ELECTRICAL ENERGY FORECASTING: EMERGING ISSUES AND A CASE STUDY OF RESIDENTIAL AND GENERAL SERVICE LOADS IN NEWFOUNDLAND

BY

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ABSTRACT

The study reviews the increasingly more difficult environment in which electricity demand forecasts must be prepared and concludes that forecasting models should be developed to explicity account for variations in a range of economic, energy, demographic, and energy policy factors.

Particular attention is given to the emerging issue of rate structure reform because of the implications that altered levels and patterns of electricity demand can have on systems expansion plans and hence costs. On this issue the study concludes that demand modelling methodologies must be developed to facilitate an analysis of consumer response to changes in rate design.

After reviewing selected econometric studies on electricity demand, separate electricity demand models were constructed for Newfoundland. The results indicate: (1) that prices and incomes in particular are important determinants of electricity demand but that the relative size of the elasticities depends on the market being analysed and whether one is examining demand responses in the short or long-term; and (2) that more extensive data is necessary to develop more reliable forecasting models to accomodate the range of future planning complexities.

LIST OF DEFINITIONS

All-Electric Customers: residential customers on the Newfoundland Light and Power Company system that use electricity as a principal source of space heating in addition to other uses, eg. hot water, appliance and lighting requirements.

Appliance Saturation: the quantity of a specific household appliance connected to a utility's lines divided by the total number of residential customers.

Demand: the power (watts) required to supply the load at any given time.

Electric Energy: the energy associated with the product of voltage and current over an interval of time. It is measured in kilowatt-hours.

Load Factor: the ratio of average power delivered to an electrical load over a certain period divided by the maximum rate at which power was delivered over the period.

Peak Load: the highest average load during a time interval of specified duration, eg. 20 minutes, occurring during a given period of time, eg, in a day.

Peak Load Generation: this is generation whose energy output is produced chiefly during the daily peak load period. At other times of the day it is shut down or operated at minimum safe loadings.

Regular Domestic Customers: residential customers on the Newfoundland Light and Power Company system that use electricity for hot water, appliance or lighting requirements, but essentially use another energy form for the bulk of their space heating requirements.

Thermal Plant: a type of electric generating station in which the source of energy for the prime mover is heat.

Transformer: an electromagnetic device for changing the voltage of alternating current electricity.

Transmission: the act or process of transporting electric energy in bulk from a source or sources of supply to other principal parts of the system or to other utility systems.

Utility Rate Structure: a utility's approved schedule of charges for billing utility service rendered to various classes of its customers.

Volt: the unit of electromotive force or electric pressure analogous to water pressure in pounds per square inch, which if steadily applied to a circuit having a resistance of one ohm, will produce a current of one ampere.

Watt: the electric unit of power or rate of doing work. The rate of energy transfer equivalant to one ampere flowing under a pressure of one volt at unit power factor.

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INTRODUCTION

In recent years, utility managements and regulatory agencies have increasingly focused their attention on electricity demand forecasts, in an attempt to carefully scrutinize the need for additional generation, transmission and transformation facilities. There are a number of factors that have contributed to this interest: (1) the past decade has seen rapid increases in the real price of energy and there is every prospect that these increases will continue, (2) inflationary problems have persisted at unprecedented levels and real income growth has slowed, (3) there is a new awareness that there are significant environmental and social consequences of expanding an electric utility system, and (4) there have been significant changes in the underlying demographic profile of many utility jurisdictions, with implications for future demand.

As a reaction to these concerns, there has been a significant impetus in the industry to alter the design of electricity rate structures to reflect marginal cost pricing principles, in place of the average accounting cost methodology that is currently in use. Since pricing and demand are closely linked, the reformation of electricity rates is of particular interest.

Chapter 1 attempts to put the role of demand forecasting into an electric utility perspective, and elaborate on the new forecasting environment in which utilities must now plan.

In Chapter 2 the issue of rate reform and its implications for demand analysis are addressed.

In the remaining chapters, an attempt is made; (1) to discuss a rational and defensible framework for electricity demand analysis, and (2) to develop electrical energy demand models for the residential and general service sectors of Newfoundland.

In Chapter 3 attention is drawn to some of the problems of applying the traditional framework for demand analysis to an analysis of electricity demand.

Chapter 4 contains a review of selected econometric studies on the demand for electrical energy. The focus is primarily on research related to the residential sector, although some references are made to the commercial sector. These studies were reviewed to highlight the various techniques and problems of modelling electricity demand and they provide a useful point of reference for an econometric study of electricity demand in Newfoundland.

The methodology and results of an econometric analysis on residential and general service electricity demand in Newfoundland are reported in Chapter 5.

Finally, Chapter 6 contains a summary, and the conclusions emanating from the study.

CHAPTER 1

PLANNING & DEMAND FORECASTING

1.0 Introduction

As most firms exist in an economic climate that is constantly fluctuating and transforming, business profitability depends, to a large degree, on good business planning. The ability to anticipate changes in the volume of demand for certain outputs, or changes in the costs of production inputs, and to respond to these changes in a timely fashion can ensure the firm an opportunity to maximize revenues and minimize costs.

An accurate forecast of the demand for a particular output is a critically important element in the formulation of a sound business plan.[1] There are, however, other considerations relating to production, technology, management, political philosophy, financing and pricing that are as vital to the planning process.[2]

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[1]Under conditions of perfect competition, accurate forecasting is a "given" for all participants: somehow it mysteriously gets done. In the real world, and in the far from perfectly competitive markets in which public utilities exist, demand forecasting is essential.

[2]Ontario Hydro for example, as recently as 1976 would (a) estimate electricity demand requirements, (b) secure the financing to increase the generating capacity,

Notwithstanding the importance of all the elements in the planning process, the demand forecast is frequently the foundation upon which power utility planning begins.[3]

Under conditions of imperfect competition, in which power utilities tend to operate, the features of a demand forecast for short-term or tactical planning are significantly different from those for a longer term or strategic planning exercise. These distinctions are worth noting since this paper is primarily concerned with long-range electrical demand forecasting.

In the short-term electric utility planners are pre-occupied with immediate operational decisions. In particular, a "hedging of bets" and concern to "retain flexibility" tends to underlie their planning. Consequently, the short-run demand forecast reflects the immediate demand climate, focusing on peak periods in particular, to enable an assessment of the basic capacity the electric utility requires.

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and (c) increase rates to cover total costs. This procedure was short circuited in 1976 when the Ontario Provincial Government put a limit on the capital borrowings of the utility. See _Memorandum to the Ontario Royal Commission on Electric Power Planning with Respect to the Public Information Hearings_. (Toronto: Ontario Hydro, May 1976). Volume entitled _Load Forecast_ p. 33.

[3]The word demand in electric utility jargon often denotes the amount of power (watts) required to supply the load at a given time. References to "the demand forecast" in this paper are intended to suggest a more general interpretation, i.e. the assessment of both power and energy requirements.

For the longer term, far broader ranges of information are required regarding structural changes anticipated in the economy, i.e. the long-term demand forecast attempts to identify evolving demand preferences.

Horrendous penalties can be incurred as a result of poor demand forecasting and hence, sub-optimal planning. Costly production facilities could be constructed without an adequate demand for the output materializing. As a result, revenues would simply not cover costs, and the continued existence of the firm might very well be jeopardized. Alternatively, if the demand function for a firm's output were underestimated, the pricing advantages that could be obtained by utilizing economies of scale in its expansion of productive facilities, might easily accrue to a competitor that has a better estimation of market potential.

1.1 Planning and Demand Forecasting in Electric Utilities

Many of the electric utilities in Canada, as both regulated monopolies and instruments of the Crown, have corporate objectives to provide adequate electricity within the framework of "efficient economic planning". By way of example, section 5 of the Newfoundland and Labrador Hydro Act, 1975, reads:

> "The objects of the Corporation are to develop the use of power on an economic and efficient basis......at rates consistent with sound

financial administration.........[4]

This notion of "economic and efficient" however, normally includes an element of equity, i.e. utility planning need not be efficient in the more purist sense.[5]

Indeed, accurate demand forecasts and sound strategic planning are probably more important to electric utilities than to most types of business concerns. A brief discussion and overview of the unique characteristics of the electric utility industry will illustrate this point.

1. The required lead times for the construction of generating plants vary from approximately a year for gas turbine installations to roughly twelve years for nuclear capacity, whereas most manufacturing companies face construction lead times of approximately 2 - 3 years.

2. The productive facilities of electric utilities are more equipment-bound than most manufacturing concerns. A fish plant, by comparison, is more labour-bound and altered demand patterns for the output of such an industry can be handled more easily, by reducing or increasing its variable labour costs. The capital-bound

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[4]Newfoundland and Labrador Hydro Act, 1975, Section 5, p. 4.

[5]For a discussion on the issue of equity and rate making refer to R. I. McAllister, Rural Electrification Policy: Newfoundland and Labrador, A Report to the Board of Commissioners of Public Utilities, Province of Newfoundland". January, 1979, pp. 17-23. Also see J. C. Bonbright, Principles of Public Utility Rates, Columbia University Press, New York, London, 1969.

characteristics of the electric utility industry do not easily permit these variable types of supply adjustments so that requirements for expensive facilities must be carefully forecasted.

3. Electric utilities lack what one writer has termed a "finished goods inventory capability".[6] Whereas most manufacturing industries have the ability to store products to meet peak demands, electric utilities produce products that do not readily have storage characteristics. Expensive generating facilities must be installed, therefore, to compensate for the lack of an inventory capability in order to help meet peak load requirements.

1.2 Cost Considerations

It is important to recognize that the costs of inaccurate demand estimates can be significant. Four ways of assessing costs will be highlighted: (1) economic, (2) financial, (3) social, and (4) environmental. The main distinction is between economic and financial, or accounting costs. Social and environmental costs are captured in the economic concept of externalities.

1. Economic costs, or "opportunity costs" are measured as the foregone value of investing resources in the best alternative available.

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[6] C. K. Motlagh, Structuring Uncertainities in Long-Range Power Planning, East Lansing, Michigan, Michigan State University, 1976, pp. 10 - 11.

2. Financial costs include the actual expenses experienced by consumers and firms, i.e. costs that affect cash flows.

3. Social costs encompass the costs imposed on society by the actions of certain households and firms. These are often referred to as "externalities" as they are typically considered beyond the financial and economic cost concerns of specific consumers and producers. An appreciation of the importance of such costs is obviously essential if a project is to be appraised in a reasonably comprehensive manner.

4. Environmental costs have historically tended to be lumped with social costs. As man has become more knowledgeable about the environmental implications of many of his activities, the importance of assessing environmental costs is increasingly appreciated.

For an electric utility, the economic or opportunity costs of any investment are measured as the rate of return foregone by not utilizing investment resources in other alternatives.

The financial costs of investments in generating capability tend to be very visible. Utilities incur the explicit costs of developing and transmitting electricity to consumers who in return remunerate the utilities for their investments. Underinvestment in generating plants can have significant financial impacts on all consumers, depending of course on the severity of the short-fall. To the utility, the costs are implicit and measured only by the value of revenues foregone by underinvesting in productive capacity - the regulatory process has historically permitted utilities to pass on increases in operating costs to the consumer. Inadequate investment will then have an explicit cost impact on the consumer, by increasing the average cost per unit of electrical consumption.

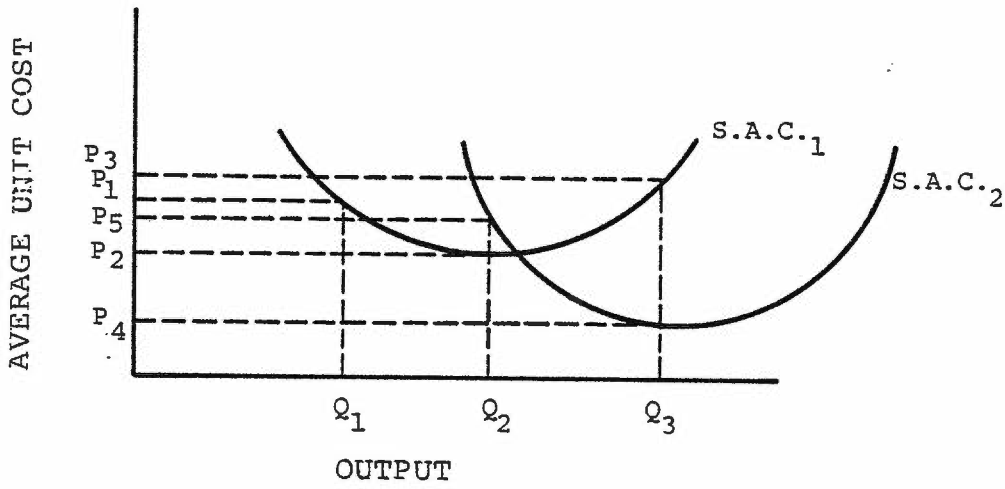
Figure 1 shows two short-run average total costs curves, each corresponding to two distinctly different plant sizes. If we assume a generating plant was constructed on the basis of a forecast for output Q_2, our short-run average cost curve of S.A.C.$_1$ would produce average unit costs of P_2. When output increases from Q_1 to Q_2 average unit costs would decline from P_1 to P_2. Further increments in the demand for the output, however, will result in higher average unit costs. At output Q_3 for example, a plant size that has a short-run average cost curve of S.A.C.$_1$ will create average unit costs of P_3. If, however, the demand for electricity had been correctly forecasted at Q_3 and generating facilities subsequently built with a short-run average cost curve corresponding to S.A.C.$_2$, the average unit cost at output level Q_3 could have been P_4.

If the underestimation of demand is severe the implications for all customers can be more pervasive than that of increased average unit costs. For example, brown-outs and black-outs can leave some manufacturing companies without the necessary energy to continue their productive

FIGURE 1

HYPOTHETICAL SHORT-RUN

AVERAGE COST CURVES



processes and their financial losses as a consequence can be significant. A recent study of Ontario Hydro surveyed a number of customers with consumption over 5 mw[7], asking them to estimate the costs that they would incur as a result of interrutption in the supply of power.[8]

> "The results of the survey showed that of the 115 respondents interviewed, costs ranged from $1.8 million for a momentary interruption to $7.0 million for a one-hour interruption".[9]

Moreover, if there was a 24-hour interruption in power supply, total user costs were estimated to amount to over

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[7] 1 megawatt (mw) is the equivalent of one million watts.

[8] Ontario Hydro, Survey on Power System Reliability: Viewpoint of Large Users, Report No. P.M.A. 76-5, April 1977.

[9] Ibid, p. 13

$40 million.[10]

As in the case of underinvestment, excessive generating capability has financial implications that are best illustrated by reference to Figure 1. We assume a utility installs capacity that results in a short-run average cost curve of S.A.C.$_2$ on the basis that demand of Q_3 will materialize. If, in fact, demand of Q_2 is realized, average unit costs of P_5 will be much greater than those that would have occurred had output actually reached Q_3.

A discussion on the cost implications of inaccurate demand estimates is incomplete without some reference to both "social costs" and "environmental costs".

While the social costs of our construction activity are difficult to measure they are receiving much more attention in the evaluation of prospective projects. Similarly, there are environmental costs associated with utility investments that must be reckoned with. The flooding of large tracts of wilderness, the release of noxious gas into the atmosphere, the danger of nuclear radiation, and the routing of transmission lines all have important environmental implications for society. It is important that both the social and environmental costs of utility investments be explicity factored into the calculation of

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[10] Ibid, p. 4. The questionnaire was designed to ascertain the total costs to a customer from a power interruption. Foregone revenues and fixed costs, for example, are included.

total project costs. This ensures that the price of the output will reflect the true cost of resource development.

It was noted earlier that the opportunity costs to a utility of one investment was the rate of return foregone by not investing those resources in the best alternative available. While these were private economic or opportunity costs, the argument is analagous for the whole economy. If for example, a crown-operated utility overinvested in generation and transmission facilities, the social opportunity cost would be the value foregone by society's failure to invest scarce capital resources in the best alternative available. The alternatives could be in health services, fisheries, transportation or tourism to name a few. Moreover, what might appear to be adequate capacity levels could very well be excessive or inadequate. For example, if electricity is priced below its economic cost, inefficient planning and a misallocation of scarce resources will be the result. This occurs as excessive consumption, resulting from improper pricing practices, stimulates overinvestment in expensive generating, transmission and transformation capacity. This point will be discussed more rigorously in Chapter 2 as alternative pricing schemes will in all probability, have a large impact on (1) future demand levels, and (2) the methodology for estimating demands.

1.3 The New Forecasting Environment

Forecasts of long-term electrical load requirements are receiving a great deal more attention today than those of previous years. There are a number of reasons for this emphasis.

1. Rising oil prices have dramatically increased the cost of thermal generated electrical energy. Since the OPEC oil price increase in 1973, there has been a steady increase in the real cost of electricity, whereas, prior to 1973 real electricity prices declined (see Table 1).

2. Increased oil costs haven't been the only factor affecting electricity prices, however. The costs of developing new generating sources have escalated at a phenomenal rate. Real increases in construction costs, particularly for hydro-electric plants, are attributable to the fact that the remaining sites are more expensive to develop. Furthermore, increased public participation on environmental issues has lengthened project lead times, significantly increasing project construction costs.

3. As new generating sources become ever more expensive to develop, the ability and desirability of financing new projects is being seriously questioned. The attitude of "supply at any cost" is being challenged by those that advocate conservation and more efficient utilization.

4. Conservation programs, that are designed to

TABLE 1

HISTORY OF RESIDENTIAL ELECTRICITY PRICES
¢/KWH
1967-1979

YEAR	PRICE[a] ¢/KWH (Current $)	PERCENT CHANGE	PRICE ¢/KWH (1971 = 100)
1967	1.060[b]	N/A	1.18[b]
1968	1.284	21.13	1.367
1969	1.284	-	1.328
1970	1.284	-	1.304
1971	1.284	-	1.284
1972	1.284	-	1.214
1973	1.284	-	1.107
1974	1.458	13.58	1.115
1975	1.719	17.90	1.179
1976	2.007	16.75	1.276
1977	2.283	13.75	1.350
1978	2.510	9.94	1.373
1979	2.896	15.38	1.442

Source: Newfoundland Light and Power Company Limited and Historical Statistics of Newfoundland and Labrador, Table I-1, August 1979, Volume II (2).

(a) Electricity prices refer to end block prices. They include retail sales tax and fuel adjustment charges and are weighted by the number of months the rates were in effect.

(b) Estimate.

affect insulation levels, efficient energy utilization and the efficiency of new energy using equipment, are expected to have a large impact on future demand trends.

5. In recent years, many utilities have experienced reductions in the growth rate of their overall electrical loads. For example, Table 2 shows the trend in average kwh consumption for all-electric and regular domestic customers on the Newfoundland Light and Power System. For "all-electric" customers, average consumption peaked in 1975 and decreased thereafter to a level in 1979 that is lower than the average consumption experienced in 1971. For regular domestic customers, average consumption appears somewhat more stable, but nevertheless has slowed considerably.

Higher real electricity prices, conservation programs, the fact that a certain level of appliance saturation is being reached, reductions in real income growth & population growth are believed to be the principal reasons for the current and projected reductions in the growth of electrical energy demand. Predictably, utility managements have become increasingly more interested in electrical load forecast results and anxious to improve estimation methodologies. Simple trend projections, while appearing to be quite adequate in the pre-1974 period, are no longer acceptable. Demand forecasting today requires that utilities take account of an increasing number of these factors in a systematic fashion.

TABLE 2

AVERAGE ANNUAL KWH CONSUMPTION
FOR ALL-ELECTRIC AND REGULAR DOMESTIC CUSTOMERS
1968-1979

YEAR	AVERAGE ANNUAL ALL-ELECTRIC CONSUMPTION (KWH'S)	AVERAGE ANNUAL REGULAR DOMESTIC CONSUMPTION (KWH'S)
1968	18,073	3,784
1969	19,313	4,076
1970	20,601	4,359
1971	22,074	4,601
1972	22,583	4,987
1973	25,030	5,577
1974	25,282	6,276
1975	25,400	6,823
1976	25,243	6,947
1977	23,919	6,809
1978	22,091	6,811
1979	21,997	6,789

Source: Newfoundland Light and Power Limited, Total Company and Divisonal Energy sold reports.

(a) All-Electric average consumption is adjusted for degree day variation.

While greater emphasis is being placed on improved demand forecasting methodologies, in the face of increased energy prices and future supply uncertainities, a critical debate is being waged on the current pricing structures of electric utilities, that will have a great influence on demand modelling methodologies.

Essentially, the proponents of alternative rate designs argue that at present, electric utilities are failing to charge consumers the economic cost of supplying electricity. More specifically, a majority of North American utilities have electricity rate schedules that are based on average production costs and characterized by declining block features, whereas those same utilities are now experiencing marginal production costs that exceed average system costs. Since consumers are not receiving a signal of the real cost of their consumption, the consequences include excessive consumption, an overinvestment in utility capacity, and a misallocation of scarce capital resources.

1.4 Summary

An accurate demand forecast is an important element in the development of a sound business plan. It is particularly crucial for electric utilities; since (1) their planning horizons often extend 15-20 years into the future, (2) their investments are capital intensive, and (3) they lack the ability to store their product as inventory. The cost consequences then, of poor forecasting, can be readily appreciated.

In recent years the job of forecasting electricity demand has become more difficult by virtue of the fact that; (1) the price of energy has been increasing in real terms against a history of declining real prices, (2) inflation has persisted at unprecedented levels and real income growth has slowed, (3) much more attention is given to the social and environmental consequences of expanding the electric utility system, and (4) the demographic profile of the population in many utility jurisdictions is changing.

As a consequence, improved forecasting methodologies and new pricing and costing procedures are being encouraged to facilitate sound and efficient utility planning.

CHAPTER 2

RATE REFORM: OVERVIEW AND IMPLICATIONS FOR DEMAND ANALYSIS

2.0 Introduction

In recent years there has been widespread interest in rate reform, directed at changing traditional costing and pricing practices to those that are based on the theory of marginal cost pricing.

In Chapter 2 an attempt is made to: (1) familiarize the reader with the very basic principles underlying marginal cost pricing and how it is purported to engender economic efficiency and efficient resource allocation; (2) discuss the basic determinants of electric utility costs; (3) describe the current pricing methods, their inherent problems, and the alternatives; and (4) draw some conclusions with particular reference to demand analysis requirements.

2.1 The Theory of Pricing and Economic Efficiency

The notion of economic efficiency requires that goals be pursued within a framework that clearly attempts to maximize satisfaction from limited resources. Prices play a key role in facilitating efficiency by acting as a rationing mechanism for scarce resources. Price is determined by the interaction of market supply and demand, and in theory it provides consumers and producers with a signal of the true value that society places upon goods and services.[11]

When one speaks of an efficient allocation of resources, or an optimal level of output, it is important to remember that the desire to produce an optimum arises only because there are finite limits to our resources. Establishing adequate criteria for determining optimal outputs of various commodities is then problematic.

A great deal has been written about efficient resource allocation critieria and the subject has earned the title of "Welfare Economics".

Since the supporters of new electricity pricing schemes often refer, in their theoretical rationalizations, to "efficient pricing" and "optimal output levels", or to "second-best considerations", it is important to understand the essence of "Welfare Theory".

In short, Welfare Economics attempts to establish

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[11]We do not live in a theoretical world, however, but in markets where many imperfections exist that distort the clarity and trueness of the pricing mechanism. For example, certain production externalities or diseconomies may not be included in the market price in which case prices would not reflect the true costs of producing a given commodity. Moreover, government often uses its subsidy and taxation powers to raise or lower market prices for one reason or another. An appropriate example of doubtful merit is the Federal Government's Oil Import Compensation Program which has, since 1973, kept domestic oil prices below world prices.

criteria by which we can identify; (1) optimal output allocations among consumers, (2) optimal input allocations to firms, and (3) the optimal allocation of resources between commodities.

One very important characteristic of a perfectly competitive model is that it satisfies the three marginal conditions for an optimal allocation of resources. This result is a very important one for Welfare Economics. It has led to the conclusion that under pure competition the allocation of resources will be optimal. Furthermore, since economic efficiency is achieved in a perfectly competitive model by equating a commodity's price with its marginal social cost of production, many economists have deduced that marginal cost pricing principles should be adopted by all industries including the crown-owned industries like electric utilities if a more efficient allocation of resources is to be realized.[12]

While the principles of marginal cost pricing seem straight-forward and the rewards attractive, there are a number of flies in the ointment.

(1). The application of marginal cost pricing principles is a problem for firms that experience declining average unit costs with increases in production. This

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[12] There is evidence of this as early as 1938. Refer to H. Hotelling, "The General Welfare in Relation to Problems of Taxation and of Railway and Utility Rates", Econometrica 6 (1938): 242-269.

point is illustrated by Baumol:

> "If average costs are falling, by standard rules of the average-marginal relationships..., marginal cost must be less than average cost. Therefore if the firm sells at a unit price equal to marginal cost, price must be less than average cost, i.e. unit costs will exceed unit returns so that the firm will lose money on each and every unit it sells. There is nothing the management of such a firm can do to make any profits, no matter how efficient its operations, if it sticks to a marginal cost price. Thus....marginal cost pricing must, at the very least, lead to serious administrative difficulties in decreasing cost firms".[13]

(2). If one or more of the marginal conditions for a welfare optimum (Pareto Maximum) cannot be satisfied, then in general, it is neither necessary nor desirable to satisfy the remaining conditions. The preceding proposition has become known as "The General Theory of Second Best" and was developed in the 50's by Lipsey and Lancaster.[14] The theory has some important implications for welfare economics. In fact, when one of the marginal conditions is left unfulfilled it may be advisable to avoid policies that attempt to meet the remaining marginal conditions.

> "It is not true that a situation in which more but not all of the optimum conditions are fulfilled is necessarily, or even likely to be, superior to a situation in which fewer are fulfilled".[15]

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[13] W. J. Baumol, p. 391.

[14] K. Lancaster and R. G. Lispey, "The General Theory of Second Best", Review of Economic Studies, Vol. 24 (1956-1957): 11-32.

[15] Ibid, p.12.

(3). While this paper is attempting to focus on the efficiency aspects of the marginal cost pricing question, it is important to be cognizant of the distributional consequences. Welfare criteria based on marginal analysis are useful but they do not guarantee the simultaneous achievement of both efficient and equitable or social resource allocations. These criteria have been proposed to assist in evaluating whether one policy option is preferred to another on efficiency grounds, but they are all devoid of an equity dimension.

The application of marginal cost pricing principles to electric utility rate design is a complex issue and while an exhaustive review of the theoretical arguments for and against equating prices to marginal costs is beyond the scope of this paper, some elementary perspective was necessary before discussing the uniqueness of the pricing problem in electric utilities.

2.2 Determinants of the Costs of Supplying Electricity

To assess the applicability of marginal cost pricing principles to electric utilities it is important to first assess and understand the nature of a utility's production costs.

There are three physical properties of electricity that have important cost implications: (1) the amount of electricity supplied, usually referred to as "electrical energy", and measured in kilowatt hours (kwh); (2) the rate of consumption at any instant, i.e. "electrical capacity", measured in kilowatts (kw); and (3) "electrical potential", which is measured in volts (v) and is usually described analogously as the pressure at which water is forced through a pipe.

Apart from these physical characteristics, the timing of electrical consumption has a particularly important influence on a utility's cost function. This occurs because the value of electrical output to consumers varies directly with the time pattern of the electricity consuming activity of all customers and also because electricity cannot be stored: expensive generating capability must therefore be installed to meet only peak load requirements.[16]

To demonstrate the variable demand patterns of electrical consumers, Figure 2 shows a typical daily load curve that was recorded on the Newfoundland Island grid system during February 1979. It is quite evident from the figure that demand fluctuates constantly throughout the hours of a day, with the largest energy requirements usually occurring at midday and suppertime. During the remainder of the day consumers require varying amounts of capacity and energy. The cost implications of fluctuating demands on electricity, a product that cannot be stored, are obvious. Electric utilities must construct adequate generating,

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[16] In addition to the time dimension of costs, a level of reserve capacity must be maintained on an electric system, and this too has an impact on a utility's production costs.

transformation and distribution capability to meet peak load requirements even though peaking capacity may be required for only a few hours during any given day. It is also important to note that capacity must be available to meet a seasonal peak as well as time of day or day of the week peak.[17] This is particularly relevant in Newfoundland as we experience a relatively high winter heating demand. The magnitude of the seasonal differences in demand are illustrated by comparing typical daily load curves for February and July, 1979 (refer to Figure 2).

Advocates of marginal cost or peak load pricing schemes argue that reductions in the growth of hourly, daily, or seasonal peak demands could be effected by alternative rate designs. These reductions could result in signficant dollar savings as there would be a diminished need to dedicate new peaking capacity, i.e. by shifting price-elastic peak loads to shoulder or off-peak hours. An electric utility could therefore improve its overall system load factor and reduce costs by operating base load and intermediate capacity, which typically have lower operating costs per kwh.

Electric utilities have some technological flexibility with respect to the type of plant they choose to produce electricity. This flexibility relates to a trade-

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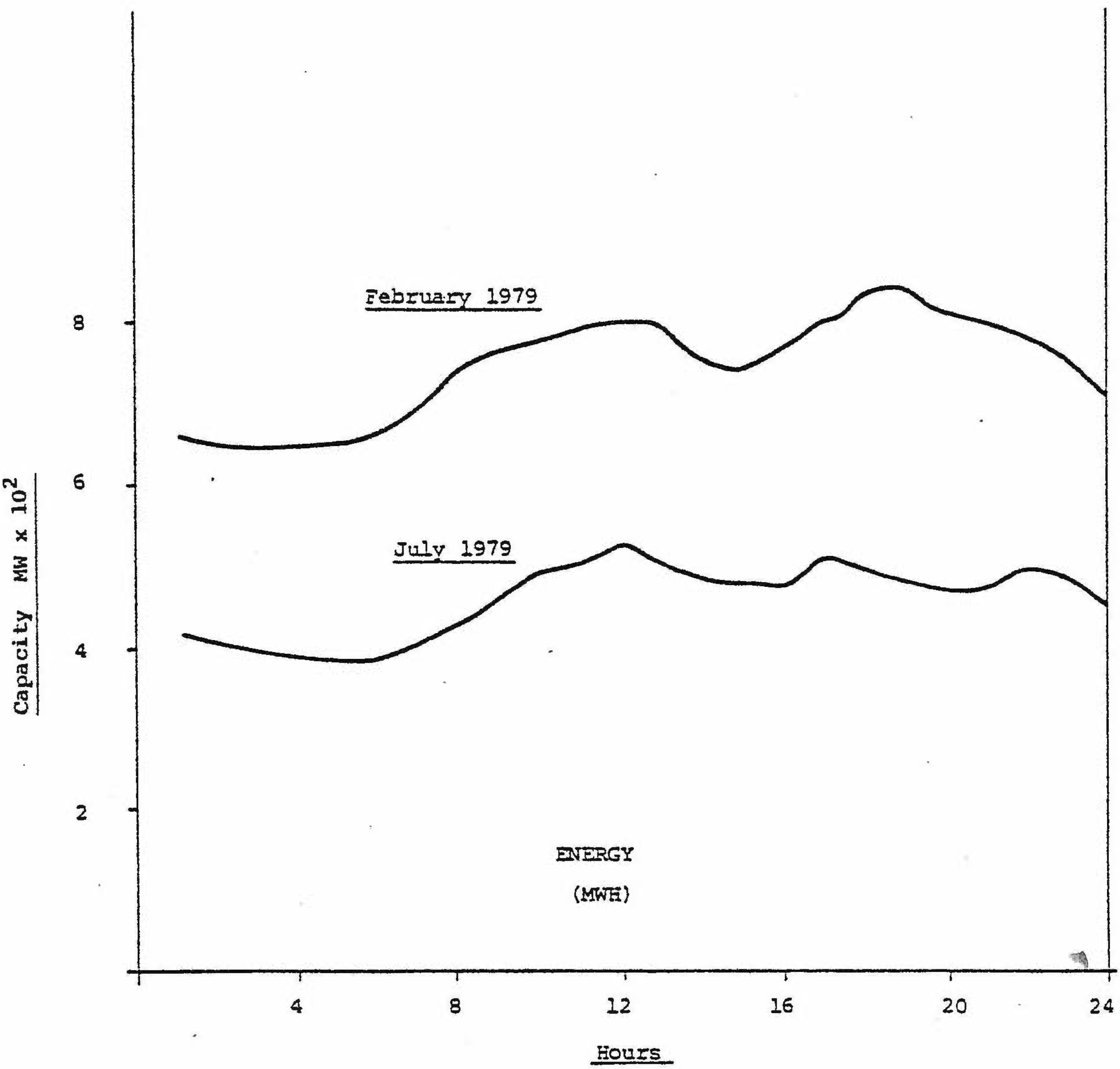
[17] Electrical consumption varies not only by seasons, or by the hours of a day, but also by the days of the week.

FIGURE 2

TYPICAL DAILY LOAD CURVES
ISLAND GRID SYSTEM
1979



Source: Newfoundland and Labrador Hydro, System Planning Department.

off between capital costs per kw of capacity and the operating costs per kwh.

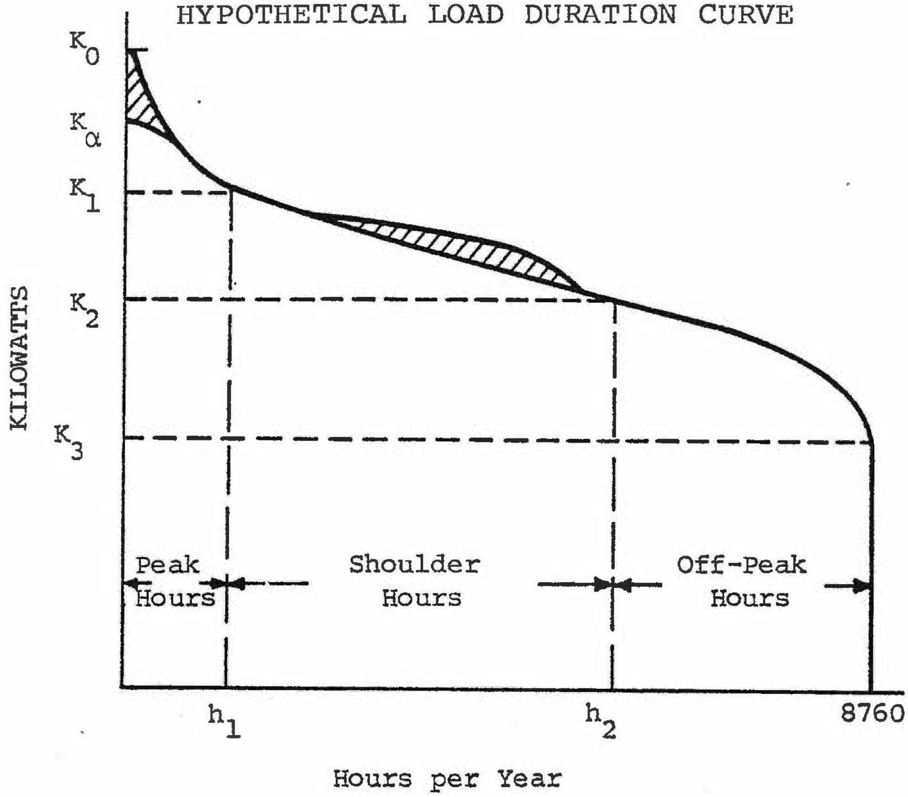
Three classifications are typically used to describe the various plant options: (1) baseload facilities usually have high capital costs per kw and very low operating costs per kwh, hydro and nuclear installations are good examples; (2) intermediate plants usually have lower capital costs but higher operating costs, oil and coal-fired plants are typical intermediate facilities; (3) peaking capacity, such as gas turbines, have much lower capital costs but the highest operating cost relative to both baseload and intermediate plant categories.

Because load fluctuates hourly, daily and seasonally, a utility can effectively plan to minimize the cost of supplying electricity by utilizing a combination of baseload, intermediate and peaking equipment. Figure 3 illustrates a hypothetical load duration curve which shows the total quantity of electricity that is demanded during every hour of the year. It is typically constructed by reviewing all daily load curves for any given year and is helpful when one wishes to plan an optimal plant mix.

It shows, for example that K_0 units of capacity are required for only a few hours in any given year, whereas K_3 kilowatts are demanded during every hour. Once the capital and operating costs of baseload, intermediate, and peaking capacity are known, a system planner can ascertain which load will be satisfied by a particular plant type.

FIGURE 3

HYPOTHETICAL LOAD DURATION CURVE



Source: B.M. Mitchell, W.G. Manning, J.P. Acton, Peak Load Pricing European Lessons for U.S. Energy Policy, Ballinger Publishing Co., Cambridge, Massachusetts, 1978, p 26-28.

In the example, capacity up to K_2 kilowatts will be demanded for h_2 or more hours per year, and is for illustration purposes, most efficiently supplied (in terms of both capital and operating costs) by baseload capacity. Similarly, a kilowatt demand ranging anywhere from h_1 hours to h_2 hours, i.e. between K_1 and K_2, is shown to be economically supplied by intermediate plants. Finally a kilowatt capacity between K_0 and K_1 will be demanded for less than h_1 hours per year and is assumed to be most efficiently supplied by peaking capacity.

In the simple model of Figure 3 a utility will seek to minimize short-run operating costs by engaging units with the lowest operating costs and successively adding more expensive and less efficient plants as demands increase.

While such a simple exposition of plant optimizing criterion is useful, the actual planning for and dispatching of facilities is usually much more complex. There can be technological impediments to using an oil-fired steam set to meet rapid fluctuations in load. In fact it is typical for many utilities to utilize hydro plants for peaking or intermediate capacity, simply because the turbines can be readily adjusted to meet load variations. To this extent technological or convenience constraints also have cost implications. Moreover, the actual and projected shape of a utility's load duration curve can encourage utilities to install hydro or intermediate facilities for peaking demands.

The proponents of marginal cost-based rates assert then, that rates should reflect the time dimension of costs. Reducing the peak load on an electrical system from K_0 to K_α in Figure 3 by shifting the load to a time where demands are lower, i.e. between h_2 and h_1 could result in lower costs. The shift is denoted by the shaded areas in Figure 3. The cost savings in the short-run will be equal to the difference in the running costs of peaking and intermediate facilities. In the long-run the savings will include the difference in fuel costs plus the capital cost savings effected by the reduced need for peaking capacity.[18]

In conclusion, it is important to remember that while several factors contribute to electric utility production costs the timing of electricity demands has been ignored in the setting of electricity rates.

2.3 Current Pricing Methods and Their Deficiencies

In Canada and the United States, regulatory agencies have historically been ratifying electricity rates that cover average costs as opposed to marginal costs, devoting little attention to rate schedules, which have characteristically had declining block features. However, with each new wave of oil price increases and gasoline shortages and with the recent realization that energy sources will be both expensive and hard to come by, many industry spokesmen, economists and government officials are arguing for a more rational and resource efficient approach to pricing electrical output - the consequences on electricity demand should be significant.

In Table 3 the residential electricity rate schedules of Newfoundland Light and Power Company Limited, are shown for the 1970-1979 period. It is easily seen that the price per kwh is cheaper in the end blocks, i.e. the more

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[18]You will note that up to this point the discussion has only referred to generation costs but the analysis is equally applicable to distribution or transmission costs.

TABLE 3

RESIDENTIAL ELECTRICITY RATE SCHEDULES[a]
NEWFOUNDLAND LIGHT AND POWER
1970-1979
$/KWH/MONTH

YEAR	FIRST BLOCK	SECOND BLOCK	THIRD BLOCK
1970	1.85 (15)[b]	.025 (15-200)	.012 (200 +)
1971	1.85 (15)	.025 (15-200)	.012 (200 +)
1972	1.85 (15)	.025 (15-200)	.012 (200 +)
1973	1.85 (15)	.025 (15-200)	.012 (200 +)
1974	1.85 (15)	.025 (15-200)	.012 (200 +)
1975	2.25 (15)	.025 (15-200)	.012 (200 +)
1976[c]	3.00 (15)	.030 (15-200)	.017 (200 +)
1977	3.75 (15)	.033 (15-300)	.020 (300 +)
1978	4.25 (15)	.036 (15-300)	.0215 (300 +)
1979[d]	.039 (380)	.0255 (380 +)	-

Source: Newfoundland Light and Power Company Limited.

(a) Fuel adjustment charges and taxes are not included. Discounts of $1.00/month for payment of accounts within 10 days of billing are not included. All figures apply to January 1, of each year.

(b) Block Range is denoted in Parentheses (in kwh/month.

(c) The COSA of 7% for January 1, 1976 is not included.

(d) as of 1979 a service charge of $4.70 was imposed on all residential customers.

consumers use, the lower their average bill per kwh. In short, there is no financial signal to the consumer that extra consumption, eg. at peak time or as systems reach capacity points, necessitating the construction of extra higher cost units, is now often resulting in higher cost thresholds. Indeed, the current pricing method no longer bears a rational relationship to the costs of production and utilities are beginning to question their pricing theories as they see their marginal production costs exceeding their average system costs.

Declining block rates found their rational during the period when utilities were constructing large hydro-electric facilities. The projects were lumpy and had excess capacity and in such situations the marginal cost of a kwh generated by an under-utilized hydro plant was often negligible. Rate structures were subsequently established to encourage increased consumption.

Historically, residential, commercial and industrial rate structures have played a promotional role in the sense that utilities have encouraged increased electricity consumption. As the economics of generating electricity have changed in recent years, however, there have been a growing number of criticisms about continuing past pricing schemes. They are summarized below:

1. Current rate designs tend to promote consumption at a time when marginal production costs are exceeding marginal revenues and also at a time when

additional energy sources are more expensive per unit of output.

2. Consumers receive no signal that production costs are higher during peak periods (hourly, daily or seasonal) and lower during off-peak periods.

3. Declining block rates, by giving quantity discounts to large consumers, effectively discriminate against small consumers. Both marginal costs and average costs are lower for large consumers. The logic that once applied to justify such preferential treatment no longer exists in many cases today, though each needs examining in its own right.

4. Increasing or decreasing demand charges do not differentiate between system peak and off-peak periods, and are, therefore, largely ineffective in covering generation costs at time of system peak.[19]

While the problems with current rate structures are obvious, there are some very practical issues that

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[19]For many commercial and industrial customers, the Hopkinson or two part rate is used. With this rate structure, there is a separate charge for maximum demand (kw) to accompany the declining block rate for energy. The kw charge relates to the highest rate at which a customer records kw demand during any 15-30 minute period in a month regardless of the hour that the maximum occurs. There are some instances where the rate applies to the maximum achieved over the whole year, rather than 1 month, and examples of rates where these maximum demand charges are subject to declining block features.

complicate the adoption of strict marginal cost pricing principles.

1. Marginal costs vary instantaneously over time and customers, and any attempt to reflect the exact level of these costs would undoubtedly result in very complex tariffs and expensive metering requirements.[20]

It is doubtful that the benefits of such a rate design would exceed the costs. While marginal cost pricing principles are the proper benchmark with which to design more efficient rates, the costs of exactly metering marginal cost levels may be prohibitive and utilities could be forced to adopt a second-best solution. It is generally believed, however, that pricing schedules which closely approximate marginal cost principles will effect a greater degree of economic efficiency than those prices that are currently in use.[21] On the general theory of second-best, Turvey suggests that a first-best solution must be pursued, and if major non-optimalities cannot be corrected then departures from marginal cost based prices can be tolerated.[22] In general, however, Turvey believes the inefficiences should be resolved first.

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[20] B. M. Mitchell, W. G. Manning, J. P. Acton, Peak Load Pricing European Lessons for U.S. Energy Policy, Ballinger Publishing, 1978, p. 3-49.

[21] Ibid, p. 3-49.

[22] R. Turvey, Optimal Pricing and Investment in Electricity Supply, George Allen and Irwin Ltd., 1968.

> "Consider as one possible case, a situation where there is no winter-summer differential in gas prices despite a large excess of winter marginal cost over summer marginal cost. If this non-optimality is entirely and permanently unalterable it consititutes a reason, ceterius paribus, for introducing a similar divergence in electrical pricing for sales in competing uses. But if there is a chance that it could be altered, those responsible for electricity pricing have to allow for the possibility that if they allow for the non-optimality they are likely to perpetuate it, while if they do not they may hasten its removal."[23]

According to Mitchell et.al. many European utilities have implemented tariffs based on the pattern of marginal costs rather than their absolute level, and have kept rate schedules simple to reduce administration costs. These departures from actual marginal costs represent a less than optimal pricing policy and loss of welfare but a more efficient and true pricing alternative to declining energy rates.

> "European utilities....in fact embrace the objective that rates should be simple and understandable. They limit themselves to no more than three different price levels over the 24 hour or weekly period, and to one or two periods at which each of those prices pertain. They attempt to make each period such that the marginal costs of generation are roughly equal during the hours it encompasses and to reflect major temporal patterns of consumer loads."[24]

2. There can be serious conflicts between pricing electricity according to efficiency criteria and achieving distributional objectives. Lifeline rates which are

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[23]Ibid, p 88.

[24]Mitchell, Manning, Acton, p 42.

intended to assist low income groups are a good example of departures from optimal pricing criterion. Another example would be value of service pricing, where utilities subscribe to the policy of charging what the market will bear.

As noted earlier, distributional or equity goals are not necessarily fostered by achieving "an economically efficient allocation of resources". Many economists will argue however, that legislative authorities should achieve equity and distributional goals through tax and transfer arrangements, leaving the market place relatively undisturbed.

3. Marginal cost pricing principles are a problem for utilities that experience declining average unit costs with increases in production. As a result, if prices were based on marginal production costs, a utility might not recover an adequate revenue to remain financially viable. A number of proposals have been formulated to deal with this problem. One alternative is to raise rates to cover average costs, but this has the disadvantage of being a significant departure from optimal pricing. A second-best solution is to design rates that introduce some degree of economic efficiency while satisfying the overall financial requirements of the utility.

Specifically, utilities could design rates initially on the basis of marginal costs and in the event of predictable deficits, raise prices in the inelastic periods by a greater percentage than those in the elastic periods of demand. Typically, peak prices would be more inelastic than off-peak prices. Alternatively, it has been suggested that higher rates be apportioned to those customers that are least sensitive to the increase. It has also been suggested that costs be allocated between segments of the rate structure since blocks of electricity schedules exhibit different price elasticities. The inelastic first block could be increased to satisfy the deficit and the last block designed to reflect marginal costs.

All of these proposals are second-best solutions and are based on the "inverse elasticity rule" or "Ramsey prices", whereby prices are increased proportionately higher in the inelastic service and less in the elastic areas of service. The revenue requirement is thereby satisfied with minimal distortions in the level of optimal consumption.

This inverse elasticity rule would be equally useful in an instance where reliance on marginal cost pricing produced a revenue surplus. Prices could be decreased the most in the least elastic areas of demand.

4. Current regulatory practice in the U. S. and Canada permits the calculation of total costs on the basis of historical costs with depreciation rates that reflect no adjustment for inflation. By setting prices equal to marginal costs a revenue surplus may be incurred in terms of historical costs, but in fact these marginal cost prices may not cover the current costs of replacing equip-

ment.[25]

2.4 Conclusions

There appear to be a number of compelling arguments against the rate structure designs that now characterize many North American utilities. Rate designs that have marginal cost pricing principles as their basis would seem to be a more efficient and rational pricing alternative. There are some caveats however, in the application of marginal cost-based rates and whether it is indeed desirable to implement marginal cost pricing principles will undoubtedly depend on rigorous benefit-cost studies in each particular jurisdiction.

In recent years the interest in rate reform has resulted in numerous studies. In the Canadian context for example, Ontario Hydro, Hydro Quebec, British Columbia Hydro, Nova Scotia Power Corporation and the Canadian Energy Research Institute have initiated or completed studies on rate reform.[26] To date, however, rate reform based on marginal cost pricing principles has not been implemented in Canada. A major hurdle that has foreclosed implementation

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[25] Mitchell, Manning, Acton, (1978), p 46.

[26] G. J. Protti, R. N. McRae, The Impact of Rate Structure Change on Electricity Demand: A Case Study of Calgary Power Limited, Canadian Energy Research Institute, Calgary, Alberta, 1980, p 11.

to date, notably in the Ontario Hydro case, is the absence of reliable information on the impact of rate reform.[27] In particular, the Ontario Energy Board, upon review of Ontario's electricity costing and pricing study, reported the following:

> "Lack of comprehensive data on customer response and impact meant that Ontario Hydro was unable to assist the Board in responding to the Minister's instruction to identify the significant effects of costing and pricing changes. Apparently no reliable studies relevant to Ontario are available of the public response to time differentiated pricing, and a quantitative net benefit analysis is not possible at present".[28]

Protti and McRae (1980) point out that the importance of "rate structure impact analysis is also evident in the conclusions to the first phase of the United States Electric Utility Rate Design Study (EURDS)".[29] In short, the study (EURDS) recommended that more reliable impact analysis be conducted on the impact of rate reform.

It is apparent from these developments that electricity demand analysis must advance to the stage where utilities can assess consumer response to rates that are

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[27]This point was brought out by Protti and McRae, (1980), p 1-3.

[28]Ontario Hydro Energy Board, Report to the Minister of Energy on Principles of Electricity Costing and Pricing for Ontario Hydro, (Toronto, Ontario Energy Board, December 20, 1979), H.R.5 p IX, quoted in G. J. Protti and R. N. McRae (1980) p 3.

[29]G. J. Protti and R. N. McRae (1980) p 3.

based on marginal cost pricing principles and thereby facilitate analyses of the respective costs and benefits of rate reform.[30] Without this information the benefits of designing a tariff based on marginal cost pricing cannot be adequately measured. It would be very inefficient indeed, to implement a rate where the costs of its metering, billing and accounting exceed the savings that arise from deferred capital programmes and/or lower operating costs. To achieve this result, but with some loss in economic efficiency, European practicioners of these marginal cost-based rates simplify electricity tariffs to reduce administration costs.[31]

It is recommended that all utilities carefully examine and assess the arguments for tariffs based on marginal cost pricing principles. Moreover, it is important that utilities develop suitable techniques to assess the impact of time differentiated rates upon consumers.[32] Existing electricity demand studies have estimated price,

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[30]For example, to avail of off-peak rates consumers may have to operate their laundry appliances during the evening. That may not be an acceptable adjustment to some consumers, in which case they would prefer to pay the higher electrical costs associated with operating their appliances during the peak hours.

[31]Mitchell, Manning, Acton, (1978), p 8-49.

[32]Time differentiated rates are based on the premise that marginal costs vary by hour, day or season.

income and cross-price elasticities on the premise that a kilowatt-hour is one commodity irrespective of the time in which it is consumed and the costs that are incurred in its production.

If electricity tariffs are formulated on the basis of marginal cost pricing principles, demand forecasting models must take explicit account of peak and off-peak elasticity measures to be truly effective strategic planning tools.

CHAPTER 3

THE THEORETICAL FRAMEWORK FOR AN ANALYSIS OF ELECTRICITY DEMAND

3.0 Introduction

Prior to an econometric consideration of electricity demand it is useful, if not necessary, to review the theoretical framework for such an analysis. The conclusions to this chapter highlight the ingredients necessary to an adequate analysis of electricity demand.

3.1 Problems of Applying the Theory of Consumer Demand to an Analysis of Electricity Demand

The theory of consumer demand dictates that a properly specified demand function includes income, the price of the commodity, and the price of other goods as explanatory variables. There are two reasons why the application of this traditional demand framework to a study of electricity demand is complicated.[33]

1. By itself electricity does not create satisfaction or utility - rather it is a factor or input utilized

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[33] These points were brought in a paper presented to the Canadian Electrical Association, March 13, 1979, by Frank Trimnell of Ontario Hydro, entitled Econometric Analysis of Residential, Commercial and Industrial Demands for Electricity - An Overview.

in the production of commodities that do yield utility. Heating, lighting and appliance operation are examples of those commodities. Baseboard heaters, lighting fixtures, refrigerators, and similar durable products are part of the capital stock that must be simultaneously consumed with electricity in order to provide the desired commodities.

We could say then that electricity has a derived demand, in the sense that it is demanded to operate capital stock, which in turn is demanded for the commodities they provide. Electricity then is clearly a factor of production.[34]

For some services like those provided by television and small appliances, electricity is an indispensible factor input, for without it the service would not exist. Alternatively, for other commodities like lighting, heating and refrigeration for example, alternate energy inputs can be utilized as substitutes for electricity to produce the same service. It is important, however, to remember that while substitution of one energy form for another is technically feasible in certain end-use sectors, the capital stock is purchased to use a specific energy form. Consequently, substituting oil for electricity is a long-run decision as it also entails substituting the capital equipment.

To properly use the traditional framework of consumer demand in forecasting electricity two steps are

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[34]Commodities are defined as the goods and services that provide satisfaction or utility.

necessary: (1) the quantity of services that produce satisfaction and that the capital stock produce, must be forecasted over time within the constrained utility maximization framework; and (2) because the price of services are important relative to incomes and the price of other services it would also be necessary to assume that consumers would be sensitive to the cost of production inputs so as to minimize the costs of producing those services.

Immediately, we have the practical problem of adequately measuring these services. For example, how many lumens of light, how many hours of colour T.V. or how many days of 0^{0} C frost-free refrigeration will be required? Indeed a suitable proxy for these commodities must be selected and that proxy must originate with the production relationship, i.e. the capital stock or the production inputs.

In the short-run, with a fixed capital stock, the quantity of electricity will depend upon the quantity of services demanded which in turn will be determined by the price of electricity. In the long-run, demand for electricity will depend on its price relative to the price of substitute factors of production.[35]

To accurately reflect electricity demand in the

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[35]While the price of electricity relative to the price of other desired commodities and income are important explanatory variables, there are others that will be discussed in Chapters 4 & 5.

long-run it is important to also examine the growth in the capital stock since it is this item which actually utilizes electrical inputs.

(2) The second complication in applying the traditional demand framework to an analysis of electricity demand relates to the declining block features of electricity tariffs. They imply that the supply curve is downward sloping, i.e. that average and marginal prices decline with increased consumption. Simultaneity and identification problems occur then as a consumer's demand level determines and is determined by price. As a result, O.L.S. estimates of price elasticities could be biased because of the difficulties in disentangling the supply and demand effects.

The problem is more clearly illustrated in the following example taken from Berndt.[36]

We let the demand for electricity (Q_d) be a function of income (Y), average price (AP), a vector of other explanatory variables (X_d), and a disturbance term (u).

(i) $Q_d = F\ (Y, AP, X_d, U)$

Next, Berndt assumes that the utility is regulated so that average price equals average cost. Average cost is said to include a normal rate of return on capital.

(ii) $AP = AC$

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[36] E. R. Berndt, "The Demand for Electricity: Comment and Further Results", University of British Columbia, Program in Natural Resource Economics, Resources Paper No. 28, August 1978, pp 10 - 12.

Since electricity is not readily stored quantity demanded (Q_d) is set equal to quantity supplied (Q_s).

(iii) $Q_d = Q_s$

If the disturbance term in (i) becomes positive the simultaneity problem is clearly evident. Quantity demanded increases, which by the relationship in (iii), implies an increase in quantity supplied. If the utility experiences increasing returns to scale the increase in quantity supplied results in lower average costs. Since average costs are equal to average price by (ii), Berndt concludes that variations in quantity demanded might spuriously be attributed to reductions in AP; when in fact they were effected by the disturbance term. The example demonstrates that an estimate of the price elasticity is likely to be biased upward.

The question of which price to include in the estimating equation is also at issue here - at least theoretically. Much of the econometric work on electricity demand has used ex post average price; i.e. total revenue divided by total kwh sales. The simultaneity problems associated with this price measure are now obvious, but notwithstanding, economic theory suggests that marginal prices are the more appropriate price variable to include in an estimating equation. This follows, as we assume consumers equate benefits and costs at the margin. Simultaneity problems, however also accompany the use of ex post marginal prices.

Estimation bias associated with the simultaneity problem can be minimized by using an appropriate simultaneous estimation procedure or by taking the price variable directly from the rate schedule, as tariffs are independent of demand in the short-run.

The problems associated with the electricity tariff and the empirical consequences of using both average and marginal prices are discussed in Chapter 4, within the context of a selected literature review.

3.2 Conclusion

The theory of consumer behaviour suggests that utility maximizing individuals consider prices and incomes to be important determinants of demand.

In applying this theoretical framework to an analysis of electricity demand it is important to remember that electricity has a derived demand, i.e. it is consumed jointly with durables (appliances) to produce services. Because capital stocks are important to the demand for electricity, it is crucial that (a) the price of these appliances be included in the demand equation and (b) the short and long-run demands be specified as this distinction will facilitate the identification of the separate effects that price and income changes are believed to have in the short and long-run.

Finally, it is important to recognize the estimation biases caused by declining block tariffs. The problems can be resolved by devising appropriate estimation procedures or by taking prices directly from the rate schedule.

CHAPTER 4

REVIEW OF SELECTED ECONOMETRIC STUDIES ON ELECTRICITY DEMAND

4.0 Introduction

Before attempting to construct unique electricity demand models for the residential and general service customer classifications, some of the prominent econometric papers on the subject have been reviewed. Eight studies, written between 1972 and 1979, were selected for review because, (a) they were useful in demonstrating various modelling techniques, and some of their associated problems, (b) they addressed important conceptual issues and (c) they provided a useful benchmark for comparison with my own results.

It would be quite a lengthy task to arrive at a distillation of eight studies if one were to review all the current papers on the subject, given the surprisingly large number in circulation. This problem was circumvented somewhat by referencing three major reviews, by Taylor, N.E.R.A. and Wilson, that provide a good synopsis of the literature completed up to 1976.[37] Five of the studies

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[37] L.D. Taylor, "The Demand for Electricity: A Survey", Bell Journal of Economics 1 (Spring 1975): 74-101

reported on below were directly referenced from these secondary sources.[38] The other three papers are of a later vintage and selected among primary references for inclusion in this review.[39]

4.1 Literature Review

This review attempts to bring out the salient features of each study, with comments directed in general, at the level of data aggregation, the type of functional form used, the explanatory variables included or omitted in the models, the way the electricity price variable was specified, and the short and long-run elasticity results.

A) Anderson (1972)[40]

Using cross-sectional regression analysis of 50 states for 1969, Anderson attempts to model the average

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N.E.R.A. "Considerations of the Price Elasticity of Demand for Electricity", Electric Utility Rate Design Study (January 1977), T.M. Wilson & Associates, "Elasticity of Demand", Electric Utility Rate Design Study (February 1977).

[38] The five studies include those by Anderson (1972), Anderson (1973), Mount Chapman and Tyrrell (1973), Houthakker, Verleger, and Sheehan (1973) and Halvorsen (1975).

[39] These three studies include those by Taylor (1975), Berndt (1978) and Berndt, May, Watkins (1980).

[40] K.P. Anderson, Residential Demand for Electricity, Econometric Estimates for California and the United States, (Santa Monica: California Rand Corporation, 1972) referenced in N.E.R.A. & Wilson of footnote 37.

kwh consumption for residential customers, and the percentage of all-electric homes. He included the following causal variables in his constant elasticity model:

1. Price of Electricity (measured as the incremental cost per kwh between 500 and 1000 kwh/month).

2. Price of Gas (measured as the average revenue per therm).

3. Income (measured as the average personal income per household).

4. Household size (measured as the number of persons per household).

5. Urbanization (measured as the proportion of the population living in non-metropolitan areas).

6. Temperature (two separate temperature variables measured as the average temperature for the months of January and July).

Anderson deflated all income and price data by regional cost-of-living indices.

His empirical work demonstrates that average residential consumption has an electricity price elasticity of -.91. The estimate for a gas cross-price elasticity was 0.13, having the proper sign but insignificant at the 95% confidence level. Income elasticity was significant and estimated at 1.13. The most peculiar result of Anderson's analysis was a coefficient of -.85 on the household size variable. The sign clearly indicates that as household size increases, average residential consumption decreases. A priori reasoning would lead one to expect a positively signed coefficient since fewer persons per household would probably induce a trend towards smaller dwelling units, and the corrollary of smaller dwelling units would seem to be reduced consumption. Anderson, on the other hand, suggested that as household size decreases, standards of living increase, and income growth and appliance ownership, (hence consumption) are positively related. It is noteworthy that the coefficients on the price of gas, household size, and temperature variables were all insignificant at the 95% confidence level.

For electric home saturation rates Anderson estimated own price elasticity at -4.59, indicating a high degree of sensitivity. The gas cross-price elasticity estimate was 1.17 and the income elasticity was 3.72.

Anderson's use of average total residential consumption, as the observational unit for his equation's dependent variable, creates interpretation problems. One difficulty emanates from the author's aggregation of both competitive and uncompetitive energy markets into the one model. As a consequence, the elasticities are a blend of both inter-fuel substitution elasticities in the very competitive end uses, (eg. the space heating and water heating markets), and short-run utilization elasticities in sectors with no practical substitutes (eg. for lighting and certain appliance end uses). A second interpretation problem comes from the use of state-wide data. The resulting elasticities will not reflect the diversity in the climatological and socio-economic characteristics of the individual utility jurisdictions, and consequently make the application of such elasticity values to particular service areas highly suspect.

The use of a double logarithmic equation specification is convenient because the coefficients of the estimated equation are in fact the elasticities. There is, however, no reason to believe that price or income elasticities will be constant, (as they are in double log equations), throughout a whole range of new prices or incomes. Indeed, economic theory suggests that at high prices substitutes could be more attractive and demand could be more price elastic.

Anderson's U.S. study provides elasticities that have been interpreted as long-run in nature. A distinction between short and long-term elasticities would have been useful. Dynamic model specifications, as seen in Houthakker, Verleger and Sheehan (1973), do permit a separate identification of both short and long-term effects.[41]

The price variable in Anderson's model is defined as the incremental cost per kwh of consumption between 500 and 1000 kwh per month. This is in fact an ex-post marginal price calculated from the F.P.C. publication Typical Electric

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[41] See Taylor, p 103 for a particularly critical view of those that interpret cross-sectional coefficients as necessarily being long run elasticities.

Bills, and in theory it would have been more appropriate to include the marginal price from the actual rate schedule. It is interesting, however, that the empirical results of Taylor (1977) indicate that parameter estimates using both the ex-post calculation of marginal prices and the marginal price from the actual schedule are quite similar.[42] The merit of using the marginal rate from the rate shcedule is considered in greater detail in the reviews of Taylor (1975), Berndt (1978) and Berndt et al. (1980).

B) Anderson (1973)[43]

In this study, Anderson separates the modelling of residential energy consumption into two components. He attempts (1) to predict the saturation of several appliances among competitive fuel types, and (2) model variations in total average residential consumption per household. The approach was designed to allow the separate identification of both "inter-fuel substitution elasticities" and "utilization elasticities"; the latter only reflecting variations in the intensity of appliance operation.

By subtracting the price elasticity derived in the inter-fuel substitution model from the estimate of price elasticity derived in his total average use model, Anderson

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[42]Berndt, p 13.

[43]K.P. Anderson, Residential Energy Use: An Econometric Analysis, (Santa Monica, California, Rand Corporation, 1973) reference in Taylor, N.E.R.A. & Wilson of footnote 37.

calculates an estimate for "utilization elasticities".

In addition to the causal variables in his 1972 study, Anderson included the following in his model of total average use:

1. Price of Bottled Gas
2. Price of Fuel Oil
3. Price of Coal
4. Proportion of Single Family Households

With the exception of electricity prices, all variable definitions were identical to those used in the 1972 study. The price of electricity, however, was defined as the typical electric bill for 1000 kwh per month. Data for the model was based on 1960 and 1970 observations for the 50 states.

Total residential own price elasticity was measured at -1.19, slightly greater than his estimate of -.91 in 1972. Like the 1972 analysis, all of the cross-price elasticity coefficients in the total average use model were insignificant.

The second model in Anderson's 1973 study began with a prediction of the relative differences in appliance saturation rates by fuel type.[44] These saturation ratios, eg. of electric space heating to gas space heating, were

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[44]Anderson studies the following appliances: space heating, cooking stoves, washing machines, clothes dryers, air conditioners, food freezers, dishwashers, and televisions. Refer Taylor (1975) p. 96.

estimated by including the prices of the competitive fuels and the prices of the competing appliances, as well as other explanatory variables in the estimating equations. In several of these appliance saturation equations Anderson found that both own price and gas cross-price elasticities were significant.

An indirect estimate of average own price and cross-price elasticities over each appliance was then created. This calculation was facilitated by Anderson's assumption that the average energy consumption per household, and the technical efficiency of each appliance were constant over the estimation period. Anderson then defined an average elasticity over all appliances as the weighted sum of the individual elasticities by type of appliance, with the contribution in energy consumption of each appliance to total household consumption as the weights.[45] Anderson's estimate of own price and cross-price inter-fuel substitution elasticities are reported in Table 4, for both electricity and gas energy forms.

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[45] N.E.R.A., "Consideration of the Price Elasticity of Demand for Electricity", Electric Utility Rate Design Study (January 1977) p B-18.

TABLE 4

ANDERSON'S INTER-FUEL SUBSTITUTION

ELASTICITY ESTIMATES

Energy Type	Price Variables	
	Electricity	Utility Gas
Electricity	-.84	.81
Utility Gas	.28	-1.73

Source: N.E.R.A., "Considerations of the Price Elasticity of Demand for Electricity", Electric Utility Rate Design Study (January 1977) p B-19.

The own price elasticities for both electricity and gas indicate a significant amount of price responsiveness. The high gas cross-price estimate of .81 in the electricity demand equation is intuitively appealing especially when it is compared to the electricity cross-price coefficient of .28. Clearly this is an expected result as there are more end uses for which electricity is a substitute.

By subtracting the own price inter-fuel substitution estimate of -.84 from the elasticities derived in his total average use equation, Anderson calculates own price utilization elasticities at -.35.

Anderson's study makes a very good attempt at separating inter-fuel substitution and utilization elasticities but his assumption of constant appliance utilization rates and constant efficiency rates bias the estimation results. This bias will occur because movements in electricity prices are likely to affect average appliance efficiency, and utilization rates. Anderson has, therefore, underestimated his indirect estimate of inter-fuel substitution elasticities and the proper utilization elasticity should be somewhat below -.35.

Since Anderson uses state wide average consumption as the unit of observation, problems arise when one attempts to interpret these coefficients for a particular service area.

A final comment relates to the use of a typical electric bill for 1000 kwh's per month as the electricity price variable. From the discussion in Chapter 3, it would appear to have been more appropriate to use the marginal price from the rate schedule rather than the electricity bill for a selected consumption level.

C) Mount, Chapman, and Tyrell (1973)[46]

This analysis is based on an autoregressive model using pooled cross-sectional data for 47 states between 1947 and 1970. The authors specify both constant and variable elasticity functional forms. The observation unit is total consumption by class and the following variables were included in the residential equation:

1. Population

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[46]T.D. Mount, L.D. Chapman, and T.J. Tyrell, <u>Electricity Demand in the United States: An Econometric Analysis</u> (Oak Ridge National Labratory, June 1973), referenced in Taylor, N.E.R.A. and Wilson of footnote 37.

2. Price of Electricity (measured as the average revenue per kwh)

3. Price of Gas (measured as the average revenue per therm)

4. Income per capita

5. Price of Appliances

6. 9 Regional Dummy Variables

7. Lagged Dependent Variables

8. Climate Variables

The climate and appliance price variables were not found to be statistically significant. The residential sector elasticities of Mount _et al._ are reported in Table 5. These estimates are based on their logarithmic model specification.[47]

TABLE 5

MOUNT _ET_. _AL_.

RESIDENTIAL ELASTICITIES

Type	Short-run	Long-run
Price of Electricity	-.14	-1.21
Price of Gas	.02	.21
Income	.03	.30

Source: N.E.R.A., "Considerations of the Price Elasticity of Demand for Electricity", _Electric Utility Rate Design Study_, (January 1977), p B-10.

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[47]The results from their variable elasticity model were not significantly different from those reported in Table 5.

Mount *et al*. also report elasticities for the commercial sector. They are illustrated in Table 6.

TABLE 6

MOUNT *ET AL*.

COMMERCIAL ELASTICITIES

Type	Short-run	Long-run
Price of Electricity	-.20	-1.60
Price of Gas	.01	.05
Income	.10	.80

Source: T.M. Wilson & Associates, "Elasticity of Demand", Electric Utility Rate Design Study (February 1977) p 113.

Mount *et al*. have severe aggregation problems because the observational unit is total residential consumption over 47 states. Consequently, the authors (1) obscure identification of both competitive and uncompetitive energy markets, and (2) camouflage the diversity in climatological, demographic and socio-economic characteristics between states. These problems jeopardize the reliability of the elasticities and their possible application in any one service area.

The commercial sector equations suffer from more serious aggregation biases. This class of customer is far more heterogeneous than the residential sector, as the only area of commonality amongst commercial class customers is the quantity of electricity they consume.

The use of an autoregressive model enabled Mount *et al*. to separately identify short and long-run elasticities. While this was a valuable contribution, the short run own price elasticity value for the residential sector appears to be unusually low, as do the income elasticities in both the short and long-run.

From Chapter 3, we recall that the use of ex post average revenue as a measure of the price of electiricity creates simultaneity problems. Moreover, the theory of consumer demand suggests that marginal prices are the more relevant price variable, as consumers equate benefits and costs at the margin.

D) Houthakker, Verleger, Sheehan (1973)[48]

Houthakker et al. also estimate an autoregressive model based on cross-sectional data from 48 states for the years 1961 to 1971. They specify a logarithmic flow-adjustment model where the change in consumption between the current time period and the next is a function of the desired level of consumption in the next time period less the consumption in the current period. Mathematically this is expressed in equation (1).

$$(1) \quad \ln q_t - \ln q_{t-1} = \lambda(\ln q_t^* - \ln q_{t-1})$$

where q_t = is the quantity of electricity consumed in time period t.

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[48] H.S. Houthakker, P.K. Verleger, and D.P. Sheehan, Dynamic Demand Analysis for Gasoline and Residential Electricity (Lexington, Mass: Data Resources Inc., 1973) Referenced in Taylor (1975) and Wilson (1977).

λ = adjustment coefficient where $0 < \lambda < 1$

q_t^* = is the desired quantity of electricity in time period t.

The presence of a lagged dependent variable enables the estimation of both short and long-run elasticities. The authors included the price of electricity, income and a lagged dependent variable in the equation. Electricity prices were measured alternatively as the incremental rate per kwh between typical electric bills for consumption levels of 250 and 500 kwh, 100 and 500 kwh, and 100 and 250 kwh. Based on the incremental price for consumption levels between 100 and 500 kwh's Houthakker et al. report short-run own price and income elasticities at -.09 and .14 respectively. The long run estimates for own price and income were -1.0 and 1.6.

Like other studies, this model has aggregation biases as there is no distinction between competitive and uncompetitive electricity markets. Moreover, the use of state-wide total residential consumption as the dependent variable reduces the value of the estimates to individual utility service areas.

The dynamic structure of the model is useful as it allows the explicit calculation of both short and long-run elasticities. Unfortunately, however, many important causal variables were omitted - demographic and economic. There is also no provision for climatological or cross-price effects. Omission of these variables could bias the results reported by Houthakker *et al*.

E) Halvorsen (1975)[49]

The author specifies both static and dynamic models using pooled cross-sectional data for 48 states between 1961 and 1969. The unit of observation is average residential consumption and the electricity price variable is measured alternatively as (a) the average revenue per kwh and (b) the typical bill for 250 kwh of consumption. Other causal variables in his demand equation include:

1. Income
2. Price of Gas
3. Climate
4. Size of Household
5. Size of Rural Population

The most innovative feature of Halvorsen's work is the estimation of a simultaneous equation system to remove the simultaneity problems associated with the inclusion of an average electricity price. While his demand model includes average electricity prices he simultaneously estimates an average price model that uses demand and cost factors as causal variables. Halvorsen estimates total

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[49] R. Halvorsen, "Residential Demand for Electric Energy", The Review of Economics and Statistics 1 (February 1975): 12 - 18 Referenced in N.E.R.A. (1977) and Wilson (1972)

own price elasticity to be in excess of -1.50, gas cross-price elasticity to be .13 and income elasticity as .70.

While this model also suffers from aggregation problems similar to those of other studies it makes a large contribution to the modelling literature by its use of a simultaneous equation estimation system. Recall from Chapter 3 that if the simultaneity problem is not accounted for, the elasticities on the other explanatory variables, eg. income, will be biased downwards, thereby resulting in an upward bias on the price coefficient.

F) Taylor (1975)[50]

This article provides a very comprehensive review of electricity demand modelling literature. It also contains an excellent discussion of the theoretical problems associated with multi-step block pricing and the importance of distinguishing between short and long-run effects. It is this discussion of multi-step pricing that merits some discussion.

Taylor asserts that most of the problems in the econometric literature emanate from the fact that consumers face a price schedule, with declining block rates, rather than a single valued price. Indeed, Taylor argues that the entire price schedule has implications for the equilibrium of consumers. Since Houthakker's work of 1962,

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[50] L.D. Taylor, "The Demand for Electricity: A Survey", Bell Journal of Economics 1 (Spring 1975): 74-101

many researchers have been of the opinion that the marginal price was the theoretically correct variable to include in an electricity demand equation. This conclusion comes from the proposition that a consumer equates benefits and costs at the margin. Taylor contended, however, that marginal prices only conveyed part of the pricing information and concluded that both a marginal and average price variable be included in the demand equation. He advised, however, that these two price variables not be calculated ex post but instead be derived directly from the rate schedule. Taylor asserts that prices taken directly from the rate schedule eliminate the simultaneity problems associated with the use of ex post prices because rate schedules are independent of demand in the short-term. Consequently, the marginal price should be defined as the end block rate whereas the average price variable should be calculated as the average price per kwh up to, but not including, the end block. Taylor further postulates that this average or "intramarginal" price variable really measures an income effect, as changes in the intramarginal rate affect disposable incomes. The marginal price variable then measures both income and price effects. Taylor concludes that failure to include the intramarginal price variable tends to bias the coefficient on the marginal price variable upwards, since it is quite likely the two are positively correlated.

G) Berndt (1978)[51]

This paper is a critique of Taylor's 1975 study and makes a substantial contribution to the issue of a proper specification of the electricity price variable. In summary, the article shows that the omission of the average "intramarginal" price variable has a negligible impact on an electricity demand equation. Berndt analytically demonstrates that the omission creates a bias of approximately .005 on the remaining marginal price variable - a negligible variance to say the least. The bias on other coefficients were also found to be very small.

On the subject of simultaneity the author illustrates how the use of ex post marginal price creates identification problems similar to those experienced with the use of an ex post average price. He suggests that appropriate simultaneous equation estimation procedures be devised to remedy the identification problem but acknowledges Taylor's point, that use of marginal prices from the actual rate schedule would be an acceptable alternative. Berndt also takes note of Taylor's findings that elasticities using marginal prices from the actual schedule were quite similar to those using ex post marginal prices based

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[51]E.R. Berndt, "The Demand for Electricity: Comment and Further Results", University of British Columbia, Program in Natural Resource Economics, Resources paper No. 28, August 1978.

on data from typical electric bills.[52]

H) Berndt, May, Watkins (1980)[53]

In this study of Alberta, the authors separately analyse the residential, commercial and industrial customer classes. Two modelling approaches were used:

1. electricity demand was estimated in isolation of overall energy demand, and

2. electricity requirements were treated as a component of overall energy demand.

The latter method is typically called a "share approach" and involves at first, the estimation of total energy demand and then the subsequent estimation of an electricity share equation. Berndt et al. employ both isolated and share methods in their analysis of the residential sector but use only the share approach for the commercial and industrial classes.

The most interesting feature of the paper is a comparison of elasticities, when alternative specifications of electricity prices were introduced. The following variables were included in their residential models:

1. Price of electricity (both marginal, intramarginal and ex post average)

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[52]Ibid, p 13.

[53]E.R. Berndt, G. May, and G.C. Watkins, "An Econometric Model of Alberta Electricity Demand", Data Metrics and the University of Calgary" to be published in Energy Policy Modelling, United States and Canadian Experiences, Martinus Nijhoff Publishing, Boston, 1980.

2. Price of competing fuels

3. Price of appliances

4. Real income per household

5. Weather fluctuations

6. Household densities

7. Female labour participation rates (to measure second income effect)

The authors create a very good marginal price data series. They matched historical rate schedules with bill frequency distributions and then calculated a weighted average marginal price by noting the number of bills ending in each block of a given rate structure.[54] They also created an intramarginal price variable series similar to that suggested by Taylor.[55]

The equations were estimated using both linear and logarithmic specifications of a flow-adjustment model.

Average consumption per household is the unit of observation and is estimated using annual data from 1961 to 1976.

The results of their linear regression specification are presented in equation (2) (t statistics in parantheses).[56]

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[54] Ibid., p 4

[55] Taylor, p 80

[56] Berndt _et al._, p 5

(2) $QELEC = 3.742 - 0.006^{*}\ MPELEC - 0.0002^{*}\ IMEXHH$
$(2.4)\ (-2.3)\qquad (-0.3)$
$+ .408^{*}\ YPDHH + 0.685^{*}\ QELEC\ (-1)$
$(1.4)\qquad (3.8)$

where:

QELEC = electricity consumption per household.

MPELEC = real marginal price of electricity.

IMEXHH = real intramarginal expenditure.

YPDHH = real personal disposable income per household.

QELEC (-1) = lagged dependent variable.

The short and long-run price and income elasticities derived from equation (2) are listed in Table 7.

TABLE 7

BERNDT *ET AL*.

RESIDENTIAL ELASTICITIES

Type	Short-run	Long-run
Price of Electricity (Marginal)	-.23	-.73
Income	.31	.98

Source: E.R. Berndt, G. May and G.C. Watkins, "An Econometric Model of Alberta Electricity Demand", Date Metrics and the University of Calgary.

The intramarginal price variable (IMEXHH) had the proper sign but was not statistically significant. Moreover, when the intramarginal variable was dropped from the equation the elasticities on marginal price and income were virtually identical. The results of including and excluding the IMEXHH variable are compared in Table 8. These empir-

TABLE 8

BERNDT ET. AL.

RESIDENTIAL ELASTICITIES

COMPARED WITH INTRAMARGINAL PRICE VARIABLE INCLUDED

Type	Short-run		Long-run	
	Included	Excluded	Included	Excluded
Price of Electricity	-.23	-.23	-.73	-.82
Income	.31	.26	.98	.94

Source: E.R. Berndt, G. May and G.C. Watkins, "An Econometric Model of Alberta Electricity Demand", Data Metrics and the University of Calgary.

ical results serve to support Berndt's conclusion, that the inclusion of an intramarginal price variable was not important.

The authors also reported that while natural gas prices had a positive sign, the coefficient was not statistically significant at the 95% confidence level. The lack of substitutability for natural gas is a good explanation for this result. Electricity is rarely used for space heating or water heating in Alberta - hence the insignificant cross-price elasticity. A number of other variables did not prove to be statistically significant. These included; (1) female participation rates, (2) ratio of apartments to total households, (3) real price of appliances, (4) nominal household income deflated by the price of electrical appliances, and (5) weather fluctuations.

Another interesting result from the study is that substitution of ex post average prices for marginal prices in equation 2 above, increased own price short-run elasticities only slightly and lowered them in the long-term. Refer to Table 9.

TABLE 9

BERNDT ET. AL.

RESIDENTIAL ELASTICITIES

COMPARED WITH

EX POST AVERAGE PRICES INCLUDED

Type	Short-run		Long-run	
	Marginal	Ex Post	Marginal	Ex Post
Price of Electricity	-.23	-.24	-.73	-.60
Income	.31	.37	.98	.95

Source: E.R. Berndt, G. May, and G.C. Watkins, "An Econometric Model of Alberta Electricity Demand", Data Metrics and the University of Calgary.

As in many studies, Berndt et. al. use total average residential use as the dependent variable. While aggregating over both competitive and non-competitive electricity markets was a problem in many of the other studies, there doesn't appear to be any such difficulty in this Alberta study. Essentially, Albertans only use electricity for end uses where few, if any, practical substitutes exist. In fact, rarely is electricity used for space heating or hot water heating. In 1976 for example natural gas captured approximately 80% of total residential energy demand in Alberta, whereas electricity had only about 12%.

Demographic and weather variables were not statistically significant. The absence of a significant coefficient for weather is, however, quite understandable given the relative absence of weather sensitive uses.

The study is a good test of Berndt's conclusion that "intramarginal" price variables are relatively unimportant and, contrary to Taylor (1975), do not by their omission bias the remaining elasticities to any measurable degree.

4.2 Summary

In general, the studies on residential electricity demand indicate that consumption is price elastic in the long-term. Despite their different methodologies, data, and problems, most studies report long-term price elasticity to be in the vicinity of -1.00. While only a few of the studies report short-run price elasticities, the results indicate that demand tends to be less sensitive to electricity price changes - an expected result given the assumption, that the stock of electricity consuming appliances is fixed in the short-term.

The results on long-run income elasticity vary substantially between .30 in Mount et. al. (1973) to 1.60 in Houthakker et. al. (1973).

There appeared to be little agreement on the statistical significance and size of cross-price elasticities, with estimates ranging from .13 to .81 in value.

Finally, many of the studies suffer from data and estimation problems that could very well affect the reliability of the resulting elasticity estimates. In summary, these problems are those of 1) excessive data aggregation, 2) the use of restrictive functional forms, 3) a failure to estimate both short and long-run elasticities, 4) specifying the appropriate price variable, and 5) omitting what would appear to be, important economic, demographic and climatological variables from their analyses.

CHAPTER 5

MODELLING RESIDENTIAL AND GENERAL SERVICE ELECTRICITY DEMAND: A CASE STUDY

5.0 Introduction

In Chapter 5 the methodology and results of an econometric analysis on electricity demand in Newfoundland are described. There has been some success in avoiding many of the methodological and conceptual problems that plagued the studies reviewed in Chapter 4, yet some weaknesses persist and are outlined herein. Indeed, the intent of this paper was not to resolve all the theoretical and empirical problems encountered in electricity demand analysis, but rather to; (1) attempt an empirical quantification of the determinants of demand, (2) compare the results with those of other studies, and (3) outline areas for improvement and continued research. Many of the problems encountered in the analysis originate with the data base, especially in the General Service Sector, which is a difficulty not easily rectified in the short-term. However, it has served to underscore the importance of a comprehensive data set for testing theoretically plausible models.

With respect to the problem of simultaneity, the electricity price variable in the residential sector is specified as the marginal or end block rate taken directly from the rate schedule. As mentioned in Chapters 3 and 4, the use of this price specification with O.L.S. minimizes simultaneity bias as rate structures are independent of demand in the short-term. Notwithstanding, much of the research on electricity demand, notably those reported in Chapter 4, indicate that the empirical results with ex post average and ex post marginal prices are very similar to those with prices from the actual rate schedule.

Throughout Chapter 5 the residential estimation results are compared to those of other researchers.[57] After allowance is made for varying methodologies and service area characteristics, there appears to be some degree of unanimity in the results.

5.1 Estimation Method and Data Series

The models were estimated using ordinary least squares regression analysis on annual time series data for the 1967 - 1979 period.

The energy consumption data pertains only to customers of Newfoundland Light and Power Company, one of the two distribution utilities on the Island portion of the Province. Historical data was available before 1977

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[57] Very little econometric work has been done on the general service sector, and since the work that is available, including that reported in Chapter 5, suffers from severe aggregation biases, no comparisons were attempted.

for the other utility, nevertheless the study is quite representative as Newfoundland Light and Power services approximately 98% of the total residential and general service load.

5.2 Modelling Framework (Residential)

Two separate models were developed for the residential sector in an attempt to separate the very competitive space heating market from other end uses that would appear to have, with the exception of hot water heating, radically different sensitivities to energy prices and incomes, etc. Consequently, one model estimates average kwh conumption for customers that use electricity for appliance operation, lighting and hot water heating. The second model estimates the average kwh consumption required for home heating demand. Since Newfoundland Light and Power collects energy consumption statistics on customers with and without electric space heating, known respectively as "all electric" and "regular domestic" customers, an estimate for average "space heating" demand was calculated by subtracting the average kwh consumption of "regular domestic" customers from that of the "all electric" customers. Average consumption for regular domestic, all electric, and space heating use is defined in equations (3), (4) and (5) respectively:

(3) $ARDOM_t = RDOM_t \;/\; RDCUS_t$

(4) $AAEDOM_t = \sum_{i=1}^{12} ADOM_i \;/\; ADCUS_i$

(5) $AAEHEAT_t = AAEDOM_t - ARDOM_t$

where:

$ARDOM_t$ = Average kwh conumsption for "regular domestic" customers in year t.

$RDOM_t$ = Total "regular domestic" consumption in year t.

$RDCUS_t$ = Total "regular domestic" customers in year t.

$AAEDOM_t$ = Average kwh consumption for all-electric customers in year t.[58]

$ADOM_i$ = Total "all electric" customers' consumption in month i.

$ADCUS_i$ = Total "all electric" customers in month i.

$AAEHEAT_t$ = Estimated average kwh consumption of all electric customers for "space heating" in year t.

As described earlier, the advantage of modelling both "space heating" and "regular domestic" uses is that it permits the separate identification of space heating and regular domestic consumption responses to changes in prices, incomes and other explanatory variables.

Notwithstanding the advantage of attempting to separately model regular domestic and space heating demands,

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[58] AAEDOM was defined as the sum of average monthly demands as opposed to a calculation of average yearly consumption using year end data. Because this customer class is relatively small with high average consumption characteristics the latter method could be misleading, as many new customers are connected to the grid in the later months of the year.

three caveats deserve attention.

1. Like space heating, hot water heating would appear to be a much more competitive end use market than the appliance and lighting markets. Indeed few practical energy substitutes exist on the Island to operate televisions, washing machines, toasters, dryers, refrigerators or lighting fixtures, etc. However, oil is a viable substitute in the hot water heating market as it is for space heating, so to some degree bias is introduced when appliance and lighting demands are jointly modelled with hot water heating demands. Currently, the average regular domestic customer uses approximately 2,950 kwh per annum for hot water heating - roughly 40% of total regular domestic average use in 1979. The degree of upward bias then will be measured by the extent that the price elasticities embody (a) different short run utilization responses and (b) the long-run inter-fuel substitution responses associated with the hot water heating market. The degree of upward bias was not empirically estimated in this analysis.

2. The estimate of space heating price elasticities will be biased to the extent that "all electric" customers use more energy for appliance operation, lighting and hot water heating, than do their "regular domestic" counterparts. While there is no hard evidence to suggest that all electric customers use more electricity for appliances and lighting, they do on average use more kwh for

hot water heating.[59] As a result, the estimate of space heating average use embodies the excess hot water heating consumption of the all electric home, which is roughly 3,529 kwh per customer. Consequently, the "space heating" equation monitors some hot water heating load in addition to space heating requirements. The inclusion of hot water heating load should not bias the space heating price elasticity estimates to any significant degree, as we would expect space heating and hot water heating responses to be roughly equal in the long term.[60]

3. There is evidence that approximately 13% of the "regular domestic" customers in Newfoundland use electric-

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[59]According to a recent appliance saturation survey conducted by Newfoundland and Labrador Hydro, approximately 69% of all households have electric hot water heaters. Moreover, about 34% of all households use electricity for space heating. It is generally assumed that all of the electric space heating households have electric water heaters. We calculate then, that approximately 24% of hot water heaters are owned by electric heat customers, since 69% x .34 = 24%. The remainder or 45% are owned by "regular domestic" customers. If we assume that a 40 gal. hot water appliance consumes an average about 6480 kwh/yr. then the average "regular domestic" customer consumes 2951 kwh/yr. for hot water heating since 6480 kwh x .4554 = 2951. Because the average all electric customer consumes 6480 kwh/yr. for hot water heating, the calculation of the average kwh required for space heating is approximately inflated by 3529 kwh on average.

[60]The similarity of the price responsiveness between the space heating and water heating markets was pointed out by Anderson (1973) pages 45-46. He reports saturation elasticities (with respect to the price of electricity) for space heaters and water heaters to be approximately -2.21 and -2.60 respectively.

ity, to some degree, for supplementary space heating.[61] Depending on the magnitude of this load, relative to average regular domestic use, the elasticity values will be biased to the extent that changes in electricity prices and oil prices affect supplementary electric heating differently than other regular domestic end uses. Because there is only a small percentage of "regular domestic" customers with supplementary electric space heating, the degree of bias is again suspected to be minimal.

5.3 Functional Form (Residential)

Both "regular domestic" and "space heating" demands were estimated using "Flow or Partial Adjustment Models".[62] Generically, the specification is also termed "autoregressive" as it is characterized by the inclusion of a lagged dependent variable, as a regressor in the equation. This is often a useful way of representing habitual consumption tendencies in a demand model.

The flow adjustment model specifically assumes that the desired, not the current, level of consumption is

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[61] Refer to Newfoundland and Labrador Hydro's 1980 Appliance Saturation Survey.

[62] This specification was also used by Houthakker, Verleger and Sheehan (1973) and by Berndt, May and Watkins (1980). For a discussion of partial adjustment models see R.S. Pindyck and D.L. Rubinfeld, Econometric Models and Economic Forecasts, McGraw Hill, 1976, page 215. Also refer to Peter Kennedy, A Guide to Econometrics, M.I.T. Press, Cambridge, Mass., 1979, pages 97-101, for a good discussion of autoregressive models.

determined by the independent variables. Moreover, it assumes that in any one time period, the actual level of consumption does not adjust to the desired level. A number of factors such as technical constraints, lack of knowledge or increased costs associated with rapid change, impede the attainment of the desired consumption level.

We assume, for example, that the quantity of electricity desired by consumers is given by Equation (6).

$$(6) \quad Y_t^{*'} = \alpha_0 + \alpha_1 X_t' + \alpha_2 U_t' + \alpha_3 Z_t'$$

where:

Y_t^* = is the desired level of electricity consumption in year t and statistically not observable.

X_t, U_t, Z_t = are causal or independent variables.

$\alpha_0, \alpha_1, \alpha_2, \alpha_3$ = are parmaters to be estimated

' = indicates the value is expressed in logarithms.

Equation (7) illustrates that the changes in consumption between the current time period and past period is some function of the desired level of consumption in the current period, less the level of consumption in the past period.

$$(7) \quad Y_t' - Y_{t-1}' = \gamma(Y_t^{*'} - Y_{t-1}')$$

where:

Y_t = the actual level of electricity consumption in year t.

Y_{t-1} = the actual level of electricity consumption in the previous year.

γ = an adjustment coefficient with a value that lies between 0 and 1. A small value for γ would indicate that only a small part of the gap between the actual and desired consumption levels would be closed in any one year. A value close to 1 would indicate almost immediate adjustment.

' = indicates the value is expressed in logarithms.

Solving for Y_t' and substituting, yields Equation (8) as follows:

$$(8) \quad Y_t' = \gamma\alpha_0 + \gamma\alpha_1 X_t' + \gamma\alpha_2 U_t' + \gamma\alpha_3 Z_t' + (1-\gamma)Y_{t-1}'.$$

All variables in Equation (8) are now observable. The coefficients in (8) are simplified by writing Equation (9) and then estimated using ordinary least squares.[63]

$$(9) \quad Y_t' = \beta_1 + \beta_2 X_t' + \beta_3 U_t' + \beta_4 Z_t' + \beta_5 Y_{t-1}'.$$

where:

$\beta_1 = \gamma\alpha_0$ $\quad\beta_3 = \gamma\alpha_2$

$\beta_2 = \gamma\alpha_1$ $\quad\beta_4 = \gamma\alpha_3$

$\beta_5 = 1 - \gamma$

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[63] The partial adjustment model assumes a simple disturbance term, U_t . Use of O.L.S. will yield biased but consistent parameters. It is not clear however, that alternative estimation methods are superior to O.L.S. in such a case. Refer to P. 307 in J. Johnston Econometric Methods, 2nd. Ed., New York, McGraw Hill Inc. 1972. Also refer to R.S. Pindyck and D.L. Rubinfeld Econometric Models and Economic Forecasts, New York, McGraw Hill, 1976.

"While it is possible to devise estimation procedures which remain consistent and adjusted to remove bias, such procedures are not very popular, because the variance of the adjusted unbiased estimator tends to be large relative to the variance of the biased ordinary least-squares estimator." P.217.

then:

$$\alpha_0 = \frac{\beta_1}{\gamma} = \frac{\beta_1}{1-\beta_5} \qquad \alpha_3 = \frac{\beta_4}{\gamma} = \frac{\beta_4}{1-\beta_5}$$

$$\alpha_1 = \frac{\beta_2}{\gamma} = \frac{\beta_2}{1-\beta_5} \qquad \gamma = 1 - \beta_5$$

$$\alpha_2 = \frac{\beta_3}{\gamma} \quad \frac{\beta_3}{1-\beta_5}$$

Therefore, to obtain least squares estimates of the parameters in Equation (8), we estimate Equation (9) and use the identities above to obtain estimates of γ, α_0, α_1, α_2 and α_3.

The most interesting feature of this type of model is its dynamic characteristics. It permits the identification of both short and long-run elasticities. The short-run elasticities are measured by the coefficients in Equation (9), i.e., β_2, β_3, and β_4 whereas the long-run elasticities are given by $\frac{\beta_2}{1-\beta_5}$, $\frac{\beta_3}{1-\beta_5}$, $\frac{\beta_4}{1-\beta_5}$.

5.4 Empirical Results (Residential)

A) Average Regular Domestic Consumption

The model for average regular domestic consumption is shown in Equation (10), (t- statistics in parentheses).

$$\text{(10)} \quad ARDOM'_t = -.7330' \underset{(-2.38)}{-.2358} MPE'_{t-1} + \underset{(2.48)}{.6526} PCPDI'_t$$

$$+ \underset{(2.57)}{.4498} ARDOM'_{t-1}$$

$$\bar{R}^2 = .981$$

$$D.W. = 1.88$$

where:

$ARDOM_t$ = Average regular domestic consumption (kwh/annum) in year t.

MPE_{t-1} = Price of electricity, lagged one year and defined as the marginal rate, or the end block rate. Includes fuel adjustment charges and sales tax. The rate is weighted by the number of months it was in effect, and deflated by the consumer price index for St. John's (1971 = 100).

$PCPDI_t$ = Per capita personal disposable income deflated by the consumer price index for St. John's (1971 = 100).

$ARDOM_{t-1}$ = Average regular domestic consumption (KWH/annum) lagged one year.

' = Indicates that the value is expressed in logarithms.

Lagged prices were included in recognition of the fact that some time typically elapses between movement in prices and a corresponding response in consumption.

A number of other variables were included as regressors but were eventually deleted because (1) they carried unexplainable signs, (2) the coefficients did not prove to be statistically significant, and (3) they did not improve the overall estimation properties of the model. These variables are listed below along with an explanation for their inclusion in the estimating equation, and a brief description of the estimating problems.

1. Price of Electricity Relative to Oil and the Price of Oil

These series were separately incorporated to test the possible sensitivity of hot water heating demand to changes in either relative energy prices or oil prices. There are really few other uses for which oil is a viable substitute. The coefficients were not statistically significant.

2. Price of Appliances Relative to the Consumer Price Index

Consumers seek to maximize satisfaction subject to a budget constraint. The price of appliances relative to other consumer goods was believed to be a causal variable. The sign on the coefficient was not in agreement with a priori expectations and unexplainable.

3. Persons per Household

Intuitively, one would expect that fewer persons per household would also mean smaller dwelling units and lower average electricity consumption. Specifically, fewer persons would not require the same quantity of hot water, appliance and lighting energy as do larger households. When this variable (denoted PPHOS) was included in the estimating equation, the t- statistics on both the price and household variables were significant at the 90% confidence level, whereas the coefficients for the income and lagged dependent variables were significant at 95%. (See equation (11), t- statistics in parentheses)

$$(11)\quad ARDOM'_t = -1.2480' \underset{(-1.60)}{-.1538} MPE'_{t-1} + \underset{(2.60)}{.5991} PCPDI'_t + \underset{(1.89)}{.6756} PPHOS'_t + \underset{(3.48)}{.6915} ARDOM'_{t-1}$$

$$\bar{R}^2 = .991 \qquad D.W. = 1.621$$

Irrespective of the higher $\bar{R}^2$ value, the persons per household variable was eventually dropped because it did not significantly improve the overall statistical properties of the model. However, the sign on the PPHOS variable agreed with a priori expectations. This result is at odds with that reported by Anderson (1972) (see Chapter 4).

4. Degree Days

The weather variable was defined as the average number of degree days below 18°C. It was weighted by the energy sales in each of four weather station areas and was included in the equation to capture the temperature sensitivity of supplementary electric heating. Approximately 13% of "regular domestic" customers have some degree of supplementary electric space heating. The statistical results, however, were inconclusive.

You will notice that Equation (10) yields short-run own-price and income elasticities of -.24 and .65 respectively. The corresponding long-run price and income elasticities are calculated at -.43 and 1.19. The coefficient on the lagged dependent variable in Equation (10) suggests an adjustment factor (γ) of .55. This indicates that consumers adjust their consumption rapidly - in fact, by just over half of the desired amount in the first year.

The estimate of own-price elasticity in Equation (10) indicates a relatively price-insensitive or inelastic market. One would interpret the elasticity value of -.24 as suggesting that a 10% increase in real electricity prices, last year, would cause approximately a 2.4% decline in average consumption this year, other things held constant. This result agrees with a priori expectations, as currently there appear to be few energy substitutes for this consumption category. The long-term price elasticity value of -.43 still indicates a degree of unresponsiveness in consumption trends in the long-term. The estimate of short-term income elasticity (.65) demonstrated a more sensitive consumption response to changes in income than was the case with prices, yet it is still classified as being income inelastic. In the long-term however, changes in income induce more than proportional changes in average consumption. This may be attributed to the fact that consumers respond to real income increases in the long-term by adding to their stock of energy-using appliances - hence the long-run income elasticity value of 1.19.

A comparison of the price and income elasticities derived from Equation (10) with those of Berndt et. al. (1980), points out some very interesting similarities and discrepancies. This comparison with Berndt et. al. is probably the most meaningful as the residential sector studied in that analysis compares favourably with the characteristics of the market studied in Equation (10), the exception being that some hot water heating demands are being modelled in Equation (10). Comparisons of the two studies are also useful since similar equation specifications and independent variables were used. Moreover, they are both recent time series studies of two Canadian provinces.

A summary of the elasticities reported in Equation (10) and Berndt et. al. are shown in Table 10.

TABLE 10

COMPARISON OF ELASTICITY RESULTS

Type	Equation (10) Short-run	Equation (10) Long-run	Berndt et. al. Short-run	Berndt et. al. Long-run
Price of Electricity	-.24	-.43	-.23	-.73
Income	.65	1.19	.31	.98

Source: E.R. Berndt, G. May and G.C. Watkins, An Econometric Model of Alberta Electricity Demand, Datametrics and the University of Calgary, 1980

The short-run own-price elasticities are virtually identical, whereas the long-run estimates show some disparity. Because Berndt et. al. estimate a slightly higher coefficient on the lagged dependent variable than shown in Equation (10), their estimate of the long-run own-price elasticity is slightly higher. On the other hand, Equation (10) ascribes much more demand responsiveness to the income variable than occurs in the specification of Berndt et. al. There appears to be a rational explanation for these higher short and long-run income elasticities. The average income level in Newfoundland is substantially lower than that of Alberta, as is the level of appliance ownership. (See Table 11) It seems reasonable to assume then, that Newfoundlanders are likely to have a higher propensity to spend new income on energy using appliances than Albertans, who are to some extent satiated with the appliances that Newfoundlanders have yet to purchase.

TABLE 11

COMPARISON OF INCOMES AND SELECTED APPLIANCE SATURATION LEVELS - NEWFOUNDLAND AND ALBERTA

1970, 1975, 1979

	1970		1975		1979	
	Nfld.	Alta.	Nfld.	Alta.	Nfld.	Alta.
Income [(a)]	1,744	2,534	2,389	3,690	....[(b)]	....[(b)]
% Color TV	4	15	31	59	62	80
% Dryers	17	42	34	46	46	68
% Washers	15	47	34	55	39	65
% Refrigerators	79	98	91	99	96	99
% Record Players	50	74	71	78	74	81

Source: Statistics Canada, Catalogue #13-207, Income Distribution by Size in Canada 1979, and Statistics Canada, Catalogue #64-202, Household Facilities and Equipment 1979.

(a) Income refers to per capita personal disposable incomes in 1971 $.

(b) Income figures were not available for 1979 although the estimates for 1978 were $2,432 and $3,965 for Newfoundland and Alberta respectively.

There are a number of other interesting comparisons with the analysis by Berndt et. al.

1. Berndt et.al. define income as being real average household income, whereas real per capita personal disposable income is used in Equation (10). However, when

real average household income was substituted for PCPDI in Equation (10), the elasticities did not change by any significant amount.[64]

2. In Equation (10), a double logarithmic functional form is used whereas Berndt <u>et. al.</u> use a linear specification. They did report, however, that a double logarithmic function was tested and while the long-term price elasticity was similar, the income coefficient was insignificant and of the wrong sign.

3. Berndt <u>et. al.</u> employ a much richer price series than that used in Equation (10). They develop an average marginal price that is weighted by the number of bills ending in the various blocks of the rate schedule. It is not known whether such a price series would significantly improve the results reported in Equation (10), and while the creation of such a price series was beyond the scope of this study, it is theoretically the more appropriate series.

4. Berndt <u>et. al.</u> also estimate short-run price elasticity at -.28 using a share equation methodology. This result corroborates the elasticities reported in Table 10.

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[64]While the regression statistics were marginally better with the average household income (AHOSI) specification, PCPDI was selected because that specification predicted the 1979 actual better than the AHOSI specification.

B) Average Space Heating Demand

The results of the empirical work on space heating demand are shown in Equation (12) below (t- statistics in parentheses).

$$(12) \quad AAEHEAT'_t = -.4752 \underset{(-6.16)}{-.6164} MPE'_{t+1} + \underset{(3.66)}{.6362} DDAYS'_t + \underset{(10.85)}{.5736} AAEHEAT'_{t-1}$$

$\bar{R}^2 = .923$

D.W. = 1.94

where:

$AAEHEAT_t$ = Average space heating consumption (kwh per annum) in year t.

MPE_{t+1} = Price of electricity, leading one year, and defined as the marginal rate or the end block rate. Includes fuel adjustment charges and sales tax. The rate is weighted by the number of months it was in effect and is deflated by the consumer price index for St. John's (1971 = 100).

$DDAYS_t$ = The number of degree days below 18°C in year t and weighted by the energy sales in each weather station area.

$AAEHEAT_{t-1}$ = Average "space heating" consumption (kwh per annum) lagged one year.

' = Indicates variables are expressed in logarithms.

The price term requires further elaboration at this point because it was specified as a leading variable, rather than either as a coincident or lagged term. Inclusion of a leading price series suggests that consumers adjust current demand levels in anticipation of prices in the next heating season. There is evidence that this theory is probable and realistic. In recent years consumers have come to expect electricity price increases, and for good reason.[65] Since 1973, for example, electricity prices have increased at approximately 15% per annum in current terms - about 5% per annum in real terms.

It is not difficult then to understand why a certain degree of inflationary psychology is firmly estabished. Moveover, this expectation phenomenon is occasionally reinforced when the public statements surrounding rate applications warn that the medium term will see continued price increases. Regulatory lags also lend themselves to the establishment of anticipatory behavior. From the time the initial announcements are made about the magnitude of a price increase, and the time when retail rates are in fact altered, many months may have elapsed.

It is also noteworthy that since the energy crisis of 1973, energy conservation programs have encouraged consumers to upgrade insulation, turn thermostats down at night, and perform small caulking and weather stripping improvements - all actions designed to conserve on space heating demands. It could very well be that the changes in electric space heating demand, attributable to moral suasion and incentive programs, such as the Canadian Home Insulation Program (CHIP), are being captured by the

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[65] An attitudinal question on Hydro's 1979 Appliance Saturation Survey indicates that consumers expect electricity costs to increase.

leading prices series.

The use of a leading price series in the estimating equation has a serious interpretation problem, however. By including the actual value of next years price in an equation that predicts this years consumption, we immediately assume that consumers correctly anticipated the magnitude of the price increase.

Inclusion of coincident and lagged price variables into Equation (12) did not prove to be worthwhile. Lagged prices were insignificant and while current prices were statistically significant depending on the other variables included in the equation, serial correlation was a serious problem.[66]

The weather variable (DDAYS) was included to account for the temperature sensitivity of space heating demand, and a lagged dependent variable was included to represent the relatively stable heating demand requirements of most dwellings. As noted earlier, the inclusion of a lagged dependent variable, captures habitual consumption tendencies and also permits the identification of both

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[66] The results of including MPE_t in the equation are noted below. Notice that the D.W. Statistic which is typically biased toward 2 in the presence of a lagged endogenous variable is still below acceptable levels. The $\bar{R}^2$ is also lower than the specification with the leading price series.

$$AAEHEAT' = .4637' - .7771' \underset{(-4.62)}{MPE'_t} + .6376 \underset{(2.91)}{DDAYS'_t} + .3544 \underset{(3.88)}{AAEHEAT'_{t-1}}$$

$$\bar{R}^2 = .8657$$

$$D.W. = 1.4034$$

short and long-run elasticities.

As with the regular domestic equation, a number of other variables were included as regressors but were eventually deleted from Equation (12) for various reasons. These variables are listed below and brief explanations for their inclusion and eventual removal are also given.

1. Income

It seemed reasonable to assume that since income affects household size, income and average space heating demands were positively correlated. The empirical results did not verify either the expected sign of the relationship or the statistical importance of this variable. The coefficient was not significant, even at the 70% confidence level. It might be that higher income households have a greater ability to initiate energy saving repairs and consequently there is ambiguity about the sign and importance of this income regressor. Alternatively, the income variable and the lagged dependent variable tend to be highly correlated themselves, and it appears that income falls out as a result.

2. Persons per Household

Once again it was reasoned that household size was positively related to persons per household and consequently as the number of persons per household decreased, heating demands similarly would be expected to decrease. The PPHOS variable was statistically significant at the 80% confidence level but was dropped from the equation as the overall statistical properties of the estimating equation were enhanced with its exclusion.

3. Percentage of Single, Detached Dwellings

Apartments, row and multiple dwelling units were assumed to require less electricity for space heating than single detached dwelling units. A variable defined as the percentage of single detached dwellings was subsequently included but was statistically significant only at the 80% confidence level.

4. Price of Oil

Since the space heating market is susceptible to inter-fuel substitution, the price of oil was included to estimate a cross-price elasticity. The coefficient was significant at the 80% confidence level. A curious and unexplainable result, however, was the fact that the sign of the coefficient was negative indicating an inverse relationship between electricity consumption and the price of oil.[67]

5. Wood Heating Dummy Variable

In the past three years there has been a tremendous revival in wood burning for supplementary heating. In fact, Newfoundland and Labrador Hydro's 1980 Appliance

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[67]It is interesting to note that a similar finding was reported by Ontario Hydro. Refer to the Report of the Royal Commission on Electric Power Planning, Vol. 3, Factors Affecting the Demand for Electricity in Ontario, February 1980, published by the Royal Commission on Electric Power Planning, p. 27.

Saturation Survey, reports that currently approximately 22% of all households have wood burners. Consequently, a dummy variable was included in the equation and set = 1 during the period 1977-1979 to capture the wood burning phenomenon. The negative sign of the coefficient agreed with a priori expectations but the t-statistic was only significant at the 80% level.

Equation (12) suggests that own-price elasticity is approximately -.62 in the short run and -1.45 in the long term. The short-run estimate suggests that consumers would reduce their average electricity demand by 6.2% when faced with a 10% increase in price. In the long-term, an impending price increase of 10% would cause about a 15% decline in consumption. These elasticities indicate that "space heating" demand is quite a bit more price responsive than "regular domestic" end uses, which is in agreement with a priori expectations.

The coefficient on the weather variable, DDAYS, indicates that a 10% increase in the number of degree days below 18°C will cause a corresponding 6.5% increase in average consumption.

It is difficult to compare the results from the space heating equation to any of the elasticities reviewed in Chapter 4, because many of these studies used total average residential consumption as their unit of observation. However, a suggestion by N.E.R.A. was useful for comparing the results achieved in both Equations (10) and

(12) with the aggregate results of the studies reviewed in Chapter 4. In particular, N.E.R.A. suggest that:

> "......for usual specifications of the residential demand for electrical energy, the elasticity estimate for each variable explaining total residential consumption should be equal to a weighted average of the elasticities estimated in explaining each of the two components of total residential consumption......where the weights are the relative proportions of each of these two components in total residential consumption".[68]

In Newfoundland Light and Power's service area, approximately 57% of total residential load is made of regular domestic use, and the balance (43%) is attributable to space heating demand. Since the short-run own-price elasticities for regular domestic and space heating demands are -.23 and -.62 respectively, an estimate of the short-run own-price elasticity for total residential average use is -.40.

Similarly, since the long-run own-price elasticities for regular domestic and space heating demands are -.43 and -1.45 respectively, the long-run own-price elasticity for total residential average use is -0.87.

Identical calculations can be done for income, despite the fact that income was not a significant causal variable in the space heating equation.

In Table 12, the results of the aggregative studies reviewed in Chapter 4, are summarized. Also illustrated in Table 12 are the estimates of total residential

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[68]N.E.R.A., Appendix C, pp. C-4, C-5.

average use elasticities from N.E.R.A. (1978) and from this research using the N.E.R.A. methodology outlined above.

TABLE 12

COMPARISON OF SELECTED PRICE AND INCOME ELASTICITY RESULTS FOR TOTAL RESIDENTIAL LOAD

	Electricity Prices		Income	
	Short-run	Long-run	Short-run	Long-run
Anderson (1972)	N/A	-.91	N/A	1.13
Anderson (1973)	-.35	-1.19	N/A	.80
Mount *et al*. (1973)	-.14	-1.21	.03	.30
Houthakker *et al*. (1973)	-.09	-1.00	.14	1.60
Halvorsen (1975)	N/A	-1.50	N/A	.70
N.E.R.A. (1978)	N/A	-1.00	N/A	.60
Coleman (1980)	-.40	-.87	.37	.68

Sources: L.D. Taylor, "The Demand for Electricity: A survey", *Bell Jounal of Economics*, 1 (spring 1975), pp 74-110; N.E.R.A. "Considerations of Price Elasticity of Demand for Electricity", *Electric Utility Rate Design Study*, (January 1977), Appendix C; T.M. Wilson and Associates, "Elasticity of Demand", *Electric Utility Rate Design Study*, (January, February 1977), pp. 93-125.

Despite the fact that the results of Table 12 were generated by studies using different methodologies, on service areas with different economic and demographic charteristics, there appears to be some degree of unanimity about the magnitude of the long-run price and income elasticities. With the exception of Anderson's (1973) study there is less agreement on the short-run own-price elasticity estimates.

5.5 Modelling Framework (General Service)

The General Service Sector contains a variety of customer types. For example: churches, schools, apartment complexes, office buildings, grocery stores, and light industrial customers would all be included in this customer classification. It is this customer heterogeneity that makes modelling difficult. The problem is one of aggregating customers or end uses that have different degrees of sensitivity to electricity prices, oil prices, and incomes, etc.

For the purpose of this paper, three sub-classes of the General Service Sector were separately modelled. Newfoundland Light and Power define these sub-classes by specific consumption levels. In particular, the Small General Service classification includes customers that have consumption ranging between 0 - 100 kw. The Large General Service classification includes customers with consumption in excess of 100 kw and the All-Electric General Service classification distinguishes customers that use electricity for space heating, amongst other end uses.

While this breakdown, 1) separates electric space heating customers, and 2) separates the very large commercial and the light industrial loads from the smaller general service customers, the aggregation problems are still awesome. To avoid the problem of having to forecast different customer types, the models were developed for total load, as opposed to average use.

5.6 Functional Form (General Service)

As in the residential sector, double logarithmic flow adjustment models were used for each of the General Service Customer classes to facilitate identification of both short and long-run price effects.

5.7 Empirical Results (General Service)

A) Small General Service (0 - 100 KW)

The econometric results in this sector were the most statistically significant and are shown in Equation (13) (t- statistics in parentheses).[69]

$$\text{(13)}\quad SGSS'_t = -5.2109'_t \underset{(-4.37)}{-0.1949} APE'_t + \underset{(3.52)}{2.2460} POP'_t + \underset{(3.20)}{.4126} SGSS'_{t-1} + \underset{(2.76)}{.1596} DDAYS'_t$$

$$\bar{R}^2 = .998$$

$$D.W. = 2.54$$

where:

$SGSS_t$ = Small General Service Sales (GWH per annum) in year t.

APE_t = Average Price of Electricity in year t, defined as the total sales for the Small General Service Sector divided by the Small General Service load. Deflated by the consumer price index for St. John's (1971=100).

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[69] While the results are significant, it is acknowledged that the high degree of aggregation in these commercial classes possibly inhibits the specification of more theoretically plausible models. Nevertheless, the problem is one of data classification and an attempt has been made to include broad causal variables that accommodate these aggregative classes of customers.

POP_t = Population on the Island in year t.

$SGSS_{t-1}$ = Small General Service Sales (GWH per annum) lagged 1 year.

$DDAYS_t$ = Number of degree days below $18^{\circ}C$ weighted by the energy sales in each weather station area (year t).

' = Indicates variables are expressed in logarithms.

The estimate of price elasticity indicates general insensitivity whereas the population and income elasticities indicate quite a bit more responsiveness. An ex post average price variable was used as a regressor in place of a marginal price variable, because the commercial sector rates typically involve KW and KWH charges. As a result, the average price variable was a more readily accessible series.

B) Large General Service (> 100 KW)

The model of the Large General Service Sector is described in Equation (14) below (t- statistics in parentheses).

$$(14) \quad LGSS'_t = -1.6295' + \underset{(4.14)}{1.0546}\ GDP'_t + \underset{(2.38)}{.2812}\ LGSS'_{t-1} + \underset{(3.19)}{.0542}\ D1972 + \underset{(5.33)}{.1164}\ D1977$$

$$\bar{R}^2 = .9923$$

$$D.W. = 2.21$$

where:

$LGSS_t$ = Large General Service Sales (GWH per annum) in year t.

GDP_t = Real Provincial Gross Domestic Product in year t (1971 \$).

$LGSS_{t-1}$ = Large General Service Sales (GWH per annum) lagged one year.

D1972 = A dummy variable, set equal for 1 from 1972-1979. This was included to account for the large transfer of customers from the Power Distribution District to Newfoundland Light and Power in 1972.

D1977 = A dummy variable set equal to 1 from 1977-1979. This was included to account for the large transfer of customers from Bowater Power Company to Newfoundland Light and Power Company in 1977.

' = Indicates variables are expressed in logarithms.

Ex post average prices were not a significant causal variable in the regression work on this sector - significant only at the 60% level. The addition of the two dummy variables significantly improved the modelling abilities of the equation. Oil prices were also an insignificant variable.

C) All Electric General Service

As in the case of the Large General Service Sector, the model for this rate class depends on real provincial gross domestic product, a lagged sales variable and a dummy variable for its explanatory power. Once again, electricity prices were not significant in the equation nor were degree days which was surprising, given the fact that this is an electric space heating sector. See Equation (15) (t statistics in parentheses).

$$(15) \quad AEGS'_t = -4.1441' + \underset{(5.0)}{1.839}\ GDP'_t + \underset{(3.83)}{.3245}\ AEGS'_{t-1} + \underset{(2.97)}{.0622}\ D1972$$

$\bar{R}^2 = .9876$

D.W. = 2.42

where:

$AEGS_t$ = All Electric General Service Sales (GWH per annum) in year t.

GDP_t = Real Provincial Gross Domestic Product in year t (1971 $).

$AEGS_{t-1}$ = All Electric General Service Sales (GWH per annum) lagged one year.

D1972 = A dummy variable set equal to 1 from 1972-1979. This was included to account for the transfer of customers from the Power Distribution District to Newfoundland Light and Power Company in 1972.

' = Indicates variables are expressed in logarithms.

5.8 Conclusions

The results of the "regular domestic" model were encouraging and the magnitude of the short and long-run elasticities in agreement with a priori expectations. Average annual kwh demand is estimated to be price inelastic in both the short and long-run, as the elasticity estimates were -.24 and -.43 respectively. The magnitude of these results are testimony to the earlier assertion that the regular domestic market is relatively unresponsive to price changes. This is likely attributable to the fact that the market is uncompetitive in the absence of viable energy substitutes and also to the fact that most services for which electricity is a factor of production, are treated as necessities rather than luxuries. The relatively higher long-term price elasticity is intuitively pleasing as in the short-run it is assumed that only utilization rates are free to vary whereas in the long-term the capital stock can be adjusted. The income elasticities for both the short-run (.65) and long-run (1.19) are also quite plausible. These estimates suggest that increments to income, ceterius paribus, induce inelastic responses in the short-run and elastic demand responses in the long-term. Since electricity is combined with appliances to produce services, increments in income induce purchases of electricity using appliances and hence induce changes in electricity demand. Once again the distinction between short and long-run responses to income changes is appealing as we assume the capital stock i.e. appliances are only adjusted in the long-term and consequently demand should react more over the long-term than over the time period where, by definition, only utilization rates are free to vary.

Like many of the other research studies, however, the appliance price and demographic variables were not statistically significant. A significant coefficient for oil prices was not expected as approximately 60% of the average "regular domestic" consumption, in 1979 for example, was on relatively non-competitive end uses.

The model on "space heating" demand reports an own-price elasticity of -.62 in the short-run and -1.45 in the long-term. These results indicate that the space heating market is considerably more price responsive than the market described by the "regular domestic" model.

A leading price series (MPE_{t+1}) was included in the model to test the hypothesis that consumers adjust demand in the current period in anticipation of prices in the next heating season.

Income and demographic variables were not found to be statistically significant causal variables, and the coefficient on the oil price variable had a peculiar and unexplainable negative sign. As a result none of these variables were included in the final model.

The model does report that weather has a significant impact on electricity demand, an expected result given the temperature sensitivity of the space heating market.

The models describing the General Service classifications suffer from severe aggregation problems. This criticism is especially relevant for the Large (>100 KW) and the All-Electric General Service Sectors.

The Small General Service Sector model has very good statistical results, and reports an own-price elasticity of -.16 for the short-term and -.33 for the long-term indicating, in general, a price insensitive market. A weather variable was also found to be a significant factor influencing demand.

The Large General Service and All-Electric General Service models depend on Real Gross Domestic Product, lagged dependent variables, and dummy variables (included to account for customer transfers) to drive the equations.

CHAPTER 6

SUMMARY AND CONCLUSIONS

The 1970's have been characterized by increases in the real price of energy, unprecedented inflationary problems, and changes in the underlying demographic profile of many jurisdictions. These events coupled with the fact that much of our energy resource base is finite, and with the increased concern for the social and environmental consequences of expanding utility systems, are dictating that electrical energy forecasting models be improved. More importantly however, it is crucial that these models be able to explicitly account for changes in a range of economic and energy policy factors, if they are to be considered rational planning tools.

The issue of rate reform, based on the principles of marginal cost pricing, is an argument put forth to engender economic efficiency in terms of the proper allocation of scarce resources. It is an emerging issue that forecasters must contend with because of the implications that altered levels and patterns of electricity demand will likely have on systems expansion plans and hence costs. Moreover, demand studies, that test the sensitivity of consumer response to a change in rate design, are required immediately if the benefits and costs of rate reform are to be logically assessed.

A properly specified demand model typically includes prices (own and substitutes) and incomes as explanatory variables. When developing demand models for electrical energy, however, it is important to appreciate that electricity has a derived demand, i.e. it is consumed jointly with durables to produce services. Moreover, models should be capable of isolating both short-run and long-run effects, as changes in prices and incomes for example, are believed to have different impacts on demand over time. This occurs, as we assume capital stocks are fixed in the short-term whereas they are free to vary in the long-term.

Another difficulty with constructing electric energy demand models, is the specification of the price variable. The problem stems from the fact that electricity is sold on a declining block basis so that the more kilowatt-hours one consumes, the lower is the average unit price. Using a price variable then, (average or marginal) which is defined as ex post is worrisome as it not only impacts on demand but it is determined by the level of demand. One way to resolve the problem is to solve the demand and supply sides simultaneously. Alternatively, one can circumvent the problem in the short-run by using the marginal end block rate directly from the rate schedule. The bias of simultaneity is removed as rate schedules are typically only revised after lengthly regulatory procedures. There is, no doubt, more work required on this potential area of estimation bias.

It is evident from many of the existing studies on electricity demand that residential consumption is price and income elastic in the long-term. Specifically, most studies estimate price elasticity in the area of -1.00 and income elasticity between .68 and 1.60. In the short-term, demand responsiveness was estimated to be significantly lower; a plausible result given the assumption that capital stocks are fixed in the short-term. Many of the electricity demand studies completed to date suffer from some of the following estimation problems: 1) excessive data aggregation, 2) the use of restrictive functional forms, 3) a failure to estimate both short and long-run eslaticities; 4) specifying an inappropriate price variable and, 5) omitting what would theoretically appear to be important causal variables. While each of these problems introduces a different degree of bias in the estimation results, some are unavoidable given data limitations and research constraints. Indeed, some of these estimation problems still exist in the analysis of electricity demand in Newfoundland. Nevertheless, the empirical results of the analysis on electricity demand in Newfoundland were useful for a number of reasons:

1) There was a conscious attempt to avoid estimation biases due to aggregation. For example, residential

electricity demands were separated into "competitive" (space heating) and "non-competitive", (regular domestic) end uses, which facilitated the identification of distinctive price and income elasticities for each category.

2) Partial adjustment model specifications permitted the identification of both short and long-run elasticities.

3) The price variable was specified as the marginal or end block rate, taken directly from the rate schedule. This avoided the simultaneity problems, at least in a theoretical sense, caused by using ex post average or ex post marginal prices.

Undoubtedly, improvements to the empirical work of Chapter 5 can be made in a number of areas.

1) Removing the hot water heating demands from both the regular domestic and space heating categories.

2) Creating a marginal price series that is weighted by the number of bills ending in each block of the rate schedule.

3) Create a more disaggregate commercial sector data base. It would be useful to separate commercial customers by homogeneous customer groups or by homogeneous end uses. Classifying customers according to S.I.C. codes would be a logical starting point.

The empirical analysis of residential electricity demand in Newfoundland indicates that for "regular domestic" end uses, eg. appliance, lighting and hot water heating loads, the short and long-run price elasticity estimates are -.24 and -.43 respectively. The income elasticity results were .65 and 1.19 for the short and long-term respectively.

The "space heating" equation which models space heating and some hot water heating demands, estimates an own-price elasticity of -.62 in the short-run and -1.45 in the long-term. No income coefficient was estimated for this sector.

These elasticity results were found to be quite comparable with those of other researchers.

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