A RAND NOTE

PROMOTING ENERGY EFFICIENCY THROUGH IMPROVED ELECTRICITY PRICING: A MID-PROJECT REPORT

Jan Paul Acton, Daniel F. Kohler,
Bridger M. Mitchell, Rolla Edward Park

March 1982

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Prepared For

The John A. Hartford Foundation
The Ford Foundation
The National Science Foundation

Rand
SANTA MONICA, CA. 90406

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PREFACE

Rand's work in electric utility demand, costing, and ratemaking has a number of facets that are supported by complementary grants from the John A. Hartford Foundation, the Ford Foundation, and the National Science Foundation. The overall project receives guidance and assistance from an advisory committee consisting of members of regulatory commissions, ratemakers within publicly and privately owned utilities, and representatives of industrial consumers, residential consumers, and the environmental movement. The work also benefits from the cooperation and involvement of several electric utilities who provide data for the study and critically review draft reports.

This report contains five briefings that were delivered to the advisory committee in fall 1981 and discusses work in progress in several main areas of the study. This report is intended as an interim document describing the general progress and preliminary findings in several aspects of the work.

SUMMARY

This report presents results of research in five related areas of electricity demand analysis under alternative rate forms. The first two sections examine adjustments by large commercial and industrial customers. The third and fourth sections examine residential demand under time of day (TOD) pricing. The fifth section develops and applies a methodology for evaluating alternative rate structures.

LARGE CUSTOMER RESPONSE TO TOD RATES IN EUROPE AND THE UNITED STATES (SECTIONS I AND II)

European data permit us to examine some aspects of long-term adaptation by industrial customers to time of day electricity rates. In contrast, the relatively recent experience of U.S. customers facing such rates permits analysis only of short-term response. The European data have relatively limited price variation, with very similar pricing structures applied across the entire nationalized systems. As a consequence, we can analyze load shapes among European firms or estimate highly simplified econometric models. In contrast, the U.S. data contain sufficient variation across utilities so that we can estimate a satisfactory set of demand equations--identified in both energy (kwh) and demand changes (kw)--as well as analyze load shapes. Even though we cannot always apply identical analysis to European and U.S. data, analysis to date suggests broadly consistent findings. Using European data, which extend more than twenty years in some cases, presents an important methodological challenge. In general, we cannot observe the same firm through time, or under both TOD and non-TOD rate structures.

As a result, we can only examine the patterns of electricity consumption after the rates have been in effect some time. The result is to make our measures of responsiveness relatively conservative estimates of potential responsiveness in the United States.

By comparing loads for customers in different seasons of the year, we find that increasing numbers of firms show responsive load shapes when the price is increased and that the magnitudes of average response to TOD prices grow as winter peak prices apply. There is considerable variation from firm to firm and from industry to industry. Self-generation enhances the degree of responsiveness, and industrial processes characterized by certain kinds of loads--such as electric heating, crushing and grinding, stamping, and pumping loads--all show above-average responsiveness. Statistical analysis, employing a very simple econometric model of demand in three distinct periods of the day, confirms the basic finding that, on average, customers respond to TOD prices. The effects of price in a given rating period (the own price) is generally statistically significant, while the cross-price effects are generally of the expected sign, but often not significantly different from zero. In addition, the presence of self-generation decreases relative peak and shoulder usage, and increases relative off-peak usage.

The U.S. data permit us to perform each of the types of analysis reported for European data, as well as perform more complex econometric analysis. In our U.S. analysis we study the relative importance of various factors that may affect the response of large industrial customers to time-of-use electricity rates: factors such as energy charges,

demand charges, peak period length, industry, and weather. We have collected detailed data from ten utilities on consumption patterns by time of day for nearly 6000 large customers that now face time-of-use rates. We use data for four of the utilities that have been processed into working files to illustrate the types of analysis we shall undertake. Load curve comparisons (1) before vs. after the introduction of time-of-use rates, (2) winter vs. summer where rates differ seasonally, and (3) one utility vs. another with different rate structure, all suggest that firms in the primary metals industry are responsive to TOD rates. Firms seem to make greater proportional reductions when the peak rating periods are relatively short (4 to 6 hours) than when the peak rating periods are 10 to 12 hours long.

Simple regressions also indicate responsiveness. The regressions also illustrate the use of our multi-utility data base to estimate the separate effects of energy and demand charges--an important result that could not be accomplished using data from a single utility. These results, which should be considered preliminary until all ten utilities can be included in the estimation, indicate statistically significant own price effects in the afternoon and early evening, but not at other hours of the day; these results are based on price as a combined energy and demand charge. The magnitudes of price elasticities are similar to those found in the simple regressions on European data. When energy and demand prices are entered separately, the energy charges remain statistically significant in the afternoon and early evening and the magnitudes

are little changed; the demand charges are not statistically significant, though they are of the correct negative sign in the afternoon and early evening in regressions based on these four utilities.

DETERMINING THE TRANSFERABILITY OF FINDINGS FROM RESIDENTIAL TOD RATE EXPERIMENTS (SECTIONS III AND IV)

We employ two approaches to assess the transferability of rate experiment results from one setting to another. First, we develop a highly detailed econometric model estimated on Los Angeles data in order to assess the forecasting accuracy in other situations. Second, we compare the reported results from three different rate experiments.

The Los Angeles Electricity Rate Study produced a rich set of empirical findings, based on a large number of participating households and a relatively complex experimental design that included 34 TOD rates and 6 seasonal or time-invariant rates. Households participated for a period of 30 months, and extensive survey information was compiled on appliance holdings and other household characteristics. We developed a hybrid model of demand to examine the transferability of these results to other utility systems who might wish to use an already completed experiment rather than launch a time-consuming and expensive experiment of their own. The model combines engineering and economic approaches to forecasting the daily patterns of energy use, and permits suitable adjustments for weather, housing conditions, appliances, and other factors that may vary importantly from one service territory to another. The empirical results suggest that the hybrid model fits the data quite well in Los Angeles, that the estimated results correspond well with engineering economics studies, and that the model can be conveniently

used for application in other service territories.

To compare findings from different rate experiments, we examine the Los Angeles, Wisconsin, and North Carolina studies, each of which is relatively well designed and relatively comprehensive in its treatment of experimental rates. The nominal reported results of these studies differs widely: Peak period elasticities in Los Angeles range from -3 to -15 percent on average; in Wisconsin from -35 to -81 percent; and in North Carolina are insignificant and essentially 0. Such diverse findings can support a wide variety of policies ranging from very selective application of TOD rates to a limited number of customers all the way up to nearly universal application.

We find that these differences in reported price responsiveness are often due to faults in the analysis or handling of data. When more comparable definitions of price elasticities are used, when less restrictive econometric models are used, and when the data are handled properly--to account for seasonal changes in rates and changes in weather conditions--the apparent price elasticities fall into a much narrower and more comparable range. Further research on this topic will include estimating and testing the hybrid model with uniform analytic and data handling procedures applied to all three experiments.

CRITERIA FOR MEASURING THE EFFECTS OF ELECTRICITY RATE CHANGES (SECTION

Since TOD rates generally require new meters capable of measuring use in different rating periods, they raise a legitimate benefit-cost question for residential customers, whose lower level of usage may not justify the added metering cost. In particular, the legislative mandate

under the PURPA standards of the National Energy Act requires that the 50 state regulatory commissions go through a "cost effectiveness" analysis of alternative rate standards, including TOD and seasonal rates. In general, three criteria for evaluation seem to have been used: the revenue effects criterion, the effect on the amount of fuel or energy saved, and the effect on economic welfare.

The first two criteria is a poor basis for policy evaluation. The revenue effects criterion constitutes a very poor guide to evaluating rate changes; it often indicates that a rate is desirable merely because it raises more revenue, at the same time rejecting any rate that might be desirable on other grounds but is designed to raise the same revenue as the present rate. Secondly, the fuel savings or energy savings criterion is extremely limited in its value, because it considers the benefits only from the perspective of the utility, and not from the customers who may enjoy increased economic welfare associated with certain changes in their relative patterns of demand.

In contrast to these first two approaches, the welfare economics criterion--consisting of changes in producers' and consumers' surplus--provides a conceptually sound approach for measuring the benefits in the context of formal rate evaluation and, important, is relatively easy to implement. In particular, the data needed to estimate revenue effects or fuel savings effects permit measuring the changes in economic welfare.

Illustrative calculations use the price elasticities estimated from the Los Angeles Electricity Rate Study. Not only is the welfare economic criterion superior on conceptual grounds, but also we demon-

strate that it often leads to important differences in the measured impacts compared with fuel savings or energy savings criteria. These differences would support quite different policy conclusions; sometimes leading to a widespread economic criterion, and in other cases leading to the rejection of a rate that would produce a significant benefit to the consumers.

ACKNOWLEDGMENTS

In preparing this report, we benefited from the comments of Rand's advisory committee members during the original briefings and in response to a written draft which was circulated later. The committee is chaired by John Tillinghast of Wheelabrator-Frye and includes Carol Barger, SW Regional Office of Consumer Union, S. David Freeman, Commissioner, Tennessee Valley Authority, Carl Gilzow, Consumers Power Company, Leigh Hammond, Commissioner of the North Carolina P.U.C., Robert Higgins, The John A. Hartford Foundation, William Pendleton, now of the Russell Sage Foundation, Grant Thompson, Conservation Foundation of America, Dennis Whitney, Los Angeles Dept. of Water & Power, and Charles Zielinsky, of Wald, Harkrader & Ross. In addition, we received comments from several individuals at utilities whose data are included in the study. We wish to thank Ken Baker of Consumers Power Company, Lynne Gedanken of Commonwealth Edison, Barbara Haskew of TVA, James Yorke of Consolidated Edison, and Curt Biren of The John A. Hartford Foundation. Finally, Leland Johnson of The Rand Corporation carefully reviewed the report and made numerous useful suggestions, and Will Harriss's editing improved the text at several points. We appreciate the help of each of these people.

CONTENTS

PREFACE iii

SUMMARY v

ACKNOWLEDGMENTS xiii

FIGURES xvii

TABLES xix

FOREWORD xxi

Section

I. LONG-TERM ADAPTATION TO TOD RATES BY EUROPEAN CUSTOMERS 1
Importance of the European Data 1
Sources of Data 3
French Rates and Response 6
Factors Behind Patterns of Response 14
Conclusion 25

II. U.S. INDUSTRIAL RESPONSE TO TIME-OF-DAY RATES 27
Data 28
Illustrative Analysis 32
Conclusion 41

III. THE TRANSFERABILITY OF FINDINGS FROM THE LOS ANGELES RESIDENTIAL TIME-OF-DAY RATE EXPERIMENT 43
The Rate Experiment in Los Angeles 43
Transferability Analysis 50
Conclusions and Extensions 61

IV. COMPARING RESULTS TO DETERMINE TRANSFERABILITY BETWEEN SERVICE TERRITORIES 64
Differences Due to the Definition of Elasticity Employed 65
Differences Due to Models 68
Differences Due to Data Handling 71
Results of Correcting for Weather Differences in North Carolina Data 73
Conclusions and Extensions 75

V. CRITERIA FOR MEASURING THE EFFECTS OF ELECTRICITY RATE CHANGES 78
Desirable Features of an Evaluation Standard 79
Three Alternative Rate Evaluation Criteria 80
Illustrative Calculations 91
Conclusion 95

FIGURES

1.1 French TOD Rates and Hypothetical Pattern of Response 8

1.2 Breakdown of Summer Load Shapes 10

1.3 Breakdown of Fall Load Shapes 10

1.4 Breakdown of Winter Load Shapes 13

1.5 Aggregate Load Shifts with Changing Rating Seasons 13

1.6 The Role of Self-Generation 16

1.7A Seasonal Changes in Cement Industry Load Shapes..... 17

1.7B Seasonal Changes in Cement Industry Load Shapes..... 17

1.8A Seasonal Changes in Petroleum Pipelines 19

1.8B Seasonal Changes in Petroleum Pipelines 19

2.1 States with TOU Rates 29

2.2 Rates--Winter 33

2.3 Before-After Comparison; Metals Industry 35

2.4 Seasonal Comparison; Metals Industry 35

2.5 Cross Utility Comparison; Metals Industry 36

2.6 Rate Periods 36

3.1 Rate Plans in the Los Angeles Experiment 48

3.2 The Hybrid Model 52

3.3 Weather Effects 52

3.4 Rate Plan Effects 56

3.5 The General Case 56

3.6 Load Forecasts 60

TABLES

1.1 Types of Data for Detecting Responsiveness 4

1.2 Simple Econometric Model 23

1.3 Simple Model Including Effects of Self-Generation 25

2.1 Utilities Cooperating in Rand/Hartford Study 30

2.2 Tariff Summary 33

2.3 Illustrative Initial Regression Results Price Indices (P) 40

2.4 Illustrative Initial Regression Results: Separate Energy (PE) and Demand (PD) Prices..... 40

3.1 Objectives of the Los Angeles Experiment 44

3.2 Rate Plans in the Los Angeles Experiment 48

3.3 Average Electricity Consumption of Major Appliances in Los Angeles 54

3.4 Various Ways of Summarizing the Effects of TOD Rates 54

3.5 Full Price Elasticities 54

3.6 Full Own-Price Elasticities of Demand (%) 58

3.7 Plans for Further Analysis 58

4.1 Full, Partial, and Overall Price Responses in Los Angeles, Wisconsin, and North Carolina 62

4.2 Price Responses in Wisconsin and North Carolina Assuming A -18 Percent Overall Elasticity 67

4.3 Difference Between Average kwh Shares of Control Group and "Core" Rate Group: Winter 74

4.4 Difference Between Average kwh Shares of Control Group and "Core" Rate Group: Summer 74

5.1 Effects of an Illustrative TOD Rate Based on Long Run Marginal Costs--All Households 92

5.2 Effects of an Illustrative TOD Rate - Households With Swimming Pools 96

5.1 Demand Curves 82

5.2 Revenue Neutrality 82

5.3 Effects on Consumer..... 85

5.4 Effects on Producer (Utility) 85

5.5 Net Change in Economic Welfare 87

5.6 Fuel Savings Criterion 87

5.7 Summary of Three Alternative Evaluation Criteria 90

FOREWORD

The costs of supplying electricity vary almost continuously, reflecting changes in the efficiency of operation in generating equipment and the congestion effects of peak demands on installed generating, transmission, and distribution capacity. In practice, electricity rates cannot reflect this full complexity of costs, which vary from moment to moment and at different locations in the utility systems; instead, rates are based on averages of costs over some or all hours of the year and averages over broad areas of the system. In principle, efficiency and the economic welfare of consumers can be improved by charging rates that reflect the more varied pattern of cost differentials; seasonal rates, time of day (TOD) rates, and rates with many different pricing periods are all examples that have been considered.

Some utility systems, notably those in Europe, have included this greater complexity in their retail electricity rates for several decades, and a number of U.S. utilities began applying TOD rates in the mid-1970s. By the late 1970s, several regulatory commissions were considering the applicability of seasonal and TOD rates to the utilities under their jurisdiction, and the Public Utility Regulatory Policies Act of 1978 (PURPA, a part of the National Energy Act) required systematic consideration of the costs and benefits of several different ratemaking standards, including seasonal and TOD rates.

Rand's work in electricity costing, demand, and ratemaking is designed to assist participants in this process with methodology and findings. It is addressed to both large commercial and industrial cus-

tomers and to residential customers, and considers the transferability of findings from one setting to another. Within the class of large customrs, we are considering the nature of findings from European experience with more complex electricity rates and the applicability of those findings to U.S. utilities. Within the United States, we are considering the transferability of large-customer findings from one U.S. setting to another. In the residential class, we are considering the transferability of findings from one time of use electricity experiment to another utility system.

Our methodological analysis is designed to identify improved measures for analyzing the magnitudes and significance of load shape changes. We are also working to develop theoretically sound, but practical, methods for evaluating the effects of rate structure changes. The substantive and methodological findings are brought together to identify the principal policy implications of our work. We are attempting to identify the circumstances under which more complex rate structures are likely to lead to improvements in social welfare, and identify the groups of customers likely to benefit from more complicated rates.

Five topics are chosen for presentation in this interim report. They represent work that is either partly or completely finished in each of these major areas. Three studies (presented in Secs. I, III, and V) are based on work that is largely finished. The material in Secs. II and IV are at an earlier stage of completion, and the presentations are designed to indicate the character of the approach and the nature of findings that are likely to emerge.

The presentations can also be viewed in terms of their relationship to one another. Sections I and II present the results of analyzing large customer response under time of use pricing. Section I presents an analysis of the European experience--focusing primarily on France, and to a lesser degree on the United Kingdom--where long-term adaptation to time of use rates can be observed. Using European data also presents an important methodological challenge because of the limited amount of price variation that exists within any one of these nationalized utility systems. As a result, we must develop methods for inferring the degree of load response that may have taken place as customers came under the terms of time of use pricing. Section II presentsfpreliminary data for four of ten U.S. utilities that have supplied extensive load data for our analysis. We present illustrative findings and examine their consistency with the longer-term adjustments that are observed in the European data.

Residential responses to time of use rates are discussed in Secs. III and IV. Section III presents the results of the Los Angeles Electricity Rate Study, an extensive body of data employing forty different TOD and seasonal rates. We present a statistical model for analyzing the load curve changes that is suitable for comparative analysis and transfer to other service territories. The model can be used in relatively simple or relatively complex form; it is deliberately designed for ease of applicability in other service territories, where varying degrees of local information may be available for forecasting existing and potential load shapes. The material in Sec. III also presents the

type of principal policy conclusions that can be drawn from the Los Angeles experiment.

Section IV presents a comparative analysis from three of the most important rate experiments that were conducted during the late 1970s. It starts by observing the widely disparate findings that have been reported from these studies (in Los Angeles, North Carolina, and Wisconsin) and attempts to identify the principal reasons for these differences. We find that significant amounts of the nominal differences are due to different concepts being reported (chiefly different measures of the price elasticity of demand), restrictive models that were employed, and faulty data handling procedures. When these three identified shortcomings are taken into account, the nominal results from the three studies reported to date are much more consistent with one another, although some important differences remain. Future analysis will attempt to determine how much of these remaining differences are due to fundamental differences in the behavior that customers are exhibiting, and how much are due to noncomparabilities across experimental settings.

Section V discusses factors that should be taken into account in evaluating rate structure changes. The results are applicable to rates changes for both large industrial and commercial customers and for residential customers. We discuss three of the most commonly applied evaluation techniques: changes in the revenue effects for the utility, changes in the amount of fuel or energy consumed, and changes in economic welfare as measured by changes in producers' and consumers' surplus. We have found important conceptual differences across the three measures, and discuss the kinds of data--including the data that

are being generated in the analysis reported in Secs. I through IV--for conducting such analysis. We illustrate the applicability of the alternative evaluation criteria using the results of the Los Angeles Electricity Rate Study for residential customers. We find important conceptual and quantitative differences across the alternative methods.

I. LONG-TERM ADAPTATION TO TOD RATES BY EUROPEAN INDUSTRIAL CUSTOMERS

The industrial response to time-of-day (TOD) electricity rates is an important subject for study for two principal reasons. First, industry is a large user of electricity, accounting for about 35 percent of retail sales in the United States, although the number of industrial customers is relatively small. Second, when utilities offer TOD rates on either an optional or mandatory basis in the United States, they almost always offer them first to large industrial and commercial customers. Nevertheless, little is known as yet about the degree and pattern of response. Individual utilities have conducted isolated studies, but very little cross-utility comparison has been done, even though the Public Utilities Regulatory Policies Act of 1978 (PURPA) requires that the cost-effectiveness of TOD rates be estimated for different classes of customers.

Most of the policy questions that arise are straightforward empirical questions: (1) Do firms respond to TOD rates? (2) What is the magnitude of their response, if any? (3) Why are some more responsive or less responsive than average? (4) What lessons do European data sources and experience offer for U.S. applications?

IMPORTANCE OF THE EUROPEAN DATA

Although some firms in the United States have faced TOD rates for almost five years, it is still rewarding to examine the European data. One reason is that Europe enjoys a substantial head start on the United States; the European experience therefore will always be more mature

than ours. This difference in years of experience gives us a chance to ask if there is an important difference between long-run and short-run adaptation--given other differences that may occur across countries. For several more years, only European data will enable us to study long-term, steady-state adjustment by industrial and commercial customers.

It is also relevant to review recent European analysis at this point, because French and British utilities furnished additional data to us that previously had been unavailable for our analysis or anybody else's. We now have information at the level of individual-firm load curves, whereas previous analysis had been largely limited to class-average data.

Accordingly, the following discussion is divided into three parts: (1) a quick review of rate structures that these industrial firms face, and their broad patterns of responsivess; (2) the factors behind variation in load shapes from industry to industry, and other aspects that may be important; and (3) a brief sketch of an econometric analysis that we were able to perform primarily with the French data and, briefly, some parallel work in England and Wales. The principal focus throughout will be on the French data.

The circumstances affecting the use of electricity are fundamentally similar in the U.S. and European industries. In the United States, on the average, electricity purchases are about two percent of value added in the manufacturing sector. In a few electric-intensive industries, such as petroleum refining, electricity costs approach 15 percent of value added. And in a couple of isolated cases, such as

electric arc furnaces and air separation, electricity costs may approach 90 percent of variable (not total) costs of production; but in manufacturing as a whole in the United States, it is about 2 percent. The percentages are similar in Britain and France, where comparable industrial definitions are found. They might be 3 percent instead of 2 percent, on on average, for value added; but they are not 10 percent of the cost in France and only 2 percent here, a circumstance that might lead one to expect to find more price responsiveness in Europe than in the U.S.

Furthermore, it appears that labor cost differentials by time of day should not significantly inhibit response. It turns out that the wage differential for night work in both the U.S. and Europe is generally only 15 cents to 25 cents per hour, at least with the number of employees now working night shifts. This is a trivial fraction of the current labor bill. The situation might be different if industry attempted to substantially increase the number of workers in off-peak operations. At that point, there might be a problem attracting skilled workers, or the wage differentials might need to increase in order to attract triple the number of workers; but at least in today's situation, shift differentials are a very minor factor.

SOURCES OF DATA

Broadly speaking, four types of data reveal the responsiveness of customers to TOD rates (see Table 1.1). First are before-and-after data, comparing the load shape before and after TOD rates were introduced. Because such data furnish strong evidence of specific responsiveness to the rates, they hold considerable policy interest for elec-

tricity forecasters, who need to estimate how rapidly firms may change during the first few years that the rates are in effect.

The second type of data derives from side-by-side comparisons of customer responses to price variation. Within a service territory, for instance, different prices might be charged to different groups of customers or across utilities, with similar rate schedules at different price levels. The patterns of response would again hold strong policy interest; they are especially useful for forecasting demand at different price levels.

The third type of data is produced by responses to seasonal price variation--as in France, for example, where summer rates rise to a higher level in October, and still higher in November through February for a few hours of the day. This is weaker evidence of price responsiveness, however, because customers may have made many changes when the

Table 1.1

TYPES OF DATA FOR DETECTING RESPONSIVENESS

Type of Data	Advantages	Rand Work Europe	U.S.
Before-and-after	Strong evidence; high policy interest	Not possible	Will report
Side-by-side price variation	Strong evidence; good for forecasting	Some data	Will report
Seasonal price variation	Weaker evidence; some policy interest	Will report	Will report
"Intrinsic" load shape	Weakest evidence; some policy interest	Will report	Not reporting

rate was first introduced--changes that would be revealed only in before-and-after data, or perhaps in side-by-side comparisons. Having made one-time changes, customers may display no further price response, even in winter when the peak charges come in effect. Such data are useful to a utility that is contemplating similar types of rates at similar price levels, but have limited value to utilities considering dissimilar rates.

Finally, there is intrinsic load shape analysis, in which the very shape of a customer's load suggests that a TOU response must exist. It is of policy interest when similar rates and similar pricing levels prevail. Otherwise, it is the weakest evidence of all because it is based solely on after-the-fact data compiled some months or years after the rates were introduced. The prior pattern is unavailable for comparison. Unfortunately, these are the only data we have to work with for many European countries.

Although we cannot make before-and-after comparisons with European data, we have some data for studying side-by-side price variation--primarily in England and Wales but not France--and for performing seasonal price analysis and intrinsic load shape analysis. In the case of the United States, we have data that would permit any one of those four approaches to analyzing responsiveness. The presentation in Section II will focus on the before-after comparisons, side-by-side price variation, and seasonal price variation.

FRENCH RATES AND RESPONSE

In the winter months of November through February, the French Green Tariff has a three-part rate. An off-peak rate goes into effect at 10:00 p.m. and lasts until 6:00 a.m. At 1978 rates of exchange, the charge is about 2 cents/kWh. At 6 a.m. the rate jumps up to the shoulder level at about 4 cents/kWh. Then, for two hours in the morning and two hours in the evening, the price is on the order of 7 cents/kWh.[1] There is a parallel set of maximum-demand charges that reinforce that pattern. The rate is about 107 francs ($27) per kW per year for each incremental kW of demand in peak hours, around $11 incremental in shoulder hours, and $1.80 per kW of incremental demand in off-peak hours. These strong price incentives at peak hours in winter, and weaker price incentives at shoulder and off-peak hours, encourage the customer to reduce or shift loads whenever possible.

If the industrial customer has any ability to respond to such rates--given both the economics of demand for its product as well as the intrinsic production process--it should try to reduce peak-period consumption as much as possible; use as much electricity in off-peak hours as possible; and use some intermediate level in the shoulder hours.

Beyond this time-of-day price variation, seasonal changes in rates provide further data for our analysis of response. In the months of October and March, shoulder and off-peak rates are offered at the winter levels shown in Fig. 1.1. In the summer, only a shoulder and an off-

[1] In 1978, the morning peak hours were changed from 7 a.m.-9 a.m. to 9 a.m.-11 a.m. and the evening hours changed from 5 p.m.-7 p.m. to 6 p.m.- 8 p.m. Our empirical data are drawn from the earlier pricing period.

peak rate are charged, at an even lower level.

FRENCH TOD RATES AND HYPOTHETICAL PATTERN OF RESPONSE

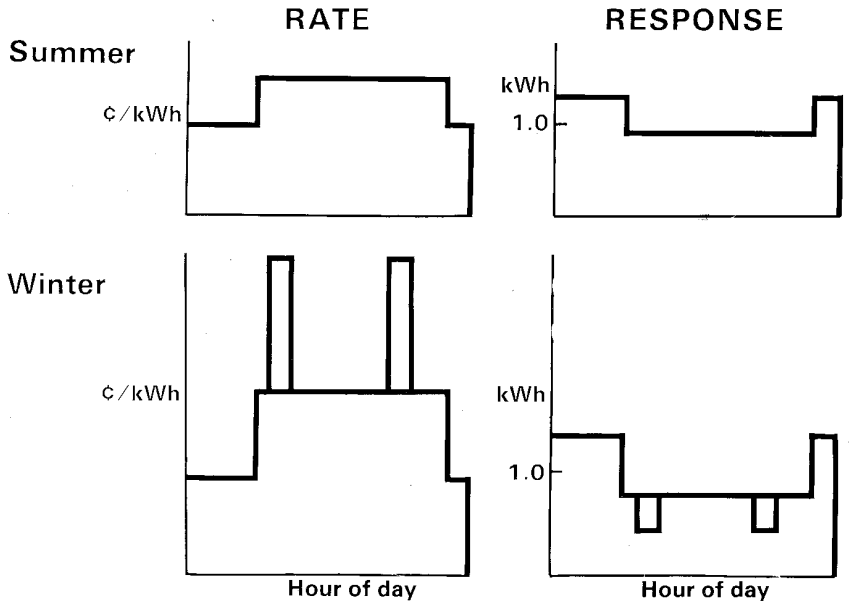

Fig. 1.1

Hypothetical Response

In the summer, a hypothetically responsive firm that is able to cut back when confronted with a shoulder-period price of about 3 cents per kWh and an off-peak price of about 2 cents might reduce its demand only moderately. In the fall and spring, when the price differential is more like 2 cents to 4 cents, we would expect somewhat greater reductions, and still further reductions during the peak-charge months of November, December, January, and February. The study of such responses is what we call intrinsic load shape analysis. On the face of it, looking at the load shape should reveal what the customer is doing in response to a particular rate.

Not every responsive firm will necessarily reduce its consumption below average during expensive hours. For example, a firm might follow a fairly pronounced daytime peaking pattern and a similar but more blunted pattern in winter. This kind of change in response to price level would be detectable only by comparing data across seasons.

Seasonal Changes in Load Shapes

Using the data made available to us on the 448 largest firms in France that are served on the high-voltage tariffs and that face the price incentives shown in Fig. 1.1, we found the sort of breakdown shown in Fig. 1.2. when we looked at the summer data. In the summer, the majority of firms had a flat pattern of demand, within 5 percent of daily average in the shoulder and in the off-peak period. About 45 percent of the 448 firms had a very steady rate of demand in the summer, and about 42 percent had a daytime-peaking shape. The curve was not

BREAKDOWN OF SUMMER LOAD SHAPES
LARGEST FIRMS (448)

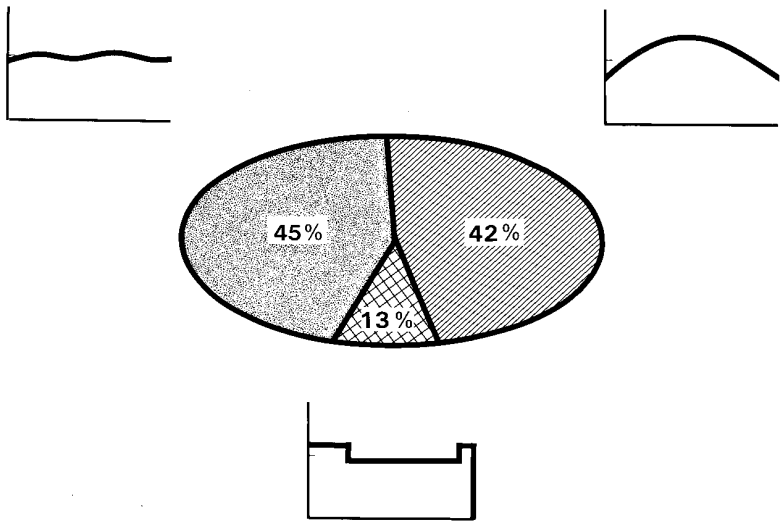

Fig. 1.2

BREAKDOWN OF FALL LOAD SHAPES
LARGEST FIRMS (448)

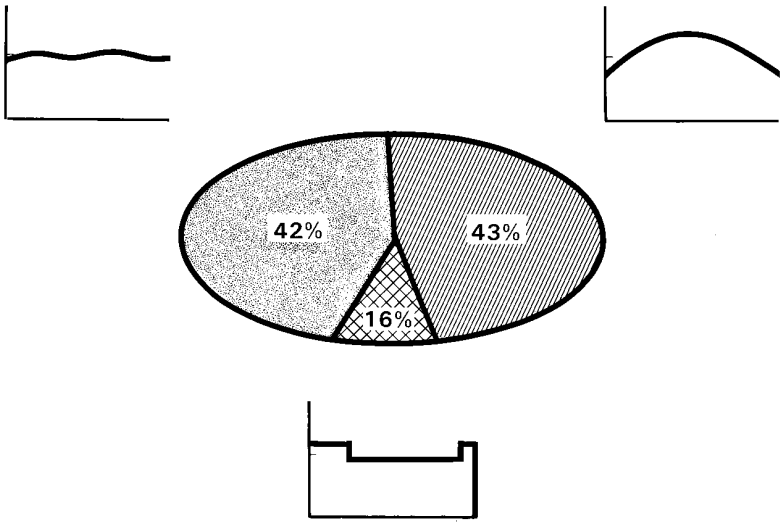

Fig. 1.3

really as pronounced as the one in the figure, but these firms did use more electricity during the day. Presumably, they based their consumption on the demand for the product and the relative cost of electricity compared with the costs of production around the clock.

About 13 percent of the firms showed a clear response to the TOD rates, with daytime consumption (from 6 a.m. until 10 a.m.) at least 5 percent below the average for a 24-hour period.

In the fall season, with a sharper price differential, a somewhat greater percentage of the customers responded and they responded with a load shape that was a little more pronounced (Fig. 1.3). The majority of them still had either a flat load shape or a daytime-peaking load shape, but now something like 16 percent of them were reducing their demand on average during the 16-hour shoulder period.

Most of the responsive firms were formerly among those whose load shapes were flat, although some had been day-peaking in the summer. It is difficult to find any other reason that a continuous-process plant should reduce its demands during daytime hours. It almost certainly has to be related to price responsiveness. However, there may be many firms in the other two groups that are also responding to TOD rates, but we are simply missing this response because we lack before-and-after data. It is also possible that many firms that now have flat load shapes were previously day-peaking and evened out their consumption when TOU rates were introduced. In other words, a flat load shape may in fact reflect a good deal of price responsiveness among firms in both groups. For that reason, we tend to regard all of the numbers that come out of these

comparisons as conservative measures of the numbers of firms and magnitude of price responsiveness.

Winter Load Shape Response

In the winter months of November through February, when a three-part rate schedule goes into effect in France, the breakdown is more dramatic (see Fig. 1.4). Around two-thirds of the customers remain either flat or day-peaking in their demands, but almost one-third follow a pattern that means that they must be responding to TOD pricing. We find that 9 percent of them sharply reduce their demand at the two-hour morning peak and two-hour evening peak. About 15 percent respond to both the shoulder charge and the peak charge. About 7 percent concentrate their electricity demand into eight hours of the day so that they start just after the peak period and end before the evening peak charges go into effect.

Comparisons between October and December reveal some interesting patterns (Fig. 1.5). About 50 percent of the firms have the same load shape in both months. Something like 8 percent move from an October pattern of mild reduction during the shoulder-charge hours to a pattern with an additional reduction in the morning and evening peak-charge hours. And then something on the order of 9 or 10 percent go from either flat or slightly day-peaking patterns into either a U-shape or a U-shape with the additional reduction during the peak-charge hours. Rather obviously, then, customers are generally moving in directions that show increasing TOD price response--despite the fact that the climate turns colder in the winter, with demand for heating and lighting

BREAKDOWN OF WINTER LOAD SHAPES
LARGEST FIRMS (448)

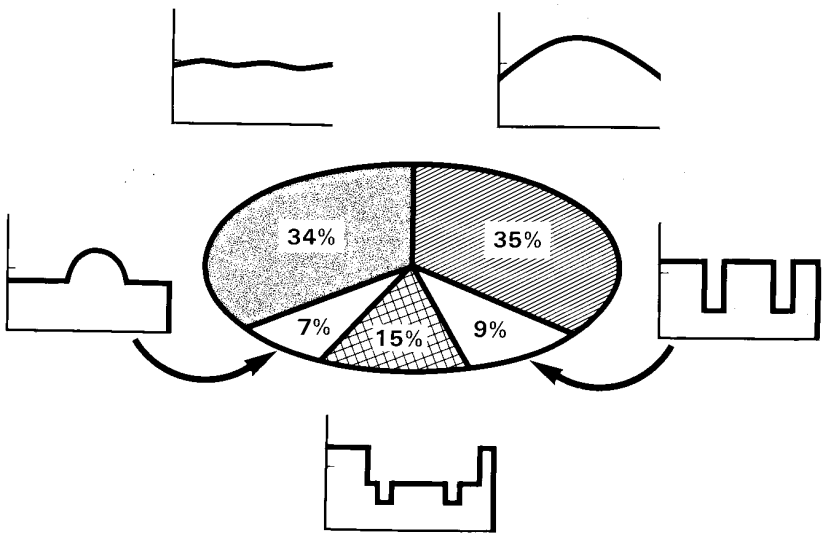

Fig. 1.4

AGGREGATE LOAD SHIFTS WITH CHANGING RATING SEASONS
(OCTOBER — DECEMBER)

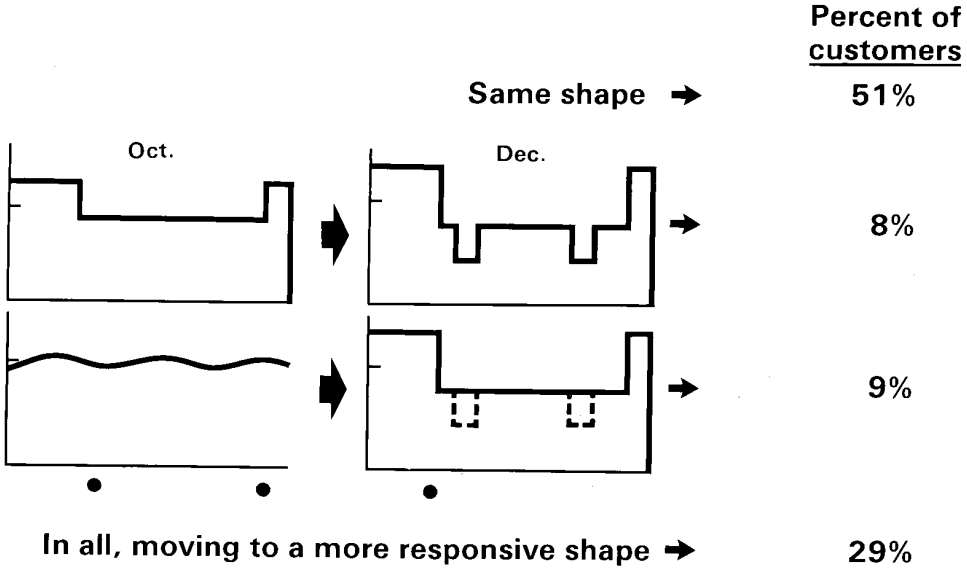

Fig. 1.5

rising in December and January.

In summary, with increasing price differentials, increasing numbers of firms show responsive load shapes and the magnitude of average response increases when the price is increased; but there is still considerable variation from firm to firm and industry to industry.

FACTORS BEHIND PATTERNS OF RESPONSE

The remainder of this section isolates a few of the factors that may be associated with greater and lesser degrees of responsiveness from customer to customer. We will look at the role of self-generation and at a few industry-specific patterns of response.

Self-Generation

Self-generation is one obvious recourse in responding to time-of-day pricing. It could be either cogeneration--if the plant has combined heat and power operations--or it could be stand-alone generation capacity. Price-responsive firms with self-generation may modulate the level of electricity production to economize on purchased energy costs. Self-generation is more common among industrial firms in France than in the United States. We estimate that about 20 percent of the firms in our sample had some self-generation or cogeneration capability. Among the group of firms that revealed a day-peaking load shape, 135 had no self-generation and showed a more sharply day-peaking pattern than the 22 day-peaking firms with self-generation. Demand in the self-generation group was about 1.10 times the daily average during daytime hours; the figure was about 1.19 for the group with no self-generation.

These figures suggest that self-generation helps firms modulate their purchased energy.

In contrast, firms with self-generation that were reducing their peak usage present a different picture. They had a relatively flatter load curve, suggesting that they were not using self-generation to enhance their price responsiveness. Across all firms, this is a weak conclusion since we do not know how the self-generation is being used; for a few users, however, we were able to isolate the actual amounts of purchased and self-generated energy. For example, the petroleum refinery shown in Fig. 1.6 clearly uses its self-generation to reduce energy purchases from Electricité de France. It makes up for its sharp reductions by sharply increasing self-generation when shoulder charges come into effect between 6 a.m. and 10 p.m. We do not know whether it is burning oil for that purpose; we believe it more likely that it is using the topping process, first generating electricity, then using the exhaust heat for process purposes.

In summary, although the evidence is not as complete as we would like, many firms are clearly using self-generation to enhance their responsiveness to TOU rates.

Industry-Specific Examples

Other industries display differing degree of price responsiveness for various reasons. In the summer, the cement industry as a whole shows a mild reduction in its relative demand for energy during the shoulder period and a very slight, almost undetectable, reduction during the fall and spring (Fig. 1.7A). Beginning in December, however, firms

HOURLY ELECTRICITY USE IN A FRENCH PETROLEUM REFINERY WITH SELF-GENERATION CAPACITY

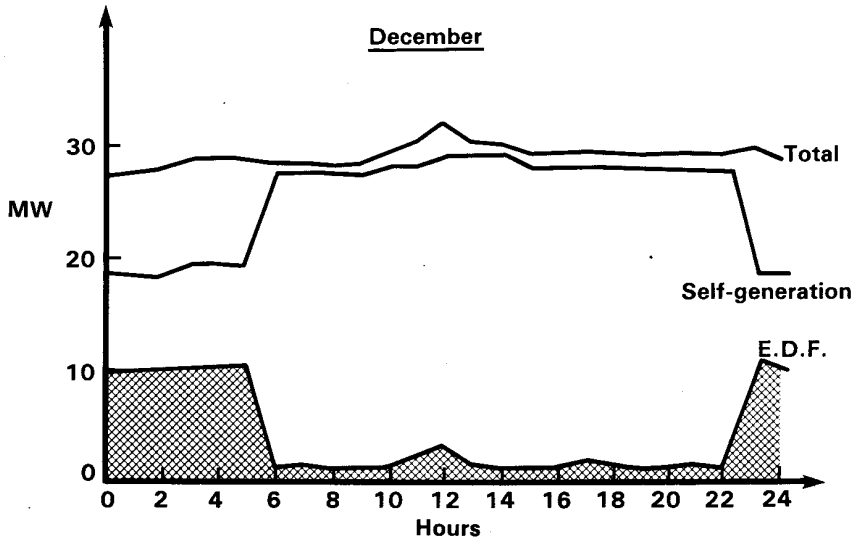

Fig. 1.6

SEASONAL CHANGES IN CEMENT INDUSTRY LOAD SHAPES

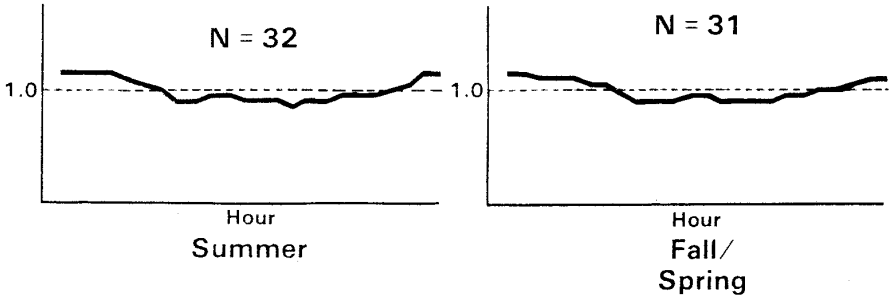

Fig. 1.7A

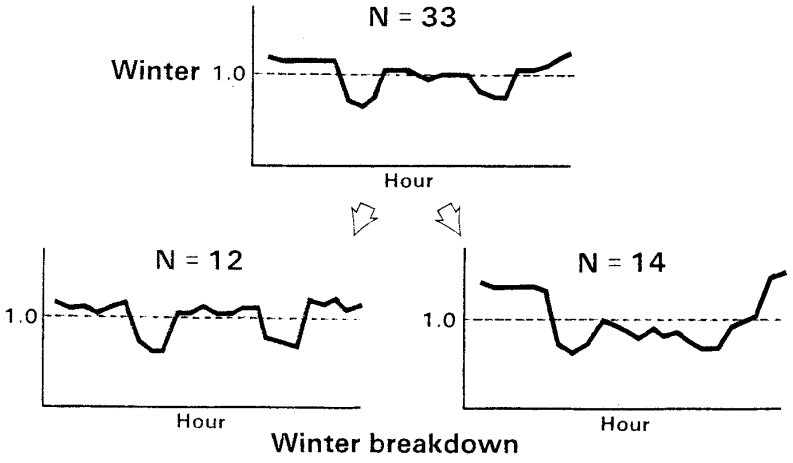

Fig. 1.7B

SEASONAL CHANGES IN PETROLEUM PIPELINES

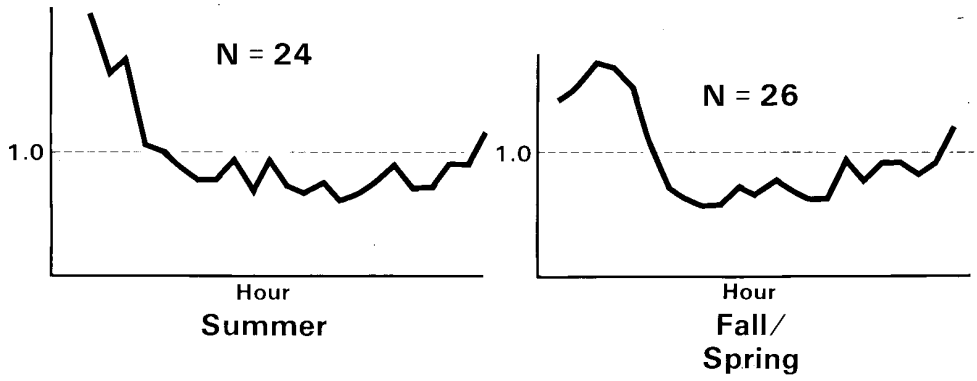

Fig. 1.8A

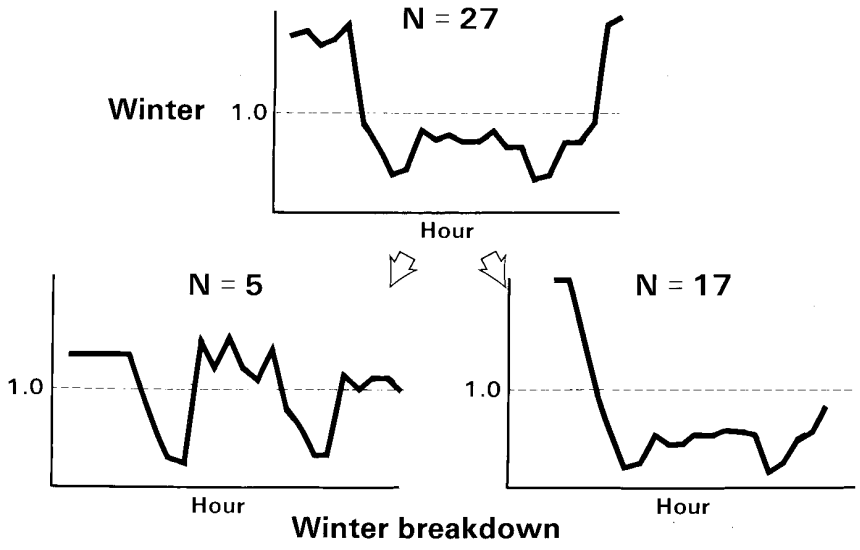

Fig. 1.8B

corresponding amount. The picture is further complicated when a utility that is responding to one set of TOD rates tries to reduce its own pumping but force throughput through another utility that has a different rate structure.

This is an important policy issue in the United States: coordination of rates to customers that are crossing utility boundaries. Formerly, that was not a problem in France, which had a uniform pricing structure around the clock and around the country through 1978, with very slight regional differences in average prices. In 1978, France reformed the Green Tariff and moved the morning peak hours to start two hours later, which corresponds to the time of the system peak. But utility officials allowed discretion at the distribution level in selecting the peak charge hours--particularly for medium- and low-voltage customers. Henceforth, we can therefore expect some regional variation in pricing periods in France. That is probably good from the point of view of load diversification--which was the reason for the local discretion--but it makes life difficult for the analyst looking at the aggregate load curve, who sees the changes at certain hours of the day under TOD rates but also sees that they are not as pronounced as they used to be. Dramatic response is no longer visible in the total system data, which will have to be broken down firm by firm and region by region to make load curves correspond with rating periods.

Industries that Are Responsive to TOD Rates

The cement and petroleum refining industries show clear patterns of responsiveness. The petroleum pipelines have pumping loads, and as long

as cross-utility coordination problems do not interfere, they can and do turn down the flow rather dramatically. The same appears to be true for the waterworks in France. The data are scanty but they show the same very sharp modulations, sometimes dropping to zero during expensive hours. Some refining operations that require pumping of the products also respond. The pulp and paper industries, basic metal industries, and some of the chemicals and air products industries all have processes that show clear patterns of response to increases in price levels.

There are also some industries that, at least on the surface, appear unresponsive to rate structures. French automobile manufacturers, for example, like those in Michigan, are evidently preoccupied with more important problems than the price of electricity. The auto industry is one of those in which electricity costs account for something like 2 percent of value added. Other unresponsive industries include some highly integrated works that embody complex, sequentially linked processes or interrelated products. For example, they may have stamping and pressing loads that seem to be candidates for interruption but cannot be stopped, because they have continuous feed to other production steps.

In summary, there is considerable variation across industries, and from firm to firm within an industry, in the degree and pattern of response to TOU rates. A given industry may contain a majority of not very responsive firms, and then a few individual firms that respond very dramatically. That finding can be important for U.S. ratemaking deliberations and load forecasting. Frequently, when TOD rates are being offered in a service territory, they will attract only a few customers

in a particular industry grouping. If an average of 20 percent of the firms in the entire county are very responsive to TOD rates, then the situation for a particular utility with (for example) only three customers in that industry will find either zero, 33, 67, or 100 percent of the firms displaying a dramatic response. Evidently, we should expect a fair degree of utility-to-utility variation in the United States at the firm level. Similarly, self-generation can enhance responsiveness to TOD prices, but again it presents something of a mixed picture and there will be considerable variability across utilities.

Econometric Model

One way to exploit the combined cross-firm variation in prices and seasonal variation in prices is to pool the data for analysis econometrically. We used a very simple model in which we pooled data from four seasons of the year in France. The same hours of the day were consistently defined as "peak," "shoulder," and "off-peak" regardless of what price levels actually applied. We asked only what the particular price was in that particular time period, and what was the corresponding level of demand.

We had data on the average demand for electricity during the peak hours--namely, 7 a.m. to 9 a.m. and 5 p.m. to 7 p.m.; average demand during the shoulder hours, which consist of a 16-hour period minus the 4 peak hours; and the average demand during an 8-hour off-peak period, year round. We examined each level as a function of the price that applied in each period of time. The estimating equations take the form

$$\ell n(Y_i) = a_i + \sum_{j=1}^{3} b_{ij} \ell n(P_j),$$

where Y_i is the average demand in period i, P_j is the price in period j, and a_i and b_{ij} are coefficients to be estimated. The periods of time are

i = 1 = "Peak," 7-9 a.m. and 5-7 p.m.

2 = "Shoulder," 6 a.m.- 10 p.m. except "peak"

3 = Midnight-6 a.m. plus 10 p.m.-midnight.

Table 1.2 presents the results of the simple model. The values down the diagonal are the own-price elasticities, that is, the influence of the price in that period of time on the demand for electricity during that period. Each one of the own-prices is negative and statistically significant at the 5 percent level of signifiance. The negative coefficient means that for any given period of the day when the price is higher, customers will on average use less electricity than when the price is lower.

Table 1.2

SIMPLE ECONOMETRIC MODEL

	Explained by Price in:		
Average Demand in	Peak	Shoulder	Off-peak
Peak	-.026*	-.450*	.736*
Shoulder	.011	-.118*	-.007
Off-peak	.008	.057	-.614*

NOTE: * = statistically significant at the .05 level. Specification is log of average demand in period as a function of log of prices. Therefore, coefficients are price elasticities.

The demand in each period should also be influenced by the price in other periods. When we consider peak-period response, for instance, we find that the shoulder period price has a negative coefficient, meaning that the higher shoulder price will reduce the peak average as well. We interpret this to mean that if a firm finds it worthwhile to reduce demand during the shoulder hours, it will also find it worthwhile to do so during the peak hours, which are internally contained in the 16-hour shoulder. In contrast, there is a positive coefficient on the off-peak price in this peak-period equation. This is a cross-price elasticity, in which the positive coefficient means that when the off-peak price is lower, demand is somewhat less during the peak period.

In the shoulder period, we have a statistically significant coefficient only on the shoulder price. A higher price in the shoulder will reduce consumption in shoulder hours; the same is true for the off-peak period. The other cross price coefficients were not statistically significant.

Because we are able to look at the role of self-generation in determining the share of electricity consumed, we included a variable in the model that indicated whether or not self-generation was available. This is a simple variable because we lack data on the installed capacity in France. The results are almost identical to the ones given above (Table 1.3). In every case, the basic price effects stayed the same, as did the pattern of statistical significance. Self-generation seems to enhance responsiveness, reducing the share of peak and shoulder electricity consumption and increasing the share of off-peak consumption.

Table 1.3

SIMPLE MODEL INCLUDING EFFECTS OF SELF-GENERATION

	Explained by Price in:			
Demand in	Peak	Shoulder	Off-Peak	Self-generation
Peak	-.024*	-.451*	.729*	-.018*
Shoulder	.013	-.121	-.004	-.010
Off-peak	.007	.062	-.007*	.047*

NOTE: * = statistically significant at the .05 level.

Qualitatively, our more limited studies of the United Kingdom are broadly consistent with our French analysis. We were able to conduct firm-by-firm interviews in England to find out what elements of production process were involved, and to do some econometric analysis of the kind reported here for France. The same basic pattern of statistical significance holds up, although at lower overall levels of significance. Mainly it is the own-price effects that are statistically significant. The same sorts of industries, such as basic steel, cement, and pulp and paper, are responding to TOU prices. In addition, there is an interruptible rate in Britain that produces additional benefits to the utility system in terms of reduced peak loads.

CONCLUSION

In sum, looking at these long-run patterns of response, firms apparently are reacting to TOD rates. On average they are reducing their peak usage and increasing their relative off-peak usage, and there

is additional seasonal variation in their patterns of demand. There is still a considerable amount of variation among firms, and variation persists even if one tries to adjust for the industrial processes at the SIC code level. The types of responsive industries seem to have discrete power loads and heating loads that can be interrupted easily. Generally, self-generation enhances their responsiveness. Over all, if similar patterns of response prevail in the U.S. in the long run, important savings in energy and capacity are possible here.

Our future work may include some additional breakdown by industries to see if we can find out what is going on in a couple of the major industries. But most imortant, we will continue to apply the findings from our European analysis to our U.S. analysis, making systematic comparisons across industries or comparing long-term European results with what may be shorter-term U.S. results. The important next question is what degree of long-run responsiveness can be expected in the United States.

II. U.S. INDUSTRIAL RESPONSE TO TIME-OF-DAY RATES

Our study of U.S. industrial experience with TOD rates has the advantage of starting with some information furnished by previous non-Rand studies. The following summary of previous results is based on a recent EPRI survey of five studies, each of which considered the experience of a single utility.[1] Over all, the findings were broadly consistent with the European experience reported in Sec. I.

U.S. industry seems to respond to time-of-day rates. The customers of the utilities in the EPRI survey reduced their peak-period consumption of energy (kWh) between 1 and 10 percent and their peak demand (kW) between 3 and 10 percent, depending on the utility. Some industries respond more than others, as do some firms within an industry. The high-response industries parallel those in Europe. High-response firms tend to be the larger users, those with spare capacity, and those with self-generation capability.

These previous studies leave a number of questions unanswered, however. Most important are questions on why the range of responses observed is so large; after all, 1 percent to 10 percent is quite a range. Several explanations are possible, including differences in tariffs across the utilities. Utilities have various peak and off-peak

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[1] Ahmad Faruqui, Dennis J. Aigner, and Robert T. Howard, Customer Response to Time-of-Use Rates, Topic Paper 1, Electric Utility Rate Design Study, Palo Alto, Calif., March 1981. A similar survey by Jan Paul Acton and Bridger M. Mitchell reaches the same conclusions; see "Do Time-of-Use Rates Changes Load Curves? And How Would You Know?" Public Utilities Fortnightly, May 22, 1980, and "The Effect of Time-of-Use Rates: Facts versus Opinions," Public Utilities Fortnightly, April 23, 1981.

energy price differentials, and charge different peak-demand prices. They define their peak periods differently, and their tariffs have a number of other characteristics that might affect industrial response. In addition, some utilities may have more high-response industries among their customers than do other utilities. Similarly, some of them might have more firms that have characteristics that allow them to respond more. Regional variations in climate and weather also may affect customers' ability to respond to TOD rates.

A major goal of our U.S. study is to quantify the relative importance of these various features that may explain differences in response from utility to utility. The following discussion is in two major parts. First, it reports on the status of our data gathering and management effort; the second part discusses our methodological approach for analyzing the data.

DATA

The map in Fig. 2.1 identifies states with TOD rates in effect for large customers and shows how many customers are subject to those rates in several states. Rand researchers have obtained the cooperation of ten utilities throughout the country. The numbers in the rectangles show the number of customers for which the ten utilities have agreed to supply us with data; they make up a substantial fraction of the firms that are now subject to time-of-use rates in the United States. The geographic representativeness also is good.

We have now received a great abundance of data from the ten utilities, which are listed in Table 2.1. In most cases we have 15-minute

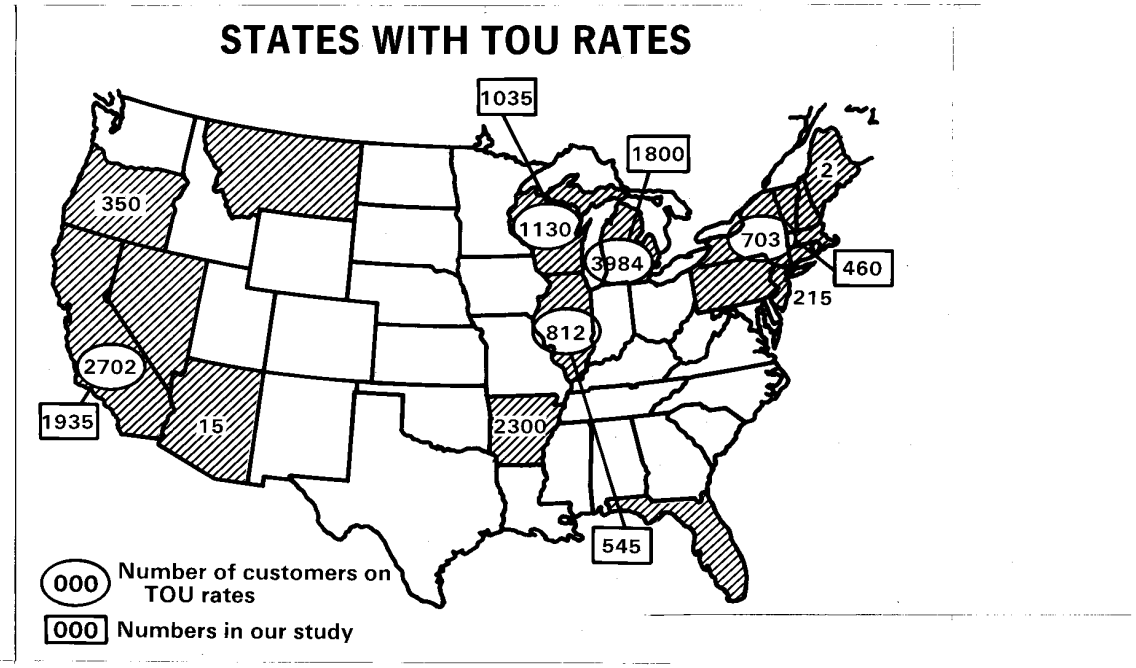

STATES WITH TOU RATES
1035
1800
2
350
1130
703
3984
460
215
812
2702
1935
15
2300
545
000 Number of customers on TOU rates
000 Numbers in our study

Fig. 2.1

Table 2.1

UTILITIES COOPERATING IN
RAND/HARTFORD STUDY

Utility	Customers	Years of data
California		
Los Angeles Department of Water & Power	180	4
Pacific Gas & Electric	860	4½
Southern California Edison	895	4½
Illinois		
Commonwealth Edison	545	2
Michigan		
Consumers Power	1800	4
New York		
Consolidated Edison	220	1
Long Island Lighting Co.	240	5
Wisconsin		
Madison Gas & Electric	220	4
Wisconsin Electric Power Co.	465	4
Wisconsin Power & Light	350	4
	5775	

consumption data stretching over a period of up to four or five years. We have data for nearly six thousand customers; that adds up to something approaching a billion data elements. This level of detail opens up great opportunities for analysis, but it also feels overwhelming at times. These data come to us in idiosyncratic forms from each utility. We have to combine the data, aggregate them to a level useful for analysis, and put them in the same form before we can begin to work with them. So far we have completed our data processing for four of the ten utilities: the Los Angeles Department of Water and Power, Southern California Edison, Commonwealth Edison in Illinois, and the Wisconsin Electric Power Company.

Our analysis thus far focuses on four months out of the many months of data that we have. We have chosen one winter month and one summer month during each of two years--one year before and one year after the introduction of TOD rates. Our analysis also focuses on seven industries defined at the two-digit SIC code level: paper, chemicals, petroleum, metals, pipelines, utilities, and stone, clay, and glass. We chose those industries because previous studies led us to expect some responsiveness from them. We have done some limited analysis, including load-curve plots and some preliminary regressions.

We chose to begin with those four utilities partly because they exhibit some interesting contrasts in their rate structures. Figure 2.2 plots the rate for each of the four utilities. The top row of graphs shows the energy charge in cents per kilowatt-hour during peak and off-peak periods (in the case of Southern California Edison, peak, shoulder, and off-peak periods). The bottom row of graphs shows the demand charge

measured in dollars per kilowatt maximum demand during the month, and again breaks it down by peak and off-peak periods. The Los Angeles Department of Water and Power and Southern California Edison exhibit particularly striking differences in the relative weights that they put on energy and demand charges, with about a 2:1 energy charge differential for Los Angeles and nearly flat energy charges throughout the day for Southern California Edison. Los Angeles' demand charge is small and constant around the clock. Edison has a fairly substantial demand charge during the peak period only. The two Midwestern utilities fall someplace in between, and the winter and summer rates are qualitatively similar.

Table 2.2 summarizes the major features of the four tariffs. Each has at least one characteristic that might lead one to expect a large response from its customers. In the case of Los Angeles, of course, it is the large kilowatt-hour charge differential, and for the other three utilities the high demand charges. In addition, it may be true that the relatively short peak periods for Southern California Edison and Los Angeles are easier to substitute out of than are the longer peak periods for the other two utilities.

ILLUSTRATIVE ANALYSIS

As mentioned in Sec. I, at least three basic kinds of comparisons can be made to detect the responsiveness to TOD rates. First, we could look at the same utility before and after TOD rates go into effect. This is the kind of analysis used in the single-utility studies that were summarized by EPRI. Second, we can also look at seasonal differ-

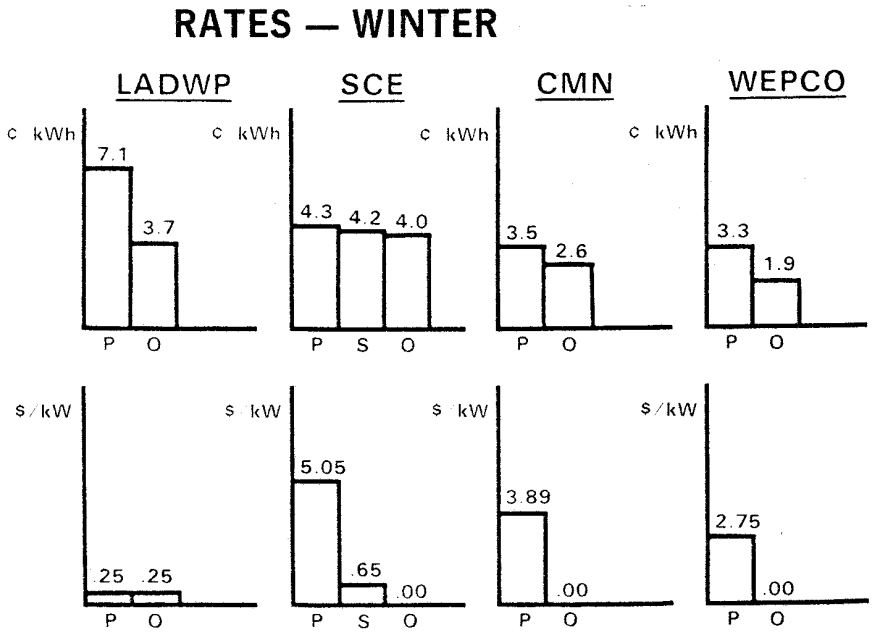


Fig. 2.2

Table 2.2

TARIFF SUMMARY

Item	Utility			
	LADWP	SCE	CMN	WEPCO
Energy charge differential	Large[a]	Almost none	Moderate	Moderate
Demand charge differential	None	Large[a]	Large[a]	Large[a]
Length of peak period	8 hours[a]	5-6 hours[a]	13 hours	12 hours

[a]May lead to relatively large response.

ences when TOD rates are in effect and vary by season of the year. This is the kind of comparison we relied on heavily in the European analysis. Third, because we have data on several utilities with different rates in effect, we can also compare the load curves for customers in different utilities and see if it is possible to pick up differences due to features of the tariff. In addition, we plan to do regression analysis on pooled data, a method that uses all three types of comparisons simultaneously.

There are two main purposes for all of this. One is merely to see if we can detect a response to TOD rates in the United States; the other is to try to quantify the relative importance of the various factors that might affect the magnitude of response.

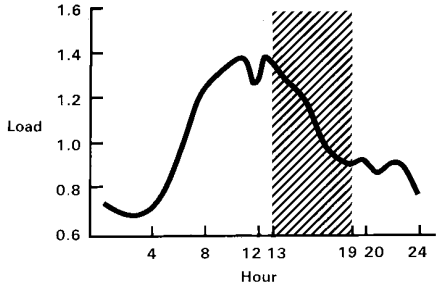
Figures 2.3 to 2.5 present an example of each of the three kinds of load curve comparison. These are all for the primary metals industry, which includes both ferrous and nonferrous metal production and excludes the fabrication of finished metal products. All of the curves are based on a healthy sample size: three to four dozen customers.

Before/After Comparison

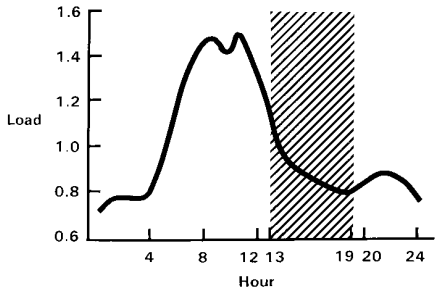
Figure 2.3 is a comparison for Southern California Edison, before and after the adoption of TOD rates. The top curve is for a flat rate. The bar shows what is to be the peak period upon adoption of TOD rates. Under a flat rate, of course, the price is uniform throughout the day. The bottom curve shows what the load looks like after the adoption of TOD rates. These metals firms certainly appear to be responding. The load peak seems to be squeezed earlier in the day to avoid peak period

BEFORE-AFTER COMPARISON; METALS INDUSTRY

SCE
Summer 1977
(Standard rates)



SCE
Summer 1980
(TOD rates)

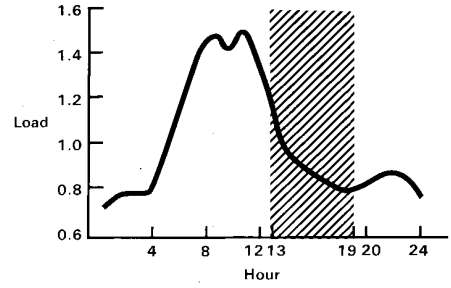


Peak period

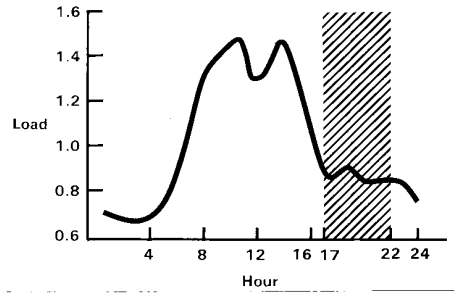
Fig. 2.3

SEASONAL COMPARISON; METALS INDUSTRY

SCE
Summer 1980
(TOD rates)



SCE
Winter 1980
(TOD rates)



Peak period

Fig. 2.4

CROSS UTILITY COMPARISON; METALS INDUSTRY

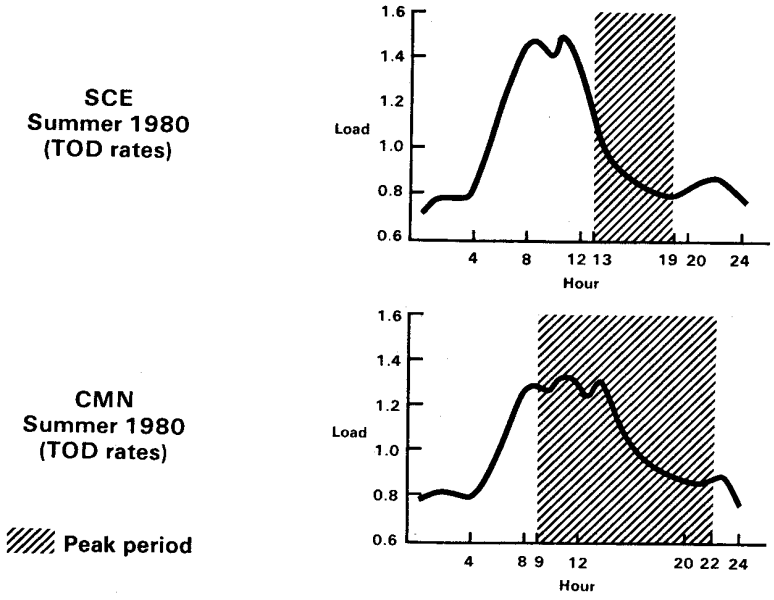


Fig. 2.5

RATE PERIODS

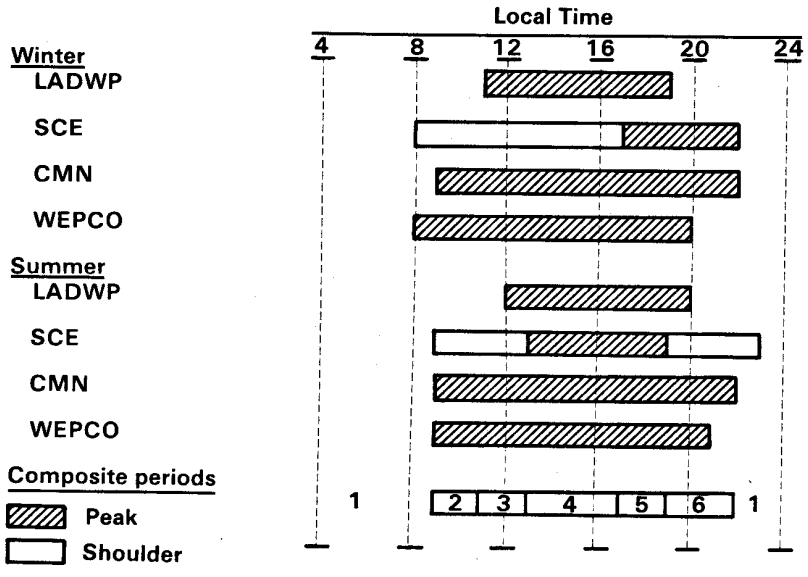


Fig. 2.6

charges.

Seasonal Comparison

A seasonal comparison (Fig. 2.4), also based on Southern California Edison's metals industry customers, likewise seems to show response. Although the level of charges does not vary much from winter to summer, the summer peak period is in the afternoon, and the winter peak is in the evening. With the peak price period later in the day in winter, the load curve seems to spread out to follow it. Again, the industry appears to be responding.

Cross-Utility Comparisons

Fig. 2.5 is a cross-utility comparison of load curves for metals customers of Southern California Edison and Commonwealth Edison under summer TOD rates. The contrast is interesting. The consumption peak for Southern California Edison lies almost entirely outside the peak price period, while Commonwealth's consumption peak is well within it. We can speculate on the reasons for this: It may be that the greater length of the Commonwealth peak rating period makes it more difficult to substitute out of, but at this point that has to be only speculation. In fact, this kind of one-to-one comparison of load curves cannot take one very far in the attempt to quantify the effects of the various factors that influence response.

Statistical Regression Analysis

To go beyond what can be done with these one-to-one comparisons, we need to get into statistical methods and use regression analysis, which exploits all of the various sources of variation in order to come up with quantitative estimates of the relative effects of the various factors. The regressions presented here are preliminary results. We have pooled four months of data for all four of our utilities, yielding about 370 observations. Our regression attempts to explain consumption during various periods of the day in the light of prices during those periods. It is a more complex matter to define the pricing periods in the present case than it is for Electricité de France, where one can merely pick off the peak, shoulder, and off-peak periods defined by the French tariff. Our four U.S. utilities define their peaks in different ways, as shown in Fig. 2.6. The crosshatched portions of the bars are peak periods, blank portions are Southern California Edison's shoulder periods, and the rest of the times are off-peak.

For our preliminary regressions, we defined six composite price periods during the day, in each of which the price is constant or almost constant for all of the utilities all of the time. For example, during afternoon period 5, which is two hours long, the peak price is in effect for all of the utilities. We had to fudge a bit on some of the other composite pricing periods. For example, off-peak period 1 has off-peak prices in effect for almost all of the utilities almost all of the time, but there are exceptions. We had to tolerate some of those exceptions to hold the periods down to a reasonable number until data for all ten utilities are ready for analysis.

Table 2.3 shows the results for the initial regression. These are six regressions of the form

$$\ell n(Y_i) = a_i + b_i \ell n(P_i), \; i = 1, \ldots, 6,$$

where Y_i is relative hourly energy consumption during period i, P_i is price during period i, and a_i and b_i are coefficients to be estimated. The effect of the price on consumption during period 4, for example, is estimated to be -0.14, the minus sign indicating that an increase in price reduces consumption, as expected. That estimate appears to be statistically significant at well beyond the 0.05 level, and the other own price elasticity estimates during afternoon and evening periods are similar. In contrast, the morning and off-peak price estimates are positive, which is counter to what we expect, but the estimates are small and statistically insignificant. With the European data it was possible to estimate cross-price effects--for example, the effect of price during period 4 on consumption during period 3. We are not able to do that with much precision as yet, because of the limited scope of the data available to us thus far.

As in the European regressions, we have used a single price index here that lumps together the effect of the energy charge and the demand charge. We are not forced to do so, however, because we have data on several utilities that have independent variations in the level of their demand charge and energy charge; by pooling those data, we can get separate estimates of the effect of the energy and demand prices, as in Table 2.4. The equations are

Table 2.3

ILLUSTRATIVE INITIAL REGRESSION RESULTS:
PRICE INDICES (P)

Effect of	On relative hourly consumption during period 1	2	3	4	5	6
P1	.02					
P2		.05				
P3			.03			
P4				-.14[a]		
P5					-.17[a]	
P6						-.16[a]

[a]Significant at .05 level.

Table 2.4

ILLUSTRATIVE INITIAL REGRESSION RESULTS:
SEPARATE ENERGY (PE) AND DEMAND (PD) PRICES

Effect of	On relative hourly consumption during period 1	2	3	4	5	6
PE1, PD1	.03, -.01					
PE2, PD2		.08, .00				
PE3, PD3			.02, .01			
PE4, PD4				-.11,[a] -.02		
PE5, PD5					-.17,[a] -.03	
PE6, PD6						-.21,[a] -.03

[a]Significant at .05 level.

$$\ell n(Y_i) = a_i + b_i \ell n(PK_i) + C_i \ell n(PD_i + .1),$$

where PK_i is the energy price during period i and PD_i is the demand price during period i. Again, the effect of the energy price on consumption in period 4 is estimated to be negative and statistically significant. The demand price in period 4 has a negative coefficient, as expected, but a much smaller coefficient. It is not statistically significant. The other afternoon and evening results are much the same, and the morning and off-peak results are small and statistically insignificant. Because we do not account for cross-price effects, this is an incompletely specified model. It is an initial step, and these numbers are certain to change when we estimate richer, more correctly specified models with our larger data base. These preliminary exercises illustrate an important feature of our approach, however. Without pooling data across several utilities in order to get independent variation in these prices, it would be impossible to estimate the separate effects of the energy and demand charges as we have done here.

CONCLUSION

Ten utilities have supplied us with load data on nearly 6000 large customers now under TOU rates. We are processing the raw data to produce consistently structured working files for analysis.

Initial plots of load curves for the primary metals industry illustrate comparisons (1) before and after the introductions of TOU rates, (2) between seasons with different rates in effect, and (3) across utilities with different rates. The plots suggest that the metals industry can respond to TOU rates by shifting loads to off-peak periods.

Initial regression results are also very encouraging. Although they are based on only a small fraction of the data we will ultimately use, the preliminary estimates are plausible. They are about the same magnitude as corresponding estimates for the shoulder period in France (Sec. I). When we estimate better-specified models using more complete data, we expect that the statistical significance of our results will increase. The resulting models should be very useful for analyzing the effects of different electricity tariffs on industrial load curves.

III. THE TRANSFERABILITY OF FINDINGS FROM THE LOS ANGELES RESIDENTIAL TIME-OF-DAY RATE EXPERIMENT

The basic questions in this section are: How and to what extent can we obtain information from the several extensive (and expensive) experiments with time-of-day rates for residential households, and extrapolate it to areas that have not had experiments? To what extent can we make direct comparisons of the results of two or more experiments?

THE RATE EXPERIMENT IN LOS ANGELES

The following discussion is based on Rand's work with the Los Angeles Department of Water and Power in conducting a major experiment that has furnished a large part of the foundation for our analysis in this project. It produced an extensive body of data that can be used not only for Los Angeles but also for comparison with other studies. The major part of this commentary will focus on how, in the last year, we have extended our analysis to focus on national implications, and on the transferability of experimental results to other areas.

Objectives

The Los Angeles experiment was a joint undertaking of the Department of Water and Power (DWP) and The Rand Corporation, with partial funding by the U.S. Department of Energy. Design of the the experiment started in 1975. We were in the field about mid-1976; test rates for individual customers lasted for 30 months; and the study had a concluding period of analysis in 1979-80. Table 3.1 indicates what we

Table 3.1

OBJECTIVES OF THE LOS ANGELES EXPERIMENT

Evaluate benefits of TOD rates for the city
- -- Measure how rates change load curves
- -- Compare benefits with added costs

Forecast future electricity use
- -- At higher prices
- -- At TOD rates

Produce data to assess national applicability of findings

and DWP hoped to accomplish in this study, with the primary focus on determining the benefits of TOD rates for residential customers. That of course involved assessing, first, how and to what extent TOD rates would change load patterns and total consumption by residential households; second, evaluating those changes in terms of the utility's current or projected costs of providing power by time of day; and third, calculating the additional cost of converting to a TOD rate--the costs of a new meter and its installation, and some administrative complications. We were also interested in being able to forecast how electricity patterns and levels of use would change if electricity rates continued to rise (as they were forecast to do in the mid-1970's) and what TOD rates might do to alter that effect. Finally, a distinguishing feature of the project was the particular attention that was given to its design in order to obtain data that would be applicable to other than Los Angeles conditions; that objective will be seen in the kind of rates that were finally selected.

In retrospect, we regard the Los Angeles study as unusually strong in having a variety of rates (both TOD and some seasonal rates) and in varying the actual overall price of electricity. The average price per kWh ranged from 2 to 5-1/2 cents for different households. Because of this variation it was possible to measure the intrinsic costliness of electricity as well as the effect of high prices in particular peak periods. Abundant data were also collected regarding specific appliances, weather, and household characteristics--factors that are crucial to transferring or adjusting Los Angeles results to other areas of the country.

An important limitation of this study was that, because it had to go into the field rather quickly, it was not possible to put meters in place and observe consumption under standard rates for one year preceding the establishment of TOD rates, as has been done in a number of other experiments. We therefore do not have "baseline" data on each household's TOD use prior to the experiment. Our recourse is to use data from the flat rates that were tested for some customers--2 cents or 5 cents per kWh--to estimate each customer's baseline TOD pattern of use. This situation increases the complexity of the modeling effort.

Finally, the Los Angeles experiment, like all the others that have been conducted in the United States, does not really get at the problem of how to allow for decade-long adjustments that might occur if TOD rates were really widespread. We can imagine the major appliance manufacturers beginning to put timers in washing machines and dishwashers as they have in many ovens. Energy efficiencies of appliances might well improve in some cases in response to high peak prices, but the improvement cannot be measured reliably with only a few hundred customers in one city: to a certain extent, then, the findings may understate the effect of TOD rates in a widespread application ten or fifteen years from now.

Rates

In Los Angeles we divided the day into eight three-hour increments, beginning at 9 a.m. The first pricing period, then, was from 9 a.m. until noon. In one particular test that was the peak period, during which the charge was 5 cents per kWh; the rate was 2 cents for the other

21 hours of the day. Other rate schedules were also tested. In the morning period we had three different plans with successively higher peak rates--some as high as 13 cents per kWh (see Fig. 3.1). Other plans had peak periods in the early afternoon (noon to 3 p.m.), midafternoon, and late afternoon, and one even had an overnight peak period. These rates do not reflect the utility's cost, of course--almost no utility in the United States has an overnight peak period--but they highlight the experimental nature of this effort. The experiment deliberately changed the rates in a way that would allow measurement of a peak price's effect in any one part of the day. Out of that data will come the possibility of forecasting responses under conditions that may not apply to Los Angeles; such an ability could be very useful to a utility with a different type of peak and off-peak structure.

The other factor to mention here is that we had peak prices that ran for as long as 6, 9, and 12 hours a day, as shown by the bottom bars in Fig. 3.1, with 5, 7, and 9 cent peak prices. The reason for these variations was the speculation that consumers might show a lively response if the peak period is only a few hours long, but if it covers most of the time when the household is using appliances, they may show little or no response. We needed to find out.

Principal Findings

Table 3.2 summarizes the principal findings of the experiment. TOD rates did, indeed, shift households load curves and did so most strongly and most consistently for households that had large appliances. Air conditioning and swimming pools proved to be particularly important;

Table 3.2

PRINCIPAL FINDINGS OF THE LOS ANGELES EXPERIMENT

Time-of-day rates:

- Shift load curves, chiefly for homes with air conditioning or swimming pools
- Reduce total use somewhat when price rises
- Are cost-effective for about 5% to 10% of homes (15% to 20% of use)
- Should be targeted for:
  -- Large homes or
  -- Homes with air conditioning or pool

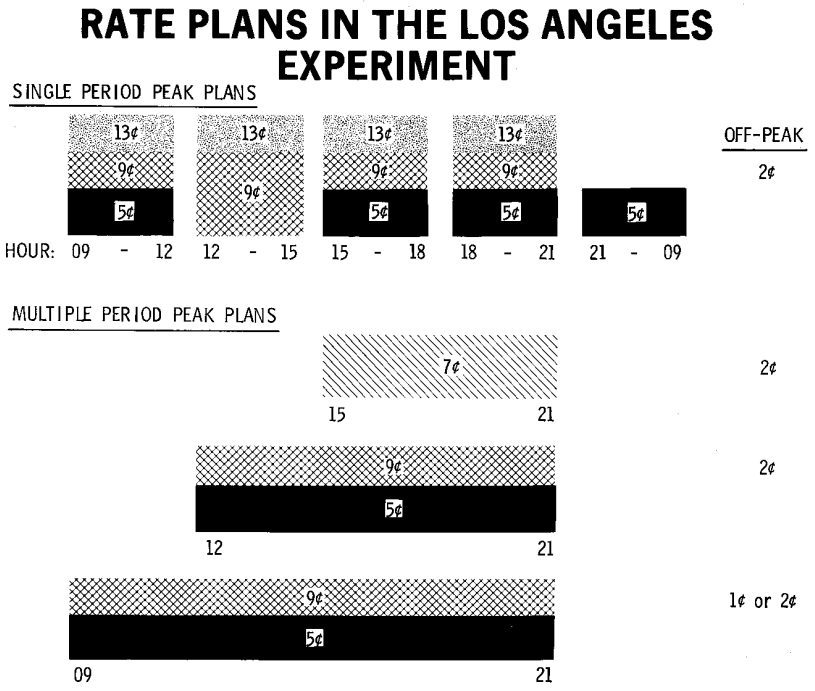


Fig. 3.1

households that had them showed substantial responses in nearly every case. The TOD rates that led to a rise in the average price of electricity per kWh also reduced total use, but by relatively small amounts.

Of course, what we are really trying to get at is a policy decision on where and to what extent TOD rates could be cost-effective for the utility and also in the public interest. Our basic conclusion was that if one looks at Los Angeles as a whole, only some 5 or 10 percent of the households, primarily those at the upper end of the consumption curve (above about 1100 kWh a month) would change their electricity usage enough to justify the cost of TOD meter installation and the added administrative costs. These users account for perhaps as much as 20 percent of the electricity consumed by residential users in Los Angeles.

This conclusion is very specific to Los Angeles conditions, however. If the city did not have so high a proportion of homes with swimming pools, if the air conditioning load were different, and if electric heating in the winter were substantial, one could be virtually certain that TOD rates would be cost-effective at a different point. So little of this kind of cost-benefit analysis has been done elsewhere, however, that analysts have sometimes seized on the Los Angeles findings for lack of anything better. For example, some of our study results have been quoted or introduced in rate proceedings involving PURPA hearings, and the 1100 kWh cutoff point appeared in testimony in a proceeding in Wisconsin. It is gratifying to have one's analysis used by others, but we are particularly concerned that it may not, as it stands, be appropriate for other service territories. For that reason, we are all the more anxious to gather reliable data from other parts of the coun-

try, fuse them with our Los Angeles data, and devise a model that will be widely usable with appropriate adjustments for local conditions. Our immediate concern, though, is to determine the degree to which the Los Angeles findings can be transferred.

TRANSFERABILITY ANALYSIS

For now, that is the central question: how to make the adjustments that will be suitable for other areas--adjustments for weather, housing conditions, appliances, and possibly, important characteristics of individual consumers. If we can do that on a sound statistical basis, the question will be: Do the Los Angeles results, suitably adjusted, compare in a systematic way with what has been found in other price experiments--for example, in North Carolina, Wisconsin, and Arizona, where major studies have been done? And are the policy conclusions in some broad sense similar? Is it true that residential TOD rates should be applied only to a small minority of customers? Do TOD rates make sense at all in a service territory where swimming pools are rare? Issues of that sort need to be checked. And one can equally ask: Can we use information from other studies to cross-check what has been done in Los Angeles? That type of validation is always desirable when separate sources of data are available.

We are currently at work on the Los Angeles data, focusing particularly on this more general analysis and modeling. We have combined two approaches. One derives from standard techniques used by utilities in which they apply engineering forecasting analysis to take account of weather conditions, major appliances, and types of consumers. The

second approach derives from economic theory, which emphasizes the importance of individual prices; understandably, this approach held little interest for utilities before TOD rates were seriously proposed.

Engineering Forecasting Analysis

Figure 3.2 depicts the kinds of effects we are incorporating in our hybrid model: air conditioning, size of residence, space heating, and the like. To mention a few of the results that have come out of the hybrid model: First, the weather effects as we estimate them from the experimental data track fairly well with what utility analysts have found using load-study data in a variety of conditions (see Fig. 3.3.) For average conditions during a Los Angeles summer, a household with a central air conditioner uses a little more than 300 kWh a month for space cooling. That is an important load in Los Angeles, particularly in the central area and in interior valleys that are relatively hot and dry and separated from the coast by low mountains. Only a small proportion of Los Angeles households use electric space heating, natural gas being available in nearly all parts of the city. For households that do have it, however, electric space heating is a significant load; even with fairly mild winter temperatures, 200 kWh is an average load. These effects alone--the variations in temperature among rate periods--account for as much as half of the variations from one month to the next in electricity use, depending upon the particular period of day.

The second set of factors in this model relates major appliances to the nature of the housing. Because there are sharp differences across a sample of nearly 1000 TOD customers, we get the independent effect of

THE HYBRID MODEL

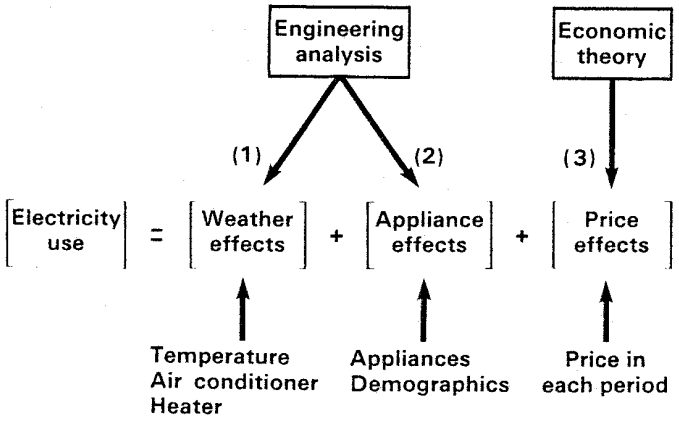
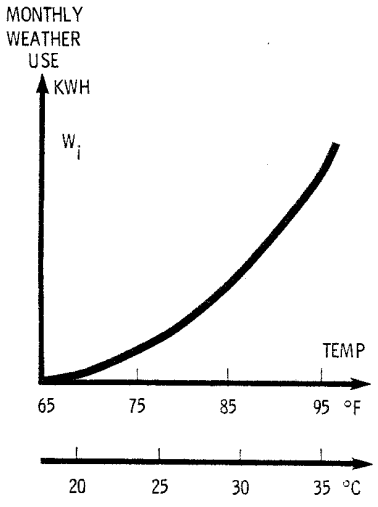


Fig. 3.2

WEATHER EFFECTS



AVERAGE MONTHLY USE (KWH)

AIR CONDITIONER (IN SUMMER)	325
SPACE HEATER (IN WINTER)	220

R^2 = .18 to .53

Fig. 3.3

one household's having a swimming pool, for example. Table 3.3 lists average annual consumption per month due to the various appliances. These figures are estimated from regression equations that explain total household consumption in terms of the additive contribution of each appliance. The estimates generally agree quite well with the small-sample end-use measurements that have been taken by placing separate meters on, for example, water heaters or refrigerators. (The range shown for a refrigerator in Table 3.3 is due to the difference between standard and frost-free models.) Again, the enumerated appliances account for a large proportion of the variation in electricity usage, and the estimates check very well with direct measurements. The water-heater value does not include the additional effects of having a dish washer or clothes washer. The electricity use for dishwashers and clothes washers is also shown in Table 3.3, but the additional water-heater use due to these appliances is estimated by additional coefficients not shown in the table.

Economic Forecasting Analysis

Of major interest are the effects of the prices themselves, and Table 3.4 indicate that there are a number of ways of getting at the effects on load curves. Figure 3.4 depicts three different summaries of those effects. The upper curve in the figure is a typical load curve for a Los Angeles household facing a flat rate (measured over two years of data in the experiment). If we average that load curve for three hours at a time, we find that some 11 percent of its total consumption is used in the three-hour period from 9 a.m. to noon. The "relative"

Table 3.3

AVERAGE ELECTRICITY CONSUMPTION OF MAJOR APPLIANCES IN LOS ANGELES

Appliance	Annual Average per Month Use (kWh)
Swimming pool	368
Water heater	140
Refrigerator	64-148
Freezer	104
Microwave oven	51
Stove	18-46
Dishwasher	50
Washer	71
Dryer	65

Table 3.4

VARIOUS WAYS OF SUMMARIZING THE EFFECTS OF TOD RATES

Effects can be summarized in terms of:

- Changes in kWh
  - -- Total use
  - -- Time pattern of use
- Elasticities--percentage effect
  - -- On total use
  - -- Matrix of effects--each price on every hour
- Load forecasts
  - -- Predicted load curve for each rate structure of interest

load curve in Fig. 3.4, consisting of level loads in three-hour increments, is the basis for our subsequent analysis in which we will statistically analyze how the shape of this curve is affected. (One could, of course, also do an hour-by-hour or fifteen-minute-period analysis.)

Recall that there were several TOD rate that had high peak-period prices in the morning. For example, the plan shown in Fig. 3.4 had a 5 cents/kWh price in the morning; the measured effect of that price is to reduce the morning percentage of the entire day's use of electricity from 11.2 percent to about 9.7 percent. Two other experimental plans also had peak prices in the morning--one at 9 cents, the other at 13 cents--and both plans led to greater and greater reductions in consumption during the morning period. That kind of analysis has been made for each of the 17 plans, and the results are broadly consistent across all of them (the sample sizes from a particular plan can be small, however).

That is only part of the story, of course. Because we have divided the day into eight 3-hour periods there are potentially 8 separate peak rating periods (plus combinations of time periods). In fact, for each test rate the prices in the four overnight periods (9 p.m.-9 a.m.) were the same, so that a total of five separate price periods were tested. In the example in Figure 3.4 all five prices will be 2 cents. Fig. 3.5 illustrates how a change in any one of these prices might change the load in all five periods. We want to be able to measure, in parametric form, the changes in the entire load shape. To represent that, we have divided the day into a matrix of effects. First, consider the overall price effect. Many of the rates increased the average price of electricity--for example, from the 2 cents flat rate to an average of

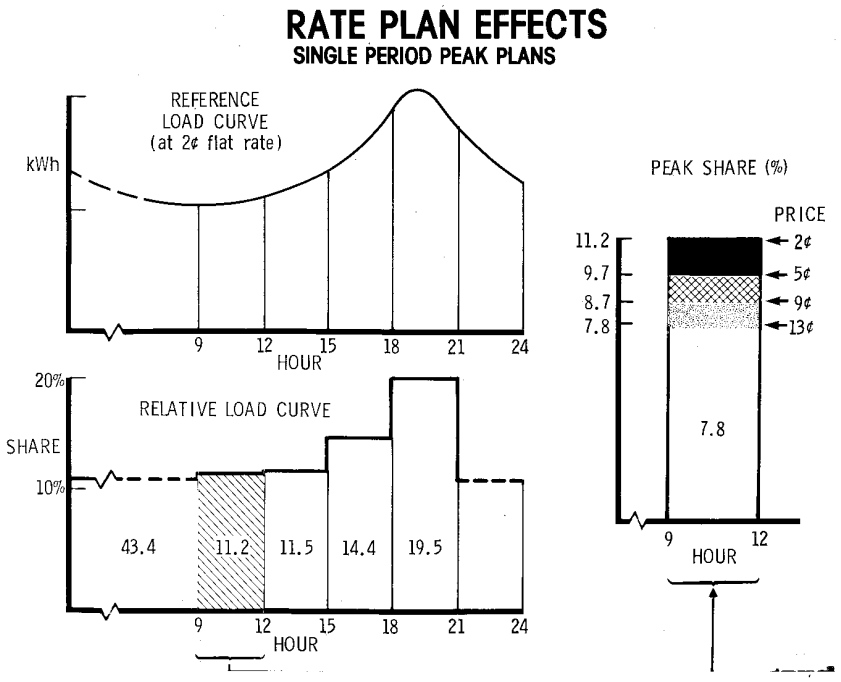

RATE PLAN EFFECTS
SINGLE PERIOD PEAK PLANS
REFERENCE
LOAD CURVE
(at 2¢ flat rate)
kWh
9
12
15
18
21
24
HOUR
20%
SHARE
10%
RELATIVE LOAD CURVE
43.4
11.2
11.5
14.4
19.5
9
12
15
18
21
24
HOUR
PEAK SHARE (%)
PRICE
11.2
9.7
8.7
7.8
2¢
5¢
9¢
13¢
7.8
9
12
HOUR

Fig. 3.4

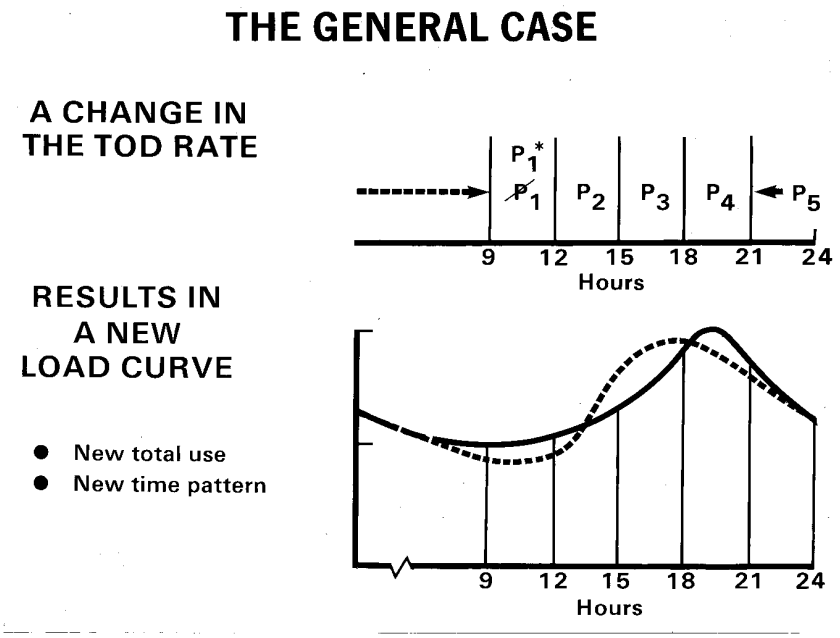

THE GENERAL CASE
A CHANGE IN
THE TOD RATE
RESULTS IN
A NEW
LOAD CURVE
New total use
New time pattern
P1*
P1
P2
P3
P4
P5
9
12
15
18
21
24
Hours
9
12
15
18
21
24
Hours

Fig. 3.5

2-1/2 cents per kWh because of the higher rate in effect in the peak period. If you double the average price of electricity, say from 2 cents to 4 cents (a very large increase), that will have a measured effect of reducing overall consumption by 18 percent. ("Doubling" is a convenient way of thinking about elasticities, but in fact most of the changes in average prices were not that large.)

The effect in particular hours of the day is represented in matrix form in Table 3.5. The numbers on the diagonal are the effect in the peak period that would accompany an increase in the peak price. Doubling the price from 9 a.m. to noon would lead to a 35 percent reduction in consumption in these hours, for example. Another plan might double the price from noon to 3 p.m. and that would lead to about a 20 percent reduction in the peak period; and so on. The general pattern that stands out here is that the greatest response appears in the morning, the early evening, or overnight. The numbers in Table 3.5 are for households that have air conditioning and swimming pools--the most responsive households. Now, arriving at the full change in the load curves requires filling in the other cells of the matrix. The off-diagonal value provides that kind of information. For example, if we had increased the peak price in the morning, that would have had an effect on consumption in the afternoon, the late afternoon, and into the night, as you can see from the first column of numbers in this particular case. The rate has almost no effect in the early afternoon but increases loads in the late afternoon, evening, and night. The overall effect of a peak price, however, is still to reduce total consumption. And out of this whole set of parameters, one can make predictions of

Table 3.5 -- FULL PRICE ELASTICITIES FOR HOMES WITH AIR CONDITIONING AND POOLS

Overall elasticity = -18%

Time-of-day Elasticities (%)		Price in Period 9-12	12-15	15-18	18-21	21-09
	9-12	-35	-1	7	5	13
Use	12-15	-1	-20	-2	1	12
in	15-18	6	-2	-17	-4	6
period	18-21	4	1	-4	-12	1
	21-09	5	5	3	0	-23

Table 3.6 -- FULL OWN-PRICE ELASTICITIES OF DEMAND (54)

(At P_i = 5 cents/kWh)

Period	Households with: No AC, No Pool	AC, No Pool	AC and Pool
09-12	-6	-16	-35
12-15	-2	-11	-20
15-18	-11	-12	-17
18-21	-6	-12	-12
21-09	-11	-22	-23

what any particular TOD rate would do to a reference load.

Table 3.5 illustrates how response varies across different types of households. If the price is doubled, households that do not have major appliances and are therefore smaller users of electricity will reduce their loads only up to 11 percent. A cost-benefit analysis for such a household would find that the cost of the time-of-day meter considerably exceeds the cost-saving to the utility. The other columns in Table 3.6 show that a household with an air conditioner but no pool is more responsive, although not much more, during the middle of the day. Households with both air conditioning and pools make the largest load shifts. For these households TOD rates can be cost-effective.

There is a third way to summarize these data. Figure 3.6 looks at two types of households: a responsive household with a swimming pool and air conditioner, and a basic household--it might even be an apartment, although the actual load value would be a little different. The solid lines in the figure show typical loads under a flat rate, in this case 5 cents. The use of air conditioning and swimming pools clearly affects the shape of the curve, and the consumption curve for the first household is of course higher. If we put a 9 cents per kWh TOD rate in effect from noon to 9 p.m. and an off-peak price of 3 cents (this particular peak/off-peak was not actually tested in the experiment but its effects are predicted by the model), then the dashed load curve shows a reduction in each of the 3 peak rate periods and somewhat greater consumption in the morning and the overnight periods. There is a slight reduction in total consumption for households with air conditioning and pools; the average price of electricity goes up for such households fac-

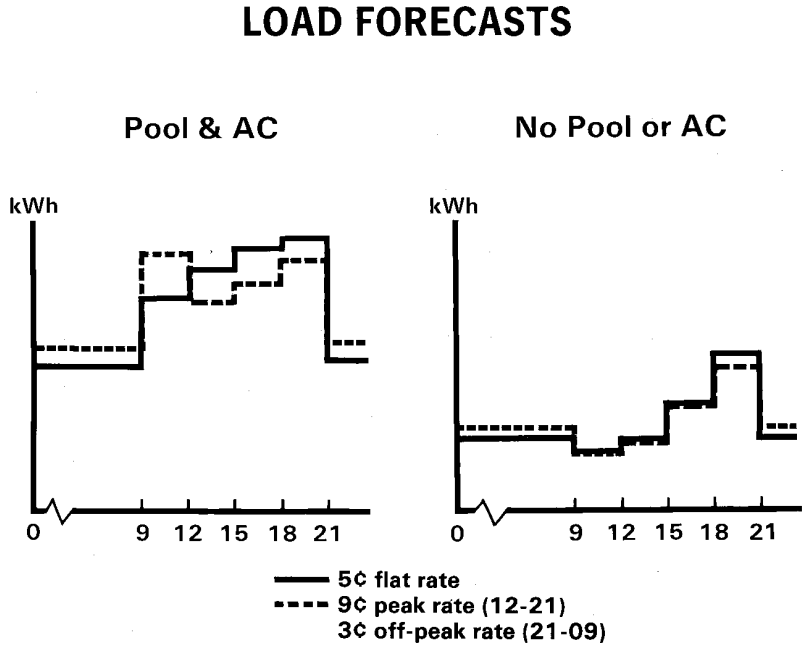

LOAD FORECASTS
Pool & AC
No Pool or AC
kWh
kWh
0
9
12
15
18
21
0
9
12
15
18
21
5¢ flat rate
9¢ peak rate (12-21)
3¢ off-peak rate (21-09)

Fig. 3.6

ing this peak rate. Households without pools and air conditioners make only a small reduction in the evening period when the peak rate applies, and a minor reduction in the overnight period.

CONCLUSIONS AND EXTENSIONS

These exercises illustrate the kind of flexibility one obtains from the hybrid model: A wide variety of rates can be examined that would be appropriate for different utilities and differences in weather conditions and appliances. Under Los Angeles conditions we have found that household responses to TOD rates vary systematically according to the level and hours of the peak rate. Also, households that have no major appliances respond minimally to TOD rates, but others with air conditioners or swimming pools have the largest price elasticities. This varied pattern of response suggests that residential TOD rates may be efficient for only selected groups of more responsive, high-consumption households.

We are now considering the next steps for this analysis, as listed in Table 3.7. One possibility would be to model loads on an hour-by-hour basis. Such a model may be useful for forecasting by utilities that have peak periods at different hours from those used in the Los Angeles experiment. We also hope to incorporate seasonal variation in electricity use in our hybrid model. Some utilities will find it important to know how loads are affected as the year moves into the peak months.

As mentioned earlier, we want to use data from other experiments to see how robust the Los Angeles analysis is to the lack of data on time-

Table 3.7

PLANS FOR FURTHER ANALYSIS

- Extend the Los Angeles analysis:
  - -- To 1-hour or 15-minute load curves
  - -- From annual to monthly analysis
- Check adequacy of the hybrid model, using other experiments to examine:
  - -- Reliability of weather adjustments
  - -- Robustness in absence of baseline data
- Compare Los Angeles results with other experiments:
  - -- Size and pattern of elasticities
  - -- Desirability of TOD rates

of-day electricity use before TOD rates were tested, and how satisfactory our weather adjustments are. Finally, we want to compare the quantitative results and the policy findings from Los Angeles with those of other experiments.

IV. COMPARING RESULTS TO DETERMINE TRANSFERABILTY BETWEEN SERVICE TERRITORIES

In a further extension of our work on the Los Angeles experiment, we have sought to find out the extent to which our results are generally applicable, how much of them hold true when we change location and setting, and how much of them are directly transferable. As a first step, we looked at the price responses published in studies of the three major experiments. The responses varied widely: Peak period elasticities reported for Los Angeles (DWP and Rand) range from -3 percent to -15 percent; for Wisconsin (Caves and Christensen) from -35 percent to -81 percent; and for North Carolina (Research Triangle Institute) they are insignificant and essentially zero. The -3 percent elasticity for Los Angeles applies to households that do not have pools and air conditioning, the -15 percent elasticity to those that do.

In Wisconsin (where pools are probably less common), the estimated elasticities indicate a much larger response to time-of-day prices; the response in North Carolina is almost nil. Obviously, such disparities are bound to lead to problems because they have completely different policy implications. The published analysis of the Wisconsin study implies that peakload pricing is so worthwhile that all households should be on TOD rates. The published North Carolina results essentially say it is not worth it. Los Angeles seems to be saying Yes, it is worthwhile for some households but not necessarily for all of them. To clarify this issue, we tried to find out what accounts for this wide spread of results.

Several explanations are possible. It may be that the various studies are not using the same concept of elasticity. Part of the difference may also be due to the different analytical methods chosen--straight linear regression models, hybrid models, and the like. Different data handling, different opinions on which variables are important, and different ways of aggregating the data will influence the results. Let us look at those points one by one, beginning with differences of interpretation.

DIFFERENCES DUE TO THE DEFINITION OF ELASTICITY EMPLOYED

Using noncomparable definitions of elasticity accounts for some differences. Numbers produced for the same area under different definitions are almost certain to disagree sharply--and comparability is virtually lost if we try to compare, say, Wisconsin with Los Angeles.

The elasticity definition we use is that for the full or total price elasticity of demand. The following illustrates what total elasticity measures. Assume an initial flat rate of 2 cents per kWh over the day, with the customer paying a bill of $30 a month. TOD rates are then instituted: 4 cents per kWh during the peak, and 2 cents during off-peak hours. We observe that usage drops 15 percent during peak hours, and possibly increases in the off-peak period. This is the effect of changing one price. But we also most likely observe that the customer's bill increases.

This 15 percent reduction is what we call total elasticity. We can also identify partial elasticity. For example, if we rescale the data to artificially freeze the bill at $30, we see that the customer has to

make a considerably larger reduction in peak use--45 percent--to keep his bill within the $30 limit. The main point is that the partial elasticity is calculated under the condition that the total expenditure on electricity remains unchanged. Partial elasticity, then, addresses a limited question: What is the customer's response to peak prices if we force total expenditure on electricity back to the level it had on the initial rate?

Partial elasticities are subject to many more theoretical restrictions, of course, and they cannot be used directly for predicting loads because they do not describe reality as we see it. However, they can provide very useful partial information, which, combined with other information, will enable us to reconstruct full elasticity. What we can do is consider the customer's response to TOD rates in two phases. We can say that the full price response--what we are measuring--is the sum of two different responses: a partial response, and an overall price response, which is the customer's reaction to the general increase in the expensiveness of electricity owing to the new rates.

Table 4.1 lists the full, partial, and overall price elasticities for Los Angeles, Wisconsin, and North Carolina. The full elasticity for Los Angeles households with air conditioning was around -13 percent, and around -3 percent without it. The overall elasticity which measures the reaction to the average price of electricity in both peak and non-peak hours was -18 percent, implying an 18 percent reduction in electricity usage if the average price were doubled. These figures also imply partial elasticities in Los Angeles of -30 and -20 percent, derived by compressing or rescaling the data so that the total expenditure for the

Table 4.1

FULL, PARTIAL, AND OVERALL PRICE RESPONSES IN LOS ANGELES, WISCONSIN, AND NORTH CAROLINA

(In %)

Area	Elasticity		
	Full (Peak)	Partial (Peak)	Overall
Los Angeles			
With air conditioning	-13	-30	-18
Without air conditioning	- 3	-20	
Wisconsin	-26	-35	-50[a]
North Carolina	±0	n.a.	n.a.

[a]Value assumed by Caves and Christensen.

Table 4.2

PRICE RESPONSES IN WISCONSIN AND NORTH CAROLINA ASSUMING A -18 PERCENT OVERALL ELASTICITY

(In %)

State	Elasticity		
	Full (Peak)	Partial (Peak)	Overall
Wisconsin	-20	-35	-18
North Carolina	±0	-24	-18

experimental customers is at the level observed before the experiment. The peak-period elasticity of -35 percent reported by Caves and Christensen for Wisconsin is actually a partial elasticity. Caves and Christensen made assumptions about the overall response of residential customers based on some historical studies, and assumed a value of -50 percent, a number considerably larger than what we observed in Los Angeles. By combining the measured partial elasticity value of -35 with the assumed overall elasticity value of -50, they calculated a full price elasticity of -26 percent.

Table 4.2 shows what happens if we change Caves and Christensen's assumed -50 percent overall response to the -18 percent found in the Los Angeles experiment. The effect is to lower their calculated full price elasticity value of -26 percent to -20 percent. The reader can see that we now get much closer when we start comparing full-to-full and partial-to-partial elasticities. Table 4.2 also shows the results of making the same assumption of -18 percent overall elasticity for North Carolina: We arrive at a -24 percent partial price response, given that the full price response is zero percent.

DIFFERENCES DUE TO MODELS

Aside from disparities stemming from differences in definition, several other mismatches remain to be explained. To a considerable extent, they are due to differences in the types of models used, and in the assumptions they embody. Caves and Christensen used a very highly structured model for Wisconsin. For North Carolina, the Research Triangle Institute did the opposite: They avoided models, preferring to rely

on statistical correlations. Our analytical approach for Los Angeles lies between these two extremes. Our model consists of equations that are structured according to basic economic principles but also incorporate statistical characteristics derived essentially from engineering models, particularly weather effects and appliance effects.

The highly structured Wisconsin model makes certain stylized assumptions about consumer behavior. It assumes separability of consumer preferences; it assumes homotheticity; it assumes a generalized Leontief form; and it uses expenditure-share equations for estimation. To explain these terms further:

Separability is the assumption that the consumer proceeds through two stages in allocating his electricity expenditure under different time-of-day rates. In the first stage he decides the total amount he will spend on electricity, taking into account the general price index for electricity and the prices of all other goods; in the second stage, he divides his electricity budget between peak and off-peak periods, depending on their relative prices.

Homotheticity, in essence, assumes that the consumer's allocation between peak and off-peak periods does not depend on his total expenditure. In other words, a customer who has a very large electricity bill will make the same allocation between the two periods as will a customer who has a small bill--provided they face the same prices, of course.

The generalized Leontief form is a specific form of a utility, or preference, function from which the system of demand equations is derived.

Caves and Christensen estimate the system of demand equations using expenditure shares. They do not regress kilowatt-hours during the peak period on the explanatory variables; instead they regress peak-period expenditure on electricity on the explanatory variables. Some things about the assumptions do not always ring right. We suspect that this procedure may be putting too much reliance on structure, with the possible result that these assumptions largely predetermine the outcome.

To check on our suspicions, we drew a set of random numbers and applied the Wisconsin model to them. The result? We found statistically significant results and a good fit, which means that this structural model--a homothetically separable, generalized Leontief model--actually seemed to "explain" the numbers we had made up. This exercise produced partial peak-price elasticities very similar to those that Caves and Christensen estimated for Wisconsin. The same holds true for the off-peak price elasticity and all the other elasticities we checked. In essence we reproduced the Wisconsin results from a set of random numbers, with the true price elasticity arbitrarily set to zero. The implication is that Caves and Christensen's results are due as much to their model assumptions as they are to the data.

At the other extreme is the North Carolina analysis, which avoided models and the making of assumptions about customer response. The problem with such an approach is that the analysts allow themselves very little guidance on what is important. That may have led them to omit some important variables, which will be discussed below. Also they used standard statistical analysis of variance and covariance methods, which unfortunately are highly sensitive to data errors. They are very sensi-

tive to omitted variables, and it is quite possible that the lack of a structural model accounts for the failure to find a price responsiveness, which may actually have been present.

DIFFERENCES DUE TO DATA HANDLING

Differences in data handling can also produce disagreement among studies. By data handling we mean the general management of the available data: how the data are aggregated and represented, what is included in the data set, what is considered important, and the like. Faulty data handling often means the loss of useful observations, a reduction in the sample size that can impair the significance of the results. The omission of relevant variables can also be classed as faulty data handling. These shortcomings appear to have affected the North Carolina experiment.

As an example of the aggregation problem, North Carolina customers were billed in billing cycles, and also were charged prices that differed between summer and winter months. The transitional months present a problem for the data analyst. For example, customers were informed that all bills written in June would be based on summer rates. Consequently, customers billed early in June had summer rates applied to their May consumption, but customers billed late in May had May consumption billed at winter rates. In preparing their analytic files, however, Research Triangle Institute (RTI) did not adjust for that overlap in seasonal rates; instead, they aggregated all May consumption into the calendar month regardless of the billing date.

The result is that analysts can no longer distinguish what price the customer actually paid in May, which means that May data must be dropped from the data set. In all, aggregation by calendar months instead of billing cycles inflicts a data loss of about 25 percent.

Carolina Power and Light (CP&L) has helped us recover the billing cycle dates, so that we should be able to aggregate the data properly. This will permit us to increase the effective sample size considerably by recovering the spring and fall transition months that other analysts have had to drop. The analytic results based on corrected billing files will be reported at the completion of this updating process.

The omission of other variables can also distort the picture of customer response. Weather, in particular, affects electricity usage for heating and air conditioning.

In North Carolina, we find experimental customers on a flat rate with air conditioning and electric heat. The reported RTI analysis did not allow for the effects of changing weather on electricity use. In our analysis we accounted for monthly changes and found that if the number of cooling degree hours increase 10 percent during the month--which is equivalent to saying that it is an average 10 percent hotter than it was last month--the result will be a 2.65 percent increase in kilowatt-hours used. Similarly, a 10 percent rise in humidity will cause a 2.87 percent increase. Temperature and humidity often rise together. If August is 10 percent hotter and 10 percent more humid than July, then one would expect electricity consumption to increase more than 5 percent in August because of weather alone. Similar things occur in a very cold month.

Clearly, it is not only prudent but also useful to take weather into account in our calculations. If we can point to weather as the main reason for the difference between July and August consumption, and adjust for it, we can start combining the data from the two months. Doing so yields more useful data and leads to increases in the statistical significance of our results and will permit more accurate forecasting as well. For the North Carolina experiment in particular, it is important to be able to correct for extreme differences in different locations. The CP&L study was spread over the entire service area of the North Carolina utility. That area includes Charlotte, Asheville, and many other localities. Now, Asheville is a winter-peaking subpart of the CP&L system, while the system as a whole is summer-peaking. This suggests that Asheville's weather differs sharply from the weather in Charlotte or in any other locality in North Carolina. If we do not correct for this difference, we will get some spurious correlations that will not be due to prices but simply to differences in where people live.

RESULTS OF CORRECTING FOR WEATHER DIFFERENCES IN NORTH CAROLINA DATA

Table 4.3 shows what happens to the data when we correct for weather. (These are still calendar-month data; we do not yet have the necessary billing-cycle information.) The table compares the responses of a "core" rate group in the winter in North Carolina under three time-of-day rates with the consumption of a control group under a flat rate. The data in the table are differences in relative shares of consumption in a period, not straight comparisons of kilowatt-hours con-

Table 4.3

DIFFERENCE BETWEEN AVERAGE KWH SHARES OF CONTROL GROUP AND "CORE" RATE
GROUP: WINTER

Period	Without Weather Adjustment	With Weather Adjustment
Peak	-1.8%	-5.3%
Intermediate	-0.3	-0.3
Off-peak	+6.3	+6.1

Rates: Control ..... 3.45¢/kWh
"Core" rates:
Peak ..... 4.75¢
Intermediate ... 2.65¢
Off-peak ..... 1.37¢

Table 4.4

DIFFERENCE BETWEEN AVERAGE KWH SHARES OF CONTROL GROUP AND "CORE" RATE
GROUP: SUMMER

Period	Without Weather Adjustment	With Weather Adjustment
Peak	-4.9%	-6.7%
Intermediate	+1.9	+1.4
Off-peak	+9.2	+12.9

Rates: Control ..... 3.45¢/kWh
"Core" rates:
Peak ..... 5.06¢
Intermediate ... 3.34¢
Off-peak ..... 1.37¢

sumed. (A group's share of consumption for a period is the kWh consumed in that period divided by total kWh consumed.) Without the weather adjustment, for example, we observe that "core" customers use 1.8 percent less electricity during the peak period than do control customers. When we adjust for weather, that figure almost triples, to 5.3 percent less. Intermediate and off-peak comparisons remain virtually constant. Table 4.4 shows the same sort of comparison for the summer months. Peak-period and intermediate-period relative consumption of the "core" group drop somewhat with weather adjustment, while the relative proportion of off-peak consumption rises from +9.2 percent to +12.9 percent in the off-peak period. Such figures are roughly what our Los Angeles experience would lead us to expect. They are not statistically significant, however, which means that the sample sizes of the North Carolina experiment, as it is now, may have not been large enough. Also, we have not made all the adjustments yet. In short, these are very provisional figures. Explaining a large portion of the unexplained variation in the North Carolina experiment calls for much more work on our part.

CONCLUSIONS AND EXTENSIONS

Two major conclusions emerge from all this. First, we can explain a considerable portion of the apparent contradictions between studies by their different definitions of the measures--full versus partial elasticities; by their different analytic assumptions-- Wisconsin's use of a very structured model, for example, versus the essentially model-free approach in North Carolina; and by data handling problems--primarily, omitting variables that matter in electricity consumption. Second,

after we use the information that we now have to adjust for those factors, especially weather, the results are no longer very contradictory. In other words, after digging a little deeper into the data, the case for transferability no longer seems as hopeless as it did at first.

Our plan for the future is to apply the hybrid model to North Carolina and Wisconsin--to perform analysis similar to that for Los Angeles. We also plan to develop models and methods by which we can use time-of-day responses in one experiment to predict responses in other service territories. Eventually, we hope that we may be able to pool all the information from North Carolina, Wisconsin, and Los Angeles into a common data set from which we can estimate a hybrid model that will be generally applicable, with appropriate adjustments for special local conditions.

Such a model would certainly produce more powerful conclusions, whether positive or negative. It would gain confidence among other analysts, policymakers, and ratemakers if its predictive power proved satisfactory when applied to three completely different locations: the Mediterranean climate of Los Angeles, the humid climate of North Carolina with its large air conditioning load, and the colder climate of Wisconsin with its large heating load. Such a model would also give us more insight into what other variables matter. Humidity, for instance, does not seem to matter much in Los Angeles, but makes a considerable difference in North Carolina.

Ultimately, a hybrid model embodying all of the most important variables will enable analysts to predict with greater accuracy and confidence what will happen when particular rate schedules are offered to

customers in different locations.

V. CRITERIA FOR MEASURING THE EFFECTS OF ELECTRICITY RATE CHANGES

This section discusses some of our preliminary work on identifying a suitable methodology for evaluating electricity rate changes. The methodology is applicable to studies of the industrial and the residential sector demand for electricity. We had expected to perform most of the work on evaluation during the second and third years of our research under this project; some of the preliminary work has already been completed, however, and because of the high-level interest in the utility and regulatory communities for these types of discussions, we thought an interim report would be appropriate.

Formal evaluation, in the economist's sense of comparing benefits with costs, is needed for a number of reasons. First, time-of-day (TOD) meters are more expensive than conventional meters. Consequently, TOD rate structures will be inefficient if the costs of erecting and administering them exceed the benefits. They may still be judged desirable on the basis of other considerations, such as their distributional effects in allocating electricity charges more equitably among different groups of customers, but if costs exceed benefits they are not efficient in the strict sense of the word.

The second major impetus for evaluation is the legislative mandate under the PURPA standard of the National Energy Act.[1] This mandate

[1] Public Utilities Regulatory Policies Act of 1978, a component of the National Energy Act, requires hearings by all 50 state Public Utilities Commissions and the regulatory bodies of any utility with annual electricity sales in excess of 500 million kWh. The PURPA standard requires an assessment of the "cost effectiveness" of time of day rates, but other sections of the act make it clear that a systematic comparison of benefits and costs is the legislative intent. The hearings were to be completed by the fall of 1981.

applies to all 50 state regulatory commissions, as well as to any publicly owned utility with annual sales exceeding 500 million kWh a year. As a result, something in excess of 200 determinations of the costs and benefits of TOD rates were required.

The PURPA standard covers all classes of customers, but the discussion here focuses primarily on residential customers. (The methodology and other considerations are identical for both the industrial and residential sectors.)

DESIRABLE FEATURES OF AN EVALUATION STANDARD

An evaluation criterion should have at least the three following important features. First, it should be a conceptually sound measure. That is, it should be able to measure the theoretically important effects in terms of costs and benefits. Second, it should be a practical measure; since any criterion will have to be applied repeatedly by regulatory commissions and utility rate staffs, it should be readily applicable to the kinds of data that can reasonably be expected to be available for rate determinations. Third, it should be an understandable criterion to assure its widespread acceptability among ratemakers and other participants in the ratemaking process.

The cost/benefit comparison requires an identification of the major components of each. The benefits can be grouped into those affecting producers and those affecting consumers. Any change from one rate structure to another will affect the producers (electric utilities in this case), in terms of demand for their output, their operating costs, their long-term capital requirements, and their revenues. The principal

effects on consumers are measured by increases in their well-being (economic welfare or utility) and the effects on their bills. On the cost side, TOD rates add to metering costs, and often to administrative costs as well. There being general agreement about the components of costs, we will assume that they are accurately measured. The general disagreement on evaluating new structures has focused on the benefit component, which will be the focus of our discussion as well.

The remainder of this section is divided into three parts. First, we review three alternative criteria that have been suggested for rate evaluation and used in rate structure hearings. Second, we illustrate the calculations using residential demand data from the Los Angeles experiment. The third and last part discusses implications of this work.

THREE ALTERNATIVE RATE EVALUATION CRITERIA

Three principal alternatives have been applied in ratemaking cases:

- The revenue effects on the utility
- The amount of fuel saved
- The effect on economic welfare

Treating each in turn, we first present arguments that the revenue effects on utilities constitute a very poor guide to evaluating rate-structure changes. Second, we demonstrate that the amount of fuel savings is a misleading and often erroneous basis for evaluating rate changes. Third, we argue that welfare economics provide a conceptually sound approach to measuring benefits in the context of formal rate

evaluation.

Figure 5.1 illustrates the basic challenge confronting attempts to evaluate the benefits of an alternative rate structure. Assume that customers initially face non-time-differentiated charges for electricity at the level p, leading to consumption Q_1 in the peak period and Q_2 in the off-peak period. When TOD rates are introduced, the peak price is raised to some level P_1 and the off-peak price is lowered to some level P_2. As long as customers display any sensitivity to prices at all, they will reduce their peak-period consumption to some level Q_1* in the peak period, and increase their consumption in the off-peak period to some level Q_2.* The challenge for the evaluator is to measure the effects on producers and consumers of these associated changes in quantity. We will assume throughout the discussion that prices in the peak period under the TOD rate are set equal to marginal costs in that period, and that prices in the off-peak period are set equal to marginal costs in the off-peak period.[2] Our second major assumption is that the effects on producers and consumers are valued equally. Within the framework discussed below, however, one can easily assign different weights to the effects on producers and consumers, or to the effects on subgroups of consumers. For simplicity we assume that all effects are valued equally regardless of the recipient.

[2] Marginal costs may be either short-term or long-term, depending on the relative importance of emphasizing the longer-term adjustments that a utility may make--as determined by the regulatory body. For a utility with excess capacity, or a utility in equilibrium and with an appropriate mix of generating equipment for its present fuel costs and demand, short-run and long-run marginal costs are equal.

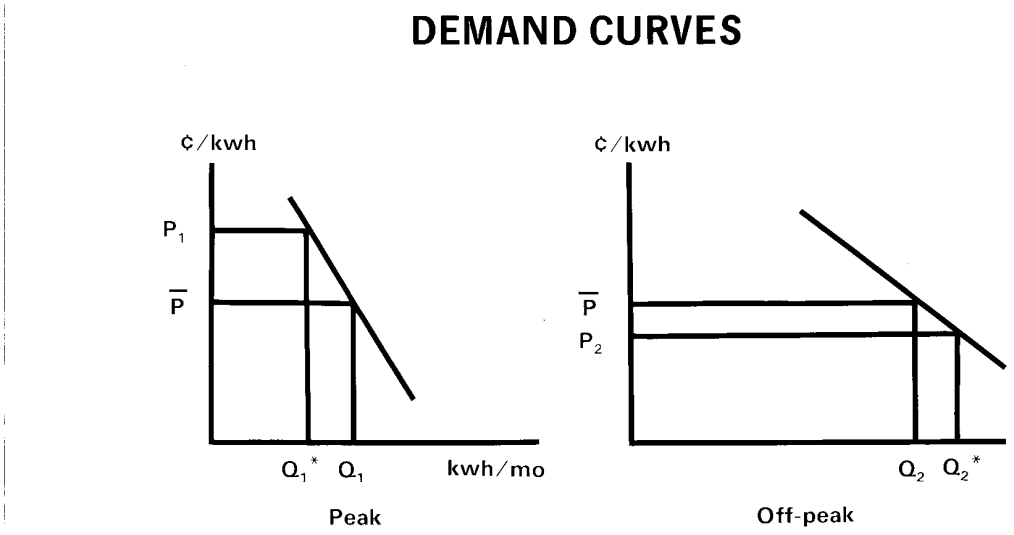

DEMAND CURVES
¢/kwh
P_1
$\bar{P}$
Q_1^* Q_1
kwh/mo
Peak
¢/kwh
$\bar{P}$
P_2
Q_2 Q_2^*
Off-peak

Fig. 5.1

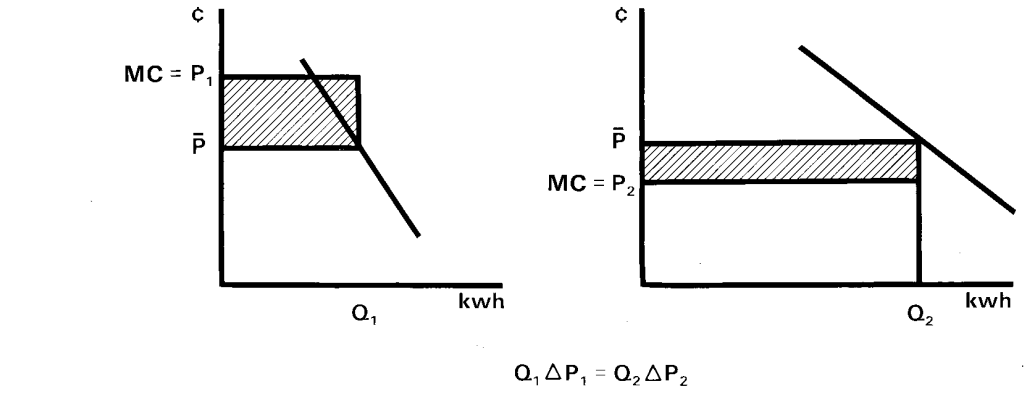

REVENUE NEUTRALITY
¢
MC = P_1
$\bar{P}$
Q_1
kwh
¢
$\bar{P}$
MC = P_2
Q_2
kwh
$Q_1 \Delta P_1 = Q_2 \Delta P_2$

Fig. 5.2

Revenue Effects Criterion

The revenue effects criterion concentrates solely on how a rate structure change affects producers. This alone would be an important limitation, but in addition the revenue effects criterion is unsuited for evaluating many of the interesting rate changes that will face a regulator when TOD rates are considered.

Figure 5.2 illustrates the meaning of a revenue effect. At initial levels of consumption, Q_1 and Q_2, the effect of the TOD rate is to raise ex ante revenue by an amount shown as the shaded quantity in the left-hand side of Fig. 5.2 and to reduce revenue by an amount shown as the shaded area on the right-hand side. If the TOD rate is designed to be revenue-neutral--that is, to raise the same amount of revenue at initial levels of consumption as the non-TOD rate presently in effect--then the shaded area on the left ($Q_1\Delta P_1$) equals the shaded area on the right $Q_2\Delta P_2$).

It should be obvious that the revenue effects criterion will be irrelevant to any alternative rate structure that is designed from the outset to produce the same anticipated revenue for a given producer as the present rate structure does. Because such a structure will not raise an additional amount of revenue, it would lead to a rejection of all rate changes, since even trivial metering or implementation costs would outweigh the zero benefit that is calculated. Correspondingly, any rate that raises more revenue--even if it is a bad rate by everyone's evaluation--will pass a revenue effects criterion because it produces an increase over the alternative being considered. Therefore, the revenue effects criterion should be rejected.

Welfare Effects Criterion

In contrast, the economic welfare criterion considers effects on both producers and consumers. It is often rejected for pragmatic rate evaluation on the grounds that it is too complex or requires data that are not easily available. As we show below, however, it requires no more data than the alternative rate criteria that are being discussed, and its complexity is more apparent than real.

Consider first the effects on consumers, which are measured as gains in consumer surplus under a proposed new rate structure. Figure 5.3B illustrates what happens when the price is lowered from P to P_2 during the off-peak period. The consumer's original level of consumption (Q_2) now costs him a lower price per kWh--a clear gain, shown as the rectangular hashed area in Fig. 5.3B. He reaps a further gain by increasing his consumption from Q_2 to Q_2*, indicated by the triangular solid area in the figure. These are kWh of consumption that are of more value to him at the new price P_2 than under the old price P.

Conversely, Fig. 5.3A depicts what happens when the price is raised in the peak period from the level P to P_1. The customer suffers some loss in consumer surplus--the difference between what he would be willing to pay for electricity and what he is actually required to pay. He loses the entire trapezoidal area in Fig. 5.3A. The rectangular portion of the trapezoid represents his loss as he pays a higher price per kWh for the same quantity Q_1* in the peak period. The solid triangular portion represents the lost value to him of the electricity whose consumption he has forgone by reducing his demand from Q_1 to Q_1*.

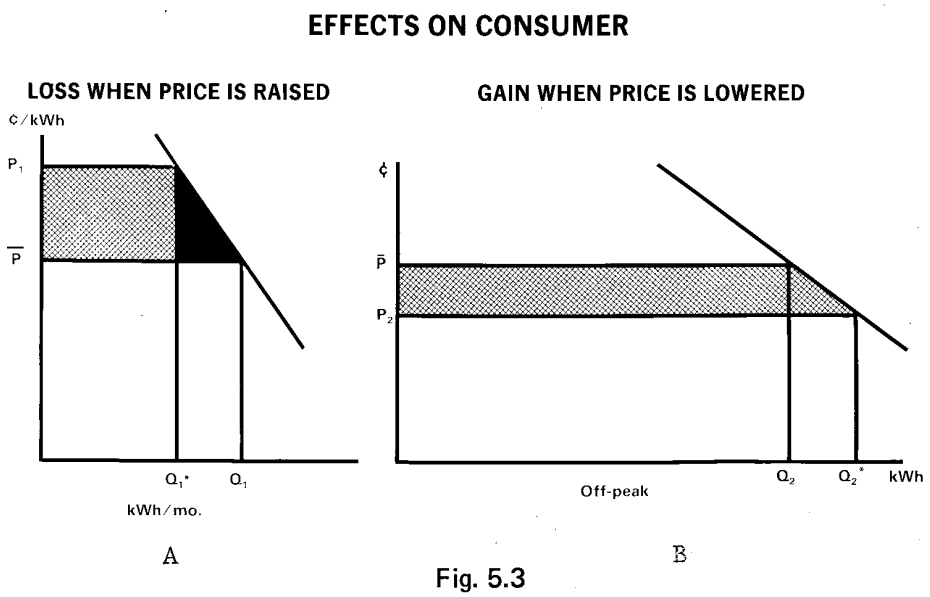

EFFECTS ON CONSUMER
LOSS WHEN PRICE IS RAISED
GAIN WHEN PRICE IS LOWERED
¢/kWh
P1
P̄
Q1*
Q1
kWh/mo.
¢
P̄
P2
Off-peak
Q2
Q2*
kWh
A
B

Fig. 5.3

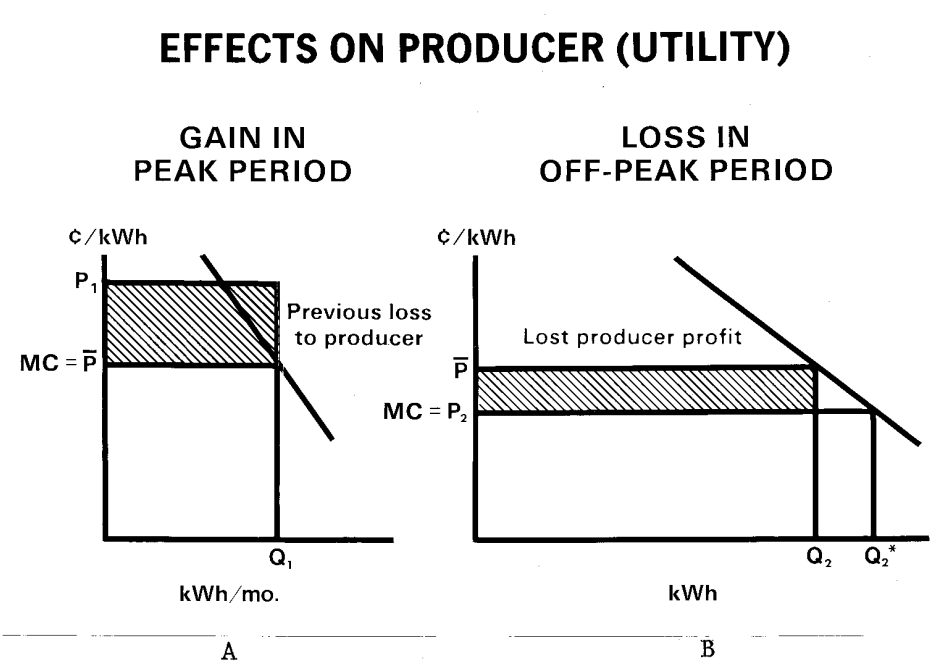

EFFECTS ON PRODUCER (UTILITY)
GAIN IN PEAK PERIOD
LOSS IN OFF-PEAK PERIOD
¢/kWh
P1
MC = P̄
Previous loss to producer
Q1
kWh/mo.
¢/kWh
Lost producer profit
P̄
MC = P2
Q2
Q2*
kWh
A
B

Fig. 5.4

The effects on producers are--in some sense--the mirror image of the effects on consumers, although the magnitudes are not identical. In the peak period, (Fig. 5.4A), if the marginal cost of production MC is reflected in price P_1, the producer was previously losing the difference between P_1 and P on every kWh sold. Introducing TOD pricing nullifies this loss.[3] Correspondingly, in the off-peak period, the producer earns some excess profit on the difference between his revenue per kWh (P) and his actual marginal costs of supply (P_2). TOD pricing eliminates this profit, shown as the shaded area on the right (Fig. 5.4B).

In all, the gain to the producer in the peak period minus the loss in consumer surplus due to an increased price in the peak period leads to a net increase in economic welfare shown as the shaded triangle WWp at the left side of Fig. 5.5. In the off-peak period, the increased consumer surplus associated with the lower price, minus the loss in excess producer profits, leads to a net increase in welfare shown as the shaded triangular area ΔWop at the right side of the Fig 5.5.[4]

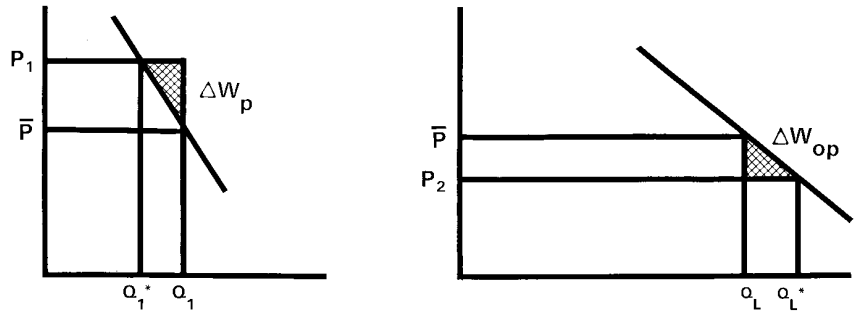
Fuel Savings Criterion

It is now straightforward to understand the effects of the fuel savings criterion and to realize the differences it produces from the previous two criteria. The fuel savings criterion applies only to the effects on producers. It ignores entirely the effects on consumers, except as they lead to changes in level of consumption. It leads to

[3] If marginal costs of production are not constant, then the rectangle is replaced by a shaded area with an upward sloping curve on top.

[4] Of course the peak and off-peak demand curves are not necessarily straight lines. In reality, the triangular areas are likely to have curved hypotenuses.

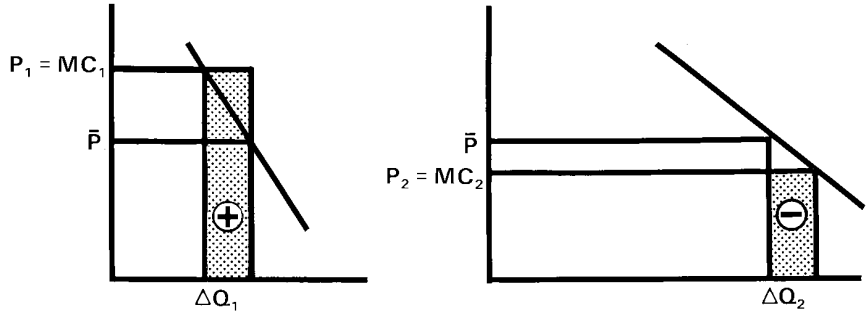
NET CHANGE IN ECONOMIC WELFARE



A B

Fig. 5.5

FUEL SAVINGS CRITERION



A B

Fig. 5.6

radically different measures of benefits in both peak and off-peak periods from those of either of the two alternatives discussed.

The proponents of the fuel savings criterion do not always make clear what they have in mind, but we will assume that they mean the reduced expenditure on fuel in the peak period minus the increased expenditure on fuel in the off-peak period. In a thermoelectric utility system with oil, gas, or coal-fired plants operating at the margin at all times, the majority of short-run marginal costs are reflected in incremental fuel expenditure (there is some incremental non-fuel operating and maintenance expense, but it is relatively small); for simplicity, we assume that fuel costs are the entire short-run marginal costs. If short-run marginal costs in the peak and off-peak periods equal P_1 and P_2, respectively, then the net effect of fuel savings is as shown in Fig. 5.6. Clearly, these are importantly different measures from those just produced by the welfare economics criterion. The fuel savings criterion criterion yields an apparent benefit for the peak period, shown as the shaded rectangular area, much larger than the welfare triangle shown in Fig. 5.5. In the off-peak period it yields a substantially lower measure of benefit--in fact a loss--whereas the welfare criterion indicated a gain in consumer surplus net of the loss to producers. In other words, the fuel savings criterion regards any increase in consumption during the off-peak period as bad, regardless of the associated benefits to consumers. The question then arises: Is it possible that the two large errors can cancel out and that, in net, the fuel savings criterion yields a net benefit that is fairly close to that of the welfare criterion? The answer is that yes, it is possible, but it is

highly unlikely with the magnitudes of demand elasticity that we have encountered and the likely changes in peak and off-peak prices that a TOD rate would introduce.

Figure 5.7 summarizes the net gains of these alternative measures. The revenue effects criterion indicates a gain in revenue during the peak period, shown as area a, and a loss in revenue in the off-peak period shown as area b, for a net change of a - b. If the TOD rate is designed to be ex ante revenue-neutral, then a - b will equal zero. The welfare effects criterion leads to a net increase in economic welfare in the peak period, shown as area c, as well as the net increase in economic welfare in the off-peak period, shown as area d; their sum necessarily exceeds zero. The fuel savings criterion indicates a large gain in the peak period (area e) and a loss in the off-peak period (area f), for a net change of e - f, which could be greater than or equal to zero, depending on the magnitudes of price elasticities and the level of price changes involved.

In conclusion, the welfare effects criterion is conceptually sounder than either of its alternatives. It considers the effects on both producers and consumers, and measures the net change between the loss to one party and the gain to the other in each respective pricing period. The welfare effects criterion requires understanding the relationship between price and quantity demanded under both the existing rate structure and the TOD rate structure. TOD elasticity information has not been widely available in the past, but it is now becoming better understood through a variety of studies of experimental and nonexperimental data. Furthermore, the data requirements for measuring welfare

SUMMARY OF THREE ALTERNATIVE EVALUATION CRITERIA

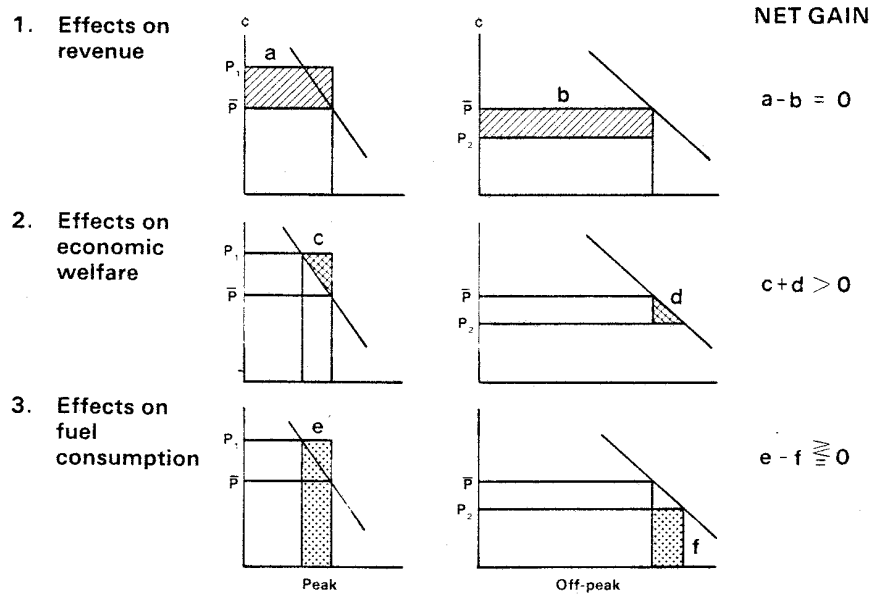


Fig. 5.7

effects are essentially those that are needed to measure the effects of either of the alternative criteria. No additional data collection is required (unless non-fuel incremental operating and maintenance expenses are needed).

ILLUSTRATIVE CALCULATIONS

We will illustrate the application of both the welfare-effects and fuel-savings criteria using the residential demand elasticities derived from the Los Angeles experiment. Since the candidate rate for this calculation is designed to be ex ante revenue-neutral, the revenue effects criterion will not be explicitly discussed.

When considering a change from non-TOD rates to TOD rates, many potential combinations of peak and off-peak prices as well as rating periods could be considered. The set of rates chosen for illustration here closely approximates the TOD rate structure introduced in Los Angeles in 1979. That structure was designed to be revenue-neutral. It charged 9 cents/kWh during the peak period and 3 cents/kWh during the off-peak period. The non-TOD rate was approximately 5 cents/kWh. The peak period was chosen to be noon to 9 p.m. Monday through Friday, as in the Los Angeles experiment.

Table 5.1 illustrates the effect of a TOD rate on households at different levels of monthly energy consumption. For purposes of this calculation, the mean characteristics of households (in terms of their demographics, appliance ownership, income, and so forth) at each level of use are taken as explanatory variables. The TOD rate's expected effect on peak-period consumption is shown to range from a very small

Table 5.1

EFFECTS OF AN ILLUSTRATIVE TOD RATE BASED ON LONG-RUN MARGINAL COSTS--ALL HOUSEHOLDS

	Initial Tariff	TOD Rate
	5¢/kWh, all hours	9¢/kWh, noon-9 a.m., weekdays 3¢/kWh all other hours

Household Consumption (kWh/month)	Change in Peak Usage (kWh/month)	Change in Off-Peak Usage (kWh/month)	Change in Welfare ($/month)	Fuel Savings[a]	"Fuel & Capital"[b] ($/month)	Net Present Value of Welfare Change[c] ($)
0-200	0	5	.08	-.22	-.15	8.43
201-400	-1	10	.19	-.34	-.21	20.01
401-500	-3	15	.31	-.43	-.18	32.65
501-600	-6	18	.42	-.48	0	44.24
601-700	-9	22	.55	-.35	.15	57.94
701-800	-15	28	.75	-.26	.51	79.00
801-900	-23	36	1.01	-.10	.99	106.39
901-1000	-24	38	1.08	-.14	1.02	113.77
1001-1100	-33	47	1.38	.02	1.56	145.37
1101-1200	-44	56	1.72	.33	2.28	181.18
1201-1300	-45	59	1.81	.33	2.28	190.66
1301-1400	-57	72	2.21	.51	2.97	232.80
1401-1500	-64	72	2.38	.96	3.60	250.70
1501-2000	-78	82	2.84	1.37	4.56	299.15
2001-2500	-123	65	3.81	4.98	9.12	401.34
2500+	-174	132	5.78	5.32	11.70	608.85

SOURCE: J. P. Acton and B. M. Mitchell, "Welfare Analysis of Electricity Rate Changes," in S. Berg (ed.), *Innovative Electric Rates: Issues in Cost-Benefit Analysis*, Lexington Books, Lexington, Mass (forthcoming).

[a]Based on short-run fuel savings of 6-1/3¢/kWh in peak, 4-1/3¢/kWh in off-peak periods.

[b]Based on 9¢ and 3¢/kWh in peak and off-peak periods.

[c]Based on 15-year amortization at 8 percent.

number at low levels of monthly consumption to more than 170 kWh per month at the highest levels of consumption. This increasing proportional response is a feature of the empirical findings of the Los Angeles experiment, in which increasing price elasticity was found at higher levels of consumption (primarily due to the increased appliance holdings at those higher levels of use). Similarly, the expected rise in off-peak consumption increases more than proportionally as the monthly level of consumption increases. The net effect on welfare ranges from a modest value of less than 20 cents per month at the lowest levels of consumption up to an average value of almost $6 per month for consumption exceeding 2500 kWh per month. In contrast, the fuel savings criterion (based on short-run fuel costs of 6-1/3 cents/kWh in peak and 4-1/3 cents/kWh in off-peak periods) yields a much lower value at each level of consumption, and--as could be expected from the fact that it calls any increase in off-peak consumption a loss--actually yields a negative net benefit at the lower levels of consumption.[5] If a more comprehensive "fuel plus capital" cost-saving criterion is used (with 9 cents and 3 cents as assumed values), then the gain is slightly larger, but still quite different from that of the welfare measure.

In 1979, when Los Angeles was considering these rate alternatives, the installed metering cost for a two-register, time-of-day meter was

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[5] The calculations here do not consider possible "shadow price" differences between the nominal price of a fuel, such as oil, and its value to society. The issue is the so-called import premium, which is intended to reflect the value to the United States of not having to import costly foreign oil, for example, thus improving our balance of payments and possibly reducing our vulnerability to disruptions. Shadow-price differences can be included in any one of the three criteria discussed, but for comparability should be included in all three. Their inclusion would alter the data in Tables 5.1 and 5.2.

estimated to be approximately $150. Assuming a 15-year service life, and using an 8 percent real discount rate, this implies a monthly carrying cost of approximately $1.42 per meter. The welfare measure indicates an average net increase in welfare of over $1.42 for customers using more than 1100 kWh. This implies that a net benefit would be realized by making such a rate available above but not below that level of consumption.[6] Of course, the net benefit calculation is a function of all three factors: assumed changes in price level, price elasticity of demand by the customers, and anticipated metering costs. For greater values of either price differential or elasticity of demand, the net benefit increases; it could also increase at lower values of metering costs per month.

An alternative application of the welfare-effects and fuel savings criteria is presented in the last column of Table 5.1. Again using average elasticities and household demographics at different levels of monthly consumption, we calculate the maximum increased metering costs that would still yield to an increase in net welfare over costs at different levels of consumption. For example, for all households, using the welfare effects criterion, customers using 201 to 400 kWh/month would experience a net gain in welfare for any metering costs up to $20 (Table 5.1). At higher levels of consumption, of course, a more expensive meter could be installed and still yield a net improvement in welfare. At the highest level of consumption, the meter could cost more

[6] Some customers using less than 1100 kWh and having a greater than average elasticity of demand would of course reap a net benefit in excess of the metering costs even at lower monthly levels of consumption. This is particularly true of customers with a swimming pool or air conditioning.

than $600 and still yield a net gain in economic welfare. In contrast, the fuel savings criterion indicates a lower acceptable metering cost at every level of consumption (in fact, it would have to be negative at low levels of use) if a welfare gain is to be realized.

The greater price elasticity of demand by households with swimming pools leads to greater response to TOD rates and correspondingly greater changes in economic welfare; (see Table 5.2). As a consequence, higher metering costs are acceptable at any given level of monthly consumption, given the other household characteristics of that level of consumption. For example, a TOD meter costing $150 could be installed for all households with swimming pools whose monthly consumption exceeded 800 kWh a month, and still yield a net welfare gain.

CONCLUSION

In summary, economic welfare is a conceptually sound and practical criterion for evaluating rate changes. All the data needed to perform the calculations are now available for residential consumers on the basis of rate experiments that have been conducted. If the regulator and the utility official are willing to apply those empirical relations to a particular service territory--adjusting appropriately for local values of household characteristics and average elasticities--then those experimental results can be used as a basis for the welfare calculation. If the regulatory process is unwilling to use the results of an experiment conducted in another service territory, then alternative estimates of the elasticity of demand under time-of-day pricing must be supplied. This empirical requirement for time-of-day price elasticity is equally

Table 5.2

EFFECTS OF AN ILLUSTRATIVE
TOD RATE: HOUSEHOLDS WITH SWIMMING POOLS

Initial Tariff	TOD Rate
5¢/kWh all hours	9¢/kWh, noon-9 a.m., weekdays 3¢/kWh all other hours

Household Consumption (kWh/month)	Change in Peak Usage (kWh/month)	Change in Off-Peak Usage (kWh/month)	Change in Welfare ($/month)	Fuel Savings ($/month)	Net Present Value of Welfare Change ($)
0-200	N.A.	N.A.	N.A.	N.A.	N.A.
201-400	-6	27	.43	-.27	45.30
401-500	-14	36	.71	.18	74.79
501-600	-21	38	.90	.75	94.80
601-700	-26	44	1.11	1.02	116.93
701-800	-32	50	1.31	1.38	137.99
801-900	-40	51	1.51	2.07	159.06
901-1000	-44	58	1.70	2.22	179.07
1001-1100	-49	64	1.88	2.49	198.04
1101-1200	-55	68	2.08	2.91	219.10
1201-1300	-60	72	2.26	3.24	238.06
1301-1400	-66	81	2.48	3.51	261.24
1401-1500	-75	81	2.71	4.32	285.47
1501-2000	-90	93	3.19	5.31	336.03
2001-2500	-125	108	4.23	8.01	445.58
2500+	-199	148	6.48	13.47	682.59

SOURCE: J. P. Acton and B. M. Mitchell, unpublished research notes, The Rand Corporation, June 1981.

applicable to the other two evaluation criteria we discussed.

The fuel savings criterion is a highly misleading and conceptually unsound alternative to the economic welfare criterion. It yields greatly overstated apparent benefits in the peak period and calls any increase in consumption during off-peak periods a loss in well-being. It is not only conceptually unsound, but also has been found unreliable in practice. Our illustrative calculations using actual price elasticity and time-of-day rates applied in Los Angeles indicate important differences in the magnitudes of benefit calculated on the basis of the fuel savings criterion.

The revenue effects criterion is also highly misleading and considers only the effects on producers. It is not suited for many candidate rates that regulators and utility officials will wish to consider. This is particularly true of an alternative rate structure that might be considered for optional application in the service territory, where the optional rate is designed on average to raise the same revenue as the standard rate. In light of its major deficiencies, it is surprising that the revenue effects criterion has been used at all in PURPA hearings.