elasticity model was estimated. In the case of the linear model, the results of those specifications that were found free from autocorrelation were accepted. These are reported in the following sub-section.

4.2.2 Results of the Linear Model

The results obtained from the static and dynamic models are presented in equations 4.8 and 4.9 respectively.

$$Q = \underset{(15.51)}{4.14} - \underset{(-16.50)}{1.39\ PE} + \underset{(2.69)}{.009\ PO} + \underset{(7.67)}{.920\ YD} \qquad R^2 = .99 \qquad DW = 1.76 \tag{4.8}$$

$$Q = \underset{(7.64)}{4.454} - \underset{(-.08)}{.009\ LQ} - \underset{(-7.41)}{1.40\ PE} + \underset{(2.47)}{.009\ PO} + \underset{(5.49)}{.933\ YD} \qquad R^2 = .99 \qquad DH = .90 \tag{4.9}$$

* Figures in the parentheses are t-statistics.
** YD = YD/N.

It is evident from the t-statistics that all the variables included in the equations are significant (except LQ) and the R^2 suggest that 99 per cent of the variations in the quantity demanded per residential customer is explained by the variables included in the equations. The signs for the coefficients of own price, cross price and income conform to expectations as discussed earlier.

It is interesting to note that the results of the dynamic model are not significantly different from those of the static model (see equation 4.10). The estimated coefficient of the lagged dependent variable (LQ) and its t-value are so low that it can safely be concluded that, in the present case, the short run and the long run demand elasticities are not different. This means that there are no lags in the response of the dependent variable. Though it sounds unlikely that the electricity consumption changes instantaneously with the changes in the explanatory variables, since the response may involve acquisition of major appliances, it is not so surprising in the present case when we consider that the data used in the study are annual data. There might have been sufficient time within a year for adjustment to changes in the independent variables. Moreover, the price of electricity was persistently falling (initially both in nominal and real terms and later in real terms only) for the entire sample period. This is true even in the face of a rising price of oil in the seventies. On the other hand, the real disposable income per capita was persistently rising except for the period from 1952 to 1954 and from 1958 to 1960. Under these circumstances, it is possible that consumers developed an expectation as regards further falls in the relative price and further rises in personal income.[18] This seems to have

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18 Purchase of appliances might have been made in anticipation of further price falls. Recall that the newly formed ETSA was pushing hard until the late fifties to popularize electric appliances by introducing hire purchase and 'rent an appliance' systems to its customers. It is likely that the decision to buy these types of appliances and the decision to retain the hired appliances was largely influenced by the actual and expected tendency of the electricity price to fall.

TABLE 27

Elasticities of Demand for Electricity Under Various Linear Models

	Models	R^2	DW	rho	Elasticities* Own Price	Oil Price	Income
1.	No lags	.99	1.76	.11	-.811 (-16.48)	.084 (2.69)	.392 (7.65)
2.	One year's lag	.97	2.27	-.20	-.710 (-9.15)	.044 (.67)	.475 (6.50)
3.	Two year's lag	.97	1.67	.08	-.765 (-6.63)	.122 (.92)	.428 (5.62)
4.	Three year's lag	.92	.85	.56	-.572 (-2.47	.302 (1.06)	.741 (7.65)
5.	Four year's lag	.94	.96	.49	-1.050 (-4.03)	.896 (2.87)	.645 (10.11)
6.	No lag for PE & PO One year's lag for YD	.99	1.88	-.0003	-.839 (-15.88)	.079 (2.23)	.363 (6.53)
7.	No lag for PE & PO Two year's lag for YD	.97	.77	.44	-1.020 (-12.74)	.162 (3.20)	.124 (1.73)
8.	No lag for PE & PO Three year's lag for YD	.97	.53	.65	-1.130 (-12.83)	.187 (3.42)	.014 (.211)
9.	Distributed lag for Two years, Order=1	.99	2.19	-.11	-.963 (-11.04)	.092 (1.84)	.342 (6.32)
10.	Distributed lag for Three years, Order=1	.99	2.22	-.12	-1.080 (-8.11)	.110 (3.40)	.283 (4.51)
11.	Distributed lag for Three years, Order=2	.99	1.91	.03	-1.176 (-3.63)	.202 (1.02)	.279 (1.08)
12.	Distributed lag for Two years, Order=2	.99	1.54	.23	-1.055 (-3.96)	.330 (1.57)	.348 (2.08)
13.	Koyck Distribution	.99	DH .90	.11	-.817 (-7.41)	.084 (3.47)	.400 (5.48)

* Figures in the parentheses are t-statistics.

made the demand adjustment rather quick.

It is worthwhile mentioning here that the similarity between the short run and the long run elasticities is not confined to the Koyck model, the results of which were reported in equation 4.9. The differences between the coefficients estimated from the static model and those from the dynamic models with simple and distributed lags are not very large either.[19] This may be seen in Table 27.

The estimated Durbin-Watson statistics and the autocorrelation parameter (rho) as reported in the table suggest that models 4, 5, 7 and 8 are plagued with severe autocorrelation. As such, these models are not acceptable. Models 9 and 10 have their DW-statistics above the critical upper levels but not smaller than $(4-d^U)$, which indicates the presence of negative autocorrelation. As such the results of these specifications are of only doubtful validity. Similarly, the DW-statistics in models 11 and 12 fall inbetween d^L and d^U and therefore, provide no conclusive indication of whether or not autocorrelation exists (see Rao and Miller, 1971, p. 122). Note that the use of the Cochrane-Orcutt method of removing autocorrelation is recommended only when it is established that the autocorrelation is due to the First Order Markov Scheme.

The estimated elasticities for the remaining models 1, 2, 3, 6 and 13 are not significantly different. The results for model 1 show that there is a 95 per cent probability that the elasticity estimates are within the following ranges:

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19 A similarity between short run and long run elasticities in the residential sector was also reported by Halvorsen (1978, p. 29).

$$
\left.
\begin{array}{r}
-.71 \leqslant \eta\ PE \leqslant -.91 \\
.02 \leqslant \eta\ PO \leqslant \ \ .15 \\
.29 \leqslant \eta\ YD \leqslant \ \ .50
\end{array}
\right| \qquad (4.10)^*
$$

* η_i elasticity of demand for electricity with respect to i^{th} variable.

From the above analysis, it seems fair to conclude that in the present case, the differences between the short run and the long run elasticities are small enough to give an option to the researcher to choose either a static or a dynamic model to estimate the demand elasticities and to estimate the future demand for electricity in South Australia. In doing so, he or she must resolve at least two questions. First, which of the various models provides the best forecast and second, whether the demand elasticities measured from a particular model can be expected to remain stable throughout the forecast period. We shall deal with these issues in Chapter Ten. Suffice it to say at this stage that on the basis of the Theil inequality coefficient and the root mean square error (RMSE) (see equation 10.3, p. 292), it appears that the Koyck model (model 13) provides the best results. We, therefore, report in the following table the elasticities measured on the basis of this model.

From the table below, it is apparent that the demand elasticities tend to vary over time and over the levels of the dependent and the independent variables. This conforms to theoretical expectations as discussed earlier.[20]

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20 A brief discussion on magnitudes of demand elasticities is to be found in Section 4.2.3.

TABLE 28

Elasticities of Demand for Residential Electricity in South Australia

Period	Own Price	Oil Price	Income
At Mean	-.817	.085	.400
1950	-3.410	.304	.786
1970	-.580	.058	.340
1980	-.330	.088	.382
1950-70	-1.270	.110	.410
1971-80	-.390	.058	.381

Both in the short run and in the long run, the own price seems to be a more important determinant of electricity demand than either income or prices of other forms of energy. However, a high elasticity of demand with respect to a variable does not necessarily indicate its high contribution to the variations across observations in the quantity of electricity demanded. A variable with a high elasticity but a low variance may not be as important as its elasticity suggests. Goldberger (1964) has suggested the following formula (Beta Coefficient) to measure the importance of an explanatory variable.

$$B_j = b_j \, (S_j/S_q) \tag{4.11}$$

where B_j = the beta coefficient of variable j;

b_j = the estimated regression coefficient of variable j;

S_j = the standard deviation of variable j;

S_q = the standard deviation of the dependent variable.

The estimated beta coefficient for the results reported in equation (4.9) are given below.

TABLE 29

Estimated Beta Coefficients for the Dynamic Model

Variables	**Beta Coefficients**
Own Price	-.73
Oil Price	.06
Income	.32

The greater relative importance of price vis-a-vis income in influencing demand for electricity in residential sector may appear to be surprising, particularly in view of the fact that changes in the stock of electric appliances are likely to be affected more by income than by the price of electricity. Though we do not have any empirical evidence, it may, however, be intuitively argued that when changes in the prices of electric appliances vis-a-vis other domestic appliances are not significantly different, customers with a given income are likely to acquire more of those appliances which are driven by a form of energy whose prices have fallen or are expected to fall relatively more.

Historically, the decline in electricity price was more sharp and continuous than was true for the prices of competing sources of energy. Thus the change in the consumption of electricity due to any fall in price may be explained as an outcome of two combined forces. First, a fall in price has rendered the marginal utility of electricity consumption (at the present level) greater than the marginal cost (price), thus inducing consumers to use their existing appliances more intensively. Second, with the fall in price, more electric appliances were added to the existing stock, which in turn led to more consumption.

It should be noted that an increase in the stock of appliances due to a fall in the price of electricity (operation cost) is not the same thing as an addition to stock due to an increase in income. In the latter case, consumers may, in fact, reduce the intensity of usage and as such the increase in consumption may not be as much as the acquisition of stock would suggest. Thus the relatively greater importance of the price variable in the present case is not surprising.[21]

4.2.3 Further Discussion on the Estimated Results

The magnitude of the price elasticity of demand in the early years looks rather larger than might be expected of a commodity like electricity (i.e., it belongs to the group of necessities, claims only a small proportion of one's budget and has few substitutes). But considering the low base consumption and high price of electricity in the initial period it may not appear implausible.

As the consumption base increased and the real price declined, the elasticity declined too. One reason why the elasticity is smaller at a lower price is that a smaller proportion of one's income is now spent on electricity at the same level of consumption. Besides, as customers build up their stocks of electric appliances, they become locked in to electricity in the short run and over time become habituated to electric

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21 The case of commercial consumption is different since this is an activity outside home, which is likely to increase with increases in income.

equipment. This may be partly responsible for the decline in elasticity in subsequent years.

The cross elasticity with respect to oil price is found to be very low at .09. This small value suggests that residential electricity in South Australia enjoys a somewhat protected market relative to other sources of energy.[22]

Turning now to the income elasticity, it appears that its value in the early 1950s was twice that in 1980. This is not surprising in the sense that with the rise in income, customers are likely to approach saturation with electrical appliances which may lead to a decline in the value of the income elasticity of demand. Moreover, as discussed earlier, at higher income levels, customers may be more inclined to outside activities and as such the domestic consumption is likely to decline.

Thus it appears that the results reported above are in conformity with the theoretical expectations. Recall, however, that we have used average price and not the marginal price for reasons discussed earlier (see Section 3.2). It was also assumed that the price is exogenously determined and as such the simultaneity problem can be assumed away. Thus our assumption, in effect, was that the direct elasticities will, by and large, be the same as the total elasticities (see next section for definition). In order to check this assumption, we should estimate a system of simultaneous equations.

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22 This is not surprising in view of the limited range of uses for oil. The main area of competition from oil is room heating in the residential sector. In 1979, only 5 per cent of the residential consumption of electricity was used for room heating. See ABS, Cat. No. 8208.4, April 1979, p. 13.

4.2.4 Simultaneous Equations

It has been noted earlier (Section 3.2) that due to the existence of a declining block rate schedule in the ESI, it is possible that the average price paid by customers is affected by the quantity demanded.

The elasticity estimated from a single equation gives the percentage change in the quantity demanded due to the direct change in the explanatory variables. However, when the quantity changes, the average price is likely to change too due to the declining block rate schedule. This leads to further changes in the quantity demanded, which may lead to a further change in the average price and so on. Thus the total elasticity of demand is likely to be greater than the direct elasticity measured from the single equation.

In order to incorporate the effect on demand, if any, of the indirect changes in the explanatory variables, we have to identify which explanatory variables are endogenous and which are exogenous. In the present case, it is perhaps uncontroversial to assume that the per capita income and the price of oil are not significantly influenced by the quantity of electricity consumed or by its price.[23] So these two variables are considered to be exogenous. However, the average price of residential electricity may be affected by the block rate. Simultaneity may be involved in two ways: first, an individual customer may take electricity from more than one block, and second, the proportion of consumption in each block may change even though an individual customer takes from the same block. In either or both of these cases, the

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23 Sometimes it is argued that the price of electricity affects per capita income via its impact on the willingness of firms to locate in South Australia. This is, however, probably relevant only in the case of electricity price in the industrial sector.

average price is likely to be affected by the quantity of electricity taken.

Next, the price of electricity is likely to be influenced by the average cost (AC) of supplying electricity. Though ETSA is a non-profit organisation, it has to finance its own cost of supply and development. Thus the electricity tariff is set to recover costs including interest on borrowings.[24] So we treat average price of electricity (PE) as endogenous for the present purpose.

It is doubtful, however, whether ETSA considers the opportunity cost of the resources used when they fix a tariff. In the present case, we assume that they consider only the accounting cost. We continue to express prices in real terms.

As the load factor in the residential sector is likely to be different from that in the industrial sector and the transmission and distribution costs are substantially higher in the former than in the latter, it is very likely that the tariff authority takes these factors into consideration when they decide on the inter-sectoral tariff. We, therefore, use the ratio between the residential and the industrial quantity of electricity supplied as one of the determinants of the average price of residential electricity.

A time-trend variable is introduced in the price equation to measure the direction and extent of the net effect on price of the omitted time-related variables such as technology.

As discussed earlier (Chapter 2), the average cost in the case of ETSA seems to have been influenced by the quantity of electricity

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24 See ETSA, <u>Annual Report</u>, 1969, p. 16.

produced. Hence the AC is an endogenous variable. The AC is also influenced by the price indices of capital, labour and fuels. Under these conditions, a third equation with AC as the dependent variable is introduced in the system. The price indices used in the system are those used in model A.3 (see Section 2.1.5).

Thus we have three equations in the system. One with Q as the dependent variable, another with PE as the dependent variable and a third with AC as the dependent variable. These equations have been estimated simultaneously. The endogenous variables in the system are:

Q = quantity of electricity demanded per residential customer in gwh;

PE = real price of electricity in cents per kwh;

AC = real average cost in cents per kwh.

The exogenous variables are:

LQ = Q lagged by one year;

PO = average real price of heating oil and kerosene in cents/gallon;

YD = per capita real disposable income in A$'000;

R = ratio of residential to industrial electricity;

T = time in natural numbers;

PF = fuel price index;

PL = wage index; and

PK = capital price index.

On application of the Order condition and the Rank condition for identification, the system was found over-identified. This means that the reduced form equation or the Indirect Least Square (ILS) method of estimation is inappropriate in the present case. However, the exact identification for which the ILS is considered appropriate is rather a rare situation. The more common situation is an over-identified system.[25]

The estimated results are presented below.

TABLE 30

Comparison of Elasticities Estimated from Single and Simultaneous Equations

	Single Equation	Simultaneous Equations	95 per cent Confidence Interval** (Single Equation)
Own Price	-.817 (-7.47)*	-.870 (-9.70)	$-.59 \leqslant \eta$ PE $\leqslant -1.04$
Oil Price	.085 (3.47)	.066 (3.22)	$.03 \leqslant \eta$ PO $\leqslant .13$
Income	.400 (5.48)	.380 (5.74)	$.25 \leqslant \eta$ YD $\leqslant .55$

* Figures in the parentheses are t-statistics.

** η_i = elasticities with respect to i^{th} variable.

It is important to note that the results obtained from the simultaneous equations are not significantly different from those obtained from the single equation (4.9). The forecasting ability of these two models also seems to be the same. The RMSE and the Theil inequality coefficients calculated for these two models are almost identical. We thus conclude that the simultaneous equation model is not

25 See Koutsoyiannis (1977), pp. 352-366.

statistically better than the single equation model in the present case. We may, therefore, remain confident that the elasticities reported earlier represent total elasticities which, of course, are not different from the direct elasticities.

In the following sub-section, let us further test the senstivity of our results to the use of a systemwide model.

4.2.5 Results of the Systemwide Approach

In this section, we present the results obtained by estimating the systemwide demand model for electricity. This model investigates how the consumer allocates his income to all goods and services simultaneously. Recently, the model has gained remarkable popularity. Some of the important studies are Powell (1966), Barten (1977) and Theil and Clements (1980). The estimation procedure of the model adopted for the present study is similar to that of the translog cost model discussed in Chapter Two.

Since most of the previous studies used national accounts commodity groups, the own price elasticity and cross price elasticities of items within a particular commodity group could not be estimated. Powell (1966) for instance, used gas and electricity as a group. Hence, the elasticity of substitution between gas and electricity cannot be estimated from his study.

In the present study, we have used more disaggregated data for individual sources of energy and their prices. Consequently the own price and the cross price elasticities for electricity demand can be estimated employing the formula presented in equations 2.27 - 2.29.

We assume that the consumer's utility function for energy products as a whole (i.e., electricity, gas and oil) is separable from all other commodities. That is, the share of income spent on energy is not influenced by other expenditure. This assumption may be criticised on the ground that the expenditure on energy is likely to be influenced at least by consumers' expenditure on energy equipment. While we recognise this shortcoming of our assumption, we cannot improve on it because of the lack of relevant data on consumers' appliances.

Data for expenditure on gas and oil are not available separately for each sector. The South Australian State Energy Committee (1976) reports the consumption of gas and petroleum fuels by the household and commercial groups combined for the period from 1960 to 1976. As the data on residential consumption are not available separately, we cannot apply the systemwide model to estimate separately the residential demand for electricity. Thus the estimated elasticities will be for residential and commercial sectors combined. Data for the rest of the period are obtained from SAGASCO and DNDE. Prices of gas and oil are those given by SAGASCO and ABS. The expenditure on individual energy sources for household and commercial purposes is calculated on the basis of a weighted average price for these two sectors. The data on expenditure and quantity of electricity in these two sectors are taken from the ETSA annual reports.

The total household and commercial expenditure on energy sources are equated to:

$$C = (VE + VG + VO) \tag{4.12}$$

where C = household and commercial expenditure on energy per capita;[26]

VE = per capita expenditure on electricity in the household and commercial sectors;

VG = per capita expenditure on gas in the above two sectors;

VO = per capita expenditure on oil in the above two sectors.

On the assumption that the consumer's utility function for energy is separable, the per capita consumption of energy is likely to be influenced by the relative price of energy and per capita income. Thus the variables used to estimate the translog demand function are: average price of electricity (PE), average price of oil (PO), average price of gas (PG) and per capita income (YD).

The function is assumed to be linear homogeneous, so that the sum of expenditure elasticities with respect to PE, PG and PO equals one (see equation 2.6 - 2.7). Recall also that the symmetry conditions are applicable in cross price parameters (see equation 2.5).

A joint estimation of the consumption function and the energy share equations (i.e., share of electricity, gas and oil in total expenditure on energy) is made using Zellner's multivariate regression (see equation 2.21 to 2.24). Two models are estimated. One makes the assumption of a non-unitary elasticity of substitution between any two energy sources, which we call model A. The second assumes unitary elasticities of substitution (see equation 2.10). This we call model B. The estimated results are presented below.

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26 Because of the problem of multicollinearity, the variables RC, CC and N could not be used explicitly in the equation. See Section 4.2.1.

TABLE 31

Regression Results of the Translog Consumption Function for Energy

Parameters*	Model A	Model B
α_o	0.428 (3.04)**	0.428 (3.04)
α_e	0.176 (2.09)	0.174 (2.80)
α_k	0.361 (9.63)	0.361 (9.63)
α_g	0.463 (3.34)	0.464 (3.35)
α_y	0.987 (20.31)	0.987 (20.31)
α_{ek}	0.023 (2.12)	
α_{eg}	0.063 (4.12)	
α_{gk}	-0.075 (-2.89)	
α_{ee}	-0.086 (-4.59)	
α_{kk}	0.052 (6.11)	
α_{gg}	0.012 (1.52)	
$\lvert\hat{\Omega}\rvert$	0.571-05	0.987-05

* The subscripts e, k, and g stand for prices of electricity, oil and gas respectively.

** Figures in the parentheses are t-statistics.

The significant t-statistics in the above table for the cross price parameters suggest that the assumption of unitary elasticities of substitution between any two energy sources cannot be accepted. This view is confirmed by the likelihood ratio test (see equation 2.11).

The elasticities of demand are estimated from model A by employing equations 2.28 and 2.29 respectively for cross price and own prices. The estimates are presented below.

TABLE 32

Elasticities of Demand for Energy in South Australia
(Sample Period 1960-1980)

Energy Sources	Own Price	Cross Price	95 per cent Confidence Interval**
Electricity	-.55 (-16.54)*	-	$-.48 \leq \eta\ PE \leq -.62$
Oil	0.26 (2.41)	-	$-.03 \leq \eta\ PO \leq -.49$
Gas	-.69 (-23.23)	-	$-.63 \leq \eta\ PG \leq -.75$
Electricity-Oil		.113 (9.15)	$.08 \leq \eta_{eo} \leq .14$
Electricity-Gas		.354 (1.74)	$-.08 \leq \eta_{eg} \leq .78$
Gas-Oil		-.211 (-2.11)	$0 \leq \eta_{go} \leq -.42$

* Figures in the parentheses indicate t-statistics (see footnote Table 19).

** η_i = elasticity of demand with respect to i^{th} variable, and P^i= price, e, o and g are electricity, oil and gas respectively.

It appears from the above exercise that the cross price elasticity for electricity demand with respect to gas price is insignificant as before and that with respect to oil price is not very high though significant. Thus these results are fairly comparable with those reported earlier. However, though the upper limit of the own price elasticity presented above overlaps with the lower limit of the price elasticity in the residential sector given in Table 30, the elasticity obtained in the present case appears to be significantly different from that reported in Table 46 for commercial demand (see Chapter 6).

In a separate run for a sub-sample from 1960 to 1980, equations 4.9 for residential demand and 6.4 for commercial demand were re-estimated. Whereas the lower limit of the own price elasticity for the residential sector appeared to have remained unchanged, that for the commercial sector fell substantially to -.48 from its previous level of -.72 (see Table 46). Thus the results are not basically different from those reported earlier either from the single equation or from the simultaneous equations. It seems, therefore, possible to conclude that the elasticities estimated from the single equation are robust measures.

4.3 Summary of Chapter Four

In this chapter, we have discussed the problems of estimating the residential demand for electricity in South Australia. Out of a number of independent variables considered only three warranted explicit inclusion. These are: the deflated average price of electricity, deflated average price of heating oil and kerosene and the deflated per capita disposable income. The price of gas, which is normally considered to be a close substitute for electricity, appeared to be an insignificant regressor in the present case. The reason for this has been identified to be its narrow field of competition with total household electricity.

A severe problem of multicollinearity was encountered between the number of residential customers, population and income. The problem was overcome by expressing the electricity consumption as per residential customer and expressing disposable income in per capita terms.

A number of demand specifications namely linear, log linear, semi-log and exponential were tried. The linear model was found to give the best results. Contrary to the conventional assumption of a constant elasticity of demand, it has been observed that the elasticity has been changing over time and over the levels of the dependent and the independent variables.

Studies on electricity demand have almost always maintained that adjustment of demand to any change in explanatory factors requires some time. Little weight was given to rational expectations in explaining demand. It has been revealed that in the present study the demand adjustment to changes in the determinants took place rather quickly and as such the differences between short run and long run elasticities are not significant. Thus any policy decision may have quicker responses than is generally believed. No significant difference was observed between the results given by the simultaneous equations model, systemwide approach and those given by the single equation model. These indicate the robustness of our estimates.

In the case of the linear model, a number of specifications with different time lags as well as order of lag distributions were tried. The results obtained appeared to be fairly stable. Nevertheless, the results obtained from the Koyck geometric distribution model were reported since this model has the best forecasting ability as judged from the root mean square errors and the Theil inequality coefficient. The estimated elasticities are presented below.

TABLE 33

Elasticities at Means for Residential Demand

	1950-80	1950-70	1971-80
Own Price	-.817	-1.270	-.390
Oil Price	.085	.110	.058
Income	.400	.410	.381

Contrary to views held widely in the ESI both within and outside Australia, the own price appeared to have the largest impact on electricity demand in the residential sector under ETSA. The second important factor was found to be the per capita disposable income. It can hardly be overemphasised that these findings have significant policy implications in the context of proper planning and control of energy resources in the state. We shall discuss the implication of our findings further in Chapters Eight, Nine and Ten. Meanwhile, in the next chapter we address ourselves to the estimation of industrial demand for electricity in South Australia.

CHAPTER FIVE

INDUSTRIAL DEMAND FOR ELECTRICITY IN SOUTH AUSTRALIA

Introduction

In South Australia, the nominal price of electricity has been rising at an accelerating rate since 1973. Recently, the rise in electricity price has exceeded the inflation rate. A portion of the increased revenue due to the price rise is committed to creation of additional capacity. The generally held view that demand is inelastic with respect to price seems to be reponsible, at least partly, for deciding upon this way of financing new projects. There have been suggestions, however, that raising prices may actually alienate some important customers (The Australian, May 6, 1983).

Recent studies overseas (e.g., Chern, 1975) suggest that industrial demand for electricity is highly elastic and as such any rise in price is likely to be followed by a fall in revenue *ceteris paribus*. No such study has yet been made for South Australia and the likely impact of a price rise is, therefore, unknown.

Some Australian studies considered industrial demand for electricity combined with either commercial demand (McColl, 1976) or commercial and residential demand (Donnelly and Saddler, 1982) or along with the total demand for electricity (Department of National Development and Energy (DNDE), 1981). Such aggregated demand equations do not reveal anything about the differences in elasticities pertaining to different sectors. Empirical evidence as well as intuition suggest that elasticities are likely to be different in different sectors. Moreover, the functional specification of demand may be different in different sectors. The same criticism is also applicable to those studies which used the same functional specification for each sector separately (Mount, et al., 1973; Griffin, 1974).

The structural changes in electricity demand in South Australia and the growth rates of demand in various sectors have undergone substantial changes over the period under study (see Tables 1 and 5). During this period the growth rate in the number of industrial customers was higher than in the demand for electricity. Hence consumption per industrial customer declined from 91 Gwh in 1950 to 63 Gwh in 1970, and rose only slightly to 66 Gwh in 1980. This is in sharp contrast with the growth in consumption per customer in the other two sectors, namely the residential and the commercial. In both of these sectors, the consumption per customer increased remarkably (see Table 24). In view of these differences in growth rates and the likely difference in functional forms, it seems inappropriate to use an aggregative model.

Among the Australian studies, Hawkins (1975) and Turnovsky, Folie and Ulph (1982 - henceforth called TFU) estimated industrial demand for electricity separately from other types of demand. Hawkins reports the price elasticity of demand as being insignificant. Based on his findings, Hawkins concludes that "demand forecasts that do not explicitly consider the effects of future electricity price changes may perform quite well in practice" (Hawkins, 1975, p. 16). However, the data used by Hawkins were, by his own admission, inadequate and, therefore the results he obtains are of doubtful validity.

TFU's study is more interesting since it provides not only the own price elasticities for energy sources but also the interfuel substitutability in Australian manufacturing industries. Their "results indicate that solid fuels and gas are complementary as are oil and electricity but in all other cases the fuels are substitutes" (TFU, 1982, p. 70).

TFU used annual time series data from 1946-47 to 1974-75. Since the classification of industries in the Manufacturing Establishment census introduced in 1968-69 is different from that in the original Factory census up to 1967-68, TFU found it "impossible to link these two time series at the level of each individual industry". Hence they did not disaggregate their data by ASIC sub-divisions and therefore, the differences in elasticities (if any) within the industrial groups are not known. In the present study, we have used data from 1968-69 to 1979-80 for the explicit cost model (see equation 5.5). These data do not suffer from the classification differences which were encountered by TFU. We have estimated different equations for total industrial demand and for individual two digit ASIC sub-divisions.

In Section One, we outline the model and in Section Two, we discuss the results obtained. Section Three gives the conclusions. The nature and the sources of the data used are detailed in Appendix IV(A)

SECTION ONE: THE MODEL

5.1 The Model

The bulk of the industrial demand for electricity is for operating machinery or as an input to various processes and thus is directly related to the volume of industrial production. Electricity is also used in industry for lighting, cooling and heating of buildings. Indirectly, this is also related to output. This second category of use constitutes only a minor portion of the total industrial demand for electricity.[1]

From a theoretical point of view, we may consider electricity a variable input in the production process. The behaviour of an industrial customer can be described by either cost minimization or profit maximization models. In either case, firms will be minimising costs.[2] We therefore concentrate our attention on the cost minimization model since this requires fewer data than the other.

Under the cost minimization model, it is assumed that a firm (an industrial customer) determines the optimal uses of inputs by minimizing its costs for a given level of output. Prices of output and inputs may be assumed to be given for a firm under competitive market conditions. Solving for equilibrium positions, one can derive the input demand equation as:

$$Q_i = f(O, P_i, \ldots, P_k) \qquad (5.1)$$

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1 Chern, C.S., (1975), p. 29.

2 In individual cases the possibility of a firm being indifferent to profit maximisation or cost minimisation cannot be ruled out. Nevertheless, it is hypothesised that on the average, firms are likley to be cost minimisers.

where Q_i = the quantity of i^{th} input demanded; O = the output level; P_i = the price of i^{th} input, and $i = 1, 2, \ldots, k$.

The theory implied in the above equation is well known as the theory of derived demand for inputs, pioneered by Marshall and further developed by Friedman and others.[3] Although the theory was originally developed to describe the behaviour of an individual firm, it has been widely used to estimate the aggregate demand for an input pertaining to the industrial sector as a whole. The aggregate input demand is derived by summing the demand equations of all the individual firms. Though such aggregate models may not exactly represent the behaviour of an individual firm, since firms differ in the intensity of use of a particular input (electricity), nevertheless, the estimates of such models may be useful in representing the behaviour of a 'representative firm' (see Phlips, 1974, p. 100). The use of the aggregate model is unavoidable given the data which are available. However, the data disaggregated by ASIC two digit sub-divisions are available since 1968-69. We, therefore, use them in separate equations so that the idiosyncracies of different industries may be accounted for (see Table 37).

In accordance with equation (5.1), industrial demand for electricity can be expressed as a function of the level of output, the prices of electricity and its substitutes such as gas, coal and oil and the prices of other inputs such as labour and capital. The number of industrial customers (IC) may be used as an additional regressor when an aggregate model is used.

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3 Friedman, M., Price Theory, Revised edition, Aldine Publications, Chapter 7, 1962.

Further, to represent technological change (and other time-related variables which could not be explicitly introduced into the regression equation, such as composition of output), we may use time as an independent variable. In doing so, it is assumed that technology changes at a constant rate per unit of time. The technological improvement may be neutral or non-neutral. A positive coefficient for T (time) will imply more electricity-intensive techniques and a negative coefficient will represent electricity-saving techniques. However, some economists have expressed strong views against using time as a proxy for technology.[4] In the absence of more direct measures of technological change, it is felt desirable to include time though the results should be interpreted with caution. (Technological impacts are discussed separately in Section Three).

It is important to note that natural gas was not available in South Australia before 1968-69 though customers were supplied with manufactured gas. One way to incorporate the effects of the availability of natural gas, if any, on the quantity of electricity demanded (Q), when estimating an equation for the entire sample period (1950-80) is to use a dummy variable (D) with a value of zero for the period before 1970 and a value of one for the period thereafter. The implicit assumption in using a dummy variable is that the regression lines for the two periods differ only in the intercept but have the same slope coefficients. However, the interaction term of the dummy variable with a particular independent variable will indicate whether slope coefficients have changed.

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4 Fisher (1962) considers that the person "who explicitly introduces time into his regression equation is usually doing something meaningless ... (in view of the collinearity usually involved), the coefficient of the time variable is generally of no economic significance", p. 25.

It may be noted that the shift in the regression line which D is expected to represent in the present study may be either to the right or to the left. To the extent that natural gas is a substitute for electricity a leftward shift in the demand curve is expected. However, this is not obvious since the marketing techniques adopted by ETSA and SAGASCO may differ from one another. In South Australia, the number of industrial customers for gas decreased from 1,162 in 1973 to 1,093 in 1976 but rose again to 1,125 in 1980. On the other hand, the actual industrial consumption of gas has more than trebled over the period (SAGASCO, Annual Report, 1981, pp. 8-9). As against this, the number of industrial customers for electricity increased from 25,620 in 1973 to 28,220 in 1976 through to 29,920 in 1980 (ETSA, Annual Reports). Since gas was not available to all the industrial customers of electricity, whether the coefficient of D will have a positive or negative sign cannot be determined *a priori*.

The above discussion refers to a static model. As discussed earlier, the response of electricity demand to changes in the explanatory variables may not be instantaneous. Therefore, the equilibrium level of demand may be attained only in the long run (see Section 4.1.1). If a linear relationship is assumed the equilibrium functional form may be written as:

$$Q_t^* = \alpha + \sum_{i=1}^{n} \beta_i X_{it} + U \qquad (5.2)$$

where Q_t^* = the equilibrium level of electricity demand at time t;

X_{it} = the i^{th} independent variable at time t;

i = 1, 2, ..., n;

α and β_i's are unknown parameters to be estimated; and

U = error term, assumed normally distributed and uncorrelated with included variables.

Adopting a partial adjustment model suggested by Nerlove (1958) and later elaborated by Chern (1975), Halvorsen (1978) and others, we may assume that the difference between the equilibrium demand and the demand in the previous period is a multiple of the difference between observed current demand and the demand in the previous period. Ignoring the error term, we may re-write equation 5.2 as:

$$Q_t - Q_{t-1} = \lambda(Q_t^* - Q_{t-1})$$

or

$$Q_t = \lambda\, Q_t^* + (1 - \lambda)Q_{t-1} \tag{5.3}$$

Substituting (2) into (3), we get:

$$Q_t = \lambda\alpha + (1 - \lambda)\, Q_{t-1} + \lambda \sum_{i=1}^{n} \beta_i X_{it} + \lambda U \tag{5.4}$$

Note that the adoption of the partial adjustment model results in a geometrically declining lag structure, originally developed by Koyck (1954). This latter formulation was discussed earlier in Section 4.1.1.

It may be recalled that equations 5.1 and 5.4 represent the derived demand for electricity (or any input). In these formulations the impact upon quantity of electricity demanded of changes in the prices of other inputs is realised only indirectly since neither the quantity nor the outlay on other inputs is regressed along with that of electricity. A more specific functional form can be derived by using an explicit cost function where cost per unit of output is expressed as a function of input prices. This provides a direct inter-relationship of how expenditure on a particular input (e.g., demand for electricity) is influenced by its own price and prices of other inputs. Since the outlay on all inputs and the respective share of an individual input in the total cost are regressed simultaneously, the budget constraint is explicit in this model. This latter formulation also provides price elasticities for all inputs (inlcuding electricity) and the elasticities of substitution between two inputs. Thus the explicit cost model provides some additional information compared with the derived demand model. Assuming further that the energy cost function is independent of the prices of non-energy factors, we can write

$$C_F = f(P_e, P_g, P_o) \tag{5.5}$$

where C_F = fuel cost per unit of output,

P = price; and

e, g and o are electricity, gas and oil respectively.[5]

The above specification implies the (energy) cost elasticity with respect to output is unity. In view of the results obtained for the linear functional form (see Tables 34 and 36), this appears to be plausible.

Transformation of equation 5.5 into a translog cost function would produce:

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5 Total expenditure on other fuels such as coal, coke and wood was small. It was 13 per cent of the total industrial energy cost in 1972-73 and 14 per cent in 1979-80. See ABS: Manufacturing Establishment: Usages of Electricity and Fuel by Industry Sub-Division 1968-69 to 1979-80, pp. 40-49.

$$\log C = \alpha_o + \alpha_e \log P_e + \alpha_o \log P_o + \alpha_g \log P_g$$
$$+ \tfrac{1}{2}\, \alpha_{ee} \log P_e \log P_e$$
$$+ \alpha_{eo} \log P_e \log P_o + \alpha_{eg} \log P_e \log P_g$$
$$+ \tfrac{1}{2}\, \alpha_{oo} \log P_o \log P_o + \alpha_{og} \log P_o \log P_g$$
$$+ \tfrac{1}{2}\, \alpha_{gg} \log P_g \log P_g + U \qquad (5.6)$$

The function is homogeneous of degree one in prices. This implies $\sum_i \alpha_i = 1$ and $\sum_i \alpha_{ij} = \sum \alpha_{ji} = 0$. Moreover, the second derivative of equation (5.6) gives $\alpha_{ij} = \alpha_{ij}$ (see equations 2.5 - 2.7).

Applying the Shephard Lemma to the cost function one can derive cost share equations for individual fuels. That is, the first derivatives of equation 5.6 with respect to individual fuel prices will give respective share equations (see equations 2.13 - 2.15). As said earlier, the parameters of the cost function can be estimated more efficiently if the cost function and the share equations are estimated jointly.

Recall that the elasticities to be obtained from a linear model such as equation (5.4) are variable over the levels of dependent and independent variables, whereas those from a log linear model are constant. In order to test the nature of the data, it is customary to try different functional forms and to choose the best one on the basis of economic, econometric and statistical criteria (see Appendix III). In Section Two, we present our results and discuss which functional form appears to be the best.

5.1.1 Choice of Variables

On the basis of the theoretical model discussed above, the following independent variables are considered for the demand equation for industrial electricity in South Australia (i.e., derived demand function). The own price of electricity (PE), the demand for which is the dependent variable; prices of substitutes such as oil, gas and coal (PO, PG and PC respectively); prices of complementary inputs such as labour and capital; the level of industrial output represented by industrial value added (VA), and the number of industrial customers connected to ETSA. In addition to these, time and the lagged dependent variable are also used as independent variables. As mentioned earlier, time is included to represent technological changes, changes in the composition of industrial output and other variables which could not be explicitly included in the equation. The lagged dependent variable is used to account for the dynamic adjustment process.

It should be noted at this stage that all these theoretically plausible variables were not found to be significant in the present study and some of them could not be included in the final equation because of the problem of multicollinearity.

Discussion of the nature and the sources of the data used is to be found in Appendix IV(A).

Choice of Price Variables

The problem of selecting the appropriate price variable for estimating electricity demand is well recognised (see Section 3.2). It arises because of the use of a declining block rate schedule for electricity consumption. For reasons discussed in Section 3.2.3, we have decided to use the average price. One advantage of using average price is that this is actually the price which enters as a cost component of industrial output: marginal price, either ex ante or ex post, refers only to a particular block, thus neglecting all other block prices in a rate schedule.

We expect that the parameters estimated using the average price will not be very different from those using the marginal price. This expectation stems from two factors: one is that because we are dealing with the entire industrial sector, containing a large number of firms with different electricity consumptions, the relevant marginal prices would, in fact differ between firms. So at best, in aggregating across firms, we would be taking an average marginal price in any event. The other is that, in the case of the log linear functional form, Halvorsen (1978, p. 11) and Uri (1979, p. 15) have shown that the use of average price instead of marginal price affects the intercept only.

The problem of simultaneity in the determination of price and quantity, discussed in Chapter 4, is also relevant here. It should be noted, however, that the marginal block from which the average individual customer in South Australia takes electricity does not seem to have changed over the sample period. (Note that though the price of electricity has been raised several times since 1971, the structure of the block rate schedule has remained by and large the same throughout the sample period). This can be inferred by looking at the changes in the ex post average price and in the ex ante marginal prices. Since the nominal tariff did not increase prior to 1971, it should suffice to examine the relative changes since 1971. It appears that the real marginal prices (in all blocks) declined more sharply than did the real average price. Alternatively, the nominal marginal prices rose less sharply than the nominal average price.

Now this could happen in two ways. One is if all industrial customers were taking electricity from blocks with higher prices than previously, which is unlikely because it implies that they have been forced to cut back their output significantly, or the new customers have a smaller demand than the average, and hence are taking from the upper blocks. This second proposition seems more likely since consumption of electricity per industrial customer in South Australia declined over the years though the total consumption increased. Under these circumstances, one can probably assume that, on the average, the consumption of an individual customer did not change sufficiently to qualify for the lower (or upper) prices, so that the ex post marginal block price for an individual customer remained by the large the same.

With the above assumption, the question as to whether the price of electricity can be considered an exogenous variable (whether a simultaneity is involved) no longer poses a serious problem, since the price paid by an individual customer does not seem to be significantly affected by the quantity taken. Moreover, since the average price includes such items as maximum demand charge (tariff W), off peak discounts (tariff P), voltage discounts and discounts for accepting an interruption of supply, these components tend to reduce any simultaneity bias otherwise built into the average price due to the declining block rate schedule.

Nevertheless, we have estimated a system of simultaneous equations assuming that electricity price is a function of quantity of electricity sold, cost of electricity supply and the ratio of industrial consumption to total consumption of electricity. Cost of supply is estimated as a function of quantity generated and prices of capital, labour, gas, oil and coal. The estimated results were not significantly different from those reported below.

SECTION TWO: THE RESULTS

Of all the theoretical functional forms estimated - (for the derived demand model) - the linear model seems to provide the best results judged on the basis of such standard statistical measures as R^2, t-statistics, d-statistics, residual variance as well as on the basis of signs and magnitudes of the regression coefficients.

On the Spearman rank correlation test, residuals were found free from heteroscedasticity (see Appendix III).

5.2.1 <u>Results of the Static Model</u>

In a preliminary run, with all the independent variables included in the equation, prices of coal, gas, capital and labour were found to be not significant. The absence of these variables from the equation does not significantly change the value of either R^2, residual variance, or the coefficients of other variables. Thus these variables were dropped out in the final run with a view to saving degrees of freedom.

Among the remaining variables, number of customers (IC), industrial value added (VA) and time (T) were found severely intercorrelated.[6] However, on a stepwise regression, IC was not found important enough to be included in the equation. Further, it was observed that the values of all other coefficients except T remain by and large the same whether IC is included or not. Again, the exclusion of T makes a significant

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6 The simple correlation coefficients between IC and T and between IC and VA were .99. The correlation coefficient between VA and T was .98. Also $R^2_{IC} > R^2_Q$ i.e., R^2 obtained with IC as dependent variable was greater than that obtained for Q. The R^2_T or $R^2_{VA} < R^2_Q$ but the Farrar-Glauber t-statistics for the partial correlation coefficient between T and VA was 8.41 which is greater than $t_{.05} = 2.04$. Thus the existence of collinearity is established.

difference to only the coefficient of VA. Changes in other coefficients are not statistically significant.

Under these circumstances, T can be either retained or excluded from the equation - of course, with the results carefully interpreted accordingly. However, the t-values for the coefficients of both T and VA were found significant which may imply that the remaining degree of multicollinearity is not harmful (see Dutta, 1975, p. 154). The regression results are presented below:

(1) T Included:

$$\underset{(1.94)}{Q = 401.03} + \underset{(5.23)}{190.35\,D} - \underset{(-3.15)}{281.08\,PE} + \underset{(3.26)}{.77\,VA} + \underset{(3.09)}{1.33\,PO} + \underset{(4.39)}{21.98\,T}$$

$$R^2 = .996 \qquad DW = 1.84 \qquad (5.7)$$

(2) T Excluded:

$$\underset{(1.52)}{Q = 413.89} + \underset{(3.32)}{185.25\,D} - \underset{(-4.09)}{307.20\,PE} + \underset{(3.18)}{1.64\,PO} + \underset{(7.74)}{1.57\,VA}$$

$$R^2 = .993 \qquad DW = 2.15 \qquad (5.8)$$

* Figures in the parentheses indicate t-statistics.
** D = Dummy variable.

All the coefficients in the equations with or without T appeared significant and have plausible signs. The R^2 indicates that over 99 per cent of the variation in the industrial demand for electricity in South Australia is explained by the independent variables included in the equation. The DW-statistics suggest the absence of autocorrelation or mis-specification. The Chow test and the Gujarati tests suggest that the slope coefficients did not significantly change over the sample period.[7] In Table 34 we report the elasticities estimated on the basis of the regression results.

TABLE 34

Elasticities of Demand at Means Estimated From the Static Model

	Variables	Equation* T Included	Equation* T Excluded	95 Per cent Confidence Interval** (Equation Without T)
1.	Own Price (PE)	-.55 (-3.16)	-.58 (-4.02)	$-.28 \leqslant \eta PE \leqslant -.90$
2.	Oil Price (PO)	.17 (3.09)	.20 (3.13)	$.07 \leqslant \eta PO \leqslant .33$
3.	Output (VA)	.41 (3.26)	.84 (7.78)	$.62 \leqslant \eta VA \leqslant 1.06$

* Figures in the parentheses are t-values.
** η_i = elasticities of demand with respect to i^{th} variable.

It appears from the above table that the upper bound of the 95 per cent confidence level for price elasticity of demand is below one, thus indicating that any rise in electricity price is unlikely to reduce total revenue from the industrial sector. The upper bounds are much lower at the 90 per cent confidence level.

Recall that these elasticities are estimated from the static model. As there may be some time lag before demand fully adjusts to changes in the independent variables, a dynamic model needs to be estimated to see if the long run elasticities differ significantly from

7 See Dutta, M., (1975), pp. 173-178 for Gujarati test and Chow test.

those of the static model, which are usually interpreted as the short run parameters.

5.2.2 The Results of the Dynamic Model

The results of the dynamic model as specified in equation (5.4) are presented below. It should be noted that in our dynamic model T is not used as an additional explanatory variable. It appeared collinear with VA and its coefficient appeared to have a high standard error. However, the absence of T does not change any other coefficients except that of VA. The R^2 obtained with or without T in the equation was the same. Following are the regression results:

$$Q = \underset{(1.61)}{412.22} + \underset{(1.68)}{91.69}\, D + \underset{(2.00)}{.29}\, LQ - \underset{(-2.79)}{238.68}\, PE + \underset{(3.49)}{1.09}\, VA + \underset{(3.18)}{1.14}\, PO$$

$$R^2 = .993 \qquad DH = -1.07 \qquad (5.9)$$

The estimated long run elasticities are presented in Table 35.

TABLE 35

Elasticities of Demand Estimated From the Dynamic Model

	Explanatory Variables	Elasticities at Means	Elasticity at 1980 Values	Beta Coefficients
1.	Own Price	-.63 (-2.80)*	-.19 (-2.84)	-.22
2.	Oil Price	.20 (3.18)	.27 (3.16)	.11
3.	Output	.81 (3.50)	.60 (3.47)	.36

* Figures in the parentheses indicate t-statistics.

The 95 per cent confidence intervals for the above elasticities are given below:

TABLE 36

Confidence Intervals for Long Run Elasticities

For Elasticities at Means	For Elasticities at 1980 Values
$-.17 \leq \eta_{PE} \leq -1.09$*	$-.05 \leq \eta_{PE} \leq -.33$
$.07 \leq \eta_{PO} \leq .33$	$.10 \leq \eta_{PO} \leq .44$
$.33 \leq \eta_{VA} \leq 1.28$	$.25 \leq \eta_{VA} \leq .95$**

* -1.00 at 90 per cent confidence level.
** 1.02 at 99 per cent confidence level.

It should be noted that the differences in elasticities obtained from the static and the dynamic models are not significant. The small coefficient obtained for the lagged dependent variable (LQ) in our dynamic model suggests that the demand adjustment was rather rapid. The elasticities are higher for higher values of the price variables and lower for higher values of the dependent variable. These effects are reflected in the estimated elasticities for 1980 as presented above. There seems to have been a rightward shift in the demand curve in the 70's as indicated by the positive sign for the coefficient of the dummy variable.

From the estimates of beta coefficients as suggested by Goldberger (1964) (see equation 4.11) it appears that the industrial value added is the most important determinant of electricity demand followed by own price and the price of oil respectively.

5.2.3 Results of the Explicit Cost Model

The cost function and the energy share equations have been estimated simultaneously using Multivariate Regression. On application of the Farrar-Glauber set of tests, the independent variables included in equation (5.6) appear to be free from severe multicollinearity. The share equation of gas was dropped from the system. The results appeared insensitive to which share equations was dropped.

The regression results are presented in Appendix IV(B) and the estimated elasticities are presented in Table 37.[8]

An impressive feature of the table below is that nearly all the values are plausible, have the expected signs and tell a consistent story. This reinforces one's confidence that the trends and tendencies they identify are real and not spurious.

Several observations may be made on the above results.

1. For aggregate industries electricity and oil as well as gas and oil appear to be substitutes. The elasticity of substitution between electricity and oil appears to be significantly less than one and that between gas and oil is significantly larger than one. The substitutability between electricity and gas appears to be not significantly different from zero. Thus a Cobb-Douglas type of model seems to be inconsistant with the findings of the present study.

2. Substitution between electricity and oil was not significantly different from zero in ASIC 24, 25, 26, 29, 32 and 34 sub-divisions.

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8 See equations 2.27 - 2.29, for the formula used.

TABLE 37

Elasticities Estimated from Explicit Cost Function
(at Means for 1969-1980)

	Total Manufacturing	ASIC* 21-22	23
Elasticities of Substitution			
σ_{eo}	.488 (7.51)	1.089 (6.02)	.486 (3.22)
σ_{eg}	.624 (.87)	.620 (1.00)	-.066 (-.04)
σ_{og}	3.76 (7.62)	2.88 (1.85)	8.74 (3.10)
Cross Price Elasticities			
η_{eo}	.130 (7.50)	.370 (11.21)	.136 (1.35)
η_{oe}	.310 (7.49)	.634 (5.98)	.330 (1.33)
η_{eg}	.063 (.88)	.047 (.98)	.003 (.04)
η_{ge}	.395 (.89)	.361 (.99)	.045 (.04)
η_{og}	.380 (7.60)	.219 (1.85)	.350 (3.10)
η_{go}	1.000 (7.62)	.979 (4.55)	2.44 (3.13)
Own Price Elasticities			
η_{ee}	-.194 (-4.22)	-.420 (-8.23)	-.32 (-4.00)
η_{oo}	-.779 (12.17)	-.660 (-3.57)	.674 (-3.57)
η_{gg}	-1.39 (-9.27)	-.930 (-2.25)	-2.36 (-2.85)

* ASIC Codes are:
(21-22): Food, Beverage and Tobacco; (23): Textile.

TABLE 37 (continued)

	ASIC* 24	25	26
Elasticities of Substitution			
σ_{eo}	-.58 (-.92)	-1.04 (-1.84)	.354 (.98)
σ_{eg}	1.61 (2.05)	1.39 (1.08)	1.32 (2.07)
σ_{og}	-7.45 (-1.67)	-11.57 (-2.00)	.767 (1.08)
Cross Price Elasticities			
η_{eo}	.02 (.95)	.182 (1.83)	.138 (.97)
η_{oe}	-.49 (-.92)	.847 (1.84)	.212 (.96)
η_{eg}	.06 (2.11)	.020 (1.07)	.015 (2.06)
η_{ge}	1.36 (2.07)	1.13 (1.08)	.789 (2.06)
η_{og}	.25 (1.69)	.115 (2.01)	.008 (1.06)
η_{go}	.86 (1.65)	2.02 (2.00)	.300 (1.09)
Own Price Elasticities			
η_{ee}	.012 (.17)	.168 (1.78)	-.153 (-2.28)
η_{oo}	.74 (1.21)	.963 (2.14)	-2.20 (-2.15)
η_{gg}	-.500 (-1.14)	.910 (.35)	-.99 (-2.20)

* ASIC Codes are:
(24): Clothings and Footwears; (25): Wood, Wood Products and Furniture;
(26): Paper, Paper Products, Printing and Publishing.

TABLE 37 (continued)

	ASIC* 27	28	29
Elasticities of Substitution			
σ_{eo}	2.230 (13.68)	1.260 (2.33)	-.161 (-.63)
σ_{eg}	-.878 (-2.35)	.753 (1.96)	1.571 (1.00)
σ_{og}	13.45 (3.39)	8.360 (4.05)	6.85 (2.80)
Cross Price Elasticities			
η_{eo}	.700 (13.72)	.282 (2.33)	-.052 (-.65)
η_{oe}	1.233 (13.70)	.501 (2.31)	.106 (1.58)
η_{eg}	-.117 (-2.34)	.285 (2.03)	.035 (1.01)
η_{ge}	-.485 (-2.40)	.300 (1.98)	1.031 (1.00)
η_{og}	1.789 (3.37)	3.16 (4.05)	.151 (2.82)
η_{go}	4.223 (3.36)	1.87 (4.05)	2.20 (2.83)
Own Price Elasticities			
η_{ee}	-.582 (-14.55)	-.567 (-4.14)	.018 (.21)
η_{oo}	-3.035 (-5.74)	-3.670 (-5.83)	-.050 (-.26)
η_{gg}	-3.754 (-3.04)	-2.180 (-3.89)	-3.200 (-3.60)

* ASIC Codes are:
(27): Chemical, Petroleum and Coal; (28): Non-Metalic Mineral Products;
(29): Basic Metal Products.

TABLE 37 (continued)

	ASIC* 31	32	33	34
Elasticities of Substitution				
σ_{eo}	1.680 (4.62)	-.258 (-.76)	1.829 (3.48)	.661 (1.93)
σ_{eg}	.690 (3.81)	1.494 (3.11)	.047 (.09)	.264 (.35)
σ_{og}	-1.421 (-1.56)	15.142 (4.92)	12.917 (4.46)	20.79 (5.18)
Cross Price Elasticities				
η_{eo}	.233 (4.60)	-.031 (-.76)	.207 (3.46)	.097 (1.94)
η_{oe}	1.214 (4.62)	-.196 (-.77)	1.421 (3.47)	.519 (1.95)
η_{eg}	.095 (3.80)	.175 (3.10)	.005 (.10)	.018 (.36)
η_{ge}	.499 (3.83)	1.137 (3.12)	.036 (.10)	.207 (.35)
η_{og}	-.196 (-1.56)	1.772 (4.93)	1.421 (4.47)	1.39 (5.17)
η_{go}	-.197 (-1.55)	1.847 (4.90)	1.459 (4.46)	3.05 (5.18)
Own Price Elasticities				
η_{ee}	-.330 (-6.70)	-.143 (-2.38)	-.222 (-2.68)	-.116 (-1.66)
η_{oo}	-1.022 (-3.12)	-1.541 (-5.46)	-2.796 (-6.66)	-1.90 (-5.06)
η_{gg}	-.304 (-2.90)	-2.949 (-11.80)	-1.454 (-4.81)	-3.25 (-3.91)

* Figures in parentheses indicate t-statistics (see footnote of Table 19).

ASIC Codes are:
(31): Fabricated Metal Products; (32): Transport Equipment; (33): Other Machinery and Equipment; (34): Miscellaneous.

3. Substitution between oil and gas was not significantly different from zero in ASIC sub-divisions 21-22, 24, 25, 26 and 31.

4. For ASIC 31 and 32, the substitution between electricity and gas was not significantly different from one (not zero).

5. The own price elasticities for electricity demand in all ASIC industries were lower than those for oil and gas, price elasticity for gas demand being the highest. In ASIC 24, 25, 29 and 34, the price elasticity of demand for electricity were not significantly different from zero.

5.2.4 Comparison with Other Studies

It is worthwhile to make a comparison of our results with those of other studies both in Australia and elsewhere. The results of recent studies on the industrial demand for electricity have been presented in Table 26. It appears from the table that the long run own price elasticity ranges from -.51 (Griffin, 1974) to -2.60 (Fisher and Keyson, 1962). The estimate of the present study is -.63 at mean for the sample period from 1950 to 1980 and -.19 for 1980.

The long run cross price elasticities with respect to gas and oil prices range from .06 (Mount et al., 1973) to .53 (Chern, 1975). In the present study for the sample period from 1950 to 1980, it has been estimated to be .20 with respect to oil price. For 1980, the estimate is .27. Estimates from the explicit cost function are not significantly different from those of the derived demand model. In all models, gas price appears to be an insignificant determinant of electricity demand.

As regards energy substitution, the findings of the present study appear to be substantially different from those reported by TFU except in the case of substitution between oil and gas. The differences in the own price elasticities obtained in these two studies however, are not significant.

Recall that TFU used Australia-wide data which will not reflect differences in the availability of fuel types and industrial structure from state to state. Moreover, the relative price of various energy sources has changed substantially since 1974-75 - which was the last year in TFU's sample. Since our study relates to an individual state and incorporates more recent data (upto 1980), the fact that there are differences in results is not surprising.

The output elasticity of demand for electricity was measured only by Baxter and Rees (1968), Chern (1975) and Hawkins (1975). Baxter and Rees' estimates range from 0.162 (for clothing) to 2.57 (for food, drinks and tobacco). Chern estimates a value of 0.97 for an aggregate of 16 three digit SIC industries. The present study finds the long run output elasticity at 0.81 which is closer to Hawkins estimates but this appears to be lower than the findings of the other two studies, especially those of Baxter and Rees. There may be at least two explanations for this. First, the industrial structure in the areas concerned are substantially different from one another and second, the time span considered is different for different studies. Baxter and Rees used data for the early 1960's, Chern used data for 1959-71 and the present study incorporated data for the period from 1950 to 1980.

It is possible that the energy price increases in the seventies induced energy-saving technology. Due to the problem of intercorrelation between T and VA it was not possible to isolate the effects of technology from that of output (VA) in our regression equation. However, in the following sub-section an attempt is made to do so.

SECTION THREE: IMPACT OF TECHNOLOGICAL CHANGES ON INDUSTRIAL DEMAND FOR ELECTRICITY IN SOUTH AUSTRALIA

During the 31 year period of our investigation, there might have been important changes in production technology which must be taken into account. In specifying our demand model, we have included time (T) as an explanatory variable which is supposed to account for technological changes over time. Looking back to equation 5.7 it may be seen that the regression coefficient with respect to T is significant, thus indicating that even if other explanatory variables had remained constant, industrial consumption of electricity might have increased over time. Column one of the following table shows the changes which took place as regards electricity consumption per unit of output (EIC) between the years 1950 and 1980. It seems that electricity consumption per unit of value added has increased over time. But it would be wrong to infer that the entire change was due to technology.

At least three other factors may be responsible for this. First, the real price of electricity has decreased during the period under study; second, there has been an increase in the real price of non-electrical fuel and third, changes in industrial composition may have contributed to this change.

Given the data on the real price of electricity and oil, the effect of changes in these prices on the consumption of electricity may be calculated from the price elasticities (both own and cross price). The remaining changes in the electricity input component (EIC) may be attributed to changes in technology. Of course, this provides an upper bound for the impact of technological change on industrial demand for electricity. (Among other effects which this residual may represent is the composition of output). To estimate this impact, the percentage change in the prices of electricity and oil have been multiplied by the respective elasticities. This gives the maximum percentage change in the EIC which would have occurred (EIC*), had technology and other things remained unchanged. However, the actual change may be more or less depending on the impact of changes in technology and other things.

The EIC* can be computed as follows:

Let	Final Year Adjusted Electricity Input Component be	=	EIC*
	Base Year Electricity Input Component	=	EIC
	Own Price Elasticity	=	ηP
	Cross Price Elasticity	=	ηC
	Own Price	=	PE
	Cross Price	=	PC

then,

$$EIC^* = [EIC(1 + \eta P \Delta PE + \eta C \Delta PC)] \qquad (5.10)$$

where Δ means % change from the base year to final year.

The estimated EIC, adjusted EIC* and the residuals attributable to other changes such as technology and composition of output are presented in Table 38 below.

TABLE 38

Technological Impact on the Industrial Demand for Electricity in S.A.

Year	EIC	Adjusted EIC*	Impact of Technolgy (etc.) in Percentage
1950	.729	-	-
1970	2.159	.976	1.623
1980	2.546	3.447	-.354

It appears from the above table that the changes in technology and composition of output that took place in South Australian industry during the period from 1950 to 1970 tended to increase the quantity of electricity of each unit of output. But in the post 1970 period, the technological change seems to have been energy (electricity) saving, though the electricity input component (EIC) has increased. This increase is probably due to the continued decline in the real price of electricity in the face of unprecedented rises in the prices of competing fuels, especially oil and coal.

It may be interesting to examine which of the ASIC sub-divisions were most sensitive to the technological changes, and which were relatively insensitive. This may be seen in Table 39 below. Unfortunately, the comparison has to be restricted to the period from 1968-69 to 1979-80. No disaggregated data are available for the previous period.

The figures in the table reveal a fairly consistent story that energy (electricity) saving technology seems to have been underway in almost all the industrial groups. The two classes that seem to have energy intensive technologies, though of small magnitudes, are ASIC 21-22 (Food, Beverage and Tobacco) and 25 (Wood, Wood Products and Furniture). Increased electricity consumption per unit of output in some industries (e.g., 21-22, 27) seems to be due more to the incentive given by changes in relative prices than to technology.

Apart from the fact that the energy saving technology seems to be an outcome of the energy price increases in the seventies and the consequent apprehension that energy may be in short supply in future, the finding of the present study reinforces one's belief that energy

TABLE 39

Changes in Electricity Input Component and Technological Impact on Electricity Demand by ASIC Sub-Divisions from 1968-79 to 1979-80

ASIC Code	EIC (1968-69)	Percentage Change in CE/VA*	EIC** (1980)	Percentage Change in CE/VA Due to Technology etc.
Total Manufacturing	.032	-12.5	.039	-34.4
21-22	.019	21.4	.022	1.2
23	.031	-27.1	.034	-35.5
24	.010	-47.7	.010	-47.7
25	.022	1.6	.023	1.6
26	.034	-12.3	.035	-16.3
27	.033	21.7	.044	-12.1
28	.051	-19.0	.062	-39.9
29	.094	-21.8	.094	-21.4
31	.016	-25.2	.018	-37.5
32	.015	-19.0	.015	-20.0
33	.017	-21.3	.019	-29.0
34	.029	-18.2	.029	-18.0

* CE = total expenditure on electricity in 1966-67 constant price.
VA = industrial value added in 1966-67 constant price.

** See equation 5.10.

prices may act as an important mechanism in allocation of energy resources.

5.4 Summary and Conclusion

In this chapter, we have discussed the industrial demand for electricity in South Australia. Two different models were estimated: the derived demand for input model (both static and dynamic) and the explicit cost model. The own price as well as cross price elasticities estimated from these models appear to be not significantly different from one another (comparison is restricted to aggregate demand for 1970's only). We reproduce below the results obtained from the dynamic model for recapitulation.

The beta coefficients indicate that industrial output is the most important determinant of industrial demand for electricity in South Australia. The second most important determinant is the own price followed by the price of oil.

TABLE 40

Elasticities of Demand for Industrial Electricity in S.A.

	Variable	Elasticities at Means	Elasticities for 1980	Beta Coefficients at Means
1.	Own Price	-.63	-.19	-.22
2.	Oil Price	.20	.27	.11
3.	Output	.81	.60	.36

It appears from the present study that if all prices (i.e., electricity price as well as price of substitutes) and the industrial output increase by the same percentage, the electricity demand is likely to go up despite a rise in its price. However, since the price of electricity appears to have a significant effect on the industrial consumption of electricity, it would be wrong to suggest that "demand forecasts that do not explicitly consider the effects of future electricity price changes may perform quite well in practice".[9]

The findings of the present study have important policy implications. Since the price elasticity of demand is less than one, more so in recent years, it seems ETSA may have recourse to further increases in tariffs without much risk of falling revenue.

Since our study concentrated on a single region within a country, our results may not have reflected the influence of energy prices on the location of industry. Our estimates may, therefore, underestimate the overall price elasticity of demand for electricity.[10]

As regards energy substitution, the findings of the present study appear to be substantially different from those reported by TFU except in the case of substitution between oil and gas. The difference in the own price elasticities obtained in these two studies however, are not significant.

The estimated elasticities across industrial classes appear to be significantly different from one another.

In the next chapter, we devote our attention to the estimation of the commercial demand for electricity.

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9 Hawkins, (1975), p. 16.

10 I am indebted to R.G. Hawkins for this point.

CHAPTER SIX

COMMERCIAL DEMAND FOR ELECTRICITY IN SOUTH AUSTRALIA

Introduction

Of the three sectors under study, the commercial sector demands the smallest quantity of electricity but stands first in terms of growth rate of demand and second to the residential sector in terms of the number of customers. Commercial consumption as a percentage of total has been increasing over time (see Tables 1 and 5).

As has been noted earlier (Section 3.1.4), the explanatory variables for the commercial demand for electricity are by and large the same as those for the residential sector (i.e., the own price, prices of substitutes and complementory goods, per capita income, number of customers and population). The signs and magnitudes of the coefficients are also expected to be the same as discussed in Section 4.1.2. The nature and sources of the data used are the same as discussed in Appendix II. However, the relevant types of oil used in the commercial sector are more similar to those in the industrial sector (e.g., fuel oil) than the types used in the residential sector (i.e., kerosene and heating oil). So the oil price index used for estimating commercial demand for electricity is the one used for industrial demand (see Appendix IV(A)). The statistical characteristics of the data used are given below in Table 41.

TABLE 41

Statistical Characteristics of the Data Used for Commercial Demand for Electricity

	Variables	Mean	Standard Deviation
Q	(quantity of electricity in gwh)	421.99	368.87
PE	(average price of electricity in cents/kwh)	3.12	.98
PG	(average price of gas in A$/GJ)	2.53	.79
PO	(oil price index)	120.28	56.56
PC	(coal price index)	2.17	1.63
YD/N	(per capita disposable income in A$ '000')	1.39	.41
N	(population in '000')	1041.1	189.62
CC	(commercial customers in '000')	35.28	9.88
CQ	(Q/CC in gwh)	10.27	7.00

6.1 The Results

A number of functional forms of the demand equations were estimated and the results compared on the basis of goodness of fit and economic expectations as regards signs and magnitudes of the coefficients (see Appendix III). The results obtained from the linear equation appeared to be the best of all and only this form is, therefore, discussed below.

As in the case of residential and industrial demand, two models, static and dynamic, are estimated to get the short run and the long run elasticities. In addition, the explicit cost model was estimated, the results of which have been reported in Table 32 (combined with residential demand).

On application of the Klein's rule and the Farrar-Glauber set of tests (see equation R.6-R.9, Appendix III), the disposable income (YD) was found collinear with population (N), number of customers (CC) and time (T). Two alternative steps were taken to deal with this problem. In the first case, the dependent variable (Q) was expressed in terms of per customer consumption and the disposable income (YD) was expressed in per capita terms, thereby reducing the possibility of intercorrelation in the set of independent variables. In the second case, the YD was expressed in per capita terms and the Q has been left in absolute terms (total quantity demanded for commercial purposes). In both the cases, the transformation seems to have removed the severity of intercorrelation. In the latter case, the CC appeared to be insignificant and its inclusion or deletion did not significantly change any of the other coefficients or the summary statistics.

As in the cases of other two sectors, the gas and coal prices (PG, PC) appeared to be insignificant, their inclusion or deletion from the equation did not change any of the other parameters or the summary statistics such as the multiple correlation coefficient and the residual variance. Though T was found significant in the static model, it was not so in the dynamic equation. The inclusion or deletion of PG, PC and T from the dynamic equations do not significantly change any of the other parameters nor do they improve the precision of the measures. Under these circumstances they can very well be dropped from the equation (see Smyth and McMahon, 1975, p. 120).

The estimated regression results for the static and the dynamic models are presented below in equations 6.1 to 6.4.

Static Model

$$CQ = 1.45 - \underset{(-6.31)}{2.16\ PE} + \underset{(7.66)}{.028\ PO} + \underset{(9.13)}{8.75\ YD/N} + \underset{(2.39)}{.028\ T} \qquad (6.1)$$

$R^2 = .992 \qquad \bar{R}^2 = .991 \qquad DW = 1.79$

$$Q = -61.95 - \underset{(-6.06)}{106.89\ PE} + \underset{(10.40)}{1.98\ PO} + \underset{(8.44)}{417.01\ YD/N} + \underset{(2.27)}{1.27\ T} \qquad (6.2)$$

$R^2 = .993 \qquad \bar{R}^2 = .992 \qquad DW = 1.68$

Dynamic Model

$$CQ = 2.55 + \underset{(2.02)}{.24\ LQ} - \underset{(-4.87)}{1.91\ PE} + \underset{(3.92)}{.02\ PO} + \underset{(4.40)}{6.38\ YD/N} \qquad (6.3)$$

$R^2 = .993 \qquad \bar{R}^2 = .992 \qquad DH = .588$

$$Q = 65.47 + \underset{(3.10)}{.37\ LQ} - \underset{(-4.72)}{88.04\ PE} + \underset{(4.32)}{1.25\ PO} + \underset{(3.58)}{242.93\ YD/N} \qquad (6.4)$$

$R^2 = .995 \qquad \bar{R}^2 = .994 \qquad DH = -.61$

* CQ = quantity of electricity per commercial customer.
** Figures in the parentheses are t-statistics.

The estimated elasticities are presented below in Table 43.

It is important to note at this stage that the forecasting ability (detailed in Chapter 10) of the above two models are almost identical. This may be seen in the following table. The estimates are based on the data from 1950 to 1970 and an out of sample forecast for the period from 1971 to 1980.

TABLE 42

Relative Efficiency of Forecasting: Static and Dynamic Models

Dependent Variable	Theil U* Static Model	Dynamic Model
Q/CC (Consumption per Commercial Customer)	.35	.37
Q (Total Commercial Consumption)	.36	.36

* See equation 10.3 for definition.

The Theil inequality coefficients in both of the above two models are far below one, indicating that the forecasting ability of the models are fairly good.

A comparison of these figures makes it evident that for forecasting purposes, the choice between either the static or the dynamic model will not make much difference. But for the purpose of evaluating pricing policies, it is important to examine whether the long run elasticities (those given by the dynamic model) are different from the short run elasticities. Recall that in the case of the residential as well as the industrial demand for electricity the results obtained from the static and the dynamic models were not significantly different. Although it is theoretically possible to have different lag structures in different sectors, in the present study, however, it appears that the adjustment process in all the sectors were fairly rapid.

TABLE 43

Comparison of Elasticities: Static and Dynamic Models

Variables	Elasticities at Mean			
	Dependent Variable Q		Dependent Variable CQ	
	SM	DM	SM	DM
1. Own Price	-.79 (-6.06)	-.99 (-7.46)	-.66 (-6.30)	-.74 (-7.46)
2. Oil Price	.56 (10.00)	.55 (4.25)	.33 (7.62)	.31 (3.92)
3. Income	1.37 (8.42)	1.24 (5.56)	1.18 (9.12)	1.12 (4.52)

* Figures in the parentheses indicate t-statistics.
** SM = Static Model and DM = Dynamic Model

On application of the 95 per cent confidence interval (see Table 46) it appears that the difference between elasticities obtained from the static and the dynamic models are not statistically significant. Further, the results obtained from the equations with per customer consumption as the dependent variable were not statistically different (at the 99 per cent confidence level) from those obtained from the equations with total consumption as the dependent variable (see Table 46).

As is evident from the above, the income elasticity of demand in this sector (unlike that in the other two sectors) is the largest of the elasticities estimated. It should be noted, however, the income used in our equation is the income of the people at large and not that of the commercial customers themselves. That the electricity consumption in this sector changes in larger degree than that in the residential sector (for the same change in income) should not be surprising as people tend to spend more of their time outside home as their income increases and vice versa (see Halvorsen, 1978, p. 142). Moreover, the multiplicity of activities in the commercial sector is larger than that in the residential sector.[1] The Goldberger's Beta coefficients (see equation 4.11) estimated for the dynamic model are presented below.

TABLE 44

Estimated Beta Coefficients for Commercial Demand for Electricity

Independent Variables	Dependent Variable Q	Dependent Variable CQ
Own Price	-.36	-.34
Oil Price	.30	.21
Income	.43	.49

We now turn to examine if there was any change in the slope of the demand curve during the period under investigation.

6.2 Parameter Stability in the Commercial Sector

As was true for the other two sectors, it appears that the slope of the demand curve for electricity in the commercial sector remained by and large the same over the period under investigation. The Chow test and the dummy variable test as suggested by Gujarati (1970) and Dutta (1975) was applied. Nevertheless, we estimated elasticities for two periods from 1950 to 1970 and from 1971 to 1980 on the basis of the coefficients obtained for the entire sample period. The variations in the estimated elasticities are given by the differences in the levels of the dependent and the independent variables for the two sub-periods. We report below the long run elasticities estimated from equation 6.4.

1 e.g., Sauna, flood-light tournaments, disco, etc.

TABLE 45

Long Run Elasticities for Two Sub-Periods

	Variables	Elasticities at Means 1950-80	1950-70	1971-80
1.	Own Price	-.99 (7.46)	-2.57 -7.51)	0.34 (-7.66)
2.	Oil Price	.55 (4.25)	.58 (4.36)	.48 (8.16)
3.	Income	1.24 (5.56)	2.12 (5.51)	.86 (5.72)

* Figures in the parentheses indicate t-statistics.

It appears from the table that the estimated elasticities for two sub-periods from 1950 to 1970 and from 1971 to 1980 are substantially different from one another. The year to year difference may, of course, be smaller than this.

6.3 Summary and Conclusions

In this chapter, we have estimated the elasticities of commercial demand for electricity in South Australia. It is observed that per capita income has the largest impact on demand, the second important variable being the own price. The prices of gas and coal seem to have no impact on the demand for electricity in this sector. However, the price of oil appeared to have a larger influence on electricity demand in this sector vis-a-vis its influence in the other two sectors. This indicates that the possibility of substitution between electricity and oil in this sector is higher than that in the other two sectors. In view of the fact that a larger proportion of commercial demand for energy is likely to be for heating and cooling purposes, where competition from non-electrical energy is rather intense, it seems plausible that commercial customers are more sensitive to changes in the prices of alternative fuels than are customers in the other two sectors.[2]

The short run and the long run own price elasticities in this sector appear to be higher than those in the residential and the industrial sectors for the period from 1950 to 1970. However, for the period from 1971 to 1980, the own price elasticity was not significantly different from those obtained in the other two sectors. Theoretically, there is no reason why elasticities in all sectors should be the same. The findings of our study are at odds with those of Doctor, et al. (1972) which suggest that the price elasticity in the commercial sector is likely to be higher than that in the other two sectors. According to their view, commercial customers can respond to price changes more quickly and have a larger ability to change the equipment usage hours. It seems that the above thesis works well when the relative share of commercial consumption of electricity is low or at the low base consumption. This is evidenced by the higher elasticity obtained for the period from 1950 to 1970 in our study.

Further, the findings of our study belie the possibility that the demand parameters are likely to be unstable over the period before and after the oil embargo of 1972-73 and the following rise in energy prices in general.[3]

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2 The reason why gas price appears insignificant even in this sector may be that gas is not available to all commercial customers of electricity. In 1981, whereas the number of commercial customers for electricity was 51,192 that for gas was only 5,424. See ETSA, Annual Report, (1982), p. 12 and SAGASCO, Annual Report, (1981), p. 9.

3 See Sutherland, R.J., (1983), "Instability of Electricity Demand Function in the Post Oil Embargo Period", in Energy Economics, October 1983, pp. 267-272.

It may be recalled, however, that unlike in many industrial economies, electricity price in South Australia continued to fall in real terms during the period under study despite nominal rises after 1972. The real rise in electricity prices has occurred initiated only since 1981. The period from 1981 to 1983 is too short to provide a meaningful measure of elasticity of demand. Nevertheless, incorporation of these latter years' data into the equation for the sub-period from 1972 does not produce results significantly different from those reported earlier.

The estimated elasticities are represented in Table 46.

TABLE 46

Elasticities of Demand for Electricity in the Commercial Sector of South Australia

Variables	Elasticities at Means 1950–80	1950–70	1971–80	95 Per cent Confidence Interval (1950–80)*
Own Price	-.99	-2.57	-.34	** $-.72 \leqslant \eta\ PE \leqslant -1.26$
Oil Price	.55	.58	.48	$.29 \leqslant \eta\ PO \leqslant .81$
Income	1.24	2.12	.86	$.79 \leqslant \eta\ YD \leqslant 1.69$

* η_i = elasticity of demand with respect to i^{th} variable.
** -.66 at the 99 per cent confidence level.

The inter-sectoral differences observed in own price elasticities are interesting. These estimates are important in evaluation of the pricing policy pursued by ETSA. To this we shall turn our attention in Chapter Eight. Meanwhile, we present a literature review of electricity pricing in the following chapter.

P A R T   T H R E E

PRICING

CHAPTER SEVEN

A SURVEY OF THE LITERATURE ON PRICING OF ELECTRICITY

7.1 An Overview of Pricing Practice in the ESI

Early in the history of the electricity supply industry, because of the lack of metering capability, the price was fixed at a flat rate per period of time. The first improvement in pricing electricity took place when the price was fixed on the basis of the number of connected fixtures in the household.

Soon after the development of metering techniques, charges on the basis of quantity consumed were adopted, though initially the rates were a constant unit charge over all units of output taken. However, it was quickly realised that the average cost of electricity declines as the output increases and block rate schedules (BRS) were introduced to parallel the decreasing average cost (Clemens, 1950, p. 287).

Initially, the BRS were step rates, a variant of discriminating pricing where per kwh price declines when the quantity demanded reaches a prescribed level, with the reduction applying to total consumption. Such pricing had obvious drawbacks from ESI's point of view as the consumers could lower their total bills by increasing consumption. Thus the BRS was subsequently modified to make this price reduction applicable only to units consumed in excess of the specific critical level. It was, however, noticed that sharp peaks of demand occur at certain times and the plant remains with a light load most of the time. This had its effect on the degree of capital utilization and therefore, on the cost. Pricing policy was, therefore, seen as a means of keeping down average cost by spreading the demand over time (Byatt, 1979, p. 132). In 1892, Hopkinson argued that consumers should be charged a running cost on the basis of the units they consume and a standing cost on the basis of their maximum demand. However, due to the existence of a diversity factor, the maximum demand charge strategy differed from peak hour charging.[1] Gibbings (1894) pointed out that it was the station's maximum demand and not the consumers' maximum demand that was relevant for pricing electricity. Byatt (1963, p. 8) says that these modifications, representing an attempt by the ESI to keep the price closer to cost, arose largely in an ad hoc manner rather than as a result of careful theorizing. However, he quotes Baker (1902) that the load factor of stations using a price based on a maximum demand system did not differ significantly from those using flat rate charging (pp. 11-12).

In any case, economists seem never to have failed to present suitable theories to analyse the new developments in society. In the next few pages we shall review the principles of economic theory as regards pricing of electricity. This will be followed by a discussion on the theory and implication of block rate pricing in the ESI.

Economic Principles of Pricing Electricity

The economies of large scale production and the obvious misuse of resources in having more than one transmission and distribution system in one area have rendered to the ESI the status of a natural monopolist. Given a market demand, lowest cost per unit can only be

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1 See glossary of terms for definition of diversity factor.

achieved by elimination of competition so long as diseconomies of scale do not appear (see equation 2.34, p. 80).[2] The natural monopoly status of ESI's has conventionally been taken to mean that the industry should either be subject to regulation (of rate of return or price), or taken into public ownership so that price and output can be set in a way that maximises social welfare.

Recent developments in the theory of regulation, popularly referred to as the theory of contestable markets,[3] have challenged this conventional approach by observing that "competition for the entire market" may be a substitute for "competition within the market" as a means of securing efficiency in production and pricing. While these developments have potentially interesting implications for the ESI, they are not central to this study which is concerned, rather, with production and pricing within the existing public ownership structure of ETSA. Accordingly, we focus attention here on more conventional aspects of welfare maximising price behaviour in ESI.

It is well known that efficient pricing, at least in a first-best world, requires equality between price and marginal cost (see equation 7.3). It is equally well known that application of the marginal cost pricing in an industry with increasing returns to scale such as the ESI, would result in financial losses. A central question thus revolves around the choice of strategies to cover such costs. Since strategies

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2 Whether ETSA truly is a natural monopoly remains an open question even though there has been a large reduction in per unit cost as the quantity generated increased. To what extent this reduction was due to scale and to what extent due to technology could not be separated. However, the per unit cost in the small independent supply authorities is large enough to support the view that ETSA obtains substantial economies of scale.

3 See Demsetz (1968), Baumol (1982).

involving price discrimination are one important means of addressing this problem, we begin with a discussion of forms of price discrimination. The welfare maximising price for electricity is separately discussed in Sections 7.2 and 7.3.

Price Discrimination in the ESI

As a monopolist, the ESI often finds it possible to practice discrimination in pricing. In the absence of storage facilities and because of the necessary physical connection between the producer and the user, each customer is physically separated and retrading of the commodity is impossible.

Pigou (1933, pp. 275-89) has described three kinds of discrimination, namely first degree discrimination (FDD); second degree discrimination (SDD); and third degree discrimination (TDD). FDD occurs when the monopolist charges a separate price for each unit of his product on the basis of a 'take it or leave it' price designed to capture the entire consumers' surplus. This approach of a perfectly discriminating monopolist is popularly known as charging 'what the traffic will bear' (Saunders et al., 1977, p. 10). Under these circumstances, the marginal revenue curve will coincide with the Marshallian demand curve. Consequently, the profit-maximizing output will be larger than under any other pricing scheme but the income distribution consequences may be undesired.

Second Degree Discrimination would be obtained

> "if a monopolist were able to make n separate prices in such wise that all units with a demand price greater than x were sold at a price x, all with a demand price less than x and greater than y at price y, and so on".
> (Pigou, 1933, p. 279)

The unique aspect of the SDD is that the same consumer pays different prices for units of products which are identical except for the temporal order of their consumption during the billing period. This characteristic distinguishes SDD from the more common version of discrimination known as TDD, where the monopolist divides the market into sectors to exploit the variations in the price elasticity of demand among the sectors. While no market segmentation is necessary in the case of SDD, it is an essential part of TDD.

A monopolist's profit is maximised at a point where marginal revenue derived from each market is equal i.e., $MR_1 = MR_2$ or

$$P_1 (1 - 1/e_1) = P_2 (1 - 1/e_2) \quad (= MC) \tag{7.1}$$

where e = price elasticity of demand;

P = price in market 1 and market 2; and

MC = marginal cost of the whole output.

In this formulation, the intersection points of individual marginal revenue curves with the marginal cost are irrelevant (see Robinson, 1938, p. 183), since MC attributable to different sectors is considered to be the same (or inseparable). Thus accoarding to equation 7.1, if $e_1 = e_2$, then $p_1 = p_2$. The analysis ignores the possibility of different MC in the ESI due to different load factors, diversity factors, number of customers and generation in peak and off peak hours (see Sections 2.3.2 and 8.3).

For TDD it is necessary that $e_1 \neq e_2$. The monopolist will find it profitable to charge a higher price and sell less in a market where elasticity is lower and charge a lower price and sell more where elasticity is higher.

It should be noted that according to equation 7.1, any value of elasticity (e) less than infinity will put the profit maximising price above marginal cost.[4] As against this the social welfare (W) is maximised only when the price is set equal to marginal cost (MC). This is illustrated in the following equation. Let

$$W = TR + CS - TC \tag{7.2}$$

where TR = total revenue; CS = consumers surplus; and TC = total cost. Let P(Q) be the demand curve so that TR + CS = $\int P(Q)\, dQ$; and $\frac{d}{dQ}(TR + CS) = \frac{d}{dQ}\int P(Q)\, dQ = P(Q)$.

Now differentiating equation 7.2 with respect to Q, we get

$$\frac{\partial W}{\partial Q} = P(Q) - \frac{d}{dQ} \cdot TC = 0 \tag{7.3}$$

Since P(Q) is price and $\frac{d}{dQ} \cdot TC$ is the MC, we have the result:

$$P - MC = 0 \quad \text{or} \quad P = MC$$

(see Webb and Rickett, (1980), p. 80).

Though equation 7.3 identifies the ideal, pricing equal to marginal

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4 This is also true in the case of a non-discriminating monopolist. The relationship between price and marginal revenue in such a case is expressed as:

$$P(1 - 1/e) = MR$$

See Robinson (1938), p. 54.

cost may not always be possible especially in cases where the firm has increasing returns to scale. We shall discuss this further in Section 7.3. Suffice it to say at this stage that while FDD is considered to be too impracticable to be of other than theoretical interest (see Saunders, et al., 1977, p. 10) SDD and/or TDD are thought to be socially advantageous in cases where average cost curves lie above the aggregate demand curve throughout the range of possible outputs or in cases where marginal cost pricing entails a loss for the ESI. In such a case, price discrimination may permit the supplier to break even or even to make a profit.

7.2 Block Rate Pricing

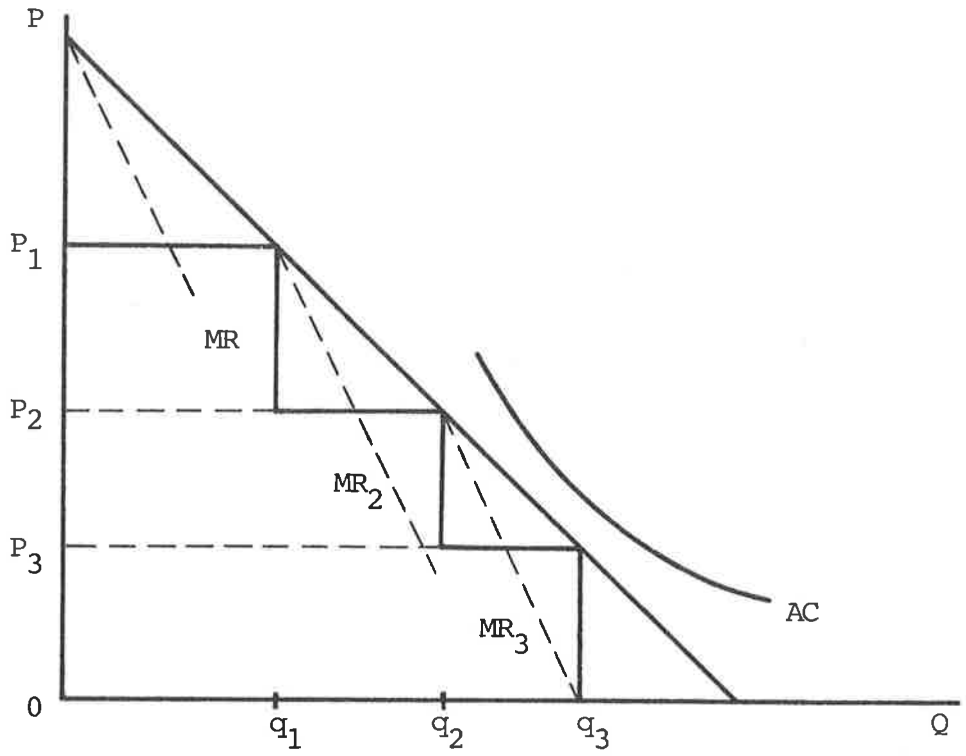
As noted earlier, block rate pricing (i.e., Second Degree Discrimination) was originally adopted in an ad hoc manner to relate price to declining costs in the ESI. But its importance was soon clearly appreciated. Block rate schedules (BRS) help attain lower cost and larger output, harnessing the economies of scale.

The most important aspect of the BRS is that it presents a potential solution to the dilemma commonly observed in a decreasing cost industry.

> "On the one hand, block pricing may enable consumers to purchase some units of output at a price equal to marginal cost insuring optimality in resource allocation ... On the other hand, (BRS) may make it possible to satisfy the requirement that total revenue equals total cost". (Crockett, 1976, p. 294).

The way BRS helps to monetize the consumers' surplus is illustrated below where marginal cost is assumed to be zero.

FIGURE 5



Corresponding to each block, MR has a kink which effectively raises the MR above what it would have been in the absence of BRS.

However, the BRS is a unmixed blessing. Crockett (1975) and Bell (1978) have shown that the use of BRS by firms under rate of return regulations may induce them to set a price where marginal revenue (MR) is less than marginal cost (MC). The marginal loss they make by expanding output beyond the socially optimum level (where price (P) is equal to MC), can be recovered by the surplus extracted from the upper blocks.

A monopolist under rate of return regulation may be inclined to do so since it will give him a larger profit though the rate of return may not exceed a certain limit. In addition to providing a safe avenue for additional investment, it may give the monopolist the psychological satisfaction of becoming bigger or merely to keep potential competitors out of the market. If the firms do so, it would undoubtedly be inefficient from the social point of view. In addition to the Averch-Johnson (1962) type of inefficiency in which firms under rate of return regulation fail to produce at the least cost input combination (i.e., employ overly capital intensive techniques), the BRS may generate a new type of inefficiency by making it possible to set price below marginal cost. This is illustrated below.

Let the price be a negative function of quantity demanded (q_i). For the two block case, the total revenue (TR) is:

$$TR = P_1 q_1 + P_2(q_2 - q_1) \tag{7.4}$$

Let total cost (TC) be a function of fixed cost (F) and the quantity produced:

$$TC = F + c(q_2) \tag{7.5}$$

The total profit (Π) is given by

$$\Pi = TR - TC$$

or

$$\Pi = P_1 q_1 + P_2(q_2 - q_1) - F - c(q_2) \tag{7.6}$$

subject to the constraints

$$\Pi \leqslant (s - k)\, X; \quad \text{and} \quad s \geqslant k, \tag{7.7}$$

where X is the capacity level which is a function of output (q_2), s is the rate of return allowed and k is the cost of capital.

Combining equations 7.6 and 7.7 in a Lagrangian expression, we have

$$L = P_1q_1 + P_2(q_2 - q_1) - F - c(q_2) + \lambda[(s - k)\ X(q_2)$$

$$- P_1q_1 - P_2(q_2 - q_1) + F + c(q_2)] \qquad (7.8)$$

Profit will be maximised when:

$$\frac{\partial L}{\partial q_2} = P_2 + q_2 \frac{\partial P_2}{\partial q_2} - q_1 \frac{\partial P_2}{\partial q_2} - \frac{\partial c}{\partial q_2}$$

$$+ \lambda[(s - k) \frac{\partial X}{\partial q_2} - P_2 - q_2 \frac{\partial P_2}{\partial q_2} + q_1 \frac{\partial P_2}{\partial q_2}$$

$$+ \frac{\partial c}{\partial q_2}] = 0 \qquad (7.9)$$

Re-arranging equation 7.9, and solving for λ we get:

$$P_2 + q_2 \frac{\partial P_2}{\partial q_2} = MC + q_1 \frac{\partial P_2}{\partial q_2} - \frac{\lambda}{1 - \lambda} [(s - k) \frac{\partial X}{\partial q_2}]$$

or (assuming $\partial X/\partial q_2 = 1$)[5]

$$P_2(1 - \frac{1}{e}) = MR = MC + q_1 \frac{\partial P_2}{\partial q_2} - \frac{\lambda}{1 - \lambda} (s - k) \qquad (7.10)$$

since[6]

$$\frac{\partial P_2}{\partial q_2} < 0, \quad 0 < \lambda < 1$$

and also

$$s > k,$$

---

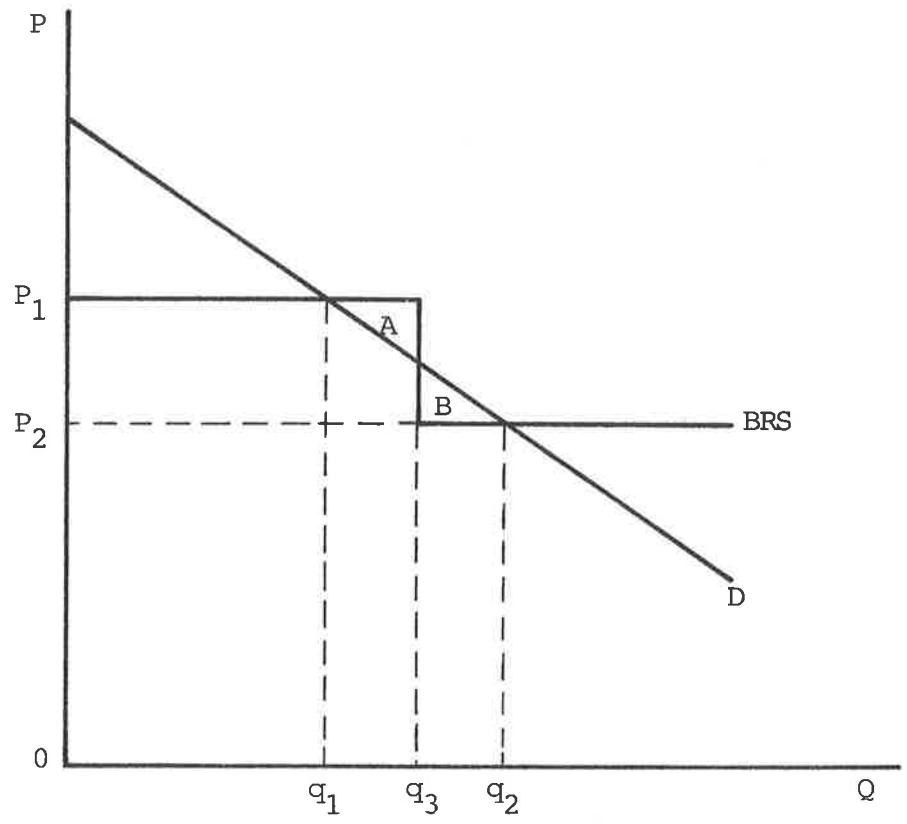
5 i.e., capacity is always expanded to accommodate increased demand.

6 λ is the imputed value of a slight relaxation in the regulatory constraint and is assumed to be positive but less than one. See Bailey (1972), p. 668.

the RHS of equation 7.10 is marginal cost minus the amount of sheltered revenue made possible by the BRS. Thus, MR < MC. This is of course, a theoretical possibility which has not yet been confirmed by any empirical study.

In order to examine the conceptual ability of BRS to increase revenues and sales it is important to examine responses of customers to a given BRS: i.e., whether they behave as they would have done in the absence of such BRS or they modify their behaviour to avail themselves of the opportunity offered by the BRS. This can be illustrated by the following figure in which D is assumed to be an income compensated demand curve so that income effects introduced by the BRS are ignored.

FIGURE 6



Customers unaware of the opportunity offfered by the BRS would take Oq_1 at price Op_1. This assumption was common in the early treatment of the BRS including Clemens (1950) and Davidson (1955). Gabor (1955) has argued that the consumer is aware of the opportunity offered by the BRS and as such he would end up with Oq_2. It is, however, important to note that even where the consumers are aware of the opportunity offered by the BRS, they are likely to weigh the gain in consumers surplus represented by area B in the figure against the loss (the area A). As the length of the first block increases, so does his loss. Identifying q_3 as the mean of $q_1 - q_2$, if the length of the first block is less than q_3, the consumer is expected to take q_2. Under these circumstances, the firm is likely to produce more than it otherwise would have done (i.e., q_2). This aspect has been elaborately dealt with by Clemens (1950), Davidson (1955) and recognised by Stackleberg (1958).

However, whether consumers are aware of the opportunity offered by the BRS is still a debated issue. It needs a detailed survey to identify the percentage of customers who take sufficient amounts to qualify themselves for the final block. In South Australia, less than 2 per cent of residential customers take electricity from the lowest block.

Though we do not know anything about the percentage of industrial and commercial customers in the lowest block available from ETSA, it can be inferred from the comparison of average level of consumption in these two sectors with the (ex ante) marginal consumption required to qualify for the lowest price. It appears that the former was always higher than the latter in these two sectors indicating that a majority of customers had the opportunity to take from the lowest block. Nevertheless, it is difficult to conclude from this whether the level of consumption would have been different if the lowest block price were the average price. It needs further empirical study and experimental data to support or reject the view that consumers are, in fact, responsive to the BRS.[7]

Further, in a world of non-identical demand curves, it is often crucial to decide to which demand curve the BRS should be tailored. Nordin (1976, pp. 719-21) argues that customers who do not qualify themselves to take from the final block pay a premium over what they would have paid if they could take from the final block. This premium may have a negative income effect on the consumption of electricity.

Moreover, it is sometimes argued that it is unfair that, under declining block rate schedules, small consumers have to pay higher prices than the larger consumers.[8] As a remedy to this situation, cross-subsidisation or an ascending block rate is often proposed. In an increasing returns industry, however, the ascending block pricing would be inefficient (see Rushdi, 1983). To examine the revenue and welfare consequences of these recommendations, again one must have a fair knowledge of the shape and position of the individual demand curves of different classes under consideration, as well as the shape and position of the marginal cost curve of the ESI. Unfortunately, detailed information to estimate individual demand is not available.

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7 From a random approach to about 100 persons in the University of Adelaide, it appears that customers in the residential sector are not aware of the opportunity offered through BRS. To the extent that this represents the market condition, the foregoing discussion on the impact of BRS on social welfare is only of academic interest rather than any practical significance to ETSA's objectives (see Section 8.1). Thus the conceptual superiority of BRS hinges upon whether customers are responsive to marginal block prices.

8 It may happen that the first block price is set so high that some consumers would be thrown out of the market due to the BRS. See Mitchel, et al., (1978), p. 13.

Major Points on Electricity Pricing

The major points which emerge from the above discussion are:

(i) The economic and technical characteristics of the ESI make it possible for the industry to practice price discrimination.

(ii) The Pigouvian SDD and TDD can provide a Second Best solution to the problem of marginal cost pricing in the ESI with increasing returns to scale. A multiple tariff with intra-marginal price greater than marginal cost (MC) and marginal price equal to MC may ensure efficient resource allocation and satisfy the requirement that total revenue equals total cost or even permit a profit.

(iii) With the possibility of siphoning off the consumers' surplus under a Block Rate Schedule, the ESI may even set the final block price below the marginal cost.

(iv) For efficient application of SDD and TDD, the ESI would require a reasonable knowledge of the class differentials in the elasticities of demand for electricity.

(v) It has not been empirically proved as yet whether customers are responsive to BRS. If they are not responsive, other more simple pricing systems can be recommended for maximising social welfare.

In the following sub-section, we briefly review the theory and implications of price regulations in the ESI. This will be followed by a discussion of peak load pricing.

7.3 The Theory of Cost-Related Price

Electricity, being regarded as a public utility, has always attracted price regulation. It has been argued that, more often than not, these regulations remained ineffective or favoured a class other than the one that economic rationality might have suggested. Among the writers who held this view are Stigler (1962), Joscow (1973), Moore (1975) and Bell (1978). As discussed earlier Crockett (1975) and Bell (1978) have shown that the rate of return regulation in the ESI may result in inefficiency in resource allocation in addition to the technical inefficiency of the Averch-Johnson model (1962).

Ideally, efficiency in resource allocation is achieved by pricing equal to marginal cost (MC) (see equation 7.3). However, if prices deviate from MC in any one sector of an economy, then it may not be optimal to set prices equal to MC in other sectors (Lipsey and Lancaster, 1956). Some recent studies, however, take the view that the problem arising out of the non-marginal cost pricing in other sectors of the economy can be solved by shadow pricing of inputs (see Pearce and Nash, 1981, p. 119; Munasingh, 1982, p. 333; Saunder et al., 1977, p. 12).

It is important to note at this stage that pricing equal to MC in monopoly industries such as the ESI may give abnormal profit to the producers in case of an upward sloping AC curve. Setting price equal to average cost (AC) in such industries can improve consumers' welfare by more than the loss in producers surplus (see Sharkey, 1982, p. 148), though this would ignore the differences in inter-class marginal costs.

In the case of a decreasing cost industry, P = MC would result in a deficit. Marshall advocated a subsidy to "turn(ing) the economic actions of individuals into those channels in which they will add the most to the sum total of happiness".[9] He was criticised on both practical and conceptual grounds, the latter revolving around the interpersonal comparison of utility which modern welfare economics disallows (Graff, 1957, pp. 313-14). Hotelling (1938) also suggested marginal cost pricing to avoid misallocation of resources, and advocated tax funded subsidies to meet the deficit. But the tax imposed may itself give rise to misallocation through excess burden effects (Little 1951) and may involve a transfer of welfare from taxpayers to utility consumers (Coase, 1970). Frisch (1939, pp. 145-50) considered that it was not necessary for prices to equal MC provided they are proportional to it. Hotelling agreed with this point but Samuelson (1947), Lerner (1944) and Coase (1946) did not.

It is important to mention here that a natural monopoly does not necessarily exhibit decreasing average cost over the entire range of output (though it must over some output range). Given its demand curve, it is conceivable that the existing firm is operating at an output level where average costs have begun to increase, yet it is not socially efficient for a second firm to enter into the industry (see Panzar and Willig (1977), p. 7). Thus contrary to widely held views, a natural monopoly can practice marginal cost pricing under certain circumstances and yet remain financially viable.

The basic contribution to the theory of cost-related pricing in decreasing cost industries was made by Ramsey (1927). Though the theory of Ramsey pricing was originally developed to explain how consumer's benefit can be maximised in a regulated multi-product firm which must break-even, the theory is equally applicable to the ESI where the same

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9 Marshall, A., (1930), 8th edition, p. 475.

product is sold to different distinct markets e.g., residential, industrial and commercial. The Ramsey prices are "second best" prices whereby sufficient revenue to cover the total cost is raised with the least possible reduction in total welfare. Under this scheme prices are "set so as to curtail all outputs in the same proportion from the hypothetical levels at which they would have been if prices were equal to marginal costs" (Sharkey, 1982, p. 50). That is to say, P_1 and P_2 are Ramsey prices if the ratio of demand at P_1 to the demand at MC price in market one is equal to the ratio of demand at P_2 to the demand at marginal cost price in market two. So that

$$\frac{D_1(P_1)}{D_1(MC_1)} = \frac{D_2(P_2)}{D_2(MC_2)} \tag{7.11}$$

Note that the deviation of prices from MC is not just proportional as Frisch (1939) has suggested. If the price elasticity of demand in market one is less than that in market two, then the Ramsey price in market one has to be raised above MC_1 by an amount which is proportionately larger than that in market two.

Thus in the words of Samuelson (1947, p. 240) "if a subsidy financed by ideal lump sum taxes is not feasible, the feasible optimum involves greater P/MC discrepancies where demand is inelastic". In spite of the fact that Ramsey rules were devised from a viewpoint completely different from profit maximisation (i.e., to maximise social welfare), technically the Ramsey equation (7.11) will not appear different from the profit maximising relationship between average revenue (P) and marginal revenue (MR) as given by

$$P\,(1 - \frac{1}{e}) = MR \tag{7.12}$$

Setting MR = MC, equation 7.12 can be expresed as:

$$(P_j - MC_j)/P_j = \frac{1}{e_j} \tag{7.13}$$

where j indicates j^{th} market or sector.

The above equation represents a case of unconstrained monopoly, which maximises profit. In a regulated monopoly (such as ETSA), the above equation may be replaced by

$$(P_j - MC_j)/P_j = \frac{\alpha}{e_j} \tag{7.14}$$

where α is a proportionality constant which may take a value $0 \leqslant \alpha \leqslant 1$. The actual value of α may be determined by the regulating body according to the necessity of achieving overall budget balance or to ensure a certain rate of return. If $\alpha = 1$, equation 7.14 becomes identical to equation 7.13, and if $\alpha = 0$, price becomes equal to marginal cost (equation 7.3). Given that maximisation of social welfare is the objective, subject to the budget constraint, equation 7.14 directly follows from equation 7.11 (see Sharkey (1982), p. 51).

Note that the price we are considering in equations 7.11-7.14 is the average price, which is larger than marginal cost, the difference depending upon the objective of the firm (i.e., highest for the profit maximiser and lowest for the welfare maximiser). The basic difference between the Ramsey price as enunciated in equation 7.14 and the third degree discrimination as enunciated in equations 7.1 and 7.13, is that a recognition of differences in MC in different sectors is not explicit in the latter while the former advocates a differentiated price on the basis of differences in MC. However, when the average cost curve lies above the aggregate demand curve, neither TDD nor the Ramsey price is of any assistance to induce the firm to produce and thereby give at least some benefit to the consumers. In such a situation the second degree discrimination (SDD) (which has been suggested by Clemens (1941), Lewis (1946), Coase (1946), Tyndall (1951) and Buchanan (1968) among others), may be applied to recover the deficit or to make some profit.

Since the BRS is considered a potentially powerful instrument to maximise profit or to breakeven in cases where no other pricing is useful, and since the regulation of ESI is explicitly aimed at eliminating monopolistic abuses (see Section 8.1), it is important to look at the question whether the existing pattern of differential pricing in ETSA is consistent with profit or social welfare maximisation. It is also interesting to investigate whether under the present condition ETSA should follow SDD, TDD, Ramsey price or some combination of them. This we discuss in Chapter Eight.

7.4 Peak Load Pricing

A particular issue in marginal cost pricing is peak load pricing: pricing such that in a situation where demand fluctuates over a cycle, the cost of service varies with the magnitude and the timing of the particular demand. The peak load problem was first considered by Boiteux (1949), but his work was unknown to the English speaking world until 1960.[10]

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10 A translation of Boiteux's article appeared in Journal of Business, April 1960, "Peak Load Pricing", pp. 157-179, Reprinted in Nelson (ed.), Marginal Cost Pricing in Practice, Prentice-Hall Inc., 1964.

Unaware of Boiteux's work, Steiner (1957) produced a similar solution to the peak load problem. The concept may be represented as follows:

(i) for any output below capacity, the short run marginal cost is equal to average variable cost; SMC = AVC; and

(ii) long run marginal cost equals short run marginal cost plus marginal capacity cost; LMC = SMC + MCC.

Steiner argued that with equal hours of peak and off-peak in the system the peak load customers be charged the entire marginal capacity cost. Williamson (1966) has shown that the conclusion is similar with unequal length of peak and off-peak hours if the motivation behind the peak load pricing is maximising welfare. Define:

$$W = (R_n + S_n)\,\phi_n + (R_d + S_d)\,\phi_d - eX_n\phi_n - eX_d\phi_d - cX_d \qquad (7.15)$$

where W = net welfare gain,

d = peak hours,

n = off peak hours,

ϕ = proportion of the cycle accounted for each period,

R = total revenue,

e = marginal energy cost,

X = output,

S = consumers' surplus,

c = marginal capacity cost.

then welfare would be maximised when

$$\frac{\partial W}{\partial X_n} = P_n\phi_n - e\phi_n = 0 \qquad \text{for} \qquad [R_n = P_nX_n] \qquad (7.16)$$

so that $P_n = e$

$$\frac{\partial W}{\partial X_d} = P_d\phi_d - e\phi_d - c = 0 \qquad (7.17)$$

therefore $P_d = e + \frac{c}{\phi_d}$.

If $\phi_n = \frac{1}{3}$ and $\phi_d = \frac{2}{3}$ then $P_n = e$ and $P_d = e + c/\frac{2}{3}$. Thus we may conclude with Williamson and Boiteux that welfare maximisation requires that the price in the peak be equal to marginal energy cost plus the entire capital cost. Davidson (1955, p. 115) has shown that if the peak is shared by various classes, the burden of the capacity cost should be proportional to the share of each class in the peak load. Also, if the full capacity is utilized in more than one period, then each period should share the MCC in proportion to the volume of demand in each period (Pressman, 1970, p. 323). This is a case of discrimination unless the difference between price and the energy cost is defined as the economic rent to the scarce plant capacity. Whereas Steiner (1957) admits the existence of discrimination in the multiple peak situations, Hirshleifer (1958, p. 462) rules it out if by cost we mean the most valuable alternative foregone.

7.5 Some Australian Studies on Electricity Pricing

Among the Australian studies arguing in favour of cost-based pricing, Kolsen (1966) is noteworthy. He criticised the equity argument as "merely a nice word for permitting internal cross-subsidisation at the whims of local authorities". In his view "the efficiency standard (MC pricing) is in the end more equitable" (Kolsen, 1966, p. 571).

In deciding to price according to marginal cost, it is necessary to distinguish marginal capacity-cost from the cost of additional capacity. The former is likely to be less than the latter since the installation of new capacity may change the merit order of operation and displace some inefficient plant, thus contributing to fuel savings. Turvey (1971) rejects the concept of constant marginal cost even at levels of output within the capacity of existing plants in the system. He concludes that higher prices should be charged to consumers of heavier demand because of the higher variable costs associated with the use of less efficient plants at the margin.

In line with Turvey, McColl (1976) and Harvey (1982) argue for marginal cost pricing in the Australian ESI. However, their discussions "focus on the implications of temporal variations in demand for pricing and investment and ignore the implication of its spatial distribution".[11] Thomson and Walsh (1981) demonstrated how social benefit is reduced due to spatial cross-subsidisation in favour of rural customers of electricity by not charging them on the basis of marginal cost of supply.

McColl (1976) favours a 'time of day' (TOD) tariff, so that a higher price is charged for peak period consumption than for the off-peak consumption, because the "lowest cost operation of an electricity system requires that demand be spread as evenly as possible over the day and the year" (p. 82). While Thomson (1979, p. 7) prefers a two part tariff, Harvey (1982) seems to be in accord with McColl (1976) in suggesting a TOD tariff. It should be noted, however, that whether TOD

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11 Neutze and Bethune, "Urban Economics", in F.G. Gruen (ed.), Surveys of Australian Economics, Vol. II, Allen and Unwin, Sydney, 1979, p. 78.

pricing will improve the system load factor (lower the operation cost) will depend on the extent to which timing of demand responds to tariff differences. "The question here is not whether research is needed but where to start" (Taylor, 1975, p. 108).

No study either overseas or in Australia seems to have been made as yet to determine the relationship between interclass differences in marginal cost pertaining to residential, industrial and commercial customers vis-a-vis the price differentials in these classes. Nor is there any study on the possible impact of prices charged on the basis of respective marginal cost. The present study is aimed at illuminating these issues.

In the next chapter, we present an evaluation of pricing practices in ETSA.

CHAPTER EIGHT

AN EVALUATION OF PRICING PRACTICES IN ETSA

Introduction

The basic economic principles of pricing with respect to an ESI have been discussed in the previous chapter. It was observed that in an increasing return industry like ETSA, marginal cost pricing, as is often suggested for maximising welfare and the optimum allocation of resources, would entail a financial loss and therefore require subsidy. If the ideal subsidy is not available or is considered inexpedient, the ESI may still breakeven or make a profit by using either Ramsey prices (equation 7.14), a block rate schedule (BRS) or a combination of such strategies. In the case of SDD, the marginal price may be set equal to marginal cost (MC) and the intra-marginal block prices would be higher than the marginal cost. In the case of the Ramsey rules of pricing, the average price should deviate from marginal costs in such a way that the firm can cover its total cost or make any stipulated profit. Whether we are dealing with a profit maximising or loss minimising situation, the deviation from marginal cost should be inversely proportional to the price elasticity of demand in any sector. This conclusion may be drawn directly from equation 7.13 which is reproduced below.

$$(P_j - MC_j)/P_j = 1/e_j \qquad (8.1)$$

where e_j = price elasticity of demand in the j^{th} sector.

For inter-sectoral balance, equation 8.1 can be re-written as:

$$[(P_j - MC_j)/P_j]/[(P_k - MC_k)/P_k] = e_k/e_j \tag{8.2}$$

Thus, if MC is the same in all sectors, then the sectoral prices should be the same for the same elasticities of demand with respect to price but should vary inversely with variations in the elasticities. On the other hand, if elasticities are the same in all sectors, prices should differ on the basis of differential MC only. Needless to say, if both marginal costs and elasticities are the same in all sectors, there is no efficiency case for price differentiation.

As discussed in the previous chapter, equation 8.1 represents the profit maximising (or loss minimising) rule for an unconstrained monopoly. If the monopoly is constrained to breakeven or to make only a reasonable surplus then the differences in sectoral prices (P_j, P_k) from their respective marginal costs (MC_j, MC_k) will have to be scaled down by a constant α, to be determined by the regulatory authority to suit their specific purpose (see equation 7.14). Thus for a regulated monopoly, equation 8.1 should be replaced by

$$(P_j - MC_j)/P_j = \alpha/e_j \tag{8.3}$$

where $0 < \alpha < 1$.

It may be emphasised that a regulated monopoly need not necessarily be the lowest cost supplier. The quality of service such as risk of breakdown, loadshedding or voltage fluctuations, is also important. For instance, if customers are satisfied with or persuaded to accept a 95 per cent guarantee of continuous service, then a 10 per cent spare capacity may well serve the purpose. But a 100 per cent guarantee may require a 20 per cent spare capacity, thus raising the per unit costs.[1] Moreover, the risk of over-capitalisation (Averch-Johnson, 1962), topheavy administration or excessive emphasis on engineering efficiency as against commercial and economic efficiency (Hartley, 1983) are also present in almost all sorts of firms - unconstrained, constrained, private or publicly owned monopolies. In other words, the MC may vary according to differences in what the firm is maximising (minimising) and also on the element of competition which prevails.[2] Nevertheless, equation 8.3 would be an appropriate rule in all the above cases to meet the profit (or break even) target.

We look now at the major objectives of ETSA so that its pricing policy can be evaluated in the light of its objectives.

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1 A good discussion on premium for high quality products is to be found in Shapiro, C. (1983), "Premiums for High Quality Products as Returns to Reputations", The Quarterly Journal of Economics, November 1983, pp. 659-679.

2 Under the profit maximising or cost minimising hypotheses, there is no reason to believe that competition will lower operating cost below the monopoly level. But under competitive pressure, managers may be forced to trade off the disutility of greater effort, search and control for the utility of less (or no) pressure and better interfirm relations. It is therefore, believed that competitive pressures are conducive to cost reduction (see Primeaux, 1975). However, cost reductions due to such pressures have to be weighed against reductions due to larger size operation (economies of scale, see Chapter Two) under monopoly. Of course, aspects of competition might be introduced even in natural monopolies by auctioning the monopoly (with a prescribed quality of service) at certain intervals. Some elements of competition might also be introduced by separating generation and distribution activities and allowing the distribution authority to buy electricity from the cheapest sources. See Section 7.1 and also Demsetz (1968), Stigler and Friedland (1962).

8.1 The Objectives of ETSA

The ETSA Act of 1946 does not seem to have spelled out any clear cut economic objective except "that the Trust shall administer this Act in such manner as in its discretion it deems to be in the best interest of the general public" (Section 15.2, ETSA Act, 1946). However, one of the reasons behind the nationalisation of the then Adelaide Electric Supply Company (AESC) in 1946 clearly seems to have been that "the company must under no circumstances be allowed to become an exploitative monopoly".[3]

The AESC commenced operation in 1904 and by 1930, it had accumulated a reserve of $3,689,546. This is the latest figure available, and might well have been more in the 1940's. The Auditor General reported in 1944 that the AESC paid a dividend on its old shares at the rate of 7 per cent and it could be 10 per cent if the issue of new preferential shares were permitted. This was quite high in relation to the then prevailing dividend rates and especially in view of the prevailing low rates on long term government bonds (3 per cent in May, 1944).[4] The Crown solicitor felt that the Government was neglecting its duty to the public by not regulating the electricity price (Findlay (1962), p. 34). It was felt that South Australia had been rejected as a possible site for new industries because of the high price of electricity.[5]

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3 Official Report of the Parliamentary Debates: South Australia, Government Printer, Adelaide. See Hannaford, W., 17.10.1922, p. 930. Also McCallum, T., 18.10.1922, p. 980.

4 See Statistical Bulletin, 1943 to 1949, Commonwealth Bank of Australia, p. 65.

5 See Advertiser, 2.10.1945, comment by Mr. Wainright, the Treasurer's representative on the Royal Commission 1945 on AESC.

One of the reasons why the ETSA Act had wide support, even from those who were traditionally opposed to state ownership, was that the ETSA bill was seen as necessary for rural electrification and for the use of local coal (Leigh Creek). The AESC was unwilling to extend supply network to the rural areas and to use local coal since, according to them, it was uneconomic to do so.[6] Opposition members who had large rural interests could see the benefit of rapid electrification. The Playford Government, which seems to have been committed to seeing South Australia self-sufficient in energy, insisted, on the basis of the Plaine Committee Report, 1943 that the Leigh Creek coal could be used to meet the necessity for an immediate increase in electricity supply (see Year Book of the Commonwealth of Australia, 1953, pp. 1186-87).

The main criticism of public ownership was that a state enterprise 'would mean production for use and not for profit' and as such would require extra taxes on the public to meet its deficit.[7] However, the ETSA Act 1946, seems to have taken a stand that ETSA should be a self-sufficient organisation. Section 21 of the Act reads:

> "The Trust may at the end of any financial year set aside out of its revenue such sums as it thinks proper as payment to reserves or sinking funds and may invest any such reserves or sinking funds or use them in its undertaking".

Under Section 19 of the Act, the Trust was empowered to borrow money from the Treasurer or from any other authority or person or from the public. Also under Section 16, the Trust was made liable to pay rates.

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6 See Fifty Years of Progress, AESC, 1949, p. 135; also Stockley (1967), p. 86.

7 See Marrow, W., Official Report of the Parliamentary Debates, 4.12.1924, p. 1426.

In view of the above historical perspective, one may outline the major objectives of ETSA as follows:[8]

1. to operate as a non-profit but self-sufficient organisation;[9]

2. to keep the price as low as possible;

3. to provide adequate service to the entire public on demand (even if this requires cross-subsidisation of rural customers by urban customers).

4. to make the state self-sufficient in energy (that is, to use South Australian sources of energy).

With these objectives in view and also keeping in mind the substantial economies (see Table 21) obtaining to ETSA, a choice must be made between BRS and the Ramsey rules (as enunciated in equation 8.2 and 8.3) as to which is the best available guide for its pricing policy.

Conceptually, it seems possible to argue that BRS with marginal price equal to marginal cost represents a better solution than does the Ramsey rule or TDD. But the superiority of BRS hinges heavily on the assumption that customers are responsive to marginal price and that the cost of information necessary to successfully implement and administer

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8 The existence of differences between the objectives of an institution and the behaviour of its decision makers is not uncommon (see Hartley, 1983, p. 32). But it is believed that such differences are constrained by the fact the public bodies are subject to occasional review and parliamentary debates.

9 See ETSA Annual Report 1969, p. 16, it reads that "the Trust's primary function is not to make profit but to provide service to the community. Nevertheless, a revenue surplus of less than one per cent of sales must be considered inadequate for an undertaking which has to play a key role in the expansion and development of the state".

BRS is not greater than the social surplus lost under Ramsey pricing due to deviation of price from marginal cost.

In ETSA, marginal prices in all three sectors under study, though differing from one another, are far above the estimated sectoral marginal costs.[10] It is highly doubtful whether customers would consume as much as is required to qualify for the marginal price (=MC) and at the same time pay an intra-marginal price (average price) large enough to cover the average cost.[11]

Under these circumstances, and given that the demand curve faced by ETSA intersects the average cost curve so that a BRS arrangement is not strictly required to ensure that costs are covered, it is possible to argue that the Ramsey pricing rules are the more appropriate. We now examine possible difficulties in the application of these rules.

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10 The possibility of setting marginal price (MP) below marginal cost (MC) arises only under rate of return regulation (RRR). Since ETSA is not a monopoly under RRR, the fact that MP > MC in ETSA does not prove or disprove anything except that ETSA is not a profit maximiser. As enunciated in equation 7.1 profit maximisation would require equal marginal revenue (MR) from all sectors. Moreover, if profit is to be maximised, the length of blocks should be designed in a way that the percentage difference in block prices, say, the first and second blocks, should be inversely proportional to the elasticity of demand with respect to the first block price. In other words, the MR obtained from the first block equals the price in the second block. This is illustrated below. Differentiating equation 7.6 with respect to q_1, we have:

$$\partial\Pi/\partial q_1 = P_1 + q_1 \partial P_1/\partial q_1 - P_2 = 0$$

or $P_1(1 - 1/e) = P_2$

or $(P_1 - P_2)/P_1 = 1/e$

The BRS in ETSA do not conform to the above rule nor do they conform to the Ramsey rules as we shall see later.

11 In the residential sector in 1982 less than 2 per cent of customers were in the last block (personal contact with ETSA).

8.2 Problems Associated with Cost Related Pricing

The basic problem with the cost related pricing of electricity as enunciated above is to know what the respective marginal costs are. A general definition of marginal cost is that "it is the net additional discounted system cost of meeting an increment in demand" (Reid, et al., 1973, p. 207). The marginal cost estimates given in Tables 23 and 25, are obtained on the basis of annual increments in demand and cost of supplying electricity. These estimates, therefore, conceal the variations in the value of MC due to the character of the increments in demand. For instance, an increase in demand from existing customers will involve a MC different from that due to new customers.[12] Likewise, an increase in demand from rural customers may have a MC different from that due to urban customers. The marginal cost of supplying electricity in peak hours (and in peak seasons) is likely to be significantly higher than that in the off peak (off season) hours. Again, the MC of meeting demand that requires additional capacity is fundamentally different from that due to an increment which can be met with the existing capacity. In short,

> "there is no single figure for the marginal cost of electricity supply ... The time element alone would give as many marginal costs as there are half hours in a year and on top of this there are (differences in) voltage of supply and location of customers, which give yet more differences" (Reid, et al., 1973, p. 209).

If we assume for the moment that all necessary information is available so that marginal cost can be estimated for each time of day,

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12 Not only will new customers involve additional customer-related fixed costs, such as connection, meter reading and sending bills but also demand from new customers is more likely to add to the peak demand and thereby reduce the load factor.

each voltage level and location of customers etc., the cost of introducing such a comprehensive pricing system may be too high to justify such a venture.[13] Moreover, such a system may appear too complicated for customers to understand and without any purpose for small customers in particular.

In the present study, we have estimated marginal costs for three major consumer classes, namely residential, industrial and commercial customers in South Australia. No further disaggregation was possible due to lack of data. The estimates are inter-sectoral estimates which though incorporate differences in voltage level, time of day, seasonal variations in demand between sectors, ignores such differences within a sector and so on. The forced aggregation over such differences made it impossible to estimate marginal cost at peak and off peak hours and as such consideration of peakload pricing is not possible on the basis of current information. However, on the assumption that the suppressed variable elements are roughly similar in the different sectors, our findings provide a reasonable comparability of estimated marginal costs between sectors. Thus the inter-sectoral price discrimination (and price differentiation) practiced by ETSA can be evaluated on the basis of the estimates reported in Tables 23 and 25 and on the basis of the sectoral price elasticities reported in Chapters Four, Five and Six.

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13 The cost of full time-of-day meters is estimated to be between A$50 and A$60 per customer (over the life of meters). The cost of equipping all South Australia's customers (552,000 in 1980) will be more than $A33 million. See Reid, et al., 1973, p. 211.

8.3 Evaluation of Pricing Practices in ETSA

Estimates of the price elasticities of demand for electricity in the residential, industrial and commercial sectors of South Australia have been given in Chapters 4, 5 and 6 respectively. The main findings are represented below.

TABLE 47

Long Run Price Elasticities of Demand for Electricity in South Australia

(1)	1950-80 (2)	1950-70 (3)	1971-80 (4)
Residential	-.82	-1.27	-.39
Industrial	-.63	-.95	-.35
Commercial	-.99	-2.57	-.34

It is clear from the above table that the relative inter-class elasticities have undergone substantial changes in the recent past. It is interesting to examine whether this changing pattern of inter-sectoral elasticities has been reflected in the pricing policy of ETSA.

8.3.1 Relative Price Changes in Various Sectors

The real average price of electricity in the three sectors under study were as follows:

TABLE 48

Average Prices* of Electricity (in Cents) in South Australia

	1950-80	1950-70	1971-80
Residential	1.99	2.32	1.28
Industrial	1.85	2.16	1.25
Commercial	3.12	3.67	2.03

* Mean deflated price per kwh over the sample period.

A comparison of Tables 47 and 48 tells us that though the ratios of inter-sectoral price elasticities have undergone a substantial change between the two sub-periods under investigation, the relative average prices have remained by and large the same. This may be seen in the following table.

TABLE 49

Comparison of the Intersectoral Prices and Elasticities

	Inverse Ratios of Inter-sectoral Price elasticities		Ratios of Inter-sectoral Prices	
	1950-70	1971-80	1950-70	1971-80
RES/IND*	.75	.90	1.08	1.02
RES/COM	2.02	.87	.64	.63
IND/COM	2.70	.97	.59	.62

* RES = Residential, IND = Industrial and COM = Commercial.

The apparent stability in relative prices against the changing relative elasticities is probably the outcome of the way the prices are changed by ETSA. It seems that prices are changed by a certain percentage which is by and large the same for all sectors and is thus at odds with the profit maxmising, welfare maximising or loss minimising criteria discussed earlier.

8.3.2 The Theory of Equi-Marginal Revenue From All Sectors

The profit maximising principle of equi-marginal revenues from all sectors (equation 7.1) requires that the price be set in the elastic zone of the demand curve for non-negative marginal revenue. As may be seen in Table 47, the price elasticities of demand in all the sectors were below one for the period from 1971 to 1980; for the preceding period the price elasticity in the industrial sector was below one; and the average price elasticities for the entire sample period in all the sectors were below one. This suggests that had ETSA been a profit maximiser, prices in all the sectors would have been higher. Secondly, as the inverse ratios of the inter-sectoral price elasticities differ widely from those of inter-sectoral prices (see Table 49), one may conclude that ETSA could have maximised revenue either by lowering price in the sector where elasticity was larger or by raising price in the sector (e.g., industrial sector) where elasticity was lower.

It needs to be stressed at this stage that the principle set out in equation 7.1 presupposes a continuous marginal revenue curve which is negative corresponding to a price in the inelastic zone of the demand curve. But the existence of a block rate schedule (BRS) in the ESI makes this straightforward formula difficult to apply. The BRS makes the marginal revenue curve discontinuous. That is to say, each block has a separate marginal revenue curve (see Figure 5, p. 226). Second Degree Discrimination (SDD) makes the marginal revenue and the average revenue equal within a particular block. Thus even when a block price is set in the inelastic zone of the aggregate demand curve, the marginal revenue may still remain positive. This together with the differences observed in the inter-class marginal costs makes the principle of equi-margnal revenue rather inappropriate. A more appropriate principle for evaluating the profit maximising (loss minimising) or welfare maximising behaviour of a firm under increasing returns to scale seems to be given by equations 8.1 to 8.3 i.e., by the Ramsey set of rules. To this we turn in the following sub-section.

8.3.3 The Theory of Cost Related Price: Revisited

Under the Ramsey principle, the best operational price in a sector will depend upon not only the price elasticity of demand but also the marginal cost pertaining to that sector. As stated earlier, equation 8.1 provides profit maximising price and output and equation 8.3 provides those for welfare maximisation subject to a budget constraint. Note that under this principle, the inter-sectoral price ratio will be different for different values of the marginal cost, even though the marginal cost is the same for all the sectors and the inter-sectoral elasticity ratios are given.

As reported in Table 25, the interclass marginal costs in ETSA were found to be different from one another. The sectoral price differences from the respective marginal costs are given below:

TABLE 50

Sectoral Price Differences (in Cents) from Marginal Costs*

	1950-70				1971-80			
(1)	P (2)	MC (3)	P/MC (4)	(P-MC)/P (5)	P (6)	MC (7)	P/MC (8)	(P-MC)/P (9)
Residential	2.32	1.49	1.56	.36	1.28	.75	1.71	.41
Industrial	2.16	.39	5.54	.82	1.25	.65	1.92	.48
Commercial	3.67	1.29	2.84	.65	2.03	.52	3.90	.74

* P and MC are expressed in constant (1966-67) prices.

It appears from the above table that though the marginal cost in the residential sector was the highest in both the sub-periods from 1950 to 1970 and from 1971 to 1980, it is the commercial sector that was charged the highest price. Viewed from the sectoral marginal cost of supply, it was the industrial customers during 1950-70 and the commercial customers during 1971-80 that paid the highest premium to ETSA.

The ratio of price to marginal cost in each sector is given in columns four and eight of the above table.

The price deviations do not appear to be in line with the Ramsey rules nor do they seem to be related to the respective marginal costs (Frisch, 1939). ETSA appears to be maximising neither profit nor welfare. This may be seen in the following table.

TABLE 51

Comparison of Sectoral Differentiated Prices with Inverses of Sectoral Elasticities

	1950-70 (P-MC)/P	1950-70 1/e*	1971-80 (P-MC)/P	1971-80 1/e
Residential	.36	.79	.41	2.56
Industrial	.82	1.05	.48	2.86
Commercial	.65	.39	.74	2.94

* e is price elasticity of demand.

It appears from the above table that for the period between 1950 and 1970, in the cases of the residential and the industrial sectors, the left hand side of equation 8.1 was lower than the right hand side indicating that more resources were used in satisfying demand for electricity in these two sectors than were justified on the ground of maximising social surplus i.e., the sum total of consumers' plus producers' surplus.

Further, it seems that ETSA has disregarded the differences in sectoral marginal costs when setting prices. The marginal cost in the residential sector was nearly four times greater than that in the industrial sector for the period from 1950 to 1970 and only about 15 per cent greater during 1971-80 period. Yet the price in the former was only slightly higher than that in the latter (i.e., by 7 per cent, and 2 per cent respectively for the two sub-periods).

The differentiated price (P-MC) charged in the commercial sector during 1950-70 was much higher than the level that Ramsey rules would have suggested. Considering the very high price elasticity of demand observed in this sector during the 1950-70 period, it may be concluded that more revenue could have been obtained from this sector by lowering the price (and as a consequence increasing the consumers' surplus). Since the cost elasticity of supply has been estimated to be less than one (see Table 21), this means that any decline in price (less than the decline in cost) would have increased profit as well.

It may be noted at this stage that in the process of price changes, the adjustment takes place on both sides of equation 8.1. As price is raised, the value of (P-MC)/P goes up. At the higher price, the quantity demanded is likely to be less and the price elasticity of demand would be larger, thus making 1/e smaller. The opposite happens when the price is lowered. Thus the equilibrium between the left and the right hand sides of equation 8.1 takes place rather more quickly than appears at first sight.

For the period from 1971 to 1980, the differences between prices charged and the respective marginal costs in all three sectors are less than the profit maximising differences. This suggests that ETSA was not a profit maximiser. Whether it maximised social welfare (i.e., the sum total of consumers' and producers' surplus) is detailed in Table 56. Before turning to that, however, we examine the profit maximising price and output for ETSA to identify their differences from the existing price and output. For the global (inter-sectoral) optimum, inter-sectoral price differentiation should conform to the inter-sectoral differences in elasticities of demand with respect to price (see equation 8.2). The following table shows the difference between the observed ratio of inter-sectoral prices and the desired ratio as indicated by equation 8.2.

TABLE 52

Comparison of Ratios of Inter-sectoral Price and Elasticities

	$[(P_j-MC_j)/P_j]/[(P_k-MC_k)/P_k]$		e_k/e_j	
	1950-70	1971-80	1950-70	1971-80
(1)	(2)	(3)	(4)	(5)
RES/IND	.45	.92	.75	.90
RES/COM	.57	.59	2.02	.87
IND/COM	1.26	.65	2.70	.97

* RES = residential, IND = industrial and COM = commercial.

Note that the so called desired ratio as given in columns four and five of the above table are on the basis of average price and average quantity of electricity demanded. Any change in price (say towards Ramsey optimisation) will change all the ratios and a near equilibrium (Ramsey) set of prices and quantities can be achieved only by an interative process. Probably a full equilibrium can never be achieved since prices cannot be changed too frequently and by the time price is changed on the basis of an estimated marginal cost, the marginal cost itself might have changed due to changes in quantities and load factors (endogenous) and/or due to changes in input prices and technology (exogenous).

Nevertheless, on the basis of the estimated class marginal costs in ETSA, it may be concluded that the price charged for commercial electricity was disproportionately high in relation to its marginal cost of supply. Looking at Table 52, it appears that if ETSA had been a profit maximising monopolist, it should have either reduced price in the commercial sector or raised it in the industrial sector or both. Similar conclusions apply to residential versus commercial sectors.

Parenthetically, it may also be concluded that ETSA can raise sufficient funds to meet its own expenditure (and probably to increase internal funding for creating new capacity) by practicing the Ramsey pricing rules as enunciated in equations 8.1, 8.2 and 8.3.

The following two tables show the prices in different sectors and the estimated maxima that ETSA could earn by following the rules for an unconstrained monopolist given in 8.1 and 8.2.

The unconstrained monopoly prices in the table below are substantially different from class to class. The actual prices that ETSA charged over these periods are substantially lower than the above prices in all cases except the commercial sector for the period from 1950 to 1970.

TABLE 53

Expected Price and Quantity Under Unconstrained Monopoly: ETSA

	Residential		**Industrial**		**Commercial**	
	1950-70	**1971-80**	**1950-70**	**1971-80**	**1950-70**	**1971-80**
1. Price (cents/kwh)	2.83	2.65	2.42	3.06	3.19	4.30
2. Quantity (gwh)	429.00	1116.00	534.00	812.00	266.00	528.00
3. Revenue (A$m)	12.14	29.57	12.92	24.85	8.49	22.70
4. Cost (A$m)	8.49	14.51	10.57	10.57	5.27	6.86
5. Producers Surplus	3.65	15.06	2.35	14.28	3.22	15.84
6. Elasticity (e)	-2.15	-1.38	-1.20	-1.28	-1.67	-1.14
7. 1/e	.47	.72	.83	.78	.60	.88
8. (P-MC)/P	.47	.72	.83	.78	.60	.88

* Figures in items 1, 3, 4 and 5 are in 1966-67 constant prices.

** Total cost (item 4) has been estimated on the basis of the average cost calculated aggregating over the three sectors.

The following table shows the percentage differences between the actual and the unconstrained monopoly prices that ETSA could charge had profit maximisation been its motive.

TABLE 54

Differences Between the Actual and the Unconstrained (Ramsey) Monopoly Prices (in Cents)

	1950-70			1971-80		
	Actual	Hypothetical	% Change	Actual	Hypothetical	% Change
Residential	2.32	2.83	+ 22	1.28	2.65	+ 107
Industrial	2.16	2.42	+ 12	1.25	3.06	+ 145
Commercial	3.67	3.19	- 13	2.03	4.30	+ 112

The differences between the actual quantity of electricity consumed by these sectors and the hypothetical level of consumption under unconstrained monopoly prices are shown below.

TABLE 55

Differences Between the Actual and the Hypothetical Levels of Consumption of Electricity (gwh) at Unconstrained Monopoly Prices

	1950-70			1971-80		
	Actual	Hypothetical	% Change	Actual	Hypothetical	% Change
Residential	653	429	- 34	1,936	1,208	- 32
Industrial	603	534	- 11	1,648	812	- 51
Commercial	200	266	+ 33	853	528	- 38
Total	1,456	1,259	- 14	4,437	2,648	- 40

It should be emphasized that the hypothetical prices and quantities shown above are the levels at which an unconstrained monopolist is likely to operate. This is a profit maximising level of production, a departure from which will generally increase consumers' surplus more than any loss to the producer. As discussed earlier, the public ownership of the ESI in South Australia and the formation of ETSA was motivated not to maximise profit but to provide maximum service at a minimum cost. We may, therefore, relax the profit maximisation hypothesis and assume that ETSA wants to earn only as much revenue as is required to breakeven. This could be achieved in two ways. First, by charging each sector a price equal to average cost of supply which would, of course, ignore the differences in sectoral marginal costs obtaining in different sectors. Second, by charging Ramsey prices given by equation 8.3. The difference in Marshallian consumers' surplus under both pricing equal to average cost and pricing according to equation 8.3 appears to be insignificant at the 95 per cent confidence level.

The sum of consumers' surplus under the above two methods of pricing is significantly greater than the sum total of consumers' and the producers' surplus under the unconstrained monopoly rule. If the aim is to breakeven and to maximise consumers' surplus, equation 8.3 is satisfied when we set a value α = .45 for the period from 1950-70 and α = .15 for the period from 1971 to 1980. Instead of breaking even, however the firm may actually wish to build up a certain amount of internal funds for its development purposes, in which case it may suitably raise the value of α in equation 8.3. For this latter procedure the required changes in price and quantities are obtained by an iterative process.

In the following table, the Marshallian consumers' surplus and the producers' surplus (TR - TC) under various pricing methods are compared.

TABLE 56

Comparison of Consumers and Producers Surplus Under Various Pricing Methods

		Present 50-70	Present 71-80	AC = P 50-70	AC = P 71-80	Constrained Monopoly*** 50-70	Constrained Monopoly*** 71-80	Unconstrained Monopoly 50-70	Unconstrained Monopoly 71-80
1.	TR	35.51	62.70	36.15	58.57	35.95	58.91	33.55	77.12
2.	TC	28.83	57.68	36.15	58.57	35.95	58.94	24.33	31.93
3.	CS + PS	30.52	103.28	37.03	103.55	36.85	103.64	29.48	78.56
4.	PS	6.68	5.02					9.22	45.19
5.	CS	23.84	98.26	37.03	103.55	36.86	103.64	20.26	33.37

* All figures are in million A$ in 1966-67 price per year aggregated over the period mentioned.

** AC = average cost, P = price per unit, TR = total revenue, TC = total cost, PS = producers surplus and CS = consumers surplus.

*** α = .45 for 1950-70 and α = .15 for 1971-80 to achieve breakeven.

It may be observed that for the period from 1950 to 1970, though ETSA has earned a net surplus of A$6.68 millions, the consumers' surplus is substantially lower than that which could have been achieved either by setting price equal to average cost or in accordance with equation 8.3. If we take the sum total of consumers' and producers' surplus as representative of the net social benefit, it appears that ETSA could substantially increase the social benefit by practicing either of the above two pricing principles.

It is interesting to note, however, that though ETSA did not follow either of the above policies (P = AC or Ramsey Price), the aggregate social benefit obtained per year during the period from 1971 to 1980 seems to be very close to what could have been achieved by either of the two methods mentioned above. During this period, ETSA obtained a surplus averaging A$5.02 million per year. The consumers' surplus seems to have been to the tune of A$98.26 million (see Table 56), thus raising the total surplus to A$103.28 millions. On the basis of pricing equal to average cost or following equation 8.3 for breakeven (setting $\alpha = .15$), ETSA would have no surplus; the net social benefit still would have been a little higher; but consumer surplus would have been significantly higher.

The similarity of the actual and the maximum aggregate surplus is merely a coincidence and provides no guidance for the required changes in prices and quantities to meet any planned target of surplus nor does it consider the differences in sectoral marginal costs and elasticities. If, for instance, ETSA wishes to accumulate as much surplus as it obtains now, it can follow the rule set in equation 8.3 and set $\alpha = .185$ (by interative process). This is illustrated in the following table.

TABLE 57

Ramsey Price and Quantity under Regulated Monopoly: ETSA, 1971-80

		Residential	Industrial	Commercial	Total
1.	Price (cents/kwh)	1.35	1.35	1.67	-
2.	Quantity (gwh)	1,895.00	1,602.00	904.00	4,401.00
3.	Total Revenue ($m)	25.58	21.62	15.10	62.30
4.	Total Cost ($m)	24.63	20.83	11.75	57.21
5.	Producers surplus ($m)	.95	.79	3.35	5.09
6.	Consumers surplus ($m)	30.51	38.45	29.30	98.26
7.	Percentage change in price	+5.50	+8.00	-17.70	-

In calculating the total cost reported above, the cost savings that are likely to be obtained due to differences in the relative quantities supplied to each sector have not been included. If such savings are taken into account, the net affect of the Ramsey pricing would be to increase the consumers' plus producers' surplus by about half a million dollars over the present surplus.

8.4 Conclusion

In the light of the above discussion it can be concluded that ETSA's pricing policy has not been in conformity with the objectives set forth from time to time since its formation in 1946. However, prices charged by ETSA were lower and the output sold was larger than the price and output that would have been under unconstrained monopoly. A decreasing cost firm such as ETSA would incur losses if it has to price equal to marginal cost. It may, however, be able to breakeven following either average cost pricing or the Ramsey rules of pricing appropriately scaling down the inverse elasticities (see equation 8.3). The latter method is recommended since in this method the differences in sectoral marginal costs are accounted for and as such one sector is not likely to be subsidised by another. Moreover, the Ramsey pricing is likely to introduce structural charges in electricity demand in favour of a sector which has the lowest marginal cost, thus increasing the existing economies of scale. It may also help improving the system load factor and thereby reducing the system average cost. This method is also appropriate for raising any planned amount of capital by appropriately setting the value of α in equation 8.3.

P A R T   F O U R

FORECASTING

CHAPTER NINE

A SURVEY OF LITERATURE ON DEMAND FORECASTS FOR ELECTRICITY

Introduction

A reasonably accurate demand forecast is necessary 'to provide adequate service to the entire public on demand' (see Objectives of ETSA, Section 8.1) and to keep the cost of supply at the minimum possible level. If future demand is underestimated, ETSA may have to have recourse either to load shedding, at considerable inconvenience to industry and individuals, or to using inefficient and otherwise discarded plant at considerable cost and at considerable risk of breakdowns. On the other hand, if future demand is overestimated, unnecessary new generating plant as well as transmission and distribution equipment will be installed. Since additional charges for this new capacity will not be covered by additional consumption, charges on existing consumption will be unnecessarily high and thereby significantly reduce consumers' welfare.

The long gestation period for power projects and the existence of significant economies of scale also make demand forecasts all the more important. Since economies of scale can be realised only by increasing capacity by magnitudes larger than the annual growth rate of demand, it is necessary to forecast with reasonble accuracy what is likely to be the demand in the foreseeable future.[1]

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1 Additional cost involved in installing capacity larger than the annual growth of demand has to be weighed against the cost reduction per kw and savings in operating cost, if any.

A reasonable knowledge of likely future demand is also important to permit a balanced development of generation, transmission and distribution facilities and to attain an optimum plant mix i.e., baseload versus peak load generators. It is equally important to know the structure of future demand (e.g., whether rural demand might increase more (less) than urban demand or whether industrial demand might increase more (less) than residential demand) in order to quantify the total additional capacity required for generation, transmission and distribution. An increase in industrial demand for electricity, for instance, will require fewer distribution facilities than an increase in the residential or commercial demand.

It is important to make clear the distinction between the word "demand" as it is used by electrical engineers and the economists' "demand" which is synonymous with quantity of electricity users wish to consume per period at a given price. The former is measured in terms of kilo watts (Kw) or mega watts (MW) while the latter is measured in terms of kilo watt hours (kwh) or mega watt hours (mwh). A kwh is the normal unit of electricity for pricing purposes. Since electricity cannot be stored in an economical way, production and consumption of electricity have to be synchronized at a point of time. Thus it is essential in an ESI that generation capacity match the peak demand. But the system peak demand depends on two factors. The first is the diversity factor of an individual customer, i.e., whether all power points in the premises of a customer are used simultaneously - whether a customer is taking all his electricity in a single hour or spreading his consumption over a number of hours. The second is the diversity factor among customers i.e., whether all customers are taking electricity at the same time. The higher is the diversity, the lower will be the system load for a given quantity of electricity over a period of time. This is conveniently measured in terms of the load factor (see Glossary of terms).

For a given quantity of electricity demanded, the load factor will be higher the lower is the maximum demand, and vice versa. Alternatively, given the maximum of generation capacity, a higher level of quantity can be consumed (supplied) only with a longer duration of maximum demand. Since the diversity factor or the duration of maximum demand differs from sector to sector, the load factor is likely to be different for different groups of customers. Thus, with a given pattern of demand, an increase in consumption by a sector with a higher load factor will require an increase in capacity which is less than that if the increase was from a sector with a lower load factor. Under these circumstances, a forecasting model which ignores the idiosyncracies of various sectors cannot produce a reliable forecast for capacity requirement.

Despite these overriding considerations for disaggregated forecasting, many utilities including ETSA are still relying on the aggregative and/or time trend methods. We present below some of these crude techniques of forecasting.

9.1 The Time Trend Method

Until recently, electricity demand forecasting was fairly straight forward. Demand was observed to have a strong linear relationship with time and forecasting would have involved merely an extension into the future of the graph drawn on the basis of the past relationship. The time trend method was also prescribed by ESCAP (1967).[2] The basic

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2 A very good summary discussion on time trend methods is to be found in Greenberg and Webster (1983, pp. 69-135).

assumption of such a method is a strong persistence of the time pattern of the past into the future.

In a complex dynamic system, however, fundamental changes do occur which the time trend method does not reflect. Moreover, time trend gives no information on the causal factors influencing demand. It may describe what has happened, but does not explain why. An evaluation of the explanatory variables and their relative importance is necessary especially in view of the fact that the energy crisis in the seventies and the concomitant changes have led to the belief that the future pattern of energy demand may not be the same as in the past.

Anderson (1970), in an ex post evaluation of electricity demand forecasts in 38 countries, found that the trend method produced very inaccurate results compared to the actual position. Brookes (1975, pp. 50-51) observes that the short run trend method applied in the U.K. over-estimated the demand for energy since 1960. It has been observed that the percentage growth rate for electricity demand is steadily declining in the U.K. and elsewhere. The growth of demand for electricity in the U.K. was 8.4 per cent for the decade 1948-58, 7.3 per cent for 1958-68 and 2.8 per cent for 1968-78. Again, whereas demand for electricity in 1978 was only 2.5 per cent above its 1977 level, it rose by 4.7 per cent in 1979 and declined by 0.45 per cent in 1980.[3] This led to the employment of what is known as an S curve in forecasting electricity demand.

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3 See CEGB, Statistical Year Book 1979-80, p. 5.

The S Curves

The two most commonly used S curves are the logistic and Gompertz curves. The main assumptions are that the rate of growth at any point of time is a function of both present size and distance from the saturation level. The functions are:

Logistic $$\frac{\partial y}{\partial t} = ay(k - y)/k \qquad (9.1)$$

Gompertz $$\frac{\partial y}{\partial t} = ay(\log k - \log y) \qquad (9.2)$$

where y = current quantity of electricity consumption;

k = saturation level at which no new demand will be forthcoming;

t = time and

a = constant of proportionality.

Apart from the difficulties of identifying the value of k, the S curves represent only a variant of time trend method which does not reveal anything about the explanatory variables.

A similar rigid formula has been given by Scheers. The growth rate is assumed to be determined by the present size of per capita consumption and the growth rate of population in the country. It also postulates that "for every hundred-fold increase in the per capita generation, the rate of growth of generation will be reduced by half" (see Das, 1977, p. 62). Scheers equation is presented below:

$$g = \frac{10^{c}}{U^{.15}} \qquad (9.3)$$

where g = percentage energy growth per year;

c = 1.33 + .02P;

P = average population growth rate;

U = energy consumption per capita in kwh.

The ease with which Scheer's formula can be applied has attracted planners in many countries including India, Pakistan and Bangladesh, to use this in projecting electricity demand in their respective countries. But ease of application is not the only characteristic that makes a formula useful.

The formula places too much emphasis on population growth as the leading force for the growth in electricity demand and ignores all other plausible explanatory variables such as income, price of electricity and prices of its substitutes and complementary goods. The First Five Year Plan of Bangladesh, based on Scheers formula, forecast that the demand for electricity in the country would grow at the rate of 15.6 per cent per annum for the period from 1973 to 1978.[4] The actual growth rate achieved was only 1.3 per cent.

9.2 Survey Method

Another way of forecasting is to use the customer survey technique, which amounts to a weighted or unweighted averaging of attitudes and expectations. The underlying assumption is that attitudes affecting economic decisions can be defined and measured well enough in advance. However, various studies have revealed that the technique, though able to predict the directions of change, is not useful for forecasting the

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4 See, The First Five Year Plan 1973-78, Planning Commission, Government of Bangladesh, p. 342.

magnitude of the change. This is, perhaps, due to the fact that average customers are not well informed planners and their decisions are influenced by a wide range of economic and emotional complexities which they cannot use as an accurate basis for forecasting demand. Consumers also do not know future key variables such as income and relative prices.

Kerby (1983) attempted to use the survey technique to examine the effect of rising prices on household demand for energy in Adelaide. The author admits that the study "does not purport to provide definitive results" (p. 2).

9.3 Input-Output Model

Forecasting on the basis of planned investment and planned output may be considered as a good substitute for a sample survey. This approach requires an input-output table and has the advantage of assessing the interaction between sectors within the economy. One such model was adopted by the Project Independence Report on U.S. energy needs for the period from 1973 to 1985, (see Hausman, 1975). However, it does not take into account the effects of changes in own price and cross prices, structural changes and changes in technology and in taste. A meaningful application of the approach requires construction of a table for each year to come. The time and effort required to do so may not be justified since the energy coefficients for a future date are bound to be hypothetical.

End-Use Method

A particular variety of input-output model is the end-use method. The fundamental proposition is that the demand for electricity (any good) is a demand for a bundle of characteristics (see Lancaster, 1966, pp. 133-34). One implication of recognising this principle is to recognise the possibility of substitution between energy sources over a wide range of uses. Under this scheme, the total demand for energy is determined as a component of the expected total flow of goods and services in the economy. At the second step, the demand for individual energy sources (e.g., electricity) is determined with reference to the market share approach, the share being allowed to vary according to market forces.

It should be clearly noted, however, that all energy types are not homogeneous[5] and, therefore, substitutability is not perfect. The elasticity of substitution between two energy types and the cross price elasticities need to be estimated and their influences incorporated in the forecasting model.

The Stewart Committee (1983) attempted to use the end-use method by assuming the stock of appliances over the forecast period and calculating the peak demand on the basis of the fixed energy coefficients. Apart from its weakness in applying some sort of an S curve in working out the future stock of appliances, the method suffers from the same inadequacies as the input-output model.

It seems useful to consider the information given by planned investment or survey results as the basis for likely changes in the

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5 See Webb and Pearce (1977, p. 129) and Nordhaus (1977, p. 185).

level of explanatory variables of an econometric model. Unfortunately, this is the least tried method as yet in the ESI. Econometric models can also be integrated with such widely used time series models as ARIMA.[6] We have already presented a review of econometric studies on demand for electricity in Chapter Three. Most of our observations in that chapter are also applicable to econometric forecasting. Nevertheless, we present a brief review of econometric studies on demand forecasts for electricity in the following sub-section.

9.4 Econometric Method

By subjecting historical data on relevant variables to statistical analysis, econometrics as a system of measurement and forecasting stands as a bridge between the abstract theory and sheer description of facts and occurences. However, in recent times, econometric models using macro variables have come under considerable attack. In a recent study by the Energy Research and Development Administration [ERDA], (1974, pp. 1-2) it has been observed that "the econometric model linking GNP-Energy offers an extremely shaky foundation upon which to construct forecasts of electricity consumption". It needs to be pointed out here that these criticisms are levelled against the macro models where attempts are made to explain changes in total demand for electricity by such broad aggregates as GNP, population or temperature.

The Department of National Development and Energy [DNDE] (1981) in its electricity demand forecast for the 1980's used such an aggregative model with, of course, additional variables such as own price and oil

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6 Autoregressive Integrated Moving Average Models. See Greenberg and Webster (1983), p. 139.

price. The estimated demand elasticities with respect to GDP and own price seem to be highly sensitive to whether the price of heating oil or crude oil is used along with other variables. With price of heating oil as the substitute variable, the elasticity of demand with respect to GDP was 0.78 and that with respect to own price was -0.86, each of them being significant. But if the price of crude oil is used in place of the price of heating oil, the elasticity with respect to GDP rises sharply to 1.27 while that with respect to own price appears insignificant. Their estimated results are given below:

$$\log Q = \underset{(2.46)}{4.63} + \underset{(5.36)}{.78} \log GDP - \underset{(-6.09)}{.86} \log PE + \underset{(9.38)}{.25} \log PHO$$

$$R^2 = .998 \qquad (9.4)$$

$$\log Q = \underset{(-.63)}{-1.68} + \underset{(6.16)}{1.27} \log GDP - \underset{(-.98)}{.19} \log PE + \underset{(6.16)}{.11} \log PO$$

$$R^2 = .996 \qquad (9.5)$$

* Figures in the parentheses are t-statistics.

where Q = total demand for electricity;

PE = price of electricity;

PO = price of crude oil;

PHO = price of heating oil; and

GDP = gross domestic product.

The DNDE has selected equation 9.5 as "the most suitable for preparing the 10 year projections of public electricity demand on an Australia wide basis" (DNDE, 1981, p. 150), without explaining, however, why this model was considered better than equation 9.4. Had equation

9.4 been chosen, their forecast growth rate (5 per cent) would have been significantly lower.

Further, the model uses a double log specification wherein the parameters with respect to independent variables are elasticities. This implies that elasticities remain constant over time and/or over levels of the regressors and the regressand. This, however, does not satisfy the theoretical expectation of changing elasticities. The same criticism is applicable to Donnelly and Saddler (1982), which also uses an aggregative and constant elasticity model for forecasting demand for electricity in Tasmania.

As said earlier, these models tacitly assume that the electricity demand in all sectors have the same functional specification. Empirical findings (see Chapters 3-6) as well as intuition, however, suggest the opposite. Moreover, since the load factor in different sectors varies significantly, a separate forecast for each of the major sectors is needed to estimate the expected capacity requirement.

Chapman et al. (1973), Mount et al. (1978), Aronofsky et al. (1978, pp. 77-94) and Griffin (1974), among others, disaggregated the total demand into major sectors but used the same functional specification for each sector separately. As discussed in Chapter Three, the functional forms for different sectors are likely to be different and the use of the same variables (e.g., population) for all the sectors may not be valid on theoretical grounds.

In the present study, we disaggregate the consumption data into the three major consumer classes namely residential, industrial and commercial. Each of these disaggregated data sets is then fitted with the most suitable explanatory variables which differ from sector to sector. The present study, therefore, captures the idiosycracies of particular sectors. It also incorporates the impact on sectoral energy demand of the possible future changes in the value of explanatory variables.

In an out of sample test, the forecasting ability of the models used in the present study appeared to be satisfactory (see Chapter Ten). It is, therefore, believed that the estimated demand parameters as presented in Chapters 4, 5 and 6 are reasonably good estimates. On the basis of these parameters a forecast of electricity demand in South Australia is presented in the following chapter. Since the load factors in different sectors are likely to be different, the impact on the system load demand (maximum demand) of the differential sectoral growth rates of consumption is expected to be more accurately reflected by our disaggregated model than by the aggregative models of the past.

No econometric study, to my knowledge, has so far attempted to estimate system load demand. Consequently, forecasts of capacity requirements were usually made on the assumption of a constant load factor. In the present study, we make an attempt to estimate the system load factor, on the basis of which the system load demand is forecast.

CHAPTER TEN

FUTURE DEMAND FOR ELECTRICITY IN SOUTH AUSTRALIA

SECTION ONE: ELECTRICITY DEMAND FORECAST

Introduction

The problems associated with forecasting demand for electricity have been discussed in the previous chapter. In view of the fact that future changes in explanatory variables may not be the same as in the past, it was observed that the widely used time trend methods are not appropriate. These techniques cannot answer the questions, for instance, what if the real price of electricity does not decline (or rise) in future as it did in the past or what if income does not rise in future as it did in the past? Similarly, the aggregative models which use as a dependent variable the total demand for electricity (DNDE, 1981) or the consumption in the major three sectors (Donnelly and Saddler, 1982) or that of the two major sectors (McColl, 1976) ignore the idiosyncracies of different sectors with respect to load factor and responses to changes in individual explanatory variables.

Empirical evidence as reported in Chapters 3-6 suggests that the elasticities of demand in different sectors in South Australia are substantially different from one another. Moreover, the functional specifications of demand in different sectors are different. Thus to use a single equation for all sectors or to use the same functional specification for each sector separately (e.g., Mount, et al., 1973; Griffin, 1974) does not seem to be appropriate. In the following section, we discuss the disaggregated model adopted for the present study.

10.1 The Forecasting Model Adopted in the Present Study

The development of a model that can accurately forecast demand requires an extensive study of the factors that actually influence demand for electricity in various sectors in South Australia. The insight gained from the present study provides valuable knowledge concerning the relationship and interrelationship of various factors found to be influencial in determining demand for electricity. This knowledge can provide a useful basis for projecting future demand.

In the present study, we have disaggregated the consumption data into three major consumer classes; namely residential, industrial and commercial. Further disaggregation of consumption between rural and urban and, in the case of industrial consumption, by ASIC sub-division, was desirable but could not be undertaken due to the lack of data. Though consumption by ASIC sub-division is available since 1977, this was not used for forecasting purposes since the small number of observations will not permit any test of the forecasting ability of the model by taking out-of-sample observations.

Each of the disaggregated data sets in the present study has been fitted with the theoretically plausible explanatory variables especially relevant to a particular sector. Each independent variable was evaluated on the basis of its standard error and t-statistics. Each sector model was evaluated in terms of multiple correlation coefficients, the sum of the squared errors and F-statistics. Sector models were also evaluated by using Durbin-Watson and Durbin H-statistics for autocorrelation and by Farrar-Glauber tests for multicollinearity. The differences observed in functional specifications and sectoral responses to a particular independent variable suggest that our models have sufficiently accounted for the idiosyncracies of different sectors in South Australia. The forecasting ability of each of the sectoral models was found quite satisfactory when an out of sample prediction was made with the observed data.

Our study incorporates the possibility of future changes in the explanatory variables which differ in degree and dimensions (of changes) from that experienced in the past. Thus we believe that the present study will produce a reasonably reliable forecast for electricity demand in South Australia.

Recall, however, that a forecast is not an attempt to foretell the future to an exact degree. There are many variables that influence the behaviour of individuals and no forecasting model can incorporate all of the possible variables nor foretell how these variables will change. However, the forecast need not be exactly accurate to be a useful device. The real test of any forecast is whether it is accurate enough to enable management to make better planning decisions than would be made without it (see McMahon, 1970, p. 1).

In the following section we put forward our assumptions as regards the levels of the independent variables over the forecast period (1981 to 1990).[1]

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1 The years from 1981 to 1983 provide some checks on how close the forecast is to actual consumption.

10.1.1 Assumptions as Regards Independent Variables for the Forecast Period

If we want to predict next year's consumption of electricity in any sector, then equation 4.4 can be rewritten as

$$Q_{t+1} = \alpha\lambda + (1 - \lambda)\, Q_t + \beta_i X_{it+1} + U \qquad (10.1)$$

and to predict consumption for five years hence, the same procedure has to be followed, i.e., t + 5 and so on. A crucial judgement in a conditional forecast such as ours, therefore, involves predicting the likely levels of explanatory variables over the forecast period.

The problem can be avoided if the values of the independent variables lagged by a number of years equal to the forecast period give better predictions than the current values (see Rhyne, 1976). In the present study, the root mean square errors (RMSE) and the Theil inequality coefficients (U) obtained for an out of sample prediction for the period from 1972 to 1980 when the lagged values of the independent variables were used appeared larger than those (RMSE and U) obtained with the current values. Moreover, some of the demand functions with various length of lag structure other than the Koyck distribution appeared misspecified (see Table 27). That is, the forecasting ability of the models used in the present study seems to be better than those using lagged independent variables. Thus a prediction about the future values of the independent variables is necessary.

Naive Assumptions

Recall that the sets of explanatory variables that were found significant in influencing demand for electricity in three major sectors of South Australia include price of electricity, price of oil and per capita disposable income in the cases of residential and commercial demand and industrial value added in the case of industrial demand. One way to predict the future levels of these variables is to naively assume that they will grow (or decline) at the same rate as observed in the past. But this will not be a realistic assumption, particularly in the case of own price and cross prices.

The real price of electricity in South Australia in all three sectors under study declined continuously between 1950 and 1980, despite several rises in nominal prices after 1971 (see Table 4). However, since 1981, the rise in electricity price has exceeded the inflation rate and this trend is likely to continue.

Similarly, the oil price continuously declined in real terms until 1974 when dramatic increases began. However, since 1982, the crude oil price declined at least by $6.00 per barrel and somewhat stabilized at its present level of around $28.00 per barrel. Thus an extrapolation of the recent trend in oil price as well as in electricity price is likely to be misleading.

Likewise, personal income and industrial production have had setbacks from the recent economic recession and as such extrapolations from different base years are likely to give different forecast values.

Assumption as Regards Future Electricity Price

The continuation of upward pressures on electricity prices is expected despite the fact that the oil price has stopped rising and may remain by and large stable over the forecast period. Since the major part of ETSA's primary fuel demand (79 per cent in 1982) is met by gas from the Cooper Basin, much of the future fuel cost to ETSA will depend upon changes in the price of gas.

Until recently, producers in the Cooper Basin had tended to reduce estimates of proven reserves. In order to accelerate exploration and development of gas fields, ETSA has been paying a surcharge to the South Australian Oil and Gas Company. Since 1982, the surcharge has been raised to 7.4¢ per giga joule (GJ) from its previous rate of 3.7¢ per GJ (see ETSA, Annual Report, 1982, p. 13). Thus even if gas remains dominant as a source of primary energy to ETSA in the foreseeable future, the price of gas is likely to go up.

The next most important fuel to ETSA is coal. Since South Australian coal is of inferior quality, a special type of boiler is needed to burn it. Currently, ETSA is facing difficulties in getting the right type of design for a boiler necessary to burn coal from local deposits such as Port Wakefield, Sedan and Lochiel. "A lot of test work is being undertaken to determine boiler design but until you build a full scale boiler and try the coal, you don't know what problem may be encountered" (Mr. Dinham, General Manager, ETSA, The Advertiser, April, 28, 1983). Not only do these tests involve costs but, more importantly, it has now become certain that a plant capable of burning local coal cannot be developed before the mid-1990's. Since, according to the present forecast, South Australia needs additional capacity before 1990, it may have to import New South Wales coal. The cost of the imported coal may be high, not only because the import price is higher than the local price but also because existing boilers, designed with special characteristics to burn local coal (e.g., Thomas Playford), will not be able to take the imported coal. Thus to burn imported coal, ETSA may have to install a conventional boiler, which would increase the capital cost.

The Torrens Island power station is so designed that it can be operated either by gas or by oil. In the event of gas not being available to ETSA, this station may have to be fuelled by oil. Even at its stabilized level, the price of oil far exceeds the price of gas in terms of energy content. Moreover, stabilisation of crude oil prices does not necessarily mean a price stabilisation for the type of fuel used by ETSA. Prices of heating oil, fuel oil and some other distillates have continued to rise (Ian Perkin, The Australian, August 25, 1983) and are likely to be further pushed up due to increases in government taxes.[2] Furthermore, with the development of hydrocracking technology in oil refining, residual fuel which is generally used in power stations has been used increasingly as an input for producing light distillates such as motor spirit or aviation gasoline and middle distillates such as diesel oil, which are in high demand. This development has reduced the volume of residual fuel to its direct users such as ETSA. Thus the oil price pertaining to ETSA is likely to go up despite the somewhat stabilized crude oil price. Even if one assumes that the oil price is constant, ETSA will have to pay a higher fuel price if it has to have recourse to a large intake of oil in place of gas.

Two other important cost components are labour cost and capital cost. For many years in South Australia, wages have been increasing at a faster rate than prices. To the extent that these increases are matched by increased labour productivity, their impact on per unit costs

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2 DNDE, (1982) predicts oil price to increase at 2 per cent per annum in real terms. See DNDE, (1982), Energy Forecast for the 1980s, p. 1

of production will be small. There has been a remarkable increase in labour productivity measured in terms of gwh sold per worker since the inception of ETSA (see Introduction, pp. 3-4). But the decline in labour requirement per gwh sold seems to have been closely associated with the significant improvement in load factor (i.e., from 44 per cent in 1950 to 61 per cent in 1977).

In recent years, the load factor has started declining: it dropped to 56 per cent in 1980 and has not improved since then. Moreover, since the load factor in the industrial sector is normally higher than that in the other two sectors, a drop in the share of industrial consumption of electricity is likely to be responsible for a decline in the overall load factor. As may be seen in Table 5, the share of the industrial sector in the total consumption of electricity declined from 43 per cent in 1950 to 34 per cent in 1980 and to 32 per cent in 1982. This drop in the share of industrial demand was partly offset by an increase in the share of commercial demand for electricity from 14 per cent in 1950 to 21 per cent in 1980. The percentage increased slightly to 21.5 per cent by 1982. The share of the residential sector remained by and large stable. If this trend in structural changes in electricity consumption continues over the forecast period, the average load factor is likely to decline, and thereby reduce labour productivity. The decline in load factor by itself will increase generation cost and thereby contribute to increases in price (see footnote 24, Chapter Two).

Another source of increase in labour productivity (defined as gwh per worker) are economies of scale. The size of plants installed recently and of those likely to be installed shortly is not substantially different. Thus further improvement in labour productivity cannot be expected at least from the scale effect.[3]

Thus it seems likely that not only will the real wages in ETSA go up during the forecast period, but also their impact on cost per unit of electricity is likely to be felt more heavily than before.

The cost of capital services to ETSA is likely to increase for at least two reasons. First, the cost of capital equipment may go on increasing in the foreseeable future. It has been rising sharply in recent times and there is no sign of a slow down in the forecast period. Second, the interest rate payable on outstanding government loans to ETSA will almost double following a recent decision by the South Australian Government (see The Advertiser, August 12, 1983). It now appears that although the Loan Council's restriction on outside borrowing has been withdrawn since 1982, ETSA may be inclined to rely increasingly on internal funding, which already provides, on average, 50 per cent of ETSA's capital outlay.

Thus whether ETSA borrows from outside or not, it seems almost certain that electricity charges will rise, due to increases, though in various degrees, in almost all components of cost. The upward pressure on cost may, to some extent, be offset by the existence of economies of scale in ETSA as discussed earlier. It needs to be stressed, however, that since ETSA is not planning to install within the forecast period any generator significantly larger than those already in use, further improvement in scale economies may not be forthcoming, though economies of density may be obtained. As discussed earlier, these latter

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3 Labour economies in the transmission and distribution network have already started declining due to extension of the service to remote areas.

economies may arise out of density of plants and density of customers. However significant they may be in their own sphere, these are unlikely to be sufficiently large to offset the upward trend in cost due to the factors discussed above. Historically, the major portion of cost reduction came through scale effects (see McColl, 1976, pp. 30-33). There is no reason to believe that the density effect will be more important in the future than in the past.

The technological impact on cost reduction comes mainly through increases in thermal efficiency i.e., the ratio:

$$\frac{\text{Desired Energy Transfer Achieved by the System}}{\text{Energy Input to the System}} \qquad (10.2)^4$$

Tyrrell (1973, p. 6) suggests that cost reduction through improved thermal efficiency came to an end by the mid-1960's. Nevertheless, some technological improvements are embodied in larger plants, which cannot be separated from scale effects. Larger plant in ETSA (about 500 MW) cannot be expected before the early 1990's (Interview by Managing Director ETSA, The Advertiser, April 28, 1983).

Under the above circumstances, it seems reasonable to conclude that the real price of electricity will continue to rise during the forecast period due to diminished economies of scale and rising factor cost.

Electricity price rose by 19.8 per cent in July 1981, followed by a further rise of 16 per cent in May 1982. These rises were in the context of a continual decline in the real price since 1950. Future rises are unlikely to be as sharp as these, particularly now that inflation seems to have been contained. It would probably be realistic

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4 According to the Law of Thermo-dynamics and Law of Entropy this ratio is always less than one. See Slesser, M., (1978), p. 106.

to assume a price rise of 2 per cent per annum in real terms.[5] This we may call scenario one (or low scenario for electricity demand). To incorporate some flexibility in our forecast, we make a second assumption of a 1 per cent rise per annum and call it scenario two (or high scenario).

Assumption as Regards Cross Prices

The cross price found significant in influencing demand for electricity was the price of oil. Recently, the crude oil price stopped rising. This does not necessarily mean, however, that the price of a particular type of refined oil such as industrial diesel or residual fuel will remain constant. As a matter of fact, prices of heating oil, fuel oil and kerosene have been rising recently. For the present purpose we may probably assume a moderate 1 per cent rise in real terms under scenario one (low scenario) and a 2 per cent rise under scenario two (high scenario) for the relevant types of oil on the average (see footnote 2).

Assumptions as Regards Per Capita Income and Industrial Value Added

Among the shift variables used in our regression analysis, per capita disposable income in the cases of residential and commercial demand and industrial value added in the case of industrial demand for electricity were found significant.

Per capita real disposable income in South Australia has increased at a compound growth rate of 2.4 per cent per annum since 1950.

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5 Donnelly and Saddler (1982, p. 12) also assumed a 2 per cent growth rate in the real price of electricity.

Donnelly and Saddler (1982, p. 12) have projected a 2 per cent compound growth rate in real per capita income for the 1980's in Tasmania. The State Electricity Commission of Victoria (SECV) projected a GDP growth rate (in real terms) of 2.7 per cent per annum for Victoria (see Smith and Wilson, 1982, p. 68). The Department of National Development and Energy considers that "A GDP growth rate of four per cent is believed to be close to that of many private economic forecasts" (DNDE, 1978, p. 4).

Since 1950, the South Australian industrial value added in real terms has increased at a compound growth rate of 4.4 per cent per annum. The INDECS group of economists, in their recent report (see Business Review Weekly, June 18-24, 1983, p. 74), say that South Australia has been relatively depressed for some years. "Its unemployment rate has consistently exceeded the national average since 1977-78 and a net 33,000 people had left South Australia since 1976-77". Nevertheless, the INDECS team believe that the South Australian economic performance is set to improve due mainly to the breaking of the recent drought, with its boost to agricultural surplus, and to the improved competitiveness of South Australian industry because of the exchange rate devaluation since March 7, 1983.

South Australia traditionally maintains a lower than national average rate of industrial disputes and has the lowest level of state taxation per head. In the labour market, South Australian industries seem to be in a better position compared with interstate competitors. The Centre for South Australian Economic Studies reports a relative decline in South Australian male wages to 94 per cent of the national average. Such a reputation will no doubt improve the prospect for industrial growth in the state. Moreover, the Federal Government has adopted policies to subsidise industries to undertake expansion or maintain employment levels (see The Age, August 12, 1983). This is expected to provide incentives to grow.

Under these circumstances, we may assume with reasonable confidence that the real per capita income and the real industrial value added in the state will increase over the forecast period and the sluggish growth rate observed since 1976 will make way for a somewhat faster growth rate. Compound growth rates of 1.5 per cent and 3 per cent per annum respectively seem the most likely. These rates we assume for scenario one. For scenario two, growth rates of 2.5 per cent and 4 per cent respectively are assumed.

Assumption with Respect to the Number of Residential Customers

It may be recalled that in estimating sectoral demand for electricity, the dependent variable for residential demand was expressed in terms of consumption per customer. In the other two sectors, the total sectoral demands were used as dependent variables. Thus, for forecasts of total demand in the residential sector, we need to predict the likely number of residential customers over the forecast period. That is to say, our equation for the residential sector with predicted values of explanatory variables as discussed in the previous section will give us a prediction of demand per customer. This predicted value has to be multiplied by the predicted number of residential customers over the forecast period.

The number of residential customers under ETSA has grown at a compound growth rate of 4.55 per cent per annum since 1950. However, the annual growth rate declined from 7.41 per cent in 1951 to 1.51 per cent in 1980.

The growth rate of residential customers in an area depends *inter alia* on the growth rate of households and the ratio of residential customers to number of households. The latter is unlikely to be important in the context of South Australia as the ratio has already reached close to one. The number of households, in turn, depends on growth rate of population, growth rate of dwellings and the average size of a household.

The compound growth rate of population in the state over the period from 1950 to 1980 was about 2 per cent per annum. However, the annual growth rate has declined from 3.26 per cent in 1951 to 1.65 per cent in 1970 through to 0.5 per cent in 1980. Over the forecast period, the official State range of forecasts of population varies from 0.56 per cent per annum to 1.04 per cent per annum for low and high growth cases respectively (see Stewart Committee Report, 1983, p. 18).

The number of dwellings grew at a compound growth rate of 3.2 per cent per annum between 1950 and 1980. However, the increase in 1980 over the 1979 level was only 1.78 per cent.[6] Over the forecast period, the number of dwellings is unlikely to grow at the previous rate, due mainly to a higher base and diminished population growth. However, the prevailing concessional interest rates and the tax incentives may induce people to invest in real estate, including dwellings.

Historically, the number of dwellings increased at a faster rate than population. There may be at least two explanations for this. First, for various reasons the average size of a household in South Australia, as elsewhere, has declined over time (see Report of the South Australian State Energy Committee, 1976, p. 51). Secondly, with increases in income, an increasing number of families own more than one house.

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6 These calculations are based on information obtained from the ABS.

Thus in spite of the higher base and the diminished growth rate of population we may assume that the number of dwellings and the number of residential customers will continue to grow over the forecast period at rates which are the same as those observed in 1980. We assume this for our scenario one and a growth rate of 2 per cent for scenario two.

Summary of Assumptions

We now have assumptions with respect to the most likely values of all the independent variables which appeared to have a significant influence in determining the demand for electricity in South Australia over the past 31 years. The predicted growth rates of the explanatory variables in real terms are summarized below:

TABLE 58

Predicated (Real) Growth Rates of the Explanatory Variables for Electricity Demand in South Australia - Per cent per annum

Variables	Scenario One (Low)	Scenario Two (High)
Electricity Price	2.0	1.0
Oil Price	1.0	2.0
Per Capita Income	1.5	2.5
Industrial Value Added	3.0	4.0
Number of Residential Customers	1.5	2.0

With these assumed growth rates, the likely levels of the independent variables will be estimated for the forecast period. These estimates will then be used, together with the estimated parameters as reported in Chapters Four, Five and Six, to predict the sectoral demand for electricity over the forecast period. The sensitivity of our demand predictions can be tested by assuming alternative growth rates for the explanatory variables.

Once we have estimates for the major three sectors which constitute over 95 per cent of the total demand, we can derive the estimates for the total assuming that the residual share would remain by and large the same.

10.1.2 <u>Residential Demand Forecast</u>

In order to examine the relative strengths of various models in forecasting demand for electricity in the residential sector, we have estimated all the models listed in Table 27 with data sets from 1950 to 1971 leaving nine years from 1972 to 1980 to compare the predicted demand given by diferent models with the actual demand. The Theil inequality coefficient (see equation 10.3 below) and the root mean square error (RMSE) have been computed on the basis of the differences between the observed and the predicted demand. The results are presented in Table 59.

It may be noted that whereas the RMSE measures the differences between the actual and the predicted quantity (dependent variable), the Theil inequality coefficient gives the ratio of RMSE to the root mean square of the actual changes in the dependent variable. This is defined by the following expression:

$$U = \sqrt{\frac{\Sigma\ (P_i - A_i)^2/n}{\Sigma\ A_i^2/n}} \qquad (10.3)$$

TABLE 59

Relative Efficiency of Various Models in Forecasting Electricity Demand

Models	Variables: PE, PO, YD	RMSE	Theil U
1.	No lag	.490	1.36
2.	lag = 1	.560	1.48
3.	lag = 2	1.173	3.11
4.	lag = 3	1.128	2.99
5.	lag = 4	1.167	3.09
6.	No lag for PE & PO; lag = 1 for YD	.346	0.92
7.	No lag for PE & PO; lag = 2 for YD	.695	1.84
8.	No lag for PE & PO; lag = 3 for YD	.698	1.85
9.	Distributed lag = 2, Order = 1	.380	1.00
10.	Distributed lag = 3, Order = 1	.434	1.15
11.	Distributed lag = 3, Order = 2	.426	1.13
12.	Distributed lag = 2, Order = 2	.400	1.06
13.	Koyck Distributed lag	.273	0.52

where U = Theil inequality coefficient;

P_i = Predicted change in the dependent variable;

A_i = Actual change in the dependent variable;

n = number of observations in the forecast period.

The forecast is perfect if there is no difference between the actual and the predicted quantity i.e., U = 0. On the other hand, if U = 1, this means that $P_i = 0$. Under these circumstances, the model forecasts no better than a naive zero change prediction. The model is even worse if U is greater than one. The closer is the value of U to zero, the better.[7]

7 See Theil, H., (1966), Applied Economic Forecasting, North Holland, 1966, pp. 26-36.

It appears from the above table that on the basis of the Theil inequality coefficient, the Koyck model clearly provides the best results. Similarly, when the data for the entire sample period (1950-80) were used, the RMSE, and the Theil U for prediction for the period from 1971 to 1980 were the lowest again for the Koyck model. The RMSE and Theil U in this case were 0.10 and 0.39 respectively.

The forecasting model having been selected on the basis of the lowest RMSE and Theil-U and the scenario assumptions having been made as given in Table 58, the following forecast can be made for residential demand for electricity in South Australia over the period from 1981 to 1990.

TABLE 60

Forecast Residential Demand for Electricity

	Scenario I Gwh	Scenario II Gwh
1980	2,383	2,383
1981	2,447	2,544
1982	2,473	2,607
1983	2,500	2,684
1984	2,548	2,764
1985	2,576	2,835
1986	2,603	2,911
1987	2,632	2,989
1988	2,662	3,068
1989	2,691	3,154
1990	2,721	3,238
Compound Annual Growth Rate	1.4%	3.1%

It is interesting to note that the predicted demand under scenario one falls short of the actual by 2 per cent in 1981 and by 5 per cent in 1982. Prediction under scenario two seems to be closer to the actual consumption in 1981 and 1982. Whereas predicted consumption in this scenario was 1.6 per cent above actual in 1981, it was almost the same as actual consumption in 1982. We may probably take heart from this that our forecast is reasonably accurate and reliable for planning purposes.[8]

It is possible to test the sensitivity of predicted demand to any change in the assumed rates of explanatory variables. For instance, in scenario one, if we assume a 2.5 per cent growth rate for per capita disposable income instead of 1.5 per cent, the predicted demand in 1990 would have been 2,846 gwh. If this assumption combines with a 1 per cent rise in electricity price instead of 2 per cent assumed, the predicted demand would have risen to 2,980 gwh *ceteris paribus*.

As stated earlier, whereas a forecast of consumption (kwh) is important for revenue purposes, it is the forecast of load demand (capacity) which is relevant for supply planning purposes. We shall deal with this issue in Section Two. Before that we present the forecasts of industrial and commercial consumption of electricity in the following two sub-sections.

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8 Normally a 8-9 per cent net surplus capacity over the expected maximum demand is maintained to account for uncertainties. See *The Monopolies and Merger Commission Report*, 1981, H.M.S.O., London, p. 61.

10.1.3 Industrial Demand Forecast

The set of explanatory variables found significant in determining industrial demand for electricity comprises the price of electricity, the price of oil and the level of industrial value added. The most likely levels of these variables over the forecast period have been discussed in Section 10.1.1. Given the assumed levels of the explanatory variables under scenarios one and two, the expected quantity of industrial consumption of electricity is presented in Table 62. This forecast is made on the basis of the parameters obtained in equation 5.9, p. 194. The forecasting ability of this equation seems to be the best among all the equations estimated. The RMSE and the Theil inequality coefficients (U) computed for both out-of-sample prediction and in-sample prediction indicate that the forecasting ability of the model is 'fairly good'. The summary statistics of the estimates are presented below.

TABLE 61

Summary Statistics for Industrial Demand Forecast

	Sample 1950-71 Prediction: 72-80	Sample 1950-80 Prediction: 72-80
R^2	.91	.99
$\bar{R}^2$	.89	.99
F	581.71	703.99
RMSE	68.76	66.53
Theil U	.56	.36

It is evident from the forecasts given under scenarios one and two in Table 62 that the impact of the rise in own price on the industrial demand for electricity is more than compensated for by the opposite impact of the rise in cross prices and industrial output. Thus the total industrial demand for electricity continues to increase.

Note that the percentage variance of forecast demand from the actual in 1982 was 1.7 per cent and 0.5 per cent respectively for scenarios one and two. Such a small variance makes us more confident as to the reliability of our forecast. Note also that our scenario two gives a compound growth rate per annum of 3.5 per cent which is very close to the growth rate for industrial consumption of electricity for the period from 1970 to 1980 (3.4 per cent).

TABLE 62

Forecast Industrial Demand for Electricity (Gwh) in South Australia Over the Period from 1981 to 1990

Year	Scenario I	Scenario II
1980 (Observed)	1,989	1,989
1981 (Predicted)	2,000	2,010
1982	2,050	2,097
1983	2,106	2,190
1984	2,176	2,280
1985	2,259	2,370
1986	2,319	2,453
1987	2,378	2,534
1988	2,423	2,618
1989	2,478	2,706
1990	2,537	2,798
Compound Annual Growth Rate	2.5%	3.5%

On a sensitivity test, it appears that if a 2 per cent growth rate for industrial value added is assumed instead of 4 per cent in scenario two then the predicted demand declines to 2,395 gwh in 1990 compared with 2,798 as shown in Table 62. However, the prediction seems to be less sensitive to price changes. For instance, if electricity price in the industrial sector declines at the rate of one per cent per annum (combined with two per cent growth rate for output) instead of increasing at one per cent rate then the predicted demand increases by only 69 gwh to 2,464 gwh.

10.1.4 Commercial Demand Forecast

Commercial demand for electricity in South Australia grew at a compound growth rate of 11 per cent per annum over the period from 1950 to 1980. While the growth rates in the other two major sectors declined sharply in the seventies, that of commercial demand was as high as 10 per cent over the decade (see Table 1). The lower base consumption in this sector may, partly, be responsible for the higher growth rate of demand in this sector. Since the relative share of the commercial sector has increased substantially from 14 per cent in 1950 to 21 per cent in 1980, the future growth rate may not be as spectacular as in the past. In 1979-80, the growth rate was observed to be 7.7 per cent which fell to 4.3 per cent in 1983 (ETSA, Annual Report, 1983, p. 16).

Recall that the set of explanatory variables that were found significant in this sector is the same as in the residential sector. Given the assumed levels of explanatory variables as discussed in Section 10.1.1 (see Table 58), the forecast commercial demand is shown in Table 64 under two scenarios as before. Forecasts under scenarios one and two are made on the basis of parameters obtained from equation

TABLE 63

Summary Statistics for Commercial Demand Forecast

	Sample 1950-71 Prediction: 71-80	Sample 1950-80 Prediction: 71-80
R^2	.99	.99
$\bar{R}^2$	.98	.99
F	255.51	1182.66
RMSE	70.80	34.77
Theil U	.36	.23

TABLE 64

Forecast Commercial Demand for Electricity in GWH

Year	Scenario I	Scenario II
1980 (observed)	1,233	1,233
1981	1,301	1,312
1982	1,312	1,334
1983	1,336	1,378
1984	1,362	1,441
1985	1,395	1,510
1986	1,440	1,580
1987	1,490	1,669
1988	1,540	1,740
1989	1,595	1,825
1990	1,655	1,919
Compound Annual Growth Rates	3%	4.5%

6.4. The forecasting ability of this model as evidenced from the summary statistics (Table 63) seems to be fairly good.

The percentage variance of forecast demand from the actual consumption in 1982 is 2 per cent under scenario one and 0.4 per cent under scenario two. In scenario two, if oil price is assumed to increase at 1 per cent per annum instead of 2 per cent, the predicted demand in 1990 would be 1820 gwh instead of 1919. On the other hand, in scenario one, if electricity price rises at one per cent per annum instead of the 2 per cent as assumed, then the predicted demand will grow to 1735 gwh instead of the 1655 gwh shown in Table 64.

10.1.5 Total Demand Forecast

In the previous three sub-sections we have presented sectoral forecasts of demand for electricity in South Australia under two scenarios. These scenarios represent conditional forecasts i.e., forecasts depending on the assumed values of the explanatory variables that were found significant in determining demand for electricity in three major sectors connected to ETSA.

Recall that the sum of consumption in the three major sectors constitutes 95-96 per cent of the total demand (see Table 5). On the assumption that this percentage will remain by and large the same over the forecast period, the expected total consumption can be estimated by taking a multiple of 1.05 of the aggregate of the forecast demand.[9] This estimate is presented below in Table 65. Also shown there two

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9 An exact multiple would have been 1.0417 when the three sectoral demands constitute 96 per cent of the total and 1.0527 when they sum up to 95 per cent of the total.

TABLE 65

Forecast Total Demand for Electricity (GWH) in South Australia

	Scenarios			
Year	**I**	**II**	**III**	**IV**
1980 (Observed)	5,799	5,799	5,799	5,799
1981	6,035	6,159	6,433	6,224
1982	6,127	6,340	7,032	6,585
1983	6,239	6,565	7,687	6,970
1984	6,390	6,809	8,402	7,383
1985	6,541	7,051	9,189	7,824
1986	6,680	7,291	10,049	8,296
1987	6,825	7,552	10,990	8,802
1988	6,956	7,797	12,021	9,344
1989	7,102	8,069	13,150	9,926
1990	7,259	8,348	14,386	10,550
Compound Annual Growth Rates	2.25%	3.72%	9.5%	6.2%

* Scenarios I and II are conditional forecasts (see Table 58) and Scenarios III and IV are time trends since 1950 and 1970 respectively.

additional Scenarios (Three and Four), which represent simple extrapolations of the past trends in sectoral demand between 1950 and 1980 and between 1970 and 1980 respectively.

As may be seen in the table, the growth rates of electricity consumption under the conditional forecasts are far below the time trend growth rates. A growth rate for a conditional forecast equal to that given by scenario four (6.2 per cent) would require, for example, that the real price of electricity remained unchanged, oil price increased by 2 per cent per annum and that per capita income and industrial value added increase at a compound growth rate of 10 per cent per annum. A growth rate equal to that under scenario three would require an assumption of still higher growth rates for per capita income, industrial value added and cross prices and a substantial reduction in the price of electricity in all sectors. This is most unlikely to happen in the foreseeable future, as we have discussed earlier.

Thus the application of the historical trend method in the present case will suggest far more investment in capacity building than is likely to be needed. As has happened in many places (e.g., Tasmania, France), creation of additional capacity on the false expectation of additional demand will only waste valuable resources.

Total electricity sold in 1982 was 6,244 gwh which lies between our forecasts under scenarios one and two. We may, therefore, feel confident that our forecasts are closer to reality than those obtained by extrapolation of past trends.

The year 1981 was the beginning of a new era in the history of ETSA since, for the first time since its inception, from that date the real price of electricity started rising. This will undoubtedly have its impact on consumers' long run planning on acquisition of electrical equipment and on electricity consumption. On the other hand, the apprehension that South Australia may face an acute shortage of natural gas after 1987 (see The Australian, August 19, 1983) may influence customers' choices away from gas and towards electricity. However, such an apprehension may drive some prospective industrial customers away from South Australia, thus pulling down the growth rate of electricity consumption. Our forecast could not allow for these possibilities.

In addition to structural changes with respect to consumer classes which our model takes into account, there may be changes in the composition of industrial output, rural-urban transfer of consumers, distribution of income and so on. Small changes in these variables comparable to changes which have occurred in the past will not be a problem since these are accounted for, in our model, by the coefficient of the lagged dependent variable (LQ) and by T. But substantial episodic changes (e.g., commissioning of something like an aluminium smelting company) may not be accounted for by our model. Nevertheless, the method of prediction adopted in the present study provides a greater insight into the predicted values than does the conventional time trend method or the GDP-based prediction. This is so because the method used here gives policy-makers the freedom to choose the post-sample values of the independent variables in line with changed circumstances. This method is also quite different from that of investment prediction. In the latter method, the electricity coefficient for a particular use is assumed to be constant over time and the intensity of use of the existing appliances is tacitly assumed to remain unchanged as well. In the present model, no such restrictions are imposed. The absence of these restrictions makes the model able to be adjusted in a flexible way to changing conditions as they emerge.

It may be reiterated that quantitative forecasts may have a spurious air of precision. One must be on guard not to slip into an acceptance of these figures at more than their true value: there may always be some margin of errors in any forecast.[10] The important thing to look at is how narrow are these margins. It is all the more important to keep the forecast under frequent review so that the impact of any changes in circumstances can be incorporated.

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10 There may be technological breakthroughs leading to substantial structural changes within each group of customers. Big export contracts, import restrictions, natural calamities, bumper crops or droughts may substantially change the rates of growth assumed in our scenarios.

SECTION TWO: LOAD DEMAND FORECAST

Introduction

As noted earlier, the supply authority must have adequate capacity to meet peak demand, even though that peak lasts only for a short time. In order promptly to meet any variation in system peak demand, the authority must also have spinning reserves which can be switched over to full load at very short notice. Moreover, a margin of spare capacity is usually maintained to meet routine 'outage' such as overhauling or maintenance of plant or to meet emergencies such as breakdowns in the system. Normally additional capacity equal to the largest plant in the system is reserved for this purpose.

10.2.1 Forecast for Electricity Generation

The forecasts presented in the previous section are for consumption i.e., quantity at the consumers' level. Quantity sold is less than the quantity generated by an amount which equals the "technical loss factor". This technical loss includes power consumed at the power station for lighting and running auxiliary plant together with losses in transmission and distribution.[11]

ETSA's technical loss came down from 18 per cent in 1950 to 14.25 per cent in 1980 though occasionally it rose as high as 25 per cent. The 1980 loss factor seems to be about the minimum to which technical

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11 In any power station, auxiliary equipment is required to generate electricity. This equipment draws power from the main generating unit. Energy thus consumed by the auxiliary equipment is not really wasted. Yet this is termed as station loss, which is the difference between electricity generated and electricity sent out.

loss can be reduced (see ESCAP, 1976, p. 17). On the assumption that technical loss will remain stable at the present level over the forecast period, one can estimate the quantity required to be generated to meet the forecast demand by multipling the latter by a technical loss factor (TLF) equal to:

$$1/.8575 = 1.1662 \qquad (10.4)$$

where .8575 is the ratio of electricity sold to electricity generated in 1980.

But to use the above equation is to assume that technical loss in all three sectors under study is the same percentage of the sectoral demand. This would be an unrealistic assumption since technical loss varies inversely with the voltage at which power is supplied and directly with the distance of customers from the power station and the major load centres. It would be surprising if customers in all sectors happened to take power at identical voltage and if the 'phases' (e.g., single phase or four phase) of distribution lines are the same for all groups of customers.

Nevertheless, it is extremely difficult to know what the voltage level or what the line losses are at the individual sector level, let alone at the individual customer level. This is so because the transformers and the transmission and distribution lines are not used separately for each class.

No survey has yet been made on the diversity factor, demand factor or class load factor in South Australia. Thus in the present state of knowledge, we can only state qualitatively that the residential sector is likely to have a relatively high diversity factor, a relatively low demand factor and a relatively low voltage level whereas the industrial sector is likely to have a lower diversity factor, a higher demand factor and a higher voltage level. The commercial sector may lie between these two sectors. Thus the load factor in the industrial sector is likely to be higher and that in the residential sector to be lower; and the line losses are higher for the latter and lower for the former. The station loss is assumed to be same for all sectors. Normally the station loss constitutes about 7 per cent of total generation (PEP, 1966, p. 223). This 7 per cent may first be subtracted from the assumed 14 per cent technical loss over the forecast period and then added to the assumed line loss for individual sectors.

Most of the line losses occur in the distribution channel (because of the low voltage and high distance).[12] Since the proportion of distribution lines servicing the residential sector is much higher than for the other sectors, line losses attributable to this sector should be the highest. For the same reason, line loss attributable to the industrial sector should be the lowest. If we now arbitrarily assume that the line loss for the residential sector is 10 per cent of electricity at the generation terminal and those for the industrial and commercial sectors are 4 per cent and 7 per cent respectively,[13] the total technical loss in 1980 under the ETSA system can be apportioned as follows:

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12 See CEGB, Statistical Year Book, 1979-80, p. 5.

13 This apportioning leaves the total loss at 14.29 per cent which is about the same as in 1980. Since the industrial sector needs only limited distribution facilities from the transmission lines, line loss attributable to this sector has been assumed to be close to the (2.5 per cent) transmission loss observed in the case of CEGB (London) in 1980. There is no separate estimate for transmission loss in ETSA.

TABLE 66

Apportioning of Technical Loss in 1980

	Generated	Sold	Station Loss	Line Loss	Total Loss
	Quantity in GWH				
1. Major Three Sectors	6,540*	5,605	458	477	935 (1,278)**
2. Residential	2,871	2,383	201	287	488 (663)
3. Industrial	2,235	1,990	156	89	245 (346)
4. Commercial	1,434	1,233	101	101	202*** (269)

* The multiplier used for this table is 1.2048 for residential; 1.1236 for industrial; and 1.1628 for commercial consumption, so that the respective technical losses are 17, 11 and 14 per cent.

** Figures in the parentheses are total loss in 1990 under scenario two.

*** Slight differences may be observed due to rounding up.

As before, the sum of the sectoral generation scenarios can be elevated by a multiple of 1.05 to represent the total generation of electricity required, since the scenarios for the major sectors combined represent about 4-5 per cent less than the total. This we present in the following table.

TABLE 67

Forecast Total Electricity Generation (GWH)

Year	Scenario I Major Sectors	Scenario I Total	Secenario II Major Sectors	Secenario II Total
1980	6,540	6,867	6,540	6,867
1981	6,703	7,038	6,841	7,183
1982	6,805	7,145	7,041	7,394
1983	6,930	7,276	7,291	7,656
1984	7,097	7,452	7,563	7,941
1985	7,265	7,629	7,831	8,223
1986	7,419	7,790	8,098	8,503
1987	7,580	7,959	8,387	8,807
1988	7,726	8,112	8,660	9,093
1989	7,888	8,283	8,962	9,410
1990	8,062	8,465	9,272	9,736
Compound Annual Growth Rates	2.1%	2.1%	3.5%	3.5%

The above forecasts are based on the assumption that the system technical loss factor as well as that for the sectors remains at its 1980 level. But it need not necessarily be so in practice. Since the sectoral technical loss factors differ from one another and since the sectoral shares in total demand are likely to change over time, the system loss factor is, therefore liable to change. The system technical loss may also vary from time to time and from sector to sector depending on variations in voltage at which power is taken, length of transmission and distribution lines, number of customers and so on. It is therefore, desirable to segregate the sectoral forecast (as we did) and to incorporate the changes in loss factor, if any, so that the quantity of electricity lost in each sector can be readily observed (see Table 66). Needless to say, this information is important for pricing purposes.

We present below an aggregate technical loss diagram for illustration only. The sectoral diagram will differ only in the magnitude of the technical loss factor.

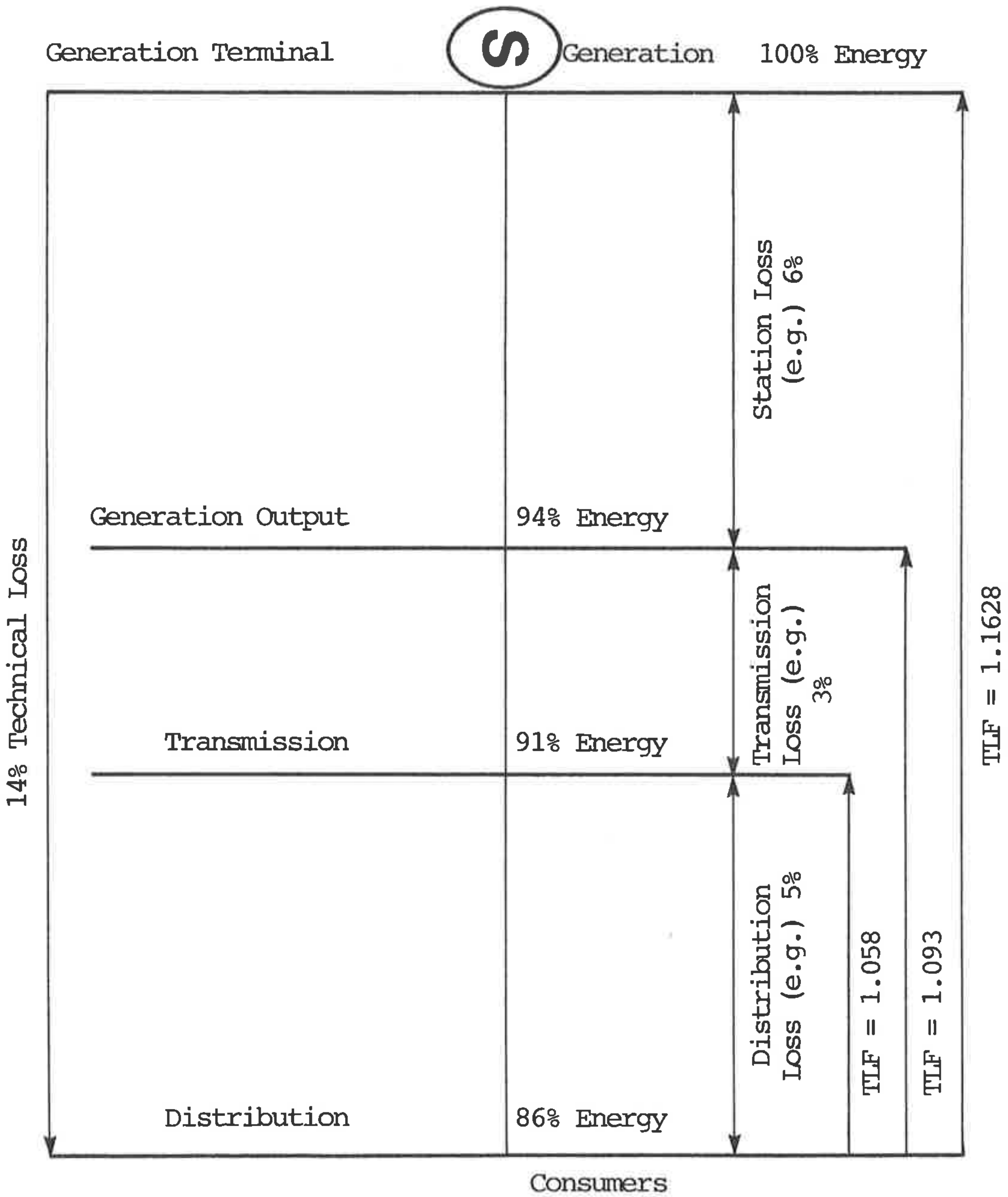
10.2.2 Estimates of System Load Factor

Once the quantity of electricity required at the generation terminal is estimated, it becomes important to know (or assume) the load factor (L.F.) to plan for the capacity required to meet the expected demand.

For the purpose of the present study, we have estimated the annual L.F. obtained in the ETSA system since 1950, based on the maximum system load recorded for each year by ETSA. It appears that the L.F. in ETSA has improved substantially - from 44 per cent in 1950 to 57 per cent in 1960, 58 per cent in 1970 through to 61 per cent in 1977. The L.F. has declined since then to 56 per cent in 1980 and stayed at this level in 1981 and in 1982. If we now assume that the L.F. will remain stable at this level over the forecast period, the forecast of maximum demand becomes straight forward. But such a forecast will not represent the differences in sectoral peak demand which may be an important determinant of the system peak especially in view of the differential growth rates observed in different sectors.

FIGURE 7

TECHNICAL LOSS DIAGRAM



TLF = Technical Loss Factor

Unfortunately, no survey on sectoral peak demand is available in South Australia. Although direct estimates of sectoral L.F. are not possible, an informed guess can be made that the industrial L.F. is likely to be higher than the average and the residential L.F. is likely to be lower than the average. Even this is not obvious, particularly when it is noted that the contribution of the industrial sector to the increments of total consumption declined over time (see Table 24).

The system load factor will largely depend upon how location and density of customers, the voltage at which they take electricity and the pattern of their peak demand (i.e., duration of individual peaks and the diversity between peaks) change over time. One way to incorporate these factors is to express sectoral consumption in per customer terms. An increase in total consumption associated with a decline in per customer consumption would indicate that an increasing number of small customers have been added to the system.[14] The lower is the consumption, the lower is likely to be the voltage at which electricity is taken. Historically, large customers are located in the vicinity of power stations. With the extension of service to remote areas new customers are added, who are also likely to be small customers. Thus changes in per customer consumption are likely to represent changes in location and density of customers.

The consumption per customer by itself will not reveal anything about the duration of peaks and the diversity between peaks. But in the absence of peak load pricing (as is the case with ETSA) there is no

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14 This may also indicate a decline in consumption of existing customers but this is less likely particularly in view of the declining electricity prices and increasing per capita income and industrial value added over the sample period.

incentive for customers to diversify or to use lower capacity equipment for longer duration. Thus the newcomers are likely to follow the same pattern of demand as the existing customers.[15] It appears from the historical data that the capital stock in South Australian industries expanded at a faster rate than did the industrial output. This provides some tentative evidence to suggest that the duration of consumption by an average industrial customer declined over time, especially during the recent downturn in economic activities.

While per customer consumption in the industrial sector under ETSA declined over time, that in the residential and commercial sectors increased. An increase in per customer consumption can take place through either an increase in the stock of appliances or an increase in the intensity of use of existing equipment. In the latter case the duration of use is increasing and in the former (unlike in the case of the industrial sector) the diversity of use is likely to increase.[16] However, some appliances such as air conditioners are used only seasonally. An increase in these types of appliances is likely to reduce the load factor.

It seems reasonable to conclude that per customer consumption in various sectors is likely to be a reasonable surrogate for the more direct explanatory variables for changes in the load factor in ETSA. With the estimated load factor since 1950 used as the dependent variable and per customer consumption in the three major sectors and total

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15 An industry may find it more costly to introduce a night shift in place of a day shift.

16 In the industrial sector, the main purpose of electricity use is motive power. There is virtually no physical limit as to how much capacity one can use at a time. But in the residential and commercial sectors, heaters and air conditioners are not likely to be operated simultaneously, nor are two air conditioners likely to be used at the same room.

consumption in the other sectors as independent variables, the following regression estimates are obtained.[17]

$$\log LF = \underset{(-1.21)}{-1.475} + \underset{(3.62)}{.438} \log RQ + \underset{(2.95)}{.217} \log IQ$$

$$+ \underset{(2.93)}{.101} \log CQ - \underset{(-.57)}{.016} \log OQ \qquad (10.5)$$

$R^2 = .90$, DW = 2.15 RMSE = .037

Theil U = .43 F = 16.68

* Figures in the parentheses indicate t-statistics.

where LF = Annual System Load Factor;

RQ = Quantity of electricity demanded per residential customer;

IQ = Quantity of electricity demanded per industrial customer;

CQ = Quantity demand per commercial customer and

OQ = Quantity of electricity consumed by other sectors.

All independent variables except OQ are significant. Judged from the value of R^2, it can be concluded that 90 per cent of the variation in L.F. in the ETSA system can be explained by the independent variables included in the equation. DW-statistics indicate the absence of auto-correlation.

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17 Based on the growth rate given by the Tariff Board (see The Australian Market for Selected Domestic Appliances, 1972, p. 73) an index of room air conditioners was constructed and used as an additional variable. However, a severe collinearity was encountered between this index and the consumption per customer in the residential sector (RQ). The simple correlation coefficient between these two variables was found to be .99 and the R^2 obtained when RQ is regressed with the index is .98. This is greater than the R^2 obtained when L.F. is regressed with all the independent variables (see equation 10.5). Inclusion or deletion of this variable does not change the parameters of any other variable except RQ. The results, therefore, are to be interpreted accordingly.

The RMSE and the Theil U indicate that the forecasting ability of the model is 'fairly good'. In addition, the out of sample prediction from 1972 to 1980 also gives the value of the Theil-U as low as 0.45. Under these conditions, we can use equation 10.5 with some confidence and make a conditional forecast of the system load factor in ETSA for the 1980's. The following assumptions are made.

TABLE 68

Assumptions for Conditional Load Forecast: ETSA

		Growth Rates	
		Scenario I	**Scenario II**
1.	Total Electricity Generation (see Table 67)	2.1	3.5
2.	Consumption in Residential Sector (see Table 60)	1.4	3.1
3.	Consumption in Industrial Sector (see Table 62)	2.5	3.5
4.	Consumption in Commercial Sector (see Table 64)	3.0	4.5
5.	Number of Residential Customers (see Table 58)	1.5	2.0
6.	Number of Industrial Customers	2.0	3.0
7.	Number of Commercial Customers	1.5	2.0

Assumptions 1 to 5 are derived from previous assumptions as outlined in Table 58. As to the number of industrial and commercial customers, a judgement has to be made.

The compound growth rate of the industrial customers for the period from 1950 to 1980 was 10 per cent per annum. However, with 1970 as base year, the growth rate works out to be 2.8 per cent per annum.

The number of commercial customers increased at a compound growth rate of 3.5 per cent from 1950 to 1980 and at 2 per cent from 1970 to 1980. However, the growth rates observed in 1981 were 1.5 per cent in both the sectors. The decline in the growth rate of customers in these two sectors seems to be an outcome of the local and global recession in the last few years. Since the possibility of economic recovery now seems to be bright, it would probably be realistic to assume a growth rate of customers in the industrial sector between 2-3 per cent per annum and that in the commercial sector between 1.5-2 per cent per annum. Accordingly, we assume a 2 per cent and a 1.5 per cent growth rate under scenario one for industrial and commercial sectors respectively and 3 per cent and 2 per cent growth rates under scenario two.

Forecasts of the load factor under scenarios one and two are given below in Table 69. A third and a fourth scenario are also presented extrapolating time trends for 1950-80 and 1970-80 respectively.

It is important to note that the extrapolation of time trend since 1970 (scenario IV) has a negative growth rate of 0.28 per cent per annum. However, the forecast load factor in 1990 under scenarios one and three are very close to one another.

The similarity of our conditional forecast with that given by the long run trend method (1950-80) should not lead one to conclude that the time trend method is as good as the (disaggregated) econometric method used in the present study simply because the results happen to be

TABLE 69
Forecast System Load Factor: ETSA

Year	Scenarios I	II	III	IV
1979 (Observed)	.598	.598	.598	.598
1980 (Observed)	.563	.563	.563	.563
1981 (Predicted)	.565	.572	.567	.561
1982	.568	.576	.572	.560
1983	.571	.576	.577	.558
1984	.575	.576	.581	.557
1985	.580	.577	.586	.555
1986	.584	.577	.591	.554
1987	.590	.578	.595	.552
1988	.595	.578	.600	.551
1989	.600	.578	.605	.549
1990	.602	.578	.610	.548
Compound Annual Growth Rates	0.7%	0.3%	0.8%	-0.28%

similar. Apart from the fact that the similarity is an outcome of our assumptions, and our choice of 1980 as base year,[18] our model (equation 10.5) provides an insight into the factors that have been found influential in determining the load factor. Thus any change in these factors in future will indicate the direction in which the load factor is likely to move.

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18 The use of 1979 as base year would have produced a load factor of .67 in 1990 under Scenario III.

10.2.3 Forecast Maximum Demand and Capacity Requirement

The expected maximum load demand under four scenarios for the load factor (Table 69) and the two scenarios for electricity generation (Table 67) are presented below in Tables 70A and 70B. The calculations are based on the formula given in equation 10.6.

$$MD = \frac{E}{L.F. \times 8760} \tag{10.6}$$

where MD = maximum load demand in the system in MW; and

E = electricity generated in mwh.

L.F. = load factor (see glossary of terms).

TABLE 70A

Forecast Maximum Demand (MW) in ETSA System: Scenario One*

	Spectrum			
Year	**I**	**II**	**III**	**IV**
1980 (Observed)	1,372	1,372	1,372	1,372
1981 (Predicted	1,422	1,405	1,434	1,449
1982	1,436	1,416	1,445	1,476
1983	1,455	1,442	1,456	1,506
1984	1,480	1,474	1,475	1,538
1985	1,502	1,509	1,486	1,569
1986	1,523	1,539	1,493	1,593
1987	1,540	1,572	1,505	1,622
1988	1,556	1,602	1,514	1,649
1989	1,576	1,636	1,524	1,679
1990	1,605	1,672	1,534	1,708
			(1,397)**	

* First two spectra are based on conditional forecasts of load factor (see Table 68) and the third and the fourth are based on time trend load factor for the periods 1950-80 and 1971-80 respectively.

** The figure in the parenthesis is the expected maximum demand for L.F. = .67. See footnote 17.

TABLE 70B

Forecast Maximum Demand (MW) in ETSA System: Scenario Two

Year	Spectrum I	II	III	IV
1980 (Observed)	1,372	1,372	1,372	1,372
1981 (Predicted)	1,451	1,433	1,467	1,483
1982	1,486	1,465	1,493	1,525
1983	1,531	1,517	1,521	1,573
1984	1,577	1,571	1,567	1,634
1985	1,618	1,627	1,597	1,686
1986	1,662	1,679	1,628	1,736
1987	1,704	1,739	1,662	1,791
1988	1,745	1,796	1,694	1,844
1989	1,790	1,857	1,728	1,904
1990	1,846	1,923	1,763	1,962
			(1,604)*	

* Expected maximum demand on the basis of L.F. = .67

Unlike the Stewart Committee Report (1983) the present study takes the view that the system load demand is not a simple summation of sectoral load demands (see Stewart Committee Report, 1983, p. 30). The diversity factor in inter-sectoral peaks is an important determinant of the system peak load. Any value greater than one for the diversity factor will definitely reduce the total capacity required to meet the entire demand from all sectors. A simple summation would, in such a case, be an overestimation of the capacity required. In the absence of accurate information on the diversity factor, the present study estimates the maximum system demand on the basis of the forecast system load factor and the quantity of electricity required to be generated. Since the diversity factor is reflected in the system load factor, the estimates of maximum demand in the present study are likely to be more representative than those of the Stewart Committee.

The percentage variance of the forecast demand with the actual observed (1,482 MW) in 1982 is presented below.

TABLE 71

Percentage Variance of Forecast Demand in 1982

Spectrum	Scenario I	Scenario II
1	-3.1	+0.27
2	-4.4	-1.1
3	-2.5	+0.07
4	-0.4	+2.9

Considering the fact that normally an 8-9 per cent net surplus over the expected maximum demand is maintained to account for uncertainties (see footnote 7) the above percentage variance is rather small. Alternatively, if we adopt a time trend method of forecasting, the forecast maximum demand in 1982 would have been 9.3 per cent above the actual and in 1990 would appear as 3,145 MW which is more than twice the forecast demand under all spectra in scenario one and nearly twice that in scenario two.[19]

It is now clear that the trend method cannot be relied upon,

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19 Note that scenarios three and four in Tables 70A and 70B are based on time trend forecasts of load factor and econometric (conditional) forecasts of electricity consumption.

especially where there is reason to believe that changes in the explanatory variables over the forecast period are likely to be different from those observed in the past.

The last step to be taken to plan capacity requirement is to decide upon the spare capacity to be maintained. A higher margin will provide some extra leverage to the management in maintaining security standards and avoiding shortage of power. But this advantage will be secured at a cost. In order to keep the cost at a minimum, the management must make a judgement with respect to the minimum capacity margin needed. Estimates of the following three factors affect the size of the margin:

1. The expected availability of plant during peak periods;

2. The expected variation in plant availability at that time (i.e., the standard deviation of 1);

3. The expected variation in forecast peak demand (e.g., due to weather or forecasting error).

Normally an 8-9 per cent net surplus over the expected maximum demand is maintained to account for the second and the third factors above (depending, of course, on the expected forecast error).[20]

The available capacity as a percentage of installed capacity varies from system to system. No published statistics are available on ETSA's plant availability factor except that no shortage of power (capacity) was ever encountered throughout its life.

Estimated plant availability in other systems varies from 85 per

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20 See The Monopolies and Merger Commission Report (1981), p. 61.

cent to 90 per cent.[21] Accepting 85 per cent availability and 8 per cent net surplus as the norm, a gross margin of 27 per cent would be required over and above the estimated maximum demand. This is so because with 85 per cent availability factor, a capacity of 117.6 MW must be held to achieve an average of 100 MW and to maintain 8 per cent net surplus, the conversion factor which needs to be used is:

$$1.176 \times 1.08 = 1.27 \qquad (10.7)$$

On application of this conversion factor, one can find the rated capacity (the ratio of maximum capacity at which plants operate to the installed capacity) required to meet the expected demand in the ETSA system. Thus according to our forecast, the rated capacity requirement in 1990 would vary from 2,038 MW (Scenario I, Spectrum I) to 2,442 MW (Scenario II, Spectrum II).

10.2.4 Some Limitations of the Present Forecast

The above forecasts does not take into consideration the possibility of any major change in the industrial structure of the state (e.g., establishment of an aluminium smelting industry, though it is perhaps unlikely) nor does it account for the possibility of a substantial reduction in the availability of natural gas within the forecast period.

Moverover, our forecast is based on the assumption that there will

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21 See NEAC, (1983), p. 38. A spinning reserve of 10 to 15 per cent is to be maintained for instant use in the event of an unscheduled shutdown. Additional capacity is needed to meet the routine outage which cannot be avoided during the peak load on the system, since it is difficult to ascertain sufficiently ahead of time when the peak demand would actually occur.

be no major change in the extent to which consumers generate their own electricity or in the innovation and introduction of new energy-saving technology; and we have only forecast the quantity and capacity required. We have not considered the cost minimising plant mix or optimal investment path.

10.3 Summary and Conclusion of Chapter Ten

In this chapter, we have discussed the reasons why a disaggregated forecast is necessary and adopted an econometric model to predict electricity demand in three major sectors of South Australia. Judged from the summary statistics, the RMSE and the Theil inequality coefficients, the forecasting ability of the model appeared to be satisfactory.

Explanatory variables that were found significant in determining demand for electricity in different sectors are the own price, prices of substitutes, per capita disposable income and industrial value added (in the industrial sector only). Two values for each of these variables were assumed over the forecast period under two scenarios. Thus conditional forecasts for electricity demand under two scenarios were made. A third and a fourth scenario were also presented on the basis of long run and short run trend methods. A detailed discussion was given as to why the conditional forecast should be considered surperior to the trend forecast.

Applying different technical loss factors attributable to different sectors the forecast demand was upgraded to represent electricity generation required for each sector. The sum total of the sectoral generation forecasts was then multiplied by a conversion factor (1.05) to represent the total electricity generation under ETSA.

Based on an econometric model, the system load factor for ETSA has been forecast. Unlike the Stewart Committee Report, the present study held the view that the system load demand is likely to be less than the sum total of the sectoral peak demands (i.e., the diversity factor of the sectoral peaks is likely to be more than one). The estimated load factor has then been used to estimate the maximum demand and capacity required until 1990. We have concluded that the results obtained under the conditional forecasts are better and easier to interpret (and recast if necessary) than is the extrapolation of trends.

The forecast for total generation, consumption, load demand, load factor and capacity requirement are summarized below.

TABLE 72

Summary Forecast: ETSA

		1990	
		Scenario I	**Scenario II**
1.	Total Generation (GWH)	8,465	9,736
2.	Total Consumption (GWH)	7,259	8,348
3.	Total Consumption by Major Sectors (GWH)	6,913	7,950
4.	Residential Consumption (GWH)	2,721	3,238
5.	Industrial Consumption (GWH)	2,537	2,798
6.	Commercial Consumption (GWH)	1,655	1,919
7.	Maximum Demand (MW)	1,605	1,923
8.	Load Factor	.602	.578
9.	Maximum Capacity (MW)	2,038	2,442

This chapter closes our discussion of major issues in the present thesis. We present the major conclusions in the next few pages.

MAJOR CONCLUSIONS OF THE THESIS

This study has concentrated on the cost, pricing and demand conditions pertaining to ETSA. Although the impact of changes in technology could not be separated from the "pure" economies of scale, it was found that ETSA has obtained substantial reductions in average cost as it has expanded. This implies that costs of production in ETSA rise less than proportionately to any general rise in factor prices provided that output increases. To the extent that this reduction in cost is due to "pure" scale effects, ETSA's "natural monopoly" position is reinforced.

Capital and energy inputs were found substitutable in the production function of ETSA. Thus any upward (downward) change in the relatve price of these two factors involves a less (more) than proportionate change in cost. Improvements in load factor (and improvements in technology, applicable to a given level of output, which we could not specify) are also important in reducing cost. These reductions are not strictly related to expansion of output and can be obtained in a variety of market conditions.

The estimated marginal costs of supplying electricity are different for different sectors; so are the estimated price elasticities of demand. On the basis of these estimates, it is concluded that ETSA could better serve the community by following the Ramsey rules of pricing.

A cost-related pricing system, such as Ramsey Pricing will encourage consumption in a sector which makes the largest contribution towards economies of scale. Moreover, since peak load consumption is one of the most important determinants of marginal cost in any sector, Ramsey pricing is likely to reduce the peak demand, thereby improving the system load factor and reducing the capacity cost (though this is, nonetheless, a second-best approach to the peak load issue which we have not considered in detail in this thesis).

Ramsey pricing also provides an excellent planning device to set targets for internal funding. It is in this way that they introduce an endogeneity into the forecasting process. That is, electricity charges will be determined not only by the exogenous factors such as input prices, but also by the choice of either break-even or positive levels of surplus.

Interfuel substitution among consumer classes was found to be significant and the own price elasticities for electricity demand were higher than the cross price elasticities in all sectors. This suggests that if all energy prices rise by the same percentage, the electricity demand will increase despite a rise in its price. The large and sigificant income and output elasticities also convey the same message. Not surprisingly, the growth rate of forecast demand in the present study is more closely related with the assumed growth rates of per capita income and industrial output than with changes in electricity prices (see Tables 58 and 65).

The relative importance of various explanatory variables were different in different sectors. Thus a disaggregated model of forecasting, such as ours, can claim to give more reliable forecasts than those of the aggregate and time trend models. Moreover, the present forecast provides significant insight into the outcome of such policy variables as Ramsey pricing.

It must be recognised, however, that econometric techniques have their own limitations and therefore, many of the interesting socio-economic details may remain outside the scope of such studies. Nonetheless, it can be claimed that the present study provides important insights into the electricity supply industry, particularly ETSA. A number of interesting aspects of the industry, which were hitherto unexplored, have been brought to light.

APPENDIX I

CALCULATION OF CLASS MARGINAL COSTS: ETSA

Model A.1 Period 1950-1970

Variables	Parameters	Shares in the Change in Consumption	Cost Elasticity	AC (Cents)	MC (Cents)
RQ	.297 (8.09)	.40	.742 (8.07)	1.774	1.31 (8.04)
IQ	.081 (2.46)	.41	.198 (2.47)	1.774	.35 (2.46)
CQ	.087 (4.46)	.14	.621 (4.47)	1.774	1.10 (4.46)
OQ	-.018 (-13.16)	.05	-.360 (-13.16)	1.774	-

* The cost elasticity with respect to aggregate quantity sold for the period from 1950-70 was set at .447 see Table 23.

Model A.1 Period 1971-1981

Variables	Parameters	Shares in the Change in Consumption	Cost Elasticity	AC (Cents)	MC (Cents)
RQ	.234 (7.69)	.40	.585 (7.68)	2.47	1.44 (7.66)
IQ	.141 (12.34)	.28	.504 (12.38)	2.47	1.24 (12.32)
CQ	.126 (3.91)	.30	.420 (3.90)	2.47	1.04 (3.92)
OQ	.014 (28.76	.02	.700 (28.76)	2.47	1.73 (28.75)

* The cost elasticity with respect to aggregate quantity sold for the period from 1971-81 was set at .515 see Table 23.

CALCULATION OF CLASS MARGINAL COSTS: ETSA

Model A.3 Period 1950-1970

Variables	Parameters	Shares in the Change in Consumption	Cost Elasticity	AC	MC (Cents)
RQ	.30 (9.40)	.40	.75 (9.39)	1.66	1.25 (9.39)
IQ	.08 (3.46)	.41	.20 (3.46)	1.66	.33 (3.54)
CQ	.09 (2.48)	.14	.64 (2.47)	1.66	1.06 (2.48)
OQ	-.03 (-10.20)	.05	-.06 (-10.20)	1.66	-

* Parameter restriction = .445.

Model A.3 Period 1971-1981

Variables	Parameters	Shares in the Change in Consumption	Cost Elasticity	AC	MC (Cents)
RQ	.23 (12.39)	.40	.575 (12.38)	2.34	1.354 (12.39)
IQ	.14 (4.85)	.28	.500 (4.84)	2.34	1.17 (4.86)
CQ	.12 (3.49)	.30	.400 (3.49)	2.34	.94 (3.50)
OQ	-.01 (.59)	.02	-.500 -	2.34	-

* OQ means quantity of electricity consumed by other than the major three sectors.
** Parameter restriction = .483 (see Table 23).

APPENDIX II

DATA USED FOR ESTIMATING THE RESIDENTIAL DEMAND FOR ELECTRICITY

Data on the quantity of electricity consumed for domestic purposes in South Australia have been obtained from the Annual Reports of ETSA from 1949-50 to 1980-81. The Annual Reports also provide information on the number of residential customers (RC) for each year and the total revenue derived from the sale of electricity to residential customers. The average price charged has been calculated from the data given in the ETSA reports. The average price has then been deflated by the CPI of South Australia (with 1966-67=100) obtained from the ABS.

Per capita disposable income has been calculated from the data on household disposable income given by the Australian National Accounts and the population figures quoted from the South Australian Year Books.

The average consumption and the average income figures reveal nothing about the differences between various regions of South Australia. It is, however, assumed that the regional disparity of income is small and since the population of the state is highly urbanised (about three quarters live in Adelaide alone) the estimated income elasticity in our model is expected to be representative for all regions of the state.[1]

Information on the total supply of gas to residential customers and the sale proceeds were obtained from SAGASCO. Before 1968-69, the

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1 In the 1966 Census, the population living in Adelaide was 77.45 per cent of the total. See South Australian Year Book, 1967, p. 98.

households in South Australia were supplied with manufactured gas, which was charged at a nominated price per 1000 cubic feet (MCF). However, with effect from 1968-69, when natural gas was introduced, the prices are charged per GJ. As natural gas contains more energy in joules per MCF than manufactured gas, it was necessary to convert the MCF of gas sold before 1968-69 into GJ, to construct the price series over the entire sample period (1950-1980).

Prices of oil are conspicuous by their scarcity. Fortunately, prices of kerosene and heating oil for Adelaide since 1949-50 were available in the South Australian Price Commissioner's Office. As a large proportion of the total number of residential customers live in Adelaide, the price for Adelaide may be assumed to represent the price for the state as a whole.

Per capita disposable income as well as prices of oil and gas have been deflated, as usual, by the CPI.

The number of persons per household has been taken from the Report of the South Australian State Energy Committee, 1976 and from the census data of 1954, 1961, 1971, 1976 and 1981.

A price index for household electric appliances was constructed on the basis of information given in The Australian Market for Selected Domestic Appliances, (Tariff Board, May 1972). Variations in size and other attributes of appliances were incorporated in the price index by regressing a cross-section of price observations on the number of attributes for each year. The implicit price index thus constructed was substantially different from (lower than) the unit value of each appliance. This index could be constructed only for the period from 1950 to 1971. Although a price index for domestic appliances since 1971 is available from the ABS, changes in the quality of appliances are not known. Thus the index for the second sub-period is a unit price index only and not the implicit index as for the first period.

As said earlier, a large number of electric appliances such as air conditioners and refrigerators face no competition from gas or oil appliances which compete mainly with electric cookers and space and water heaters. Thus an index leaving electric cookers and heaters aside was constructed but the magnitude of changes in both of these indices (all inclusive and all but cookers and heaters) appeared to be the same. The marketing experts both in SAGASCO and ETSA are also of the opinion that the price of electric appliances and that of gas appliances moved in the same direction during the period of study and their relative prices remained by and large the same. Thus the price differentials between different types of appliances (e.g., gas or electric stove) do not seem to have been important in determining the stock of a particular type of appliance. The use of a separate price index for competing appliances appears to be unnecessary under this condition.

The estimated Australia-wide growth rates for household electric equipment are available in the previously mentioned Tariff Board publication. An index constructed on the basis of these growth rates appeared to be severely collinear with disposable income. As such, this information could not be incorporated in our estimation.

The statistical characteristics of the data used are presented below.

TABLE R-1

Statistical Characteristics of the Data Used for Residential Demand

Variables	Mean*	Standard Deviation
Q (consumption per customer, in gwh)	3.24	1.24
PE (average real price of electricity in cents per kwh)	1.98	.69
PO (average real price of oil in cents per gallon)	31.68	8.58
PG (average real price of gas, A$ per GJ)	3.01	.87
YD (per capita disposable income in A$'000)	1.39	.41
D (number of dwellings in '000)	332.56	91.09
PA (price index of appliances)	1.16	.21
N (population in '000)	1041.1	189.62

* 31 observations from 1950 to 1980.

APPENDIX III

ECONOMIC, ECONOMETRIC AND STATISTICAL TESTS FOR REGRESSION RESULTS

The results obtained by regression can be assessed by three types of criteria, namely economic, econometric and statistical. The signs and magnitudes of the estimated parameters will suggest whether the estimation is theoretically valid. Secondly, the best linear unbiased estimates are obtained only when the variables are serially independent and free from multicollinearity. Finally, the statistical validity of the results is measured by the coefficient of multiple correlation (R^2), the standard error (SE), student's t-statistics, F-values and d-statistics. When a model builder has a choice between alternative estimation procedures, he should choose the one which gives more precise results. The precision can be determined by computing the above summary statistics. Apart from the t-statistics, the significance of a variable can also be tested by computing residual variance. This can be done in the following steps:

(i) Regress the dependent variable with all the independent variables including the questionable variable;

(ii) Regress again excluding the questionable variable;

(iii) Divide the sum of squares of the residual by the degrees of freedom;

(iv) If this resulting value, which is known as Residual Variance, is less in step one than in step two, then the variable is considered significant.

Econometricians are not unanimous as to the superiority of R^2 as compared with SE. When R^2 is high and SE is low, the acceptability is, of course, unquestioned. The majority of writers seem to agree that R^2 is a more important criterion when the model is to be used for forecasting, while the SE is more important when the purpose is the estimation of reliable values of particular economic parameters. In any case, priority should always be given to proper signs and magnitudes of the estimated parameters.

One of the basic assumptions regarding the disturbance term in the OLS technique is that the variance of each U (e.g., see equation 4.2) is the same for all values of the explanatory variables. This is known as the assumption of homoscedasticity. In practice, however, this assumption may not be valid and the U may be heteroscedastic. The presence of heteroscedasticity renders statistical tests such as t-statistics unreliable and the prediction inefficient (see Koutsoyiannis, 1977, p. 185). In order to test whether the assumption is valid, the Spearman rank correlation and Glejser tests are used.

Johnson (1972) has preferred to use the Spearman method in detecting the heteroscedasticity and the Glejser method for removing the problem of heteroscedasticity (Johnston, 1972, p. 221). The following steps are involved:

1. Using OLS, obtain the residuals (i.e., U's);

2. Order the U's ignoring signs and the values of the independent variables in ascending or descending order;

3. Compute the Spearman Rank Correlation Coefficient:

$$r' = 1 - \frac{6\ \Sigma D^2}{n(n^2 - 1)} \qquad (R.1)$$

where D = differences between the ranks of corresponding pairs of X and U; and

n = number of observations.

4. Compute the Standard Error of r' as:

$$\frac{1}{\sqrt{n - 1}} \qquad (R.2)$$

The standard error thus computed will suggest whether the rank correlation is statistically significant. If it is found significant, then the presence of heteroscedasticity is detected. In order to remove the heteroscedasticity:

5. Regress the residual term obtained in the first run with the independent variables found heteroscedastic;

6. Divide all the original variables by the error term obtained in step five.

The residual obtained in the final run is expected to be free from the problem of heteroscedasticity.[1]

Autocorrelation may appear because of misspecification of the model, omitted independent variables or because the disturbance terms (U) are not independent of one another (Koutsoyiannis, 1977, p. 8). In

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1 See Goldfeld, S.M. and R.E. Quandt, "Some Tests for Homoscedasticity", Journal of American Statistical Association, 1965, pp. 539-47, also Glejser, H., "A Test for Heteroscedasticity", Journal of American Statistical Association, 1969, pp. 316-23.

the presence of autocorrelation, the significance of the estimated parameters cannot be judged from the computed t-statistics or standard errors.

The Durbin-Watson (d) statistics are considered to be an important test for detecting autocorrelation. It should, however, be noted that the d-statistics do not provide guidance when the lagged dependent variable is used as a regressor. In such cases, the Durbin H-statistics (DH) are the proper guide. The DH are calculated as follows:

$$DH = (1 - 1/2d)\sqrt{[T/(1 - T)\ (SE)^2]} \qquad \text{(R.3)}$$

where d = Durbin Watson statistics;

T = number of observations;

SE = standard error of the lagged variable.

If the observed value of DH exceeds the critical value of a standard normal distribution with mean zero and variance unity at a chosen level of confidence (e.g., 95 per cent confidence level = ± 1.65), we reject the null hypothesis that the errors are serially independent (see Rao and Miller, 1971, p. 124).

If it is established that the error terms are not serially independent i.e., $U_t = \hat{\rho}U_{t-1}$ where

$$\hat{\rho} = \Sigma\ \hat{U}_t\hat{U}_{t-1}/\Sigma\ U^2_{t-1} \qquad \text{(R.4)}$$

then the Cochrane-Orcutt method of removing autocorrelation is recommended.

For the Cochrane-Orcutt method, the following steps are necessary:[2]

(i) Regress dependent variable, Q, with independent variables (X_i) and find residuals (U);

(ii) Calculate DW statistics, i.e.,

$$d = \frac{\sum_{t=1}^{T} (\hat{U}_t - \hat{U}_{t-1})^2}{\sum_{t=1}^{T} \hat{U}_t^2} \qquad \text{(R.5)}$$

(iii) Calculate $\hat{\rho}$ using R.4;

(iv) Transform Q, X and U as follows:

$$Q = Q_t - \hat{\rho}Q_{t-1}, \qquad X = X_t - \hat{\rho}X_{t-1}, \qquad U = U_t - \hat{\rho}U_{t-1}$$

(v) Re-estimate the transformed equation and calculate DW-statistics to examine the presence of autocorrelation.

(vi) If autocorrelation persists, repeat the process until DW-statistics appear to be satisfactory.

The Klein's rule and Farrar-Glauber tests provide indications of whether the results are affected by inter-correlation between two or more independent variables. According to Klein's rule, the collinearity is considered severe when

$$R_X^2/R_Q^2 > 1 \qquad \text{(R.6)}$$

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2 See Dulta, M., (1975), pp. 112-131.

where R_X^2 = multiple correlation coefficient when one independent variable is regressed on others, and

$R_Q^2 = R^2$ for the dependent variable.

Farrar and Glauber (1967) developed a set of three tests to detect multicollinearity. A Chi-Square test for the presence and severity of multicollinearity, an F-test for establishing the pattern of multicollinearity and a t-test for locating the multicollinearity. The Chi-Square test is given by:

$$\chi^{*2} = -(n - 1 - \frac{1}{6}(2k + 5)) \log e\, |X'X| \qquad \text{(R.7)}$$

where χ^{*2} = the computed value of Chi-Square;

n = size of the sample;

k = number of explanatory variables;

$|X'X|$ = value of the standardised determinants.[3]

If the value of the χ^{*2} is greater than the theoretical value of χ^2 with 1/2k(k - 1) degrees of freedom, multicollinearity is suspected. The higher the observed χ^{*2}, the more severe is the multicollinearity. Secondly, an F-test of the multiple correlation coefficients among the explanatory variables may be computed by:

$$F^* = \frac{R^2_{X_i}/(k - 1)}{(1 - R^2_{X_i})/(n - k)} \qquad \text{(R.8)}$$

where F* = the computed value of F as against the theoretical value as given in standard F-tables.

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3 When a regression equation has several parameters to be estimated, the least square algorithm for β is usually expressed in matrix notion as: $\beta = (X'X)^{-1}(X'Y)$. When a linear relation exists between independent variables, then the matrix (X'X) is singular and has no inverse. See Rao, op cit., p. 49.

If $F^* > F$ with $v_1 = (k - 1)$ and $v_2 = (n - k)$ degrees of freedom, at the chosen level of significance, it is accepted that the variable x_i is multicollinear.

Thirdly, the t-test is aimed at detecting the variables which are responsible for multicollinearity. The partial correlation coefficients of all the explanatory variables are computed and their statistical significance are tested with the t-statistics. The general formula is given by:

$$t^* = \frac{(r_{x_{ij}} \cdot x_1 x_2 \ldots\ldots x_k)\ \ n - k}{\sqrt{1 - r^2_{x_{ij}} \cdot x_1 x_2 \ldots\ldots x_k}} \qquad (R.9)$$

where $r_{x_i x_j} \cdot x_1 x_2 \ldots\ldots x_k$ represent the partial correlation coefficients between x_i and x_j.

If the t^* is greater than the theoretical t-value with $v = (n - k)$ degrees of freedom at the chosen level of significance, then the correlation coefficient between x_i and x_j is considered significant, and responsible for the multicollinearity in the function.

APPENDIX IV(A)

SOURCES AND NATURE OF THE DATA USED FOR ESTIMATING THE INDUSTRIAL DEMAND FOR ELECTRICITY

The Data

The sample period in the present study extends from 1950 to 1980 for the derived input demand model and from 1968-69 to 1980 for the explicit cost function. Most of the data used were obtained from the Australian Bureau of Statistics (ABS) and the Electricity Trust of South Australia (ETSA). The Annual Reports of ETSA provide information on the total industrial consumption of electricity (Q) during a year, the total number of industrial customers (IC), and the total revenue derived from the sale of electricity to industrial customers.

The data on industrial value added (VA) were taken from the South Australian Year Books.

The average price of electricity (PE) has been estimated from the data on total revenue derived by ETSA from its sale of electricity to industrial customers. The price thus obtained has been deflated by the CPI (S.A.) to give the expression in real terms. It should be noted at this stage that the CPI may not, in fact, reflect the real cost to industrial customers. An appropriate deflator in this case would have been a price index for industrial inputs. No such index is, however, available for the entire period under study. Under such conditions, we assumed that the CPI approximately represents the price index for industrial inputs. A price index of the articles produced by the manufacturing industries in South Australia since 1968-69 is available from the ABS. This index (called the manufacturing price index (MPI)) was thought to represent the price index for inputs more closely than the CPI. In a bid to examine the difference, if any, in the results, a separate estimation was made using the MPI as a deflator for the price since 1968-69, but the results were not different from those obtained using the CPI.

Similarly, the GDP deflator, which is available for Australia as a whole, was used in the present case as well as in the case of industrial value added. The results were not significantly different from those obtained by using the CPI. The real value added that we have used in our final run, are those deflated by the CPI (S.A.). The increase in the real wages in South Australia is assumed to be a reflection of the increased average productivity of labour.

Statistics on gas price (PG) for industrial consumption were obtained from the South Australian Gas Company (SAGASCO) and deflated by the CPI (S.A.).

Statistics on oil prices (PO) are conspicuous by their scarcity. In the absence of any price index for industrial diesel oil and furnace oil, which are the relevant types of oil to compete with electricity in industrial production, we have taken the price index of petrol in South Australia as a proxy for the prices of diesel oil and furnace oil. On personal contact, the officials of the South Australian Energy Information Centre and Mobil Oil, South Australia, have assured me that this is a reasonable proxy. Since we are interested in the rate of change rather than the absolute level of prices, the surrogate price index used may well represent the actual price index so long as the relative prices of various petroleum products remain unchanged. The price index of petrol is obtained from the ABS (S.A.).

Statistics on average industrial wages (W) have been calculated from the total annual wage bill paid to industrial employees, which is available from the ABS. The wage bill was divided by the number of industrial employees in each year since 1949-50. The average wage level thus obtained has been deflated by the CPI. The following sources have been used:

1. South Australian Year Books;
2. Manufacturing Establishment: Details of Operation, ABS; and
3. South Australia Statistical Register 1950-76.

The problem of aggregating all categories of labour into one measure is well recognised (see Nadiri, 1970, pp. 1137-77). As usual, the solution lies in more and better data. In the absence of more detailed information, we have had to remain content with the aggregate data.

Data on coal prices (PC) are not available for South Australia. However, those for the Commonwealth of Australia were taken from Turnovsky and Donnelly (1982). We assume that the price of coal in South Australia (for industrial purposes) will not be significantly different from that in Australia as a whole.

The price of capital services (PK) is by far the most difficult to estimate. On the basis of the price series of investment goods available from the ABS and Haig (1966), we have constructed a price index for capital services applying the following equation originally developed by Christensen and Jorgenson (1969) and later elaborated by Magnus (1979).

$$PK_t = (P_{it})d + (P_{it-1})r - (P_{it} - P_{it-1}) \qquad (A.1)$$

where PK_t = price index of capital service at time t; P_{it} = price index of investment goods at time t; r = discount rate; d = depreciation rate.

The last term of the right hand side of the above equation stands for capital gains, if any. Whether entrepreneurs anticipate capital gains when they consider purchasing capital equipment is an empirical question. When including the capital gain term, Magnus (1979, p. 422) obtained a highly volatile value of PK_t, which was considered to be implausible. For the purpose of this paper, we do not take this last term of equation A.1 into consideration.

Following Clark (1970) and Hawkins (1977), we have used a 12 per cent depreciation rate on diminishing balance. The discount rate has been calculated by applying the following equation:

$$(1 + r) = (1 + \dot{p})\ (1 + i) \qquad (A.2)$$

where $\dot{p}$ = rate of inflation; i = social time preference (assumed to be a constant 3 per cent over time). There was no significant change in the results obtained when i = 0 was assumed. The assumption i = 0 indicates that the discount rate is equal to the rate of inflation.

The data on fuel expenditure by industries under ASIC two digit sub-divisions since 1968-69 are taken from ABS: <u>Manufacturing Establishment: Details of Operation by Industry Class</u>.

The statistical characteristics of the data used are presented below:

TABLE A.1

Statistical Characteristics of the Data Used

Variables*		Mean	Standard Deviation
Q	(Quantity of Electricity Consumption in gwh)	946.97	594.89
Q/IC	(Consumption per Industrial Customer)	61.34	11.45
PE	(Average Price of Electricity in ¢ per kwh)	1.85	0.54
PG	(Average Price of Gas in A$)	2.36	0.93
PO	(Price Index of Oil)	120.28	56.56
VA	(Industrial Value Added in Million A$)	505.42	195.81
W	(Average Real Wage Level in A$'000)	2.71	0.73
IC	(Number of Industrial Customers in '000)	16.21	9.83
PC	(Coal Price Index)	2.17	1.63
PK	(Capital Price Index)	.26	.18
TC	(Total Unit Cost for Energy cent per dollar)	3.94	.33
SE	(Share of Electricity in TC)	.63	.40
SO	(Share of Oil in TC)	.26	.20
SG	(Share of Gas in TC)	.11	.07

* 31 observations for all variables.

APPENDIX IV(B)

REGRESSION RESULTS OF THE EXPLICIT COST MODEL FOR THE INDUSTRIAL DEMAND FOR ELECTRICITY IN SOUTH AUSTRALIA

TABLE B.1

Parameters	Total Manufacturing	ASIC* 21-22	ASIC* 23
α_o	3.817 (247.27)	3.564 (187.46)	3.845 (254.36)
α_e	.657 (40.85)	.582 (59.26)	.702 (27.46)
α_o	.249 (20.45)	.347 (28.81)	.260 (14.30)
α_g	.094 (6.65)	.071 (7.78)	.038 (3.31)
α_{eo}	-.086 (-7.75)	.018 (.48)	-.098 (-3.40)
α_{eg}	-.024 (-.52)	-.017 (-.62)	-.029 (-.60)
α_{og}	.074 (-5.57)	.049 (1.21)	.085 (2.91)
α_{ee}	.110 (3.79)	.001 (.03)	.127 (2.33)
α_{oo}	-.012 (-.71)	-.067 (-1.05)	.013 (.26)
α_{gg}	-.050 (-3.33)	-.032 (-1.03)	-.056 (-1.70)

* ASIC Codes are:
(21-22): Food, Beverage and Tobacco; (23): Textile.

** The figures in the parentheses indicate t-statistics.

*** Subscripts e, o and g stand for electricity, oil and gas respectively.

TABLE B.1 (continued)

	ASIC		
Parameters	**24**	**25**	**26**
α_o	2.125 (78.09)	3.36 (115.52)	4.02 (193.66)
α_e	.875 (59.90)	.867 (46.19)	.622 (29.20)
α_o	.088 (5.66)	.123 (6.42)	.367 (17.58)
α_g	.037 (6.76)	.010 (2.95)	.011 (10.94)
α_{eo}	-.156 (-2.49)	-.291 (-3.64)	-.151 (-3.75)
α_{eg}	.018 (.82)	.003 (.25)	.002 (2.56)
α_{og}	-.033 (-1.76)	-.022 (-2.15)	-.001 (-.35)
α_{ee}	.138 (2.30)	.288 (3.74)	.149 (3.72)
α_{oo}	.189 (2.70)	.313 (3.96)	.152 (3.80)
α_{gg}	.015 (1.07)	.019 (.73)	.001 (.20)

* ASIC Codes are:
(24): Clothing and Footwear; (25): Wood, Wood Products and Furniture;
(26): Paper, Paper Products, Printing and Publishing.

TABLE B.1 (continued)

Parameters	ASIC 27	ASIC 28	ASIC 29
α_o	4.260 (352.73)	4.693 (138.18)	4.844 (109.09)
α_e	.530 (38.21)	.407 (24.46)	.702 (49.04)
α_o	.424 (13.87)	.221 (6.38)	.272 (20.05)
α_y	.046 (1.77)	.371 (9.12)	.026 (4.46)
α_{eo}	.214 (7.33)	.023 (.47)	-.245 (-4.63)
α_{ey}	-.139 (-5.11)	-.037 (-.64)	.008 (.37)
α_{oy}	.523 (3.20)	.626 (3.62)	.041 (2.31)
α_{ee}	-.075 (3.40)	.014 (.26)	.237 (4.23)
α_{oo}	-.737 (-4.45)	-.649 (-4.57)	.204 (3.64)
α_{gg}	-.384 (-2.33)	-.589 (-2.75)	-.049 (-2.45)

* ASIC Codes are:
(27): Chemical, Petroleum and Coal; (28): Non-Metalic Mineral Products; (29): Basic Metal Products.

TABLE B.1 (continued)

Parameters	ASIC 31	ASIC 32	ASIC 33	ASIC 34
α_o	2.976	3.22	3.09	3.60
	(215.44)	(82.24)	234.94)	(281.52)
α_e	.717	.773	.782	.799
	(80.03)	(62.96)	(47.60)	(41.36)
α_o	.156	.090	.121	.153
	(16.41)	(8.64)	(10.03)	95.86)
α_g	.127	.137	.097	.048
	(27.00)	(8.53)	(7.79)	(2.13)
α_{eo}	.068	-.117	.073	-.039
	(1.86)	(-3.75)	(1.58)	(-.99)
α_{eg}	-.031	.044	-.081	-.039
	(-1.68)	(1.03)	(-1.76)	(-.99)
α_{og}	-.046	.198	.143	.194
	(-2.60)	(4.50)	(4.03)	(2.51)
α_{ee}	-.037	.073	.008	.078
	(-1.06)	(1.59)	(.123)	(1.39)
α_{oo}	-.022	-.081	-.216	-.155
	(-11.00)	(-2.38)	(-4.80)	(-2.76)
α_{gg}	.077	-.242	-.062	-.155
	(5.31)	(-8.34)	(-1.88)	(-2.77)

* ASIC Codes are:
(31): Fabricated Metal Products; (32): Transport Equipment; (33): Other Machinery and Equipment; (34): Miscellaneous.

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