IC UTILITY SYSTEMS ENGINEERING DEPARTMENT

DESCRIPTIVE HANDBOOK

OPTIMIZED GENERATION PLANNING PROGRAM

FINANCIAL SIMULATION PROGRAM

(PROPRIETARY)

March, 1983

GENERAL ELECTRIC

Descriptive Handbook

Optimized Generation Planning Program

Financial Simulation Program

(Proprietary)

Generation Planning and Economics

Electric Utility Systems Engineering Department

General Electric Company

Schenectady, New York 12345

TABLE OF CONTENTS

TABLE OF CONTENTS (CONTINUED)

PREFACE

The Optimized Generation Planning (OGP) Program and the Financial Simulation Program (FSP) are being offered to the electric utility industry to assist planners in analyzing alternate patterns of generation additions.

The General Electric Company warrants that it has exercised professional competence in writing these programs and in testing them extensively. The Company does not assume responsibility for specific results obtained from the programs and will not be liable for direct, special or consequential damages arising from decisions based on these results.

If a program error is discovered and is reported to the Company within 30 days, the liability of the Company is restricted to the limitations of liability as stated in the License Agreement or in the Agreement for Computer Services signed with the General Electric Information Services Company (GEISCO). The General Electric Company will not assume liability for incorrect results obtained from incorrect input data.

INTRODUCTION

This handbook is designed to aid users in the application of the Optimized Generation Planning (OGP) Program and Financial Simulation Program (FSP) by providing a general, but comprehensive, explanation of the supporting theory and the composition of OGP and FSP. Additional documentation in various levels of detail is available from the Electric Utility Systems Engineering Department (EUSED). This documentation includes a four-page introductory brochure (5204.40A), a twelve-page overview in pamphlet form (GEA-10390A) and complete User's Manuals, which are continually updated as program enhancements are implemented. For further background on the history of the use of OGP/FSP, a separate Experience List and a compilation of typical studies can also be obtained from EUSED. More detailed information can be obtained on many of the subjects treated in this handbook by referring to the listing of available "Supplementary Information" included at the end of specific sections. These materials can be obtained from EUSED by specific request.

This introductory section covers the background and status of OGP/FSP within the context of performing the tasks inherent in the general area of generation system expansion planning. This handbook has been segmented according to the sections illustrated in the schematic flow chart illustrated in Figure 1-1*. This will allow the reader to more easily locate answers to specific functional questions that may arise. Note, however, that the simplified schematic flow chart in Figure 1-1 is not intended to represent the actual computational flow of OGP/FSP, but rather to represent the conceptual flow the user is most likely to follow while performing a complete study.

Another significant point to be noted is that the user can execute OGP/FSP in total in one integrated step, which could involve the entire sequence of 2 through 16 and allow examination of the entire planning spectrum, including the following phases: reliability evaluation, operational simulation, investment costing and financial analysis. Typically, those who use OGP/FSP most often utilize almost all of these automated capabilities and obtain a total system cost evaluation of a thirty-year expansion plan. However, it is perhaps equally important to note that, for certain studies, only portions of the overall analysis may need to be executed, or perhaps a predetermined stream of additions needs to be analyzed. Flexibility is the keynote of OGP/FSP, thus making it a very efficient medium for conducting these types of studies.

---

* Figure 1-1 is printed for easy reference on the foldout on the last page of this handbook. Turn to this page now and fold out this art for your reference as you read through the remainder of this handbook.

The Spectrum of Generation Planning Activities

What is known today as the Electric Utility Systems Engineering Department (EUSED) originated more than half a century ago. Since its origination, one of the Department's primary goals has been to foster the development and maintenance of state-of-the-art tools in generation, transmission, distribution, control and automation, to aid planners and decision makers of the electric utility industry with their work.

As a result of the effort applied to satisfy this goal, many of the major historical breakthroughs in the area of digital computations of system reliability analysis and operational simulation and costing of generation systems have originated from EUSED staff members. Figure 1-2 symbolically presents a summary of EUSED's current offerings of computer programs which address all facets of the generation system expansion planning problem.

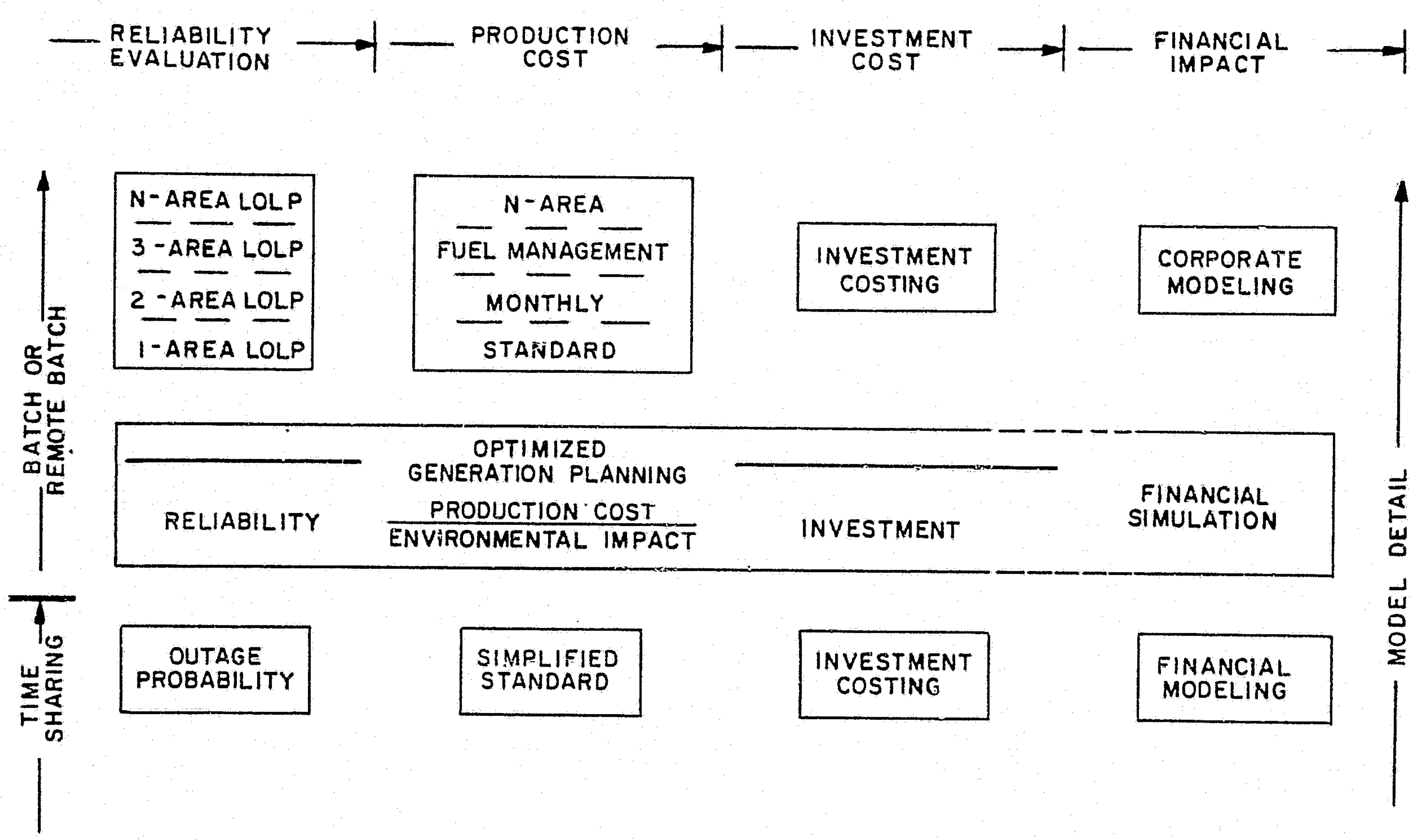


Figure 1-2. Electric Utility Systems Engineering Department Generation System Planning Programs

Because all of the different challenges presented to generation planners today cannot be most efficiently solved with only one tool, EUSED has made a spectrum of models available, ranging, on one hand, from interactive time-sharing programs to the most detailed batch-mode models accessible in the electric utility industry today. As shown in Figure 1-2, OGP/FSP is represented as the program it is--a single, free-standing, integrated tool which spans in one step all four major areas of interest to the generation planner.

Users can access OGP/FSP in three ways. Members of the technical staff of EUSED will perform complete studies under the customer's direction, or, with a minimum of assistance by EUSED, users can access OGP/FSP completely from a time-share terminal in their own offices in the "remote batch" mode provided through the General Electric Information Services Company's (GEISCO) MARK III Service. OGP/FSP is also available under a licensing agreement for installation on an in-house computer.

It should be noted that, in some respects, OGP/FSP is less detailed than some of the free-standing models shown in the blocks above it in Figure 1-2. OGP/FSP was designed with less detail so it would be easier and less costly to use than the more highly detailed, free-standing models. Highly detailed programs are best suited to short-range studies involving little uncertainty in the data assumptions, while OGP/FSP has been designed for long-range studies which characteristically require many cases involving ranges of parametric assumption.

This does not mean, however, that every feature of OGP/FSP is less detailed than those of some of the free-standing models. There are many areas where the level of detail and computational accuracy of OGP/FSP are essentially identical to even the most detailed programs. This is because the calculational procedures within OGP/FSP were mostly derived from the algorithms contained within the free-standing programs. No significant deviations in accuracy from these more detailed models were accepted for inclusion in OGP/FSP if it appeared that compromise would have rendered OGP/FSP unsuitable for its intended purposes in these areas.

Overall Generation Planning and OGP/FSP

Regardless of the processes or models generation planners can apply to their work, the elemental driving forces and starting points that feed into any orderly planning analysis must also be considered. For example, before executing the charge from their organizations, planners must deal with many uncertain elements as well as their knowledge of the existing system to determine the impact of these factors upon the plans developed. Specifically, planners must consider the impact of such factors as new generation technologies, the effect of inflation, money market conditions, fuel availability, environmental constraints, etc. Then, planners must use their knowledge of the existing system to develop data estimates and assumptions in areas such as generation, load, operational rules, and economic factors.

An organization's charge can be summarized by the following four major questions posed by planners and decision makers of the electric utility industry:

- How much generation needs to be added in the future?
- What kind of units will satisfy this need?
- What is the total cost of this plan in terms of revenue requirements?
- What are the financial implications of pursuing this course of action?

In the past, these questions were not that difficult to answer. The "How much?" question could be answered almost by rule of thumb. The "What kind?" question did not involve a multitude of technologies, many of which are characterized by undefined cost and availability. "Total cost" meant something fairly straightforward such as "the sum of fixed charges on investment and expenses for fuel and operation and maintenance (O&M)." It did not include any extensive consideration of the costs and performance of pollution controls, the anticipation of operational restrictions due to environmental rulings, oil boycotts, etc. Finally, the "financial implications" factor perhaps would not even have been considered by the system planner because it probably would not have been included in the responsibility and job scope of the system planner. However, that was before the days of restricted money markets, tight cash flows and delayed and reduced rate increases. Today, planners and decision makers must have a common basis of discussion. The projected plans developed must not only be attractive in terms of their engineering economics, but they must also be imminently feasible in terms of their technological availability, environmental acceptability and financial practicality.

During the last decade, generation planners' needs have expanded significantly, and consequently, their goals have become more difficult to achieve. Because of its foresight, EUSED developed OGP/FSP more than ten years ago to help planners meet their needs.

OGP addresses and answers questions posed by the conventional generation planning process including: (1) how much generation needs to be added in the future, (2) what types of units will satisfy this need, and (3) what the total cost of the plan is in terms of revenue requirements. However, OGP also extends far beyond these bounds. The program's optimization capabilities not only can derive a feasible plan, but also can derive the best mix of new generation in terms of minimizing the revenue requirements. OGP also can consider a myriad of environmental restrictions and derive a plan which simultaneously addresses lowest cost and minimum environmental impact. Finally, the financial impacts of any stream of unit additions are presented by FSP to aid the user in further ranking alternative plans.

To obtain further perspective and knowledge of the scope and capabilities of OGP, refer to Figure 1-3. In a simplified flow chart, Figure 1-3 represents the conventional manually aided iterative process a planner would have to use to derive the total system cost for one thirty-year expansion plan, using a combination of free-standing computer models. First, a preset list of unit types, along with their sizes and timing, is tested until the sequence is found that would satisfy the required level of system reliability for each year under study. Then some type of operational simulation is conducted to obtain fuel and O&M costs for the system. A stream of investment

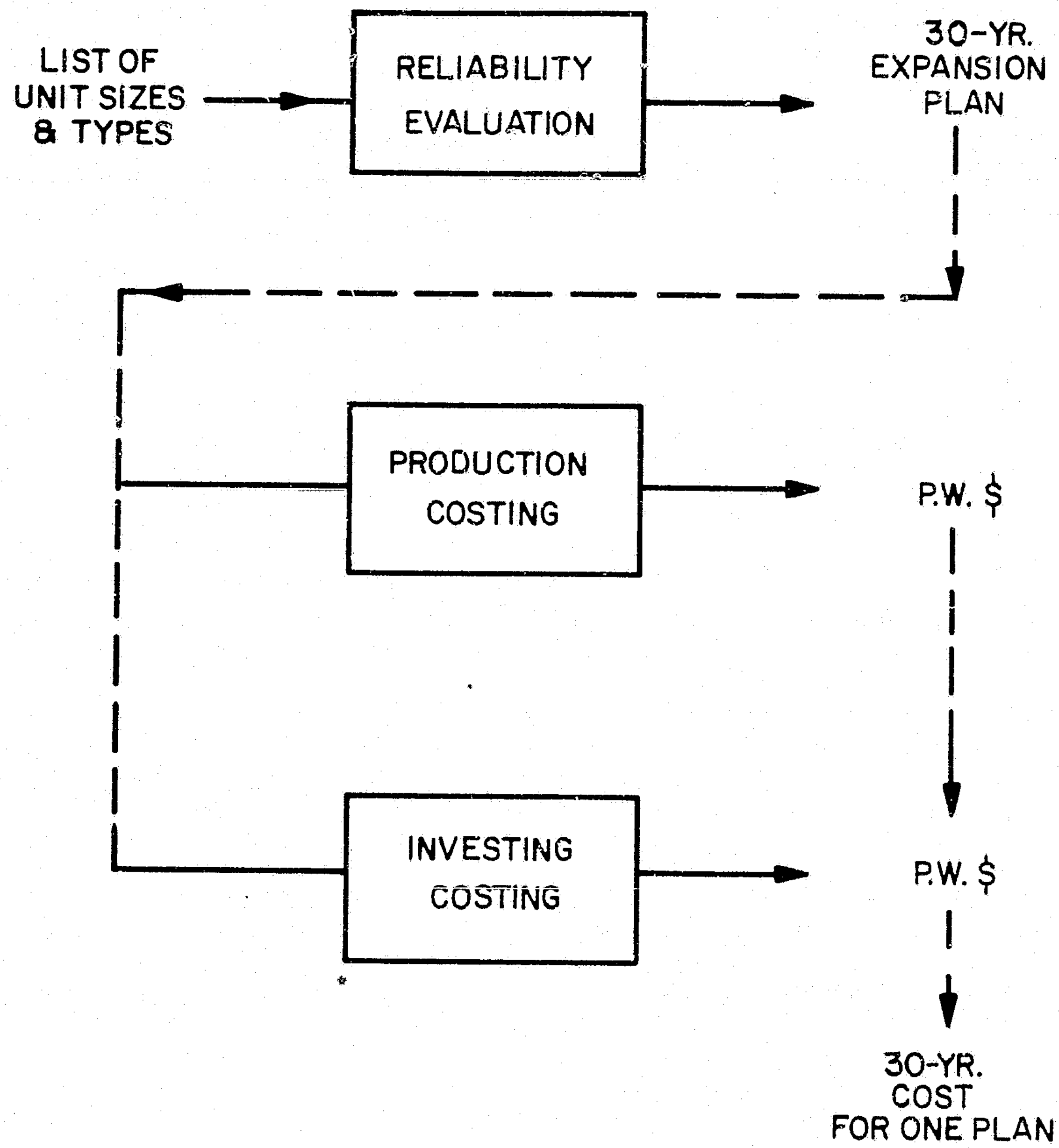


Figure 1-3. Conventional Generation Planning

charges is added to the fuel and O&M charges to determine the annual revenue requirements. Then the cumulative present worth of all revenue requirements is derived to provide one figure of merit or "bottom line" which represents the cost for the one plan. If the impact of other input data on the preferable additions needs to be compared, this sequence would have to be repeated. Iteration could also help planners select a single "optimum" plan.

Even today, the conventional manually aided iterative process can be a tractable approach for many organizations. With the number of alternatives and uncertainties in basic parametric assumptions being so great, however, it is not a very efficient or comprehensive technique, particularly when one considers that the resources and time available to most planners are rapidly exhausted under the barrage of remaining questions to be answered in today's planning climate. Thus, OGP/FSP was developed not only to allow planners to fulfill their responsibilities, but also to free them to address more topics than previously thought practical.

The construction of OGP/FSP, as it exists today, was motivated by the electric utility industry's need to address and accomplish the following goals:

- To find the best type of unit that will satisfy future generation system expansion requirements
- To be able to study alternative generation system expansion plans
- To determine financial and environmental implications of proposed generation system expansion plans

Thus, to help achieve these goals, the authors imposed the following major objectives to be met in the development of OGP/FSP:

- Data and logic simplification
- Linking of programs
- Optimization of expansions

The OGP/FSP Process

The OGP/FSP process can be represented in various ways. Sections 2 through 16 of this handbook (illustrated schematically in Figure 1-1) are a segmented treatment of the various facets of OGP/FSP. The information is presented in the handbook in this way merely to facilitate reference and discussion. However, as you read the following overview of the logical structure of OGP/FSP, refer to Figure 1-4, which represents a more simplified breakdown than that shown in Figure 1-1.

As you review Figure 1-4, you can see that there are certain points at which the user can furnish input data and there are points where output information can be obtained after appropriate calculations have been executed. In the first block, user-furnished input data describes the given or fixed system, which represents all existing and committed generation (i.e., all in-service, under-construction and pre-planned units that are not likely to change except for scheduled retirement). For more details on this user-furnished input data, see Section 2.

Once the user has furnished the necessary generation data, the user must then input an hourly representation of load values for the study period. Supplementary modeling and manipulative capabilities facilitate the automated handling of these hourly loads, particularly when load management studies involving many hourly load changes are being performed. This facet of OGP is described further in Sections 3 and 4.

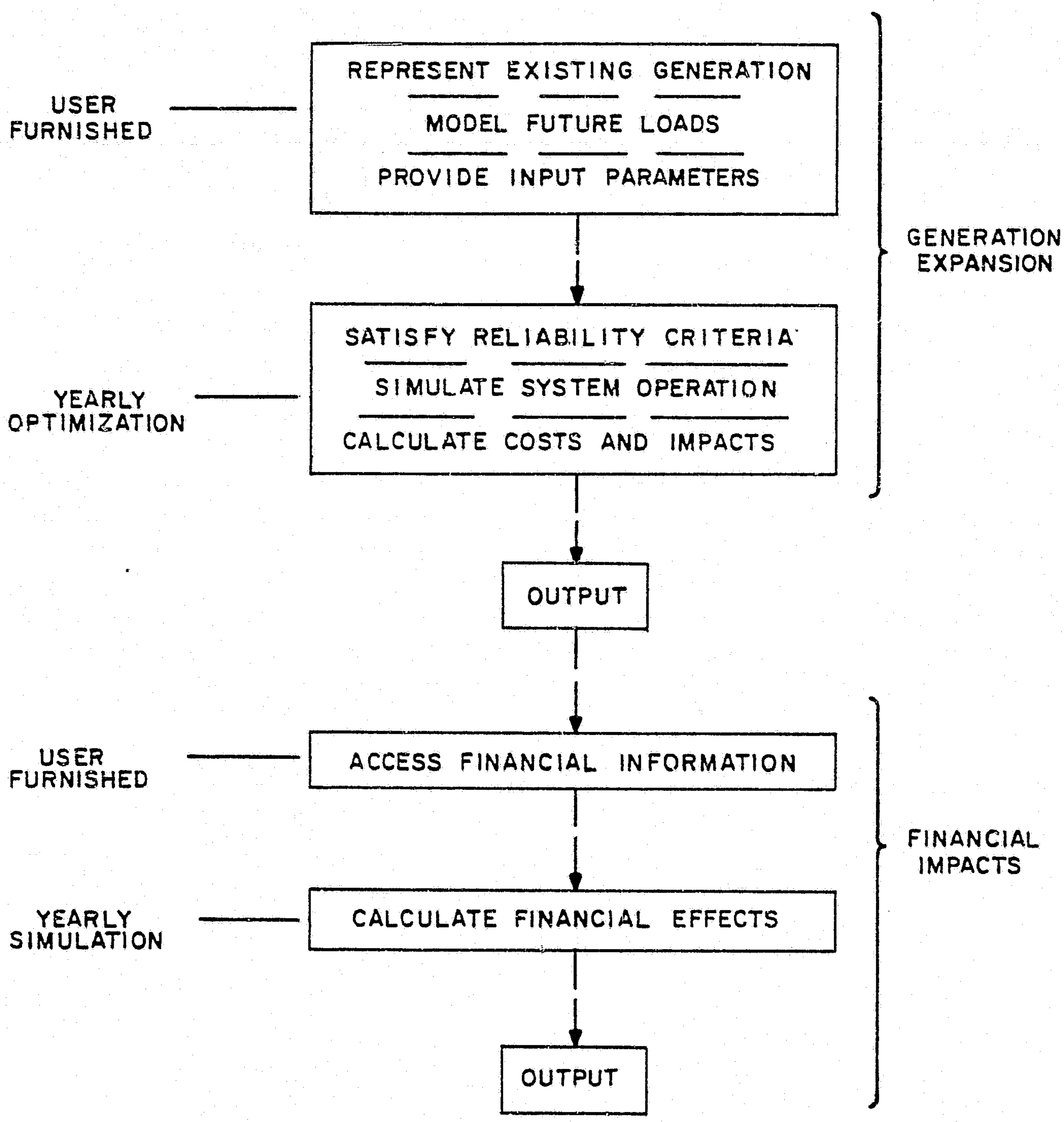


Figure 1-4. The OGP/FSP Process

Next, as indicated in the second block of Figure 1-4, economic and operational parameters must be supplied by the user. To ease input effort and minimize the possibility of inadvertent errors, an automated process of data by exception, integral to the OGP data assimilation logic, is used. Thus, entire classes of data can be specified and stored for further access by a single number which, for example, could represent a variable that applies to all of a certain generic type of generating unit. Simple controls direct the program on how these variables vary according to parameters such as unit size and study year, thus making it unnecessary for the user to perform side calculations to derive unique values for each generating unit. Of course, if atypical values need to be specified for any or all generation, this can also be accomplished. For further information on this subject, refer to Section 5.

Section 6 describes how this input data is automatically checked for nominal errors, sorted and then adapted for use within the program. The data is also displayed via formatted outputs for examination and reference by the user (see Figure 1-4, Block 3). If some individual items of input data are not readily available to the planner, the technical staff of EUSED usually can, upon request, provide average or suggested types of general industry information to aid in the completion of study data.

As discussed in Section 7, OGP then derives a complete expansion plan up to thirty years in length, and documents all the attendant generating unit and system costs associated with it. The user may evaluate a manual or predetermined expansion scenario for any or all of the years under study. Alternatively, if calculated as necessary by the reliability criterion input [e.g., either a percentage of installed reserve or desired loss-of-load probability (LOLP)], OGP will automatically add enough generation each year to satisfy that criterion.

The OGP optimization process not only considers and rigorously evaluates the relative economics of each different type of new generating and storage unit shown as available to it for commercial operation, but if the load growth compared to individual unit sizes allows, the program will also identify and compare all reasonable mixtures or combinations of the different types of units. This capability precludes the need for inputting preset limits on the absolute number of each type of unit that is to be evaluated. The OGP optimization logic is not forced to remain within a defined "tunnel" of alternatives.

Section 8 explains in detail the computations involved in answering the question of "How much generation is to be added each year?" If LOLP, either daily or hourly, is the design measure, a very efficient technique is used to convolve the capacity outage table with the load model. Unit maintenance requirements, purchases and sales as well as the known emergency tie capacity to external systems are considered. The effect of load forecasting uncertainty may also be addressed at this point.

All of the alternative configurations which satisfy the reliability criterion must then be evaluated in terms of their total system costs and impacts. This begins with the operations analysis discussed in Section 9. The simulation strategy is a detailed, six-step process involving the reflection of any contracts that may be specified externally to the system under study, the scheduling of conventional hydroelectric generation and the automatic, unit-by-unit allocation of maintenance (designed to maximize committable reserves in all months). Any energy storage on the system is also scheduled to minimize cost while observing storage limitations. Then, an hourly based algorithm (<u>not</u> a simple load duration curve approach) commits and dispatches all units through time to simulate an entire year of operation.

An approximated, or otherwise predetermined, loading order is not used for this simulation because the objective function of minimizing total variable operating costs constantly changes the commitment and dispatch priorities which are based on factors such as individual unit thermal cycling capabilities, maintenance schedules, spinning reserve requirements, and fuel and O&M costs. All of these factors can be a function of time. Also, the OGP hourly approach, which recognizes the preceding factors, is of critical importance when the impact of load management or certain new generation technologies are under scrutiny. At this point, the random forced outaging of each unit is simulated and the expected unserved energy calculated.

The overall production cost calculation may be based solely on economics or, as described in Section 10, it may also be simultaneously or independently a function of up to seven other environmentally related constraints. Thus, the resultant operational simulation may more accurately reflect real-world production costs versus idealized values based solely on economics. In addition, absolute energy output or fuel usage constraints on individual thermal units may also be input and considered when calculating production costs.

Section 11 documents the resultant calculation of all fixed costs including the major category of revenue requirements due to capital investment based on the fixed-rate charge approach. If present, the demand costs of contractual agreements are also factored into the fixed costs. The total annual cost of each alternative plan as well as the cumulative present worth of all revenue requirements is also calculated at this time.

This calculation may be all that is needed for most manual addition scenarios, but we have not addressed how the economics of alternative plans are evaluated when the user requests OGP's optimization capabilities. To meaningfully address this issue, we must slightly retrace our description of the overview of the OGP process and discuss how the program logic anticipates the effects of cost inflation and maturing outage rates. This is accomplished within the program by the use of what has been coined the "look-ahead" option. This logic will choose the best selection of units each year based on the lowest total cost alternative that has been derived from future conditions (both in terms of reliability and operations) rather than the lowest current total cost alternative.

Section 12 describes the "look-ahead" option in detail. This option calculates capacity needs and production costs, using surrogate values rather than the current decision year's outage rates and economic parameters. The surrogate values are calculated by OGP in response to a single user-supplied input, which is the specification of the "number of years to look ahead."

For example, a ten-year "look-ahead" study would cause mature (instead of immature) planned and forced outage rates to be substituted for all alternate or trial units being considered by the comparative decision logic. This results in a more meaningful measure of the reliability worth of new generation to the system. In addition, the complete hourly production cost simulation is calculated with ten-year levelized equivalent fuel and O&M costs for all units based on the previously input decision-year costs, inflation rates and present worth factor.

Thus, the OGP logic accumulates a set of all alternative annual scenarios calculated with "look-ahead" values, and is then ready to make a logical selection of the "best" or optimum new generation to be added in the decision year in question.

OGP then selects the lowest total cost scenario from among all the alternatives it evaluated. It also performs another important function by permanently adding the units to the existing system and recalculating all reliability, operations and investment data in order to properly document each figure of merit for the year in question. The next step is to enter the beginning of the next year under study with the new total system and repeat the process just described. Thus, after this process is followed for thirty years, the study is complete and self contained.

It should be noted that an important outcome of the OGP optimization approach is a lack of end effects. For example, if two cases are started in the same study year and have no differences in input data except that the first OGP study is terminated after ten years and the second after twenty, both cases will yield exactly the same results for the first ten years.

Section 13 briefly reviews the output reports available from OGP. These reports contain an abundance of planning information, and are presented in a highly organized, easy-to-use format. Many user-requested outputs have been added during the past years to enhance understandability and minimize additional calculations and tabulation by the user. Detailed results are available for the optimum plan as well as for others which were tried, but rejected. The output can also be saved on a file and later accessed by the user for reformatting or plotting.

The Financial Simulation Program (FSP) can be used to evaluate the financial impact of the expansion plan developed by OGP. Much of the data describing the generation system and annual costs associated with the OGP expansion plan can be automatically transferred from OGP to FSP. Alternatively, FSP can be run independently of OGP by using a separately available program to input the necessary data to FSP.

FSP is a simplified corporate model which combines a description of initial financial conditions with a generation expansion scenario in the future to project the annual balance sheets, income statements, cash reports and many other key financial quantities for the system under study. The model is used chiefly to determine the relative desirability of alternative plans on a measurement basis which goes beyond the "bottom line" of engineering economics' revenue requirements approach.

Section 15 describes the internal processes of FSP. Like OGP, it is a highly automated model that can make the required decisions involving key financial driving forces in an unstructured environment. Use of FSP does not require the user to have knowledge of items such as future rate changes, the timing of new issues, etc. While the generation plant is treated in most detail (the annual expenditures for every new generating unit are separately tracked), other plant, such as transmission and distribution (T&D) and a second business, like gas or steam, are also included as aggregates so the firm can be treated on a consolidated and complete basis. It should also be noted that FSP has been mainly written to accommodate the structure and policies of privately financed utilities.

Section 16 notes that the variety and level of detail of the outputs available from FSP can best be surveyed by examining an actual case study.

In this portion of the introductory material we have discussed the highlights of OGP/FSP based upon the graphic representation shown in Figure 1-4. However, the OGP/FSP model is not useful to planners or decision makers unless it is gainfully applied.

The Application of OGP/FSP

Before proceeding through the remainder of this handbook, you should be familiar with the numerous applications for which OGP/FSP is suitable. Table 1-1 represents a descriptive sampling of some of the actual applications for which users of OGP/FSP have found the programs suitable. Except for the first few items near the top, the actual uses in Table 1-1 are not listed according to frequency or importance. In fact, the most important application might be the next one for which a planner intends to use the programs. It should also be noted that Table 1-1 was not assembled to suggest applications for which OGP/FSP is best suited, because again, that is an extremely subjective and variable measurement.

TABLE 1-1
OGP/FSP Applications

- Optimum Generation Mix
- Parametric Sensitivity Tests
- Joint Ownership
- Long-Range Fuel Supply
- Economic Justification
- Peaking Capacity Needs
- Unit Slippages
- System Reliability Design Level
- Emission Levels
- Company Planning in a Pool
- Impact of Forced Outage Rates
- Unit Size
- Cash Flow Impacts
- Purchase/Sale Contracts
- Impact of Non-Optimum Additions
- Breakeven Costs for Advanced Technologies
- Effect of Nuclear Moratorium
- Load Management Impacts
- New Financing Requirements

EUSED would be the last to ever conjecture or recommend that OGP/FSP can be successfully applied to address all questions that may arise in the realm of generation system expansion planning. Any real test or prediction of the applicability of OGP/FSP to provide useful computed information on a given subject in the broad planning area depends on many physical variables such as the utility's size, present and contemplated generation, complexity of interchange agreements, level of detail of output required, etc.

Perhaps it is more meaningful to note that, to date, approximately eighty organizations have successfully applied OGP/FSP, and the majority of them continue to do so repeatedly. If there is any question about the appropriateness of a contemplated application, the best policy to follow is to contact the responsible technical staff member within EUSED and describe the projected study. EUSED is always prepared to assist users with all phases of their OGP/FSP work.

The remainder of the information presented in this Descriptive Handbook will focus on the OGP/FSP process segmentation topics illustrated in Figure 1-1. The discussion, which is organized according to the numerical designations corresponding to the process segments in Figure 1-1, covers the topics listed in Table 1-2.

TABLE 1-2

Section No.	Topic or Information Discussed
2	Representing Generation
3&4	Representing Loads
5&6	Parametric Input Data
7	What OGP Does
8	Determine "How Much" Generation to Add
9&10	Determine Operating Costs and Environmental Impacts
11	Calculate Fixed Costs
12	What Has Been Accomplished With OGP
13	Available OGP Output Information
14	Additional Input Data for Financial Analysis
15	What FSP Does
16	Available FSP Output Information

INTRODUCTION

SUPPLEMENTARY INFORMATION

1. Electric Utility Planning Models, L.L. Garver, 1975 ORSA/TIMS Meeting.

2. Overview of Electric Utility Generation Planning Methods, R.W. Moisan, 1977 National Conference of Regulatory Utility Commission Engineers.

3. Overall General Planning Study, R.W. Moisan, 1974 GE Memorandum.

4. Perspectives on the Design and Application of Generation Planning Programs, W.D. Marsh, R.W. Moisan and T.C. Murrell, 1974 Nuclear Utilities Methods Symposium.

5. General Electric's OGP Program: The Practical Approach to Generation Planning, R.P. Felak and J.E. Lapsa, 1978 EEI Engineering Computer Forum.

6. OGP and FSP Program Descriptions, February, 1982 GE Memorandum.

7. The Application of OGP to Worldwide Energy Issues, D.L. Dees, B.W. Erickson, R.P. Felak, G.E. Haringa and H.G. Stoll, 1981 Conference on Electric Generating System Expansion Analysis.

PREDETERMINED GENERATION

There are two types of data input available to the user to represent present and future committed generating units. The first can be stored separately on a permanent file, and the second can determine unit characteristics while a specific OGP case is running.

The former is a Generation Model created for use as a data base representing the user's in-service and on-order generating units. In general, the user should build into the Generation Model all data about the units that is not expected to change during a study or series of expansion planning cases. Such an approach will tend to minimize data preparation time and potential errors, ultimately minimizing the cost of executing a study.

There are two options available to users for easily modifying their generation model data. As represented in Figure 2-1, an auxiliary generation modification program is available which will override existing information to create a new file. This file can then be stored separately for use in subsequent expansion planning cases. Or, representation of the Generation Model data can be changed during the course of an OGP run by individual data value entry for any particular units. If that is done, the original Generation Model will not be altered permanently.

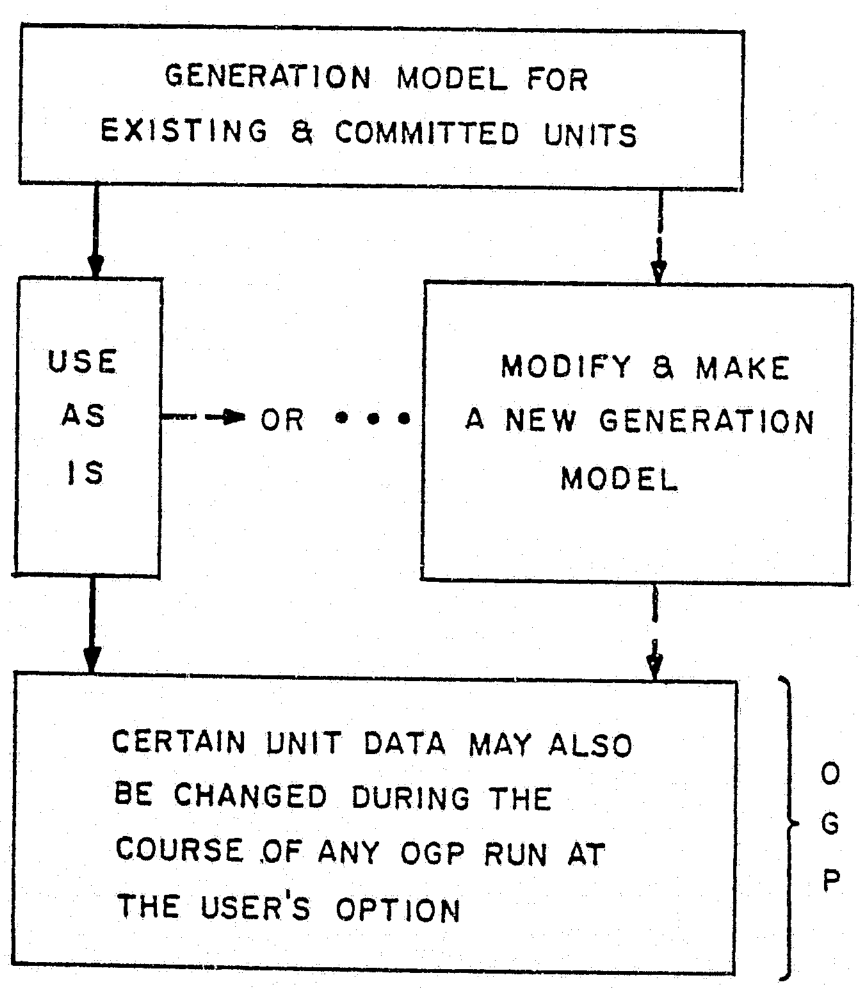


Figure 2-1. Input Options for Generating Unit Data

The user has the option of specifying all of the data in the Generation Model. Or, if desired, customers may use and modify the available generation model data EUSED maintains for most electric utilities in the United States. In all cases, the data contained in the EUSED files is obtained solely from public sources such as the Federal Energy Regulatory Commission, Edison Electric Institute, etc.

At the Generation Model data level, the information is stored by individual unit. There is no limit to the number of units that may be represented in a Generation Model; however, the maximum number of individual generating units with thermal characteristics that may be separately represented at any point in an OGP study is limited to 250. Also, only one equivalent hydro and three equivalent energy storage units will be used by OGP. Sections 6 and 7 will describe how lumping and equivalencing are directed and accomplished.

The following information refers to some of the ways the Generation Model data is used later in the OGP simulation process. It is intended to guide the user in the initial placement of units within one type or the other and to highlight the flexibility of generating unit representation that has been built into this format.

Units designated as Types 1 through 6 are basically designed to represent thermal generation. Type 7 units are designed to represent conventional hydroelectric generation. Additions of Type 7 units will not be made automatically by the OGP program; their timing and quantity must be specified by the user. Units designated as Types 8 through 10 represent energy storage units such as pumped storage hydro, compressed air storage and batteries. At the user's command, OGP will choose an optimum generation mix from among the nine types of thermal and energy storage units. The characteristics that can be specified by the user at the Generation Model level for each unit type are listed in Table 2-1 and summarized in Table 2-2. Data not input here can be separately specified later during the OGP run. This is discussed in more detail in Section 5. Note that only the data required for a particular study needs to be entered. For instance, if environmental discharge results are not required, the characteristics for those aspects may be omitted from the data.

If a pool-wide study is being conducted, each company or area may input data separately. Automatic merging of the data is then done by the program for regional planning.

It is important to note that any individual unit data not input here can be easily input at the Data Preparation level via the same mechanism used for characterizing new units, namely "standard tables." These tables are composed of a few discrete data points which are a function of factors such as unit size or year of installation. Then, the program automatically interpolates for all sizes, where needed, thus saving the user from having to specify separate values for all parameters for every unit. This mechanism can save a considerable amount of time and tedious labor.

In summary, the user supplies any or all data for those individual units, as desired. For data that is not supplied, the program will access the data found in the standard tables. This process is described in Section 5.

TABLE 2-1

Unit Type No.	General Characteristics	Specifiable Generation Model Data
1	Suitable for nuclear units because fixed and variable fuel costs can be entered for this type of unit. Time variation of these costs to simulate effects such as core equilibrium may also be input by the user via use of per-unit multipliers. A maximum of 100 nuclear units may be separately represented.	For Unit Types 1 through 6 (OGP-6): Station Name, Unit Type No. and Plant No. Company Assignment and % Ownership Maximum Net Output, MW Minimum Net Output, MW Net Station Heat Rate, Btu/kWh Fuel Input at Minimum Rating Installation Year and Month Retirement Year and Month Fuel Type No. Fuel Cost, ¢/MBtu (also a $/kW/yr for unit types 1 and 5 or 6) Fuel Inflation Pattern No. Fixed and Variable O&M, $/kW/yr and $/MWh Mature Outage Rates Plant Cost, $/kW
2	Suitable for central station types of fossil units. At the user's option, smaller units of this type may be automatically lumped by the program before the first year of the study to save computational expense during the yearly calculations. Fuel type may also be specified by company for these units.	The Following Additional Data May Be Specified When Using OGP-6A: Atmospheric Heat Rejection, per unit Sulfur Removal Fraction, per unit Precipitator Efficiency, per unit Carbon Monoxide, Nitrogen Oxide and Particulate Emission Coefficients, Pounds, Pounds/MW/hr and a per-unit Scaling Factor Water Consumption Coefficients, Gallons, and Gallons/MW/hr
3	Suitable for peaking units, such as combustion turbines, because this type of unit is normally used to trim the yearly expansion to prevent overbuilding relative to the reliability criterion. May also be lumped at the user's option.	
4	Another possibility for base load or mid-range duty fossil units. Combined cycle units, such as STAG* (Steam and Gas Turbine) plants can also be easily represented here.	

* Trademark of the General Electric Company

TABLE 2-1 (CONTINUED)

Unit Type No.	General Characteristics	Specifiable Generation Model Data
5	Another possible nuclear type of unit, because, if desired, this unit can also be given a fixed fuel cost with cost variations independent of inflation similar to Unit Type No. 1. Alternatively, another type of fossil unit can be represented here.	
6	Same as Unit Type No. 5. However, a maximum of two unit types may have the characteristics of a fixed and variable fuel cost: Unit Types 1, and 5 or 6. This allows for the representation of up to two separate types of nuclear units, such as light water and fast-breeder reactors.	
7	Suitable for conventional hydro installations. Might also be used for the simulation of certain contracts or other unique forms of energy supply. The program will lump all individual units into a single aggregate. During the annual system production cost calculations, the total minimum rating is used as base load generation. Surplus energy available, up to the monthly total maximum rating, is then used to decrease peaking requirements. This type of unit must be derated if the user wishes to take outages into account in the reliability calculations. This is not necessary with Unit Types 1 through 6, which can be assigned forced and planned outage rates for probabilistic reliability and production costing calculations.	For Unit Type 7: Station Name and Unit Type No. Company Assignment and % Ownership Monthly Energy, GWh Monthly Minimum Output, MW Monthly Maximum Output, MW Installation Year and Month Retirement Year and Month Plant Cost, $/kW
8-10	Suitable for pumped-storage hydro plants, batteries, compressed air, or the representation of other energy storage devices. Will be automatically refilled or charged up on an economic basis whenever possible. A percentage of unused stored generation can automatically be applied to decrease spinning reserve requirements during OGP system dispatch simulation. These units, which are similar to Unit Type 7, can also be derated for reliability calculations.	For Unit Types 8-10: Station Name and Unit Type No. Company Assignment and % Ownership Maximum Net Output, MW Maximum Charge Rating, MW Maximum Storage Size, MWh Installation Year and Month Retirement Year and Month Plant Cost, $/kW

TABLE 2-2
Generation Model Data

Types	Typical Plants	Assignable
1-6	Nuclear Fossil - Base Load - Mid Range - Peaking	Unit Identification Ratings Heat Rates Service Period Fuel Data O&M Costs Plant Cost Outage Rates Environmentally Related Data (OGP-6A)
7	Conventional Hydro	Unit Identification Energy Ratings Service Period Plant Cost
8-10	Energy Storage	Unit Identification Ratings Storage Capacity Service Period Plant Cost

Before executing an OGP case, the user also has the option of modifying the Generation Model through the use of an auxiliary program. This program allows the user to modify an existing Generation Model and produce a new one while simultaneously retaining the old one. This option is presented schematically in Figure 2-1.

In general, two types of modifications can be made to an existing file: (1) change selected characteristics of units already on the file, or (2) add or delete complete units on the file. The attributes of the generating unit that can be changed or initially specified are the same as those tabulated in Table 2-1. A program option also allows the deletion of all units from a particular record by the specification of a single input variable.

LOAD MODEL

The user specifies the system Load Model used by OGP to represent peak and shape characteristics which are projected to occur for the years included in the OGP study. This means the Load Model Program does not have any independent forecasting capabilities integral to it. Figure 3-1 presents an overview of the basic load modeling options. As was the case with the Generation Model, the user has the option of supplying basic load shape data for use by OGP or of using historical data available from EUSED, which is obtained from the Federal Energy Regulatory Commission's or Edison Electric Institute's records for electric utilities.

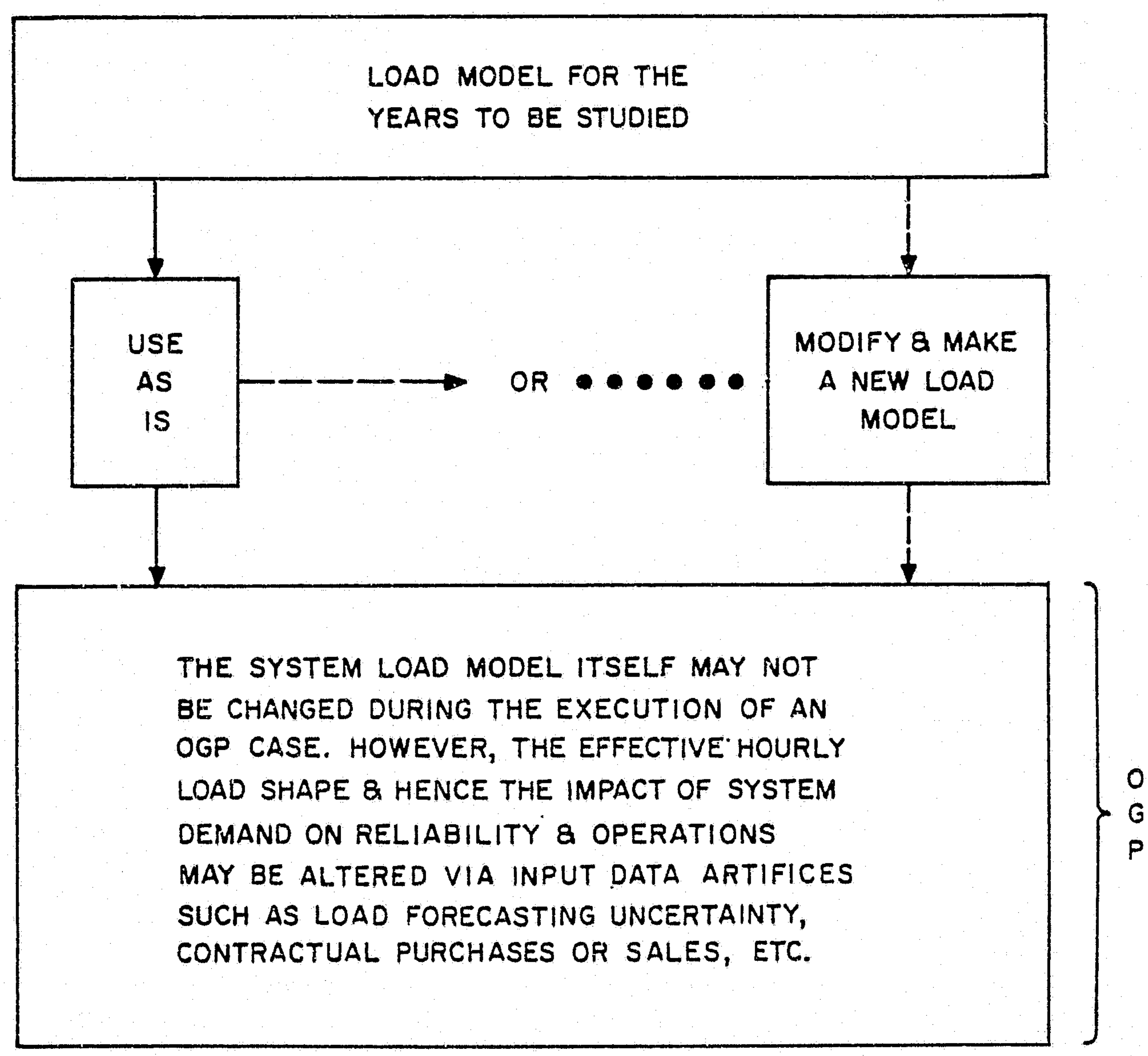


Figure 3-1. Input Options for Load Model Data

In addition to the Load Model Program usually used with OGP, EUSED also has available a separate program that will convert a maximum of five years of historical hourly load data, in EEI format, into the input required by the OGP load modeling program. This hourly load data, which can be input by company or load area, will be automatically merged. Although up to 40 separate companies or areas may be input, a maximum of 25 is allowed in the OGP run. Alternatively, the user may supply load data for the combined pool.

All data is converted to and stored on a per-unit basis as shown in Figure 3-2.

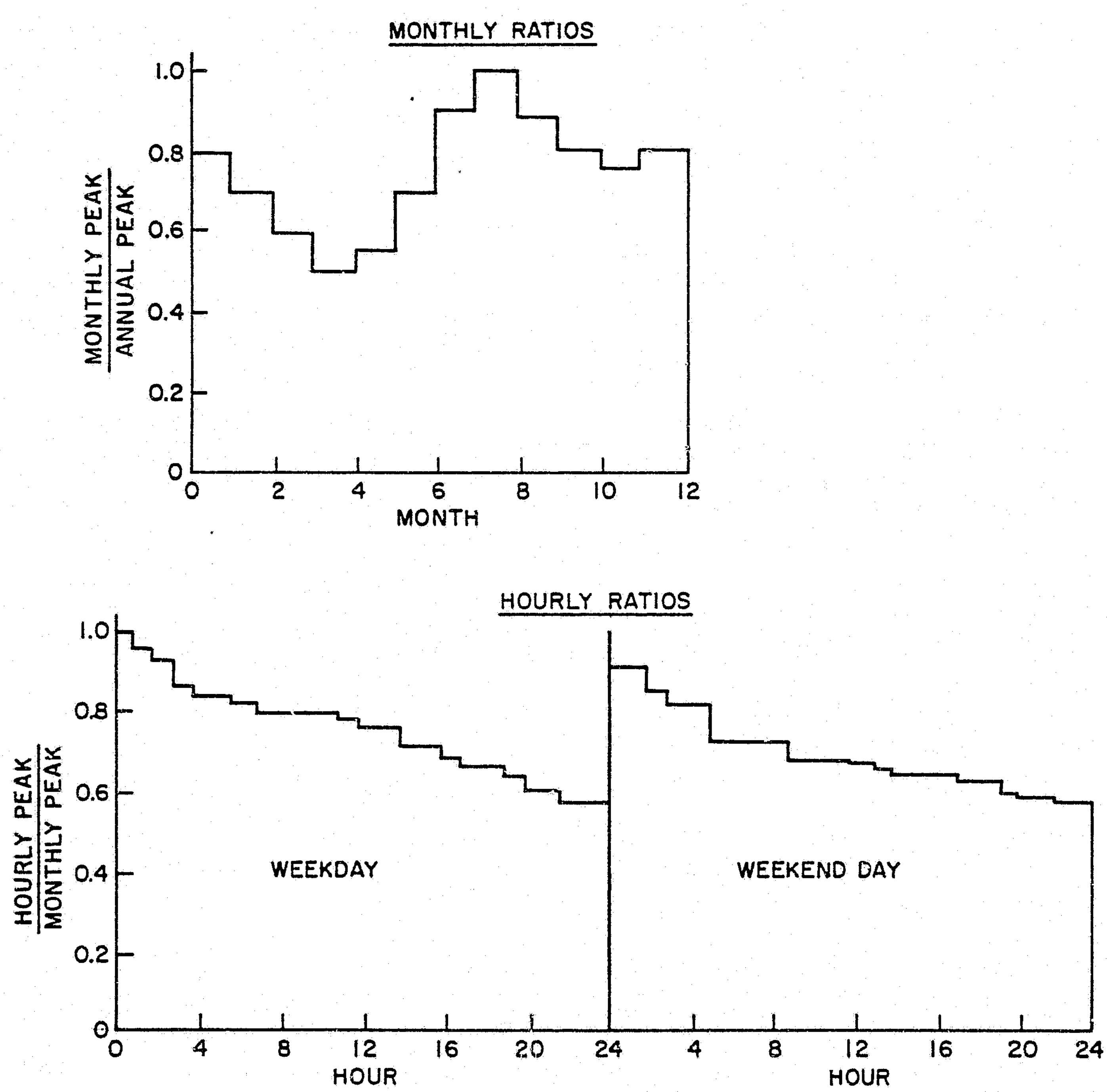


Figure 3-2. Examples of Per-Unit Load Models

The resultant Load Model produced by the OGP Load Model Program will actually consist of two distinct models: (1) one model will be used for reliability analysis via loss-of-load probability (LOLP) calculations, and (2) the second model will be used for system production cost simulations. Use of these models is discussed further in Sections 8 and 9.

The basic time period for the OGP process is the calendar month. The daily LOLP load model consists of a weekday peak load model to be used for risk evaluation, and the system operation load model breaks down each month into hours with a different shape of twenty-four hourly loads for both weekdays and weekend days. Both of these models may be prepared to cover a forty-year period, thus providing the user with flexibility for producing alternate OGP cases. However, the time period for any single OGP run is limited to thirty years.

One of the major factors contributing to the amount of computer running time used for large-scale production simulation programs is the chronological load model. Experience with both chronological and daily load duration load models indicates that the daily load duration approach is clearly justifiable for most long-range planning studies because of the favorable trade-off in computer processing time and model accuracy. Reductions in computer processing time, which can be achieved with the daily load duration approach are significant, while losses in accuracy are relatively small. However, the daily approach is substantially more accurate than using a weekly, monthly or annual load duration curve.

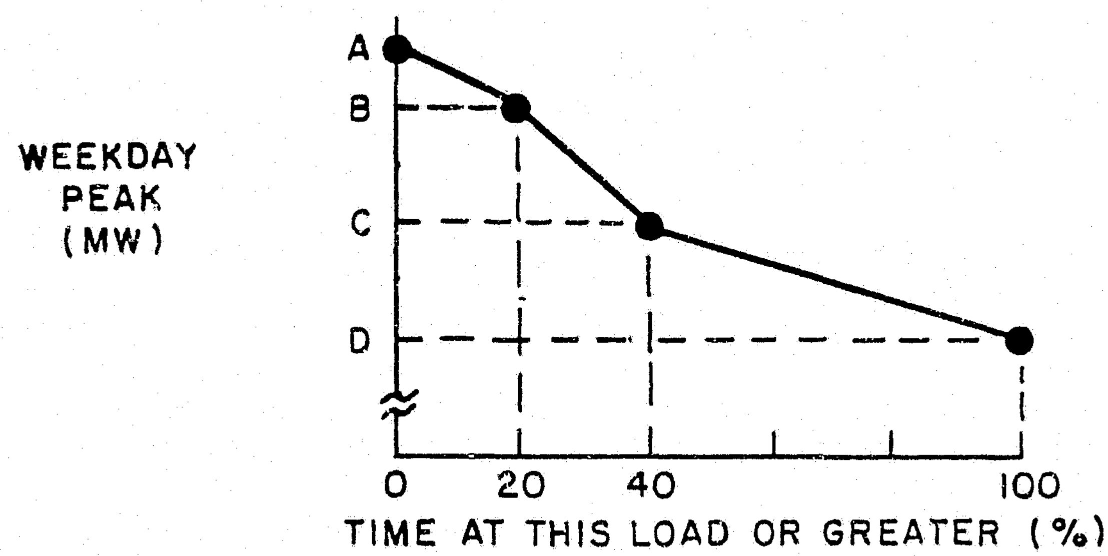


Figure 3-3. Example of a Load Model for Daily LOLP Calculations

The daily LOLP load model is used to represent the distribution of weekday peak loads that can be expected during each month. This distribution is derived from company or pool history. As illustrated in Figure 3-3, the sample load model for daily LOLP calculations contains four values for weekday peak load and the probabilities of the weekday peak loads being at this load or greater during the month. The load designated by point A MW is the highest weekday peak to be expected during the month; the load designated by point D MW is the lowest. The conditions illustrated in Figure 3-3 are also represented in Table 3-1.

TABLE 3-1

Load in MW	% of Weekdays When a Peak Load Equal to or Greater Than Amount Shown May Be Expected
A	0%
B	20%
C	40%
D	100%

In OGP, information such as that listed in Table 3-1 is assembled on a per-unit basis and then reconverted to MW as required for each year of the study. Each month may be different and may have its own distribution of four peaks. This information may also change from year to year.

This formulation of the data can be modified by including a load forecasting uncertainty function to recognize that the forecasted peak may either be exceeded or may fail to materialize. This is accomplished during the execution of an OGP case. Input data required for this option is described in Section 5.

In contrast to the probabilistic load model that was concerned with the weekday peak loads only, the production cost load model must consider all of the hours in a day, both weekdays and weekend days, in order to meaningfully schedule generation and determine the resulting operating costs. Holidays are considered to be weekend days. Each month is different and is characterized by a typical shape for a weekday and a weekend day as shown in Figure 3-4. The number of times each of these shapes occurs is determined from a built-in calendar. Each of these day types is represented by twenty-four, one-hour periods of constant load.

In addition to daily LOLP, the user may choose to calculate or design a system based on an hourly LOLP. To do the hourly LOLP calculation, the daily LOLP load model is used to define four weekly peaks for each month at 0%, 20%, 40% and 100% of the time. Then the weekday and weekend day per-unit values from the production cost load model are multiplied by each of the four weekly peaks, thus producing a typical weekday and typical weekend day at 0%, 20%, 40% and 100% of the time. The four typical weekday and weekend day shapes plus the number of weekdays and weekend days for each month define the load model used to compute hourly LOLP.

As was true of the Generation Model, the Load Model may be used repetitively for OGP studies. Alternatively, certain characteristics of the Load Model are easily modifiable when required. This option is discussed in detail in Section 4. During the modification process, alternate Load Models are created and saved for use by OGP. Unlike the Generation Model which could be changed during an OGP run, the Load Model, with one exception, must be modified before OGP is executed. It is possible to input new values for the annual peaks as part of the OGP data, but the per-unit shapes and load factors from the input Load Model will not be modified.

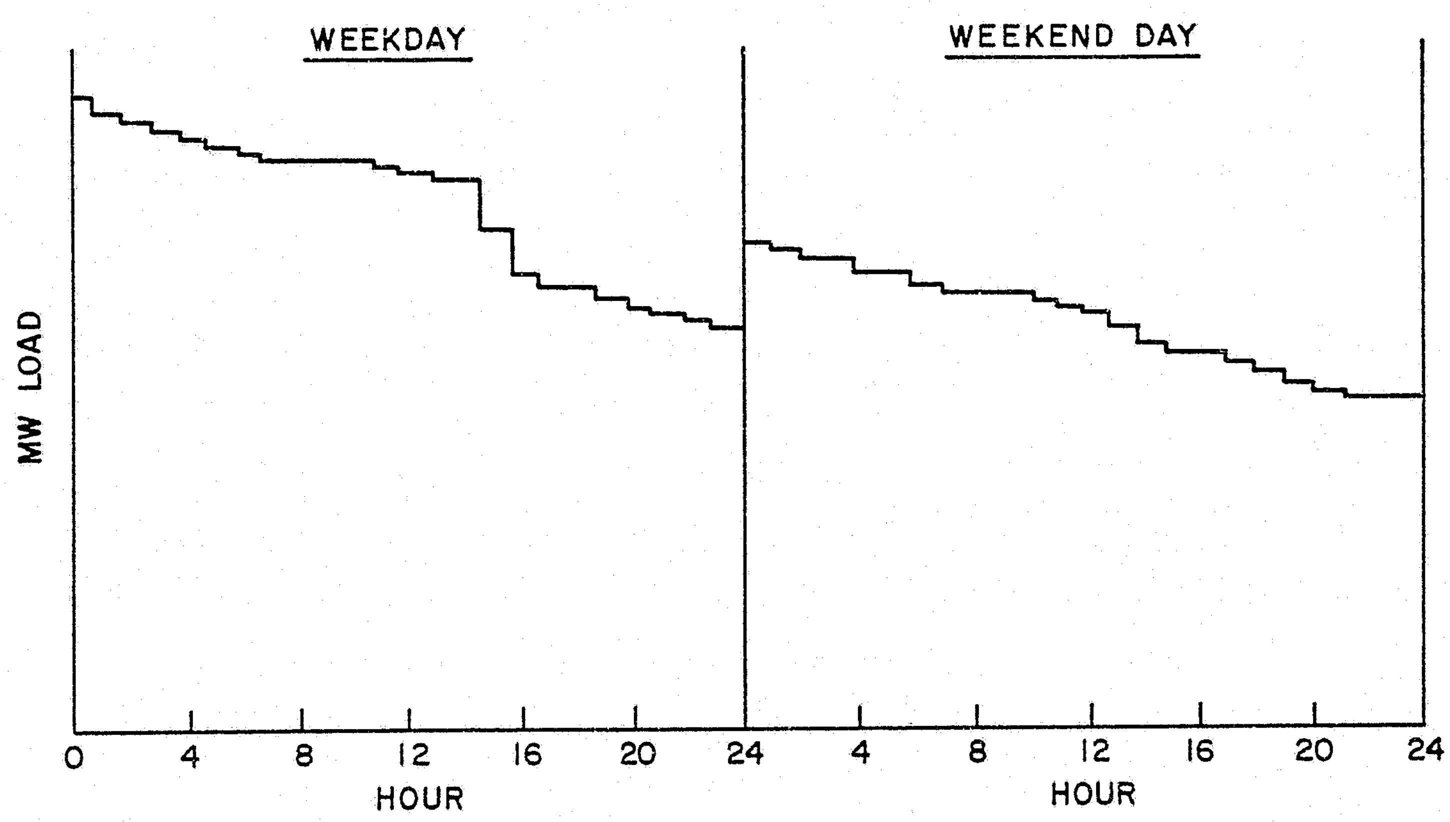


Figure 3-4. Example of a Load Model for Production Cost Calculations

Certain minimum data must be made available for the Load Model Program to operate including the starting year, the number of years desired, and the number of companies or areas to be represented. The following data must also be specified:

1. Data for the reliability load model

   a. Month/annual per-unit ratios, by month

   b. Per-unit ratios associated with the 0%, 20%, 40%, and 100% points on the peak load duration curve, by month

2. Data for the production cost load model

   a. Month/annual per-unit ratios, by month

   b. Weekday and weekend day per-unit hourly ratios in descending order, by hour, by month

The following data may also be specified on an annual basis:

3. Annual peak MW load, by year and company or area

4. The per-unit ratio of the company peak loads to that of the pool, by company

5. The per-unit peak load growth multipliers, by company

If the user does not wish the program to utilize its built-in calendar to determine the number of weekdays and weekend days and holidays for each month, the number of each may be separately specified.

LOAD MODEL
SUPPLEMENTARY INFORMATION

1. Load Shape Modeling, T.C. Murrell, 1974 GE Memorandum.

LOAD MODIFICATIONS

A load modification program is available to facilitate changes in OGP Load Models. Historically, EUSED has used per-unit or normalized load models. The use of per-unit load data allows direct conversion of the per-unit load model to a MW load model each year by supplying only the annual peak load. If load shapes do not vary during the course of the study, loads for each year in the study can be created simply from one year of shape data and forecasted annual peaks for each study year. Modification of a monthly/annual peak ratio allows energy in that month to be altered while preserving the daily load shape.

Because of the uncertainty of future loads and their shapes, the Load Model Program provides the user with several convenient methods for altering load shapes by specifying consistent combinations of monthly or annual load factor, load growth and/or energy growth. This capability enables the user to evaluate the impacts on the magnitude or shape of the system load due to load management, new rate structures, etc. To minimize input data requirements, the actual load changes are performed automatically.

The Load Model Program can be used in several ways to perform a variety of tasks. The following information is a brief summary of the major permutations that are possible and the input items which must be provided to accomplish those changes.

1. The overall yearly Load Model can be changed in the following ways:

   a. Input the annual MW desired or the annual per-unit growth multipliers for the pool annual peak loads.

   b. Input the desired annual load factors in per unit.

   c. Specify annual energies by inputting the MWh for the first year and annual per-unit growth multipliers thereafter.

   d. Input the per-unit ratio of company-to-pool peak for each company or area on an annual basis, the individual company peak load growth per-unit multipliers, or the annual MW peak loads for each company.

2. The Load Model can be modified on a monthly basis by specifying certain combinations of the following data:

   a. Input the monthly energies by specifying the desired MWh for each month and year or by specifying initial values and a growth rate for each month of each year thereafter.

   b. Specify monthly load factors for each year.

   c. Input monthly pool peaks for each year in MW, by specifying an annual pool peak and twelve per-unit multipliers to define the monthly peaks, or by inputting monthly growth multipliers for each year. At the user's option, only the production cost load model or both the production cost load model and reliability load model monthly pool peaks will be changed.

3. The load model used for the reliability calculations within OGP can be changed in one of the following ways:

   a. Input the month-to-annual peak ratios annually.

   b. Change the per-unit ratios for the 0%, 20%, 40%, and 100% points of the distribution of monthly weekday peak loads for each year.

4. The load model used for the production simulation calculations within OGP can be changed, using one of the following three options:

   a. Change the per-unit month-to-annual ratios for each month each year.

   b. Change the per-unit weekday-hour to peak-hour ratios on an hourly basis each month or annually.

   c. Similarly, change the per-unit weekend-hour to peak-hour ratios on an hourly basis each month or annually.

5. To account for special holidays or other unique time periods, the following modifications can be made to override the program's built-in calendar logic:

   a. Input the number of weekdays in each month annually.

   b. Specify the number of weekend days and holidays per month annually.

6. The number of years covered by the Load Model can be extended in either of the following ways:

   a. Use the complete per-unit load model associated with the last year, whether it is user supplied or read from the original Load Model file.

   b. Manually input the data to be utilized in the extended time period on an annual basis.

   c. To add years to the beginning of the load model, use the per-unit load model associated with the first year on the original Load Model.

   In all cases, the maximum total time period permissible for Load Models is forty years. However, a single OGP run can cover only thirty years.

If the user wants the load modeling program to automatically adjust the load factor, two options are available: modify the month-to-annual ratios or modify the daily shapes. The option chosen should reflect the changing load patterns that are impacting the load factor.

Figure 4-1 shows an example of modifying the monthly peaks to increase the overall load factor. The program first determines the change in energy to be included on the load model. This energy is then allocated to the individual months in proportion to the "valley depth." As a result, the lowest monthly peak load will be modified the most. The user can specify which months are to be excluded from modification.

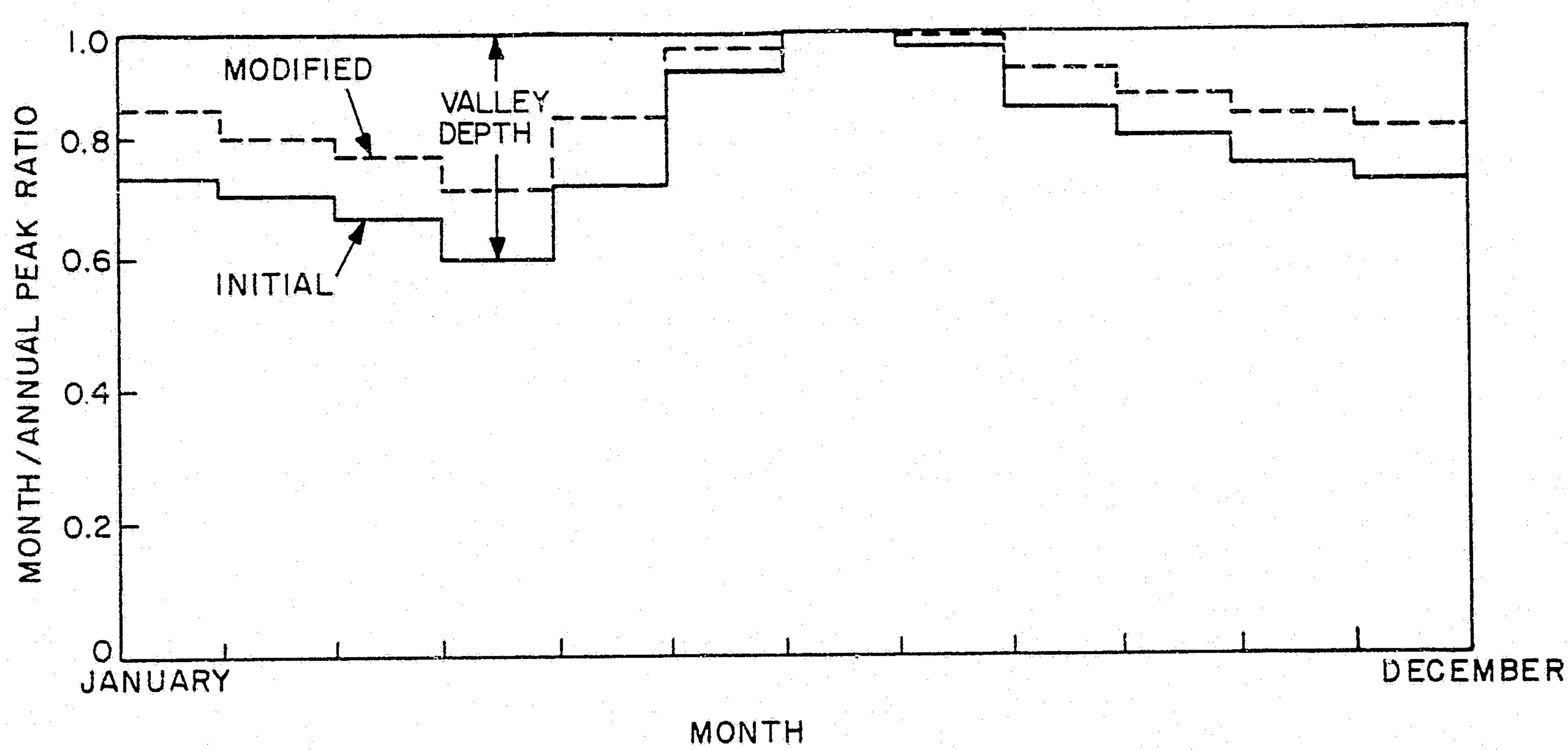


Figure 4-1. Example of Monthly Peak Modification

The load factor can also be changed by modifying the daily shapes, as shown in Figure 4-2. The program starts by determining the change in energy on the load model required by the new load factor. This energy is allocated to the individual months in proportion to the original monthly energies. Within a month, the energy is divided between the weekdays and the weekend days according to the original energy for each day type. It is then allocated to the hours in the day in proportion to the "valley depth" of each hour, with the lowest hour being adjusted the most. The user can specify the months and day types to be modified.

The hourly LOLP load model cannot be changed directly. However, any change introduced to either the production cost per-unit shapes or the daily LOLP load model will implicitly change the load model used to calculate hourly LOLP.

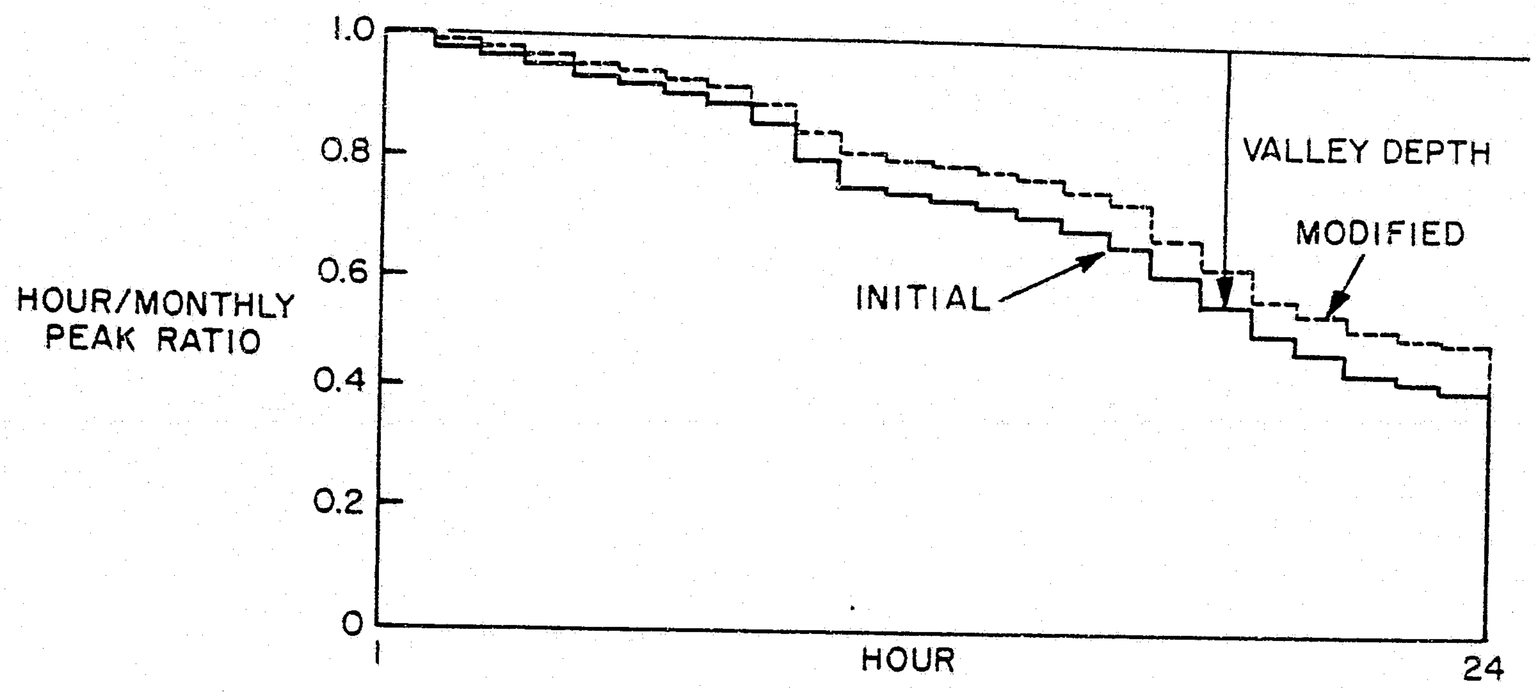


Figure 4-2. Example of Daily Shape Modification

LOAD MODIFICATIONS
SUPPLEMENTARY INFORMATION

1. Examples of Load Management Calculations, G.A. Jordan, 1977 GE Memorandum.

2. The Impact of Load Factor on Economic Generation Patterns, G.A. Jordan, W.D. Marsh, R.W. Moisan and J.L. Oplinger, 1976 American Power Conference.

3. Load Management and Generation Planning, C.D. Galloway, L.K. Kirchmayer and R.W. Moisan, 1976 Conference on Power System Planning and Operations.

STUDY DATA

Study data is defined as all information supplied by the user other than that which has already been described in the discussion of the Generation and Load Models. In this section of the handbook, the following OGP study input data are discussed:

- Attributes by Unit Type
- Alterations of the Effective Load Model
- System Reliability Controls
- Operationally Related Items
- Financial Information

Only a few study data input items will alter the effective Load Model. Along with the specification of load forecasting uncertainty and the application of contractual purchases and sales, it is possible to input new values of annual peak load. However, with the use of input study data at this point in the overall OGP study process, a user can modify the Generation Model in many ways. For example, override data and manual installations and retirements can be specified.

The information in this section provides a complete description of nine types of optimizing units, as well as certain economic and operational characteristics of the Generation Model units. These descriptions are for data that can be applied to describe various types of generating units.

1. Generating Unit Descriptive Data for the Six Types of Thermal Units

a. Kind of Generation

Each type of thermal unit is assigned to one of four physically descriptive categories. Each category, in turn, is assumed to have certain characteristics which are generically represented as either nuclear, base load fossil, intermediate fossil (such as mid-range steam, peaking steam or combined cycles), or peaking fossil (such as combustion turbines). The user can make a maximum of two nuclear designations, and these must correspond to units designated as Type Nos. 1 and 5 or 6. A maximum of 100 nuclear units is allowable.

b. Permissible Unit Sizes and Earliest Service Year Allowable

Data for permissible unit sizes and earliest service year allowable applies to new thermal units only, and is illustrated in Figure 5-1. For the six thermal types, a total of sixty sizes and the years in which these sizes became available can be specified. OGP uses only discrete sizes and years. The types of units to be included in the optimization each year are at the user's discretion. OGP will choose one unit size from each type from among only those units which have been listed as available for installation in a given year. As an option, when the annual load growth or reliability criterion is sufficient to accommodate more than one new added unit, the user can

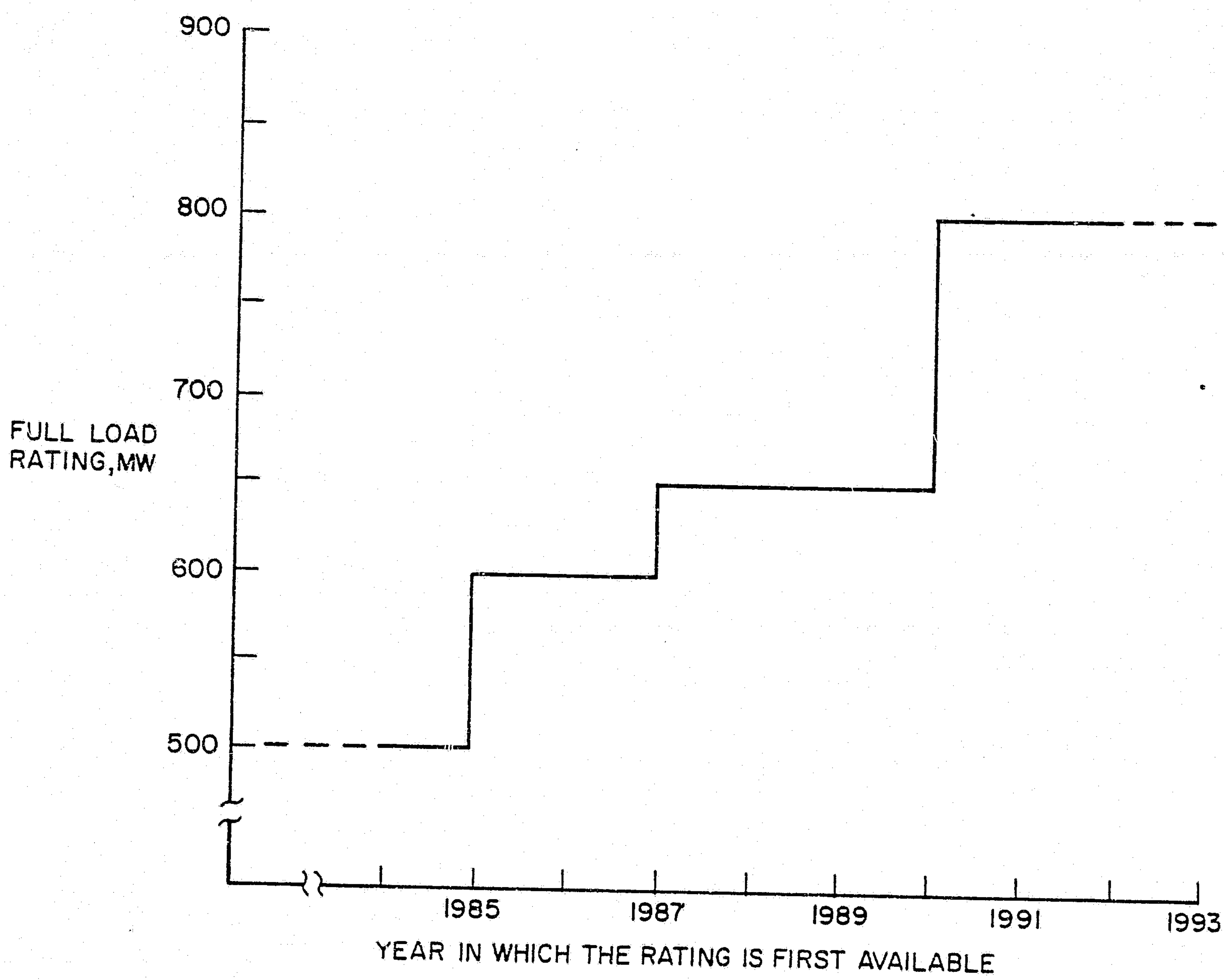


Figure 5-1. Example of Unit Size Availability Input

also specify that the program try mixtures of more than one type of unit in the optimizing trials. This is discussed further in Section 7. In any case, the maximum number of units, thermal or otherwise, which can be installed and/or retired in any one year is 100.

c. Plant Cost

To represent the plant cost as a continuous function of unit size, a set point, (MW_o, C_o) and a "D" (doubling) factor can be specified for each type of unit as shown in Figure 5-2. The "D" factor is calculated so that when $MW = 2(MW_o)$, $C = (1-D)(C_o)$. This means that when unit size is doubled, the cost (expressed in $/kW) is reduced by the fraction D. For intermediate points, where a factor

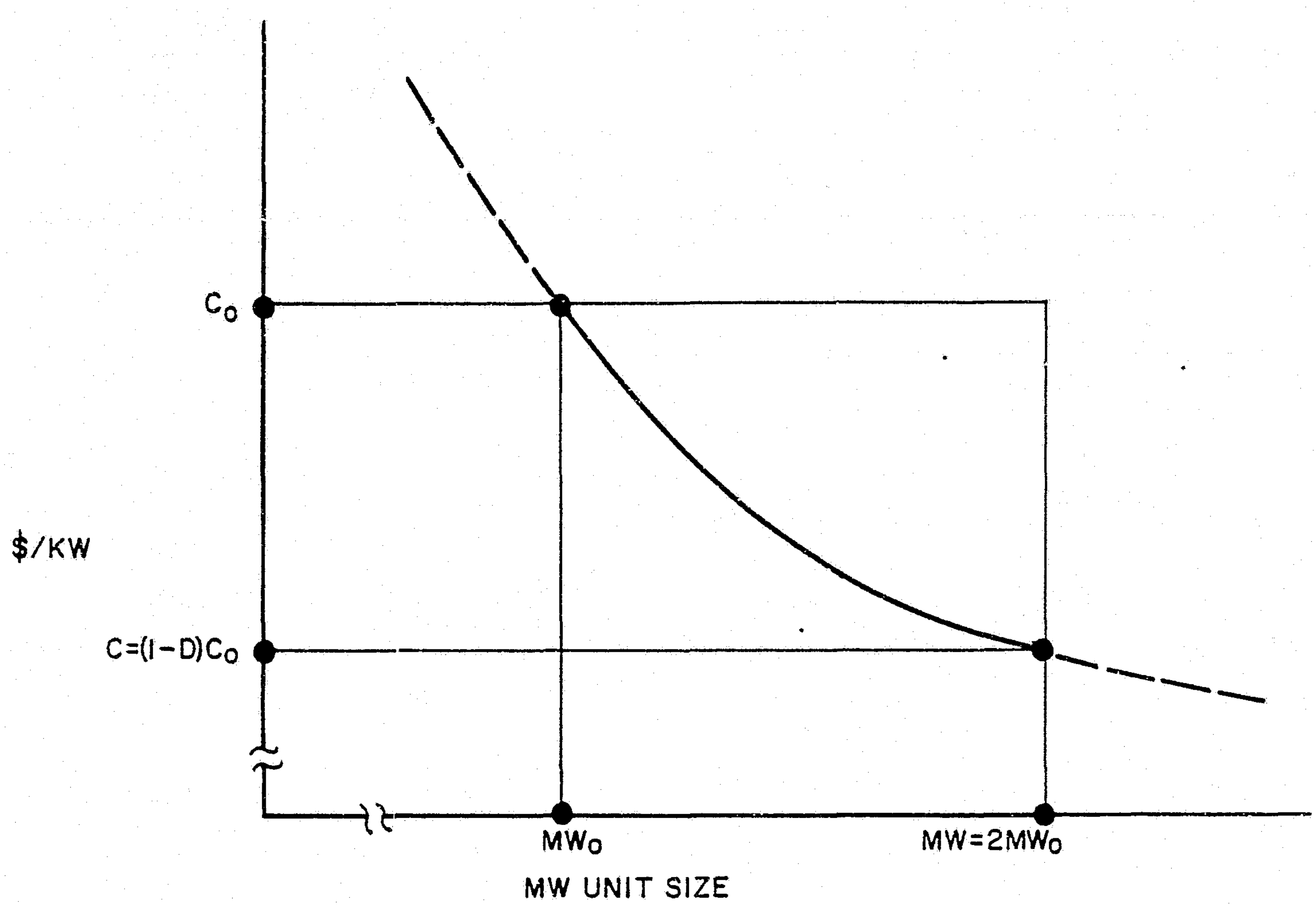


Figure 5-2. "D" Factor Representation for Thermal Generation

of two does not apply to the change in unit size, $C = C_0(MW_0/MW)^k$ where $k = \ln(1.0-D)/\ln(0.5)$.

For each type of unit, the user can also specify the per-unit inflation multipliers to be applied to plant costs on an annual basis. In addition, if more than one company or area is represented in the study, the plant cost can be adjusted with another per-unit multiplier for each company. Of course, any atypical unit may be assigned its own individual plant cost.

d. Fuel Types and Costs

A different fuel type can be assigned to each type of unit. The fuel designation given to unit Type No. 2 has the capacity for additional flexibility. Different fuel types can be assigned by the class of Type No. 2 units, which is comprised of automatic addition choices and manually installed units, and the class of units comprised solely of generation model units. The type of fuel assigned can also differ for each of the twenty-five companies or areas the user may have chosen to represent in the study. Information on a maximum of twenty fuel types plus their attendant cost and yearly inflation rates can be stored and accessed later. Up to twenty different patterns of inflation can be specified. Units designated as Type No. 1 and either No. 5 or No. 6 may also be given a fuel cost inputted on a fixed $/kW/yr basis. Both the variable and fixed portions of the fuel costs for those types of units can also be represented as varying factors during the years of the OGP study. This variation can be accomplished in a maximum of five separate steps inputted as per-unit multipliers as shown in Figure 5-3. This program feature facilitates the more exact treatment of such phenomena as nuclear unit core equilibrium or changes in coal pile storage volume. Atypical units may also be assigned their own specific fuel costs on a unit-by-unit basis.

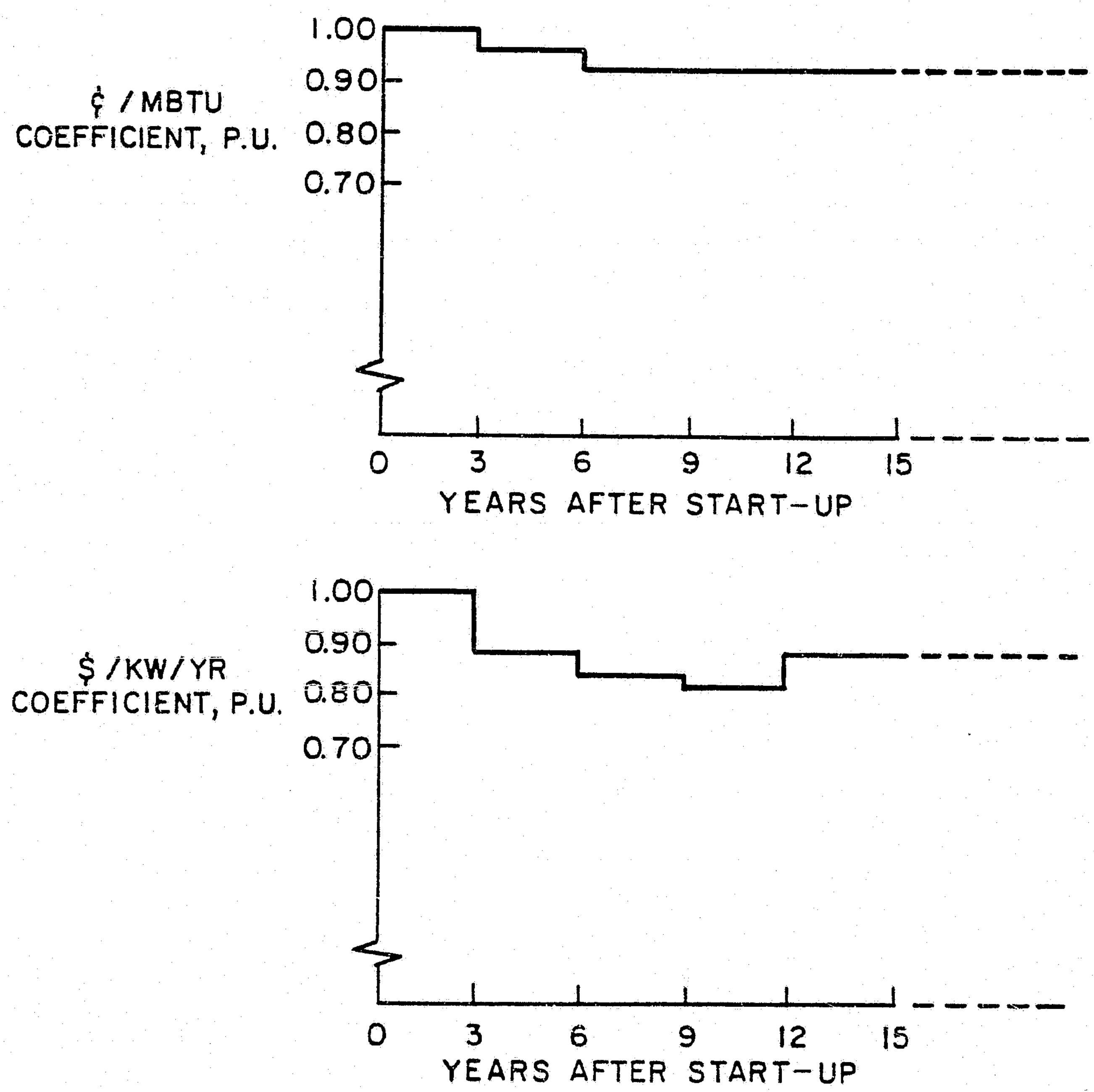


Figure 5-3. Example of Nuclear Fuel Cost Variation With Time

e. O&M Costs

The user can input fixed and variable components of O&M costs. The fixed O&M cost is input in $/kW/yr via specification of a set point and a "D" factor similar to that used for plant costs as was shown in Figure 5-2. The variable portion may be specified either as $/fired-hour/MW or as $/MWh. Each component, as well as the yearly inflation factor, may differ for each type of unit. O&M costs may also be assigned on an individual unit basis.

f. Heat Rates

Heat rate data for each type of unit is input by specifying the continuous full load, net station heat rate in Btu/kWh. In addition, as shown in Figure 5-4, to represent the unit characteristics at minimum load, the minimum load output as a per-unit of full load output (A) and the fuel input as a per-unit of full load fuel input (B) are specifiable for each type of thermal unit. Individual characteristics can be input for atypical units.

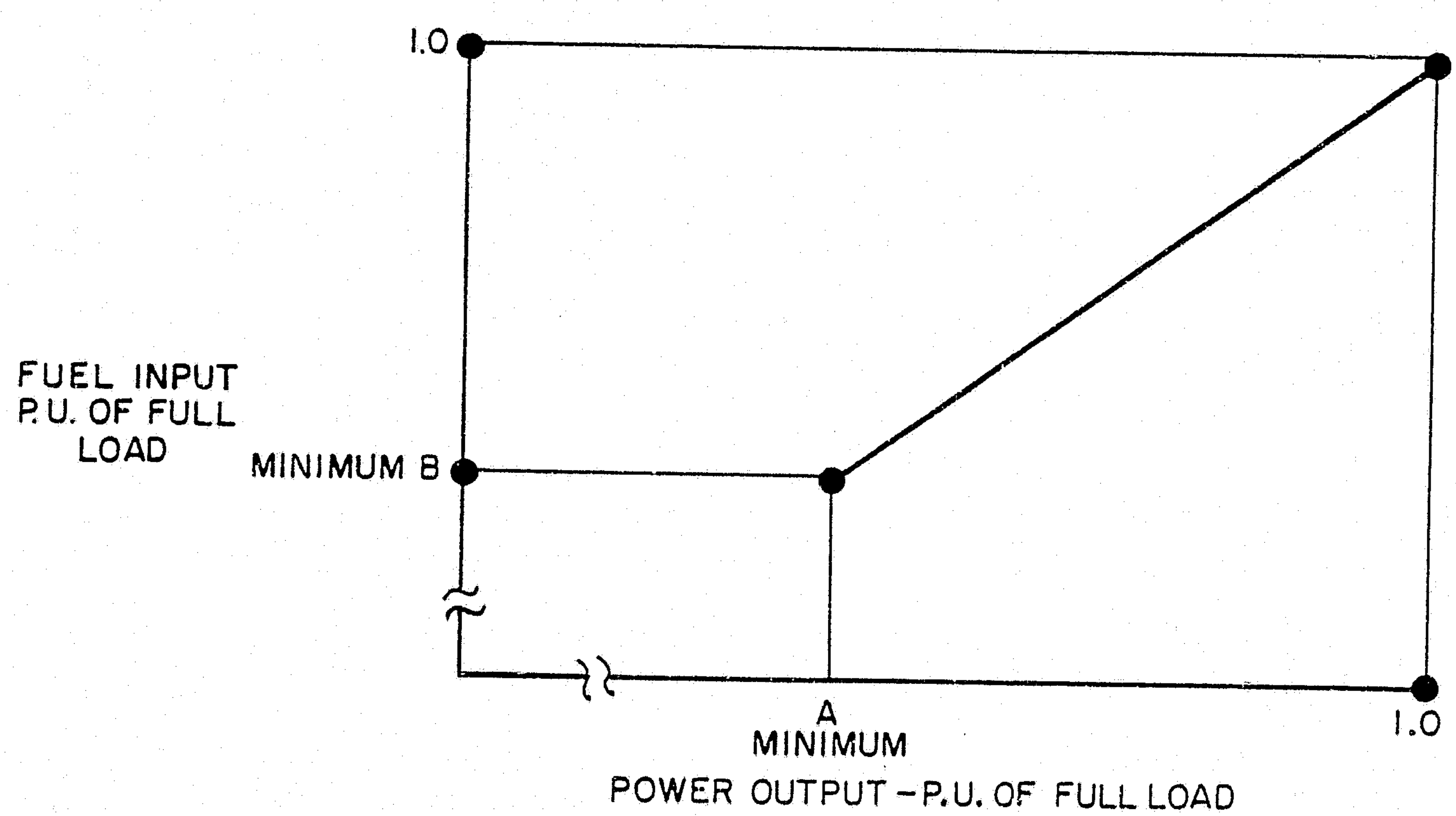


Figure 5-4. Input-Output Representation for Thermal Generation

g. Commitment Minimum Uptime Rule

The Commitment Minimum Uptime Rule can differ for each type of unit. The uptime rule assigned to each type of unit may be overridden on a unit-by-unit basis. Once a unit is committed, it must operate, at least at its minimum output level, for the entire commitment period. The four different categories which may be assigned to a unit are listed in Table 5-1:

TABLE 5-1

Rule No.	Characteristics
-1	The unit must be committed all week, at least at its minimum, unless it is on planned outage.
1	If committed, the unit must remain committed for the entire week.
2	If committed for a weekday, the unit must remain committed for all weekdays; if committed for any of the daytime hours of a weekend day, the unit must also be committed for at least the night hours of that weekend day.
3	If committed, the unit must remain on line for all of the hours in the commitment zone.

Due to program logic constraints, the final economic priority list developed for each month of the production simulation must have the unit uptime rule values listed in monotonically increasing order. Occasionally, this requirement will automatically cause the program to change this variable for some units. If the user does not want the input uptime rules to be changed by the OGP program, the user can select the option to develop the priority list based on the input uptime rules and sort, by economics, the units with the same uptime rule.

h. Mature Unit Forced Outage Rates

Mature unit forced outage rates can be specified separately for each type of unit in per unit as a function of unit size. As illustrated in Figure 5-5, when points (X,A), (Y,B) and (Z,C) are input, the OGP program will interpolate linearly between the three points and assume outage rates at a constant value for units with capacities greater than Z MW or less than X MW. This variable may also be specified on an individual, unit-by-unit basis.

i. Mature Unit Planned Outage Rates

Mature unit planned outage rates are handled similarly to the forced outage rates just discussed, and they also are uniquely specifiable by unit.

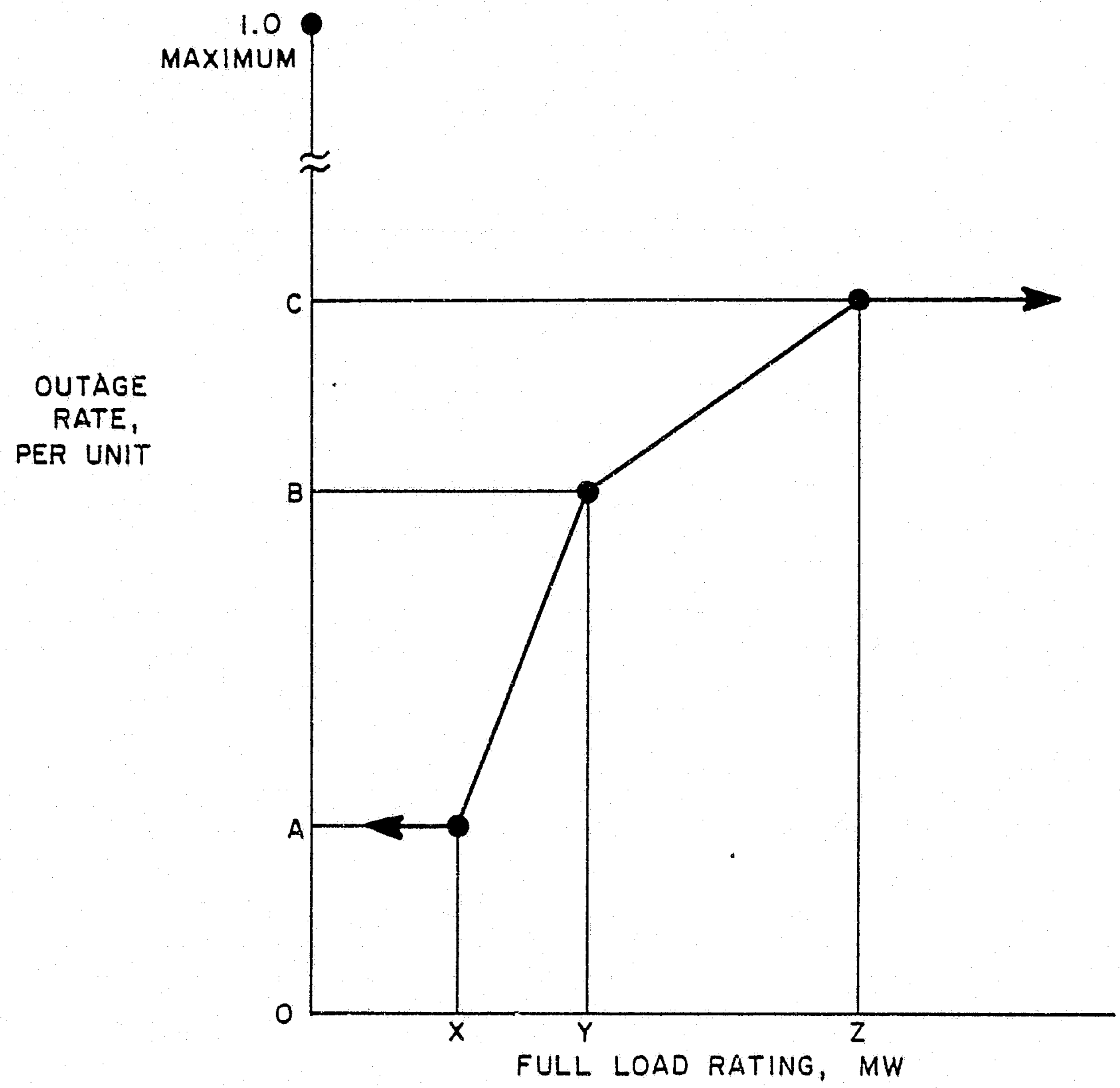


Figure 5-5. Mature Outage Rate Representation for Thermal Generation

Alternatively, the user can input the specific months during which maintenance is to be scheduled for particular units. A maximum of 25 manual maintenance patterns can be defined, and these can be assigned to any or all of the units on the system. If a manual maintenance pattern is specified, the unit's planned outage rate will be ignored.

If a unit is installed or retired in mid-year (i.e., during any month except January), the program, at the user's option, will prorate the planned maintenance for the year, based on the number of months the unit is in service.

j. Immature Unit Outage Rates

To obtain immature unit outage rates, a different per-unit multiplier may be input for forced and planned outage rates for each type of unit. The number of years for which the adjusted rate is to apply is also input; however, the same number of years must apply to both the forced and planned outage rates. The alternative method is to input yearly multipliers for the first ten years after a unit has been placed in service. An example of this approach is illustrated in Figure 5-6.

If the unit is a mid-year installation, the first immaturity multiplier is applied to that portion of the first calendar year in which the unit is in service.

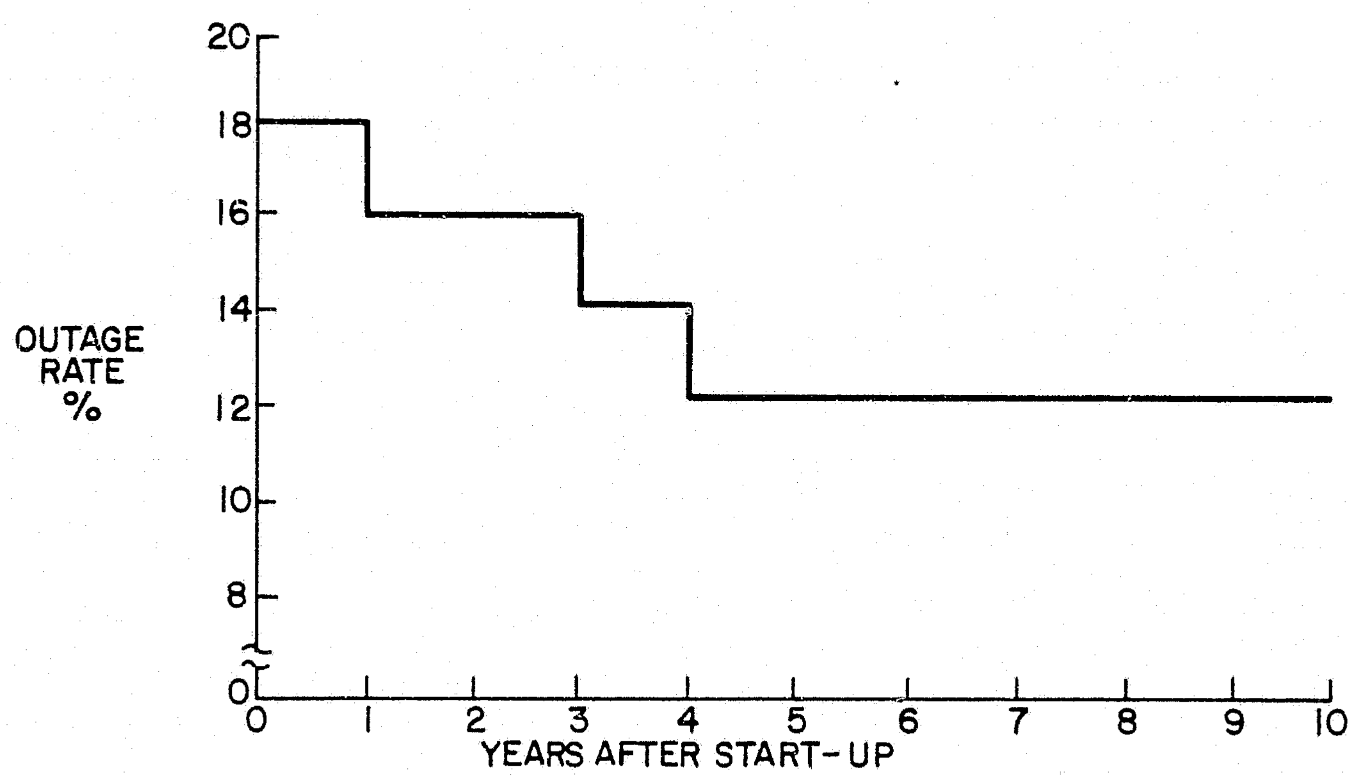


Figure 5-6. Example of Multi-Step Immature Outage Rate Treatment for Thermal Generation

k. Environmental Discharge Data

If environmental discharge calculations are desired, the characteristics can be input by type of unit and fuel. For summarization purposes, individual units may be assigned to one of 100 possible plants and the plants subsequently assigned to one of 25 regions. Other units which may be added during the course of the study may be assigned to different plants by unit type. If desired, unit commitment and dispatch can be simulated on a basis which biases operations to minimize the calculated environmental impact.

(1) Characteristics Assigned by Unit Type

The following data may be specified on a per-unit basis in OGP-6A for each of the six types of thermal units.

- Waste heat rejected to the atmosphere
- Sulfur removal efficiency
- Precipitator efficiency

(2) Fuel Type Assignations

The following data may be specified in OGP-6A for the maximum of 20 types of fuel.

- Heating value expressed as Btu/unit of fuel (OGP-6 also)
- Sulfur content in pounds/unit of fuel and as a percentage by weight
- Carbon monoxide in pounds, pounds/MW/hr and a scalar per-unit quantity to reflect the actual amount released with combustion
- Nitrogen oxides in pounds and pounds/MW/hr along with a unique scalar
- Particulates in pounds and pounds/MW/hr along with a unique scalar
- Water consumption in gallons and gallons/MW/hr

(3) Unit Commitment Weighting Coefficients

At the user's option, per-unit weighting coefficients, assigned by region, can be used to alter or modify the priority list developed from the combination of economic and environmental factors. The objective function to be minimized is

$$\sum_{I=1}^{N} \sum_{J=1}^{M} \omega_J [E_{IJ}(P_I)],$$

where N is the number of units committed, M is the number of economic and environmental factors (M = 1 for OGP-6, M = 8 for OGP-6A), ω_J is the weighting coefficient for each factor, and E_{IJ} is the hourly type J emissions or the hourly cost for unit I as a function of P_I, the power output of unit I.

The following per-unit weighting coefficients can be used in OGP-6A:

- Fuel plus variable O&M, $ (OGP-6 also)
- Atmospheric heat rejection, MBtu
- Cooling medium heat rejection, MBtu
- SO_2, tons
- NO_x, tons
- CO, tons
- Particulates, tons
- Water, thousands of gallons

Fuel plus variable O&M is initialized to 1.0; all other coefficients have been initialized to 0.0, resulting in a unit commitment based strictly on economics.

(4) <u>Unit Dispatch Weighting Coefficients</u>

The unit dispatch weighting coefficients that may be used are similar to the unit commitment weighting coefficients. However, the values need not be the same. Where the commitment considered full load emissions and costs, the dispatch uses incremental values.

1. <u>Energy and Fuel Usage Constraints (OGP-6A only)</u>

OGP-6A has an option that enables the user to limit the energy output of certain units. This option is useful to model units with a limited supply of fuel or environmental restrictions. To use this option, all units within a specific thermal type designation are assigned a maximum monthly capacity factor or a maximum monthly energy output in MWh. Alternatively, a maximum fuel usage may be specified to limit the operation of units assigned to the designated fuel type. The energy or fuel limits may also be input on a unit-by-unit basis. Details describing how the commitment and dispatch procedures change when the energy or fuel limitations are in effect are presented in Section 9.

All new thermal optimizing selections must be made from among the six types of generating units just described. The three types of energy storage units to be considered for automatic addition are described in part four of this section.

2. Generating Unit Descriptive Data for Unit Types 7-10 (Conventional Hydro and Energy Storage)

a. Deration

To simulate unavailability for reliability calculations, the user can specify a per-unit multiplier to reduce total apparent maximum output.

b. Plant Cost

The user can specify a $/kW and inflation rate which may vary annually for each type of unit.

c. O&M Cost

For each type of unit, the user can specify a fixed component in $/kW/yr, as well as its yearly inflation rate.

3. Generating Unit Descriptive Data for Unit Type 7 Only (Conventional Hydro)

a. Scheduling

The user has the option of specifying that hydro generation be scheduled either all week or on weekdays only.

b. Reliability Energy

The amount of hydroelectric energy available for use in the reliability calculations may be specified separately from the production cost energy. This is done on a monthly basis. If a separate reliability energy is not specified, OGP will use the production cost energy with the run-of-river portion derated.

c. Excess Energy

If there is more hydro energy available in a month than can be used, the user has the option of spilling the excess energy or carrying it forward into the next month. The user can also specify a maximum amount of energy to be carried forward.

4. Generating Unit Descriptive Data for Unit Types 8-10 Only (Energy Storage)

a. Efficiency

One overall efficiency value is input for all units of each type by month and year. The efficiency is the ratio of the energy generated to the energy stored. If the unit also burns fuel (as with compressed air energy storage), the efficiency should include the energy from the fuel, resulting in an efficiency that might exceed 100%.

b. Charge/Discharge Ratings

For each energy storage unit, a separate maximum charge and maximum discharge rating is specified on a monthly basis.

c. Heat Rate

Heat rate data can be specified for compressed air storage units.

d. Scheduling Order

The order in which the three types of energy storage are scheduled can be specified.

e. Cost Biasing

The OGP energy storage algorithm schedules energy storage units to minimize production costs. However, to operate the energy storage unit more or less than the economically desirable amount, the charging cost may be biased with a per-unit multiplier. This biasing is done separately for each type of the three types of energy storage.

f. Operational Mode

Each type of energy storage must be assigned an operational mode from among the following possibilities:

Option 1:	weekday charge - weekday generate weekend charge - weekday generate
Option 2:	weekday charge - weekday generate weekend charge - weekday generate weekend charge - weekend generate
Option 3:	weekday charge - weekday generate weekend charge - weekend generate

Note that Option 1 specifically excludes generation on the weekend, regardless of economics. Option 2, however, permits weekend generation. The third option, unlike the previous two, results in a daily charge/discharge cycle, which means the energy storage device is fully charged at the beginning of each day.

g. Free Energy

For each type of energy storage, extra energy that was not generated by the thermal system may be included for dispatch. This specification is done on a monthly basis, and can represent rainfall, melting snow, or any other inputs to a pumped-storage pond. The variable can be negative to represent such things as evaporation from the pumped-storage pond or air loss in compressed air caverns.

The three types of energy storage units to be included in the optimization will have the characteristics just described for Unit Types 8-10.

5. Generating Unit Descriptive Data for Unit Types 1-10

a. Fixed Charge Rate

The levelized annual fixed charge rate may differ for each type of unit as well as for each of the companies or areas represented in the OGP study. This rate may also vary each year of the study.

b. Retirement Policy

For each type of unit, the number of years from the initial installation date to retirement is entered. This data can be input separately for existing units and for the units automatically added by the program. Alternatively, any existing or manually installed unit may be assigned a particular retirement year and month. A maximum of 100 units may be retired and/or installed each year of the OGP study. Units that have been added automatically during the study may also be retired during the study period.

6. Data Concerning Effective Load Model Modification

a. Purchases and Sales

A maximum of ten individual contractual commitments for purchases and sales may be represented, and all the data in the following list may be changed each year of the OGP study. To simulate the impact on the reliability calculations of emergency purchase capability from neighboring systems, zero-hour contracts can be specified.

- Contract name
- Number of hours/day for which the contract is in effect
- All week or weekday only operation
- Demand charge, $/kW/yr
- Demand charge inflation rate, per unit
- MW used for calculating the demand charge, if different than the monthly contractual demand
- Energy charge, $/MWh
- Energy charge inflation rate, per unit
- Monthly demand, MW

b. <u>Load Forecasting Uncertainty</u>

As shown in Figure 5-7, the user can specify a distribution of peak loads in per unit of the forecast peak load on the Load Model along with the per-unit probability of each of the peak loads occurring. A maximum of ten points on the distribution may be input. Thus, a maximum of ten new peak load forecast values is calculated from each point on the original Load Model for use in the reliability calculations only. The LOLP is calculated at each load level and weighted by the probability to produce one expected value for LOLP. However, one should note that the use of load forecast uncertainty with the hourly LOLP option may incur substantial computational expense.

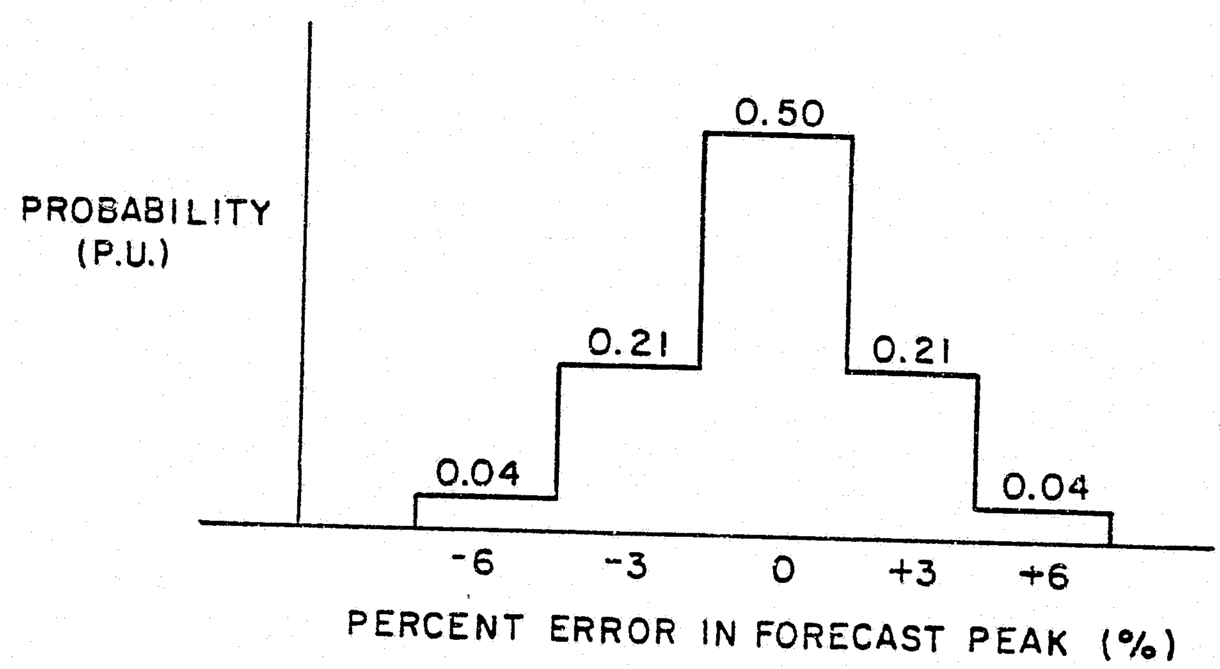


Figure 5-7. Example of Load Forecasting Deviation Input for LOLP Calculations

c. <u>Overriding the Annual Pool Peak</u>

New values for the annual pool peak on the Load Model can be input. All of the per-unit information on the Load Model will remain unchanged, and the MW loads will increase or decrease in proportion to the new pool peak.

7. Other Reliability Related Data Input Items

a. Unit Size Guide

The user can control the unit size selected by OGP for optimizing comparisons each year if the type of unit is available in more than one size in a given year. Different guidelines can be input for the three kinds of units: base load, intermediate or peaking.

To control unit size selection for base load units, the user must state the approximate number of base load units that should be added to meet a certain number of the years of load growth. The program will use that input while maintaining the percent reserve margins or reliability of the system to determine the unit size to consider.

For intermediate-sized thermal units, the user can control size selection by specifying a per-unit multiplier which is applied to the current year's load growth. To select the size for thermal peaking units, the user can specify a per-unit multiplier which is applied to the system installed capacity. Both of these multipiers may be changed annually.

As an optimization alternative, a single generator size (MW), maximum charging rate (MW) and storage capacity (MWh) may be designated for each of the three types of energy storage. These three quantities may be changed annually.

b. Using a Unit Type to Trim the Yearly Expansion

To minimize possible overbuilding of a system in any year while optimizing, the user can state that when the system's capacity deficiency for any type of unit under consideration is at or below a specified percentage of that unit's size, the difference can be compensated for with an appropriate amount of capacity of trim units. Any one of the unit Type Nos. 1-6 can be designated as the trim type. If not otherwise specified, the program will trim with unit Type No. 3. Implicit in the use of this option are two assumptions: (1) the type of unit selected as the trim type has an economically desirable peaking capacity and (2) the unit's size is not greater than that of the type of generating unit it has been allowed to supplant. A different percentage is specifiable for each of the six types of units.

c. New Capacity Installation Criterion

The criterion upon which new capacity installation is to be based may be specified as either a probabilistic risk index of days per year (daily LOLP), hours per year (hourly LOLP), or an installed percentage reserve requirement. There are several ways in which the percent reserve margins of system reliability can be specified. Normally, it is based on the month of each year in which the annual peak load occurs. Alternatively, the user can specify any other month during which this test should be conducted.

The actual calculation of the percentage of system reserve can be specified in three different ways. The program uses the first method listed unless the user specifies one of the others.

Method 1: [(Capacity + Contracts) - Load]/Load

Method 2: [Capacity + Other Contracts - (Load - 0 Hour Contracts)]/(Load - 0 Hour Contracts)

Method 3: [Capacity - (Load - Contracts)]/(Load - Contracts)

Additionally, the user may specify any month other than January in which all automatically added units are to be installed.

d. Economic Reserve Margins

The new capacity installation can also be based on economic reserve margins. The program will automatically add new units beyond those needed for system reliability, if the savings in production costs, resulting from the displacement of higher cost generation, is enough to offset the additional investment cost.

The user specifies the years in which this economic overbuilding is to be evaluated and the unit types to be used. A maximum percent reserve margin can also be input.

e. Mature Outage Rates in Optimizing Decisions

In the optimization process, a decision-biasing option, termed the "look-ahead" feature, may be utilized. To do so, the user specifies that the relative economic merits of new generating units will be evaluated with their mature planned and forced outage rates which are anticipated to be in effect for most of their service lives. Thus, by the use of this option, new generating units are not penalized by their immature characteristics. Instead, a total system evaluation is made of the new generating units based on their anticipated future outage patterns.

After the preferred new generation alternative has been decided, the OGP process then recalculates the year in question, utilizing the immature outage rates that have been specified. This recalculation is necessary to obtain an accurate estimate of the actual total system costs for each year of the study. Since the decision to add capacity is based on mature outage rates, the recalculation with immature outage rates may indicate a capacity shortage. When this occurs, the program adds enough thermal units designated for trimming (usually gas turbines) to satisfy the reliability criterion.

8. Other Operationally Related Data Input Items

a. Levelized Future Fuel and Variable O&M Costs in Optimizing Decisions

At the user's command, anticipated variable operational costs may be simulated and taken into account similar to the procedure just discussed for using mature outage rates to make new generating unit evaluations. In this case, however, when the cost inflation of these operational factors is defined, OGP automatically calculates and substitutes levelized values for use in the yearly production cost calculations. The user inputs the number of years following the decision year for which the program is to calculate these levelized values. Also, as is done for the outage rates, after the best type of generating unit is selected using these levelized values, the current year's values are retrieved, and a complete production simulation is calculated to supply the correct values for the record.

b. Planned Maintenance

An outage due to planned maintenance may be disallowed during the month in which the annual system peak load occurs. Alternatively, a maximum of five months may be specified in place of that month. The user can also define a maximum of 25 maintenance patterns, which can be changed annually. Specific units may then be assigned to one of these patterns. In order to minimize the annual system risk, OGP will select maintenance months for all units not assigned to a specific pattern.

The maintenance schedule developed by OGP can be saved and used for subsequent OGP runs. The system must have the same units in all runs using the same maintenance schedule.

c. Unplanned Maintenance Treatment

By extending a unit's planned outage period, the user can simulate forced outages. Alternatively, the user can select a stochastic treatment in all the yearly decision calculations or only in the calculation of the final yearly costs. This technique calculates the effect of random forced outages after unit commitment and will result in the simulation of emergency energy purchases.

d. Spinning Reserve Specifications

The spinning reserve may be expressed on a yearly basis in one of three ways: (1) as a percentage of the monthly peak load, (2) as a specific MW requirement, or (3) as a per-unit ratio of the largest unit that is not on maintenance during the month under study. Further, the maximum percentage of unused pumped-storage hydro generation that may be considered available for credit toward the spinning reserve required can also be input separately.

e. Sale of Excess Energy

In cases where generating unit cycling limitations and minimum output specifications result in a system operating condition where the load is less than the sum of the minimum rating of the committed units, OGP will terminate its calculations. The user has the option of allowing the case to proceed automatically. To do this, the user must specify that some of the excess generation be sold by stating the maximum percentage of the minimum unit loadings that may be sold. The $/MWh and annual inflation rate which is to be associated with this transaction may also be specified.

f. Purchase of Emergency Energy

In instances where manual expansion or random forced outage rate calculations are utilized in the production simulation, shortfalls of available generation may be indicated for some periods of time. An indication of a shortfall may be interpreted as the expected value of energy not served. In such cases, the user can specify the cost of such an unexpected tie energy purchase in $/MWh along with its own yearly inflation rate.

g. Commitment Zone Specifications

A maximum of six commitment zones may be defined, and these must be apportioned between the average weekday and average weekend day. The number of hours in each of these zones must also be defined, as shown in Figure 5-8. The unit commitment will remain constant throughout each zone. Commitment changes between zones depend upon the minimum uptime rules associated with the generating units.

9. Other Financially Related Data Input Items

a. Initial Plant Investment Accounts

To account for the capital costs of the existing system, the user can input one number which represents annual fixed charges for the units on the system at the start of the OGP study.

b. Changes in Investment Cost

If a unit is added either manually or automatically, its fixed charges on investment may be deleted at the user's option when the unit is retired before the end of the OGP study.

c. Cost Basis Year

All cost data input to OGP must be referenced to one specific year. The various annual inflation rates input separately will adjust the costs from this reference year to the year being studied.

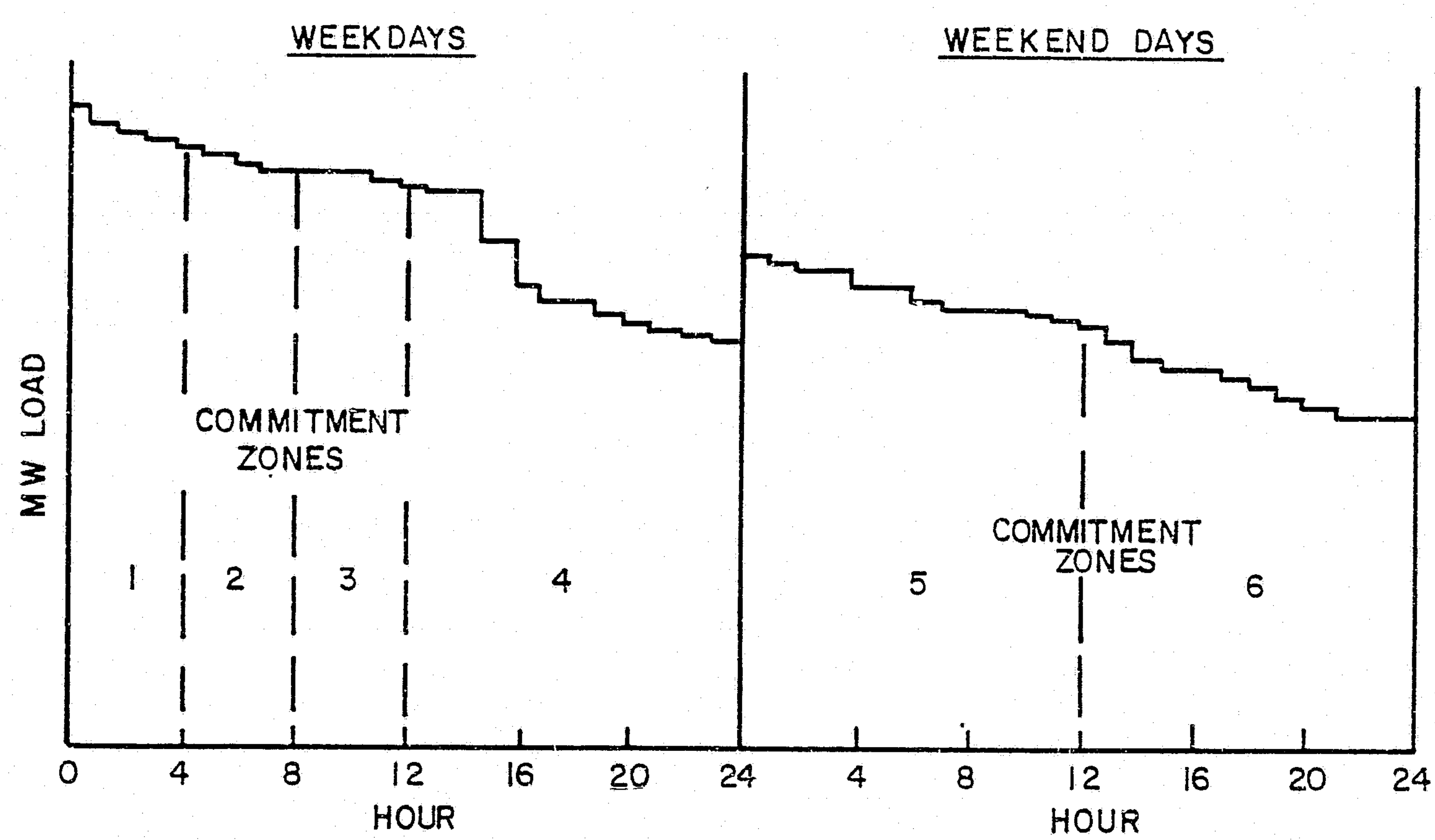


Figure 5-8. Example of Thermal Commitment Zone Specification

d. <u>Present Worth Calculations</u>

The user specifies the present worth interest rate and the reference year for doing the present worth calculation on the annual system costs. It is assumed that the costs for each year occur either at the end of the year in December, or at the beginning of the year in January.

STUDY DATA

SUPPLEMENTARY INFORMATION

1. "D" Factor, GE Memorandum.

2. Typical Generation Planning Inputs, H.H. Heiges, Power Generation Report No. 162.

DATA PREPARATION

The Data Preparation portion of OGP reads the user's input data, adapts it as needed for use by the OGP program, and then displays it in a printed output format which enables the user to easily examine and refer to the data. Input data is accepted from three sources: the Generation Model, Load Model, and study data. These topics are discussed in Sections 2, 3 and 5.

The following major automatic data preparation processes are performed by OGP:

- Checking of the user's input data for nominal errors
- Lumping of certain fossil units according to the user's specifications
- Aggregation of conventional hydroelectric and other types of energy storage
- Initialization of the system for future planning

This section of the Descriptive Handbook covers a number of the key functions that are initiated in the Data Preparation portion of OGP.

First, the user's input data is checked for nominal errors. If errors are found, a summary of the errors detected is displayed on the output, and program execution is stopped. Next, the data is merged, sorted, and reduced for further use. The reduction logic used is designed to minimize the cost of computation in areas that have little effect on model accuracy. For example, the program routines process individual station data for conventional hydro plants (i.e., generating unit Type No. 7) and lump these individual plants into one aggregate conventional hydro plant. This single plant is characterized by a monthly maximum output in MW, a monthly minimum output in MW, and a monthly energy output in MWh. All values are determined by summing individual unit characteristics. The OGP Data Preparation routines also lump individual energy storage units within generation unit Type Nos. 8, 9, and 10 into a single energy storage plant for each type.

The cycle efficiency of the lumped energy storage plant is specified by the user. A weighted average of the individual unit cycle efficiencies is the preferred approach for estimating the lumped unit's cycle efficiency. Caution is advised when the user chooses to lump two plants of very dissimilar characteristics such as one with large storage and small generation capacity and one with small storage and large generation capacity.

The user can exercise more control over the lumping procedure for thermal generating unit Type Nos. 2 and/or 3 than that used for hydroelectric generating units. The user specifies the largest unit capacity to be lumped as well as the maximum lump size allowable. Lumping is recommended only for the smaller units in relatively large systems. When utilized judiciously, lumping can reduce program computation expense both in the reliability calculation and production costing areas without resulting in a prohibitive loss in calculation accuracy.

Characteristics are assigned to each lumped generating unit as indicated in Table 6-1. The standard table data values used are based on the size of the resultant lump. For example, if five 10 MW units are lumped together, they will be assigned the characteristics of a 50 MW unit. Maintenance patterns, energy limits, and/or fuel limits should not be specified manually for the individual units which comprise a lump; however, the lumped units together may be assigned a specific maintenance pattern, energy limit, and/or fuel limit. If no maintenance pattern is specified for the lumped units, OGP automatically will schedule maintenance, using the standard table planned outage rate. Unless specified by the user, all lumped units are assumed to have no energy or fuel limits, even when some or all of the units comprising a lump have these limits.

TABLE 6-1

Unit Characteristic	Numerical Value
Fuel Cost	Weighted MW Average Based on Lump Components
Fuel Input at Minimum Output	Standard Table
Fuel Input at Maximum Output	Standard Table
Heat Rate	Weighted MW Average Based on Lump Components
Inflation Pattern	Pattern Assigned to Thermal Type
Installation Year (Type 2)	Zero
Installation Year (Type 3)	Weighted MW Average Based on Lump Components (used to determine the lump's retirement year)
Minimum Output Rating	Standard Table
O&M Costs	Standard Table
Planned Outage Rate	Standard Table
Forced Outage Rate	Standard Table
Environmental Emissions (OGP-6A)	Standard Table
Retirement Date	Standard Table
Station Name (Type 2)	"Equivalent No."
Station Name (Type 3)	"G.T. Lump No."
Plant Identification No.	Plant 100

ADDITION OPTIMIZATION

The next portion of the program with which the user becomes involved is the OGP optimization logic, which compares the total system cost of thermal and energy storage alternatives. The generation and loads are modeled, and all other input data has been initialized to reflect the conditions for the first year to be studied.

The user can direct and control OGP's optimization process. Usually, the optimum expansion is the one that minimizes the present worth of future revenue requirements. In OGP-6A, the economics used to determine the optimum expansion can be biased by other factors. The impact of restrictions on unit operation due to fuel or energy limitations can be included in the decision-making process. By judicious data specification, OGP can be biased toward expanding the system to produce the least total impact on the environment. The OGP process automatically spans time, year by year, to determine answers to the following questions for each year of the study: (1) How much generation should be added to the system? and (2) What kind of generation should be added to the system? Then OGP tabulates the total system costs or impacts of that stream of additions.

After the user has input into the program a list of available units and their characteristics, the OGP process chooses from this list the optimum combination of unit additions for each of the years under study. This selection is made in a logical manner which satisfies the input constraints. OGP produces a year-by-year plan that also has been optimized through time.

OGP's addition optimization process differs in several ways from a "screening curve" approach. One difference is that screening curves for a system change after each new unit is added and also each time the load and generating unit availability change. Thus screening curves are a very gross approximation of system operation. As a result, the process does not lend itself to studying a mixture of new additions or accurately calculating resultant system costs. The OGP method, on the other hand, actually performs for every new type of generation being considered a complete hourly system commitment and dispatch in the context of the total system's operation. The costs calculated via the OGP method are a very accurate simulation of how the new units being considered would actually impact on the total system's operation. Thus they aid the planner in the decision-making process by providing an excellent guide for the selection of the type of unit with the lowest overall cost. The user may also study the merits of a manually fitted expansion and obtain meaningful documentation of the costs and impacts of those additions.

The use of separate computer programs to determine generation reserve requirements and perform production simulation does not lend itself to minimizing the sum of the investment and operating costs for a thirty-year study. Thus to help synthesize system expansions, in 1968, the reserve and simulation calculations were packaged into one computer code with an optimization procedure. Dynamic programming was considered, but since the Markov property does not apply (i.e., factors such as generating unit outage probabilities and nuclear fuel costs depend on the maturity of the unit), the number of combinations to be considered in a thirty-year expansion becomes prohibitive. Linear programming also has been applied, but it is difficult to model the nonlinear load carrying capability of the system with unit additions or the many individual operating rules of utilities such as minimum run or shutdown times.

OGP's inherent optimum-seeking capabilities are enhanced by several user-controlled features which are internal to the program. These include logic (e.g., the "look-ahead" feature) which allows for the anticipation of future operating costs and outage rates, the addition of a mixture of types of new units in any given year, and the use of decision-making aids which seek to closely fit unit sizes to yearly load growths.

Two additional points regarding the accuracy of the OGP optimization process should also be emphasized. Because the OGP optimization process is continuous, there are no end effects to complicate the interpretation of the study results. In other words, if two studies were conducted and there were no changes in the input data except for the number of years studied, the results from the two OGP cases for the initial overlapping time period would be the same. For example, if case A used the same input data as case B, except that in case A the years 1990 through 1999 were studied, and in case B the years 1990 through 2009 were studied, both cases would display the same optimum expansion plans and output quantities through the year 1999. Thus, the OGP optimum stream of additions, as produced by application of the "look-ahead" feature, is continuously self-correcting and can effectively answer both of the following questions: (1) What is the best unit to add to my system next? and (2) What should my system mix be through the end of the study?

The second major advantage of the OGP optimization logic is that the user is never required to deterministically or otherwise artificially restrict the absolute number of any type of future generating unit candidate that may be optimally evaluated or added by the program, either on an annual basis or as a total for the entire time period under study. The only exceptions are the current built-in limitations of 100 units added or retired in any one year and 250 units in total on the system in one year. These limitations are dictated solely by an effort to minimize core storage requirements, and could be increased, if the user's needs dictate it.

Because OGP does not require arbitrary estimates or restrictions on the number of unit additions per year, the program yields two significant benefits for the user. First the program cannot find itself halted during the study by a preset tunnel or wall. This means all cases will continue through the final year of the study and yield complete results, thus obviating restarts and iteration solely to obtain full-term outputs. The other benefit of this feature is that it precludes spurious or "local" optimums.

In any case, it is only logical that the following question should arise: How can a yearly decision-making process be utilized to produce a stream of optimized results when, in retrospect, future conditions will almost always prove past assumptions to have been faulty? For example, fuel cost inflation may affect the relative economic desirability of operating certain types of units, or the maturation of outage rates may increase the effectiveness of certain kinds of base load generation and, hence, strengthen their usefulness.

To address such possibilities, the user has the option to "look ahead" at each unit in the yearly decision-making process. When each type of generation is considered by the program for comparison with other types to choose the "best" one, levelized values of fuel and O&M costs and mature outage rates can be utilized in all calculations. The number of years for which the "look-ahead" feature is to be implemented is specified by the user. Typically, the number specified will be a function of the study length and the planning philosophy of the company, thus reflecting the critical payoff period for projects and the uncertainty present in the input data.

Thus, through use of the "look-ahead" feature, the potential anomaly of "smart" decisions made year-by-year proving incorrect in time is avoided by anticipating the effect of future changes in system conditions. Naturally, if the input data is time invariant, there is no need for "looking ahead" in the OGP optimization process, and the optimizing loop will proceed directly to the solution.

In any case, for cost and impact documentation and for advancement to the next decision year of the study, after the optimum type of unit has been chosen with the use of "look-ahead" calculations, a final complete system dispatch and costing process is then conducted using the input data specified for the year under consideration.

The addition logic, which searches to install the best combination of new units each year, operates only during the years in which system load growth and the reliability criterion will accommodate the addition of more than one unit. Briefly, the program begins by considering each of the available types alone, adding as many units as may be required. The total levelized operating and capital charges which accrue from each type by itself for the first year are stored. This provides the program with a relative ranking of the economic desirability of the unit types available. Beginning with the type that gave the lowest total cost, the program starts mixing. One or more of these lowest cost units is replaced (as required by their relative size and availability) by one or more units of the next cheapest type of available generation. This levelized cost is then computed and stored.

Next, a comparison is made to determine if the cost of the second combination is less than the cost of the first. If it is, the logic replaces more units of the first type with the required number of additional units of the second type, and then computes the total levelized costs which are compared once again to the lowest previously obtained cost.

When a mixture of units is obtained that yields a cost greater than that from a previous trial, the program no longer will attempt to increase the number of units of the particular type of generation it had most recently added. Instead, OGP recalls the lowest cost combination obtained thus far and tries to beneficially replace some of these units with the next cheapest type of unit allowed. Computation costs are thus conserved by avoiding the calculation of patently unprofitable combinations.

If the user chooses to allow the program to overbuild the system based on economics, the process begins as described earlier. OGP considers each of the available types alone, adding sufficient capacity to the system to satisfy the reliability criterion. Then, for the types of units designated as available for overbuilding, the program continues to add units beyond those necessary for reliability, as long as the total system costs decrease. At the user's option, the program will then take the lowest cost overbuilt expansion from the types of units labeled "base load" and attempt additional overbuilding with the lowest cost energy storage option. The best expansion evaluated thus far now becomes the starting expansion for the mix logic, where combinations of unit types are evaluated.

It is important to note that in the preceeding description it has been assumed that the OGP program preselected a single available unit size for each of the available types of generation. This unit size selection was based on the user-specified size availability definition, described in Section 5, and the unit size guidelines input for the three kinds of generation--base load, intermediate, and peaking. Although OGP simultaneously observes other factors, such as maintaining an appropriate amount of installed reserve, it is the user who has controlled the sizes on which to optimize. When factors such as negative economies of scale or dramatic changes in availability as a function of size or time are represented, caution must be exercised in specifying the optimization choices.

In addition to the yearly unit mix and size selection logic, it is also possible to trim the expansion to prevent an excessive amount of capacity overbuilding in any one year. This input item also was described in Section 5. As discussed in that section, trimming may not be advisable when the relative system economic desirability of the unit used for trimming purposes would not normally be exhibited, or when the only size of trim unit available in a given decision-making year is greater than that of the unit being supplanted.

The net effect of the OGP optimization process is discussed further in Section 12. At this point, however, it is sufficient to remember that the program logic performs the unit selections via a comparative, iterative simulation process to obtain an expansion which recognizes the realities of the generating units' physical and economic attributes and restraints. Thus, the OGP optimization program logic represents the actions ordinarily performed by a system planner.

ADDITION OPTIMIZATION
SUPPLEMENTARY INFORMATION

1. How Are Optimization Methods Used In the Optimized Generation Planning Approach?, L.L. Garver, 1978 GE Memorandum.

2. Unit Size Selection, G.E. Haringa, 1977 GE Memorandum.

3. OGP-5 Unit Mix Logic, G.E. Haringa, 1978 GE Memorandum.

4. OGP-5 Siting Logic, G.E. Haringa, 1978 GE Memorandum.

RELIABILITY EVALUATION

Based on a user-specified reliability criterion, OGP will automatically determine how much new generation is needed each year by analyzing the system loads and generation. One of three possible reliability criteria may be specified: (1) daily loss-of-load probability (LOLP), (2) hourly LOLP, or (3) percent reserve margin. The system can also be expanded to the economic reserve margin. After adding new capacity to satisfy the reliability criterion specified, the program will install additional capacity if it is economical to do so. The maximum number of individual generating units that may be added and/or retired in any one year is limited to 100.

The amount of generating capacity required to serve a specified sequence of load demands for a given year may be computed using a probability model of generating unit availability termed the loss-of-load probability (LOLP) method. Since its introduction in 1946, the LOLP method has gained wide acceptance in the electric utility industry. Currently, OGP will calculate a daily LOLP and/or an hourly LOLP.

Historically, utility system planners measured generation system reliability with a percentage of generation reserve index. This planning design criterion only measured the difference between total installed generating capacity and annual peak load demand. However, this approach proved to be a relatively insensitive indicator of system reliability, particularly when new alternative units with varying sizes and forced outage rates were compared.

Today, LOLP is the accepted measure of generation system reliability. The LOLP technique is a probabilistic measurement of the expected number of days per year on which the available capacity cannot meet the load demand. The LOLP index provides a consistent and sensitive measure of generation system reliability, although its name is somewhat misleading in two respects. First, the index is not a probability; it is an expected value of the number of days per year of capacity deficiency. Second, it is not a loss of load, but rather a deficiency of installed available capacity. Despite the misnomer, the LOLP approach is well accepted in the utility industry today.

It should also be noted that, in general, daily LOLP is not related to hourly LOLP by a factor of 24 hours; i.e., daily LOLP does not equal hourly LOLP divided by 24. The following discussion refers mainly to daily LOLP. Similar program processes are used when hourly risk is desired.

The process of calculating the OGP system's reliability index involves the following steps:

1. Choose an index.

2. Deterministically modify loads to reflect contracts and zero-hour contracts.

3. Schedule conventional hydro (derated) to minimize LOLP.

4. Schedule energy storage (derated) to minimize LOLP.

5. Schedule maintenance to minimize risk.

6. Build a system cumulative capacity outage table.

7. Convolve the capacity outage table with the load model.

8. Add new units as required to satisfy the specified reliability criterion.

9. Determine resultant risk(s) and effective load carrying capability.

Generation system reliability is affected by several factors such as load characteristics, unit size, and planned and forced outage rates. A generating unit's planned outage rate is a measure of the time required each year to provide for planned maintenance during scheduled outage periods. Typically, these planned unit outages are scheduled in the spring and fall when peak loads are reduced from summer or winter. In OGP, unit maintenance periods are automatically scheduled to minimize risk. Despite the scheduling of maintenance to minimize the effect on system reliability, adequate generating reserves must frequently be installed to maintain system reliability during unit maintenance periods.

The forced outage rate of a generating unit is also important in assessing a unit's effect on generation system reliability. While unit size determines the magnitude of the outage, the forced outage rate indicates the total duration of failure or unplanned downtime. The effect on system reliability will vary with the type of generating unit as well as with the unit's maturity, its design, and the effectiveness of its maintenance program.

After the individual unit forced outage rates are known, the cumulative capacity outage table is developed. Basically, this requires the identification of all possible outage events (e.g., in a system with N units, this means 2^N events) and a determination of the probability of the outage occurring. However, since the LOLP approach is more concerned with system capacity outages than with particular unit outages, the probability of a given total amount of capacity being on outage must be calculated. This information is presented as a cumulative capacity outage table as described in the upcoming example. OGP uses a highly efficient recursive computer technique to directly calculate the cumulative capacity outage table from a list of unit ratings and forced outage rates. For example, consider a small system comprised of only three units. The thermal system is represented by a cumulative capacity outage table which answers the following question: Given the three unit sample system characteristics listed in Table 8-1, what is the probability of having X MW of capacity or more on outage?

TABLE 8-1

Unit	Capability (MW)	Forced Outage Rate (P.U.)	(1 - F.O.R.) Innage Rate (P.U.)
A	100	0.01	0.99
B	150	0.02	0.98
C	200	0.03	0.97

The probabilities of all possible combinations of units being in or out are calculated as shown in Table 8-2. The cumulative column, which gives the probability of X MW or more on outage, is obtained by starting with the value at the bottom of the probability column and adding upwards. For example, a cumulative value of 0.000600 is obtained for X MW = 350 by adding exact probabilities of 0.000006 and 0.000594.

TABLE 8-2

Units On Outage	X MW	Probability	Probability of X MW or More on Outage
None	0	(0.99)(0.98)(0.97) = 0.941094	1.000000
A	100	(0.01)(0.98)(0.97) = 0.009506	0.058906
B	150	(0.99)(0.02)(0.97) = 0.019206	0.049400
C	200	(0.99)(0.98)(0.03) = 0.029106	0.030194
A,B	250	(0.01)(0.02)(0.97) = 0.000194	0.001088
A,C	300	(0.01)(0.98)(0.03) = 0.000294	0.000894
B,C	350	(0.99)(0.02)(0.03) = 0.000594	0.000600
A,B,C	450	(0.01)(0.02)(0.03) = 0.000006	0.000006

The cumulative capacity outage table must be recalculated each time there are any changes in unit rating, forced outage rate, unit retirements, or new unit additions. This requirement is a significant factor that should be considered in the writing of LOLP computer codes, if computer running times are to be maintained at reasonable levels without sacrificing accuracy. An example of a system with a larger number of units, and hence a fairly smooth cumulative capacity outage probability characteristic, is shown in Figure 8-1.

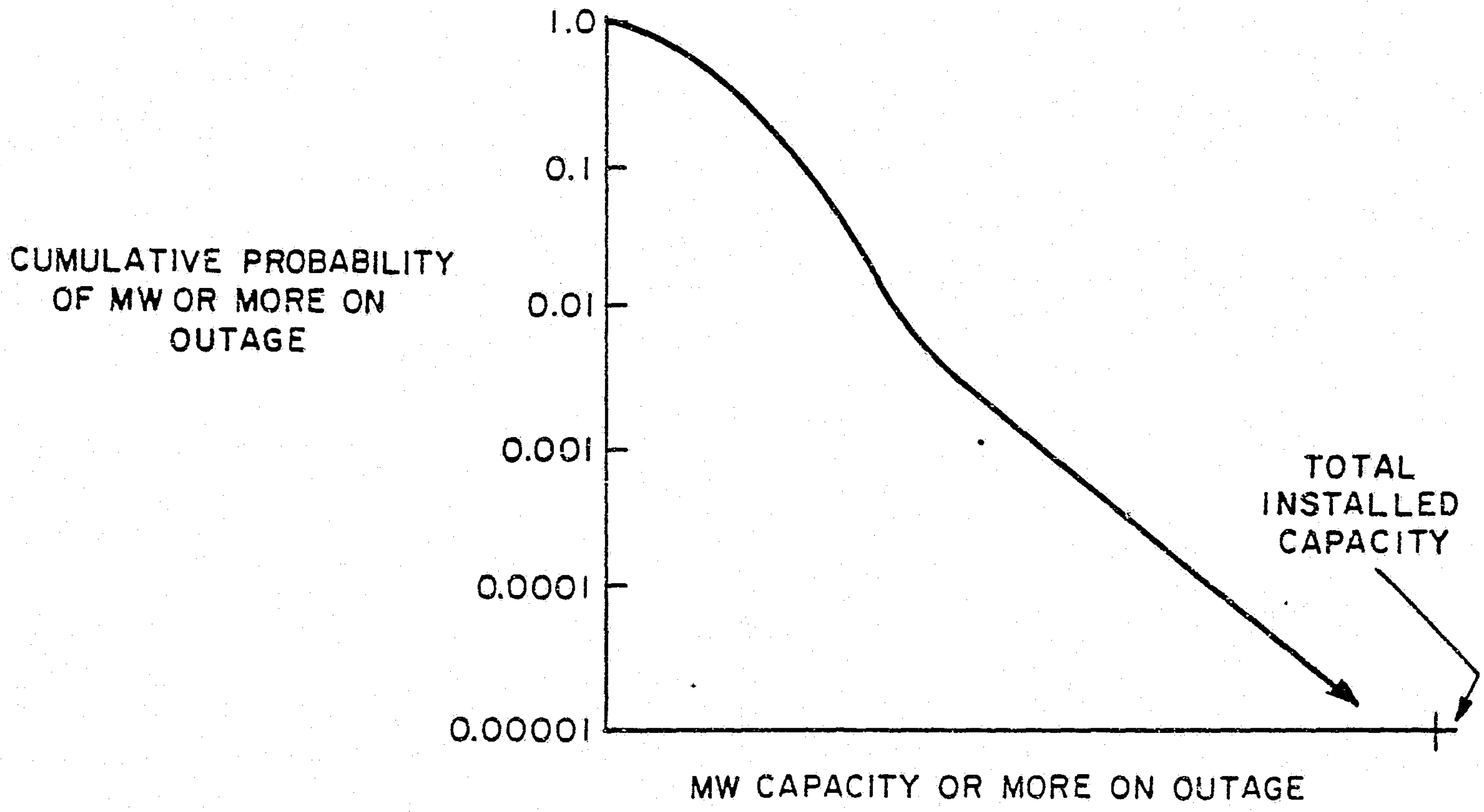
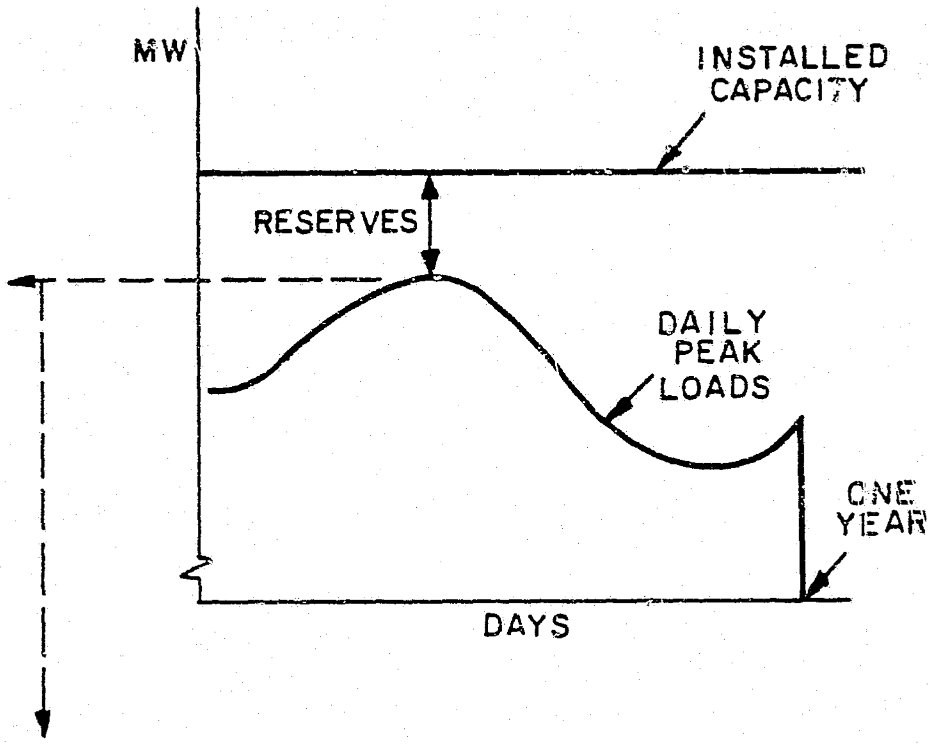


Figure 8-1. Example of a System's Cumulative Outage Probability

If the load demand is known for a particular hour and the installed capacity is known, the LOLP can be calculated. As shown in Figure 8-2, the reserves are obtained by subtracting load from capacity. On this basis, a deficiency in available capacity (i.e., loss of load) occurs if the capacity on outage exceeds the reserves. The probability of this outage is read directly from the cumulative capacity outage table, and is the LOLP for one hour.

The annual LOLP is the summation, which thereby becomes an expected value, of the hourly probabilities. Conventional utility practices analyze the weekday peak hourly loads only (260 in all). Although, in the past, computer running time was a major factor considered in the selection of this approach, the current use of only the weekday peak hours for calculating daily LOLP is based upon several technical considerations. First, the probabilities vary exponentially with load changes. Off-peak loads of less than 90% of the daily peak load will generally add less than one percent to the LOLP risk. Second, generation outages usually tend to persist for at least one day. Third, the interpretations of other utility personnel, particularly system operators, are more meaningful when expressed in terms of days/year rather than in hours/year of expected problems. Simply dividing the hours/year by 24 will seriously misstate the actual number of days/year.

CUMULATIVE PROBABILITY	OUTAGE OR GREATER
1.0000	0 MW
0.6342	10
0.3719	20
0.2463	30
0.1986	40
0	0
0	0
0	0
0	0
0	0



DAYS/YEAR = Σ DAILY OUTAGE PROBABILITIES

Figure 8-2. Example of the Daily LOLP Calculation Procedure

The preceding discussion is based on the assumption that the hourly demand was specified deterministically. The loads, which are convolved with the cumulative capacity outage table, result from modifying the original system loads to reflect contracts, conventional hydro and energy storage. Contracts are assumed to be firm; that is, purchases reduce the load and sales add to the load. After contract modification, conventional hydro is scheduled in a peak shaving mode recognizing the derated capacity and energy limitations. Finally, energy storage units are scheduled to minimize system LOLP, using a derated generator rating, derated charge rating and a derated maximum storage capability.

The inclusion of load forecasting uncertainty is easily integrated into the computational procedure. First, the LOLP is calculated at each demand point in the uncertainty distribution. The equivalent is then determined by weighting the LOLP result at each demand point with the probability distribution value.

By utilizing the LOLP technique, system planners can design the generation system to a specified level of reliability. As the demand increases with time, generation additions are automatically scheduled by OGP so the LOLP does not exceed the design criterion. Figure 8-3 illustrates LOLP plotted versus the annual peak load for a specific generation system. Since the graph is almost a straight line on a semi-log basis, one can see that LOLP varies exponentially with load changes. The design criterion used in this example is 0.1. Based on the peak load for 1985 indicated on the graph, the generation system is able to meet the 1985 load at a reliability level better than 0.1. Therefore, no additional capacity is required.

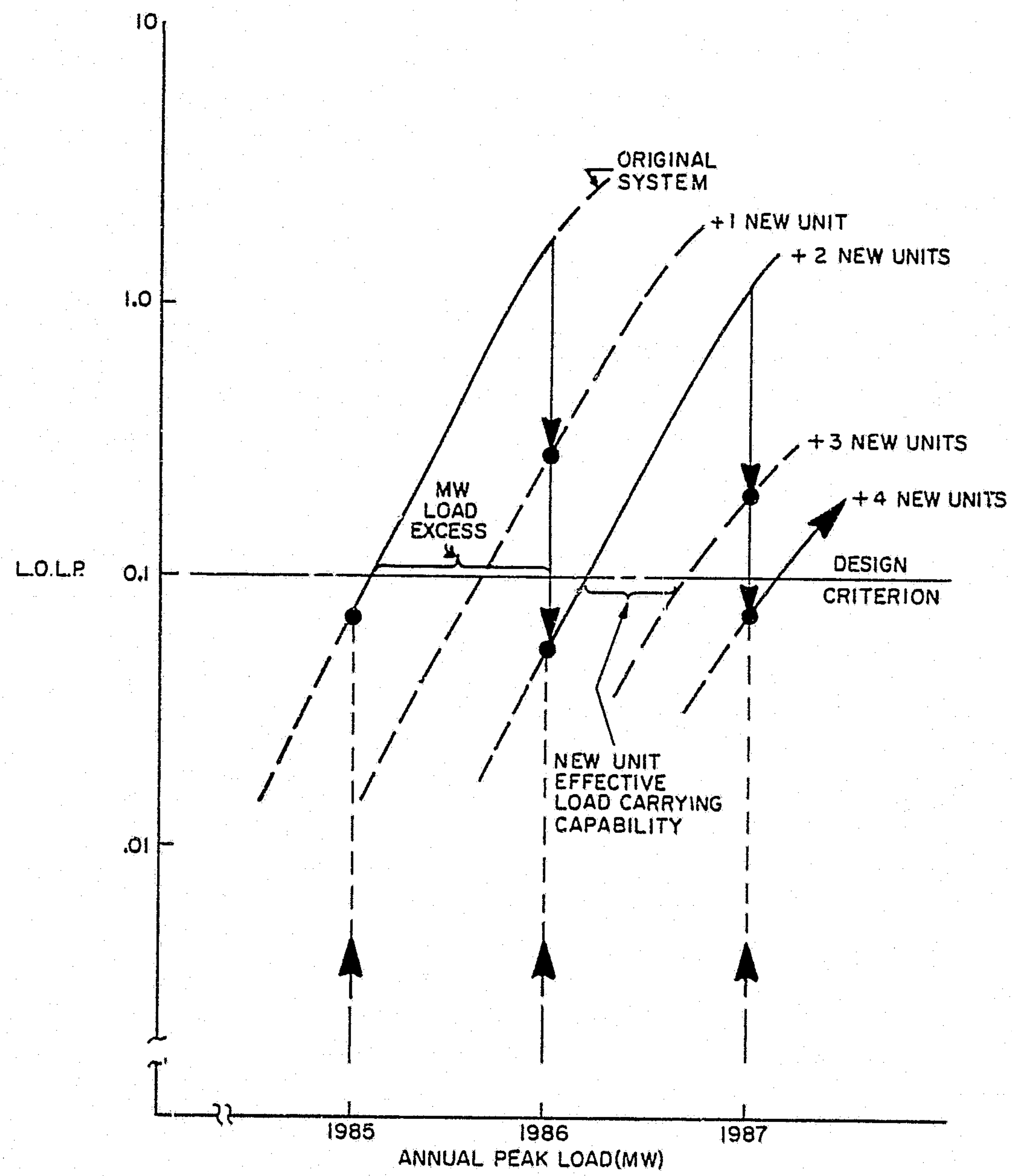


Figure 8-3. Example of the Automatic Unit Addition Process

In 1986, the annual peak load growth has increased the peak demand to a point where the generation system cannot maintain the desired LOLP. In anticipation of this, OGP would schedule a unit addition for 1986. The MW excess of load, indicated by the bracket on the graph, is the difference between the 1986 peak load and the system's load carrying capability at the desired LOLP before any new units are added. With the installation of the additional new unit, the curve shifts to the right. In 1986, the LOLP has decreased with the new unit addition, but has not yet fallen below the example's design criterion of 0.1. Thus, a second unit is required. As indicated on the graph, the addition of the second unit causes the LOLP to fall below the desired level.

A similar occurrence is exhibited for the planning process in 1987. It is also interesting to note how the effective load carrying capability of each unit is measured. As shown by the brackets between the curves for 1986 and 1987, this capability is the difference in MW, measured at 0.1 LOLP, between the annual peak loads that can be supported with and without the additon of each new unit.

If the user is designing the system to meet a certain percentage of installed generation reserve, the automatic addition process proceeds straightforwardly based only on the ratings of the units on the system and the load model specified. The calculations of the percentage of installed generation reserve are based on the peak load of a specified month. They are referenced to the maximum specified ratings on all generating units. The percentage of reserve can be calculated via one of the following three approaches:

- [(Capacity + Contracts) - Load]/Load
- [(Capacity + Other Contracts - (Load - 0 Hour Contracts)]/(Load - 0 Hour Contracts)
- [Capacity - (Load - Contracts)]/(Load - Contracts)

Percentage of installed generation reserve is also calculated for reference, even if LOLP is the design criterion being used.

When multi-company or regional studies are being conducted in which the identity of more than one area has been retained within OGP by the user's data specifications, automatic additions will be distributed among all of the different companies as smoothly as possible. The only exception is for areas which may be restricted to having no generation. Automatic addition units are assigned to a specific company to maintain an approximately equal percentage of installed reserves and percentage of peaking capacity for each company. When these two items are a tradeoff between the companies, an economic comparison is made.

When using OGP-6A, there may be energy- or fuel-limited units. For daily LOLP calculation, limited units are checked each month to determine if they could operate at full load for all the weekdays in the month. Units which pass this test are treated as usual. The units which fail this test are not included in the daily LOLP calculation for the month in question. Limited units must have enough energy to operate at full load during all the hours in the month in order to reduce the hourly LOLP for that month.

RELIABILITY EVALUATION
SUPPLEMENTARY INFORMATION

1. Load Shape Modeling for LOLP Calculations, R.W. Moisan, 1972 GE Memorandum.
2. Calculation Procedure for LOLP, L.L. Garver, R.W. Moisan, 1972 GE Memorandum.
3. Adjusting Maintenance Schedules to Levelize Risk, L.L. Garver, 1972 Winter Power Meeting.
4. Analysis of Partial Outages, R.W. Moisan, 1974 GE Memorandum.
5. Computing the Loss-of-Load Probability, 1972 GE Memorandum.
6. Effective Load Carrying Capability of Generating Units, L.L. Garver, 1966 Winter Power Meeting.
7. Loss-of-Load Probability (LOLP), G.A. Jordan, 1977 GE Memorandum.
8. Generation Reserve Value of Interconnections, A.M. Adamson, A.L. Desell, L.L. Garver, 1976 IEEE Summer Power Meeting.
9. Determining Interconnection Benefits Using Single-Area, Loss-of-Load Probability Studies, L.L. Garver, 1974 GE Memorandum.
10. The Cost Benefits of Alternative Generation Reserve Levels, M.H. Bensky, H.G. Stoll, R.S. Szczepanski, R.E. Usher, 1978 American Power Conference.

PRODUCTION COSTS

In OGP, the fuel and related operating and maintenance costs are determined by an hourly simulation of the system's operation. Until 1971, deterministic models were used almost exclusively to estimate overall fuel costs by simulating the operation of individual units. Today, with the availability of large, efficient digital computers, utility system planners can utilize production costing programs which simulate the actual system operation on an hourly basis. Although this calculation involves a significant amount of computer time, these simulation programs allow planners to completely investigate unit performance and various system operating strategies.

The basic production simulation model performs various analytical functions required to simulate generation system operations during the OGP study. Although the production simulation is performed on an hourly basis, the routines are designed to determine monthly and annual electric power generation operation expenses consisting of fuel and operating and maintenance expenses.

In addition, OGP-6A can determine the operational characteristics of the generating system with respect to various environmental effects. The user has the option of biasing or overriding the normal, unconstrained, economically determined unit commitment and dispatch. This is accomplished by specifying weighting factors for various environmentally related quantities which will direct the program to operate units such that their environmental impact will be minimized. This capability is addressed separately in Section 10.

The operational simulation for both OGP-6 and OGP-6A first accesses the Load Model. For each month, the number of weekdays and weekend days within that month is specified. As previously described in Section 3, the Load Model contains twenty-four hourly loads for each typical weekday and weekend day of every month. (Refer to Figure 3-4 for an example.)

The basic sequential functions of the operational simulation strategy are outlined in the following six steps:

- Determine load modification based on recognition of contractual purchases and sales (i.e., reflect firm contracts).

- Schedule conventional hydro.

- Schedule monthly thermal unit maintenance based on planned outage rates or input manual maintenance.

- Schedule pumped storage hydro or other types of energy storage.

- Commit thermal generating units to serve the remaining loads based on economics or environmental factors, spinning reserve rules, and unit cycling capabilities.

- Dispatch the generation based on relative production costs and environmental emissions specified by the user.

The production simulation performed is for a total utility system or pool commitment and dispatch assumed to have an unlimited power transfer capability between areas or companies internal to the pool represented.

Since the user is not required to input or otherwise predetermine a loading order or sequence of unit commitment and/or dispatch, the user is relieved of the responsibility for this complex and error prone calculation. OGP automatically determines the ideal loading order for every commitment and dispatch period of the study at the time it is first needed.

This section describes how OGP follows the six steps outlined above to determine production costs. It also discusses the commitment and dispatch of units with fuel or energy limits.

1. Purchases and Sales

The hourly loads are initially modified by OGP to consider the firm purchases and sales that exist between the area being studied and entities outside that area. A purchase is subtracted from the Load Model for the number of hours specified in the input. A sale adds to the Load Model. This concept is illustrated in Figure 9-1. The specified schedule and cost of the purchases and sales may differ for each contract. The demand and energy charges will be determined separately. Also, before proceeding to the next step, OGP resorts the resulting Load Model.

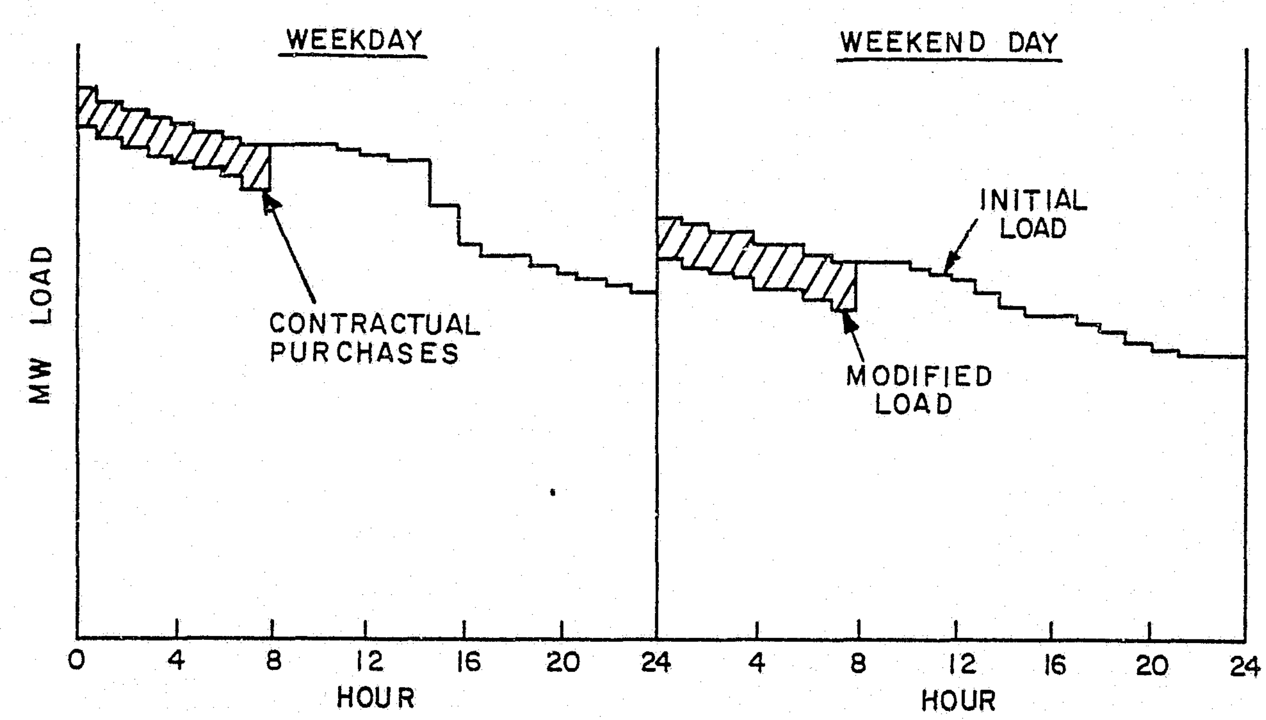


Figure 9-1. Example of Load Modification Based on Firm Contracts

2. Conventional Hydro Scheduling

Hydroelectric energy is assumed to have an incremental fuel cost of zero, and is scheduled to maximize its beneficial effect upon system operating costs. There are generally two types of conventional hydro. The first, run-of-river hydro, is typically an installation which has minimal storage and probably a low head. Units in this type of installation tend to be base loaded, because the river flow requirements and dam characteristics dictate that the unit must be operating most of the time. The second form of conventional hydro is the pondage or simple storage hydro. Units in these installations are usually scheduled during peak load time periods because the system's incremental fuel cost is the highest at these times. If the pondage hydro is scheduled to shave peaks, it maximizes its effect on system operating costs.

A sample schedule of both run-of-river and pondage hydro is provided in Figure 9-2. The run-of-river energy that must be produced by this type of hydro unit is accounted for by subtracting a constant capacity from every hourly load in the month as shown on the graph. This capacity value is referred to as the plant minimum rating and is provided as input data. After run-of-river energy is used, there may be remaining energy, which can be used for peak shaving. In such situations, the program uses the remaining capacity and energy of the hydro unit to reduce the peak loads as much as possible. If any excess energy exists at the end of a month, a user-specified maximum storage amount can be carried forward into the next month.

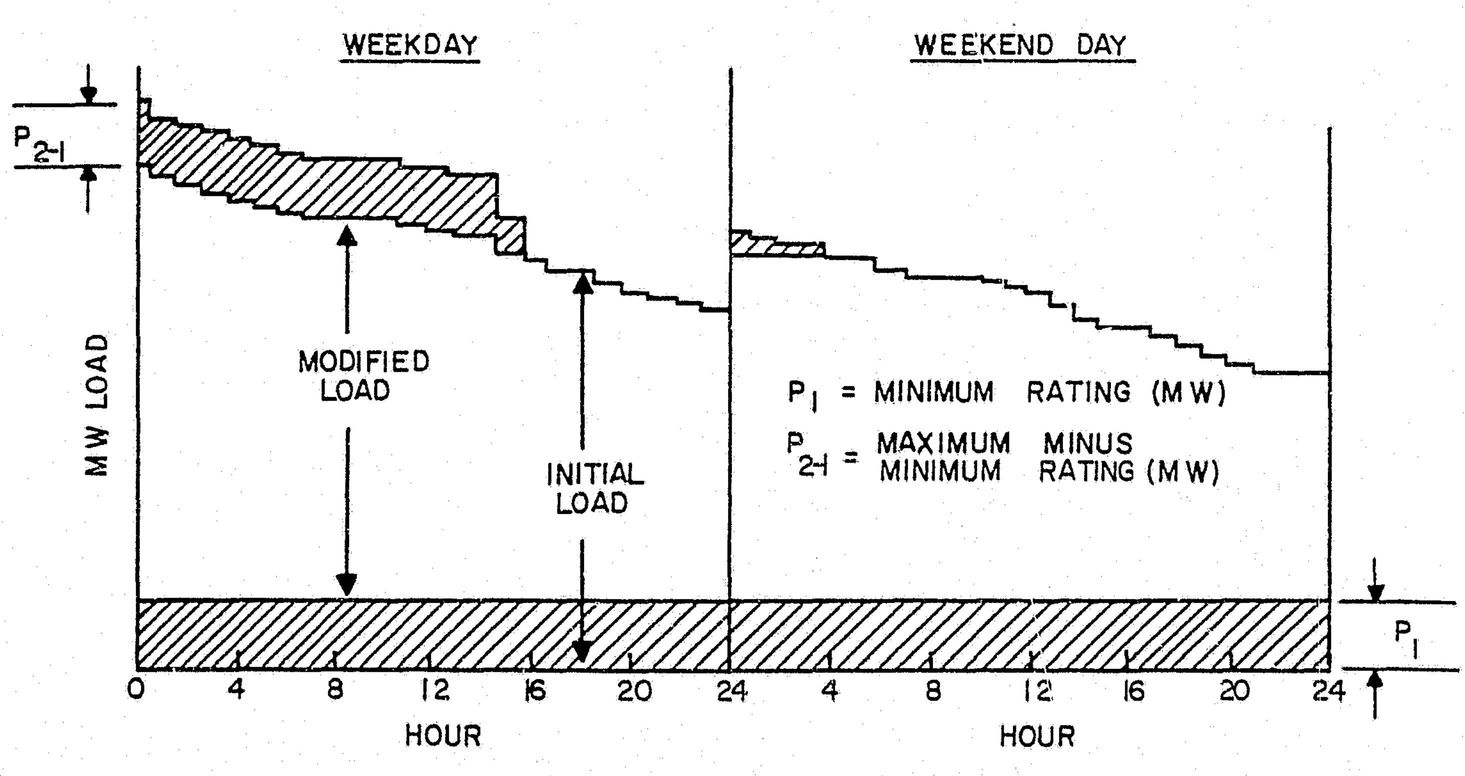


Figure 9-2. Example of Conventional Hydro Operations

3. Thermal Unit Maintenance

Maintenance schedules designed to account for planned downtime, due to activities such as repairs or refueling, are developed by OGP for each generating unit based on user-specified planned outage rates (POR). Increased maintenance levels, which might be required during the first several years of a unit's operation or during its shakedown period, are modeled using an immature multiplier [e.g., Immature POR = (1.15)(Mature POR)].

Often the planned maintenance of individual thermal units on a utility system is scheduled on a monthly basis. During these scheduled maintenance periods, an individual generating unit is unavailable for energy production. Planned maintenance is normally scheduled to minimize its effect on both system reliability and system operating costs. The levelized available reserves approach is one strategy commonly used to schedule maintenance. With this approach, the peak loads are examined throughout the year, and individual generating units are scheduled in an attempt to levelize the peak load plus capacity on maintenance throughout the year. The starting point for implementation of this approach is during the months where peaks are at their lowest (i.e., valley months). The user can specify a maximum of five months during which maintenance is not to be allowed.

The illustration in Figure 9-3 represents an annual OGP-derived maintenance schedule for a particular utility system. The shaded area indicates the total amount of capacity on maintenance for each month. Thus the generating units available for service are identified for each point in time. If a prespecified maintenance pattern has been input for any or all units, those will be scheduled first. Any remaining units will automatically be scheduled by the OGP program.

Thermal generating units are scheduled for maintenance by OGP for an integer number of months. This assumption is reasonable for large base load capacity, but tends to be less accurate for smaller sized mid-range and peaking capacity. Based on this assumption, and the user-specified planned outage rate for each generating unit, a target megawatt-months of planned maintenance is calculated for each unit, and the units are maintained for the nearest whole number of months. The actual megawatt-months of maintenance may differ from the target level; i.e., a fractional megawatt-month of residual maintenance may exist. This residual can be either positive (not enough maintenance was done) or negative (too much was done). When this occurs, the program applies that residual to the next unit scheduled for maintenance, and includes the residual in its maintenance calculation. Residuals are carried over only for units of the same type of generation. The residual maintenance for the last unit in each type of generation is used to derate that unit. The overall effect of the residual calculation is to ensure that, for each type of generation, the correct amount of megawatt-months of maintenance is scheduled, even though the scheduled maintenance for an individual unit may vary slightly from that actually desired.

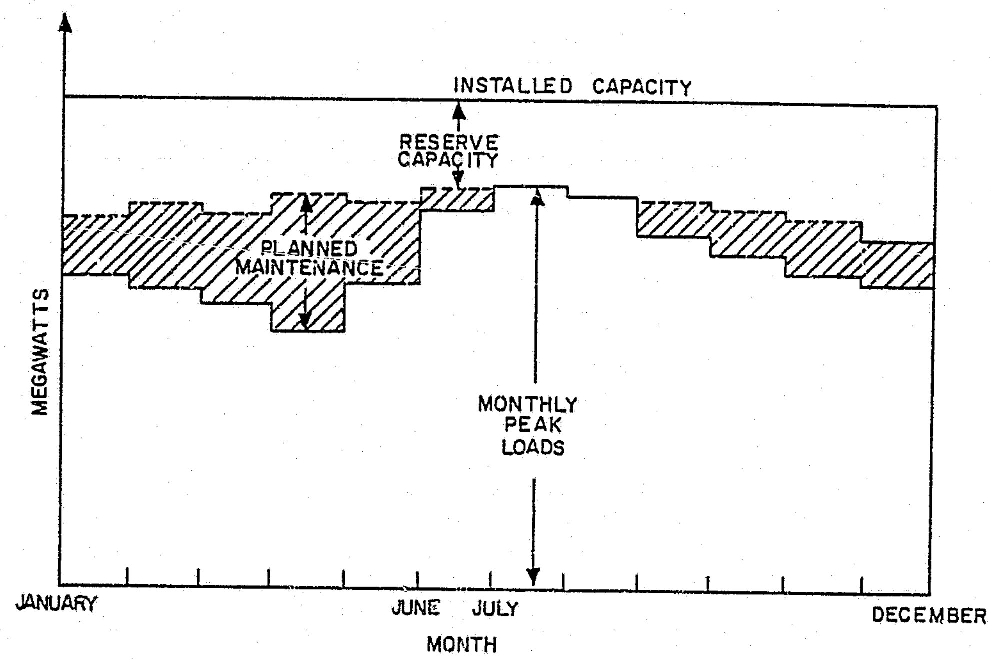


Figure 9-3. Example of Maintenance Scheduling

The user may specify that a maintenance schedule from a previously run OGP simulation be used. It is necessary that the first run save this schedule on a file, and that both cases be manual expansions (i.e., there are no automatic additions) with the same generating units.

It should be noted that the maintenance scheduling algorithm used for production costing differs somewhat from that which is used for the system reliability analysis discussed in Section 8. Although, levelization is still the criterion, risk, rather than reserves, is levelized when the LOLP calculation is performed.

4. Pumped-Storage Hydro Scheduling

The system operating conditions involved when pumped-storage hydro or other energy storage devices exist on the system must also be considered. Energy storage scheduling algorithms have been included in production costing programs for some time. Although the devices studied are usually referred to as pumped-storage hydro, these algorithms have been utilized to study other energy storage devices on electric utility systems such as batteries, thermal storage, etc.

The dispatch of energy storage units is scheduled to minimize the total system fuel costs during a specified time period. OGP recognizes losses in the cycle as the program schedules generation and charging energy to maximize the system fuel cost savings. The user can specify that the scheduling be done on a daily or weekly basis. Energy storage units are assumed to be fully charged at the start of a week, and incremental amounts of generation are balanced by enough charging to fully recharge the unit before the start of the next week. Since system fuel cost tradeoffs are an integral part of energy storage scheduling, a specification of the system fuel cost in $/hr as a function of the system's hourly thermal megawatt output is required. This specification is derived from the cost characteristics of the individual thermal generating units. Because of the nonlinearity of system operating costs, operation of the pumped-storage hydro unit can save fuel dollars, despite a cycle efficiency of less than 100 percent.

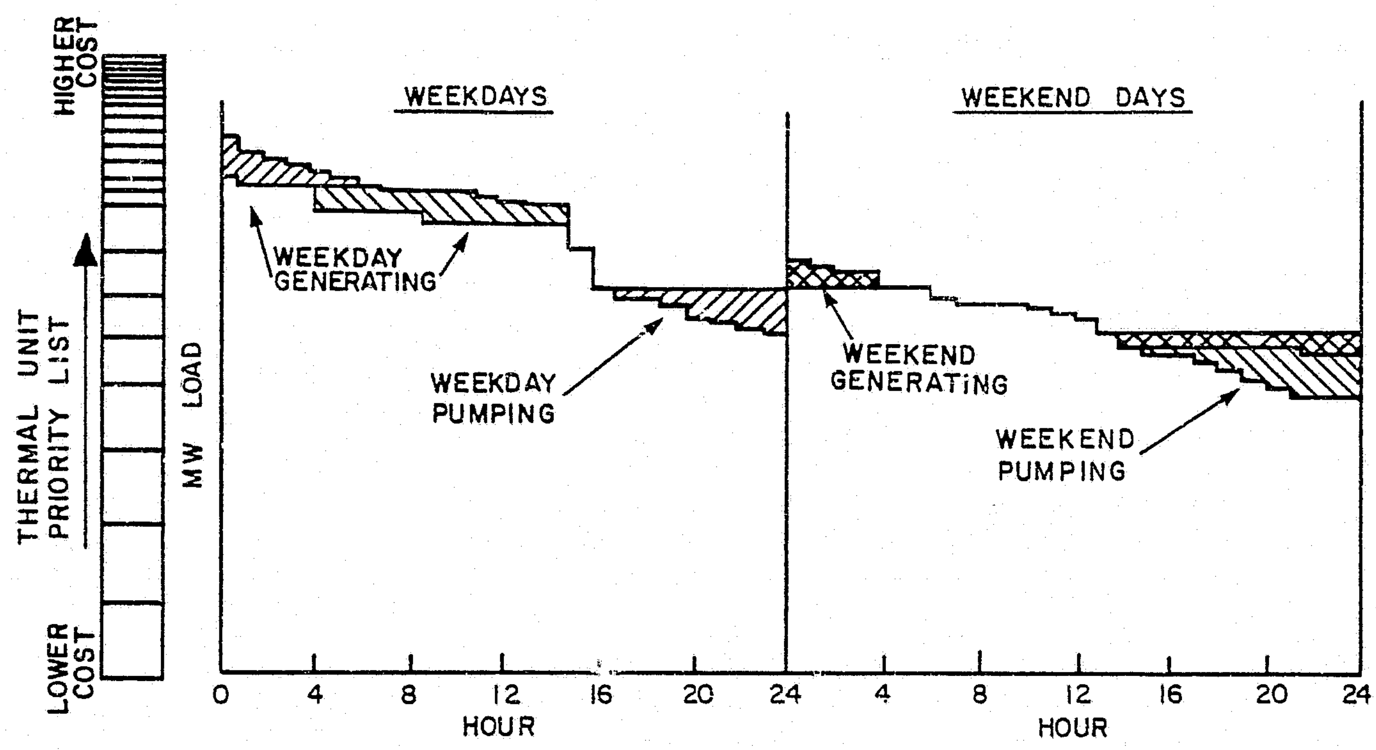


Figure 9-4. Example of Energy Storage Scheduling on a Weekly Basis

As shown in Figure 9-4, OGP's basic scheduling approach for energy storage devices is to do the following:

1. Start with the highest load, i.e., the load which is the costliest to serve during the week.

2. Schedule one megawatt-hour of generation.

3. During the lowest load in the day (if on a daily refill cycle) or week (if on a weekly refill cycle), schedule enough charging energy to replace the one megawatt-hour of generation plus the losses in the cycle. Thus, for every megawatt-hour of generation, there must be a correspondingly greater number of megawatt-hours of pumping.

4. The fuel cost savings provided by the megawatt-hours of generation are then compared with the increased cost of the megawatt-hours of pumping. The fuel and variable O&M costs of the storage device are included in the pumping costs. If the savings exceed the costs, the process is continued.

During the scheduling of the energy storage devices, one of two conditions will limit the amount of energy storage operation. The first is when the incremental savings balance the increased cost, causing additional operation to be no longer economically beneficial. The second occurs when the physical limits of the storage reservoir are reached. The storage reservoir conditions are being monitored while the iterative scheduling of the storage is in progress. The scheduling will not violate the minimum or maximum reservoir level of the unit anytime during the week.

5. Thermal Unit Commitment

After modifications for contracts, hydro, and energy storage operation have been made, the remaining loads must be served by the thermal units on the system. The cost characteristics of thermal generating units are modeled, using a single incremental heat rate. This yields a single incremental cost curve as illustrated in Figure 9-5. Specific unit operating costs are determined by the fuel input curve, fuel cost and variable O&M cost. In order to minimize the thermal generating unit operating expense of a power system, two fundamental objectives must be met: (1) the number of units committed each hour should be minimized, subject to the commitment policy and operating constraints of the power system, and (2) the generating units in each commitment, as determined for the first objective, should be dispatched on an equal incremental cost basis.

Since system production costs are extremely sensitive to variations in unit commitment, it is essential that the unit commitment policy of the power system be fully considered. In addition, most, if not all, production costing algorithms used in the electric utility industry dispatch generating units on an equal incremental cost basis. However, dispatching generating units on an equal incremental cost basis within a zone of constant commitment will minimize production costs only with respect to the units included in the commitment. If the zone commitment has not been minimized with regard to the commitment policy, the zone production cost will not be minimized.

Based on discussions with utility system planners and experience with large-scale production costing programs, three commitment conditions have been found to prevail. Night time periods generally have one commitment because the cycling of units during the night is avoided, if possible. Second, a generating unit committed to peaking service for a specified hour generally remains on line for at least four hours. Finally, commitment variations during weekends tend to be minimal.

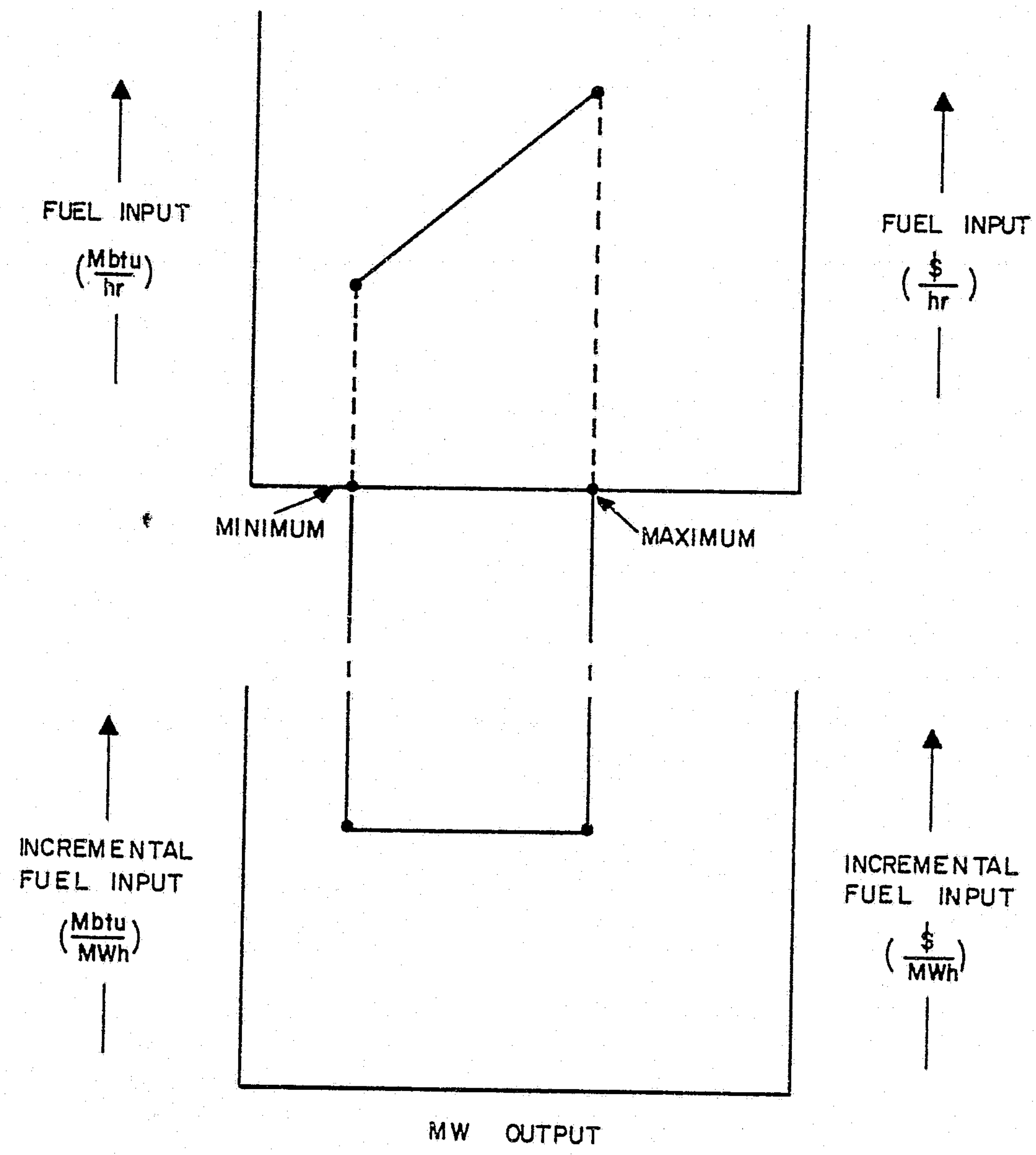


Figure 9-5. Example of Thermal Unit Cost Characteristics

Based on these three observations, OGP was developed to accommodate six zones. As shown in Figure 9-6, each weekday has four zones of constant commitment and, each weekend has two zones of constant commitment. The user can define the duration of these six zones. Typically for weekdays, there will be three four-hour zones during the day and a twelve-hour zone during the night, whereas for weekend days there will be two twelve-hour zones.

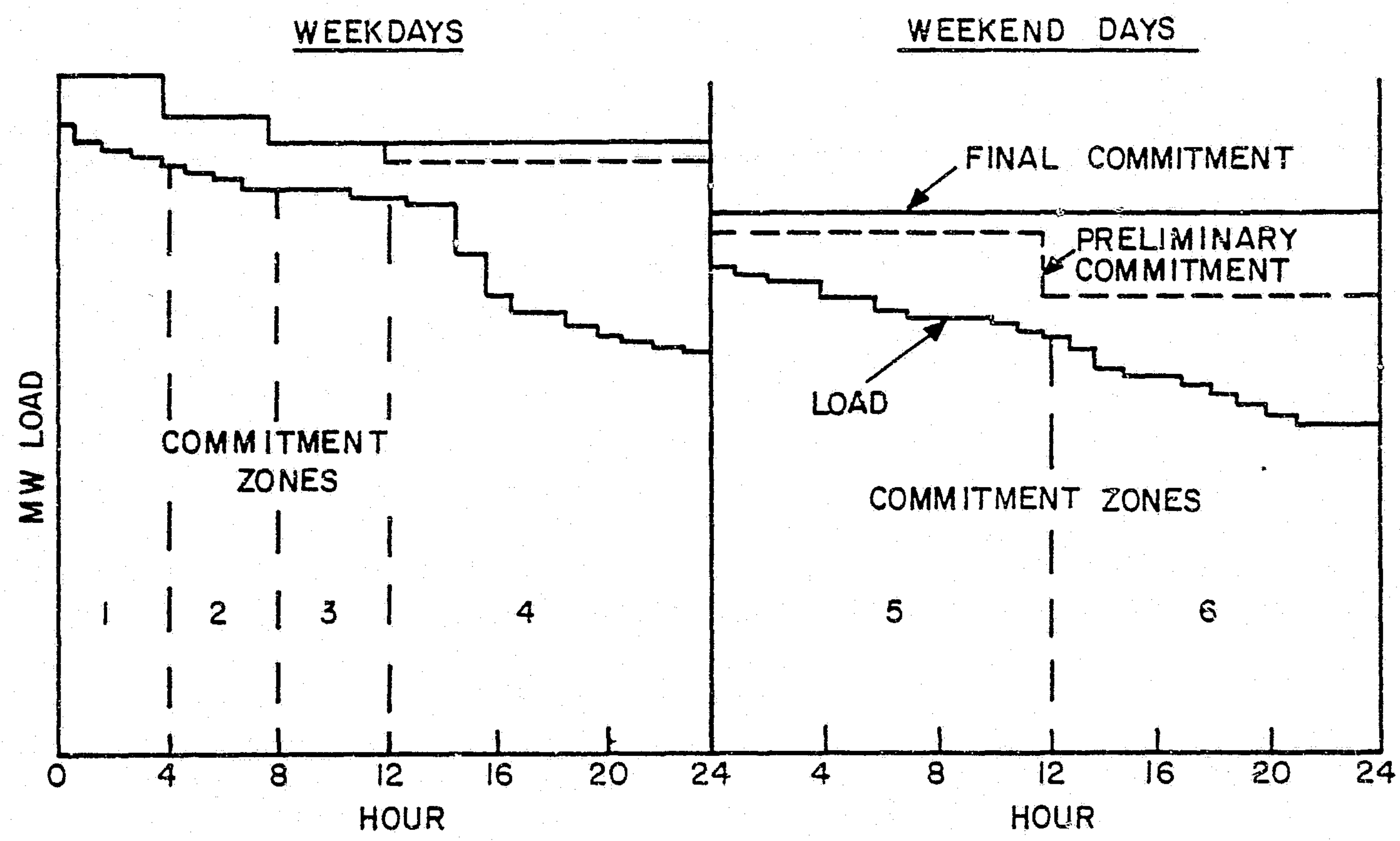


Figure 9-6. Example of the Thermal Unit Commitment Process

Unit commitment determines how many units will be on line each hour, and attempts to provide an adequate level of operating reliability, while at the same time, minimizing system operating costs. The reliability requirement is addressed by committing enough generation on line to meet the load plus a spinning reserve margin. This spinning reserve margin protects the system from units suddenly tripping off line or from tie lines opening. The economic aspect of the reliability requirement is addressed by committing units in the order of their full-load energy costs. For example, the least expensive units are committed first, and additional units are scheduled on line until enough generating capacity is available to meet the load and spinning reserve margin. Once generation has been scheduled to meet the load plus spinning reserve margin, the preliminary commitment is complete.

This commitment is preliminary because it requires specific generating units to be shut down in the middle of the night and turned on again the next day. During peak hours, some units are shut down on an hourly basis. Yet, as discussed earlier, the generating units may not have the ability to cycle as required by the preliminary commitment. The preliminary commitment is then reviewed to determine if any unit's cycling rules or capabilities have been violated. If there is a violation, the preliminary commitment will be increased in order to keep the unit on line during the problem hours. This observation of the minimum downtime rules for individual generating units allows the preliminary commitment to become the final commitment.

The user also has the option of basing the commitment order on both economics and minimum uptime rules. When this option is used, the Rule 1 units are committed first, then the Rule 2 units and finally, the Rule 3 units. Within each uptime rule, the commitment order is based on full-load fuel costs plus variable operation and maintenance costs.

6. Thermal Unit Dispatch

If a unit is committed, its output must be equal to or greater than its minimum loading level. When the final commitment has been established, all the units' minimum loads will be scheduled first. Typically, the sum of the minimums does not equal the load. The remaining load will be served by the units' incremental loading sections as shown in Figure 9-7.

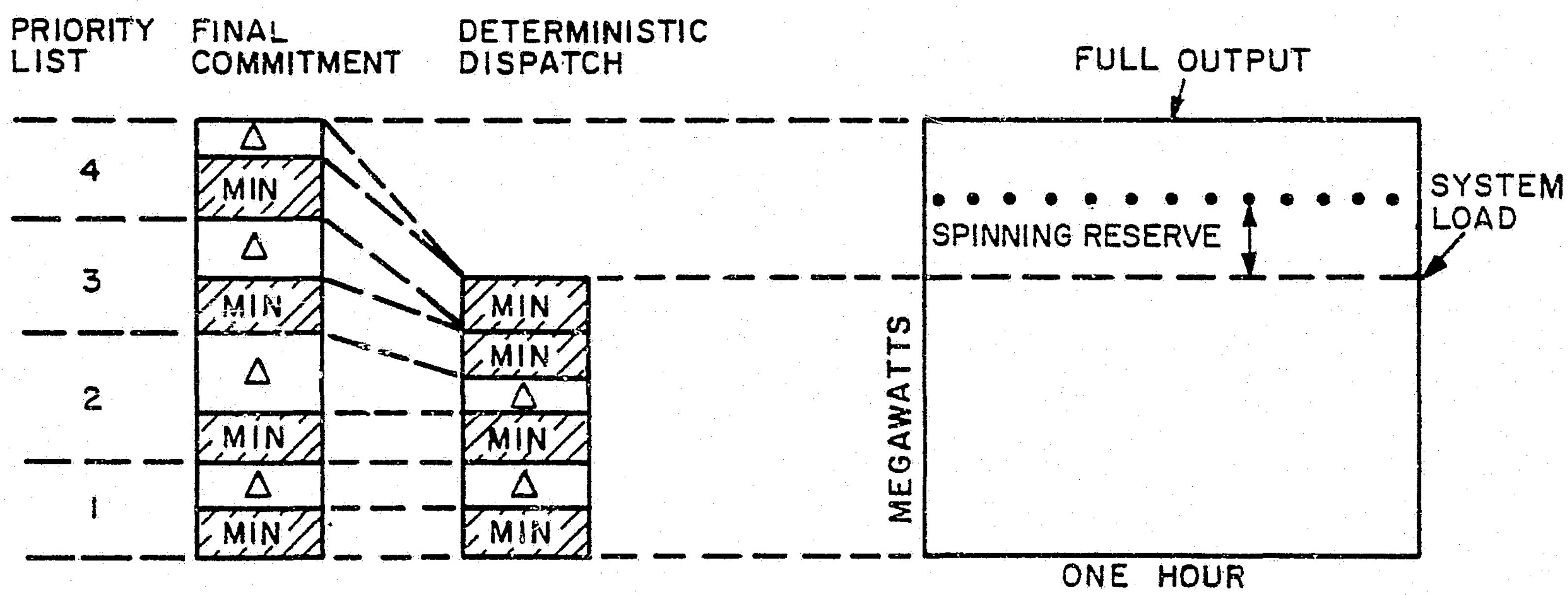


Figure 9-7. Example of Thermal Unit Dispatch

The dispatching function in a production costing program loads the incremental sections of the committed units in order to serve the demand at minimum system fuel cost. This dispatch technique is referred to as the equal incremental cost approach (or minimum incremental cost approach). The incremental loading sections are dispatched beginning with the least expensive unit. When enough incremental loading sections have been scheduled so the load is served, the remaining unloaded incremental sections will be the most expensive. Thus, the system spinning reserve margin is allocated to the generating units so system fuel costs are minimized.

At this point, loading levels on the individual generating units are established. The hourly energy disposition is scheduled, and the hourly production cost is determined for each unit.

The thermal dispatching function for the system utilizes the incremental heat rate curve, an additional piece of performance information available from the input-output curve. As shown in Figure 9-5, the incremental heat rate curve is a partial derivative of the input-output curve with respect to power output. As with the input-output curve, the incremental heat rate is transformed to an incremental fuel cost curve when it is multiplied by the fuel price.

The random forced outage option illustrated in Figure 9-8 is a technique for simulating the effects of forced outages on system operation. The program commits units and arranges them according to their incremental cost, beginning with the least expensive unit. The committed units are sequentially dispatched until each load has been met. However, as the units are dispatched, the technique recognizes that each unit will be out of service for a period of time proportional to its forced outage rate. During these outages, load is transferred to more expensive generating units. With full consideration of all possible combinations of forced outages in the system, via modified recursive convolution, the program then computes the expected dispatch for each generating unit.

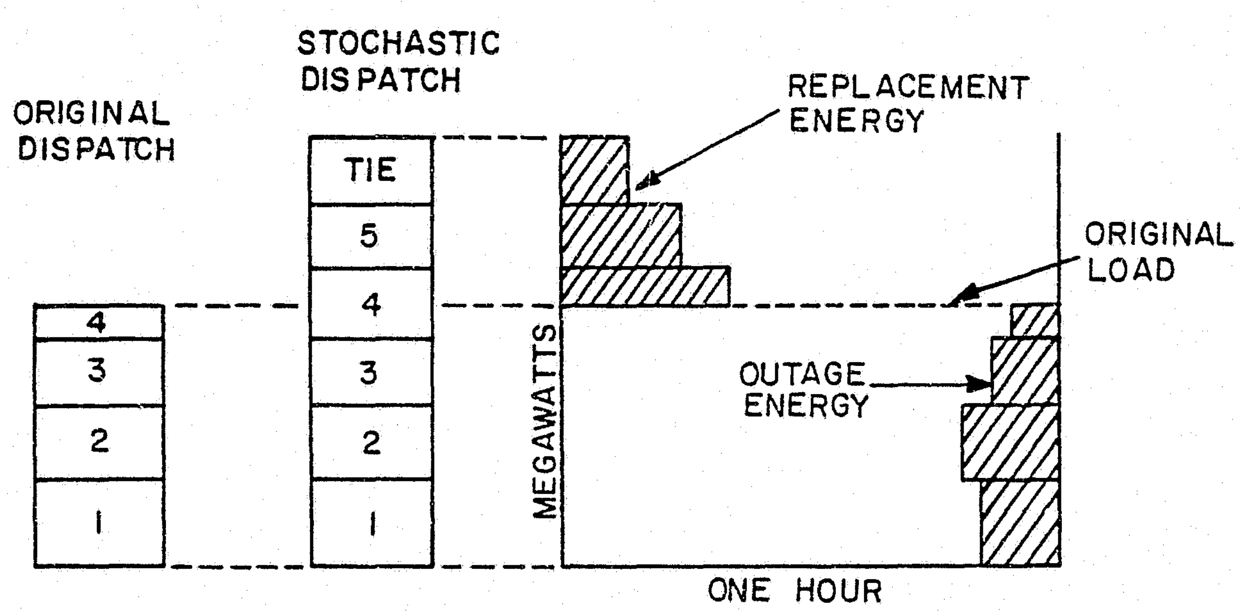


Figure 9-8. Example of the Effect of Random Forced Outages

Also considered in these calculations, with respect to the generating units that originally were not committed, are operating policy constraints, relative incremental costs and spinning reserve requirements. Once a combination of forced outages requires a unit not originally committed to be placed into service, the unit remains in service for the number of hours it is needed to overcome the capacity shortage. Likewise, when a combination of forced outages creates a spinning reserve violation, the program will bring additional units into service to provide a sufficient amount of additional capacity to remove the violation and maintain spinning reserve.

Another option for including forced outage rates in production costing is based on a deterministic technique in which the period of forced outage is added to planned maintenance. When systems are large enough to permit maintenance throughout the year, this procedure of extending each unit's maintenance in proportion to the unit's forced outage rate yields production cost results that are very close to those yielded by the stochastic option just described. Since the extended maintenance approach is a less complicated method of treating forced outages, it has the advantage of requiring less computer processing time. It is recommended that the user specify the application of the stochastic technique only in the final calculations for each year rather than for every decision trial.

Through the execution of the production simulation, all hourly fuel and O&M costs for the individual units, energy and demand charges from purchases and sales, and nuclear fuel inventory charges are accumulated and totaled on a monthly basis. The user has the option of specifying monthly or annual output for the optimum system only or for all trials evaluated. Other quantities which are also available unit by unit include maintenance months, energy output, hours on line, capacity factors, and $/MWh for the total of the fuel and O&M costs. Capacity factors are calculated on an annual basis when annual results are printed, and on a monthly basis when monthly output is obtained. Other output quantities, such as fuel consumption, are summarized by type of generation and fuel as well as on a system-wide basis. Energy from contracts, hydro, and energy storage devices is also shown.

All production simulation results may be stored on a separate file. The user can later access this file to perform additional calculations based on the production simulation results or to reformat the output.

7. Commitment and Dispatch with Fuel and/or Energy Limitations

The OGP-6A program has an option which allows the user to specify that all units within a thermal type or all units that burn a specific kind of fuel must operate in a limited mode. The monthly energy limitation may be input as MWh or as capacity factor. The fuel limitation is specified in physical units of fuel such as barrels of oil or tons of coal.

If a unit has both a fuel and energy restriction, a comparison of the two limits is made, based on the assumption that the unit is operating at full load. The more severe limit is used to commit and dispatch the unit.

A limited unit assigned to minimum uptime Rule 3 (refer to Table 5-1 for an explanation of each uptime rule) is tested to its limit before being committed to each commitment zone. If the fuel or energy limitation is not a factor, assuming full-load operation for commitment zone one, the unit is committed and dispatched in the usual manner. Before a unit is committed and dispatched to zone two, the monthly fuel or energy allotment for the unit is decreased by the amount of energy or fuel actually used in commitment zone one, rather than according to the assumption of full-load operation for commitment zone one. This process is repeated for subsequent commitment zones until there is insufficient fuel or energy for the unit to operate at full load for the commitment zone under consideration.

Units that have been assigned to uptime Rule 2 must have sufficient energy or fuel to operate at full load for all weekdays during the month, or they are excluded from further consideration. Those units which pass this test are committed and dispatched for the weekdays, as long as no fuel or energy limitations apply. The monthly fuel or energy limit is then reduced by the actual weekday usage. Next, these units are tested to determine if there is sufficient fuel or energy remaining to operate at full load during all weekend days in the month. If so, the units are committed and dispatched in the usual manner. If not, the units are prohibited from weekend operation.

Finally, units assigned to uptime Rule 1 must have sufficient energy or fuel to operate at full output for all days in the month. Units that do not satisfy this condition are prohibited from operating at all during the month.

If one assumes that weekday commitment zones contribute more to total production costs than weekend zones, this procedure will maximize the economic benefit of a limited unit. Furthermore, although assuming full-load operation for a unit may be a poor method of estimating its actual operation, there is an option which allows each month's unused fuel or energy to be carried forward for use the next month. Energy or fuel residuals may not be carried forward to the next year.

PRODUCTION COSTS

SUPPLEMENTARY INFORMATION

1. Commitment and Minimum Uptime Rules, 1973 GE Memorandum.

2. OGP-5 Modified Recursive Convolution Effects, D.L. Dees, 1978 GE Memorandum.

ENVIRONMENTAL IMPACTS

Section 9 discussed the program logic that simulates the operation of the generation system. As stated earlier, this simulation is done to minimize the total system cost of serving the load. In the environmental option of the OGP-6A version of the program, the factors listed in Table 10-1 may also be considered in the logic. In addition to calculating the environmental quantities in physical units, OGP also has the flexibility to commit and dispatch units to minimize operating costs, emissions, or a weighted sum of costs and emissions.

TABLE 10-1

Environmental Factors	Units
Heat rejection into the atmosphere	MBtu
Heat rejection into the cooling medium	MBtu
SO_2 emissions	Tons
NO_x emissions	Tons
CO emissions	Tons
Particulate emissions	Tons
Water consumption	Thousands of gallons

Through use of the fuel and/or energy limiting option for generating units in the OGP production simulation, the absolute level of all the quantities listed in Table 10-1 can also be controlled. This control can be accomplished by precalculating the hours of operation or the amount of fuel to be consumed based on the quantity in Table 10-1 being limited, and then inputting that value into the program.

Eight weighting coefficients to be applied to unit economics plus the seven factors listed in Table 10-1, can be input into the program. A unique commitment number will then be calculated for each unit in the system. This commitment number is the sum of the weighting coefficients times their corresponding quantities. The units are then committed on the basis of lowest commitment number, subject, as stated earlier, to their minimum uptime rules. Therefore, to achieve an accurate environmental commitment of units, the original emission factors should accurately predict the emissions at full load.

In the environmental dispatch logic, the same eight factors may be considered, but the incremental values are used rather than the full-load values. The incremental value is the slope of the line passing through the curve at the minimum and maximum rating of the unit. The dispatch logic is similar to the commitment logic. Thus a set of eight weighting coefficients is input into the program, and a unique incremental dispatch number is calculated for each unit. The units are then loaded to their maximum rating on the basis of lowest dispatch number.

In the areas of emission calculations, environmental commitment of units and environmental dispatch of units, the greatest accuracy will be obtained when the emission curve is approximated by a straight line which passes through the actual emission curve at the minimum and maximum rating of the unit as shown in Figure 10-1. The values input into the program are the slope and intercept of this straight line. They are determined using the following equations:

$$\text{SLOPE (lbs/MWh)} = \frac{(\text{lbs/hr})_{max} - (\text{lbs/hr})_{min}}{MW_{max} - MW_{min}}$$

$$\text{INTERCEPT (lbs/hr)} = (\text{lbs/hr})_{min} - (\text{SLOPE})(MW_{min})$$

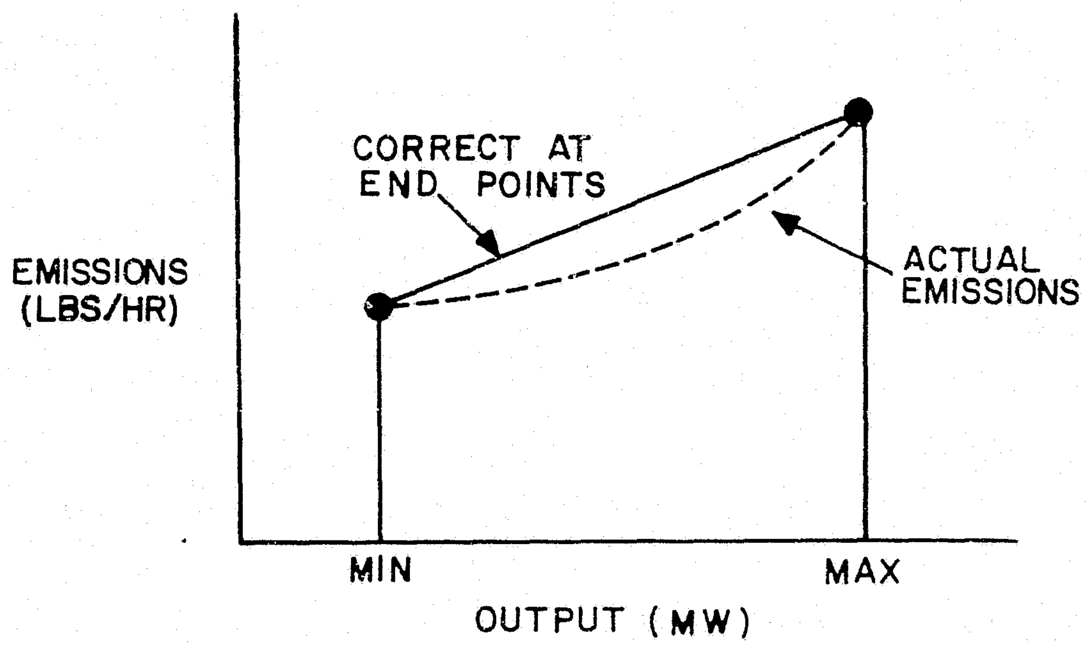


Figure 10-1. Unit Emissions Characteristics and Representation

Since a single step incremental representation of the units is used in OGP's dispatch logic, all of the units committed during a given hour except the "swing unit" will be operating either at their minimum or maximum rating. Therefore, it is more important to accurately predict the emissions at the end points rather than throughout the length of the curve. For a typical system, the one swing unit during each hour represents only a small part of the total system output, so an error in the emissions of this unit will cause only a slight effect on the total emissions of the system. For larger systems, the effect of the swing unit will be negligible. Therefore, only the end points of the emission curve, not the entire curve, are required to obtain a high degree of accuracy in the environmental output.

The user may assign individual generating units to plants, and subsequently may assign plants to regions within the total company or pool-wide area being studied. Thus, by judiciously assigning specific weighting coefficients, which are input by region, the operation of specific groups of generating units can be controlled. Regardless of whether the unit commitment and dispatch is being biased by the environmental factors, the user may also obtain summaries on fuel consumption and environmental emissions in physical units such as barrels of oil or tons of SO_2. These summaries are available by unit, plant, region, and/or fuel type.

For consistency, the user also can reflect the cost of various emission control equipment via other inputs, such as O&M and plant cost data.

ENVIRONMENTAL IMPACTS

SUPPLEMENTARY INFORMATION

1. Fossil Fuel Emissions, G.A. Jordan, 1975 GE Memorandum.

2. Calculation of Emission Factors, G.A. Jordan and R.B. Roginska, 1975 GE Memorandum.

3. Environmental Input Data, G.A. Jordan, 1975 GE Memorandum.

4. Costs of Meeting Clean Air Requirements, D.R. Vierath, W.W. Walkley, September, 1976 Power Engineering.

INVESTMENT COSTS

The investment cost routine computes the total capitalized investment costs at the time of start-up or initial commercial operation for units added to the system. Then, based on a levelized fixed charge rate (FCR), the routine calculates the annual investment cost in terms of carrying charges on investment. Installation costs will vary according to unit size via use of the "D" factor, company or area location, percentage ownership, type of unit, and, because of inflation, year of installation. The levelized FCR used for each unit addition may also vary, depending on the type of unit and company ownership.

The annual capital investment cost portion of the total system costs for each generating unit is determined with the following equation:

$$\text{Capital, \$/yr} = (\text{\$/kW})(\text{kW})(\text{FCR})(\text{\% Ownership})(\text{\% of Year in Service})$$

This equation represents the revenue requirements approach for determining the impact of capital expenditures on the total system costs.

Also included with the investment costs are the demand charges associated with the contracts specified to OGP. These charges are calculated for each contract with the following equation:

$$\text{Demand Charges, \$/yr} = \sum_{i=1}^{12} (\text{kW rating in month } i)(\text{\$/kW/yr})/12$$

At this point, the following costs are available on an annual basis: fuel (both variable and inventory), O&M (both fixed and variable), and contracts (both demand and energy). The capital component is added to these costs. Then the cumulative present worth of all revenue requirements is obtained directly to enable alternative generation expansion plans to be compared.

OPTIMIZATION RESULTS

This section includes a discussion of the development of an optimum generation expansion plan regarding the mixture of generation types. It also provides a more detailed description of the optimization methods used in OGP. In this section, the normal connotation of the term "optimum" is used (i.e., an optimum plan has the lowest total cumulative present worth of the sum of annual charges on investment, fuel, and operation and maintenance costs during the expansion period). It should be noted that other objective and subjective criteria also can be used to reach generation expansion decisions. For example, one of those alternative yardsticks could focus on environmental effects. Others could disregard any impacts of the expansion plan on the system operation and costs that may occur after the period under study. OGP addresses non-economic aspects, and can be used to ensure that the future has not been mortgaged solely to optimize a single addition.

The cost characteristics of the generating units on a utility system make it possible to cost effectively serve a spectrum of loads, ranging from base loads, which have an annual duration of 100 percent, to peak loads, which have a duration approaching zero. There are infinite gradations between these two basic types of loads which, for convenience, are referred to as mid-range loads. Each MW of base load requires the generation of a maximum amount of energy; thus fuel cost per MWh is of major importance to the total system costs. Conversely, peak load MW's require minimum amounts of energy, which means fuel cost is of minimum importance.

In contrast to fuel cost, the capital cost of generating units affects the total system cost equally, whether the units are used for base, mid-range or peaking loads. This contrast provides the opportunity for OGP to minimize the system's total sum of fixed charges and fuel cost if types of generating units with varying capital costs and fuel costs per MWh can be selected to meet the requirements of the load, resulting in a mixed pattern generation system. In recent years, types of generation have been developed which make mixed patterns possible as well as economical on a total system cost basis. Thus the OGP optimization process essentially is one of determining the lowest cost mix of future units.

The OGP program normally is not used to select optimum unit sizes. From the allowable sizes of each of the alternate types of units available for selection in a given year, the program, based on the unit size guidelines input for each kind of generation, chooses the size of each type of unit to be considered in the optimization that year. If the user wishes to more closely investigate unit size, alternate sizes may be considered for selection based on economics by appropriate use of the six types of new thermal generation which may be represented. For example, one type of base load unit could be specified as 600 MW and another as 750 MW, thus allowing the OGP program to conduct a head-to-head economic comparison of the two sizes.

For the sake of simplicity, the first situation that will be used to illustrate the OGP optimization process is one in which conditions are fixed. This means there is no inflation of fuel or capital costs; nuclear fuel costs do not change as core equilibrium is approached; and there is no immature period of planned or forced unit outage rates. Under these conditions the OGP program will directly select, each year, the type of generation that results in the lowest system cost, and this will be the optimum thirty-year expansion.

To understand why this selection yields the optimum thirty-year expansion, one must first consider the cost trade-offs involved in selecting between the extremes of a base load or peak load generating unit to satisfy the load growth requirement of a system in a specified year. The amount of new generation needed is determined by a reliability calculation. This calculation takes into consideration unit size as well as forced and planned outage rates. Since the increment of new load has a base component as well as peaking and mid-range components, and since it is known that some kind of mixed pattern will be the most economical alternative during the thirty-year study period, it is not obvious which type of generation should be added to the system for the specified year.

If a base load unit is added, its lower production cost will make it economical to operate, perhaps even to the unit's maximum availability. The amount of low-cost energy generated will be much more than that required by the new load increment and, therefore, will result in a significant decrease in the system's average fuel cost per MWh compared to the previous year. On the other hand, if peaking units rather than base load units are added, the higher production cost of the peaking units will make it desirable to run them as little as possible and perhaps not at all, if the total amount of peaking capacity on the system is less than the installed reserve. However, the addition of peaking units will result in an increase in the system's average fuel cost per MWh compared to the previous year. This increase is due to the added increment of load energy that will have to be supplied by the existing types of generation at the higher production cost end of the spectrum.

The amount of decrease or increase in the system's average fuel cost obtained with the addition of either type of generation in a given year depends on the mix of units in the existing system. For example, if, in the preceding year, the system was composed entirely of base load units, less of a fuel cost benefit will accrue from the addition of another base load unit, and less of a fuel cost penalty will result from added peaking capacity.

Balanced with these shifting system fuel costs is the difference in capital costs of the base load and peaking units, which may be assumed to be fixed, i.e., independent of system composition. The net effect of the fixed and variable cost components may favor base load or peaking generation, depending on the composition of the system before the addition is made. Figure 12-1 illustrates this concept by showing how the combination of capital cost difference and system average fuel cost determines the economic choice of unit additions. In reality, this unit-selecting mechanism is a kind of economic control system equipped with negative feedback to prevent instability. For example, assume that point "A" represents the situation in the first year of a study. Since it is to the right of the dividing line, the decision that year would be to add base load generation. However, as a result of that decision, the system average fuel cost will have moved to the left in the following year. More than one year of base load additions may be required, but eventually the system average cost will move across the dividing line to point "B." At that point, the decision will be changed, and peaking

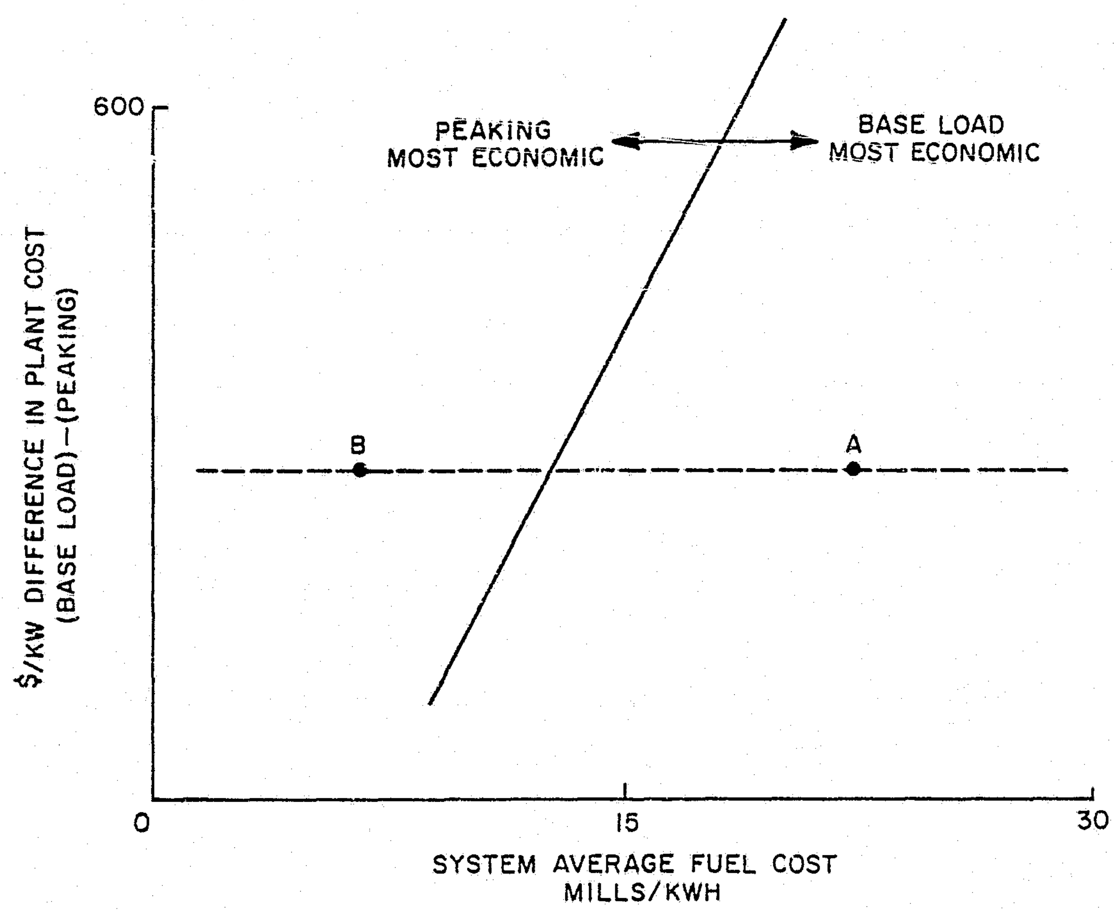


Figure 12-1. The Mechanism of Economic Choice

generation will be added to the system. Each year peaking generation is added, the system fuel cost moves toward the right, until the dividing line is again crossed. The system average fuel cost is now high enough so the next decision to be made will be to add base load generation again.

This simplified example illustrates an aspect of year-by-year optimization, but the OGP program does not calculate the economic merit of each alternative in this fashion. It rigorously performs a complete simulation each year for each type of generation to be tested. The decision regarding the type of generation to be added is based on the lowest total system cost rather than on the approximation a screening curve analysis would yield.

Although the sum of a series of minimal annual costs should produce a minimum total for the expansion, planners must still contend with the question of whether a decision in an early year might compromise the future design in such a way as to force unnecessarily high costs in the later years of the expansion. In effect, planners must answer the question, "In 1995, would we wish we had done something differently in 1985?"

Each year, enough new capacity is added to a system to accommodate the new load plus reserve. Thus as long as the units are properly maintained, their contribution to the system's ability to reliably serve the load never diminishes. The decision to add a particular type of generating unit one year does not mean planners are committed to add that same type of unit in future years. Furthermore, there is relatively little under- or overbuilding of the system. The requirement for continuous annual additions to the generating system means that there is also a continuous opportunity to adjust the mix of unit types without ever departing significantly from the absolute optimum in any particular year. Year-by-year optimization produces an optimum cumulative expansion, provided future changes in costs or outage rates do not occur. This statement has been demonstrated by numerous unsuccessful attempts to manually devise a less expensive expansion than that produced by the OGP program.

Under conditions where assumptions regarding future changes in outage rates or costs, such as escalating fuel prices, have been made, a similar situation of not departing significantly from the optimum mix of units in any particular year will exist if OGP's "look-ahead" feature is utilized in the optimization. The mechanisms by which levelized system costs and mature outage rates are utilized in yearly decisions have been described earlier in Section 7. Figure 12-2 is a graphic description of the effects of the "look-ahead" process on yearly system costs. Experience with the OGP program indicates that, where inflation and immature forced outage rates exist, the "look-ahead" feature produces a lower present worth of expansion costs. This result is obtained by permitting somewhat higher system costs in the early expansion years. The resultant savings in later years are more than enough to compensate for these higher system costs in the early years.

Figure 12-2 plots the cost differences between a "non-look-ahead" and a "look-ahead" expansion case. Note the annual deficits for the "look-ahead" case for approximately the first five years, followed by a substantial savings, which was anticipated by the "look-ahead" decision logic. Of course, as time progresses, the "look-ahead" case also becomes less costly in terms of cumulative present worth.

In summary, in the absence of changing cost and outage parameters, the inherent nature of the economic framework of the generation system makes year-by-year optimization feasible and correct. However, with parameters that change with time, the annual decision regarding the type of generation to be added should be biased by levelized fuel costs and mature outage rates in order to anticipate these changing parameters and produce an optimum expansion.

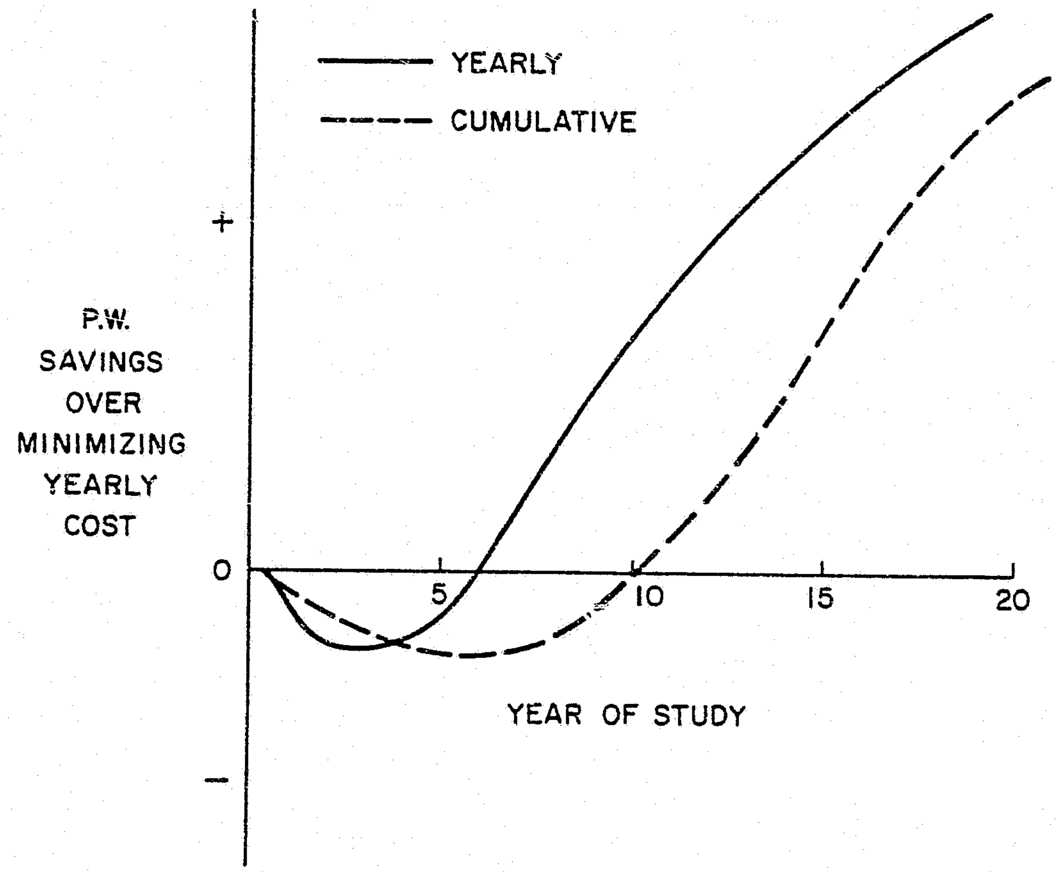


Figure 12-2. Example of the Effects of a Ten-Year "Look-Ahead" Period

EXPANSION OUTPUTS

Output options have been designed and included in OGP to provide the user with flexibility in the level of detail and volume of documentation received. Complete batch output reports as well as summary outputs are available. In addition to being included in the bulk output, the summary outputs may be obtained at the user's time-sharing terminal. These remote summaries usually contain sufficient information to enable the user to make decisions and/or proceed to run the next case, when execution of the next case depends on the results of the previous one. Most of the OGP output can also be written to a file and stored for future analysis. This enables the user to reformat the output to meet specific needs, plot particular results, or compare or combine the results of several OGP runs.

The output available from the OGP program includes the following information:

1. Listing of the input data.

2. Standard tables, as defined by the user, for various unit characteristics.

3. Listing of the unit types and sizes available for optimization and their characteristics.

4. Listing of the Load Model for the study period.

5. Listing of the generating units on the system and their characteristics.

6. Year-by-year summary of the firm contracts input by the user.

7. Production simulation summaries, listing all of the generating units of the system with their energy output, fuel and O&M costs, fuel consumption, and environmental emissions. These summaries can be obtained on a monthly or annual basis, for all the decision passes or just the optimum system.

8. Summary of all of the expansion alternatives, with their associated costs and reliability measures, evaluated during the optimization.

9. Summaries of the final system expansion through time and the associated costs.

The "bottom line" result from the OGP program is the annual summary of additions. Figures 13-1 and 13-2 present the annual capacity additions by type of generating plant (e.g., nuclear, coal, gas turbine, etc.). As shown in Figure 13-1, in the year 1995, the OGP program added in this sample run one 1300 MW nuclear unit and one 300 MW block of gas turbines as well as 600 MW of pumped storage hydro. The generating units indicated with an asterisk (*) are those units which have been previously committed for service. For example, in 1986, a 500 MW compressed air energy storage unit was committed for service.

At the bottom of the Annual Capacity Additions by Type report, a summary is provided. The first row is the sum of megawatt additions (MW ADD) during the period. The second row is the capacity in service in 2014 (end of the study). The third row is the MW additions that were added automatically (AUTO) by the OGP program (total additions less committed additions).

Other summaries are also provided by the OGP program. Figure 13-3 presents the load, capacity, reserve, LOLP and cost summary. Figure 13-4 presents a more detailed cost summary both on a yearly basis and also on a cumulative present worth basis.

OGP makes available more detailed yearly and monthly results as illustrated in Figure 13-5. This is the annual production cost summary and shows the annual history of each generating unit's maintenance period, hours on line, capacity factor, fuel cost, etc. At the bottom of the report, the energy output, capacity factor, and fuel cost results are summarized by type of generating plant (e.g., nuclear, coal, gas turbine, etc.).

Annual fuel consumption and environmental reports are shown in Figure 13-6.

A complete sample of the OGP output is included in the OGP Program User's Manual.

OGP's basic structure was designed to maintain a consistent level of detail among three items: the user input, program logic and output format. The level of detail in the program and the computer processing time are intertwined. Adjuncts of these two factors are, of course, data gathering and the results of the analysis effort. In addition, as the study progresses into the future, the inherent accuracy and confidence represented by the input data diminishes as a result of greater uncertainty in input assumptions.

The references included at the end of this section address some of the uses for which OGP was written, namely as a long-range generation expansion system planning tool using conventional engineering economics analysis and revenue requirements. Sections 14, 15, and 16 describe the extension of OGP via the Financial Simulation Program (FSP) into the realm of financial analysis.

GENERAL ELECTRIC COMPANY
OGP-6A GENERATION PLANNING PROGRAM V6.10 - SUMMARY OUTPUT

OGP ELECTRIC SYSTEM
USERS MANUAL EXAMPLE
JOB NUMBER 2526NT 01/13/82 16.886

GENERATION SYSTEM

	NUCL.	F-COAL	G.T.	STAG	C-COAL	F-OIL	TYPES	
TYPE	1	2	3	4	5	6	7-10	
OPTMZING	1991	1990	1985	1987	0	0	***	
PCT TRIM	25	25	0	25	25	25		
1984 MW	9805	5449	1752	1000	300	4424	1434	SUM= 24164

YR	Y E A R L Y		M W		A D D I T I	O N S		TOTAL CAPAB. + TIES
**	*******	*******	*******	*******	*******	*******	*****	******
85			2X 300					25684
86			2X 300				500*	26784
87							1200	27809
88							1200	28878
89							1200	30078
90				4X 400				31563
91	1X1300		2X 300	1X 400				33748
92				4X 400				35248
93	1X1300		1X 300	1X 400			300	37402
94	1X1300		2X 300	2X 400				39810
95	1X1300		1X 300				600	41847
96	1X1300	1X1300	2X 300					44727
97		1X1300	1X 300				600	46777
98		2X1300	2X 300					49661
99	1X1300	1X1300	2X 300					52535
0		2X1300	2X 300					55501
1		1X1300	1X 300				900	57876
2		2X1300	2X 300				600	61361
3	2X1300	1X1300	2X 300					65221
4	1X1300	1X1300	1X 300				900	68521
5		2X1300	2X 300				600	72112
6	1X1300	2X1300					1200	76076
7	1X1300	2X1300	1X 300				600	80349
8	2X1300	1X1300	2X 300				1200	84773
9		3X1300	3X 300	1X 400			300	89374
10	1X1300	2X1300	2X 300				900	93814
11	1X1300	2X1300	2X 300				600	98814
12	3X1300	2X1300	4X 300				300	104779
13		3X1300	2X 300				900	109969
14	2X1300	2X1300	2X 300				600	115819

MW ADD	26000	42900	13500	5200	0	0	15200	SUM= 102800
MW RET	-2845	-3724	-702	0	0	-4424	-500	SUM= -12195
2014	32960	44625	14550	6200	300	0	16134	SUM= 114769
PCT TOT	28.7	38.9	12.7	5.4	0.3	0.	14.1	SUM=100 PCT
AUTO	26000	42900	13500	5200	0	0	14700	SUM= 102300
PCT TOT	25.4	41.9	13.2	5.1	0.	0.	14.4	SUM=100 PCT

Figure 13-1. Annual Capacity Additions by Type

GENERAL ELECTRIC COMPANY

OGP-6A GENERATION PLANNING PROGRAM V6.10 - SUMMARY OUTPUT

OGP ELECTRIC SYSTEM
USERS MANUAL EXAMPLE
JOB NUMBER 2526NT 01/13/82 16.886

GENERATION SYSTEM

	THERMAL	HYDRO	PSH	BATRES	COMPAR	
TYPE	1-6	7	8	9	10	
OPTMZING		***	1987	0	0	
PCT TRIM			0	0	0	
1984 MW	22730	310	624	500	0	SUM= 24164

YR	YEARLY	MW	ADDITIONS			TOTAL CAPAB. +TIES	LOAD MW	LOLP D/Y
**	******	******	******	******	******	******	*****	*******
85	600					25684	19429	0.4384
86	600				500*	26784	20498	0.3606
87			4X 300			27809	21625	0.3904
88			4X 300			28878	22814	0.4489
89			4X 300			30078	24069	0.4720
90	1600					31563	25393	0.4962
91	2300					33748	26790	0.4363
92	1600					35248	28263	0.4829
93	2000		1X 300			37402	29818	0.4334
94	2700					39810	31458	0.3611
95	1600		2X 300			41847	33188	0.4040
96	3200					44727	35013	0.3728
97	1600		2X 300			46777	36939	0.4323
98	3200					49661	38970	0.4184
99	3200					52535	41114	0.4404
0	3200					55501	43375	0.4533
1	1600		3X 300			57876	45761	0.4739
2	3200		2X 300			61361	48278	0.3987
3	4500					65221	50933	0.4010
4	2900		3X 300			68521	53734	0.4600
5	3200		2X 300			72112	56690	0.4085
6	3900		4X 300			76076	59807	0.4590
7	4200		2X 300			80349	63097	0.4881
8	4500		4X 300			84773	66567	0.4444
9	5200		1X 300			89374	70228	0.4385
10	4500		3X 300			93814	74091	0.4589
11	4500		2X 300			98814	78166	0.4862
12	7700		1X 300			104779	82465	0.4414
13	4500		3X 300			109969	87001	0.4836
14	5800		2X 300			115819	91786	0.4926

MW ADD	87600	0	14700	0	500	SUM= 102800
MW RET	-11695	0	0	-500	0	SUM= -12195
******	******	******	******	******	******	***********
2014	98635	310	15324	0	500	SUM= 114769
PCT TOT	85.9	0.3	13.4	0.	0.4	SUM= 100 PCT
AUTO	87600		14700	0	0	SUM= 102300
PCT TOT	85.6		14.4	0.	0.	SUM= 100 PCT

Figure 13-2. Annual Capacity Additions by Type

GENERAL ELECTRIC COMPANY
OGP-6A GENERATION PLANNING PROGRAM V6.10 - SUMMARY OUTPUT
****

OGP ELECTRIC SYSTEM
USERS MANUAL EXAMPLE
JOB NUMBER 2526NT 01/13/82 16.886
****

		TOTAL CAPABILITY (INCLUDING TIES)			LOSS OF LOAD		COST IN MILLION $	
		YEAR	TIME OF	PCT.	PROBABILITY		YEARLY	CUM. PW
YEAR	LOAD	END	PEAK	RES.	D/Y	H/Y	COST	TOTAL
****	*****	*****	*****	****	******	******	*******	*******
1985	19429	25724	25684	32.2	0.438	0.55	2189.9	1123.8
1986	20498	26824	26784	30.7	0.361	0.43	2547.6	2312.3
1987	21625	27849	27809	28.6	0.390	0.46	2974.7	3573.9
1988	22814	28918	28878	26.6	0.449	0.52	3512.9	4928.2
1989	24069	30118	30078	25.0	0.472	0.53	4134.1	6377.2
1990	25393	31603	31563	24.3	0.496	0.55	4870.8	7929.2
1991	26790	33788	33748	26.0	0.436	0.48	5899.5	9638.1
1992	28263	35288	35248	24.7	0.483	0.53	6799.6	11428.6
1993	29818	37442	37402	25.4	0.433	0.47	7997.6	13343.2
1994	31458	39850	39810	26.6	0.361	0.39	9383.1	15385.2
1995	33188	41887	41847	26.1	0.404	0.44	10818.0	17525.5
1996	35013	44767	44727	27.7	0.373	0.41	12578.6	19787.9
1997	36939	46817	46777	26.6	0.432	0.47	14189.4	22107.9
1998	38970	49701	49661	27.4	0.418	0.45	16226.1	24519.8
1999	41114	52575	52535	27.8	0.440	0.48	18681.9	27044.4
2000	43375	55541	55501	28.0	0.453	0.49	21186.6	29647.0
2001	45761	57916	57876	26.5	0.474	0.51	23717.7	32295.8
2002	48278	61401	61361	27.1	0.399	0.42	26968.0	35033.7
2003	50933	65261	65221	28.1	0.401	0.43	31167.7	37910.4
2004	53734	68561	68521	27.5	0.460	0.49	35230.3	40866.4
2005	56690	72152	72112	27.2	0.409	0.43	39196.2	43856.2
2006	59807	76116	76076	27.2	0.459	0.48	44550.5	46945.5
2007	63097	80389	80349	27.3	0.488	0.51	50365.6	50120.5
2008	66567	84813	84773	27.3	0.444	0.46	57340.8	53406.6
2009	70228	89414	89374	27.3	0.439	0.46	64109.6	56746.7
2010	74091	93854	93814	26.6	0.459	0.47	72605.2	60185.4
2011	78166	98854	98814	26.4	0.486	0.50	81304.2	63686.1
2012	82465	104819	104779	27.1	0.441	0.45	94524.7	67386.1
2013	87001	110009	109969	26.4	0.484	0.50	104423.0	71101.9
2014	91786	115859	115819	26.2	0.493	0.50	117168.8	74892.2

Figure 13-3. Summary of Load, Capacity, Reserve, LOLP, and Cost

OGP ELECTRIC SYSTEM 01/13/82 16.886
USERS MANUAL EXAMPLE 2526NT

YEAR	POOL PEAK (MW)	TOTAL ENERGY (GWH)	LOAD FACTOR	YEARLY COSTS (MILLION $) INVEST.	FUEL	O+M	NUC INV	TOTAL	YEARLY COSTS ($/MWH) INV.	FUEL	O+M	N.I.	TOTAL
****	******	*********	*******	*******	*******	*******	*******	********	******	******	******	******	*******
1985	19429.	102120.0	60.00	46.0	1776.7	281.3	85.8	2189.9	0.5	17.4	2.8	0.8	21.4
1986	20498.	107735.8	60.00	111.4	2044.8	299.9	91.4	2547.6	1.0	19.0	2.8	0.8	23.6
1987	21625.	113662.0	60.00	209.8	2352.6	315.0	97.4	2974.7	1.8	20.7	2.8	0.9	26.2
1988	22814.	120241.2	60.00	313.5	2761.5	334.2	103.7	3512.9	2.6	23.0	2.8	0.9	29.2
1989	24069.	126508.4	60.00	423.0	3240.7	360.1	110.4	4134.1	3.3	25.6	2.8	0.9	32.7
1990	25393.	133465.5	60.00	589.6	3768.3	395.3	117.6	4870.8	4.4	28.2	3.0	0.9	36.5
1991	26790.	140807.1	60.00	1111.8	4202.5	443.3	141.9	5899.5	7.9	29.8	3.1	1.0	41.9
1992	28263.	148957.2	60.00	1294.6	4868.1	485.8	151.1	6799.6	8.7	32.7	3.3	1.0	45.6
1993	29818.	156721.9	60.00	1901.6	5375.6	540.7	179.7	7997.6	12.1	34.3	3.5	1.1	51.0
1994	31458.	165341.6	60.00	2579.6	5991.3	600.7	211.5	9383.1	15.6	36.2	3.6	1.3	56.7
1995	33188.	174433.9	60.00	3249.9	6656.2	665.4	246.6	10818.0	18.6	38.2	3.8	1.4	62.0
1996	35013.	184533.7	60.00	4294.5	7256.8	741.9	285.4	12578.6	23.3	39.3	4.0	1.5	68.2
1997	36939.	194150.6	60.00	4815.8	8261.4	808.3	303.9	14189.4	24.8	42.6	4.2	1.6	73.1
1998	38970.	204828.8	60.00	5742.2	9275.4	884.8	323.7	16226.1	28.0	45.3	4.3	1.6	79.2
1999	41114.	216094.4	60.00	6996.8	10332.7	980.2	372.2	18681.9	32.4	47.8	4.5	1.7	86.5
2000	43375.	228603.6	60.00	8036.8	11675.6	1077.8	396.4	21186.6	35.2	51.1	4.7	1.7	92.7
2001	45761.	240517.8	60.00	8743.2	13380.7	1171.7	422.2	23717.7	36.4	55.6	4.9	1.8	98.6
2002	48278.	253746.9	60.00	10017.1	15217.1	1284.3	449.6	26968.0	39.5	60.0	5.1	1.8	106.3
2003	50933.	267703.7	60.00	12566.8	16611.4	1440.9	549.5	31167.7	46.9	62.1	5.4	2.1	116.4
2004	53734.	283201.0	60.00	14416.7	18590.2	1600.6	622.9	35230.3	50.9	65.6	5.7	2.2	124.4
2005	56690.	297961.6	60.00	15932.2	20843.9	1756.7	663.4	39196.2	53.5	70.0	5.9	2.2	131.5
2006	59807.	314347.0	60.00	18754.1	23092.7	1954.5	749.2	44550.5	59.7	73.5	6.2	2.4	141.7
2007	63097.	331773.3	60.02	21643.7	25701.9	2176.6	843.4	50365.6	65.2	77.5	6.6	2.5	151.8
2008	66567.	351011.2	60.03	25413.0	28512.1	2420.6	995.1	57340.8	72.4	81.2	6.9	2.8	163.4
2009	70228.	369230.7	60.02	28221.7	32161.6	2666.7	1059.8	64109.8	76.4	87.1	7.2	2.9	173.6
2010	74091.	389548.7	60.02	31799.4	36728.3	2934.5	1143.1	72605.2	81.6	94.3	7.5	2.9	186.4
2011	78166.	410798.6	59.99	35512.1	41256.3	3259.8	1275.9	81304.2	86.4	100.4	7.9	3.1	197.9
2012	82465.	434716.3	60.01	42803.2	46629.6	3636.5	1455.4	94524.7	98.5	107.3	8.4	3.3	217.4
2013	87001.	457363.0	60.01	46351.0	52520.3	4001.7	1550.0	104423.0	101.3	114.8	8.7	3.4	228.3
2014	91786.	482501.3	60.01	52693.9	58206.5	4476.3	1792.2	117168.8	109.2	120.6	9.3	3.7	242.8

CUMULATIVE PRESENT WORTH (MILLION $)

YEAR	INVEST.	FUEL	O+M	NUC INV	TOTAL
****	*******	*******	*******	*******	********
1985	23.6	911.8	144.4	44.1	1123.8
1986	75.6	1865.7	284.3	86.7	2312.3
1987	164.6	2863.4	417.9	128.0	3573.9
1988	285.4	3928.1	546.7	168.0	4928.2
1989	433.7	5063.9	672.9	206.7	6377.2
1990	621.6	6264.6	798.9	244.1	7929.2
1991	943.6	7482.0	927.3	285.2	9638.1
1992	1284.5	8763.9	1055.2	325.0	11428.6
1993	1739.7	10050.8	1184.6	368.1	13343.2
1994	2301.1	11354.7	1315.4	414.1	15385.2
1995	2944.1	12671.5	1447.0	462.9	17525.5
1996	3716.5	13976.7	1580.4	514.2	19787.9
1997	4503.9	15327.5	1712.6	563.9	22107.9
1998	5357.4	16706.3	1844.1	612.0	24519.8
1999	6302.9	18102.5	1976.6	662.3	27044.4
2000	7290.2	19536.8	2109.0	711.0	29647.0

Figure 13-4. Detailed Summary of Costs

GENERAL ELECTRIC COMPANY, EUSED GENERATION PLANNING PROGRAM OGP-6A V6.10 PAGE 22

OGP ELECTRIC SYSTEM 01/13/82 16.886
USERS MANUAL EXAMPLE 2526NT

OPTIMUM

STAG

1990 YEARLY PRODUCTION COST SUMMARY
COSTS IN THOUSANDS OF DOLLARS

TERRITORY PEAK 25393. MW THERMAL PEAK 19950. MW
SPINNING RESERVE 1200. MW

UNIT ID	STATION NAME	CO. IDENT.	UNIT TYPE	FUEL TYPE	RATING MW	MAINTENANCE PTRN.	MONTHS	MIN. UP RULE	ENERGY OUTPUT MWH	HRS. ON LINE	CAPACTY FACTOR	FUEL COST	OPER.+ MAINT. COSTS	FUEL INVT. COSTS	FORCED OUTAGE RATE	PLANNED OUTAGE RATE	FUEL PRICE $/MBTU
16	NEWTON 01	EDISON	2	2	705.0	0	JAN.	-1	5026059.	7359.	0.814	147592.	11135.	0.	0.082	0.113	3.259
20	SEASHORE 01	EDISON	1	1	960.0	0	OCT.	1	6779612.	7062	0.806	92841.	17347.	11515.	0.119	0.120	1.369
38	EAST PT 02	PUBSER	1	1	960.0	0	MARCH APRIL	1	6170665.	6428.	0.734	84502.	17347.	11515.	0.119	0.120	1.369
42	SEASHORE 02	EDISON	1	1	960.0	0	MAY	1	6779612.	7062.	0.806	92841.	17347.	11515.	0.119	0.120	1.369
39	EAST PT 01	PUBSER	1	1	925.0	0	FEB. MARCH	1	5991602.	6477.	0.739	82050.	16916.	11095.	0.118	0.120	1.369
49	EAST PT 03	PUBSER	1	1	1200.0	5		1	8387943.	6990.	0.798	118312.	20181.	14394.	0.128	0.120	1.369
51	SEASHORE 05	PUBSER	1	1	1200.0	0	OCT.	1	8387943.	6990.	0.798	118312.	20181.	14394.	0.128	0.120	1.369
54	SEASHORE 06	EDISON	1	1	1200.0	0	APRIL MAY	1	7634535.	6362.	0.726	107685.	20181.	14394.	0.128	0.120	1.369
43	SEASHORE 03	EDISON	1	1	1200.0	0	MAY	1	8385174.	6990.	0.798	141931.	20181.	14394.	0.128	0.120	1.369
44	SEASHORE 04	EDISON	1	1	1200.0	0	APRIL	1	7843207.	7011.	0.746	133397.	20181.	14394.	0.128	0.120	1.369
10	STATE 02	EDISON	2	2	210.0	0	SEPT. OCT.	2	1406843.	6924.	0.765	42003.	5483.	0.	0.051	0.100	3.259
6	LINCOLN 02	EDISON	2	2	170.0	0	JAN. FEB.	2	1134987.	6977.	0.762	34013.	4845.	0.	0.050	0.100	3.259
7	WATERSIDE 01	EDISON	2	2	163.0	0	JAN.	2	1186918.	7615.	0.831	35571.	4728.	0.	0.050	0.100	3.259
5	LINCOLN 01	EDISON	2	2	150.0	0	NOV.	2	1094828.	7638.	0.833	32812.	4503.	0.	0.050	0.100	3.259
9	STATE 01	EDISON	2	2	125.0	0	APRIL	2	903903.	7638.	0.825	27100.	4048.	0.	0.050	0.100	3.259
8	WATERSIDE 02	EDISON	2	2	117.0	0	JAN.	2	844149.	7615.	0.824	25308.	3894.	0.	0.050	0.100	3.259
45	BLUE LAKE 05	PUBSER	5	2	300.0	0	APRIL	2	2064658.	7509.	0.786	62308.	7519.	0.	0.066	0.103	3.259
50	NEWTON 02	EDISON	2	2	750.0	0	SEPT.	2	5182862.	7365.	0.789	164762.	11545.	0.	0.084	0.114	3.259
35	FRONTIER 02	PUBSER	2	3	621.0	0	SEPT. OCT.	2	3801003.	6742.	0.699	148814.	10338.	0.	0.076	0.111	4.318
33	FRONTIER 01	PUBSER	2	3	320.0	0	JUNE	2	2174064.	7582.	0.776	85638.	7015.	0.	0.057	0.103	4.318
41	BLUE LAKE 04	PUBSER	2	3	210.0	0	MAY	2	1396967.	7607.	0.759	55513.	5483.	0.	0.051	0.100	4.318
29	BLUE LAKE 03	PUBSER	2	3	146.0	0	JUNE	2	979670.	7638.	0.766	39092.	4433.	0.	0.050	0.100	4.318
32	RIVERSIDE 05	PUBSER	2	3	105.0	0	FEB. MARCH	2	628190.	6977.	0.683	25136.	3655.	0.	0.050	0.100	4.318
26	BLUE LAKE 02	PUBSER	2	3	146.0	0	SEPT.	2	960638.	7638.	0.751	39265.	4433.	0.	0.050	0.100	4.318
25	RIVERSIDE 04	PUBSER	2	3	100.0	0	NOV.	2	653784.	7638.	0.746	26915.	3552.	0.	0.050	0.100	4.318
52	NEWTON 01	PUBSER	2	3	750.0	0	JULY	2	4723155.	7343.	0.719	199764.	11545.	0.	0.084	0.114	4.318
46	FRONTIER 03	PUBSER	2	3	225.0	0	JUNE JULY	2	1249224.	6917.	0.634	53003.	5709.	0.	0.052	0.101	4.318
34	LOON MT 03	PUBSER	6	4	550.0	0	MAY	2	3351117.	7599.	0.696	146876.	5720.	0.	0.052	0.089	4 798
40	BAY VIEW 04	EDISON	6	4	550.0	0	NOV.	2	3275351.	7622.	0.680	143741.	5720.	0.	0.052	0.089	4.798
31	LOON MT 02	PUBSER	6	4	117.0	0	JULY AUG.	2	651148.	7054.	0.635	28988.	2313.	0.	0.030	0.080	4.798
28	LOON MT 01	PUBSER	6	4	150.0	0	MAY	2	875058.	7776.	0.666	39143.	2675.	0.	0.030	0.080	4.798
14	STATE 03	EDISON	6	4	527.0	0	APRIL	2	2963520.	7638.	0.642	138104.	5579.	0.	0.050	0.088	4.798
15	STATE 04	EDISON	6	4	527.0	0	MARCH	2	2819845.	7615.	0.611	131745.	5579.	0.	0.050	0.088	4.798
13	HARBOR 03	EDISON	6	4	456.0	0	JULY	2	2465715.	7647.	0.617	115460.	5126.	0.	0.046	0.086	4.798
12	HARBOR 02	EDISON	6	4	209.0	0	MARCH	2	1056709.	7768.	0.583	50162.	3248.	0.	0.031	0.080	4.798
11	BAY VIEW 03	EDISON	6	4	320.0	0	JAN.	2	1211801.	7711.	0.432	58739.	4167.	0.	0.038	0.083	4.798
30	NORTHRIDGE02	PUBSER	6	4	163.0	0	APRIL	2	598865.	7799.	0.419	29200.	2808.	0.	0.030	0.080	4.798
27	MIDLINE 03	PUBSER	6	4	163.0	0	JULY	2	603956.	7776.	0.423	29496.	2808.	0.	0.030	0.080	4.798
4	BAY VIEW 02	EDISON	6	4	170.0	0	NOV.	2	538068.	7799.	0.361	26783.	2878.	0.	0.030	0.080	4.798
24	NORTHRIDGE01	PUBSER	6	4	115.0	0	MAY	2	421085.	7776.	0.418	20690.	2290.	0.	0.030	0.080	4.798
2	SO. SIDE 02	EDISON	6	4	146.0	0	DEC.	2	532426.	7671.	0.416	26274.	2633.	0.	0.030	0.080	4.798
3	SO. SIDE 03	EDISON	6	4	146.0	0		2	570496.	8392.	0.446	28201.	2633.	0.	0.030	0.080	4.798
53	NO. SIDE 03	PUBSER	4	5	400 0	0	FEB.	3	1755646.	6111.	0.501	85296.	5401.	0.	0.060	0.080	5.876
57	COMMITTED 3	EDISON	3	5	150.0	0	MARCH	3	15037.	591.	0.011	2079.	437.	0.	0.060	0.040	5.376
58	COMMITTED 4	EDISON	3	5	150.0	0		3	12742.	506.	0.010	1773.	402.	0.	0.060	0.040	5.876
59	COMMITTED 5	EDISON	3	5	150.0	0	AUG.	3	8649.	356.	0.007	1232.	341.	0.	0.060	0.040	5.876
60	COMMITTED 6	EDISON	3	5	150.0	0		3	7023.	336.	0.005	1104.	333.	0.	0.060	0.040	5.876
61	COMMITTED 7	EDISON	3	5	150.0	0	OCT.	3	5083.	246.	0.004	804.	296.	0.	0.060	0.040	5.876
19	HARBOR-GT 02	EDISON	3	5	150.0	2		3	3644.	193.	0.003	754.	274	0.	0.060	0.040	5.876
37	G.T. LUMP 3	PUBSER	3	5	100.0	0		3	1843.	141.	0.002	379.	169.	0.	0.067	0.040	5.876
18	UPTOWN-GT 02	EDISON	3	5	100.0	0	SEPT.	3	1515.	122.	0.002	323.	164.	0.	0.067	0.040	5.876
62	G.T. LUMP 4	EDISON	3	5	94.0	0		3	1263.	109.	0.002	274.	151.	0.	0.067	0.040	5.876
17	G.T. LUMP 1	EDISON	3	5	128.0	0		3	1340.	94.	0.001	318.	200.	0.	0.063	0.040	5.876
36	G.T. LUMP 2	PUBSER	3	5	130.0	0		3	866.	63.	0.001	216.	190.	0.	0.063	0.040	5.876
	TIE ENERGY								1368.			254.					
	TOTAL THERMAL				24979.0				133198873.			3736173.	380798.	117610.			
	CONV. HYDRO				310.0				2208000.				544.				
	PUMPED HYDRO				4224.0				-2162494.			0.	10998.				
	BATTERIES				500.0				-52438.			0.	2006.				
	COMPRESD AIR				500.0				-36593.			3164.	951.				
	PURCHASE + SALES				1050.0				310200.			28931.					
	SYSTEM TOTALS				31563.0				133465549.			3768268.	395298.	117610.			

TYPE	RATING MW	ENERGY OUTPUT MWH	CAPACITY FACTOR.	FUEL COST THOUSAND $	O + M THOUSAND $	THERMAL $/MWH
1 NUCL.	9805.	66360293.	0.7726	971872.	169861.	17.21
2 F-COAL	5013.	33347245.	0.7594	1182301.	106341.	38.64
3 G.T.	2952.	734591.	0.0284	79397.	11454.	123.68
4 STAG	2600.	8745561.	0.3840	426439.	29348.	52.12
5 C-COAL	300.	2064658.	0.7856	62308.	7619.	33.87
6 F-OIL	4309.	21945160.	0.5814	1013603.	56175.	48.75
TIENG		1368.		254.		185.45
TOTAL	24979.	133198873.		3736173.	380798.	30.91

* * * *MANUAL MAINTENANCE PATTERNS* * * *

PTRN	J	F	M	A	M	J	J	A	S	O	N	D
1	1	1	0	0	0	0	0	0	0	0	0	0
2	0	0	1	0	0	0	0	0	0	0	0	0
3	0	0	0	0	0	0	0	0	1	1	0	0
4	0	0	0	0	0	0	0	0	0	0	1	0
5	0	0	0	0	0	0	0	0	0	0	0	1

NOTE WHEN USED, PATTERNS OVERRIDE THE
COMPUTED P.O.R.-A 1 INDICATES
SCHEDULED MAINTENANCE

Figure 13-5. Annual Production Cost Summary

OGP ELECTRIC SYSTEM 01/13/82 16.886
USERS MANUAL EXAMPLE 2526NT

ENVIRONMENTAL REPORT

******** PLANT SUMMARY ********

1990 YEARLY

PLANT ID	PLANT	AVG. OPER. EFF.	TYPE	FUEL CONSUMPTION	HEAT REJECTION (MBTU X 1000) ATMOS.	HEAT REJECTION (MBTU X 1000) WATER	SO2 (TONS)	NOX (TONS)	CO (TONS)	PARTICULATES (TONS)	WATER CONSUMP (GX1000)
1	STATE	0.356	2	931413. TON	9177.	32537.	180855.9	19247.4	689.8	17537.1	0.
			4	6674349. BBL							
2	LINCOLN	0.371	2	894599. TON	2973.	10542.	125243.9	5469.0	227.9	15720.8	0.
3	WATERSIDE	0.371	2	739065. TON	2457.	8711.	103469.1	4516.7	188.2	10973.4	0.
5	SOUTH SIDE	0.327	4	485543. BBL	456.	1616.	3670.7	929.6	31.0	341.4	0.
6	BAY VIEW	0.360	4	5539392. BBL	4949.	17546.	41877.8	11663.3	389.4	3838.5	0.
7	HARBOR	0.340	4	3721749. BBL	3926.	12069.	28386.4	7632.2	252.5	3106.4	0.
			5	99194. BBL							
8	NEWTOWN	0.358	2	3710853. TON	18119.	64240.	282086.9	47127.1	1046.5	395107.3	0.
			3	2364464. TON							
9	UPTOWN	0.145	5	54414. BBL	287.	0.	137.1	69.1	1.1	190.4	0.
10	SEASHORE	0.311	1	405458. LB. U	340653.	0.	0.	0.	0.	0.	53759797.
11	EAST POINT	0.337	1	175676. LB. U	142035.	0.	0.	0.	0.	0.	25234914.
12	MIDLINE	0.336	4	481013. BBL	446.	1582.	3636.5	944.1	31.5	346.7	0.
13	NORTH RIDGE	0.337	4	1039413. BBL	962.	3410.	7858.0	2049.8	68.4	752.8	0.
14	FRONTIER	0.370	3	3817519. TON	8778.	31124.	130627.4	42995.9	205.9	59113.5	0.
15	BLUE LAKE	0.367	2	799255. TON	6430.	22797.	176879.4	22923.9	288 7	28848.0	0.
			3	1624592. TON							
16	RIVERSIDE	0.362	3	696688. TON	1623.	5754.	27867.5	7671.8	36.7	5407.9	0.
17	LOON MT.	0.368	4	5947708. BBL	5248.	18605.	44964.7	12799.8	427.3	5236.4	0.
18	NORTH SIDE	0.404	5	2197286. BBL	3628.	4435.	2768.6	7791.2	120.1	21459.8	0.
25	UNSITED	0.341	2	3001186. TON	32811.	72401.	44309.6	43120.9	1504.3	710054.9	0.
			3	2581988. TON							
			5	4148739. BBL							
100	UNSITED	0.131	5	222416. BBL	1190.	0.	280.2	256.2	3.9	705.6	0.
TOTAL SYSTEM		0.337			586147.	307368.	1204919.6	237208.0	5513.5	1278740.9	78994[illegible]11.

Figure 13-6. Annual Environmental Report by Plant

EXPANSION OUTPUTS
SUPPLEMENTARY INFORMATION

1. Parametric Sensitivity Method for Establishing Optimum Long-Range Generation Mix, A.M. Adamson, J.F. Kenney and R.W. Moisan, 1973 American Power Conference.

2. Impact of Uncertainty on Long-Range Generation Planning, L.L. Garver, H.G. Stoll and R.S. Szczepanski, 1976 American Power Conference.

3. Solving Today's Capital and Fuel Supply Problems in the Selection of New Generation, W.D. Marsh, R.W. Moisan and H.G. Stoll, 1975 American Power Conference.

4. Analysis Approach to Evaluate the Impact of Electric Heating Loads on Utility Operations, J.L. Oplinger, 1975 Workshop on Solar Energy Heat Pump Systems for the Heating and Cooling of Buildings.

5. Power Plant Productivity--Techniques for Assessing Benefits and Cost Effectiveness, R.M. Nelson, Jr., M.A. Korn, R. Habermann, Jr., J.B. Tice, R.W. Keller and M.J. Smith, 1978 American Power Conference.

6. Market Potential for New Coal Technologies, O.D. Gildersleeve and D. Spencer, EPRI Journal, May 1978.

7. Reducing Oil Consumption Through Economic Generation Reserve Margins, D.L. Dees, G.E. Haringa and H.G. Stoll, 1980 American Power Conference.

8. Utility Generation Planning Within an Interconnected Power System, D.L. Dees, B.W. Erickson, G.E. Haringa, H.G. Stoll and J.B. Tice, 1981 American Power Conference.

FINANCIAL DATA

The Financial Simulation Program (FSP) is designed to serve as a tool for evaluating the financial impact of alternative generation expansion plans. FSP is a simplified corporate model which focuses mainly on the generation plant. There are two basic categories of input data for FSP: system data and financial data.

The following types of system data must be input into FSP:

- Generation additions
- Peak loads
- Annual energies
- Fuel and O&M costs

The following types of financial data must also be input into FSP:

- Initial balance sheet
- Financing ratios and limits
- Regulatory and tax rules
- Future projections (e.g., interest, inflation, etc.)

The OGP program has the capability of storing the system data on a separate file for input into the FSP program. If the user runs FSP independently of OGP, the information transferred from OGP to FSP can be input to FSP through a separate Data Preparation program. The Data Preparation program reads in the data normally transferred from OGP and writes it onto a file in the proper format for FSP. The following system data is transferred from OGP or the Data Preparation program to FSP via this file.

Generation Data

The following generation data for each unit is transferred to FSP:

- Name
- Rating
- Years of installation and retirement
- Unit Type No.
- Plant cost relative to the year costs were quoted in OGP or the Data Preparation program
- Per-unit plant cost modifier by company for future units

Annual Data

The following data is transferred from OGP or the Data Preparation program to FSP for each year of the study:

- Peak load
- Generated energy, including contracts
- Generation production costs, including emergency energy and contracts
- Fuel cost by type of unit
- Demand and energy charges for purchases and sales
- Per-unit plant cost inflation modifiers

The generation and annual data from a generation expansion study, such as one done with OGP, defines a fixed expansion which will be input into FSP. One of these fixed expansions may become the basis for a number of parametric FSP studies. As is true with much of the OGP input data, the user also has the option of manually modifying the FSP input data which may change on an annual basis.

In addition to the generation and annual data just discussed, the user must provide additional basic data input, including the financial data, directly to FSP. This basic data input is divided into the following thirteen areas:

- Run identification
- Initial balance sheet
- Income statement data
- Common and preferred dividend data
- General financial information
- System data
- Generation plant data
- Other electric plant data
- Tax data
- Regulatory data

- Second business data
- Nuclear fuel data
- Optional output specifications

A description of each of these data items is included later in this section.

FSP requires sufficient data input in order to calculate the following items for each year: balance sheet, income statement, cash report, other miscellaneous data such as tax information and financial ratios (e.g., earnings per share), etc. In all instances, dollar values are input in thousands of dollars.

The FSP logic is not designed to operate in an unstructured environment. Therefore, the initial data input must be realistic and must reflect the assumptions that were incorporated into the accompanying OGP or other system expansion study. For example, the beginning balance sheet must be balanced; Construction Work in Progress (CWIP) accounts must reasonably reflect the ongoing projects represented in the expansion study; yearly issue size limits imposed on long-term financing must be consistent with the load growth, capacity growth and real dollar inflation specified.

In most situations, the input data required may be taken directly from documents such as a utility's annual report or EEI Uniform Statistical Report. However, because of the extensive variation among methods of reporting by different electric utilities, the user may have some choices to consider when determining where to place certain accounts. This is particularly true with the specification of the initial balance sheet. For example, the user may maintain separate accounts for nuclear fuel which has been purchased and that which has been leased. Before this data can be input into FSP, these accounts must be added together. The discussion of how the financial simulation actually is done, which is presented in Section 15, may help the user make such decisions concerning account placement.

The remainder of this section of the handbook provides a detailed description of the input data required for FSP, except for the data that previously has been noted as originating from OGP or the Data Preparation program. All of the individual pieces of input data will not be listed separately. Instead, comments will be made in selected areas to facilitate the user's understanding of FSP's processes.

1. Run Identification

a. If the user desires a printout of a unique description, a case identification is required because this type of information will not be carried through from the OGP program.

b. The FSP study must begin with the first year of the OGP or Data Preparation case, and it cannot extend beyond the thirty-year time limit of a single OGP or Data Preparation run.

2. Initial Balance Sheet

a. All monetary values, as of December 31st of the year before the start of the study, must be input in thousands of dollars.

b. It is not necessary to input all of the items on the initial balance sheet. FSP will use the information supplied to calculate the remaining accounts not input.

The following items are actually input to FSP:

Assets

- Total plant in service, including the Allowance for Funds Used During Construction (AFDC), but not including CWIP
- Total generation plant in service, including AFDC, but excluding CWIP
- Total second business (e.g., gas or steam) plant in service, including AFDC, but excluding CWIP
- Generation plant CWIP, including AFDC
- Other electric plant CWIP, including AFDC
- Second business plant CWIP, including AFDC
- Electric system depreciation reserve
- Second business depreciation reserve
- Net nuclear fuel
- Cash balance, end of year
- Accounts receivable and deferred debits
- Fossil fuel inventory
- Total inventory, excluding nuclear fuel

Liabilities

- Short-term debt
- Long-term debt, including current maturities
- Common stock, including premiums
- Retained earnings
- Preferred stock

- Accounts payable and deferred credits
- Accumulated deferred federal income tax
- Accumulated deferred investment tax credits

c. Total assets must equal total liabilities. By combining all of the items on the company's actual balance sheet with the quantities listed in Item 2. b., the user's ability to attain this goal without undue iteration is enhanced.

d. CWIP for the generation plant, including AFDC, may be omitted if the user chooses to supply this information for each individual unit.

3. Income Statement Data

a. The net operating income for non-electric sources will be held constant by the program.

b. During the study, other plant operating expenses will increase proportionately according to the value of the other plant in service account.

4. Common and Preferred Dividends Data

Ratios specified in the input will determine dividend payouts during the study.

5. General Financial Information

a. Inflation rates for items related to other plant are used to establish the value of these items through time.

b. Many of the values entered in this group of general financial data are ultimately related to the present worth and fixed charge rates which were used for the OGP input data. The input data provided for both programs (OGP and FSP) should be consistent.

6. System Data

Historical data will be used to determine the portion of the plant-in-service accounts that was placed into service in each of the years prior to the start of the study. This will directly affect retirement quantities during the FSP analysis.

7. Generation Plant Data

a. If individual values of $/kW and/or inflation factors for the existing generation plant are supplied, the resultant aggregate value should be consistent with that listed on the initial balance sheet.

b. FSP will simulate the addition of generating units beyond the end of its designated study period by assuming a continuation of the same generation mix and load growth trend exhibited during the last five years of the study. Although loss-of-load probability (LOLP) is not explicitly considered in the FSP logic, the percent reserve margin is maintained at the same level as in the last year of the study. These additional generating units are necessary to enable FSP to take into consideration a continuing stream of plant construction expenditures. The user, however, has the option of manually defining the additional units.

8. Other Electric Plant Data

The other electric plant includes all of the non-generation plant (e.g., transmission, distribution, and general plant) on the system.

9. Tax Data

a. Deferred investment tax credits will be carried forward until they are used up.

b. The tax rates input into FSP should be consistent with those which were reflected in the fixed charge rates used in the expansion study.

10. Regulatory Data

a. If CWIP is included in the rate base, it should be reflected in the plant cost ($/kW) input into the OGP or Data Preparation program.

b. A lag in regulation means that the rate change indicated for the current year will not be implemented until a future year.

11. Second Business Data

The second business is completely defined through the input of growth and inflation rates on plant, sales, and expenses.

12. Nuclear Fuel Data

The net amount of nuclear fuel on the balance sheet and the portion treated as a direct expense are controlled through input.

13. Optional Output Specifications

Use of optional output specifications may provide more "bottom lines," other than conventional financial quantities, for use in evaluating alternate expansion plans.

FINANCIAL SIMULATION

A corporate model is a logical structure by which inputs from the planning, operating and financial components of a company are combined to produce financial statements. The Financial Simulation Program (FSP) performs a financial simulation of the capital cost portion of a system expansion plan developed by the Optimized Generation Planning (OGP) Program. Thus, FSP is an extension of OGP; it is not part of the optimization process.

FSP is a strategic corporate model, designed to provide the user with information needed to do long-range expansion planning. As a long-range planning tool, FSP needs less detail than is found in corporate models used to study the near-term expansion requirements. As a result, the input data requirements for FSP are simplified; the simulation is done on an annual, rather than monthly or weekly, basis; and FSP assumes there is just one average customer class, rather than segregating the customers into residential, commercial, and industrial classes.

As a generation planning tool, FSP focuses on the generation plant. Transmission and distribution are treated as an aggregate. Provisions to model a second business, such as gas or steam, allow the program to calculate consolidated financial results for the company in the form of balance sheets, income statements, and cash reports. Thus, FSP allows utility planners to quickly and inexpensively evaluate future expansion plans by providing more "bottom lines" for comparison than does the revenue requirements approach.

Some typical functions of FSP include evaluating the financial effects of non-financial decisions, performing general studies of long-term financing, investigating the effects of different cash management and dividend policies, and evaluating the consequences of different tax rates and costs of capital. In this section, the models and techniques used in FSP to perform these functions will be described.

The logical structure of FSP is shown in Figure 15-1. The analysis to be performed by FSP has been categorized into ten major areas, each of which is described in detail in this section. The main loop on Figure 15-1 advances the FSP simulation one year at a time. If calculations indicate an unacceptable rate of return, FSP, through an inner loop, will adjust the rates so satisfactory revenues will be obtained, and the desired level of return will be achieved. When the expansion period has been completed, overall financial summaries are provided which enable the user to evaluate the total expansion.

1. Pre-study Initialization

Before doing the annual financial simulation, FSP must calculate some quantities relating to the plant in service at the start of the study. These quantities are necessary to calculate book and tax depreciation and other plant expenditures during the study period.

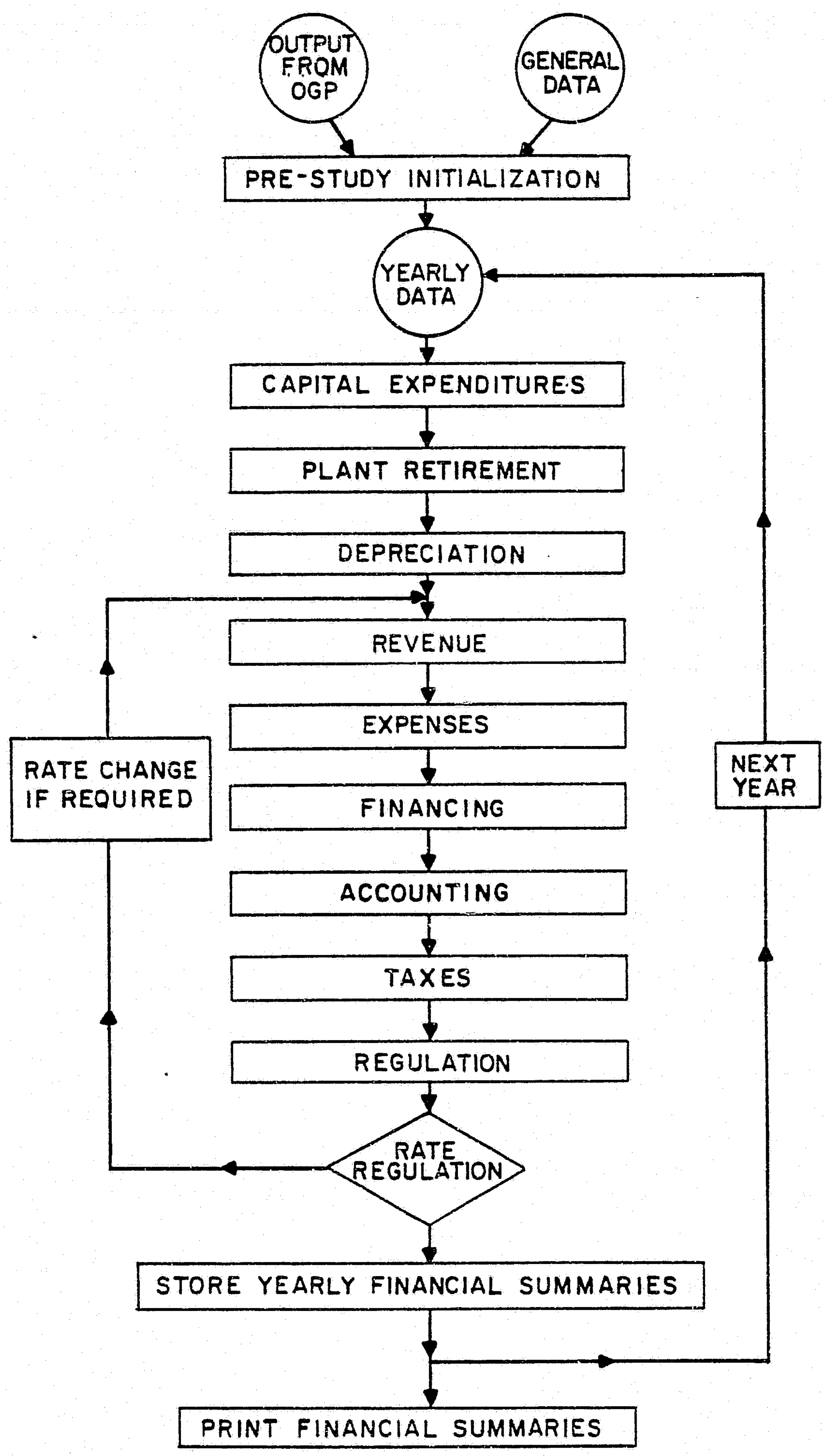


Figure 15-1. Logical Structure of the Financial Simulation Program

For each generating unit in service at the start of the study, FSP calculates the unit's cost, including and excluding Allowance for Funds Used During Construction (AFDC). To perform this calculation, each generating unit is first described by an installation date, construction period, total installed cost, and construction expenditure pattern. The construction expenditure pattern is a series of per-unit numbers that shows the rate at which the actual construction expenditures were made during the construction period.

The total installed cost (including AFDC) of each unit is then adjusted so the sum of the installed cost for all units on the system equals the generation plant account on the initial balance sheet.

The expenditures on the other plant (e.g., transmission, distribution, and miscellaneous plant) for the years before the start of the study are calculated from the book life for the other plant and the other plant account on the initial balance sheet. FSP assumes that these expenditures increased at a constant rate equal to the average historical load growth times the average historical inflation rate. Similar calculations are made for the second business. The user has the option of inputting historical expenditures year by year for the other plant and/or the second business.

Also, as part of the pre-study initialization, FSP, based on the installation dates and costs of the generating units on the system at the start of the study, determines the historical issue dates for the long-term debt shown on the initial balance sheet. The user has the option of inputting this historical bond schedule.

2. Capital Expenditures

The area of capital expenditures computes additions to the plant accounts during the FSP study. Plant additions are accomplished in two ways: (1) by using an explicit project-by-project basis to model generation additions on a unit-by-unit basis; and (2) by calculating expenditures on a continuous basis as a function of growth in electric load demand (this method is used for modeling other plant) or as a function of the plant growth rate input for the second business.

Each generation unit is described by an installation date, a construction period, a pattern describing per-unit construction expenditures, total installed cost, and, for projects underway at the start of a study, the Construction Work in Progress (CWIP) opening balances.

This data is used to calculate the year-by-year expenditures during the study period. AFDC is calculated based on the mid-year CWIP balance for each project. At the close of a project, the accumulated charges are transferred from CWIP balances to the appropriate plant-in-service account. In order to accurately represent the CWIP account for the entire period included in the FSP study, the program defines the units to be added after the last year studied. Alternatively, the user may specify a stream of unit additions for the years following the end of the FSP study.

FSP assumes that units installed during the study are placed in service on July 1st of the installation year, regardless of the actual installation month in the OGP study. The user has the option of specifying the month of installation by unit type or unit by unit. If the unit is installed in mid-year (i.e., other than January 1st), the user can specify whether construction expenditures are to be made in the months before the unit goes into service or if they are to end in the previous year. The month of installation is also considered when calculating book and tax depreciation.

In a given study year, other plant expenditures are first made to replace, at current costs, any equipment being retired. Then, additional capital expenditures are made so that the current replacement cost of the other plant changes in proportion to system demand and the inflation rate for other plant expenditures. Or, at the user's option, other plant expenditures may be specified on a year-by-year basis.

FSP assumes that other plant expenditures are made on January 1st and that a user-specified portion goes into service on July 1st, earning one-half year's AFDC. The remainder is added to the CWIP account and goes into service on January 1st of the following year, earning a full year's AFDC for the year in which the expenditure was made. The user can also define the portion of other plant expenditures eligible for AFDC.

The second business capital expenditures are treated in a similar manner except that they are grown proportional to the input second business plant growth rate rather than the load growth. The actual expenditures may also be input year by year.

Capital expenditures for nuclear fuel are also calculated by FSP. Three pieces of data are input for each year of the FSP study: (1) the fraction of nuclear fuel to be capitalized, (2) the number of years of nuclear fuel costs to be carried on the company books, and (3) the ratio of net to gross nuclear fuel. The fraction of nuclear fuel to be capitalized tells FSP how much of each year's nuclear fuel will be capitalized as an asset and how much will be treated as a direct expense. The number of years worth of nuclear fuel to be carried on the company books is combined with the yearly nuclear fuel costs from OGP or the Data Preparation program to determine the net nuclear fuel that will appear on the balance sheet. This reflects the lead time involved in purchasing and processing nuclear fuel several years before it is used. The ratio of net to gross nuclear fuel determines the rate at which nuclear fuel is disposed of and removed from the company books. The capital expenditures for nuclear fuel are equal to the change in gross nuclear fuel from the previous year to the current year plus the cost of the nuclear fuel being removed from the company books in the current year. The cost of nuclear fuel removed from the company books includes the capitalized portion of the burn-up cost for the current year and the change in amortization.

3. Plant Retirement

A generation plant is retired and removed from the balance sheet unit by unit, based on the retirement date assigned to each unit by OGP or the Data Preparation program. Other plant and the second business plant are retired at the end of their respective book lives.

4. Depreciation

Book and tax lives are input separately for each of the ten types of generation, the other plant, and the second business. Straight line depreciation is used for book purposes. The depreciation method used for tax purposes depends on the year in which the asset was installed. Sum-of-the-years' digits (SYD) depreciation, based on the input tax lives, is used for equipment installed after 1954. Shorter tax lives, reflecting the Asset Depreciation Range (ADR) guidelines, are used for assets placed in service during the years 1971 through 1980. Assets installed after 1980 are depreciated according to the Accelerated Cost Recovery System (ACRS) as outlined in the Economic Recovery Tax Act of 1981 and modified by the Tax Equity and Fiscal Responsibility Act of 1982. If the ACRS tax lives are not input, FSP will calculate them based on the ADR tax lives that were supplied. The tax savings due to liberalized depreciation can be normalized over either the book life (full normalization) or the tax life (partial normalization).

5. Revenue

The revenue section of FSP computes the annual revenues obtained from the sales of electricity and from the second business. The MWh sales are calculated from the MWh generation and the energy loss factor. The MWh sales times the average electric rate yields the total electric revenues. These revenues can be adjusted by the fuel cost adjustment which allows a user-specified portion of the change in average fuel cost since the last rate adjustment to be passed through to the customers. The revenues from the second business are calculated from the second business sales (an input item) and the price per unit of second business sales. The electric and/or second business revenues may also be input on a yearly basis.

6. Expenses

Expenses calculated include fuel and O&M costs and taxes other than federal income tax. The fuel expense and the O&M costs associated with generation are obtained from OGP or the Data Preparation program. The O&M expenses for the other plant are calculated as a per unit of the initial other plant in service. Then they are increased through time in proportion to the load growth and a user-input inflation rate. Production expenses for the second business are calculated from the second business plant at the start of the study, then increased in proportion to inflation and the rate of growth in the second business plant. Sales, customer, and other general administrative expenses are usually included in the O&M expense category.

Property and revenue taxes are also computed. The property tax is calculated from a user-input tax rate and the total plant in service, excluding CWIP and nuclear fuel inventory. The tax rate may also be specified for individual generating units. The revenue tax is computed as a per unit of the total revenues.

7. Financing

External financing requirements for the year are determined by estimating the long-term financing requirements, including the retirement of existing bonds, and subtracting from this estimate the internal sources of funds such as depreciation, deferred taxes, and earnings. Debt financing, preferred stock, and common stock will be issued, in that order, subject to the user-input constraints on minimum and maximum issue sizes, debt ratio, and preferred stock ratio. If the amount required from a certain type of financing (e.g., debt, preferred, or common) is less than the minimum issue size for that type, no financing with that type will occur, and FSP will consider the next type.

FSP issues short-term financing as needed to maintain the company's cash position above a minimum level specified through input. Additional short-term financing can also be issued to maintain short-term debt as a user-specified per unit of total capitalization.

The market price of common stock is determined from the current year's earnings per share and the price-to-earnings ratio input by the user. The user can inhibit the issuance of common stock if the ratio of market price to book price falls below a user-specified limit. When this occurs, any remaining financing will be obtained from long-term debt or short-term debt, as specified by the user.

8. Accounting

At this point in the FSP logic, the income statement and cash report are computed. This is done iteratively by computing operating income after income taxes and combining this value with other sources of income and the estimated interest and dividends for the existing and new financing to determine the year-end cash position of the company.

The dividend rate for preferred stock is a per-unit multiplier of the long-term interest rate. The user has two options in specifying the common stock dividends. One option is to input a payout ratio which is multiplied by the earnings per share to calculate the dividends per share. The second option is to input a growth multiplier which is applied to the previous year's dividends.

The minimum allowable cash position is checked. When cash is outside the limit, the short-term financing pattern will be adjusted. If this occurs, the income taxes and year-end cash positions are recalculated using the new short-term financing pattern and the new amounts of interest, dividends, and taxes paid. This procedure is performed until convergence is achieved.

The balance sheet is then updated and reviewed to make sure total assets equal total liabilities. The company's cash flow is audited by comparing the difference between sources and applications of funds for the year with the balance sheet change in cash. These comparisons ensure that the accounts have not become unbalanced.

9. Taxes

Since FSP does not explicitly calculate state income taxes, they are usually included with the federal income taxes. To determine taxable income, the book income is reduced by the AFDC, the net non-operating income, and the difference between tax and book depreciation. Then the federal income tax is obtained by multiplying the taxable income by the tax rate input by the user. This quantity is then reduced by the investment tax credits allowed in that year to determine the federal income tax liability. A user-specified portion of the tax savings due to liberalized depreciation can be normalized, and the remainder will be flowed through to current income. For equipment governed by ACRS (i.e., equipment installed after 1980), all of the tax savings will be normalized. Normalization can be done over the book life (full normalization) or tax life (partial normalization). The tax effects of the borrowed-funds portion of AFDC can also be normalized.

The total investment tax credit allowed for an asset may be taken when the asset is placed in service or when the annual construction progress payments occur. Unused investment tax credits will be carried forward until they can be used. The user can specify the portion of investment tax credits to be normalized, and the period over which normalization is to occur. The portion not normalized will be flowed through to current income.

FSP can also simulate the tax effects of stopping construction on a generating unit before it is placed in service. A unit cancellation is modeled by assigning a negative tax life to the type of generation associated with the unit to be cancelled. In the year designated by the unit's installation year, FSP will refund to the Internal Revenue Service any accumulated investment tax credits taken on progress payments, and it will depreciate the unit fully for tax purposes. For tax book purposes, depreciation will be calculated on a straight line basis using the absolute value of the tax life input.

10. Regulation

Rate regulation in FSP is simulated by maintaining within specified limits the rate of return on rate base, the percentage earned on common equity, or the pre-tax interest coverage. The user also specifies the "regulatory lag" from the time a rate change is requested until it is actually implemented.

The regulatory process begins with the calculation of the rate of return or interest coverage based on revenues determined from the electric and second business rates currently in effect and any applicable fuel rider revenues. If the return produced by these revenues is within the acceptable range, the program proceeds to the next year of the study. If the return is outside the acceptable range, a rate change will be initiated. Based on the input value for the desired rate of return or coverage, the program will estimate the new rates needed for an acceptable return. As shown in Figure 15-1, the program will feed these new rates back to the revenue calculation and repeat part of the FSP simulation. It will continue iterating in this manner until the return falls within the range of acceptable values.

If the regulation is being done currently, the new rates will be implemented immediately. However, if the regulation is being lagged by one or two years, the new rates will become effective one or two years later. Whenever a rate change becomes effective, a new fuel adjustment basis is calculated for use in future years.

The rate regulation in FSP will automatically adjust both the electric rate and the second business rate. The second business rates can be held constant between runs by inputting the second business revenues or rates. The electric rate would then fully reflect any changes due to sensitivities being studied. It is also possible to input the electric revenues or rates for some or all of the study years.

The dollar returns and bases for the computation of rate of return on rate base, percentage earned on common equity, and interest coverage are as follows:

- Rate base = Gross plant in service + CWIP (optional) - Book depreciation reserve + Net nuclear fuel + Materials and supplies - Deferred federal income tax (optional) - Deferred investment tax credits (optional)

  (CWIP may be included in the rate base to the extent desired by the user, and AFDC will automatically be adjusted accordingly.)

- Return on rate base = Net operating income/Rate base

- Common equity base = Common stock outstanding + Retained earnings - (0.5)(Common stock issued during current year)

- Return on common equity = (Net income - Preferred dividends)/Common equity base

- Pre-tax interest coverage = (Income before interest + AFDC from borrowed funds + federal taxes, including deferred and adjustments)/(long-term interest + short-term interest)

Regulation based on a combination of return on rate base and return on common equity is also available. The common equity associated with equipment in the rate base will earn the rate of return specified by the user. The common equity associated with CWIP will earn a return consistent with the AFDC rate. Based on the mix of capitalization in the company and the range of values input for return on common equity in the rate base, FSP will calculate the values for return on rate base to be used in the regulation. This is done as follows:

$$\text{Return on Rate Base} = \frac{\text{L.T. Int.} + \text{S.T. Int.} + \text{Preferred Div.} + \text{Common Div.}}{\text{L.T. Debt} + \text{S.T. Debt} + \text{Preferred Stock} + \text{Common Equity Base}}$$

where L.T. Debt includes current maturities,

S.T. Debt is the average outstanding for the year, and

Common Div. equals the common equity base times the input value for return on common equity in the rate base.

At this point in the FSP logic, all quantities necessary for the yearly output financial statements have been calculated. Three basic reports are developed: annual balance sheet, income statement, and cash report. In addition, tax statements and numerous other financial ratios and indicators are calculated and displayed for reference. Present worth treatments of key quantities such as earnings per share, revenues, capital expenditures, etc., are also available to the user.

FINANCIAL RESULTS

The output from FSP begins with a display of the input data, which includes the beginning consolidated balance sheet. Then, for each year of the FSP study, the user can obtain remote summaries or batch output consisting of annual balance sheets, income statements, cash reports and miscellaneous tax data and financial information such as earnings per share, etc. A yearly breakdown of the construction expenditures for each new generating unit is also provided.

Sample output pages are shown in Figures 16-1, 16-2, 16-3, and 16-4. More detailed information regarding the output is included in the FSP User's Manual.

01/29/82 17.250 JOB NUMBER 1862YT

OGP ELECTRIC SYSTEM, FILE UMFSP6L

USERS MANUAL EXAMPLE

EDISON AND PUBLIC SERVICE CONSOLIDATED

B A L A N C E S H E E T AS OF DECEMBER 31 (THOUSANDS OF DOLLARS)

	1990	1991	1992	1993	1994
ASSETS					
UTILITY PLANT					
ELECTRIC PRODUCTION	13371559	16424413	17500606	21073872	25018993
OTHER PLANT	9184020	10124191	11166822	12323095	13605413
GAS PLANT	0	0	0	0	0
CONSTR. WORK IN PROGRESS	13090024	13601454	16604326	17564014	19205592
TOTAL NUCLEAR FUEL	1609180	1682848	2023485	2374839	2750062
TOTAL UTILITY PLANT	37254783	41832905	47295240	53335819	60580059
LESS DEPRECIATION RESERVE	7531141	8406564	9370376	10444046	11696965
LESS AMORT OF NUCLEAR FUEL	402295	420712	505871	593710	687515
NET UTILITY PLANT	29321347	33005629	37418992	42298063	48195579
CURRENT + ACCRUED ASSETS					
CASH + EQUIVALENT	9859	10034	10662	10884	8969
ACCTS. REC. + DEF. DEBITS	821984	933482	1023137	1184605	1347858
MATERIALS AND SUPPLIES	885951	963993	1137342	1238901	1365561
TOTAL CURRENT ASSETS	1717795	1907510	2171140	2434390	2722388
TOTAL ASSETS	31039142	34913139	39590132	44732453	50917967
LIABILITIES					
CAPITALIZATION					
COMMON STOCK OUTSTANDING	7029800	7961800	9173800	10457800	11970800
RETAINED EARNINGS	3117951	3468065	3829622	4279307	4790334
COMMON STOCK EQUITY	10147751	11429865	13003422	14737108	16761134
PREFERRED STOCK	3205931	3610931	4107931	4654931	5294931
L.T. DEBT+CURR.MATURITIES	13356947	15044536	17118171	19397327	22062327
TOTAL CAPITALIZATION	26710629	30085332	34229524	38789366	44118392
CURRENT + ACCRUED LIABILITIES					
SHORT TERM DEBT	245525	222576	386127	260687	333673
ACCOUNTS PAYABLE + MISC.	1754564	1992547	2177970	2528575	2877046
TOTAL CUR.+ACCRUED LIAB	2000089	2215124	2564097	2789262	3210718
DEF. TAXES+OTHER CREDITS	2328423	2612683	2796512	3153825	3588856
TOTAL LIAB. + CAPITAL	31039142	34913139	39590133	44732453	50917966
NEW FINANCING					
CHANGE IN BONDS	1811021	1687588	2073635	2279156	2665000
BOND RETIREMENTS	29979	18412	45365	71844	0
TOTAL BOND FINANCING	1841000	1706000	2119000	2351000	2665000
PREFERRED STOCK	435000	405000	497000	547000	640000
COMMON STOCK	1072000	932000	1212000	1234000	1513000
TOTAL	3348000	3043000	3828000	4182000	4818000

Figure 16-1. Annual Balance Sheets

01/29/82 1[illegible] 250 JOB NUMBER 1862YT

EDISON AND PUBLIC SERVICE CONSOLIDATED

I N C O M E S T A T E M E N T AS OF DECEMBER 31, (THOUSANDS OF DOLLARS)	1990	1991	1992	1993	1994
ELECTRIC REVENUE	9768835	11093922	11736056	14078380	16018560
GAS REVENUE	0	0	0	0	0
ELEC. FUEL ADJ. REVENUE	0	0	423364	0	0
TOTAL	9768835	11093922	12159420	14078380	16018560
ELECTRIC OPER. EXPENSE					
FUEL AND O+M	4252245	4756478	5471139	6059626	6764138
NET PURCHASED POWER	61155	65575	70448	75408	80869
OTHER PROD. EXPENSES	575233	637215	705875	781933	866186
TOTAL ELECTRIC PROD.	4888633	5459268	6247462	6916966	7711193
GAS PROD. EXPENSES	0	0	0	0	0
DEPRECIATION EXPENSE	805824	907055	1001902	1113756	1323470
F.I.T. LIABILITY	731338	741103	758566	936654	1073246.
OTHER TAXES	882559	1000613	1124810	1264055	1465155
DEFERRED + ADJUSTMENTS	146092	284259	183829	357313	435031
TOTAL OPER. EXPENSES	7454445	8392299	9316569	10588744	12008095
OPERATING INCOME	2314390	2701623	2842851	3489636	4010465
AFDC-EQUITY FUNDS	378198	394883	476142	502123	542187
NET OTHER NON-OPER. INCOME	16601	16601	16601	16601	16601
INCOME BEFORE INTEREST	2709189	3113107	3335594	4008360	4569253
LONG TERM INTEREST	1103280	1262016	1432043	1629759	1855060
SHORT TERM+OTHER INTEREST	24702	23171	30131	32017	29421
AFDC-BORROWED FUNDS(CRED)	242248	251849	306182	322990	347594
NET INCOME	1823454	2079769	2179602	2669574	3032366
PREFERRED DIVIDENDS	289507	329197	371817	421146	477232
AVAILABLE TO COMMON	1533947	1750572	1807785	2248428	2555135
COMMON DIVIDENDS	1227158	1400457	1446228	1798743	2044108
NET INCOME AFTER DIV	306789	350114	361557	449686	511027
COMMON SHARES YEAR AVG.	117731740	126030359	134778024	144378544	154026030
EARNINGS PER SHARE	13.0292	13.8901	13.4131	15.5731	16.5890
DIVIDENDS PER SHARE	10.4233	11.1121	10.7304	12.4585	13.2712
PAYOUT RATIO	0.8000	0.8000	0.8000	0.8000	0.8000
STOCK BOOK VALUE - $/SHARE	86.1938	90.6914	96.4803	102.0727	108.8201
STOCK MKT. PRICE - $/SHARE	117.2626	125.0107	120.7175	140.1583	149.3008
MARKET/BOOK RATIO	1.3605	1.3784	1.2512	1.3731	1.3720
PRICE/EARNINGS RATIO	9.0000	9.0000	9.0000	9.0000	9.0000
RETURN ON RATE BASE	0.1352	0.1326	0.1295	0.1344	0.1321
RETURN ON COMMON EQUITY	0.1596	0.1597	0.1458	0.1595	0.1596
RETURN ON CAPITALIZATION	0.1105	0.1118	0.1064	0.1117	0.1114
PRETAX INTEREST COVERAGE	3.3944	3.4161	3.1352	3.3851	3.4095
AFTER TAX INTEREST COVRAGE	2.6166	2.6183	2.4907	2.6065	2.6091
DEBT RATIO	0.5001	0.5001	0.5001	0.5001	0.5001
PREFERRED RATIO	0.1200	0.1200	0.1200	0.1200	0.1200
AFDC AS PRCNT OF EARNINGS	40.4477	36.9441	43.2753	36.6973	34.8232
GROSS PLANT/REVENUE	3.6489	3.6191	3.7232	3.6198	3.6102
OPERATING RATIO	0.6733	0.6641	0.6887	0.6602	0.6555
ELECTRIC RATE CENTS/KWH	8.0433	8.6580	8.9704	9.8715	10.6463
GAS RATE CENTS/CF	0.	0.	0.	0.	0.

Figure 16-2. Annual Income Statements

01/29/82 17.250 JOB NUMBER 1862YT

EDISON AND PUBLIC SERVICE CONSOLIDATED

CASH REPORT AS OF DECEMBER 31 (THOUSANDS OF $)

	1990	1991	1992	1993	1994
BEGINNING CASH BALANCE	11374	9859	10034	10662	10884
FUNDS FROM OPERATIONS					
NET INCOME AFTER DIVIDEND	306789	350114	361557	449686	511027
NON CASH EXPENSES					
DEPRECIATION	805824	907055	1001902	1113756	1323470
AMORT. OF NUCLEAR FUEL	1089482	1337839	1399084	1682283	1974391
PROVISIONS FOR TAXES	1759989	2025976	2067205	2558022	2973431
TOTAL FUNDS FROM OPER.	3962084	4620984	4829748	5803747	6782320
FUNDS FROM OUTSIDE SOURCES					
EQUITY SECURITIES	1507000	1337000	1709000	1831000	2153000
LONG TERM DEBT	1811021	1687588	2073635	2279156	2665000
SHORT TERM INSTRUMENTS	-7988	-22948	163551	-125439	72985
TOTAL OUTSIDE FUNDS	3310032	3001639	3946186	3984716	4890985
PROVISION FOR INT. + DIV.					
INTEREST	1127982	1285187	1462174	1661776	1884481
DIVIDENDS	1516665	1729654	1818044	2219888	2521339
TOTAL SOURCES OF FUNDS	9916763	10637464	12056153	13670127	16079125
APPLICATION OF FUNDS					
CAPITAL EXP. - GEN.	3449282	3553696	4070290	4521014	5599499
CAPITAL EXP. - OTHER	885824	982391	1089497	1208297	1340069
CAPITAL EXP. - GAS	0	0	0	0	0
CAPITAL EXP. - NUC. FUEL	1313528	1393089	1654563	1945798	2255808
INTEREST PAID	1127982	1285187	1462174	1661776	1884481
TAXES PAID	1613897	1741716	1883376	2200709	2538401
DIVIDENDS PAID	1516665	1729654	1818044	2219888	2521339
CHANGE IN WORKING CAP.	11099	-48443	77581	-87577	-58557
TOTAL APPLIED FUNDS	9918277	10637289	12055526	13669905	16081039
ENDING CASH BALANCE	9859	10034	10661	10884	8969
FEDERAL INCOME TAX					
BOOK INCOME W/O INC. TAX	2700884	3105131	3121996	3963541	4540642
LESS OTHER TAX ADJUST.	839687	947534	1155868	1288011	1489185
TAXABLE INCOME	1861198	2157598	1966128	2675530	3051458
FEDERAL INCOME TAX	856151	992495	904419	1230744	1403671
LESS INVESTMENT TAX CR.	124813	251392	145853	294090	330425
F.I.T. LIABILITY	731338	741103	758566	936654	1073246
F.I.T. DEFERRAL, DEPREC.	49582	66748	74656	106338	154904
F.I.T. DEFERRAL, AFDC	0	0	0	0	0
TAX DEPRECIATION	1008464	1191255	1358846	1560053	1906274
MISCELLANEOUS					
RATE BASE	17117275	20368169	21952008	25972951	30355548
COMMON EQUITY BASE	9611751	10963865	12397422	14095637	16004635

Figure 16-3. Annual Cash Reports

GENERAL ELECTRIC COMPANY, EUSED FINANCIAL SIMULATION PROGRAM FSP-6 V6.10
01/29/82 17.250 JOB NUMBER 1862YT
BASED ON OGP6 JOB 2526NT DATED 01/13/82

OGP ELECTRIC SYSTEM, FILE UMFSP6L
USERS MANUAL EXAMPLE

PLANT ACCOUNTS
(THOUSAND DOLLARS)

YEAR 1995
****

UNIT ID	UNIT NAME	INSTL YR TOT.COST	******* *EXPEN.	1995 AFDC	******* TOTAL*	***** * CWIP	CUMULATIVE AFDC	***** TOTAL*
43	NUCLEAR	3602552	112273	173293	285566	2806819	795733	3602552
44	FOSSIL-COAL	2442130	171161	124006	295168	2053936	388194	2442130
45	GAS TURBINE	113455	53365	5043	58408	106731	6724	113455
46	GAS TURBINE	113455	53365	5043	58408	106731	6724	113455
47	FOSSIL-COAL	2588658	362862	114302	477164	1995742	280039	2275780
48	PUMPED HYDRO	275254	9512	11985	21497	194993	63071	258064
49	PUMPED HYDRO	275254	9512	11985	21497	194993	63071	258064
50	GAS TURBINE	119128	56034	1765	57799	56034	1765	57799
51	FOSSIL-COAL	2743978	576951	90870	667820	1730852	175682	1906534
52	FOSSIL-COAL	2743978	576951	90870	667820	1730852	175682	1906534
55	NUCLEAR	4351701	542479	145249	687728	2576777	380210	2956987
56	FOSSIL-COAL	2908616	611568	57793	669361	1223136	89900	1313036
59	FOSSIL-COAL	3083133	432175	27227	459402	648262	34034	682296
60	FOSSIL-COAL	3083133	432175	27227	459402	648262	34034	682296
63	PUMPED HYDRO	340991	35351	8908	44259	159077	25797	184875
64	PUMPED HYDRO	340991	35351	8908	44259	159077	25797	184875
65	PUMPED HYDRO	340991	35351	8908	44259	159077	25797	184875
66	FOSSIL-COAL	3268121	229053	7215	236268	229053	7215	236268
70	PUMPED HYDRO	359746	37295	7049	44344	130532	17818	148350
71	PUMPED HYDRO	359746	37295	7049	44344	130532	17818	148350
74	NUCLEAR	5598317	348941	21983	370924	523411	27479	550890
75	NUCLEAR	5598317	348941	21983	370924	523411	27479	550890
79	NUCLEAR	5962208	185811	5853	191664	185811	5853	191664
80	PUMPED HYDRO	400406	27673	3487	31160	69183	6538	75721
81	PUMPED HYDRO	400406	27673	3487	31160	69183	6538	75721
82	PUMPED HYDRO	400406	27673	3487	31160	69183	6538	75721
85	PUMPED HYDRO	422429	21897	2069	23966	43793	3219	47012
86	PUMPED HYDRO	422429	21897	2069	23966	43793	3219	47012
92	PUMPED HYDRO	445662	15401	970	16371	23101	1213	24314
93	PUMPED HYDRO	445662	15401	970	16371	23101	1213	24314
94	PUMPED HYDRO	445662	15401	970	16371	23101	1213	24314
95	PUMPED HYDRO	445662	15401	970	16371	23101	1213	24314
99	PUMPED HYDRO	470174	8124	256	8380	8124	256	8380
100	PUMPED HYDRO	470174	8124	256	8380	8124	256	8380
	TOTAL		5498432	1003506	6501938	18677890	2707329	21385217
	OTHER PLANT		1471743	14487	1486230	367936	5795	373731
	GAS		0	0	0	0	0	0
	GRAND TOTAL		6970174	1017994	7988168	19045825	2713124	21758948

YEAR 1996
****

UNIT ID	UNIT NAME	INSTL YR TOT.COST	******* *EXPEN.	1996 AFDC	******* TOTAL*	***** * CWIP	CUMULATIVE AFDC	***** TOTAL*
47	FOSSIL-COAL	2588658	181431	131447	312878	2177173	411486	2588658
48	PUMPED HYDRO	275254	4756	12434	17190	199749	75505	275254
49	PUMPED HYDRO	275254	4756	12434	17190	199749	75505	275254
50	GAS TURBINE	119128	56034	5295	61329	112067	7060	119128
51	FOSSIL-COAL	2743978	384634	121160	505793	2115486	296841	2412327
52	FOSSIL-COAL	2743978	384634	121160	505793	2115486	296841	2412327
53	GAS TURBINE	125084	58835	1853	60689	58835	1853	60689

Figure 16-4. Annual Plant Expenditures

FINANCIAL RESULTS

SUPPLEMENTARY INFORMATION

1. Adding Financial Simulation to Long-Range Generation Planning, R.P. Felak, W.D. Marsh, R.W. Moisan and R.M. Sigley.

2. The Effect of Load Factor on Generation Mix and Financial Planning, R.P. Felak, B.M. Kaupang, W.D. Marsh and R.W. Moisan, 1976 Frontiers of Power Technology Conference.

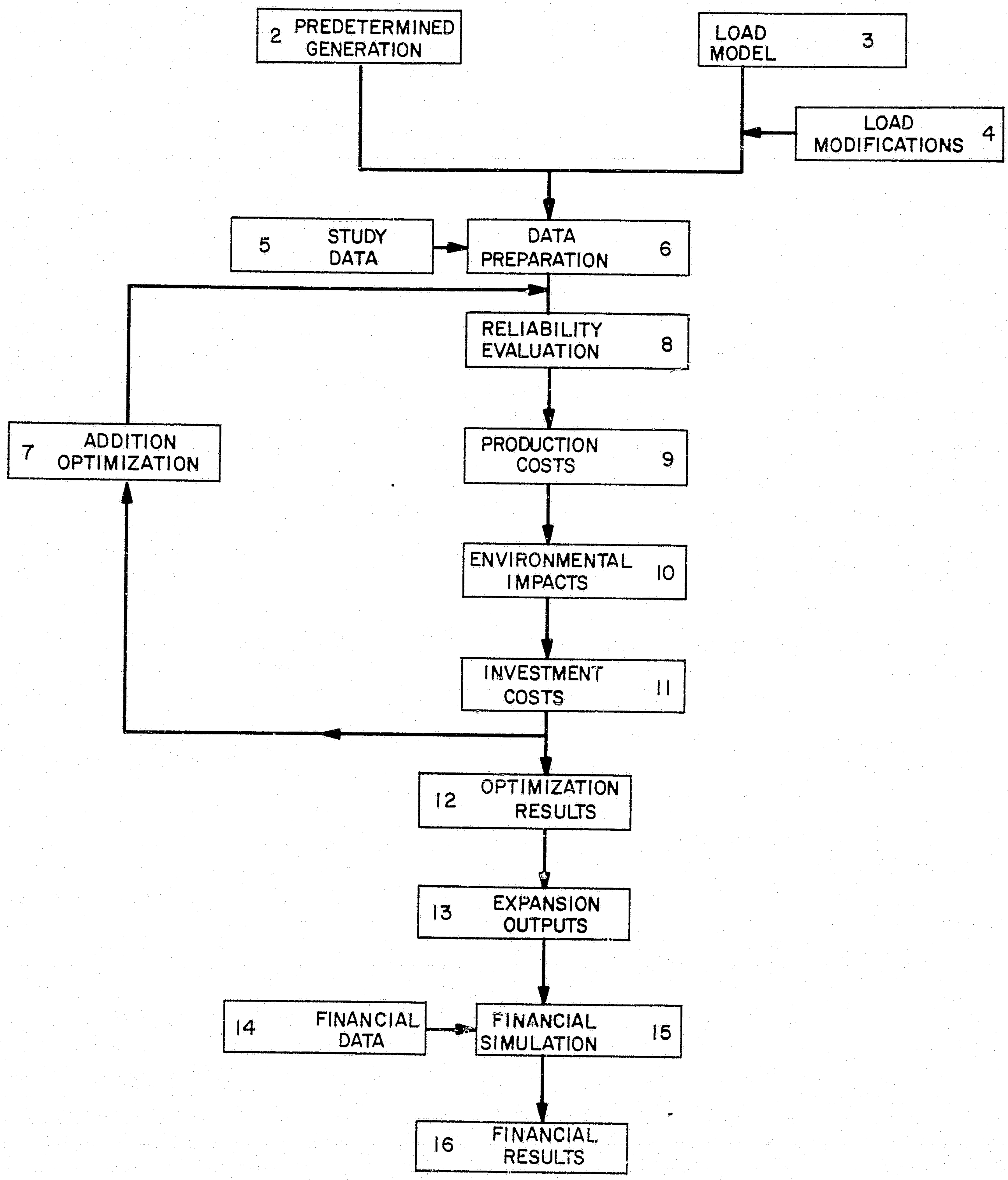
3. Planning to Improve Utility Profitability, V.A. Rydbeck and R.M. Sigley, 1975 American Power Conference.

4. Economic Implications of Growth, G.N. Creighton and R.M. Sigley, 1976 Joint Power Generation Conference.

5. The Effect of Load Growth Uncertainty on Generation System Expansion Planning and Financial Analysis, D.L. Dees, R.P. Felak and G.A. Jordan, 1978 American Power Conference.

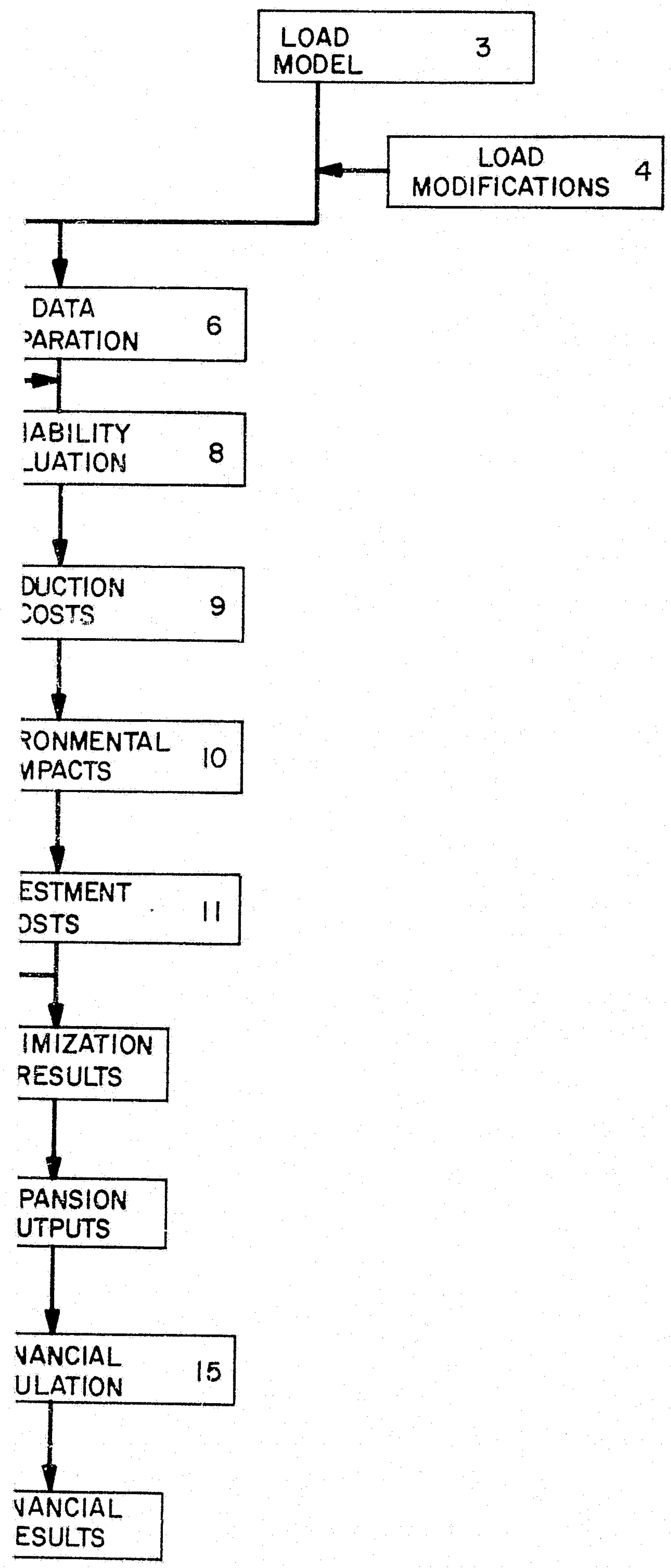
6. The Necessity of Including Financial Simulation in Long-Range Generation Planning, R.P. Felak, C.D. Galloway, G.E. Haringa, R.M. Sigley and H.G. Stoll, 1978 American Power Conference.

7. Integrating Financial Analysis with Generation Planning, R.P. Felak and R.M. Sigley, 1978 Pennsylvania Electric Association System Planning Conference.



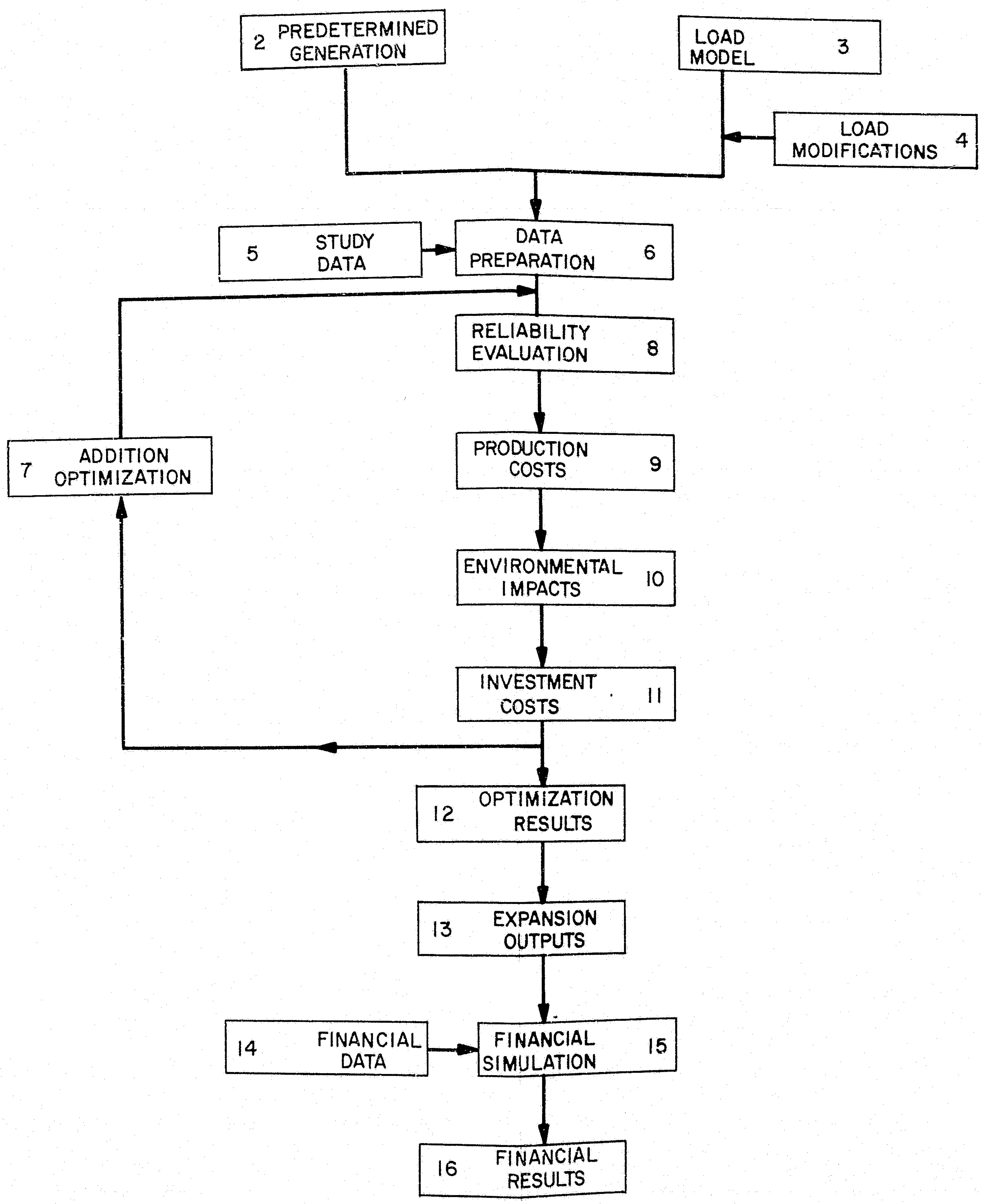
* Numbers indicate handbook section in which each topic is discussed.

Figure 1-1. OGP/FSP Schematic Flow Chart



ch each topic is discussed.

hematic Flow Chart



* Numbers indicate handbook section in which each topic is discussed.

Figure 1-1. OGP/FSP Schematic Flow Chart