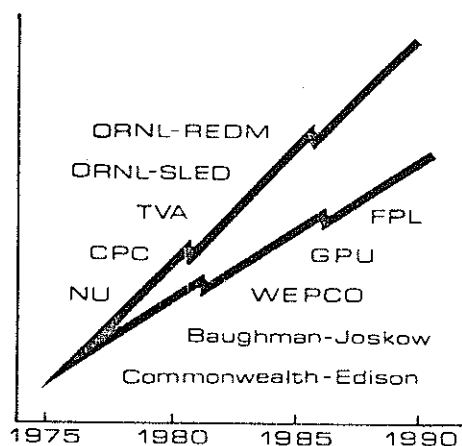


# ELECTRIC LOAD FORECASTING

## PROBING THE ISSUES WITH MODELS



EMF Report 3

Volume 1

April 1979

Energy Modeling Forum  
Stanford University  
Stanford, California 94305

#### LEGAL NOTICE

This report was prepared by the Energy Modeling Forum (EMF), administered by the Institute for Energy Studies, Stanford University, as an account of work sponsored by the Electric Power Research Institute, Inc. (EPRI). Neither EPRI, members of EPRI, EMF, nor any person acting on behalf of either: (a) makes any warranty or representation, express or implied, with respect to the accuracy, completeness, or usefulness of the information contained in this report, or that the use of any information, apparatus, method, or process disclosed in this report may not infringe privately owned rights; or (b) assumes any liabilities with respect to the use of, or for damages resulting from the use of, any information, apparatus, method, or process disclosed in this report.

This report summarizes the results of the EMF working group study. It does not necessarily represent the views of Stanford Institute for Energy Studies or Stanford University.

## EXECUTIVE SUMMARY

### ELECTRIC LOAD FORECASTING: Probing the Issues with Models

Forecasts of peak load (kilowatts) and electricity consumption (kilowatthours) are the starting points in the electric utility planning cycle. As the lead times required to add new generation capacity have lengthened, and the costs of new capacity have risen, the importance of forecasting has increased substantially. At the same time, the growth of electricity consumption has broken with past trends, and the uncertainty of forecasting has widened.

To help utilities deal with the new complexities and uncertainties of forecasting, the Energy Modeling Forum has examined several forecasting issues with 10 current models. This report presents (1) observations from that investigation and (2) recommendations for improving the quality and use of forecasting methods.

This study was conducted by a working group with participants from utilities, government agencies, universities, and consulting firms. The working group was chaired by a senior utility planner and included model developers and users of model results. The group met four times over nine months to design, implement, and interpret several experiments with the models.

Two major objectives were met in this process:

- the experiments identified and illuminated key forecasting issues; and
- the interactions among working group members improved their understanding of the capabilities and limitations of the use of models.

The models studied illustrated two approaches:

- the econometric approach, which uses statistical methods and historical data to infer the response of consumers to changes in prices, incomes, and other variables; and
- the engineering approach, which emphasizes the end-use detail needed to analyze the patterns of electric loads and to assess the impacts of load management and efficiency standards.

Based on its discussions and analysis, the group reached the following conclusions:

- Electricity consumption, given the assumptions of the modelers, is forecast to grow more slowly than in the past; see Figure 1.
- Load shape, peak demand, and electricity consumption are critical determinants of future generation capacity requirements. Implementation of time-of-use pricing and load management techniques will make forecasting load shape crucial in the future.

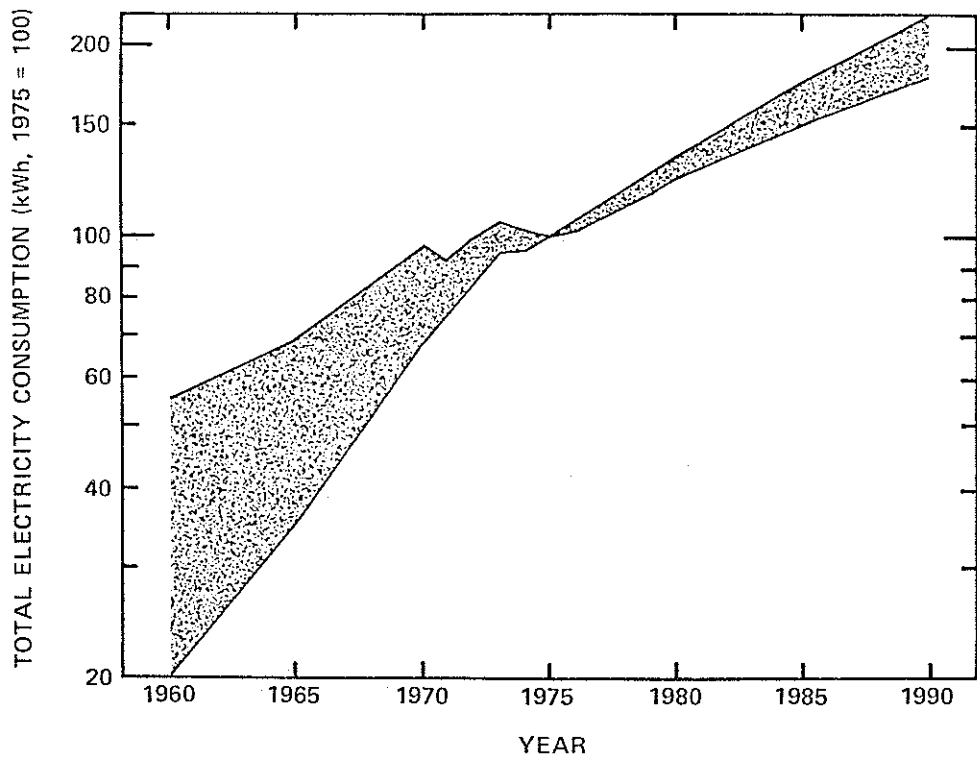


Figure 1 Range of Historical Electricity Consumption and Reference Case Projections for Participating Models

- Increases in real electricity prices significantly reduce the consumption projected with models that explicitly include prices, although the degree of response was substantially different among the models; see Figure 2. As electricity prices change, capturing this effect in the forecasts will continue to be important.
- Increases in the relative prices of other energy sources (e.g., natural gas) cause increases in the electricity consumption projected with models that explicitly include the prices of these fuels. As prices of competing fuels change, it will be vital to capture these effects in the models.
- Combined historical data from many regions represent a largely untapped source of information, but the appropriate use of these data was hotly debated in the group. The significance of the issue has been highlighted by the observation that the price effects are much larger in two of the three models estimated with combined data than in the models estimated with data from a single utility area. One view is that the empirical estimates obtained using single utility area data are most relevant, while the other view is that the estimates derived from combined data are most appropriate.
- Adoption of efficiency standards for appliances and building construction may significantly influence electricity consumption. Thus, forecasting techniques should be able to reflect the effects of standards and other regulatory changes.

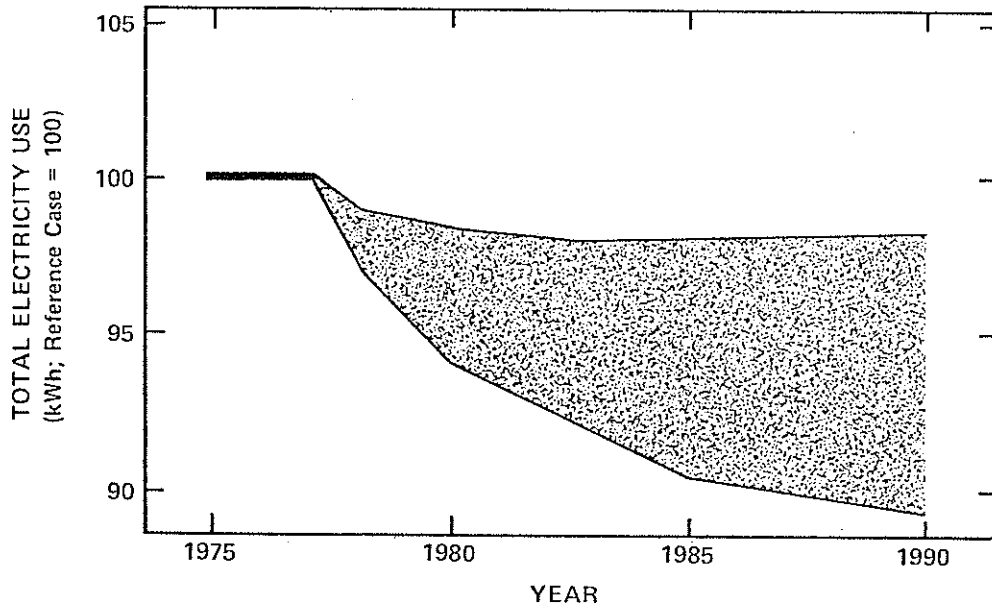


Figure 2 Range of Projected Changes in Electricity Consumption in Response to 10% Price Increase Relative to Reference Case (for those models that were price-responsive)

The working group observed several limitations on the use of the models it considered:

- Uncertainties associated with input variables, such as future electricity prices, fuel prices, economic growth, population, efficiency standards, and other regulatory changes, create uncertainties in the forecasts of electricity consumption. Specifying the values of these input variables is a critical part of the forecasting process. These uncertainties are in addition to the uncertainties inherent in the models themselves.
- Econometric models, which focus on the estimation of consumer response, normally are too aggregated to represent the effects of detailed regulatory or load management policies. Conversely, engineering models, which have extensive end-use detail, normally do not represent the response of consumers to changes in prices and other economic factors.
- Despite the recognized significance of load shapes, explicit projections of future load shapes are found in only 1 of the 10 models.
- Future electricity prices will be strongly influenced by the forecast of future demand that guides the utility's expansion program, especially during a period of increasing costs of new generating facilities. These higher prices, in turn, will dampen the growth of electricity consumption. This feedback is considered explicitly in only a few of the models.

The working group recommends:

- A comprehensive forecasting effort should provide a range of forecasts. Utility planners should recognize the uncertainty in the forecast in making capacity expansion decisions.
- Econometric and engineering methods should be used together, either through the use of complementary models or as a single model.
- Current data collection procedures should be scrutinized to improve their cost effectiveness for forecasting purposes; e.g., standardized definitions would permit data exchanges between utilities.
- Improved data should be collected, e.g., load characteristics of appliances, further disaggregation of consumption by industrial classification, and consumer response to alternative pricing structures.
- Since the models give meaning to the data, forecasting methodologies should be improved in concert with the data bases; e.g., in order to utilize better end-use data, improvements in engineering models may be necessary.
- Comparing and evaluating forecasting models is very difficult. Programs aimed at defining evaluation criteria should be examined to ensure that model development is not stifled.
- Cooperation among utilities with similar forecasting problems should be encouraged. Examples of mechanisms for joint actions include the Energy Modeling Forum and the Utility Modeling Forum. In addition, the EPRI load forecasting symposium was a successful vehicle for the industrywide dissemination of information, and conferences of this type should be continued.

## TABLE OF CONTENTS

	<u>Page</u>
Volume 1: Executive Summary . . . . .	iii
Preface . . . . .	ix
Senior Advisory Panel . . . . .	xi
Working Group Participants . . . . .	xii
Third Report: Electric Load Forecasting: Probing the Issues with Models . . . . .	1
Introduction . . . . .	1
The Problem Setting . . . . .	1
Study Process . . . . .	4
The Role of Forecasts and the Contribution of Models . . . . .	6
Overview of Electricity Forecasting Issues . . . . .	8
The Models . . . . .	12
Exploring Models and Issues Through Scenarios . . . . .	15
Observations and Conclusions . . . . .	20
Limitations of the Models . . . . .	32
Recommendations . . . . .	34
 Volume 2: Appendixes	
A. Model Descriptions . . . . .	A-1
B. Issues in Electric Load Forecasting . . . . .	B-1
C. Scenario Design . . . . .	C-1
D. Scenario Results . . . . .	D-1
E. An Analysis of Results and Models . . . . .	E-1
F. Forecasting the Impact of Time-of-Day Rates . . . . .	F-1
G. A Case Study of Needle Peaks . . . . .	G-1
H. Estimated Cogeneration Potential in the TVA Region . . . . .	H-1
I. Econometric Issues in Regional Demand Forecasting . . . . .	I-1

LIST OF TABLES

Volume 1

<u>Table</u>		<u>Page</u>
1	Models Used in the Electric Load Forecasting Study . . . . .	12
2	Definition of Scenarios Used in the Electric Load Forecasting Study . . . . .	17
3	Percent Improvement in Efficiency of New Residential Electric Equipment and New Residential Structures . . . . .	18
4	Models Used to Address the Scenarios . . . . .	19

LIST OF FIGURES

Volume 1

<u>Figure</u>		<u>Page</u>
1	Range of Historical Electricity Consumption and Reference Case Projections for Participating Models . . . . .	iv
2	Range of Projected Changes in Electricity Consumption in Response to 10% Price Increase Relative to Reference Case (for those models that were price-responsive) . . . . .	v
3	Nuclear Power Plant Lead Times . . . . .	2
4	Total Electric Utility Generation . . . . .	3
5	National Average Price of Electricity . . . . .	9
6	Reference Case Electricity Consumption . . . . .	21
7	Change in Electricity Consumption with 10% Price Increase Relative to Reference Case . . . . .	21
8	Change in Electricity Consumption with 20% Increase in the Price of Competing Fuels Relative to Reference Case (for those models that were price-responsive) . . . . .	22
9	Reference Case Electricity Price Assumptions . . . . .	23
10	Reference Case Natural Gas Price Assumptions . . . . .	24
11	Electricity Price Elasticity of Kilowatthour Use . . . . .	25
12	Competing Fuels Price Elasticity of Kilowatthour Use . . . . .	25
13	Change in Peak Kilowatt Load with Appliance Efficiency Standards Relative to Reference Case . . . . .	28
14	Load Factor Changes with Appliance Efficiency Standards Relative to Reference Case . . . . .	30
15	Ratio of Kilowatthour Consumption to Economic Activity . . . . .	31
16	Electric Space Heating Elasticities with Respect to Electricity Price . . . . .	43



## PREFACE

Concern over the level of future energy demand is a key issue in energy policy planning. The models utilized to project this demand are important ingredients in developing strategies which can potentially keep the United States energy solvent through the end of the century. It was for this reason that the Energy Modeling Forum (EMF) chose the forecasting of future electricity demand as a topic for the third Energy Modeling Forum working group (EMF 3).

In the winter of 1977, the EMF Senior Advisory Panel requested Bill Hogan, Executive Director of the EMF, to establish a working group on modeling for electric load forecasting. Shortly thereafter, Bill asked me to serve as chairman. We then selected appropriate individuals currently involved in the modeling of electrical demand. The main section of this report, Volume 1, is the product of the combined efforts of the working group. Although the members of the working group are in general agreement on this report, not everyone necessarily agrees with every statement. The responsibility for any remaining errors rests with me.

The efforts of the participants in the EMF 3 and the EMF staff make the result of the work, in my view, highly beneficial to the energy community. In particular, I believe that the overall objective of providing a vehicle for communication between modelers and policymakers has been well realized in this activity. In completing this project, I would like to express a deep appreciation for the contributions of the members of the working group. These members, although they had been assured by me in the early working group formulation that the effort would not impose unduly on their time, ended up contributing time and energy well beyond that which had been anticipated. The "encounter" sessions which were held in late 1977 and early 1978 developed the issues which needed to be evaluated. The cases which were later produced by various models in the evaluation of these issues further tested the endurance of all of the participants in the program. I would like to acknowledge particularly those working group members who utilized their models as a part of this effort. They included Paul Parker and Gary Ackerman of Commonwealth Edison; Wen Chern, Hoang Nguyen, and Eric Hirst of Oak Ridge; Bill Irish of TVA; George Tu of Consumers Power; Mike Mills and W. G. Bentley of FP&L; Don Burbank and Bruce Blakey of Northeast Utilities; Martin Baughman and Dilip Kamat of the University of Texas; Paul Neergaard of WEPCO; and Tom Jacob of GPU. I believe it is appropriate and not coincidental that these participants will reap the lion's share of the benefits from this effort.

I would like to acknowledge the major contributions which were made by Bill Hogan, Jim Sweeney, and Mark Swift who, through their prior experience in EMF activities, were able to give me perspectives in the EMF process which helped bring EMF 3 to a successful conclusion. Mark Swift provided the daily coordination that kept our group operating and guided the report to completion. Mary Fenelon, Rami Grunbaum, David Kline, and Tom Wilson of the EMF staff provided tremendous support in compiling, collating, and analyzing the results of the hundreds of cases which were run to provide some comparison of the various models which were used. Their

efforts brought order out of potential chaos. The efforts of all the other people on the EMF staff who labored at Stanford were extremely important in making the whole effort come together. Dorothy Sheffied and Nancy Silvis provided valuable assistance. The unflappable nature of Dee Druhe and Pam Sherby of the EMF administrative staff in dealing with a large volume of correspondence and numerous phone calls was most important. And finally, in my office, Sally O'Brien was a tremendous help.

Financial support for the overall EMF program is provided through the Electric Power Research Institute. We are most grateful for this institutional support as well as for the contributions of time and talent of the EPRI working group members.

B. H. Cherry

ENERGY MODELING FORUM

SENIOR ADVISORY PANEL

The Energy Modeling Forum seeks to improve the usefulness of energy models by conducting comparative tests of models in the study of key energy issues. The success of the Forum depends upon the selection of important study topics, the broad involvement of policymakers, and the persistent attention to the goal of improved communication. The EMF is assisted in these matters by a Senior Advisory Panel that recommends topics for investigation, critiques the studies, guides the operations of the project, and helps communicate the results to the energy policymaking community. The role of the Panel is strictly advisory. The Panel is not responsible for the results of individual EMF working group studies.

Mr. Charles J. Hitch (Chairman)	President, Resources for the Future
Dr. Philip H. Abelson	Editor, <u>Science</u> , American Academy for the Advancement of Science
Dr. Harvey Brooks	Professor, Harvard University
Mr. David Cohen	President, Common Cause
Mr. Gordon R. Corey	Vice Chairman, Commonwealth Edison
Dr. Floyd L. Culler, Jr.	President, Electric Power Research Institute
Mr. Charles Di Bona	President, American Petroleum Institute
Mr. Herman M. Dieckamp	President, General Public Utilities Service Corporation
The Honorable John D. Dingell	Member, United States House of Representatives
The Honorable Joseph L. Fisher	Member, United States House of Representatives
The Honorable William P. Hobby	Lieutenant Governor of Texas
Mr. Jack K. Horton	Chairman, Southern California Edison Company
Mr. W. F. Kieschnick, Jr.	Vice Chairman, Atlantic Richfield Company
Dr. Henry R. Linden	President, Gas Research Institute
Mr. Guy W. Nichols	President, New England Electric System
Mr. John F. O'Leary	Deputy Secretary, United States Department of Energy
Dr. Alan Pasternak	Member, California Energy Commission
Dr. John Sawhill	President, New York University
Dr. Chauncey Starr	Vice Chairman, Electric Power Research Institute
The Honorable Morris K. Udall	Member, United States House of Representatives

## WORKING GROUP PARTICIPANTS

Gary Ackerman	Systems Control, Incorporated
Martin L. Baughman	University of Texas
W. G. Bentley	Florida Power & Light Company
E. L. Bivans	Florida Power & Light Company
Bruce Blakey	Northeast Utilities
Donald Burbank	Northeast Utilities
Wen Chern	Oak Ridge National Laboratory
Bernard Cherry	General Public Utilities Corporation
Robert Crow	Electric Power Research Institute
Terry A. Ferrar	General Public Utilities Corporation
Dominic Geraghty	Electric Power Research Institute
Martin Greenberger	The Johns Hopkins University
Eric Hirst	Minnesota Energy Agency
William W. Hogan	Harvard University
William F. Irish	Tennessee Valley Authority
Thomas W. Jacob	General Public Utilities Corporation
Dilip Kamat	University of Texas
Anthony G. Lawrence	Electric Power Research Institute
Rene H. Males	Electric Power Research Institute
Lynn Maxwell	Tennessee Valley Authority
Michael Mills	Florida Power & Light Company
Paul Neergaard	Wisconsin Electric Power Company
Thomas B. Neville	United States Department of Energy
Hoang Dang Nguyen	Oak Ridge National Laboratory
E. Victor Niemeyer	Electric Power Research Institute
Paul Parker	Commonwealth Edison Company
Stephen Peck	Electric Power Research Institute
Roy J. Shanker	Resource Planning Associates, Incorporated
Robert Shaw, Jr.	Booz, Allen & Hamilton Incorporated
James L. Sweeney	Energy Modeling Forum
Mark A. Swift	Energy Modeling Forum
George C. Tu	Consumers Power Company
Robert G. Uhler	Electric Power Research Institute

## ELECTRIC LOAD FORECASTING:

### Probing the Issues with Models

#### INTRODUCTION

*Utility planners confront new problems.*

Forecasts of peak load (kilowatts) and electricity consumption (kilowatthours) are two of the inputs used by utility planners to determine the amount, type, and timing of additions to electric power generating capacity. Over the past several years, disruptions of historical relationships in the electricity market and of trends in the growth of electricity consumption have led planners to the development of new, more complicated forecasting methods. This study has two major purposes: (1) to learn about the relative behavior and usefulness of some of the new forecasting methods and (2) to examine the potential impact of factors that might strongly influence future electricity consumption.

#### THE PROBLEM SETTING

Prior to the events of the early 1970s, planning in the electric utility industry was less complicated than it is now.<sup>1</sup> During the three decades preceding 1970, the cost of generation from new facilities was usually less than the cost of generation from previously installed capacity.<sup>2</sup> The utility industry's cost of capital for financing new generation facilities was relatively low and stable.<sup>3</sup> Several alternative generation technologies were available for new facilities. These facilities could be sited and constructed within the time horizon of a reliable projection of load growth. Relative to today, load growth was more predictable, utility companies were more healthy financially, and they had less trouble in financing construction programs. Planning under these conditions involved shorter time horizons and fewer constraints.

Lead times are longer.

Since 1970, the lead times required for capacity additions have increased substantially because of new environmental concerns, greater complexity and larger scale of new generation technologies, and longer regulatory proceedings. Figure 3 indicates that nuclear power plant lead time has almost doubled in the last 10 years, increasing from five and one-half years in 1967 to 10 years in 1977, and increasing by two and one-half years from 1974 to 1977. Coal-fired power plant lead time also has increased.<sup>4</sup> With longer lead times needed to add new capacity, planners must look further into the future, which increases the uncertainty they must face.

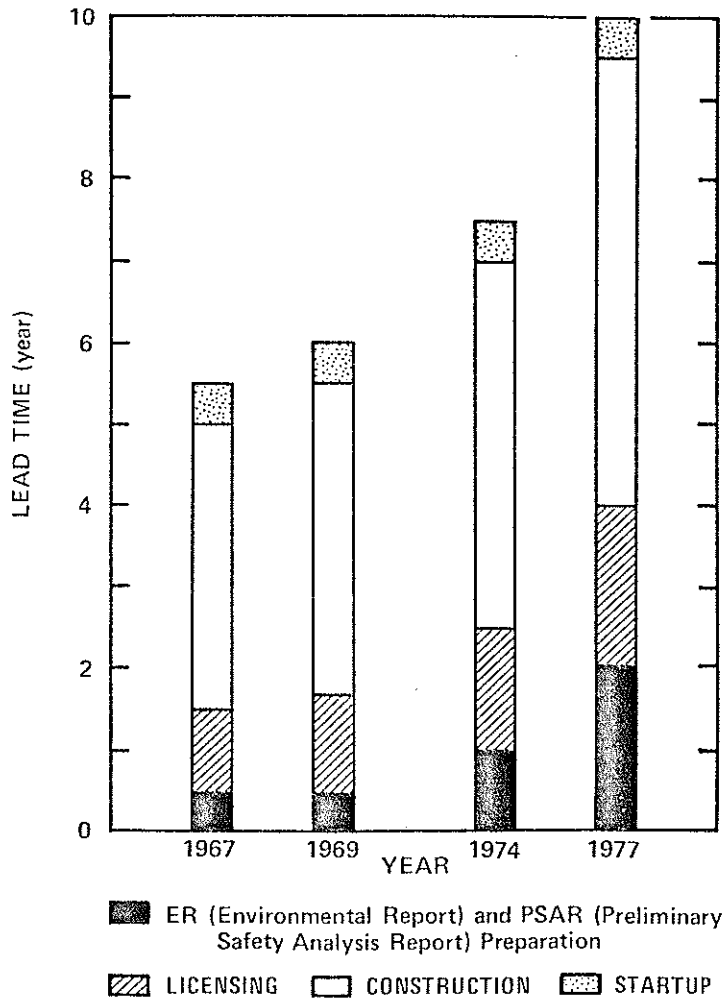


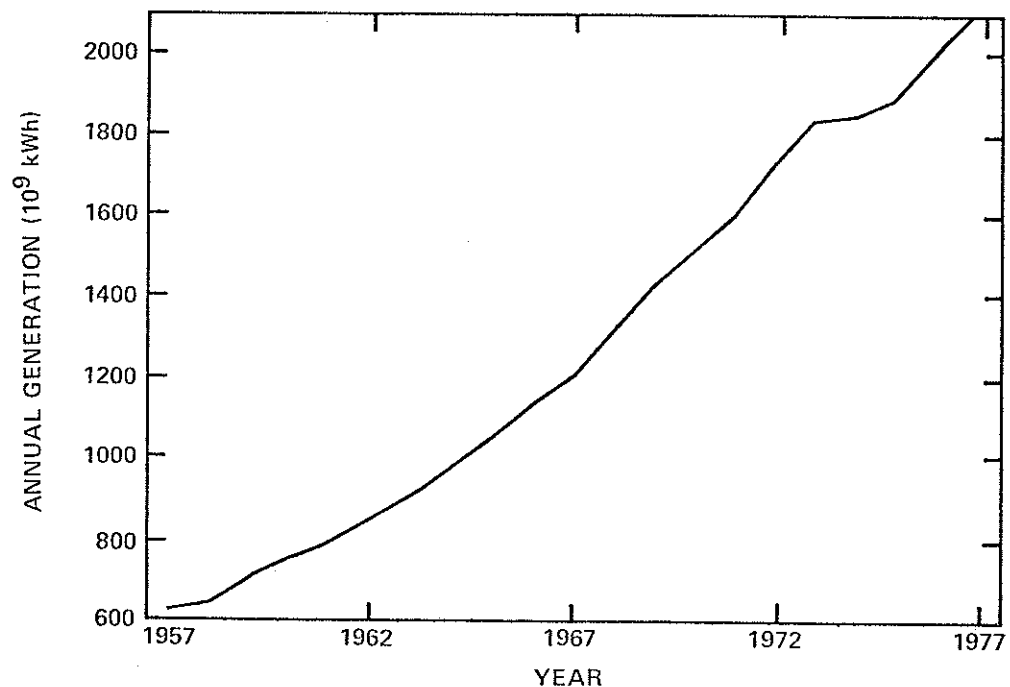
Figure 3 Nuclear Power Plant Lead Times<sup>5</sup>

Costs are up.

Generation costs are now increasing because of rising fuel, capital, and construction costs, all of which are accentuated by the rapid general inflation.<sup>3,6</sup> National average electricity prices declined from 1957 to 1969 and then increased by 248% (in nominal dollars) from 1970 to 1975.<sup>2</sup> Any errors, whether in the form of overexpansion or underexpansion of capacity, will be more costly than in the past.<sup>7</sup>

Uncertainty is greater.

The growth rates of electricity consumption are lower on average and also less stable than in the past. From 1960 to 1973, the average annual growth rate in national kilowatthour consumption was 7.1%, while from 1973 to 1977 it was only 3.4%; see Figure 4. This break in the growth rate of electricity consumption reflects changes in underlying factors, such as economic, demographic, and regulatory conditions. The instability in the growth rates and the variations in the underlying conditions suggest that more factors and more complex interactions between factors should be considered in forecasting.



Source: From Column 1, Table 10s, of the Edison Electric Institute Statistical Year Book for 1976.  
1977 data from Advance Release of Data for the Statistical Year Book 1977.

Figure 4. Total Electric Utility Generation

## STUDY PROCESS

*New forecasting tools are emerging.*

The need for accurate, longer-range forecasts in capacity planning at a time of greater complexity and uncertainty in electricity consumption trends has led planners to the development and use of new forecasting methods. Each of these methods represents an attempt to quantify the impact on electricity use of some of the variations in regulations and in economic and demographic factors. The methods include a variety of modeling techniques and emphasize different factors. The impact of the different modeling approaches on the electricity consumption forecasts is neither easily observed nor well understood.

We can increase our understanding of the relative forecasting behavior of the various modeling techniques and of the importance of some of the changes in conditions or factors by applying the models to scenarios. Each model can be used to project electricity demand for each year between 1979 and 1990. Then a single common input, such as electricity price, can be changed and a new projection obtained. Comparison of the output of the two cases will identify the relative responsiveness of each model to the change in that input. This knowledge is valuable both in designing a forecasting model and in understanding the results of that model.

*Modelers and planners must examine the models.*

The development and use of such knowledge will be enhanced by improving communication between the builders of the models and the users of the forecasts--the capacity planners and regulators--as well as between the model builders themselves. The objective of the Energy Modeling Forum (EMF) is to stimulate and facilitate such communication and, thereby, to improve the use and usefulness of the energy models.<sup>8</sup> The EMF is funded by the Electric Power Research Institute and administered by the Stanford University Institute for Energy Studies through the Departments of Engineering-Economic Systems and Operations Research.

The EMF operates through ad hoc working groups. Focusing on an important issue, such as the forecasting of electric loads, each working group applies a set of models to specified scenarios



and contrasts the results. The investigation of similarities and the explanation of differences in the key results help in clarifying the specific energy issue while isolating the vital characteristics of the models. Previous EMF studies examined the interactions between energy and economic output,<sup>9</sup> and the changing nature of coal markets.<sup>10</sup> The investigation of electric load forecasting is the third effort by an EMF working group to study a relevant class of models in the context of a pressing energy decision problem.

*Our working group spanned the industry;*

The members of this working group were from individual utilities, state and federal government agencies, universities, research institutes, and consulting firms. The utilities that were invited to participate were selected so as to provide diversities of region, climate, size, and economic conditions. No effort was made to identify or locate particular types of models or particularly sophisticated models. The group met four times over nine months to define the problems, design the scenarios, analyze the results, and prepare the findings.

*examined many generic planning issues;*

The first meeting of the working group made clear the need for more communication among forecasters. The members of the group had little knowledge of the specific capabilities and limitations in the use of the models employed by other members of the group. The discussion centered on the existence of a common, seemingly unlimited set of modeling questions and forecasting issues faced by the various forecasters. It was difficult to find a common framework for examining models which were designed for disparate regions and which emphasized region-specific forecasting problems. The common set of modeling questions and the problems of model comparisons were again discussed at the second meeting. A few key issues were selected and scenarios were designed to permit the examination of the issues and of the relative behavior of the various models. The final two meetings were spent analyzing the results of the scenarios and drawing conclusions and recommendations about the role of modeling in forecasting and planning by electric utilities.

*compared  
10 models;*

The 10 models investigated in the current study cover a spectrum of purposes and methods. Some of the models are policy oriented with national perspectives, while others are designed to provide information for capacity planning for a single utility. Some of the models emphasize econometric methods and attempt to estimate the behavioral response of consumers to changes in prices, incomes, and other aggregate variables through statistical analysis of historical data. Other models emphasize the engineering detail needed to analyze the electricity consumption of various appliances or production processes in specific residential, commercial, and industrial settings.

*and studied  
8 common  
scenarios.*

These models were applied to a set of eight scenarios. The scenarios were designed to examine several issues expected to be important in future policy or capacity planning decisions. The issues include changes in the levels of electricity prices and the prices of competing fuels, changes in the structure of electricity prices (time-of-day rates), and the introduction of appliance efficiency regulations.

This report presents the main results of the discussions and analyses of the working group. Volume 1 is the summary report; Volume 2 is a series of appendixes.

#### THE ROLE OF FORECASTS AND THE CONTRIBUTION OF MODELS

*Forecasts  
serve many  
purposes.*

In addition to capacity planning decisions, forecasts are used for financial decisions, system design, development of fuels and energy policies, environmental impact studies, rate setting, evaluation of load management programs, and a range of related activities that are routinely carried out in the utility planning environment. In each case, the objective is to obtain a forecast of appropriate detail and accuracy, and there is a large variation in the requirements associated with each application. For example, the development of appropriate rates requires a projection of the kilowatthour consumption in each rate class over a horizon of about one or two years, while the development of capacity plans requires estimates of total kilowatthour

consumption, peak load, and possibly load shape, over a horizon of 10 to 15 years. In this study, we focused on the forecasting tools that are used in capacity planning.

Forecasts are not simply inputs to capacity planning decisions. In some utilities, there is explicit feedback: the load forecast is used to produce a system plan, which is used to predict future costs and electricity prices. These prices are then used to modify the load forecast. The forecasts are part of a dialogue about the proper trade-offs of conflicting goals and the likely outcomes of uncertain events. The use of a model to help produce the forecasts can contribute to this dialogue by making explicit the assumptions and judgments that are inherent in any forecast.

*Modeling  
can aid  
planning.*

On a general level, modeling begins the structuring of the problem by defining data needs and organizing the data through the framework of the model. The data accessible in the model and the construction of the model begin to clarify both the judgments that are needed to carry the analysis forward and the assumptions that are implicit in these judgments. If all aspects of the capacity expansion decision are modeled, the explicit nature of modeling can be exploited to facilitate the gradual improvement in our understanding of the decision by structuring the debate about assumptions, outcomes, and trade-offs.

*But there  
are limita-  
tions of  
modeling.*

The limitations of modeling are important to recognize also. The basic boundaries of the modeler's understanding are transferred to a model. For example, the effects of time-of-day rates cannot be modeled without data, assumptions, and a theory about how consumers will respond to the rates. Modeling, when properly integrated with the decision process, does not compete with good judgment and clear thinking; it both exploits and reinforces them. Modeling has the potential to help formalize the decision problems, extend the scope of the analysis, and guide the decision process.

*Better communication, understanding, models, and forecasts.*

In the more specific area of forecasting electric loads, the full potential in the use of models is not always being realized, despite the industrywide use of such formal analytical tools. Although new forecasting tools are being developed rapidly by many utilities, EPRI, and others, there has been little in the way of systematic comparison of methods or results. There is also a need for better communication between model builders and users in order to appreciate the capabilities and limitations in the use of existing models and to identify the most fruitful areas for future model development. The opportunities are particularly ripe today for examining the diverse approaches of different utilities in dealing with their common forecasting and planning problems. Examination of the relative behavior of different models applied to a common scenario can highlight the impact on the forecast of different approaches to the particular problem, assumption, or issue represented in that scenario.

#### OVERVIEW OF ELECTRICITY FORECASTING ISSUES

*Analysis begins with the issues.*

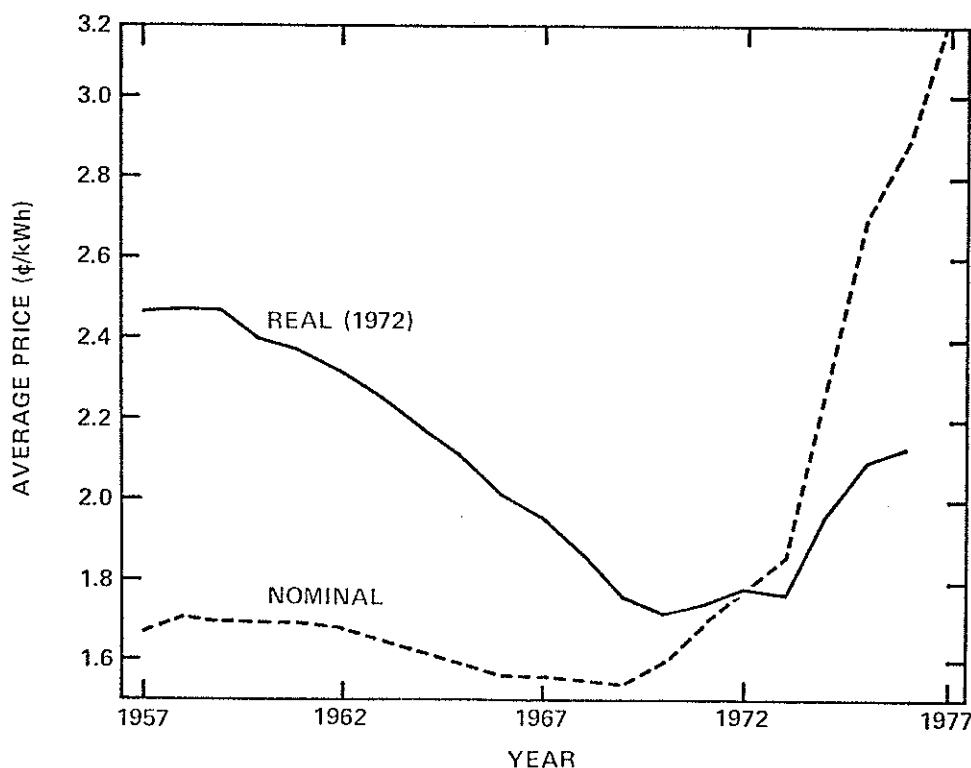
Electricity forecasting issues vary in the ways they impact on the forecasting problem. The impacts may be divided into three general groups:

- those that are directly related to the consumption of electricity, such as from the development of new appliances or industrial processes, the adoption of appliance efficiency regulations, or a change in the relative prices of competing energy sources;
- those pertaining to the forecasting method itself, such as determination of how price response should be estimated and how it should be included in the model; and
- those that are concerned with the general process of making and using forecasts, such as the treatment of forecast uncertainty in planning decisions or the treatment of the relationship between supply and demand through the effect of generation costs on electricity prices.

Although this study concentrates on the first two types of impacts, the working group recognizes that the issues surrounding the forecasting process may be the most important in determining the usefulness of models.

Electricity prices have increased.

Among the most consequential forecasting issues are those that arise from the need to describe the effects of changing economic conditions, particularly the effects of recent increases in energy prices. The economic changes have direct effects on electricity consumption, and they may affect developments in technology and in regulation. In the early 1970s, there was a reversal of a long-term trend of decreasing electricity prices: after dropping from 2.5 cents per kWh (measured in constant 1972 dollars) in 1957 to 1.7 cents per kWh in 1970, prices increased to 2.1 cents per kWh by 1977; see Figure 5. The prices of competing fuels followed similar trends.



Source: Edison Electric Institute Statistical Year Book for 1976; 1977 data from Advance Release of Data for the Statistical Year Book 1977.

Figure 5 National Average Price of Electricity

Higher fossil fuel prices affect electricity costs and competition.

The increases in the price of electricity and its competing fuels, such as oil and gas, will directly affect the demand for electricity. The general increase in energy prices also will influence the demand indirectly through the impact of escalation in the cost of transportation on the location and density of new development. To capture explicitly the effects of these

factors, the appropriate price variables must be incorporated in the structure of the model. (The structure of a forecasting model is the form of the equations that are used and the variables that are included in those equations.) Furthermore, the response of electricity demand to variations in prices must be accurately reflected in the coefficients of the model. (The coefficients or parameters are the numbers that describe the size of the impact on one variable of a change in another variable.)

*Price increases affect technological innovation.*

During the period of declining energy prices, technological development moved in the direction of more energy-intensive production processes and labor-saving consumer appliances. Economic theory implies that in a period of rising energy prices this trend can be expected to slow down or reverse, which could have a large impact on electricity consumption. These impacts of higher prices should be considered in forecasts of electricity demand.

*New regulations are prevalent.*

Another complicating factor is the increased participation of regulatory agencies in the electricity market. In several states, new rate structures have been introduced to promote efficiency of energy use. For example, variants of marginal-cost or time-of-day pricing have been introduced as incentives to shift consumption away from periods of peak demand.

Efforts to improve the efficiency of electricity use have included regulations specifying minimum standards for appliances and for building construction, such as those proposed by Congress.<sup>11</sup> Other efforts have been directed at encouraging the development and use of dispersed sources of energy, such as cogeneration facilities and solar devices. Each of these regulatory activities affects the structure of the electricity market. Because the regulations are recent developments, little data are available on which to estimate their impact on demand. However, efforts are under way to collect such data. Expansion of the models to include the detail needed to represent alternative structures of demand is one of the major trends in the analysis of load forecasting problems, but it is in its early stages.

The lack of data is a major obstacle in quickly implementing more detailed modeling methodologies.

Another set of issues derives from a possible shift in social values. Higher energy prices, the threat and the reality of supply interruptions, and the exhortations of national leaders have focused our attention on energy problems. Whether the public response to these changes is through the emergence of a new energy ethic or simply the natural response to a change in relative prices is unresolved.

*Environmental controls affect costs and lead times.*

Efforts to reduce environmental impacts include closer scrutiny of and more control over the siting of generation facilities, greater emphasis on plant safety, and stronger controls on air and water pollution. Although these measures will serve to increase the price of electricity, their effect on lengthening the time required to bring new generation plants on line may be just as important for the forecasting problem as the effect of increased prices. In the case of nuclear plants, the average regulatory review time has grown from about one year to between three and four years. Such increases lengthen the time horizon for capacity planning, increase the importance of long-range forecasts in the planning process, and expand the uncertainty of the forecasts and capacity plans.

*The working group examined key issues.*

From this set, the working group selected a few specific issues to use in the design of the scenarios to which the models would be applied. The primary selection criterion was that the issue would be likely to have a significant impact on capacity planning decisions. The following issues were chosen for study:

- increases in the prices of electricity;
- increases in the price of competing fuels, such as oil and natural gas;
- load management in the form of time-of-day pricing of electricity;
- the adoption of conservation regulations in the form of appliance efficiency standards and residential construction standards; and

- technological change in the form of the development of cogeneration facilities.

For each of these issues, scenarios were designed to highlight the potential impact of the assumed changes on demand and on the behavior of the forecasting models.

#### THE MODELS

*Our 10 models are actively used for many purposes.*

Ten models were used in this study; see Table 1. All of the models, or variations of them, are currently being used as inputs to utility capacity planning decisions, national policy analyses, or regulatory decisions. Seven of the models were developed by utilities. Two of the models were from the energy research group at Oak Ridge National Laboratory. One was from the Center for Energy Studies at the University of Texas. All were applied to the scenarios in this study by the analysts who developed them or who currently have responsibility for applying them to planning problems. In this section, we present a brief discussion of the differences between the particular methods used in the models. More detailed descriptions of the models are given in Appendix A in Volume 2 of this report.

Table 1

#### MODELS USED IN THE ELECTRIC LOAD FORECASTING STUDY

Commonwealth Edison Company, Econometric Model (Comm. Ed.)  
Consumers Power Company, Kilowatthour Sales Model (CPC)  
Florida Power & Light (FPL)  
General Public Utilities (GPU)  
Northeast Utilities, Electric Energy Demand Forecasting Model (NU)  
Oak Ridge National Laboratory, Residential Energy Demand Model (ORNL-REDM)  
Oak Ridge National Laboratory, State-Level Electricity Demand Forecasting Model (ORNL-SLED)  
Tennessee Valley Authority, Load Forecasting Model (TVA)  
University of Texas, Baughman-Joskow Regionalized Electricity Model (Baughman-Joskow)  
Wisconsin Electric Power Company (WEPCO)



*Model designs reflect data-detail trade-offs.*

Each model in this study can be characterized in terms of trade-offs between the use of detail in the description of the energy consumption processes and the use of empirical data to infer the behavior of electricity consumers. Ideally, both elements would be developed fully in each model: extensive detail about the many energy-using possibilities would be described in terms of data drawn from the observation of actual choices made by consumers. In practice, these elements are in conflict. Empirical data are not generally available to describe all the choices of a very detailed model. For example, when dealing with new or speculative technologies, data on prices and market penetration are not available, so judgment and calculation must be used in place of empirical data to establish the behavior of the system. Conversely, the use of the available data may restrict the modeler to a very aggregate structure, correlating prices and quantities without uncovering the technological workings of the relationship.

*Models reflect engineering or econometric designs.*

Both approaches have merit and each can be found in the models used in this study. The models with very detailed descriptions, but little behavioral data, are called "engineering models." The Northeast Utilities model for the residential sector is an example of an engineering model. The models based on the inference of consumer behavior, but restricted to a very aggregate representation of demand, are called "econometric models." Examples of econometric models are the Baughman-Joskow, ORNL-SLED, and Commonwealth Edison models. Some analysts have attempted to capture the chief features of both methods; the ORNL-REDM model represents an important early attempt at such a synthesis and points to a promising direction in the development of load forecasting models.

*Models differ in the regions covered.*

The Comm. Ed. model used in this study is an econometric model of peak demand for its service area, which includes metropolitan Chicago and portions of northern Illinois. The ORNL-REDM uses a mixture of econometric and engineering techniques to forecast national residential demand for gas, oil, and coal as well as for electricity. The ORNL-SLED model is an econometric model of

electricity consumption and prices for New York state. TVA uses several methods to forecast demand for its service area, which includes parts of seven southeastern states; the primary model is econometric. CPC uses an econometric model to forecast for most of Michigan. The FPL model is an econometric model of southern and eastern Florida. Northeast Utilities uses engineering models for the residential and commercial sectors and an econometric model for industrial sectors in parts of Connecticut and Massachusetts. The Baughman-Joskow model embeds econometric equations of electricity consumption in a regionalized, national system. WEPCO uses a very large econometric model of the regional economy and the electricity use in southeastern Wisconsin, including Milwaukee. GPU uses an engineering model to forecast for parts of New Jersey and Pennsylvania.

*Models differ in the systems covered.*

In addition to the differences in regions and in forecasting methods, the models differ in the framework in which these forecasts are set. Some models are strictly electricity forecasting models. In others, the demand forecasting equations are included as a component in a larger model that incorporates various aspects of supply, such as generation and distribution. In the Baughman-Joskow model, the econometric demand model is set in a framework that represents the entire utility planning, financing, and regulatory process. With the ORNL-SLED model, simultaneous forecasts of electricity prices and consumption are obtained. The designs of the other models do not explicitly incorporate both supply and demand relationships. However, the forecasting procedures of some of the participating utilities include review by system planners to ensure that the prices used in the forecast are consistent with the supply implications of the load forecast.

The variation in the regions represented is an important difference between the models. Although each utility company model is designed for a specific service area, there is tremendous diversity in the areas represented. For example, the Comm. Ed. service area is dominated by the heavily urbanized and industrialized region of Chicago and northern Illinois,

while TVA encompasses extensive rural areas in seven southeastern states and includes substantial amounts of electricity use by federal uranium enrichment facilities.

#### EXPLORING MODELS AND ISSUES THROUGH SCENARIOS

*Scenarios were designed around the issues.*

The examination of the relative behavior of the different models was accomplished through the application of the different models to a common set of scenarios. Scenarios were constructed to represent a subset of the important forecasting issues described above. The issues selected were among those that the working group expected to have a major impact on capacity planning decisions and were typical of major areas of debate in demand forecasting. Of the issues initially identified as important on the basis of these two criteria, some were not examined because of limitations in the design of the models available to the working group participants.

*Problems remain in comparison of model results.*

Even with a common set of scenarios, comparative analysis of electricity forecasting models is difficult. As mentioned above, there is no common geographical focus in the models. In comparing the results of several models for each scenario, this means that some of the observed differences will be due to the variations between the methods and some will be due to the variations between the regions. The working group could not devise a way to separate conclusively the effects of methodological differences from the effects of regional differences. To help alleviate this problem, the scenarios were designed in terms of deviations from a Reference case. Each participating modeler specified the Reference case for his own model and region. The forecast results for each of the issue-specific scenarios were then examined in terms of the deviations from the Reference case results. This eliminates the most obvious variations across regions, but does not completely isolate the causes of differences in the results.

*The Reference case was unique for each model.*

The Reference case for each model was the modeler's own current planning or "Base" case with two modifications. Since one of the scenarios specifies a particular structure for pricing

electricity by the time of day when it is consumed, any time-of-day pricing influence was excluded from the Reference case. Another scenario specified a set of appliance efficiency standards, so the effect of any other such set of standards was removed. Aside from these two modifications, the Reference case reflected the experience and knowledge of each forecaster about his region and model. It thus embodied the best judgments for each region and provided a basis for examining the changes in the forecasts that resulted from each of the issue-specific scenarios. The assumptions for these scenarios are summarized in Table 2 and described below.

*Other  
scenarios  
examined  
prices,*

The working group constructed three scenarios to assess the impacts of an increase in the price of electricity on kilowatt-hour consumption and peak load. In addition to the effect of an increase in the average price of electricity, the group examined separately higher charges for peak kilowatt usage and an increase in the charges for kilowatthour consumption.

The effect of increases in the prices of fuels that compete with electricity was studied in a scenario in which the delivered prices of oil and natural gas were increased by 20% over the Reference case. Note that the price of electricity was not changed from the Reference case.<sup>12</sup>

*cogenera-  
tion,*

Two models, CPC and TVA, were applied to a scenario to ascertain the potential impact of greater use of cogeneration.

*efficiency  
standards,  
and*

For another scenario, a set of efficiency standards was assumed to apply from January 1, 1978 for new residential appliances and buildings. These standards are specified in terms of percent improvements in the efficiency of energy utilization of new appliances and housing stock relative to the typical appliance and housing stock existing in the early 1970s. The percentages shown in Table 3 are intended to be approximations to those proposed by Congress.<sup>11</sup>

Table 2

DEFINITION OF SCENARIOS USED IN THE  
ELECTRIC LOAD FORECASTING STUDY

<u>Scenario</u>	<u>Definition</u>
A. Reference Case	each modeler's current planning of "Base" scenario with time-of-day pricing and appliance efficiency standard effects removed
B. Price of Electricity--1 (Average Price Increase)	10% increase in the average price of electricity over the price used in the Reference case <sup>a</sup>
C. Price of Electricity--2 (Demand Charge Increase)	10% increase over the Reference case in any demand charge with energy charges held at the Reference case values <sup>a</sup>
D. Price of Electricity--3 (Energy Charge Increase)	10% increase over the Reference case in energy charges with demand charges held at Reference case values <sup>a</sup>
E. Competing Fuels Price	20% increase over the Reference case in the delivered prices of oil and natural gas <sup>a</sup>
G. Appliance Efficiency Standards	Efficiency improvements relative to typical equipment or buildings in place in 1974 were specified for major appliances and residential buildings <sup>a</sup> (Table 4).
K. Technological Change-- Cogeneration	10% incremental tax credit on the cost of investment for cogeneration facilities <sup>b</sup>
L. Time-of-Day Pricing	6-to-1 price ratio for on-peak to off-peak consumption for all customers with the peak period being 8:00 a.m. to 8:00 p.m. on nonholiday weekdays <sup>a</sup>

<sup>a</sup>All changes are specified to begin on January 1, 1978 in the model runs.

<sup>b</sup>Although the scenario was initially specified in this manner, later study showed that none of the models could be used to assess the impacts of such a tax incentive. Two models were used to assess the potential for cogeneration on a more judgmental, or implicit, basis by preparing a separate analysis of the demand for cogeneration and using this to adjust the model results.

Table 3

PERCENT IMPROVEMENT IN EFFICIENCY OF NEW RESIDENTIAL  
ELECTRIC EQUIPMENT AND NEW RESIDENTIAL STRUCTURES

<u>Equipment</u>	
Space heating	0
Water heating	20
Refrigerators	50
Freezers	30
Room air conditioners	55
Central air conditioners	25
Other (television, clothes washers and dryers, etc.)	20
<u>Structures<sup>a</sup></u>	
Single-family	40
Multifamily	80
Mobile home	25

<sup>a</sup>Improvements apply only to space heating.

*time-of-day  
pricing.*

For the scenario on time-of-day pricing, separate rates were specified for two periods, peak and off-peak, with the peak period rate being six times the off-peak rate. The peak period was from 8:00 a.m. to 8:00 p.m. on nonholiday weekdays.

All of the changes in the scenarios are assumed to begin on January 1, 1978. The two modifications of each modeler's own Base case, which must be made to obtain the Reference case for this study, combined with the assumption that the changes in each scenario are instituted on January 1, 1978, preclude the interpretation of the results of this study as forecasts, and the Reference case is not intended to be a forecast of the group. It merely provides a basis for measuring the relative importance of various factors or issues and the sensitivity of different models to these factors. (Graphs of the results for all models and scenarios are presented in Appendix D of Volume 2.)

Not all of the models were applied to every scenario. Table 4 indicates which models were applied to each scenario.

Table 4  
 MODELS USED TO ADDRESS THE SCENARIOS

Model	Scenario									
	A	B	C	D	E	G	K	L		
	Reference Case	Average Price	Demand Charge	Energy Charge	Competing Fuels Price	Efficiency Standards	Cogeneration	Time-of-Day Pricing		
1. Comm. Ed.	X	X	X	X	X	NA	NA	NA		NA
2. ORNL-REDM	X	X	NA	NA	X	X	NA	NA		NA
3. ORNL-SLED	X	X	NA	NA	X	NA	NA	NA		NA
4. TVA	X	X	X	X	X	X	X	NA		NA
5. CPC	X	X	NA	NA	X	X	X	NA		NA
6. FPL	X	X	NA	NA	NA	X	NA	NA		NA
7. NU	X	NA	NA	NA	NA	X	NA	NA		X
8. Baughman-Joskow	X	X	NA	NA	X	NA	NA	NA		NA
9. WEPCO	X	NR	NA	X	NR	NA	NA	NA		NA
10. GPU	X	NA	NA	NA	NA	NR	NA	NA		NA

NA--Not Applied to this scenario--relevant variables or equations were not part of the model used in this study.

NR--Not Run for this scenario--these (two) models joined the study late and time did not permit application to all scenarios.

## OBSERVATIONS AND CONCLUSIONS

Analysis of the application of the models to the scenarios and more general discussions of the working group led to several observations and conclusions.

### Growth Rates

*Reference case demand growth projections are lower than historical growth rates.*

The rapid growth of total electricity consumption that existed prior to 1973 is not projected to continue under the conditions used by the modelers in the Reference case of this study. Under the Reference case assumptions, the median model projection is a growth rate of 4.7% from 1975 through 1990 (Figure 6) in comparison to a national average annual rate of 7.1% from 1957 to 1973 (Figure 4). Between 1973 and 1977, the national average annual growth rate of electricity consumption was only 3.4%. The drop in the growth rate from that which occurred between 1957 and 1973 reflects the adjustment of electricity consumers to many new factors: low economic growth rates, higher energy prices, and policies designed to increase the conservation of all forms of energy. To a degree, the modelers address all of these factors. The results are projections that are different from those of the past. In only one of the scenarios examined does the growth rate in electricity consumption approach the historical rate. In this case, the rise in the price of competing fuels, with no increases in the price of electricity, causes a shift towards electricity.

### Price Relationships

*Higher electricity prices reduce demand. But modelers disagree on price impacts,*

The increase of real electricity prices has contributed to the recent reduction in the growth rate of electricity use. In most regions, the price of electricity is expected to continue to increase. Figure 7 shows the changes in electricity consumption in response to a 10% increase in the average price of electricity relative to the Reference case. As can be seen, there is a wide range in the size of the projected impacts. The reduction in the consumption of electricity in 1990 in response to the 10% price increase ranges from more than 10% for the Baughman-Joskow model to less than 2% for the CPC model.



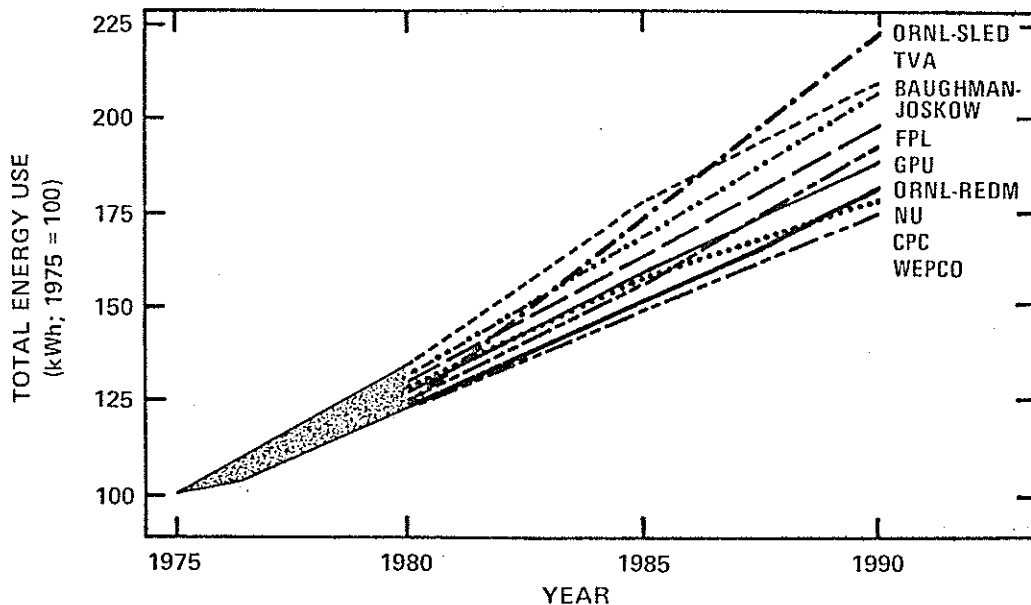


Figure 6 Reference Case Electricity Consumption

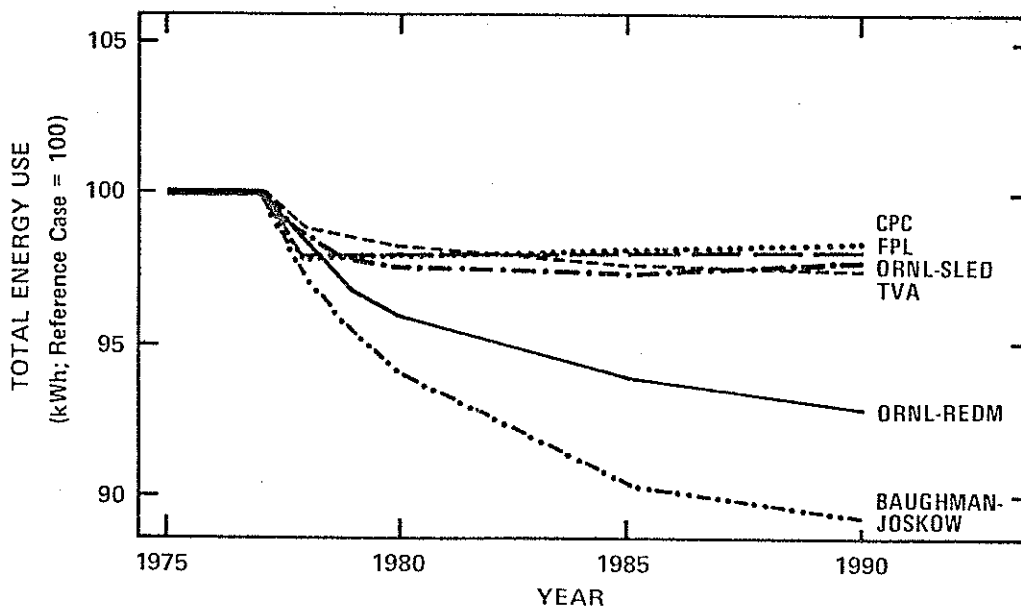


Figure 7 Change in Electricity Consumption with 10% Price Increase Relative to Reference Case<sup>13</sup>

Similar results are observed in the projections of peak load. These results indicate that prices could have a significant impact on future electricity consumption. The results also indicate that there are considerable differences between the models

as to the importance of prices in determining demand. These differences and the magnitude of the potential impacts identify a key forecasting problem that deserves priority attention by utility planners.

*both for electricity and competing fuel prices.*

The prices of fuels that compete with electricity--oil and natural gas--are also likely to continue to increase. Figure 8 shows the change in electricity consumption in response to a 20% increase in the prices of all competing fuels but no change in the price of electricity relative to the Reference case. Again, there is a wide range in the projected impact on the level of electricity consumption in 1990, from 8% for the ORNL-REDM model to 1% for the CPC model.

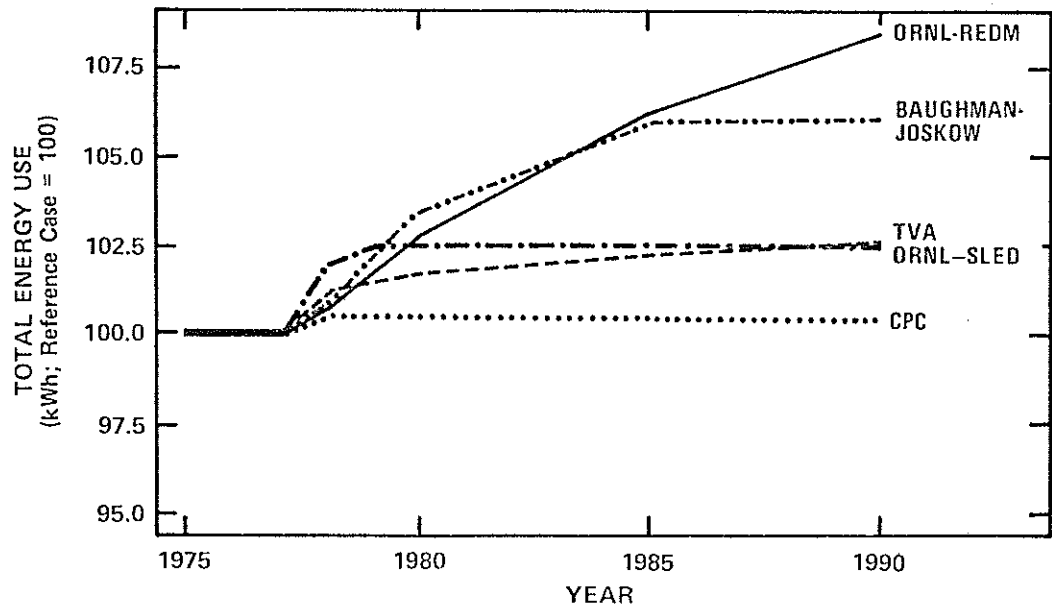


Figure 8 Change in Electricity Consumption with 20% Increase in the Price of Competing Fuels Relative to Reference Case (for those models that were price-responsive)

*Effects of higher prices a key, unresolved issue, with large costs for errors.*

The importance of these variations in price response is underlined by examining the projected growth in electricity prices; the wide variations in the projected impact of prices would not be important if no significant price changes were expected. However, such price changes are expected. Figure 9 shows the

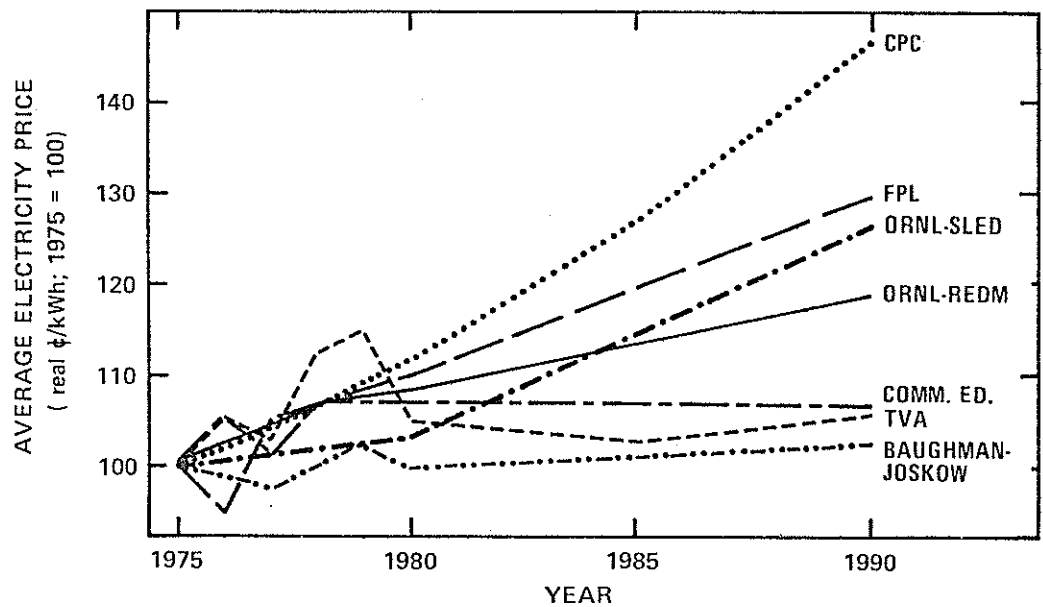


Figure 9 Reference Case Electricity Price Assumptions

future electricity prices projected by the working group for the Reference case. These range from an increase of only 2% over the 1975 to 1990 period in the Baughman-Joskow model to approximately 47% in the CPC model. The median, which is about 20%, is used in the ORNL-REDM model.

Figure 10 shows the natural gas price projections used by the modelers in the Reference case. The 15-year increase ranges from about 30%, employed in the Baughman-Joskow and ORNL-SLED models, to 350%, used in the Comm. Ed. model. Again, the median value, which is 100%, is input to the ORNL-REDM model. Thus, the expected price increases are quite large and their impacts could be significant.

As an example of the potential significance of price changes, let us consider the case of a hypothetical utility which, under our median price projections (as shown in Figures 9 and 10) and median price responsiveness (as shown in Figures 7 and 8), forecasts a 1990 peak load of 10,000 megawatts (MW). If the response to changes in the price of electricity was not equal to the median value, but was equal to the higher value found in the Baughman-Joskow model, this difference alone would

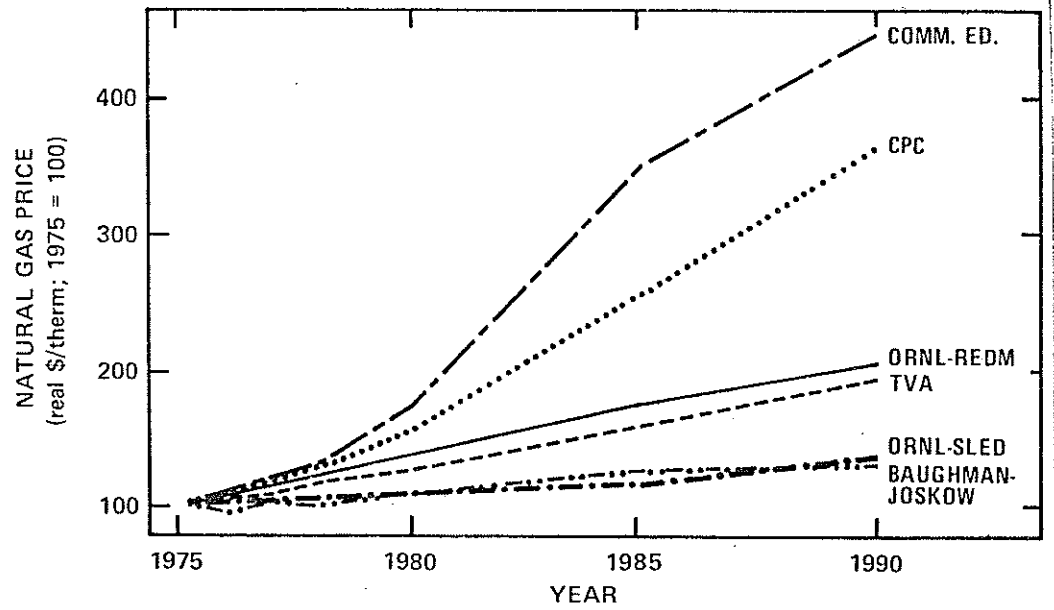


Figure 10 Reference Case Natural Gas Price Assumptions

reduce demand by about 1500 MW, the equivalent of one and one-half large baseload plants. Similarly, changing only the response to natural gas price from the median value to the highest response (exhibited by the ORNL-REDM model) could increase demand by more than 1200 MW. Addition of this amount of generating capacity would cost well over a billion dollars. While these differences in total demand of 15% and 11% are significant, they are an even larger percentage of the new capacity requirements which, in our hypothetical example, with median growth rate, would be approximately 5000 MW between 1975 and 1990. These simple examples indicate the importance of having accurate estimates of the response of demand to price changes.

*A comparison of price elasticities highlights the debate.*

The number that indicates the responsiveness of demand to a price change is the elasticity of demand. If price changes by a small percentage, the elasticity is given by the ratio of the resulting percentage change in demand to that percent change in price. For example, if a 10% increase in price resulted in a 5% reduction in demand, the price elasticity would be  $-5/10$ , or  $-0.5$ . Figure 11 displays the own-price

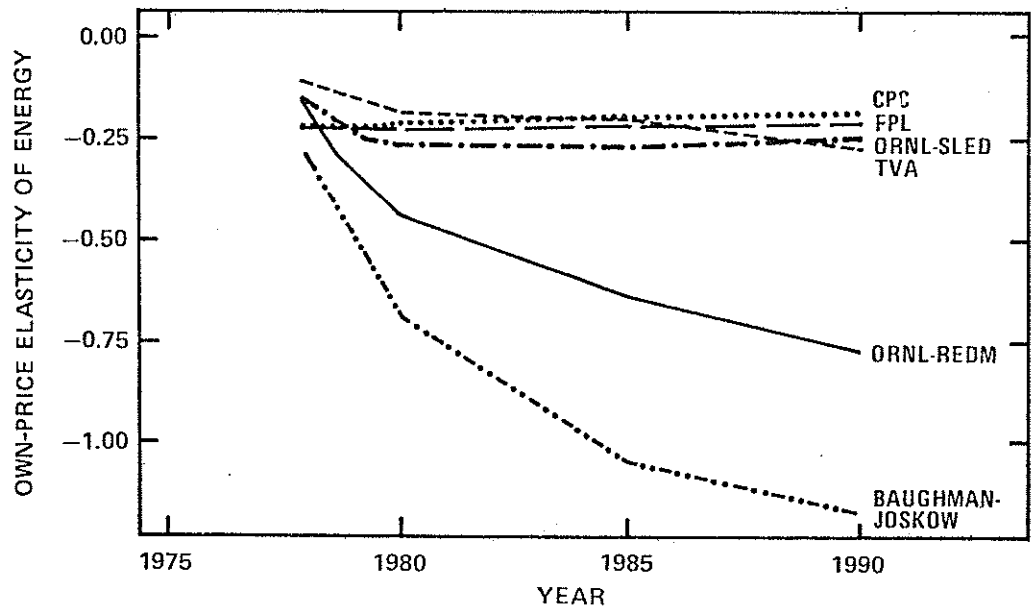


Figure 11 Electricity Price Elasticity of Kilowatthour Use

elasticity of electricity consumption exhibited in the models in this study: the response of kilowatthours to a change in the price of electricity with all other variables held constant. Figure 12 displays the cross-price elasticity of electricity

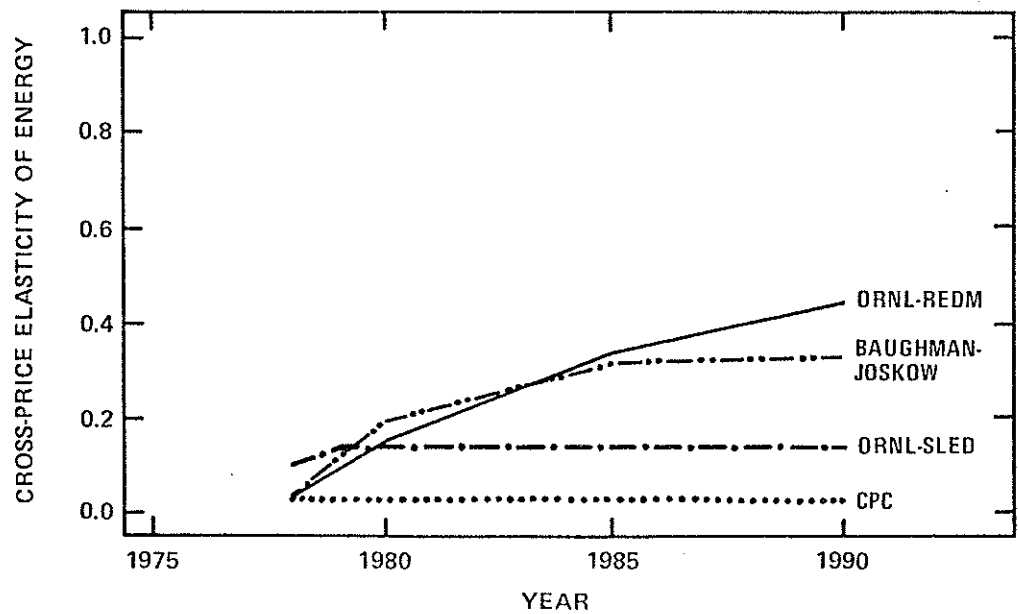


Figure 12 Competing Fuels Price Elasticity of Kilowatthour Use

consumption: the response in consumption of kilowatthours to a change in the price of competing fuels with all other variables held constant. These two graphs again show the wide variation between the models. They also show distinct differences in the dynamics of the response to price changes: some achieve the total response, albeit a small one, in only one year, while others are still adjusting after 12 years.

It is difficult to reconcile the elasticity estimates from the models for several reasons. First, there are different structures or types of equations in the models to represent the relationship between price and demand. Second, each model is estimated for and applied to a particular region, and the regions exhibit great diversity. Third, the type of data used to estimate the coefficients in the models varied from a single time series of the values of variables from one region to a pooled set of several time series of data from a cross section of many regions. Nevertheless, examination of the results of this study reveals that the magnitudes of the elasticities vary directly with the geographical scope of the data used to estimate them: larger geographic scope seems to be associated with larger elasticities. This property may be simply a chance occurrence due to the small number of models considered. However, the working group's analysis indicates some of the differences in the elasticities may well be caused by the type of data used.

*What do inter-regional differences tell us?*

This phenomenon is a common occurrence in econometric modeling. The time-series data from a single region, or a single utility, tend to yield relatively low estimates of the effects of prices. Although this could be caused by many factors, the main difficulty may be the slow response of demand to changes in prices. It is very difficult to get data of sufficient variety, duration, and accuracy to untangle the complexities of the demand adjustment; the resulting econometric estimates may be an undefined mixture of short- and long-run responses. One solution to this dilemma is to combine the data from many regions. If the structural differences in the regions can be accounted for

(i.e., if the differences in income, population, weather, etc. can be controlled by inserting appropriate variables in the model), the correlation between price and demand across regions can be interpreted as the long-run behavioral response. Even if the prices are the same across regions, combinations of the data increase the range and size of the sample and may improve the precision of the elasticity estimate. Higher estimates by as much as a factor of five may result from a combination of the data; however, it is difficult to be sure that the differences across regions have been isolated from the effect of prices. (A general discussion of important econometric issues in electricity forecasting, including the impact of single-region (time-series) versus multiregion (cross-section) data, is contained in Appendix I, Volume 2, of this report.)

#### Efficiency Standards

*Efficiency standards also are important.*

The introduction of efficiency standards for new appliances, construction, and industrial processes is a major thrust of national energy conservation programs. These standards also represent a major modification to the forecasting problem; the models are being adapted to accommodate this new situation. Examination of the models indicates that there is a wide variation across models in the way that new standards are treated. Also, the results of the scenarios indicate that the efficiency standards could be a significant factor in changing future levels and shapes of electricity load. Figure 13, for example, shows the reductions in peak load due to the efficiency standards relative to the Reference case. The models with explicit engineering detail, often with separate representations of the use of individual appliances, are the most sensitive to the introduction of new standards; frequently this is the purpose for which these models were designed. For example, the NU model, which is a strictly engineering approach to the residential sector, shows the greatest impact of the standards--an 18% reduction. To some extent, all the modelers are increasing the engineering detail in their systems and this trend is expected to continue. The full impacts shown in Figure 13 may be greater than those that might actually occur,

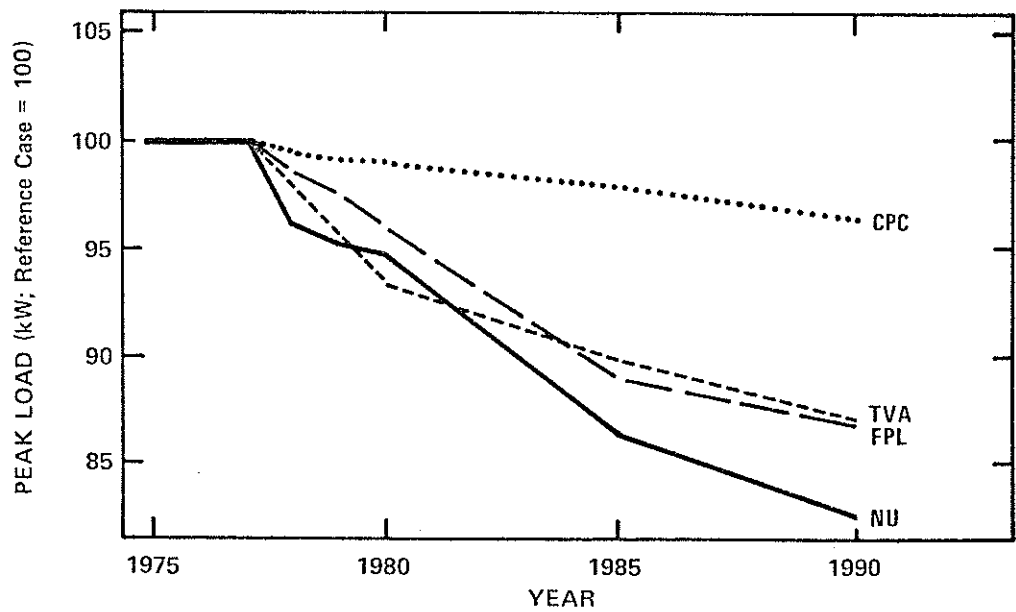


Figure 13 Change in Peak Kilowatt Load with Appliance Efficiency Standards Relative to Reference Case<sup>14</sup>

because the standards tested here are slightly more stringent than those recently proposed by Congress.<sup>11</sup> The scenario nonetheless provides a good test of the importance of standards and of the capabilities of models to incorporate this new information.

*Standards and price effects--double counting?*

One problem in modeling the effect of efficiency standards on electricity consumption is separating the effects of the standards from those reductions that would occur normally in response to higher prices. If there are no efficiency standards, then as the price of electricity rises, a consumer can reduce electricity consumption in three ways: by reducing the use of currently owned appliances, by changing the number of electrical appliances owned, and by purchasing appliances that use electricity more efficiently. Each change in use contributes a component to the measured demand elasticity. Mandated standards will increase appliance efficiency to the regulated levels. Thus, in the presence of binding standards, as the electricity price rises, a consumer further reduces electricity consumption



only by reducing the utilization or number of electric appliances, but not by increasing the efficiency of his appliances.

*More detailed models needed to resolve double counting and*

Accurate estimation of the consumption reductions associated with price increases plus efficiency standards is possible through the use of a structural model that separates appliance ownership and utilization decisions from appliance efficiency choices. There has been only one attempt, among the models included in this study, to separate the components of the demand elasticity--the ORNL-REDM model. All three components of the demand elasticity are significant in this model; no one component dominates the others over the 15-year horizon examined.<sup>15</sup>

*to evaluate load shapes.*

Only two of the models, NU and TVA, explicitly forecast load factor.<sup>16</sup> The methods used in the two models are different; however, both results suggest that efficiency standards will have a significant impact on load factor, as shown in Figure 14. Since the efficiency standards apply to appliances operated primarily during peak hours, imposition of standards improves the load factor. Hence, the load factor, an important input into capacity planning decisions, may be quite sensitive to economic and regulatory conditions.

#### Load Shapes

Even explicit modeling of the overall load factor may not be sufficient for capacity planning; the shape of the load curve on peak days may be more important. A possible result of time-of-day pricing, as projected with the NU model, is the rapid escalation in load at the time when the rates change from the higher, "peak" rate to the lower, "off-peak" rate. This could result in a double peak; the normal daily peak would remain, albeit at a lower level, and a secondary peak would be introduced at the end of the peak pricing period. It might be necessary to use peaking capacity twice each day, with attendant startup problems and inefficiencies. "Shoulder" or intermediate rates between the two periods could reduce the abruptness of the load changes and simplify the capacity dispatching problems.

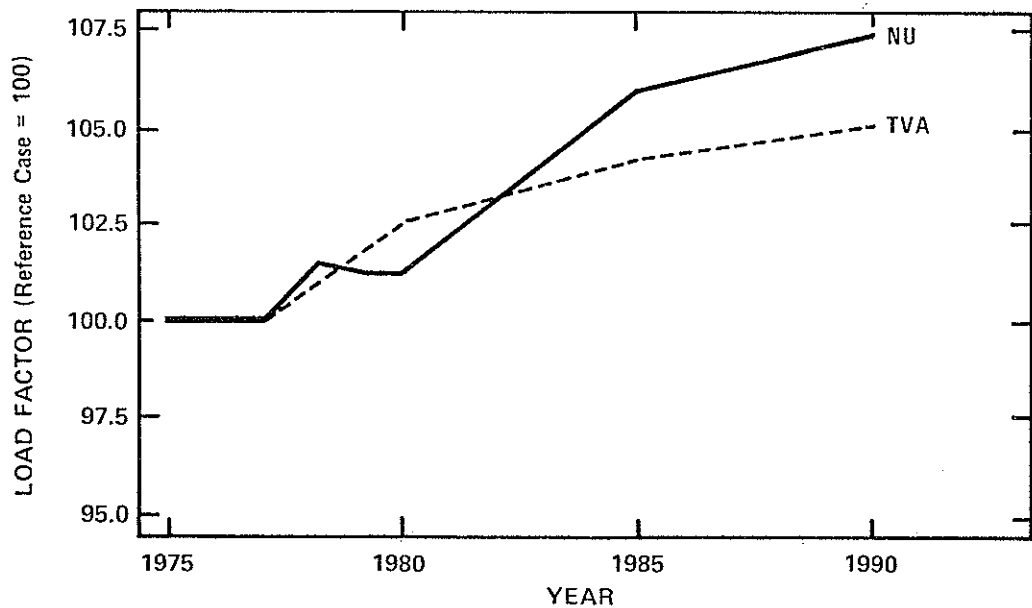


Figure 14 Load Factor Changes with Appliance Efficiency Standards Relative to Reference Case

Weather changes can also produce needle peaks with large, rapid increases in load, which require that the necessary capacity be available to be brought on line quickly. These rapid changes in load create complicated problems for dispatching and capacity planning, particularly in selecting the appropriate mix of generating facilities. Therefore, it is important to forecast the daily load shape as well as the annual kilowatthour consumption and the peak kilowatt demand. The problems of needle peaks and the experience of one utility are discussed in more detail in Appendix G, prepared by the working group members from Florida Power & Light Company. The experience of another utility with time-of-day rates is discussed in Appendix F, prepared by working group members from Northeast Utilities Service Company. Both appendixes appear in Volume 2 of this report.

## Economic Activity

*Electricity consumption may cease to grow faster than the economy.*

A further result of interest from this study is the relationship between the kilowatthour projections in the Reference case and the measures of economic activity in each model. In the past, the growth of electricity consumption has been much faster than the growth in the output of the economy. The use of electricity per dollar of real GNP increased at an annual rate of almost 5.8% from 1950 to 1973. With the trend to higher energy prices and greater conservation, this increase in the saturation of electricity might be expected to diminish. But the full implications of the data in Figure 15 are surprising; many of the ratios projected with the models are essentially constant after 1985. This indicates that the increasing saturation of electricity may soon come to an end.

## Model Comparisons

These analyses, especially those concerning elasticities, depend on comparing the results of models which have been designed for and applied to regions with major differences in demographics,

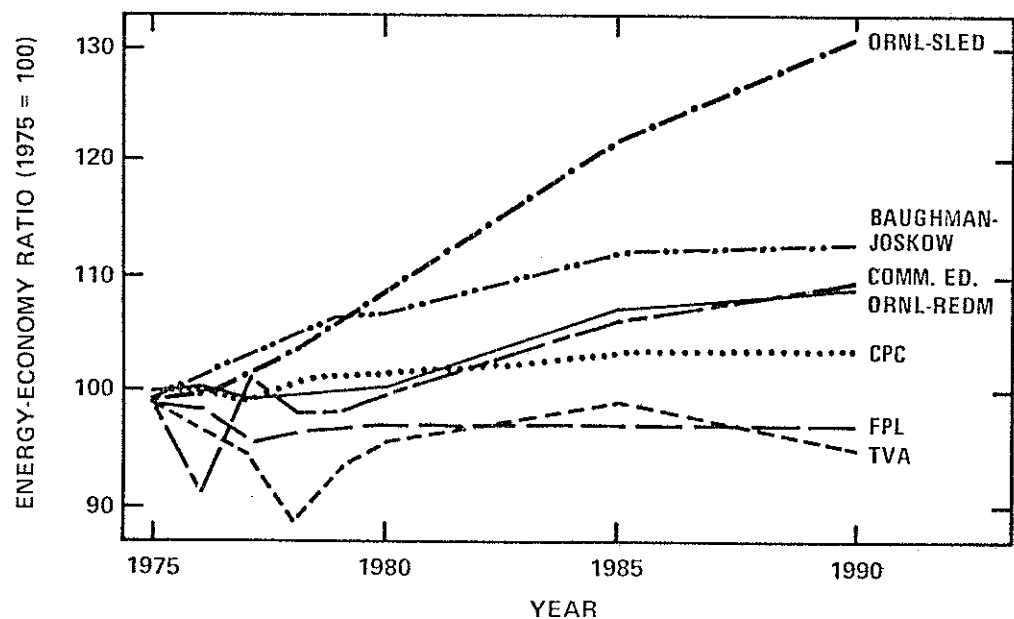


Figure 15 Ratio of Kilowatthour Consumption to Economic Activity

climate, and industry. Even with carefully designed scenarios and painstaking examination of the results, it is difficult to draw firm conclusions about the relative behavior and capabilities of the different forecasting methods. Similarities and differences due to regional effects were not conclusively isolated from those due to methodological effects. The results of the scenario applications provide the setting for analysis of alternative modeling approaches, but they are not the only component of the study. There was a consensus among the working group that the primary benefit of the study to them was inherent in the processes of communication, analysis, and comparison, rather than in specific results.

*Model evaluation techniques need improvement.*

Part of the process included consideration of the requirements for better model evaluations. Improved methods for comparing the results of models from different regions need to be derived, but any comparative analysis should stress flexibility in modeling, not certification of a few narrow approaches. Improvement of model analysis represents a serious challenge to the modeling profession. In developing new standards for modeling, the broad contributions of models must be addressed, emphasizing the modeling process as well as the details of the models' designs. Models are complex, but this complexity cannot be circumvented by creating a guarantor to separate the "good" from the "bad" models. The entire process, including the interaction between the model user and the model developer, must be designed to develop better insights into the forecasting problem.<sup>17</sup>

#### LIMITATIONS OF THE MODELS

*Modeling has limitations:*

In the preceding section, we noted some of the strengths of modeling in highlighting important issues and in structuring the debate on those issues. In this section, we discuss some limitations of modeling. Consideration of the limitations is essential for proper application of the models and use of the results.

*uncertainty  
is seldom  
explicitly  
treated*

The lack of an explicit treatment of uncertainty in forecasts is a limitation of most applications of models. There are two major sources of uncertainty in the models: that associated with the accuracy of projected values of the input variables, and that associated with the accuracy with which the model equations and parameters represent real world phenomena. Some of the input variables, such as population, prices, and future regulatory actions, can significantly impact electricity use. With the uncertainty in the values assumed for these variables, the sensitivity of the model to changes in the values can be a limitation on the reliability of the forecast. In addition, the equations and coefficients that describe the relationships between the variables are, at best, approximations to actual behavior. The uncertainty associated with input and coefficient values usually receives some treatment by forecasters. The uncertainty associated with the model structure is less frequently addressed, although the accuracy of the approximation to historical data is usually considered.

*(but several  
approaches  
can be used);*

An explicit treatment of uncertainty in the values of the input variables is found in the FPL model. This is achieved through the use of subjective probability distributions over the range of likely future values for these variables. Other modelers examine the impact of a range of input variable values and coefficient values on electricity consumption; sensitivity analysis is used by many utilities to analyze future loads under high "optimistic" or low "pessimistic" assumptions. However, this approach usually does not allow for formal examination of the effect of uncertainty on planning decisions.

During model development, alternative forms of equations are tested to determine which best fits historical data or best suits some other statistical standard. This is usually the only recognition given to the uncertainty associated with the structure of the model and the form of the equation. It is possible that the model that best fits historical data may not provide the most reliable predictions. Many utilities address this problem by using several models and evaluating the various results before arriving at a forecast.

*limited end-use detail;*

Two closely related limitations were noted by the working group: it was difficult to use econometric models for scenarios that involved specific changes in end-use components, such as efficiency standards, while the pure engineering models cannot be used explicitly to deal with price-induced changes.

*difficult to examine load shape;*

Load shape was considered explicitly only by Northeast Utilities. Currently, most models are designed with constant load factors, and peak demand is derived from annual kilowatthour consumption. Even those models designed for peak demand estimation usually cannot be used for load shape forecasts. A modeling approach that yields load shapes would simultaneously forecast energy and peak demand for a given type of day (e.g., peak day). This information would contribute directly to the decision on the capacity mix as well as on the total amount of capacity required.

*or capture feedback effects.*

The price of electricity influences demand, which determines capacity requirements. Capacity additions affect the cost and hence the price of electricity, which then influences demand. The separation of supply planning from demand forecasting opens this critical loop and may bias the results of the forecasts. This is particularly likely in the current situation of increasing costs of generation and long lead times for plant construction. This loop can be closed either through explicit modeling of the relationships, as in the case of the ORNL-SLED and Baughman-Joskow models, or through management review and interaction between the capacity-planning and demand-forecasting divisions of a utility.

#### RECOMMENDATIONS

The working group recommends that modelers explicitly recognize the uncertainty in their forecasts by providing both a range of estimates and a mechanism for incorporating subjective probabilities in the estimates.

*Integrate analysis of uncertainty, forecasting, planning.*

Once the uncertainty is described, the forecasters should work within the planning process to help assess the probable costs and benefits of alternate capacity decisions. Ultimately, uncertainty in the forecasts is reflected in capacity additions and so should be considered in capacity planning. If future electricity demand falls short of capacity, consumers will pay unnecessarily high rates. If demand exceeds capacity, outages will occur and consumers will incur extra costs in the form of production and property losses. The costs associated with each type of error, and hence with the uncertainty in the forecast, can be explicitly incorporated in capacity planning. Forecasting methods must advance to the level of incorporating explicit treatment of the uncertainty associated with the forecast in order to permit full use of this available capacity planning tool. This could be accomplished, for example, by embedding the range of forecasts within a formal decision analysis.<sup>5</sup>

*Use econometric and engineering methods together.*

The working group believes that a fruitful direction for methodological development is the integration of econometric and engineering approaches in modeling both electricity consumption and peak load. These techniques complement each other over a wide range of problems.

Econometric forecasting models work through behavioral relationships estimated with historical data, linking the consumption of electricity to such factors as its own price, the price of competing fuels, income, and weather and demographic variables. While the econometric approach is good at capturing the behavioral patterns of electricity consumers, it also has disadvantages. Generally, data availability limits econometric forecasts to aggregate variables, making it difficult to examine the role of particular end uses of electricity. Also, since they are based on historical data, econometric models may not be appropriate in forecasting the effect of new technologies or radical departures from historical patterns of behavior.

The engineering approach is based on detailed information on the end uses of electricity. These models can be used to describe the efficiency and utilization of appliances and electricity-using equipment. With the description of electricity consumption at the end-use level, the effect of changes in the equipment can be assessed. Assumptions about behavioral responses to new technologies or price structures can be made with greater confidence when limited to a specific end use, and the effect of these innovations can also be assessed. The major disadvantage to the engineering approach is that the data are not available at this level of detail to describe the response of consumers to changes in income, in prices of electricity, or in prices of competing fuels. The econometric and engineering approaches differ greatly, and the working group believes that their integration could exploit their complementary strengths.

*Develop  
better data*

The working group recommends that efforts should be made to improve the quality of the data. All of the forecasting methods could benefit from better data. The econometric models could benefit from more reliable estimates of the behavioral coefficients, which would be facilitated by the existence of more complete and consistent data. The development of engineering models, or more detailed econometric models, or integrated engineering-econometric models requires more detailed data.

*through load  
research on  
residential  
uses,*

In the residential sector, load research data are needed on the amount and time of use of specific appliances. Much data of this type currently exist, but updating is necessary to measure recent changes in consumption patterns and to incorporate the use of newer, more efficient appliances. Since more efficient appliances are both more costly to purchase and less expensive to operate, ownership and use of these appliances may not follow the same patterns as with current appliances.

*disaggregation of  
industrial  
uses,*

In contrast to the residential sector, the equipment and appliances used in the commercial and industrial sectors are too diverse to permit forecasting on the basis of ownership and utilization of a common set of appliances. Some other basis



of disaggregation must be found. One promising approach is to disaggregate on the basis of similar types of business or industry. Collecting data on total consumption and hourly load patterns by industrial sector (perhaps by SIC class) would facilitate the implementation of this approach.

*and standardization and sharing of data.*

Some standardization of the data collected by different utilities or research groups would also be beneficial. Currently, data which purport to measure the same general phenomena differ across utilities in the definitions used and in collection or survey techniques. There are different definitions for appliance saturations, usage, and efficiencies; for the separation of residential, commercial, and industrial customers; and for prices. This inhibits the transfer of data, the transfer or comparison of model coefficients or other results, and requires duplication of efforts and expense. Some standardization of data definitions and collection procedures could provide improved forecasting, as well as improved opportunities for model analysis and examination, at little cost. Such standardization might even result in a net reduction of costs.

*Extend models by incorporating new features.*

The working group recommends that model development efforts should proceed simultaneously with data development. Although improved data are necessary to facilitate better application and use of existing techniques, improved modeling techniques could be utilized with more detailed and reliable data to produce more accurate forecasts.

Forecasters should work to include, wherever possible and appropriate for their service areas, the following additional factors in their models:

- the effects of changes in the rate, such as two-part, time-of-day, inverted-block, and seasonal;
- changes in appliance and other end-use efficiencies stemming from price changes or from mandated energy-use standards governing insulation, lighting, space conditioning equipment, etc.;

- technical change, such as cogeneration and load management; and
- the effect of electricity prices on appliance saturation.

The working group recommends that additional techniques for examining and comparing alternative forecasting methods be pursued. However, this process of model analysis must proceed with an understanding of the purpose of modeling and the limitations of model comparisons. Comparing and evaluating forecasting models is extremely difficult. Just as the primary use of models should be to produce insight rather than to produce numbers, so the primary goal of model analysis or evaluation should be for building understanding rather than certification and standardization. The model evaluation process should promote the development of new techniques. Rigid standards may retard or misdirect the development of models as evaluation criteria begin to decay into modeling constraints. Programs aimed at defining evaluation criteria and procedures should be scrutinized to ensure that model development is not stifled.

*Expand the model comparisons*

However, the examination and analysis of forecasting models can provide substantial benefits to load forecasting and capacity planning. During the early discussions of the working group, one of the most surprising discoveries was the lack of knowledge by the participants of the specific techniques being used by other members of the group, even though all were confronted with similar forecasting problems. By the end of the study, there was consensus among the working group that one of the primary benefits of the EMF process was the exchange of ideas and information.

*and the communication between forecasters and planners.*

There was consensus that an annual meeting of load forecasters should be held, similar to the EPRI load forecasting symposium. There was also consensus that part of the work to be presented at such a meeting should consist of the results of further comparative model studies such as this one. For example, three or four such working groups could be operating independently but simultaneously, each one focusing on one particular issue (rather

than the multi-issue approach of this study), and the results could be presented to the industry at the annual meeting. Our study identified many topics that could serve as the issue foci for these groups, including demand elasticities, appliance saturation and efficiency elasticities, load shape forecasting, and the impact of developing technology, among others. The Energy Modeling Forum and the Utility Modeling Forum provide vehicles for the conduct of these studies. Other similar efforts should be encouraged.

NOTES

1. See, for example: Vennard, E., "Forecasting" in The Electric Power Business, Chapter 6, McGraw-Hill Book Co., Hightstown, N.J., 1970.
2. Generation costs are ultimately reflected in prices and revenues. The Edison Electric Institute Statistical Year Book provides data on total generation and revenues for utilities in the United States. The yearbook for 1976 and advance data from the 1977 yearbook provided the following data on revenues (nominal prices deflated with the Consumer Price Index).

AVERAGE REVENUE PER KILOWATTHOUR SOLD

Year	Residential		Total Ultimate Customers	
	(current ¢/kWh)	(1972 ¢/kWh)	(current ¢/kWh)	(1972 ¢/kWh)
1957	2.56	3.75	1.67	2.46
1958	2.54	3.67	1.71	2.47
1959	2.51	3.60	1.69	2.47
1960	2.47	3.48	1.69	2.39
1961	2.45	3.42	1.69	2.37
1962	2.41	3.33	1.68	2.32
1963	2.37	3.23	1.65	2.26
1964	2.31	3.12	1.62	2.18
1965	2.25	2.98	1.59	2.11
1966	2.20	2.82	1.56	2.01
1967	2.17	2.72	1.56	1.96
1968	2.12	2.54	1.55	1.87
1969	2.09	2.38	1.54	1.76
1970	2.10	2.26	1.59	1.72
1971	2.19	2.26	1.69	1.74
1972	2.29	2.29	1.77	1.77
1973	2.38	2.24	1.86	1.76
1974	2.83	2.40	2.30	1.96
1975	3.21	2.49	2.70	2.10
1976	3.45	2.53	2.89	2.13
1977	3.78	2.61	3.21	2.22

3. The cost of capital to utilities is reflected in the interest rates which they must pay on bonds. The following data show capital and fuel costs (in current dollars) for utilities.

Year	Interest Rates on New Light, Power, and Gas Bonds (percent)	Electric Utility Fuel Costs (cents per million Btu)			
		Coal	Oil	Gas	Average
1955	3.3	25	34	19	24
1960	4.7	26	34	24	26
1965	4.6	24	33	25	25
1970	8.8	31	40	27	31
1975	10.0	86	200	75	108

These data were taken from Rate Design and Load Control: Issues and Directions, Electric Power Research Institute, Palo Alto, California, November 1977, pp. 10 and 11.

4. Coal-fired power plant lead time, from licensing to startup, has increased from six years in 1974 to eight years in 1977. The licensing and design phase increased from two years to four years in this period; the construction and startup phase required four years. These coal-fired power plant lead time data are from Bowers, H. I., "Capital Investment Cost Estimates for Large Nuclear and Coal-fired Power Plants," a paper presented at a seminar entitled Coal vs. Nuclear Electric Utility Generating Costs in the 1980s (in the Perspective of Recently Announced National Energy Policy), Washington, D.C., June 29-30, 1977, Oak Ridge National Laboratory, Oak Ridge, Tenn.
5. These nuclear power plant lead time data for 1967 and 1969 are from Brewer, S.T., et al., "Power Plant Capital Costs--Current Trends and Sensitivity to Economic Parameters," WASH-1345, U.S. Atomic Energy Commission, Washington, D.C., October 1974. The data for 1974 and 1977 are from H. I. Bowers, as referenced in Note 4.

6. Steam Plant Construction Costs

<u>Year</u>	<u>Current \$/kW</u>
1964	127
1966	119
1968	118
1970	126
1972	144
1974	193

Source: same as in Note 3.

7. Additions to capacity in excess of that needed to meet actual growth in demand result in losses to consumers in the form of unnecessarily high electricity rates. On the other hand, insufficient additions can result in blackouts, with losses in production and employment, disruption of transportation, and damage to goods. The relative magnitudes of the losses from these two situations, together with the shape of the probability distribution over possible future loads, have specific implications for capacity planning decisions in the face of uncertain future loads. These issues are addressed at length in EPRI EA-927, "Costs and Benefits of Over/Under Capacity in Electric Power System Planning," prepared by Decision Focus, Inc. for the Electric Power Research Institute, Palo Alto, California, October 1978. This paper demonstrates the advantage of the use of range forecasts, rather than point forecasts in capacity planning, and describes the decision analysis methodology for incorporating that uncertainty.
8. More complete discussions of the Energy Modeling Forum appear in: Greenberger, M., "Closing the Circuit between Modelers and Decision Makers," EPRI Journal, October 1977, No. 8, Electric Power Research Institute, Palo Alto, Calif., pp. 6-13; Hogan, W. W., "The Energy Modeling Forum: A Communication Bridge," paper presented at the 8th Triennial IFORS Conference, Toronto, Canada, June 20, 1978; and Sweeney, J. L., and Weyant, J. P., "The Energy Modeling Forum: Past, Present, and Future," Journal of Business Administration, 1978, (forthcoming).
9. EMF Report 1, Energy and the Economy, Volume 1, Energy Modeling Forum, Stanford University, Stanford, Calif., September 1977.
10. EMF Report 2, Coal in Transition: 1985-2000, Volume 1, Energy Modeling Forum, Stanford University, Stanford, Calif., July 1978.

11. In 1975, Congress passed Public Law 94-163, also known as the "Energy Policy and Conservation Act of 1975." This act specifies that "energy efficiency improvement target(s)" be set for all major household appliances. These targets were to be in terms of percent improvements over the efficiencies of typical 1972 appliances and were to be the "maximum" percentage improvement which "...is economically and technologically feasible," with the proviso that the aggregate improvement over the appliances should be not less than 20%. A member of the working group devised the efficiency standards that were used in this study as approximations to the legal guidelines.
12. This scenario was designed to isolate and examine the response of electricity demand to changes in the price of fuels that compete with electricity. Therefore, electricity price was held constant for this scenario, even though 20% increases in the prices of oil, gas, and coal would raise the cost of generation and cause the price of electricity to increase.
13. The Commonwealth Edison model was also applied to this scenario. Since it forecasts peak load and not electricity consumption, results are not reported here.
14. The ORNL-REDM model was also applied to this scenario. Since it forecasts electricity consumption and not peak load, its results are not reported here.
15. The Oak Ridge National Laboratory Engineering-Economic Model of Residential Energy Use separates price and income elasticities into three components. One component represents the changes in the intensity of utilization of various appliances in response to price and income changes. Another component represents the technological developments in appliance efficiencies (or building insulation in the case of space heat) that result from changes in price. The final component represents changes in the purchase and ownership of appliances. In the short run, the utilization response dominates the other two components. Over a 15-year horizon, the price elasticity of utilization tends to be smaller than the price elasticity of efficiency. However, all of the components are significant over such a time horizon. Information is not available on the magnitude of each of these components for the aggregation of all appliances, although it does exist for each appliance individually. Figure 16 shows the evolution over time of the magnitudes of the components and of the total elasticity for electric space heating as found in the ORNL-REDM model.
16. Load factor is a measure of the "flatness" of the load experienced by a utility. It is the ratio of the kilowatthours actually consumed to the number of kilowatthours that would be consumed if the peak kilowatt load was maintained throughout the year. Mathematically, this is expressed as

$$\frac{\text{actual kWh consumption in a year}}{(\text{peak kW load}) (8760 \text{ hours/year})}$$

17. This issue is discussed at greater length in, "Energy Modeling: Building Understanding for Better Use," by W. W. Hogan, in Proceedings, Second Lawrence Symposium on Systems and Decision Sciences, Western Periodicals, Co., North Hollywood, Calif., 1978, pp. 1-10; and in "The Energy Modeling Forum: Past Present, and Future," by J. L. Sweeney and J. P. Weyant, Journal of Business Administration (forthcoming).

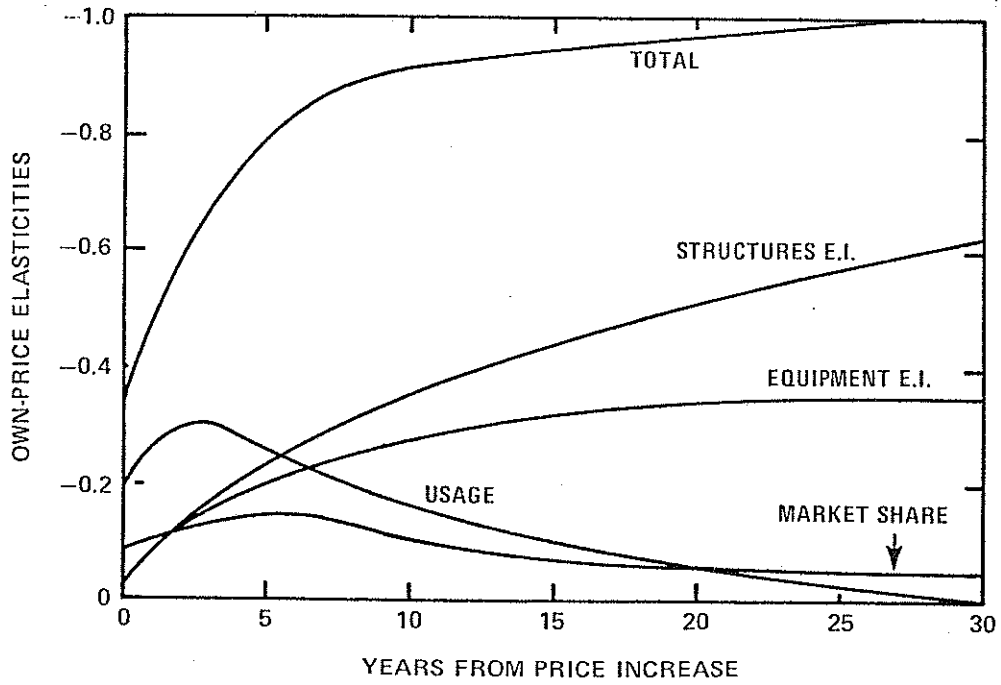


Figure 16 Electric Space Heating Elasticities with Respect to Electricity Price