DYNAMIC SIMULATION OF THE ELECTRIC UTILITY COMPONENT OF A REGIONAL ENERGY SYSTEM

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Submitted to the Faculty of the Graduate College
of the Oklahoma State University
in partial fulfillment of the requirements
for the Degree of
DOCTOR OF PHILOSOPHY
December, 1975

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ACKNOWLEDGEMENTS

I wish to express my sincere appreciation to Dr. Peter Moretti, Chairman of my Doctoral Committee, for his guidance and encouragement, not only in this research effort, but throughout my studies at Oklahoma State University. I wish also to express my appreciation to the other members of my Doctoral Committee, Dr. Jerald Parker, Dr. Joe Mize, and Dr. Larry Zirkle for their encouragement, counsel, and personal involvement.

I gratefully acknowledge the financial support received from the School of Mechanical and Aerospace Engineering and the Center for Systems Science.

I would like to thank Public Service Company of Oklahoma and Oklahoma Gas and Electric Company for their financial support and continual cooperation. Without their assistance this study would have been quite difficult, if not impossible. In particular, I would like to thank Jim Pogue of PSCO and Tom Hoke of OG&E who were instrumental in providing this assistance and most generous with their own time.

Finally, to my wife, Melanie, I would like to express my deepest gratitude for her sacrifices, support, and encouragement during this work.

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NOMENCLATURE

e	- base of natural log
t	- time
A	- availability
C	- cost
D	- duration of demand
F	- forecasted value
G	- growth rate
K	- time constant
L	- load
P	- profit
Q	- energy resource supply quantity
U	- utilization
X	- input
Y	- output
CN	- proportionality between deliverability and supply
CP	- capacity
DL	- deliverability
EG	- energy generated
EP	- economy energy purchased
ES	- economy energy sold
FC	- fixed cost
FD	- firm demand

FL	- fraction long-term
FP	- fixed price
LD	- value on load duration curve
TC	- total cost
TD	- total demand
VC	- variable cost
VP	- variable price
ICP	- incremental demand price
IGC	- incremental generation cost
ISP	- incremental supply price
ϕ	- defined by $\phi(x)=\begin{cases} x & x \leq LD \\ x & x \geq LD \end{cases}$

Subscripts

a	- total available to electric utilities in region
e	- existing long-term supply
f	- firm power
g	- growth rate
n	- new long-term supply available
s	- spot market
y	- input variable
gn	- generation
lt	- long-term possible
na	- actual new supplies secured

CHAPTER I

INTRODUCTION

Numerous energy models have been developed in an attempt to better understand the operation of the energy system and predict its future. To be of use in making in-depth studies and specific recommendations, a large degree of detail is required. Models of this nature are not overly abundant. The models currently available which do contain a significant level of detail use traditional static and equilibrium approaches. While these models are quite useful, the phenomena which they can investigate is limited.

These traditional modeling methods are unable to address the dynamic behavior of the energy system. During periods of change in the economic and political environment in which the energy system must operate, its dynamic behavior can be the dominant characteristic. In view of the uncertain economic and political future, the ability of traditional models to accurately describe the operation of the energy system is questionable. Even in the time of relative stability, much of the behavior of the system arises from dynamic feedback effects. Relationships which describe these effects are difficult to incorporate into a static or equilibrium model.

The dynamic system simulation approach to enconomic and industrial modeling allows a more complete consideration of dynamic characteristics (1). With this approach, model structure is based on information feedback and centers around relationships which describe the forces of change. Unfortunately, the dynamic system simulation models developed for energy studies tend to have relatively simple structures based on general characteristics of the energy system. This lack of complexity prevents in-depth studies. Since important dynamic relationships and limits often arise from the technical details, even their general descriptions of system behavior are questionable.

This study attempts to overcome this deficiency of previous dynamic system simulation models for energy studies by basing a model on the technical details involved in the functioning of the energy system. This approach not only provides for a thorough description of the system, but provides sufficient detail for in-depth studies which can address precise policy questions, and make specific recommendations.

The model developed simulates the electric utility component of a regional energy system. A regional geographic scale was selected for several reasons:

1. It is at the regional or local level where a large number of the day to day decisions are made which are essential in the operation of the energy system.
2. The actual physical entities and processes in the system are more easily identified and described at the regional level.
3. There is less variability in characteristics of the system on a regional level.
4. More precise policy questions can be asked at the regional level. This gives the possibility of more detailed policy recommendations.

The electric utility part of the energy system was selected for this initial modeling effort for several reasons:

1. The electric utility industry is at a uniquely strategic location in the energy system. Through conversion to electricity, nearly every energy resource can be reduced to a common product. Thus, at this point in the energy system the energy resources are direct substitutes for each other and are highly competitive. Also, electricity is one of the most easily used forms of energy existing.
2. The electric utility industry is probably the most regulated industry in the energy system. In order to make wise decisions, a thorough understanding of the response of the electric utility industry to regulation policy is needed. A poor understanding of this response can lead to unexpected and harmful side effects from poor decisions. On the other hand, a good understanding can indicate policy options which can alleviate problems in this critical part of the energy system.
3. The demand for electricity has been growing rapidly in the past; more rapidly than the demand for most other forms of energy. There is considerable uncertainty as to whether this rapid growth will continue. The long construction period required to build some generation facilities and the non-storable nature of electricity makes accurate planning essential if electric utilities are to meet demands efficiently.

4. Local electric utility companies provided a considerable amount of cooperation in this study. Since the modeling method used emphasizes technical relationships and decision processes, this cooperation was considered to be very valuable.

In order to use technical details in the formulation of the model, a complete, quantitative description of the important variables is necessary. This objective is met by considering:

1. variations in the demand for electrical energy throughout the year as well as growth from year to year;
2. all major energy resources, their prices, and their availabilities;
3. capital investment requirements and the effect of a limited capital supply;
4. all major types of generation facilities, their costs, and their variation in availability throughout the year;
5. various types of inter-regional electrical energy and power transactions; and
6. a complete accounting of generation costs.

The electric utility model developed in this study will serve as a component of a comprehensive regional energy model. The particular niche it will fill in this regional model was discussed in an earlier study (2). It is also designed to be used for a wide range of independent studies. Chapter III gives an in-depth accounting of the development of the electric utility component model.

In Chapter IV the question of model validity is addressed by comparing predicted results to historical data for the geographical region defined by the State of Oklahoma. Although no validation can be considered as final, this provides the user with some degree of confidence. Following this, the practicality of the model for useful studies is demonstrated in Chapter V. This is done with sample case studies for potential limitations on the use of natural gas as a boiler fuel in Oklahoma.

It is felt by the author that this model represents the first time this level of detail has been included in a dynamic system simulation model of any part of a regional energy system. It also appears to be the first attempt to develop a comprehensive regional energy model using dynamic system simulation models of each component as building blocks.

CHAPTER II

REVIEW OF ENERGY MODELS

Introduction

The use of energy models is certainly not new. Hundreds of different energy models have been developed in the last few decades. Many state, national, and international agencies, as well as most companies in the energy industry use energy models regularly. To attempt to discuss all of these is far beyond the scope of this review. Instead, where appropriate, selected illustrative examples will be used. For an in-depth review of most of the major energy models and studies recently completed or still in progress, the reader is referred to the comprehensive study by Decision Sciences Corporation (3). Reviews have also been made on electrical demand forecasting methods by the Federal Power Commission (4) and Edison Electric Institute (5). Reviews of national energy studies and demand forecasts have been made by Battelle-Columbus (6), Edison Electric Institute (7), and for the Committee on Interior and Insular Affairs of the U. S. Senate (8,9).

For the purpose of the following discussion, energy models will be grouped into three classes - static, equilibrium, and dynamic. This classification is somewhat arbitrary. It was chosen to point out the differences and the relative advantages and disadvantages of the dynamic systems simulation method as compared to other modeling methods.

The static models are those which do not deal directly with changes in time. They are generally not used for predictive purposes, but rather for studying energy system structure and operation. Equilibrium models, on the other hand, usually do directly consider variables which change with time and are often used for predictive purposes. However, they consider the response of the system to inputs by assuming pseudo steady state conditions or consider only the net result after all transients have died out. Dynamic models are able to consider transient responses, as well as steady state solutions. Dynamic models are normally used for predictive purposes where transients are of prime importance.

Static Models

The most commonly used modeling method for static energy models is linear programming. Linear programming models are primarily used to study the structure of energy systems and the various flows of energy and other associated materials. They are also well suited for optimization. Linear programming models are useful for studying the effects of new technologies and in assessing various strategies to achieve certain goals, for example, the most effective methods to reduce SO_2 emissions in a region.

The use of linear programming models can, in some cases, be used in an equilibrium context. These often involve supply and demand considerations and price equilibrium. Thus, the distinction between a static application and an equilibrium application often becomes blurred. In the following discussion this lack of a precise distinction between classes should be remembered.

The geographic scale of the linear programming energy models developed is quite diverse. They range from the model centered around the energy system of New York City being developed by Brookhaven and the State University of New York (10,11) to the national energy model developed by the Atomic Energy Commission (12), to the international energy model which considers both the United States and Canada developed for the Canadian National Energy Board (13). The types of energy studied varies considerably as well, ranging from the electrical energy model developed at Battelle-Northwest (14) and Waverman's (15) natural gas model to the total-energy model developed by Battelle-Columbus and the Associated Universities (16). Linear programming can also be combined with other modeling methods as is done by Griffin (17). The Griffin model uses a standard econometric model to drive a linear programming model.

An alternative to linear programming is network analysis. It is very similar to linear programming, and models formulated using network analysis could also be formulated using linear programming methods. Debanne (18), who uses this method for a model to assess pollution control and new technology, claims network analysis can result in significant savings in computation time as compared to linear programming.

The energy "flow maps" which describe how the different forms of energy flow through an energy system can be considered another form of static energy model. These energy maps are widely used to show the relative magnitudes of various energy uses and to show the processes whereby energy resources are used to supply demands. These energy maps may consider only a certain region and may be quite detailed, as in the work being done at the University of Wisconsin (19,20). Similar energy maps are also necessary for the development of some linear programming models. On the other hand, energy maps, such as the ones developed for the Joint Committee on Atomic Energy (21) may be very simple and consider the entire nation or even the whole world. These are usually used to give a quick overall perspective of the energy supplies and demands.

Equilibrium Models

Input-output models are a common form of equilibrium model widely used in economic studies. They are now beginning to find useful application for energy studies. However, for energy studies, the models must be formulated on a unit of energy basis (BTU, KWH etc.) rather than on a dollar basis. Input-output models are well suited for showing both the direct and indirect energy cost of individual products. They are also useful for showing how different products contribute to total energy demand. The main drawback to widespread use of energy input-output models is the tremendous amount of work involved in gathering and interpreting sufficient data to develop a detailed model.

Heredeon (22) has converted the 1963 input-output tables to energy terms and shown how they can be applied to a number of energy questions. The energy input-output coefficients for a number of years are being derived in work at Battelle-Northwest (23,24). By determining the coefficients for a number of years, the trends in energy use for various products can be seen. Almon (25) combines direct energy input-output coefficients with an economic model to forecast demand for petroleum. A more extensive model is being developed at Data Resources (26) which will fully couple energy input-output models and economic models and allow price effects and substitutions between fuels to be considered.

A different form of energy input-output model is used by Maxim and Brazie (27) to assess the total system enviornmental impact and the efficiency of alternatives. The structure of their model, in many ways, is more analogous to some of the linear programming models than the traditional input-output models. Rather than use traditional input-output variables, they use the stages along the energy chains from natural resource to end product. Each stage derives energy inputs from and provides outputs to other stages. Also, pollution outputs are associated with each stage. This method shows great promise for assessing total system effects of attempted improvements in the system.

Econometric models are widely used for energy studies. Most often, these are equilibrium models. The areas of the energy system to which econometric models are applied are diverse as are the particular methods used in individual models. This makes it somewhat difficult to address the advantages and disadvantages of the traditional econometric techniques. Examples of the wide variety of problems for which econometric models are used range from Spann and Erickson's (28) assessment of joint costs in oil and gas exploration to the determination of substitution effects in energy demand by Erickson et al. (29).

In some of the larger studies, econometric and economic models are being used as a complementary model to, or driver for, other types of models. This was seen earlier in the Almon's model (25), the Data Resource model (26), and the Griffin model (17). This may well prove to be one of the most promising areas for application of econometric models. This is becoming especially true as energy models are growing more comprehensive and considering economic factors beyond the confines of the energy system alone.

Dynamic Models

Transient responses, as well as equilibrium considerations, are sometimes included in econometric models. Traditionally, this has involved only explicit functions for the time for certain variables to respond to input changes. These time response functions can reflect limits such as the time required to build new equipment or constraints such as the life time of existing equipment. This approach is used to account for the delays likely to be seen in making substitutions among different kinds of energy as prices change in the model developed by Mount et al. (31) which predicts energy demand. A similar approach is used in the Rand (32) study of regional electric demands.

DSS (Dynamic Systems Simulation) models consider dynamic characteristics much differently than is normally done in econometric models. In a DSS model, a large part of the structure is based on the feedback loops in the system from which the dynamic nature arises. This allows the model to consider a much wider range of dynamic responses such as overshoot, oscillation, and stability. The capability to simulate this type of dynamic response makes DSS models uniquely valuable for studying transient and alignment problems.

The theory behind using DSS for modeling industrial and economic systems was largely developed by Forrester (1). He later expanded the use of DSS to socio-economic systems as well (33,34). Meadows et al. (35) have continued the development of this application. Due to its relatively recent introduction, compared to other techniques, DSS has not been extensively used in energy modeling. Also slowing its widespread use is the considerable amount of work, comparable to input-output and linear programming models, involved in developing detailed quantitative DSS models. However, DSS shows great promise for energy studies where dynamic factors may be of prime importance.

DSS models for energy studies can be either qualitative or quantitative. The qualitative models follow along the lines of the earlier socio-economic models developed by Forrester (34) and describe the basic structure of the interactions and feedback loops in the energy system. The qualitative models are useful for studying general dynamic behavior in the energy system and general policy questions. A model of this type was developed by White (36) to describe the essential workings of the energy system in the United States. Odum (37) has also used qualitative DSS energy models to study the interaction between the energy system and the ecological and economic systems.

Quantitative DSS energy models need to include a considerable amount of technical detail. The inclusion of detail allows them to address more precise questions of system dynamics and to analyze detailed policy alternatives. The inclusion of technical detail, however, requires much more emphasis on analyzing data and deriving technical relationships than for a qualitative model. Two DSS energy models currently in existence show the wide range of possibilities that exist for the technique. A DSS model which simulates interfuel competition has been developed by Baughman (38,39). His model considers the competition between the major fuels on a national basis. Both the demand and supply sides of the markets are considered simultaneously. Garret (40), on the other hand, uses a DSS model to simulate a single electric utility company. His model considers both capital investment and capacity expansion as a joint planning problem to obtain optimal management strategies. The study reported here by the author should demonstrate still further potential of quantitative DSS models by simulating an industry in the energy system at the regional level.

Other Modeling Methods

Probably, the most widely used modeling technique in energy studies is extrapolation of time series trends. There is little theoretical justification for extrapolation of a variable, since any time a variable is extrapolated there is an implicit assumption that all forces affecting the variable will be the same in the future as in the past. However, the technique still is used extensively by the electric industry and other industries in the energy system (4,9). Extrapolation has performed reasonably well in the past when trends have been relatively smooth, giving many users a false sense of reliability. It would be hazardous to expect it to perform similarly in a period of uncertainty and irregular trends. The main advantage extrapolation has over other techniques is the relative ease with which sophisticated analysis can be used. Such sophistication can be seen in the electric utility load forecasting model developed at Purdue (41), and the regional projection of residential electric demand study made by Rand (42). The Purdue model incorporates extensive statistical analysis of weather data, as well as historical data. This is used to give the forecast a probabilistic dimension. The Rand model projects end use saturations as part of the extrapolation technique.

To overcome some of the drawbacks of the extrapolation technique, many energy studies project energy demands by using correlation models to relate demands to other economic variables. By showing their relationship to other variables, insight is gained into the factors which affect demands, and a better description of the forces affecting observed trends is obtained. However, there are also some drawbacks to the use of correlation models. The models depend upon independent projections of the economic variables which may be no more accurate than extrapolations of energy demands. The correlations derived from historical data may not be valid in the future, especially if the data is taken from a time period where most of the variables had monotonic trends.

The most common method used to develop a correlation model is to use multiple regression analysis. A typical example of this can be seen in probabilistic energy demand forecasts made at Rand (43). Another approach at correlation used by Sadiq and Schoeppel (44,45) is to make crossplots of dimensionless groups of economic variables. With this method they were able to make use of data from a number of countries in addition to U. S. historical data.

Combined Analysis

In most major energy studies, no one single model or single modeling method is used for all of the analysis. There is no one method which is best for all types of investigation. Also, time constraints often force the use of extrapolation of other simple methods as part of the analysis. It has already been pointed out that econometric models are often used as complements or as drivers for other models.

There appears to be two trends in the area of combined model studies. One is to use a number of independent models to study separate parts of the system. This approach can be seen in the Rand (42,46,47) models used for estimating total regional electric demand. The other approach is to develop an overall modeling framework within which all of the individual models operate simultaneously. Such a modeling framework, which includes both energy supplies and demands, can be seen in the TERA model being developed by Decision Sciences (48). As the need for major, comprehensive energy studies increase, it can be expected that more and more emphasis will be placed on combined models. In this light, model builders should be aware of what niche each type of modeling method best fills and how the different methods can interface with each other.

CHAPTER III

FORMULATION OF A REGIONAL ELECTRIC UTILITIES MODEL

Introduction

The electric utility companies which make up a regional electric supply system are involved in a wide range of activities. Although all of these activities may be important for overall operation of an electric utility company, each activity does not need to be considered in detail for a simulation of electrical energy supply. The activities which relate directly to the ability to meet demands and the cost of meeting these demands are those which must be fully simulated. Five groups of activities are seen as being fundamental in meeting these requirements:

1. forecasting future conditions;
2. planning the addition of new generation facilities;
3. securing supplies of energy resources;
4. intermediate planning of operation; and
5. hour to hour scheduling.

Figure 1 shows how these activities act to supply the desired information. Using historical values of key variables and the current values of these variables, forecasts are made of future conditions. These variables include:

1. peak demands for electrical energy;
2. prices of energy resources; and
3. quantities of energy resources available for use.

Given these forecasts, plans are made for future generation capacity. These plans are quite important since there are severe limits to the kinds of fuel a particular generation plant can utilize. Thus, once generation facilities are built, the choice of fuel is restricted for a number of years.

Given the generation facilities built and planned, plans are made to secure supplies of energy resources to fuel these facilities. Utility companies will normally make long-term arrangements for these supplies if possible. This is to insure supplies for future years. These long-term arrangements may involve contracts with suppliers or actual purchase of gas fields, coal mines, etc.

The forecasting and planning activities discussed effectively control the state of the system. That is, they determine what generation facilities exist and what energy resource supplies are available. This state of the system, in turn, limits what options are available for intermediate planning and operation. This planning takes place on a time scale of one year or less. Given the generation facilities existing and energy resource supplies available, short-term plans must be made to allocate the use of any energy resource that is in short supply. Also, arrangements are made for firm power transactions with neighboring regions.

Up to this point, all the activities have involved some form of planning. However, it is the actual hour to hour operation of the generation facilities that determines what demands are met and what energy resources are used. At this point the actual scheduling of generation facilities takes place and most decisions concerning inter-regional transactions are made. Intermediate planning, in turn, supplies the framework in which these decisions are made.

The important costs in generation come from building generation facilities, purchasing energy resources for fuel, and other operation expenses. The ability to meet demands comes from the existing generation facilities and energy resources available in relation to the demands that arise. The activities discussed form a chain of information and actions which are critical in determining these factors. There are several other activities which may be important in some cases. They are:

1. power plant siting;
2. planning and construction of transmission and distribution lines; and
3. financing of capital expenditures.

These activities are not simulated but are included in the following manner:

1. The available sites are incorporated as an upper limit on the amount of different types of generation facilities allowed. This limit is an input to the simulation.
2. Transmission and distribution lines are assumed to be built as needed. However, limits to the transmission capability between regions may exist. These limits are inputs to the simulation.

3. The capital available for building new generation facilities is an input to the simulation.

Since this simulation is developed for a regional energy system, more than one electric utility company will normally be involved. There are several assumptions made relating to this fact which have a direct impact on the simulation;

1. It is assumed that in meeting the hour to hour demands for electrical energy in the region, the lowest cost generation facilities will be used first, regardless of the distribution of demands and facilities among individual companies. Economy energy transactions between the various electric utilities in the region normally makes this possible.
2. When new generation facilities are planned, it is assumed that individual companies are fully aware of the plans of other companies. That is, generation facilities are selected so that they complement other facilities being built in the region, regardless of which company owns what facilities.
3. The region is assumed to be small enough such that no major transmission losses are encountered in supplying demands at one point in the region.
4. It is assumed that all demands for electrical energy in the region are supplied before non-firm demands in other regions, regardless of on which company's system the demands occur. Firm demands in other regions are given the same priority as demands from within the region.

Indirectly, these assumptions say the individual electric utility companies cooperate fully with each other.

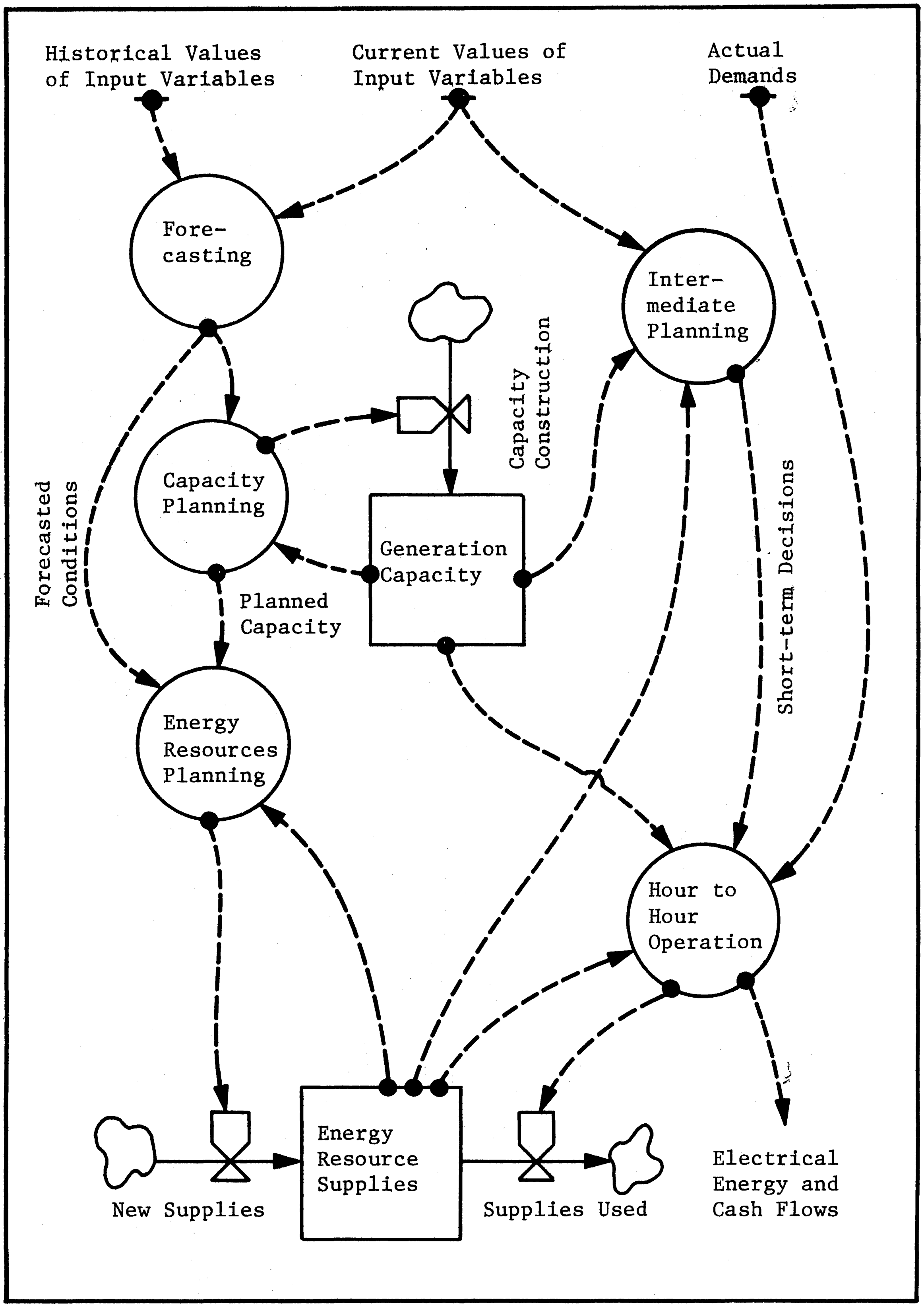


Figure 1. Simplified Forrester Diagram of Electric Utility Simulation

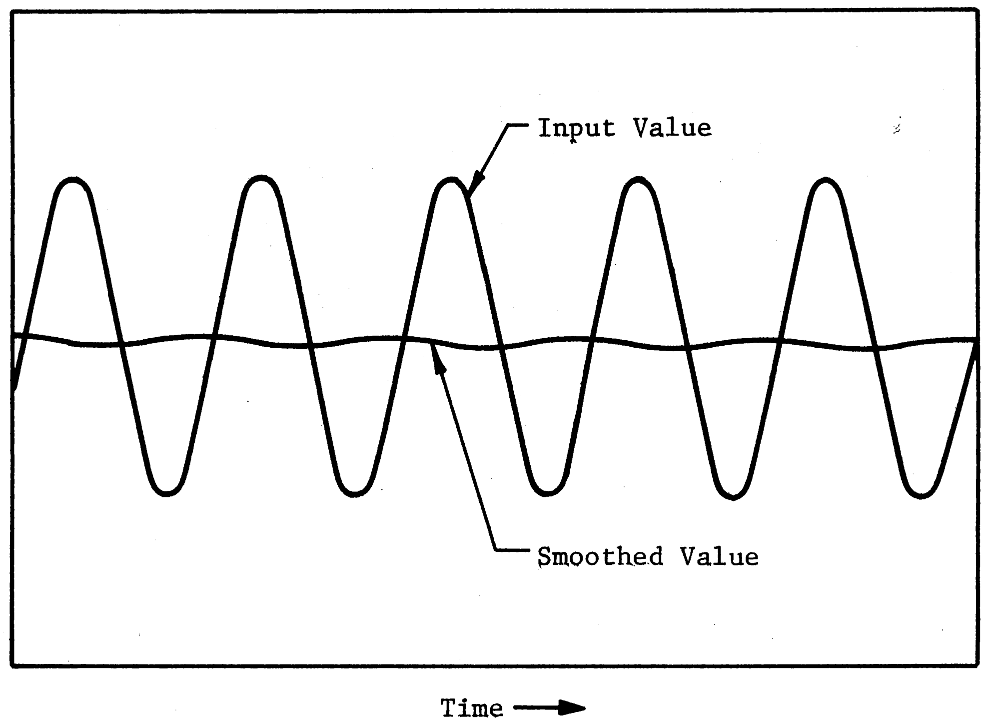
Forecasting

Whether they involve well defined mathematical techniques or simply intuitive judgment on the part of company management, forecasts of future conditions are one of the most important activities in the electric utility industry. The information derived from forecasts are the basis for all major decision options involving construction of new facilities and the selection of energy resources. A number of different formal forecasting techniques are employed by the electric utility industry. Just as important as the formal techniques, however, are the informal or judgment type forecasts that are always present. Thus, it would be difficult to develop a simulation which would always determine how forecasts are to be made. Instead, the model can be altered to test the effect of different forecasting techniques. Since trend extrapolation techniques are still the dominant approach for forecasting in the industry, a technique of this type was selected for the basic simulation (4).

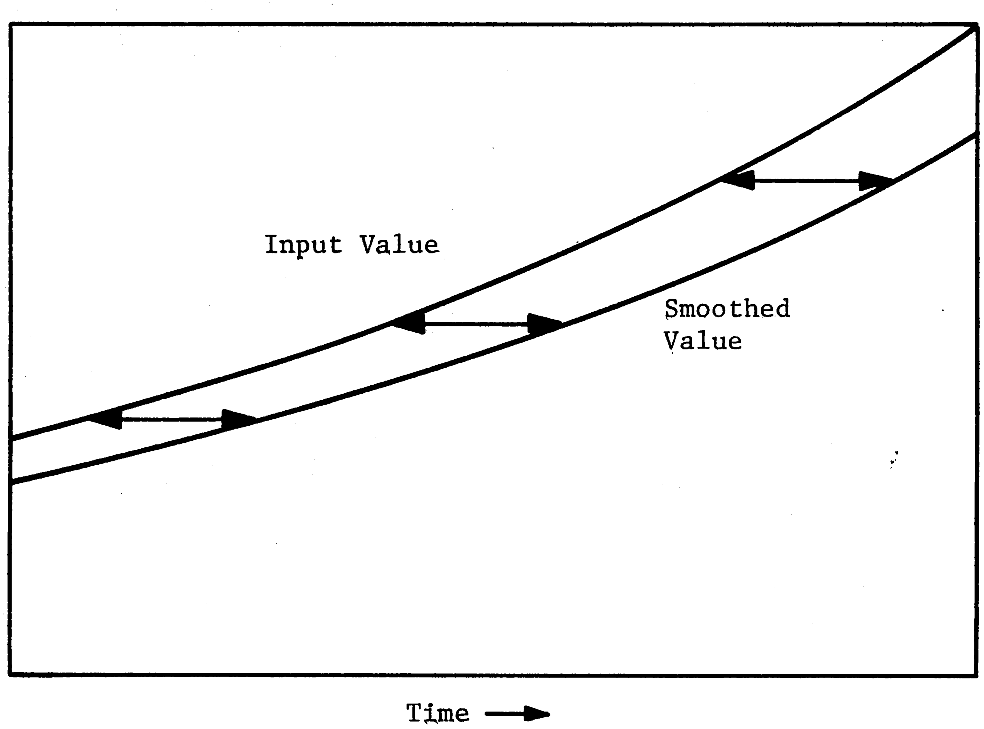
The properties of the first order exponential delay make it well suited for forecasting simulation (1). Mathematically it is expressed by:

$$\frac{dY}{dt} = \frac{X - Y}{K_y} \qquad 3.1$$

where X is the input, Y the output, and K a time constant. The exponential delay can be used to smooth a fluctuating variable or to delay a smooth trend as in Figure 2. The simulation makes use of the smoothing ability of the delay to simulate the averaging of historical data. The delay capability is used to simulate the time required for forecasts to respond to changes.



(a) Fluctuating Input



(b) Input with a Smooth Trend

Figure 2. Effect of Smoothing Delay

The commonly used assumption of a constant percentage growth rate in forecasting is combined with exponential delays to develop simulation forecasts. First, the input variable is smoothed with the exponential delay, mathematically expressed in Equation 3.1. At the same time, the percentage growth rate is calculated and then smoothed with another exponential delay yielding:

$$\frac{dG}{dt} = \frac{(\frac{dX}{dt})/X - G}{K_g} \qquad 3.2$$

where G is the percentage growth rate of the input. Using this average value of growth rate G and the smoothed value of the input variable, a forecast can be generated. However, one additional consideration must be made. In using the constant growth rate approach there is an implicit assumption that a smooth trend existed in the input variable. Thus, the smoothed value of the input variable also represents a delayed value of the input variable. For an input with a constant growth rate, the lag is exactly equal to the time constant. Considering this lag in the forecast yields:

$$F(t) = Y \times e^{[(t - t_o + K_y) \times G]} \qquad 3.3$$

where F(t) is the forecasted value of the variable and $t-t_o$ is the number of years in the future.

Several additional points should be made concerning this forecasting simulation to assess its suitability.

1. Counteracting the delay effect from smoothing does not imply the time required to adjust to changes is not simulated. First, a delay is still present in determining the growth rate.

Second, the form of 3.3 effectively assumes that current small fluctuations are not part of the long-term trend and corrects for these fluctuations. An actual change in the trend is only represented by a change in the delayed variable.

2. The use of the exponential delay to smooth variables is more than a statistical average of historical data. More recent values are more heavily weighed. Thus, emphasis is placed on recent trends.
3. The technique is equally suitable for declining trends and increasing trends. For declining trends the variable is forecast to decline asymptotically to zero at a constant negative percentage growth rate.

A Forrester diagram representing the forecasting simulation technique is shown in Figure 3. The symbology used in this figure is described in Appendix B.

There are a number of variables that change with time which are important factors in electric utility company decision options. These include: future demands for electricity in the region, energy resources prices, quantities of energy resources available, the characteristics of demand for electricity, and construction cost of power plants. The peak demand for electricity is used as the key variable in simulation of the forecasting of electrical demand. Along with this, the characteristics of the demand are included as an input parameter. Demand characteristics will be discussed further at a later point in this chapter. The market price of each of the energy resources being considered is forecasted using the same technique. For the base simulation these energy resources include: coal, oil, natural gas, and nuclear fuel. Other energy resources can be added. The quantity available of each of these energy resources must also be forecasted. In many cases there may only be limited quantities of these energy resources which the electric utilities can use. The forecasting of this is divided into two parts. First, the quantity of each energy resource expected to be available to all users in the region is forecast. Second, the fraction of each of these energy resources which is likely to be available to the electric utilities is forecasted. These are combined to obtain the quantity of each energy resource expected to be available for electric generation. The previously described technique is modified slightly to simulate the forecasting of the fraction available. Since the fraction available must remain in the interval between zero and one, forecast values cannot lie outside this range. If the percentage rate of change is negative no problem is encountered, as the forecast values approach zero asymptotically. However, if the percentage rate of change is positive, the previously described technique would forecast values to increase past one. To overcome this problem the simulation allows the forecast values to approach one asymptotically for a positive rate of change in the same manner as they approach zero for a negative rate of change. This requires the use of the following relation in place of Equation 3.3 when the percentage rate of change is positive.

$$F(t) = 1.0 - e^{-[(t - t_o + K_y) \times G]} \qquad 3.4$$

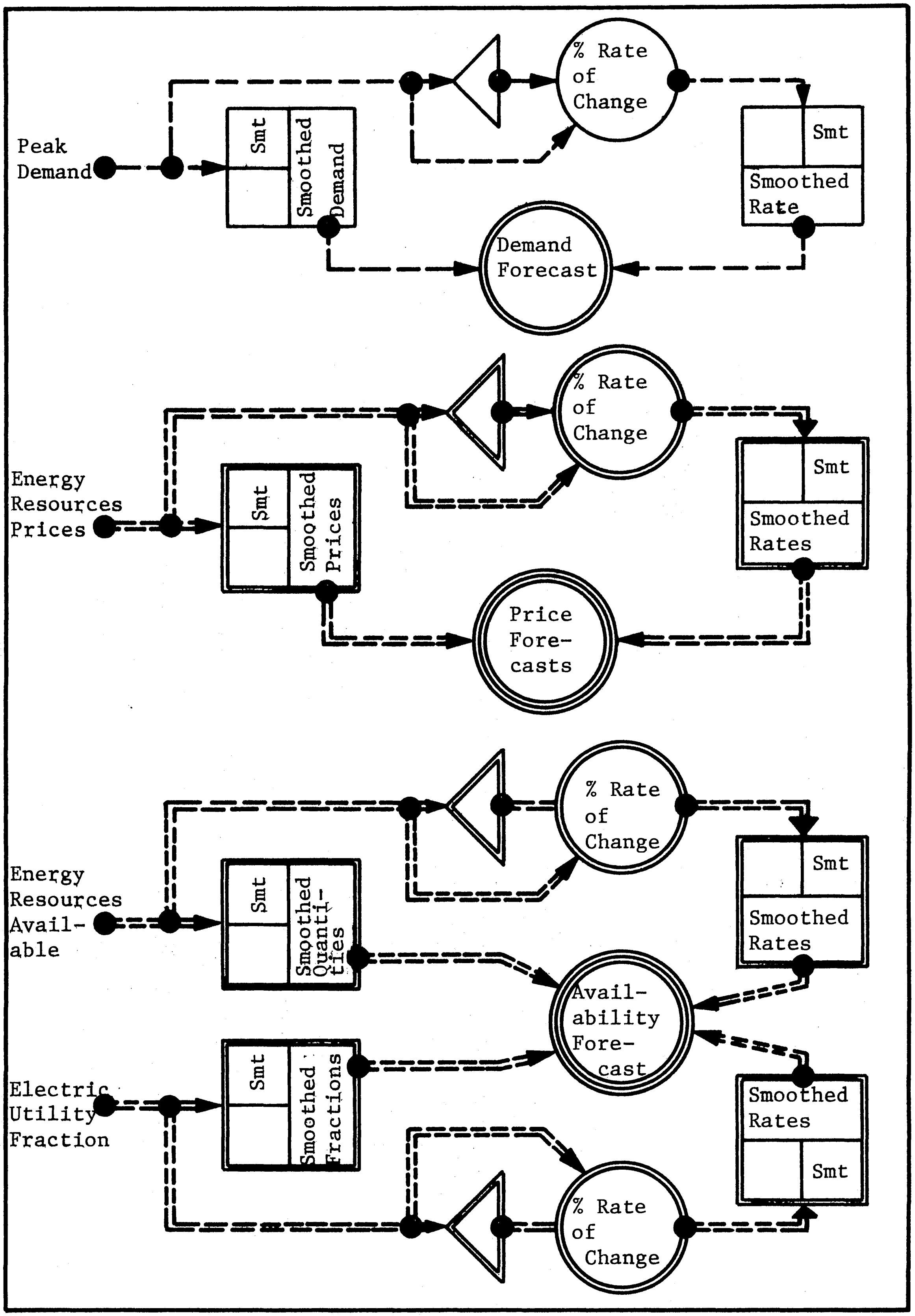


Figure 3. Modified Forrester Diagram of Forecasting

An argument could also be made for forecasting the cost of constructing the various types of power plants. There is no doubt that this is an important decision parameter. However, the initial studies are not aimed at determing response to this parameter. Thus, rather than develop a forecast for this variable it is included as an input parameter which may vary with time. If later studies require a simulation of the forecasting of this variable, it can be easily included.

Capacity Planning

The purpose of building new generation facilities is to be able to efficiently supply anticipated demands. The demand for electrical energy in a region varies considerably from hour to hour as well as from day to day. The non-storable nature of electrical energy makes it necessary to have generation facilities which can adjust to this demand if requirements are to be met at all times. Thus, in planning for new capacity, the time characteristics of the demand can be as important as the total demand. It is not feasible to use the hour by hour demand variations for planning, yet it is important to be able to characterize a whole years demand to study the economics of generation alternatives. The most commonly used technique to achieve this is to reduce the yearly demands to a load duration curve as shown in Figure 4. The load duration curve characterizes the demand by showing for what length of time each level of load exists. Some loss of information is results from describing the demand characteristics with a load duration curve as it does not describe how fast the demand fluctuates or when various demand levels occur.

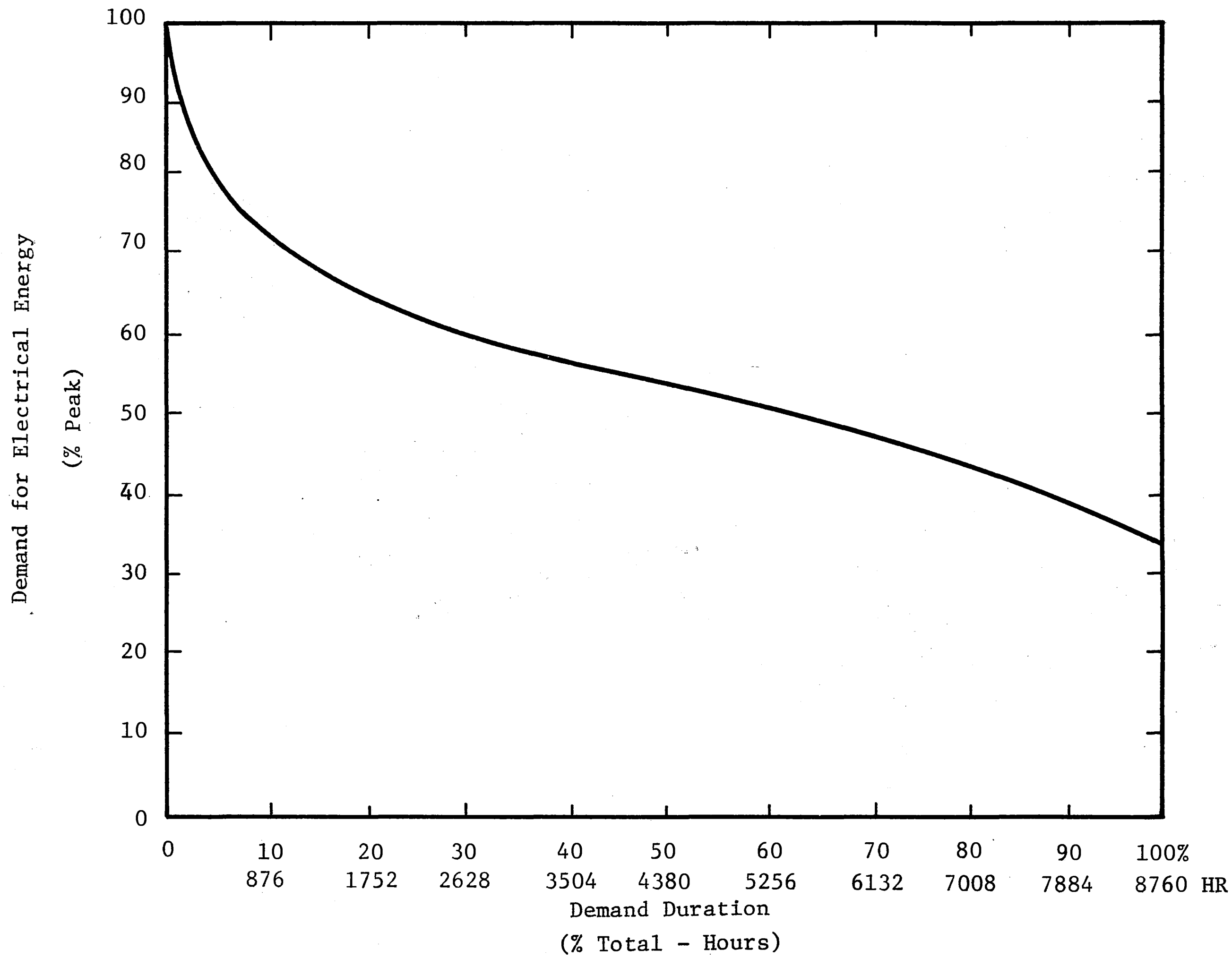


Figure 4. A Typical Load Duration Curve for the Demand for Electrical Energy in a Region

However, it is simple, concise, and widely used for planning purposes.

Once the anticipated demand for future years is thus descirbed, it is necessary to account for the capabilities and costs of various generation facilities which might be used to supply these demands. Due to routine maintenance, breakdowns, fuel availability, and possibly government regulations, the availability of a group of facilities will fluctuate throughout a year. These fluctuations may not coincide with fluctuations in demand. Thus, it is necessary to define the fluctuations of availability on the same time bases as demand in the load duration curve. The technique used to do this is described in Appendix A.

Given the characteristics of demand and availability of generation facilities, the electric utility companies must determine the most economical way to match power plant additions to expected demands. This normally involves a capacity expansion plan which charts the additions planned for approximately twenty years. The basis for developing a capacity expansion plan is to build a combination of power plants which provide an economical and reliable means to meet future demands.

Computer programs which attempt to derive an optimum capacity expansion plan have been developed (40,49). However, the actual development of capacity expansion plans are more the result of management judgment than any formalized mathematical technique. The uncertainty in the forecasts of the critical variables affecting capacity expansion alternatives is usually quite large. Thus, long range optimization techniques are often of less value than they would seem. For these reasons, the development of a capacity expansion plan is not simulated as a true optimizing process. Instead, the simulation aims at capturing the key economic factors which affect the decisions as to what new generation facilities are desired.

The first part of the simulation capacity expansion plan determines what mix of generation facilities are desired. This is done by selecting an arbitrary planning year, in this case the last year of the simulation planning period. Given the forecasts for demand, energy resource prices, and quantities of energy resources available for that year, an attempt is made to determine the least cost mix of generation facilities. In determining the least cost mix, the cost for generation facilities are broken into yearly fixed cost and variable cost. The yearly fixed cost (FC) is primarily the cost for the capital required to build the power plant, although a small amount of the maintenance cost is probably fixed. The variable cost (VC) consists of most of the oepration and maintenance cost as well as the cost of fuel to run the generation facilities. Given the fixed and variable costs for the different types of facilities, the total cost (TC) of operation for each facility for a load of duration (D) can be determined by:

$$TC = VC + FC/D \qquad 3.5$$

If these costs were the only consideration, then the optimum mix could be obtained by filling the loads of each range with the lowest cost option in that range as shown in Figure 5.

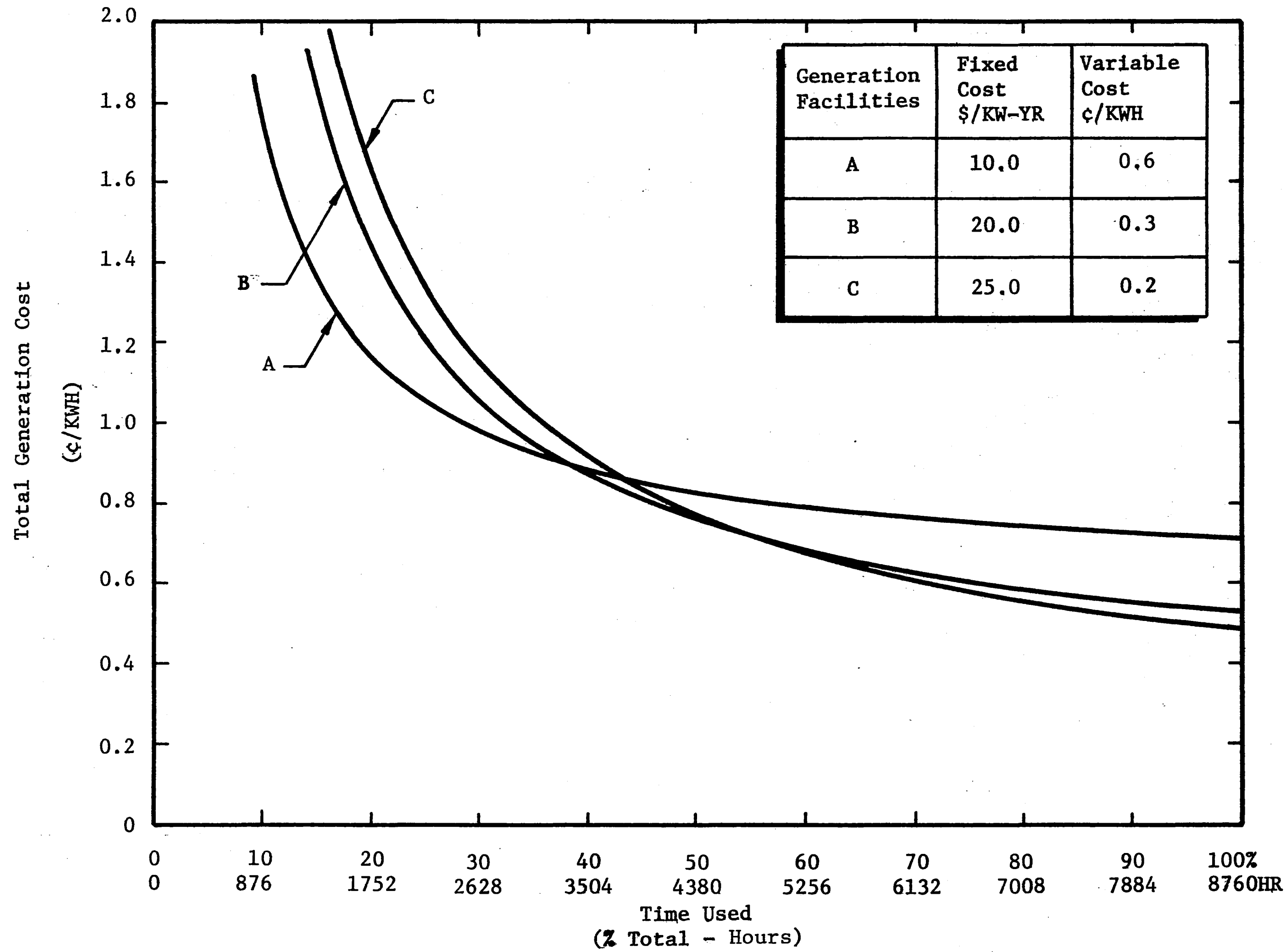


Figure 5. Total Generation Cost vs. Time Used for Several Cost Combinations

Unfortunately, several other factors which makes the calculations more difficult must be included in the decision process.

1. Since the facilities on line or under construction at the beginning of the planning period are already committed, no fixed cost should be included for these facilities in determining the optimum mix.
2. No type of generation facility has a 100% availability at all times. Thus, the variations in availability must be included in the calculations.
3. There may be a limit to the amount of capacity of a given type which can be built. For example, there are a limited number of sites where hydroelectric plants can be built.
4. The alternative of contracting for large supplies of electrical power from other regions may be a realistic alternative in many regions.
5. There may be limited quantities of a given type of energy resources available.

With these complications, it is no longer a simple matter to calculate the optimum mix. Because of the varying generation availabilities, the demands each type of generation is to supply must be measured directly on the load duration curve as shown in Figure 6. The optimum can then be found by minimizing cost (C):

$$C = \sum_{i=1}^{n} FC_i * CP_i + \int_0^{1\ Yr} \int_0^{LD} VCdLdt \qquad 3.6$$

where LD represent the load duration curve, CP an increment of capacity, and n the total number of types of generation facilities.

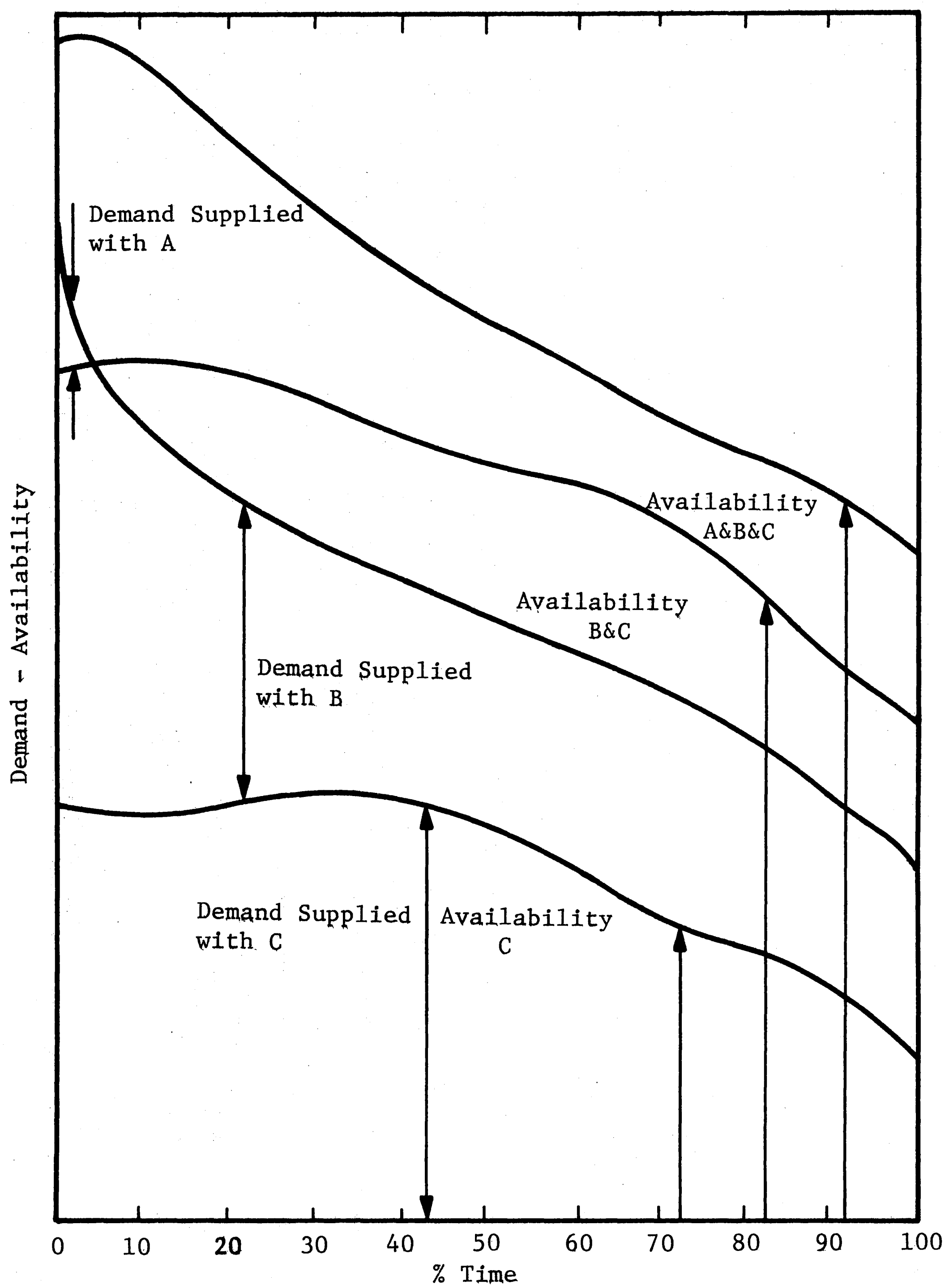


Figure 6. Load Duration Curve and Availability Curves for a Grouping of Hypothetical Capacity

In minimizing this function, the maximum capacity and energy resource availability limits must also be observed. Although it is possible to find an optimum in this manner, it is not feasible in the context of a dynamic simulation. Such an optimization would require a complex, trial and error solution which would result in an unacceptable amount of computation.

In view of this limitation, developing a simulation which could incorporate the previously stated considerations and could determine a near optimum mix was deemed more important than using a fully optimizing technique. The scheme actually used meets these considerations in the following manner:

1. Committed capacity of a given type is considered completely separate from new capacity of the same type. Thus, each can be considered with different cost parameters. The only way in which committed capacity and new capacity of a given type are considered together is in determining whether energy resource limits are observed.
2. The full availability curve as compared to the load duration curve is considered for each type of capacity in calculating costs, evaluating total capability, and in determining energy resource use.
3. No more new capacity of a given type is allowed than a prescribed limit which is an input.
4. Contracts for power from other regions, if they are available, are considered in the same manner as building new generation facilities.

5. The use of a given type of capacity is limited to the quantity of energy resources available.

The desired mix is determined as shown in Figure 7 by adding small increments of the lowest total cost capacity given by:

$$TC = VC + FC \;/ \int_{p} \phi(AxCP)\,dt \qquad 3.7$$

where A is capacity availability, p the cummulative availability, and ϕ is defined in the Nomenclature. When either a maximum capacity or maximum energy limit is met, that type of capacity is removed from consideration. Figure 8 and Table I summarize this algorithm.

Given the mix of generation facilities desired, the second part of the capacity expansion plan calculations determine when what type of generation facilities will be added to achieve the desired mix, if possible. In developing this part of the capacity expansion plan several limiting factors must be observed.

1. Demands at all points in the planning period must be met if possible, even if this requires more capacity of some types than desired.
2. The existing on-line facilities and those under construction at the beginning of the planning period are fixed and must be considered a part of the expansion plan.
3. The time to build each type of generation facility must be observed when planning additions.
4. Construction on new facilities cannot proceed faster than capital is made available for this activity.

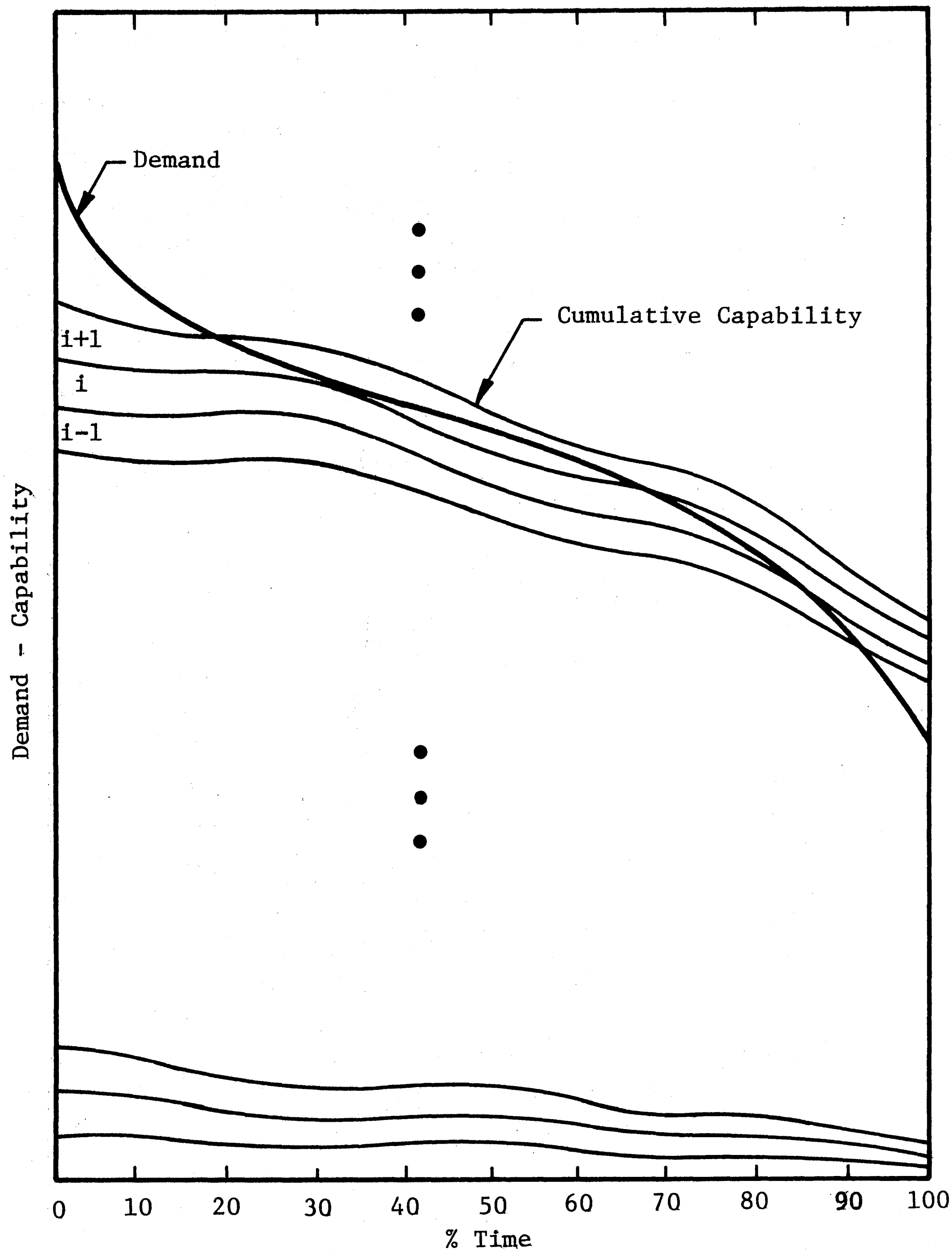


Figure 7. Building Up Generation Capability by Increments

Initialization:

Energy resource of each type required $ER_i=0$

Capacity of each type desired $CP_i=0$

Total generation capability $CC(D)=0$

Calculate variable cost for each type capacity by:

$$VC_i=FRP_i \mathrm{x} HR_i+NC_i$$

for capacity built in region and

$$VC_i=NC_i$$

for contracted capacity.

Calculate total cost (TC_i) for each type of capacity using equation 3.7 along path CC(D). Then:

j = type of capacity with minimum TC, and

k = type of energy resource used by type j capacity.

Add increment of type j capacity and account for this added capacity:

$$CP_j=CP_j+\Delta CP$$

$$ER_k=ER_k+HR_j \mathrm{x} \int_L A_j(D)\Delta CP dt$$

$$CC(D)=CC(D)+A_j(D) \mathrm{x} \Delta CP$$

Are limits exceeded?

$CP_j \geq M_j$ - type j capacity no longer considered.

$ER_k \geq FE_k$ - capacity using type k resource no longer considered.

$CC(D) \geq L(D)$ for all D - terminate capacity mix calculations.

Figure 8. Summary of Capacity Mix Algorithm

TABLE I

INFORMATION SUPPLIED TO DESIRED CAPACITY MIX ALGORITHM

Information	Symbol Used in Figure 8
Load Duration Curve for Planning Year	L(D)
Generation Availability Curves for Each Type of Capacity	$A_i(D)$
Heat Rate for Each Type of Capacity	HR_i
Non-Fuel Variable Cost of Operation for Each Type of Capacity (Total Variable Cost for Contracted Capacity)	NC_i
Yearly Fixed Cost for Each Type of Capacity	FC_i
Forecast Price of Each Energy Resource	FRP_i
Amount of Each Energy Resource Forecast as Being Available	FE_i
Maximum Amount of Each Type of Capacity Possible (Current On-Line Capacity for Existing; Limit Input to Simulation for New Additions)	M_i

5. Any limit on the maximum capacity of a given type allowed must be observed.

Another very important limitation is introduced by assuming generation facilities are unable to be converted to use a different energy resource. Although conversions can be made, it appears to be the experience of the industry that they are unlikely to be economical in the near future. Conversions from coal to oil or gas are simple and inexpensive. However, the reverse is not true. Unfortunately, this is the direction of conversion that is likely to be needed. If particular studies involve conversions from oil and gas to coal, it is necessary to remove this assumption.

In view of these limitations, the capacity expansion plan is developed one year at a time, starting at the beginning of the planning period. For each year the capacity which is under construction and will come on line in that year is added to the capacity from the previous year first. If more capacity is needed to meet anticipated demands, the type which is the furthest below the desired mix is added first. Capacity of this type is added until it is no further below the desired mix than the next lowest capacity. Then both are added until they are no further below the desired mix levels than the next lowest, and so on until all anticipated demands met. In doing this, only those types of facilities which can be built in time to come on line in that year are considered. Figure 9 and Table II summarize this algorithm.

Given the capacity expansion plan which is developed, the simulation is able to directly determine the rates at which new construction is started on the different types of generation facilities. The rate at which construction starts is simply the rate at which new capacity

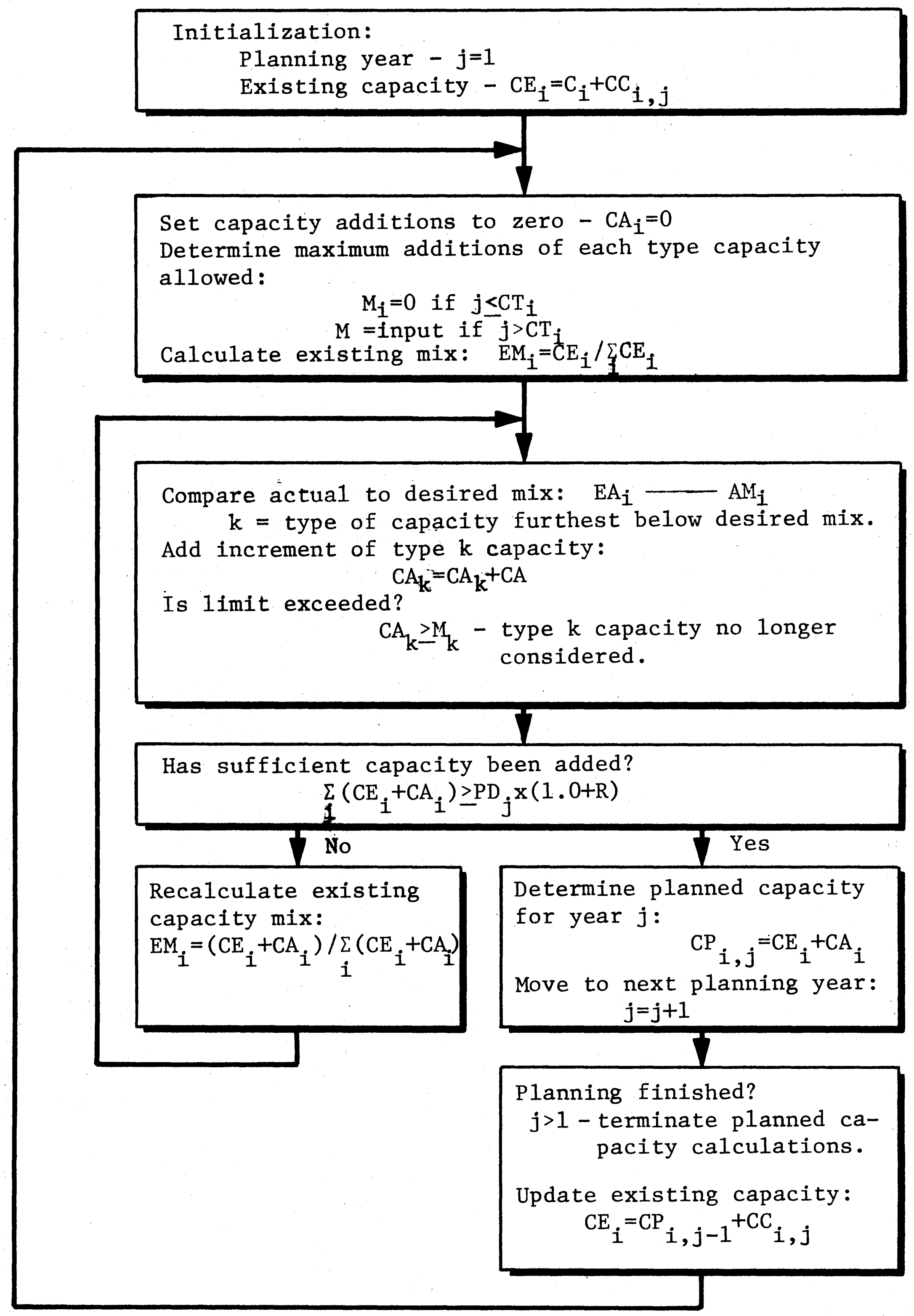


Figure 9. Summary of Planned Capacity Algorithm

TABLE II

INFORMATION SUPPLIED TO PLANNED CAPACITY ALGORITHM

Information	Symbol Used in Figure 9
Peak Demand Forecast for Each Year in Planning Period	PD_i
Reserve Capacity Desired	R
Construction Time for Building Capacity (Contract Lead Time forContracted Capacity)	CT_i
Capacity Currently On-Line	C_i
Capacity Under Construction Due to Come On-Line for Each Year in Planning Period (Future Capacity Contracts for Contracted Capacity)	$CC_{i,1}$
Length of Planning Period	1

is added in the capacity expansion plan the first year in which the construction time allows new capacity to be added. These rates then determine the amounts of capacity that are eventually brought on-line. Figure 10 shows a Forrester diagram of the capacity planning process and the resulting capacity levels. The construction time for building new generation facilities is represented by a boxcar delay. The on-line facilities are represented by a third order delay which feeds into a capacity level referred to as semi-retired. The semi-retired level and the on-line third order delay serve to gradually derate the capacity as it ages while allowing all facilities to be accounted for. Contracts for power from other regions are treated much the same as building new facilities. Since major inter-regional contracts would require the construction of large transmission lines and possibly new generation facilities in the selling region, there is a time delay required before new contracts can be used. However, the "on-line" contracts are represented by a boxcar delay as it is assumed they will be made for a fixed length of time and will specify certain power levels.

Energy Resource Planning

Once a plan for future capacity is determined, the electric utility companies must plan for the energy resources they will need to fuel these planned generation facilities. There are several options available to the electric utility companies depending upon their location and the fuels they intend to use:

1. The utility companies can purchase their own sources. For example, a gas field or a coal mine could be purchased.

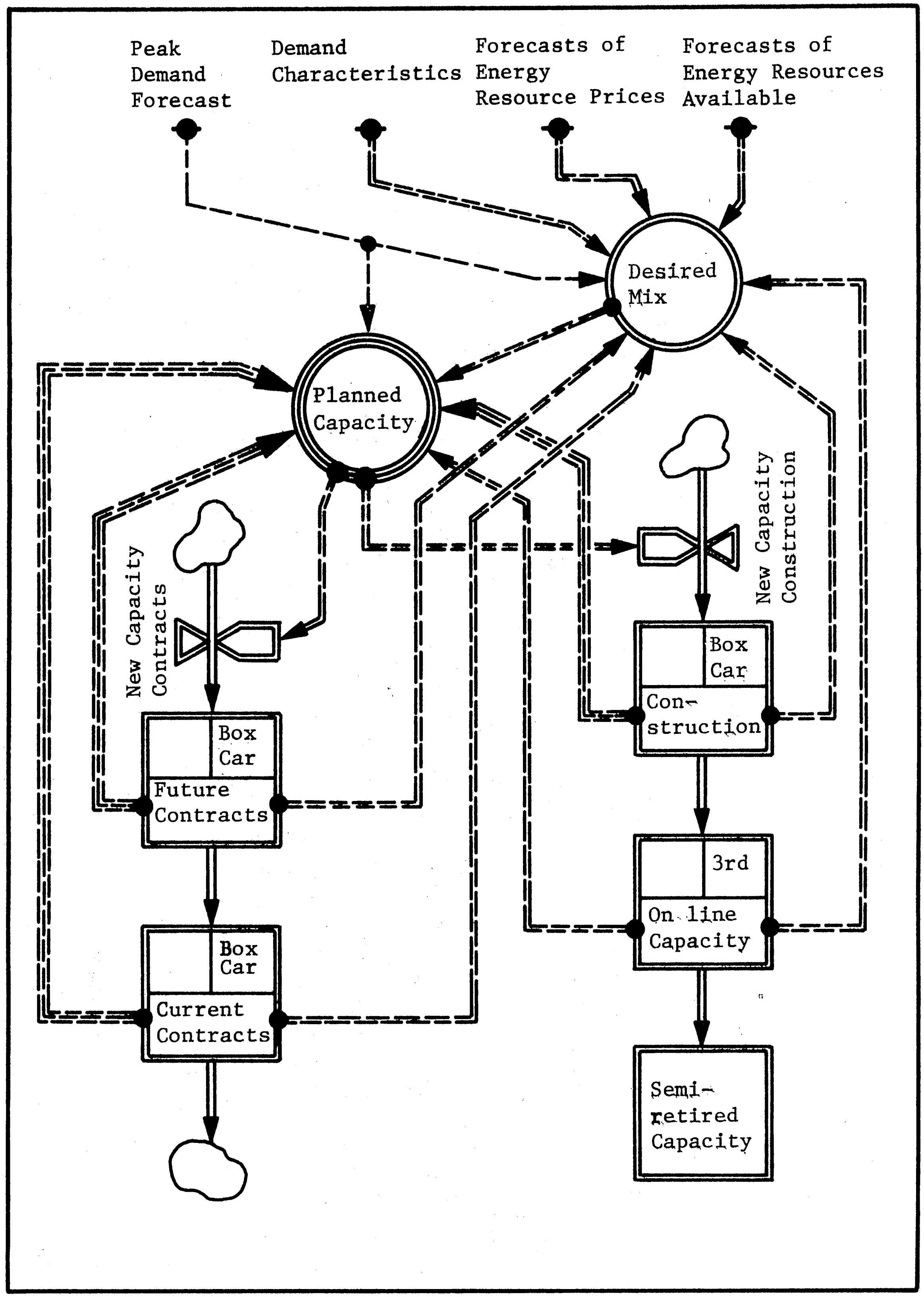


Figure 10. Modified Forrester Diagram of Capacity Planning

2. Long-term contracts can be made with other suppliers to assure availability of needed energy resources.
3. The utility companies can rely upon short-term spot market purchases.

Most utility companies prefer to arrange for long-term supplies for their major sources of fuel and will either attempt to purchase their own supplies or make long-term contracts for these fuels when possible. They normally will rely upon spot market purchases for energy resources which are used in small quantities. They may also be unable to arrange for long-term contracts for some energy resources and must sometimes rely on spot market purchases for major fuel supplies also.

When a utility company purchases an energy resource supply, it will normally be developed and in production. With such facilities the deliverability possible will decline with time. This is especially true of gas and oil fields and is also true of some coal mines. Similarly, many long-term contracts will also reflect this declining deliverability. To maintain or increase the rate at which they can use energy resources from these sources, the utility companies must continually purchase new supplies or add new contracts as shown in Figure 11. In addition, there exists some control over the rate of which the deliverability declines in these cases. The faster a resource is used, the more rapidly the deliverability declines. Thus, a resource supply can be made to last longer by not consuming it at the maximum rate possible.

For simulation purposes, there is little difference between energy resource supply purchases and long-term contracts which reflect declining deliverabilities. Assuming the maximum deliverability of a supply (DL) to be proportional to the total quantity of the supply (Q), the deliverability at any point in time can always be determined by:

$$DL = CNxQ$$

where CN is the proportionality constant. The validity of this expression can be tested by assuming the energy resource is used continuously at the maximum rate possible. This yields:

$$\frac{d\,(DL)}{dt} = CN\,\frac{dQ}{dt} \qquad 3.9$$

$$\frac{dQ}{dt} = -DL \qquad 3.10$$

$$\frac{d\,DL}{dt} = -CNxDL \qquad 3.11$$

Equation 3.11 is recognizable as an exponential relationship.

$$DL(t) = DL_o e^{-CNxt} \qquad 3.12a$$

or

$$DL(t) = CNQ_o e^{-CNxt} \qquad 3.12b$$

Thus, using Equation 3.8 gives an exponentially declining deliverability which is typical of the deliverability in Figure 12.

A single level for each fuel obtained which has a declining deliverability is used to simulate the quantity of energy resources either purchased or contracted for as shown in Figure 13. The maximum rate at which they can be utilized is then proportional to this level.

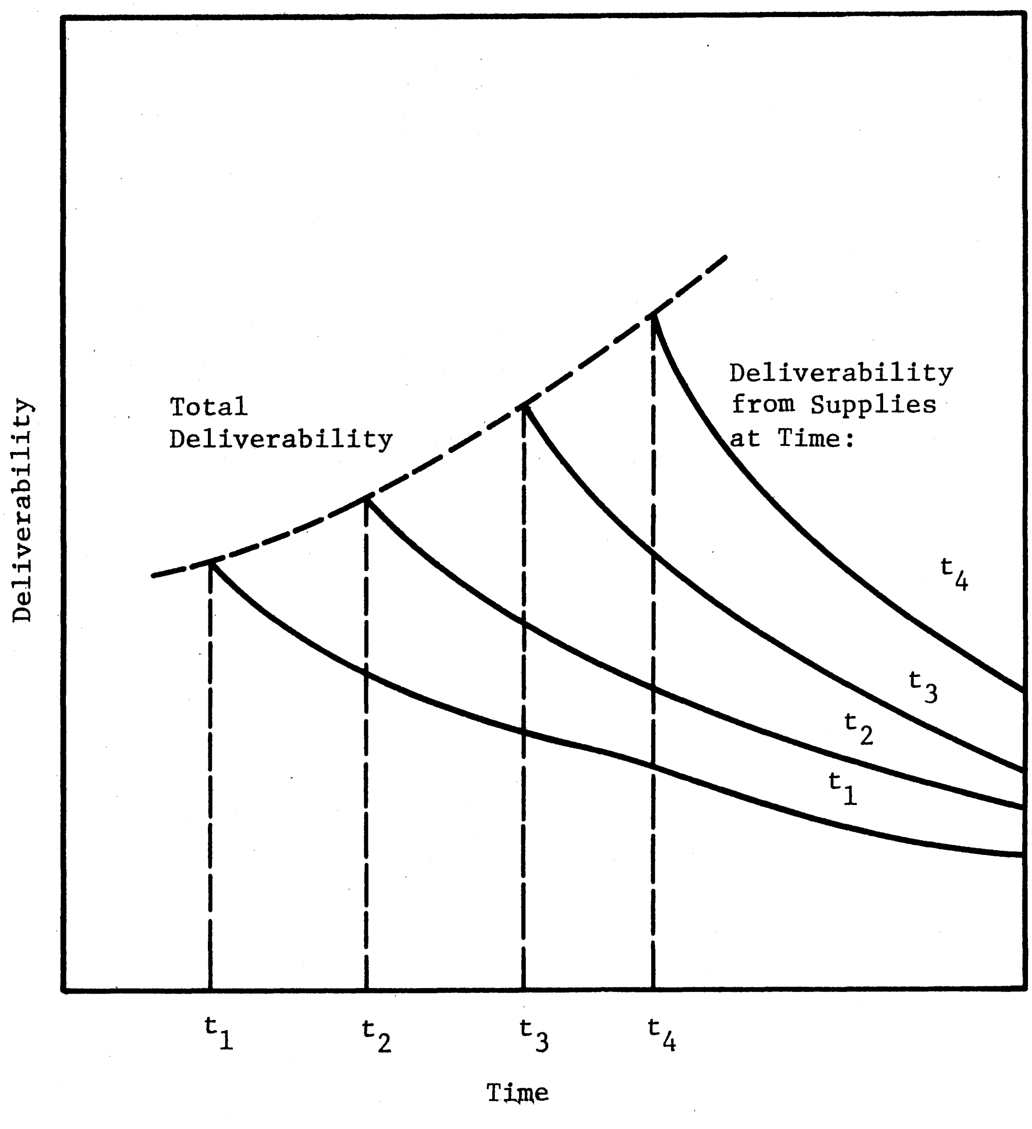


Figure 11. Adding Energy Resource Supplies to Build Up Deliverability from Declining Sources

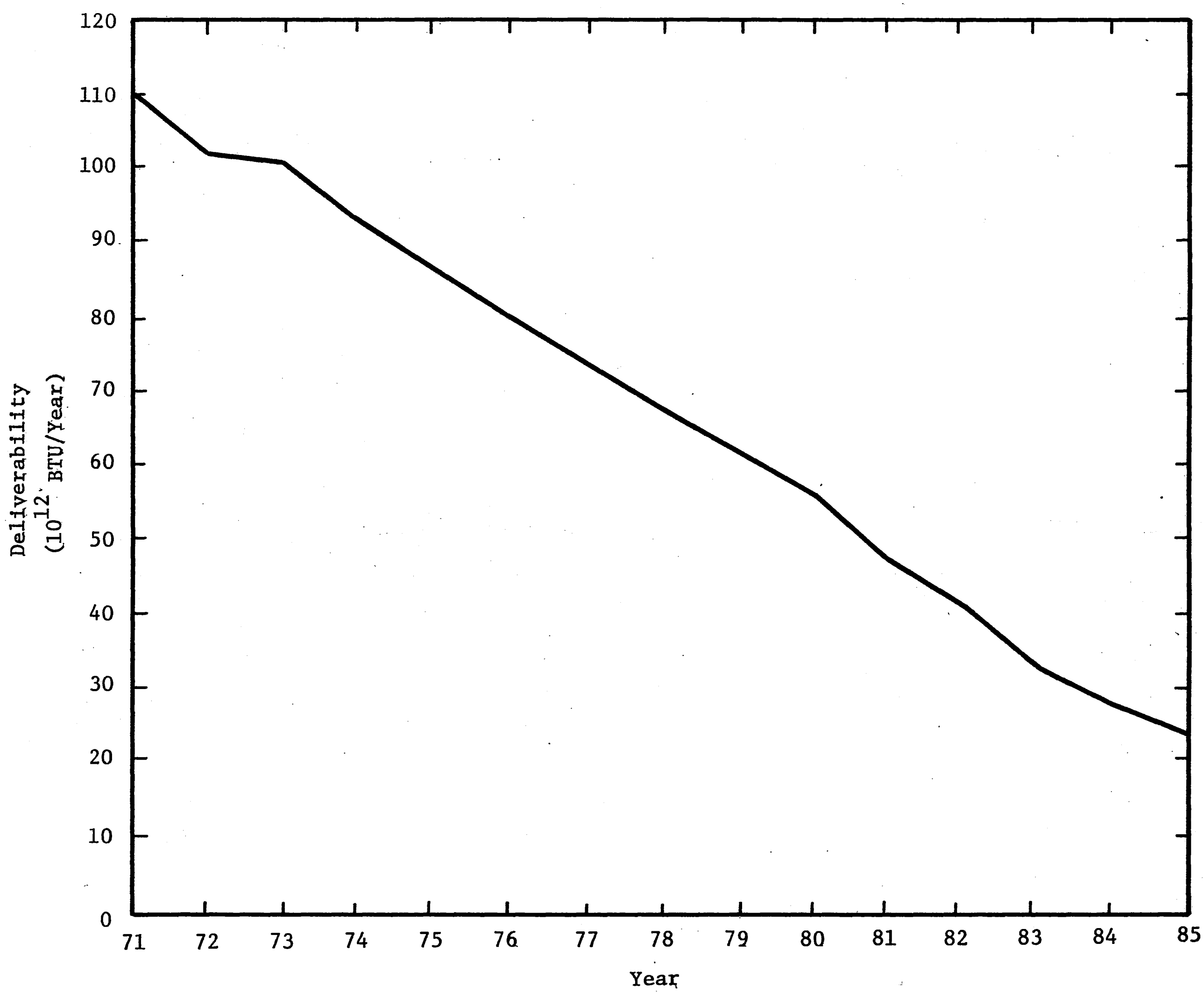


Figure 12. Anticipated Decline in the Deliverability of an Electric Utility's Natural Gas Supply with No New Supplies Added

Since the deliverability is dependent upon the resource supply, if the maximum rate is not used, the deliverability is that much higher for later times. An argument could also be made for minimum usage rates as some contracts also contain conditions to this effect. No provision has been made in the base simulation for this possibility. If this proves to be a limiting factor in a given study, then a minimum rate of delivery should also be included.

There is also the possibility for some energy resources to be obtained where the delivery rates are essentially constant. This case is more typical of an energy resource, such as nuclear fuel, where the deliverability in the near future will be more dependent upon fuel processing facilities than the rate at which the energy resource can be extracted from the earth. These sources are simulated differently than sources with declining deliverability. Rather than simulate the total quantity of the supply, the maximum deliverability is used as a simulation variable. Since this remains constant throughout the life of the contract, a boxcar delay serves to simulate this quantity as shown in Figure 13. Also, this type of contract most often applies to energy resource supplies that are not into full production. Thus, there will be a significant waiting time required before they can be utilized once they have been secured. This requirement is also met in the simulation with a boxcar delay.

Simulation of spot market supplies is relatively straightforward. From the electric utility company point of view, a given quantity is available at a given price. These are both inputs to the simulation.

One additional consideration in simulating energy resource supplies is the price paid for long-term contracts and owned sources.

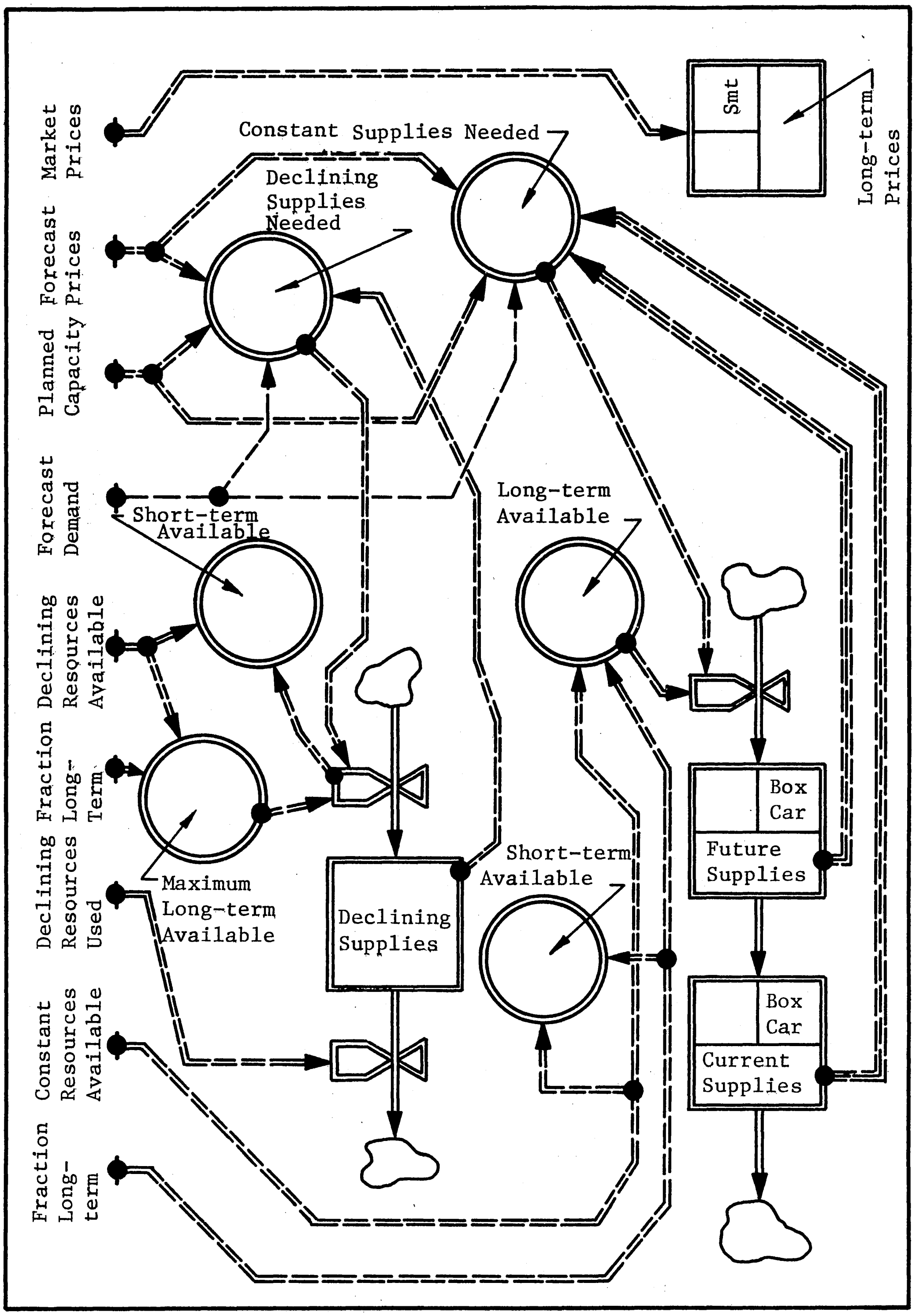


Figure 13. Modified Forrester Diagram of Energy Resource Planning and Energy Resource Supplies

In the past, long-term contracts were often made with a fixed price for the life of the contract. This practice is rapidly disappearing due to the recent increases in market prices and uncertainty about future prices. Most suppliers are reluctant to commit themselves to a fixed price in this kind of an environment. A provision for periodic price updating is now a very common part of long-term contracts. This approach is simulated in the model by using a first order exponential delay to represent the time required for the contract price to respond to changes in the market price as shown in Figure 13.

It is difficult to characterize the cost of using energy resources owned by the electric utility companies. Particular accounting methods of individual companies can have a large effect on this. In addition, there is, at least in theory, the alternative of selling these energy resources at the current market price. For the sake of simplicity, in the simulation, the prices of energy resources owned by the utility companies are assumed to be the same as for those obtained through long-term contracts.

Now that the nature of energy resource supplies has been discussed, attention must be turned to how the electric utility companies determine supplies they actually obtain. As stated earlier, utility companies normally prefer to use long-term arrangements for most of their supplies when possible. On the other hand, it is not usually the policy of the electric utility companies to arrange for any greater quantities of supplies than are needed, nor to secure these supplies for long time periods before they are needed.

The energy resources desired for a given year in the planning period are determined by calculating the energy resources that would be used in supplying the anticipated demand with the planned capacity. This is done in the simulation as shown in Figure 14. The generation facilities with the lowest variable costs are used to supply the longest loads; the higher variable cost capacity is used to supply the shorter loads. The area under the load duration curve filled by a given type of facility can then be used to determine the energy resources it would use during that year. In this manner the energy resources desired of each type for each year in the planning period can be determined.

It is assumed that in a given region that the nature of all of the long-term supplies of an energy resource will be the same. That is, the declining deliverability or constant deliverability simulation will be typical of all of the supplies of a given energy resource. This information is considered an input to the model. If the energy resource is one with a declining deliverability, there is no long delay involved in utilizing new sources. New sources can be sought which will raise the deliverability to meet the requirements of the first year in the planning period. If the energy resource is one with a constant deliverability, there will normally be a delay in utilizing a new source. This delay must be accounted for in securing new supplies. Thus, new sources must be sought which raise the deliverability to the desired level for the first year in which these sources can be utilized.

Energy resource supplies sought will not always be obtained. It is necessary to include in the simulation a maximum limit on what is obtainable. The same limits to total resoruce availability which were inputs to the forecasting section applies here as well.

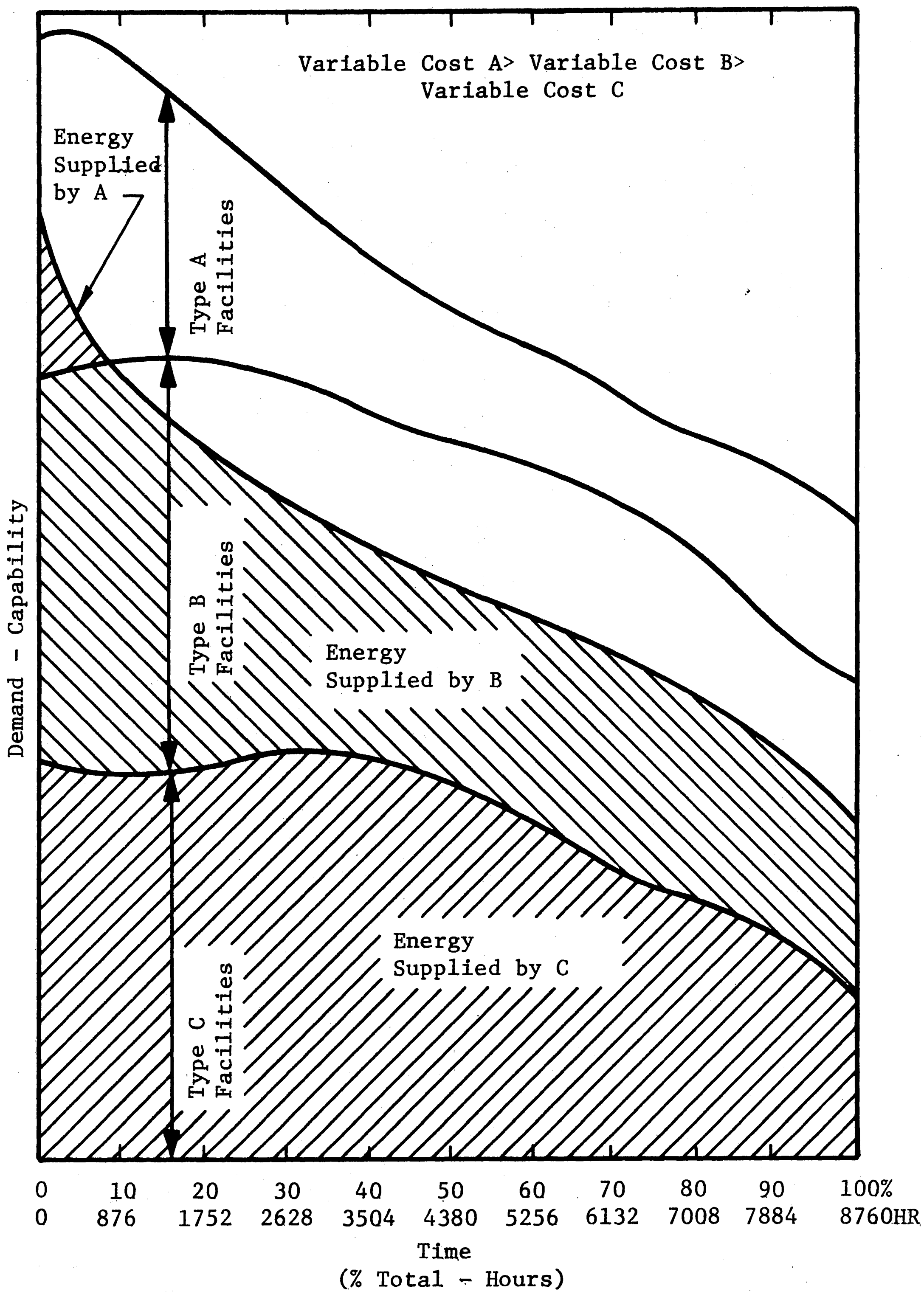


Figure 14. Use of Generation Facilities to Fill Demand in Energy Resource Planning

An additional parameter (FL) is needed to describe what fraction of these are available as long-term supplies. The use of this second fraction is slightly different for long-term sources with declining deliverability than for sources with constant deliverability.

First, consider the limits for sources with declining deliverability. With these sources it is assumed that the supplies are developed and ready for use. Sources which are not tied up with long-range contracts are normally available on the spot market. The spot market deliverability can then be determined by:

$$Q_{1t} = FL x Q_a \tag{3.13}$$

where subscript lt indicates long-term, a indicates total available, and

$$Q_n = Q_{1t} - Q_e \tag{3.14}$$

where subscript n indicates new long-term, e existing long-term, and

$$DL_s = CN x (Q_a - Q_e - Q_{na}) \tag{3.15}$$

where subscript s indicates the spot market and na new supplies secured.

The sources with constant deliverability primarily refer to supplies where depletion is not causing a declining deliverability. In this case the spot market supply is not as closely related to the long-term supply as before. The spot market supply results from facilities which are in operation. The long-term supply results from facilities which can be put into operation if a buyer is available. For a simple simulation these supplies are assumed independent. Thus, two separate quantities are used as inputs - the spot market supply and the long-term supply. The fraction parameter is used to separate these.

In any situation - spot market, long-term sources with declining deliverability, and long-term sources with constant declining deliverability - these maximums set upper limits on the supply. If the electric utility companies are unable to obtain more than this, they must either use alternative fuels or go without.

Intermediate Planning

Up to this point only the part of electric utility operation which deals with planning one or more years in the future has been discussed. Later, the hour to hour operation of the electric utility companies will be discussed. However, there are some operations which do not fit nicely into either of these categories. Such operations deal with planning for a time horizon of a few weeks to a year. They must still be carried out when there is some uncertainty as to total demand. The two important operations of this nature are:

1. allocation of the use of power plants to meet demands; and
2. contracting with neighboring regions for firm power purchases and sales.

Economic dispatch of electric power is based on using the lowest variable cost capacity first. Demand will normally be filled in the same manner as was discussed in energy resource planning and shown in Figure 15a. However, at each point where variable costs change (the boundaries between different types of generation facilities) there is now the alternative of purchasing firm power from other regions. Such a purchase requires the selling companies to guarantee a power supply. A fixed cost is required to cover this expense. To account for this cost, the firm power must be utilized enough to allow the cost to be spread sufficiently so that:

$$VC_g > VC_f + FC_f/U \tag{3.16}$$

where U is the time used, f indicates firm power cost, and g indicates generation costs. Based on this criterion, increments of firm power are purchased until it is no longer economical. This gives a generation capability as shown in Figure 15a.

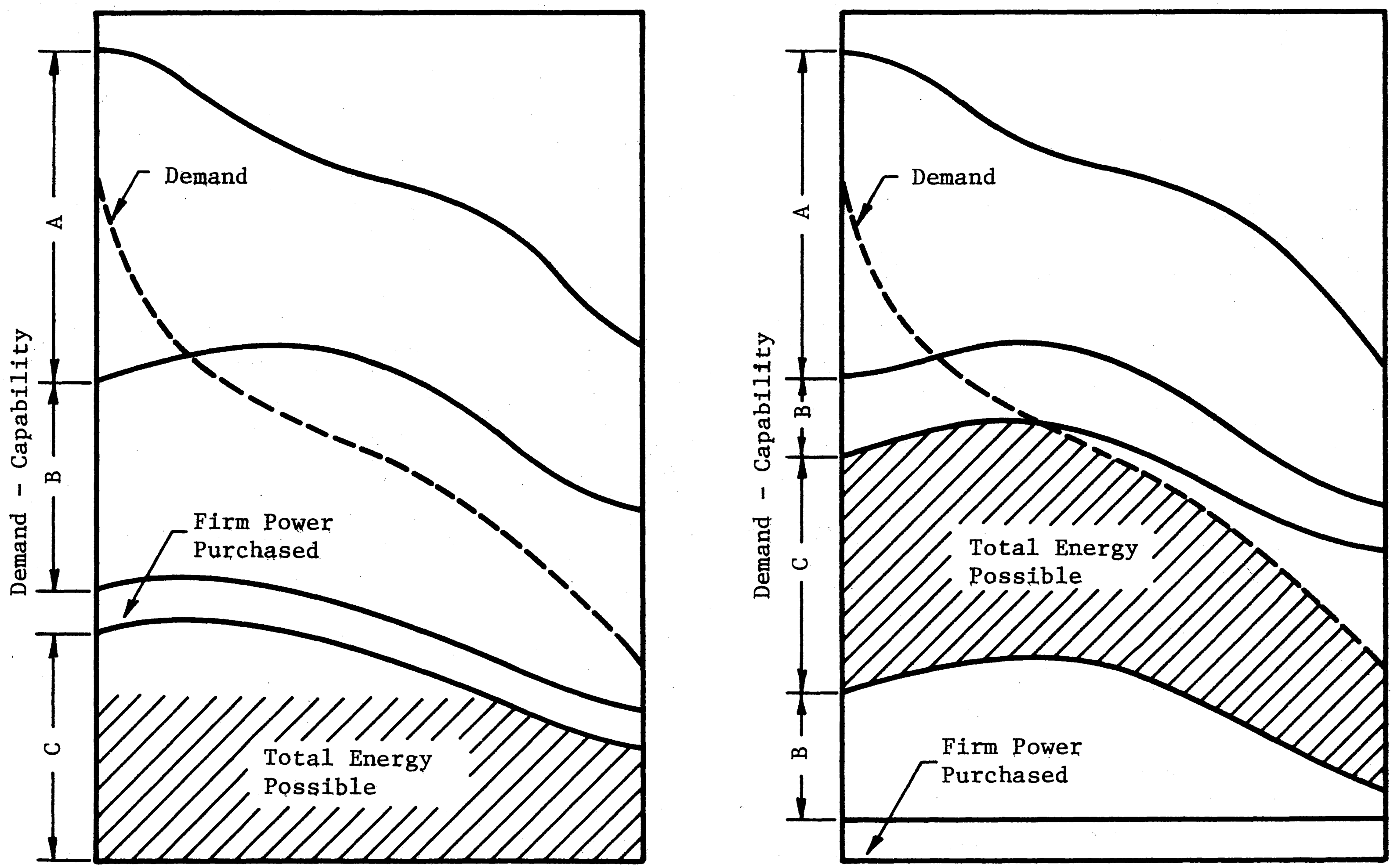
If all energy resources needed for fueling the power plants are available, the above considerations are sufficient. However, it is possible that one or more energy resources may be in short supply. If the energy resource in short supply is a low cost fuel, economic considerations are partially overlooked. In order to meet all possible demands it may be necessary to use a more costly energy resource for the longer duration load and save the cheaper energy resource for peaking loads. To determine the optimum filling of the demand under these conditions the same complex mathematical requirements as discussed in capacity planning are necessary. Thus, it is again not feasible to use a true optimizing approach in the simulation.

The scheme used in the base simulation assumes that only one energy resource is in short supply. This assumption greatly simplifies the calculations. However, simulation results should be scrutinized for violation of this assumption. If a cheap energy resource is in short supply, the objective is to utilize both all of the capacity available and all of the energy resources available. To achieve this goal, the load supplied by this energy resource should be moved up the demand curve until the point is reached where the energy required utilizing full capacity is equal to the energy available as shown in Figure 15b.

To achieve this objective, a ranking system is used in the base simulation. Initially the generation facilities are ranked according to variable cost. Firm purchases desired are determined as discussed previously. If all energy resource supplies are sufficient, no further calculations are necessary. If an energy resource is in short supply, the corresponding capacity is raised one step in rank. The firm purchases and energy requirements are recalculated. This re-ranking is repeated until the energy resource supply is sufficient.

It should be noted at this point that an important assumption is implicit in this part of the simulation. No consideration is given to fluctuations in the deliverability of energy resources throughout the year. Thus, it is assumed that these deliverabilities can be matched to the rates at which the fuels are used, or storage facilities exist which can be used to store the fuels for later use if necessary when excess deliverability exist. Thus, both spot market and long-term sources of energy resources are assumed to be available as demanded when the hour to hour calculations are made later in the simulation.

One additional consideration must be made before proceeding further. The calculations made here are economic in nature and have therefore been based on the expected demand. Short-term planning must also consider the maximum probable demand. The maximum probable demand is not viewed from the standpoint of economics, but from the ability to meet the demand. Utility companies normally maintain set fraction of reserve capacity for this contingency. If



(a) Without Shift
(b) With Shift

Figure 15. Shifting Capacity to Account for Limiting Energy Resource Supply

insufficient reserve capacity exists, additional firm power must be purchased if it is available. This is simulated by assuming that minimum reserves will exist at the peak demand and only checking this one point. Firm power is purchased if it is available to eliminate any deficiencies.

Once provisions have been made to meet all anticipated demands the electric utilities can consider selling any excess capability as firm power. The capability above the expected load duration curve is available for this purpose as shown in Figure 16. Again, as shown in the figure, reserve capacity must also be maintained. Thus, the maximum firm power which can be sold is the minimum excess capability. Within this limit then, capacity is sold if it appears to be economically justifiable. That is, if the anticipated revenue from the sale is greater than the cost of generation. This depends upon the expected demand from firm power sales. To determine the economic feasibility of selling firm power, the anticipated demand for an increment of firm power is compared to the generation capability used to supply it as in Figure 17. The profit (P) on the sale of an increment of firm power (i) can then be calculated by:

$$P_i = FP_i + \int_{FD_{i-1}}^{FD_i} \int_0^{1\ Yr} (VP_f - VC_g)\ dtdL \qquad 3.17$$

Hour to Hour Operations

The long-term and intermediate planning determines what facilities are built, what energy resource supplies are secured, how energy resource supplies which will be insufficient are allocated, and

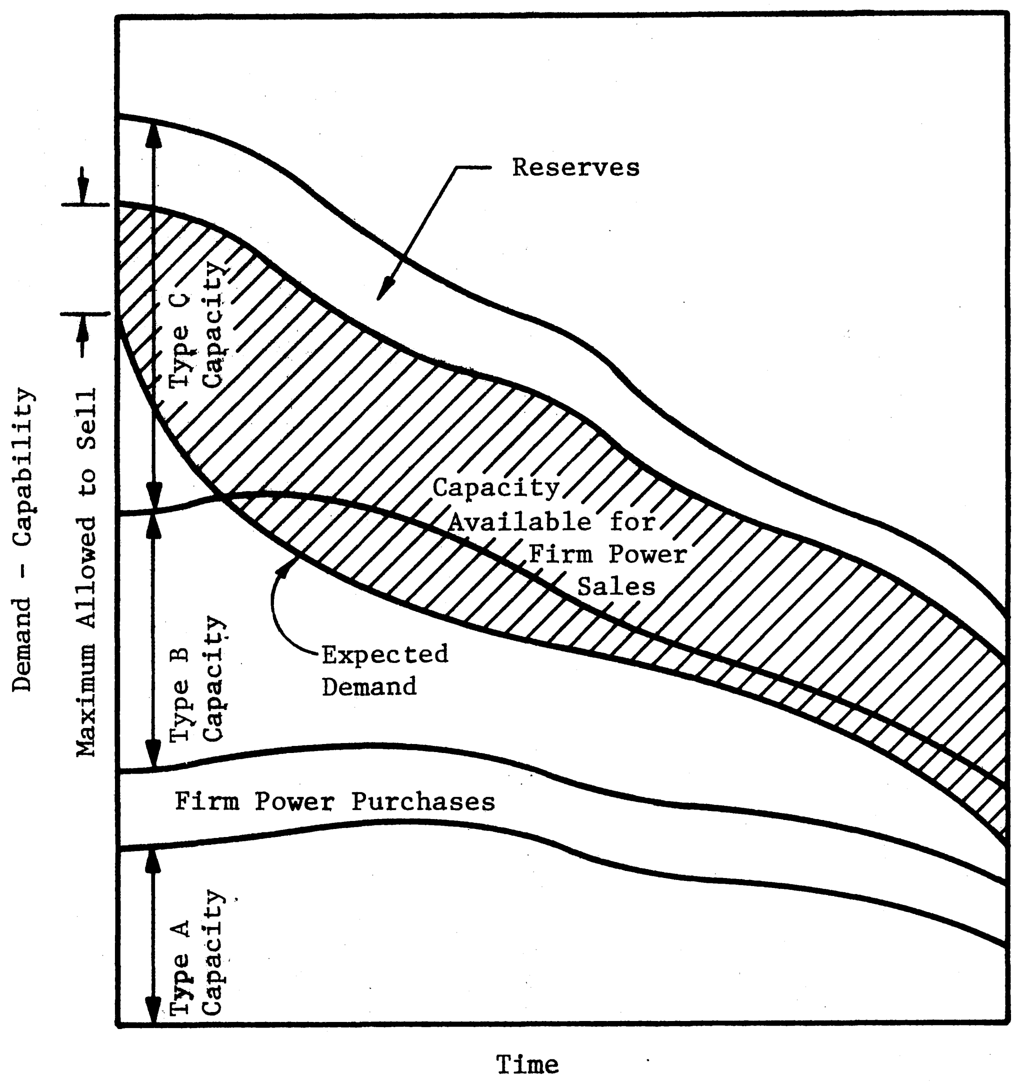


Figure 16. Excess Capability Available for Firm Power Sales

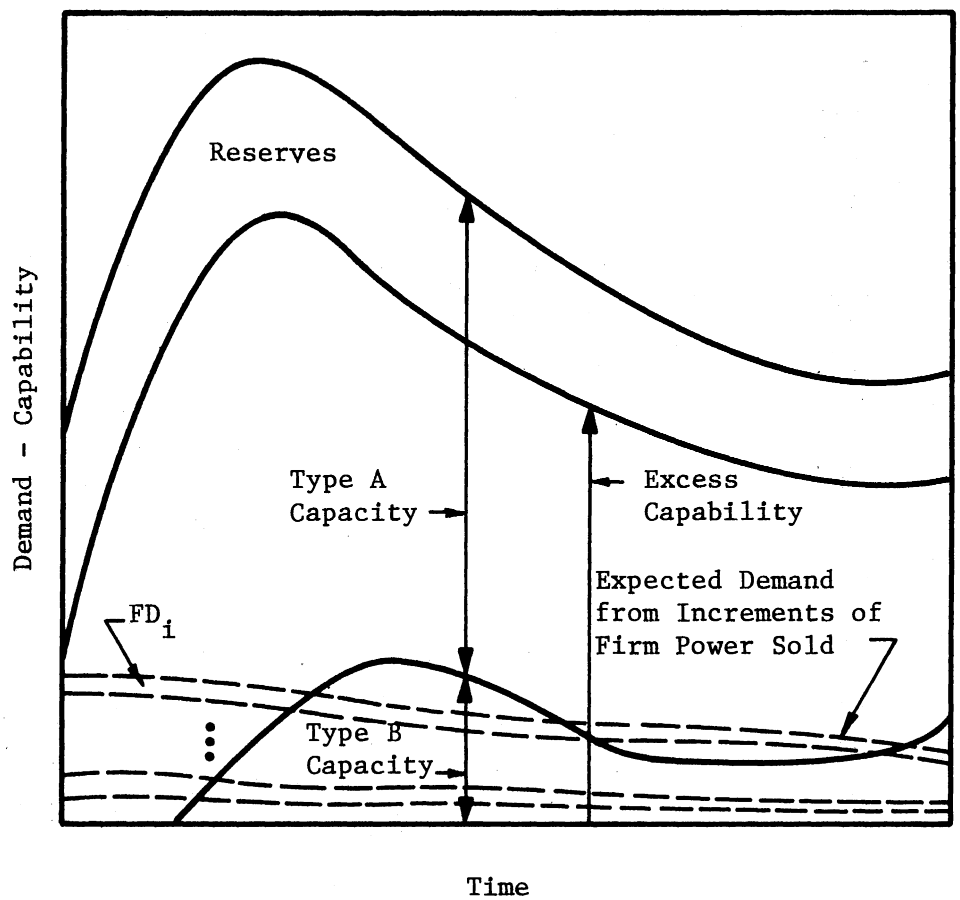


Figure 17. Comparing Expected Demand from Firm Power Sales to Excess Capability for Economic Evaluation

what firm power is bought and sold. However, it is the hour to hour operation of the electric utilities which actually determines what generation facilities are used, what energy resources are used, what demands are met, and how electrical energy flows to and from other regions. These hour to hour activities require a number of decisions which must be continuously updated. Figure 18 shows the hierarchy of these decisions.

The operation of the system each hour cannot be simulated. Instead, the load duration curve must be used to represent the yearly demand. All other fluctuating variables are also reduced to the same time basis. These variables include the previously discussed generation availability curves and the demand from firm power sales. In addition, it is necessary to describe the demand for emergency energy from other regions, and the supply and demand for economy energy. The supply and demand for economy energy must be further descirbed by the values at different prices. Thus, they must be represented as multiple curves as in Figure 19. Given these demands, supplies, and generation capabilities, each point on the load duration curve time axis is simulated as independent and the decision process of Figure 18 is applied[1].

Initially, the demand at a particular point in time is compared to the capability of the electrical utilities to supply demands at the same point in time. The demand includes both the regional demand and the demand from firm power sales. The capability includes all generation facilities at that point in time, plus any firm power

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[1]A point is meant to refer to a segment of the curve.

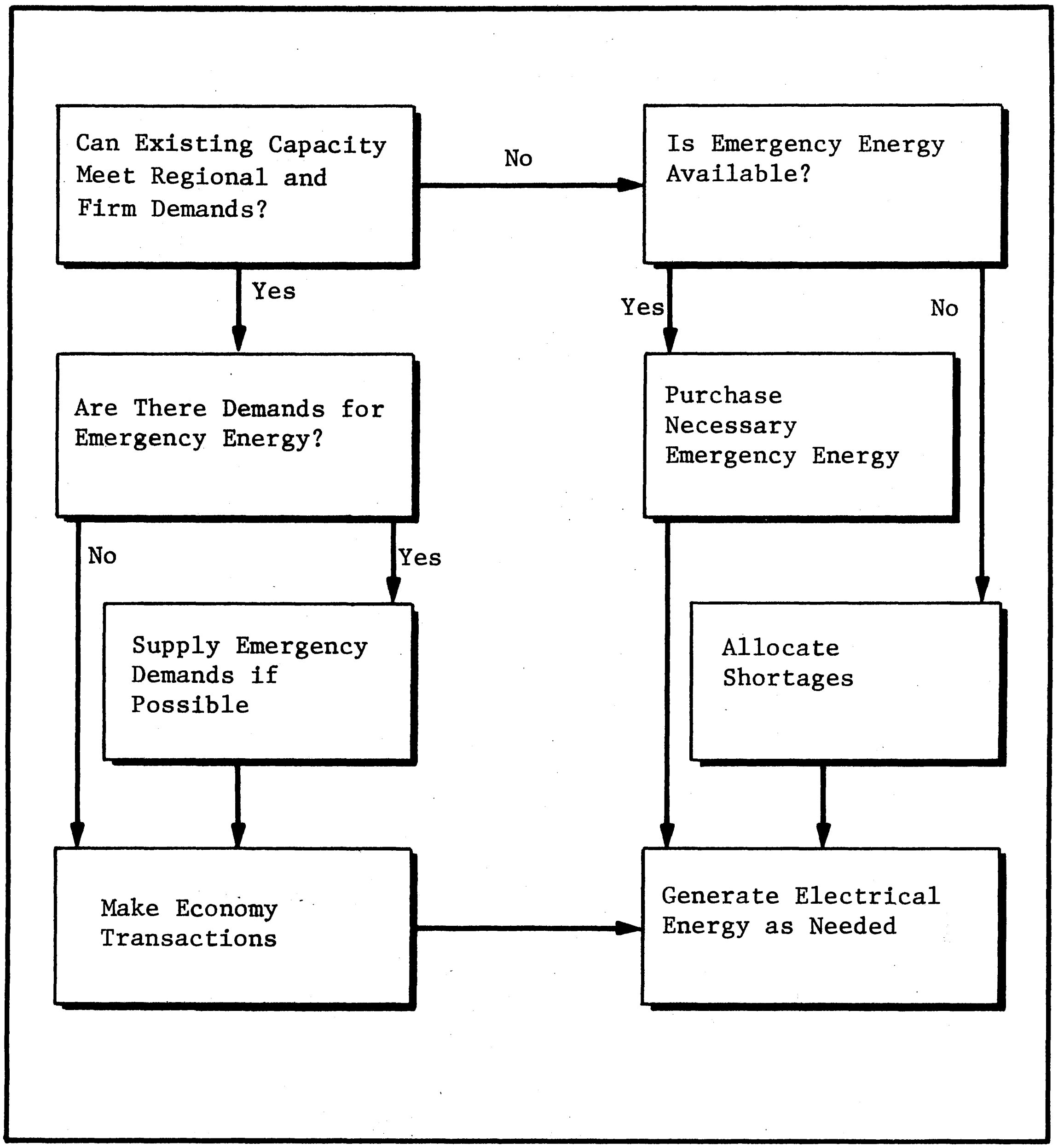

Figure 18. Hierarchy of Decisions for Hour to Hour Operation

which was purchased. As shown in Figure 18 there are two distinct paths the decision options take at this point, depending upon whether or not sufficient capability exists.

First, consider the path where insufficient capability exist. In this case the only alternative available, if the electric utilities are to meet all demands, is to purchase emergency energy. Otherwise, some demands will not be met. In the simulation it is assumed that all demands will be met if possible. Thus, there are no economic considerations involved. Emergency energy is purchased if it is available. The supply of emergency energy is assumed to be described by the uppermost curve of the economy supply. If there is insufficient supply, then shortages are divided proportionally between the regional demand and the firm demand. The nature of emergency demands effectively precludes any economy transactions. Thus, no additional calculations are needed.

The second possibility, when sufficient capability exists, results in a completely different decision path. The first consideration in this case is if any demands for emergency power exist. Again, as in the case of emergency purchases, economics are not considered. Electric utilities are normally required to supply emergency demands if they are able. Once any emergency demands are taken care of, the companies can turn their attention to economy transactions. This involves attempting to purchase and sell energy to other regions so as to minimize the total cost of operation. The basic concept involved in this is simple. If the incremental price curves for economy supply and demand are compared to the incremental cost curve of using the region's capability, as shown in Figure 20, the

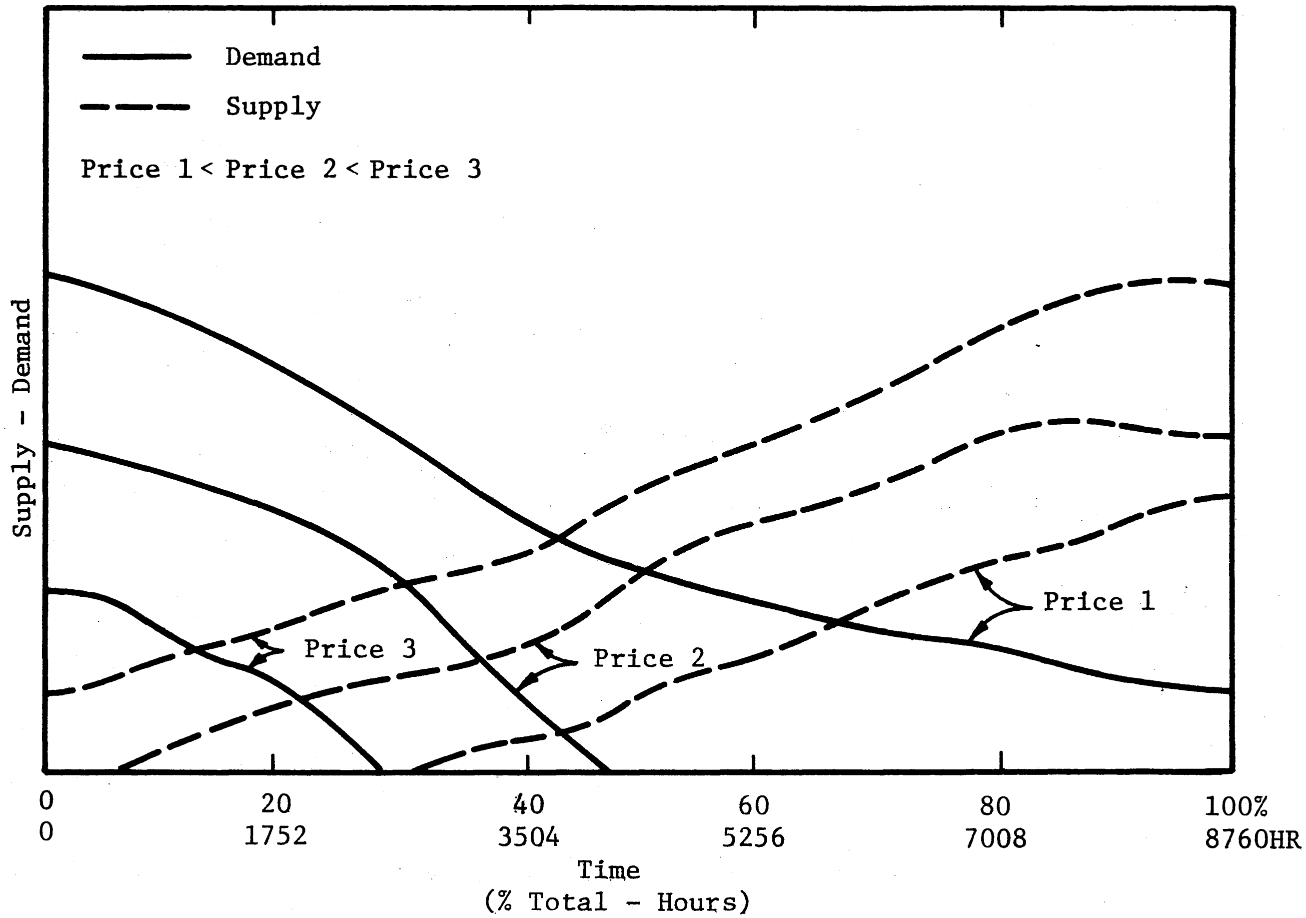

Figure 19. Representation of Economy Energy Supply and Demand

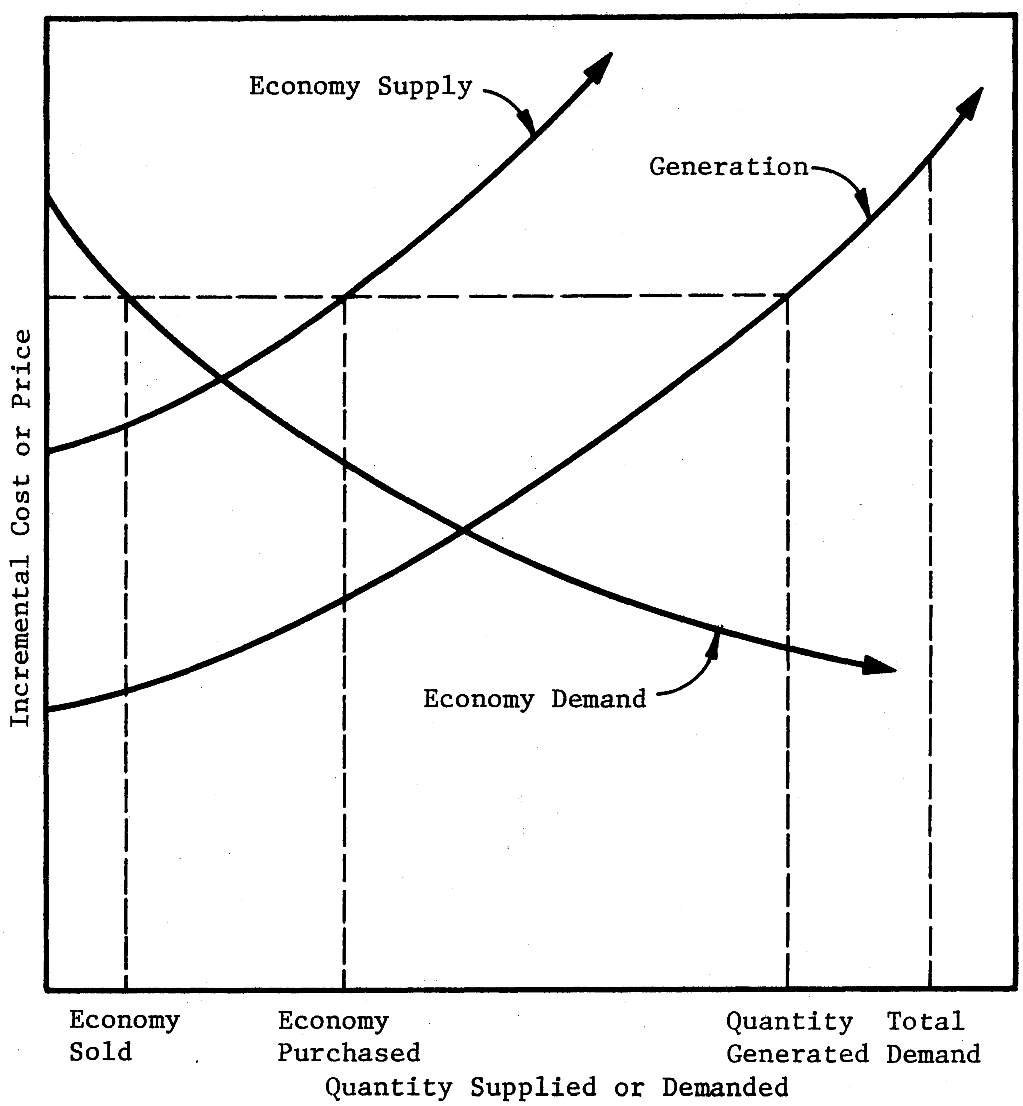

Figure 20. Economy Supply and Demand Prices Compared to Generation Costs at a Point in Time

solution is evident. The requirements necessary for the optimum mix are:

$$TD = EP - ES + EG \tag{3.18}$$

where TD is the total demand, EP is the economy energy purchased, ES is the economy energy sold, and EG is the energy generated, and

$$ISP = IDP = IGC \tag{3.19}$$

where ISP is the incremental economy supply price, IDP is the incremental economy demand price, and IGC is the incremental cost of generation. Equation 3.18 results from the requirement of meeting demands. Equation 3.19 assures that no additional purchases or sales will decrease total cost. Unfortunately, the ranking of the use of facilities according to cost is altered when energy resource shortages occur. If this happens, economics are no longer the only factors considered in the decision process, and the cost of generation will not be a monotonically increasing function as shown in Figure 20. The purpose of reranking is to conserve the scarce energy resource. Thus, the decision process should reflect this concern. Since economics are no longer the only criterion, the decision process is unclear. This problem is overcome in the base simulation by arbitrarily assigning a psuedo variable cost to the capacity which has been reranked to reflect the scarce energy resource supply. This psuedo cost should be between the actual costs of the capacities ranked above and below it. Thus, the curve is again returned to its monotonic form and the calculations can proceed as before. The curve will not accurately represent the cost of the arbitrarily ranked capacity. However, the purpose of reranking in the first place was to account for a low price which did not reflect the availability of the energy resource.

These calculations for hour to hour operation are used to determine the value of a number of important modeling variables. These include:

1. regional demand supplied;
2. firm energy bought and sold;
3. emergency energy bought and sold;
4. economy energy bought and sold; and
5. electrical energy supplied by each type of generation facility.

Variable 5 above can in turn be used to directly determine the amount of each energy resource used. The electrical energy flows to and from other regions will also have corresponding cash flows. Also, these variables, when combined with the fixed charges for generation facilities, can be used to determine probably the single most important output variable - the total cost of generation.

CHAPTER IV

MODEL VALIDATION AND DETERMINATION OF INITIAL CONDITIONS

Introduction

Before using the simulation model to make particular studies, it must be validated to insure that it can simulate an electrical energy supply system. Ideally, this would be done by simulating the system under the conditions encountered in the study and comparing the simulation to actual system behavior. Obviously this cannot be done. Thus, validation must rely on comparison to historical system behavior. A measure of the model's validity is obtained by simulating the system's operation using the historical values of inputs and parameters and comparing the results of the simulation to the historical behavior. If the model closely approximates historical behavior, confidence is gained in its ability to simulate the behavior of the system under conditions encountered in a particular study. Similarly, if the model is unable to simulate historical behavior, it is unlikely to correctly simulate the behavior of the system for other conditions.

The validation requirements for the model can be divided into two categories. The first deals with the general structure of the model. The second deals with the values of particular parameters. Proper structure is much more important than precise values of parameters, as all of the basic system behavior results from the structure of the system. Thus, most of the validation work centers around verifying that the model structure represents the system structure. Until the structure is validated, attempting to determine correct values of particular parameters makes little sense.

The validation of a model is not a once through process and cannot be considered separate from model building. The process is iterative in nature. First, an attempt is made to describe the system structure. This is then tested and revised again and again until all contradictions and inconsistencies are eliminated. Thus, the formulation of the model discussed in the previous chapter and the validation of the model discussed in this chapter are closely related. Both must be considered simultaneously. They are presented separately here only for the sake of clarity. Likewise, only the final model structure and the validation results for this structure are presented.

Unfortunately, good validation results with historical data do not insure the model will provide accurate simulation for studies of future conditions. Factors which significantly affect system behavior can appear in such studies which were nonexistant or unimportant during the validation time period. Such factors may include environmental regulations, alternative energy resources, energy shortages, etc. Because of this possibility, validation with historical data cannot be considered the end of the validation process. As studies are made and new and different conditions are encountered, the model behavior must be constantly reviewed. If inconsistent or unlikely behavior is predicted, the model structure must be examined to see if there is

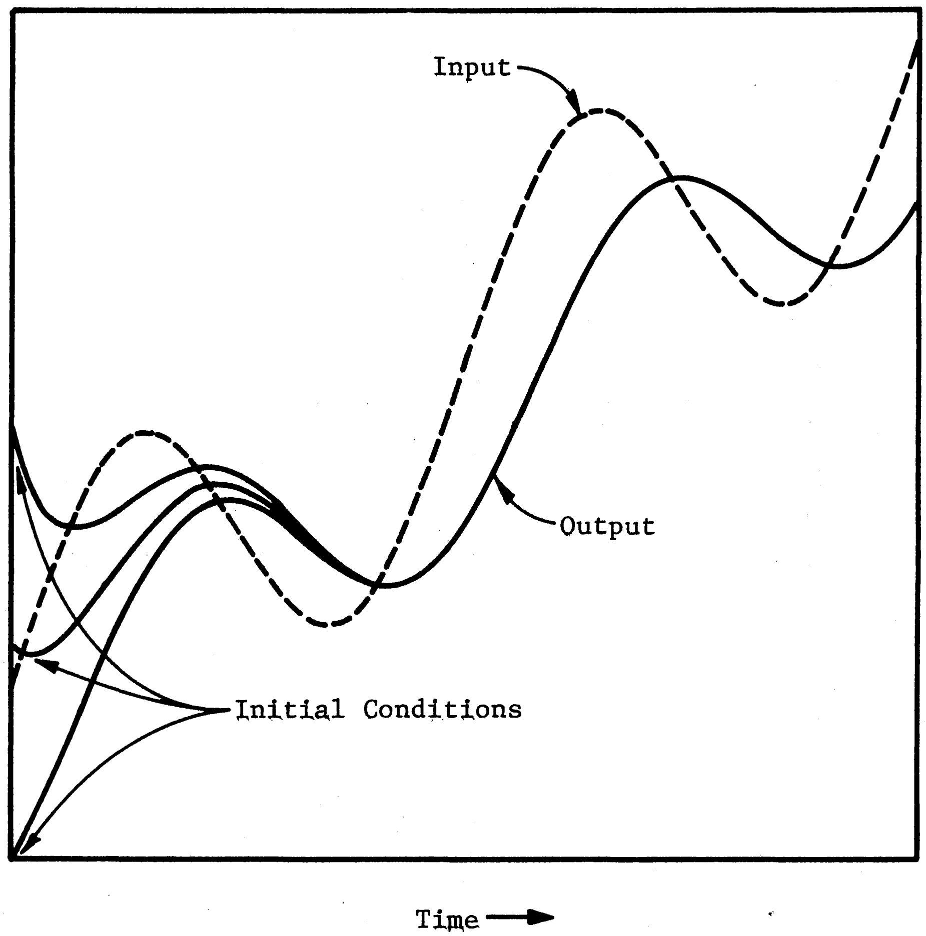

Figure 21. The Effect of Initial Condition on the Response of a First-Order Delay to a Complex Input

an error in the simulation or if the perverse behavior is reflective of the true behavior of the system. It is only after being applied in a number of studies that the model can be considered fully validated and can be used with a large degree of confidence.

In addition to model structure and parameters, the responses simulated by the model depend upon the initial conditions of the state variables. Figure 21 shows this dependency for a single first order delay. The effect of initial conditions on a large, complex system can be even more dramatic. In the electric utility system, values of such state variables as generation capacity and energy resource supplies can affect system operation for a number of years. Thus, for any medium range study to be meaningful, the proper initial conditions for the system must be established. For this reason, determination of initial conditions is considered an integral part of model validation.

The initial values for many levels which represent physical entities in the system can be determined directly from data regarding the system. These would include: on-line capacity, capacity under construction, and to a lesser extent energy resource supplies. The values of the more abstract state variables, such as those involved in forecasting, are more difficult to determine. The common method used to determine initial conditions for such variables is to assume a steady state condition exists. However, this concept cannot be used in the electrical energy supply system since steady state has little real significance and much of the structure is based on change.

By including initial condition determination in the validation process, the validity of the selected initial conditions can be evaluated by comparing the model results to the data for a number of years. This helps eliminate the problem in two ways. First, by using a time series of data, rates of change in model vairables can be evaluated along with the values of the variables. This provides a much more demanding test of the initial conditions. Second, by moving the beginning point back to the start of the validation time period, errors in the value of the initial conditions will tend to dampen out by the end of the validation time period. This dampening effect can clearly be seen in Figure 21 Thus, the values of the state variables at the end of the validation period should provide accurate and consistent initial conditions for studies which start at this point in time.

Validation Data

The initial studies to be made using the model will deal with the energy system in the geographical region defined by the State of Oklahoma. Therefore, the validation of the model is also based on this region. The electric utility system in Oklahoma consists of: two privately owned electric utility companies which generate about 90% of the State's electricity; two publicly owned electric utility companies, one which operates all of the hydro-electric generation in the State; and a number of small municipal generation facilities which together generate less than 2% of the State's electricity. Due to their small contribution, the municipal facilities are not included in the data base for validation.

A number of variables are involved in the validation process. Tables III-VI list the inputs, outputs, parameters, and initial conditions associated with the model. The inputs, outputs, and parameters are divided into primary and secondary groups. This division is somewhat arbitrary. It is made to reflect the relative importance of the variables in the studies to be made. The primary variables are emphasized in the validation; whereas with the secondary variables, values in the correct range are deemed sufficient. Inputs must be supplied to the model in the form of time series. Similarly, the historical values of the outputs must be expressed as time series for comparison to simulated values. The parameters can be expressed as constants unless the values vary significantly during the validation time period. The initial conditions correspond to the beginning of the validation time period. A brief discussion of the data for each of the validation variables is presented in Appendix C.

Unfortunately, from the validation point of view, the history of the electric utility system in Oklahoma has been rather uneventful. There is no evidence of energy resource limitations being encountered. Thus, three of the primary inputs - total energy resources available, fraction available to electric utility companies, and fraction available as long-term supplies - play no important role in the validation. Consequently, the validation results for two of the primary output variables - total electrical energy supplied to region and unmet demand for electrical energy - are almost automatically correct.

Due to the fact that natural gas resources historically have been much cheaper and easier to use than other energy resources, almost all generation capacity built is for this fuel. Thus, the simulation of the choice among the different types of capacity is difficult to test. Similarly, the variables "energy generated by each type of facility" and "the quantity of each energy resource consumed" are of limited value also.

One final problem in the validation data is the smooth demand growth that has been experienced. This smooth trend provides very little dynamic response to demand to observe.

The Validation Program

Before any validation runs can be made it is necessary to taylor the model to the exact situation being modeled. This involves specifying a number of different options in the structure listed in Table VII. A brief discussion of these options used in the validation follows.

Number of Energy Resources

Although natural gas is the predominant energy resource used during the validation period, all commonly used energy resources are included. This gives the simulation the opportunity to select energy resources other than natural gas and hence, the opportunity to make mistakes. Thus, the selection of natural gas as the primary energy resource is an important test. The energy resources included are: natural gas, coal, oil, and nuclear fuel. Hydro sources are also included, but in a different way and will be discussed later.

Classification of Energy Resources

The classification of the energy resources available is somewhat arbitrary. Natural gas is considered as a declining

TABLE III

MODEL INPUTS

Primary Inputs
Peak Electrical Demand
Market Prices of Energy Resources
Total Quantity of Each Energy Resource Available to Region
Fraction of Each Energy Resource Available to Electric Utilities
Fraction of Each Energy Resource Available as Long-term Supply
Secondary Inputs
Economy Energy Supply
Economy Energy Demand
Firm Power Supply
Firm Power Demand
Emergency Energy Demand
Maximum Capacities Allowed
Capital Limits

TABLE IV

MODEL OUTPUTS

Primary Outputs
Amount of Each Type of Generation Facility Constructed
Energy Generated by Each Type of Generation Facility
Quantity of Each Energy Resource Consumed
Total Electrical Energy Supplied to Region
Unmet Demand for Electrical Energy
Total Cost of Generation
Secondary Outputs
Economy Energy Purchased
Economy Energy Sold
Firm Power Purchased
Firm Power Sold
Firm Energy Purchased
Firm Energy Sold
Emergency Energy Purchased
Emergency Energy Sold

TABLE V

MODEL PARAMETERS

<u>Primary Parameters</u>

Demand Characteristics

Capacity Availabilities

Capital Cost of Generation Facilities

Yearly Fixed Costs for Generation Facilities

Non-Fuel Variables Costs for Generation Facilities

Heat Rates

Construction Times

<u>Secondary Parameters</u>

Expected Regional Demand Characteristics

Characteristics of Demand from Firm Power Sales

Desired Reserve Capacity

Proportionality Constants Relating Deliverability to Total Energy Resource Supplies

Forecasting Delay Constants

Energy Resource Supply Delay Times

Long-Term Supply Price Delay Constants

TABLE VI

INITIAL CONDITIONS REQUIRED FOR MODEL

State Variables

Third Order Delay Levels for On-Line Capacity

Semi-Retired Capacity

Capacity Under Construction

Long-Term Capacity Contracts

Future Long-Term Capacity Contracts

Smoothed Variables in Forecasting

Supplies of Declining Energy Resource Supplies

Deliverability of Constant Energy Resource Supplies

Deliverability of Future Constant Energy Resource Supplies

Prices of Long-Term Energy Supplies

Derivatives

Peak Electrical Demand

Energy Resource Prices

Total Quantity of Energy Resources Available

Fraction of Energy Resources Available to Electric Utilities

TABLE VII

STRUCTURE OPTIONS IN MODEL

Number of Energy Resources Considered
Classification of Energy Resources as Declining or Constant
Corresponding Number of Generation Facility Types
Capacity Contracts from Outside of Region

supply. Figure 12 shows this decline for the supply of a single company at a point in time. Since the coal reserves in states near Oklahoma are extensive and largely untapped, this resource is considered to be of the constant type. Nuclear fuel supplies are currently dependent upon processing facilities, thus, they are a constant type source. Oil is more difficult to classify. If only Oklahoma sources were available then it would be a declining source. However, if world wide sources are included, then contracts for supplies with constant deliverability might be more typical. However, it has been typical for most oil to be purchased on short-term markets. This makes the declining classification more usable.

Generation Facilities

The types of generation facilities correspond directly to the energy resources used. These are: natural gas fired boilers, coal fired boilers, nuclear plants, and oil fired plants. The oil fired plants are assumed to be peaking plants and are thus gas turbines rather than boilers.

Hydroelectric generation is a significant factor in Oklahoma. Thus, it is necessary to include it in the validation. However, the construction of hydroelectric facilities usually involves multiple uses - flood control, navigation, recreation, etc. The economics of hydroelectric facilities are seldom the sole criterion for building such facilities. The decision is usually more heavily dependent upon the other factors and the hydroelectric facilities are more or less by-products. For this reason there is no simple method by which hydroelectric facilities can be included. Instead, the construction of hydroelectric facilities is considered an input. Once built they are used in the same manner as any other facility.

Long-Term Capacity Contracts

No long-term capacity contracts have been made with other regions in the past. Also, no evidence is available which indicates such contracts were ever considered; nor, is there any information indicating what terms may have been available if such contracts had been sought. For these reasons no long-term capacity contracts were considered in the validation.

Validation Results

Figures 22-26 compare the primary outputs of the simulation with historical data. It is somewhat difficult to interpret the significance of these comparisons in view of the "monotonic history" of the system.

The simulation selects the same types of capacity and in approximately the same proportion as is evidenced in the historical data. However, there does appear to be a tendency for the simulation to lead the historical data for natural gas boiler capacity by one to two years. Also, the simulation tends to indicate more gas turbine capacity than does historical data. However, considering the relatively small quantities of this type of capacity, this is not too upsetting. In addition, the agreement in the trends for gas turbine capacity is excellent.

Given the agreement between the simulation and historical data for the capacity built and the heavy reliance on natural gas boilers,

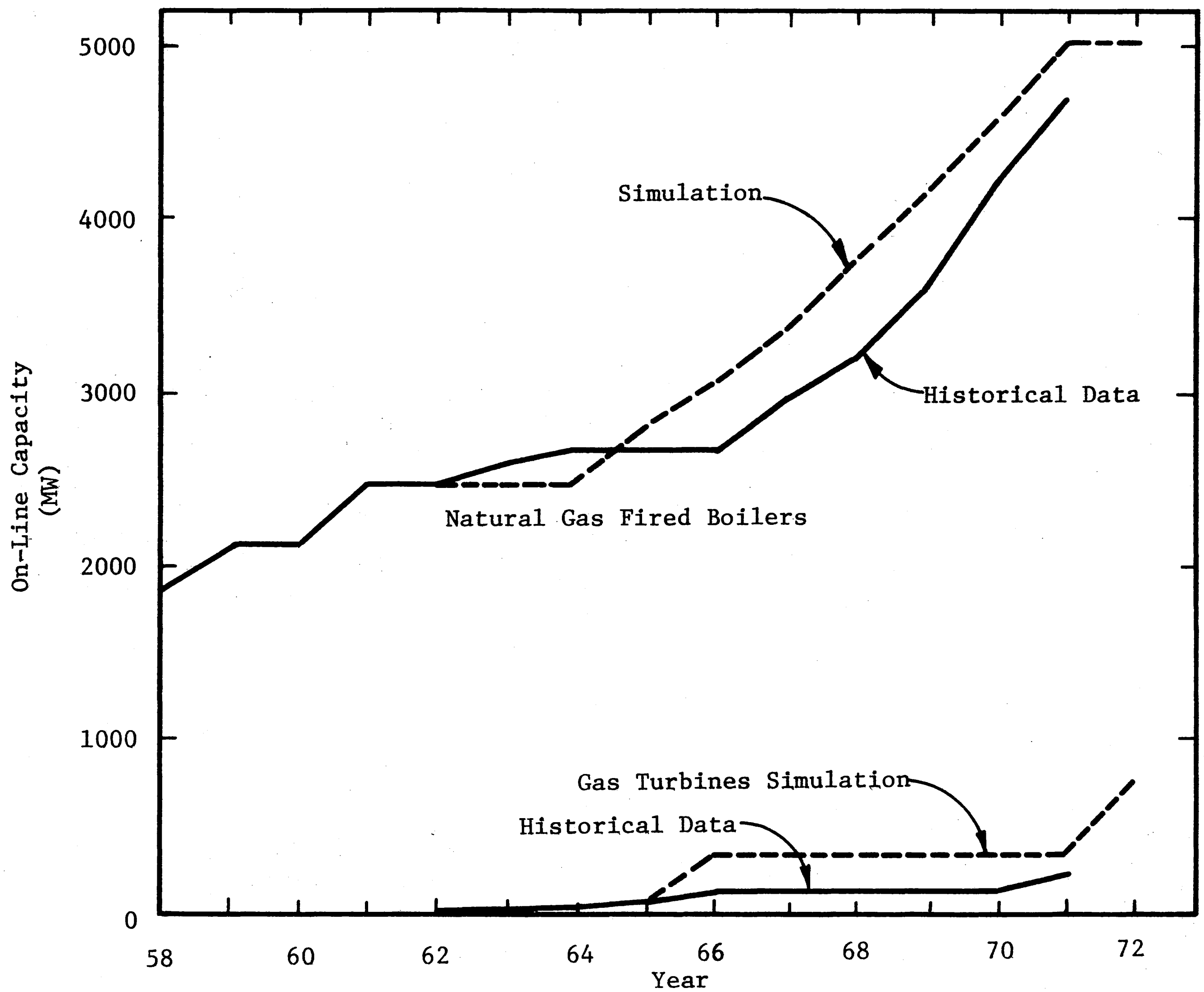

Figure 22. Comparison of On-Line Capacity with Simulation to Historical Data

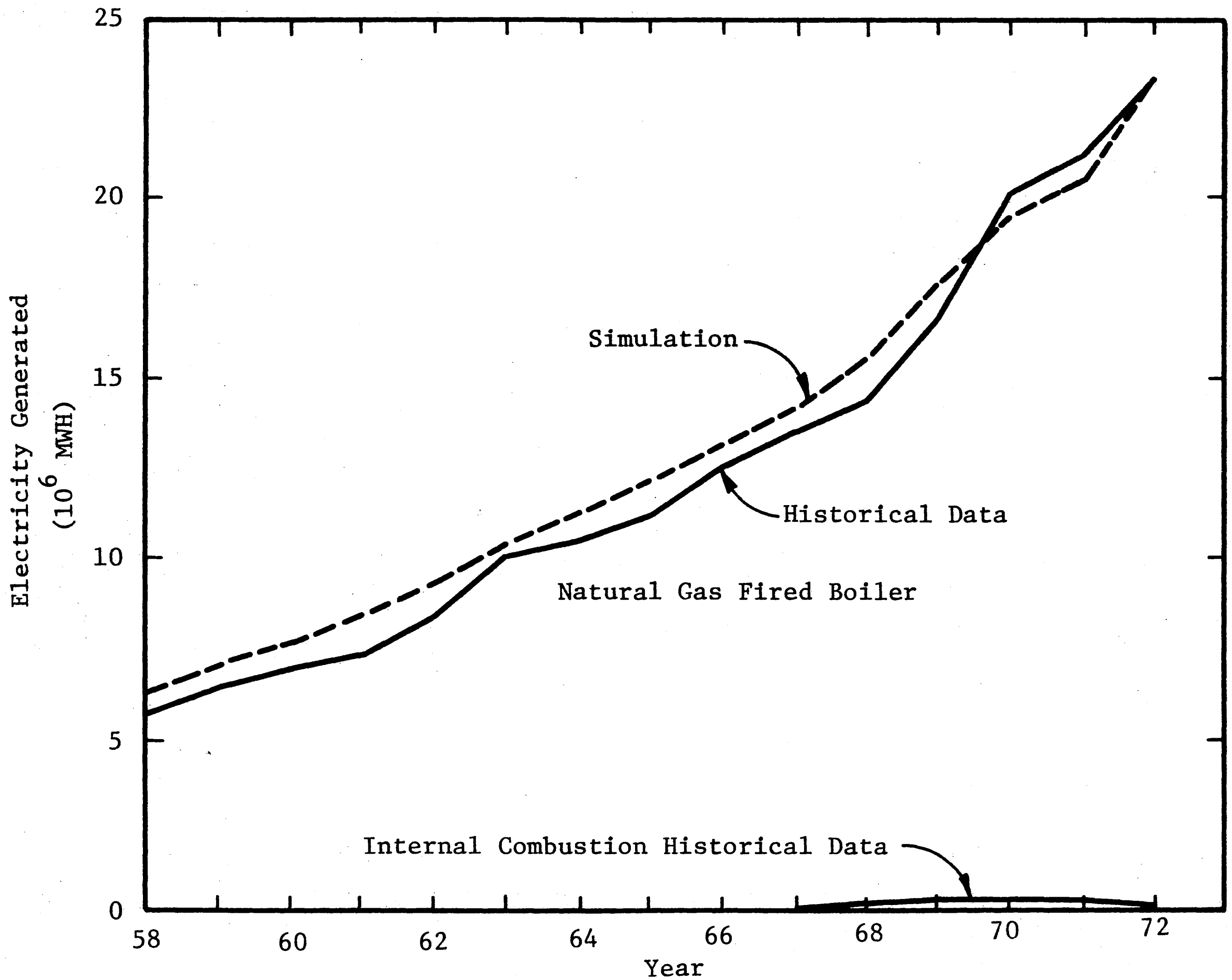

Figure 23. Comparison of Electrical Energy Generated with Simulation to Historical Data

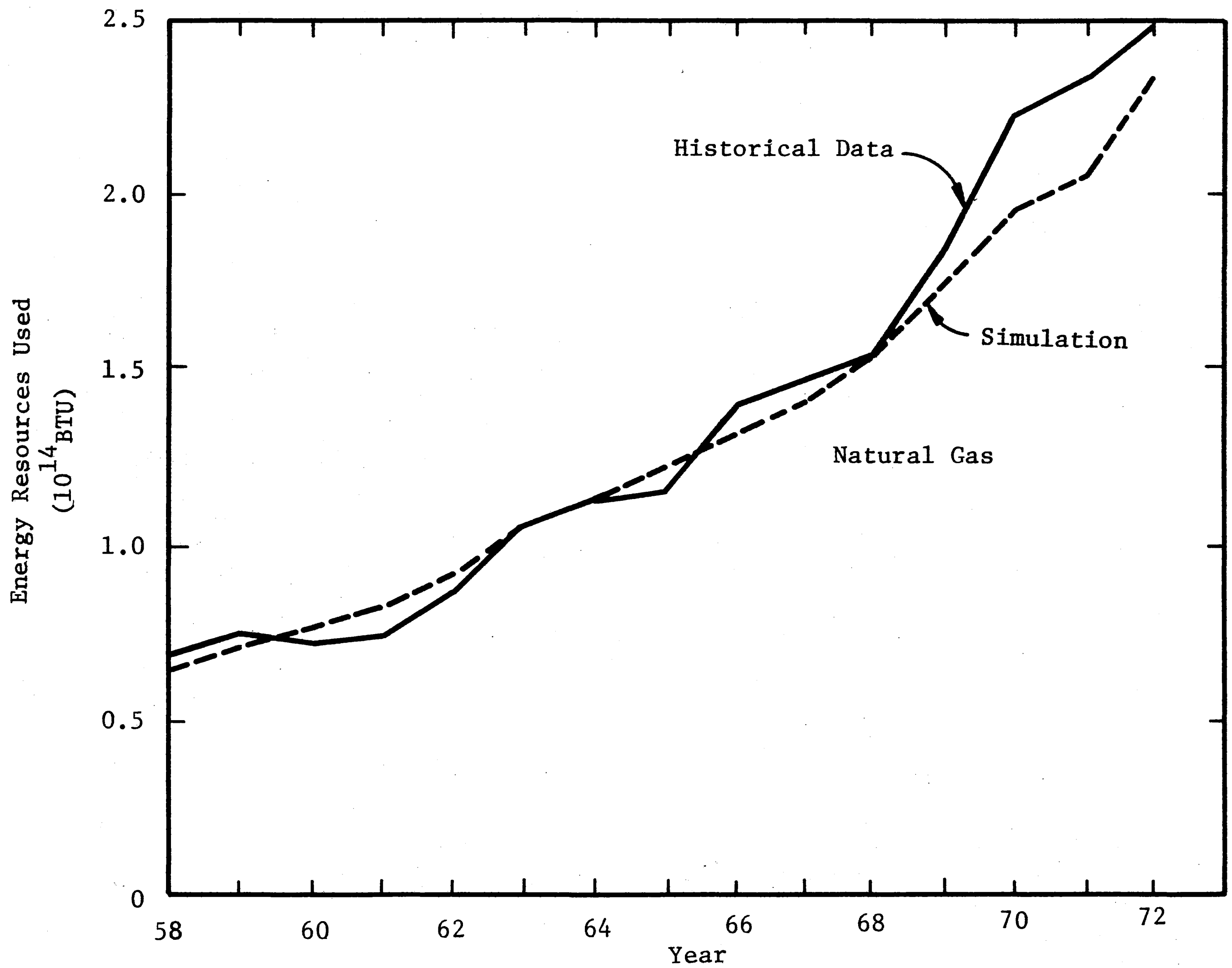

Figure 24. Comparison of Energy Resources Used in Simulation with Historical Data

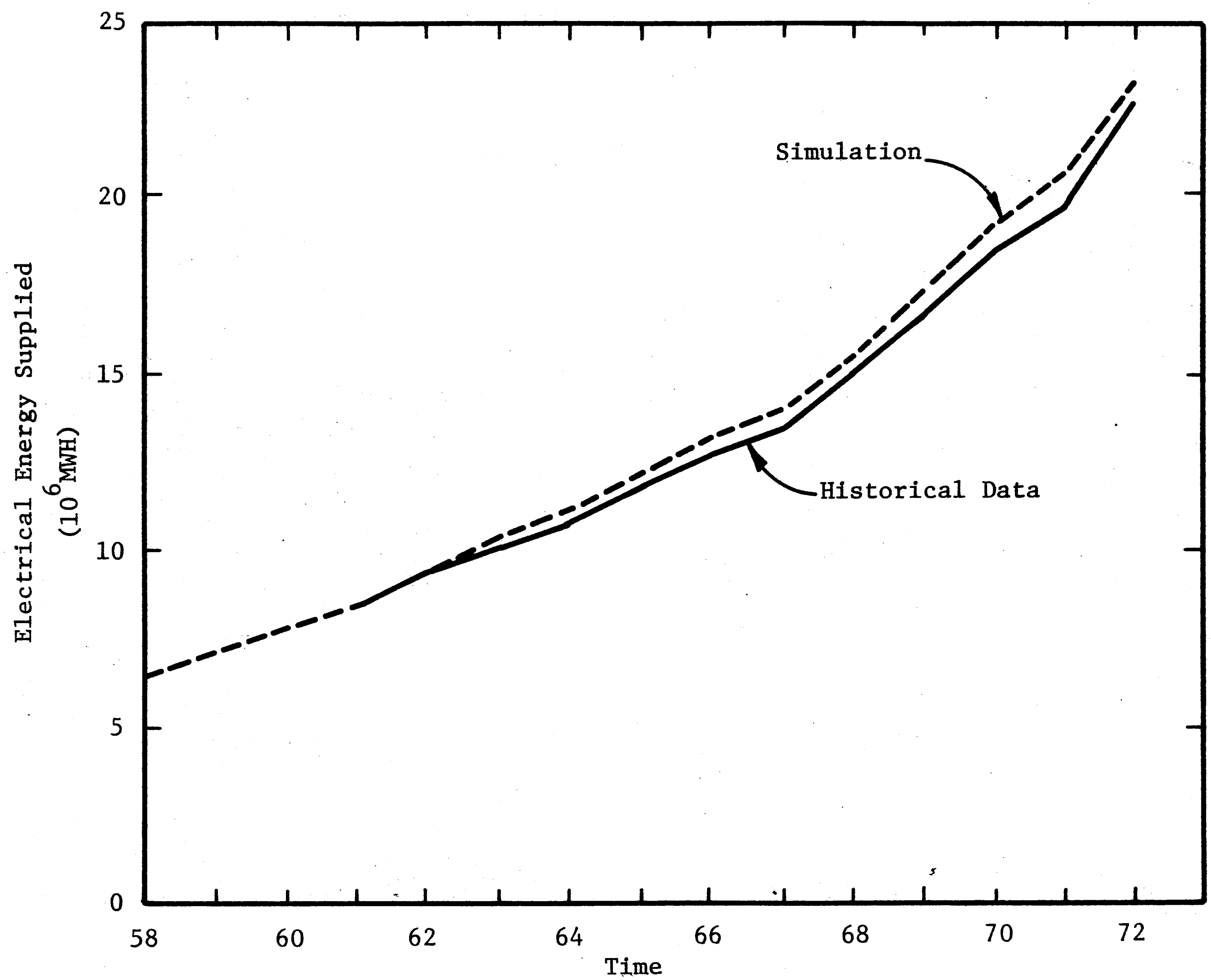

Figure 25. Comparison of Total Electrical Energy Supplied to Region with Simulation to Historical Data

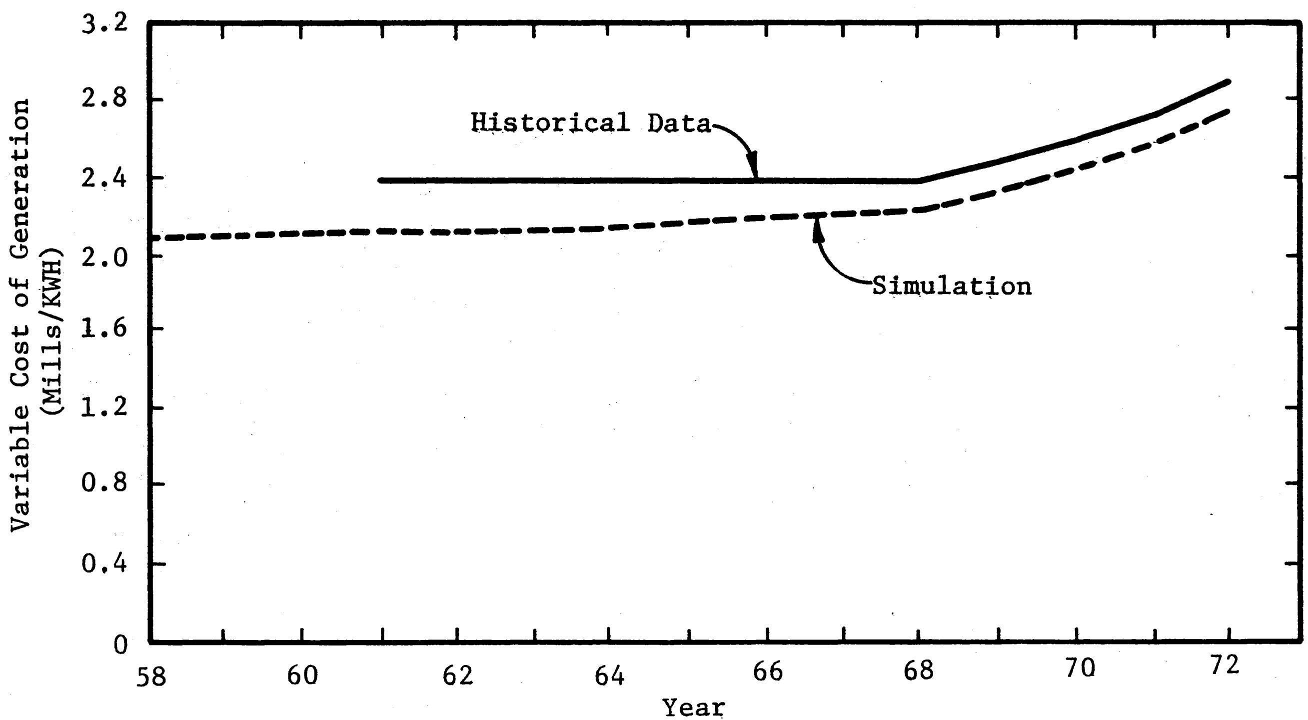

Figure 26. Comparison of Total Variable Cost of Generation with Simulation to Historical Data

there was every reason to expect energy resource use and generation of electrical energy to follow historical data quite closely. This appears to be the case. There are small discrepancies between historical data and the simulation. Most of these can be ascribed to fluctuations in water flow for hydroelectric facilities and changes in the load duration curve. Both of these parameters were held constant for the entire validation period. There does appear to be a larger discrepancy near the end of the validation period for use of natural gas. This is, in part, due to a rapid increase in the sale of electrical energy to other regions at about that time. This was not reflected in the constant economy supply and demand curves used in the simulation.

Because of the possibility of inconsistencies in accounting procedures for capital costs, data for total generation cost are not compared to the simulation results. Instead, the total variable cost is used. As can be seen in Figure 26, the simulation agrees fairly well with the historical data. The simulation tends to underestimate cost somewhat, but the trend is quite consistent with the historical data.

Discussion of Validation Results

As stated earlier, because of the nature of the history of the electrical energy system in Oklahoma, it is difficult to evaluate the validation results. There are some discrepancies. One could go to great effort to adjust parameters so as to get a closer agreement between the simulation and historical data. However, it is doubtful whether this would improve the simulation. An obsession with exactly fitting simple monotonic curves, not likely to be typical of future conditions, could cause serious problems. By fine tuning the parameters to fit these trends, more important structural characteristics may be overlooked. Although the simulation results might reproduce historical behavior exactly, the model would be invalid for studies of possible future situations with different conditions.

In fact, an earlier form of the model actually predicted capacity construction which agreed more closely with the historical data than the current form of the model (2). Upon close investigation, it was found that the economic logic of this earlier form was incorrect. However, the selection of capacity types was the result of demand dynamics rather than economics. When demand grew faster than expected, there was insufficient time to build the desired natural gas boiler capacity. Instead, gas turbines were installed. Thus, the correct capacity mix was predicted although the economics in the model were incorrect.

For these reasons, additional effort was not expended in attempting to eliminate the small discrepancies that are evident. Most of the discrepancies can be attributed to a lack of accurate inputs and parameters. It is unlikely that these inputs and parameters can be determined any more accurately for studies of future situations. Thus, further effort at improving validation results is likely to only give the model user a false sense of security.

It should be remembered that the model cannot be considered verified as being completely correct. The validation serves only as one test for inconsistencies. The model must be continuously reviewed for inconsistencies not apparent from the validation when it is being used for other situations.

CHAPTER V

USE OF THE MODEL FOR A STUDY OF BOILER FUEL REGULATIONS

Introduction

As discussed previously, the electric utility model was developed to serve as part of a larger model which includes similar models for other parts of the energy system. Only in this context can the maximum use be made of the electric utility model. The electric utility models should also be useful as an independent model. To demonstrate the practicality of using the model separately, a study was made of possible regulations on the use of natural gas as a boiler fuel. This problem was selected because of its current relevence to the electric utility industry in Oklahoma. It also demonstrates the versatility of the model.

As noted in the validation, almost all of the electricity in Oklahoma is generated with natural gas. Unfortunately, natural gas is now in short supply in many parts of the nation. There are many people who propose banning the use of natural gas as a boiler fuel to make it available for other uses. Such a ban could cause considerable difficulty for electric utility companies in Oklahoma due to the nature of most gas fired boilers. These boilers usually have the capability to burn oil but are unable to burn coal. Since oil is quite expensive and is also in short supply, the electric utilities would have to consider building new boilers to convert these generation facilities to coal if such a ban were made. Since the base model does not provide for conversion of generation facilities to a different fuel, it must be altered to include this possibility. This demonstrates how the model can be adapted to new and different situations.

Model Alterations

In order to incorporate the possibility of converting natural gas facilities to coal, several changes were required in the model. In setting up the model for the study, a new type of generation capacity was added which is referred to as GCC (gas converted to coal) capacity. Also, the hydroelectric and gas turbine classifications were eliminated since they are a relatively insignificant part of the current capability. In addition, several changes were made in the logic and structure of the model:

1. Generation capacity must be off-line for 9-12 months to switch from the gas boiler to the coal boiler. Thus, a rate was added which removes on-line natural gas facilities the year before new GCC facilities come on-line.
2. The logic in calculations of the desired mix of facilities was altered to account for the fact that quantities of existing natural gas facilities and new GCC facilities are not independent. If, as the load duration curve is filled in these calculations, GCC capacity becomes economical lower on the demand curve than existing natural gas capacity, the maximum new GCC capacity allowed is set equal to the existing natural gas capacity. Then the existing natural

gas capacity is decreased by the quantity of GCC capacity desired. If existing natural gas capacity becomes economical first, the maximum new GCC capacity allowed is set equal to any existing natural gas capacity not desired.

3. In developing the capacity expansion plan, it is assumed that natural gas capacity will not be taken off-line if it means a shortage of capacity will result, unless there is a projected shortage due to energy resource limits anyway.
4. The natural gas availability forecast is based on the regulation being studied rather than historical values.

Regulations and Future Scenarios

A complete study of regulations of natural gas use in electricity generation would require dozens of simulations. A wide range of regulation alternatives would need to be considered for various scenarios of future conditions. The purpose here is to demonstrate the use of the model and not to make an exhaustive study. Thus, only two regulation alternatives to reduce the use of natural gas are considered. A single scenario of future conditions is used. This scenario is kept as simple as possible to allow attention to be focused on the reaction to regulation rather than to other inputs. The scenario used for inputs and parameters is summarized in Tables VIII and IX and the regulations are summarized below.

Regulation 1. In the first regulation, a total ban is not imposed on natural gas. The electric utilities are allowed to use their existing long-term supplies. They are also allowed to purchase

TABLE VIII

INPUTS FOR STUDY

Peak Electrical Demand	6100 mw in 1975, Increases 5%/Year
Market Prices of Energy Resources	Natural Gas $1.80/$10^6$ BTU in 1975 Coal $1.50 in 1975 Nuclear $0.50 in 1975 All increase 5%/Year
Energy Resources Available	Assume all coal and nuclear fuel required is available, natural gas as prescribed by regulation.
Maximum Capacities Allowed	No restrictions on new coal and nuclear. Assume all on-line natural gas as candidate for conversion.
Capital Limits	Assume all capital required is available
Economy Energy Supply and Demand	See Figure 27 Price 1 = 0.25¢/KWH Price 2 = 1.0¢/KWH Price 3 = 2.5¢/KWH All prices increase at 5%/Year.
Firm Power Supply and Demand	Not Required.
Emergency Energy Demand	Assume None.

TABLE IX

PARAMETERS FOR STUDY

Demand Characteristics	Same as for validation.
Capacity Availabilities	Same as for validation, GCC capacity same as with conventional coal capacity.
Capital Costs for Generation Facilities	Natural Gas $200/KW in 1975 Coal $500/KW in 1975 Nuclear $800/KW in 1975 GCC $125/KW in 1975 All increase 6%/Year
Yearly Fixed Costs for Generation Facilities	A motorized at 12%/year, 30 year life span, 20 year life span for GCC capacity.
Non-Fuel Variable Costs for Generation Facilities	Same as validation, GCC same as conventional coal.
Heat Rates	Same as validation, GCC same as conventional coal.
Construction Times	Same as validation, 3 years for conversion construction, 1 year actual outage of plant.
Expected Regional Demand Characteristics	Same as validation
Characteristics of Demand from Firm Power Sales	Not required
Desired Reserves Capacity	Same as validation
Proportionality Constants Relating Deliverability to Total Energy Resource Supplies	Same as for validation
Forecasting Delay Constant	Same as for validation

TABLE IX (Continued)

Energy Resourece Supply Delay Times	Same as for validation
Long-Term Supply Price Delay Constants	Same as for validation

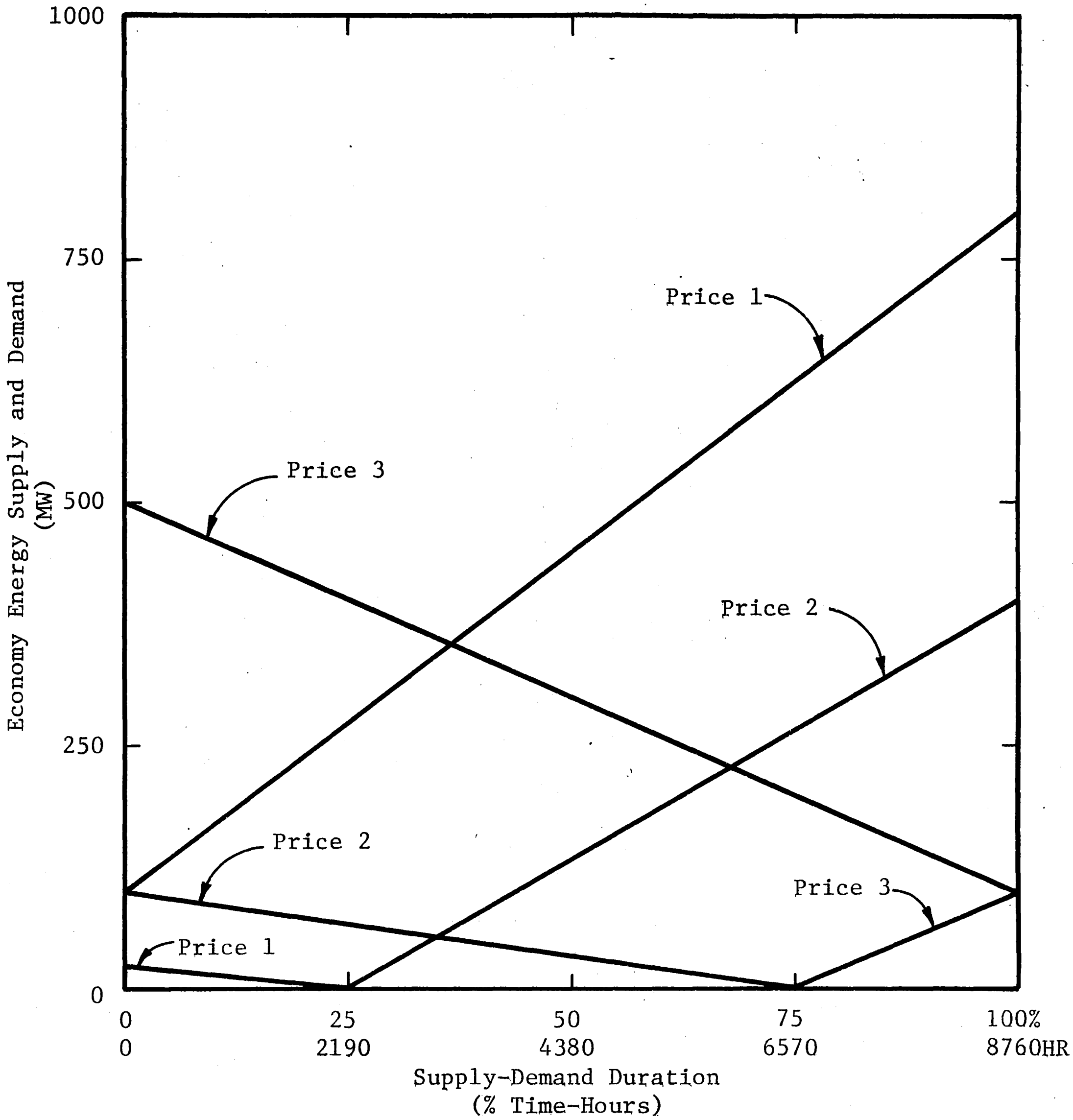

Figure 27. Economy Energy Supply and Demand Used for Regulation Study

up to 3.0 X 10^{14} BTU/YEAR on the spot market. However, they are not allowed to add any new long-term supplies.

Regulation 2. The second regulation is the same as the first, except that the spot market purchases allowed are decreased linearly from 3.0 X 10^{4} BTU/YEAR in 1975 to none in 1990.

Study Results

The effect of the regulation alternatives on key variables for the years 1975 through 2000 is shown in Figures 28-31. As would be expected, there is a rapid conversion of some of the natural gas facilities to coal with both regulations. The speed of this conversion may be somewhat unrealistic as no capital constraints or limits on construction rates were imposed. This is followed by a rapid increase in conventional coal capacity. The use of the remaining natural gas capacity is relegated to peaking and standby service and the coal capacity carries the base load. As can be seen in Figure 30, this results in an even more rapid decline in natural gas usage than anticipated and coal becomes the dominant fuel. However, the dominance of coal is short lived as the economics in this scenario cause nuclear capacity to replace coal capacity for the base load.

The differences in the response to the two regulation alternatives are not striking. More natural gas capacity is converted to coal with the more severe regulation. Likewise, less natural gas and more coal are consumed in generation with the more severe regulation. The conventional coal capacity initially built is the same in either case and is limited to that already under construction. The most striking difference resulting from the regulations

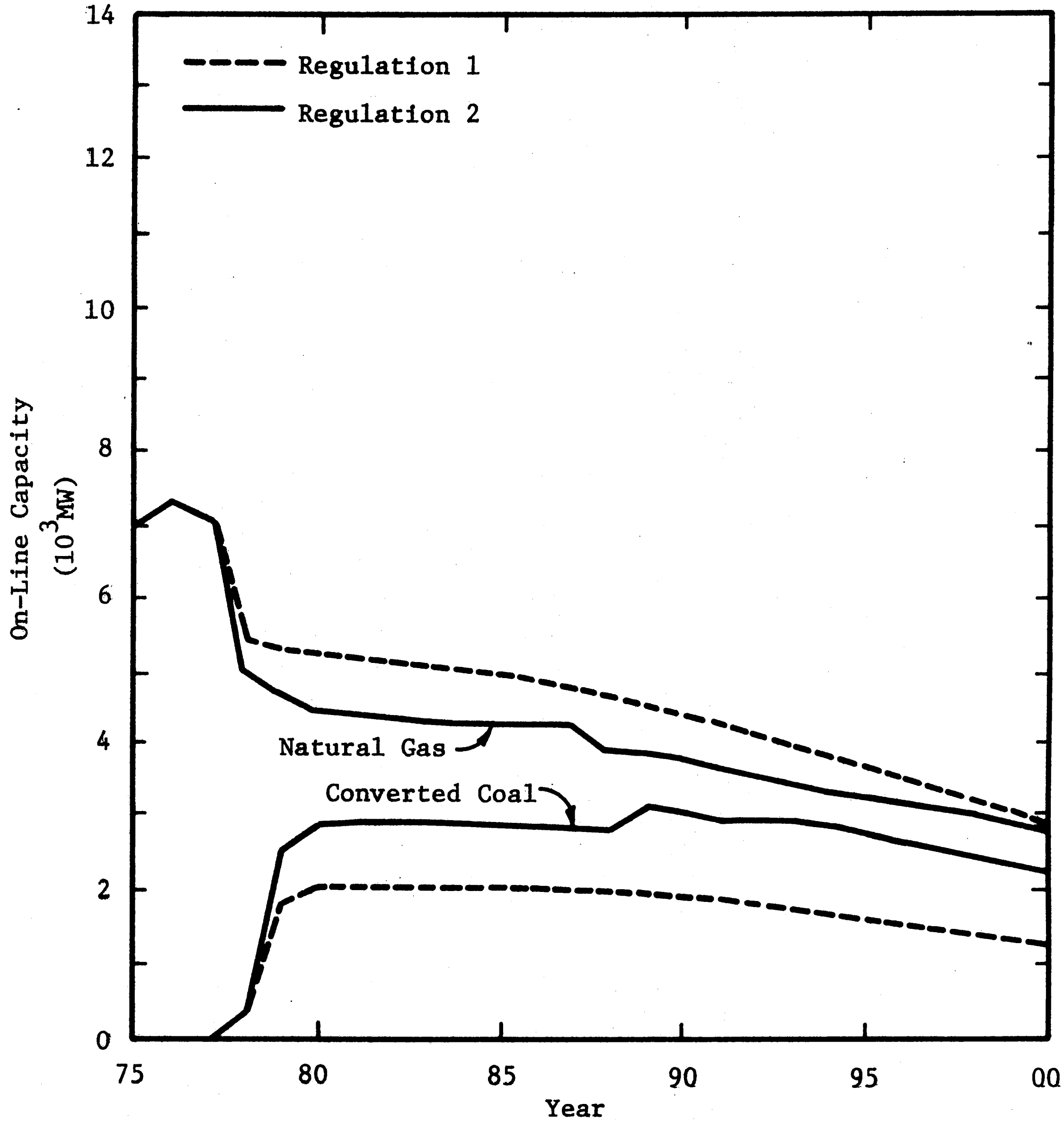

Figure 28. Comparison of On-Line Capacity for Different Regulations

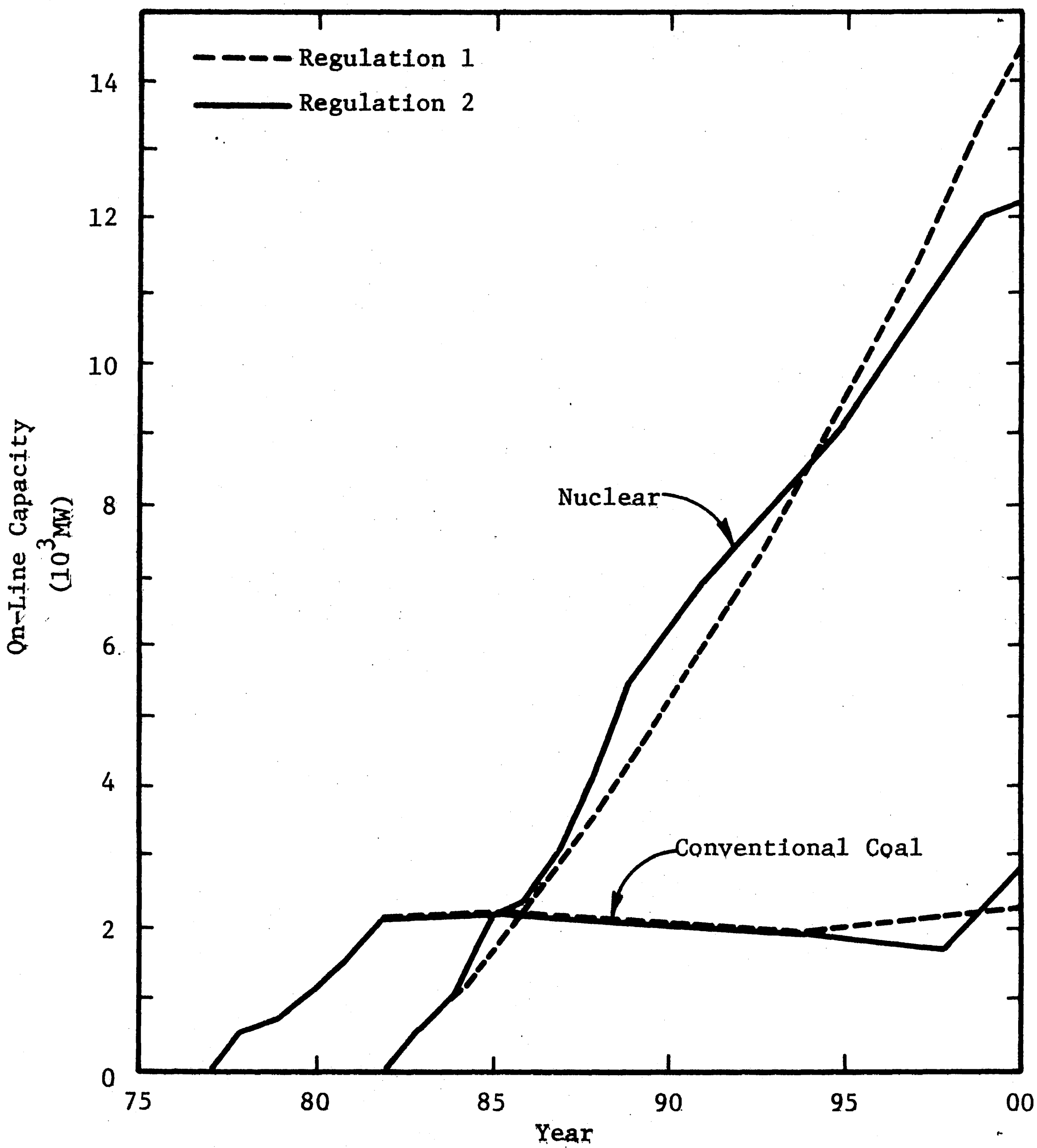

Figure 29. Comparison of On-Line Capacity for Different Regulations

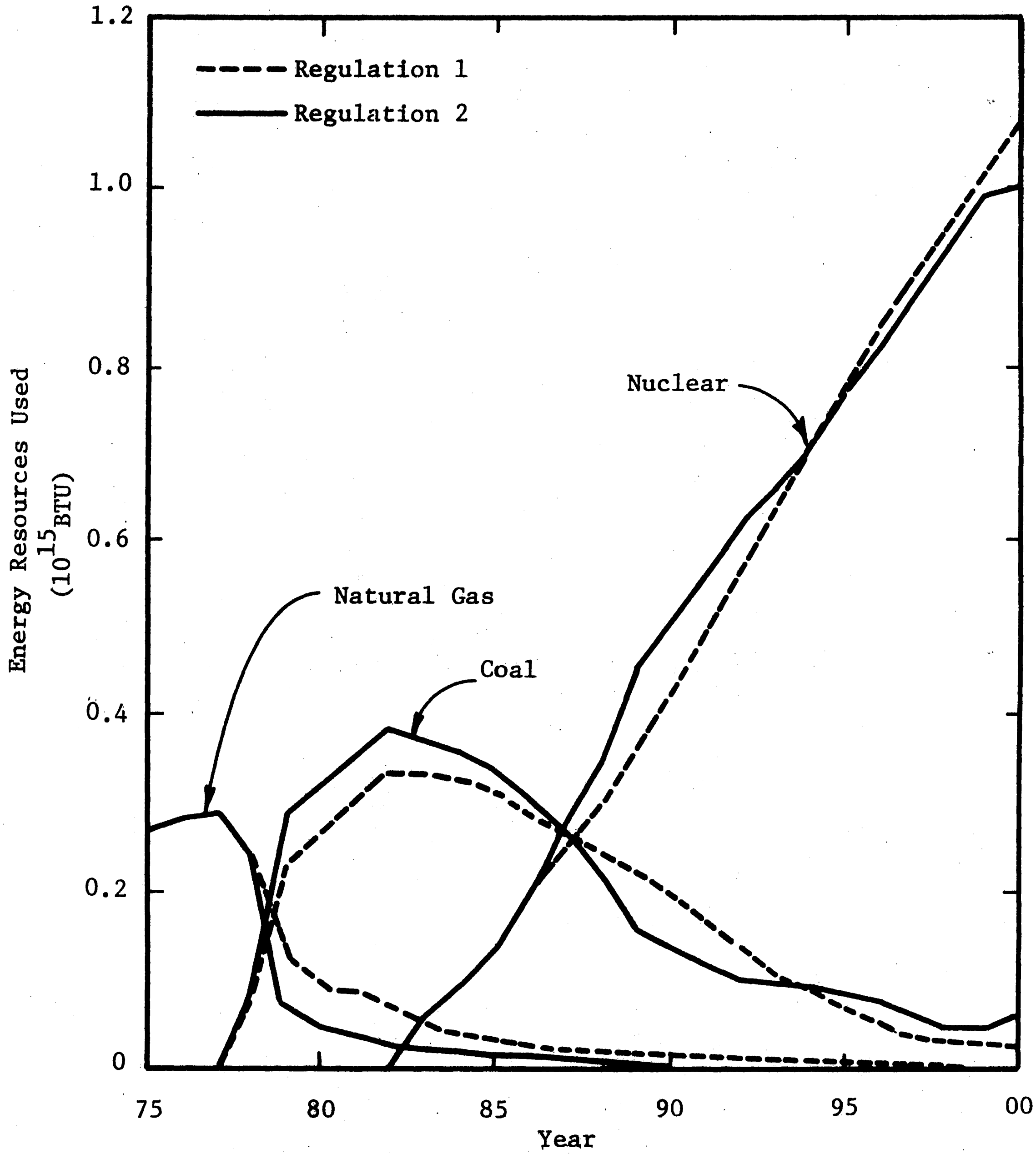

Figure 30. Comparison of Energy Resource Usage for Different Regulations

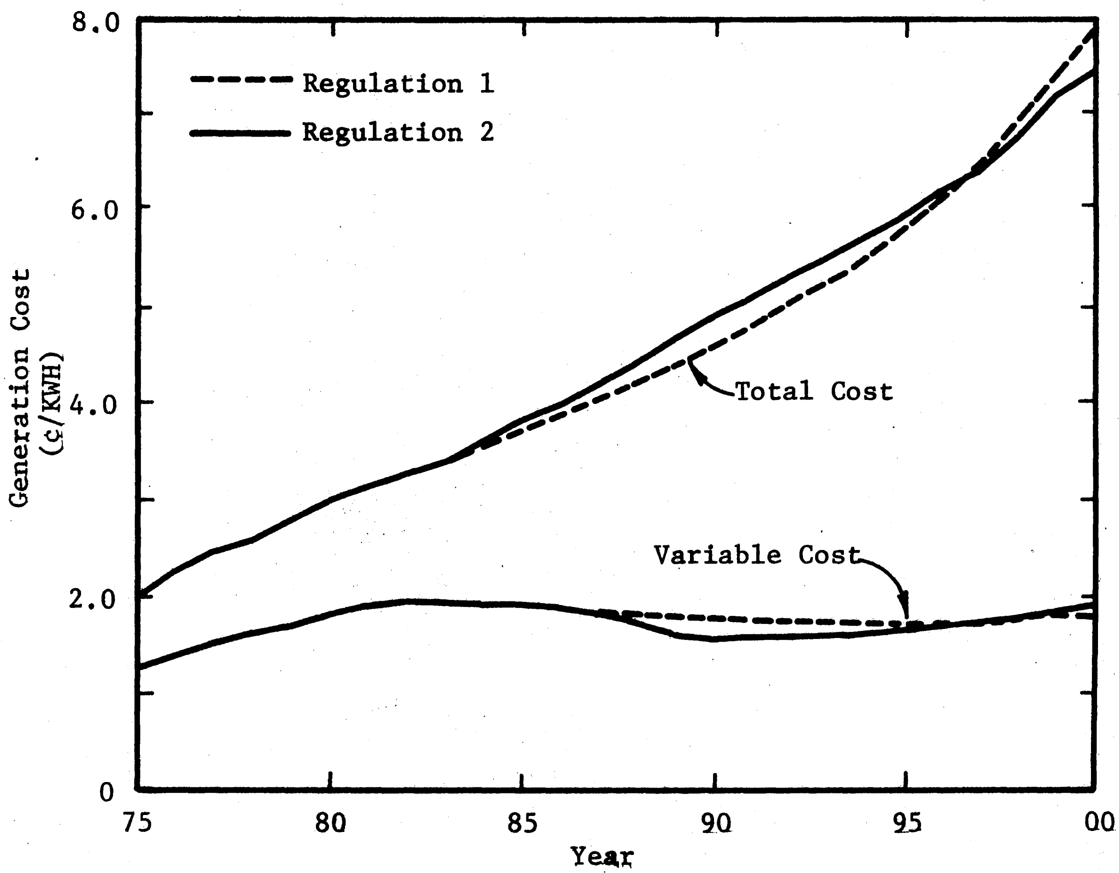

Figure 31. Comparison of Generation Costs for Different Regulations

is seen in the long-term response. Even though natural gas usage has essentially declined to zero by the end of the study period for both cases, the mix of nuclear and coal capacity is still considerably different. At this point there is no evidence that they are converging. Although it is difficult to identify the cause of this unexpected response due to the complexity of the system, two possible causes are identifiable.

The first possibility is an over-response in changing the capacity mix. With the more severe regulation, more nuclear and coal capacity is built. As natural gas use is phased out, the resulting mix of coal and nuclear capacity is not in the desired proportions. In attempting to correct this imbalance, an over-response can easily result. The same argument can be applied to the less severe regulation. As natural gas usage is phased out, the resulting capacity mix may be off in the opposite direction. The same potential for an over-response exists in this case. In fact, the capacity mix could be off in the same direction for both regulations, but more over-response results in one case than the other.

The second cause for the unexpected response is the continued availability of natural gas for the less severe regulation. This fuel supply allows the existing natural gas capacity to be used for peaking or reserve capacity in calculating the desired mix, causing a shift from coal to nuclear in the desired mix for regulation 1 as compared to regulation 2.

The question of greatest concern to many people is the effect on the cost of electricity for the alternative regulations.

Figure 31 shows the cost to be relatively insensitive to the different regulations. During the critical "transition period" the difference in cost is negligible. It is only after a number of years that some increase in cost for the more severe regulation is observed. This situation eventually reverses, again indicating a possible over-response. However, an imperfection in the model was noted that causes some distortion of the total cost. The capital cost was escalated for both old and new capacity rather than just for new capacity. In the real system, capital cost is based on the original investment. This inconsistency tends to increase the total cost for both cases but has a much smaller effect on the relative cost for the two regulation alternatives.

Another important question deals with the ability of the electric utilities to meet demands. All demands were met for both regulations. However, in both cases small amounts of emergency energy were purchased for several years during the "transition period." The quantities purchased with the more severe regulation were somewhat larger, especially in 1978 when a significant amount of existing capacity was off-line. Even though the quantities of emergency energy purchased were quite small, they do indicate the system was in a marginal state in respect to ability to meet demands at times. If unexpected demand growth or other problems had occurred, outages could have resulted.

This study should not be considered a conclusive study of boiler fuel regulations. It only demonstrates the use of the model for practical studies. It also demonstrates one of the advantages of using a dynamic systems simulation. It is unlikely that the unexpected behavior could be predicted with a more conventional modeling technique. In comparing the alternative regulations, these unexpected parts of the response are as big a factor as the expected parts.

CHAPTER VI

SUMMARY AND CONCLUSIONS

The model developed in this study for the electric utility component of a regional energy system demonstrates the practicality of incorporating a high level of technical detail into an energy model based on dynamic system simulation. The model is capable of making in-depth studies of precise questions concerning the electric utility industry in a region. It is designed to also serve as a component to a comprehensive regional energy model.

The validation presented in Chapter IV shows the model correctly simulates the results of the major decision options in the electric utility industry. The case study presented in Chapter V demonstrates the versatility of the model and its ability to address precise policy questions. In addition, its ability to predict unexpected results is seen in the case study.

The model can address the performance of a regional electric utility system in terms of:

1. the ability to meet demands for electrical energy;
2. the cost of generating electrical energy;
3. energy resources used for generating electricity;
4. capital requirements for generation facilities; and
5. the energy and cash flows from inter-regional transactions involving electrical energy.

The model is designed for use either as a component of a comprehensive regional energy system model utilizing similar models for the other parts of the system, or as an independent model for studies involving the electric utility industry. As a component for a comprehensive model, the information supplied to the electric utility model is obtained from other component models. The only exception would be the information concerning supply and demand pertaining to interregional transactions. These inputs must be treated as an exogenous variable even for a comprehensive model. The information output from the model could in turn be used as inputs for other component models.

As an independent model, all of the input information must be supplied by the user. In this mode the model appears to be useful for studies in several areas:

1. The model can be used to predict the response of the electric utility industry in a region to scenarios for future conditions. These scenarios could pertain to a study of the electric utility industry, or to more comprehensive energy studies. In either case, the model should provide a tool for detailed analysis of electrical energy supply questions.
2. More general response characteristics of the electric utility industry in a region can be studied using the model. This would deal with the effects of fluctuating inputs or changes in the long-term trends of inputs.
3. One of the most promising areas of study for which the model can be used appears to be in the analysis of regulations and controls on the electric utility industry by government agencies. Particular questions which can be readily addressed

involve limits and restrictions on what kinds and amounts of power plants which can be built and on what kinds and amounts of energy resources which can be used for generation.

4. Similar studies can also be made of policies in the electric utility industry. These policies involve forecasting, generation expansion decisions, and the use of energy resources for generation.

The model may be improved for some studies with additional refinement. The refinement required would depend primarily on the particular questions to be analyzed. However, several areas where this refinement would be beneficial can be identified:

1. The relationships for parameters which vary throughout the year could be improved if more data were incorporated into their derivation. Ideally, a full statistical analysis as described in Appendix A would be used.
2. As noted in Chapter V, problems can arise in the model when certain parameters change significantly over a period of time. Parameters which are affected in this way would be better represented by allowing information about their past values to be utilized in the model.
3. In the model developed here, the construction of transmission and distribution facilities was not simulated. Inclusion of this part of utility company operation may be desirable in studies relating to capital expenditures. It is also possible that this area of operations could affect the ability to meet demands in some circumstances.

There are most likely other areas where additional research could improve the model. However, it is only when it is incorporated into a comprehensive regional energy model that the full capabilities of the model described here can be utilized. Thus, probably the most important area for additional research is in the development of similar models for the other components of a regional energy system.

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APPENDIX A

REPRESENTATION OF VARIABLES WITH PERIODIC FLUCTUATIONS

In several parts of the simulation it is necessary to be able to compare the demand for electrical energy in the region to other simulation variables. These variables include:

1. the availability of a group of generation facilities;
2. the demand for firm energy in other regions;
3. the demand for emergency energy in other regions;
4. the demand for economy energy at a given price in other regions; and
5. the supply of economy energy at a given price in other regions.

Since the demand for electrical energy fluctuates, it is represented by a load duration curve to describe how it varies during the period of a year. The load duration curve is derived by ordering the demands according to magnitudes. This is analogous to deriving a distribution function for a random variable. The variables which are compared to demand also fluctuate. Thus, it is necessary to describe how they vary throughout the period of a year. These variables could be reduced in the same manner as demand to obtain functions analogous to the load duration curve. However, when this technique is used, inconsistent time axes result. Each point along load duration curve represents the demand at a point in time. Since the curve is obtained by ordering according to magnitude, two adjacent points on the curve may represent two widely separated points in time. This erratic time axis causes no great problem when the load duration curve is considered alone. However, if another variable, reduced using the technique, were to be compared with the load duration curve, the time axes for the two curves would not be consistent and errors could result.

To make accurate comparisons at a point in time on the load duration curve it is necessary to reduce these variables using the same time axis as the load duration curve. That is, each point on the curve for the reduced variable must correspond to the same point in time as for the load duration curve. Unfortunately, this results in an irregular and discontinuous curve. Figure 32 shows a small element of hypothetical curve resulting from the application of this technique.

It would be virtually impossible to use a curve such as the one shown in Figure 32 in the simulation. In order to gain any useful information from such a curve, statistical analysis techniques are necessary. For simulation purposes, the same element of the curve shown in Figure 32 could be represented with a frequency distribution as in Figure 33. If each element of the curve is reduced in a similar fashion, a relationship as shown in Figure 34 can be derived. In this form, the value of the variable is represented by a smooth curve through the average value of each element and the distribution of the variations from this average.

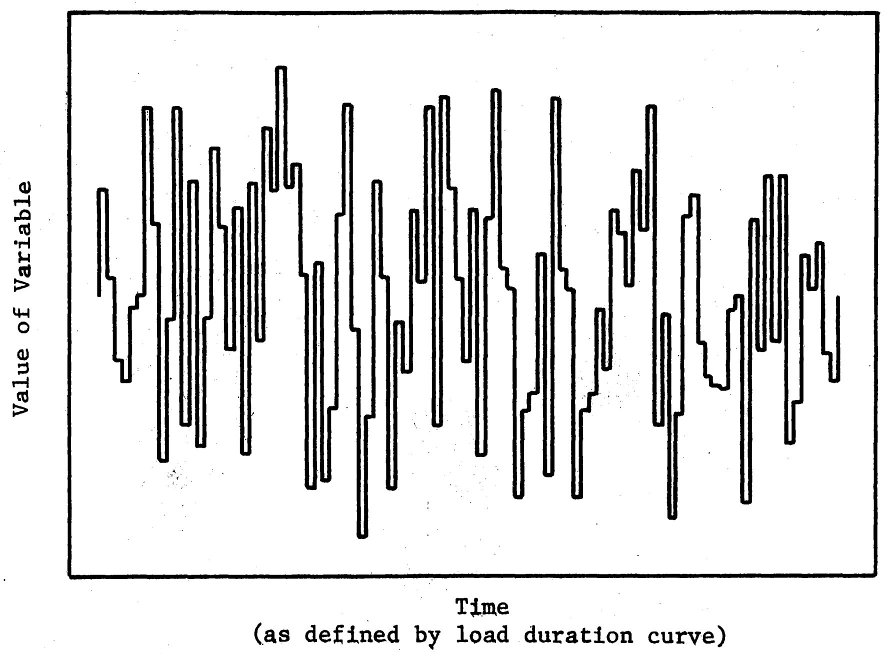

Figure 32. Segment of Curve Which Results from Using Load Duration Time Axis for Another Variable

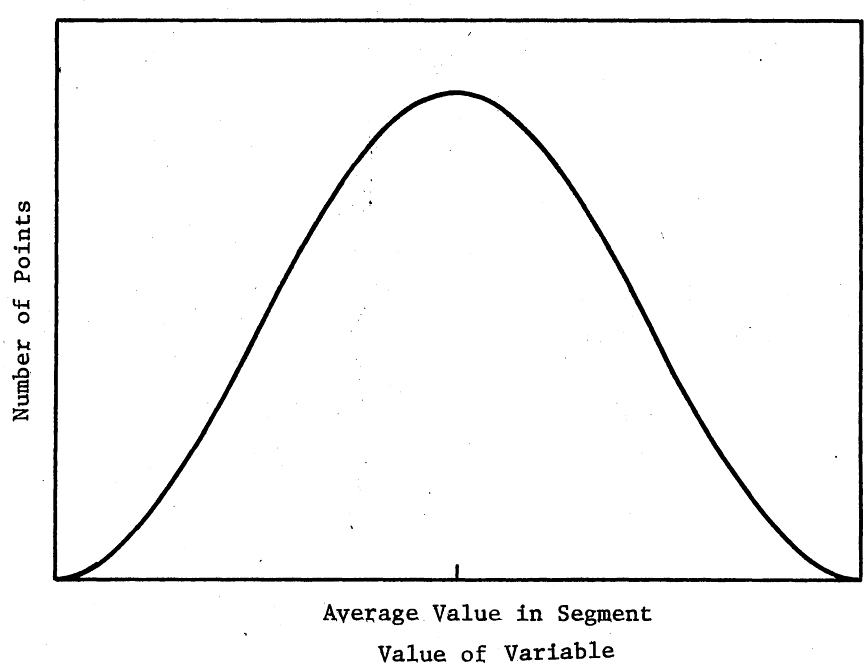

Figure 33. Distribution of Variations from Average

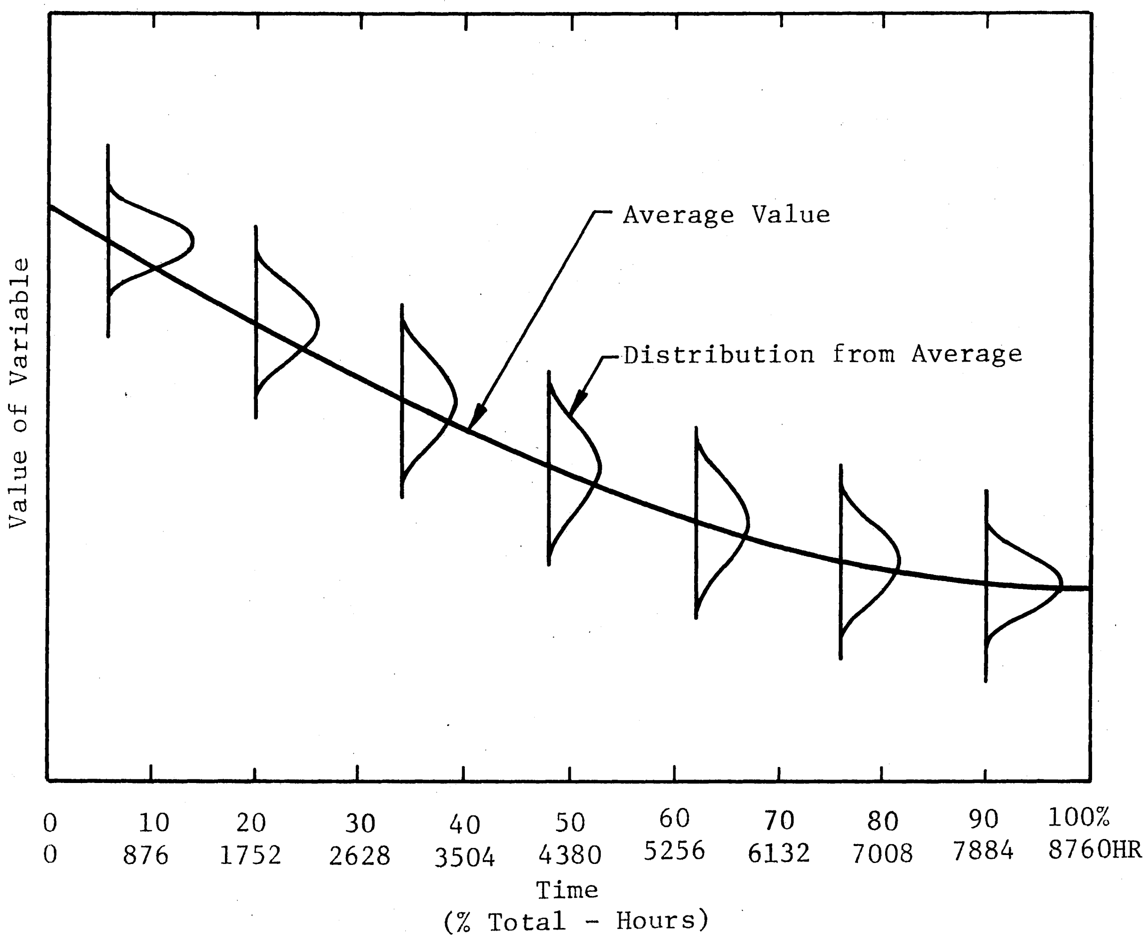

Figure 34. Stochastic Representation of Variable

The stochastic form shown in Figure 34 is desirable and should be used in developing the model when possible. Unfortunately, data which allow such a relationship to be derived for most of the variables is not available. In fact, even an average value curve may be more the product of guesswork than empirical techniques. Due to this lack of data, stochastic representation for these variables is not used in developing the model. For the present, stochastic representation will have to be considered only as a logical next step in improving the model.

APPENDIX B

NOMENCLATURE

The nomenclature used throughout this report in the simulation diagrams is based on the nomenclature developed by J. W. Forrester (1) for the same purpose. The elementary symbols are shown in Figure 35.

In simulating the energy system there are a number of variables which are described in the same way. For example, the generation facilities of different types and energy resources of different types. Also, some variables in planning and forecasting are represented in the same manner for a number of years. Where a number of variables are represented in the same way, a lot of clutter in the simulation diagrams tends to develop. For this reason, Forrester's nomenclature was modified to allow variables to be indexed. This can refer to either a "time" index or a "type" index or both. The kind of index is usually obvious from the context.

If a variable is indexed once, all symbols are represented as double lines. If it is indexed twice, all symbols are represented as triple lines. Examples of both are shown in Figure 36. This modification not only removes a lot of clutter from some simulation diagrams with little loss in information, it also shows at a glance the "dimension" of any variable or information flow in the system.

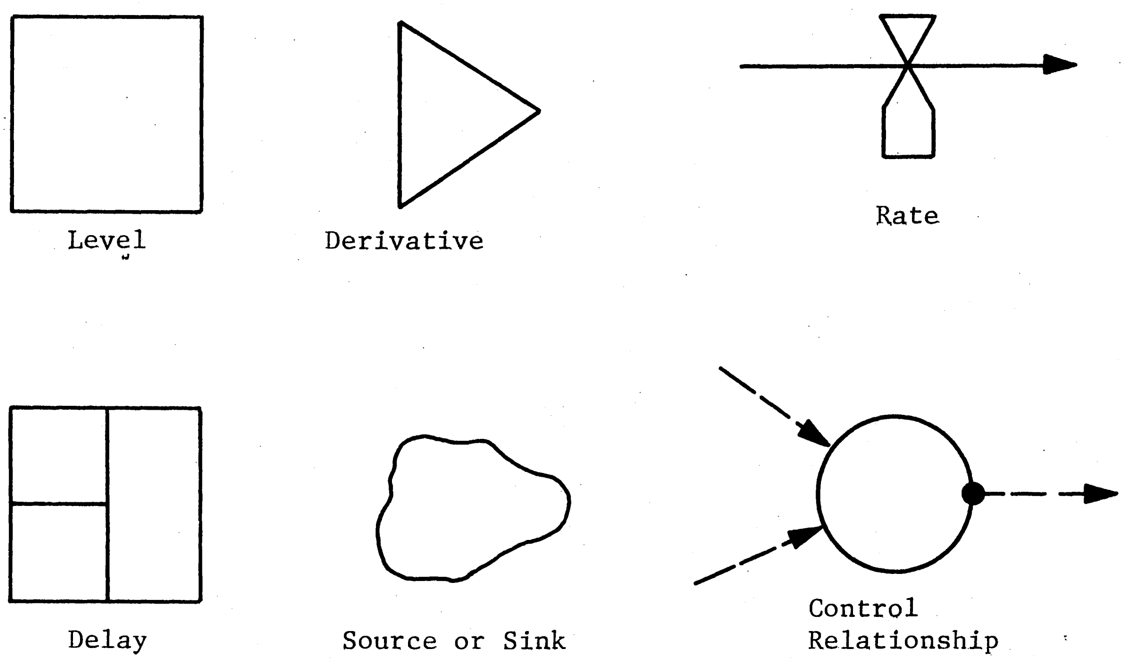

Figure 35. Symbols Used in Simulation Diagrams

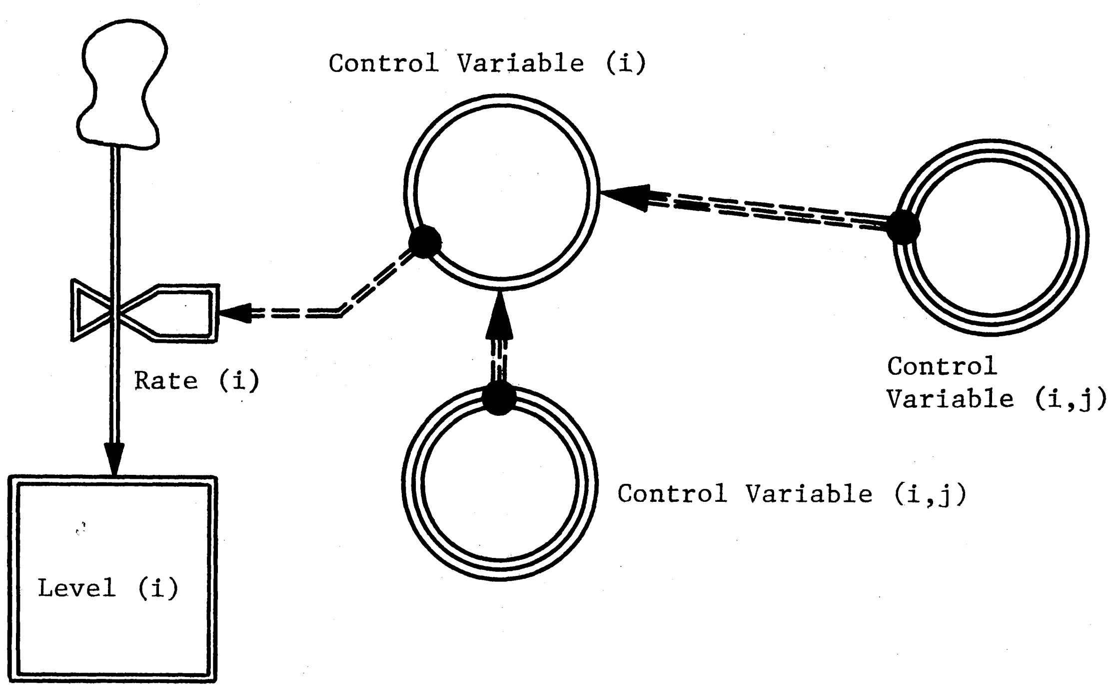

Figure 36. Example of Modified Symbols

APPENDIX C

VALIDATION DATA

Due to the nature of the simulation model and the inputs and parameters required, data often was not readily available in a usable form. Often, a considerable amount of judgment had to be exercised in selecting the exact numbers used. When possible, data supplied by the Federal Power Commission (50,51,53,54,55) was used. However, in many cases their data were not sufficient and other sources had to be tapped. A brief discussion of each of the inputs and parameters used in the validation follows.

Primary Inputs

Peak Electrical Demand

The peak electrical demand for the Oklahoma electric system was not directly available. However, total system energy demand was available in reference (50). The total net system energy was approximated by summing the net system energy for the four major electric utilities[2]. Data for the Western Farmer's Electric Cooperative were not reported separately before 1963. For these years the values used

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[2]Oklahoma Gas and Electric Company, Public Service Company of Oklahoma, Grand River Dam Authority, and Western Farmer's Electric Cooperative.

for that utility were extrapolated from the later data. Given the total net system energy, the peak demand was approximated using the load duration curve derived for the region. This curve results in a load factor of about 0.5. The derivation of the curve will be discussed later. The peak system demand data are shown in Figure 37.

Market Prices of Energy Resources

Almost all of the fuel used by power plants in Oklahoma (exclusive of hydroelectric facilities) during the validation period was natural gas. Thus, it was the only energy resource for which reliable data for the prices paid by electric utility companies could be found. The data used for this were obtained from reference (51). The values used for the validation run were the average of the price paid for all of the gas reported consumed by the four major electric utilities. They are shown in Figure 38.

Small amounts of fuel oil have been used at times by some of the electric utilities. This provided a few data points for oil price. However, there were not enough points to establish a good trend for the entire validation period. Information was available through 1969 for the average price at Oklahoma refineries (38). These data were used for this time period and were extrapolated for later years using the actual price paid as a guide. The values used in the validation are shown along with the data points for average price paid by the electric utilities in Oklahoma in Figure 38.

Even less coal has been purchased by the electric utility companies than oil. Thus, there was no good information regarding market prices from electric utility data. Instead, data for the average price at Oklahoma mines were used (52). Although it is unlikely that Oklahoma coal would have been used extensively if the utility companies had relied on this fuel, competitive forces should cause the Oklahoma mine price to reflect the cost of coal from other sources. The values used for coal price in the validation are shown in Figure 38.

Nuclear power plants were given little attention in Oklahoma during the validation period. Thus, there is little information about nuclear fuel prices in Oklahoma during this time. The price for nuclear fuel was arbitrarily set at 12¢/MMBTU at the beginning of the validation period and increase linearly to 18¢/MMBTU in 1973.

Energy Resources Available

The three variables describing energy resources available - Total Quantity of Each Energy Resource Available to Region, Fraction of Quantity Available to the Electric Utilities, and Fraction of Quantity Available as Long-Term Supplies - had little significance during the validation period. There was a sufficient supply of all energy resources. For this reason, no data were gathered. The inputs were arbitrarily set at values which allowed all supplies desired, to be purchased.

Primary Outputs

Generation Facilities Built

The data for generation facilities built were taken directly from the references (53) and (54), using only information for the four major electric utilities. The values used in the validation are shown in Figure 39.

Energy Generated by Each Type of Facility

Data concerning electrical energy generated were obtained from references (53) and (54). They are shown in Figure 40.

Energy Resources Consumed

Data for energy resources consumed were reported for each power plant in reference (51). Total use was derived by summing the use of individual plants. Natural gas was the only fuel used in significant quantities. The data are shown in Figure 41.

Electrical Energy Supplied to Region

Data was obtained for net electrical energy supplied by summing the net system energy for each of the four major electric utilities as discussed earlier. The data are shown in Figure 42.

Unmet Demands

There were no significant instances where electric demand was unmet in Oklahoma during the validation period. Thus, there are no data for this variable.

Total Cost of Generation

The total cost of generation depends, to some extent, on the method used to calculate the capital cost of the generation facilities. For this reason it was felt that for validation the variable cost would provide a better comparison. The data for this variable were obtained for 1963-1970 from reference (55). Since there was a dramatic rise in costs at the end of the validation period it was deemed necessary to extend the data beyond 1970. This was done by averaging the variable cost of each plant reported in reference (51). The costs were weighed according to electrical energy generated. The data are shown in Figure 43.

Primary Parameters

Demand Characteristics

No data were available for the demand characteristics (load duration curve) for the combined system of the electric utilities in Oklahoma. Typical load duration curves for the validation period were obtained from both Public Service Company of Oklahoma and Oklahoma Gas and Electric Company. Since both of these companies supply widespread regions in the state, it was felt that the load duration curves for either company should be fairly representative of the load duration of the state. The load duration curve used was obtained by averaging the curves for a number of years. The curve derived is shown in Figure 44.

Capacity Availability

The availability of each type of generation facility needs to be defined. Furthermore, this availability needs to be defined in relation to the time axis described by the load duration curve. The technique for developing the required curve is described in Appendix A.

Unfortunately, sufficient data were not available to use such techniques. Since natural gas boilers are the only type of facility which has been used extensively in the region, this was the only type for which data were available. Unfortunately, this data was reduced by "magnitude ordering" the outages. Thus, it could not be directly converted to the desired time base. For lack of better information, this curve was used on an "as is" basis.

Natural gas boilers have typically had fewer problems than other types of generation facilities using heat energy. Thus, availability curves were generated for coal boilers, gas turbines, and nuclear plants by arbitrarily decreasing the availability for natural gas boilers. On the other hand, hydroelectric generation facilities usually have very few outage problems. However, in Oklahoma they are often severely limited by water flow rates. This causes some problems in formulating the availability curve. The water flow rate can vary considerably throughout the year as well as from year to year. Also, there is a certain amount of peaking capability at most times, since the water flow can be stored for short periods in a lake. With all of this in mind, an availability curve was derived using the average load factor as the main criteria in developing the curve. All of the availability curves used in the validation run are shown in Figure 45.

Capital Cost of Generation Facilities

Capital cost data for steam powered plants were available from reference (51). The values used for coal and natural gas plants were derived by averaging costs for new plants during the validation period. Data from other regions were included in these calculations. Due to the long construction time required for capacity construction and the rapid increase in its cost, this scheme was deemed insufficient for nuclear capacity. The cost for it was arbitrarily increased to 50% greater than the average cost. Data were not available from the same source for gas turbine capital cost. Discussions with people in the industry indicated gas turbines usually cost about 75% of the cost of natural gas boilers. The capital costs used in the validation run are shown in Table X. These values are meant to reflect the cost seen by the electric utilities during the validation period and should not be considered as indicative of current costs.

Yearly Fixed Costs for Generation Facilities

The yearly fixed cost of generation facilities is directly related to the capital cost. For the validation run the capital cost was amortorized at 8% interest using equal payments over an assumed thirty year life span. The results are shown in Table X. Again, these values are meant to reflect the conditions during the validation period and not present conditions. In reality there are probably some non-capital fixed costs associated with maintenance. These costs are included with the variable costs.

Non-Fuel Variable Costs

The non-fuel variable costs were considered equivalent to operation and maintenance cost. Data for this were available from reference (51). Again, data for other regions were used. The variation in these costs were considerable. Natural gas boiler plant costs ranged from 0.3 - 0.4 mills/KWH for newer plants and 0.5 - 1.0 mills/KWH for older plants. Coal plants costs ranged from 0.6 - 1.0 mills/KWH for new plants and 1.0 - 3.0 mills/KWH for older plants. The variations for nuclear plants was even more dramatic with costs ranging from 0.4 - 19.3 mills/KWH.

No data were available from the same source for gas turbine costs. Discussions with people in the industry indicated that these run considerably higher than the costs for natural gas boilers.

With variations such as these it is difficult to select a single value for each type of capacity which is representative of the costs. The values used are shown in Table X and represent mid-range values.

Heat Rates

Heat rate information was available from reference (51) for all but gas turbine generation. The heat rate values tended to vary considerably. The heat rates for natural gas boilers were around 10,000 BTU/KWH for all new plants and ranged up to 15,000 BTU/KWH for older plants. The heat rate for new coal plants ranged from 8550 BTU/KWH to 10,500 BTU/KWH depending upon the type of plant, quality of coal used, and the pollution equipment installed. For older plants it ranged up to 16,000 BTU/KWH. All nuclear plants are relatively new and their heat rates ranged from 10,000 BTU/KWH to 12,000 BTU/KWH, depending upon the type of plant. Gas turbine data were not included in the source, but their heat rates run considerably lower than modern fossil fuel plants. This allows their heat rates to be inferred.

The values used for heat rates in the validation are shown in Table X. These values represent mid-range values for the newer plants.

Construction Time

The construction times used in the validation program are shown in Table X. These values resulted from discussions with people in the electric utility industry.

Secondary Inputs and Parameters

Few data were readily available for the secondary inputs. This is especially true of the variables describing supplies and demand of the various energy forms. In view of this lack of data, all short-term inter-regional transactions were included in the model as economy energy supply and demands. The supplies and demands were then arbitrarily defined so as to yield results in the correct range. Inter-regional transactions were relatively small during the validation period. Thus, this simplification should cause no major problems. The supplies and demands used in the validation are shown in Figure 46.

The other two secondary inputs - maximum capacity allowed and capital limits - were not important factors during the validation period. Thus, they were set at sufficiently high values to prevent them from affecting the simulation.

Many of the secondary parameters were rather arbitrary. Table XI summarizes the values used in the validation.

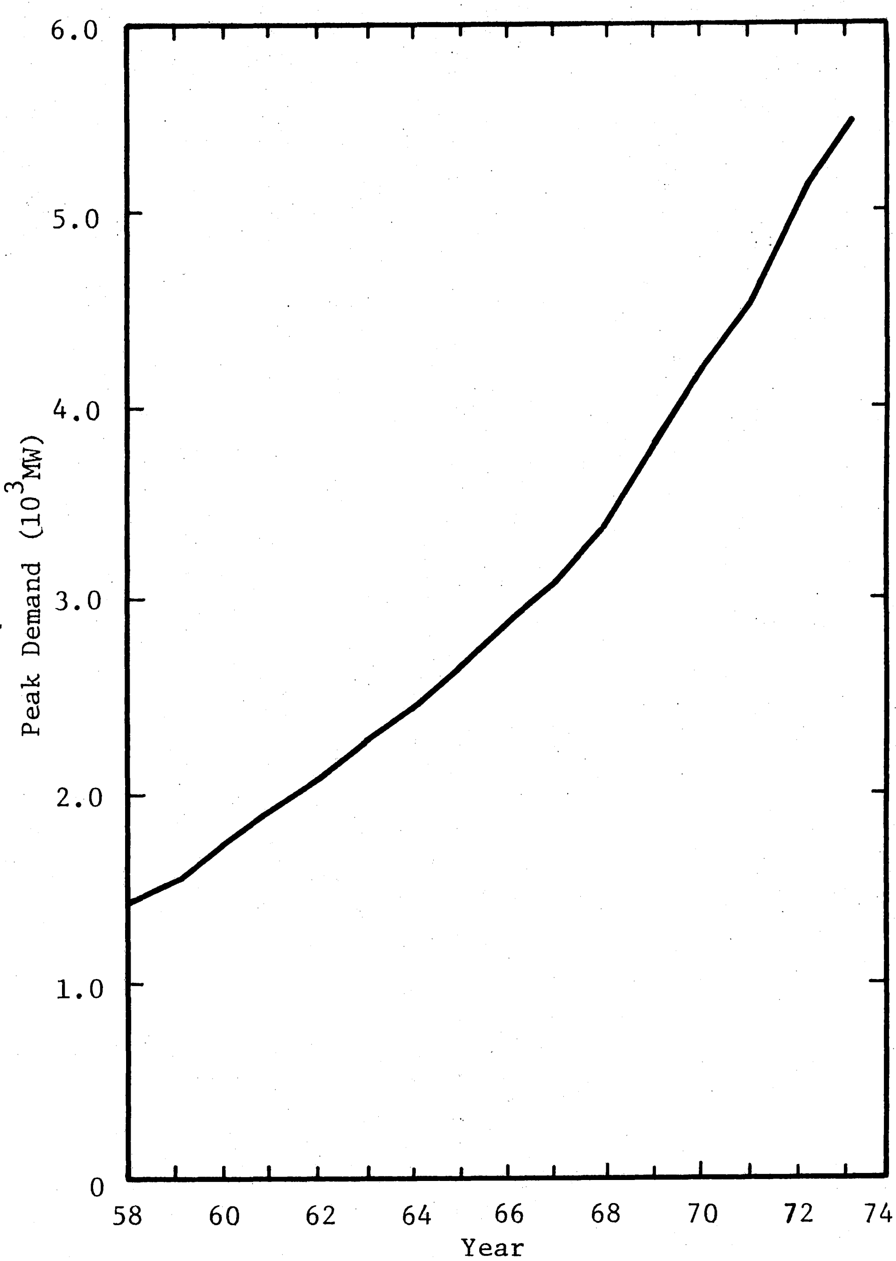

Figure 37. Historical Data for Peak System Demand

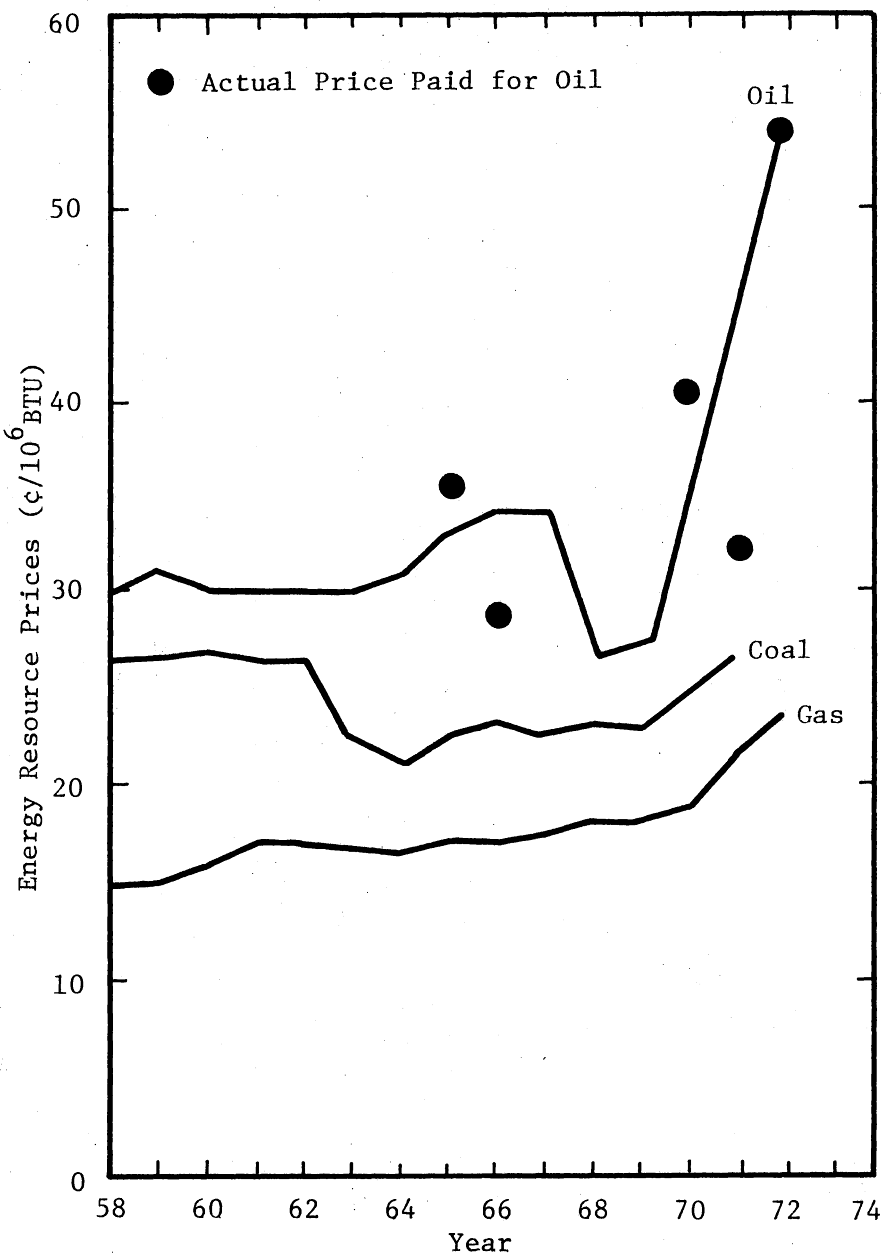

Figure 38. Historical Data for Energy Resource Prices

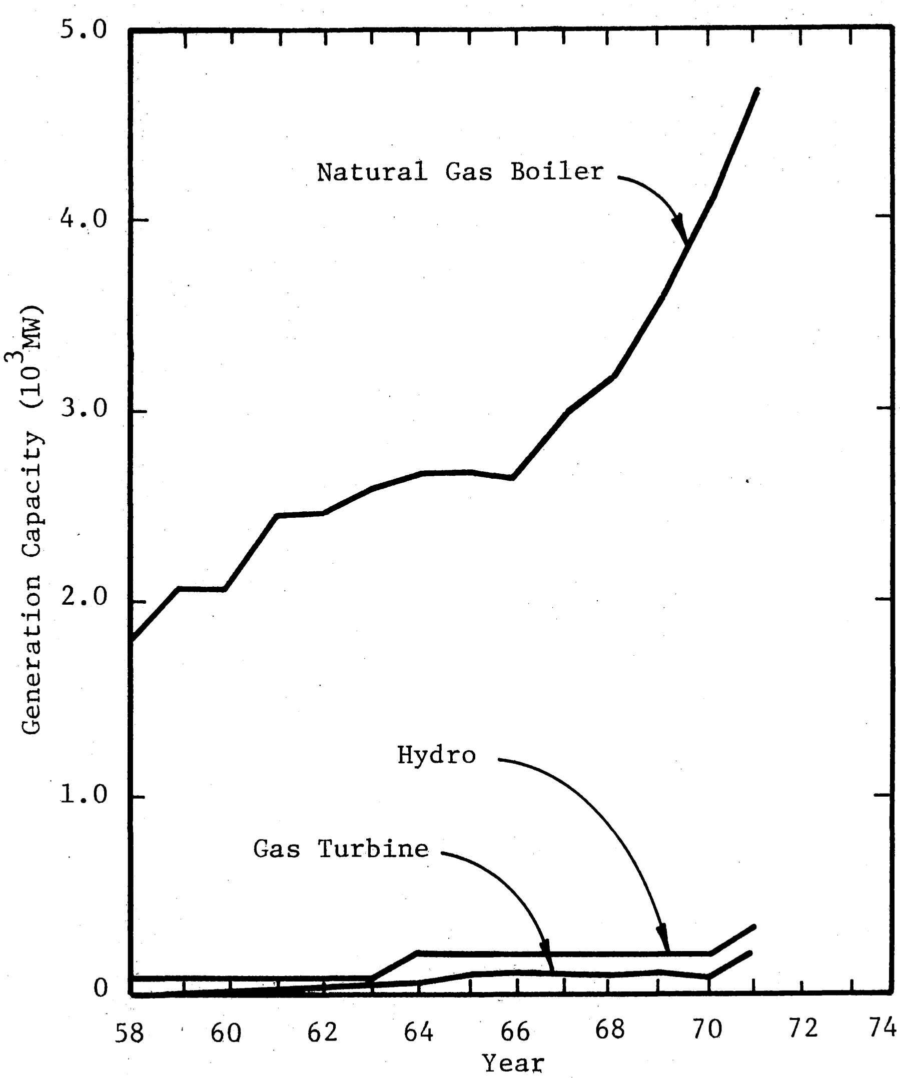

Figure 39. Historical Data for Generation Facilities Installed

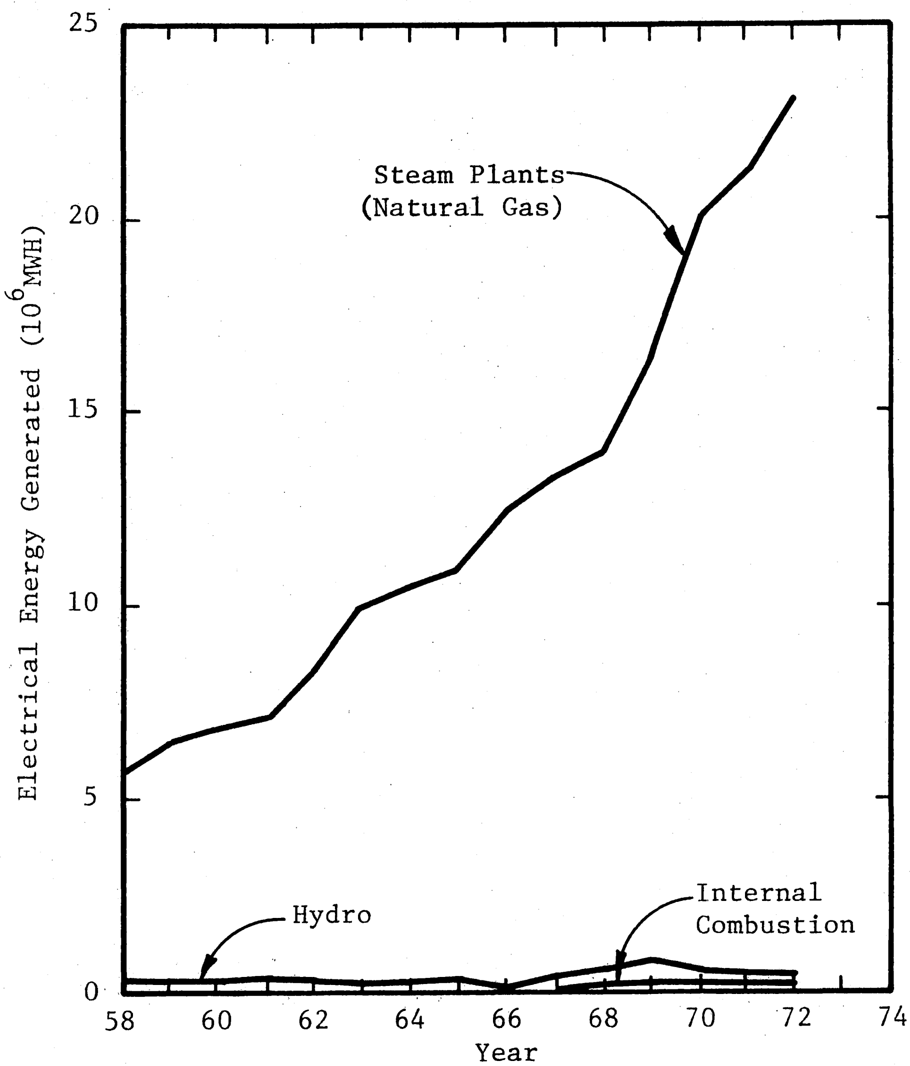

Figure 40. Historical Data for Electrical Energy Generated

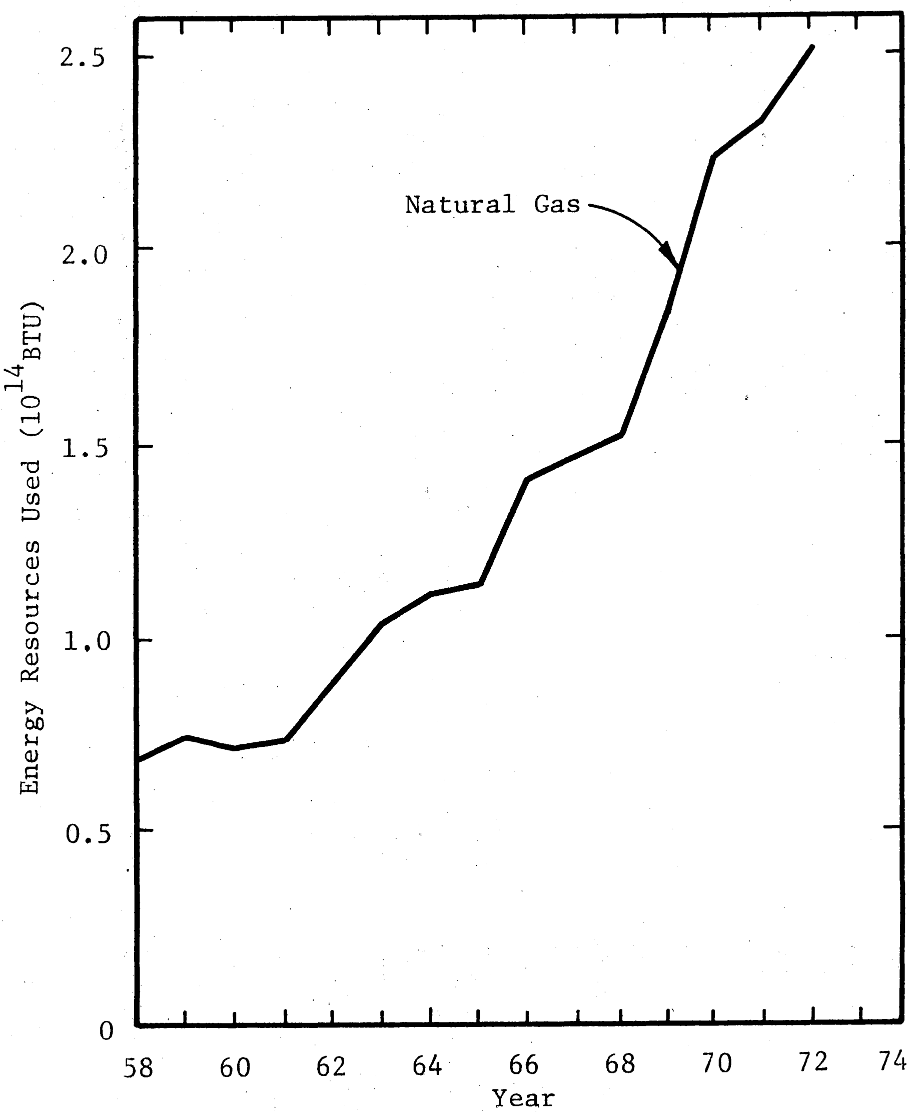

Figure 41. Historical Data for Energy Resources Used

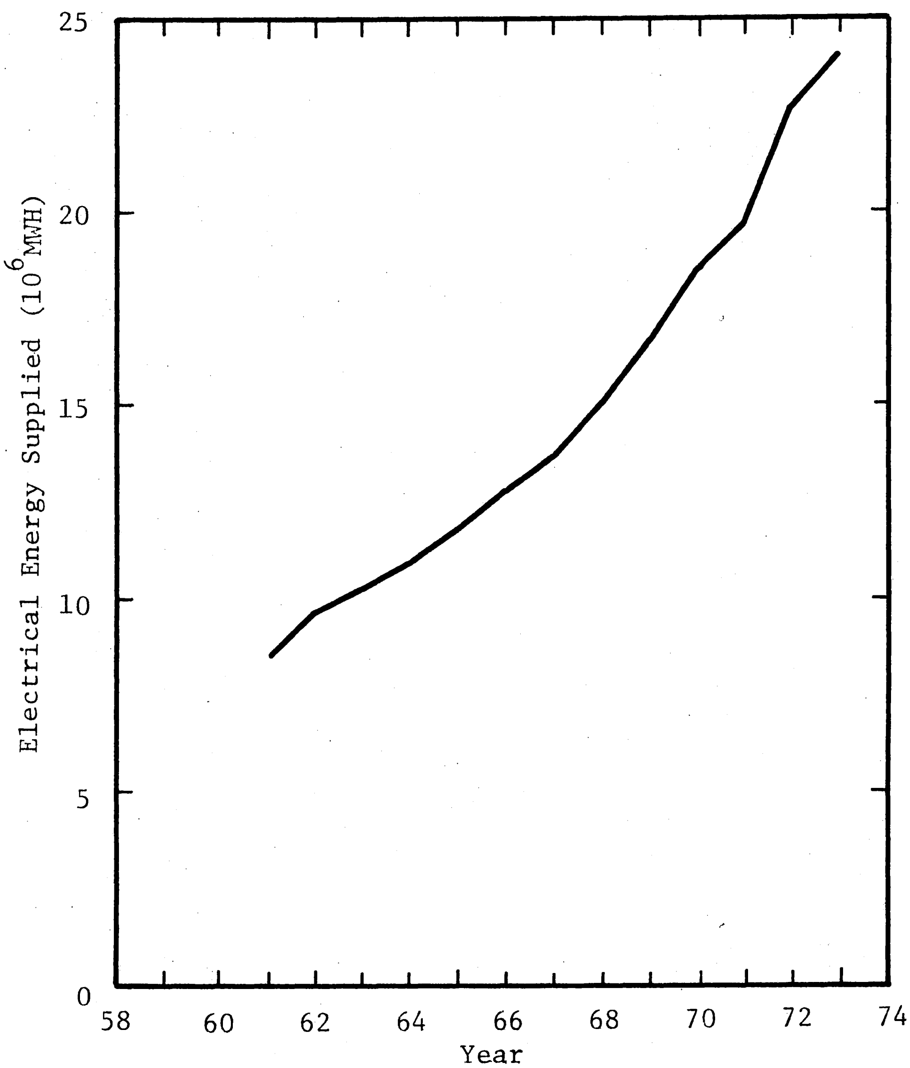

Figure 42. Historical Data for Electrical Energy Supplied

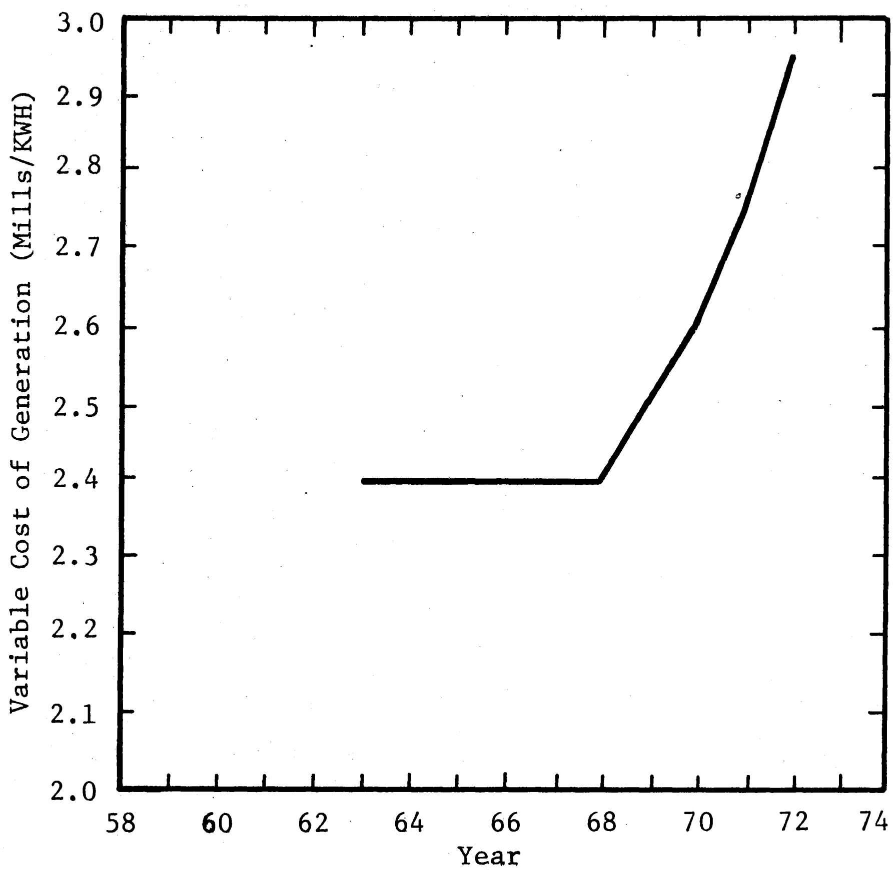

Figure 43. Historical Data for Variable Cost of Generation

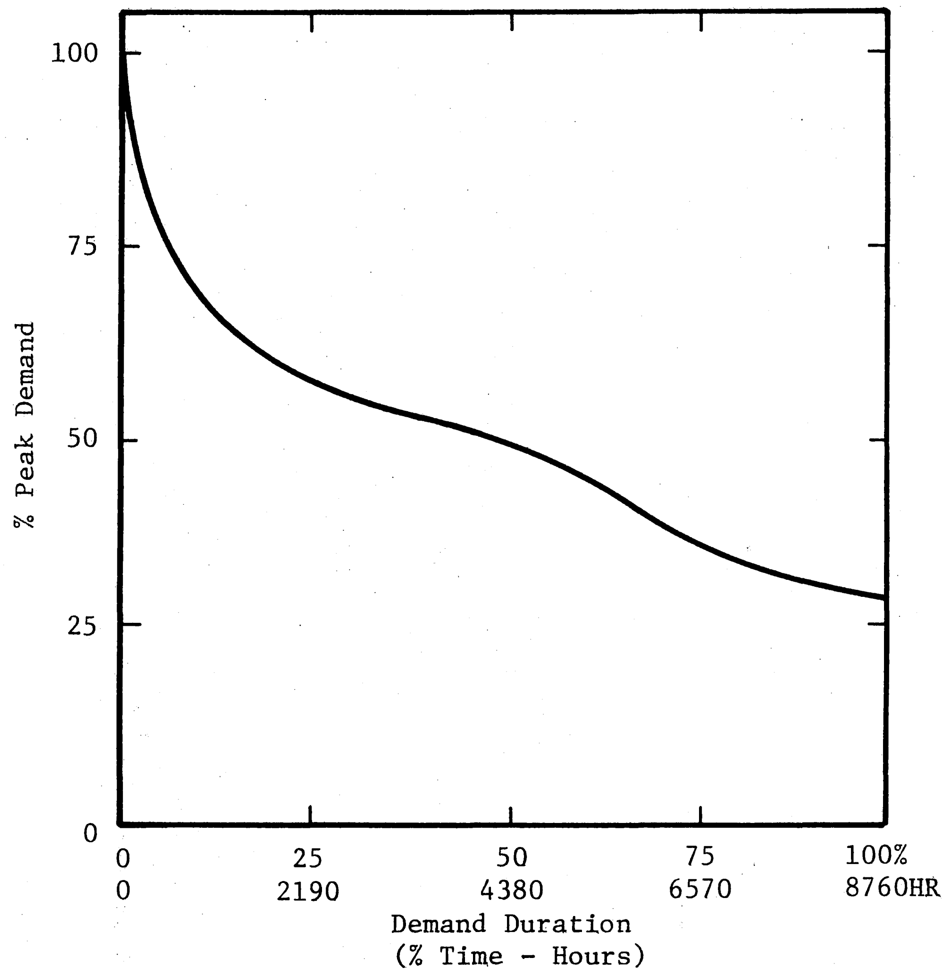

Figure 44. Demand Characteristics Used for Validation

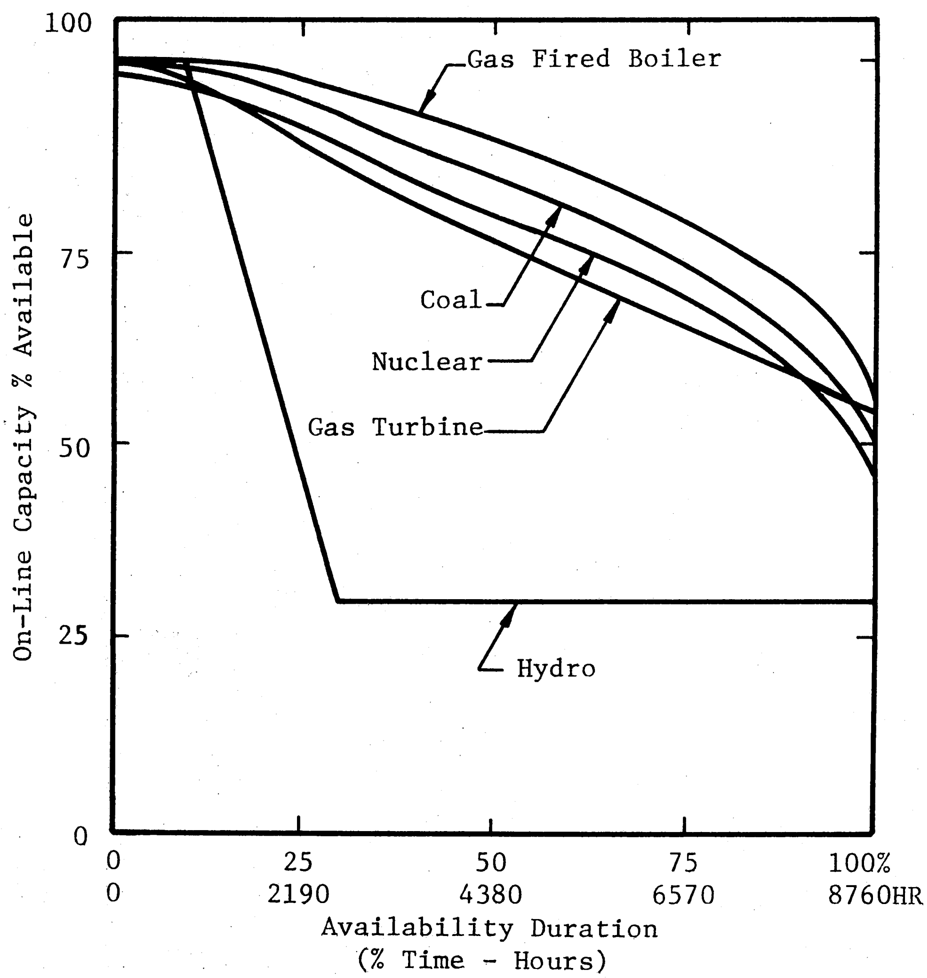

Figure 45. Generation Availability Curves Used for Validation

TABLE X

PARAMETERS USED IN VALIDATION

Capacity Type	Capital Cost ($/KWH)	Yearly Fixed Cost ($/KWH-yr)	Non-Fuel Variable (mills/KWH)	Heat Rates (BTU/KWH)	Construction Time (Yr)
Natural Gas Boilers	100	8.88	0.50	10,000	4
Coal Boilers	145	12.87	0.90	9,250	6
Nuclear	315	28.00	1.90	11,000	9
Gas Turbine	85	7.55	1.75	11,500	2

TABLE XI

SUMMARY OF SECONDARY PARAMETERS

Variable Name	Values Used
Expected Regional Demand Characteristics	Same as Actual Demand Characteristics
Characteristics of Demand from Firm Power Sales	Not Required
Expected Characteristics from Firm Power Sales	Not Required
Desired Reserve Capacity	15% Minimum
Proportionality Constant Relating Deliverability to Total Energy Resource Supplies	Relevant only for Natural Gas 0.10/year
Forecasting Delay Constants	Inputs - 2 years Growth Rates - 3 years
Energy Resource Supply Delay Constants	5 years
Long-Term Supply Price Delay Constants	5 years

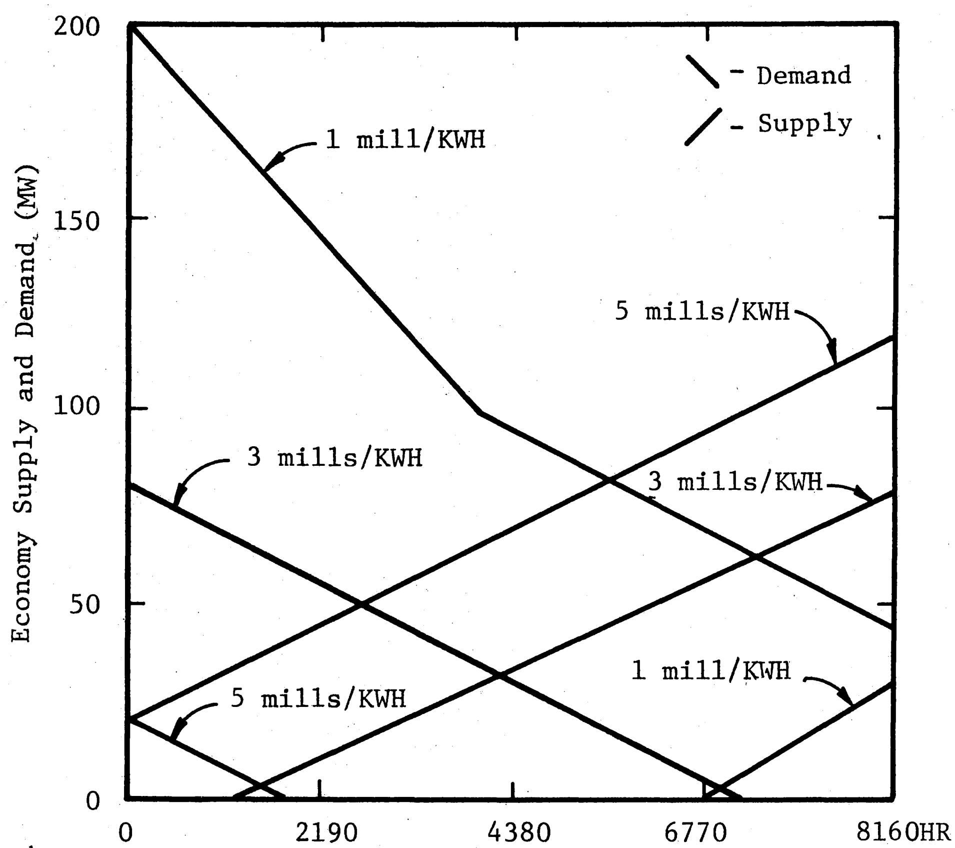

Figure 46. Supply and Demand for Economy Energy Used for Validation

APPENDIX D

COMPUTER PROGRAM

This appendix contains a complete FORTRAN listing of the model. The listing is for the program as it was used in the boiler fuel study. Statements with CC in the last columns represent additions to the base model which were necessary for this study. Statements with CCR1 are statements that were used for regulation 1 in this study.

A list of the important variables and their definitions is presented in Table X. The variables are grouped according to their function. After the definition of each variable the proper units are shown in parenthesis. It is not necessary to use the units shown as long as a consistent set is used. The output for the simulation, however, assumes the units shown are used.

The computer program consists of a series of subroutines. The main program serves only to control the simulation. That is, it determines when to call subroutines which initialize the system, output information, input information, updates levels, etc. All of the detailed calculations are made in subroutines.

All information used in the simulation, except for simulation control variables, is obtained through two input subroutines - ELIN and ELIP. The simulation control variables are read in or specified in the main program. ELIN is called on only once, at the beginning of the simulation. It reads in all of the initial conditions and values of parameters which do not normally change during the simulation. ELIP is called at each time step in the simulation. It reads in values for all inputs and parameters which may change during the simulation.

ELIN is a regular part of the simulation program. A 8G10.3 format is used for all decimal variables. The G format is used to provide maximum flexibility. A 20I5 format is used for all interger variables. The standard FORTRAN practice of using variables starting with letters I through N for interger variables is used throughout. The order of data input is seen in the listing of ELIN.

ELIP is a user supplied subroutine. However, a user of the model may wish to use the subroutine presented in the listing. In this version, all inputs and parameters not read in ELIN are read at the beginning of the simulation by ELIP. This part of the subroutine is skipped during the rest of the simulation and only changes in variables are considered. The only FORTRAN statements required by the user are those which specify changes in variables. The formats and nomenclature for this version of ELIP are the same as in ELIN.

TABLE XII

DEFINITION OF VARIABLES IN COMPUTER PROGRAM

Simulation Control

BEGTIM - Starting date for simulation. (YR)

DT - Integration time step. (YR)

FINTIM - Ending date for simulation. (YR)

NDT - Integration steps per year. (YR^{-1})

NOUT - Number of integration steps between outputs. (-)

NRD - Computer reader number. (-)

NW - Computer printer number. (-)

TIME - Time (or date) in simulation. (YR)

Inputs

CAPM(I,J) - Maximum capacity of type I that is allowed to be built to come on line in year J. (MW)

CPTLM - Maximum rate at which capital can be committed for new generation facilities. ($/YR)

ECDEM(I,J) - Demand for economy energy at price PDEM(I). (MW)

ECSUP(I,J) - Supply of economy energy at price PSUP(I). (MW)

ELDM - Peak demand for electricity. (MW)

EMCOS - Cost of emergency energy. ($/MWH)

EMER(I) - Demand for emergency energy. (MW)

EMPRC - Price received for emergency energy sales. ($/MWH)

ERAP (I) - Fraction of energy resource type I available to electric utilities. (-)

ERAQ(I) - New energy resources of type I available in region. (BTU/YR)

ERFLT(I) - Fraction of energy resource type I available as long-term supply. (-)

ERP(I) - Price of energy resource type I. ($/BTU)

FIRMX - Maximum firm capacity purchase allowed. (MW)

FRMSM - Maximum firm capacity sale allowed. (MW)

FRMVC(I) - Variable cost of firm energy purchased vs. capacity purchased. ($/MWH)

TABLE XII (Continued)

FRMVP(I) - Variable price of firm energy sold vs. capacity sold. (\$/MWH)

FXCF - Fixed cost or price of firm capacity. (\$/MW-YR)

PDEM(I) - Price levels for economy energy demand. (\$/MWH)

PSUP(I) - Price levels for economy energy supply. (\$/MWH)

Parameters

AFDEM(I) - Anticipated demand from firm capacity sales. (MW)

AVL(I,J) - Availability of type I capacity. (-)

CPCOS(I) - Investment cost of capacity type I. (\$/MW)

DCNST(I) - Deliverability of type I declining resources. (YR^{-1})

DUR(I) - Load duration of demand in region. (-)

EMXCN(I) - Maximum energy which can be supplied with type I contracted capacity. (MWH/MW-YR)

FC(I) - Fixed cost of capacity type I. (\$/MW-YR)

FSDM(I) - Demand which arises from firm capacity sale. (MW)

FSF - Ratio of peak demand from firm capacity sale to capacity sold. (-)

HTRT(I) - Heat rate for capacity type I. (BTU/MWH)

ICPT(I) - Time required for construction of type I capacity. (YR)

ICTT(I) - Length of capacity contract I. (YR)

IFF(I) - Array for function description - altered. (*)

IFS(I) - Array for function description - standard. (*)

IYPLN - Length of planning period. (YR)

K1 - Number of price levels in supply of economy energy. (-)

K2 - Number of price levels in demand for economy energy. (-)

N - Total number of capacity types considered. (-)

NCAP(I) - Specifies capacity I's classification (1 - inside region, 0 - outside region)

NER - Number of energy resources types considered. (-)

NERT(I) - Classification of energy resource I (0 - declining, 1 - constant)

RES - Fraction of reserve capacity desired. (-)

VCNF(I) - Non-fuel variable cost of operation for capacity type I. (\$/MWH)

---

* See subroutine AFNC

TABLE XII (Continued)

Levels

CAPOL1(I) - On-line capacity delay level 1 for type I. (MW)

CAPOL2(I) - On-line capacity delay level 2 for type I. (MW)

CAPOL3(I) - On-line capacity delay level 3 for type I. (MW)

CAPSR(I) - Semi-retired capacity type I. (MW)

CERCNC(I,J) - Constant long-term energy resource supplies of type I to be available for J years. (BTU/YR)

CPCN(I,J) - Capacity type I under construction J years from being completed. (MW)

CPCNC(I,J) - Type I long-term capacity contracts J years from expiring. (MW)

CPCNCT(I) - Total long-term type I capacity contracts. (MW)

CPCNF(I,J) - Future type I long-term capacity contracts J years from being active. (MW)

CPCNFT(I) - Total future type I long-term capacity contracts. (MW)

CPCNT(I) - Total capacity type I under construction. (MW)

ERCN(I) - Supplies of energy resource type I. declining - (BTU) constant - (BTU/YR)

FERCNC(I,J) - Constant energy resource type I supply available in J years. (BTU/YR)

SMD - Smoothed peak demand. (MW)

SMDG - Smoothed growth rate of peak demand. (YR^{-1})

SMERQ(I) - Smoothed quantity of new resource type I available. (BTU/YR)

SMERQG(I) - Smoothed rate of change of quantity of new resource type I available. (YR^{-1})

SMERQG(I) - Smoothed rate of change of quantity of new resource type I available. (YR^{-1})

SMRA(I) - Smoothed fraction of new resource type I available to electric utilities. (-)

SMRAG(I) - Smoothed rate of change of fraction of new type I resources available to electric utilities. (YR^{-1})

SMRP(I) - Smoothed price of resource type I. ($/BTU)

SMRPG(I) - Smoothed rate of change of price or resource type I. (YR^{-1})

Derivatives

ELDML - Previous value of peak demand. (MW)

TABLE XII (Continued)

ERAPL(I) - Previous value of fraction of new energy resource type I available to electric utilities. (-)

ERAQL(I) - Previous value of quantity of new energy resource type I available. (BTU/YR)

ERPL(I) - Previous value of energy resource price. ($/BTU)

Rates

DCAPL1(I) - Rate at which capacity type I comes on-line. (MW/YR)

DCAPL2(I) - Rate at which capacity type I enters delay level 2. (MW/YR)

DCAPL3(I) - Rate at which capacity type I enters delay level 3. (MW/YR)

DCAPSR(I) - Rate at which capacity type I is retired. (MW/YR)

DCPCN(I) - Rate at which construction starts on new capacity type I. (MW/YR)

DCPCNC(I) - Rate at which new long-term capacity contract type I comes into use. (MW/YR)

DCPCNF(I) - Rate at which new long-term capacity contract type I is made. (MW/YR)

DERCNC(I) - Rate at which new long-term supplies of energy resource type I are secured. declining - (BTU/YR), constant - (BTU/YR-YR)

DSMD - Rate of change of smoothed peak demand. (MW/YR)

DSMDG - Rate of change of smoothed rate of change of peak demand. (YR^{-2})

DSMERQ(I) - Rate of change of smoothed new energy resources of type I available. (BTU/YR-YR)

DSMRA(I) - Rate of change of smoothed fraction of new resource type I available to region. (YR^{-1})

DSMRAG(I) - Rate of change of smoothed rate of change of new resource type I available. (YR^{-2})

DSMRP(I) - Rate of change of smoothed resource price of type I. ($/BTU-YR)

DSMRPG(I) - Rate of change of smoothed rate of change of resource price of type I. (YR^{-2})

DSMRQG(I) - Rate of change of smoothed rate of change of new resource type I available. (YR^{-2})

ERUSED(I) - Rate at which declining resource type I is used. (BTU/YR)

TABLE XII (Continued)

EXCPCR(I) - Rate at which long-term capacity contracts of type I expire. (MW/YR)

Output Variables Not Previously Listed

ACCAP - Rate at which capital commitments are made for new generation facilities. ($/YR)

CAPP(I,J) - Capacity planned of type I for year J. (MW)

CFEB - Cash flow for economy energy purchased. ($/YR)

CFERU(I) - Cash flow for energy resources of type I purchased. ($/YR)

CFES - Cash flow from economy energy sold. ($/YR)

CFFB - Cash flow for firm energy purchased. ($/YR)

CFFS - Cash flow from firm energy sold. ($/YR)

CFMB - Cash flow for emergency energy purchased. ($/YR)

CFMS - Cash flow from emergency energy sold. ($/YR)

ERC(I) - Electrical energy generated by capacity type I. (MWH/YR)

EREB - Economy energy purchased. (MWH/YR)

ERES - Economy energy sold. (MWH/YR)

ERFB - Firm energy purchased. (MWH/YR)

ERFS - Firm energy sold. (MWH/YR)

ERMB - Emergency energy purchased. (MWH/YR)

ERMS - Emergency energy sold. (MWH/YR)

ERUR - Electrical energy supplied to region. (MWH/YR)

FELDM(J) - Forecast of peak demand in year J. (MW)

FERAQ(I,J) - Forecast of new energy resources of type I available in year J. (BTU)

FERP(I,J) - Forecast price of energy resource type I in year J. ($/BTU)

FIRM - Firm capacity purchased. (MW)

FMSL - Firm capacity sold. (MW)

TGCOS - Total generation cost for supplying electrical energy to region. ($/MWH)

UEDF - Unmet demand from firm capacity sold. (MWH/YR)

UEDR - Unmet demand in region. (MWH/YR)

VGCOS - Variable cost of generation for electrical energy supplied to region. ($/MWH)

Computer Program Listing

80/80 LIST

```
00000000011111111112222222222333333333344444444445555555555666666666677777777778
12345678901234567890123456789012345678901234567890123456789012345678901234567890
C*****     COMMON VARIABLES ********************************************
C*****     SIMULATION CONTROL VARIABLES
      COMMON TIME,FINTIM,BEGTIM,DT,NOT,NW,NRD,NOUT
C*****     BASIC INPUTS
      COMMON ECSUP(3,42),ECDEM(3,42),CAPM(5,10),DUR(42),EMER(42),
     1FSDM(42),FRMVC(20),FRMVP(20),PSUP(3),PDEM(3),ERP(4),ERAP(4),
     2ERAQ(4),ERFLT(4),ELDM,FXCF,FIRMX,FRMSM,EMPRC,EMCOS,CPTLM
C*****     PARAMETERS
      COMMON AVL(9,42),AFDEM(21),VCNF(9),HTRT(9),EMXCN(1),FC(5),CPCOS(5)
     1,DCNST(4),RES,FSF
      COMMON NCAP(5),ICPT(5),ICTT(1),IFF(5),IFS(5),ICNTIM(4),
     1NERT(4),NERCT(4),NERDT(4),N,NER,K1,K2,IYPLN
C*****     LEVELS
      COMMON CERCNC(3,20),FERCNC(3,10)
      COMMON CPCN(4,20),CPCNC(1,30),CPCNF(1,10),SMRP(4),SMRPG(4),SMRA(4)
     1,SMRAG(4),SMERQ(4),SMERQG(4),CPCOL(4),CAPOL1(4),CAPOL2(4),
     2CAPOL3(4),CAPSR(4),CPCNCT(1),CPCNT(4),CPCNFT(1),ERCN(4),ERCNS(4),
     3ERCNM(4),SMD,SMDG
C*****     RATES
      COMMON DSMRP(4),DSMRPG(4),DSMRA(4),DSMRAG(4),DSMERQ(4),DSMRQG(4),
     1DCPCNF(4),DCPCN(4),DCAPL1(4),DCAPL2(4),DCAPL3(4),DCAPSR(4),
     2DCPCNC(1),EXCPCR(1),DERCNS(4),DERCNC(4),ERCCF(4),ERUSED(4),
     3CFERU(4),DERUP(4),DSMD,DSMDG
C*****     DERIVATIVES
      COMMON ERPL(4),ERAPL(4),ERAQL(4),ELDML
C*****     INTERNAL VARIABLES
      COMMON FERAQ(4,10),FERP(4,10),CAPP(5,10),AA(42),SCLCP(9),ERUP(4),
     1VC(9),ENR(9),FCPL(9),FCP(9),ERC(9),CAPMX(5),FELDM(10),CAPMAX(10),
     2ENRMX(5),ERN(5),CAPD(10),ERUS(5),E1LLOW(4),DERATE(9),ERAV(4)
      COMMON SCLDM,SCLDF,FIRM,FMSL,ERFB,ERFS,EREB,ERES,ERMB,ERMS,CFFB,
     1CFEB,CFES,UEDR,UEDF,ERUR,CFFS,VGCOS,CFMB,CFMS,ACCAP,TGCOS
      COMMON NR(20,2),NS(21),NC(10),KRANK,NN,III,IL
C*****     FUNCTION VARIABLES
      COMMON XFNC(25,21,2),IFNC(25,5),IERROR
      NRD=5
      NW=6
      READ(NRD,1000) BEGTIM,FINTIM,DT
      READ(NRD,1001) NOUT
      WRITE(NW,1002) BEGTIM,FINTIM,DT,NOUT
      NCT=IFIX(1./DT+.1)
      TIME=BEGTIM
      NOT=0
      CALL ELIN
      BT=BEGTIM+.01
  100 CALL ELIP
      IF(TIME.GT.BT) GO TO 105
      IT1=IFIX(BT)
      IT2=IFIX(FINTIM+.01)
      WRITE(NW,1003)
      WRITE(NW,1004) IT1,IT2,N,NER
  105 CALL ALGEL
      IF(NOT.NE.0) GO TO 110
      CALL OUTPUT
  110 NOT=NOT+1
```

80/80 LIST

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000000000111111111122222222223333333333444444444455555555556666666666777777777778
12345678901234567890123456789012345678901234567890123456789012345678901234567890
      IF(NOT.GE.NOUT) NOT=0
      IF(TIME.GE.FINTIM) GO TO 200
      TIME=TIME+DT
      CALL ELUD
      GO TO 100
  200 CONTINUE
 1000 FORMAT(8G10.3)
 1001 FORMAT(20I5)
 1002 FORMAT(10H DATA DUMP//3G15.4,I5)
 1003 FORMAT('1'////////////40X,40H *************************************
     1***//40X,40H DYNAMIC REGIONAL ENERGY SYSTEM ANALYSIS//44X,
     232H ELECTRICAL ENERGY SUPPLY SECTOR)
 1004 FORMAT(//////////46X,15H SIMULATION FOR,I5,3H TO,I5//////////48X,
     1I2,22H TYPES OF POWER PLANTS//46X,I2,26H FORMS OF ENERGY RESOURCES
     2)
      STOP
      END
C
      SUBROUTINE ELIN
C*****     INITIALIZE NON-VAR.ING PARAMETERS
      READ(NRD,1001) N,NER,K1-K2,IYPLN
      WRITE(NW,1001) N,NER,K1,K2,IYPLN
      READ(NRD,1001) (NERT(I),I=1,NER)
      WRITE(NW,1001) (NERT(I),I=1,NER)
      DO 95 I=1,NER
      IF(NERT(I).EQ.0) GO TO 90
      READ(NRD,1001) NERCT(I),NERDT(I)
      WRITE(NW,1001) NERCT(I),NERDT(I)
      GO TO 95
   90 READ(NRD,1000) DCNST(I)
      WRITE(NW,1000) DCNST(I)
   95 CONTINUE
      READ(NRD,1001) (IFS(I),I=1,5)
      WRITE(NW,1001) (IFS(I),I=1,5)
      READ(NRD,1001) (IFF(I),I=1,5)
      WRITE(NW,1001) (IFF(I),I=1,5)
      READ(NRD,1001) (ICPT(I),I=1,N)
      WRITE(NW,1001) (ICPT(I),I=1,N)
      READ(NRD,1001) (NCAP(I),I=1,N)
      WRITE(NW,1001) (NCAP(I),I=1,N)
      READ(NRD,1001) (ICNTIM(I),I=1,NER)
      WRITE(NW,1001) (ICNTIM(I),I=1,NER)
C*****     INITIALIZE LEVELS
      READ(NRD,1000) SMD,SMDG
      WRITE(NW,1000) SMD,SMDG
      READ(NRD,1000) (SMRP(I),I=1,NER)
      WRITE(NW,1000) (SMRP(I),I=1,NER)
      READ(NRD,1000) (SMRPG(I),I=1,NER)
      WRITE(NW,1000) (SMRPG(I),I=1,NER)
      READ(NRD,1000) (SMRA(I),I=1,NER)
      WRITE(NW,1000) (SMRA(I),I=1,NER)
      READ(NRD,1000) (SMRAG(I),I=1,NER)
      WRITE(NW,1000) (SMRAG(I),I=1,NER)
      READ(NRD,1000) (SMERQ(I),I=1,NER)
```

80/80 LIST

```
00000000011111111112222222222333333333344444444445555555555666666666677777777778
12345678901234567890123456789012345678901234567890123456789012345678901234567890
CARD
      WRITE(NW,1000) (SMERQ(I),I=1,NER)
      READ(NRD,1000) (SMERQG(I),I=1,NER)
      WRITE(NW,1000) (SMERQG(I),I=1,NER)
      READ(NRD,1000) (CPCOL(I),I=1,NER)
      WRITE(NW,1000) (CPCOL(I),I=1,NER)
      READ(NRD,1000) (CAPOL1(I),I=1,NER)
      WRITE(NW,1000) (CAPOL1(I),I=1,NER)
      READ(NRD,1000) (CAPOL2(I),I=1,NER)
      WRITE(NW,1000) (CAPOL2(I),I=1,NER)
      READ(NRD,1000) (CAPOL3(I),I=1,NER)
      WRITE(NW,1000) (CAPOL3(I),I=1,NER)
      READ(NRD,1000) (CAPSR(I),I=1,NER)
      WRITE(NW,1000) (CAPSR(I),I=1,NER)
      READ(NRD,1000) (CPCNT(I),I=1,NER)
      WRITE(NW,1000) (CPCNT(I),I=1,NER)
      READ(NRD,1000) (ERCN(I),I=1,NER)
      WRITE(NW,1000) (ERCN(I),I=1,NER)
      READ(NRD,1000) (ERUP(I),I=1,NER)
      WRITE(NW,1000) (ERUP(I),I=1,NER)
      DO 100 I=1,NER
      NA=ICPT(I)*NDT
      READ(NRD,1000) (CPCN(I,K),K=1,NA)
  100 WRITE(NW,1000) (CPCN(I,K),K=1,NA)
      NA=N-NER
      IF(NA.EQ.0) GO TO 200
      READ(NRD,1001) (ICTT(I),I=1,NA)
      WRITE(NW,1001) (ICTT(I),I=1,NA)
      READ(NRD,1000) (CPCNCT(I),I=1,NA)
      WRITE(NW,1000) (CPCNCT(I),I=1,NA)
      READ(NRD,1000) (CPCNFT(I),I=1,NA)
      WRITE(NW,1000) (CPCNFT(I),I=1,NA)
      DO 110 I=1,NA
      NB=ICTT(I)*NDT
      READ(NRD,1000) (CPCNC(I,K),K=1,NB)
  110 WRITE(NW,1000) (CPCNC(I,K),K=1,NB)
      DO 120 I=1,NA
      NB=ICPT(I+NER)*NDT
      READ(NRD,1000) (CPCNF(I,K),K=1,NB)
  120 WRITE(NW,1000) (CPCNF(I,K),K=1,NB)
  200 DO 140 I=1,NER
      IF(NERT(I).EQ.0) GO TO 140
      K=NERCT(I)*NDT
      READ(NRD,1000) (CERCNC(I,J),J=1,K)
      WRITE(NW,1000) (CERCNC(I,J),J=1,K)
      K=NERDT(I)*NDT
      READ(NRD,1000) (FERCNC(I,J),J=1,K)
      WRITE(NW,1000) (FERCNC(I,J),J=1,K)
  140 CONTINUE
C*****     INITIALIZE DERIVATIVES
      READ(NRD,1000) ELDML
      WRITE(NW,1000) ELDML
      READ(NRD,1000) (ERPL(I),I=1,NER)
      WRITE(NW,1000) (ERPL(I),I=1,NER)
      READ(NRD,1000) (ERAPL(I),I=1,NER)
```

80/80 LIST

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      12345678901234567890123456789012345678901234567890123456789012345678901234567890
CARD
            WRITE(NW,1000) (ERAPL(I),I=1,NER)
            READ(NRD,1000) (ERAQL(I),I=1,NER)
            WRITE(NW,1000) (ERAQL(I),I=1,NER)
       1000 FORMAT(8G10.3)
       1001 FORMAT(20I5)
            WRITE(NW,1002)
       1002 FORMAT(' END INITIAL')
            RETURN
            END
      C
            SUBROUTINE ELIP
            IF(TIME.NE.BEGTIM) GO TO 201
      C*****     READ PARAMETERS AND INPUTS
            READ(NRD,1000) RES,FSF,FXCF,FIRMX,FRMSM,ELDM,EMPRC,EMCOS,CPTLM
            WRITE(NW,1000) RES,FSF,FXCF,FIRMX,FRMSM,ELDM,EMPRC,EMCOS,CPTLM
            READ(NRD,1000) (CPCOS(I),I=1,N)
            WRITE(NW,1000) (CPCOS(I),I=1,N)
            READ(NRD,1000) (FC(I),I=1,N)
            WRITE(NW,1000) (FC(I),I=1,N)
            NN=N+NER
            READ(NRD,1000) (HTRT(I),I=1,NN)
            WRITE(NW,1000) (HTRT(I),I=1,NN)
            READ(NRD,1000) (VCNF(I),I=1,NN)
            WRITE(NW,1000) (VCNF(I),I=1,NN)
            READ(NRD,1000) (AFDEM(I),I=1,21)
            WRITE(NW,1000) (AFDEM(I),I=1,21)
            DO 100 I=1,NN
            READ(NRD,1000) (AVL(I,K),K=1,42)
        100 WRITE(NW,1000) (AVL(I,K),K=1,42)
            DO 101 I=1,K1
            READ(NRD,1000) (ECSUP(I,K),K=1,42)
        101 WRITE(NW,1000) (ECSUP(I,K),K=1,42)
            DO 102 I=1,K2
            READ(NRD,1000) (ECDEM(I,K),K=1,42)
        102 WRITE(NW,1000) (ECDEM(I,K),K=1,42)
            READ(NRD,1000) (DUR(I),I=1,42)
            WRITE(NW,1000) (DUR(I),I=1,42)
            READ(NRD,1000) (EMER(I),I=1,42)
            WRITE(NW,1000) (EMER(I),I=1,42)
            READ(NRD,1000) (FSDM(I),I=1,42)
            WRITE(NW,1000) (FSDM(I),I=1,42)
            READ(NRD,1000) (FRMVC(I),I=1,20)
            WRITE(NW,1000) (FRMVC(I),I=1,20)
            READ(NRD,1000) (FRMVP(I),I=1,20)
            WRITE(NW,1000) (FRMVP(I),I=1,20)
            DO 103 I=1,N
            READ(NRD,1000) (CAPM(I,K),K=1,IYPLN)
        103 WRITE(NW,1000) (CAPM(I,K),K=1,IYPLN)
            READ(NRD,1000) (PSUP(I),I=1,K1)
            WRITE(NW,1000) (PSUP(I),I=1,K1)
            READ(NRD,1000) (PDEM(I),I=1,K2)
            WRITE(NW,1000) (PDEM(I),I=1,K2)
            READ(NRD,1000) (ERP(I),I=1,NER)
            WRITE(NW,1000) (ERP(I),I=1,NER)
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80/80 LIST

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1234567890123456789012345678901234567890123456789012345678901234567890123456789 0
      READ(NRD,1000) (ERAP(I),I=1,NER)
      WRITE(NW,1000) (ERAP(I),I=1,NER)
      READ(NRD,1000) (ERAQ(I),I=1,NER)
      WRITE(NW,1000) (ERAQ(I),I=1,NER)
      READ(NRD,1000) (ERFLT(I),I=1,NER)
      WRITE(NW,1000) (ERFLT(I),I=1,NER)
      NA=N-NER
      IF(NA.EQ.0) GO TO 200
      READ(NRD,1000) (EMXCN(I),I=1,NA)
      WRITE(NW,1000) (EMXCN(I),I=1,NA)
 1000 FORMAT(8G10.3)
  200 CONTINUE
      RETURN
  201 CONTINUE
C*****    CHANGES WITH TIME GO HERE
      ERAQ(1)=3.0E14*(1.0-(TIME-1975.)/(1990.-1975.))                   CCR1
      IF(ERAQ(1).LT.0.0) ERAQ(1)=0.0                                    CCR1
      ELDM=ELDM*1.05
      DO 301 I=1,NER
      ERP(I)=ERP(I)*1.05
      CPCOS(I)=CPCOS(I)*1.06
  301 FC(I)=FC(I)*1.06
      DO 302 I=1,3
      PSUP(I)=PSUP(I)*1.05
  302 PDEM(I)=PDEM(I)*1.05
      EMPRC=EMPRC*1.05
      EMCOS=EMCOS*1.05
      RETURN
      END
C
C*****    OUTPUT SUBROUTINE
      SUBROUTINE OUTPUT
      DIMENSION AOUT(5)
      WRITE(NW,1) TIME
      WRITE(NW,2) ELDM,SMD,SMDG,(FELDM(J),J=1,IYPLN)
      WRITE(NW,3)
      WRITE(NW,4) (ERP(I),I=1,NER)
      WRITE(NW,5) (SMRP(I),I=1,NER)
      WRITE(NW,6) (SMRPG(I),I=1,NER)
      WRITE(NW,65)
      DO 100 I=1,NER
  100 WRITE(NW,7) I,(FERP(I,J),J=1,IYPLN)
      WRITE(NW,8) (ERAP(I),I=1,NER)
      WRITE(NW,9) (SMRA(I),I=1,NER)
      WRITE(NW,10) (SMRAG(I),I=1,NER)
      WRITE(NW,11) (ERAQ(I),I=1,NER)
      WRITE(NW,12) (SMERQ(I),I=1,NER)
      WRITE(NW,13) (SMERQG(I),I=1,NER)
      WRITE(NW,135)
      DO 200 I=1,NER
  200 WRITE(NW,14) I,(FERAQ(I,J),J=1,IYPLN)
      WRITE(NW,15) (ERCN(I),I=1,NER)
      WRITE(NW,16) (ERCNS(I),I=1,NER)
      WRITE(NW,17) (DERCNC(I),I=1,NER)
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80/80 LIST

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12345678901234567890123456789012345678901234567890123456789012345678901234567890
      WRITE(NW,18) (ERCNM(I),I=1,NER)
      WRITE(NW,19)
      WRITE(NW,20) (CPCOL(I),I=1,NER)
      WRITE(NW,205) (DERATE(I),I=1,NER)
      WRITE(NW,21) (CAPSR(I),I=1,NER)
      III=N+1
      NN=N+NER
      WRITE(NW,205) (DERATE(I),I=III,NN)
      WRITE(NW,22) (CPCNT(I),I=1,NER)
      WRITE(NW,23) (DCAPL1(I),I=1,NER)
      WRITE(NW,24) (DCPCN(I),I=1,NER)
      WRITE(NW,241) (CAPM(I,1),I=1,NER)
      WRITE(NW,245) (DCAPSR(I),I=1,NER)
      J=N-NER
      IF(J.EQ.0) GO TO 210
      WRITE(NW,25) (CPCNCT(I),I=1,J)
      WRITE(NW,26) (CPCNFT(I),I=1,J)
      WRITE(NW,27) (DCPCNC(I),I=1,J)
      WRITE(NW,28) (DCPCNF(I),I=1,J)
      DO 202 I=1,J
  202 AOUT(I)=CAPM(I+NER,1)
      WRITE(NW,285) (AOUT(I),I=1,J)
      WRITE(NW,29) (EXCPCR(I),I=1,J)
 210  WRITE(NW,30)
      DO 300 I=1,N
      K=I+N
 300  WRITE(NW,31) I,CAPD(K),(CAPP(I,J),J=1,IYPLN)
      WRITE(NW,50) (ERC(I),I=1,NN)
      WRITE(NW,51) (ERUSED(I),I=1,NER)
      DO 350 I=1,NER
  350 AOUT(I)=ERCN(I)/FLOAT(ICNTIM(I))
      WRITE(NW,511) (AOUT(I),I=1,NER)
      WRITE(NW,515) (ERUP(I),I=1,NER)
      WRITE(NW,525) ACCAP,CPTLM
      WRITE(NW,52) FIRM,FMSL,FIRMX,FRMSM,ERFB,ERFS,EREB,ERES,ERMB,
     1ERMS,ERUR,UEDR,UEDF
      WRITE(NW,53) CFFB,CFFS,CFEB,CFES,CFMB,CFMS
      WRITE(NW,54) (CFERU(I),I=1,NER)
      WRITE(NW,55) VGCOS,TGCOS
1     FORMAT('1',' SIMULATION RESULTS'//G15.4)
2     FORMAT(////' DEMAND INFORMATION'/' CURRENT PEAK DEMAND',G15.5//' A
     1VERAGED DEMAND',G15.5//' FORECASTED GROWTH RATE',G15.5//' FORECAST
     2ED DEMAND FOR FUTURE YEARS'/5G15.5/5G15.5)
3     FORMAT(//////' ENERGY RESOURCE INFORMATION'/' ALL QUANTITIES IN BT
     2U AND ALL PRICES IN $/BTU'//)
4     FORMAT(' CURRENT RESOURCE PRICE'/5G15.5)
5     FORMAT(//' AVERAGED RESOURCE PRICE'/5G15.5)
6     FORMAT(//' FORECASTED RATE OF PRICE CHANGE'/5G15.5)
65    FORMAT(//' FORECASTED ENERGY RESOURCE PRICES BY TYPES')
7     FORMAT(/' TYPE',I4/5G15.5/5G15.5)
8     FORMAT(//' CURRENT FRACTION OF ENERGY RESOURCES AVAILABLE'/5G15.5)
9     FORMAT(//' AVERAGED FRACTION OF ENERGY RESOURCES AVAILABLE'/5G15.5
     1)
10    FORMAT(//' RATE OF CHANGE OF FRACTION AVAILABLE'/5G15.5)
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80/80 LIST

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12345678901234567890123456789012345678901234567890123456789012345678901234567890
  11   FORMAT(//' CURRENT QUANTITY OF ENERGY RESOURCES AVAILABLE'/5G15.5)
  12   FORMAT(//' AVERAGED QUANTITY OF ENERGY RESOURCES AVAILABLE'/5G15.5
      1)
  13   FORMAT(//' RATE OF CHANGE CF QUANTITY AVAILABLE'/5G15.5)
  135  FORMAT(//' FORECASTED QUANTITIES OF ENERGY RESOURCES AVAILABLE TO
      1ELECTRIC UTILITIES'//)
  14   FORMAT(/' TYPE',I4/5G15.5/5G15.5)
  15   FORMAT(//' CURRENT ENERGY RESOURCES CONTRACTS'/5G15.5)
  16   FORMAT(//' ADDITIONAL CONTRACTS BEING SOUGHT'/5G15.5)
  17   FORMAT(//' RATE AT WHICH NEW CONTRACTS ARE BEING GENERATED'/5G15.5
      1)
  18   FORMAT(//' MONEY VALUE OF ENERGY RESOURCE CONTRACTS'/5G15.5)
  19   FORMAT(//////////' CAPACITY INFORMATION'/' ALL QUANTITIES IN MW')
  20   FORMAT(//' CURRENT ON LINE CAPACITY'/5G15.5)
   205 FORMAT(/' FRACTION OF CAPACITY AVAILABILITY LIMITED BY ENERGY RESO
      1URCE AVAILABILITY'/5G15.5)
  21   FORMAT(//' SEMI-RETIRED CAPACITY'/5G15.5)
  22   FORMAT(//' CAPACITY UNDER CONSTRUCTION'/5G15.5)
  23   FORMAT(//' RATE AT WHICH NEW CAPACITY COMES ON LINE'/5G15.5)
  24   FORMAT(//' RATE AT WHICH CONSTRUCTION IS STARTED ON NEW CAPACITY'/
      15G15.5)
   241 FORMAT(/' MAXIMUM RATE CF CONSTRUCTION STARTS ALLOWED'/5G15.5)
  245  FORMAT(//' RATE AT WHICH CAPACITY IS RETIRED'/5G15.5)
  25   FORMAT(//' CONTRACTED CAPACITY IN USE'/3G15.5)
  26   FORMAT(//' FUTURE CAPACITY CONTRACTS'/3G15.5)
  27   FORMAT(//' RATE AT WHICH NEW CONTRACTS COME INTO USE'/3G15.5)
  28   FORMAT(//' RATE AT WHICH NEW CONTRACTS ARE MADE'/3G15.5)
   285 FCRMAT(/' MAXIMUM NEW CCNTRACTS ALLOWED'/5G15.5)
  29   FORMAT(//' RATE AT WHICH OLD CONTRACTS EXPIRE'/3G15.5)
  30   FORMAT(//' PLANNEC CAPACITY BY TYPES'/)
  31   FORMAT(/' TYPE',I4,'       DESIRED FRACTION',G15.5/5G15.5/5G15.5)
    50 FORMAT(//' ELECTRICAL ENERGY GENERATED IN MWH'/5G15.5/5G15.5)
    51 FORMAT(//' ENERGY RESOURCES USED IN BTU'/5G15.5)
   511 FORMAT(/' MAXIMUM AVAILABLE'/5G15.5)
   515 FORMAT(//' PRICE PAID FOR ENERGY RESOURCES IN $/BTU'/5G15.5)
    52 FORMAT(//' FIRM CAPACITY BOUGHT AND SOLD IN MW'/2G15.5/' MAXIMUM A
      1LLOWED'/2G15.5//' ENERGY BCUGHT AND SOLD IN MWH'/' FIRM',2G15.5/'
      2ECONOMY',2G15.5/' EMERGENCY',2G15.5/' IN REGION',G15.5//' UNMET DE
      3MAND'/' IN REGION',G15.5/' FROM FIRM CAPACITY SALES',G15.5)
   525 FORMAT(//' RATE AT WHICH CAPITAL IS BEING COMMITTED',G15.5/' MAXIM
      1UM RATE POSSIBLE',G15.5)
    53 FORMAT(//' CASH FLOWS IN $/YEAR'/' FIRM ENERGY PURCHASED',G15.5/'
      1FIRM ENERGY SOLD',G15.5/' ECONOMY ENERGY PURCHASED',G15.5/' ECONOM
      2Y ENERGY SOLD',G15.5/' EMERGENCY ENERGY BOUGHT',G15.5/' EMERGENCY
      3ENERGY SOLD',G15.5)
    54 FORMAT(/' ENERGY RESOURCES PURCHASED'/5G15.5)
    55 FORMAT(//' VARIABLE COST OF GENERATION OF ELECTRICAL ENERGY FOR RE
      1GION IN $/MWH',G15.5/' TOTAL COST',G15.5)
       RETURN
       END
C
       SUBROUTINE ELUD
C*****    UPDATE BOXCAR DELAYS
       DO 100 I=1,NER
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80/80 LIST

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12345678901234567890123456789012345678901234567890123456789012345678901234567890
      NA=ICPT(I)*NDT-1
      DO 101 J=1,NA
  101 CPCN(I,J)=CPCN(I,J+1)
  100 CPCN(I,J)=DCPCN(I)*DT
      DO 400 I=1,NER
C     ASSUMES 1 YEAR TIME STEP, 3 YEAR CONSTRUCTION TIME, AND
C     1 YEAR OUTAGE.
      IF(I.NE.1) GO TO 900
      IF(CPCN(4,1).LT.1.0) GO TO 900                                    CC
      IF(CPCOL(1).LT.1.0) GO TO 900                                     CC
      DCAPL2(1)=CPCN(4,1)*CAPOL1(1)/CPCOL(1)                            CC
      DCAPL3(1)=CPCN(4,1)*CAPOL2(1)/CPCOL(1)                            CC
      DCAPSR(1)=CPCN(4,1)*CAPOL3(1)/CPCOL(1)                            CC
      CAPOL1(1)=CAPOL1(1)-DCAPL2(1)                                     CC
      CAPOL2(1)=CAPOL2(1)-DCAPL3(1)                                     CC
      CAPOL3(1)=CAPOL3(1)-DCAPSR(1)                                     CC
      DCAPSR(1)=0.                                                      CC
      GO TO 901                                                         CC
  900 CONTINUE                                                          CC
      CAPOL1(I)=CAPOL1(I)+(DCAPL1(I)-DCAPL2(I))*DT
      CAPOL2(I)=CAPOL2(I)+(DCAPL2(I)-DCAPL3(I))*DT
      CAPOL3(I)=CAPOL3(I)+(DCAPL3(I)-DCAPSR(I))*DT
  901 CONTINUE                                                          CC
      CAPSR(I)=CAPSR(I)+DCAPSR(I)*DT
      CPCOL(I)=CAPOL1(I)+CAPOL2(I)+CAPOL3(I)
      CPCNT(I)=CPCNT(I)+(DCPCN(I)-DCAPL1(I))*DT
      ERUP(I)=ERUP(I)+DERUP(I)*DT
      IF(NERT(I).NE.0) GO TO 90
      ERCN(I)=ERCN(I)+(DERCNC(I)-ERUSED(I))*DT
      GO TO 95
   90 ERCN(I)=ERCN(I)+FERCNC(I,1)-CERCNC(I,1)
      K=NERCT(I)*NDT-1
      DO 91 J=1,K
   91 CERCNC(I,J)=CERCNC(I,J+1)
      CERCNC(I,J)=FERCNC(I,1)
      K=NERDT(I)*NDT-1
      DO 92 J=1,K
   92 FERCNC(I,J)=FERCNC(I,J+1)
      FERCNC(I,J)=DERCNC(I)*DT
   95 SMRP(I)=SMRP(I)+DSMRP(I)*DT
      SMRPG(I)=SMRPG(I)+DSMRPG(I)*DT
      SMRA(I)=SMRA(I)+DSMRA(I)*DT
      SMRAG(I)=SMRAG(I)+DSMRAG(I)*DT
      SMERQ(I)=SMERQ(I)+DSMERQ(I)*DT
  400 SMERQG(I)=SMERQG(I)+DSMRQG(I)*DT
C*****     LONGTERM CAPACITY CONTRACT VARIABLES
      NB=N-NER
      IF(NB.LE.0) GO TO 250
      DO 200 I=1,NB
      NA=ICTT(I)*NDT-1
      DO 201 J=1,NA
  201 CPCNC(I,J)=CPCNC(I,J+1)
      CPCNC(I,J)=DCPCNC(I)*DT
      NA=ICPT(I+NER)*NDT-1
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12345678901234567890123456789012345678901234567890123456789012345678901234567890
CARD
      DO 202 J=1,NA
  202 CPCNF(I,J)=CPCNF(I,J+1)
      CPCNF(I,J)=DCPCNF(I)*DT
      CPCNCT(I)=CPCNCT(I)+(DCPCNC(I)-EXCPCR(I))*DT
  200 CPCNFT(I)=CPCNFT(I)+(DCPCNF(I)-DCPCNC(I))*DT
C*****     SINGLE DIMENSION VARIABLES
  250 CONTINUE
      SMD=SMD+DSMD*DT
      SMDG=SMDG+DSMDG*DT
C*****      DERIVATIVES
      DO 300 I=1,NER
      ERPL(I)=ERP(I)
      ERAPL(I)=ERAP(I)
  300 ERAQL(I)=ERAQ(I)
      ELDML=ELDM
      RETURN
      END
C
      SUBROUTINE ALGEL
C*****DIMENSIONED VARIABLES FOR THE PLANNING SECTION
      DIMENSION DRA(5),DRPG(5),CAPT(5),CNND(5),COND(5),CAP(5,15)
      DIMENSION DERAQ(4)
C*****FORECASTING
      DSMD=(ELDM-SMD)/2.
      DG=(ELDM-ELDML)/(ELDML*DT)
      DSMDG=(DG-SMDG)/3.
      DO 100 J=1,IYPLN
  100 FELDM(J)=SMD*EXP(SMDG*2.)*EXP(SMDG*J)
      DO 110 I=1,NER
      DSMRP(I)=(ERP(I)-SMRP(I))/2.
      DRPG(I)=(ERP(I)-ERPL(I))/(SMRP(I)*DT)
      DSMRPG(I)=(DRPG(I)-SMRPG(I))/3.
      DO 101 J=1,IYPLN
  101 FERP(I,J)=SMRP(I)*EXP(SMRPG(I)*J)*EXP(SMRPG(I)*2.)
      DSMRA(I)=(ERAP(I)-SMRA(I))/2.
      DRA(I)=(ERAP(I)-ERAPL(I))/(SMRA(I)*DT)
      DSMRAG(I)=(DRA(I)-SMRAG(I))/3.
      DSMERQ(I)=(ERAQ(I)-SMERQ(I))/3.
      DERAQ(I)=(ERAQ(I)-ERAQL(I))/(SMERQ(I)*DT)
      DSMRQG(I)=(DERAQ(I)-SMERQG(I))/3.
      DO 110 J=1,IYPLN
      IF(I.EQ.1) GO TO 105                                              CCR1
      FERAQ(I,J)=SMERQ(I)*EXP(SMERQG(I)*J)*EXP(SMERQG(I)*3.)
      IF(SMRAG(I).GT.0.) GO TO 102
      FERAQ(I,J)=FERAQ(I,J)*EXP(SMRAG(I)*J)*SMRA(I)*EXP(SMRAG(I)*2.)
      GO TO 110
  102 FERAQ(I,J)=FERAQ(I,J)*(1.-(1.-SMRA(I))*EXP(-SMRAG(I)*J)*EXP(-SMRAG
     1(I)*2.))
      GO TO 110                                                         CCR1
  105 FERAQ(1,J)=3.0E14*(1.-(TIME+J-1975.)/(1990.-1975.))               CCR1
      IF(FERAQ(1,J).LT.0.0) FERAQ(1,J)=0.                               CCR1
  110 CONTINUE
C * * * * * * * * * * * * * * * * * * * * * * * * * * * * * * * * * * * *
C  PREPARE FOR CAPACITY PLANNING SIMULATION
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80/80 LIST

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12345678901234567890123456789012345678901234567890123456789012345678901234567890
      CALL CHNG(1,DUR,IFS)
      SCLDM=FELDM(IYPLN)*(1.+RES)
      DO 190 I=1,N
      CAPMAX(I)=0.
      DO 190 J=1,IYPLN
      IF(J.GE.ICPT(I)) CAPMAX(I)=CAPMAX(I)+CAPM(I,J-ICPT(I)+1)
  190 CONTINUE
      DO 2006 I=1,N
      IF(I.GT.NER) GO TO 2001
      VC(I)=VCNF(I)+FERP(I,IYPLN)*HTRT(I)
      CAPMAX(I+N)=CPCOL(I)+CPCNT(I)
      ENRMX(I)=FERAQ(I,IYPLN)/HTRT(I)
      GO TO 2002
 2001 CAPMAX(I+N)=CPCNCT(I-NER)+CPCNFT(I-NER)
      VC(I)=VCNF(I)
      ENRMX(I)=(CAPMAX(I)+CAPMAX(I+N))*EMXCN(I-NER)
 2002 DO 2005 J=1,42
 2005 AA(J)=AVL(I,J)
 2006 CALL CHNG(2+I,AA,IFS)
      CAPMAX(5)=CAPMAX(5)-CPCNT(4)+CPCN(4,1)                            CC
      IF(CAPMAX(5).LT.0.0) CAPMAX(5)=0.                                 CC
      CALL CAPMIX
      A=0.
      DO 2007 I=1,N
 2007 A=A+CAPD(I)+CAPD(I+N)
      DO 2008 I=1,N
C**   CAPD(I+N)=FRACTION OF CAPACITY DESIRED FROM TYPE I
 2008 CAPD(I+N)=(CAPD(I)+CAPD(I+N))/A
C**   SET CAPT(I) TO CURRENT ON LINE CAPACITY
      DO 210 I=1,N
      IF(NCAP(I).EQ.1) GO TO 201
      CAPT(I)=CPCNCT(I-NER)
      GO TO 210
  201 CAPT(I)=CPCOL(I)
  210 CONTINUE
C**   ENRMX(I)=MAXIMUM ELECTRICAL ENERGY FROM TYPE I
C**   ERUS(I)=AMOUNT OF ENERGY RESOURCE TYPE I USED IN PLANNING
C**   INITIALIZE TO ZERO
C**   ACCAP=NEW CAPITAL COMMITTED
C**   INITIALIZE TO 0
      DO 2105 I=1,NER
      ENRMX(I)=ERCN(I)/(HTRT(I)*FLOAT(ICNTIM(I)))
 2105 ERUS(I)=0.
      ACCAP=0.
      ICP=0
C * * * * * * * * * * * * * * * * * * * * * * * * * * * * * * * * * * *
C**   LOOP 250 DETERMINES PLANNED CAPACITY
C**   J IS THE NO. OF YEARS FROM THE CURRENT TIME
      DO 250 J=1,IYPLN
      ICS=0
      JJ=(J-1)*NDT+1
      JJJ=JJ+NDT-1
      DO 230 I=1,N
      IF(J.GT.ICPT(I)) GO TO 220
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CARD
C**   *** CAPACITY PLANNING LIMITS FOR J.LE.CONSTRUCTION
      IF(I.GT.NER) GO TO 212
      DO 211 II=JJ,JJJ
C     ACCOUNTS FOR CAPACITY WHICH WILL BE CONVERTED
      A=0.0                                                             CC
      IF(I.NE.1) GO TO 211                                              CC
      IF(II.GT.2) GO TO 211                                             CC
      A=CPCN(4,II+1)                                                    CC
C**   211 & 213 ADD CAPACITY THAT WILL COME ON LINE BY END OF YEAR J
  211 CAPT(I)=CAPT(I)+CPCN(I,II)-A                                      C
      GO TO 214
  212 DO 213 II=JJ,JJJ
  213 CAPT(I)=CAPT(I)+CPCNF(I-NER,II)
  214 II=I+N
C**   CAPMAX(II)=COMMITTED CAPACITY FOR YEAR J
C**   CAPMAX(I)=NEW CAPACITY WHICH CAN BE COMMITTED
      CAPMAX(II)=CAPT(I)
      CAPMAX(I)=0.
      GO TO 224
C**   *** CAPACITY PLANNING LIMITS FOR J.GT.CONSTRUCTION TEME
  220 ICS=1
      II=I+N
C**   CAPMAX(I & II) SAME AS ABOVE
      CAPMAX(II)=CAPT(I)
      CAPMAX(I)=CAPM(I,J-ICPT(I))
      IF(J-1.NE.ICPT(I)) GO TO 224
C**   ICP=1 INDICATES NO MORE CAPITAL COMMITTMENTS ALLOWED
      IF(ICP.EQ.1) CAPMAX(I)=0.
  224 IF(I.GT.NER) GO TO 225
C**   UPDATE THE AMOUNT OF ENERGY THAT CAN BE SUPPLIED AND CALCULATE VC
      ENRMX(I)=ENRMX(I)+FERAQ(I,J)/HTRT(I)-ERUS(I)
      VC(I)=VCNF(I)+FERP(I,J)*HTRT(I)
      GO TO 230
  225 ENRMX(I)=(CAPMAX(I)+CAPMAX(II))*EMXCN(I-NER)
      VC(I)=VCNF(I)
  230 CONTINUE
C**   ICS=0 INDICATES THAT NO CAPACITY CAN BE ADDED
      IF(ICS.NE.0) GO TO 240
C**   CAPD(I)=NEW CAPACITY TO BE ADDED=0 WHEN NONE ALLOWED
      DO 235 I=1,N
  235 CAPD(I)=0.
      GO TO 243
  240 SCLDM=FELDM(J)*(1.+RES)
      GO TO 2405
C**   2401 & 2402 REDUCES NEW CAPACITY ALLOWED TO ACCOUNT FOR CAPITAL
C**   LIMIT
C**   CAPAITAL LIMIT IS CALCULATED IN 241 & 242
 2401 DO 2402 I=1,N
      IF(J-1.NE.ICPT(I)) GO TO 2402
      CAPMAX(I)=CAPD(I)
 2402 CONTINUE
 2405 III=J
      IF(CAPD(8).GT.0.01) CAPMAX(1)=0.                                  CC
      IF(J.LT.4) GO TO 2409                                             CC
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80/80 LIST

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CARD
      IF(CAPD(8).LT.0.01) GO TO 2409                                    CC
      A=0.                                                              CC
      U=5.                                                              CC
 2406 CALL AFNC(U,B,1)                                                  CC
      B=B*FELDM(J)                                                      CC
 9406 A=A+(FELDM(J)-B)*438.*HTRT(1)                                     CC
      IF(A.GT.FERAQ(1,J)) GO TO 2407                                    CC
      IF(FELDM(J)-B.GT.CAPMAX(5)) GO TO 2408                            CC
      U=U+5.                                                            CC
      IF(U.LE.100.) GO TO 2406                                          CC
      U=100.                                                            CC
      B=B-FELDM(J)/20.                                                  CC
      IF(B.GT.0.) GO TO 9406                                            CC
      GO TO 2409                                                        CC
 2407 CAPMAX(4)=CAPMAX(5)-FELDM(J)+B                                    CC
      CAPMAX(5)=FELDM(J)-B                                              CC
      IF(CAPMAX(4).LT.0.0) CAPMAX(4)=0.0                                CC
      GO TO 2409                                                        CC
 2408 CAPMAX(4)=0.                                                      CC
 2409 CONTINUE                                                          CC
C**   DESCAP DETERMINES WHAT CAPACITY WILL BE ADDED DURING YEAR J
      CALL DESCAP
  241 IF(ICP.EQ.1) GO TO 243
      DO 242 I=1,N
      IF(J-1.NE.ICPT(I)) GO TO 242
C**   ADD ON NEW CAPITAL COMMITTED
      ACCAP=ACCAP+CAPD(I)*CPCOS(I)
      IF(ACCAP.LE.CPTLM) GO TO 242
      ICP=1
C**   LIMIT NEW CAPACITY TO CAPITAL LIMIT IF NECESSARY
      CAPD(I)=CAPD(I)-(ACCAP-CPTLM)/CPCOS(I)
      ACCAP=CPTLM
  242 CONTINUE
      IF(ICP.EQ.1) GO TO 2401
  243 DO 250 I=1,N
C**   ADD NEW CAPACITY TO TCTAL COMMOTTED CAPACITY
      CAPT(I)=CAPT(I)+CAPD(I)
      IF(I.NE.1) GO TO 244                                              CC
      IF(CAPD(1).LT.1.0) CAPT(1)=CAPMAX(5)                              CC
  244 CONTINUE                                                          CC
      CAPP(I,J)=CAPT(I)
      IF(J-1.NE.ICPT(I)) GO TO 250
      IF(NCAP(I).EQ.1) GO TO 245
C**   SET CAPACITY CONSTRUCTION STARTS RATES
      DCPCNF(I-NER)=CAPD(I)
      GO TO 250
  245 DCPCN(I)=CAPD(I)
  250 CONTINUE
C*****RATE VARIABLES FOR THIRD ORDER CAPACITY DELAY
      DO 270 I=1,N
      IF(NCAP(I).EQ.2) GO TO 260
      DCAPL1(I)=CPCN(I,1)/DT
      DCAPL2(I)=CAPOL1(I)/10.
      DCAPL3(I)=CAPOL2(I)/10.
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      DCAPSR(I)=CAPOL3(I)/10.
      GO TO 270
C**   CAPACITY CONTRACTS RATES
  260 DCPCNC(I-NER)=CPCNF(I-NER,1)
      EXCPCR(I-NER)=CPCNC(I-NER,1)
  270 CONTINUE
C*****ENERGY RESOURCE PLANNING
      CALL CHNG(1,DUR,IFS)
      DO 301 I=1,N
      DO 300 J=1,42
  300 AA(J)=AVL(I,J)
  301 CALL CHNG(I+1,AA,IFS)
      SCLDM=FELDM(1)
      DO 308 I=1,N
      IF(I.GT.NER) GO TO 306
      VC(I)=VCNF(I)+ERUP(I)*HTRT(I)
      GO TO 308
  306 VC(I)=VCNF(I)
  308 SCLCP(I)=CAPP(I,1)
      IL=0
      CALL ERNEED
      DO 310 I=1,NER
      IF(NERT(I).NE.0) GO TO 310
      COND(I)=ENR(I)*HTRT(I)
  310 CONTINUE
      DO 350 J=1,IYPLN
      DO 350 I=1,NER
      IF(NERT(I).EQ.0) GO TO 350
      IF(NERDT(I).LT.J) GO TO 350
      IF(J.NE.1) GO TO 321
      ERCNM(I)=ERCN(I)
  321 K11=(J-1)*NDT+1
      K22=K11+NDT-1
      DO 322 K=K11,K22
  322 ERCNM(I)=ERCNM(I)+FERCNC(I,K)-CERCNC(I,K)
      IF(NERDT(I).NE.J) GO TO 350
      DO 325 K=1,N
  325 SCLCP(K)=CAPP(I,J)
      SCLDM=FELDM(J)
      CALL ERNEED
      IF(NERDT(I).NE.J) GO TO 350
      COND(I)=ENR(I)*HTRT(I)
  350 CONTINUE
      DO 380 I=1,NER
      A=ERAQ(I)*ERAP(I)*ERFLT(I)
      B=ERAQ(I)*ERAP(I)*(1.-ERFLT(I))
      IF(NERT(I).EQ.0) GO TO 360
      COND(I)=COND(I)-ERCNM(I)
      IF(COND(I).LT.0.) COND(I)=0.
      IF(COND(I).GT.A) CONC(I)=A
      ERAV(I)=ERCN(I)+B
      DERCNC(I)=COND(I)
      GO TO 370
  360 COND(I)=COND(I)/DCNST(I)-ERCN(I)
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      IF(COND(I).LT.0.) COND(I)=0.
      IF(COND(I).GT.A/DCNST(I)) COND(I)=A/DCNST(I)
      ERAV(I)=ERCN(I)*DCNST(I)+B+A-COND(I)*DCNST(I)
      DERCNC(I)=COND(I)/DCNST(I)
  370 CONTINUE
  380 DERUP(I)=(ERP(I)-ERUP(I))/5.
C*****INTERMEDIATE PLANNING
      DO 400 I=1,N
      IF(I.GT.NER) GO TO 410
      VC(I)=VCNF(I)+ERUP(I)*HTRT(I)
      SCLCP(I)=CPCOL(I)
      SCLCP(I+N)=CAPSR(I)
      VC(I+N)=VCNF(I+N)+ERUP(I)*HTRT(I+N)
      GO TO 400
  410 VC(I)=VCNF(I)
      SCLCP(I)=CPCNCT(I-NER)
  400 CONTINUE
      SCLDM=ELDM
      CALL RANKC
      DO 415 I=1,N
      DO 420 K=1,42
  420 AA(K)=AVL(I,K)
  415 CALL CHNG(I+2,AA,IFS)
      CALL CHNG(2,FRMVC,IFF)
      SCLDM=ELDM*(1.1+RES)
      CALL STFRM
      SCLDM=ELDM*1.1
      CALL CHNG(NN+3,FRMVP,IFF)
      CALL STFS
      SCLDM=ELDM
      SCLDF=FSF*FMSL
      CALL CHNG(2,FSDM,IFS)
C*****      NEXT TWO CARDS MAY BE TEMPORARY
      CALL CHNG(3,FRMVC,IFF)
      CALL CHNG(4,FRMVP,IFF)
      DO 450 I=1,NN
      DO 451 J=1,42
  451 AA(J)=AVL(I,J)
  450 CALL CHNG(I+4,AA,IFS)
      DO 460 I=1,K1
      DO 461 J=1,42
  461 AA(J)=ECSUP(I,J)
  460 CALL CHNG(NN+4+I,AA,IFS)
      DO 470 I=1,K2
      DO 471 J=1,42
  471 AA(J)=ECDEM(I,J)
  470 CALL CHNG(NN+4+K1+I,AA,IFS)
      CALL CHNG(NN+5+K1+K2,EMER,IFS)
      CALL DAILY
      DO 480 I=1,NER
      ERUSED(I)=ERC(I)*HTRT(I)+ERC(I+N)*HTRT(I+N)
  480 CFERU(I)=ERUSED(I)*ERUP(I)
      VGCOS=0.
      DO 500 I=1,NN
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      IF(I.GT.NER) GO TO 501
      VGCOS=VGCOS+CFERU(I)+ERC(I)*VCNF(I)
      GO TO 500
  501 VGCOS=VGCOS+ERC(I)*VCNF(I)
  500 CONTINUE
      CFMB=ERMB*EMCOS
      CFMS=ERMS*EMPRC
      CFFB=CFFB+FIRM*FXCF
      CFFS=CFFS+FMSL*FXCF
      VGCOS=VGCOS+CFFB-CFFS+CFEB-CFES+CFMB-CFMS
      VGCOS=VGCOS/ERUR
      TGCOS=VGCOS
      DO 510 I=1,N
      IF(I.GT.NER) GO TO 505
      TGCOS=TGCOS+CPCOL(I)*FC(I)/ERUR
      GO TO 510
  505 TGCOS=TGCOS+CPCNCT(I-NER)*FC(I)/ERUR
  510 CONTINUE
      TGCOS=TGCOS+(CPCOL(4)+CPCNT(4))*FC(1)/ERUR
      RETURN
      END
C
      SUBROUTINE CAPMIX
      DIMENSION BB(42),ICON(10)
C     TEST FLAGS FOR CONVERSION                                         CC
      IZ2=0                                                             CC
      IZ1=0                                                             CC
      DO 85 J=1,N
      C=0.
      DO 80 I=1,21
      A=FLOAT(I-1)*5.
      CALL AFNC(A,B,J+2)
      IF(C.EQ.0.) GO TO 75
      D=FC(J)/C+VC(J)
      GO TO 76
   75 D=FC(J)/.01
   76 JK=2*I-1
      A=FLOAT(I-1)*438.
      AA(JK)=A
      BB(JK)=A
      AA(JK+1)=C
      BB(JK+1)=D
   80 C=C+B*438.
      CALL CHNG(J+N+2,BB,IFS)
      CALL CHNG(J+2*N+2,AA,IFS)
   85 CONTINUE
      DO 99 I=2,42,2
      AA(I)=0.
   99 AA(I-1)=(FLOAT(I)/2.-1.)*5.
      CALL CHNG(2,AA,IFS)
      NN=2*N
      DO 100 I=1,NN
      CAPD(I)=0.
      ICON(I)=1
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CARD
      IF(CAPMAX(I).EQ.0.) ICON(I)=0
      IF(I.GT.N) GO TO 100
      ERUS(I)=0.
  100 CONTINUE
      ICON(4)=1                                                         CC
      IGTO=1
      U=8760.
      GO TO 1000
  101 JL=1
  102 JK=NR(JL,1)
      IF(JK.EQ.5) GO TO 800                                             CC
      IF(JK.EQ.4) GO TO 810                                             CC
      GO TO 830                                                         CC
  800 IF(IZ1.EQ.1) GO TO 830                                            CC
      IZ1=1                                                             CC
      IF(IZ2.EQ.1) GO TO 805                                            CC
      GO TO 830                                                         CC
  805 CAPMAX(5)=CAPMAX(5)-CAPD(4)                                       CC
      IF(CAPMAX(5).LT.0.) CAPMAX(5)=0.                                  CC
      GO TO 830                                                         CC
  810 IF(IZ2.EQ.1) GO TO 830                                            CC
      IZ2=1                                                             CC
      IF(IZ1.EQ.1) GO TO 815                                            CC
      CAPMAX(4)=CAPMAX(5)                                               CC
      GO TO 830                                                         CC
  815 CAPMAX(4)=CAPMAX(5)-CAPD(5)                                       CC
      IF(CAPMAX(4).LT.0.) CAPMAX(5)=0.                                  CC
  830 CONTINUE                                                          CC
      JJ=JK
      IF(JK.GT.N) JJ=JK-N
      CSF=0.
      DO 105 I=1,11
      U=FLOAT(I-1)*10.
      CALL AFNC(U,A,1)
      CALL AFNC(U,B,2)
      A=A-B/SCLDM
      CALL AFNC(U,B,2+JJ)
  105 IF(CSF.LT.B/A) CSF=B/A
      CALL AFNC(8760.,ESF,JJ+2*N+2)
      A=CAPMAX(JK)
      B=(ENRMX(JJ)-ERUS(JJ))/ESF
      C=SCLDM/CSF
      IF(A.GT.C) GO TO 115
      ICON(JK)=0
      IF(A.GT.B) GO TO 113
      CAPD(JK)=A
      GO TO 120
  113 CAPD(JK)=B
      GO TO 120
  115 IF(B.GT.C) GO TO 118
      ICON(JK)=0
      CAPD(JK)=B
      GO TO 120
  118 CAPD(JK)=C
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CARD
  120 ERUS(JJ)=ERUS(JJ)+CAPD(JK)*ESF
      A=CAPD(JK)
      GO TO 2000
  135 IF(ICON(JK).NE.0) GO TO 200
      JL=JL+1
      IF(JL.GT.K) GO TO 5000
      GO TO 102
  200 IGTO=2
      CD=SCLDM/10.
  201 CALL AFNC(0.,A,2)
      IF(A.GE.SCLDM*.999999) GO TO 5000
      IF(SCLDM-A.LT.CD) CD=SCLDM-A
      U=0.
      DO 205 I=1,20
      UU=FLOAT(I-1)*5.
      CALL AFNC(UU,A,1)
      CALL AFNC(UU,B,2)
  205 IF(A*SCLDM.GT.B) U=U+438.
      GO TO 1000
  210 JK=NR(1,1)
      IF(JK.EQ.5) GO TO 900                                             CC
      IF(JK.EQ.4) GO TO 910                                             CC
      GO TO 930                                                         CC
  900 IF(IZ1.EQ.1) GO TO 930                                            CC
      IZ1=1                                                             CC
      IF(IZ2.EQ.1) GO TO 905                                            CC
      GO TO 930                                                         CC
  905 CAPMAX(5)=CAPMAX(5)-CAPD(4)                                       CC
      IF(CAPMAX(5).LT.0.) CAPMAX(5)=0.                                  CC
      GO TO 930                                                         CC
  910 IF(IZ2.EQ.1) GO TO 930                                            CC
      IZ2=1                                                             CC
      IF(IZ1.EQ.1) GO TO 915                                            CC
      CAPMAX(4)=CAPMAX(5)                                               CC
      GO TO 930                                                         CC
  915 CAPMAX(4)=CAPMAX(5)-CAPD(5)                                       CC
      IF(CAPMAX(4).LT.0.) CAPMAX(5)=0.                                  CC
  930 CONTINUE                                                          CC
      JJ=JK
      IF(JK.GT.N) JJ=JK-N
      CALL AFNC(U,ESF,2+2*N+JJ)
      A=CAPMAX(JK)-CAPD(JK)
      IF(ESF.LT.0.1) ESF=0.1
      B=(ENRMX(JJ)-ERUS(JJ))/ESF
      IF(A.GT.CD) GO TO 215
      ICON(JK)=0
      IF(A.GT.B) GO TO 213
      D=A
      GO TO 220
  213 D=B
      GO TO 220
  215 IF(B.GT.CD) GO TO 218
      ICON(JK)=0
      D=B
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CARD
          GO TO 220
      218 D=CD
      220 CAPD(JK)=CAPD(JK)+D
          ERUS(JJ)=ERUS(JJ)+D*ESF
          A=D
          GO TO 2000
     1000 K=0
          DO 1001 I=1,NN
          IF(ICON(I).EQ.0) GO TO 1001
          K=K+1
     1001 NR(I,2)=ICON(I)
          IF(K.EQ.0) GO TO 5000
          DO 1010 I=1,K
          COS=1.E20
          DO 1005 J=1,NN
          IF(NR(J,2).EQ.0) GO TO 1005
          IF(J.GT.N) GO TO 1002
          CALL AFNC(U,A,2+N+J)
          GO TO 1003
     1002 A=VC(J-N)
     1003 IF(A.GT.COS) GO TO 1005
          NR(I,1)=J
          COS=A
     1005 CONTINUE
     1010 NR(NR(I,1),2)=0
          GO TO (101,210),IGTO
     2000 DO 2010 I=2,42,2
          AA(I-1)=(FLOAT(I)/2.-1.)*5.
          CALL AFNC(AA(I-1),C,2)
          CALL AFNC(AA(I-1),D,JJ+2)
     2010 AA(I)=C+D*A
          CALL CHNG(2,AA,IFS)
          GO TO (135,201),IGTO
     5000 CONTINUE
          RETURN
          END
C
          SUBROUTINE DESCAP
          DIMENSION CAPDD(10),ICON(10)
C    *********** INITIAL SECTION
          K=0
          CAPUS=0.
          DO 100 I=1,N
          CAPUS=CAPUS+CAPMAX(I+N)
          ICON(I)=0
          IF(III.GT.ICPT(I)) ICON(I)=1
          IF(CAPMAX(I).EQ.0.) ICON(I)=0
          IF(ICON(I).EQ.0) GO TO 100
C    K=NO. OF TYPES OF CAPACITY WHICH CAN BE CONSIDERED
          K=K+1
C    CAPDD(I)=QUANTITY OF CAPACITY TYPE I IN IDEAL MIX
          CAPDD(I)=SCLOM*CAPD(I+N)
          IF(CAPDD(I).EQ.0.) GO TO 95
C    CAPDD(I+N)=FRACTION OF DESIRED CAPACITY NOW EXISTING
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CARD
      CAPDD(I+N)=CAPMAX(I+N)/CAPDD(I)
      GO TO 100
   95 CAPDD(I+N)=+1.E20
C  CAPD(I)=ADDITIONAL CAPACITY TO ADD.  INITIALIZE TO 0
  100 CAPD(I)=0.
      IF(K.EQ.0) GO TO 1000
      IF(CAPUS.GE.SCLDM) GO TO 1000
C  RANK CAPACITY TYPES ACCCRDING TO HOW FAR BELOW DESIRED MIX
C  CONSIDERED ONLY THOSE WHICH CAN BE USED
      DO 110 I=1,N
  110 NR(I,2)=ICON(I)
      DO 120 I=1,K
      A=+2.E20
      DO 115 J=1,N
      IF(NR(J,2).EQ.0) GO TO 115
      IF(CAPDD(J+N).GT.A) GO TO 115
      NR(I,1)=J
      A=CAPDD(J+N)
  115 CONTINUE
  120 NR(NR(I,1),2)=0
C  CAPACITY ADDITION CALCULATICMS
      D=SCLDM/100.
C  J=NO. TYPES CONSIDERED THIS RCUND
C  JJ=TOTAL NO. OF TYPES WHICH COULD BE CONSIDERED THIS ROUND
      J=1
      JJ=K
  205 IF(JJ.LE.0) GO TO 1000
      IF(JJ.EQ.1) GO TO 300
      IC=0
      II=0
      JI=1
      DO 210 I=1,J
      IF(JI.EQ.0) GO TO 210
      IJ=NR(I,1)
      IF(ICON(IJ).EQ.0) GO TO 210
      IC=1
      CAPD(IJ)=CAPD(IJ)+D
      IF(CAPD(IJ).LT.CAPMAX(IJ)) GO TO 208
      ICON(IJ)=0
      JJ=JJ-1
  208 CAPUS=CAPUS+D
      IF(CAPUS.GE.SCLDM) JI=0
      IF(CAPDD(IJ).EQ.0.) GC TO 209
      CAPDD(IJ+N)=(CAPMAX(IJ+N)+CAPD(IJ))/CAPDD(IJ)
  209 IF(J.EQ.K) GO TO 210
      IF(CAPDD(IJ+N).GE.CAPDD(NR(J+1,1)+N)) II=1
  210 CONTINUE
      J=J+II
      IF(JI.EQ.0) GO TO 1000
      IF(IC.EQ.1) GO TO 205
      IF(J.GE.K) GO TO 1000
      J=J+1
      GO TO 205
  300 A=SCLDM-CAPUS
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CARD
      DO 305 I=1,K
      IJ=NR(I,1)
  305 IF(ICON(IJ).EQ.1) JJ=IJ
      B=CAPMAX(JJ)-CAPD(JJ)
      IF(A.GT.B) A=B
      CAPD(JJ)=CAPD(JJ)+A
 1000 CONTINUE
      RETURN
      END
C
      SUBROUTINE ERNEED
C*****RANK ACCORDING TO VARIABLE COST
      DO 100 I=1,N
  100 ENR(I)=0.
      IF(IL.NE.0) GO TO 110
      CALL RANK1
  110 U=0.
  202 CALL AFNC(U,DEM,1)
      A=DEM*SCLDM
      B=0.
      DO 200 I=1,N
      IF(B.GE.A) GO TO 200
      CALL AFNC(U,C,NR(I,1)+1)
      C=C*SCLCP(NR(I,1))
      IF(B+C.GT.A) GO TO 201
      ENR(NR(I,1))=ENR(NR(I,1))+C*428.
      B=B+C
      GO TO 200
  201 ENR(NR(I,1))=ENR(NR(I,1))+(A-B)*428.
      B=A
  200 CONTINUE
      U=U+5.
      IF(U.LT.100.) GO TO 202
      RETURN
      END
C
      SUBROUTINE STFRM
C*****RANK ACCORDING TO VARIABLE COST
      NN=N+NER
      DO 800 I=1,NN
  800 NR(I,2)=1
      DO 802 J=1,NN
      COS=10.**20
      DO 801 I=1,NN
      IF(NR(I,2).EQ.0) GO TO 801
      IF(VC(I).GT.COS) GO TO 801
      NR(J,1)=I
      COS=VC(I)
  801 CONTINUE
  802 NR(NR(J,1),2)=0
      FIRM=0.
      U=100.
      D=ELDM/100.
  100 CALL AFNC(U,A,1)
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12345678901234567890123456789012345678901234567890123456789012345678901234567890
      A=A*ELDM
      AVLL=0.
      KK=1
      DO 150 K=1,NN
  110 IF(FIRM.GE.FIRMX) GO TO 150
      IF(AVLL+FIRM.GE.A) GO TO 150
      CALL AFNC(FIRM,VCF,2)
      C=VCF+FXCF/(U*87.6)
      IF(C.GT.VC(NR(K,1))) GO TO 115
      FIRM=FIRM+D
      GO TO 110
  115 KK=KK+1
      CALL AFNC(U,B,2+NR(K,1))
      AVLL=AVLL+B*SCLCP(NR(K,1))
  150 CONTINUE
      IF(FIRM.GE.FIRMX) GO TO 300
      A=A*SCLDM/ELDM
      IF(A*(1.+RES).LE.AVLL+FIRM) GO TO 200
      IF(KK.GT.NN) GO TO 170
      DO 160 K=KK,NN
      CALL AFNC(U,B,2+NR(K,1))
  160 AVLL=AVLL+B*SCLCP(NR(K.1))
  170 IF(A*(1.+RES).LE.AVLL+FIRM) GO TO 200
      FIRM=(A*(1.+RES)-AVLL)
      IF(FIRM.GE.FIRMX) GO TO 300
  200 U=U-5.
      IF(U.LT.0.) GO TO 300
      IF(U.LT.1.) U=1.
      GO TO 100
  300 IF(FIRM.GT.FIRMX) FIRM=FIRMX
      RETURN
      END
C
      SUBROUTINE STFS
      DO 99 I=1,NN
   99 NC(I)=1
      F=0.
      CALL AFNC(F,FP,2)
      NF=1
      IF(FIRM.LE.0.) NF=0
      KF=1
      K=1
      D=ELDM/100.
      DO 100 I=1,NN
      COS=10.E20
      DO 101 J=1,NN
      IF(NC(J).EQ.0) GO TO 101
      IF(VC(J).GT.COS) GO TC 101
      COS=VC(J)
      L=J
  101 CONTINUE
      IF(NF.EQ.0) GO TO 105
      IF(FP.GT.VC(L)) GO TO 105
      FF=0.
```

80/80 LIST

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CARD
  102 FF=FF+D
      F=F+D
      IF(F.GE.FIRM) GO TO 103
      CALL AFNC(F,FP,2)
      IF(FP.LT.VC(L)) GO TO 102
      FCP(KF)=FF
      FCPL(KF)=F
      GO TO 104
  103 NF=0
      FCP(KF)=FF-(F-FIRM)
      FCPL(KF)=FIRM
  104 NR(K,2)=0
      NR(K,1)=KF
      KF=KF+1
      K=K+1
  105 NR(K,2)=1
      NR(K,1)=L
      NC(L)=0
      K=K+1
  100 CONTINUE
      L=K-1
      KRANK=L
      CMIN=1.E20
      DO 200 K=1,21
      X=FLOAT(K-1)*5.
      CALL AFNC(X,A,1)
      A=A*ELDM
      F=0.
      NF=0
      DO 201 J=1,L
      IF(NR(J,2).EQ.0) GO TO 202
      CALL AFNC(X,FF,NR(J,1)+2)
      FF=FF*SCLCP(NR(J,1))
      GO TO 203
  202 FF=FCP(NR(J,1))
  203 F=F+FF
      IF(F.GE.A) GO TO 204
      FF=0.
      GO TO 205
  204 FF=F-A
      IF(NF.EQ.1) GO TO 205
      NF=1
      NS(K)=J
  205 XFNC(NN+3+J,K,2)=FF
  201 XFNC(NN+3+J,K,1)=X
      F=F/(1.+RES)-A*SCLDM/ELDM
  200 IF(CMIN.GT.F) CMIN=F
      F=0.
      IF(CMIN.LT.0.) CMIN=0.
      IF(CMIN.GT.FRMSM) CMIN=FRMSM
  300 IF(F.GE.CMIN) GO TO 400
      F=F+D
      COS=0.
      REV=0.
```

80/80 LIST

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     000000000111111111122222222223333333333444444444455555555556666666666777777777778
     12345678901234567890123456789012345678901234567890123456789012345678901234567890
CARD
      CALL AFNC(F,FPP,NN+3)
      DO 304 K=1,21
      J=NS(K)
      FFF=0.
  301 Z=FLOAT(K-1)*5.
      IF(NR(J,2).EQ.0) GO TO 3015
      CALL AFNC(Z,FF,NR(J,1)+2)
      FF=FF*SCLCP(NR(J,1))
      GO TO 3016
 3015 FF=FCP(NR(J,1))
 3016 FFF=FFF+FF
      IF(FFF.LT.F*AFDEM(K)) GO TO 302
      GO TO 3025
  302 J=J+1
      GO TO 301
 3025 IF(NR(J,2).EQ.1) GO TO 303
      CALL AFNC(FCPL(NR(J,1)),FP,2)
      COS=COS+FP*AFDEM(K)
      GO TO 304
  303 COS=COS+VC(NR(J,1))*AFDEM(K)
  304 REV=REV+FPP*AFDEM(K)
      COS=(COS/21.)*8760.
      REV=(REV/21.)*8760.+FXCF*D
      IF(REV.GE.COS) GO TO 300
      F=F-D
  400 FMSL=F
      IF(CMIN.LT.F) FMSL=CMIN
      RETURN
      END
C
      SUBROUTINE DAILY
      DO 99 I=1,NN
   99 ERC(I)=0.
      ERFB=0.
      ERFS=0.
      EREB=0.
      ERES=0.
      ERMB=0.
      ERMS=0.
      CFFB=0.
      CFFS=0.
      CFEB=0.
      CFES=0.
      UEDR=0.
      UEDF=0.
      ERUR=0.
      K=KRANK
      IU=0
      D=(SCLDM+SCLDF)/100.
      CALL AFNC(0.,PF2,4)
  100 U=FLOAT(IU)
      CAP=0.
      DO 110 I=1,K
      IF(NR(I,2).EQ.0) GO TO 101
```

80/80 LIST

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CARD
      CALL AFNC(U,DD,4+NR(I,1))
      DD=DD*SCLCP(NR(I,1))
      CAP=CAP+DD
      GO TO 110
  101 CAP=CAP+FCP(NR(I,1))
  110 CONTINUE
      EMP=0.
      CAPR=CAP/(1.+RES)
      CALL AFNC(U,A,1)
      CALL AFNC(U,DD,2)
      DD=DD*SCLDF
      CALL AFNC(DD,PF1,4)
      PF=(PF1+PF2)*.5
      CFFS=CFFS+DD*PF*433.644
      ERFS=ERFS+DD*433.644
      A=A*SCLDM
      ERUR=ERUR+A*433.644
      A=A+DD
      B=A-CAPR
      IF(B.LE.0.) GO TO 150
      CALL AFNC(U,C,NN+4+K1)
      EMP=B
      IF(EMP.LT.C) GO TO 120
      EMP=C
      F=CAP-CAPR
      IF(F.GT.C-B) GO TO 120
      F=B-C-F
      C=DD/A
      F=F*433.644
      UEDF=F*C+UEDF
      CFFS=CFFS-F*C*PF
      UEDR=(1.-C)*F+UEDR
      ERFS=ERFS-UEDF
      ERUR=ERUR-UEDR
  120 ERMB=ERMB+EMP*433.644
  150 EC=EMP
      CALL AFNC(U,F,NN+K1+K2+5)
      IF(F.LE.0.) GO TO 200
      C=CAPR+EMP-A
      IF(C.LE.0.) GO TO 200
      IF(C.GE.F) GO TO 151
      ERMS=ERMS+C*433.644
      EMP=EMP-C
      GO TO 200
  151 ERMS=ERMS+F*433.644
      EMP=EMP-F
  200 CAP=A-EMP
      ECB=0.
      ECS=0.
      IF(CAP.GE.CAPR) GO TO 300
      CALL AFNC(U,ECBM,NN+K1+4)
      ECBM=ECBM-EC
      CALL AFNC(U,ECSM,NN+K1+K2+4)
  201 I=0
```

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      J=0
      B=0.
      C=0.
  202 J=J+1
      IF(J.GT.K) GO TO 211
      IF(NR(J,2).EQ.0) GO TO 205
      CALL AFNC(U,F,4+NR(J,1))
      B=B+F*SCLCP(NR(J,1))
      PC=VC(NR(J,1))
      GO TO 210
  205 C=C+FCP(NR(J,1))
      B=B+FCP(NR(J,1))
      CALL AFNC(C,PC,3)
  210 IF(B.LT.CAP) GO TO 202
  211 IF(CAP.GE.CAPR) GO TO 220
      IF(ECS.GE.ECSM) GO TO 220
      JJ=1
      C=0.
      DO 212 J=1,K2
      CALL AFNC(U,B,NN+K1+4+J)
      IF(B.GE.ECS) GO TO 212
      JJ=J
      C=B
  212 CONTINUE
      IF(JJ.EQ.1) GO TO 213
      CALL AFNC(U,B,NN+K1+5+JJ)
      PES=PDEM(JJ)+(PDEM(JJ+1)-PDEM(JJ))*(B-ECS)/(B-C)
      GO TO 215
  213 CALL AFNC(U,B,NN+K1+5)
      CALL AFNC(U,C,NN+K1+6)
      IF(ABS(C-B).LT.1.) B=C+1.
      PES=PDEM(1)-(PDEM(2)-PDEM(1))*(B-ECS)/(C-B)
  215 IF(PES.LE.PC) GO TO 220
      ECS=ECS+D
      CAP=CAP+D
      I=1
  220 IF(ECB.GE.ECBM) GO TO 230
      JJ=1
      C=0.
      DO 222 J=1,K1
      CALL AFNC(U,B,NN+4+J)
      IF(B.GE.EC) GO TO 222
      JJ=J
      C=B
  222 CONTINUE
      IF(JJ.EQ.1) GO TO 223
      CALL AFNC(U,B,NN+4+JJ+1)
      PEB=PSUP(JJ)+(PSUP(JJ+1)-PSUP(JJ))*(B-EC)/(B-C)
      GO TO 225
  223 CALL AFNC(U,B,NN+5)
      CALL AFNC(U,C,NN+6)
      IF(ABS(B-C).LT.1.) B=C+1.
      PEB=PSUP(1)-(PSUP(2)-PSUP(1))*(B-EC)/(C-B)
  225 IF(PEB.GE.PC) GO TO 230
```

80/80 LIST

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CARD
      EC=EC+D
      ECB=ECB+D
      CAP=CAP-D
      I=1
  230 IF(I.EQ.1) GO TO 201
  300 J=0
      F=0.
      C=0.
      I=0
      EREB=EREB+ECB*433.644
      ERES=ERES+ECS*433.644
      IF(ECS.LE.0.) GO TO 3005
      CFES=CFES+ECS*433.644*(PC+PES)*.5
 3005 IF(ECB.LE.0.) GO TO 301
      CFEB=CFEB+ECB*433.644*(PC+PEB)*.5
  301 I=I+1
      IF(I.GT.K) GO TO 308
      IF(NR(I,2).EQ.0) GO TC 302
      CALL AFNC(U,B,4+NR(I,1))
      B=B*SCLCP(NR(I,1))
      GO TO 303
  302 B=FCP(NR(I,1))
      F=F+B
  303 C=C+B
      IF(C.LT.CAP) GO TO 305
      J=1
      B=B-C+CAP
  305 IF(NR(I,2).EQ.0) GO TO 306
      ERC(NR(I,1))=ERC(NR(I,1))+B*433.644
      GO TO 307
  306 DD=F-.5*B
      CALL AFNC(DD,PC,3)
      ERFB=ERFB+B*433.644
      CFFB=CFFB+B*433.644*PC
  307 IF(J.EQ.0) GO TO 301
  308 IU=IU+5
      IF(IU.LE.100) GO TO 100
      RETURN
      END
C
      SUBROUTINE RANKC
      CALL ERNEED                                                       CCR1
      DO 110 I=1,NER                                                    CCR1
      A=ERAV(I)-ENR(I)*HTRT(I)                                          CCR1
      IF(A.GE.0.0) GO TO 110                                            CCR1
      SCLCP(I+N)=0.                                                     CCR1
      SCLCP(I)=SCLCP(I)*(1.+A/(ENR(I)*HTRT(I)))                         CCR1
  110 CONTINUE                                                          CCR1
      RETURN
      END
C
      SUBROUTINE RANK1
      DO 100 I=1,N
  100 NR(I,2)=1
```

80/80 LIST

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00000000011111111112222222222333333333344444444445555555555666666666677777777778
12345678901234567890123456789012345678901234567890123456789012345678901234567890
      DO 102 J=1,N
      COS=10.**20
      DO 101 I=1,N
      IF(NR(I,2).EQ.0) GO TO 101
      IF(VC(I).GT.COS) GO TO 101
      NR(J,1)=I
      COS=VC(I)
  101 CONTINUE
  102 NR(NR(J,1),2)=0
      RETURN
      END
C
      SUBROUTINE CHNG(I,AAA,IA)
      DIMENSION AAA(1),IA(1)
      DO 100 J=1,5
  100 IFNC(I,J)=IA(J)
      JJ=IFNC(I,4)*2
      JX=0
      DO 200 J=1,JJ,2
      JX=JX+1
      XFNC(I,JX,1)=AAA(J)
  200 XFNC(I,JX,2)=AAA(J+1)
      RETURN
      END
C
      SUBROUTINE AFNC(XZ,Y,IZ)
      COMMON TIME,FINTIM,BEGTIM,DT,NDT,NW,NRO,NOUT
C     ***********************************************************************
C     REASSIGN THE INPUT ARGUEMENTS
      X=XZ
      I=IZ
C     THIS IS A SUBROUTINE WHICH INTERPOLATES BETWEEN TABLED FUNCTION
C     VALUES BY FITTING A POLYNOMIAL TO A NUMBER OF POINTS
C     X IS THE VALUE OF THE INDEPENDENT VARIABLE
C     Y IS THE VALUE OF THE DEPENDENT VARIABLE CALCULATED
C     I IS THE FUNCTION NUMBER
C     TWO ARRAYS MUST BE SUPPLIED TO IT THROUGH COMMON
C     THE USER MUST SUPPLY A COMMON STATEMENT SUITABLE FOR THE FUNCTIONS
C     BEING USED
C     XFNC(I,J,K) IS THE ARRAY WHICH CONTAINS THE TABLED FUNCTION
C     I IS THE NUMBER OF THE FUNCTION BEING USED
C     J IS THE INDEX FOR FUNCTION POINTS
C     K IS 1 FOR THE INDEPENDENT VARIABLE AND 2 FOR THE DEPENDENT VARIABLE
C     IFNC(I,J) DESCRIBES THE NATURE OF THE FUNCTION
C     I IS THE NUMBER OF THE FUNCTION
C     THE J VALUES ARE USED TO CONVEY INFORMATION ABOUT THE FUNCTION
C     1 STANDS FOR YES, 0 STANDS FOR NO
C     J=1--EXTEND FUNCTION BELOW MINUMUM VALUE OF INDEPENDENT VARIABLE
C     J=2--EXTEND  FUNCTION BEYOND MAXIMUM VALUE OF INDEPENDENT VARIABLE
C     J=3--EQUALLY SPACED VALUES OF INDEPENDENT VARIABLE
C     J=4--IS USED FOR THE NUMBER OF DATA POINTS IN THE FUNCTION
C     J=5--IS USED FOR THE NUMBER OF DATA POINTS TO BE USED IN THE INTERPOLATION
C     IERROR IS A SIGNAL USED TO INDICATE A MALFUNCTION IN THE INTERPOLATION
C     0 INDICATES NO ERRORS.  1 INDICATES AN ERROR
```

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000000000111111111122222222223333333333444444444455555555556666666666777777777778
1234567890123456789012345678901234567890123456789012345678901234567890123456789 0
C
C
C  REASSIGN OFTEN USED ARRAY VALUES
      J4=IFNC(I,4)
      J5=IFNC(I,5)
      X1=XFNC(I,1,1)
      XN=XFNC(I,J4,1)
C  INITIALIZE ERROR PARAMETER
      IERROR=0
C  CHECK TO SEE IF X IS IN THE PROPER RANGE
      IF(X.GE.X1) GO TO 103
      IF(IFNC(I,1).EQ.1) GO TO 102
      WRITE(6,101) I,X
  101 FORMAT(24H BELOW RANGE OF FUNCTION,I4,G15.4)
      IERROR=1
  102 Y=XFNC(I,1,2)
      RETURN
  103 IF(X.LE.XN) GO TO 106
      IF(IFNC(I,2).EQ.1) GO TO 105
      WRITE(6,104) I,X
  104 FORMAT(24H ABOVE RANGE OF FUNCTION,I4,G15.4)
      IERROR=1
  105 Y=XFNC(I,J4,2)
      RETURN
C  FIND STARTING POINT FOR SEARCH FOR INDEPENDENT VARIABLE INDEXES
  106 IX=IFIX(((X-X1)/(XN-X1))*FLOAT(J4-1))+1
      IF(IX.EQ.J4) IX=J4-1
C  ARE VALUES OF INDEPENDENT VARIABLE EQUALLY SPACED
      IF(IFNC(I,3).EQ.0) GO TO 110
C ARE AN EVEN OR ODD NUMBER OF DATA POINTS TO TO BE USED
 1065 A=FLOAT(J5)*.5
      IA=IFIX(A+.1)
      IF(A.GT.FLOAT(IA)) GO TO 107
      IX=IX-IA+1
      GO TO 150
C  WHICH PART OF INTERVAL IS POINT IN
  107 J=0
      XI1=XFNC(I,IX+1,1)
      IF((XI1-X)/(XI1-XFNC(I,IX,1)).LT.0.5) J=1
      IX=IX-IA+J
      GO TO 150
C  SEARCH FOR INDEXES
  110 J=0
      K=0
  111 IF(X-XFNC(I,IX,1)) 120,120,125
  120 IF(J.EQ.0) GO TO 121
      IX=IX-1
      GO TO 1065
  121 K=1
      IX=IX-1
      IF(IX.NE.0) GO TO 111
      IX=1
      GO TO 1065
  125 IF(K.EQ.1) GO TO 1065
```

80/80 LIST

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12345678901234567890123456789012345678901234567890123456789012345678901234567890
      J=1
      IX=IX+1
      GO TO 111
C  SET INDEXES FOR INTERPOLATION
  150 IF(IX.LT.1) IX=1
      J=J4-J5+1
      IF(IX.GT.J) IX=J
      L=IX+J5-1
C  MAKE INTERPOLATION
      Y=0.
      DO 400 K=IX,L
      YL=1.0
      DO 300 J=IX,L
      IF(J.EQ.K) GO TO 300
      XJ=XFNC(I,J,1)
      YL=YL*(X-XJ)/(XFNC(I,K,1)-XJ)
  300 CONTINUE
  400 Y=Y+YL*XFNC(I,K,2)
      RETURN
      END
```

2

VITA

Byron Wayne Jones

Candidate for the Degree of

Doctor of Philosophy

Thesis: DYNAMIC SIMULATION OF THE ELECTRIC UTILITY COMPONENT OF A REGIONAL ENERGY SYSTEM

Major Field: Mechanical Engineering

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