Title
INVESTMENT PLANNING IN THE ENERGY SECTOR

Author
Kahn, Edward

Publication Date
1976-03-01

LBL-4474 c.1
UC-95c
TID-4500-R63

INVESTMENT PLANNING IN THE ENERGY SECTOR

Edward Kahn, Mark Davidson, Arjun Makhijani,
Philip Caesar and S. M. Berman

March 1, 1976

Prepared for the U. S. Energy Research and
Development Administration under Contract W-7405-ENG-48

LAWRENCE BERKELEY LABORATORY
UNIVERSITY OF CALIFORNIA BERKELEY

LBL-4474

INVESTMENT PLANNING IN THE ENERGY SECTOR*

Edward Kahn
Mark Davidson
Arjun Makhijani
Philip Caesar
S. M. Berman+

Energy and Environment Division
Lawrence Berkeley Laboratory
Berkeley, California

+Also Stanford Linear Accelerator Center, Stanford, CA

* Work done under the auspices of the U. S. Energy Research and Development Administration

0 0 0 0 4 4 0 6 0 3 4

Table of Contents

LIST OF FIGURES

Acknowledgements

The authors wish to thank the many people who have provided aid and consultation in the course of this research. We would like to express our particular gratitude to Professor Austin Hoggatt and Professor Fred Morissey, of the UC School of Business Administration, Professor Robert Williams of Princeton University, Walter Cavagnaro of the California Public Utilities Commission, Jerry Bock of Economic Sciences Corporation, Jim Harding of the California Energy Resources Conservation and Development Commission, W. R. Willey of the Environmental Defense Fund, and Dr. Robert Budnitz, Dr. Melvin K. Simmons and Dr. Carl Blumstein of the Energy and Environment Division, Lawrence Berkeley Laboratory. None of these people are responsible for any of the views expressed here or for any errors that remain in this paper.

INVESTMENT PLANNING IN THE ENERGY SECTOR

I. Introduction

Investment planning is commonly thought to reflect consumer preferences. Individual decisions add up to produce consumption trends which are then reflected in the plans industry makes for future production. Industry planners project past behavior and current trends, trying to forecast future patterns of consumption. Such forecasts are the basis for investment decisions. Patterns of consumption, in this view, determine the pattern of investment. While this holds to a certain extent, there is also an opposite effect. Investment patterns determine the pattern of the possible range of lifestyles. The nature and distribution of capital stock in the various sectors of an economy circumscribe the range of production possibilities, favoring certain alternatives, hindering others. The range of production defines the range of consumption.

One of the consequences of the dual effects of investment planning is the danger of consumers becoming captives of large scale investments. Consider what has happened in recent years to several capital-intensive industries. Railroads, airlines, and defense industries have all experienced declining demand which has tended to drive prices up. Price increases in turn have had a further dampening effect on demand. The financial position of such industries has deteriorated because revenues are insufficient to provide an adequate return on capital. The threat of bankruptcy in these cases is real. Moreover, the impact of such business failures would be profound because the amount of capital involved is quite large. Therefore, to prevent financial instabilities from spreading throughout the economy, or to preserve significant services and production capabilities, government subsidies are necessary. The railroad industry is currently being subsidized, as is Lockheed in the defense industry. Pan American Airlines has also requested federal aid. The effect of such subsidy programs is to freeze the range of consumption alternatives. This preserves institutions that have failed, and locks consumers into a pattern of investment that does not reflect preferences expressed in the market.

We will examine the consequences of investment decisions in the energy sector. Energy occupies a central role in modern industrial economies, and investment decisions in this sector reverberate through every other sector. Moreover, the problem of energy investment is particularly timely because of rapid changes that are now occuring in supply options and demand behavior. In the period from 1945 to 1973, the United States experienced a period of decreasing energy costs which promoted extensive growth in energy consumption and little attention to end-use efficiency. With the rapid escalation of energy prices that began in 1973 and the worldwide economic downturn which followed, the situation has changed. Since 1973 demand for energy has been essentially constant. Energy supply investments, particularly by the electric utilities have committed themselves excessively to new electrical generating facilities. This is a complex problem, with many facets that need to be explored before any answers can be offered.

To begin with, the recent slowdown of demand growth but continued historical growth in supply investments points to the fundamentally different time scales that operate in the two spheres. The lead time for new energy supply facilities to come on line is long (six or eight years for a power plant). This is due to complex legal, financial, engineering, and construction problems involved in building a modern power plant, developing an oil field, or constructing a pipeline. As a result, the energy supply industry bases its investments on projections of demand five to ten years in the future. The cost of postponing or cancelling construction may be high, especially if demand subsequently resumes a high rate of growth. Users can respond relatively quickly to changes in the cost or availability of energy by curtailing demand or using their existing capital stock more efficiently. In a five to 10 year period, widespread improvement in the efficiency of a user's capital stock can be made, resulting in significant reductions in energy demand. A trend toward conservation can potentially, at least, develop rather quickly.

The patterns of investment in energy supply and conservation differ considerably. While the two sectors are complementary in terms of the whole energy system, at the margin they are competitive. The number of dollars required to supply an extra Btu of energy is often more than need be invested in conservation to save that extra Btu. For example, it would cost approximately $\$2.4 \times 10^8$ to retrofit the 16×10^6 electric water heaters in this country with commerically made water heater insulation kits. This investment would save approximately 5.35×10^9 kwhr per year. The construction of sufficient generating capacity to supply that amount of electricity would cost about $\$7.2 \times 10^8$ (1,200 megawatts at $600/kilowatt of capacity). Since new sources of energy supply, such as nuclear power or offshore oil, are getting increasingly expensive, the nation's energy requirements might be more effectively satisfied by an integrated investment plan that emphasizes further conservation investments and reduces investments in supply capacity. This reasoning is reinforced by the fact that conservation investments generally require less capital than energy supply and processing technology.

Various interpretations have been offered to explain the break in historical energy consumption trends that began in 1974. One theory attributes this behavior to the decline in economic activity. According to this theory, energy consumption will resume its previous growth rate when economic conditions improve. The hiatus will end when the recession ends. An alternate explanation attributes the effect to conservation activities by consumers. Users have begun to increase the efficiency of their energy consumption, cutting back on waste and marginally productive activity because of higher prices, anticipation of shortages, an increased conservation ethic, or response to government appeals. In any event, the expectation of higher energy prices or potential energy shortages will stimulate conservation activities, particularly by industrial consumers. This expectation is reasonable since utility prices must increase due to the relatively higher capital costs of nuclear power and increasing fuel costs. Because we can expect a significant conservation effect on the level of demand, it is important to study what can happen if historical energy consumption trends are not continued in the future.

Indeed recent studies have indicated that future electricity demand will be well below the 6-7% annual growth rates of the sixties and early seventies. For example, the econometric model in the Teknekron report, The Economic Impact of Water Pollution Control on the Steam Electric Industry, projects a national demand growth averaging 2% annually to 1983.[1] In a study of California's electricity demand, it was argued by Goldstein and Rosenfeld that adoption of conservation measures by the State Energy Resources Conservation and Development Commission could lead to demand growth of 1.2% annually.[2] Let us therefore consider the consequences of neglecting this impact on the financial stability of the electric utility industry.

Suppose that the recent decline in electricity use per capita is a consumer response to increased rates. Suppose further that the utility industry, failing to recognize this qualitative shift in demand behavior, continues to invest large amounts of capital for anticipated future needs. According to standard rate-making procedures, this added capital investment must be included in the rates of consumers. Everything else being equal, this added capital investment will increase the cost of electricity. This added cost will then further retard demand growth, increasing the error in the projections which utilities are using to plan their investments. A vicious circle could then develop, where price-induced conservation drives rates up, which then forces demand further below expected levels, decreasing utility revenues so that rates will have to increase to meet return on equity requirements, and so on. If unchecked, this inflation-recession dynamic could drive rates very high while demand might even begin to fall.

Such a scenario is not likely to develop under present government policies because the cost of utility investment is subsidized by federal tax credits. This policy dampens the impact of investment on rates, postponing the day of reckoning until the utilities can no longer acquire capital in the financial markets. If capital rationing were to become a fact of life for utilities, the huge overcapacity brought on by a high investment program would become a potent driving force on rates. The end of exponential growth in electricity investment could mark the beginning of an exponential growth in rates. This issue will be discussed further in Sections 2 and 3.

The solution to the postulated inflation-recession dilema would be a curtailed investment program. It might be argued that curtailment of supply would lead to power shortages if the conservation effect did not materialize significantly. This is not likely because the overcapacity already in the system is sufficient to absorb any sudden increase in demand (See Table I below). In the model we present in Section 3, the scenario with the most optimistic economic assumptions predicts an annual growth rate in demand of 2.6 percent. We also outline a reduced schedule of construction. In Table 1 below, our low construction schedule is used with a three percent growth in non-coincidental peak power to compute one measure of capacity, the gross peak margin (capacity - peak/peak). This table shows the high degree of excess capacity already inherent in the utility investment program. The high numbers for new capacity in our construction schedule reflect plants begun many years ago which are too close to completion for any postponement to be practical.

TABLE 1

Year	($x10^6$ kw) New Capacity	($x10^6$ kw) Total Capacity	($x10^6$ kw) 3% Growth in Non-Coincidental Peak	(%) Gross Peak Margin
1975	40	486.3	357.4	36.1
1976	35	521.3	368.1	41.6
1977	20	541	379.1	42.7
1978	10	551	390.5	41.1
1979	8	559	402.2	39.0
1980	5	564	414.3	36.1
1981	5	569	426.7	33.3
1982	4	573	439.5	30.4
1983	2	575	452.7	27.0
1984	0	575	466.3	23.3
1985	0	575	480.2	19.7

If, in the next few years, historical growth rates in demand of six percent resume, we will argue that there will be enough time to resume construction of new generating facilities. In the present situation the costs and risks of continuing a high investment program far outweigh the costs and risks of curtailment.

The problem of investment planning and energy use extends beyond the energy supply sector itself into the various energy end-use sectors of the economy. In the residential sector, both consumers and producers of buildings and appliances have traditionally been preoccupied with minimizing initial costs, not life-cycle costs, and energy-efficient units usually do cost more. Credit is expensive and competition in these industries generally takes the form of price or brand-name comparisons, not relative energy consumption. Operating costs have not been a dominant factor in people's investment decisions, with the result that the increased cost of energy conservation measures has deterred production or purchase of more efficient units, even though the return on the investment (in fuel cost savings) would have been sufficient to justify it economically. Small increases in the first cost of housing and appliances could produce significant reductions in energy consumption. In Section 4, we will examine the residential sector in more detail and estimate what the effect of energy conservation investments will be on electricity demand. Section 4 will also include estimates of the effect of energy investments in the industrial sector on electricity demand and utility investments. In particular, we will discuss by-product power generation by industry, which will tend to reduce the demand on electric utility generating facilities. Since industry will also tend to increase its demand for electricity as a substitute for declining gas supplies used in high temperature processes, we will present estimates of this effect as well. All of the sectoral influences on electricity demand will be incorporated into our projections from the model presented in Section 3. In Section 5, we will list areas for future research.

References

1. Teknekron, Inc., The Economic Impact of Water Pollution Control on the Steam Electric Industry, Berkeley, California, 1976.

2. Goldstein, David and A. H. Rosenfeld, "Projecting and Energy Efficient California", LBL-Report # 3274, Current Draft.

II. Overview of the Electric Utilities Sector

> (Utilities should give up commonly used historical-based accounting in favor of) "zero-based budgeting in which all expenditures are critically examined each year. To the extend that utilities fail, or that the public believes that they have failed, the investor-owned utility could go the way of the dinosaur."
>
> Marvin S. Lieberman, Chairman,
> Illinois Commerce Commission[1]

The most unique feature of the regulated public utilities in the the United States is the procedure for setting prices, known as rate-making. Utility rates are set by state regulatory agencies. In certain respects the process follows standard market pricing techniques. Rates must be set to cover capital costs, operating and maintenance expenses, taxes, and depreciation. The main difference comes from the return on equity. This is a proportion (determined by regulatory commissions) of the common equity investment and does not vary with market parameters such as demand or production efficiency. As a matter of accounting practice, invested capital is not included in the rate base until the facility under construction comes into operation. Thus regulated industries have no incentive to limit capital investment because they are guaranteed a rate of return. Indeed, a well known argument of Averch and Johnson suggests that this procedure biases regulated industries toward overinvesting in capital, thereby reducing economic efficiency. For electric utilities, the main factors influencing the rate level are the unit costs for capital and fuel.

We are interested in analyzing configurations of electricity demand and utility investment behavior that would lead to increasing costs and consequent effects on demand. Such configurations might produce financial instabilities that can have serious repurcussions in the economy. Qualitatively we can expect the cost of electricity to increase because the two main factors of production are bound to increase in price.

Fuel costs will increase when, for example, utilities which currently benefit from inexpensive long-term contracts for coal have to renegotiate for future supplies at considerably higher prices when those contracts expire.[3] Capital costs will also increase due to escalating construction costs for fossil-fired generating plants and the increasing proportion of nuclear power plants, with their relatively higher capital costs, which are expected to come into service in the future.

The impact of rising fuel and capital expenses will vary regionally. Some areas are more dependent on high-priced fuels than others. Regional variations in capital costs can be expected because of differing investment practices and labor and consturction costs. Rapid increases in rates will be most likely in those regions where both cost increases occur at the same time; likely areas are New England, the Northeast generally, and some parts of the mid-West. Regions with large hydroelectric facilities, such as the Pacific Northwest and Tennessee Valley, will not feel the upward pressure on rates as strongly. Despite these regional variations, there will be a tendency for problems in one area to spread to others because of interconnections and purchase agreements among utilities. For example, a southern California utility may run into financial problems and be unable to meet its obligations for power purchased from New Mexico. The utility in New Mexico then would share the instability which originated in California.

The model which is presented in Section 3 demonstrates quantiatively the effect of increasing rates upon electricity demand. The qualitative effect is a reduction in historical growth rates which in turn drives electricity prices even higher to meet capital costs. If this dynamic is allowed to continue, the financial instability of the most afflicted utilities could lead to the possibility of defaults that might eventually force these utilities to cease operations or be subsidized or nationalized. Such an outcome would entail certain social costs. It would be useful therefore to sketch the various alternatives available if such a crisis occurred.

The most obvious solution to the spiral of rapidly increasing costs and lagging demand is for the utilities to reduce their capital costs. This policy could forestall the need for government intervention, but it is a policy which runs counter to the thinking which predominates in the utility industry. For example, the 26th. Annual Electrical Industry Forecast in Electrical World predicts growth rates for the next several years near the historical level of seven percent annual increases.[4] The Federal Power Commission reports only very modest cutbacks in electric utility expansion plans for the next ten years. In 1974, FPC projected a growth rate in new capacity of 7.4 percent for the next decade; in 1975, this has been reduced to 6.7 percent.[5] The projections of our model indicate that a much sharper cutback is necessary. Utilities can delay completion of plants that are due to come on line in the next few years and cancel those planned for the more distant future. Delays would prevent the capital cost of these plants from being included in the rate base, thereby delaying rate increases and slowing the cost spiral which we have modelled. These delays must be coupled with curtailments in future expansion plans. The exact combination of construction delays and outright concellations for a particular utility must be based on detailed demand projections coupled with an analysis of the financial position of the utility involved. In principle, the model in Section 3 can be adapted for this purpose.

It might be argued by utility planners that while total electricity demand growth will slow considerably, the growth in peak demand will maintain a high growth rate of about seven percent. As is well known, peak demand drives capacity requirements and therefore an aggregated projection such as ours would not effect investment decisions. This argument is not borne out by the most recent statistics which show summer peak growth for 1975 at only 2.5 percent.[6] Moreover, such an argument ignores the potential of load management techniques for dealing with the peak power problem. Many utilities, for example, are currently experimenting with rate structures that should discourage peak usage by increasing the price. A strong program of efficiency standards for appliances could ameliorate the peak problem, since the majority of utilities have peaks related to the use of air conditioning, and some industrial uses. Industries which desired power during peak periods could generate limited amounts with on-site diesels. By ignoring load management, the utilities will only hasten financial instability because revenues will be insufficient to cover the increased capital costs caused by poor load factors.

Let us suppose, for the sake of argument, that the utilities maintain their present investment posture and demand fails to meet the expected rate of growth. The first result of this would be a shortage of revenues. A finanacially troubled utility will naturally apply to its regulatory agency for relief in the form of increased rates. The effect of rate increases will be further lagging in demand. If the cycle were to progress, it is likely that rate increases will not come as quickly as needed due to political resistance and processing delays. The deteriorating financial position of an afflicted utility would then be reflected by falling dividends and declining bond ratings. These two indicators point to a tightening of the capital market and act as a restraining force on future investment. Capital rationing will prevent overinvestment from continuing indefinitely, but it is unlikely that credit restrictions can stop excess capacity from being built in the first place. Thus we can expect that there will be cases of utilities with commitments for new capacity far beyond their needs and ability to pay. In these cases, bond defaults will be likely.

Various actions are possible to rescue a financially unstable utility. These include subsidies and government takeovers at either the state or federal level. The social cost of rescuing defaulting utilities will typically be government deficits and inflationary pressure. These phenomena usually have regressive impact on income distribution. Those who can least afford it will pay a disproportionate share of the cost.

A more desirable approach would be prevention of the overcapacity problem before it develops. The electric power industry already receives large subsidies in the form of federal income tax privileges. Specifically, the investment tax credit and accelerated depreciation allowance create a positive incentive for capital expenditures by utilities that is unrelated to technical and economic efficiency. In other industries, such as manufacturing, investment tax incentives encourage the replacement of obsolete capital equipment and thereby tend to increase productivity. If manufacturing investments do not increase efficiency, profits decline. In short, the market evaluates the quality of investment. Because of the regulated nature of utility companies, there is no external check on investment decisions. Moreover, the capital intensity of electric utilities makes the absolute subsidy due to tax policy quite large. If private utilities were to build 300 gigawatts of new capacity in the period 1975-1985, at an average cost of $600/kw, the tax credit at its 1975 rate of 10% would amount to $18 billion during this period. A construction schedule of this magnitude is projected by Electrical World. The subsidy for electricity use due to accelerated depreciation is on the same order. The recent study of Berndt and Wood, "Technology, Prices and the Derived Demand for Energy" arrives at a similar conclusion. They argue with an econometric model that "these investment incentives generate an increased demand for capital and for energy."[7] We study these tax expenditures quantitatively in Section III. E. The best policy for preventing overcapacity and the resulting financial problems is elimination of tax subsidies for new capacity.

If the electric utilities were to accept the validity and consequences of significantly lower demand forecasts, they can hedge against the uncertainty of predictions by planning smaller facilities with correspondingly shorter lead times. We propose a curtailed construction schedule (see Table 1 in Section I) that we study in Section III. E. quantitatively. There are other alternatives as well. By adopting a policy of building small conventional units, where waste steam could be used for industrial process or space heating, utilities could contribute to a more efficient and secure national system of energy use. This energy investments would be planned with more nearly optimal social and economic benefit. The utilities would gain in financial stability and investment flexibility, and consumers would be better served and in less danger of bearing the costs of bad planning.

References

1. Electrical World, November 1, 1975, p. 13.

2. Averch, Harvey and Leland Johnson, "Behavior of the Firm under Regulatory Constraint," American Economic Review, December 1962, LII, pp. 1052-1069. Also see the discussion in Alfred Kahn, The Economics of Regulation, Vol. II, New York, John Wiley and Sons, Ins., 1971, pp. 49-59.

3. Hudson, Edward A. and Dale Jorgenson, "U.S. Energy Policy and Economic Growth, 1975-2000," The Bell Journal of Economics and Management Science, Vol. 5, Autumn 1974, pp. 493-4.

4. Electrical World, September 15, 1975, p. 41.

5. FPC News Release No. 21520, June 30, 1975, p. 1.

6. Electrical World, October 15, 1975, p. 72.

7. The Review of Economics and Statistics, LVII, August 1975, p. 267.

III. Analytical Model of Electric Utility Demand and Rates

A. Introduction

In this section we present an analytical model of the electric utilities. Our aim is to present a simple and intuitive representation of an extremely complex interaction between electricity rates and demand. With this goal in mind, we have chosen a two-equation model which couples electricity demand to the rate-making mechanism, representing each component with one basic equation which is both plausible and well motivated. It is appropriate at the outset to enumerate the limitations of our model, so that its use and structure will be transparent.

On the demand side we have chosen an aggregated representation. More elaborate models of electricity demand break out sales into various end-use sectors such as industrial, residential, and commercial sectors. If one is interested only in electricity demand, this disaggregated method is superior to ours in principle. In addition, such a disaggregated demand model has more justification in microeconomic theory since consumers in each block may be imagined to be similar in type, and therefore to respond with similar behavior patterns. In this paper we have chosen to concentrate on the relationship between the rate making procedure and the market response to rates. Because rates depend upon demand, this relationship involves a feedback loop. Demand responds to rate changes, and changes in demand effect rates in turn. If we had chosen a disaggregated model, we would have had to consider disaggregated rate schedules as well. The feedback mechanism mentioned above becomes quite complicated in this case, and we have not found a suitable methodology to handle these complications. To avoid these difficulties and an undue proliferation of statistical parameters, we have chosen a very simple demand model in what follows. This gives our work several advantages. First, the subtle relationships between policy variables like construction schedules or different tax policies and electricity demand and rates are elucidated. Second, our model gives the reader an easily understandable analytic picture of the financial structure of the utility industry, and an insight into the potential instability of this industry. Our demand equation deals only with total energy consumed, and ignores variations in demand for power over short time periods usually expressed in load curves. This means we cannot test the effect of load management techniques such as peak load pricing. We consider further disaggregation of the model presented here as a fertile area for future research.

A further limitation of our demand equation is its limited ability to account for technological change. We attempt to deal with some specific aspects of this problem in Section IV where we study non-economic forces which influence electricity demand. The anticipated natural gas shortage has already forced builders to use electric resistance heating in 40 percent of new residential construction. We can expect that electricity will also be substituted for gas in some industrial processes. Industry may also turn toward generating its own electricity, thereby reducing the demand on utilities. We estimate these effects in Section 4. The general problem remains of how technological change influences demand. One must factor out those changes in demand that are due to price response (i.e., elasticity) and those which reflect drastic technological change. Such a factorization is beyond the range of the techniques presented here.

Our model of the rate-making process is also a simplification of a complex procedure. We are concerned only with the average cost of a kilowatt-hour of electricity. This means we ignore the intricacies of rate schedules with their block structure and customer classes. We look instead at how an electric utility covers its total costs and the relationship between this and investment and tax policies. While the demand equation we use is a behavioral model, our rate equation is essentially an identity which tells us how utility revenue requirements depend on capital, costs, fuel costs and demand. To study conservation policies such as peak load pricing, a more complex model would be necessary.

The coupled demand and rate equations can be applied to investment planning problems in a variety of ways.

An investment plan for electric utilities depends upon projections of future demand and rates. Demand forecasts require estimates of future fuel costs, capital costs and GNP growth. Rate projections depend upon future interest rates, changes in tax structure and accounting procedures. For our purposes we make a few simple assumptions about these variables and then examine the consequences of those assumptions. Our results should not be interpreted as predictions in any absolute sense. Rather the comparison of various scenarios shows the relative impact of the assumptions which characterize those scenarios.

The domain of the model can also vary. We present below applications of the model to (1) all sales of electricity to ultimate customers nationwide, (2) all sales by private utilities nationwide, (3) all sales by Pacific Gas and Electric Company. The demand model seems to work equally well for sales to ultimate customers and total sales. The later includes sales to other utilities. Generally speaking, one expects that the smaller the system under study, the worse will be the fluctuations of the error term in the demand equations. Thus we don't expect it to have great predictive ability for very small utilities, but even for these it may predict rough trends of demand.

Our model shares with other models the inability to incorporate non-economic shock effects into its projections. Our analysis of gas curtailment and its effect on electricity demand is one effort to d4al with this kind of problem, but we have no general method for handling shock effects. Thus the time frame over which our projections may be thought valid is relatively limited. For five years into the future the models projections are likely to be good. For ten years they will still be reasonable. Beyond that, the effects of drastic technological change difficult to foresee now are likely to reduce substantially the value of our model.

B. Basic Equations of the Electric Utility Investment Planning Model

In order to quantify the relationships between electricity demand, electric rates, and the investment policy of utility companies, some sort of model is necessary. The model proposed here, while oversimplifying many aspects of the real problem, has several features which are vitally important for investment planning. Let us define

$$D = \text{Demand (kwhr)}, \tag{1}$$

where Demand is the yearly demand of the system under study (we have applied the model to a single utility, all private utilities, and all utilities). Let us also define

$$R = \text{Average rate per kwhr.} \tag{2}$$

R is the average kwhr charge of the system under study. As a first approximation, one might imagine a static world in which both demand and rates respond <u>instantaneously</u> to market changes. Let us first consider this static case and then move on to a dynamic model.

1. <u>The Static Case</u>

In this case demand responds instantaneously to rate changes and likewise rates respond instantaneously to demand changes. We choose the following equation for D

$$\ell n\,(D) = \ell n\,(\delta) + \varepsilon_g\,\ell n\,(G) - \varepsilon\,\ell n\,(R), \tag{3}$$

where δ is a constant and G is the gross product of the region under study. ε_g is the gross product elasticity. ε is the negative of the rate elasticity. Equation 3 may also be written as:

$$D = D_e R^{-\varepsilon}\ ,\ D_e = \delta\, G^{\varepsilon_g}. \tag{4}$$

Throughout this section, R will be the number of ¢/kwhr unless otherwise stated. The reason for fixing these units is to avoid confusion in the following. With this choice D_e is the static demand in kwhr at a rate of 1 ¢/kwhr.

Equation 3 gives the response of demand to a rate change. Rates respond to demand changes in a different way. In Section III D we justify the following form for rates as a function of demand:

$$R = A + \frac{B}{D} . \tag{5}$$

Roughly speaking, A are costs (in units of ¢/kwhr), like fuel costs and some operating costs, which must be paid for each kwhr generated, whereas B are fixed costs (like capital costs) which must be shared by all users. The B term is inversely proportional to demand. The effect of this is to cause rates fo increase when demand falls. A detailed discussion of A and B is given in part D of this section, including a discussion of the limitations of equation 5. In order to make equation 5 consistent with our choice of units for R, B should be expressed in cents.

Equations 4 and 5 may be used to solve for R and D as a function of A, B, ε, and D_e. By eliminating D in equation 5 we have

$$R = A + \beta(R)^{\varepsilon} , \quad \beta = \frac{B}{D_e \ x(1 \text{ ¢/kwhr})} \tag{6}$$

Equation 6 does not always have a solution. When no solution exists it means that in the context of this static model no choice of rates will meet the revenue needs of the utilities. Three cases suggest themselves for ε greater than, less than, or equal to 1. Note that in practice A, B, D_e, and ε are greater than zero.

Case 1: $\varepsilon < 1$. In this case, there is always one, and only one solution.

Case 2: $\varepsilon = 1$. This case has exactly one solution for $\beta < 1$, and no solutions for $\beta \geq 1$.

Case 3: $\varepsilon > 1$. In this case, there may be no solutions, one solution, or two solutions, depending on the values of A and β. This case is discussed in full in Appendix I.

This static idealization is not realistic because it does not incorporate lag times which are crucial in the real world. In reality, demand changes lag significantly behind rate changes. We present below a dynamic model which has such a feature.

2. The Dynamic Case

We wish to incorporate lag times into our model. Let t denote time. What we are interested in projecting is D_i, the electricity demand in the i^{th} year in kwhr. In order to assist in understanding the demand equation that we eventually propose, let us approximate D_i by a continuous function of time D(t). Suppose for a moment that rates and D_e are held constant, and that at t = 0 demand is some arbitrary value D(o). As time progresses, demand should change, approaching the free market value of $D_e R^{-\varepsilon}$. We seek a differential equation whose solutions have these properties. For simplicity, we limit ourselves to a first order, linear differential equation. The only equation of this type with the properties we want is:

$$\frac{dD}{dt} = -K(D - D_e R^{-\varepsilon}) \quad , \quad K > 0. \tag{7}$$

If K, D_e, and R were independent of time then the solution to 7 would be

$$D(t) = D_e R^{-\varepsilon} + (D(o) - D_e R^{-\varepsilon})e^{-Kt}. \tag{8}$$

We see that $\frac{1}{K}$ is roughly the time it takes for demand to adjust to a new rate. In general D_e and R will depend on time and the solution to eq. 7 will be more complicated than this.

As far as the rate equation goes, we have not included a time lag in rates. Rates in the year i adjust to demand in that year in our model. This agrees with historical data fairly well, although it works better for large systems. The following difference equation is a discrete form of equation 7.

$$D_{i+1} - D_i = -K(D_{i+1} - D_{ei+1}(R_{i+1})^{-\varepsilon}) , \qquad (9)$$

where we have allowed for the possibility that D_e depends on time, but δ and K are independent of time. Note that we have chosen the right hand side of equation 9 to have the subscript i+1 rather than i. We found that only in this way could we fit historical data. The reason is that demand in the year i+1 certainly responds to rate changes in that year.

Solving for D_{i+1} in equation 9, we have

$$D_{i+1} = \frac{1}{1 + K} (D_i + K\, D_{ei+1}\, R_{i+1}{}^{-\varepsilon}). \qquad (10)$$

The rate equation for the year i is simply

$$R_i = A_i + \frac{B_i}{D_i} . \qquad (11)$$

These equations are the starting point of our studies of utility systems. Before proceeding, let us note what happens if D_e, ε, A_i, and B_i are independent of time. In this case one naively expects the demand and rates to approach equilibrium values. As time goes on, the left hand side of 9 would vanish in this case. The equations reduce to the static equations already studies. If these static equations have no solution, then an equilibrium does not exist. The solutions in this case either run away or are limit cycles. What this means is that no value of rate will meet the utility requirements for revenues. If the utility raises its rate to try and meet its revenue requirements, demand falls off so fast that the desired result cannot be achieved. Such a system is financially unstable, and if changes were not made, it would mean an eventual default for the industry. Generally, when B gets too large, instability sets in. B is a measure of the capital investment of the industry. Our simple model supports the conclusion that overcapitalization must be avoided by capital-intensive industries.

In the next section we discuss concrete applications of the demand equation.

3. Specification of the Demand Equation

To proceed further we need information about ε, ε_g, and D_e. Several studies have been done of sectoral elasticities for residential, commercial, and industrial consumers. Below we present sales weighted aggregate long range price elasticities

Source	Aggregate Price Elasticity[α]
Mount, Chapman, and Tyrell[1]	-1.5
Halvorsen[2]	-1.69
Verleger[3]	- .549

α. Each sector is weighted by power consumed in that sector to obtain an aggregate. See Ref. 4.

A review of demand models may be found in reference 5, where a table showing income and price elasticities of different sectors is included. Estimates of these parameters vary significantly from study to study. Population elasticities are very close to 1, according to reference 1. The literature suggest the following conclusions:

1. Long range elasticities are larger in magnitude than short-range elasticities.
2. Long range price elasticities are non-zero and estimates range form -.5 to -1.7.
3. Long-range income elasticities are non-zero and estimates range from 0 to 2.
4. Long-range population elasticities are non-zero and consistent with one.

The estimates on price and income elasticities are not good enough to enable us to decide from these what to use for ε in our medel. We can say with confidence, however, that

$$D_e \; \alpha \; \text{population,} \tag{12}$$

and that D_e increases with the general wealth of the population. Previous estimates of ε suggest

$$.5 < \varepsilon < 1.7. \tag{13}$$

Faced with these ambiguities, we have tested the following choice for ε and D_e:

$$\varepsilon = 1, \tag{14}$$

$$D_e = \delta G \text{ , ie. } \varepsilon_g = 1 \tag{15}$$

where δ is a constant independent of time and G is the gross product of the region served by the the utilities under study. G will tend to grow with population and therefore this choice is consistent with equation 12. The model equations become in this case:

$$D_{i+1} = \frac{1}{1+K} (D_i + K \delta G_{i+1}/R_{i+1}) \tag{16}$$

$$R_{i+1} = A_{i+1} + B_{i+1}/D_{i+1} \tag{17}$$

In order to understand the meaning of δ, consider the following hypothetical situation. Suppose that R, D and G have been independent of time for a few years. Then the demand equation becomes the static equation:

$$D_{i+1} \cong \delta G_{i+1}/R_{i+1} \quad , \tag{18}$$

or

$$\text{Revenues} = D_{i+1} R_{i+1} = \delta G_{i+1} . \tag{19}$$

We see that in this case the electric revenues are a fixed fraction δ of the gross product of the system under study. It is difficult to test such a claim with historical data since such a static situation has not occurred in recent times. Therefore, let us next consider a period in which demand has been increasing at a fixed rate (γ_D) each year. In this case equation 16 becomes

$$D_{i+1} \cong \frac{1}{1+K} \left(\frac{D_{i+1}}{1+\gamma_D} + K\,\delta\,\frac{G_{i+1}}{R_{i+1}}\right) , \tag{20}$$

which reduces to

$$\frac{D_{i+1}\, R_{i+1}}{G_{i+1}} = K\,\delta/(1 + K - 1/(1 + \gamma_D)). \tag{21}$$

We see that in a period of exponentially growing demand, the fraction of utility revenues with gross product is again a constant. During the 1960's the fraction of total electric utility sales to the G.N.P. was indeed roughly constant and equal to about 2.25 percent. In Section III C we apply equation 16 to three systems with quite promising results.

The assumption of equation 16 places an important constraint on the domain of applicability of the dynamic demand equation. By assuming that δ is independent of time, we in effect say that, in periods of exponentially growing demand, the fraction of the nation's product that we spend on electricity will be constant. Obviously, this cannot hold true forever. Technology changes and new inventions are incorporated into the economy; shortages of certain fuels may cause a switch to electricity. Radically different technology (i.e., technology that differs substantially from current practices and trends) may cause (1) increased electricity use, (2) electricity conservation, (3) switches from other fuels to electricity, or (4) switches from electricity to other fuels. In general, all four of these kinds of change can be expeced to occur with different ones dominating in different time periods.

The lead time for technological changes to have substantial effect on the character of the overall stock of electricity using equipment is long. It is certainly more than five years and probably more than ten years. We must remember in this context that the sort of marginal technological change that characterized the economy in the sixties is already implicit in our equations because G is a function of time. It is the efficient heat pump with a coefficient of performance of 4 or 5, or a massive switch of high temperature industrial processes from natural gas to electricity or other radical changes in the character of electricity using capital stock that ultimately vitiate the validity of the assumption that δ is constant. An aggregated model such as ours that seeks to extend the validity of the projections beyond 10 years or so must incorporate such technical change and its implementation. Perhaps this can be done by making δ a slowly varying function of time. The functional form as well as the characteristic time for δ to change substantially would depend on analysis of possible technological change and its implementation. Such an analysis is beyond the scope of this paper, but we have made an approximate technical assessment of three important electricity-consuming sectors (Section IV) to determine how the projections of electricity use in this sector may be altered by radical technical change. It would, however, be wrong to merely add the net effects of the technical changes indicated by the analysis in Section IV to the results of Section III C because one would almost surely be double counting the increases or decreases in electricity use. A satisfactory extension of this model must make technical change integral with the aggregated econometric medel. As indicated above, this could be done by making δ (and perhaps K) a function of time.

C. Application of the Demand Equation

In this section we test the demand equation 16 with historical data. Writing 16 in the form

$$D_{i+1} = \alpha D_i + \gamma \frac{G_{i+1}}{R_{i+1}} + \varepsilon_i \qquad (22)$$

with

$$\alpha = \frac{1}{1 + K} \; , \quad \gamma = \delta K/(1 + K) \; , \tag{23}$$

and with a random error term ε_i, we have performed a least squares fit to historical data for three cases:

1. Total National Electricity Demand
2. Total Demand on Privately Owned Utilities
3. A Single Utility (Pacific Gas and Electric Compan).

We assumed that the error terms ε_i were uncorrelated, and that the variance of the error distribution was independent of time (homoscedasticity). To test the assumption of uncorrelated errors, we calculated the Durbin Watson Statistic[6] of the fit, and in all three cases this was consistent with the hypothesis of no correlation in the errors at the five percent level.

1. Total National Electricity Demand

We fit the demand equation to the years 1961 to 1974. We found the following form for the equation (standard errors are shown in parenthesis):

$$D_{i+1} = \underset{(.037)}{.807}\, D_i + \underset{(.0008)}{.00564}\, G_{i+1}/R_{i+1} \tag{24}$$

$$R^2 = .998 \; , \text{ Durbin Watson Statistic } = 1.606.$$

In Table I we list the relevant data and in Figure I we plot the model demand versus historic demand. The values of δ and K one can surmise from 24 are

$$K = .239 \text{ yr}^{-1} \; , \quad \delta \approx .029 \; , \tag{25}$$

although these are biased estimates since the relationships between (K,δ) and (α,γ) and non-linear (equation 23).

2. Total Demand on Privately Owned Utilities

We fit the demand equation to this system for the years 1960 - 1974. We found the following equation (standard errors shown in parenthesis)

$$D_{i+1} = \underset{(.0348)}{.8196}\, D_i + \underset{(.0007)}{.00487}\, G_{i+1}/R_{i+1} \tag{26}$$

$$R^2 = .998, \quad \text{Durbin Watson Statistic} = 1.86 \tag{27}$$

In Table II we list the relevant data and in Figure II we plot the model demand versus historic demand. We used total G.N.P. in 26 since data was not available for the total gross product of the region served by private utilities. One would expect this gross product to be a fixed fraction of G.N.P. and so such a replacement is acceptable. Our estimate of γ (and δ) is somewhat smaller than in the total national demand case as a result of this. The values of δ and K implied by 26 are

$$K = .22\ yr^{-1}, \quad \delta = .027 \tag{28}$$

3. Pacific Gas and Electric Company Demand

We fit the demand equation to the years 1965 - 1974. We found the following form for the equation:

$$D_{i+1} = \underset{(.132)}{.6037}\, D_i + \underset{(.002)}{.00696}\, G_{i+1}/R_{i+1} \tag{29}$$

$$R^2 = .982, \quad \text{Durbin Watson Statistic} = 2.27 \tag{30}$$

In Table III we list the relevant data and in Figure III we plot historic and model demand. Since about 41 percent of the population of California reside in PG&E's region of service[7], we took G to be

41 percent of California's gross state product. The estimated values of K and δ are

$$K \cong .656\ \mathrm{yr}^{-1} \quad , \quad \delta \cong .018 \quad . \tag{31}$$

California residents seem to respond more quickly to rate increases than the national average. About 10 percent of PG&E's demand is agricultural. This fluctuates considerably depending on irrigation needs in a given year, thus causing an increase in the size of the error term for this system.

The model predicts a simple relation between percent increases in the various quantities during periods where the percent increase in D, G, and R are independent of time. The relation is

$$r_D = r_G - r_R \quad . \tag{32}$$

where r_D, r_G, and r_R are annual percent increases in D, G. and R respectively. Thus, if real G.N.P. increases at a rate of 4 percent and real rates decrease at a rate of 2 percent, demand will increase at a rate of 6 percent according to the model. Note that it doesn't matter what kind of dollars are used to express G and R (so long as the same dollars are used for both) because inflationary effects cancel out of the difference.

In Sections III E we couple the demand equation with the rate equation for all private utilities and make projections for different scenarios.

TABLE 1

U.S. ELECTRIC UTILITIES' HISTORICAL DATA

Year	GNP[1]	Revenues[2]	Rate[3]	Demand[4] Historical	Demand[4] Model	Δ %
1960	503.7	11.5	1.69	683		
1961	520.1	12.2	1.69	720.7	725.0	.6
1962	560.3	13.0	1.675	776.1	770.6	-.7
1963	589.2	13.7	1.65	830.8	828.0	-.3
1964	628.7	14.4	1.62	890.4	889.7	-.1
1965	684.9	15.2	1.60	953	960.4	.8
1966	749.9	16.2	1.56	1038	1041.0	.3
1967	793.5	17.2	1.55	1107	1126.8	1.8
1968	865.7	18.6	1.55	1202	1208.8	.5
1969	930.3	20.1	1.54	1307	1311.2	.3
1970	977.7	22.1	1.59	1391	1402.1	.8
1971	1055	24.7	1.69	1466	1475.2	.6
1972	1155.2	27.9	1.77	1578	1551.8	-1.7
1973	1295	31.7	1.86	1703	1666.8	-2.1
1974	1397	39.1	2.20	1700	1717.5	1.0

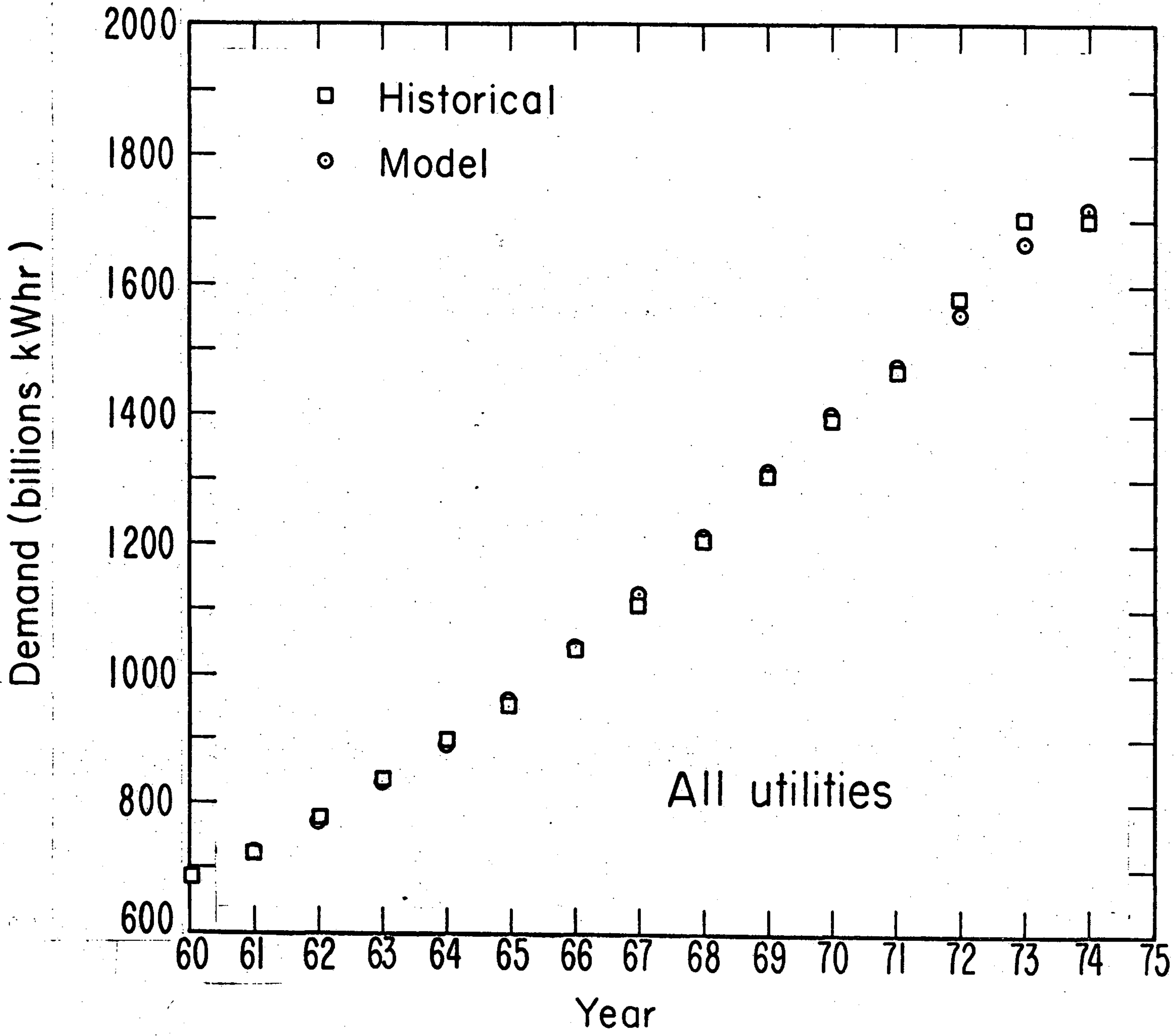
1. In Billions of Current Dollars

2. Sales of ultimate customers in billions of current dollars (from Statistical Abstracts of the U.S.

3. In units of ¢/kwhr

4. In units of billions of kwhr

Source: Statistical Abstract of the U.S., 1960-1975.



XBL 762-2331

Figure 1

TABLE 2

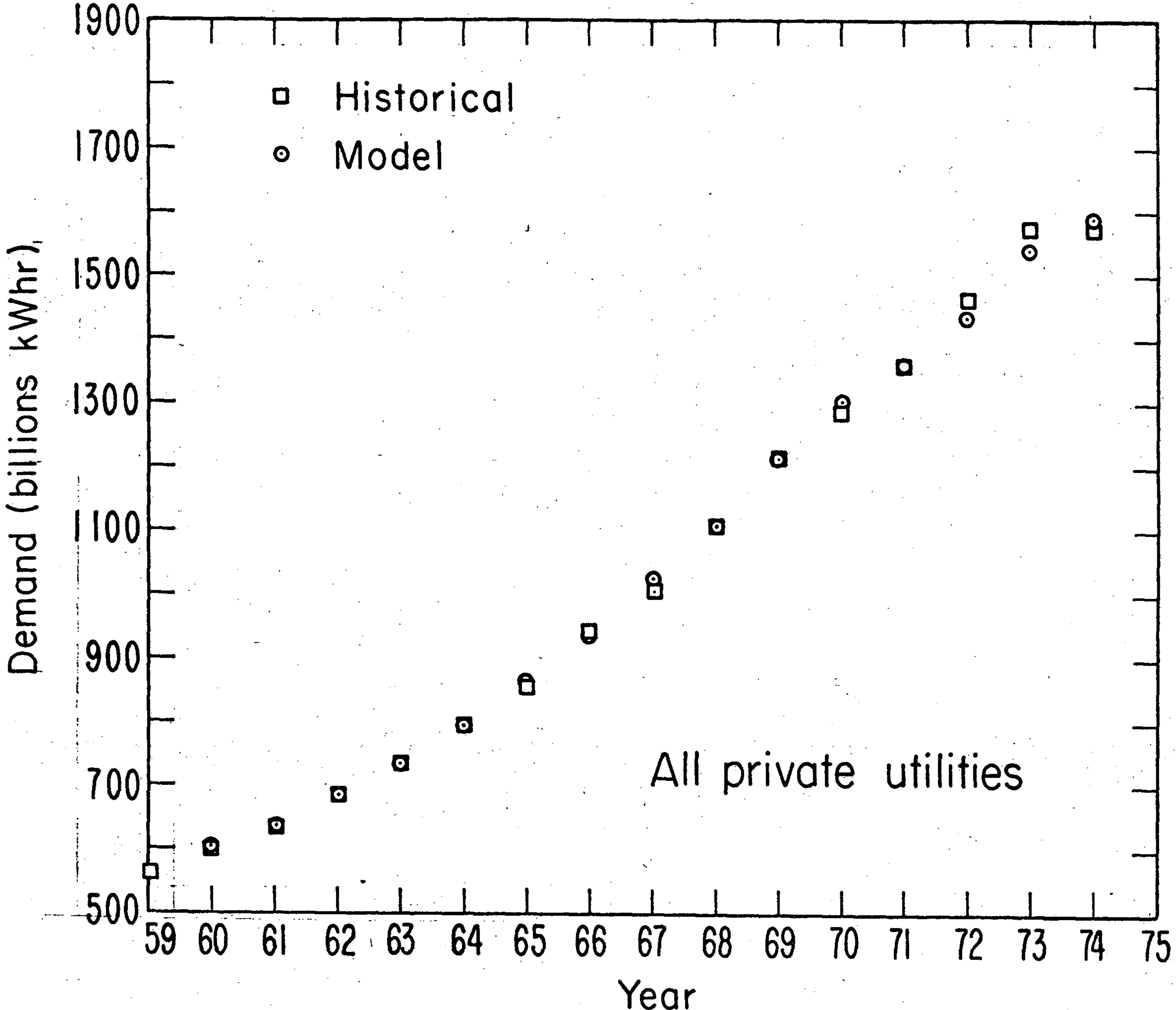
PRIVATELY OWNED ELECTRIC UTILITIES' HISTORICAL DATA

Year	GNP[1]	Revenues[2]	Rate[3]	Demand[4] Historical	Demand[4] Model	Δ %
1959	--	9.50	1.70	559	--	--
1960	503.7	10.12	1.69	597	603	1.
1961	520.1	10.67	1.69	631	639	1.3
1962	560.3	11.39	1.66	686	681	-.7
1963	589.2	12.02	1.64	733	737	.5
1964	628.7	12.67	1.60	791	792	.1
1965	684.9	13.40	1.57	854	861	.8
1966	749.9	14.37	1.53	942	938	-.4
1967	793.5	15.22	1.51	1005	1028	2.38
1968	865.7	16.54	1.50	1106	1105	-.1
1969	930.3	18.02	1.48	1215	1212	-.2
1970	977.7	19.79	1.54	1289	1305	1.2
1971	1055	22.32	1.64	1358	1369	.8
1972	1155.2	25.35	1.73	1465	1338	-1.8
1973	1295	29.10	1.84	1587	1543	-2.2
1974	1397	35.90[e]	2.28[e]	1575[e]	1591	1.0

1. In billions of current dollars
2. Total Revenues in billions of current dollars
3. In units of ¢/kwhr
4. In units of billions of kwhr

e. Estimate

Source: Statistics of Privately Owned Electric Utilities in the United States - 1973.



XBL 762-2332

Figure 2

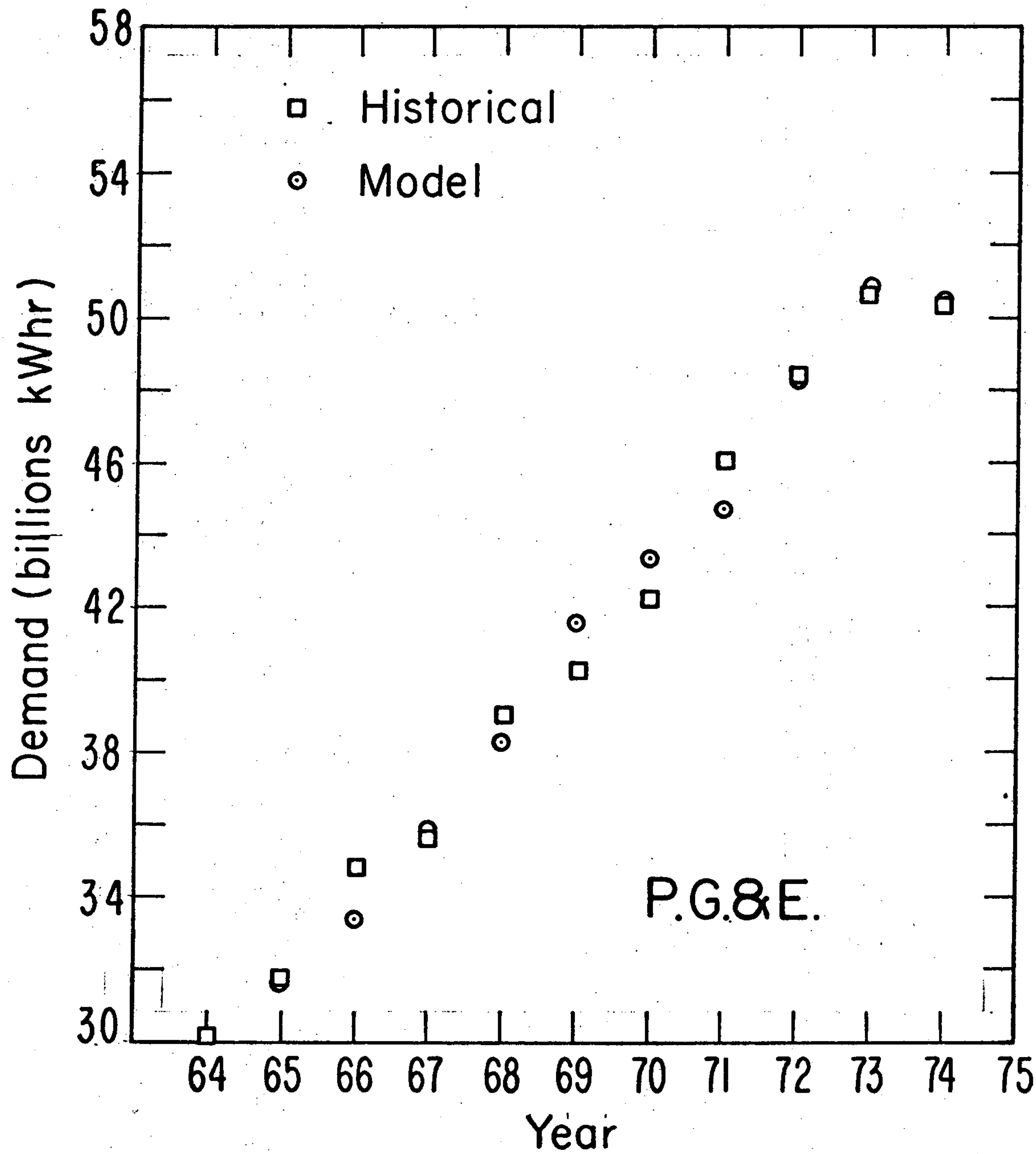
TABLE 3

ELECTRICITY DEMAND AND RATES FOR PG&E

Year	G[1]	Revenues[2]	Rates[3]	Demand[4] Historical	Demand[4] Model	Δ %
1964	30.4	.519	1.70	30.6	--	--
1965	32.	.538	1.70	31.7	31.6	-.3
1966	34.	.579	1.66	34.8	33.4	-4.
1967	36.1	.600	1.68	35.6	35.9	.8
1968	40.1	.647	1.66	39.0	38.3	-1.8
1969	43.5	.674	1.67	40.3	41.6	3.2
1970	45.5	.705	1.67	42.2	43.3	2.6
1971	47.6	.792	1.72	46.0	44.7	-2.8
1972	52.1	.856	1.77	48.4	48.2	-.4
1973	58.4[e]	.947	1.87	50.7	50.9	.39
1974	63.0[e]	1.105	2.20	50.3	50.5	.4

1. In billions of current dollars (G=.41 G.S.P. of California)
2. In billions of current dollars
3. In units of ¢/kwhr
4. In units of billions of kwhr

Source: PG&E Financial Reports



XBL 762-2333

Figure 3

References

1. T. D. Mount, L. D. Chapman, and T. J. Tyrell, Electricity Demand in the United States: An Econometric Analysis, Oak Ridge National Laboratory Report ORNL-NSF-EP49, (1973).

2. R. Halvorsen, Long Run Residential Demand for Electricity, Demand for Electric Power in the United States, University of Washington Discussion Paper No. 73-13, (1973).

3. P. K, Verleger, "An Economic Analysis of the Relationships Between Macro Economic Activity and the U. S. Energy Consumption," in Energy Modelling, Resources for the Future, Inc., Washington, D.C., (1973).

4. R. L. Cooper, Price Elasticity in Electric-Power Demand Forecasting, Lawrence Livermore Laboratory Prepring # UCRL-51890, September, 1975

5. L. D. Taylor, "The Demand for Electricity: A Survey," in the Bell Journal of Economics, Vol. 6, No. 1., Spring 1975.

6. See for Example E. Malinvaud, Statistical Methods of Econometrics, North-Holland Publishing Co., Amsterdam, 1970.

7. Information on PG&E's regional population may be found in their publication Outlook - 1975.

D. The Rate Equation

We have assumed that utility rates R (in \$/kwhr) are given by the expression

$$R = A + \frac{B}{D} \qquad (1)$$

where D is the kwhr of electricity sold over some convenient time period T (usually 1 year) and A and B are parameters (which may vary with time) to be defined later. The term rate is used here in the sense of average cost per kwhr. The intuitive basis for choosing this form is that total utility revenues in any year, DR, are the sum of fixed costs B, which include return on investment and other fixed obligations, and variable costs which are proportional to the electricity sold (primarily fuel costs and some operating and maintenance expenditures), AD. Thus (1) may also be written: DR = AD + B. This equation is an identity which defines the sources of utility revenue. Our eq. (1) has essentially the same functional form as other models of average electricity costs, for example, the model of Joskow and Baughman.[1.,2.] Utility revenues consist of

(1) interest costs, C_b, which must be shared by all customers;
(2) return on common equity (ROE), E, after taxes, usually a fixed fraction i_e of the common equity K_e;
(3) preferred stock dividends, C_p, which are a fraction of preferred stock K_p and must be shared by all customers;
(4) depreciation L (book value);
(5) operating maintenance costs, M_1, which are relatively independent of electricity sales over a wide range and must be shared by all customers (in particular M_1 = Administrative and General Expenses + Customer Accounts + Purchased Power - Franchise Requirements - Regulatory Commission Expenses);
(6) taxes, T_M, on property, etc., which are independent of other expenses as well as sales;
(7) taxes, T_R, on total revenues at a rate i_R (these are primarily state and local taxes);

(8) federal income taxes, T_F, on net income after investment tax credit (gross federal rate of tax on net income is i_F);

(9) operating and maintenance costs excluding fossil fuel costs not included in item (5) above which are proportional to the demand, M_2; and

(10) fossil fuel costs F.

The factors (1) through (6) represent the fixed costs which are included in the parameter B. The factors (9) and (10) represent costs that are proportional to demand included in the parameter A, whereas the tax factors (7) and (8) modify the parameters A and B by some multiplicative factor (which may vary from year to year). The details of the expressions for A and B in terms of known quantities such as interest rates and fuel costs are shown below. This is done so that one can use projections of capital spending, interest rates, fuel costs, etc. to project rates. These rate projections have been used in Section III E to project demand under various construction schedules and tax policies.

From the above list of components of utility revenues DR we can write down the following equation:

$$DR = (C_b + C_p + E + L + M_1 + T_M) + (T_R + T_F) + (M_2 + F) \tag{2}$$

It now remains to express the quantities on the right hand side of equation (2) in terms of known parameters. We have by the above definitions:

$$E = i_e K_e \tag{3}$$

$$T_R = i_R DR \tag{4}$$

$$M_2 = m_2 D \tag{5}$$

where m_2 is the operating and maintenance cost per kwhr excluding fossil fuel costs.

Let

D_f be the electricity <u>generated</u> from fossil fuels,

D_c be the electricity generated from all other sources plus electricity purchased;

α be the proportion of electricity generated and purchased actually sold (either to customers or to other utilities),

f be the fossil fuel cost per kwhr generated from fossil fuels,

h be the heat rate in <u>million</u> Btu/kwhr, and

f_M be the cost of fossil fuels in \$/million Btu.

We have by definition:

$$D = \alpha(D_f + D_c) \tag{6}$$

$$D_f = \frac{D}{\alpha} - D_c \tag{7}$$

$$f = hf_M \tag{8}$$

$$F = hf_m D_f = fD_f \tag{9}$$

Substituting equation (7) in (9) we get

$$F = \frac{fD}{\alpha} - fD_c \tag{10}$$

Federal taxes are taxes at the rate i_F on net income after all other taxes less the investment tax credit and allowing for accelerated depreciation. The investment tax credit is a fixed proportion i_a of the amount K_a of investment that becomes operational that year. This proportion may vary from year to year depending on the policies of the Federal government. For simplicity we can take K_{ai} equal to the increase in the gross electric utility plant in year i over the previous year provided that construction not on line in year i is not included in the base.

The net income, N, of the utilities for the purpose of computing federal taxes

$$N = DR - \{(C_b + L_F + M_1 + T_M) + T_R + (M_2 + F)\} \quad (11)$$

where L_F is the depreciation used for federal tax purposes.

We still use the following approximate expression for L_F:

$$L_F = L + i_d K_a$$

Substituting equations (4), (5) and (10) in (11) we get

$$N = DR(1 - i_R) + fD_c - (C_b + L_F + M_1 + T_M) - D(m_2 + \frac{f}{\alpha}) \quad (12)$$

Thus the federal tax T_F is given by

$$T_F = i_F N - i_a K_a$$

$$T_F = i_F DR(1 - i_R) - i_F(C_b + M_1 + T_M + L - fD_c)$$
$$- i_F D(m_2 + f/\alpha) - i_a K_a - i_F i_d K_a \quad (13)$$

Substituting equations (3) - (5), (10) and (13) in (2) and taking all the terms containing the product DR to the left hand side we get:

$$DR(1 - i_R - i_F + i_F i_R) = (C_b + L + M_1 + T_M - fD_c)(1 - i_F)$$
$$+ C_p + i_e K_e - i_a K_a - i_F i_d K_a + D(m_2 + f/\alpha)(1 - i_F)$$

(14)

On factoring this yields

$$R = \frac{(m_2 + f/\alpha)}{(1 - i_R)} + \left\{\frac{C_b + L + M_1 + T_M - fD_c}{(1 - i_R)} + \frac{C_p + i_e K_e - i_a K_a - i_F i_d K_a}{(1 - i_F)(1 - i_R)}\right\} \frac{1}{D}$$

(15)

Comparing equation (15) to equation (1), we get definitions for the parameters A and B:

$$A = \frac{m_2 + f/\alpha}{1 - i_R} \tag{16}$$

$$B = \frac{C_b + L + M_1 + T_M - fD_c}{(1 - i_R)} + \frac{C_p + i_e K_e - i_a K_a - i_F i_d K_a}{(1 - i_F)(1 - i_R)} \tag{17}$$

These formulas can be used to check the validity of the rate equation with historical data. However, to project rates we still need to express m_2, C_b, L, M_1 and C_p in terms of interest rates, capital stock, generating capacity projections and other physical and economic parameters which are understandable in terms of utility and regulatory commission planning.

Since the parameters m_2 and M_1 are primarily dependent on wage rates, we will assume that they can be projected by the equations

$$m_{2i} = m_{2o}(1 + r_w)^i \tag{18}$$

where r_w is the rate of growth of wages and the suffix o denotes the initial year (some year before 1975) and i is the i^{th} year (or time period). Similarly we have for M_1

$$M_{1i} = M_{1o}(1 + r_w)^i \tag{19}$$

For the purposes of projection, we will take book depreciation L as a fixed percentage of utility capital stock. This assumption can if necessary be relaxed to incorporate varying depreciation rates from year to year. We take

$$L_i = i_r K_i \tag{20}$$

where i_r is the book depreciation rate and K_e is the net electric utility plant. The depreciation for federal tax purposes is taken as $(L + i_d^f K_a)$ as discussed above.

Preferred stock dividends are given simply by

$$C_{pi} = i_{pi} K_{pi} \tag{21}$$

where i_p is the average embedded preferred stock dividend rate and K_p is the total preferred stock outstanding. If i_{pai} is the dividend rate on the preferred stock issued in year i and K_{pai} is the amount of the preferred stock issued in year i, we can take a weighted average to obtain i_{pi}:

$$i_{pi} = \frac{K_{pi-1} i_{pi-1} + K_{pai} i_{pai}}{K_{pi}} \tag{22}$$

where $K_{pi} = K_{pi-1} + K_{pai}$ (23)

For the purposes of rate projection we will assume that the return on common equity remains fixed at i_e, though this assumption can be relaxed if necessary. The common equity in year i is given by

$$K_{ei} = K_{ei-1} + e_i K_{ai} \tag{24}$$

where e_i is the fraction of K_{ai} that is represented by common equity. Note that as the high cost plants currently under construction come on line, it will cause rates to rise rapidly (see 17).

It now remains to express the interest on long-term loans C_b in terms of known and projectable quantities. Let the last year for which there is historical data be denoted by the suffix w. Also let

$K_{\ell w}$ be the long-term loans outstanding in year w,

$i_{\ell w}$ be the average embedded interest rate on $K_{\ell w}$

K_{cw+j} be the long-term loans raised in the j^{th} year of the projection at interest rate i_{cw+j}

K_{rw+j} be the long-term loan at interest rate i_{rw+j} which is <u>retired</u> in the j^{th} year of the projection.

In the year we have by definition

$$C_{bw} = i_{\ell w}K_{\ell w} \tag{25}$$

Further

$$K_{\ell w+1} = K_{\ell w} + K_{cw+1} - K_{rw+1} \tag{26}$$

$$K_{\ell w+2} = K_{\ell w+1} + K_{cw+2} - K_{rw+2} \tag{27}$$

$$\vdots$$

$$K_{\ell w+j} = K_{\ell w+j-1} + {}_{cw+j} - K_{rw+j} \tag{28}$$

The interest on long-term loans in the year w+1 is given by

$$C_{bw+1} = i_{\ell w}K_{\ell w} + i_{cw+1}K_{cw+1} - i_{rw+1}K_{rw+1} \tag{29}$$

This gives a new embedded long-term interest rate

$$i_{\ell w+1} = \frac{C_{bw+1}}{K_{\ell w+1}} \tag{30}$$

We can now calculate C_{bw+2}, C_{bw+3}, and so on:

$$C_{bw+j} = i_{\ell w+j-1}K_{\ell w+j-1} + i_{cw+j} - i_{rw+j}K_{rw+j} \tag{31}$$

The interest rates on long-term loans retired can be obtained from historical data. The matter does not rest here because we must still project the amount of capital to be raised in long-term loans. The interest rates on new long-term loans can be taken as a parameter in the projections that will depend on our view of the ease or tightness of capital markets.

The amount K_c raised in long-term loans by any particular utility will depend on its current financial position and construction commitments. For a particular utility it must therefore be determined by case-by-case analysis. However, certain overall funding principles do apply. According to the TBS study of electric utilities (commissioned by the Federal Energy Agency), the fraction of the capital that should be raised in long-term loans should not exceed 0.55, the fraction in common equity should not fall below 0.35. The remaining 0.1 can be in preferred stock[3]. Because of the current tight financial position of utilities, it appears likely that many utilities will be forced to borrow as much as possible (55%) in long-term loans though interest rates be high, unless present construction plans were revised downward significantly. This fact, coupled with retirement of old long-term debt which has been at very low interest rates, points to rapidly increasing long-term interest costs which will have to be reflected in rates. These factors will cause persistent increases in rates as more and more of the old, low interest long-term loans are replaced by high interest long-term loans.

In Appendix 2 we present the details of our calculations to check the rate equation (1), (16) and (17). The results of those are presented below. For a single utility, P.G.&E., the results are given in Table 1.

Table 1

	Model Rates	Actual Rates (= revenue /D)
1969	1.68 ¢/kwhr	1.67
1970	1.70	1.67
1971	1.69	1.72
1972	1.86	1.77
1973	1.98	1.87
1974	2.37	2.20

The agreement of the model rates with the acutal rates is quite good for 1969-71. The errors for 1972-74 may be due to the attempt to separate electric from gas operations. The latter is less profitable than the fomer. Another interpretation of the results for 1972-74 is that P.G.&E. did not fully cover its costs during that period.

Our check of the rate equation for all privately owned utilities is both clear and accurate. The results appear below in Table 2.

TABLE 2

	Model Rates	Actual Rates
1969	1.46 ¢/kwh	1.48
1970	1.56	1.54
1971	1.64	1.64
1972	1.74	1.73
1973	1.85	1.84

We conclude that our model is satisfactory for giving an appregated picture of average electricity costs. It will be used for this purpose in our coupled-equation projections in section III E.

SYMBOL LIST

C_b = interest costs on long term loans

C_p = preferred stock dividends

D_c = electricity generated from non-fossil sources plus purchased power

D_f = electricity generated from fossil sources

E = return on common equity

e_i = fraction of K_{ai} represented by common equity

f = fossil fuel cost per kwhr generated from fossil fuels

f_m = cost of fossil fuels in $\$/10^6$ Btu

F = fossil fuel cost

h = heat rate (10^6 Btu/kwhr)

i_a = investment tax credit

i_{cw+j} = interest rate on K_{cw+j}

i_d = depreciation rate on taxes (accelerated depreciation)

i_e = rate of return on common equity

i_F = federal tax rate on net income

$i_{\ell w}$ = average embedded interest rate on long term loans in year w

i_p = average embedded preferred stock dividend rate

i_r = book depreciation rate

i_R = tax rate on total revenues

i_{rw+j} = interest rate on long term loan which is retired in j^{th} year of projection.

K_{ai} = investment that becomes operational in year i

K_c = long term debt

K_{cw+j} = long term loans raised in j^{th} year of projection

K_e = common equity

K_i = net electric utility plant

$K_{\ell w}$ = long term loans outstanding in year w

K_p = preferred stock

K_{rw+j} = long term debt retired in j^{th} year of projection

L = book depreciation

L_F = Tax depreciation

M_1 = fixed operating and maintenance costs

M_2 = variable operating and maintenance costs

N = net income

r_w = rate of growth

T_F = federal income taxes

T_M = property taxes

T_R = revenue taxes

α = proportion of electricity generated and purchased actually sold to customers or other utilities.

NOTES

1. Joskow, Paul L. and Martin L. Baughman, "The Future of the U.S. Nuclear Energy Industry," M.I.T. Energy Law Report # 75-006, April, 1975.

Joskow and Baughman equation (1) is a simplified version of our e.g. (1), (16) and (17). They write

$$AC = \frac{100K_i a + 100F}{u} + \frac{k_2 H_r}{10^6} + O_c$$

where AC = average costs

k_1 = capital costs (\$/kw)

a = annual write off rate (1/yr) including depreciation insurance, return on investment, taxes

F = fixed operating and maintenance costs (\$/kw-yr)

k_2 = fuel costs (cents/mmBtu's)

H_r = heat rate (Btu's/kwh)

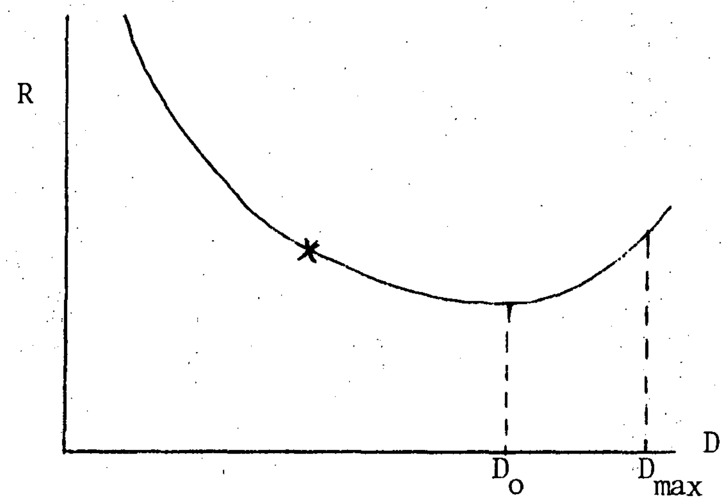
U = utilization factor (hours per year)

O_c = variable operation and maintenance costs (cents/kwh)

The first term corresponds to our term B/D. This can be seen by expressing the utilization rate U as a function of demand. We can write $U = 8760\ ({}^{D}/Dmax,)$ where Dmax is the maximum demand possible with the given capacity and D is the actual demand. Using this expression for U we get a term of the form B/D for a constant B which expresses fixed capital costs. The second and third terms of the Joskow and Baughman equation correspond to our parameter A. The main difference between our equation and the Joskow and Baughman expression is that we break out the annual write-off rate, a into its components depreciation, taxes, etc. This allows us to study the effect of tax policy on rates and demand (see Section III E).

2. A basic assumption underlying our equation (1) is that increasing demand will lower average cost. Graphically this

assumption may be illustrated by the figure below.



For given values of the parameters A and B there is an optimal demand D_o at which electricity is produced for the minimum average cost. A demand greater than D_o increases average cost because less efficient generators must be used. We assume that the electric utilities (individually and collectively) are operating at a point that is less than D_o. The evidence for this is the low capacity factors in the industry. Therefore our eq. (1) expresses increasing economic efficiency with increasing demand.

3. Temple, Barker and Sloan, Inc. A Study of Electric Utility Industry Demand, Costs, and Rates, Wellesley Hills, Massachusetts, 1975.

E. Projections - Coupling Demand and Rate Equations

Having established a method for obtaining utility rates from various exogenous variables and also having a method for predicting demand given GNP and rates, we are now in a position to couple these two equations. Our equations are of the form,

$$D_{i+1} = \alpha D_i + \gamma G_{i+1}/R_{i+1} \tag{1}$$

$$R_{i+1} = A_{i+1} + B_{i+1}/D_{i+1}. \tag{2}$$

We have applied these equations to the case of all private utilities and so we take the values of α and γ from III-B.

$$\alpha = .8196, \ \gamma = .00487. \tag{3}$$

On eliminating R_{i+1} from equation (1), we arrive at a quadratic equation for D_{i+1} whose solution is :

$$D_{i+1} = \frac{1}{2A_{i+1}} \left[(\alpha D_i A_{i+1} + \gamma G_{i+1} - B_{i+1}) + \sqrt{(\alpha D_i A_{i+1} + \gamma G_{i+1} - B_{i+1})^2 + 4A_{i+1}\, \alpha D_i\, B_{i+1}} \right] \tag{4}$$

Once D_{i+1} has been obtained, R_{i+1} may be solved for from (2). In this manner, rates and demand can be projected for each successive year.

Projecting electricity rates is a complex and very uncertain matter. We have chosen to simplify the calculation by emphasizing the variation that is due to investment behavior. As a result, construction schedules are the primary variable in our analysis. This means that all other variables (fuel cost, operating and maintenance expenses, property taxes, book depreciation, etc.) are assumed to be constant in 1974 dollars over the period 1975-85. These are very conservative assumptions, particularly as regards fuel cost. Although some econometric projections see a real rise in fuel costs of 2% annually, the stated policy of OPEC is for zero growth in the real cost of imported oil. The effect of real growth in fuel cost in our model would be higher rates and lower demand. We have omitted any explicit calculation of this effect. Our projections of the capital market are also highly simplified. We assume that utility financing will be 55% in long term loans, 35% in common equity and 10% in preferred stock. Rather than projecting interest rates for each type of financing we assume that the real interest rate on all forms of new debt is 5% annually.

Investment policy is sensitive to federal tax policy. Starting in 1975, the electric utilities will receive a 10% credit against federal income taxes on the value of new utility plant. This is an increase from 4% in 1971-74, and represents a powerful stimulus to investment. Coupled with a reduction in the corporate tax rate from 48% to 46%, and accelerated depreciation allowances, the utility industry is receiving large subsidies from the taxpayers. These subsidies in some cases are passed along directly to consumers (flow-through accounting), or indirectly by decreasing the utility's need for new capital. To quantify the effect of the investment credit on utility demand and rates we include scenarios characterized by a high level of construction with and without the tax credit.

We specify our high construction schedule by following the 26th Annual Electrical Industry Forecast in Electrical World, which gives a yearly schedule of peak capability from 1975 to 1985. In this period, Electrical World projects the new addition of 309 gigawatts of new capacity. To balance the high growth scenarios we include a curtailed construction schedule which amounts to a net capacity addition of 129 gigawatts of new capacity. The majority of the additional capacity in the curtailed schedule comes on line in the first few years. Essentially this is capacity which was planned many years ago and cannot be stopped or delayed. We assume that all new capacity will be built by the investor-owned utilities, rather than the federal government.

For the cost of new construction we have used the average figure of \$600/kW of capacity. This cost factor would be higher if a large proportion of new capacity were nuclear. Studies by the AEC and others have put the cost of new capacity in the range from \$585 in 1975 to \$1130 in 1985 (current dollars). Finally, we project each construction and tax schedule at three different rates of real GNP growth, namely 2, 3 and 4%. The results of these projections are given in the following tables. For the case of 3% real GNP growth we graph the behavior of demand, rates and revenues in figures IV, V, and VI.

TABLE - 4

DEMAND AND RATE PROJECTIONS - ELECTRICAL WORLD CONSTRUCTION SCHEDULE

Year	Net Power Growth[1]	2% GNP Growth		3% GNP Growth		4% GNP Growth	
		Demand	Rate	Demand	Rate	Demand	Rate
1974	--	1575	2.28	1575	2.28	1575	2.28
1975	45.8	1645	1.96	1649	1.96	1653	1.95
1976	35	1675	2.17	1685	2.16	1696	2.16
1977	29.1	1685	2.31	1705	2.29	1726	2.28
1978	27.4	1689	2.40	1720	2.37	1753	2.35
1979	24.8	1685	2.49	1731	2.46	1779	2.42
1980	22.6	1678	2.58	1740	2.53	1806	2.48
1981	22.3	1670	2.65	1751	2.58	1837	2.51
1982	22	1662	2.72	1763	2.62	1873	2.53
1983	22	1655	2.78	1779	2.66	1915	2.55
1984	26.3	1653	2.79	1803	2.65	1969	2.52
1985	31.8	1658	2.80	1836	2.63	2036	2.48
Average Annual Growth Rate		0.5%	1.9%	1.4%	1.3%	2.4%	.8%

1. In gw net new power coming on line. Demand grow in Billions kwhr. Rates given in constant 1974 ¢/kwhr. Real GNP is assumed to grow at rates shown.

TABLE 5

DEMAND AND RATE PROJECTIONS - ELECTRICAL WORLD CONSTRUCTION SCHEDULE
WITHOUT TAX CREDIT

Year	Net Power Growth[1]	2% GNP Growth		3% GNP Growth		4% GNP Growth	
		Demand	Rate	Demand	Rate	Demand	Rate
1974	--	1575	2.28	1575	2.28	1575	2.28
1975	45.8	1591	2.31	1595	2.31	1598	2.30
1976	35	1591	2.47	1600	2.46	1609	2.46
1977	29.1	1582	2.59	1600	2.58	1618	2.56
1978	27.4	1570	2.69	1599	2.66	1628	2.63
1979	24.8	1557	2.79	1598	2.74	1641	2.70
1980	22.6	1542	2.88	1598	2.82	1658	2.75
1981	22.3	1528	2.96	1601	2.87	1679	2.79
1982	22	1515	3.04	1607	2.93	1707	2.82
1983	22	1502	3.11	1615	2.97	1740	2.84
1984	26.3	1493	3.17	1629	3.00	1782	2.83
1985	31.8	1485	3.23	1647	3.02	1830	2.83
Average Annual Growth Rate		-0.5%	3.2%	0.4%	2.6%	1.4%	2.0%

1. In gw net new power coming on line. Demand given in Billions kwhr. Rates given in constant 1974 ¢/kwhr. Real GNP is assumed to grow at rates shown.

TABLE - 6

DEMAND AND RATE PROJECTIONS - CUTBACK CONSTRUCTION SCHEDULE

Year	Net Power Growth[1]	2% GNP Growth Demand	2% GNP Growth Rate	3% GNP Growth Demand	3% GNP Growth Rate	4% GNP Growth Demand	4% GNP Growth Rate
1974	--	1575	2.28	1575	2.28	1575	2.28
1975	40	1629	2.06	1632	2.05	1636	2.05
1976	35	1658	2.19	1668	2.18	1679	2.18
1977	20	1655	2.44	1674	2.42	1694	2.41
1978	10	1639	2.61	1669	2.58	1700	2.55
1979	8	1624	2.67	1667	2.63	1713	2.59
1980	5	1611	2.73	1670	2.68	1732	2.62
1981	5	1604	2.75	1681	2.68	1764	2.60
1982	4	1601	2.78	1699	2.69	1805	2.59
1983	2	1601	2.81	1722	2.69	1855	2.58
1984	0	1605	2.84	1751	2.69	1915	2.55
1985	0	1615	2.82	1790	2.65	1988	2.50
Average Annual Growth Rate		0.2%	2.0%	1.2%	1.4%	2.1%	0.8%

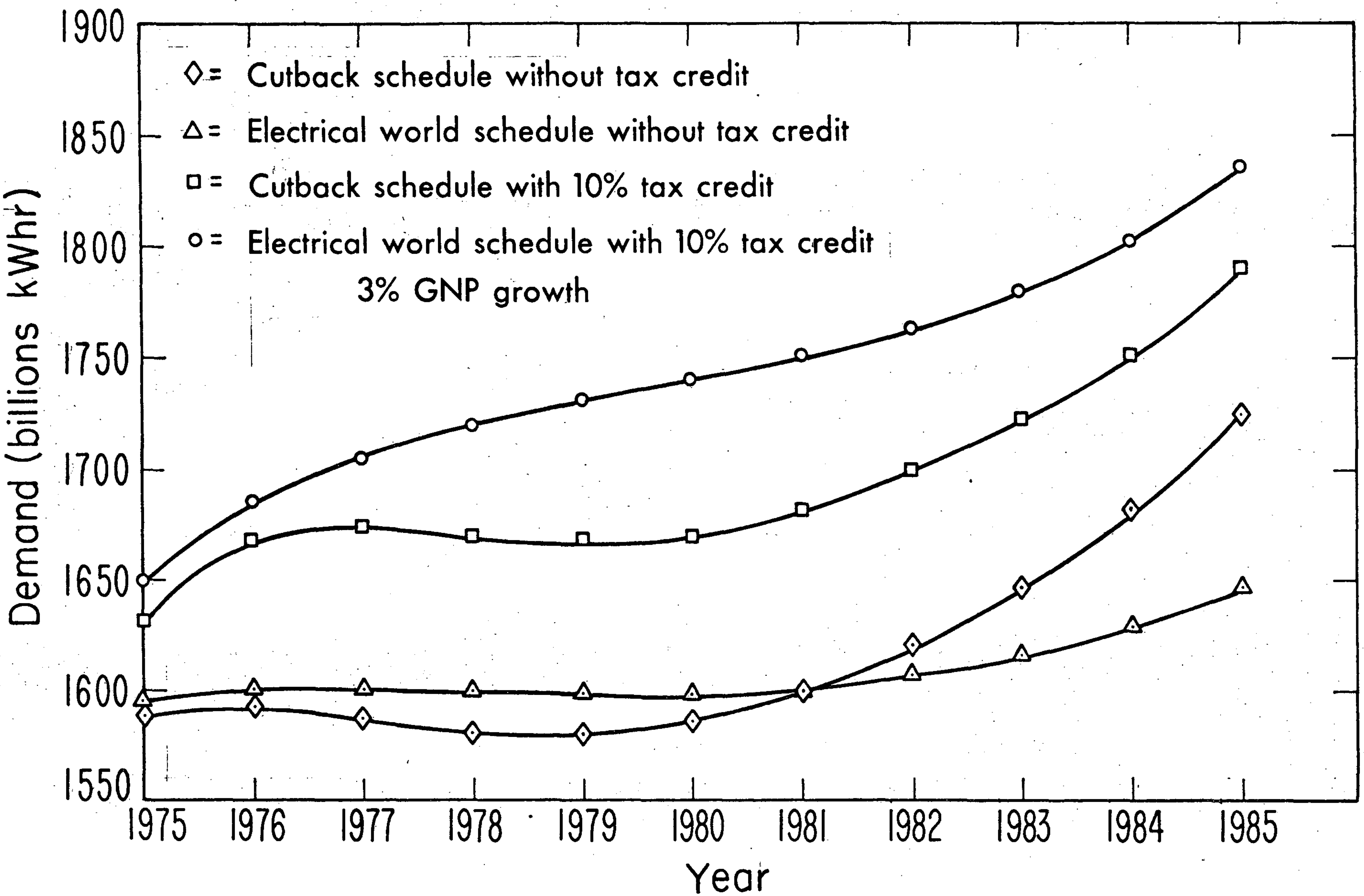
1. In gw net new power coming on line. Demand given in Billions Kwhr. Rates given in constant 1974 ¢/Kwhr. Real GNP is assumed to grow at rates shown.

TABLE - 7

DEMAND AND RATE PROJECTIONS - CUTBACK CONSTRUCTION SCHEDULE
WHTHOUT TAX CREDIT

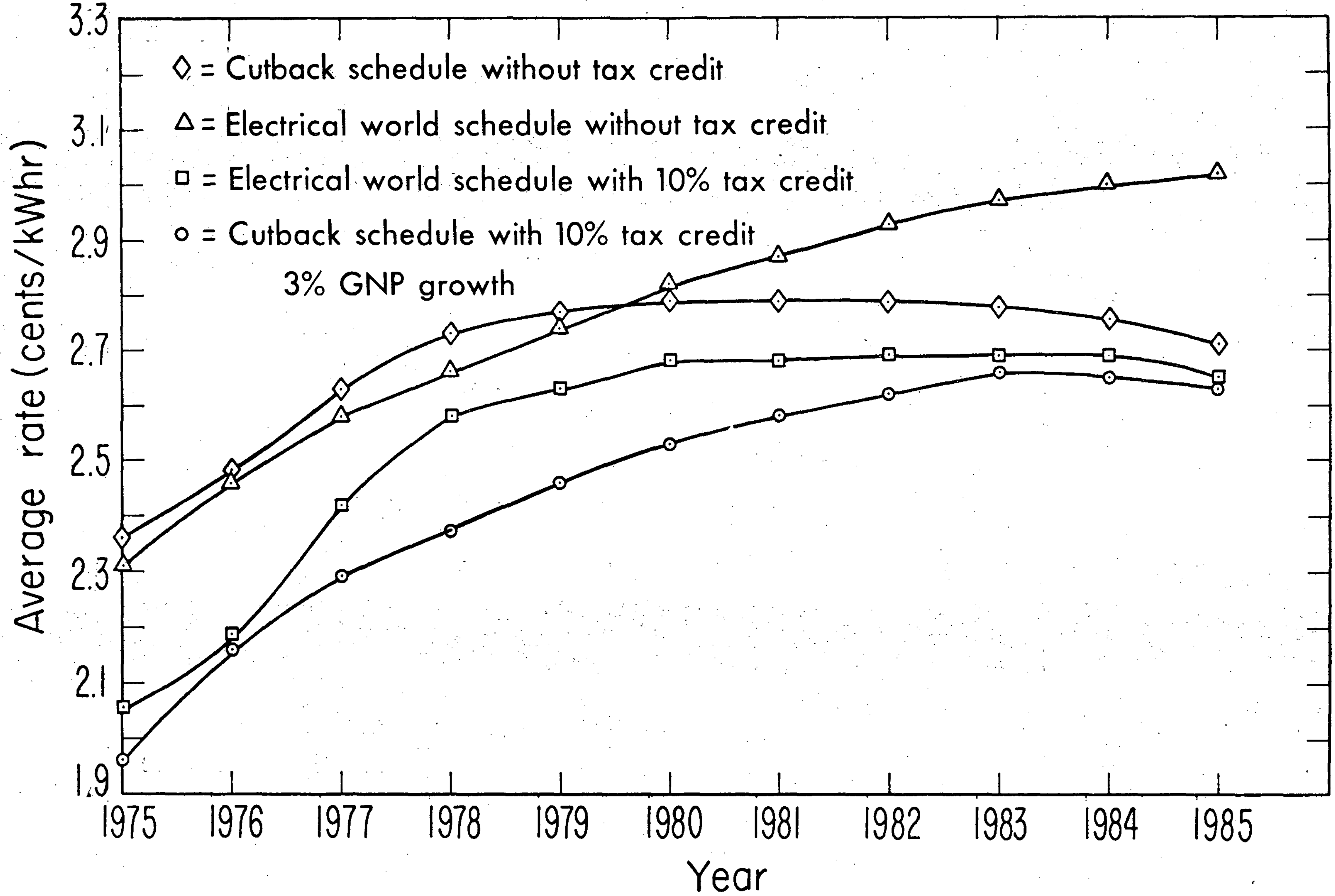
Year	Net Power Growth[1]	2% GNP Growth		3% GNP Growth		4% GNP Growth	
		Demand	Rate	Demand	Rate	Demand	Rate
1974	--	1575	2.28	1575	2.28	1575	2.28
1975	40	1584	2.36	1588	2.36	1591	2.36
1976	35	1583	2.49	1592	2.48	1601	2.47
1977	20	1569	2.65	1587	2.64	1605	2.62
1978	10	1553	2.76	1581	2.73	1609	2.70
1979	8	1540	2.81	1580	2.77	1623	2.72
1980	5	1530	2.86	1586	2.79	1645	2.73
1981	5	1526	2.88	1599	2.79	1678	2.71
1982	4	1526	2.89	1620	2.79	1722	2.69
1983	2	1530	2.91	1647	2.78	1776	2.66
1984	0	1539	2.91	1682	2.76	1841	2.61
1985	0	1554	2.89	1725	2.71	1920	2.55
Average Annual Growth Rate		-0.1%	2.2%	0.8%	1.6%	1.8%	1.0%

1. In gw new power coming on line. Demand given in Billions kwhr. Rates given in constant 1974 ¢/kwhr. Real GNP is assumed to grow at rates shown.



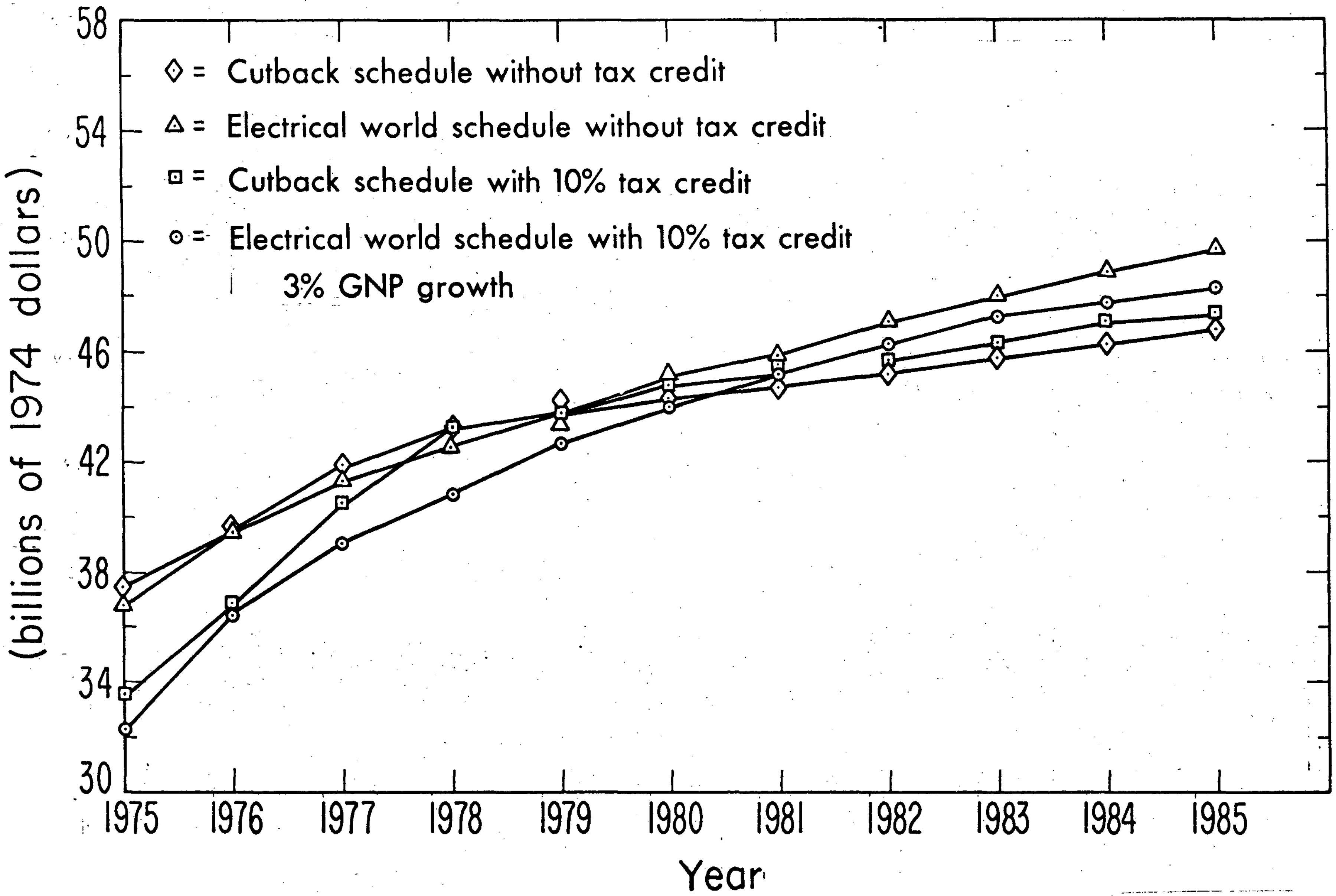
XBL 762-2334

Figure 4



XBL 762-2335

Figure 5



XBL 762-2336

Figure 6

0 0 0 0 4 4 0 5 0 7 6 6

Conclusions

In all cases, demand growth in the 1975 - 1985 period averages less than 3% annually. This is significantly lower than projections by the utility industry. Moreover, federal tax policy encourages construction and demand by lowering rates to consumers. This is particularly clear in our model projections for 1975, the first year of the 10% investment tax credit. Rates go down in this year due to the large amount of new capacity except in the scenarios which exclude the tax credit. Looking at 1985 we see that rates for the cutback schedule are almost equal to those for the Electrical World schedule, whereas the latter has slightly higher demand.

It is our impression that rates will grow significantly under high investment scenarios once the construction program ends. In our model this result appears as a large change in the parameter B in those intervals where construction drops. This can be seen in Table 8 which shows how the fixed cost parameter varies in our different construction and tax policy scenarios. When investment ceases, rates will be determined by the last value of B plus the subsidy term (tax credit and accelerated depreciation). Since the excess capacity has been built, it must be paid for. Tax policies which subsidize construction only delay the eventual increase in rates.

TABLE 8

FIXED COST TERM IN RATE EQUATION (B)[1]

	Cutback Schedule		Electrical World Schedule	
Year	With Tax Credit	Without	With Tax Credit	Without Tax Credit
1975	15.7	20.2	14.3	19.4
1976	18.2	22.2	18.1	22.0
1977	22.3	24.5	20.5	23.8
1978	24.9	25.9	22.0	25.1
1979	25.7	26.5	23.6	26.4
1980	26.5	27.0	25.1	27.6
1981	26.7	27.2	26.0	28.5
1982	27.1	27.5	27.0	29.5
1983	27.6	27.8	27.9	30.4
1984	28.0	28.0	28.1	31.1
1985	28.0	28.0	28.3	31.8

1. In billions of 1974 dollars.

The costs of overinvestment are directly borne by the taxpayer who must carry the burden of tax revenue not paid by the utilities. The tax credit from 1975-85 under the Electrical World construction schedule of 309 x 10^6 kw of new capacity will total $18.5 billion. An equal amount is due to accelerated depreciation allowances. This means that roughly $37 billion worth of utility construction will be financed by taxpayers. This contributes to budgetary deficits, higher interest rates and inflation.

The result of such tax expenditures for utility plant is excess capacity. We present in Table 9 a calculation of capacity factor in the 3% GNP growth cases for our two construction schedules.

TABLE - 9

CAPACITY FACTOR FOR 3% GNP GROWTH

Year	Capacity Factor: Cutback Schedule	Capacity Factor: Electrical World Schedule With Tax Credit
1975	.5	.5
1976	.47	.47
1977	.45	.45
1978	.44	.43
1979	.43	.41
1980	.43	.39
1981	.42	.38
1982	.43	.37
1983	.43	.36
1984	.44	.35
1985	.45	.34

Capacity factor is calculated using 10% losses for transmission and distribution. (Capacity factor = $\frac{1.1 \text{ (Totol demand)}}{\text{Capacity x 8760}}$)

IV. Some Sectoral Influences on Utility Demand and Investment

A. Introduction

One of the shortcomings of the model presented in Section III is that it does not take non-economic factors into account. For reasons explained there, we have used a single composite elasticity of electricity demand which applies to the combination of all sectors. To partially remedy this shortcoming, we have undertaken a disaggregated analysis of electricity demand in three areas--residential demand, fuel substitution in high temperature industrial processes, and by-product power generation in industry. We have chosen these three because of (1) their significant effects on electricity demand, (2) the non-economic factors (so far as demand is concerned), such as curtailments in hook-ups to utility gas systems, that may influence demand in these areas, and (3) the likekihood that future technological trends may be substantially different from the historical trends in these areas (as in by-product power).

This analysis still does not allow incorporation of non-economic factors into our electric utility model. That must be done by making the parameter δ a function of time in such a way as to reflect the implementation of such things as drastic technological change and utility gas curtailments. However, the analysis does provide an inkling of the order of magnitude of the effect of the non-economic factors in these three sectors on electricity demand and hence on utility investment.

B. Residential Electricity Demand

The demand for electricity in the residential sector was 447.8×10^9 kwhr in 1970, 32.2% of the total national consumption of 1391×10^9 kwhr.[1] The end-use consumption within the sector is shown in Table 1.

Table 1. Residential Electricity Consumption in 1970[2]

	Total Demand ($\times 10^9$ kwhr)	% of Total Residential Demand	% of National Demand
Heating	71.2	16	5.1
Cooling	58.7	13	4.2
Lighting	48.0	11	3.5
Water Heating	72.5	16	5.2
Refrigerators	82.9	18	6.0
Cooking	30.3	7	2.2
Television	25.3	6	1.8
Freezers	27.7	6	2.0
Clothes Dryers	18.5	4	1.3
Other	12.7	3	0.9
	447.8	100	32.2

Many of the determinants of residential electricity demand are not price-related and therefore not taken into account by our model. In this section, we will briefly examine the primary economic determinants and then analyze the impact of three non-economic factors--curtailments in the availability of hook-ups to utility gas systems, energy use standards for buildings and appliances, and technological change--on the use of electricity for residential space heating, water heating, cooking, and clothes drying.

1. The two primary economic determinants of residential electricity consumption are the cost of the energy-using equipment (housing and appliances) and the cost of the energy itself (the rates for electricity and its competitor fuels, primarily natural gas).

(a) The Cost of Capital - The residential sector is very sensitive to the first cost of energy-using equipment. Whether considering consumers' investments in housing or in appliances, market forces have traditionally resulted in a preoccupation with minimizing initial cost. Inexpensive energy made operating costs relatively insignificant. Where increased capital investment (first cost) is necessary to reduce future operating costs (fuel costs), market forces continue to exert their inhibiting influence, especially on low and fixed income people. While the increased cost of housing due to improved insulation, reduced infiltration, insulating windows, and the use of a more efficient heating and cooling system might be small relative to the total cost, for the over-extended individual (or speculative builder) the increase may be significant. On the other hand, the increased cost of an energy-efficient appliance, while small in amount, is often large relative to the total cost, encouraging the purchase of cheaper, less efficient models.

Producers of housing and appliances have also been pre-occupied with minimizing first (production) costs, as they have traditionally competed on the basis of price (as well as brand name), catering to the consumer's desire for convenience and low initial cost (at the expense of low energy consumption).[3] With respect to appliances at least, the situation is changing. New "energy-saving" models of refrigerators, microwave ovens, and other appliances (and their advertising) evidence the appearance in earnest of energy use competition--low energy consumption is becoming a selling point.

(b) The Cost of Energy - A number of studies have indicated that residential demand for electricity is price elastic.[4] In the short run, the nature of the existing housing and appliance stock determines whether electricity is used and, if so, how much. If rates increase, evidence suggests that the short-run effect on demand will be a reduction in consumption by curtailment and more efficient use of the existing capital stock.[5] In the long run, the situation is more complex, as the composition of the capital stock will change both through replacements and additions. If electricity rates increase relative to the price of utility gas (or fuel oil, for space heating), the substantial cross-elasticity of electricity with respect to its competitor fuel indicates that consumers will shift to increasing use of utility gas for those applications (space and water heating, cooking, and clothes drying) and in those areas (mostly urban and suburban) where possible.[6] The decreasing availability of connections to utility gas supply systems, however, is causing an increasing reliance on electricity for all major end-uses (see Table 1), even in a time of increasing rates.

Even where gas appliances can't be used, however, more efficient electric units can ... and both their efficiency and their availability are improving rapidly. In addition, solar space and water heating systems are already competitive on a life-cycle basis with resistance heating in many areas of the country. Significant reductions in the cost of solar systems are expected to result from the large-scale research, development, and production of these systems that is just now beginning.

The long-run effect on residential demand of rising electricity rates can thus be expected to manifest itself through (a) substitution, where possible, of utility gas for electricity, (b) consumer decisions not be buy electric appliances, (c) continuation of the short-run effect of reduced consumption per installation, (d) increased use of more efficient electric systems and models, and (e) substitution of alternative energy systems (primarily solar, but also wind and biofuel) for electric systems. The magnitude of these price effects is difficult to determine because of the significant non-economic determinants of electricity demand.

2. One of the most significant non-economic determinants of residential electricity consumption has already been mentioned -- the decreasing availability of hook-ups to utility gas supply systems. People in some areas are, in effect, being forced to rely on electricity for all major residential uses, including space heating, water heating, cooking, and clothes drying, end-uses where fuels such as natural gas or fuel oil can be used, if available. Although electricity is being used to some extent for these purposes even in areas where it competes with other energy sources (because of the lower first cost of some types of electric installations), it is obvious that utility gas curtailments will have the effect of increasing electricity consumption.

This fuel substitution effect is especially significant because space heating and water heating are the two largest consumers of energy in the residential sector -- households using electricity for these two purposes used an average of 14,500 and 4,500 kwhrs, respectively, in 1970.[7] Two other non-economic factors, however, technological change which improves the efficiency of systems and appliances and energy use standards for buildings and appliances, have the effect of reducing electricity consumption through the more efficient use of energy. Technological advances, such as heat pumps, solar space heating and domestic hot water systems, and microwave ovens, are beginning to diffuse more rapidly in the residential sector. Moreover, state and local governments have implemented or are considering energy-use standards for buildings, and Federal energy-use standards for appliances have been mandated by the recent Energy Policy and Conservation Act. Therefore, we will examine in more detail the aggregate impact of these three primary non-economic factors on the use of electricity for space heating, water heating, cooking, and clothes drying. (Other residential uses of electricity will also become more efficient through implementation of the conservation measures just cited).

Note in the analysis that follows that the improvements in efficiency assumed to be required by energy-use standards for buildings and appliances, while substantial, are not beyond what is currently possible - no new technological breakthroughs are assumed. It is thus the changing composition of the capital stock, as more efficient new buildings and appliances are constructed and used, that will be primarily responsible for mitigating the increase in electricity demand due to curtailments in the availability of utility gas. Average efficiency will slowly increase as less efficient buildings and appliances are replaced and new construction and appliances make up an increasingly larger percentage of the total stock. Since most residential appliances have a life of 10 to 20 years, the full impact of energy use standards that take effect in 1978 will not be felt by 1985, even by 1990. In addition, new construction will make up only 48% of total households in 1985, 59% in 1990.[8]

(a) Space Heating - In 1970, only 7.7% of all HHs (4.9×10^6 units) were electrically heated, but 28% of new construction during that year had electric heating installed.[9] By 1974, 47% of new construction (600,000 units) installed electric heating.[10] The use of heat pumps is also increasing. In 1970, 11% of the electrically-heated HHs (550,000 units) used heat pumps.[11] In 1974, 14.6% of the new construction with electric heating (93,450 units) had heat pumps installed; the estimate for 1975 is 18%.[12]

It is likely that the high demand for electric heating will continue. Based on current trends, a reasonable estimate of new electric heating installations is 45% of 1971-80 construction (12.4×10^6 units) and 50% of 1981-85 construction (6.5×10^6 units), for a total of 18.9×10^6 New electrically-heated HHs.*

* New construction is estimated to be 27.5×10^6 units during 1971-80 and 13×10^6 units during 1981-85, for a total of 40.5×10^6 new households ("New HHs").[13]

There will be few conversions from non-electric to electric heating systems, however, as HHs heating with gas or oil will continue to do so, the residential sector being given preferential access to the future supply of natural gas and fuel oil.

Not all of the increased use of electric heating is due to curtailments in the availability of utility gas, however, as the use of electricity for space heating occurs even in areas like California where natural gas is readily available. This is primarily due to the lower installation cost of electric resistance heating systems. Based on the California experience, we assumed that 15% of new residential construction will use electric heating for price-related reasons (6.3×10^6 units), while the remainder of the electric heating installations will be due to utility gas curtailments (12.6×10^6 units). At 15,000 kwhr/unit, the average electricity consumption in 1970 of HHs with electric resistance heating,[14] the fuel substitution effect will result in an increase in electricity demand for space heating of 189×10^9 kwhr by 1985. This increase in electricity consumption will be partially offset by technological change, in the form of heat pumps and solar heating systems, and building energy-use standards.

The use of heat pumps will continue to increase as their design and operation is improved. Based on current trends, heat pumps will be installed instead of resistance heating in an estimated 18% of new electrically-heated units during 1971-80 (2.2×10^6 units) and 30% during 1981-85 (2.0×10^6 units), for a total of 4.2×10^6 New HHs in 1985. Add 100,000 units during 1971-80 and 200,000 units during 1981-85 to represent the use of heat pumps instead of non-electric heating systems, for a total of 4.5×10^6 New HHs using air-to-air heat pumps in 1985. We further assumed that the Annual Cycle Energy System ("ACES")[15] or similar systems will be installed in 5% of the electrically-heated HHs constructed during 1981-85 (0.3×10^6 units), plus an additional 100,000 units representing the use of this type of heat pump instead of non-electric heating systems, for a total of 4.9×10^6 New HHs using some form of heat pump in 1985.

In 1970, the average electricity consumption for space heating of HHs with heat pumps was approximately one-half that of those with resistance heating.[16] Improvements in air-to-air heat pump technology and installation could easily result in an average reduction in electricity use of 60% in new heat pump installations of this type. The COP of the heating mode of the Annual Cycle Energy System is estimated to be 3.5-4.0.[17] The system is currently in the demonstration stage. An average COP of 3.5 by 1985 will result in a 71% saving compared to resistance heating.

Solar space heating systems will also be used more frequently, generally in situations where the alternative would have been electric heating. Assuming that their use is increasingly encouraged by continued improvements in efficiency and reductions in manufacturing cost and by government stimulation, a reasonable estimate of the number of HHs that will install solar heating systems instead of resistance heating by 1985 appears to be 500,000. We assumed that resistance heating units will be used as the auxiliary heating system in 80% of these HHs, or 400,000 units. This reduces the total number of New HHs using some form of electric heating to 18.8×10^6 units.

Solar systems can easily provide 80% of HH space heating requirements. The auxiliary resistance heating unit will thus have to provide the remaining 20%.

Energy-use standards for buildings appeared in earnest on the Federal level in 1971 when the FHA adopted revised Minimum Property Standards, increasing the insulation requirements for any FHA housing. These standards could be made much more rigorous.[18] In addition, many states have adopted or are now considering new standards regulating energy-use in buildings; communities are adopting local codes as well.[19] While much more stringent and comprehensive standards are feasible, these energy-use standards for buildings are a considerable improvement over the existing situation and should improve with time. As existing electrically heated HHs are generally insulated to some degree, however, the comparative reduction in the electricity consumption of New electricity heated HHs due to improved insulation standards will be less than for HHs with non-electric heating systems. Still, an average reduction of 20% in the electricity consumption of New electrically heated HHs is certainly possible by 1985 as a result of increasing insulation, reducing infiltration, improving window systems, and similar measures.[20]

There are other factors which will also contribute significantly to mitigating the fuel substitution effect, such as retrofitting existing HHs and lowering thermostat settings, but these are not considered here.

In order to determine the extent to which technological advances and building energy-use standards will mitigate the fuel substitution effect, however, it is necessary to estimate what percentage of the 12.6×10^6 units using electric heating because of utility gas curtailments will use heat pumps or solar systems instead of resistance heating. As the installation costs of these systems are considerably larger than conventional gas or oil systems, let alone electric resistance heating, we assumed that builders installing electric resistance heating because of its low first cost (6.3×10^6 units) will have no interest in heat pumps or solar systems. Therefore, it is in the 12.6×10^6 HHs using electric heating because of utility gas curtailments that one will find the 4.2×10^6 HHs with air-to-air heat pumps, 0.3×10^6 HHs with the ACES, and 0.5×10^6 HHs with solar systems (only 0.4×10^6 of which have electric auxiliary systems), leaving 7.6×10^6 HHs with resistance heating.

Considering all of the above, we get the following:

	# of HHs ($x10^6$)	Demand per HH (kwhr)	Total Demand ($x10^9$ kwhr)	
Resistance	7.6	12,000	91.2	20% Savings
Heat Pumps	4.5			
Air-to-air	4.2	4,800	20.2	20% x 60% Savings
ACES	0.3	3,480	1.0	20% x 71% Savings
Solar Auxiliary	0.4	2,400	1.0	20% x 80% Savings
			113.4	

The total net increase in electricity demand for space heating due to curtailments in the availability of utility gas will therefore be 113.4 x 10^9 kwhr.

(b) Water Heating - In 1970, only 25% of all HHs used electric water heating units, although 96% of all HHs had some type of water heater.[21] With respect to new construction, HHs using electric space heating generally also use electric water heaters. Some of the New HHs with non-electric space heating systems will use electric water heaters as well. Based on current trends, the installation of electric water heaters in 50% of new construction during 1971-80 (13.8 x 10^6 units) and 60% during 1981-85 (7.8 x 10^6 units), for a total of 21.6 x 10^6 New units appears to be a reasonable estimate. HHs using utility gas for water heating in 1970, however will continue to do so, residences being given preferential access to future gas supplies. There will thus be few conversions of non-electric to electric water heating systems.

On the basis of our previous estimate that 12.5 x 10^6 HHs will use electric space heating systems because of curtailments in the availability of utility gas, we can estimate that the fuel substitution effect will increase the saturation of electric water heating units by 12.5 x 10^6 HHs as well. In 1970, two types of electric water heating units were in use, standard models (averaging 4200 kwhr per year) and quick recovery models (averaging 4800 kwhr per year); all electric water heaters will be quick recovery by 1980.[22] Assuming that the additional 12.5 x 10^6 new electric water heaters will all be quick recovery models the increase in electricity consumption for water heating due to utility gas curtailments will be 60.0 x 10^9 kwhr. Again this increase in demand will be partially offset by technological change, in the form of solar water heating systems, and by appliance and building energy-use standards.

Solar water heating systems will be used more frequently, generally in situations where the alternative would have been electric water heating or propane. We assumed that solar water heating systems will be used in the HHs where solar space heating systems are used (0.5×10^6 HHs) and also used in an additional 200,000 HHs with electric space heating systems and 100,000 HHs with non-electric space heating systems, for a total of 0.8×10^6 units in use by 1985. Conventional electric water heaters will be used as the auxiliary water heaters in 80% of the HHs with solar space heating systems (0.4×10^6 units) and all of the HHs with electric space heating systems, for a total of 0.6×10^6 units.

Solar water heating systems can easily provide 80% of domestic hot water requirements. The auxiliary electric water heater will thus have to provide the remaining 20%.

We also assumed that appliance energy-use standards will be promulgated which eliminate the quick recovery feature (reducing base electricity consumption to 4200 kwhr per year) and require improved insulation, resulting in an additional 10% energy saving, in all water heating units sold after 1977.[23] Since the average water heater lasts 10 years, 80% of the water heaters in use in 1985 will meet the energy use standards. Base electricity consumption in 1985 will therefore be 3984 kwhr per year. If new energy use standards for buildings require the use of the flow reduction showerheads, faucet aerators, and similar water-saving devices in all New HHs, a further reduction of 10% in the average electricity consumption of all water heating units by 1985 will result.

An additional non-economic factor that acts to mitigate the effect of utility gas curtailments is the continuing decrease in the size of the average HH. Since hot water use is directly related to the number of people in the HH, this will reduce hot water demand per HH by 10% by 1985.[24]

In light of the above, the average annual demand in 1985 from primary electric water heating units will be 3227 kwhr/HH and from auxiliary water heating units will be 645 kwhr/HH.

In order to calculate the extent to which these non-economic factors will mitigate the fuel substitution effect, we assumed that the 0.6 x 10^6 HHs with solar water heating systems and electric auxiliary water heaters were all part of the 12.5 x 10^6 HHs using electric water heating units because of utility gas curtailments. We then have 11.9 x 10^6 HHs at 3227 kwhr/HH plus 0.6 x 10^6 HHs at 645 kwhr/HH, for a total net increase in electricity consumption for water heating due to these non-economic factors of 38.8 x 10^9 kwhr.

(c) Cooking - In 1970, 40.3% of all HHs used electric ranges, although almost all HHs had some type of cooking appliance.[25] With respect to new construction, HHs using electric space heating generally also use electric ranges. Some of the New HHs with non-electric space heating systems will use electric ranges as well. Based on current trends, the installation of some type of electric cooking appliance in 50% of New HHs during 1971-80 (13.8 x 10^6 units) and 60% of New HHs during 1981-85 (7.8 x 10^6 units), for a total of 21.6 x 10^6 New HHs with electric cooking appliances, appears to be a reasonable estimate. There will be few conversions of gas to electric appliances, as HHs using utility gas for cooking in 1970 will continue to do so, residences being given preferential access to future gas supplies.

We assumed, as we did for water heating, that the HHs using electric space heating because of utility gas curtailments will also use electric ranges, resulting in an increased saturation beyond what would result if all fuels were available of 12.6 x 10^6 HHs. At 1200 kwhr/unit, the average electricity consumption in 1970 of electric ranges,[26] the fuel substitution effect will increase electricity demand for cooking by 15.1 x 10^6 kwhr in 1985. This increase in electricity demand will be partially offset by technological change, in the form of microwave ovens, and by appliance energy-use standards.

Sales of microwave ovens went from 30,000 in 1970 to 675,000 in 1974 (19% of all sales of electric cooking appliances), their saturation increasing to 2.3%.[27] At this rate, a conservative estimate of the saturation of microwave ovens in 1985 is 10% of all HHs (8.4 x 10^6 units). However, most microwave ovens are owned by people who also have a conventional electric or gas range, and they are increasingly being sold in combination with gas or electric ranges.[28] We assumed, therefore, that 25% of all microwave ovens in use in 1985 will be used in combination with gas ranges, increasing the number of New HHs with some form of electric cooking appliance by 2.1×10^6 units, and 75% will be used in combination with conventional electric ranges, increasing the effective saturation of electric cooking appliances by an additional 6.3×10^6 HHs, for a total of 30.0×10^6 HHs.

The savings due to the use of microwave rather than conventional ovens depends on the manner in which they are used. In addition, some of the base consumption of electricity of 1200 kwhr/unit is attributable to the use of the burners, not the oven. A present average energy saving of 50% compared to the use of conventional electric ranges alone thus seems reasonable. It is likely, however, that the electricity consumption of microwave ovens will be reduced even further by future improvements in the conversion efficiency of electricity to microwaves, increasing the average energy saving to 60% by 1985.

With respect to energy-use standards for appliances, we assumed that a 40% reduction in the electricity consumption of all models sold after 1977 was required. If 50% of the electric ranges in use in 1985 meet the standards (through the use of improved insulation, door seals, and burner top configurations, for example), then the average use of electricity for cooking in the 15.3×10^6 HHs using only conventional electric ranges in 1985 will be 960 kwhr/HH, for a total of <u>14.7×10^9 kwhr</u>. Assuming that 50% of the cooking in the multiple-unit HHs (6.3×10^6 units) is done with the conventional range and 50% with the microwave, then the electricity demand from the use of the conventional ranges in these HHs in 1985 will be 480 kwhr/HH, for a total of <u>3.0×10^9 kwhr</u>. The electricity demand from the use of the microwave ovens in 1985 will be 240 kwhr/HH, for a total of <u>2.0×10^9 kwhr</u>.

In order to calculate the extent to which technological change and appliance energy-use standards will mitigate the fuel substitution effect with respect to the use of electricity for cooking, it is necessary to estimate what percentage of the 6.3×10^6 HHs with both microwave and conventional electric ranges will use electricity because gas hook-ups were unavialable. To do that, we assumed the same percentage as for electric space heating (2/3). We then have 8.4×10^6 multiple-unit HHs using both conventional electric ranges at 480 kwhr/HH and microwave units at 240 kwhr/HH, for a total net increase in electricity consumption for cooking due to these non-economic factors of 11.1×10^9 kwhr.

(d) Clothes Drying - Only 18.6×10^6 HHs (29.1%) had electric clothes dryers in 1970, but their saturation was increasing rapidly.[29] On the basis of recent sales trends, the installation of electric clothes dryers in 50% of New HHs during 1971-80 (13.8×10^6 units) and 60% of New HHs during 1981-85 (7.8×10^6 units), for a total of $\underline{21.6 \times 10^6}$ New HHs with electric clothes dryers, appears to be a reasonable estimate. There will be few conversions of HHs from gas to electric clothes dryers as HHs using utility gas for this purpose in 1970 will continue to do so, residences being given preferential access to future gas supplies.

Again we assumed that 12.6×10^6 HHs out of the total New HHs with electric clothes dryers will use electricity because of utility gas curtailments. At 1,000 kwhr/unit. the average energy consumption of electric clothes dryers in 1970, the increase in electricity demand for clothes drying due to the fuel substitution effect will be 12.6×10^9 kwhr. This increase will be partially offset by appliance energy-use standards.

We assumed that new energy-use standards for appliances will require a 20% reduction in the electricity consumption of all electric clothes dryers sold after 1977. Since the typical clothes dryer lasts 14 years, 57% of the units in use in 1985 will meet the standards. The average consumption of electricity in 1985 by electric clothes dryers will then be 886 kwhr unit.
The total net increase in electricity demand for clothes drying due to these non-economic factors will then be 11.2×10^9 kwhr.

The impact of these three primary non-economic factors on the use of electricity for residential space heating, water heating, cooking, and clothes drying can be summarized as follows:

Table 2: The Fuel Substitution Effect in the Residential Sector

	Gross Fuel Substitution Effect with 1970 Unit Energy Consumptions ($x\ 10^9$ kwhr)				Net Increase in Demand with Technological Change & Energy-Use Standards ($x\ 10^9$ kwhr)	
	# of New Installations ($x10^6$)	Demand per HH (kwhr)	Total Demand ($x10^9$ kwhr)	# of New Installations ($x10^6$)	Demand per HH (kwhr)	Total Demand ($x10^9$ kwhr)
HEATING	12.6		189.0	12.5		113.4
Resistance	12.6	15,000	189.0	7.6	12,000	91.2
Heat Pumps				4.5	4,800	21.2
Solar Auxiliary				0.3	3,480	1.0
WATER HEATING	12.5		60.0	12.5		38.8
Resistance	12.5	4,800	60.0	11.9	3,227	38.4
Solar Auxiliary				0.6	645	0.4
COOKING	12.6		15.1	16.8		11.1
Resistance	12.6	1,200	15.1	12.6	800	10.1
Microwave				4.2	240	1.0
CLOTHES DRYING	12.6	1,000	12.6	12.6	886	11.2
TOTAL			276.7			174.5

The magnitude of the fuel substitution effect is thus significant. At 1970 levels of electricity consumption per system or appliance, the increase in annual electricity demand by 1985 due to curtailments in the availability of utility gas for space heating, water heating, cooking, and clothes drying will be approximately 277 x 10^9 kwhr. Two additional non-economic factors, however, technological change which improves the energy efficiency of systems and appliances and energy-use standards for buildings and appliances, will have the effect of significantly mitigating this increase, reducing the total net increase to approximately 175 x 10^9 kwhr.

1. Electrical World, September 15, 1975, pp. 41-45.

2. Tansil, John, Residential Consumption of Electricity: 1950-1970, Oak Ridge National Laboratory, Report ORNL-NSF-EP-51, July 1973.

3. For an excellent analysis of the building industry and the institutional impediments to innovation within it, see Schoen, R., A. Hirshberg, and J. Weingart New Energy Technologies for Buildings, a report to the Energy Policy Project of the Ford Foundation, Ballinger, Cambridge, Mass., 1975.

4. Wilson, John, "Residential Demand for Electricity," The Quarterly Review of Economics and Business, II:1 (Spring 1971), pp. 7-19.

   Anderson, K.P., Residential Demand for Electricity: Economic Estimates for California and the United States, The RAND Corporation, R-905-NSF, January 1972

   Halvorsen, R. F., "Residential Demand for Electricity," Ph.D. Thesis, Harvard University, December 1972.

5. Ibid.

6. Ibid.

7. Tansil, John, op. cit.

8. Project Independence Final Task Force Report - Energy Conservation Vol. 1: Residential and Commercial Energy Use Patterns, 1970-1990, Federal Energy Administration, Washington, D.C., November 1974.

9. Tansil, John, op. cit.

10. Electrical World, op. cit.

11. Tansil, John, op. cit.

12. Electrical World, op. cit.

13. Project Independence, op. cit.

14. Tansil, John, op. cit.

15. Fischer, H.C., "The Annual Cycle Energy System," Oak Ridge National Laboratory.

16. Tansil, John, op. cit.

17. Fischer, H.C., op. cit.

18. Moyers, John C., The Value of Thermal Insulation in Residential Construction: Economics and the Conservation of Energy, Oak Ridge National Laboratory, Report ORNL-NSF-EP-9, December 1971

19. The states of California and Florida; the city of Davis, California.

20. Project Independence, op. cit.; Moyers, John C., op. cit.; Energy Conservation: A Study of Energy Consumption in Buildings and Possible Means of Saving Energy in Housing, BRE Working Party Report, Building Research Establishment, Garston, Watford, WD2 7JR, England, 1975; The Builders Guide to Energy Conservation, National Association of Home Builders, Washington, D.C. 1974.

21. Tansil, John, op. cit.

22. Ibid.

23. Mutch, J., Residential Water Heating: Fuel Conservation, Economics, and Public Policy, RAND Corporation, Doc. #R-1498-NSF, May 1974.

24. Project Independence, op. cit.

25. Tansil, John, op. cit.

26. Ibid.

27. "Merchandising Week 1975 Statistical and Marketing Report," Merchandising Week, February 24, 1975.

28. Merchandising Week, op. cit.

29. Tansil, John, op. cit.

30. Ibid.

C. Fuel Substitution in Industry

The shortage of natural gas will effect industrial energy use more severely than other sectors. The Federal Power Commission has given low priority to industrial use of natural gas and therefore the lack of availability of this fuel will force the substitution of other forms of energy. We are interested in the amount of industrial gas use that will shift to electricity. The main type of process involved in such shifts is high temperature direct heating. While it is difficult to calculate the amount of gas involved in these processes, rough estimates can be made from data in the National Gas Survey.

We begin with an estimate of the theoretical upper bound of natural gas use that might convert to electricity. The largest gas users include industries which are not involved in high temperature processes such as food processing, paper and pulp, and petroleum refining. These must be excluded from consideration. The standard industrial classification for industries such as chemicals and allied products (SIC 28) and stone, clay and glass products (SIC 32) include some high temperature processes. For the purposes of our estimate we include half the gas use in these categories as potentially available for substitution with electricity. In Table 1 below the various gas-using sectors which might substitute are enumerated. This data is for 1967.

Table 1

SIC NO.	Industry Classification	Gas Purchased*
33	Primary metals	1.14
28	Chemicals and allied products	.73
32	Stone, clay and glass products	.36
37	Transportation equipment	.14
34	Fabricated metal products	.16
35	Machinery except electrical	.15
36	Electrical equipment and supplies	.11
	TOTAL	2.79 Q

* (10^{15} Btu = 1Q)

Following the National Gas Survey, we scale the 1967 data up to 1975 by assuming 5.1 percent annual growth rate from 1967 to 1971, and 0.7 percent from 1971 to 1973. No growth in gas consumption occurred in 1974 and 1975. This gives a scaling factor of 1.24 and yields a total consumption of 3.43 Q in 1975 available for substitution. We must substract from this gas which is not subject to FPC regulation, namely the intrastate gas produced in Texas, Louisana, Oklahoma and New Mexico. Data on this is also available in volume 5 of the National Gas Survey. In Table 2 we enumerate the industrial sectors using natural gas in the Mountain and West South Central regions. For chemicals and glass we use only half the totals. The data is for 1962.

Table 2

Primary metals	.13
Chemicals and allied products	.42
Glass	.15
Other (estimated)	.15
	.85 Q

Using similar scaling assumptions (5.1% growth from 1962 to 1971), we get a growth factor of 1.56 from 1962 to 1975. This gives a total of 1.32 Q of intrastate gas. Thus the net amount of natural gas available for substitution is 2.11 Q.

To calcualte how much electricity will be required to replace this 2.11 Q of gas, we must estimate the relative efficiency of the electric processes compared to the gas processes. Any such estimate is bound to be very crude since it averages over many processes and because the data available is limited. Some examples drawn from the Natural Gas Survey can be offered to justify the estimate we use. In steel production the electric arc furnace uses 1.7 million Btu per ton compared to 4.3 million Btu per ton for open heath furnaces;

electricity is about two and a half times more efficient than the fuel-fired open hearth furnace. In heat treating steel the efficiency of fuel fired reheating furnaces is about eight percent; for induction heaters the efficiency is about 30 percent. In this case electricity is nearly four times as efficient as fuel. In ferrous foundries gas-fired nonrecuperative reverberatory furnaces are about eight percent efficient, whereas electric arc and induction furnaces are 50 percent efficient. Here the ratio is closer to 6 to 1. In the fabrication of aluminum products crucible furnaces range from 15 to 30 percent efficient, with reverberatory furnances in the 25-35 percent range. Induction furnaces for melting are about 65 percent efficient. In the glass industry, electric melters are slightly more than twice as efficient as gas-fired. Our conclusion from this data is to assume a relative efficiency of 3 for electricity over gas. A finer analysis would probably revise this estimate.

Now it is simple to calculate the amount of electricity required to substitute for 2.11 Q of natural gas. Since 1 kwhr = 3413 Btu, we conclude that

$$\frac{2.11 \times 10^{15} \text{ Btu}}{3} \left(\frac{1}{3413}\right) \frac{\text{kwhr}}{\text{Btu}} = 2.05 \times 10^{11} \text{ kwhr} \quad .$$

Thus 205 billion kwh will be the maximum potential for fuel substitution. It remains to estimate the fraction of this which will likely be implemented.

For the reasons cited below we estimate that half this total will actually appear as new industrial demand for electricity. There are a variety of reasons for expecting only a limited implementation of fuel substitution. To begin with many industries may be simply unable to convert because of the high capital cost of new equipment. Firms in this situation may just close up shop and go out of business or move to states where intrastate gas is available. Moreover, some firms may generate their own electricity, thus placing no extra demand on utilities (see the following section). Further, the estimates given in Table 1 include many small shops which have high priority in the FPC guidelines and will probably not be affected by curtailment. Curtailment itself is a regional matter and there will be areas that are not as severely affected as others. Firms in the better supplied regions will be under less pressure to convert. In addition to electricity, of course, there are other fuels which can be substituted for gas. Inevitably some firms will go to coal or oil for their process needs rather than electricity. The level of gas supply itself is by no means fixed and may tend to increase due to several factors. Among these are the gas that will become available as electricity generation switches away from using natural gas in response to FPC orders. Further, some form of deregulation may occur which will tend to increase supply. If complete deregulation does not occur there may be either variances of some kind or other limited forms of deregulation. Finally, the effect of new energy conservation technology must be figured into an estimate of fuel substitution. Industries which are faced with the high capital costs of converting to electricity, itself a high priced form of energy, will have an added incentive to adopt efficient manufacturing technology. The rising cost of gas is a further incentive for efficiency.

Thus we conclude that the probable effect of the natural gas shortage on industrial electricity requirements will be an additional load on the order of 100 billion kwhr. The lag time for complete implementation of this effect will be at least five years. At that time scale the annual effect will be at most 1½ percent increase in electricity demand. If a longer implementation horizon is considered, the annual percentage effect is correspondingly smaller.

D. By-Product Power

By-product power generation by steam using industries has been identified as a significant energy conserving option open to American industry.[1] The question arises, however, concerning what affect wide-scale industrial by-product power generation will have on public utility companies. If industries begin to generate large amounts of power for their own consumption, then estimates of the utilities' future capacity needs may be too large. The projections of Electrical World,[2] for example, do not take this into account. On the contrary, they assume that industrial generation will become less significant in the future. This may be a serious error. It is certainly true that historically the percent of total power generated by industry in this country has been on the decline. At present about 6% of our power is generated by industries which utilize waste steam for process. This decline, however, was coincident with declining rates for utility produced electric power sold to industry. It is clear that if utilities can sell power at a low enough rate to industry, then they can economically discourage industries from generating their own power.

The historic trend of declining rates has been dramatically reversed in the last few years. In addition, there has been a tendency toward rate flattening with the result that industrial rates have grown faster than average rates. Thus, industrial electricity bills have made a quantum leap in the past two years. Typically, industry takes a relatively long time to respond in full to price changes because of the size of capital investments involved in any substantial change in the companies' internal processes. After sufficient time has passed, however, the response of industries tends to be great. They have large long-range elasticities. One response of these industries to rising electricity prices in the coming decade will be to build their own generators and use waste steam for process. Some industries may pull out of the utility grid entirely. Utilities can fight this trend in various ways by imposing high stand-by power rates, by refusing to wheel power, etc. As economic forces build for industrial generation, however, legislative pressures are likely to follow since industry is a powerful influence on government. A conflict of this sort would seem to favor industry over the utilities as industry is simply a more powerful economic force. In addition to this, energy conservation is becoming a top priority item in federal and state governments, and since by-product power generation is energy conserving, pressure is likely to come from government also.

As examples of the feasibility of by-product power, one may take the Federal Republic of Germany and the Soviet Union. In the Soviet Union, 36 percent of all power generated in 1950 was by-product power.[3] Much of the waste heat from these plants was used for residential and commercial heating. The historical trend was for an increase in the percentage of by-product power. In West Germany, about 28 percent of all electricity generated is industrial by-product power.[4] There is some evidence that other European countries generate significant amounts of by-product power; available statistics[5] indicate large amounts of industrial self-generation, but do not indicate what percentage of this is by-product power. Similar evidence exists for Japan[6] although once again this data only contains industrial self-generation figures ($\sim$ 15% of total, 1972). The industries which are most suited to utilize back-pressure steam for process are the chemical industries, paper industries, petroleum refineries, and some food industries. Countires which are intensive in these industries are likely to generate the most by-product power.

The thermal efficiency of by-product power generation is typically about 80%. This is the power generated divided by the fuel required to generate the power. The thermal efficiency of the best utility power plants at present is about 40%. In other words, it takes about one-half as much fuel to produce by-product power as compared to the same amount of utility produced power. The reason for this is that the "waste" heat in by-product power generation is utilized for constructive purposes (process steam, heating, etc.) whereas utility waste heat is simply dissipated. There is no new knowledge involved in this statement. These facts have been known to power engineers for half a century. Cheap fuel prices in the past have made it more economical in this country to let the waste heat be dissipated rather than invest the capital necessary to utilize it. Now the situation has changed abruptly.

To get a rough idea of how much industry is likely to generate in the next 10 years, let us consider steam turbine generation. A typical ratio (R) of power generated over process steam produced at the low pressure end of the turbine is about 50 kwhr/10^6Btu, for process steam at 150 psig. The capital cost in addition to the cost of raising steam for a 20 mw generating system is about \$650/kw.[7] This capital cost varies inversely with the size of the system. If S is the amount of process steam needed (in enthalpy) by an industry, then the amount of electric energy that can be generated is S x 50 kwhr/10^6 Btu for 150 psig. In 1968, the amount of fuel consumed by industry for process steam was:

1968 process steam = 10.13Q of fuel.[8]

In this same year, industry generated .41Q of electric power.[8] Historically, process steam use has grown at 3-1/2% annually. At this rate of growth, about 18.2Q of energy would be associated with process steam in 1985. In 1968, 2.82Q of this steam was already associated with by-product power (if one assumes 150 psig steam). Thus, in 1985, about 15.4Q would be available for new generation (post 1968). It has been estimated[7] at industrial electric rates of about 31.9 miles/kwhr in 1980, that about 43% of the steam could be economically associated with steam turbine cogeneration. Taking this factor of 43% yields about 6.6Q. Higher rates would yield a higher number than this. Boiler conversion efficiencies are about 85% and so the enthalpy content of the steam is .85 x 6.6Q = 5.6Q. The amount of electricity which could be generated, producing this steam as waste, is

$$5.6Q \times 50 \frac{\text{kwhr}}{10^6 \text{ Btu}} = 2.75 \times 10^{11} \text{ kwhr.}$$

Assuming an industrial load factor of 85%, the capacity needed to generate this steam is about 37,000 mw. We consider this to be a fairly conservative estimate of the potential for by-product power generation in the next decade.

The estimate of 37,000 mw may be an underestimate for several reasons. First, industrial rates may be higher than those assumed in Ref. 7. Second, not all process steam is 150 psig, but may be at a considerably lower pressure. Lowering the pressure of the process steam increases the potential capacity of industry. Third, these stimates assume steam turbine generation only. Capital requirements for gas turbines are considerably lower (about $200/kw) and for diesels, lower still. For gas turbines, R can be over 100 kwhr/10^6 Btu, and for diesels even greater. Thus the by-product generating potential with these types of engines is much greater than with steam turbine alone. To get an estimate of the effect of very high industrial rates, we can turn to the West German experience where 28% of all power is generated by industry. Being on the conservative side, let us suppose that in 1985 15% of American capacity is industrially generated. Taking the Electrical World projections[2] of 755 gw total capacity in 1985, this would mean an industrial capacity of 113 gw by 1985. Thus, the uncertainties for industrial generation are great, but the possibilities are large.

Taking the conservative estimate of 37,000 mw by 1985, and a capital cost of $650/kw, the total capital investment on the part of industry would be about $24 billion over that which would be needed to produce steam only. This is roughly the amount of capital which would be displaced from utilities' capital requirements.

It is our opinion that industrial generation will be a response to economic conditions, i.e., utility rates. Therefore, we expect that there is no a priori need to amend the previously discussed demand model to take this factor into account. The option of by-product generation in industry simply contributes to the overall elasticity of electric demand. It is possible, of course, that as industries begin to generate significant amounts of power, then the constants δ and K will begin to change somewhat. It is difficult to predict what will happen to these parameters due to this effect.

The question is then what course the utilities should pursue in the light of this. The first step toward avoiding potential overcapacity is for electric utilities to acknowledge that by-product power is likely to play an important role in future electric generation, especially if industrial rates continue to increase. A useful action would be to monitor carefully the amount of industrial generation in the next few years. If industrial generation begins to grow significantly, then utilities must respond by cutting back on construction of new power plants. The alternative is wasteful excess capacity.

The utilities have several options for dealing with the tendency toward by-product generation. First, the utility companies can offer to own and run the by-product power generators on site for the industry. The thermal efficiency is still 80 percent, but the utility has control of the revenues. Second, utilities can design new power plants so that it is possible to sell waste steam to industry for process, and to commercial and residential buyers for heating. When one considers that in 1973 over 13Q of energy was wasted in the form of waste heat at utility owned power plants in this country, one gets an idea of the inefficiency involved in our system of electric power generation. This waste heat was about 17 percent of our total energy consumption in 1974! It could have been used for many constructive purposes like heating homes, process steam, etc. Instead, the fuel (mostly fossil) which generated this waste heat is gone forever, and it produced nothing of value to society.

Footnotes

1. Gyftopoulos, E. P., L. J. Lazaridis, and T. F. Widmer, Potential Fuel Effectiveness in Industry, Ballinger Publishing Company, Cambridge, Mass., 1974.
2. "26th Annual Electrical Industry Forecast," Electrical World, Vol. 184, No. 6, pg. 35, September 15, 1975.
3. Hardt, J. P., Economics of the Soviet Electric Power Industry, Ph.D. Thesis, Columbia University, 1955.
4. Goen, R. L., and R. White, Comparison of Energy Consumption Between West Germany and the United States, Stanford Research Institute, Menlo Park, California, SRI-EGU 3519, June 1975.
5. The Situation and Prospects of Europe's Electric Power Supply Industry, Secretariat of the Economic Commission for Europe in 1960-61, United Nations, Geneva, 1962 (ibid. - supplement).
6. Electric Power in Asia and the Pacific - 1971 and 1972, Economic and Social Commission for Asia and the Pacific, Bangkok, Thailand, prepared for the United Nations, New York, 1974.
7. Energy Industrial Center Study, Dow Chemical Company, Midland, Michigan, June 1975.
8. Patterns of Energy Consumption in the United States, Stanford Research Institute, Menlo Park, California, June 1972.

E. Conclusion

In this section we have attempted to estimate the impact of several different kinds of fuel changes on the demand for electricity. In two sectors, high temperature industrial processes and residential consumption, the fuel substitution effect tends to increase the demand on utilities. The influence of by-product power generation by industry tends to lower the demand on utilities. All of these estimates depend on economic factors such as rates, technical factors such as industrial process efficiencies, and public policies such as appliance standards, building codes, and utility regulations. With such a large number of highly uncertain variables, any calculation is bound to be approximate. Nonetheless, it is worthwhile to add up the sectoral influences we have studied to determine if there will be a net effect on utility demand. Our conclusion is that the effect will be almost zero; fuel substitutions will not require utilities to add extra capacity.

The contributions from the various sectors are as follows (projected to 1985):

Residential Consumption (Electric space heating, water heating, cooking, and clothes drying)	$+175 \times 10^9$ kwhr
By-product Power Generation	-260×10^9 kwhr
Fuel Substitution for Industrial Process	$+100 \times 10^9$ kwhr
TOTAL	$+ 15 \times 10^9$ kwhr

The total influence of 15 billion extra kilowatt hours is insignificantly small in the total demand on electric utilities. Because this load will not be exclusively a base load, the effect on capacity may be somewhat greater than zero. Even considering this factor, the net influence will be quite small because the most unbalanced new load (electric space heating) will tend to flatten load curves which currently peak in summer.

V. Conclusion

The purpose of this section is to present a concise summary of the main results of this paper, and to indicate areas of future research. An important conclusion from our investment planning model (IPM) is that

- Economic growth does not necessarily imply increased energy consumption.

A survey of the projections of IPM shows that even though GNP may be growing at a healthy rate in the future, electricity demand may not grow at historical rates of 6 to 7 percent annually. The reason for this is the increased cost of fuels and capital which we have witnessed in the last few years, and which is expected to continue in the future. Roughly the model suggests that the rate of increase in demand is equal to the rate of increase in GNP minus the rate of increase of average rate. Thus, a growth in GNP can be cancelled by a simultaneous growth in rates, yielding a demand which does not grow, or does not grow as fast as GNP.

An examination of Table (1) shows that

- Tax policy is a major factor in investment planning.

The investment tax credit (and accelerated depreciation allowance!) is an important stimulus for investment. Tax policy also effects demand for electricity

- High investment in generation capacity, when subsidized by the present 10% tax credit, produces increased electricity consumption.

The reason for this is that tax dollars are subsidizing the production of power, resulting in decreased rates to the user in the high investment case; these lower rates stimulate demand. By comparing lines A and E of Table 1, we see that demand grows at about .3% faster for high investment. When the tax credit is removed, the situtation reverses.

- Without the tax credit the direct user, rather than the indirect taxpayer, is is paying the cost of potential overcapacity.

If high investment occurred without the tax credit, then demand would be reduced relative to a cutback schedule. By comparing lines C and G of Table (1) we see that the demand in the cutback case increases about .4% faster than the high investment case, and rates increase about 1% slower.

- Reduction or removal of the tax credit would favor a cutback construction schedule and reduced electricity demand.

Within a given investment plan the full tax credit also increases demand. For the high investment case this is a 1% effect (compare A with C). The effect of demand is smaller for a lower investment program (compare E with G).

Table (1) shows increasing electricity rates under all assumptions. Recall that these are real rates, with inflation factored out. The present trend is for industrial rates to increase faster than average rates.

- Industrial rates may undergo large increases in the next 10 years.

This trend will encourage more industries to generate their own electricity. Our rough estimate of the amount of this generation shows that it is somewhat larger than our estimate of the potential increase in demand for electricity due to the natural gas shortage. Both these estimates involve a good deal of judgement and are therefore subject to uncertainties. However, a rough conclusion can be drawn.

- Industrial power generation could cancel the effects of fuel substitution on demand for utility produced power.

It could even dominate the fuel substitution effect.

Several important questions are raised by these results. The investment tax credit stimulates electricity consumption as well as potential excess investment. Increased electricity consumption means increased use of scarce fuels and increased environmental pollution. In addition, the tax credit reduces the revenues of the federal government by reducing the amount of taxes that utility corporations pay. This latter effect contributes to budget deficits and inflation, unless the difference can be balanced by tax increases in other sectors of the economy. Effectively the federal government pays about 20% of the cost of each new power plant that comes on line (10% is tax credit and about 10% is accelerated depreciation allowance). Our results suggest that a continuation of this policy may result in considerable overcapacity in the next ten years. It can be argued that these effects are undesirable. In this event the following strategies ought to be considered.

- Strategies to be studied:

  1. Reduce or remove the investment tax credit for utilities.
  2. Encourage utilities to implement cutback consturction schedules.
  3. Encourage by-product power in industry.
  4. Encourage load management in utilities.
  5. Encourage energy conservation in general.

This report suggests a number of areas for future research. It would be desirable to disaggregate the model considered in Section III to different customer blocks without giving up the coupled nature of the model. It would be interesting to search for a concise understanding of how utilities arrive at a construction schedule. Do they try to maximize gross revenues, net revenues after taxes, profits, or something else? It would also be interesting to study how bond ratings affect a utilities ability to raise capital, and how bond ratings are effected by over capacity. Another important item is the fuel adjustment clause, and its relationship to energy efficiency. In addition, it would be straight forward and interesting to study different tax policies for depreciation allowance.

All of the subjects discussed in Section IV need further examination, especially those concerning fuel substitution and industrial power generation. A number of studies are being done, but much of the data needed to assess the potential in these areas is lacking. More comprehensive and accurate data needs to be collected on the nature of the various end-use sectors -- present energy consumption disaggregated by final end-use, the nature of the existing capital stock (buildings, appliances, industrial equipment, etc.) and the nature of industrial processes. In the area of by-product power, some effort should be spent in making foriegn technology in this area available to American engineers and scientists. Countries such as the Soviet Union, Sweden, and West Germany rely extensively on by-product power generation, and it is likely that they have developed a certain number of engineering improvements in this field.

The electric utility industry is a central institution in the United States economy. Because of the complexity of this industry and its vital role, we believe that more effort should be spent to understand and examine its policies and practices. Electricity is a common good whose production is financed in significant part by the taxpayer. The decisions which will shape the future of the utility industry should be open to public examination and debate. To prepare for these decisions more research is necessary into the financial, political and technological aspects of electric power generation.

TABLE 1

			Percent Annual Growth		
	GNP Growth[1]		2 %	3 %	4 %
	High Investment[2]				
A	With Tax Credit	D	0.5	1.4	2.4
B		R[4]	1.9	1.3	0.8
C	Without Tax Credit	D	-0.5	0.4	1.4
D		R[4]	3.2	2.6	2.0
	Low Investment[3]				
E	With Tax Credit	D	0.2	1.2	2.1
F		R[4]	2.0	1.4	0.8
G	Without Tax Credit	D	-0.1	0.8	1.8
H		R[4]	2.2	1.6	1.0

1. Annual percent growth in real GNP assumed in the model.
2. Based on Electrical World construction schedule.
3. Based on cutback construction schedule.
4. Percent increases are for real rates.

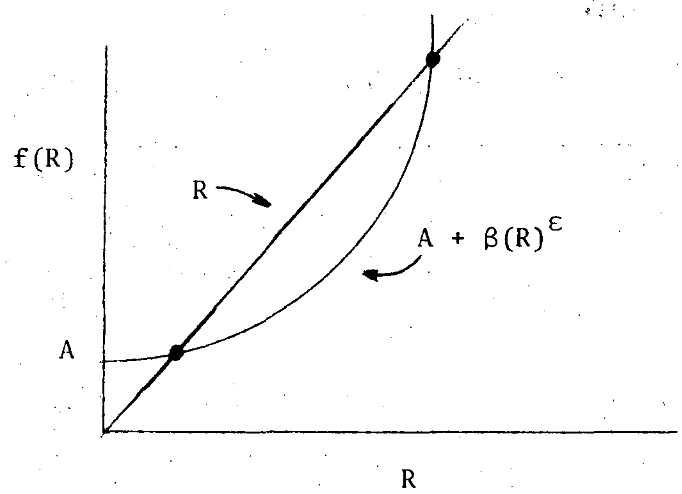
Appendix I

Conditions for Solutions for $\varepsilon > 1$

As was pointed out in Section III B, a static solution to our equation demands

$$R = A + \beta(R)^{\varepsilon} . \tag{1}$$

This may be visualized graphically as the intersection of the functions R and $A + \beta R^{\varepsilon}$.



The tangent of the two curves are equal for only one value of R given by the equations

$$1 = \varepsilon \beta(R)^{\varepsilon-1} \rightarrow r = \left(\frac{1}{\varepsilon\beta}\right)^{\frac{1}{\varepsilon-1}} \tag{2}$$

where r is the value of R at the point where the tangent of the curves are equal. We can evaluate $A + \beta R^{\varepsilon}$ at this point. Let

$$I = A + \beta\left(\frac{1}{\varepsilon\beta}\right)^{\frac{\varepsilon}{\varepsilon-1}} , \tag{3}$$

If $I > r$, then there is no static solution. If $I = r$, then there is exactly one solution, and if $I < r$, then there are two solutions. No solutions exist if

$$A + \beta\left(\frac{1}{\varepsilon\beta}\right)^{\frac{\varepsilon}{\varepsilon-1}} > \left(\frac{1}{\varepsilon\beta}\right)^{\frac{1}{\varepsilon-1}} \tag{4}$$

or

$$A(\varepsilon\beta)^{\frac{1}{\varepsilon-1}} + \frac{1}{\varepsilon} > 1, \tag{5}$$

which can be rewritten

$$A(\beta)^{\frac{1}{\varepsilon-1}} > \frac{1 - \frac{1}{\varepsilon}}{\varepsilon^{\frac{1}{\varepsilon-1}}} > 0 \quad . \tag{6}$$

As a check on consistency, let us take the limit $\varepsilon \to 1$ of this equation:

$$\lim_{\varepsilon \to 0} \qquad A^{\varepsilon-1}\,\beta > \frac{(\varepsilon-1)^{\varepsilon-1}}{\varepsilon^{\varepsilon}} \to \beta > 1 \quad , \tag{7}$$

Thus our condition for no solution becomes $\beta > 1$ in the limit $\varepsilon \to 1$, as it should.

Appendix 2: Rate Model Calculations

We will check our expression for average rates (III D eq. (1) (16) and (17) by deriving numerical results for a single utility (Pacific Gas and Electric) and for the investor - owned utilities as a whole.

Pacific Gas and Electric Company Data

Year	D	D_c	D_f	$\alpha = \frac{D}{D_f+D_c}$
1969	40.33	23.46	21.12	.905
1970	42.27	22.92	24.00	.901
1971	46.07	26.87	24.53	.898
1972	48.45	24.16	29.36	.905
1973	50.77	25.84	29.94	.910
1974	50.26	34.95	20.42	.900

Physical parameters - electricity numbers in 10^9 kwhe/year.

(Sources: FPC Statistics of Privately Owned Utilities in in the U.S., 1969-73, Electric Plant and Energy Account and 1974 Financial and Statistical Report, Pacific Gas and Electric Company.

First we calculate A_{69} to A_{74} (where the subscripts denote the year in question).

$$A_i = \frac{m_{2i} + f_i/\alpha_i}{I - i_{Ri}}$$

Electric Operation and Maintenance Expenses

Year	M_1	m_2D	($\times 10^{-3}$) m_2	F	($\times 10^{-3}$) $f = f/D_f$	($\times 10^{-3}$) f/α	($\times 10^{-3}$) A
1969	71.6	101.1	2.51	71.4	3.38	3.73	6.32
1970	88.3	107.5	2.55	82.0	3.41	3.78	6.42
1971	109.4	115.8	2.52	91.3	3.72	4.14	6.73
1972	120.1	126.5	2.62	120.3	4.09	4.52	7.24
1973	125.3	142.0	2.80	150.9	5.04	5.54	7.97
1974	153.7	179.3	3.57	206.6	10.12	11.24	15.01

Parameters for calculating A: M_1, m_2D, F are in millions of dollars; m_2, f, f/α, A are in \$/kwhe.

Taxes on revenue determine the rates i_R, i_F.

Income and Retained Earnings Account

Year	Taxes on Revenue	Revenue	i_R	Federal Taxes	i_F
1969	9.0	674.1	.013	70.9	0.48
1970	9.9	705.4	.014	58.4	0.48
1971	8.5	792.3	.011	72.5	0.48
1972	12.1	856.8	.014	61.5	0.48
1973	14.9	947.5	.016	62.5	0.48
1974	14.1	1104.7	.013	56.8	0.48

(Note: Federal taxes are on net income.) Taxes and revenues are in millions of dollars.

The ratio $\gamma = \dfrac{\text{electric utility plant}}{\text{total utility plant}}$ is applied to dividends and interest payments attributable to the electric utility portion.

$\gamma_{69} = .734 \qquad \gamma_{72} = .740$

$\gamma_{70} = .732 \qquad \gamma_{73} = .746$

$\gamma_{71} = .735 \qquad \gamma_{74} = .763$

These figures are computed from the Balance Sheet.

Calculation of B_i

T_M ; L: Income and Retained Earnings

Year	Other Taxes T_M	L	fD_c
1969	80.8	89.3	79.3
1970	82.4	94.2	78.2
1971	83.5	100.4	99.9
1972	85.5	108.6	98.8
1973	87.7	115.5	130.2
1974	90.0	127.9	353.7

FPC (1973); for 1974, see PG&E Amended Application No. 55509. All parameters in millions of dollars.

Capital Charges

Year	$\begin{bmatrix}\text{preferred}\\ \text{stock}\end{bmatrix}\gamma$ C_p	C_b	K_a	$(i_a+i_d i_F)$	($\times 10^6$) $(i_a+i_d i_F)K_a$	$i_e K_e$
1969	$13.4 $\times 10^6$	$ 61 $\times 10^6$	$200 $\times 10^6$	.109	$21.8	$111 $\times 10^6$
1970	$13.4 $\times 10^6$	$ 71 $\times 10^6$	$258 $\times 10^6$	.096	$24.8	$108 $\times 10^6$
1971	$17.6 $\times 10^6$	$ 84 $\times 10^6$	$312 $\times 10^6$	.136	$42.4	$124 $\times 10^6$
1972	$22.4 $\times 10^6$	$ 94 $\times 10^6$	$269 $\times 10^6$	.136	$36.6	$137 $\times 10^6$
1973	$26.5 $\times 10^6$	$103 $\times 10^6$	$260 $\times 10^6$	.136	$35.4	$155 $\times 10^6$
1974	$33.9 $\times 10^6$	$105 $\times 10^6$	$272 $\times 10^6$	.136	$37.0	$165 $\times 10^6$

Where C_p and C_b are computed from Income and Retained Earnings Account using the parameter γ; K_a is calculated from the Balance Sheet using the gross increase in electric utility plant + nuclear fuel; i_a is 4% for 71-74, zero in 1970, and prorated to 1.3 % in 1969 (see Federal Tax Course, 1975); accelerated depreciation i_d is computed at 20%; federal tax rate i_F is 48%; $i_e K_e$ can be computed as (Net Income - Preferred Stock dividends)γ. Note that our expression for B, flows through the savings due to tax credit and accelerated depreciation into lower rates. This is PG&E's accounting procedure.

$$B = \frac{C_b + L + M_1 + T_M - fD_c}{1 - i_R} + \frac{C_p + i_e K_e - (i_a + i_d i_F) K_a}{(1 - i_F)(1 - i_R)}$$

$$B_{69} = \$425 \times 10^6$$
$$B_{70} = \$449 \times 10^6$$
$$B_{71} = \$473 \times 10^6$$
$$B_{72} = \$551 \times 10^6$$
$$B_{73} = \$600 \times 10^6$$
$$B_{74} = \$438 \times 10^6$$

						Model Rates	Actual Rates	(= revenue/D) (¢/kwhr)
R_{69}	=	6.32	+	10.53	=	1.68	1.67	
R_{70}	=	6.42	+	10.62	=	1.70	1.67	
R_{71}	=	6.73	+	10.26	=	1.69	1.72	
R_{72}	=	7.24	+	11.37	=	1.86	1.77	
R_{73}	=	7.97	+	11.81	=	1.98	1.87	
R_{74}	=	15.01	+	8.71	=	2.37	2.20	

The agreement of the model rates with the actual rates is quite good for 1969-71. The errors in 1972-74 may be due to the crude parameter γ which doesn't separate electric and gas operations in sufficient detail. The latter is considerably less profitable than the former.

National Data for all Privately Owned Utilities

Year	D	D_c	D_f	$\alpha = \frac{D}{D_c+D_f}$
1969	1215	298	1008	.930
1970	1289	311	1078	.928
1971	1358	344	1115	.930
1972	1464	378	1190	.933
1973	1578	425	1265	.933

Physical parameters - electricity numbers in 10^9 kwhe/year

(Sources: FPC Statistics for Privately Owned Utilities in the U.S., 1973, Table 23 Composite Statements)

We calculate A_i from the data as in the previous example:

O & M Expenses

Year	M_1	$(x10^{-3})$ m_2D	$(x10^{-3})$ m_2	F	$(x10^{-3})$ $f = F/D_f$	$(x10^{-3})$ f/α
1969	2580	2815	\$2.32	2909	2.88	3.10
1970	2861	3231	\$2.51	3568	3.30	3.55
1971	3240	3651	\$2.69	4366	3.91	4.20
1972	3647	4188	\$2.86	5074	4.26	4.56
1973	4265	4642	\$2.94	6225	4.92	5.27

FPC (1973) Table 18 Composite Statements

Taxes and Revenues

Year	Tax on Revenues i.e. "Other Income Taxes"	Revenue	i_R	Federal Income Taxes	i_F
1969	87	18,000	0.005	1,450	0.48
1970	86	19,800	0.005	1,120	0.48
1971	87	22,300	0.004	950	0.48
1972	110	25,350	0.004	890	0.48
1973	114	29,104	0.004	850	0.48

Composite Income Account

$$A_{69} = \$5.44 \times 10^{-3}/\text{kwhr}$$

$$A_{70} = \$6.09 \times 10^{-3}/\text{kwhr}$$

$$A_{71} = \$6.91 \times 10^{-3}/\text{kwhr}$$

$$A_{72} = \$7.45 \times 10^{-3}/\text{kwhr}$$

$$A_{73} = \$8.24 \times 10^{-3}/\text{kwhr}$$

$$\text{The ratio } \gamma = \frac{\text{electric utility plant}}{\text{total utility plant}}$$

$$\gamma_{69} = .908$$

$$\gamma_{70} = .912$$

$$\gamma_{71} = .916$$

$$\gamma_{72} = .919$$

$$\gamma_{73} = .927$$

FPC (1973) Table 9 Composite Balance Sheet

T_M, L Composite Income Account

Year	"Other" Taxes T_M	L	fD_c
1969	1901	2011	858
1970*	2125	2198	1026
1971	2376	2411	1345
1972	2652	2657	1610
1973	2908	2995	2091

FPC (1973) Table 2: T_M = taxes other than income taxes in the electric utility operating expenses.

Table 12, 12A

* FPC (1970) Table 2A

Composite Income Account (using γ)

Year	C_p	C_b
1969	$\$280 \times 10^6$	$\$1,464 \times 10^6$
1970	$\$330 \times 10^6$	$\$1,821 \times 10^6$
1971	$\$452 \times 10^6$	$\$2,220 \times 10^6$
1972	$\$581 \times 10^6$	$\$2,589 \times 10^6$
1973	$\$732 \times 10^6$	$\$2,970 \times 10^6$

Table 12A, Composite Income Account

Table 13, Selected Income Account Items using γ

Year	K_a	$(i_a+i_d i_F)$	$(i_a+i_d i_F)K_a$	$i_e K_e$
1969	$\$ 7,645 \times 10^6$	(.109)	$\$ 833 \times 10^6$	$\$2,622 \times 10^6$
1970	$\$ 9,632 \times 10^6$	(.096)	$\$ 925 \times 10^6$	$\$2,778 \times 10^6$*
1971	$\$10,997 \times 10^6$	(.136)	$\$1,496 \times 10^6$	$\$3,076 \times 10^6$
1972	$\$12,344 \times 10^6$	(.136)	$\$1,679 \times 10^6$	$\$3,480 \times 10^6$
1973	$\$14,196 \times 10^6$	(.136)	$\$1,931 \times 10^6$	$\$3,890 \times 10^6$

K_a is give by (electric utility plant present - electric utility plant last year) from FPC (1973) Table 9 Composite Balance Sheet.

$i_e K_e$ is given by (Net Income - Preferred Stock Dividends)γ from FPC (1973) Table 2 Composite Income Account, Table 12, and Table 12A.

* FPC (1970) Table 2A

$$B = \frac{C_b + L + M_1 + T_M - fD_c}{1 - i_R} + \frac{C_p + i_e K_e - (i_a + i_d i_F)K_a}{(1 - i_F)(1 - i_R)}$$

$$B_{69} = (7,134 + 4,000) \times 10^6 = \$11,136 \times 10^6$$

$$B_{70} = (8,019 + 4,222) \times 10^6 = \$12,241 \times 10^6$$

$$B_{71} = (8,938 + 3,930) \times 10^6 = \$12,868 \times 10^6$$

$$B_{72} = (9,974 + 4,607) \times 10^6 = \$14,581 \times 10^6$$

$$B_{73} = (11,091 + 5,205) \times 10^6 = \$16,296 \times 10^6$$

Rates

Year	Model	(Elec. Ut. Revenue)/D Actual
1969	$\$14.6 \times 10^{-3}$/kwh	$\$14.8 \times 10^{-3}$
1970	$\$15.6 \times 10^{-3}$/kwh	$\$15.4 \times 10^{-3}$
1971	$\$16.4 \times 10^{-3}$/kwh	$\$16.4 \times 10^{-3}$
1972	$\$17.4 \times 10^{-3}$/kwh	$\$17.3 \times 10^{-3}$
1973	$\$18.5 \times 10^{-3}$/kwh	$\$18.4 \times 10^{-3}$

Notice that we assume flow through accounting for the tax credit and accelerated depreciation. Although only about 1/4 of all utilities have adopted this practice, the federal tax subsidy does lower the capital requirements of the utilities, thus lowering the value of the parameter B. The close agreement between the model rates and actual rates justifies this assumption.

0 0 0 0 4 4 0 0 0 3 8

TECHNICAL INFORMATION DIVISION
LAWRENCE BERKELEY LABORATORY
UNIVERSITY OF CALIFORNIA
BERKELEY, CALIFORNIA 94720