



A DYNAMIC MODEL FOR MEASURING MANAGERIAL  
PERFORMANCE IN REGULATED ELECTRIC UTILITIES

A THESIS

Presented to

The Faculty of the Graduate Division

by

Lester Jackson Turvaville

In Partial Fulfillment  
of the Requirements for the Degree  
Doctor of Philosophy in the  
School of Industrial Engineering

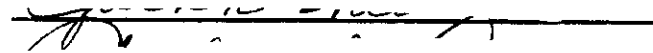
Georgia Institute of Technology

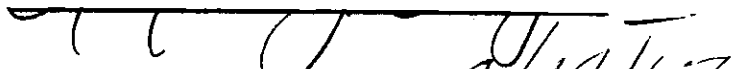
March, 1967

A DYNAMIC MODEL FOR MEASURING MANAGERIAL  
PERFORMANCE IN REGULATED ELECTRIC UTILITIES

Approved:

  
Chairman



  
Date approved by Chairman: 4/19/67

## ACKNOWLEDGMENTS

For all the assistance, inspiration and encouragement which the author received during this research, he is very grateful. Although it would be difficult to name every person who contributed, specific mention will be made of the following:

Dr. Bob Spradlin, the thesis advisor, for the support and advice which has resulted in this paper. The encouragement which he provided seemed to be perfectly timed.

Dr. Joseph Krol, the guidance committee chairman, for making it possible to reach the thesis stage.

Dr. Jack Walker, committee member, who provided much more help, encouragement and counseling than could have been expected, and which was greatly appreciated.

Dr. Andrew J. Cooper, committee member, who made many helpful suggestions and comments throughout the research and the writing of the thesis.

Other than these active participants in the thesis effort, appreciation is also extended to the department heads during my tenure -- Col. Frank F. Groseclose and Dr. Robert N. Lehrer -- for their guidance and for the financial assistantships which they made available.

The author was further supported in this research financially by the Ford Foundation. This assistance was invaluable and will always be remembered.

Special indebtedness is due my wife, Jane, and to our children, Terri and Roy, for their patience while living as a family without a husband and father. The greatest inspiration, however, was provided by my thoughts of Randy and Andy.

## TABLE OF CONTENTS

	Page
ACKNOWLEDGMENTS . . . . .	ii
LIST OF TABLES . . . . .	vi
LIST OF ILLUSTRATIONS . . . . .	vii
CHAPTER	
I. INTRODUCTION . . . . .	1
Purpose	
Nature of the Problem	
Importance of the Problem	
Scope of Study	
Limitations of Study	
II. LITERATURE SURVEY . . . . .	15
Performance Measurement	
Simulation	
Summary	
III. COST ANALYSIS OF ELECTRIC UTILITIES . . . . .	30
Introduction	
Uniform System of Accounts	
Selection of Utilities for this Study	
Analyses to be conducted	
Analysis of Expenses	
Analysis of Plant Investment	
Analysis of Variation in Expenses	
Conclusions	
IV. DEVELOPMENT OF A GENERAL MODEL . . . . .	54
Introduction	
Basic Considerations in the Production	
Department	
Selection of Factors for the Model	
The Operating Section of the Production	
Department Model	

## TABLE OF CONTENTS (Continued)

	Page
Economic Loading of the Generators	
Investment Section of the Production	
Department Model	
Investment and Capital Cost	
Property Taxes and Insurance Costs	
Income Tax Benefit Resulting from the	
Investment	
Present Worth Conversion	
Summary	
V. VALIDATION STUDY . . . . .	92
Introduction	
Description of the Company Data Required	
Company Data Used in the Validation Study	
Results of the Validation	
Conclusions	
VI. DETERMINATION OF A MEASURE OF PERFORMANCE . . . . .	108
Introduction	
Selection of Study Period	
Selection of the Alternatives	
Modifications to Validated Model	
Results of the Alternative Simulation Studies	
Measure of Performance	
Recommendations for Adoption	
Conclusions	
VII. CONCLUSIONS AND RECOMMENDATIONS . . . . .	125
Conclusions	
Recommendations	
APPENDICES . . . . .	129
BIBLIOGRAPHY . . . . .	177
VITA . . . . .	181

## LIST OF TABLES

Table	Page
1. Revenues, Expenses and Utility Plant for Private Electric Utilities, 1952-1961 . . . . .	10
2. Electric Operating Expenses for all Privately Owned Class A and B Electric Utilities in the United States (Per cent of total) . . . . .	36
3. Electric Operating Expenses for 23 Selected Privately Owned Class A and B Electric Utilities in the United States (Per cent of total) . . . . .	37
4. Electric Utility Plant for all Privately Owned Class A and B Electric Utilities in the United States (Per cent of total) . . . . .	41
5. Electric Utility Plant for 23 Selected Privately Owned Class A and B Electric Utilities in the United States (Per cent of total) . . . . .	42
6. Range of Variation Expressed as Cents Per Kilowatt-Hour by Years for Total Production and Distribution Expenses . . . . .	49
7. Coefficients of Determination for Expenses of 23 Selected Privately Owned Electric Utilities, 1951-1963 . . . . .	53
8. Monthly Cost of Coal for XCO, in Cents/ Million BTU's . . . . .	96
9. Log of Aoutages for Gan 1, 1958 . . . . .	97
10. Validation Results versus Actual Results . . . . .	107
11. Cost Estimates for Alternative Units . . . . .	115
12. Results of the Simulation for all Alternatives . . . . .	121

## LIST OF ILLUSTRATIONS

Figure	Page
1. Direct and Indirect Experimentation . . . . .	7
2. The Decision as a Controller . . . . .	28
3. Production Department Expenses as a Per cent of Total Operating Expenses for all Companies and 23 Selected Companies . . . . .	38
4. Distribution Department Expenses as a Per cent of Total Operating Expenses for all Companies and 23 Selected Companies . . . . .	39
5. Production Department Plant Investment as a Per Cent of Total Plant Investment for all Companies and 23 Selected Companies . . . . .	43
6. Distribution Department Plant Investment as a Per Cent of Total Plant Investment for all Companies and 23 Selected Companies . . . . .	45
7. Annual Variation in Average Cents per Kilowatt- Hour for Distribution, Production and Total Expenses for 23 Selected Companies . . . . .	51
8. Maximum Temperature and Steam Pressure, 1916-1959 . . . . .	57
9. Typical Heat Rate Curve . . . . .	57
10. Economic Generator Loading . . . . .	60
11. Scatter Diagram of Unit Cost Per Kilowatt of Capacity, 1962-1963 . . . . .	60
12. Block Diagram of Production Department Operation . . . . .	68
13. General Pattern of a Daily Load Profile . . . . .	70
14. Typical Daily Load Profile for One Range . . . . .	72
15. Typical Daily Load Profile for All Ranges . . . . .	72

## LIST OF ILLUSTRATIONS (Continued)

Figure	Page
16. Typical Daily Load Profile for a Continuous Operation Industrial Plant . . . . .	73
17. Typical Daily Load Profile for a Large Department Store . . . . .	73
18. Instantaneous Hourly Demand versus Average Hourly Demand . . . . .	75
19. Flow Diagram of Hourly Demand Determination Based on Monthly Data . . . . .	77
20. Flow Diagram of Economic Loading of Three Units . . . . .	79
21. Annual Book Value with Double-Rate Declining Balance Depreciation Method . . . . .	87
22. Daily Load Profile, Winter . . . . .	100
23. Daily Load Profile, Springs . . . . .	100
24. Daily Load Profile, Summer . . . . .	101
25. Daily Load Profile, Fall . . . . .	101
26. Correction Factor, 1958 . . . . .	102
27. Correction Factor, 1959 . . . . .	103
28. Correction Factor, 1960 . . . . .	104
29. Heat Rate Curves for Gan 1, Gan 2, and Gan 3 . . . . .	106
30. Total Generating Capability versus Maximum Integrated Demand . . . . .	111
31. Alternative Unit Installation Patterns . . . . .	112
32. Estimated Heat Rate Curves Including Actual Curves Used as Basis for Estimation, 130 Mw - 265 MW Units . . . . .	118
33. Estimated Heat Rate Curve, 75 MW unit . . . . .	119
34. Estimated Heat Rate Curve, 350 MW unit . . . . .	120

## CHAPTER I

### INTRODUCTION

#### Purpose

The purpose of this research is to develop a method and procedure for measuring managerial efficiency among electric utility companies. The measure of efficiency proposed would be the result of the relationship between a measure of an individual company's past performance and a measure of best possible performance for the same company for the same period of time. It is hoped that the techniques developed in this research will be a major contribution to measuring managerial performance by providing a deterministic and consistent method for determining such a measure.

#### Nature of the Problem

The objective of regulation is to insure that the customer receives satisfactory service at the lowest possible cost, and also to allow owners of the utility to receive just compensation for their investment and efforts.

Regulation by governmental bodies has evolved from the earliest form of regulator -- competition. Charters or franchises were freely granted for the construction of competing utilities in many larger geographical service areas. It was not unusual in some of these large areas to have more than two companies providing the same service; in

New York City there were as many as six gas companies serving that city at one time (40).

Competition between utility companies might have assumed many forms, but the primary one was price competition. This usually degenerated into "cut throat" price wars designed to eliminate the competitors. After the price war, instead of the consumer benefiting, as might be expected, prices were usually raised abnormally high so that the surviving utility might recoup some of the losses sustained during the price war.

Another disadvantage to the consumer arising from competition between utilities stems from the fact that utilities typically require high investments in capital assets. In the past, the duplication of these assets together with operating expenses frequently resulted in greater costs for the service to the customer. The above disadvantages suggested that competition could not always serve the function of a regulating service.

The courts then appeared as a regulative body to protect the interests of consumers. Since the courts exist to resolve disputes involving specific instances, they failed in the regulation capacity. Continuous regulation is necessary by men with technical competence and experience. The judicial procedure is also costly and timeconsuming.

Direct legislative control has also been attempted as a means of regulation through the granting of franchises and charters, and through statutes defining the obligations of public utilities. The disadvantages of this method are similar to those of the courts. Successful regulation

must be a continuing process. The legislature, with their infrequent sessions and their inevitable preoccupation with a multitude of other responsibilities, lacked both the time and the competence to administer the proper control.

The failure of the above alternatives as methods of regulation resulted finally in the formation of regulatory commissions. Under such an arrangement the legislature delegates its regulatory authority to an administrative agency which carries out the policy in accordance with standards and procedures prescribed by the legislature. This agency, the commission, is composed of full time qualified employees who can provide continuous supervision and can act immediately when questions arise.

Under all other forms of regulation up to the time of the commission, the consumer was usually receiving less than satisfactory service and paying a premium for it. Since the commission form of regulation did result in better service to the consumer at a reasonable price, the public has viewed the commission as a device only to assure the public of a continuation of this treatment. It is probable that most commissions have leaned in this direction in the past. But the commissions are also responsible for protecting the rights of the utility.

In a competitive industry the right to earn a reasonable return on an investment is not guaranteed, but is established through the action of economic forces over a long period. Through the application of these forces a competitive industry may have a number of companies which will survive. Among these, there will be a variation of investment return in general proportion to the degree of efficiency with which each firm

is managed.

A public utility, in which commission regulation replace competition, should have the right to receive the same privilege as a company in a competitive situation with regard to its rate of return. At present, however, the utilities are basically operating on a cost-plus basis which in itself does not provide a means of reward for efficiency. If, for example, a commission were to establish earnings at seven per cent of the rate base, a utility would be entitled to earn seven per cent whether it kept its expenses down or up. If a company were to have difficulty earning the seven per cent return, the commission would probably grant a rate increase. If, however, a company earning its seven per cent managed through efficient management to reduce significantly its expenses, enabling its return to rise to eight per cent, the commission would probably lower the rates.

It can be seen that there is also a lack of incentive for the utility to maintain a minimum investment. With a greater rate base the utility probably will be entitled to earn more money in terms of a return on its investment. Clearly then, the regulated utility is operating in a cost-plus atmosphere and consequently is being deprived of the opportunity to be recognized and rewarded for managerial efficiency.

To be just, regulation should establish (a) a rate of return which provides the lowest cost to the customer commensurate with the quality of service rendered, (b) a fair return to the investor, and (c) a sound financial condition for the company's operation. The last provision is particularly necessary for companies in a growing industry such as the electric utility industry, since such companies must secure

capital for expansion in the competitive market.

Regulation performs an economic function and is not a punitive process. The problem that exists -- that of no allowance for efficiency in utility operation -- has been recognized for many years. One of the earliest delineations of this problem is the Mountain States Telephone and Telegraph case in 1917 (PUR 1917B) in which the Colorado Commission noted that the company's efficient and economical operations should have a bearing in deciding the permissible fair rate of return; for "to hold otherwise would be to penalize economic, efficient and honest management."

Mr. Justice Brandeis said in 1923, in his concurring opinion in the Southwestern Bell Telephone Company v. Public Service Commission of Missouri (262 U.S. 276) case:

The compensation which the Constitution guarantees an opportunity to earn is the reasonable cost of conducting the business. Cost includes not only operating expenses but also capital charges. Capital charges cover the allowance, by way of interest, for the use of the capital whatever the nature of the security issued therefor; the allowance for risk incurred; and enough more to attract capital. The reasonable rate to be prescribed by a Commission may allow an efficiently managed Utility much more. (underlining added).

Many more court and commission decisions could be cited conveying the same concept, that efficiently managed utilities should be entitled to a reward for their efficiency. Thus the task is no longer to recognize that a problem exists, but rather, to find an appropriate solution.

In defining the problem, it appears that in order to arrive at a method for providing a reward for efficiency of management, a measurement of efficiency must first exist. And for a measurement of efficiency to exist implies first that a measurement of actual performance compared

to a measurement of optimal performance for the same period of time must be available. This optimal performance will hereinafter be referred to as "standard performance."

Quality of performance, whether excellent or poor, is not the result of one day's or even one year's operation. In a utility it is probably the result of many years of operation, since much of the effort and investment is for the future, to meet anticipated growth and conditions. An investment in a new generator installed over the past two years, for example, may result in management's being judged as excellent or poor, depending on future events. If in five years there is excess generating capacity resulting in higher investment charges than necessary, higher salaries, etc., then a measure of management efficiency for that particular five year period might indicate poor performance.

If it were possible to take the utility company into the laboratory and look at its operation in retrospect, it would probably be possible to see how it might have been operated differently to provide adequate service but at a cheaper cost. A measure of efficiency could then be derived by comparing actual operations with the reconstructed ideal operation. Since of course a company's operation for a given period can't actually be recreated in a laboratory, perhaps the next best thing would be to construct a model of the company, which could be brought into the laboratory. Figure 1 illustrates these two approaches to experimentation (2).

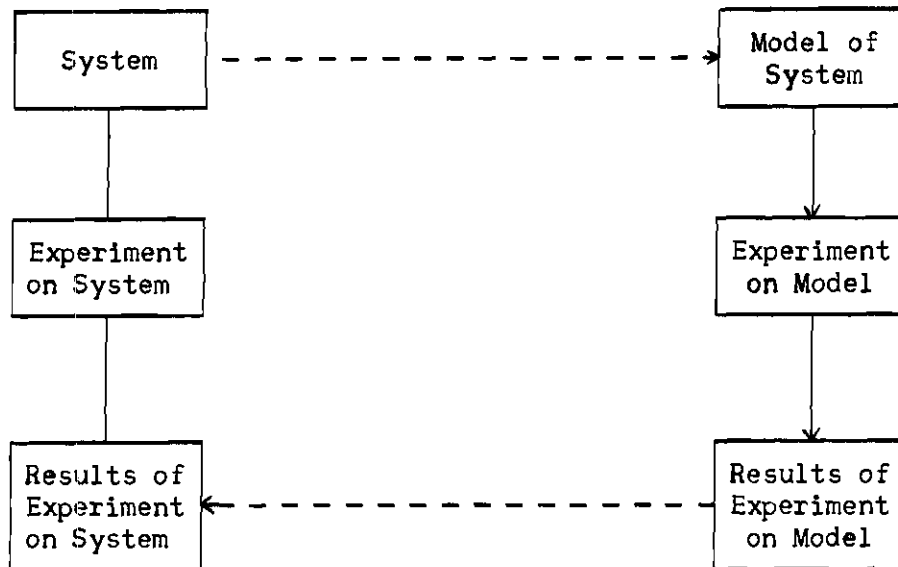


Figure 1. Direct and Indirect Experimentation.

Such systems studies, using a representation of the system (called a model) are conducted frequently and enable us to make inferences about the actual system. The use of models, then, is replacing "direct" by "indirect" experimentation. It is necessary that the model be of the mathematical type rather than of the physical type due to the nature of the utility system under consideration.

It has been previously stated that performance is a result of operation over time; thus it will be necessary to derive information about model performance by following the change of state of the model resulting from the succession of events affecting the model. This can be accomplished by programming the digital computer to follow the corresponding changes in the model and to make the numerical calculations. This technique is called "digital simulation."

After the model has been determined and the first run made, additional data is necessary for a standard operation. These are data associated with feasible alternatives which the company might have taken during the course of the study period. In the simulation, since the operation is under certainty, it is possible to determine which alternative should be selected by utilizing available data.

#### Importance of the Problem

The lack of an adequate means of measuring regulated utility performance in order to determine an efficiency rating for its management is a serious one. This means would be the first step towards achieving a plan whereby utilities might be rewarded for above average managerial efficiency. The importance of the need for such a plan is indicated in a speech delivered in October, 1962, by Chairman Swidler of the Federal Power Commission (4) when he stated:

If the industry or its consumers can suggest a workable substitute for the present system of awarding approximately the same rate of return irrespective of individual company performance, it can make a large contribution to the cause of effective regulation in the over-all public interest.

A satisfactory method for determining managerial efficiency and subsequently the installation of a workable plan of incentives would bring important benefits to many people. Utility management would benefit directly. With the increased emphasis on cost reduction, each item of expense would be closely scrutinized to assure that it contributed to greater efficiency. With a record of performance bonuses, equity capital would cost less and would encourage further investment. If a company has an inferior record, either from the absence

of a bonus or a reduction in the equity return, pressure for improvement would be brought to bear on management by the stockholders.

The customer would benefit through rates lower than would otherwise have been in effect without such an incentive for management. Further reduction could come from the willingness of the management to share the performance bonus with the customer. Being economically minded the company would provide faster and more efficient service.

If a workable solution were achieved between the commission and the companies it regulates, it would also tend to assure continuous regulation while releasing the commission to devote more time to other functions. The relationship between the commission and the utility companies should improve, since there would no longer be basis for the attitude that the commission, in order to help the consumer, must be harsh on the utility.

To understand further the importance of this research, a look at some statistics for the electric utility industry should be helpful. This will give amplification to the benefits listed above and the widespread effect that it could have on the entire economy. See Table 1, Revenues, Expenses and Utility Plant for Private Electric Utilities, 1952-1961 (43).

It is apparent that if commissions were successful in implementing an incentive program, and if this were to have only a small effect on revenues, expenses, and total utility plant (or investment), then a sizable dollar change would result.

In view of the significant potential benefits to utility management and the consumer, it appears that there is a real need for an

acceptable measure of utility performance, enabling an incentive method to be developed and installed.

Table 1. Revenues, Expenses and Utility Plant for Private Electric Utilities, 1952-1961

Year	Revenue for Electric Service <sup>1</sup>	Operating Expenses <sup>2</sup>	Total Utility Plant <sup>3</sup>
Millions of Dollars			
1952	5,426	2,577	20,636
1953	5,940	2,801	23,165
1954	6,317	2,880	25,358
1955	6,934	3,076	27,318
1956	7,521	3,356	29,499
1957	8,054	3,638	32,436
1958	8,478	3,703	35,295
1959	9,144	3,916	37,889
1960	9,697	4,097	40,456
1961	10,257	4,316	42,549

<sup>1</sup>Data cover private operating companies only.

<sup>2</sup>Excludes taxes and depreciation.

<sup>3</sup>Less reserves for depreciation and amortization.

#### Scope of Study

As indicated by the literature survey in Chapter II there has been no satisfactory method or technique developed which can provide a measurement of actual performance for a regulated utility company in comparison to a satisfactory and acceptable standard of operation. The term "satisfactory and acceptable" is used from the viewpoint of a regulatory body for the purpose of rewarding the utility for above

average performance.

The attempts at evaluating performance of industrial organizations, including utilities, have suffered from the absence of a suitable comparative standard. Thus, the results of such attempts have been of the relative type -- comparisons among utilities, or even between utilities and competitive companies. Although these methods have not produced a satisfactory means of rewarding utilities, they have remained the only approach probably due to a lack of analytical techniques, or of interest among persons capable of developing a new look at the problem.

The scope of this study was to introduce and test a technique for establishing a standard of operation and, subsequently, a measure of performance for a regulated electric utility company. Utilization was made of the principles of system simulation with the high speed digital computer.

Briefly, the procedure followed in this research was to develop a model based on those aspects of the utility which make the most significant continuing contribution to the factor selected as a criterion for comparison purposes. The model was then translated into a simulation language for the digital computer. Actual operating and growth data was collected from a test company for a selected period of time. This data was programmed into the model, which was then simulated on the computer for the selected time period. The results were considered to be the actual performance for that particular company.

Next, knowing the load growth that the company actually experienced during this period, it was possible to simulate the operation

of the company utilizing "ideal" decisions and solutions, since the operation was now being conducted under "certainty." The results of this run are called the "standard of operation."

The measure of efficiency is the relationship between the standard of operation derived from the second simulation run and the results of the first run. In order for this relationship to indicate efficiency it is convenient to think of efficiency as the relationship of output to input. In the case of an electric motor, efficiency is measured by output divided by input, where input will always be greater than output due to friction. The accepted concept that efficiency is a number equal to or less than unity was adhered to in this study. The measures of actual performance and standard performance are cost figures; therefore it is necessary to divide the standard performance measure by the actual performance measure in order to result in an efficiency measure equal to or less than unity.

The cost figure used as the measure of performance is the present worth value of all costs generated by the model during the simulation runs. Since the costs so generated during the different simulation runs occur at different times and are of different magnitudes they are difficult to compare as such. As explained in any engineering economy text book -- such as Grant and Ireson (14) -- one method of comparing alternative series of disbursements and receipts is the present worth method using an appropriate interest rate.

The model developed for representing the utility company during the simulation is based on the results of statistical analysis of cost

data for many companies. Since this study involves companies of varying sizes it is necessary to have a common figure for comparison purposes. One which seems appropriate is cost per kilowatt-hour generated, since it is this figure which efficient management is striving to keep at a minimum, and for which the customers are charged. A management deserving of a reward for an efficient operation is one which has maintained a lower cost per kilowatt-hour generated than it otherwise might have done.

#### Limitations of Study

In developing the model it is necessary to keep in mind the purpose of the study -- to determine managerial efficiency. Thus it suffices to include in the model the areas under management control which make significant contributions to costs. It is not beneficial to include other areas in order to have a "large" model or to make it appear more "realistic." Of necessity then, a part of the research must determine those areas of the company operation which should be included in the model. This is based on the results of the statistical analysis conducted in Chapter III.

Although data for 23 companies is used in the statistical analysis, only one company is used to test the validity of the model. Data for this company is also used to explore the various alternatives for arriving at a measure of performance. In securing the data for these alternatives it is necessary to develop some hypothetical data by extrapolation and interpolation. This limitation on the use of actual data would not be a handicap to a regulatory body if this

procedure were to be adopted. It would only be necessary to accumulate this data over the period of time which would later be simulated.

It is not the purpose of this study to make any statement as to the managerial performance of the one company used for test purposes. The technique for doing so is developed and its application will be illustrated by the use of data for this particular company. The model as developed might require modification for application to other companies, since it is tailored to fit the test company. The operating policies of the model would remain the same but the number of generating units might need to be increased.

It is expected that the basic model or an expanded version of the basic model would serve for any company operating under the jurisdiction of a single regulatory body, based upon the assumption that companies within this area are subject to similar managerial decisions along with external factors which management cannot control but with which they must all cope. For example, some geographical areas are experiencing spasmodic growth rates while others may have a very steady growth. If such varying conditions are found among companies operating within the same jurisdiction of a regulatory body, then perhaps the model would require modification. It would seem fair to recognize any added managerial difficulty which one company might face compared with the others.

## CHAPTER II

## LITERATURE SURVEY

Performance Measurement

Simon (30) in his book Administrative Behavior has an interesting discussion of efficiency. He feels that the scientific management movement added another meaning to efficiency. In quoting from the Encyclopedia of the Social Sciences he said:

The foundation of modern scientific management may be dated from F. W. Taylor's paper, 'A Piece Rate System' in which he described his pioneer method of establishing standards of job performance at the Midvale steel plant. When such standards were set, it became customary to refer to the ratio of actual performance to the standard performance as the efficiency of labor, a use somewhat different from that of the mechanical engineers, who apply the term to the ratio of actual output to an actual input.

Simon goes on to say that the criterion of efficiency requires that results be maximized with limited resources. A "good" (efficient) public library is not one that owns all the books that have ever been published, but one that has used the limited funds which are allowed to build up as good a collection as possible under the circumstances.

Harrington Emerson (9), another pioneer in the scientific management movement, is reported to have defined efficiency as "the relation between what is accomplished and what might be accomplished." It is precisely this definition of efficiency which is used in this study and for which a measure is sought.

A search of the literature was made to determine if such a

measure of performance is available, and, if there is not, to see what attempts have been made in this area.

An early investigation into the measurement of industrial efficiency was done by J. A. Scott (27). He made mention of a number of existing methods for arriving at a measurement of efficiency, some of which will be discussed. The first is The Investors of Stock Exchange Measurement, used by the shareholder or potential shareholder. The measurements are mainly based on comparisons with past results, the most common ones being: 1) per cent dividend on issued capital, 2) previous net profits, 3) per cent of net profit to net worth, 4) per cent of current assets to current liabilities, and 5) per cent of each asset to total assets. The measurements are all concerned either with the firm's capacity to earn profits or its financial stability.

Another measurement, similar to the first, is The Auditor's Methods of Measurement. It consists of ratios or percentages as follows: 1) per cent net profits to sales, 2) per cent gross profit to sales, and 3) per cent sales to net worth. These ratios are separated from the first because he felt that they involve information not normally available to share holders. This is not true today since such information is available in most companies' annual reports. There are numerous other ratios which may be calculated and which serve various needs. For a complete treatment of ratios and what they mean, the reader is referred to publications by analysts such as Dun and Bradstreet (38).

The Works Accountant's Basis of Measurement may be undertaken in

larger concerns where cost accountants are employed. The measurements are of the rate per ton or gallon produced, or as percentage to sales, output, or to direct labor. They are then compared with previous results, or, in some cases, to other similar firms where their compilation has been carried out on an identical basis.

Another technique adopted for measuring efficiency is commonly known as budgetary control. This measurement is the comparison of the actual results of operation with the budget.

Scott's own contribution to this field is a method he calls the Functional Survey. He claims that the total efficiency of a business is a combination of the efficiency of each of these business functions: 1) design, 2) purchasing, 3) production, 4) warehousing and packing, 5) selling and distributing, 6) finance, and 7) general administrative and management. Scott develops a questionnaire for each of the above functions and assigns points for each question, broken down into a scale with eleven possibilities. The proportion of points to be awarded for various factors presents a thorny problem. It would be difficult for even two authorities to agree on the assignment of points, thus making it almost impossible to obtain a definite index of efficiency.

According to Scott, some consulting engineers claim that after two or three days spent in a given plant, they can roughly assess its relative productive efficiency. For example, "I should think Factory B is about 50 per cent efficient." Factors on which this appraisal would be based include such items as plant layout; office layout; use of facilities; lighting, heating, and ventilation; employee morale; management morale; etc. It is probably true that a reasonable relative

position might be gleaned by these consultants, but such an approach is far too uncertain and subjective to serve the purpose of this study. None of the above methods, in fact, have met with any degree of success in specifically determining the efficiency of a firm.

Another point rating system has been developed by Martindell (20) and is called the Management Audit Procedure. This is a procedure for systematically analyzing and appraising the overall performance of management. The Audit examines ten categories or functions of the organization and the rater subjectively assigns a certain number of points to each category to reflect his rating. The total points are the measure of the management in that company. The subjective nature of assigning points precludes a satisfactory method for establishing a definite index of efficiency.

In the abstracts and indices under areas related to managerial performance, many articles are concerned with the performance of managers and individuals, or even groups, but not with complete company organizations. As determined from a search of these articles, the conventional approach, in which managers are placed in the uncomfortable position of "playing God," is the one in which the manager actually judges a subordinate's performance. This method requires skill and delicacy not possessed by many managers. McGregor (21) feels that no manager possesses nor could acquire the skill necessary to carry out this responsibility effectively. Actually, few would be willing to accept it if they were fully aware of the implications involved.

A new approach to this conventional method is Peter Drucker's (8) concept of "Management by Objectives." This approach requests the

subordinate to establish short-term performance goals for himself. The superior's role is to help the man relate his self-appraisal and his plans for the ensuing period to the realities of the organization.

Shapton (28) proposes a similar approach when he considers that there are two main areas of endeavor in the development of a functional measurements program:

- 1) To establish objectives, set goals within these objectives, make plans to achieve the goals, and measure the results; that is, the measurement of achievements in relation to goals.
- 2) To develop quantitative measurements of activity applicable to specific areas within a function wherever possible; that is, the measurement of indexes in relation to standards.

What Shapton suggests that functional measurement actually does, is in effect, to ask each function to do a better job; that is, "walk the second mile." The quantitative measurement does not appear to be something which could be used between companies, and probably not even between departments within the same firm. It must inherently be subjective in nature, based on standards which are the result of one's judgment.

Schleh (26) feels that the main purpose of measuring management is to indicate the direction toward which an individual should be going and to give him encouragement in that direction. This theme is evident in the plans he discusses. Other than the appraisal system which has been noted before, he refers to the budget system which Scott also mentioned. Schleh feels such systems dry up imagination and initiative; also, he feels that managers often fight for increased budgets and then merely try to keep within them.

The American Management Association (41) questions how far one can or should go in arriving at managerial performance standards based on numerical quantities. For example, a company could decide to use money as the basis for the standards of performance for a plant manager. This could be done by a carefully conceived budgetary system with predetermined costs and accurate estimates of income. But, if, in staying within his budget and providing a satisfactory income, the plant manager cuts maintenance costs so severely that his production equipment falls apart later, his earlier "efficient performance" was actually substandard. This certainly indicates that performance standards do not result from a budgetary period, but are dynamic over a longer period of time.

Evans (12) is one writer who feels that money should be the criteria of performance. He says, "Good management is the kind that makes money," and also, "Good management is the type that saves money." As do many others, he feels that one of the most vital obligations of management is that of adequately rewarding stockholders -- to retain present investors and to attract new ones. There is certainly no argument here, but he does not propose a method of converting this flow of money into a measure of performance.

The use of some expression of performance referring to money is not new. The early method of measuring executive performance was to relate profits to the volume of sales. Weinwurm (34) isolates a number of limitations to this measure. Among them are the difficulty of determining the "correct" figure to use for profit, the number of circumstances beyond managerial control which affect profit, the different results depending on the time period surveyed, and the lack of attention given

to the capital invested in the enterprise and the earning requirements of the investment.

At the time Weinwurm made his views known, the British Institute of Management and the British Productivity Council established a center for interfirm comparison (36) (39). There is nothing new in any of the criteria developed. Ratios were used similar to those suggested before, i.e., profits to sales, profits to assets, etc. The ratio which they regarded most highly is the return on real capital employed in the business. In using this ratio there is still the need to determine profit, as well as the amount of capital invested. Weinwurm feels that current accounting practices do not furnish adequate information to determine the amount of capital invested in a particular enterprise.

The Interfirm Comparison center also accumulates information which enables competitors to compare particular aspects of current operations. For example, the time taken to make a standard product by one company may be compared to the time a competitor takes to make the same product. This comparison, of course, provides only a relative measure and does not really provide a measure of performance.

A method typical of many is Performance Analysis developed by Edwards (11). He was concerned with the volume of work performed and the manpower utilized. According to Edwards his method accomplished such purposes as improving management, controlling backlogs of work, and better scheduling of work. At the outset of his analysis, reports were collected containing information on the amount of work done and the time spent. These reports were used for establishing statistical

performance standards. After the standards were established, a periodic measure of output was compared with the standard output to provide a performance effectiveness measure. A chart was maintained by months showing the status of the entire organization. This approach certainly provides an individual company with information which can be helpful, but it would not serve for comparison of separate firms, since it would not be a valid standard for any type of rigorous use.

Another approach to the measurement of relative performance consists of estimating a given utility's real productivity and comparing this with a standard. The term "productivity" has been used to describe the relationship between output and any or all of the associated inputs. Barzel (1) and Kendrick and Creamer (17) have examined the appropriateness of the output-per-unit of input technique as a measure of productivity change. According to Barzel, working specifically in the electric power industry, the effects of economies of scale proved to be the significant reason for productivity increase other than technical advancement. Allowing for these effects, he concluded that productivity measures were satisfactory in the electric utilities.

The problem with this approach is that it is still a relative measure of efficiency. Should the historical performance of the particular firm be taken as the standard? Or should some statistical average of a group of firms be utilized? It appears that regardless of how the standard is determined it cannot be certain that it is the exact one.

Drucker (8) develops a measure which he calls Contributed Value. This is the difference between the gross revenue received by a

company from the sale of its products or services, and the amount paid out by it for the purchase of raw materials and for services rendered by outside suppliers. In other words, it includes all the costs of all the efforts of the business and the entire reward received for these efforts. It is similar to an economy study which considers actual cash flows but not book transactions or results generated by the accounting department. It would be necessary to consider a long period of time to obtain an accurate picture of performance. The problem associated with determining a standard for the productivity method would also be a problem in this method.

A technique developed by Iulo (15) is a different and recent approach to the development of a measure of performance, and is concerned only with electric utilities. Iulo feels that in an industry as complex as electric utilities it is rather difficult to say that a company has achieved 90 per cent perfection, or 50 per cent, or only 10 per cent. For this reason he has chosen to measure relative efficiency; i.e., which ones out of a group of companies are in the top 10 per cent, which ones are in the bottom 10 per cent, etc. The position within the spectrum of efficiency occupied by a particular company can be compared to the industry average, to the best utility, or to some other point.

The approach used was to examine between 30 and 40 factors which seemed to be important, were measurable, and were relatively insensitive to short range managerial action. Further investigation led to the isolation of seven factors which seemed to have the helpful property of accounting for about 75-80 per cent of all unit cost variations among the companies studied for the years 1952 through 1957.

The seven factors found to be significantly related to unit electric costs were:

- (1) the size of the steam-electric generating stations of individual utilities;
- (2) the capacity of utilization of individual utilities;
- (3) the level of steam-electric fuel costs in the area served by individual utilities;
- (4) the level of hydroelectric "fuel" costs of individual utilities;
- (5) the distribution of the market among consumer classifications of individual utilities;
- (6) the average consumption of energy per commercial and industrial consumer of individual utilities; and
- (7) the average consumption of energy per residential customer of individual utilities.

These factors were then used to develop an "estimated standard cost" for each particular utility in each year of the study, based on average figures for all the utilities. The actual unit costs of the company were then compared with this -- the hypothesis being that a utility whose actual unit costs were consistently above these standardized estimated costs would be relatively inefficient and one whose actual unit costs were consistently below would be efficient.

The results of Iulo's study are presently indicative rather than final. One problem which could arise is that of dealing with a company which indicated a wide variation -- a large difference between the estimated and actual unit costs. This could indicate that some other factor or factors were operating which were not among the seven original factors. Should this company be removed from the study or should the factor or factors be determined and considered for all the other companies?

In connection with the standard, it should be observed that it

is a result of the average values for all the companies included in the study for each factor. This produces a relative measure instead of an absolute one. Taking statistical results of a large number of companies and using these to make statements about the individual companies does not appear to be a satisfactory basis by which a commission could operate a reward system for efficiency.

Thus there have been many methods and systems proposed for determining the effectiveness, or for appraising the results of an organization. Some have obvious faults, while others appear satisfactory to some degree. But preventing them from providing a true measure of performance there is one common failure -- the standard. As Brown (3) stated, "We can never be entirely sure that the most successful enterprise might not, under other conditions, have been more successful."

#### Simulation

It was the objective of this research to develop a method whereby this standard might be determined -- a standard which represents a level of operation which the firm could have been expected to achieve. Since this method chosen involves digital computer simulation, it was felt that a search of this literature would be worthwhile.

With the advent of electronic computers, there has been a considerable increase in the number of simulation studies of complex industrial operations. Formerly the labor of hand computation precluded the investigation of any but the simplest systems, and otherwise restricted the use of the simulation model to a single plant configuration. Because

of its great possibilities, simulation is being hailed as one of the decades great advances in the science of business management.

Simulation provides the ability to operate some particular phase of a business on paper or in a computer for a period of time. This enables various alternatives to be tested. Management can then evaluate the results of the various alternatives and make better operating decisions. It can learn results before they happen. As has been pointed out before, system simulation by digital computer offers the analyst a laboratory device for observing a model of a system in action.

As an indication of what simulation has been used for up to the present. The author offers the following examples. The H. J. Heinz Company (29) has used simulation with such effectiveness that a whole new approach to achieving the lowest practical costs of distribution has resulted. The model representing the distribution system takes into account each of the important factors involved: transportation rate structures, warehouse operating costs, the characteristics of customer demands, costs of labor and construction, factory locations, product mix, etc.

Since the model represents the essential parts of the actual distribution system, it permits the operation of the system in such a way that a year's transactions can be studied under close scrutiny. Various alternatives can be evaluated prior to their installation in the real distribution system.

Another simulation process was developed at the El Segundo Division of Hughes Aircraft Company (18) whereby actual shop operating

data contained in an existing data processing system is used as input to an IBM 7090 computer. The process for simulation of the El Segundo Fabrication Shop was used as a study tool to evaluate the effects of various management decisions on the operation of the shop.

There are other examples cited in the bibliography (7), (10), (25), (45) and many more uncited examples in which simulation techniques are employed. In addition to manufacturing operations it has been used to study such complex problems as military strategy, traffic control, and other processes which do not lend themselves to analysis by other techniques.

When talking about large-scale digital computers used in simulation work, one point should be kept in mind. Although computers are frequently called "electronic brains" they are by no means "thinking machines" in the human sense. A computer is merely a mathematical "beast of burden" which will do only what it is specifically told to do. But it does its assigned job with a speed and accuracy far beyond any other known means. Instructions to the computer must be precise and detailed. These are called the computer program.

The examples cited have used programs designed specifically to handle the particular problem involved. To spare the author the labor of designing a computer compiler language, an available simulation compiler language called "Dynamo" was used, along with its associated program language. This simulation language was developed in conjunction with the development of Industrial Dynamics by Professor Jay W. Forrester at the MIT School of Industrial Management.

Industrial Dynamics is a philosophy which asserts that organizations are most effectively viewed from the control system perspective, and treats the organization as a system of flows. (A complete description of Industrial Dynamics is published in a book by Forrester titled Industrial Dynamics (13).) Decisions are viewed as the controllers of these flows. As Roberts (24) explains it and as Figure 2 indicates, a decision is based in part on information about the contents of the source level, and on other information -- thus controlling the rate of flow to the destination level. The flows may involve men, money, material, orders, capital equipment, and information.

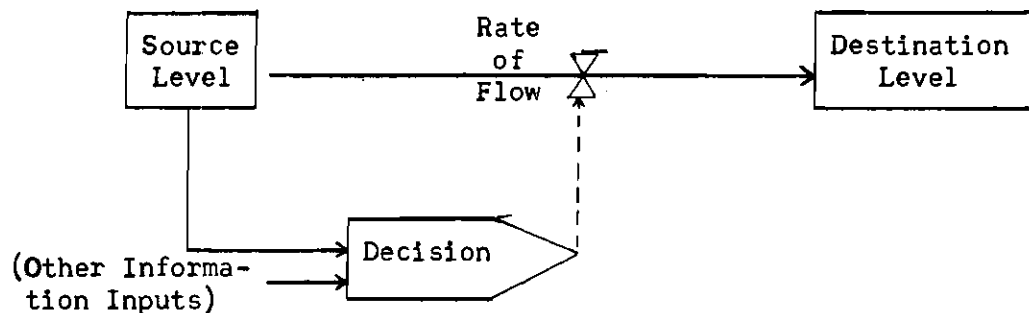


Figure 2. The Decision as a Controller.

Industrial Dynamics is designed to enable management to view the behavior in certain functions, and then to see the effects on this behavior resulting from change introduced in another factor in the system. An analysis of trends and patterns is thus possible. It is not intended that specific numerical information regarding any one factor will be produced.

Dynamo was developed to facilitate the application of Industrial Dynamics after the model has been constructed. Its use is explained in complete detail in a manual entitled "Dynamo Users Manual" (23). With this program language a model might be simulated on an IBM 7094 computer enabling ten years operation by months to be performed in 30 seconds. Not only is the speed tremendous but also the model size may be extremely large. The largest model that Dynamo can handle is one consisting of about 2000 equations.

Since this study recreated a historical operation, it is not an Industrial Dynamics study. However, the simplified simulation language of Dynamo did make its use desirable. For the reader, a knowledge of Industrial Dynamics is not necessary, but a knowledge of the Dynamo language may be of interest. A simplified discussion of Dynamo is presented in Appendix D.

#### Summary

This literature search may be concluded with the following statements:

1. There exists no measure of performance that can serve as a satisfactory basis upon which a regulatory commission could build a system of rewards for managerial efficiency.
2. With the advent of high-speed digital computers and associated simulation languages, such as Dynamo, it is possible to develop a model of a utility company and to simulate its operation over time, enabling the achievement of a satisfactory measure of performance.
3. This research will serve to extend the bounds of knowledge in this area.

### CHAPTER III

#### COST ANALYSIS OF ELECTRIC UTILITIES

##### Introduction

Over a period of time certain major areas of utility operations account for a significant portion of total operating expenses and capital outlays. By examining a common factor such as cost per kilowatt-hour generated, the researcher can find variation between companies in both total cost and in various components of total cost. This variation results from many factors, including managerial ability.

The area within a utility organization to be represented by the mathematical model is selected using three criteria. First, the area must make up a significant portion of the total operating expenses. Second, it must account for a significant portion of the total plant investment, and third, it must be responsible for a large part of the total variation in cost per kilowatt-hour generated.

##### Uniform System of Accounts

In a discussion of regulatory bodies in Chapter I, it was emphasized that commissions are the governing bodies at the state level for the regulation of public utilities. It has been quite common in many states for the commission also to have jurisdiction over the railroads. Thus, many commissions are frequently referred to as railroad and public utilities commissions. To be of mutual assistance, the state commissioners

have formed an association called The National Association of Railroad and Utilities Commissioners, frequently referred to as NARUC.

One of the goals of NARUC, which has been very successfully achieved, was the development of a uniform system of accounting, with subsequent revisions. At the 1958 Annual Convention of the National Association of Railroad and Utilities Commissioners, the following resolution was adopted (44):

WHEREAS, the Committee on Accounts and Statistics of this Association, after extended study and many conferences, recommends certain changes in the uniform system of accounts for electric utilities heretofore adopted by this Association, as set forth in a draft dated October 1, 1958, of a Revised Uniform System of Accounts for electric utilities including accounts for nuclear power operations, which has been presented by said Committee to the Association; and

WHEREAS, this Association believes that uniformity in utility accounting is most desirable in the public interest;

RESOLVED, that the Revised Uniform System of Accounts for electric utilities submitted by said Committee be recommended to the Commissions represented in the membership of this Association for consideration, and for adoption in their respective jurisdictions, with such modifications only as they may deem necessary in the public interest.

Due to the interest of all State Commissions and their desire to have uniformity in utility accounting, this goal has been achieved and is maintained. Uniformity is especially valuable to this type of research -- where data from utilities all across the United States are compared.

For privately owned electric utilities the operating expense accounts are divided into six areas as follows; 1) power production expenses, 2) transmission expenses, 3) distribution expenses, 4) customer accounts expenses, 5) sales expenses, and 6) administrative and

general expenses. Thus the total operation and maintenance expense is the sum of these six accounts. The details of all items which appear in each of the accounts is outlined in the latest publication of the NARUC, entitled Uniform System of Accounts for Class A and B Electric Utilities (44).

Also outlined in the same publication are the plant accounts, the ones which contain the investments in property, equipment, etc. These accounts are classified as follows: 1) intangible plant, 2) production plant, 3) transmission plant, 4) distribution plant, and 5) general plant. Complete details of the items which appear in each account are outlined.

There should be no question of the comparability of the available data with this degree of uniformity among the accounts of all the privately owned electric utilities. The Federal Power Commission collects these data, compiles and publishes them. Since the data received by the Federal Power Commission are a matter of public record, other associations are able to compile the statistics which suit their particular needs, and many of these are also published.

#### Selection of Utilities for this Study

This study is generally applicable to a wide range of commissions, although certain modifications might be necessary when making regional studies. In an attempt to make the study as meaningful as possible, certain guidelines were followed in selecting the companies for which data was used.

The type of power plant which the utility has employed is a major

consideration. It was decided that utilities using principally steam production, with as much as 5 per cent of other types of production would be acceptable for this study. It was felt that comparing a company which used primarily all hydroelectric generation with one using all steam would not yield meaningful results. Of the companies selected, the largest percentage of kilowatt-hour generation by hydro for 1963 was 1.6 per cent, compared to 3.4 per cent for the same company ten years earlier. Other than hydro and steam, internal combustion generation accounted for some production, but of the companies selected it was always less than 0.1 per cent, and in most cases, non-existent. During the period of study, nuclear generation was installed by one of the companies selected. In 1963, the last year included in the study, the total generation for other than fuel-fired steam was still only 3.8 per cent for this company.

A company must own and operate its own power plant. Some utilities are distributors only -- a situation made possible by purchasing wholesale the entire amount of electricity required for its system. This company would have transmission, distribution, customer accounting and sales expenses, but not production as experienced by the others. This type of operation is quite common among small municipally owned systems but is only occasionally found among privately owned companies.

Another consideration in selecting companies was the ultimate use of the electricity, since it would be more meaningful if the broad range of users for each company included in the study were similar. Thus all the companies selected serve at least residential, commercial and

industrial customers. This restriction was necessary in order to eliminate the possibility of including a company which did nothing but generate electricity, and then wholesaled it to another company. Its costs for distribution, sales, and customer accounting would be misleading.

It is common for privately owned utility companies to perform more than one public service. For example, one company may be a gas distributor or a water distributor or both, as well as an electric utility. Again to make the study as flawless as possible, another limitation was added -- that the utility be only an electric utility. Since some electric utilities have divorced themselves from these other functions only in recent years, it was necessary to insure that the utility was only an electric utility during the entire period of time covered by this study.

The limitation process resulted in a cross section of the utilities in the eastern half of the United States. This was highly desirable and probably would have been forced into the selection procedure had it not naturally resulted. The obvious reason that the West was not included is the large amount of hydroelectric generation in that area.

The resulting study group of 23 utility companies from 12 states is not an exhaustive figure, but does represent most of the companies which would meet the criteria outlined above. The only reason for not including some companies which met the qualifications was to eliminate a duplication of companies from a particular area, where a lack of variation made their inclusion seem superfluous. A list of the 23 companies is found in Appendix A.

### Analyses Conducted

The purpose of the analyses of the collected data is to examine the total cost and the cost of each component of the total cost for both the operational and investment phases of the utility. There are three individual analyses which provide the necessary information. If these three treatments of the data provide similar results, then the purpose of this section will have been accomplished.

#### Analysis of Expense

The first analysis is to investigate the operating expenses for each of the six areas defined in the Uniform System of Accounts and compare these with the total for all six areas; that is, with the total operating expenses for the company. Table 2 is a composite of the electric operating expenses for all class A and B privately owned electric utilities in the United States for the years 1951-1963. The results of this analysis indicates that the production department is responsible for more than half of the total operating expenses for all of the privately owned electric utilities in the United States.

Table 3 gives the same information for the sample of 23 utilities. Again the production department for the 13 year period accounted for more than half of the total operating expenses. The results are very similar for each of the other categories. It is apparent that there is no trend away from the average figure for the production department. This may be seen in Figure 3.

The distribution department is second in its contribution on total operating expenses. Since it is considerably less significant than the production department -- 16.9 per cent compared to 56.3 per cent on the

Table 2. Electric Operating Expenses for all Privately Owned Class A and B Electric Utilities in the United States (Per Cent of Total)

Operating Expenses	1951													
	1963	1951	1952	1953	1954	1955	1956	1957	1958	1959	1960	1961	1962	1963
Production	56.2	57.6	56.7	56.4	54.6	56.2	56.6	57.1	55.3	55.5	55.4	56.4	56.5	56.7
Transmission	3.2	3.0	3.3	3.3	3.3	3.3	3.2	3.1	3.3	3.4	3.4	3.2	3.2	3.1
Distribution	16.7	17.2	17.4	17.5	18.3	17.4	17.1	16.7	17.1	16.8	16.8	15.8	15.6	15.4
Customer Acct	6.5	6.4	6.5	6.5	6.7	6.5	6.5	6.4	6.7	6.8	6.6	6.5	6.4	6.4
Sales	3.6	3.2	3.2	3.3	3.4	3.4	3.4	3.4	3.6	3.7	3.8	3.7	3.8	4.0
Administrative General	13.8	12.6	12.9	13.0	13.7	13.2	13.2	13.3	14.0	13.9	14.0	14.4	14.5	14.4
Total	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0

Table 3. Electric Operating Expenses for 23 Selected Privately Owned Class A and B Electric Utilities in the United States. (Per cent of Total)

Operating Expenses	1951													
	1963	1951	1952	1953	1954	1955	1956	1957	1958	1959	1960	1961	1962	1963
Production	54.6	57.5	56.4	55.0	53.3	54.6	55.3	55.4	53.5	53.2	53.3	53.9	54.7	55.5
Transmission	2.9	2.6	2.7	2.7	2.8	3.0	2.9	2.8	3.2	3.3	3.2	2.9	2.9	2.8
Distribution	17.2	17.0	17.6	18.6	19.0	13.0	17.6	17.3	17.5	17.5	17.0	16.6	16.0	15.6
Customer Accts	6.7	6.4	6.6	6.6	6.8	6.8	6.8	6.7	7.1	7.0	6.9	6.7	6.5	6.5
Sales	4.4	3.8	3.9	4.0	4.2	4.1	4.1	4.0	4.3	4.4	4.8	4.8	4.9	4.9
Administrative General	14.2	12.8	12.8	13.1	13.9	13.5	13.3	13.8	14.4	14.6	14.8	15.1	15.0	14.7
Total	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0

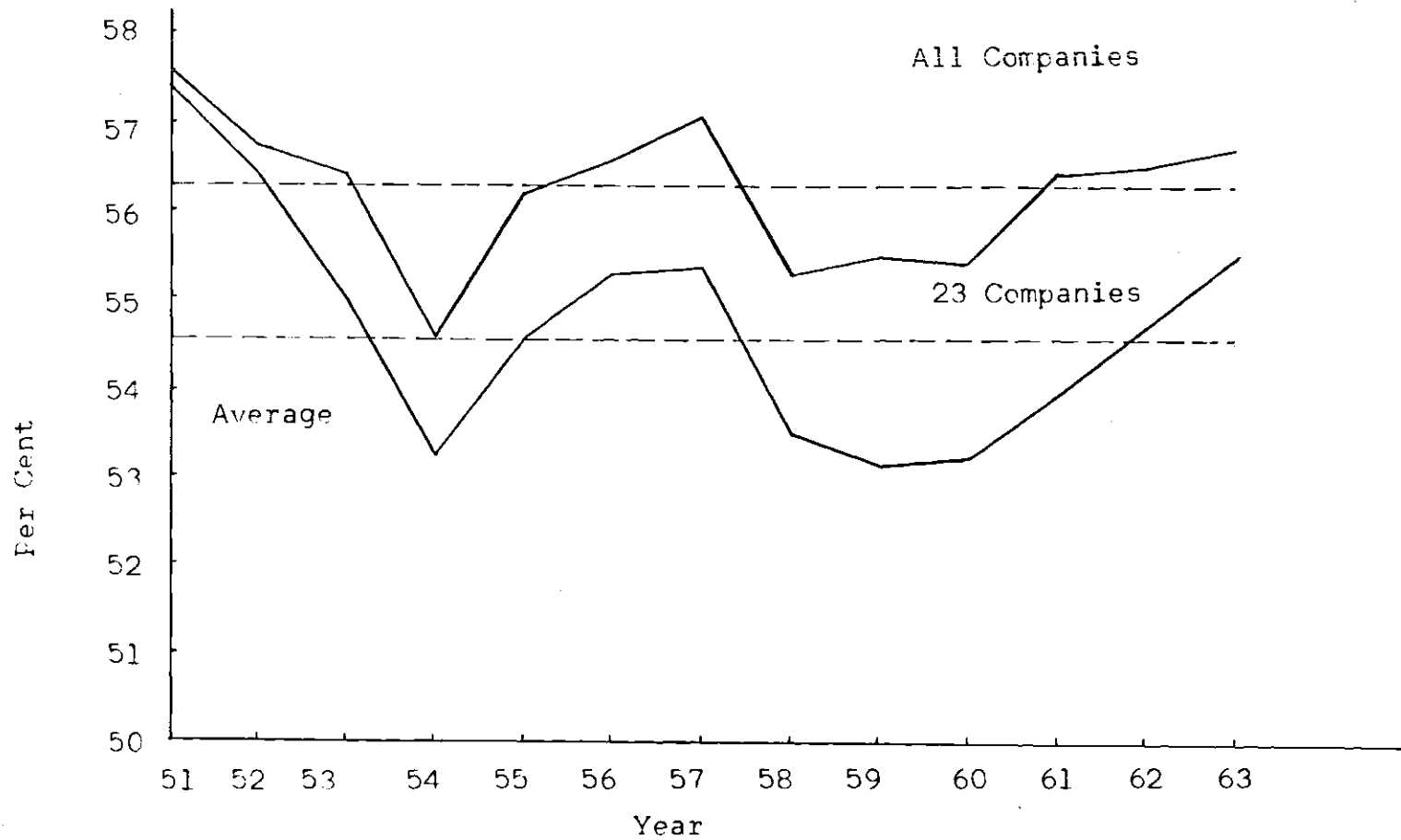


Figure 3. Production Department Expenses as a Per Cent of Total Operating Expenses for all Companies and 23 Selected Companies

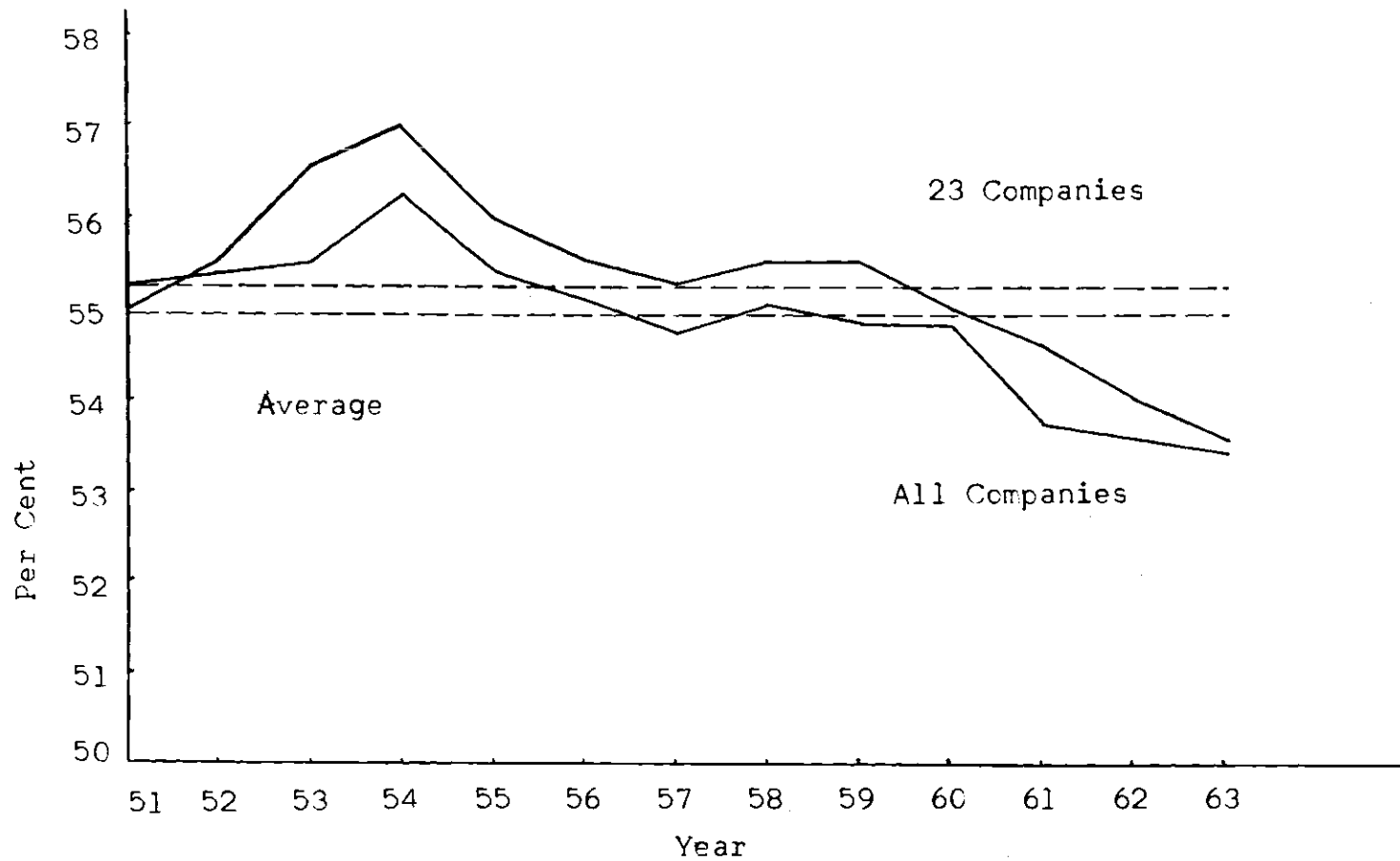


Figure 4. Distribution Department Expenses as a Per Cent of Total Operating Expenses for all Companies and 23 Selected Companies

average -- there is little reason to consider it as an alternative. Further support of this decision is apparent by observing the trend of the distribution costs as seen in Figure 4. It appears that in the foreseeable future the distribution costs as a per cent of the total operating expenses will be less significant not only for the 23 companies selected but also for all the companies.

#### Analysis of Plant Investment

The next analysis is concerned with investment in the utility plant. The intent of this part of the investigation is to determine the portion of the total plant investment for each area accounts. The percentage of the total will be the basis for comparison.

Table 4 is a composite of the electric utility plant for all class A and B privately owned electric utilities in the United States for the years 1951-1963. A look at the table indicates that there are two areas which, together, account for approximately 80 per cent of the total plant over the 13 year period. Each accounts for approximately the same -- production for 41.5 per cent and distribution for 39.6 per cent. Table 5, in which the comparable data are presented for the 23 selected companies, indicates similar results -- production with 40.5 per cent and distribution with 40.0 per cent. These findings indicate that either of these two areas, if used alone, would attribute to a significant portion of the total plant.

Figure 5 considers the same data in graphical form. During this 13 year study period there is a trend indicating that a larger portion of total plant is represented by the production department. Likewise,

Table 4. Electric Utility Plant For all Privately Owned Class A and B Electric Utilities in the United States. (Per cent of Total)

Utility Plant	1951 1963	1951	1952	1953	1954	1955	1956	1957	1958	1959	1960	1961	1962	1963
Intangible	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.0
Production	41.7	40.1	40.0	40.7	41.4	41.8	41.2	40.7	41.5	42.4	42.6	42.7	42.5	42.0
Transmission	15.7	14.9	15.3	15.5	15.7	15.6	15.5	15.7	15.9	15.8	15.6	15.7	15.9	16.2
Distribution	39.4	41.4	41.2	40.3	39.5	39.2	40.0	40.3	39.4	38.7	38.7	38.6	38.6	38.9
General	3.1	3.5	3.4	3.4	3.3	3.3	3.2	3.2	3.1	3.0	3.0	2.9	2.9	2.9
Total	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0

Table 5. Electric Utility Plant for 23 Selected Privately Owned Class A and B Electric Utilities in the United States. (Per cent of total)

Utility Plant	1951													
	1963	1951	1952	1953	1954	1955	1956	1957	1958	1959	1960	1961	1962	1963
Intangible	0.0	0.1	0.0	0.0	0.0	0.0	0.0	0.1	0.0	0.0	0.0	0.0	0.0	0.0
Production	40.5	39.7	39.4	40.0	39.7	39.8	39.2	38.6	40.2	41.2	41.8	41.9	41.4	40.0
Transmission	15.1	12.6	12.9	14.3	14.9	14.9	15.0	15.3	15.6	15.4	15.1	15.1	15.6	16.0
Distribution	40.0	42.0	42.2	40.9	40.2	40.5	41.3	41.6	40.0	39.4	39.1	39.0	39.0	39.1
General	4.4	5.6	5.5	4.8	5.2	4.8	4.5	4.4	4.2	4.0	4.0	4.0	4.0	4.0
Total	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0	100.0

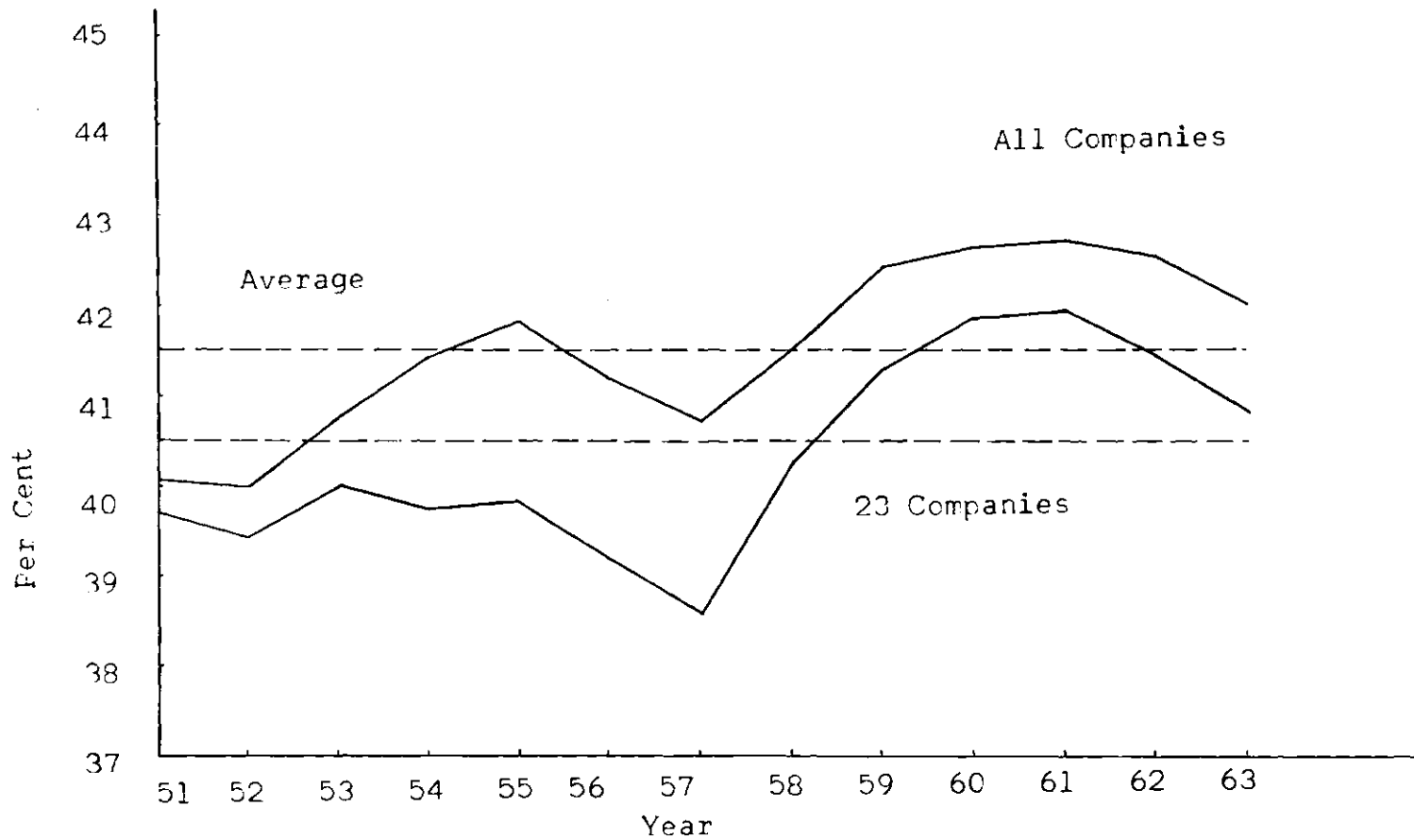


Figure 5. Production Department Plant Investment as a Per Cent of Total Plant Investment for all Companies and 23 Selected Companies

Figure 6 indicates an opposite trend in the distribution department -- less of the total plant is being accounted for by this area. The data for utility plant investment for the 23 selected companies is tabulated in Appendix C.

To summarize the analysis of the utility plant data, trends show that if a single area is to be selected the area which is increasing over time (the production department) would seem to be a better choice than the one which is decreasing (the distribution department).

An interesting observation noted from viewing the graphs of both the production and distribution operating expenses and investments is the close correlation between the curves for all the companies and for the 23 selected companies. The cycles and overall trends are approximately the same. This would indicate that the 23 companies are a representative sample of all the companies. There is a shift in the actual values, a result of imposing limitations on the selection of companies. For example, by including companies with no more than 5 per cent of the generation from a source other than fuel-fired steam generation, some companies which had large amounts of hydro-electric generating equipment were eliminated. Since the initial investment is higher for hydro-electric generators than for steam, the production investment for a sample of companies using all steam generation would be expected to be lower than for the composite companies. This is indicated by Figure 5.

No attempt will be made to explain or account for either the magnitude or direction of the shift in the other figures, since it would serve no useful purpose here and would not alter the results of

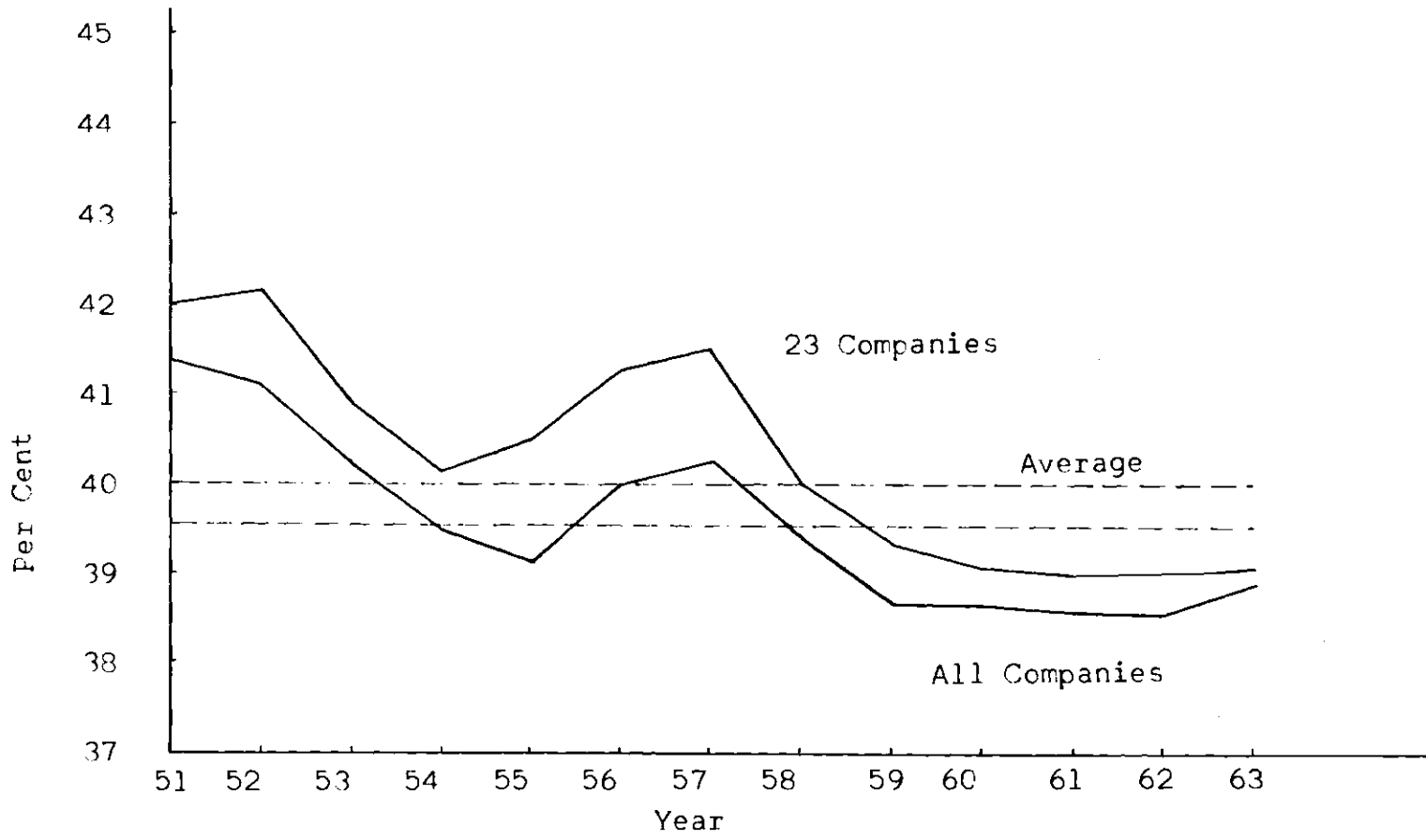


Figure 6. Distribution Department Plant Investment as a Per cent of Total Plant Investment for all Companies and 23 Selected Companies

this research in any way. In fact, because of the apparently close correlation between the data for 23 selected companies and all the companies, the following analyses of the data will be concerned only with the sample group of 23 companies.

#### Analysis of Variation in Expenses

Another statistical analysis of the data will provide some useful information for this study. The analysis of expense data at this point has only revealed which areas are accountable for a portion of the total expenses. This is necessary, but it is not sufficient. Variation in the costs must be considered. To investigate variation it is necessary to convert all cost data to a common basis. Cost per kilowatt-hour generated is used as a basis for comparison among the companies.

To explain the significance of this analysis, assume that although the production department is responsible for over half of the total expenses, the cost per kilowatt-hour for each company is exactly the same. This indicates that regardless of the type of management a company might have -- either good or poor -- it will have no affect on production costs. It is necessary that the results of the model be sensitive to management decisions. If good decisions are made, it is expected that the output from the model will yield lower costs; and likewise if bad decisions are made, the output will yield higher costs. Therefore, an area producing costs which are relatively constant for all companies would be valueless for inclusion in the model to be developed.

A basic premise underlying the study is that the variation in total cost per kilowatt-hour between different companies and even for the same company during different periods of time is at least in part due to managerial performance. This assumption is certainly more reasonable than stating that there is no difference among the 23 selected companies as far as managerial performance is concerned. This would suggest that the companies were either well-managed, poorly managed, or fell in exactly the same place in between.

In Appendix B the conversion of all operating expense data to the common basis, cents per kilowatt-hour is tabulated for all 23 selected companies by code number and year. The data is presented for all six areas as designated by NARUC as well as the total.

It may be recalled that from the previous analysis the production department accounted for over half of the total electric expenses. Again in investigating the portion of total investment for which each area accounts, it was determined that the production department and the distribution department account for almost an equal amount -- about 40 per cent. It was concluded, however, that due to the trend of both areas the production department would be the more desirable of the two. This prior knowledge of the relationship of the cost and investment producing areas will be helpful in conducting the following statistical analysis. If the total variation in the total cost can be explained by the variation in the production department or even the distribution department, then it can be expected that there is sufficient information to select the area to be modeled.

In Table 6 the range of variation is expressed as the difference between the high and low values for each year and for the overall years. It is interesting to note that there is a considerable amount of variation in the production department and the distribution department. In fact, these two areas could account for a large part of the total range of variation.

Although indications show sufficient variation among the production and distribution expenses to account for a large portion of the total variation, it is difficult to determine whether they are in the same direction or not. For example, when total expenses vary upwards, do production expenses also vary upwards? Is the converse true? An insight into this may be obtained by plotting the average annual cents per kilowatt-hour for the production, distribution and total costs. This indicates, as seen in Figure 7, that there is an apparent correlation between these expenses, although it is not high.

Based on the discussion thus far, it would be impossible to make a statement as to how much of the total variation is the result of either or both the production and distribution departments. Multiple regression and correlation analysis enables the data to be analyzed and this information provided.

A "canned" program titled "A General Multiple Regression and Correlation Analysis Program for the Burroughs 5500 Computer" by Charles L. Clark (5) was used to conduct this test.

The computer used is located in the Computer Center of the Georgia Institute of Technology. Since it was not necessary for the author to conduct any of the calculations needed for this analysis, no detail of

Table 6. Range of Variation Expressed as Cents Per Kilowatt-Hour by Years for Total, Production and Distribution Expenses.

Year	Total			Production			Distribution		
	Low	High	Diff	Low	High	Diff	Low	High	Diff
63	0.390	1.026	0.636	0.227	0.605	0.378	0.052	0.163	0.111
62	0.398	1.059	0.661	0.232	0.637	0.405	0.053	0.185	0.132
61	0.394	1.095	0.701	0.218	0.699	0.481	0.056	0.198	0.142
60	0.428	1.122	0.694	0.208	0.722	0.514	0.057	0.216	0.159
59	0.422	1.116	0.694	0.190	0.725	0.535	0.059	0.219	0.160
58	0.407	1.181	0.774	0.160	0.737	0.577	0.063	0.268	0.205
57	0.395	1.230	0.835	0.152	0.857	0.705	0.066	0.223	0.157
56	0.367	1.246	0.879	0.158	0.835	0.677	0.069	0.246	0.177
55	0.374	1.198	0.824	0.174	0.719	0.545	0.070	0.231	0.161
54	0.370	1.234	0.864	0.167	0.715	0.548	0.063	0.266	0.203
53	0.368	1.257	0.889	0.126	0.747	0.621	0.081	0.273	0.192
52	0.367	1.255	0.888	0.142	0.772	0.630	0.078	0.267	0.189
51	0.415	1.253	0.838	0.163	0.761	0.598	0.085	0.284	0.199
Over all	0.367	1.257	0.890	0.126	0.857	0.731	0.052	0.284	0.232

the theory behind it is presented. If the reader desires to investigate the technique further he is referred to the technical bulletin associated with Mr. Clark's program and with any of a number of mathematical statistical books. For a rather simplified explanation Advanced Methods and Models by Springer, Herlihy and Beggs (32) is recommended.

The data for this analysis consists of observations on six independent variables and one dependent variable for 23 companies for the years 1951 through 1963 inclusive. This totals 299 observations on the seven variables. The seven variables are the costs/kwh for each of the six areas of expense, together with the total according to the Uniform Systems of Accounts referred to previously. The total cost/kwh is the dependent variable -- being completely determined by the six areas of expense which go to make it up. The data is tabulated in Appendix B.

The results of the tests are tabulated in Table 7. For convenience the variables have been designated as follows:  $X_1$ , production;  $X_2$ , transmission;  $X_3$ , distribution;  $X_4$ , customer accounts;  $X_5$ , sales;  $X_6$ , administrative and general;  $Y$ , total. It will be observed that the  $X$ 's represent the independent variables while the  $Y$  represents the dependent variable.

The first analysis involved the use of the six independent variables. It was known beforehand what the results would be since the total can vary only as one or all of its parts varies. In other words, the variation in these six variables would have to explain the variation in the total. The results showed that the "Coefficient of Determination" did equal 100.0 per cent as anticipated. This coefficient is a measure

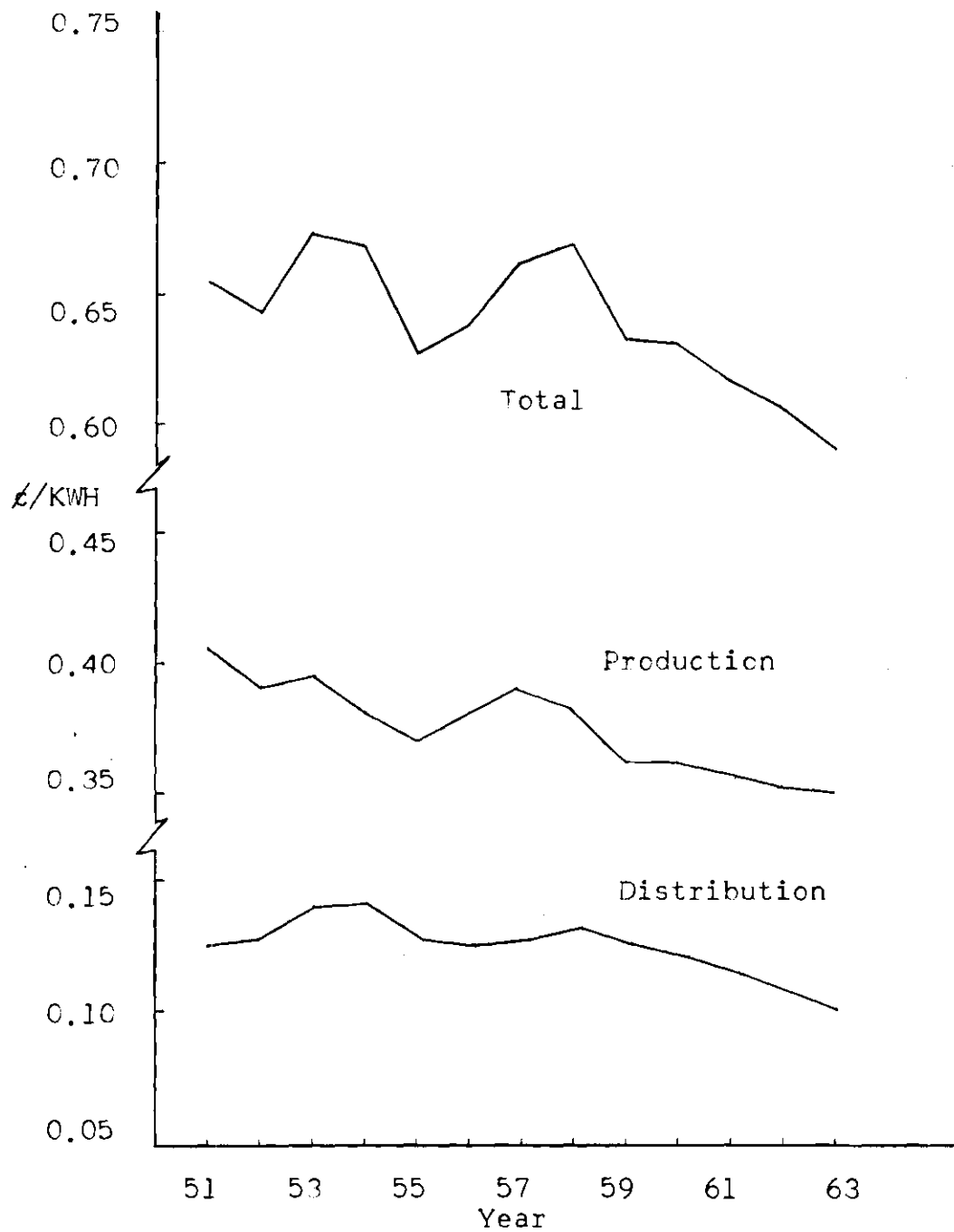


Figure 7. Annual Variation in Average Cents Per Kilowatt-Hour for Distribution, Production and Total Expenses for 23 Selected Companies

of the proportion of the total variation in the dependent variable that is explained by the independent variables operating in combination with one another.

The remaining tests were concerned with the two variables which prior tests have favored --  $X_1$ , production, and  $X_3$  distribution. The results indicate that the two variables operating together can explain about 96 per cent of the variation in  $Y$  and when separated,  $X_1$  still explains about 88 per cent of the total variation. This is to say that the variation in cost per kilowatt-hour for production costs is sufficient to account for 87.5 per cent of the variation in cost per kilowatt-hour for the total costs.

#### Conclusions

In view of the evidence revealed thus far it is concluded that no further statistical analyses need be performed on this data. The production department does satisfy the requirements expressed at the beginning of this chapter for serving as the area to be modeled to represent an electric utility company. It represented 60 per cent of the total operating expenses, 40 per cent of the total plant investment, and explained 87.5 per cent of the variation in the total operating costs.

Table 7. Coefficients of Determination for Expenses of  
23 Selected Privately Owned Electric  
Utilities, 1951-1963

---

Variables		<u>Coefficient of Determination</u>
<u>Dependent</u>	<u>Independent</u>	
Y	$X_1, X_2, X_3$	1.0000
Y	$X_1, X_3$	0.9598
Y	$X_3$	0.5967
Y	$X_1$	0.8752

---

## CHAPTER IV

### DEVELOPMENT OF A GENERAL MODEL

#### Introduction

With the selection of the production department to represent the operation of the electric utility company, it becomes necessary to determine exactly which of the production should be included in the model. The criteria for the selection of factors should include (1) their susceptibility to managerial control, (2) some assurance that the resulting model does represent this area significantly, and (3) the ease of including them in a mathematical model. To give the reader a clearer understanding of the problem, space will be devoted to an explanation of the basic operation of a power production department.

With this background, a discussion of the factors selected and the results of a statistical analysis will be presented. Following this will be a detailed description of the construction of the model.

#### The Production Department

The purpose of this department is to produce electricity. The energy in the fuel or in the falling water is converted to electricity at the power plants where the generators are housed. The power plant may contain one generator, called a unit, or many generators or units, normally driven by an internal combustion engine or a turbine, either steam or water driven. Since this study is confined to steam driven

plants, all remaining discussion will be restricted to this type.

The conventional types of fuel used in producing steam are natural gas oil and coal. Of the many factors which must be considered in the selection of a particular fuel, Skrotzki and Vopat (31) have suggested the following:

- 1) energy content
- 2) price
- 3) unit operating efficiency
- 4) handling cost
- 5) refuse disposal
- 6) operating labor
- 7) maintenance

Although energy content refers to the heating value per unit (for example, BTU per ton or barrel) and purchasing price is usually quoted on a price per ton or barrel, the two are commonly combined into an expression of cost per million BTU's.

The unit operating efficiency is determined by the ability of the unit to convert the heat content of the fuel into an output of kilowatt-hours. Efficiency is usually a design function and once the unit is constructed, its efficiency is determined. The significant design factors affecting steam plant efficiency are temperatures and pressures. The trend of temperature and pressure back to 1916 may be seen in Figure 8.

The relative efficiency of steam generators can be measured in terms of the pounds of coal required to produce a kilowatt-hour of electricity. In 1892 it took about 8 pounds of coal, in 1916 almost 4

pounds of coal, and in 1959 about 0.9 pound of coal. Today the newer, larger high-pressure and high-temperature units can produce a kilowatt-hour with less than three-fourths of a pound of coal (33).

The handling costs for the fuel supply are less with natural gas. All that is required is a connection to the meter and the installation of some control valves. Oil requires higher costs than natural gas, primarily due to the storage tanks required and pumps for unloading and transfer. Coal is the most expensive fuel to handle since it requires elaborate unloading equipment, bunkers, weigh scales and distributing belt conveyor systems. For a plant containing a number of units, this cost per unit is minimized since the same unloading equipment is common to all the units.

There is no problem in disposing of the ash content with either natural gas or oil, however, use of coal requires removal of ashes from the furnaces and a method for its disposal. At times the ashes are in demand for road building purposes and may be sold.

Labor costs in steam plant operation are usually highest when coal is the fuel used, followed next by oil, with natural gas requiring least.

Skrotzki and Vopat have concluded that maintenance is the most difficult factor to evaluate, and only extended experience with a given fuel can provide accurate figures. Thus, no general statement as to which is the most costly can be made.

After the fuel has been selected and the design and construction completed, another relationship becomes important -- that of amount of

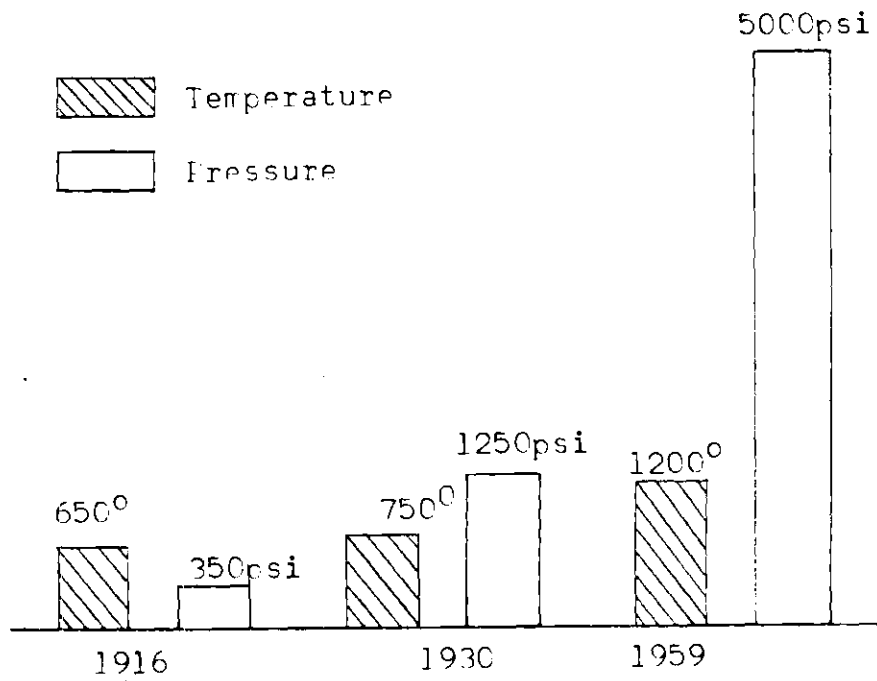


Figure 8. Maximum Temperature and Steam Pressure. 1916-1959

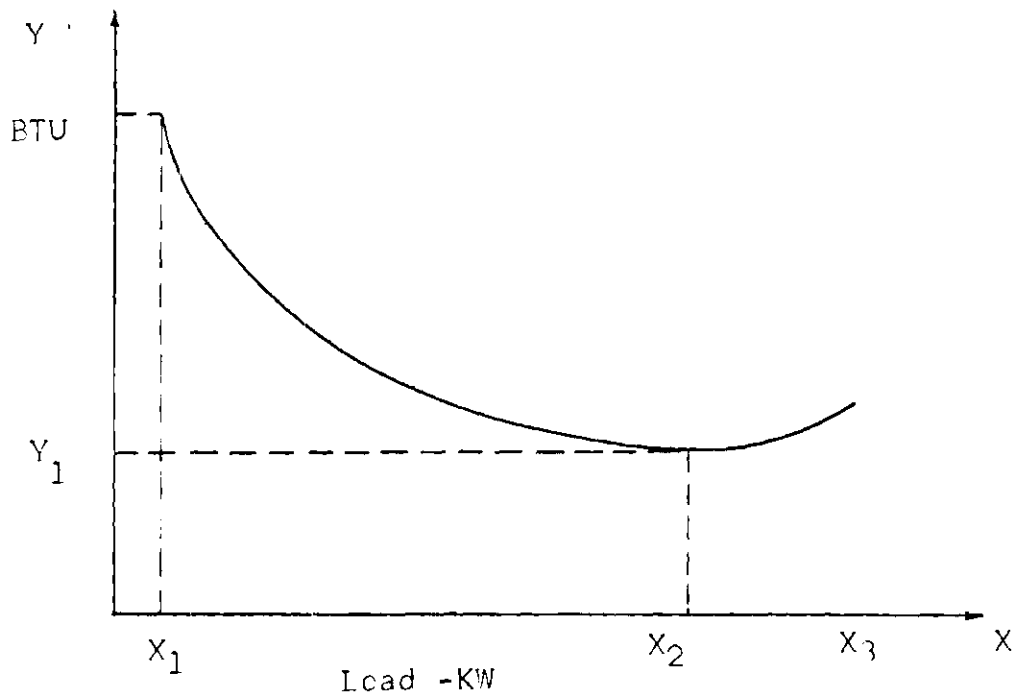


Figure 9. Typical Heat Rate Curve

fuel required versus the size of the loads placed on the generator. This relationship may be expressed either by a mathematical expression or graphically. Graphically, the relationship is referred to as a heat rate curve or an input-output curve. The manufacturers normally provide a heat rate curve for each unit, and these are based on the design specifications. A typical heat rate curve is reproduced in Figure 9. It may be seen that the most efficient point of operation is not at the maximum rated capacity. For this typical curve, a demand of  $X_2$  would require the consumption of  $Y_1$  BTU of energy every hour that  $X_2$  is demanded. Because of the magnitude of the BTU's, the Y is usually expressed in millions of BTU's.

Many privately owned electric utilities have more than one unit in their generating system. Because the units almost always differ in efficiency, the loading will be determined by economics. The calculations for determining the economic loading may be performed by hand, but today computers are being used to perform this function. The computer calculates which units should be operated each hour for the most economical operation of the whole system. Figure 10 shows how various units may be called into service during the day in the operation of a plant which consists of three units. Unit 3 is the newest, largest and most efficient unit; unit 1 is the smallest and oldest, thus the least efficient of the three.

The power plants must have some reserve or standby capacity. Otherwise it would be necessary to curtail power to some of the company's customers if one of the units failed at a time of peak load. Frequently

some or all of this capacity may be available from an interconnection with another company or companies.

Fuel costs are the largest single item of the total production costs. According to Justine and Mervine (16) the cost of fuel represents about 60 to 75 per cent of the total costs. Supervision and labor are the second largest expense -- accounting for 10 to 25 per cent of the total. The remaining 10 to 15 per cent are accountable to maintenance. Any miscellaneous supplies and expenses are insignificant compared to the total.

Maximum economy in the production department is not the results of minimizing operating costs only. It is secured when operating costs plus the costs of the investment are at a minimum. The investment costs, as used in this study, include any cash flow that results from making an investment in the power plant.

The largest item of investment costs is the cost of the generating equipment and construction. The Federal Power Commission (37) publishes cost data for plant construction in the United States. Figure 11 was compiled from their latest publication to indicate the magnitude and range of costs, expressed as dollars per kilowatt of capacity, for some coal fired units installed in 1962 and 1963. Although the scatter diagram does not indicate it, for a given set of conditions, the cost per kilowatt of capacity varies inversely as the total size of the unit. The reason this diagram does not support this statement is that the 26 units plotted represent 24 different companies (two companies are each represented by two units).

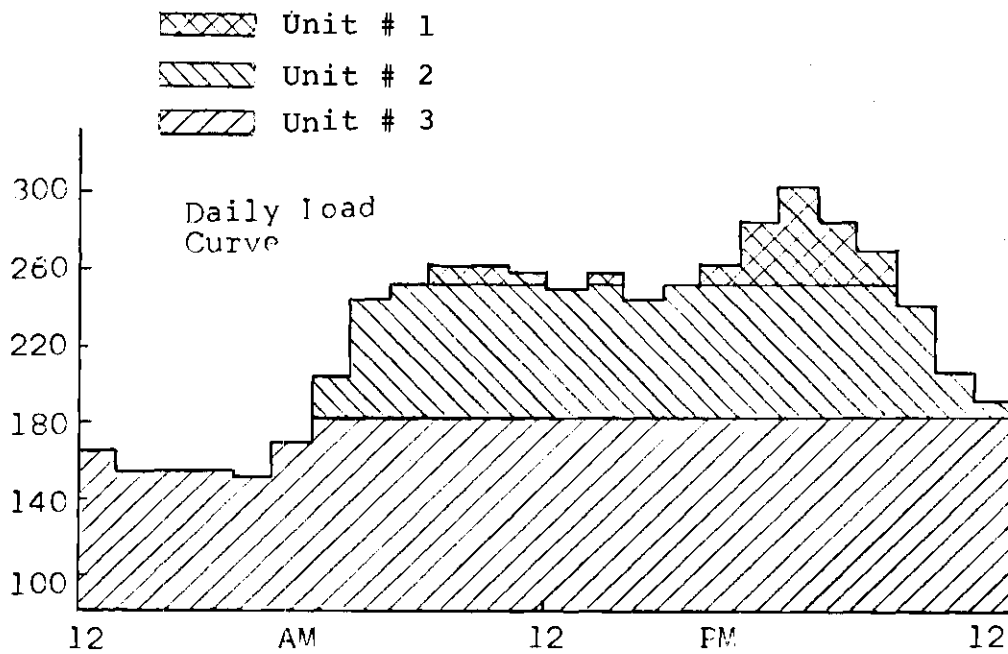


Figure 10. Economic Generator Loading

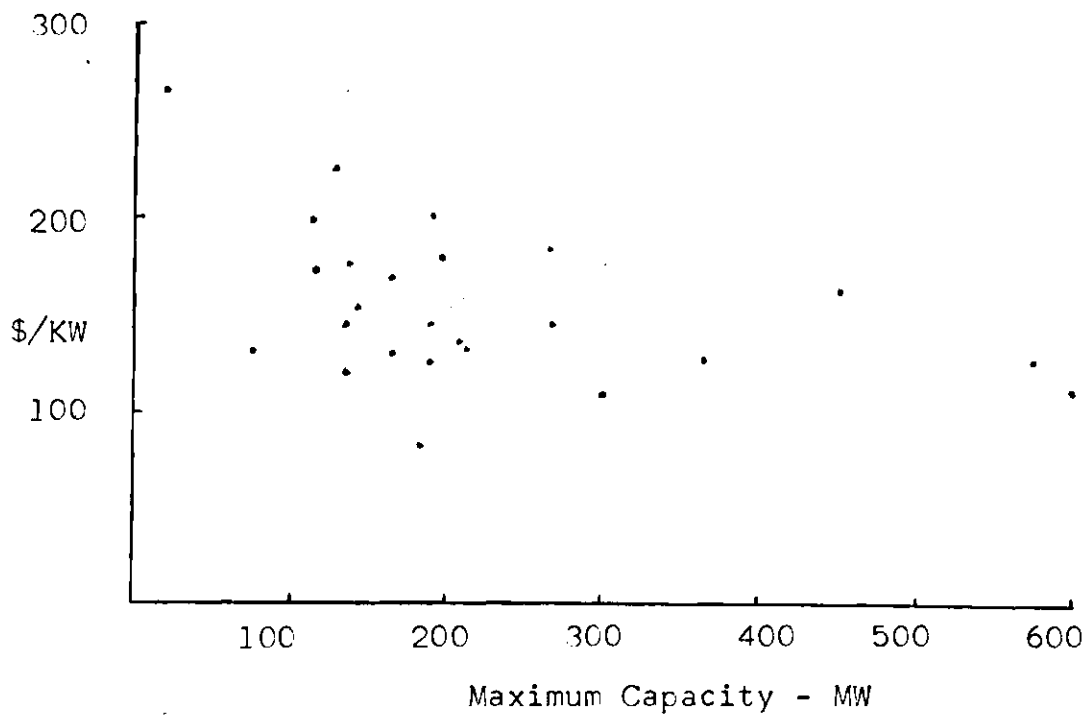


Figure 11. Scatter Diagram of Unit Cost per Kilowatt of Capacity 1962-1963

The general factors affecting the investment are location, the manner in which fuel is received, the value of the plant site, and the development program for that particular plant. Since these factors are not consistent between companies or even between plants of the same company, it is little wonder that the scatter diagram is so random.

Costs of securing the capital also vary from unit to unit and company to company and should be included in the investment costs. Although no detailed discussion will be made of these costs, they include the flotation costs of bond and stock issues, short term bank loan costs, premiums or discounts received on security issues, internal costs of retained earnings, and any other costs associated with the use of money from outside sources for plant construction.

Additional cash flows resulting from the ownership of generating equipment are property taxes to various government agencies, and insurance. These figures are usually directly proportional to the size of the investment, and are determined by local conditions.

An often overlooked cash flow associated with this investment results from the income tax structure. By having an investment in depreciable assets, a certain portion of the total investment may be written off annually as a depreciation charge. The method of writing off the asset is subject to approval by the Internal Revenue Service, but one of the most common methods is the double-rate declining balance. Regardless of the method chosen, the annual charge is used to reduce the taxable income, which in turn reduces the actual amount of income taxes to

be paid. In effect then, the larger the investment, the larger the annual depreciation charges and the lower the income taxes.

In planning a generating system, management must consider the operating costs and the investment costs over a long period of time. It must choose the system best suited, under the current and anticipated local conditions, to provide satisfactory generating capacity and output for the lowest possible total cost. This is maximum economy.

#### Selection of Factors for the Model

The basic operation of a production department is here summarized so that the selection of factors to represent this area will become more obvious. First, a demand for power is received by the power plant. A calculation either by hand or computer should have already been performed to determine which unit or units can most economically generate a specific demand. Since the demand changes from hour to hour, requiring hourly decisions as to which unit or units to use, it seems logical and reasonable to simulate the operation of the production department by the hour. This necessitates then, the inclusion in the model of a factor to generate an hourly demand which represents the demand the company actually experienced.

The next factor involves the selection of the unit or units used in meeting the demand requirement. It may be recalled that the relationship between the demand or load on a unit and the energy required per hour to generate this load is the heat rate curve. With the heat rate curves for each unit and the cost of fuel for each unit on a cost per BTU basis, it is possible to calculate the cost for generating a given

load on each of the available units. The minimum cost then determines which unit to use each hour. In this phase there are two factors which need to be included in the model -- the input-output relationship, usually expressed graphically as a heat rate curve, and the fuel costs, including any changes which occurred during the study period.

Since it is the cost of actually having the fuel in the furnace ready to be ignited that is meaningful -- the fuel costs should include the cost of transporting and handling, enabling a realistic comparison and placing the costs on a comparable basis.

Included in this phase of the model is the selection from hour to hour of the unit which will provide the most economical operation. It is necessary to keep a tabulation of the kilowatt-hours demanded and generated as well as the fuel cost incurred. These figures will be part of the total costs of operation and will be used for comparison purposes later.

The factors mentioned above do meet the criteria for the selection of factors stated at the beginning of this chapter. Other factors, considered and omitted due to the criteria, include, first, labor costs. Due to the increased use of automation as a result of computer advancement, the use of labor is decreasing with the newer, larger units. Even without these advances, there is not a direct relationship between the number of employees and the size of the plant. It may take approximately the same number of personnel to operate a plant twice the size of another plant. Also, with the union shops, management does not have complete control over the wages paid. It is felt that a given management

will be consistent in its attitude toward the degree of automation desired for its own plant. In other words, in considering different size units to meet their growth, the labor requirements would be similar for each alternative, thus labor costs would not contribute significantly to the variation in total operating costs.

Maintenance costs were also omitted as a factor in the model. The maintenance contribution to total operating costs is between 10 and 15 per cent. Apparently the variation in maintenance costs is not significant since Skrotzki and Vopat concluded that maintenance is a most difficult factor to evaluate. They could not determine that any one type of fuel was responsible for more maintenance than another. It is also felt that the company would again be consistent in its maintenance program, regardless of the type or size of the units selected.

In a previously mentioned study by Iulo, we can see the effect of the factors selected on total cost. Iulo attempted to explain the variation among electric utilities in unit cost of electricity. Of many factors which he considered, he found seven which accounted for about 80 per cent of the total cost per kilowatt-hour variation among the companies used. Of these seven, there are three which would meet the criteria of selection for this model. These are plant size, capacity utilization, and steam-electric fuel costs.

It is obvious that the operating factors so far selected involve the three factors listed from Iulo's study. Plant size has its effect on operating cost variation since efficiency is directly proportional to plant size. Thus a utility which is fortunate enough to be able to

operate only large size units will certainly have cheaper fuel costs than other utilities which are operating a series of smaller units. The size of the units is a factor which management controls.

The effect of capacity utilization on cost variation is a result of the shape of the heat rate curve. It will be remembered from Figure 9 that there is an optimal point of operation. If the capacity of the units can be utilized so that they are all operating at or near the optimal point on their respective heat rate curves, then the total fuel costs for that period of time will be minimized. Of course any other utilization of the available capacity of the units would result in higher costs -- thus the effect of capacity utilization on operating cost variation.

Steam electric fuel costs are the cost of actually getting the fuel into the furnace, and are expressed in cents per million BTU's. It is not the total fuel cost for generating a given quantity of electricity. As has been previously mentioned, this cost of fuel referred to by Iulo includes the transportation costs, the handling costs, and the cost of the fuel at the mine or oil field. It is obvious that among utilities across the country there would be a large variation in fuel costs expressed in this manner.

Data for these three factors was collected for the 23 companies previously selected for this research. An attempt was made to secure the data for the same 13 year period covered by the other statistical analyses. However, the only data available at the time the study was made was for the years 1962 and 1963. This data was used combined with the other factors to determine the extent of the total variation in

production costs per kilowatt-hour generated.

The size of the steam-electric generating plant, as Iulo uses it, is the average name plate capacity of the larger plants that comprise at least one-half of the total generating capacity of that particular utility. To get this information it was necessary to list the size of all plants for each of the 23 utilities, then, starting with the largest and taking them in descending order, to select enough of the plants to account for at least one-half of the total company capacity. The average of these plants is the figure that is used to represent the plant size of the utility. Using this figure based on the larger sized units gives weight to the fact that the larger units do in reality account for the majority of the generation.

The capacity utilization figure is also used as Iulo defines it. It is the ratio between the total number of kilowatt-hours generated by a utility during the year, and the maximum possible kilowatt-hours that could have been generated by that particular utility during the year.

The data for the fuel costs are published by the National Coal Association in a publication called Steam-Electric Plant Factors for various years (42). The data used are referred to as "as consumed" fuel costs and are presumed to include the cost of the fuel delivered at the boiler. Under this definition the "as consumed" cost would also reflect the net cost of, or amount realized from, the disposal of the ashes.

Using these three factors as independent variables and the

production department cost per kilowatt-hour as the dependent variable, the data was analyzed by the statistical technique introduced in Chapter III -- the multiple regression and correlation analysis. For the two year period, 1962 and 1963, and for the 23 companies selected for this research, the coefficient of determination is 0.7322. The variation in the three independent factors, acting together, is sufficient to explain 73.22 per cent of the variation in the production department cost per kilowatt-hour generated. The magnitude of this coefficient is such that the model, using the factors so far selected, will be representative of the actual production department.

It is necessary to include in the model factors which will represent the investment costs as previously discussed. Using the initial investment in each unit as a base, the other investment costs can be determined. It will be necessary to include the depreciation method, the income tax rate, the property tax rate and the insurance rate.

In Chapter I it was stated that the present worth method would be the basis for comparing the different results. Thus, a procedure must be included in the model to generate or provide the appropriate present worth factor throughout the time period simulated on the computer.

#### The Operating Section of the Production Department Model

Having completed a selection of the factors, we can now show the development of the model to include these factors. The discussion will follow the structural sequence found in Figure 12. The modeling of the operating end of the production department will be divided into two

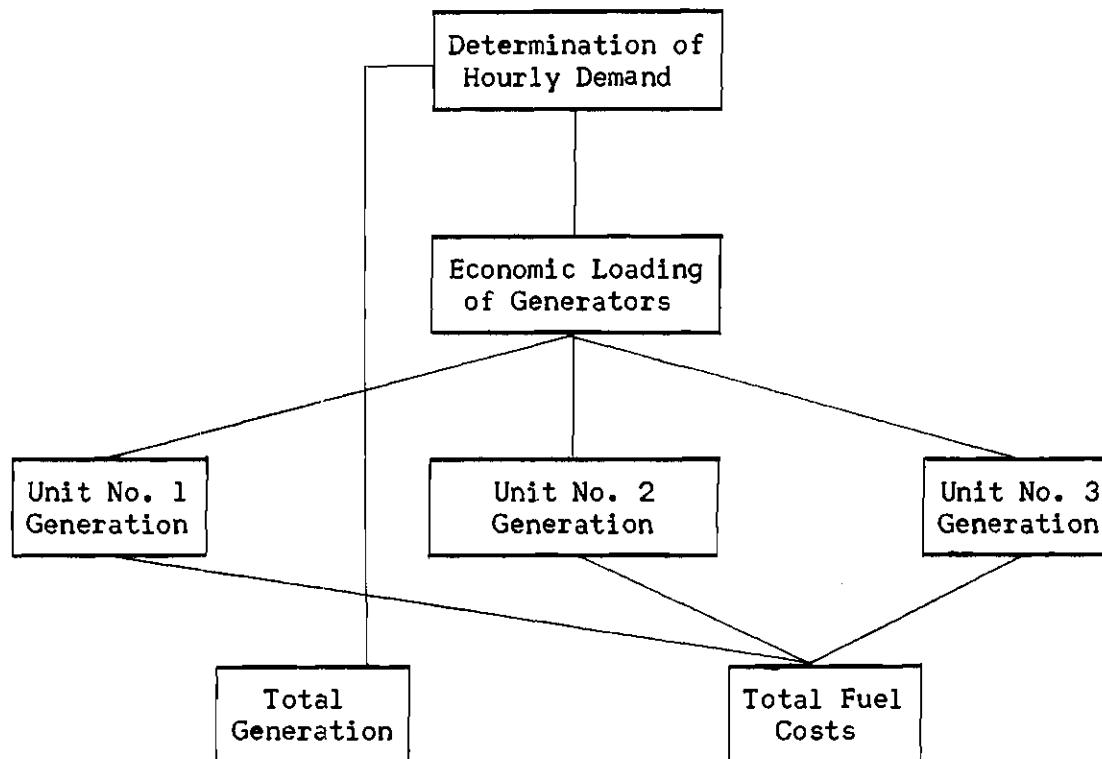


Figure 12. Block Diagram of Production Department Operation.

phases of which phase one is concerned with the determination of the hourly demand, and phase two is involved with the economic loading of the generators and the resulting total fuel costs.

#### Determination of the Hourly Demand

The purpose of this phase is to enable the model to simulate the actual hourly demand with reasonable accuracy. Using one hour time intervals, the total cycles for a five year study would be 43,800. This means that 43,800 separate hourly demands would be necessary for the model to operate. There are two possible means of providing this information. First, the 43,800 separate demands could be stored in the program, requiring, if punched cards were used, approximately 2400 cards.

Another means of providing this information is to develop a procedure within the model to approximate the demand each hour. It is not necessary that each hour of actual demand correspond respectively to an hour of simulated demand. If at the end of each month of operation there has been an equal number of each size of hourly demand, then the accuracy of the study will not be impaired. If, for example, the demand for the last hour in a particular month were 300 kilowatts, and in the simulation study this same 300 kilowatts of demand occurred in the middle of the month, the overall results of the study would be unchanged.

The second method of introducing the demand into the model was selected for this study. The number of cards required and the key punching necessary for using actual hourly figures was prohibitive. In many companies, to tabulate the demand each hour for a number of past years would be a major undertaking. If a satisfactory method of recreating within the model the actual demands is accomplished, this alone will be a significant accomplishment. This method would certainly provide more flexibility to the model, facilitating an easy addition of additional years to the study period.

The development of the method chosen is based on the fact that the demands follow certain behavior patterns. Once the patterns are determined, only a minimum of other information is required. The first investigation centered around the pattern that the hourly demand followed over each 24-hour period, from midnight to midnight. The general pattern, as pictured in Figure 13, is approximately the same from day

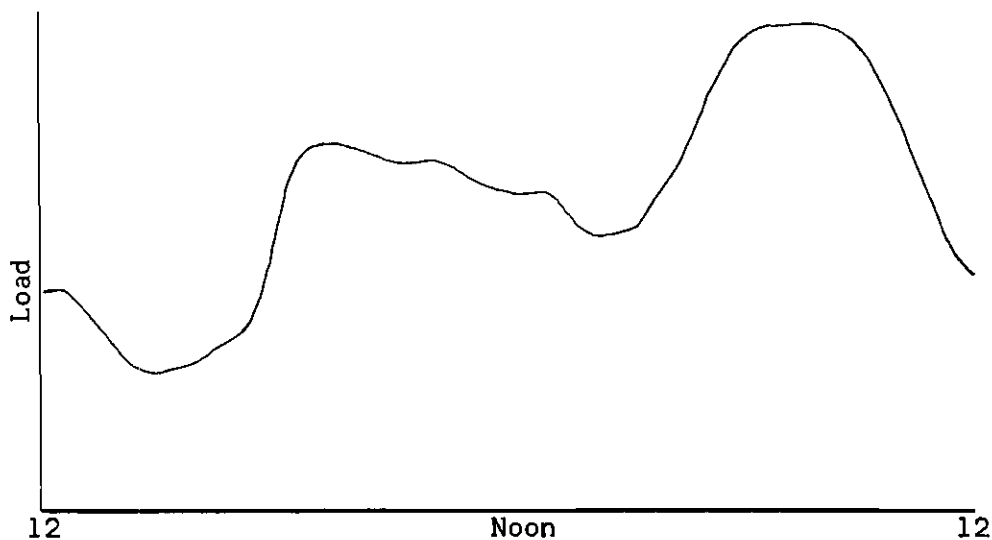


Figure 13. General Pattern of a Daily Load Profile.

to day and from month to month. The author refers to this pattern as a daily load profile.

There are many factors which serve to make up the profile. In the residential area the major loads are ranges, water heaters, lighting, refrigeration, air conditioning and heating, and miscellaneous small appliances. Each of these loads has a regular daily pattern or operation. For example, the operation of ranges would be expected to produce three distinct peaks during the day corresponding to the three normal meal times. A typical day's use for a single range is shown in Figure 14. Combine the single range profiles for all the customers of a utility and this profile could look like the profile presented in Figure 15. Although the single profile could be expected to vary considerably from day to day, the combined range profile would not. This is a result of the randomness and diversity of operation of each of the thousands of

customers. Each of the other components of residential load could be similarly analyzed with similar results.

The two other major areas of load -- commercial and industrial -- have altogether different load profiles. An industrial processing company which has a continuous operation would have basically a horizontal line for a load curve. A commercial department store might show a profile spread over the entire 24-hour period, but greatly reduced from 9 P.M. to 8 A.M. These profiles are presented in Figures 16 and 17 respectively.

The general daily load profile presented previously in Figure 13 is a composite of all the individual profiles. Although the general pattern is not expected to vary significantly from day to day, there are reasons why the pattern may change from season to season. Temperature fluctuations affect the operation of heating units, air conditioners and refrigeration. The number of daylight hours per day affects the peak and duration of the lighting load. A particular industry which may account for a large portion of the utility's load might be affected by the seasons. For example, citrus packing houses and concentrate plants operate seasonally. When the citrus has been picked and processed, these plants completely close down. For these reasons and many others it is desirable to include a sufficient number of daily load profiles to compensate for seasonal variation.

Since the magnitude of the points on the profile will vary from day to day, it is necessary to convert the vertical scale from load expressed in kilowatts to load expressed as a per cent of peak load.

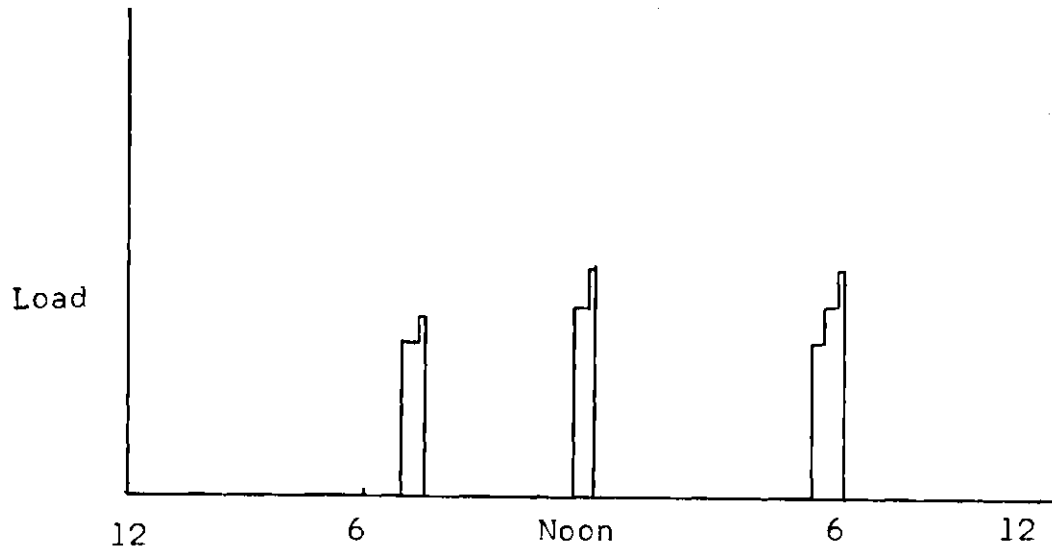


Figure 14. Typical Daily Load Profile for one Range

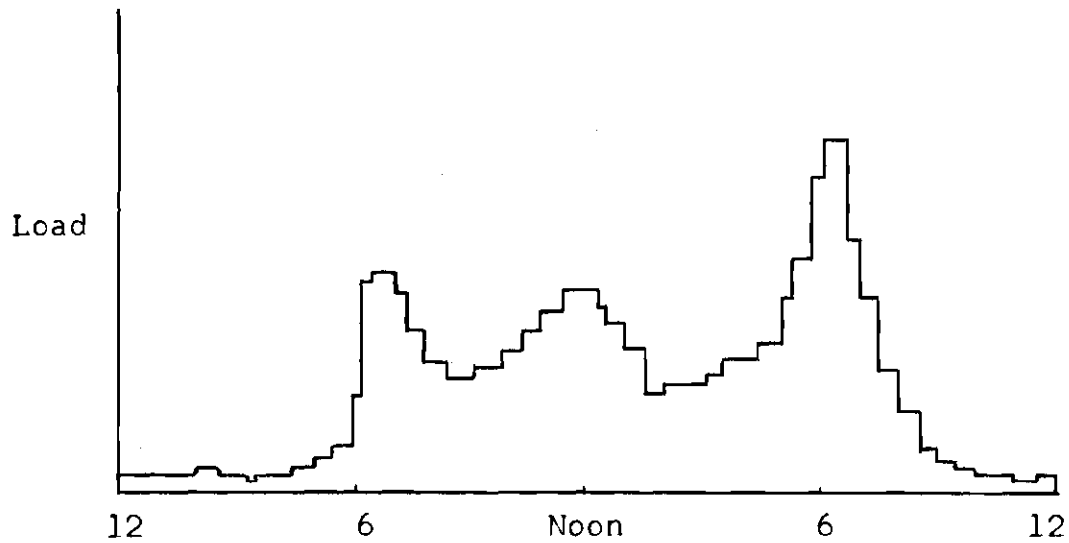


Figure 15. Typical Daily Load Profile for all Ranges

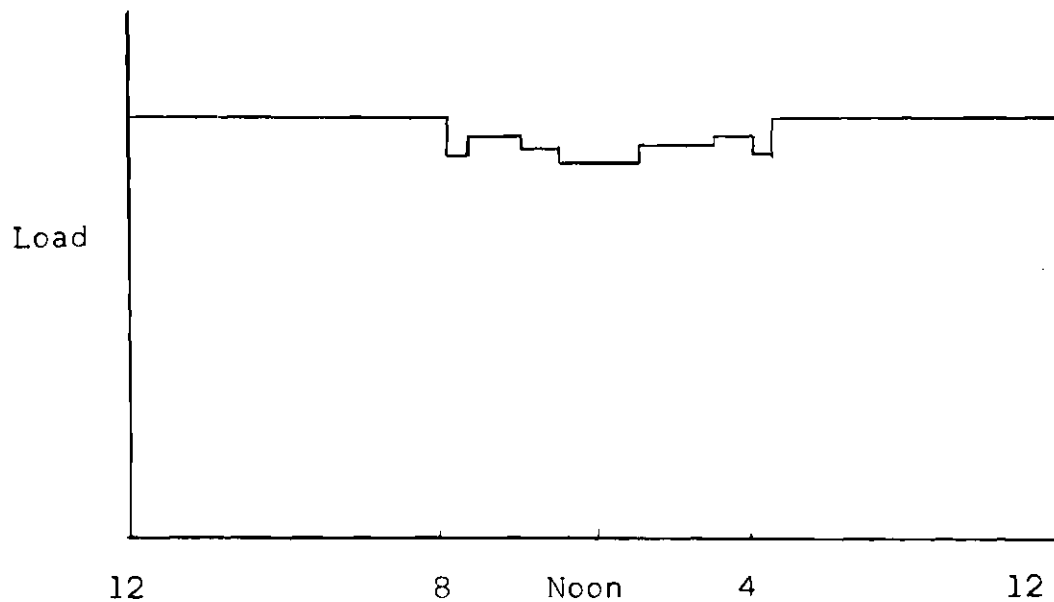


Figure 16. Typical Daily Load Profile for a Continuous Operation Industrial Plant

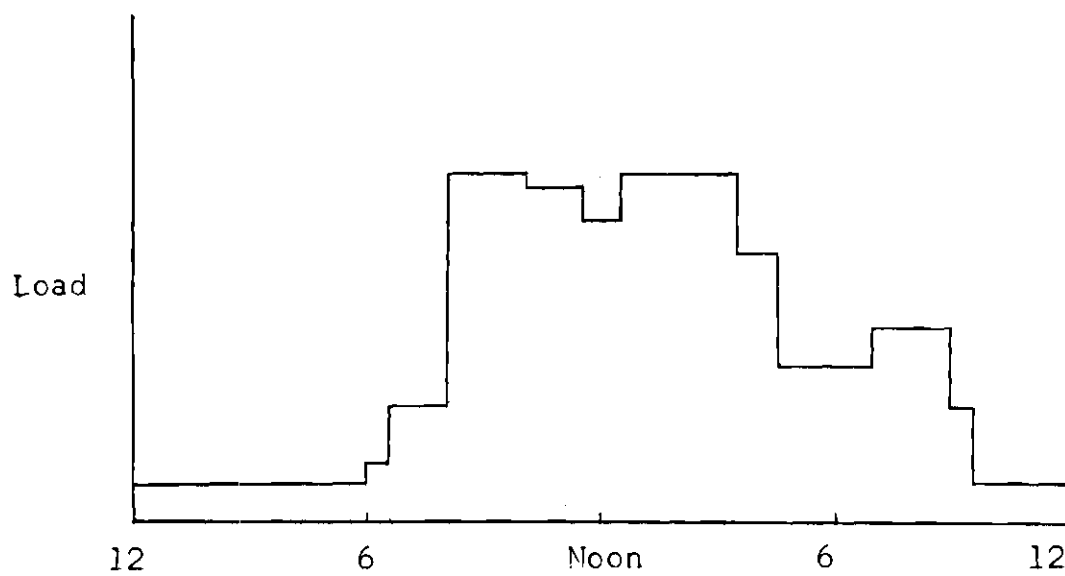


Figure 17. Typical Daily Load Profile for a Large Department Store

Thus each hourly load may be determined from the profile if the maximum daily load is known. Therefore the next step in this phase is to include in the model a method of providing the daily peak.

It is not important in this study to correlate each actual daily peak to the same simulation day, so long as each actual peak is represented. The month was selected as the time interval for the purpose of generating daily peaks. Thus the determination of the daily peaks for each particular month is independent of all the other months.

For a given month, the maximum daily peak and the minimum daily peak were selected. All other daily peaks for that month would fall between these two peaks. If all the peaks in between the maximum and minimum peaks were ranked in ascending order and plotted, they would form a pattern. If this pattern were to form a straight line, the determination of the intermediate points, given the end points, would be simple. No information was found by the author to indicate what type of pattern this data would provide. Therefore, any specific information regarding this will be postponed until actual data is collected and analyzed for a specific company. If a pattern other than a straight line results, then a correction factor can be applied. Assuming a straight line pattern, the hourly demand for a month can be generated in the model with knowledge of the maximum and minimum daily peaks for that month, and the appropriate daily load profile.

Even though the hourly demand is now available in the model, an important adjustment must be made. This is necessitated by the difference in the peak demands as reported by the utility companies, and the

peak demands required. The demand required is an average peak demand over the one-hour period -- not the instantaneous peak for the hour which may have occurred for only a small portion of the hour. Figure 18 illustrates the difference between the two. In hour A,  $Y_1$  represents the instantaneous demand and  $Y_2$  represents approximately the average hourly demand. Therefore an error would be introduced by using  $Y_1$  as the hourly demand. The extreme case is illustrated in hour B where the instantaneous demand  $Y_3$  is exactly the same as the average. There was no fluctuation in demand over the hour -- an unusual case, although possible. Without an adjustment factor, every hour would be treated as if it were the second type.

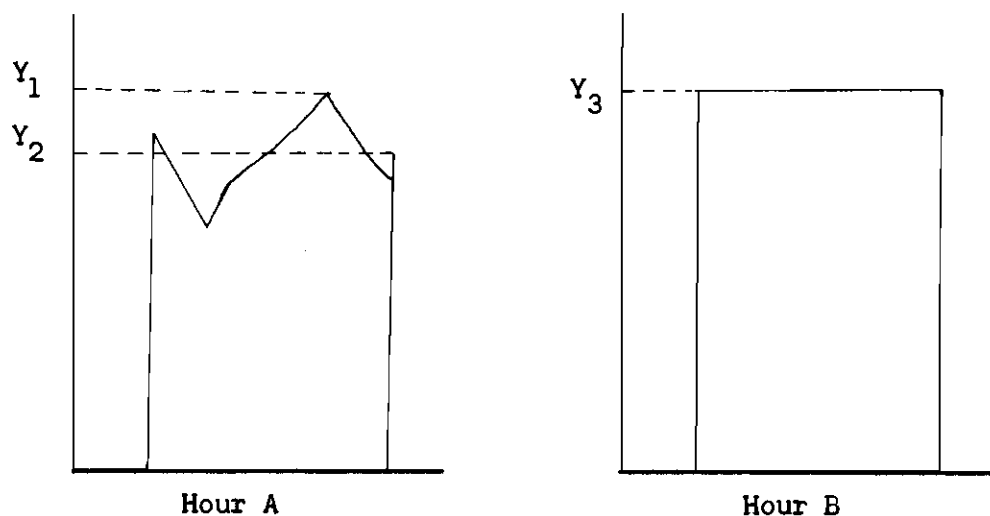


Figure 18. Instantaneous Hourly Demand Versus Average Hourly Demand.

Demand data is rarely reported for any time interval less than one hour. Therefore there is little or no data that can be analyzed to determine what the adjustment factor should be. However, it can be

determined by a trial and error method when the model is completed, and validated on an actual company.

The determination of the hourly demand by the model may be summarized by the data presented in Figure 19. With the three patterns included in the model, it is necessary to provide only two data points from the actual company data for each month of the study in order for the model to generate an average demand for each hour in each month. The suitability of this method will be determined in the validation study.

#### Economic Loading of the Generators

The model developed consists of three generating units -- unit 1, unit 2 and unit 3. Three units were selected as the optimal number to demonstrate the simulation technique being developed in this study. If the use of three units can be accommodated in the model, then more than three could be accommodated with a duplication of effort in programming and computer time.

The use of the term "economic" indicates that the loading of the units will be done so as to minimize the cost. Of the factors selected for the model, the only ones concerned with the costs of operating the units are those involved with the fuel costs. Thus the objective of the economic loading of the units as described here is to minimize the total fuel costs.

For an individual unit the fuel cost per hour of operation is determined by the average demand during that hour, the million BTU's which that unit requires to generate the demand, and the fuel cost per

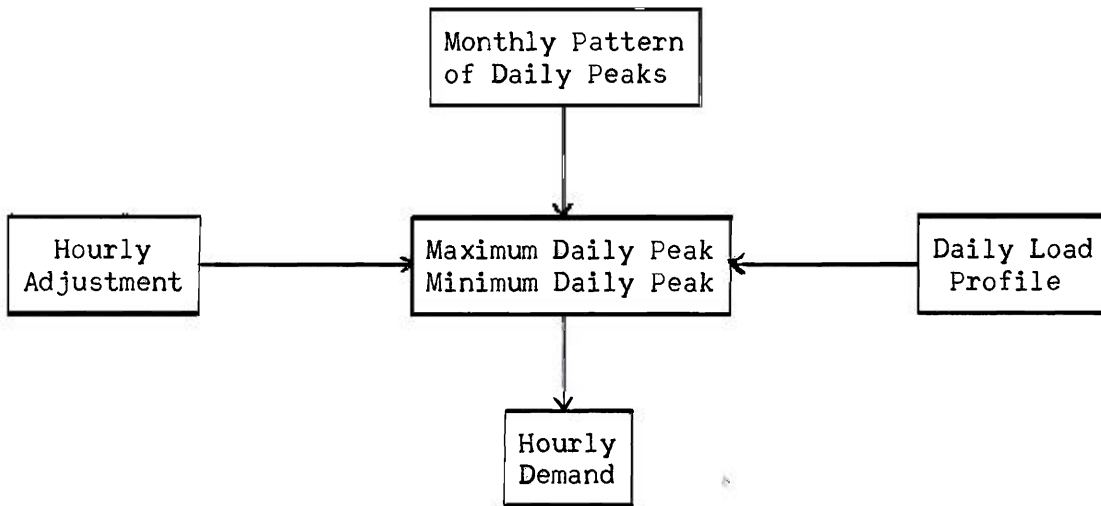


Figure 19. Flow Diagram of Hourly Demand Determination Based on Monthly Data.

million BTU's. The hourly demand has been determined in phase one. In this phase the fuel cost for the generation of the demand will be determined.

From previous discussion, the number of BTU's required to generate a given demand may be expressed graphically and is called a heat rate curve. Since each unit has a unique heat rate curve, it is only necessary to include in the model the heat rate curve for each of the three units. With the demand known, the BTU's are also known.

The cost which the utility pays for fuel is available information from the utility's records. This information will be included in the model by simply placing this data on punched cards according to a suitable Dynamo format. This information concludes all that is necessary for the model to determine the fuel cost for an individual unit.

Before an explanation of the remaining part of this phase is

undertaken it is necessary to discuss a characteristic of the generating units. At the lower end of the heat rate curve the trend is such that the BTU's required to generate the load are increasing at a much faster rate than the rate at which the load is decreasing. Therefore the economics of the cost of operating a unit are such that a lower limit is placed on the load for which the unit will be used. In Figure 9,  $X_1$  is used to illustrate this point. The operation of a unit with this heat rate curve would occur in the range between  $X_1$  and  $X_3$ .

Step one begins as soon as the hourly demand is determined. At this point none of the three units bear any load. Each unit is now loaded to either its maximum capacity or to the amount of the demand, whichever is smaller. With each unit loaded, the total fuel cost to operate each unit for an hour at this load is determined, since the heat rate curve and the cost per million BTU's is stored in the model. The cost of operating each unit is compared one with another and the one operating at the lowest cost is selected. The load of that unit and the cost for operating that unit for that hour are stored in appropriate locations so that they will be accumulated for the entire period of operation.

Step two begins by subtracting the load being generated in step one from the total hourly demand, to determine the demand remaining. The two units are each loaded to either their maximum capacity or to the amount of demand, whichever is smaller. Occasionally the remaining demand may be less than the minimum demand, so that no generation will occur in this step or in the following step. It is remotely possible that an hourly demand in step one could be less than the minimum. In this case there would be no generation for that hour by the three units.

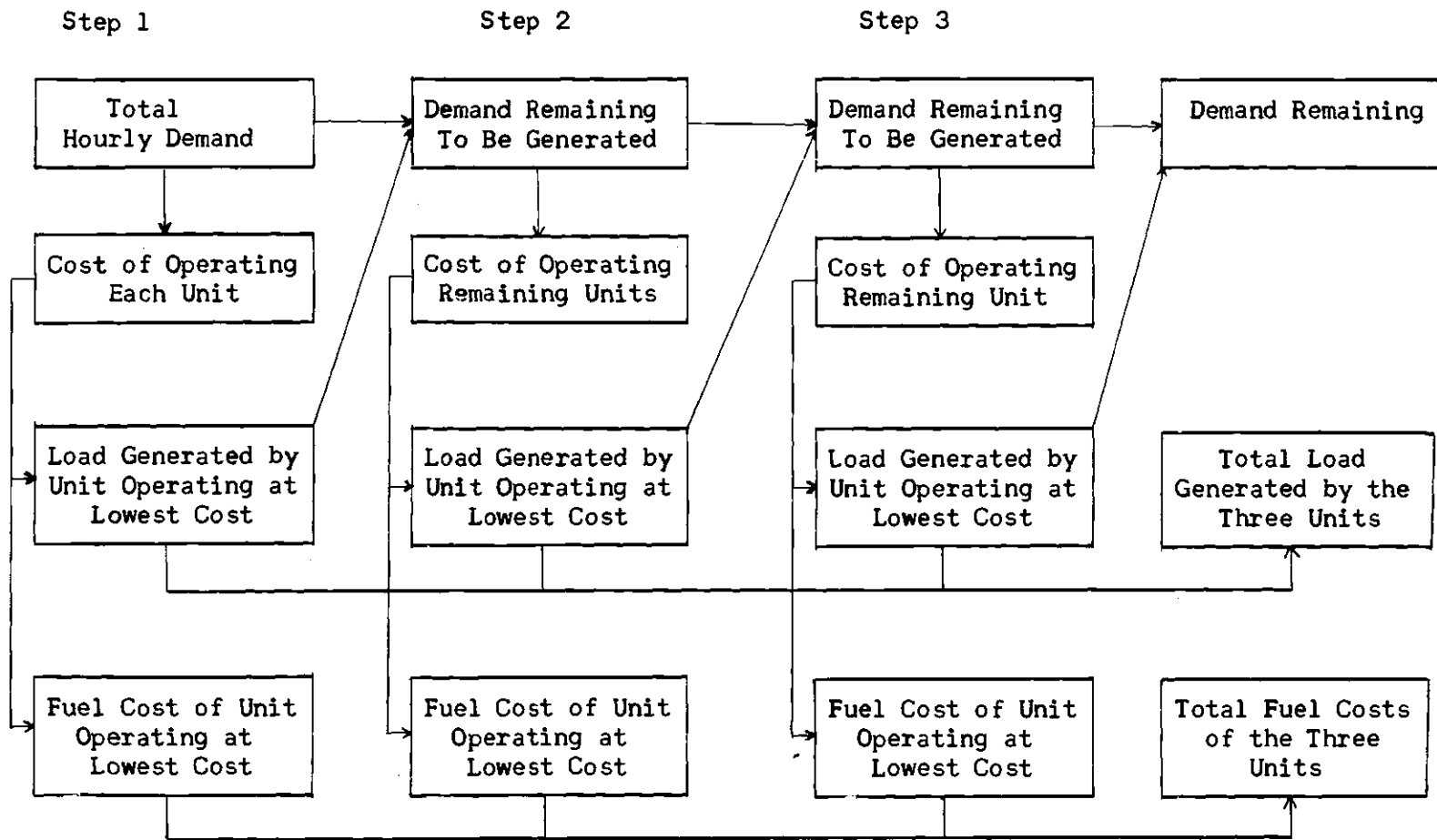


Figure 20. Flow Diagram of Economic Loading of Three Units.

As in step one, the cost of operating each unit for that hour is computed and the one with the lowest cost is selected. The load on this unit and the corresponding cost are each added to those of step one.

Since only one unit remains, step three is rather simplified. If there is any remaining demand and if it exceeds the minimum for this unit, the load is placed on this unit and the corresponding cost is determined. These figures are also added to those of step one and step two respectively. These totals yield the overall generation for that hour, and the corresponding cost for that hour. The difference between the total demand and the total generation is the amount of electricity that must either be provided from some other source or curtailed.

Regardless of the method chosen to provide for this other demand, it is possible to associate a cost with each kilowatt-hour of electricity so demanded. For example, if this amount is purchased from another utility company, there is an agreed rate. Determining a charge for other methods of providing for this remaining demand may not be as simple as the example, but for the purposes of this research some reasonable estimates will be satisfactory.

The sequence of these three steps assumes there are three units. Since units are usually installed one at a time, it is conceivable that at the beginning of the study period there might be only one unit, with other units added later. This presents no problem since it is necessary only to set the capacity of any of the later units to zero until they become operational, at which time their capacity, within the model, will

be changed.

During each hour of simulation the sequence of these three steps is followed. The totals from each hour are accumulated so that at the end of the study period cumulative totals for overall demand, generation, fuel costs and costs of other generation are available.

#### The Investment Section of the Production Department Model

The investment costs to be considered in developing the model are: 1) the investment itself, 2) the associated cost of securing the necessary funds for the investment, and 3) the property taxes and insurance on the equipment and plant. A benefit resulting from the investment is the income tax shield provided by depreciation. Since it will offset the costs it should be included in the model.

#### Investment and Capital Costs

The investment in a generating unit is the total of all amounts paid to make the unit operational, including all money expended for such items as the land and land rights, structures, boiler plant equipment, turbines, generators and all miscellaneous power plant and electric equipment. The total amounts for these items is strictly accounted for in the companies' records and is available as a total figure for each unit. This information can be placed directly into the model.

Capital costs are defined as the difference between the amount of money secured and the amount of money paid back. Since the money paid back is done so over a period of time, it is necessary for comparison purposes, to convert all the costs to some standard figure. It has already been stated that the present worth method will be used to

accumulate all the costs of the simulation study. Therefore this method will be used to explain and determine capital costs.

The capital costs resulting from any method used to finance the investment are not as well defined as the investment costs. One reason for this, is that there are many combinations of the various methods of securing funds. One combination is the use of retained earnings, short-term bank loans, and eventually a bond issue or stock issue. Other possibilities are a bond issue at the time of construction, or the complete use of retained earnings. Securing capital by each of these combinations would probably result in different costs.

As an example of what the capital costs might be for one of these methods, assume that a \$25,000,000, 4 per cent, 20 year bond issue is floated at the time of unit construction. If the customary semi-annual interest payments are made, the borrowing costs consist of 40 semi-annual interest payments of \$500,000 each, plus the administrative costs. Using the present worth method and an appropriate discount rate, the present worth of these future payments can be calculated. If this computation were to yield a figure of \$28,000,000 the capital costs would be \$3,000,000. Frequently a premium is received for the issue or a discount is allowed. This changes the amount received for the bonds and influences the cost of capital accordingly.

With funds obtained from a combination of various sources the determination of the cost of capital becomes complex and difficult. Also, because of the wide choice of financing possibilities and the uncertainty of which one or ones will be encountered in the application

of this model, the exact formulation for including the costs of capital in the model will be delayed. When the validation study is conducted on a specific company and the method of financing observed, a decision will be made as to how to include this factor in the model.

#### Property Taxes and Insurance Costs

Property taxes are generally paid to the local government which has jurisdiction over the plant location. The rate structure and the plant valuation varies from area to area. If original cost of the plant is used, the investment previously discussed would be the base for the tax calculation. However, it is common for some other valuation to be used, usually expressed as a per cent of the total original investment. If the tax assessor uses something other than 100 per cent valuation, it is possible for the tax amount itself to be expressed as a per cent of the investment. Investigation of the company records will yield the amount of taxes and the amount of the investment. The per cent of the investment for a selected year is the factor which is included in the model.

Insurance costs will be handled in the same manner. The amount of insurance premiums paid for a selected year will be expressed as a per cent of the investment accumulated up to that year. This per cent will be included in the model. It is suggested that any year during the study period be used as a representative year. Any rate change in either the insurance rate or the property taxes, should also be included in the model.

#### Income Tax Benefit Resulting from the Investment

Income taxes constitute disbursement similar to those for

operation, property taxes, and insurance. The amount of income taxes is a function of the gross income received from the operation of the company, the allowable deductions, and the income tax rate. The amount of income tax is determined by applying the tax rate to the net taxable income -- the gross income less the deductions. The larger the amount of deductions, the less the net taxable income and the less the income taxes. This factor is working in the opposite direction of the other factors associated with the investment.

Many factors affect the determination of taxable net income, but only investment in depreciable property will be considered as a part of this study.

There are generally three types of depreciation methods available, classified as rapid write-off, straight line, and slow write-off. The importance of the time value of money is the key to deciding between the rapid and slow write-off types of depreciation. The rapid write-off yields a greater financial advantage over the other two types when income tax rates are high. A condition warranting a slow write-off occurs when the tax rate in the distant future is expected to be considerably increased.

The straight line method owes its popularity to the fact that prior to 1954 it was the only method encouraged by federal tax rules, and many firms have continued it out of simple procedural inertia. While the simplicity of the straight-line method has appeal to many, in the utilities the rapid write-off is the most commonly used for income tax purposes, even though the utilities often use straight-line

depreciation for accounting purposes other than income tax.

The rapid write-off method will be used for the simulation study. The Internal Revenue Service readily recognizes and accepts two methods of rapid write-off: the double-rate declining-balance method and the sum-of-the-year-digits method. The two methods provide basically the same effect on income taxes, allowing the choice between them to be a matter of the author's convenience. Since the declining-balance method is the simpler of the two, and because it is also compatible with the programming techniques of the Dynamo language, it will be used in the model.

In any declining-balance depreciation accounting, a given depreciation rate is applied each year to the remaining book value to determine the depreciation charge for that year. The remaining book value is that portion of the cost of an asset that has not already been written off in a previous year. For example, if a 10 per cent rate is applied to an asset that cost \$50,000, the depreciation charge in the first year is  $0.10 (\$50,000) = \$5,000$ . In the second year the charge is  $0.10 (\$50,000 - \$5,000) = \$4,500$ . In the third year it is  $0.10 (\$45,000 - 4,500) = \$4,050$ . This procedure continues for the remaining years of the depreciable life of the equipment, or until it is disposed of. Figure 21 presents a plot of the resulting annual first-of-year book values if the calculations are continued for a 15 year period. For comparison purposes, the straight-line results are presented by the broken line.

The declining-balance method becomes the double-rate declining-balance method when a depreciation rate is double that of the allowable

straight-line rate for an asset with a prospective zero salvage value and a given estimated life. The rate is calculated as 8 per cent by dividing 200 by the estimated life in years. This is the maximum rate allowed by law and is the one which will yield the most rapid write-off. It is this rate which will be used in the model.

#### Present Worth Conversion

It has been stated in a previous discussion (Chapter I) that this study will use the present worth method of comparing receipts and disbursements over time. It is necessary, then, to include in the model a procedure which will convert all the costs and the income tax benefits as they occur, to a present worth figure.

According to Grant and Ireson (14), there are two conventions commonly followed in present worth conversions. The first is called the end-of-year convention. The name is descriptive in that all costs or receipts which occur during a year are added together and assumed to occur as a lump sum at the end of the year. The other method is the uniform-flow convention. Again, as the name implies, the receipts and disbursements are recognized as occurring uniformly throughout the year rather than concentrated at the end of the year.

The cash flows occurring in this model are comprised of some flows which occur annually and some which occur monthly. The property taxes and insurance payments are normally made on an annual basis. Although income taxes are normally considered as an annual expenditure, payments are made periodically throughout the year against an estimated figure. Fuel costs are probably the most uniform cost over time.

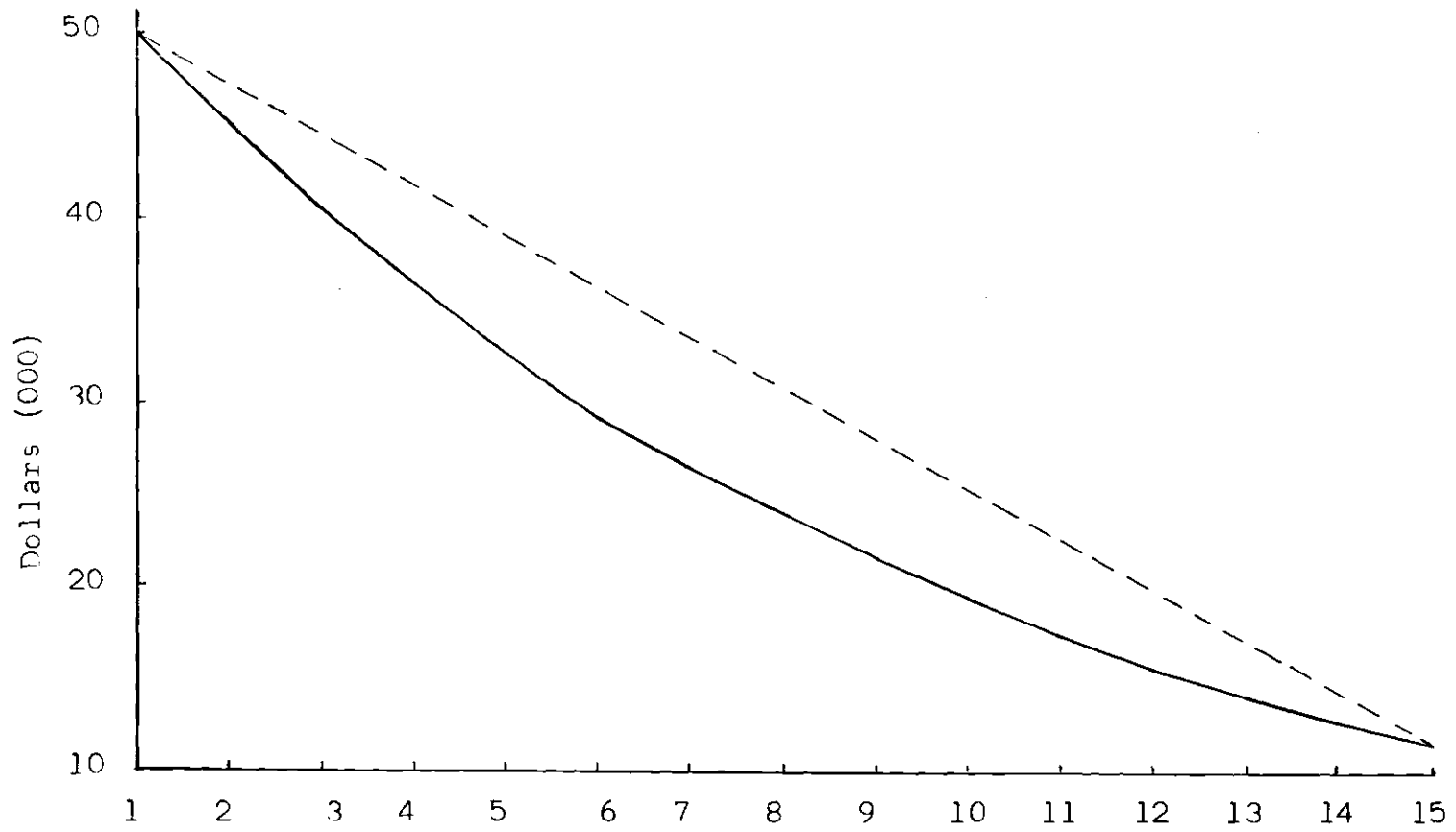


Figure 21. Annual Book Value with Double-Rate Declining Balance Depreciation Method

Since Kilowatt-hours are being generated constantly throughout the year, fuel costs are occurring at the same rate. Actually the cash paid to the fuel supplier is generally done monthly, and is still a uniform flow compared to the end-of-year flow.

It is clear that neither convention will conform exactly to the timing of all the cash flows. Grant and Ireson have the following comment on this:

All things considered, the uniform-flow convention probably comes somewhat closer to describing the way most cash flow occurs than does the end-of-year convention. Nevertheless, it is desirable to recognize that either is merely a convention to facilitate compound interest conversions; neither is a completely accurate reflection of the way in which cash flow is expected to take place.

Generally the uniform-flow convention utilizing the continuous compounding method of developing the conversion factors is more applicable in mathematical models. This method will be used in this simulation study. The development of the continuous compounding expressions for single payment present worth factors is found in most engineering economy textbooks. The factor is the value of  $e^{-rn}$  where  $r$  is the nominal interest rate and  $n$  the number of years.

A procedure will be included in the model to provide the single payment present worth factor at the end of each month and at the end of each year. This will allow the conversion of the costs paid monthly and annually. The only information required for the calculation of the factors is the interest rate.

Inclusion of any given interest rate in the model is no problem. What interest rate to use does present a problem. The term "interest

rate" as used here is the minimum attractive rate of return which a company uses in comparing alternative cash flows by a compound interest method -- in this case the present worth method. There are probably as many thoughts on what rate to use as there are writers on the subject. One suggestion is capital rationing. A complete presentation of this may be found by Joel Dean in his book Capital Budgeting (6). This method assumes that many investment projects are available and the prospective rate of return each will yield may be estimated. The projects are ranked in descending order on the basis of the rates of return and the required accumulated investment. The rate of return of the last project allowing the cumulative total of investments to equal the amount of capital available becomes the minimum rate of return.

Another idea is that of using the cost of securing money. A text on financial management such as Lindsay and Sametz (19) presents the costs of securing the funds from each of many sources. Combining the costs for these various sources by the weighted average method will provide a figure which could be used as the interest rate desired. Support for this method may be found in Weston's text (35).

Others feel that using the cost of borrowed money would not allow for a profit. Thus this figure would arbitrarily be increased to give the owners some advantage in return for the risk of borrowing and being in business.

Another theory is advanced by Modigliani and Miller (22). One of their propositions states:

the average cost of capital to any firm is completely independent of its capital structure and is equal to the capitalization rate of a pure equity stream of its class.

In other words, the cost of capital is equal to the expected earnings per share divided by the market price of a share of common stock. It is recognized that this proposition is based upon some rather limiting assumptions underlying a well-defined mathematical model. As such, it is doubtful that its strict application to a realistic business situation could be defended in every instance.

Since this research is not primarily devoted to a determination of the cost of capital or the minimum attractive rate of return, no additional theories will be mentioned. Of the ones presented, the latter is clearly the easiest to apply and the necessary information appears in the company records and in many market publications. Primarily for these reasons then, the annual rate of earnings per share divided by the market price of the common stock will be used in the model as the interest rate for calculating the continuous compounding present worth factors.

#### Summary

This chapter has developed and introduced in a general manner all of the considerations necessary to simulate the production department on a computer.

A brief description of the operation of a production department has been presented with the hope that the development of the general mathematical model which follows will be easier to understand. All factors which the previous statistical analyses indicated should be included have been discussed. With this phase of the study complete, it is possible to validate the model by taking data from the records of an

electric utility company, placing this data in the model, operating the model over a period of time, and then comparing the simulation results with the actual results. In the next chapter this activity will be discussed.

## CHAPTER V

### VALIDATION STUDY

#### Introduction

The general model described in the previous chapter is translated into a specific model through the use of the Dynamo language. This model will be used to simulate the operation of an electric utility company, and to test various alternatives by changing some of the operating input data. These alternatives will represent courses of action which the company could have followed. To assure that these results will be meaningful and realistic, it is necessary to validate the model.

The validation process consists of selecting all the necessary data from an operating company and simulating the company operation over some historical period of time. If the model does represent that phase of the company as intended, the results of the simulation using the actual data should compare favorably with the actual results of the company's operation validating the model.

The company chosen for the validation study is one of the privately owned utilities selected for the statistical analyses described earlier in this study. The company will not be referred to by its actual name, but rather will be called "XCO". XCO served an area of approximately 1700 square miles and received about 60 million dollars annually from the sale of electricity to its 180,000 customers.

Investigation of XCO's generating capacity growth reveals that the

latest plant went into operation with the completion of unit number one in September, 1957. The installation of this plant is significant in that the use of coal as a fuel is a departure from the use of oil as a fuel at the company's other two plants. XCO now has five units in operation at this coal-burning plant -- the last one having been completed in the latter part of 1965.

The model will accommodate three units, therefore, it was decided that the validation study period would begin at the first of 1958 when only one unit was available, and continue for three years -- a period which would include the installation and operation of unit three. The choice to use only the coal-burning plant was enhanced by the fact that the results of operating this plant are reported separately in the company's statistical reports. This is important when comparing the simulation results with the actual results.

#### Description of the Company Data Required

The data required for this study is divided into data on the generating units, and other company data. The data required for the generating units includes the maximum capacity which could be depended upon under normal operation conditions. Also needed is the minimum capacity requiring the generator to be put into operation (usually approximately 30 per cent of the maximum). Knowledge of the exact date of installation of each unit is also necessary.

One other cost figure is also needed -- the cost of fuel. Since all three units involved in this study use the same fuel, the cost which the company pays for fuel for each unit will be identical, and these

costs will be stated monthly for the three year period. In order to accumulate the fuel cost for each unit, heat rate curves are also required for each of the units.

In actual operation generating units are down many times during the year for both scheduled and unscheduled periods. Since the down times affect the total kilowatt-hours generated and the corresponding fuel costs, they must be included in the validation study. Therefore data concerning the time each unit is taken out of service and put back into service must be included in the model.

Other data required from the company is the monthly maximum daily peak demand and the monthly minimum daily peak demand. To determine the correction adjustment for the daily peaks, it will be necessary to analyze the peaks for each day of sample months. The data to perform this will be required. The number of correction adjustment patterns to use will be considered. For example, will the same pattern serve the entire study period or will it vary from season to season or year to year?

Determination of the daily load profile is required. In previous discussions it was noted that this profile will be expected to vary from season to season. Therefore, typical days from each of the seasons will be sampled and some average profiles will result for each of the four seasons. The hourly adjustment will be determined from experimentation on the model, and not from company's data.

Company policy dictates that at least one unit of the other plants will be in operation, a good practice which provides instant reserve capacity. The capacity of these units which are spinning without a load is called spinning reserve. At the time that the coal-burning plant

represents approximately one-half of the total generating capacity of the system, this policy is relaxed. A factor is included in the validation model establishing the total generation which will be provided at the other plants.

#### Company Data Used in the Validation Study

The generating plant under study will be referred to as the Gan plant. Gan 1 was installed on September 15, 1957, with a generating capacity of 125,000 kilowatts. Gan 2 was installed on November 15, 1958, with a generating capacity of 130,000 kilowatts. Gan 3 was installed on October 15, 1960 with a generating capacity of 180,000 kilowatts. The minimum operating capacities for the three plants were considered as 40,000, 40,000 and 55,000 kilowatts.

The monthly coal bill expressed as cents per million BTU's is shown in Table 8. This data was taken from the company's monthly financial reports for the period covered.

Data for the down times of the three units is compiled in a log at the power plants. A sample of this log for Gan 1 for 1958 is shown in Table 9. Similar information was available for the other years and the other two units, and is included in the model. It was necessary to convert the time from day and hour to a time compatible with the model. Since the simulation is for each hour, starting with 0 hour at midnight on December 31, 1957, all the times must relate to 0 hour. Thus the first outage occurred at time 707 and the unit was back in service at time 830, for a total down time of 123 hours.

The daily instantaneous maximum demands were available from

Table 8. Monthly Cost of Coal for XCO, in  
Cents/million BTU's

	1958	1959	1960
Jan.	39.58	35.58	31.94
Feb.	38.70	33.65	32.14
Mar.	37.14	35.43	32.56
Apr.	36.88	34.89	31.69
May	36.02	33.87	31.84
June	36.77	36.06	31.68
July	36.71	34.77	32.47
Aug.	34.52	34.40	33.26
Sept.	33.79	34.63	32.66
Oct.	33.35	33.75	32.53
Nov.	34.84	33.52	31.71
Dec.	35.35	32.16	31.94

company records. Also the hourly instantaneous demand for the period 1955 to 1965 were available on punched cards. A printout of these cards provided sufficient information to determine satisfactory daily load profiles and correction factors. The data on the punched cards is coded so that the day of the week is shown for each day.

To calculate the daily load profile for each of the four seasons, a sample week was randomly selected from each of the seasons for 1959. The weeks selected were the weeks beginning on January 19, April 13, August 24, and November 2. The daily load profile for each day was calculated and an average for the week computed. This was intended to give weight to the different profile which represents Saturday and Sunday as compared to the week days. A plot of these four profiles is presented in Figures 22 through 25.

Table 9. Log of Outages for Gan 1, 1958

OUT		IN		Cause of Outage	Type of Outage	Unavailable Hours
Date	Time	Date	Time			
1/30	10.45A	2/4	3.53P	Revisions to coal chutes and minor repairs	Maint.	123
2/7	4.03A	2/7	2.11P	Lightning Arrestor ruptured by Lightning	Forced	10
3/26	10.45A	3/28	4.57P	Ruptured Tube in "B" cyclone	Forced	54
5/14	10.45P	5/26	1.27P	Tube ruptured in 1A cyclone	Forced	278
6/13	11.18P	6/15	1.16P	Leaking tube in economizer	Forced	38
7/26	9.04A	7/27	10.51P	Leaking cyclone tube	Forced	38
8/1	10.42P	8/13	8.04A	Acid clean boiler and minor repairs	Maint.	273
8/13	11.38A	8/14	11.45P	Fire in furnace skin casing	Forced	37
9/28	10.33P	9/30	5.39A	Repair leak in slag tap cooling coil	Maint.	30
10/19	12.45P	10/20	4.31P	Leaking tube in 1C cyclone	Forced	27
11/21	8.11P	12/5	5.11A	General Maint. of Boiler	Overhaul	322
12/12	11.25P	12/13	11.00A	Leak in Boiler slag tap cooling coil	Forced	12

The correction factor adjustment used for determining the daily peak was calculated for each year. To calculate the correction factor by months it is necessary to compare the straight-line estimate with the actual maximum daily peak, for each day of the month. For an approximation of the correction factor for a year, using a sample of six months (every other month beginning with January) the monthly factors were each computed and averaged together for each year. The resulting correction factors appear in Figures 26, 27, and 28.

The hourly adjustment necessary to compensate for the difference between the highest hourly demand and the average demand for each hour will be applied to the correction factor. Although this adjustment has no direct relationship to the correction factor, since both are percentages applied to the daily peak, it is a convenient location to introduce the adjustment into the model. After this adjustment is performed, the resulting correction factor will be referred to as the correction factor modified.

Heat rate curves for Gan 1, Gan 2, and Gan 3 were provided to the company by the manufacturer at the time of their installation. These curves are the theoretical curves and are the only ones available. The company has not conducted any studies to determine if, under the actual operating conditions, different heat rate curves might result. Three curves for each unit are available, each for a different constant circulating water temperature -- 65°F, 75°F, and 85°F.

The company suggested that the 75°F curves be used. It was decided that during the warm months a different curve would provide more

accurate results. This was accomplished in the model by modifying the BTU per net kilowatt-hour, which is obtained from the heat rate curve. A suitable adjustment will be determined by experimentation.

The heat rate curve for each unit is shown in Figure 29. Only the 75°F curves are shown, since they are the basis for those included in the model.

To compensate for the operation of the other two plants, a base generation load of 81 megawatts is included during the time Gan 1 is in operation alone. As soon as Gan 2 is in service this base generation at the other plants is reduced to 55 megawatts. When Gan 3 is installed, all base generation at the other plants is neglected. The 81 megawatts represents the largest of the units at each of the other plants, and the 55 represents the largest unit at one of the plants plus the second largest unit at the other plant.

#### Results of the Validation

The complete model used for the validation study is given in Appendix D.

To check the validity of the model, three outputs from the simulation are compared with actual company operating results. These actual results are published by the company in an annual report of the company's financial and operating statistics. The comparisons will be on the fuel cost for operating Gan plant, the kilowatt-hours generated at the Gan plant, and the total generation demanded by the total system. The results are shown in Table 10.

The comparison indicates a very close relationship between the

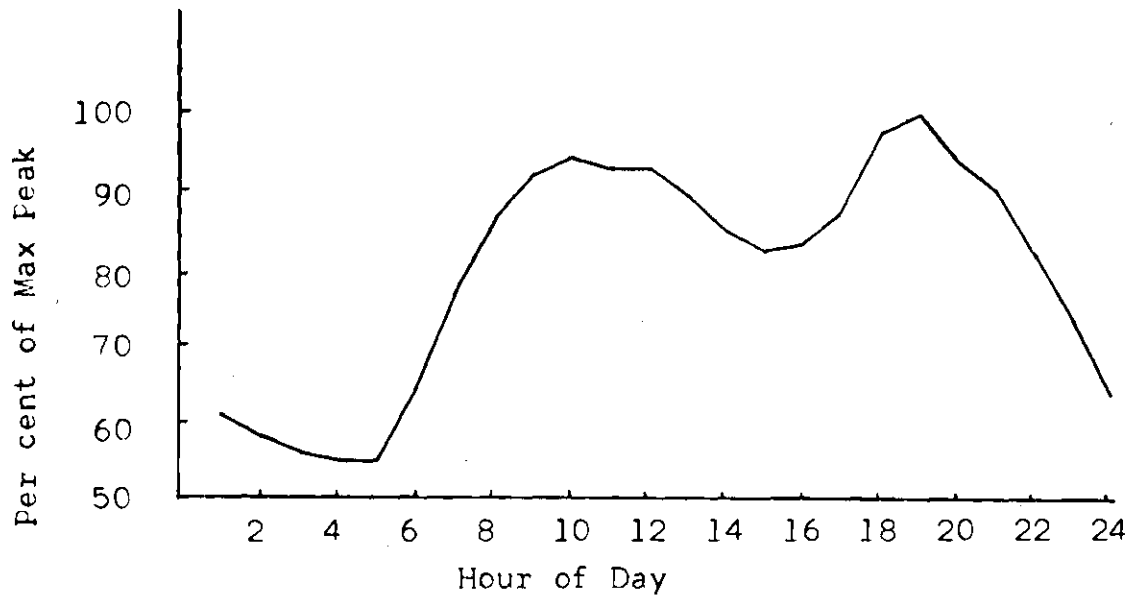


Figure 22. Daily Load Profile, Winter

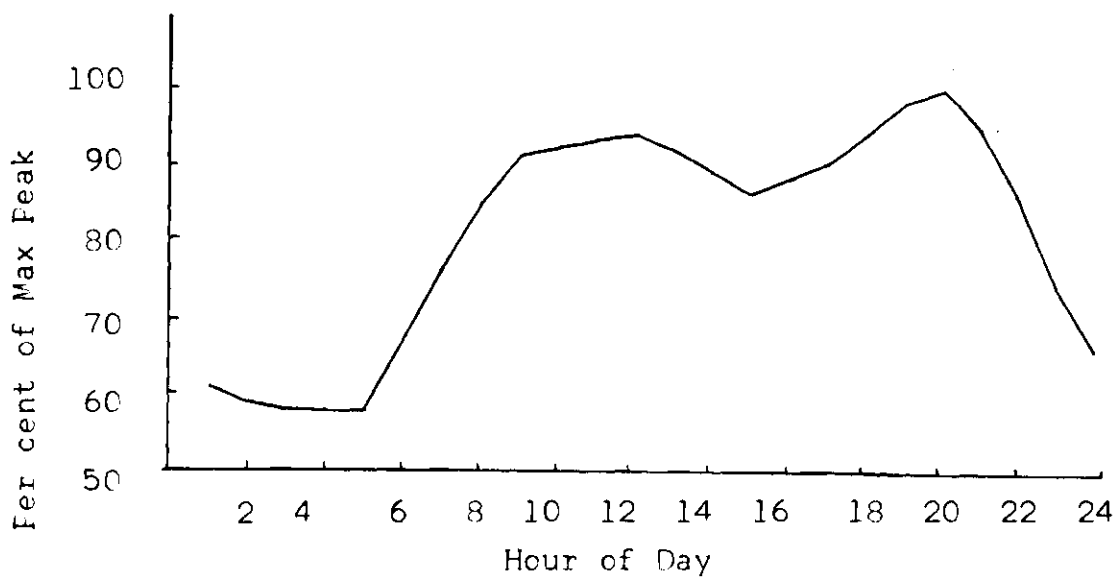


Figure 23. Daily Load Profile, Spring

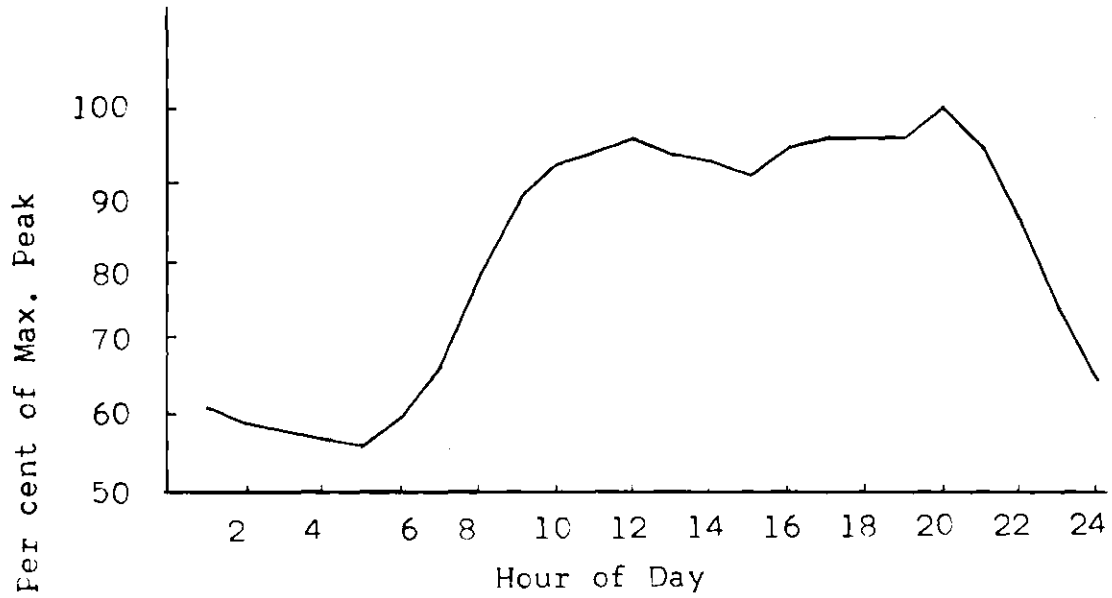


Figure 24. Daily Load Profile, Summer

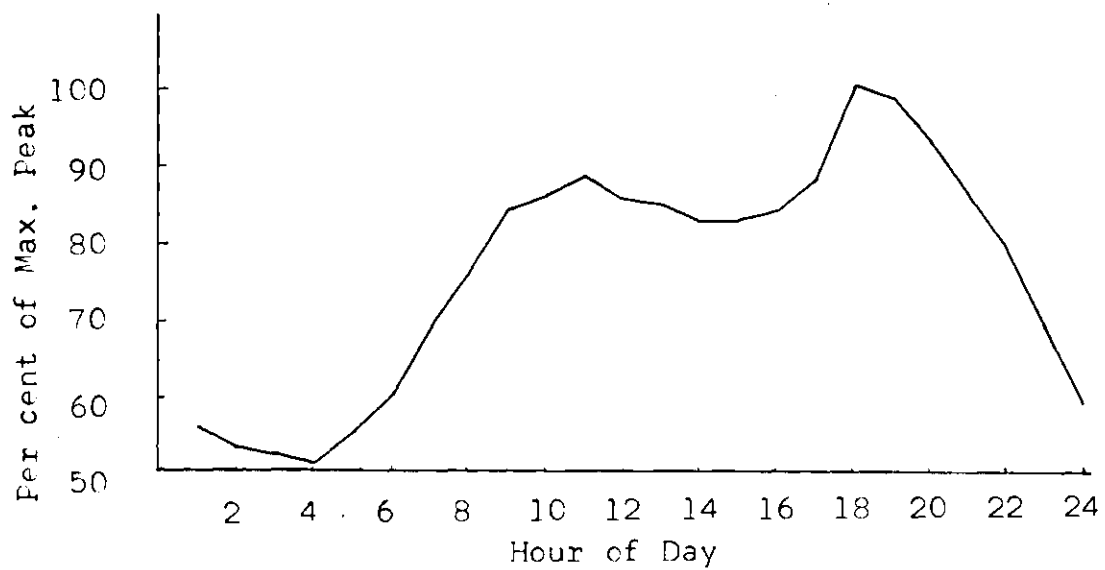


Figure 25. Daily Load Profile, Fall

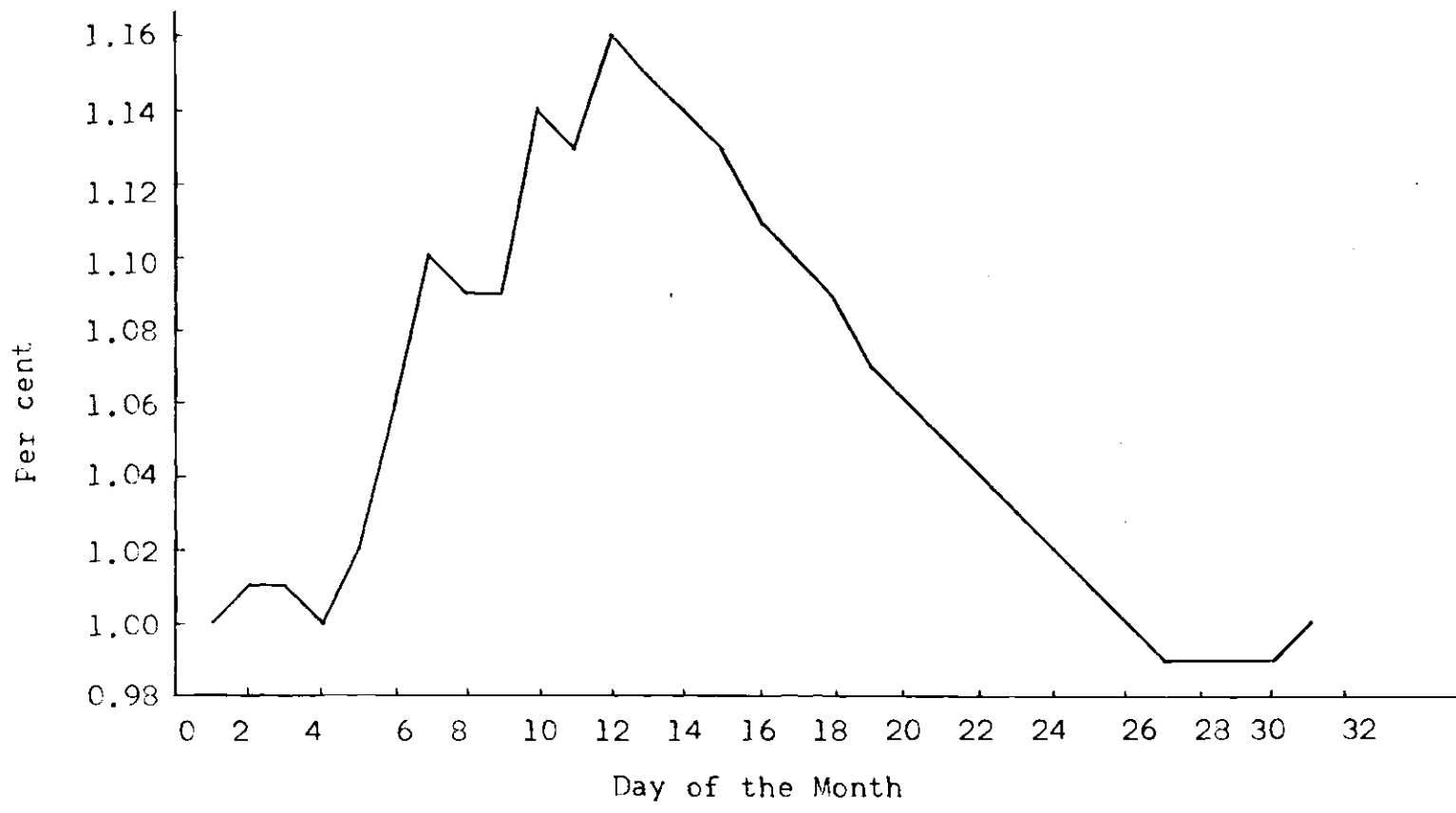


Figure 26. Correction Factor, 1958

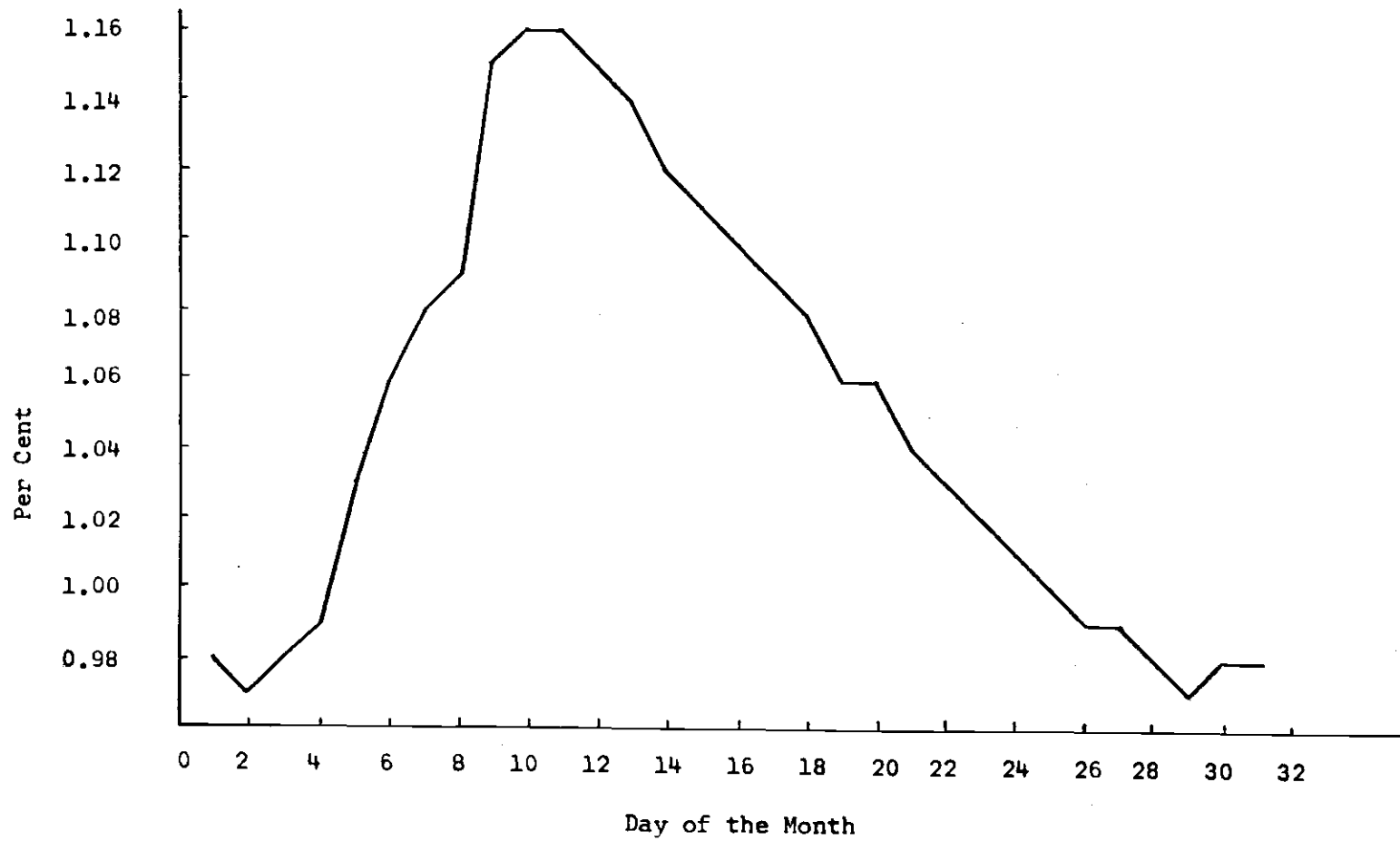


Figure 27. Correction Factor, 1959

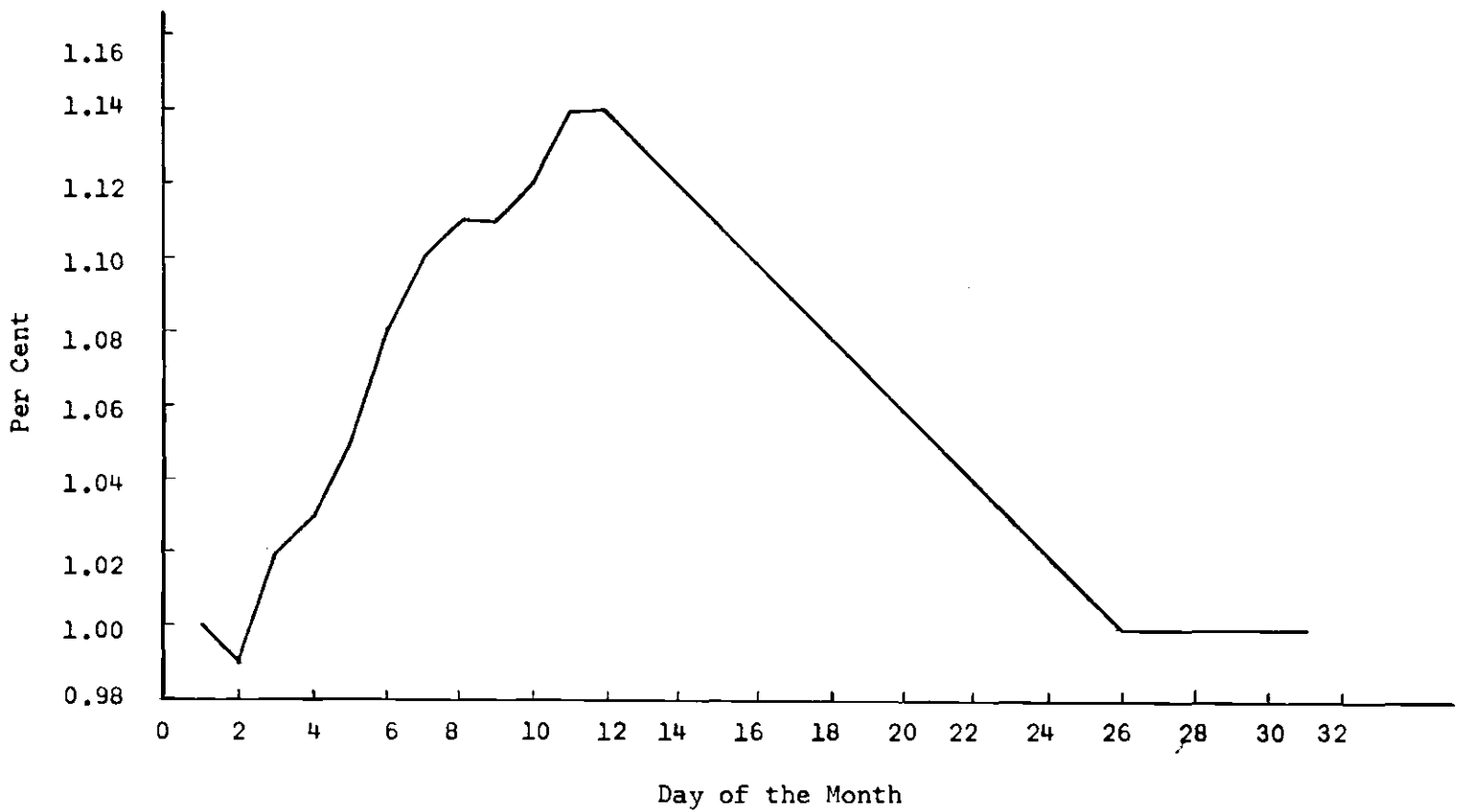


Figure 28. Correction Factor, 1960

actual and simulated results. Another indication of the satisfactory operation of the model is seen by comparing the portion of the total generation at Gan to the total company generation demanded for both the simulation and actual operation. In 1958 the simulation for Gan generated 41.8 per cent of the total and the actual was 40.4 per cent. In 1959 the simulation was 59.7 per cent compared to 56.6 per cent, and in 1960, 66.4 per cent compared to 65.5 per cent. The total for the three year study was 56.8 per cent for the simulation and 55.3 for the actual results. These results also suggest that the simulation model is behaving very closely to the actual operation of the company.

The results obtained were based on the use of 5 per cent as the adjustment to the instantaneous demand. The heat rate curve necessary to produce these results was the 70°F curve for winter and the 75°F curve for summer.

#### Conclusions

The results indicate that the selection of all of the factors is satisfactory. Further modification of the adjustments could probably make possible a closer correlation of the actual and simulated results. However the results appear to be acceptable for the purpose of this study. The following chapter will utilize the basic model to conduct experiments as required for this research.

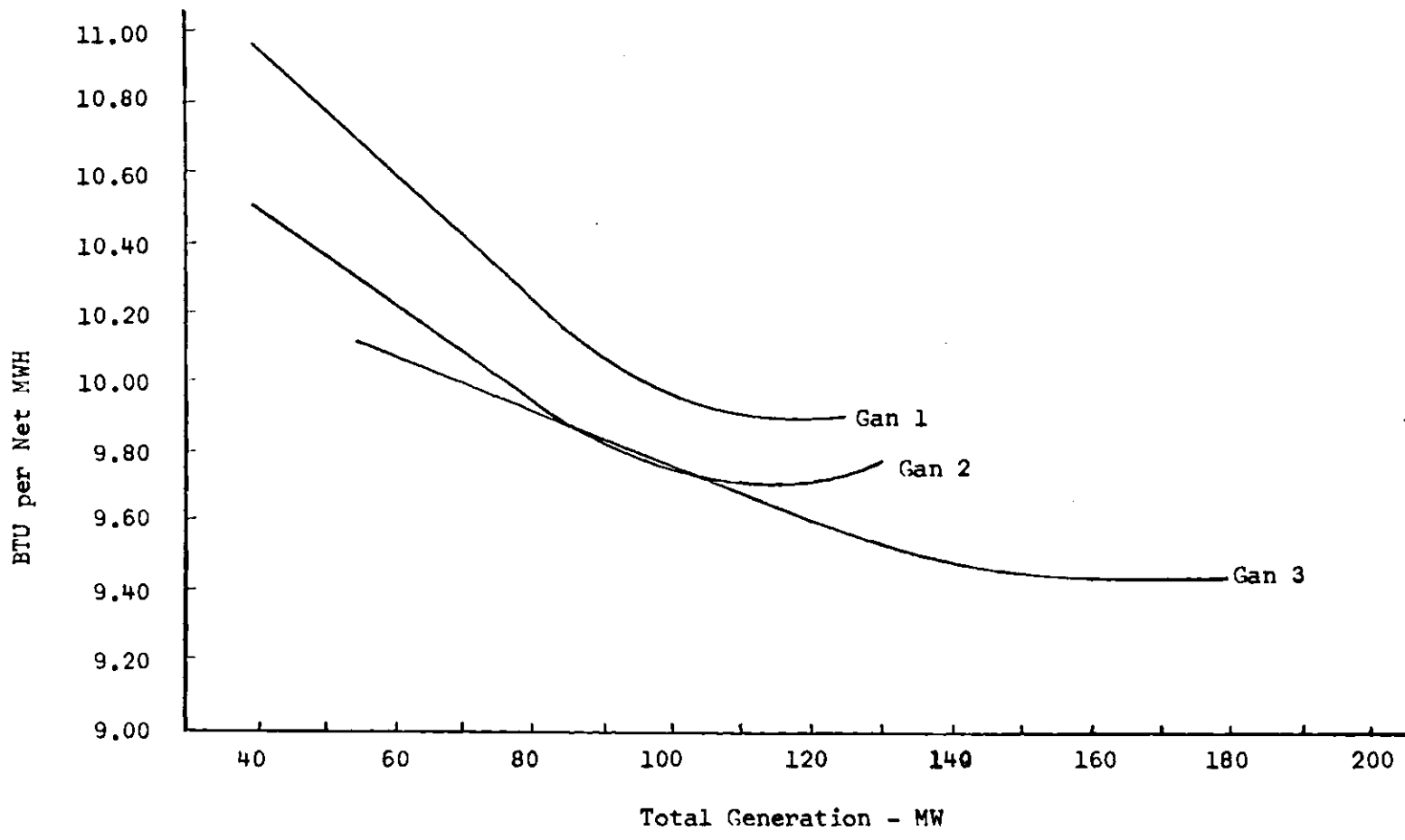


Figure 29. Heat Rate Curves for Gan 1, Gan 2 and Gan 3

Table 10. Validation Results versus Actual Results

Year	Fuel Cost	Per Cent <sup>1</sup>	MWH Gen- erated Validation	Per Cent	Total MWH Demanded	Per Cent
1958	3,006,000	102.6	829,700	105.5	1,986,800	102.1
1959	4,601,000	101.8	1,325,900	105.7	2,220,800	100.5
1960	5,324,000	94.4	1,647,700	101.1	2,480,100	99.7
Total	12,931,000	98.8	3,803,300	103.6	6,687,700	100.7
Actual						
1958	2,930,371		786,405		1,945,211	
1959	4,517,800		1,254,750		2,209,186	
1960	5,642,001		1,629,143		2,487,104	
Total	13,090,172		3,670,298		6,641,501	

<sup>1</sup>The per cent is the ratio of validation results to actual results.

## CHAPTER VI

## DETERMINATION OF A MEASURE OF PERFORMANCE

Introduction

The validation of the model having been completed, a tool is now available to conduct studies specifically intended to develop a technique for measuring managerial performance. It is reemphasized at this point that the objective of this research is not to develop a specific measure of performance for the particular company being used in this research. Rather, the objective is to develop a technique and procedure which will make a measurement of this sort possible.

For this purpose the company previously used for the validation study, XCO, is used. It is necessary to select a time period, after which various alternatives are selected and simulated on the computer model. The results of these runs will be discussed and a measure of performance presented.

The purpose of using various alternatives is to determine whether a better investment pattern and selection of unit sizes could have been followed by the management. The definition of best is the lowest total present worth cost as previously discussed.

Additional cost information necessary for this phase of the study includes cost of installation for each unit, method of financing, insurance rates, property tax rates and federal income tax rates. Also

necessary is a cost figure for each kilowatt-hour of electricity that is not generated at Gan plant.

#### Selection of Study Period

To provide a basis for this selection, it is helpful to consider the growth pattern of the company and the installation pattern. Figure 30 provides a plot of this information. At the beginning of 1958, the generating capacity was adequate for the peak load and at the end of 1963 it appeared to be adequate. Approximately the same excess capacity was available at each point, the excess being expressed as a percentage of the peak load. There are also other reasons for using this period.

In the validation study the first three years of data were already in the model. Also, during this six year period only three units were in operation. Thus no modification will be necessary to the basic model. Six years is a sufficient period to provide several alternative generating installation patterns. Therefore, the six year period from 1958 to 1963 was selected as the study period.

#### Selection of the Alternatives

Figure 30 presented the actual installation pattern the company followed with its generating units. This existing pattern is referred to as alternative A and is the same one used for the validation study. Investigation of the growth pattern suggests other management patterns which the company could and might have followed had it known with certainty what the growth pattern would be.

While many possible patterns could be considered, a study of the growth rate suggests certain obvious possibilities. The first is that of using a single large unit for the overall period under study. A 350 megawatt unit would provide sufficient capacity for this period. This size unit is more efficient than the units used in alternative A. The question to be considered is whether the extra investment at time zero would be offset by the reduced fuel costs. Also, the effects the other cost aspects might have on the total costs is not certain. This alternative is referred to as B. Figure 34 presents a comparison of this alternative and the next two.

Alternative C is suggested as a compromise between A and B. It is not expected to be the optimum but neither is it expected to be the poorest. It consists of an initial unit size of 150 megawatts and a second unit of 200 megawatts which would be placed in service in November, 1960.

Alternative D was expected to be the best solution, since the capacity remains as close as possible to the annual peaks. It begins with the same 150 megawatt unit as in C but, instead of installing a 200 megawatt unit, a 130 megawatt unit is installed in November. The total capacity remains unchanged until November, 1962, at which time a 70 megawatt unit is installed. The investment cost of this pattern will be at minimum, but it is uncertain as to whether this will be sufficient to offset the higher fuel costs resulting from using smaller less efficient units.

The three alternatives suggested are in keeping with the same

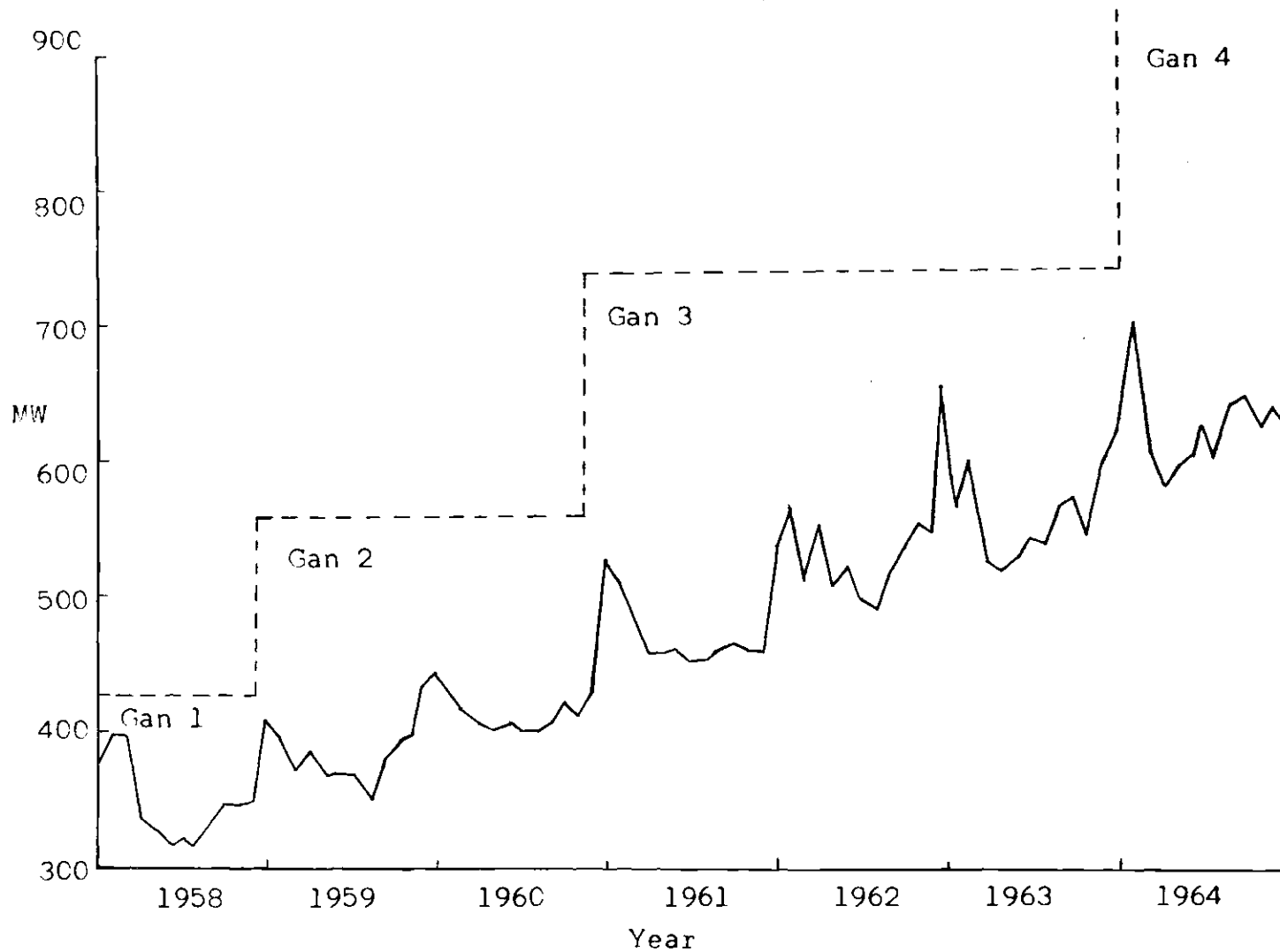


Figure 30. Total Generating Capability versus Maximum Monthly Integrated Demand

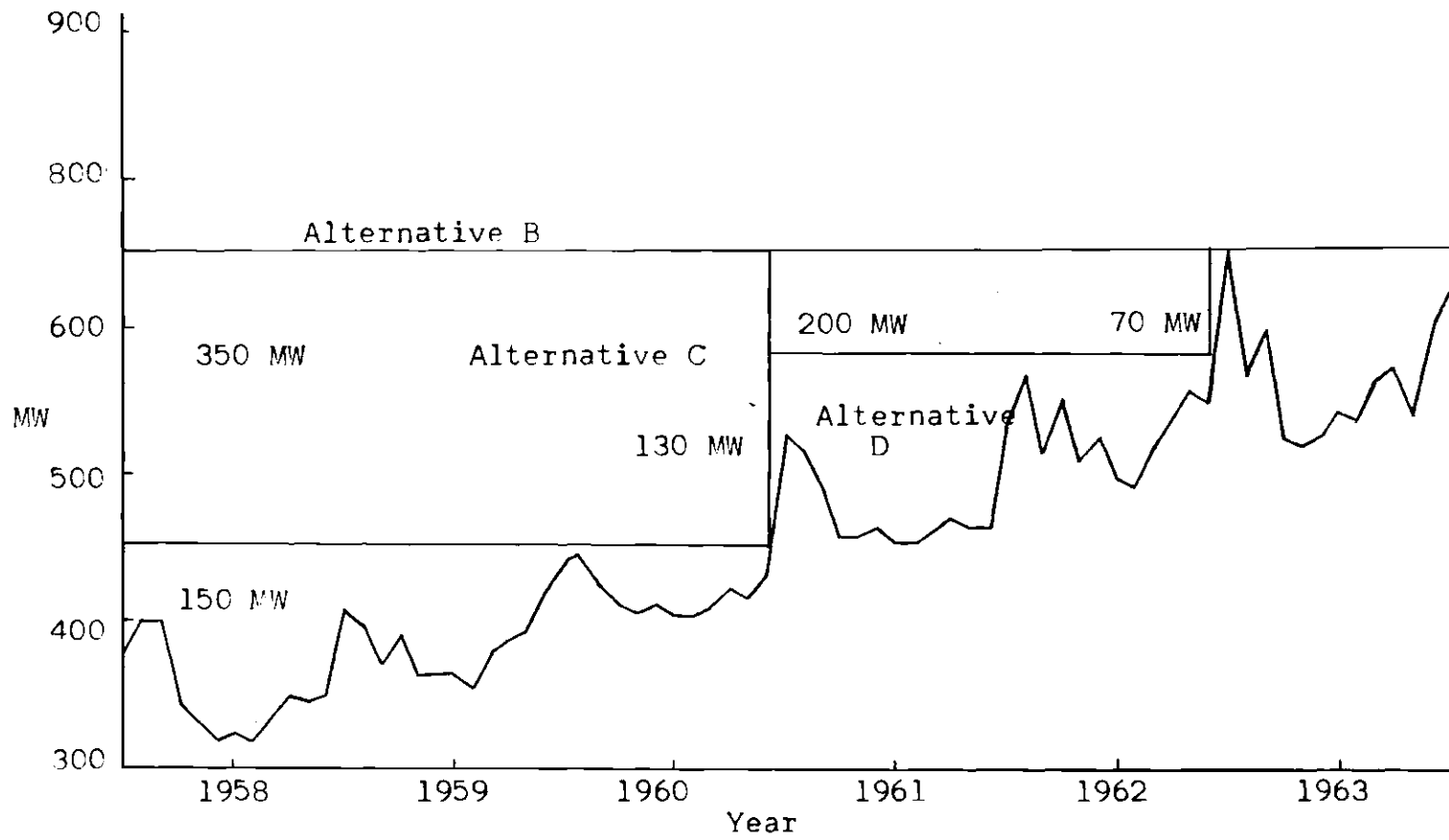


Figure 31. Alternative Unit Installation Patterns

technological advances which the company has found acceptable. No radical changes are to be introduced, such as adding a nuclear unit or switching to hydro-electric generation. All of these are possibilities but are not in the scope of this study. A measure of performance can be secured by remaining consistent with the philosophy which the management has been following regarding the type of generation to be used.

#### Modifications to Validated Model

It is necessary to modify the model to eliminate the possibility that a particular alternative might be unknowingly favored. For this reason the unit down times will not be included in the model. It would be very difficult to estimate the down times for other units. Thus, by not including any down times, all of the alternatives are being treated equally.

The base generation at other plants was withdrawn from the model. Company policy will determine the amount to use with each of the other alternatives. If this figure is left out for all four alternatives there is no bias toward any one of the plans. In conjunction with this, Gan plant will not generate all the system requirement even though there is no arbitrary base generation at the other plants. This is due to a combination of the demand of each hour and the minimum generation imposed on each generator. The minimum, it will be recalled, is the point on the heat rate curve beyond which it is economical to operate that unit.

If only one unit is serving Gan for the entire period of time, the other generation would be the sum of all of the hourly generation demands which were less than the minimum for the unit. However, with

two units, it is the balance not generated by the most efficient unit which must be compared with the minimum capacity of the remaining unit. If the remaining demand is less, then this amount is transferred to the other generation account. With three units this process would involve the complexity of the demand remaining from the first two more efficient units.

Since some other generation will occur, and it will be different for each combination of units and sizes, a cost must be attached to it so that the alternative can be fairly compared. The results will be used for relative comparison between the alternatives. Therefore if the cost is reasonably realistic the outcome of the comparison will be unchanged.

The company has two other plants which will be used for providing this additional generation. The only significant variable cost associated with the operation of these plants for other generation is the fuel cost. From information in the company's operating statistics calculations were conducted which yielded a fuel cost of approximately 0.5 cents per kilowatt-hour generated. This is the figure which establishes the cost for additional generation.

The cost of the units is needed, not only to reflect the investment, but also as a basis for calculating the insurance costs, taxes and depreciation. All costs for alternative A will be used to determine the costs of units for the other alternatives, by interpolation and extrapolation. The insurance rate for alternative A will be used on all the other alternatives. The same procedure applies for property taxes.

The costs of installing Gan 1, Gan 2 and Gan 3 were \$18,347,357, \$14,443,492, and \$19,489,280 respectively. The cost per kilowatt of capacity of the first unit is always higher than the second or third unit since it is charged with land and right-of-ways which are one-time costs. Costs for structures and improvements and miscellaneous equipment for the first unit is higher than for the succeeding units as there is some carry over in the use of some of this equipment. Therefore a base cost of installing the first unit was established as the difference between the cost of unit one and unit two. It was arbitrarily assumed that this base would be constant regardless of the size of the first unit. The variable cost was approximated by the cost per kilowatt of capacity for unit two.

The base cost was assumed to be \$3,903,865 and the variable cost was assumed to be \$115.55/KW. Table 11 contains the results of the cost estimation procedure for all units used in the B, C and D alternatives

Table 11. Cost Estimates for Alternative Units

Unit size -KW	Total Cost	Cost/KW
350,000	\$44,346,365	\$126.70
200,000	23,110,000	115.60*
150,000	21,236,365	141.60
75,000	8,666,250	115.60*

\* These units will not be the initial unit in the plant.

The cost of capital needs to be considered in this phase of the study. If the single security issue were made at the time a unit was complete, then the problem would be simple. However, this was not the case with this company. Unit one was installed in September, 1957. In July, 1957, an \$18,000,000, 5 per cent first mortgage bond issue was offered and sold for a premium. In September, 1957, some common stock was sold which yielded \$5,931,908. In July, 1958, a \$25,000,000 4.25 per cent first mortgage bond issue was made and the bulk of it was used to call the \$18,000,000 5 per cent issue made in 1957. To contribute to the complexity, short term bank loans as well as retained earnings were used during the construction period for partial financing of the construction. There were no records made available to the author indicating the actual sources of funds used to finance the installation.

Due to this problem, it was decided to use the investment as it was reported for each unit and to discount any future investment back to the present, with the earnings rate as the discount rate. The determination of the true cost of capital for each unit investment presents a formidable problem and is certainly worth consideration in a separate study.

An insurance rate was determined from the total annual insurance premium which the company paid in 1965 on the Gan plant. The total investment at that time included Gan 4 but the rate per dollar of investment should be reasonably constant. The total premium was \$56,335 or a rate of 0.0008185 dollar per dollar of investment. The property taxes for 1965 were \$331,666 for a rate of 0.004819 dollars per dollar

investment. These rates are included in the model to be used with each alternative.

The income tax rate used in this study is 50 per cent. This falls just short of the incremental rate which a corporation at that time paid on all taxable income in excess of \$25,000. There is no state income tax in the state in which XCO operates.

Additional heat rate curves are required for the units used in alternatives B, C and D. For the purposes of this study it was decided to interpolate and extrapolate from the existing curves and assume that the company would be in keeping with the technical level acceptable to them in alternative A. The curves so estimated are shown in Figures 31, 32 and 33. Another actual curve was available from the company for a 260 MW unit which was installed after this study period. The estimated curves are included in the model with reference to the alternative for which they are required.

The annual earnings rate of the company is used as the annual interest rate in the present worth conversions. The rates are as follows: 0.027, 0.021, 0.018, 0.018, 0.021, and 0.019 for the years 1958 through 1963 respectively. These rates are programmed into the model.

The fuel costs for the first three years were included in the model for the validation study. The fuel costs for the next three years are added to the model so that complete fuel cost data is in the model for the period 1958 through 1963. The same is true for the monthly demand data. It has also been updated to include the data for the overall period.

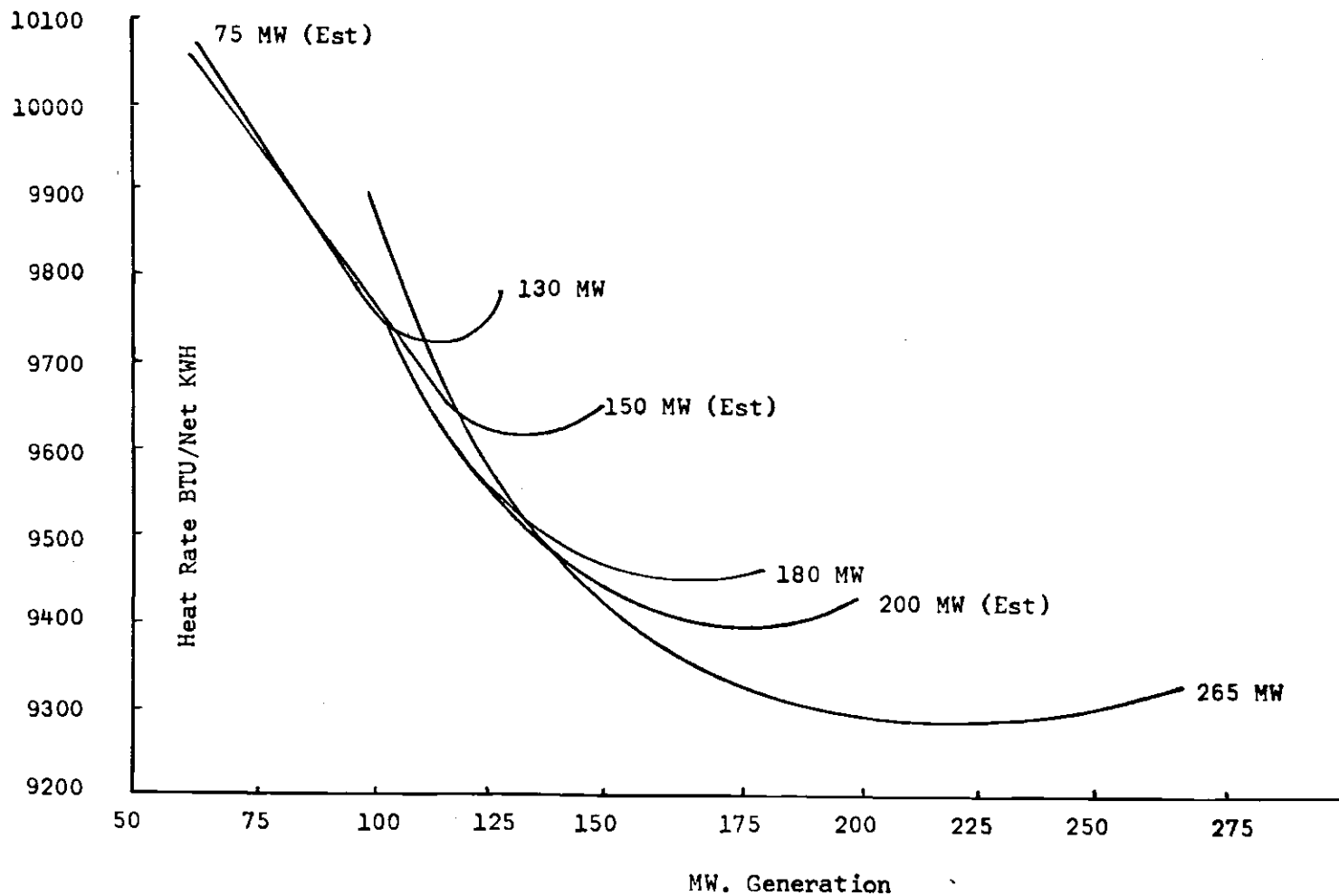


Figure 32. Estimated Heat Rate Curves Including Actual Curves Used for Basis of Estimation, 130 MW - 265 MW Units

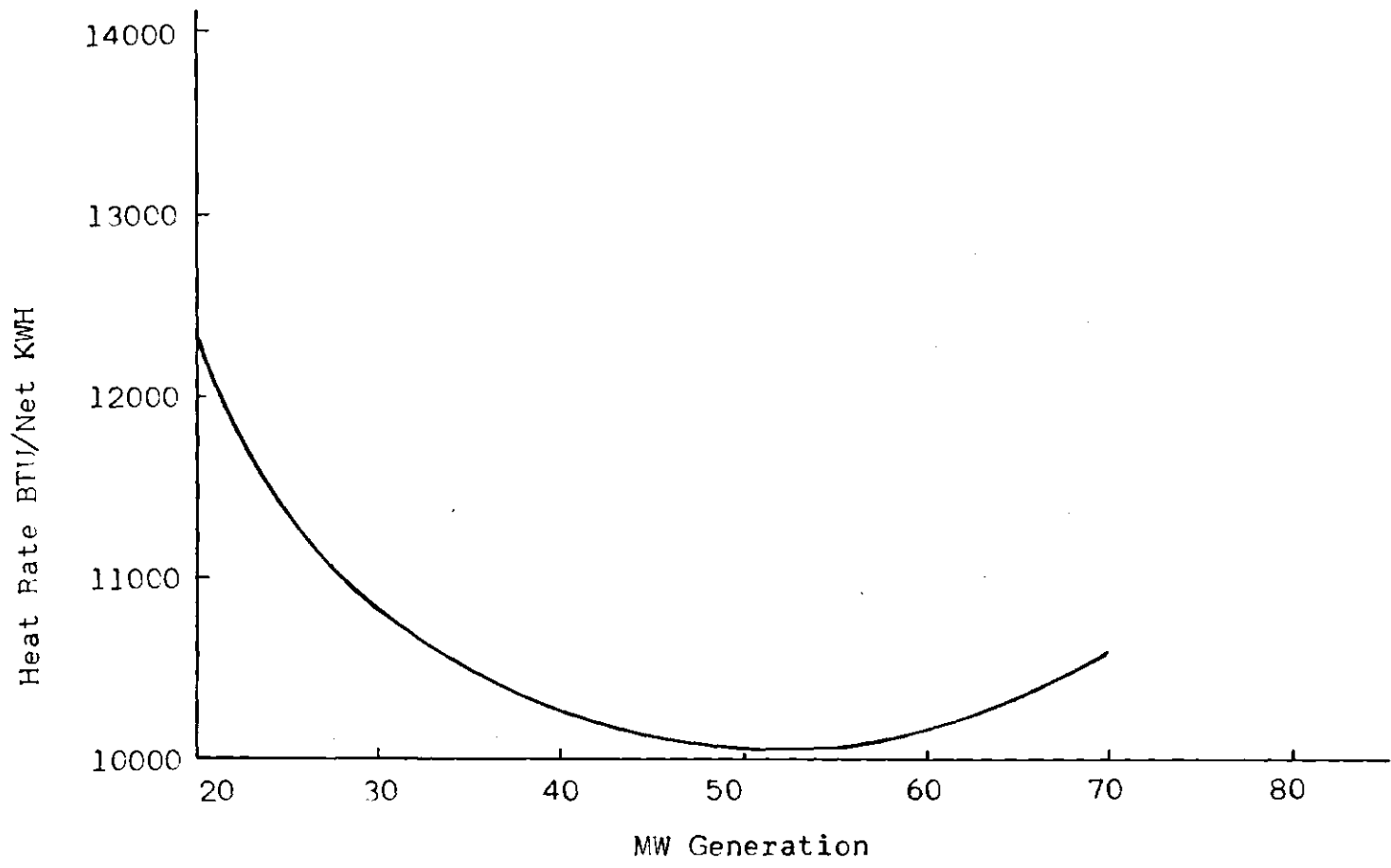


Figure 33. Estimated Heat Rate Curve for 75MW Unit

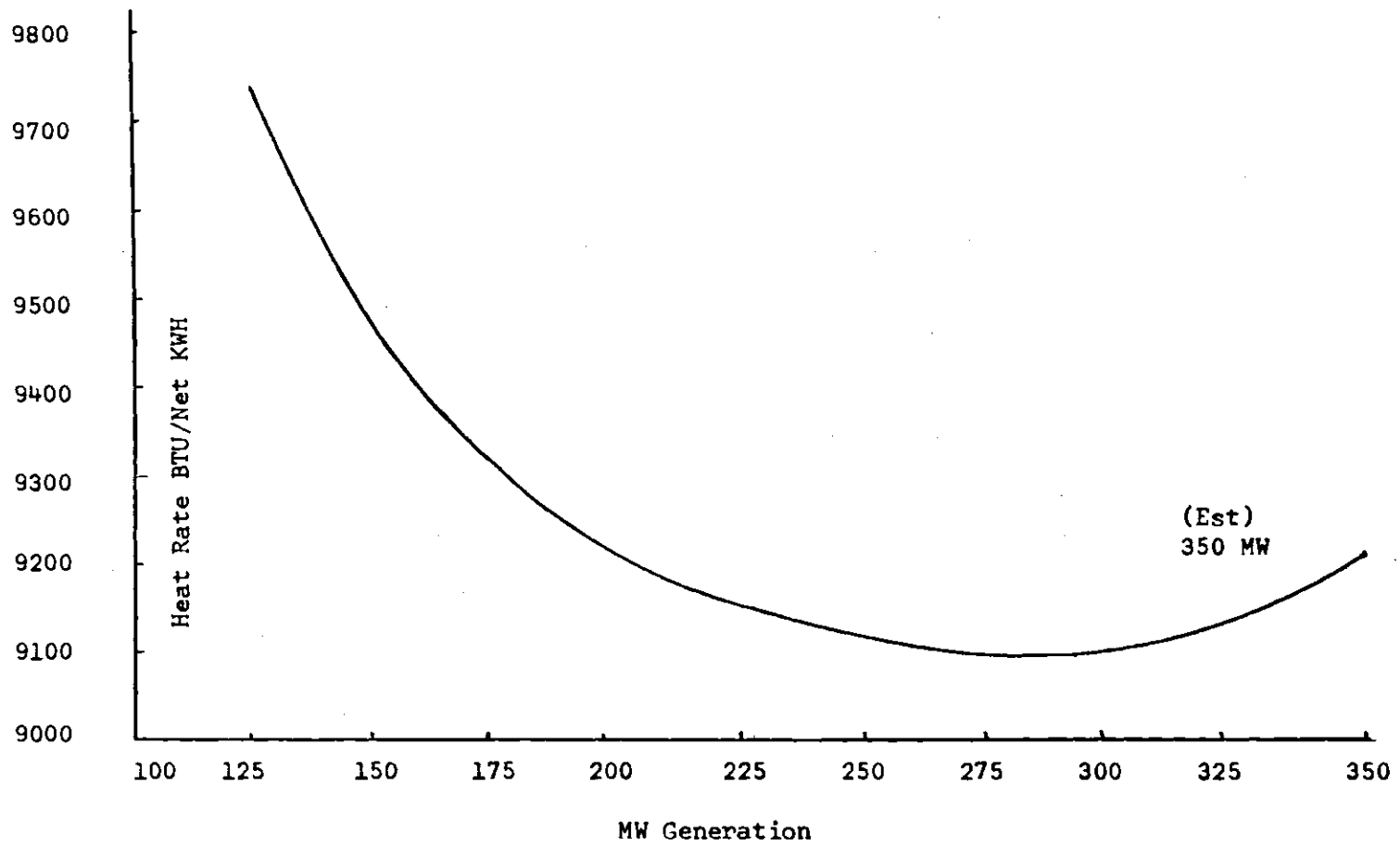


Figure 34. Estimated Heat Rate Curve for 350 MW Unit

Results of the Alternative Simulation Studies

As previously outlined, each alternative was programmed into the model and the simulation was carried out for the same period of time with the same growth rate of demand. The results of the computer simulation for each alternative are shown in Table 12. The total cost is the present worth of all of the costs which occurred throughout the study period.

Alternative B is the least expensive plant to provide services for this period of time. Alternative A is the most expensive since the total capacity of the three units exceeded those of other alternatives. Interesting is the fact that there is a variation among the other three alternatives of \$7,653,000 -- a significant difference to accrue over six years.

Table 12. Results of the Simulation for all Alternatives

Alternatives	A	B	C	D
Fuel Cost	43,281,000	45,650,000	38,290,000	35,382,000
Other Generation Costs	10,973,000	4,199,900	17,546,000	22,291,000
Investment Cost	50,917,000	44,247,000	43,117,000	42,188,000
Property Tax cost	1,230,100	1,197,400	982,170	898,740
Insurance cost	208,930	203,370	166,820	152,650
Income Tax credit	7,369,400	7,044,400	5,935,400	5,441,900
TOTAL COST	96,465,000	85,756,000	91,672,000	93,409,000
Gan Generation Cost MWH	13,549,000	14,918,000	12,155,000	11,122,000
Total Generation MWH	15,839,000	15,839,000	15,839,000	15,839,000

In analyzing the results, alternative B is the lowest primarily because of its ability to generate the largest portion of the total kilowatt-hour demand of the system. Thus fewer of the kilowatt-hours were charged to the other generation cost at 0.5 cents per kilowatt-hour. Also, the average fuel cost of generating electricity with alternative B is the least expensive of the four alternatives at a rate of 0.306 cents per kilowatt-hour. It is 0.320, 0.315, and 0.320 cents per kilowatt-hour for alternatives A, C and D, respectively.

These significant reductions in unit fuel cost are more than sufficient to offset the higher investment cost. Alternative B is also favorable regarding the income tax benefit when comparing it with alternatives C and D. It is \$1,109,000 better than alternative C and \$1,602,500 better than alternative D. When compared with alternative A the difference is close -- \$325,000.

#### Measure of Performance

The measure of performance is defined in Chapter I as the ratio of the standard performance measure to the actual performance measure. The standard performance measure is the cost of the best alternative. In this example, it would be the cost associated with alternative B -- \$85,756,000. The actual performance would be the cost associated with the alternative representing the actual investment pattern. This would be the cost for alternative A -- \$96,465,000.

The measure of performance is  $\$85,756,000/\$96,465,000$  or 0.889 which may be expressed as 88.9 per cent. This measure indicates that the company's performance could have been 11.1 per cent better than it

actually was. This calculation,  $0.111 \times \$96,465,000$ , yields \$10,709,000 which is as expected ( $96,465,000 - 85,756,000$ ). If the results of alternative D were to be considered as the actual performance, then the measure of performance would be 91.8 per cent and for alternative C it would be 93.5 per cent. There are many alternatives which the company could have followed which would have provided poorer results than alternative A. If this had happened, then the measure of performance would have been lower than 88.9 per cent.

#### Recommendations for Adoption

These results are based on estimated cost data and heat rate curves for the alternative courses of action. Thus the measure of performance is considered an indication of the performance rather than a specific measure. If a commission were to adopt this method for determining managerial performance. It might consider the following recommendation.

First, when a company considers the installation of a unit, it would be required to secure alternative bids from the manufacturers and provide this information to the commission. This information would include cost data and heat rate curves for generators which were available to the company. With this data, many alternatives could later be simulated for the specific company and the results would be realistic.

Second, a committee consisting of representatives of each of the power companies should be organized. They would make decisions regarding the arbitrary assumptions made in this study, for example the cost

of other generation, the interest rate to use, and the treatment of cost of capital.

Otherwise, the same procedure followed in this study for securing the data is recommended. Perhaps the validation study could be experimented with further, but this is not viewed as a critical point by the author.

### Conclusions

The results of applying the alternatives to the model have provided the type of information expected. The magnitude of the specific results was not necessarily as anticipated. Alternative B probably would have been difficult for management to accept, and even more difficult to sell to the directors of the company. Thus it would have taken an astute management to select such an alternative. This is an indication that this type of study is essential and can be used by the utilities for planning purposes. The measure of performance determined for XCO indicates that this method will meet the objectives of the study.

## CHAPTER VII

### CONCLUSIONS AND RECOMMENDATIONS

The literature abounds with methods for measuring managerial performance but none is applicable by regulatory commissions for the purpose of basing a reward for above average managerial performance. The development of a simulation model to represent an electric utility operation for determining a measure of managerial performance is a new approach. This approach allows the actual performance of a utility to be comparable to possible performance during the same periods of time.

Twenty-three companies were selected as the sample to study. Analyses in Chapter III revealed that among the sample the production department accounted for 60 per cent of the total operating expenses and 40 per cent of the total plant investment. Multiple correlation studies showed that among the sample 87.5 per cent of the variation in the total operating costs was attributed to variation in the production costs. Consequently, the production department was accepted as being satisfactory for the purposes of this study to represent the operation of an electric utility company.

The general model is developed in Chapter IV. The hour was selected as the basic unit of time for simulating the operation. A procedure was developed to provide accurate hourly demand information in the model with a minimum of demand information as input. The introduction of actual heat rate curves for the company's generators and actual fuel costs provided the remainder of the information required for the determination

of the economic loading of the generators during the simulation study. This provided the operating cost information. The other costs considered in this study were those associated with the investment. These included the cost of capital, insurance costs, property taxes and the income tax effect resulting from the depreciation of the production equipment.

The comparison of the costs for simulation operation of each proposed alternative was made using present worth equivalents. It was necessary to consider the minimum attractive rate of return to be used for discounting all of the costs to the beginning of the study period. Chapter IV also contains the necessary mechanics for accomplishing the actual discounting during the study, utilizing the continuous compounding technique. The general model was translated into a computer model using the Dynamo language. Data was collected from a selected company and used to operate the model on an IBM 7094 computer for validation purposes. The simulation results and the actual published results for the same time period were compared. Chapter V presents the details of this validation study. The conclusion was that the model does provide acceptable operating results.

The same company which was used for the validation study was also used for determining a measure of performance by the method proposed in this study. Alternative investment patterns were considered which management could have followed. Each of these alternatives and the actual pattern followed for this same period of time was simulated. A comparison of the present worth equivalents for each of these alternatives provided a measure of performances as outlined in Chapter VI.

The alternatives selected were not exhaustive. They did appear to consider what could be called the extreme points of the set of all possible points or alternatives. The important result of this study is not that the best alternative was considered but rather that alternatives can be selected which do provide significantly different results than those chosen by management. By the use of the extreme points it should be a quick process to select the optimum alternative by the process of elimination. The results of the alternatives selected did reveal a significant difference between results. In this particular case it was an extreme point which was the optimum.

The hypothetical nature of the study is recognized. It was necessary to make assumptions regarding costs and heat rate curves for the alternative patterns of unit installation. Suggestions were made which would make possible the use of actual data should this method be adopted by a regulatory body for measuring managerial performance.

This method does provide a technique for establishing a measure of performance which is completely independent of the results of other companies' operations. It is a measure of actual performance compared to possible performance. It can be stated that a method has been developed for measuring managerial performance in the regulated electric utility industry. This method can be adopted by a commission for application within its jurisdiction. It is expected that the nature of this technique would result in consistent and fair treatment for all the companies to which it is applied.

### Recommendations

The following suggestions are made for possible future research:

1. The development of a measure of performance is the first step toward fulfilling the need to reward managerial efficiency in the regulated utilities. With a measure of performance available, the next step is the development of a procedure for translating the measure of performance into a reward for the utility.

2. Since this study has been conducted with electric utilities, further research could be performed by developing simulation models for the other industries. Applying the same techniques used in this study to these models would provide a measure of performance for these other utilities.

3. Further research could be accomplished by developing a model with a different simulation language or developing a simulation language specifically for this type of study.

4. Investigation of the use of the model for other purposes within the electric utility is another possibility. This could include the use of the model for investigating investment pattern proposals. By varying the daily load profile which could be effected by a sales promotion, the effect on fuel costs and total generation could be determined.

**APPENDICES**

## APPENDIX A

A LIST OF TWENTY-THREE PRIVATELY OWNED  
ELECTRIC UTILITIES

A sample of 23 privately owned electric utility companies was selected for this study. The companies chosen, listed in the order in which they appear in Federal Power Commission publications, are as follows:

1. United Illuminating Company (Connecticut)
2. Potomac Electric Power Company (D.C.)
3. Florida Power Corporation (Florida)
4. Florida Power and Light Company (Florida)
5. Gulf Power Company (Florida)
6. Tampa Electric Company (Florida)
7. Savannah Electric and Power Company (Georgia)
8. Commonwealth Edison Company (Illinois)
9. Indianapolis Power and Light Company (Indiana)
10. Public Service Company of Indiana, Inc. (Indiana)
11. Louisiana Power and Light Company (Louisiana)
12. Mississippi Power Company (Mississippi)
13. Mississippi Power and Light Company (Mississippi)
14. Atlantic City Electric Company (New Jersey)
15. Jersey Central Power and Light Company (New Jersey)
16. Columbus and Southern Ohio Electric Company (Ohio)

17. Ohio Power Company (Ohio)
18. Duquesne Light Company (Pennsylvania)
19. West Penn Power Company (Pennsylvania)
20. Dallas Power and Light Company (Texas)
21. Houston Lighting and Power Company (Texas)
22. Southwestern Electric Power Company (Texas)
23. Texas Electric Service Company (Texas)

The number listed beside each company is the number which will be used to reference each company in the remaining appendices.

## APPENDIX B

OPERATING EXPENSES FOR TWENTY-THREE SELECTED  
COMPANIES, 1951-63

Operating expense data for electric utility companies is published annually by the Federal Power Commission. From this the data for each of the 23 selected utilities was tabulated on punched cards, by years, for the six expense areas as designated by NARUC, for the total expenses, and for the total kilowatt hours generated. An Algol program was written so that the punched card data could be presented as a per cent of the total and also as cents per kilowatt-hour. The output of this information is presented on the following pages.

In the column titled "CO-YR" the last two digits are the year, and the preceding digit(s) is the number assigned each company in Appendix A. The kilowatt-hours are expressed in millions of KWH and the amounts are expressed in thousands of dollars.

	PRUD	TRANS	DIST	CUST ATO	SALES	AD & GEN	TOTAL	KWH	CO-YR
AMOUNT	15780	201	3974	1747	945	4112	26756	2608	163
\$ UP TOTAL	56,973	0,751	14,852	6,529	3,532	15,167	100,000		
CLNTS/KWH	0.805061	0.007707	0.132377	0.086986	0.036235	0.157669	1.025997		
AMOUNT	74286	305	8277	2648	1374	7108	43971	4351	263
\$ UP TOTAL	55,259	0,694	16,024	5,921	3,125	16,165	100,000		
CLNTS/KWH	0.342585	0.004402	0.130326	0.041066	0.021634	0.111919	0.692344		
AMOUNT	20616	1301	4766	2505	1579	3954	34741	4403	363
\$ UP TOTAL	59,274	3,741	13,703	7,375	4,540	11,366	100,000		
CLNTS/KWH	0.468226	0.029548	0.108244	0.058256	0.035862	0.088802	0.789939		
AMOUNT	43793	2331	15314	5720	4013	14362	85537	10765	463
\$ UP TOTAL	51,198	2,775	17,908	6,697	4,692	16,790	100,000		
CLNTS/KWH	0.408809	0.021454	0.142294	0.053135	0.037276	0.133414	0.794544		
AMOUNT	7337	252	1031	601	315	1402	11074	1872	583
\$ UP TOTAL	66,230	2,275	17,407	5,967	2,843	13,378	100,000		
CLNTS/KWH	0.341944	0.013462	0.055075	0.035310	0.016427	0.079167	0.591774		
AMOUNT	13879	494	2527	1373	1094	2630	21996	3338	663
\$ UP TOTAL	63,096	2,746	11,484	6,242	4,574	11,957	100,000		
CLNTS/KWH	0.415788	0.014799	0.075704	0.041132	0.032774	0.078790	0.658937		
AMOUNT	3690	2	1068	393	235	847	6235	925	763
\$ UP TOTAL	59,182	0,032	17,129	6,303	3,769	13,585	100,000		
CLNTS/KWH	0.389919	0.00016	0.115454	0.042486	0.025405	0.091588	0.674054		
AMOUNT	127493	5662	34713	14107	9429	25496	217010	29178	863
\$ UP TOTAL	51,198	2,701	15,994	6,501	4,345	11,749	100,000		
CLNTS/KWH	0.438841	0.020090	0.118970	0.048348	0.032315	0.087381	0.743745		
AMOUNT	13121	727	3382	1388	1280	3090	22848	3762	963
\$ UP TOTAL	57,147	4,165	14,725	5,956	5,373	13,454	100,000		
CLNTS/KWH	0.348777	0.019725	0.088989	0.036304	0.034024	0.082137	0.610526		
AMOUNT	20757	1419	5886	2878	1995	6292	39037	4951	1063
\$ UP TOTAL	53,173	4,147	14,979	7,372	5,111	16,118	100,000		
CLNTS/KWH	0.298919	0.043292	0.079065	0.041404	0.028701	0.090519	0.561603		
AMOUNT	14242	474	4300	1594	1539	4554	26649	4710	1163
\$ UP TOTAL	53,317	1,778	16,109	5,972	5,746	17,061	100,000		
CLNTS/KWH	0.302186	0.010064	0.091294	0.033843	0.032675	0.096686	0.568730		
AMOUNT	8557	469	1524	753	502	1548	13459	2272	1263
\$ UP TOTAL	63,811	3,486	14,542	5,583	3,732	13,738	100,000		
CLNTS/KWH	0.378829	0.020463	0.058275	0.033055	0.022095	0.081338	0.592077		
AMOUNT	11857	514	3262	1217	1084	3962	21897	3195	1363
\$ UP TOTAL	54,149	2,347	14,897	5,558	4,950	16,094	100,000		
CLNTS/KWH	0.371111	0.016088	0.102097	0.038091	0.033929	0.124006	0.685352		
AMOUNT	10257	1105	3297	1907	1757	2231	20554	2127	1463
\$ UP TOTAL	49,903	2,376	16,041	9,276	6,546	10,854	100,000		
CLNTS/KWH	0.462228	0.051951	0.155007	0.089657	0.082804	0.104890	0.968334		
AMOUNT	10966	1170	5309	2028	1124	4774	31401	3264	1563
\$ UP TOTAL	54,030	3,726	16,907	6,534	3,580	15,203	100,000		
CLNTS/KWH	0.519792	0.035846	0.102053	0.065051	0.034436	0.146262	0.962040		
AMOUNT	12559	1171	5232	2315	1593	3521	26391	3553	1663
\$ UP TOTAL	47,588	4,447	19,425	8,772	6,038	13,342	100,000		
CLNTS/KWH	0.353476	0.039958	0.147254	0.065156	0.044635	0.099099	0.742741		
AMOUNT	34441	3779	4293	2622	3958	7726	62794	16088	1763
\$ UP TOTAL	58,029	6,018	13,204	4,143	6,303	12,303	100,000		
CLNTS/KWH	0.226510	0.023490	0.051548	0.016174	0.024602	0.048023	0.390341		
AMOUNT	25207	392	7676	3474	2458	7913	46717	7615	1663
\$ UP TOTAL	53,946	0,839	16,431	7,441	4,405	10,938	100,000		
CLNTS/KWH	0.330952	0.005148	0.103801	0.045647	0.027026	0.103913	0.613487		
AMOUNT	20031	984	7834	2994	3299	8049	43212	6885	1863
\$ UP TOTAL	46,355	2,277	18,129	6,929	7,434	16,673	100,000		
CLNTS/KWH	0.290937	0.014292	0.113784	0.043406	0.047916	0.117197	0.627625		
AMOUNT	12761	551	3190	1817	1651	3566	23537	4430	2063
\$ UP TOTAL	54,217	2,341	13,353	7,120	7,014	15,151	100,000		
CLNTS/KWH	0.288059	0.012438	0.072009	0.041016	0.037289	0.080497	0.531309		
AMOUNT	32156	588	7416	3310	1709	12308	57490	13213	2163
\$ UP TOTAL	55,943	1,023	12,903	5,758	2,973	21,409	100,000		
CLNTS/KWH	0.243366	0.004450	0.056182	0.025031	0.012934	0.093131	0.435102		
AMOUNT	9302	667	3638	1728	1280	2496	19390	3170	2263
\$ UP TOTAL	48,283	4,575	16,782	8,901	6,601	12,673	100,000		
CLNTS/KWH	0.285431	0.027981	0.114783	0.054488	0.040379	0.078738	0.611672		
AMOUNT	21135	1401	5184	2482	2139	5789	38095	6859	2363
\$ UP TOTAL	55,484	3,678	13,509	6,518	5,615	15,197	100,000		
CLNTS/KWH	0.308135	0.020428	0.075426	0.036188	0.031185	0.084400	0.555356		
SUMMARY	PRUD	TRANS	DIST	CUST ATO	SALES	AD & GEN	TOTAL		
\$ UP TOTAL	55,493	2,425	15,564	6,554	4,883	14,679	100,000		
CLNTS/KWH	0.353946	0.018016	0.099279	0.041800	0.031147	0.092626	0.637616		

	PRUD	TRANS	DIST	CUST AIG	SALES	AD & GEN	TOTAL	KWH	CO-YR
AMOUNT	15035	231	377	1506	916	3945	26007	2456	162
% OF TOTAL	60.130	0.888	14.303	5.792	3.523	15.172	100.000		
CENTS/KWH	0.636604	0.009406	0.153942	0.081319	0.037296	0.100627	1.058713		
AMOUNT	22619	450	7927	2357	1281	7351	41946	5580	262
% OF TOTAL	53.073	1.072	18.080	5.614	3.051	17.508	100.000		
CENTS/KWH	0.405330	0.008065	0.142061	0.042240	0.022957	0.131738	0.752437		
AMOUNT	18956	1103	4808	2798	1457	3876	32310	3991	362
% OF TOTAL	58.705	4.033	13.043	7.112	4.509	11.996	100.000		
CENTS/KWH	0.475259	0.032688	0.110449	0.057580	0.036507	0.097119	0.809572		
AMOUNT	40912	2139	14011	5231	3903	12478	78694	9625	402
% OF TOTAL	51.959	2.710	17.904	6.673	4.960	15.856	100.000		
CENTS/KWH	0.425016	0.027221	0.145794	0.054530	0.040246	0.129628	0.817515		
AMOUNT	6629	285	1045	625	291	1436	10391	1779	562
% OF TOTAL	6.531	2.745	10.046	6.021	2.803	13.833	100.000		
CENTS/KWH	0.376300	0.016020	0.051741	0.035132	0.016456	0.080720	0.583537		
AMOUNT	13128	430	2399	1258	971	2356	20542	3115	662
% OF TOTAL	53.908	1.710	11.674	6.124	4.727	11.469	100.000		
CENTS/KWH	0.421445	0.013804	0.077010	0.040305	0.031172	0.075634	0.659454		
AMOUNT	3351	14	954	401	235	826	5745	848	762
% OF TOTAL	57.956	0.242	16.517	6.935	4.064	14.288	100.000		
CENTS/KWH	0.395185	0.001451	0.117618	0.047288	0.027712	0.097406	0.681849		
AMOUNT	118977	5698	38952	13780	9780	25545	208715	27361	862
% OF TOTAL	57.000	2.730	18.745	6.602	4.685	12.238	100.000		
CENTS/KWH	0.438842	0.020825	0.127782	0.050384	0.035744	0.093383	0.762841		
AMOUNT	12114	698	3228	1311	1114	3059	21422	3554	962
% OF TOTAL	58.083	3.289	15.089	6.120	5.200	14.290	100.000		
CENTS/KWH	0.338042	0.019594	0.090827	0.036684	0.031345	0.086072	0.602757		
AMOUNT	19289	1778	5329	2806	1553	5853	36608	6513	1062
% OF TOTAL	52.591	4.857	14.357	7.665	4.242	15.988	100.000		
CENTS/KWH	0.296182	0.027299	0.081892	0.043083	0.023845	0.089886	0.562074		
AMOUNT	12947	485	4224	1508	1480	4115	24719	4654	1162
% OF TOTAL	52.334	1.960	17.074	6.098	5.902	16.834	100.000		
CENTS/KWH	0.278191	0.010421	0.090761	0.037402	0.031371	0.088819	0.531544		
AMOUNT	7907	440	1270	697	432	1948	12743	2071	1262
% OF TOTAL	52.050	3.453	4.486	5.470	3.190	15.679	100.000		
CENTS/KWH	0.381796	0.021246	0.011323	0.033825	0.020859	0.048475	0.613307		
AMOUNT	10197	467	3155	1122	1172	3768	19913	2862	1362
% OF TOTAL	51.204	2.345	15.844	5.785	5.886	18.922	100.000		
CENTS/KWH	0.356289	0.016317	0.110238	0.040252	0.040950	0.131656	0.693772		
AMOUNT	10121	993	3180	1847	1361	2677	20370	2022	1462
% OF TOTAL	50.658	4.875	15.611	9.018	6.681	13.142	100.000		
CENTS/KWH	0.510435	0.049110	0.157270	0.090851	0.067310	0.132394	1.007418		
AMOUNT	15740	1229	5519	1942	941	4913	30324	2986	1562
% OF TOTAL	51.908	4.053	18.204	6.404	3.235	16.202	100.000		
CENTS/KWH	0.527127	0.041159	0.104829	0.065037	0.032953	0.164534	1.015539		
AMOUNT	12511	1217	5075	2116	1419	3589	25927	3284	1662
% OF TOTAL	48.255	4.694	19.174	8.191	5.473	13.843	100.000		
CENTS/KWH	0.380505	0.037013	0.154349	0.043325	0.043157	0.109155	0.788534		
AMOUNT	35712	3789	8183	2523	3646	7441	61294	15403	1762
% OF TOTAL	58.263	6.182	13.351	4.116	5.948	12.140	100.000		
CENTS/KWH	0.231801	0.024599	0.057126	0.016380	0.023871	0.048309	0.397915		
AMOUNT	24515	355	9790	3378	1858	8314	46010	7210	1862
% OF TOTAL	53.282	0.772	16.496	7.342	4.038	18.070	100.000		
CENTS/KWH	0.380014	0.004924	0.105270	0.046802	0.025770	0.115312	0.438141		
AMOUNT	19487	949	7360	2902	3135	8055	42149	6420	1962
% OF TOTAL	46.212	2.250	17.928	7.072	7.438	19.102	100.000		
CENTS/KWH	0.303536	0.014782	0.117757	0.046449	0.048832	0.125467	0.456838		
AMOUNT	10964	534	3017	1591	1385	3227	20719	3916	2062
% OF TOTAL	52.918	2.577	14.267	7.674	6.685	15.575	100.000		
CENTS/KWH	0.279980	0.013636	0.077083	0.040628	0.035168	0.082406	0.529044		
AMOUNT	30023	501	6929	2610	1564	10583	52209	11767	2162
% OF TOTAL	57.505	0.960	13.272	4.999	2.996	20.270	100.000		
CENTS/KWH	0.255146	0.004258	0.058885	0.022181	0.013291	0.089938	0.443699		
AMOUNT	7902	918	3380	1686	1213	2470	17569	2921	2262
% OF TOTAL	44.977	5.225	19.238	9.596	6.904	14.059	100.000		
CENTS/KWH	0.270524	0.031428	0.115714	0.057720	0.041527	0.084560	0.401472		
AMOUNT	19072	1218	5568	2398	2179	6190	36623	6140	2362
% OF TOTAL	52.077	3.326	15.198	6.548	5.950	16.902	100.000		
CENTS/KWH	0.310619	0.019837	0.090351	0.039055	0.035489	0.100814	0.596445		
SUMMARY	PRUD	TRANS	DIST	CUST AIG	SALES	AD & GEN	TOTAL		
% OF TOTAL	58.743	2.925	15.976	6.496	4.849	15.012	100.000		
CENTS/KWH	0.358206	0.019137	0.104335	0.042506	0.031730	0.098228	0.654344		

	PHUD	IRANS	DIST	CUST ATG	SALES	AD & GEN	TOTAL	KWH	CO-YR
AMOUNT	15002	224	3221	1422	824	3129	24440	2232	161
% OF TOTAL	73.812	0.916	13.174	5.949	3.370	12.798	100.000		
CLNTS/KWH	0.099014	0.010036	0.144310	0.065054	0.036918	0.140188	1.095470		
AMOUNT	22072	211	8240	2230	1272	6282	40317	5529	261
% OF TOTAL	34.760	0.423	20.443	5.533	3.156	15.585	100.000		
CLNTS/KWH	0.399204	0.003810	0.149032	0.340333	0.023006	0.113619	0.729011		
AMOUNT	17884	1302	4607	2109	1324	3508	30806	3460	361
% OF TOTAL	38.024	4.226	14.755	6.844	4.298	11.387	100.000		
CLNTS/KWH	0.516679	0.337630	0.133150	0.060954	0.038266	0.101387	0.890347		
AMOUNT	17241	1962	13292	5128	3908	11878	73713	4481	461
% OF TOTAL	50.522	2.866	18.434	6.927	5.302	16.114	100.000		
CLNTS/KWH	0.439111	0.723169	0.160264	0.066465	0.046079	0.140054	0.849153		
AMOUNT	6014	303	1125	588	285	1352	9674	1574	561
% OF TOTAL	12.202	0.532	11.624	6.078	2.956	14.005	100.000		
CLNTS/KWH	0.382336	0.019250	0.071474	0.037357	0.018170	0.086086	0.414674		
AMOUNT	12022	407	2204	1180	879	2199	19092	2734	651
% OF TOTAL	62.969	2.132	11.344	6.181	4.604	12.562	100.000		
CLNTS/KWH	0.439722	0.014887	0.080614	0.043180	0.032151	0.087747	0.698317		
AMOUNT	3173	10	880	423	220	815	5510	759	761
% OF TOTAL	57.378	0.181	16.074	7.649	3.974	14.738	100.000		
CLNTS/KWH	0.413050	0.001318	0.117124	0.055731	0.029986	0.107378	0.728520		
AMOUNT	109725	5460	34770	13781	8034	25449	197428	25434	861
% OF TOTAL	55.577	2.766	17.514	6.980	4.069	12.492	100.000		
CLNTS/KWH	0.431411	0.021467	0.134742	0.054183	0.031388	0.100445	0.776237		
AMOUNT	11099	552	3034	1221	1144	2819	19844	3254	961
% OF TOTAL	55.864	2.778	15.271	6.146	5.738	14.189	100.000		
CLNTS/KWH	0.341098	0.014968	0.093232	0.037523	0.035157	0.088632	0.410572		
AMOUNT	14326	1630	5110	2611	1343	5426	34647	6046	1061
% OF TOTAL	52.893	4.705	14.749	7.536	3.874	16.238	100.000		
CLNTS/KWH	0.303109	0.026960	0.084519	0.043186	0.022413	0.093053	0.573057		
AMOUNT	50129	439	3699	1393	1240	3665	20746	3708	1161
% OF TOTAL	48.777	0.077	17.614	6.708	5.971	17.449	100.000		
CLNTS/KWH	0.273186	0.017233	0.099757	0.037557	0.033441	0.098840	0.560032		
AMOUNT	7599	338	1237	822	411	1757	11934	1826	1261
% OF TOTAL	43.570	2.831	10.382	5.462	3.443	14.718	100.000		
CLNTS/KWH	0.415604	0.018510	0.067744	0.035704	0.022504	0.096221	0.653779		
AMOUNT	8268	344	3303	1112	1098	3165	17014	2449	1361
% OF TOTAL	48.713	2.022	17.653	6.553	6.454	18.602	100.000		
CLNTS/KWH	0.338424	0.014047	0.122021	0.045529	0.044835	0.127236	0.594733		
AMOUNT	10511	852	3227	1904	1328	2249	20371	1895	1461
% OF TOTAL	51.598	4.182	17.314	9.347	6.519	11.040	100.000		
CLNTS/KWH	0.556670	0.044960	0.186121	0.108475	0.070079	0.118661	1.074997		
AMOUNT	13932	1195	5357	1814	843	4589	27730	2702	1561
% OF TOTAL	50.242	4.309	19.314	6.542	3.040	16.549	100.000		
CLNTS/KWH	0.515610	0.044226	0.198261	0.067135	0.031194	0.169837	1.028277		
AMOUNT	11095	1189	4602	1894	1328	3361	23470	3019	1661
% OF TOTAL	47.273	5.066	19.604	8.070	5.854	14.320	100.000		
CLNTS/KWH	0.367506	0.059344	0.152435	0.062736	0.043988	0.111328	0.777410		
AMOUNT	30251	3488	7845	2484	3548	7285	55701	14130	1751
% OF TOTAL	55.187	6.421	14.084	4.400	6.370	13.079	100.000		
CLNTS/KWH	0.216337	0.026100	0.055220	0.017580	0.024110	0.051557	0.394204		
AMOUNT	23933	256	7494	3268	1764	7686	44434	6401	1861
% OF TOTAL	53.929	0.576	16.670	7.355	3.970	17.298	100.000		
CLNTS/KWH	0.342440	0.003710	0.108622	0.047355	0.025562	0.111375	0.643878		
AMOUNT	19279	422	7288	2820	2038	7492	40541	6074	1961
% OF TOTAL	47.554	2.035	17.977	6.956	7.000	18.480	100.000		
CLNTS/KWH	0.317402	0.013542	0.119487	0.046427	0.046724	0.123345	0.667441		
AMOUNT	9820	489	2862	1536	1246	3007	18959	3441	2061
% OF TOTAL	51.796	2.579	15.096	8.102	6.572	15.841	100.000		
CLNTS/KWH	0.285302	0.014211	0.081173	0.044638	0.036210	0.087347	0.550974		
AMOUNT	24779	474	5875	2464	1553	9950	45094	10074	2161
% OF TOTAL	54.948	1.051	13.028	5.464	3.444	22.062	100.000		
CLNTS/KWH	0.248970	0.004705	0.058318	0.024859	0.015410	0.098749	0.447637		
AMOUNT	6602	494	3083	1522	1044	2457	15673	2580	2261
% OF TOTAL	42.258	3.722	19.734	9.742	6.810	15.727	100.000		
CLNTS/KWH	0.255891	0.036631	0.119496	0.058992	0.041240	0.095233	0.605343		
AMOUNT	16421	1188	4815	2323	1968	5358	31903	5372	2361
% OF TOTAL	51.566	3.724	14.466	7.281	6.169	16.795	100.000		
CLNTS/KWH	0.302436	0.022112	0.085908	0.043243	0.038634	0.099739	0.593876		
SUMMARY	PHUD	IRANS	DIST	CUST ATG	SALES	AD & GEN	TOTAL		
% OF TOTAL	53.850	2.947	16.560	6.744	4.780	15.135	100.000		
CLNTS/KWH	0.360990	0.019758	0.111010	0.045209	0.031909	0.101461	0.670360		

	PRUD	TRANS	DIST	CUST AIG	SALES	AD & GEN	TOTAL	KWH	CU-YR
AMOUNT	18830	193	2459	1333	779	2769	22433	1999	160
\$ OF TOTAL	98.325	0.860	11.193	5.800	3.473	12.343	100.000		
CLNTS/KWH	0.721061	0.004855	0.146024	0.065103	0.035969	0.136519	1.122211		
AMOUNT	20394	250	7208	2272	1155	5497	36944	5079	260
\$ OF TOTAL	55.805	0.677	19.513	6.204	3.120	14.876	100.000		
CLNTS/KWH	0.400489	0.004922	0.141916	0.045127	0.022741	0.106230	0.727427		
AMOUNT	15877	1152	4109	1883	1216	2730	26947	3300	360
\$ OF TOTAL	58.876	4.272	15.237	6.983	4.509	10.123	100.000		
CLNTS/KWH	0.441121	0.034904	0.124315	0.057051	0.036048	0.082727	0.417142		
AMOUNT	35628	1986	13226	5349	1765	11056	70810	7680	460
\$ OF TOTAL	50.315	2.803	18.494	7.554	2.517	15.614	100.000		
CLNTS/KWH	0.443906	0.025859	0.162502	0.069646	0.027023	0.143956	0.922074		
AMOUNT	6556	240	1120	542	303	1279	10047	1531	560
\$ OF TOTAL	95.333	2.388	11.144	5.393	3.015	12.728	100.000		
CLNTS/KWH	0.426070	0.015676	0.073155	0.035402	0.019741	0.083340	0.856434		
AMOUNT	11666	448	2908	1026	848	2165	18943	2487	660
\$ OF TOTAL	61.320	2.362	14.808	5.421	4.472	11.417	100.000		
CLNTS/KWH	0.449079	0.014014	0.112407	0.041333	0.034097	0.087033	0.742444		
AMOUNT	3454	29	456	343	227	798	5840	741	760
\$ OF TOTAL	58.942	0.495	10.114	6.741	3.874	13.418	100.000		
CLNTS/KWH	0.446127	0.003914	0.124315	0.053306	0.036634	0.107492	0.790823		
AMOUNT	10890	2851	35105	10169	7223	27125	197843	24129	660
\$ OF TOTAL	54.826	7.957	17.743	7.101	3.602	13.710	100.000		
CLNTS/KWH	0.447926	0.024249	0.145489	0.058722	0.031178	0.112417	0.419940		
AMOUNT	10488	470	3102	1210	1187	2607	18943	3124	950
\$ OF TOTAL	55.308	2.474	15.831	6.381	6.260	13.748	100.000		
CLNTS/KWH	0.335049	0.015033	0.096033	0.038704	0.037972	0.083347	0.606622		
AMOUNT	18917	1905	5449	2419	1291	4729	34710	5715	1060
\$ OF TOTAL	54.300	5.488	15.399	6.989	3.719	13.424	100.000		
CLNTS/KWH	0.330832	0.033310	0.045296	0.042303	0.022974	0.082704	0.407030		
AMOUNT	8234	853	3390	1233	1123	3998	19014	3324	1160
\$ OF TOTAL	43.251	4.481	18.359	6.477	5.899	21.002	100.000		
CLNTS/KWH	0.267715	0.025446	0.107437	0.037072	0.033764	0.120204	0.572339		
AMOUNT	7350	298	1444	628	469	1529	11714	1760	1260
\$ OF TOTAL	52.724	2.543	12.423	5.459	4.002	13.048	100.000		
CLNTS/KWH	0.417614	0.014932	0.082745	0.035682	0.026648	0.086675	0.465793		
AMOUNT	7908	492	2567	1074	1254	3345	16644	2354	1360
\$ OF TOTAL	47.456	2.952	15.404	6.505	7.249	20.073	100.000		
CLNTS/KWH	0.335854	0.020443	0.108956	0.046433	0.053366	0.141978	0.707301		
AMOUNT	10233	571	3397	1774	1377	1997	19346	1761	1460
\$ OF TOTAL	52.884	2.952	17.059	9.170	7.114	10.323	100.000		
CLNTS/KWH	0.340977	0.032025	0.142702	0.070734	0.078144	0.113401	1.008540		
AMOUNT	12340	1204	5332	1741	893	4016	25324	2464	1560
\$ OF TOTAL	48.343	4.717	20.249	6.820	3.495	15.733	100.000		
CLNTS/KWH	0.300000	0.044784	0.116445	0.070343	0.036183	0.162723	1.034279		
AMOUNT	10417	1026	4272	1937	1293	3418	22543	2420	1660
\$ OF TOTAL	46.169	4.556	20.263	8.142	5.731	15.140	100.000		
CLNTS/KWH	0.356747	0.035205	0.136275	0.062911	0.044281	0.116986	0.772703		
AMOUNT	34316	4027	7733	2301	3315	7016	58744	13536	1760
\$ OF TOTAL	58.342	6.852	13.159	4.017	5.641	11.936	100.000		
CLNTS/KWH	0.253317	0.029750	0.057129	0.017442	0.024490	0.051832	0.434141		
AMOUNT	25233	330	4175	3309	1963	6892	45952	6740	1660
\$ OF TOTAL	54.912	0.718	17.790	7.310	4.272	14.998	100.000		
CLNTS/KWH	0.374377	0.004496	0.121291	0.049837	0.029125	0.102255	0.681740		
AMOUNT	19101	1370	6790	2770	2598	7067	39695	5477	1960
\$ OF TOTAL	48.119	3.451	17.105	6.978	6.545	17.803	100.000		
CLNTS/KWH	0.319575	0.022921	0.113802	0.046344	0.043467	0.118237	0.664129		
AMOUNT	7219	428	2657	1445	1201	2924	15874	3370	2060
\$ OF TOTAL	45.465	2.890	16.734	9.101	7.564	18.447	100.000		
CLNTS/KWH	0.214214	0.012700	0.078843	0.042678	0.035638	0.086014	0.471157		
AMOUNT	23143	514	5750	2415	1474	8804	42100	9838	2160
\$ OF TOTAL	54.964	1.221	13.058	5.730	3.511	20.912	100.000		
CLNTS/KWH	0.235210	0.005223	0.058447	0.024548	0.015023	0.089490	0.427933		
AMOUNT	6394	899	3392	1497	1044	2229	15460	2520	2260
\$ OF TOTAL	41.391	5.813	21.940	9.683	6.753	14.418	100.000		
CLNTS/KWH	0.253929	0.035475	0.134803	0.059405	0.041429	0.088452	0.613492		
AMOUNT	10638	1995	5844	2361	2078	5081	27301	5106	2360
\$ OF TOTAL	38.966	6.743	21.420	8.648	7.611	18.611	100.000		
CLNTS/KWH	0.206343	0.025362	0.114332	0.046240	0.040897	0.099310	0.534645		
SUMMARY	PRUD	TRANS	DIST	CUST AIG	SALES	AD & GEN	TOTAL		
\$ OF TOTAL	53.285	3.213	17.044	6.858	4.777	14.818	100.000		
CLNTS/KWH	0.364309	0.021992	0.116016	0.046911	0.032676	0.101367	0.684069		

	PRJID	TRANS	DIST	CUST	ATG	SALES	AD & GEN	TOTAL	KWH	COUNT
AMOUNT	13948	197	2743	1221	696	2658	21461	1924	159	
\$ UP TOTAL	64,906	0,918	12,780	5,689	3,243	12,384	100,000			
CLNTS/KWH	0,724444	0,010237	0,142568	0,063402	0,036175	0,138190	1,115541			
AMOUNT	21985	199	4885	2282	1082	5271	37444	4773	259	
\$ UP TOTAL	54,857	0,531	17,034	6,035	2,887	14,082	100,000			
CLNTS/KWH	0,460617	0,004167	0,140059	0,047372	0,022669	0,110434	0,785314			
AMOUNT	14819	1230	3802	1710	1170	2459	25194	2993	359	
\$ UP TOTAL	54,915	4,882	15,090	6,811	4,644	9,759	100,000			
CLNTS/KWH	0,4495127	0,041096	0,127230	0,057334	0,039041	0,082158	0,841831			
AMOUNT	11004	1721	12221	5015	3058	10301	64129	6741	459	
\$ UP TOTAL	49,605	2,444	19,058	7,821	4,769	16,004	100,000			
CLNTS/KWH	0,471074	0,025530	0,181294	0,078395	0,045164	0,152811	0,951244			
AMOUNT	6374	219	1101	511	283	1147	9619	1413	559	
\$ UP TOTAL	64,304	2,277	11,446	5,312	2,734	11,924	100,000			
CLNTS/KWH	0,451380	0,024897	0,077719	0,036184	0,018613	0,081175	0,680797			
AMOUNT	10501	342	2325	953	745	1902	16744	2209	659	
\$ UP TOTAL	64,825	2,040	13,866	5,883	4,443	11,343	100,000			
CLNTS/KWH	0,475373	0,015482	0,105251	0,043142	0,033726	0,086102	0,759077			
AMOUNT	3240	8	444	348	233	766	5541	694	759	
\$ UP TOTAL	54,452	0,144	17,101	6,278	4,203	13,819	100,000			
CLNTS/KWH	0,448854	0,001153	0,138899	0,050144	0,033573	0,110375	0,798773			
AMOUNT	10383	543	3587	1403	681	2364	18883	2244	859	
\$ UP TOTAL	54,444	2,920	16,407	7,436	3,221	12,518	100,000			
CLNTS/KWH	0,452576	0,024028	0,155283	0,051188	0,026304	0,103007	0,822844			
AMOUNT	10464	489	2547	1144	1083	2210	18217	3003	959	
\$ UP TOTAL	57,370	2,691	15,811	5,273	5,438	12,118	100,000			
CLNTS/KWH	0,588472	0,018244	0,098305	0,034095	0,036094	0,073593	0,607243			
AMOUNT	17793	1494	5290	2224	1245	4682	33134	5433	1059	
\$ UP TOTAL	53,497	3,716	15,777	6,724	3,757	14,130	100,000			
CLNTS/KWH	0,377499	0,036941	0,097442	0,041004	0,022916	0,086177	0,609902			
AMOUNT	2475	719	3287	1140	1016	3587	17243	3458	1159	
\$ UP TOTAL	43,351	4,170	19,063	6,843	5,892	20,687	100,000			
CLNTS/KWH	0,218185	0,020792	0,095055	0,038124	0,029381	0,103152	0,498841			
AMOUNT	5050	240	1323	573	424	1352	4022	1170	1259	
\$ UP TOTAL	56,044	3,110	18,897	6,385	4,710	15,019	100,000			
CLNTS/KWH	0,368813	0,020438	0,094369	0,041925	0,030949	0,098496	0,657040			
AMOUNT	2774	372	2253	1021	1047	3001	15248	2185	1359	
\$ UP TOTAL	47,842	2,438	16,721	6,687	4,857	14,455	100,000			
CLNTS/KWH	0,332406	0,017023	0,115942	0,046728	0,047918	0,137346	0,698744			
AMOUNT	2710	448	3339	1577	1020	1964	18320	1665	1459	
\$ UP TOTAL	53,002	3,537	18,276	8,688	5,544	10,771	100,000			
CLNTS/KWH	0,588183	0,038919	0,200241	0,094715	0,061261	0,117958	1,100300			
AMOUNT	10423	1118	5014	1624	723	3393	22794	2287	1559	
\$ UP TOTAL	47,914	4,904	21,495	7,124	3,172	14,884	100,000			
CLNTS/KWH	0,477813	0,048885	0,219239	0,071010	0,031613	0,148360	0,998744			
AMOUNT	10534	1199	4443	1682	1134	3009	21942	2818	1659	
\$ UP TOTAL	47,921	3,454	20,212	7,561	5,159	13,688	100,000			
CLNTS/KWH	0,373811	0,042588	0,157865	0,058978	0,040241	0,106778	0,740057			
AMOUNT	31542	4054	7586	2312	1114	6695	55383	12812	1759	
\$ UP TOTAL	57,035	7,331	13,717	4,181	5,631	12,108	100,000			
CLNTS/KWH	0,248191	0,031842	0,052210	0,018048	0,024305	0,052256	0,431850			
AMOUNT	23827	343	7854	3298	1834	8770	43924	6387	1859	
\$ UP TOTAL	54,244	0,781	17,880	7,508	4,175	15,412	100,000			
CLNTS/KWH	0,373055	0,005370	0,122489	0,051838	0,028715	0,105997	0,687741			
AMOUNT	19121	1183	4744	2581	2343	7018	38941	5724	1959	
\$ UP TOTAL	40,040	3,034	17,296	6,819	6,000	17,499	100,000			
CLNTS/KWH	0,334050	0,040687	0,117870	0,045091	0,040933	0,122607	0,681144			
AMOUNT	5804	373	2634	1331	1075	2771	14012	3054	2059	
\$ UP TOTAL	41,480	2,662	18,798	9,642	7,672	19,776	100,000			
CLNTS/KWH	0,190177	0,012713	0,086248	0,044237	0,035200	0,090733	0,458804			
AMOUNT	14453	448	5445	2308	1384	8500	37569	8907	2159	
\$ UP TOTAL	51,774	1,171	14,600	6,143	3,884	22,625	100,000			
CLNTS/KWH	0,218401	0,004940	0,081301	0,025912	0,015538	0,095431	0,421792			
AMOUNT	5862	410	2422	1408	889	2096	14087	2333	2259	
\$ UP TOTAL	41,813	2,750	20,743	9,945	7,021	14,879	100,000			
CLNTS/KWH	0,241264	0,034719	0,125246	0,060321	0,042392	0,089841	0,403815			
AMOUNT	9144	1233	4743	2247	1758	4403	23743	4609	2359	
\$ UP TOTAL	38,711	2,184	20,044	9,288	7,398	19,370	100,000			
CLNTS/KWH	0,199288	0,028752	0,103341	0,047885	0,038143	0,099870	0,515578			
SUMMARY	PRJID	TRANS	DIST	CUST	ATG	SALES	AD & GEN	TOTAL		
\$ UP TOTAL	53,220	3,266	17,447	6,981	4,453	14,585	100,000			
CLNTS/KWH	0,365018	0,022403	0,119933	0,047878	0,030543	0,100030	0,685861			

	PRUD	TRANS	DISC	CUST AIG	SALES	AD & GEN	TOTAL	KWH	CO-YR
AMOUNT	12781	159	2752	1179	360	2139	19370	1735	158
\$ OF TOTAL	67.409	0.812	14.982	6.023	2.062	10.930	100.000		
CENTS/KWH	0.73657	0.009164	0.158817	0.067954	0.032277	0.123265	1.127954		
AMOUNT	20849	218	6304	7202	931	4890	35395	4220	258
\$ OF TOTAL	58.339	0.616	16.375	6.221	2.630	13.816	100.000		
CENTS/KWH	0.489313	0.005186	0.154123	0.052180	0.022082	0.115877	0.638744		
AMOUNT	15027	981	3363	1566	1024	2445	24406	2632	358
\$ OF TOTAL	61.271	4.020	13.779	6.416	4.196	10.018	100.000		
CENTS/KWH	0.570935	0.037272	0.127774	0.059498	0.038906	0.092895	0.927240		
AMOUNT	32009	1527	11324	4400	2807	9329	61454	5897	458
\$ OF TOTAL	52.084	2.485	18.426	7.257	4.567	15.180	100.000		
CENTS/KWH	0.522041	0.025495	0.192230	0.075632	0.047600	0.158199	1.042157		
AMOUNT	6926	192	938	470	243	1000	9799	1352	558
\$ OF TOTAL	70.987	1.959	9.372	4.796	2.460	10.205	100.000		
CENTS/KWH	0.514897	0.014201	0.069379	0.038783	0.017973	0.073964	0.724774		
AMOUNT	10129	329	2061	840	632	1713	15734	1945	658
\$ OF TOTAL	70.267	2.091	13.099	5.339	4.017	10.687	100.000		
CENTS/KWH	0.522314	0.016415	0.105964	0.043188	0.032494	0.088872	0.688966		
AMOUNT	3393	5	885	319	207	737	5545	638	758
\$ OF TOTAL	51.190	0.000	15.960	5.735	3.733	13.291	100.000		
CENTS/KWH	0.531814	0.000084	0.135715	0.049843	0.032485	0.115517	0.569122		
AMOUNT	98866	5167	32237	14207	5164	22959	178670	20759	858
\$ OF TOTAL	55.356	2.893	18.050	7.955	2.891	12.855	100.000		
CENTS/KWH	0.476256	0.024890	0.155792	0.086438	0.024876	0.110598	0.960350		
AMOUNT	9801	431	2831	1088	1000	2144	16895	2700	958
\$ OF TOTAL	58.827	2.551	15.773	6.440	5.919	12.490	100.000		
CENTS/KWH	0.535933	0.019963	0.097464	0.040296	0.037037	0.079407	0.425741		
AMOUNT	15987	2157	5330	2188	1170	4205	30976	4857	1058
\$ OF TOTAL	51.482	6.963	17.207	6.999	3.777	13.575	100.000		
CENTS/KWH	0.328333	0.044410	0.109739	0.044637	0.024089	0.088576	0.637740		
AMOUNT	6887	447	3354	938	870	2770	15271	3021	1158
\$ OF TOTAL	45.752	2.937	21.989	6.142	5.897	18.139	100.000		
CENTS/KWH	0.221331	0.021417	0.111153	0.031049	0.028798	0.091491	0.505495		
AMOUNT	3734	252	1208	537	415	1196	7347	1245	1258
\$ OF TOTAL	50.875	3.430	16.442	7.309	5.649	16.279	100.000		
CENTS/KWH	0.370241	0.020241	0.097028	0.043133	0.033333	0.096064	0.590120		
AMOUNT	6383	264	2181	950	945	2552	13273	1915	1358
\$ OF TOTAL	44.069	1.889	16.432	7.157	7.120	19.227	100.000		
CENTS/KWH	0.333159	0.017886	0.113990	0.044608	0.049447	0.133264	0.693187		
AMOUNT	9851	488	2867	1483	978	2217	17863	1513	1458
\$ OF TOTAL	55.144	2.720	16.050	8.302	5.475	12.411	100.000		
CENTS/KWH	0.651091	0.030332	0.169491	0.098017	0.064640	0.116830	1.188635		
AMOUNT	10814	1074	5342	1427	670	2927	22254	1996	1558
\$ OF TOTAL	48.803	4.425	24.000	6.411	3.010	13.150	100.000		
CENTS/KWH	0.541984	0.023888	0.267835	0.071493	0.033567	0.148843	1.115130		
AMOUNT	10134	887	4215	1526	993	2886	20842	2473	1658
\$ OF TOTAL	49.574	4.339	19.741	7.485	4.858	14.118	100.000		
CENTS/KWH	0.409788	0.035867	0.162353	0.061708	0.040154	0.116700	0.826887		
AMOUNT	24791	3188	7080	2175	2843	6220	46276	10526	1758
\$ OF TOTAL	53.222	6.853	15.316	4.705	4.150	13.456	100.000		
CENTS/KWH	0.235847	0.038897	0.087262	0.028883	0.027009	0.059092	0.439140		
AMOUNT	24384	283	8005	3226	1867	6028	43793	6209	1858
\$ OF TOTAL	55.880	0.646	18.279	7.386	4.263	13.765	100.000		
CENTS/KWH	0.392720	0.004558	0.128926	0.051957	0.030869	0.097085	0.705315		
AMOUNT	18704	1158	6175	2323	2047	6610	37023	5120	1958
\$ OF TOTAL	50.531	3.128	16.879	6.280	5.329	17.854	100.000		
CENTS/KWH	0.365391	0.022617	0.120885	0.045410	0.039980	0.129102	0.723185		
AMOUNT	4469	326	2274	1257	894	2619	12095	2787	2058
\$ OF TOTAL	16.949	1.195	8.485	4.593	3.225	9.654	100.000		
CENTS/KWH	0.160352	0.011497	0.090635	0.045102	0.032221	0.093972	0.433899		
AMOUNT	18952	421	5442	2147	1247	7721	33639	6271	2158
\$ OF TOTAL	50.126	1.252	15.583	6.382	3.707	22.953	100.000		
CENTS/KWH	0.203869	0.005890	0.083374	0.025958	0.015077	0.093350	0.406710		
AMOUNT	5401	792	2907	1296	789	1739	12624	2063	2258
\$ OF TOTAL	19.784	2.974	10.851	4.706	2.920	6.375	100.000		
CENTS/KWH	0.259289	0.034022	0.125156	0.062218	0.037878	0.083463	0.606049		
AMOUNT	8440	1259	6350	2098	1590	4300	22237	4114	2358
\$ OF TOTAL	37.955	5.682	28.461	9.433	7.150	19.337	100.000		
CENTS/KWH	0.205153	0.030603	0.110598	0.050997	0.038649	0.104521	0.540320		
SUMMARY	PRUD	TRANS	DISC	CUST AIG	SALES	AD & GEN	TOTAL		
\$ OF TOTAL	53.524	3.153	17.235	7.101	4.255	14.427	100.000		
CENTS/KWH	0.383843	0.022616	0.125885	0.050897	0.030498	0.103406	0.716745		

	PHUD	TRANS	DIST	CUST	AIG	SALES	AD & GEN	TOTAL	KWH	CU-YR
AMOUNT	14775	159	2284	1141		483	2064	21220	1726	157
\$ UP TOTAL	64,883	0,744	12,177	5,375		2,275	9,746	100,000		
CENTS/KWH	0,057064	0,000012	0,149764	0,086107		0,027484	0,119873	1,229954		
AMOUNT	20068	204	2042	2036		799	4616	33344	4300	257
\$ UP TOTAL	86,145	0,417	16,409	6,102		2,345	13,834	100,000		
CENTS/KWH	0,466644	0,000091	0,131204	0,047344		0,018581	0,107344	0,775953		
AMOUNT	14675	977	3134	1358		884	2080	23134	2785	357
\$ UP TOTAL	63,221	4,223	13,256	5,870		3,839	8,491	100,000		
CENTS/KWH	0,327844	0,035081	0,112803	0,044761		0,031885	0,074486	0,830664		
AMOUNT	32050	1249	4257	3443		2404	8658	58396	5215	457
\$ UP TOTAL	63,844	2,207	17,462	6,561		4,117	15,169	100,000		
CENTS/KWH	0,339083	0,025703	0,148445	0,078630		0,047436	0,176630	1,164427		
AMOUNT	6504	211	216	414		142	932	9274	1364	557
\$ UP TOTAL	71,216	2,275	4,074	4,517		2,470	10,047	100,000		
CENTS/KWH	0,444311	0,014664	0,067155	0,030718		0,014074	0,068328	0,640050		
AMOUNT	11144	307	1777	788		590	1507	16144	1841	457
\$ UP TOTAL	63,201	1,494	10,443	4,445		3,650	4,323	100,000		
CENTS/KWH	0,342215	0,016321	0,044471	0,041843		0,031366	0,080117	0,459343		
AMOUNT	3133	12	583	242		147	700	5032	540	757
\$ UP TOTAL	62,835	0,240	13,855	5,438		3,639	13,994	100,000		
CENTS/KWH	0,331017	0,002034	0,115783	0,049442		0,030847	0,118644	0,847737		
AMOUNT	102874	4581	34014	13822		4644	23713	183711	20624	857
\$ UP TOTAL	35,841	2,444	18,316	7,524		2,866	12,908	100,000		
CENTS/KWH	0,407741	0,022008	0,124302	0,067006		0,023744	0,114955	0,440552		
AMOUNT	9831	433	2233	1012		460	1849	16649	2685	457
\$ UP TOTAL	59,013	2,444	15,205	6,075		4,763	11,339	100,000		
CENTS/KWH	0,326145	0,014127	0,044334	0,037641		0,035754	0,070354	0,620447		
AMOUNT	16444	2158	5649	1941		1108	3856	31211	4865	1057
\$ UP TOTAL	52,703	6,914	18,094	6,374		3,550	12,355	100,000		
CENTS/KWH	0,338109	0,044358	0,116115	0,040425		0,022775	0,079260	0,641542		
AMOUNT	5200	340	2471	815		773	2428	12576	2412	1157
\$ UP TOTAL	41,344	3,101	23,824	6,401		4,147	14,291	100,000		
CENTS/KWH	0,215089	0,016169	0,123176	0,033789		0,032048	0,100580	0,521393		
AMOUNT	3702	234	1185	464		343	1100	7024	1320	1257
\$ UP TOTAL	52,875	2,330	16,081	6,807		4,880	15,652	100,000		
CENTS/KWH	0,240455	0,017727	0,069773	0,035132		0,025485	0,083333	0,532424		
AMOUNT	5814	244	2123	446		874	2686	12640	1853	1357
\$ UP TOTAL	46,000	2,164	19,783	5,688		6,425	21,233	100,000		
CENTS/KWH	0,314031	0,014138	0,114271	0,045630		0,047275	0,144454	0,642677		
AMOUNT	8450	523	2806	1407		1086	1708	16441	1538	1457
\$ UP TOTAL	54,305	3,174	17,026	8,547		6,289	14,363	100,000		
CENTS/KWH	0,561425	0,044005	0,182445	0,091402		0,070611	0,111053	1,071544		
AMOUNT	4410	944	4838	1323		549	2549	19438	2083	1557
\$ UP TOTAL	44,420	4,440	21,845	6,800		2,825	13,116	100,000		
CENTS/KWH	0,451752	0,044274	0,222860	0,063514		0,028356	0,122372	0,932941		
AMOUNT	10050	724	3864	1520		886	2464	19508	2482	1657
\$ UP TOTAL	51,517	3,711	14,807	7,742		4,342	12,631	100,000		
CENTS/KWH	0,404415	0,020170	0,155681	0,061241		0,035647	0,099275	0,785979		
AMOUNT	25843	2726	7206	1944		2801	5696	46037	10337	1757
\$ UP TOTAL	55,701	3,421	15,653	4,286		4,084	12,373	100,000		
CENTS/KWH	0,248070	0,026371	0,069711	0,019000		0,027047	0,055103	0,445341		
AMOUNT	25444	243	7454	3031		1740	5321	44062	6596	1857
\$ UP TOTAL	59,005	0,597	17,380	6,874		4,062	12,076	100,000		
CENTS/KWH	0,394163	0,003487	0,116101	0,045452		0,027138	0,080670	0,668011		
AMOUNT	20263	1151	6062	2158		1429	6440	38032	6107	1957
\$ UP TOTAL	53,321	3,024	15,452	5,674		5,076	16,946	100,000		
CENTS/KWH	0,331800	0,014447	0,099263	0,035336		0,031587	0,105453	0,622270		
AMOUNT	4194	240	2453	1143		829	2444	11416	2754	2057
\$ UP TOTAL	36,773	2,453	21,447	10,450		7,262	21,584	100,000		
CENTS/KWH	0,152433	0,010167	0,044470	0,043314		0,030102	0,084470	0,414324		
AMOUNT	16717	383	5249	1970		1049	6334	31726	4023	2157
\$ UP TOTAL	52,642	1,207	16,604	6,204		3,406	19,977	100,000		
CENTS/KWH	0,204353	0,004774	0,065674	0,024534		0,013075	0,078998	0,395434		
AMOUNT	1234	9	156	171		83	335	1989	164	2257
\$ UP TOTAL	62,042	0,452	7,583	8,547		4,173	16,843	100,000		
CENTS/KWH	0,751044	0,005488	0,044122	0,104268		0,050610	0,204268	1,212805		
AMOUNT	7887	1122	4096	2018		1474	3914	20506	4130	2357
\$ UP TOTAL	38,448	3,472	14,475	4,841		7,188	19,087	100,000		
CENTS/KWH	0,190847	0,027167	0,049177	0,048862		0,035690	0,044770	0,496513		
SUMMARY	PHUD	TRANS	DIST	CUST	AIG	SALES	AD & GEN	TOTAL		
\$ UP TOTAL	55,413	2,855	17,272	6,708		3,969	13,783	100,000		
CENTS/KWH	0,303738	0,020288	0,122727	0,047681		0,028202	0,097933	0,710550		

	PKUD	TRANS	DIST	CUST	ALG	SALES	AD & GEN	TOTAL	KWH	CU-YR
AMOUNT	13798	131	2499	875	418	2003	19725	1653	156	
\$ UF TOTAL	60,957	0,869	12,669	4,436	7,119	10,155	100,000			
CLNTS/KWH	0,434725	0,007925	0,151180	0,052934	0,025287	0,121174	1,193295			
AMOUNT	18211	143	5218	1883	767	4364	30547	3915	256	
\$ UF TOTAL	59,577	0,868	17,071	6,055	2,309	14,277	100,000			
CLNTS/KWH	0,765160	0,007453	0,133282	0,047596	0,019591	0,111469	0,780764			
AMOUNT	13771	402	2805	1197	742	1698	20975	2783	356	
\$ UF TOTAL	65,559	3,424	13,373	5,707	3,338	7,905	100,000			
CLNTS/KWH	0,494826	0,028118	0,100791	0,043011	0,026662	0,059576	0,753683			
AMOUNT	23961	1294	4045	3283	2214	7776	47594	4200	456	
\$ UF TOTAL	70,392	2,729	19,003	6,897	4,651	16,337	100,000			
CLNTS/KWH	0,570076	0,019929	0,215357	0,078167	0,052714	0,185143	1,133284			
AMOUNT	5374	198	890	359	149	427	7797	1281	556	
\$ UF TOTAL	58,524	2,539	11,415	4,604	1,911	10,607	100,000			
CLNTS/KWH	0,419916	0,015657	0,069477	0,024025	0,011632	0,064559	0,608645			
AMOUNT	4207	275	1595	757	523	1320	13677	1757	656	
\$ UF TOTAL	47,317	2,011	11,667	5,535	3,624	4,451	100,000			
CLNTS/KWH	0,525514	0,015696	0,091039	0,043208	0,029852	0,075342	0,780661			
AMOUNT	2655	5	671	295	161	526	4543	497	756	
\$ UF TOTAL	67,804	0,110	13,669	6,494	3,244	13,779	100,000			
CLNTS/KWH	0,570023	0,001006	0,124950	0,059356	0,032394	0,125956	0,914085			
AMOUNT	45157	4410	32073	13332	5047	21584	171643	19749	556	
\$ UF TOTAL	55,437	2,569	18,584	7,774	2,963	12,573	100,000			
CLNTS/KWH	0,441856	0,022331	0,162411	0,067612	0,025760	0,109297	0,969244			
AMOUNT	4254	378	2784	954	895	1481	15450	2515	936	
\$ UF TOTAL	59,896	2,447	14,409	6,175	5,793	10,440	100,000			
CLNTS/KWH	0,367527	0,015930	0,090774	0,037932	0,035284	0,066839	0,614314			
AMOUNT	17390	2143	4717	1805	934	3492	30442	4585	1056	
\$ UF TOTAL	57,050	7,030	15,475	5,922	3,064	11,456	100,000			
CLNTS/KWH	0,355988	0,044849	0,096561	0,034950	0,019120	0,071484	0,623902			
AMOUNT	3623	466	2624	729	737	2227	10494	2309	1156	
\$ UF TOTAL	34,997	4,484	25,139	6,984	7,061	21,336	100,000			
CLNTS/KWH	0,158207	0,020269	0,113682	0,031572	0,031919	0,096449	0,442087			
AMOUNT	3893	221	1104	439	310	1084	7095	1234	1256	
\$ UF TOTAL	56,358	3,141	15,744	6,240	4,407	15,124	100,000			
CLNTS/KWH	0,314988	0,017440	0,089725	0,035516	0,025041	0,086084	0,969175			
AMOUNT	5744	361	2084	826	661	2616	12501	2011	1356	
\$ UF TOTAL	45,981	2,486	16,703	6,407	4,887	20,926	100,000			
CLNTS/KWH	0,285928	0,017451	0,103829	0,041074	0,042815	0,130085	0,621631			
AMOUNT	8414	420	2794	1345	918	1607	15497	1442	1456	
\$ UF TOTAL	54,294	2,710	16,079	8,679	5,924	10,370	100,000			
CLNTS/KWH	0,583495	0,029126	0,193359	0,093273	0,063662	0,111442	1,074684			
AMOUNT	5512	455	4395	1294	559	1494	17310	1869	1556	
\$ UF TOTAL	40,174	4,939	26,285	7,475	3,229	8,631	100,000			
CLNTS/KWH	0,455431	0,045746	0,245953	0,089235	0,029909	0,079936	0,928164			
AMOUNT	9484	468	3803	1377	827	2218	18341	2384	1656	
\$ UF TOTAL	51,371	3,435	20,712	7,300	4,304	12,030	100,000			
CLNTS/KWH	0,397190	0,028020	0,159922	0,057760	0,034690	0,093037	0,770176			
AMOUNT	25749	2480	7030	1884	2615	5742	45507	9964	1756	
\$ UF TOTAL	56,391	3,451	15,451	4,141	5,747	12,620	100,000			
CLNTS/KWH	0,258420	0,024490	0,070254	0,018908	0,024244	0,057427	0,456644			
AMOUNT	26211	259	7243	2836	1753	3483	42295	4450	1656	
\$ UF TOTAL	62,104	0,414	17,420	6,720	4,154	8,490	100,000			
CLNTS/KWH	3,406372	0,004016	0,117256	0,043969	0,027174	0,055550	0,654341			
AMOUNT	18520	933	6114	2072	1730	6026	35395	5864	1956	
\$ UF TOTAL	52,324	2,638	17,274	5,854	4,888	17,025	100,000			
CLNTS/KWH	0,315825	0,016911	0,104263	0,035334	0,029502	0,102763	0,603594			
AMOUNT	4032	231	2229	1051	782	2261	10546	2555	2056	
\$ UF TOTAL	38,088	2,182	21,056	9,928	7,387	21,358	100,000			
CLNTS/KWH	0,157808	0,009041	0,087241	0,041135	0,030607	0,088493	0,414325			
AMOUNT	12841	359	4912	1895	929	5000	25925	7067	2156	
\$ UF TOTAL	49,493	1,185	18,947	7,310	3,583	19,286	100,000			
CLNTS/KWH	0,181562	0,005880	0,069506	0,026815	0,013146	0,070751	0,366846			
AMOUNT	1197	13	146	183	106	324	1969	158	2256	
\$ UF TOTAL	60,792	0,660	7,415	9,294	5,383	16,455	100,000			
CLNTS/KWH	0,757545	0,002228	0,092405	0,115823	0,067089	0,205063	1,246203			
AMOUNT	8259	1054	3352	1811	1266	3420	19162	3825	2356	
\$ UF TOTAL	43,101	3,500	17,493	9,451	6,007	17,848	100,000			
CLNTS/KWH	0,215922	0,027556	0,087634	0,047346	0,033098	0,089412	0,500967			
SUMMARY	PKUD	TRANS	DIST	CUST	ALG	SALES	AD & GEN	TOTAL		
\$ UF TOTAL	55,331	2,900	17,636	6,804	4,449	13,260	100,000			
CLNTS/KWH	0,382309	0,020037	0,121953	0,047013	0,027979	0,091755	0,690945			

	PRUD	TRANS	DIST	CUST AIG	SALES	AD & GEN	TOTAL	KWH	CO-YR
AMOUNT	10567	167	2356	777	403	1732	16001	1470	155
% OF TOTAL	66.040	1.044	14.724	4.856	2.519	10.824	100.000		
CLNTS/KWH	0.711844	0.111361	0.100272	0.052857	0.027415	0.117423	1.088533		
AMOUNT	10555	122	4600	1739	712	3959	27714	3738	255
% OF TOTAL	59.434	0.440	10.496	6.274	2.509	14.283	100.000		
CLNTS/KWH	0.443088	0.043264	0.123760	0.046522	0.019048	0.105912	0.741520		
AMOUNT	12458	918	2504	1090	647	1761	19474	2463	355
% OF TOTAL	63.954	4.713	13.369	5.546	3.322	9.041	100.000		
CLNTS/KWH	0.505806	0.037272	0.105725	0.044253	0.026269	0.071498	0.790824		
AMOUNT	19131	1065	6074	2643	1837	6876	39624	3491	455
% OF TOTAL	44.279	2.488	20.376	6.670	4.634	17.352	100.000		
CLNTS/KWH	0.563009	0.030507	0.251280	0.075709	0.052821	0.196884	1.135000		
AMOUNT	4721	180	513	342	104	709	6849	1116	555
% OF TOTAL	68.729	2.420	11.836	4.974	1.514	10.322	100.000		
CLNTS/KWH	0.423029	0.018129	0.072849	0.030645	0.009319	0.063530	0.615500		
AMOUNT	8757	250	1337	717	423	1252	10731	1357	655
% OF TOTAL	47.921	2.330	12.459	6.682	3.947	11.667	100.000		
CLNTS/KWH	0.447568	0.016623	0.098376	0.052837	0.031172	0.092262	0.790749		
AMOUNT	2253	8	553	254	155	467	4100	427	755
% OF TOTAL	67.482	0.145	13.530	6.192	3.779	13.823	100.000		
CLNTS/KWH	0.000234	0.001674	0.129777	0.059485	0.036300	0.132747	0.960654		
AMOUNT	89866	4341	29104	11613	5063	21279	160672	18503	855
% OF TOTAL	54.309	2.702	18.441	7.353	3.151	13.244	100.000		
CLNTS/KWH	0.440279	0.023681	0.154396	0.063855	0.027363	0.115003	0.848344		
AMOUNT	6524	319	2125	917	820	1593	14294	2348	955
% OF TOTAL	59.017	2.731	14.862	6.413	5.735	11.141	100.000		
CLNTS/KWH	0.363032	0.015486	0.090503	0.039055	0.034223	0.067445	0.608944		
AMOUNT	14411	1630	4660	1681	961	3292	26634	4595	1055
% OF TOTAL	54.108	6.120	17.496	6.311	3.608	12.360	100.000		
CLNTS/KWH	0.313024	0.035473	0.101415	0.036583	0.020414	0.071643	0.579630		
AMOUNT	4237	531	2510	644	675	2051	10643	1944	1155
% OF TOTAL	34.763	4.089	23.744	6.051	6.342	19.271	100.000		
CLNTS/KWH	0.217695	0.027315	0.129115	0.033128	0.034722	0.105504	0.547479		
AMOUNT	3335	202	1025	411	268	897	6137	1207	1255
% OF TOTAL	54.343	3.292	16.702	6.697	4.367	14.616	100.000		
CLNTS/KWH	0.276305	0.014736	0.084221	0.034051	0.022204	0.074316	0.508451		
AMOUNT	5767	339	1894	767	854	2431	12071	2050	1355
% OF TOTAL	47.900	2.808	15.724	6.354	7.075	20.139	100.000		
CLNTS/KWH	0.242044	0.016537	0.092585	0.037415	0.041859	0.118585	0.588829		
AMOUNT	7338	454	2747	1270	808	1540	14214	1396	1455
% OF TOTAL	51.011	3.193	19.602	8.932	5.683	10.992	100.000		
CLNTS/KWH	0.225845	0.032521	0.199842	0.090974	0.057880	0.111748	1.018451		
AMOUNT	7073	473	4368	1201	471	1075	14561	1541	1555
% OF TOTAL	48.575	4.622	27.938	8.248	3.235	7.383	100.000		
CLNTS/KWH	0.384193	0.044558	0.220767	0.065236	0.025384	0.058192	0.790929		
AMOUNT	9378	678	3394	1303	734	1931	17372	2297	1655
% OF TOTAL	53.953	3.815	19.344	7.512	4.225	11.116	100.000		
CLNTS/KWH	0.408272	0.027300	0.147845	0.056813	0.031955	0.084066	0.756291		
AMOUNT	23844	2216	8444	1414	2549	4204	41344	9454	1755
% OF TOTAL	57.145	5.360	19.501	4.387	6.286	10.168	100.000		
CLNTS/KWH	0.239944	0.022488	0.089057	0.019404	0.026375	0.042463	0.419544		
AMOUNT	25623	285	7262	2678	1812	3635	39092	6050	1855
% OF TOTAL	68.422	0.729	18.577	6.851	4.124	9.299	100.000		
CLNTS/KWH	0.390413	0.004711	0.120033	0.044284	0.026045	0.060063	0.646149		
AMOUNT	17153	978	5897	1969	1456	5457	32920	5616	1955
% OF TOTAL	52.135	2.971	17.913	5.901	4.423	16.577	100.000		
CLNTS/KWH	0.305009	0.017415	0.105004	0.035061	0.025926	0.097169	0.586182		
AMOUNT	3648	177	2173	1003	735	1816	9755	2176	2055
% OF TOTAL	39.444	1.814	22.276	10.282	7.535	18.437	100.000		
CLNTS/KWH	0.176838	0.004134	0.099862	0.046044	0.033778	0.083548	0.448300		
AMOUNT	10277	500	4281	1620	844	4455	22176	5923	2155
% OF TOTAL	46.343	2.255	19.305	7.207	3.806	20.089	100.000		
CLNTS/KWH	0.173510	0.004442	0.072278	0.030726	0.014250	0.075215	0.374405		
AMOUNT	976	12	146	172	89	283	1677	140	2255
% OF TOTAL	58.149	0.716	8.704	10.256	5.307	16.875	100.000		
CLNTS/KWH	0.697143	0.004471	0.104286	0.122457	0.063571	0.202143	1.197857		
AMOUNT	7367	1093	3270	1637	1167	3269	17803	3180	2355
% OF TOTAL	41.381	6.139	18.368	9.195	6.555	18.362	100.000		
CLNTS/KWH	0.231667	0.044371	0.102930	0.051478	0.036898	0.102799	0.559843		
SUMMARY	PRUD	TRANS	DIST	CUST AIG	SALES	AD & GEN	TOTAL		
% OF TOTAL	54.535	3.020	18.426	6.843	4.142	13.443	100.000		
CLNTS/KWH	0.371013	0.020543	0.122934	0.046884	0.026178	0.091469	0.680315		

	PMUD	TRANS	DIST	CUST AIG	SALES	AD & GEN	TOTAL	KWH	CO-YR
AMOUNT	9468	125	2428	751	355	1734	14861	1324	154
% OF TOTAL	63.715	0.841	16.375	5.054	2.389	11.669	100.000		
CLNTS/KWH	0.715106	0.009441	0.183233	0.036722	0.026813	0.130967	1.122356		
AMOUNT	16132	110	4893	1778	696	4000	27410	3409	254
% OF TOTAL	58.024	0.401	17.171	6.487	2.539	14.593	100.000		
CLNTS/KWH	0.473218	0.032267	0.137865	0.052156	0.020417	0.117336	0.804044		
AMOUNT	11082	852	2274	930	557	1648	17344	2268	354
% OF TOTAL	53.891	4.929	13.131	5.381	3.211	9.488	100.000		
CLNTS/KWH	0.485624	0.037698	0.103441	0.041045	0.024559	0.072575	0.764983		
AMOUNT	10298	1050	7403	2337	1888	8382	35030	3000	434
% OF TOTAL	46.447	2.997	20.854	6.871	4.819	16.162	100.000		
CLNTS/KWH	0.542933	0.039000	0.243500	0.077900	0.056267	0.212067	1.167647		
AMOUNT	3865	174	780	308	90	685	5912	1250	554
% OF TOTAL	15.376	2.943	13.363	5.210	1.522	11.587	100.000		
CLNTS/KWH	0.302200	0.013920	0.083400	0.028800	0.007200	0.054400	0.472960		
AMOUNT	5140	224	1407	643	366	1194	9874	1286	654
% OF TOTAL	22.184	2.769	13.237	6.512	3.707	12.992	100.000		
CLNTS/KWH	0.477449	0.017418	0.101833	0.050000	0.028800	0.092846	0.767877		
AMOUNT	2352	10	371	250	149	442	3823	366	754
% OF TOTAL	11.522	0.262	13.829	6.539	3.897	14.177	100.000		
CLNTS/KWH	0.542023	0.002732	0.142350	0.088406	0.040710	0.140087	1.044534		
AMOUNT	83548	2476	30924	10654	5248	19872	152922	16699	854
% OF TOTAL	54.834	1.681	20.272	6.967	3.437	12.864	100.000		
CLNTS/KWH	0.500317	0.017223	0.185185	0.083800	0.031427	0.117803	0.915745		
AMOUNT	3099	333	2038	942	678	1504	13595	2093	954
% OF TOTAL	59.573	2.449	14.991	6.929	4.987	11.063	100.000		
CLNTS/KWH	0.348957	0.015910	0.097372	0.045007	0.032394	0.071859	0.649546		
AMOUNT	13842	1730	4046	1610	879	2747	25253	4123	1054
% OF TOTAL	54.021	6.851	16.395	6.375	3.481	10.678	100.000		
CLNTS/KWH	0.330876	0.041960	0.112685	0.039049	0.021119	0.068626	0.612491		
AMOUNT	3789	440	2074	811	665	2047	9625	1937	1154
% OF TOTAL	39.386	4.571	21.548	8.348	6.909	21.268	100.000		
CLNTS/KWH	0.194109	0.022441	0.106250	0.031301	0.034068	0.104667	0.493084		
AMOUNT	2227	189	995	403	260	851	4925	1330	1254
% OF TOTAL	45.218	3.838	20.203	8.183	5.279	17.279	100.000		
CLNTS/KWH	0.167444	0.014211	0.074812	0.030301	0.019549	0.063955	0.370301		
AMOUNT	6482	299	1796	744	700	2921	12541	2206	1354
% OF TOTAL	51.886	2.384	14.321	5.933	5.582	24.102	100.000		
CLNTS/KWH	0.293635	0.013354	0.081414	0.033728	0.031732	0.114279	0.468499		
AMOUNT	7322	472	3164	1043	780	1845	14677	1189	1454
% OF TOTAL	49.886	3.216	21.358	7.447	5.114	12.571	100.000		
CLNTS/KWH	0.515012	0.034697	0.246108	0.091926	0.066601	0.155172	1.234399		
AMOUNT	8131	429	3840	1117	418	1722	15866	1477	1554
% OF TOTAL	51.935	4.018	23.450	7.133	2.870	10.999	100.000		
CLNTS/KWH	0.550508	0.045888	0.245445	0.079648	0.028301	0.118588	1.059944		
AMOUNT	8851	578	3195	1195	589	1925	16134	1897	1654
% OF TOTAL	53.820	3.582	19.803	7.407	3.651	11.931	100.000		
CLNTS/KWH	0.456034	0.034489	0.168474	0.062994	0.031049	0.101476	0.850501		
AMOUNT	18451	2245	7335	1841	2294	4555	36504	4220	1754
% OF TOTAL	51.359	6.150	20.093	4.832	6.295	12.478	100.000		
CLNTS/KWH	0.223813	0.027311	0.089234	0.020572	0.027956	0.053414	0.444100		
AMOUNT	21152	268	6886	2537	1958	3913	36439	5141	1854
% OF TOTAL	58.054	0.736	18.901	7.019	4.545	10.741	100.000		
CLNTS/KWH	0.411447	0.005213	0.133943	0.049737	0.032212	0.076114	0.708656		
AMOUNT	16030	921	5615	1988	1265	4453	30272	4692	1954
% OF TOTAL	52.453	3.042	18.348	6.567	4.179	14.710	100.000		
CLNTS/KWH	0.341645	0.019429	0.119872	0.042370	0.026961	0.094806	0.645141		
AMOUNT	3730	163	2156	959	483	1978	9668	2001	2054
% OF TOTAL	38.581	1.689	22.400	9.919	7.065	20.459	100.000		
CLNTS/KWH	0.180407	0.008146	0.107746	0.047926	0.034133	0.098851	0.483158		
AMOUNT	8776	371	4975	1788	794	4308	20112	5240	2154
% OF TOTAL	43.636	1.840	20.262	8.890	3.948	21.420	100.000		
CLNTS/KWH	0.167481	0.007060	0.077767	0.034122	0.015153	0.082214	0.383617		
AMOUNT	852	10	135	107	89	272	1524	127	2254
% OF TOTAL	55.906	0.456	8.958	10.958	5.840	17.848	100.000		
CLNTS/KWH	0.670866	0.007874	0.106289	0.131488	0.070079	0.214173	1.200000		
AMOUNT	6571	913	3002	1699	1103	3520	16718	2898	2354
% OF TOTAL	39.305	5.461	17.957	9.624	6.598	21.055	100.000		
CLNTS/KWH	0.226743	0.031504	0.103589	0.055521	0.038061	0.121443	0.576881		
SUMMARY	PMUD	TRANS	DIST	CUST AIG	SALES	AD & GEN	TOTAL		
% OF TOTAL	53.280	2.423	19.027	8.808	4.148	13.940	100.000		
CLNTS/KWH	0.381072	0.020199	0.136135	0.048894	0.029862	0.094741	0.715501		

	PRJ0	TRANS	DIST	CUST	ATG	SALES	AD & GEN	TOTAL	KWH	CO-YR
AMOUNT	9156	118	2557	716	308	1647	14901	1306	153	
% OF TOTAL	63.140	0.814	17.633	4.936	2.124	11.358	100.000			
CLNTS/KWH	0.701072	0.009035	0.195789	0.094824	0.023583	0.126110	1.110337			
AMOUNT	16178	73	4288	1613	662	3623	26437	3324	253	
% OF TOTAL	61.195	0.278	16.420	6.101	2.504	13.704	100.000			
CLNTS/KWH	0.486703	0.002198	0.129001	0.048526	0.019916	0.108993	0.795337			
AMOUNT	10084	773	2000	864	511	1650	15842	2060	353	
% OF TOTAL	63.401	4.879	12.625	5.494	3.224	10.415	100.000			
CLNTS/KWH	0.487573	0.037524	0.097087	0.041942	0.024806	0.080097	0.769029			
AMOUNT	13921	913	7158	2114	1482	4916	30534	2632	453	
% OF TOTAL	45.592	2.990	23.341	6.923	4.854	16.100	100.000			
CLNTS/KWH	0.528913	0.036888	0.273100	0.080319	0.056307	0.186778	1.160106			
AMOUNT	2037	144	797	272	71	665	3946	937	553	
% OF TOTAL	51.104	3.613	19.995	6.824	1.781	16.683	100.000			
CLNTS/KWH	0.217396	0.015358	0.065059	0.024029	0.007977	0.070971	0.425400			
AMOUNT	3364	222	1222	634	314	1124	6860	1068	653	
% OF TOTAL	60.405	2.500	13.761	7.140	3.536	12.658	100.000			
CLNTS/KWH	0.493015	0.020404	0.112316	0.058272	0.028860	0.103309	0.816176			
AMOUNT	2434	16	495	237	140	507	3829	326	753	
% OF TOTAL	63.588	0.418	12.928	6.190	3.656	13.241	100.000			
CLNTS/KWH	0.746626	0.004908	0.151840	0.072699	0.042945	0.155521	1.174940			
AMOUNT	41921	2667	29085	10246	5092	19245	148254	16581	853	
% OF TOTAL	55.237	1.799	19.514	6.912	3.434	12.961	100.000			
CLNTS/KWH	0.494065	0.014085	0.175812	0.061800	0.030710	0.118067	0.894144			
AMOUNT	8435	343	4883	939	596	1578	13773	2038	953	
% OF TOTAL	61.243	2.490	13.672	6.810	4.327	11.457	100.000			
CLNTS/KWH	0.413886	0.016830	0.092395	0.044075	0.029244	0.077429	0.675610			
AMOUNT	10152	1409	3778	1491	854	2473	27566	3993	1053	
% OF TOTAL	58.630	6.562	17.333	5.409	3.096	8.971	100.000			
CLNTS/KWH	0.408758	0.045304	0.119059	0.037340	0.021387	0.061933	0.690358			
AMOUNT	5430	559	2035	347	606	1614	10990	2233	1153	
% OF TOTAL	49.409	5.066	18.517	3.177	5.514	16.506	100.000			
CLNTS/KWH	0.243171	0.025034	0.091133	0.024496	0.027138	0.081238	0.492163			
AMOUNT	1382	211	961	382	242	847	4024	1094	1253	
% OF TOTAL	34.344	5.244	23.862	9.493	6.014	21.049	100.000			
CLNTS/KWH	0.126325	0.019287	0.087843	0.034918	0.022121	0.077422	0.367824			
AMOUNT	6020	218	1640	724	660	2276	11558	2052	1353	
% OF TOTAL	52.083	1.580	14.362	6.264	5.710	19.692	100.000			
CLNTS/KWH	0.293372	0.010624	0.080697	0.035283	0.032164	0.110916	0.563255			
AMOUNT	6684	415	2968	1033	705	1704	13533	1135	1453	
% OF TOTAL	49.420	3.067	21.932	7.751	5.209	12.591	100.000			
CLNTS/KWH	0.589251	0.036564	0.261494	0.092775	0.062115	0.150132	1.192335			
AMOUNT	9219	572	3248	1060	394	1154	14647	1281	1553	
% OF TOTAL	56.114	3.905	22.175	7.237	2.690	7.879	100.000			
CLNTS/KWH	0.641609	0.044653	0.253552	0.082748	0.030757	0.090886	1.143404			
AMOUNT	8009	522	2348	1034	471	1790	14174	1738	1653	
% OF TOTAL	56.505	3.683	16.566	7.295	3.323	12.629	100.000			
CLNTS/KWH	0.460817	0.030035	0.135094	0.059494	0.027100	0.102992	0.815535			
AMOUNT	21437	1982	7046	1692	2245	3947	38344	7657	1753	
% OF TOTAL	55.901	5.169	18.374	4.412	5.854	10.293	100.000			
CLNTS/KWH	0.279966	0.025825	0.092020	0.022097	0.029320	0.051546	0.500823			
AMOUNT	23897	272	6447	2464	1529	3130	37799	5402	1853	
% OF TOTAL	63.221	0.720	17.162	6.572	4.045	8.281	100.000			
CLNTS/KWH	0.426580	0.004855	0.115796	0.044341	0.027294	0.055873	0.674741			
AMOUNT	17204	646	5807	1913	1307	4148	31031	4949	1953	
% OF TOTAL	55.457	2.726	18.069	6.165	4.212	13.387	100.000			
CLNTS/KWH	0.347727	0.017094	0.113296	0.038654	0.026409	0.083815	0.627016			
AMOUNT	3444	127	2120	896	636	2096	9323	1794	2053	
% OF TOTAL	36.462	1.362	22.739	9.632	6.822	22.482	100.000			
CLNTS/KWH	0.192085	0.007079	0.118172	0.050056	0.035452	0.118834	0.519677			
AMOUNT	9081	310	3970	1708	574	3927	19570	4563	2153	
% OF TOTAL	46.403	1.584	20.286	8.726	2.933	20.066	100.000			
CLNTS/KWH	0.199014	0.006794	0.087004	0.037432	0.012379	0.086062	0.428885			
AMOUNT	726	11	146	157	71	270	1383	110	2253	
% OF TOTAL	52.639	0.795	10.557	11.352	5.134	19.523	100.000			
CLNTS/KWH	0.661816	0.010000	0.132727	0.142727	0.064345	0.245455	1.257273			
AMOUNT	6157	970	2004	1582	974	3052	15521	2980	2353	
% OF TOTAL	39.869	6.250	18.079	10.064	6.275	19.664	100.000			
CLNTS/KWH	0.206611	0.029550	0.094161	0.052416	0.032685	0.102416	0.520839			
SUMMARY	PRJ0	TRANS	DIST	CUST	ATG	SALES	AD & GEN	TOTAL		
% OF TOTAL	54.966	2.734	18.363	6.662	3.966	13.110	100.000			
CLNTS/KWH	0.396450	0.019718	0.133890	0.048049	0.028604	0.094957	0.721261			

	PRUD	TRANS	DIST	CUST AID	SALES	AD & GEN	TOTAL	KWH	CO-YR
AMOUNT	8688	105	1681	646	292	1363	12757	1179	152
% OF TOTAL	67.947	0.823	13.177	5.068	2.289	10.700	100.000		
CENTS/KWH	0.735823	0.008013	0.102699	0.054839	0.024788	0.113674	1.042937		
AMOUNT	15700	68	4057	1652	446	3461	25401	3268	252
% OF TOTAL	61.804	0.268	15.971	6.503	1.756	13.703	100.000		
CENTS/KWH	0.440415	0.002081	0.128143	0.050551	0.013647	0.106518	0.777324		
AMOUNT	9768	716	1634	745	435	1559	14857	1807	352
% OF TOTAL	65.747	4.819	10.998	5.014	2.928	10.493	100.000		
CENTS/KWH	0.580564	0.039624	0.090426	0.041229	0.024073	0.086276	0.822191		
AMOUNT	12651	779	5997	1758	1306	4389	26880	2244	452
% OF TOTAL	47.055	2.898	22.310	6.540	4.859	16.328	100.000		
CENTS/KWH	0.563770	0.036715	0.267244	0.074342	0.058240	0.195566	1.197651		
AMOUNT	1459	93	696	244	67	575	3159	643	552
% OF TOTAL	46.620	2.972	22.240	7.798	1.981	18.376	100.000		
CENTS/KWH	0.226995	0.014663	0.108243	0.037947	0.009642	0.084425	0.486695		
AMOUNT	4723	242	1044	502	288	1006	7807	1103	652
% OF TOTAL	60.497	3.100	13.373	6.430	3.689	12.911	100.000		
CENTS/KWH	0.423196	0.021940	0.094051	0.045512	0.026111	0.091367	0.707797		
AMOUNT	2323	11	408	203	110	531	3567	301	752
% OF TOTAL	64.762	0.307	11.374	5.659	3.067	14.803	100.000		
CENTS/KWH	0.771761	0.003654	0.135548	0.067442	0.038345	0.178412	1.191694		
AMOUNT	46542	1587	15977	5805	3135	11649	94894	11039	852
% OF TOTAL	59.584	1.472	16.637	6.117	3.304	12.486	100.000		
CENTS/KWH	0.512202	0.014376	0.144732	0.059566	0.028399	0.107338	0.859634		
AMOUNT	8662	335	1834	917	454	1524	13759	1863	952
% OF TOTAL	63.133	2.436	13.365	6.808	3.316	11.062	100.000		
CENTS/KWH	0.466023	0.017082	0.098059	0.049722	0.024477	0.081904	0.738164		
AMOUNT	14427	1621	4331	1408	893	2330	25004	3642	1052
% OF TOTAL	57.679	6.483	17.321	5.631	3.571	9.319	100.000		
CENTS/KWH	0.395991	0.045509	0.118918	0.038660	0.024519	0.063976	0.666546		
AMOUNT	4276	397	1834	493	540	1532	9071	1909	1152
% OF TOTAL	47.117	4.377	20.218	5.435	5.953	16.889	100.000		
CENTS/KWH	0.223667	0.020796	0.096071	0.025825	0.028287	0.080291	0.475170		
AMOUNT	1493	199	848	357	195	751	3842	1048	1252
% OF TOTAL	34.867	3.180	22.072	9.292	5.075	19.547	100.000		
CENTS/KWH	0.142462	0.014989	0.060916	0.034065	0.018607	0.071680	0.366603		
AMOUNT	5816	273	1711	645	576	1945	10965	2146	1352
% OF TOTAL	53.041	2.490	15.604	5.882	5.253	17.736	100.000		
CENTS/KWH	0.246645	0.012432	0.077914	0.029372	0.026230	0.088570	0.499317		
AMOUNT	5164	341	2624	942	601	1520	12214	1037	1452
% OF TOTAL	50.634	2.792	21.498	7.712	4.920	12.444	100.000		
CENTS/KWH	0.598432	0.032883	0.253230	0.090639	0.057496	0.146377	1.177917		
AMOUNT	8231	392	2897	921	264	914	13439	1132	1552
% OF TOTAL	61.247	2.917	20.068	6.853	2.113	6.801	100.000		
CENTS/KWH	0.727120	0.044629	0.238251	0.081300	0.025088	0.080742	1.167191		
AMOUNT	7625	448	2004	924	293	1705	13003	1621	1652
% OF TOTAL	58.640	3.445	15.443	7.106	2.253	13.112	100.000		
CENTS/KWH	0.470369	0.027637	0.123874	0.057002	0.018075	0.103162	0.602159		
AMOUNT	17572	1761	6164	1507	2173	3865	33144	7421	1752
% OF TOTAL	53.014	5.313	18.609	4.848	6.556	11.661	100.000		
CENTS/KWH	0.236787	0.023730	0.083115	0.021635	0.029282	0.052082	0.446641		
AMOUNT	24276	265	6346	2372	1396	2803	37458	5179	1852
% OF TOTAL	64.809	0.707	16.942	6.332	3.727	7.463	100.000		
CENTS/KWH	0.468739	0.005117	0.122593	0.045800	0.026935	0.054122	0.723247		
AMOUNT	13252	707	5434	2086	1457	3219	25755	4673	1952
% OF TOTAL	51.454	2.745	21.099	8.099	4.104	12.499	100.000		
CENTS/KWH	0.283387	0.015129	0.116245	0.044639	0.022610	0.068865	0.551145		
AMOUNT	2906	104	1463	638	564	1649	8242	1496	2052
% OF TOTAL	35.283	1.250	23.817	10.143	7.086	22.434	100.000		
CENTS/KWH	0.194385	0.006865	0.131217	0.055862	0.039037	0.123596	0.550936		
AMOUNT	8956	328	3710	1468	480	3362	18325	4260	2152
% OF TOTAL	48.873	1.790	20.246	8.011	2.619	18.456	100.000		
CENTS/KWH	0.210235	0.007700	0.087089	0.034460	0.011268	0.079390	0.430164		
AMOUNT	569	10	133	151	48	255	1167	93	2252
% OF TOTAL	48.757	0.457	11.387	12.939	4.113	21.651	100.000		
CENTS/KWH	0.611828	0.010753	0.143011	0.162366	0.051613	0.274194	1.254839		
AMOUNT	5743	914	2480	1472	848	2649	14106	2631	2352
% OF TOTAL	40.713	6.480	17.581	10.435	6.012	18.779	100.000		
CENTS/KWH	0.218282	0.034740	0.094261	0.059948	0.032231	0.100684	0.538146		
SUMMARY	PRUD	TRANS	DIST	CUST AID	SALES	AD & GEN	TOTAL		
% OF TOTAL	56.398	2.727	17.635	6.566	3.847	12.826	100.000		
CENTS/KWH	0.391425	0.018929	0.122396	0.045568	0.026703	0.089020	0.694039		

	PROD	TRANS	DIST	CUST AID	SALES	AD & GEN	TOTAL	KWH	CO-YR
AMOUNT	8084	82	1800	804	280	1273	11928	1083	151
\$ OF TOTAL	87,801	0,888	13,418	5,085	2,348	10,674	100,000		
CLNTS/KWH	0,760677	0,007714	0,150917	0,056820	0,026341	0,119755	1,121919		
AMOUNT	13893	87	3892	1588	521	3138	22877	3031	251
\$ OF TOTAL	60,729	0,293	16,138	6,854	2,277	13,708	100,000		
CLNTS/KWH	0,448384	0,002210	0,121808	0,051732	0,017189	0,103464	0,754747		
AMOUNT	9714	787	1494	816	394	1393	14374	1733	351
\$ OF TOTAL	67,552	3,335	10,391	4,284	2,740	9,688	100,000		
CLNTS/KWH	0,540531	0,044259	0,086209	0,034545	0,022735	0,080381	0,879660		
AMOUNT	11328	775	5500	1541	1488	4041	24271	1937	451
\$ OF TOTAL	46,665	3,193	22,883	6,349	4,483	16,649	100,000		
CLNTS/KWH	0,584719	0,040010	0,263944	0,079558	0,056164	0,208822	1,253020		
AMOUNT	1577	82	825	208	54	487	3011	540	551
\$ OF TOTAL	52,375	2,723	20,747	8,842	1,793	15,510	100,000		
CLNTS/KWH	0,292037	0,015185	0,115741	0,036148	0,010000	0,088481	0,557593		
AMOUNT	4040	194	897	447	264	905	6747	940	651
\$ OF TOTAL	50,878	2,375	13,294	6,625	3,113	13,413	100,000		
CLNTS/KWH	0,499787	0,020638	0,085426	0,047553	0,028094	0,096277	0,717744		
AMOUNT	2171	5	354	187	95	488	3279	287	751
\$ OF TOTAL	66,209	0,152	10,746	5,703	2,897	14,273	100,000		
CLNTS/KWH	0,758444	0,001742	0,123345	0,065157	0,033101	0,163086	1,142519		
AMOUNT	5744	1500	14591	4049	3383	11059	94024	11480	851
\$ OF TOTAL	81,107	1,546	13,521	6,435	3,577	11,764	100,000		
CLNTS/KWH	0,500383	0,013086	0,127049	0,052092	0,029294	0,096333	0,918844		
AMOUNT	8082	417	1834	821	400	1207	12547	1704	951
\$ OF TOTAL	83,287	3,325	13,544	6,548	3,189	9,624	100,000		
CLNTS/KWH	0,473122	0,024472	0,096009	0,048181	0,023474	0,070833	0,736033		
AMOUNT	13777	1339	4012	1278	779	2434	24017	3337	1051
\$ OF TOTAL	57,384	3,475	16,705	5,313	3,244	11,800	100,000		
CLNTS/KWH	0,413475	0,041188	0,120408	0,038295	0,023379	0,085054	0,720794		
AMOUNT	4321	788	1874	487	535	1475	8934	1719	1151
\$ OF TOTAL	44,344	2,978	20,947	5,225	5,988	18,503	100,000		
CLNTS/KWH	0,251357	0,015474	0,109017	0,027187	0,031123	0,085808	0,519943		
AMOUNT	1405	188	807	314	190	670	3573	460	1251
\$ OF TOTAL	39,323	3,282	22,384	8,788	5,318	18,752	100,000		
CLNTS/KWH	0,153377	0,021460	0,093837	0,036512	0,022093	0,077907	0,415444		
AMOUNT	4758	220	1782	532	227	1548	9414	1574	1351
\$ OF TOTAL	50,520	2,338	16,471	5,649	5,598	16,468	100,000		
CLNTS/KWH	0,253895	0,011740	0,095091	0,028388	0,028122	0,085272	0,502541		
AMOUNT	5114	244	2134	840	456	1326	10155	940	1451
\$ OF TOTAL	70,359	2,403	21,597	8,173	4,440	14,058	100,000		
CLNTS/KWH	0,344043	0,025957	0,232340	0,088290	0,048511	0,141044	1,080319		
AMOUNT	7774	400	2487	750	319	831	12540	1076	1551
\$ OF TOTAL	61,895	3,185	19,801	5,471	2,340	6,616	100,000		
CLNTS/KWH	0,722491	0,037175	0,231114	0,089703	0,029847	0,077230	1,167244		
AMOUNT	7358	386	1844	786	216	1673	12234	1460	1651
\$ OF TOTAL	59,461	3,154	15,019	6,443	1,785	13,471	100,000		
CLNTS/KWH	0,502603	0,024038	0,125890	0,053846	0,014795	0,114589	0,838219		
AMOUNT	19644	1552	5894	1495	1911	3627	33927	6740	1751
\$ OF TOTAL	57,907	4,575	16,789	4,407	5,033	10,491	100,000		
CLNTS/KWH	0,291484	0,023027	0,084510	0,022181	0,028153	0,053813	0,503344		
AMOUNT	23213	259	5500	2195	1329	2409	34904	4967	1851
\$ OF TOTAL	66,503	0,742	15,757	6,288	3,807	8,902	100,000		
CLNTS/KWH	0,467344	0,005214	0,110731	0,044192	0,026757	0,088500	0,702734		
AMOUNT	14899	616	4847	1930	974	2988	26054	4714	1951
\$ OF TOTAL	54,417	2,364	18,804	7,408	3,738	11,488	100,000		
CLNTS/KWH	0,311818	0,013067	0,102821	0,040942	0,020862	0,083386	0,552894		
AMOUNT	2464	43	1733	689	491	1731	7155	1286	2051
\$ OF TOTAL	30,493	0,401	24,221	9,630	6,862	24,193	100,000		
CLNTS/KWH	0,191913	0,003344	0,134759	0,053377	0,038180	0,134403	0,556374		
AMOUNT	6581	333	3855	1274	595	4040	16440	3521	2151
\$ OF TOTAL	30,933	2,021	22,197	7,731	3,610	24,515	100,000		
CLNTS/KWH	0,146907	0,009458	0,103891	0,036183	0,016899	0,114740	0,468049		
AMOUNT	464	13	116	139	30	232	907	85	2251
\$ OF TOTAL	44,740	1,304	11,835	13,942	3,009	23,270	100,000		
CLNTS/KWH	0,548835	0,015994	0,136471	0,163529	0,035294	0,272941	1,172941		
AMOUNT	4962	784	2129	1034	771	2356	12034	2166	2351
\$ OF TOTAL	41,226	6,514	17,884	8,541	6,406	19,575	100,000		
CLNTS/KWH	0,229088	0,035196	0,098292	0,087738	0,035596	0,108772	0,555679		
SUMMARY	PROD	TRANS	DIST	CUST AID	SALES	AD & GEN	TOTAL		
\$ OF TOTAL	57,421	2,597	17,029	6,350	3,843	12,760	100,000		
CLNTS/KWH	0,405248	0,018331	0,120184	0,044818	0,027120	0,090051	0,705752		

## APPENDIX C

PLANT INVESTMENT FOR TWENTY-THREE SELECTED  
COMPANIES, 1951-63

Plant investment data are available for electric utility companies in Federal Power Commission publications. This data for the 23 selected companies was recorded on punched cards. An Algol program enabled this data to be presented as a per cent of the total for each area of investment. The output is presented on the following pages for each year.

In the column titled "CO-YR," the last two digits are the year and the preceding digit(s) is the number assigned each company in Appendix A. The amounts are expressed in thousands of dollars.

	INTAN	PRUD	TRANS	JUST	GEN	TOTAL	CO-YR
AMOUNT	393	52805	13654	66631	6360	184523	163
\$ OF TOTAL	0.213	29.747	7.400	37.194	3.447	100.000	
AMOUNT	76	204617	63904	226165	16710	548872	263
\$ OF TOTAL	0.014	36.214	12.015	46.705	3.047	100.000	
AMOUNT	11	146371	92237	141782	20634	401340	363
\$ OF TOTAL	0.003	30.871	23.037	35.327	5.143	100.000	
AMOUNT	371	221375	127654	317636	22228	721269	463
\$ OF TOTAL	0.051	34.822	17.977	44.036	3.062	100.000	
AMOUNT	8	48725	26546	40135	4917	120381	563
\$ OF TOTAL	0.007	40.276	22.043	33.340	4.085	100.000	
AMOUNT	90	67034	35343	74591	12218	209251	663
\$ OF TOTAL	0.043	41.520	16.885	35.642	5.838	100.000	
AMOUNT	42	38232	846	29152	2507	70432	763
\$ OF TOTAL	0.064	24.262	0.704	41.390	3.559	100.000	
AMOUNT	145	694297	320372	698756	60955	2179525	863
\$ OF TOTAL	0.007	41.201	14.649	41.236	2.797	100.000	
AMOUNT	62	210216	27776	65686	17652	234596	963
\$ OF TOTAL	0.026	47.007	11.840	36.925	4.541	100.000	
AMOUNT	226	224398	141802	167739	25760	548925	1063
\$ OF TOTAL	0.041	36.427	26.022	30.782	4.727	100.000	
AMOUNT	52	67305	37632	135012	13826	273877	1163
\$ OF TOTAL	0.019	51.803	13.743	49.306	5.049	100.000	
AMOUNT	31	70743	31023	40887	3277	126111	1263
\$ OF TOTAL	0.022	40.276	24.800	32.901	2.599	100.000	
AMOUNT	34	61323	30758	81045	6912	180107	1363
\$ OF TOTAL	0.019	34.086	17.078	45.000	3.838	100.000	
AMOUNT	0	48964	39755	80471	9034	228729	1463
\$ OF TOTAL	0.000	43.269	17.381	35.400	3.950	100.000	
AMOUNT	54	74435	55059	119072	14786	265706	1563
\$ OF TOTAL	0.020	30.046	20.722	43.647	5.565	100.000	
AMOUNT	182	125234	44511	113043	16404	304392	1663
\$ OF TOTAL	0.061	41.144	16.286	37.139	5.391	100.000	
AMOUNT	2	324440	162791	164395	30065	686696	1763
\$ OF TOTAL	0.001	47.475	23.706	25.940	4.378	100.000	
AMOUNT	107	234124	41684	229315	44766	550944	1863
\$ OF TOTAL	0.019	42.493	7.582	41.619	8.306	100.000	
AMOUNT	273	186723	36793	173811	23350	420941	1963
\$ OF TOTAL	0.065	44.327	8.740	41.290	5.547	100.000	
AMOUNT	0	125184	28709	102009	8937	264843	2063
\$ OF TOTAL	0.000	47.269	10.840	36.517	5.374	100.000	
AMOUNT	0	235409	71231	201188	14041	521849	2163
\$ OF TOTAL	0.000	42.111	13.650	38.549	2.691	100.000	
AMOUNT	12	90133	36351	47861	6739	201096	2263
\$ OF TOTAL	0.006	29.003	18.076	48.664	3.351	100.000	
AMOUNT	112	123940	62123	130973	7356	354504	2363
\$ OF TOTAL	0.032	43.424	17.524	36.945	2.075	100.000	
SUMMARY	INTAN	PRUD	TRANS	JUST	GEN	TOTAL	
\$ OF TOTAL	0.024	40.903	16.025	39.052	3.998	100.000	

	INTAN	PRUD	TRANS	JUST	GEN	TOTAL	CO-YR
AMOUNT	393	44606	12356	63311	5643	178549	162
% OF TOTAL	0.220	25.014	6.919	36.575	3.272	100.000	
AMOUNT	76	209610	59163	240643	15338	524810	262
% OF TOTAL	0.014	39.939	11.273	45.852	2.922	100.000	
AMOUNT	11	128480	77018	129285	17619	351413	362
% OF TOTAL	0.003	39.501	21.917	36.505	5.014	100.000	
AMOUNT	371	232773	119176	297619	21153	670992	462
% OF TOTAL	0.055	34.637	17.772	44.382	3.154	100.000	
AMOUNT	8	48684	25404	37775	4462	116735	562
% OF TOTAL	0.007	41.704	21.762	32.350	4.165	100.000	
AMOUNT	40	66444	27505	69553	9475	193947	662
% OF TOTAL	0.046	44.614	14.160	36.064	5.091	100.000	
AMOUNT	45	30513	483	27653	2500	68966	762
% OF TOTAL	0.065	22.619	0.703	39.789	3.623	100.000	
AMOUNT	165	64264	301864	607487	61753	2072547	862
% OF TOTAL	0.007	40.997	14.565	41.856	2.981	100.000	
AMOUNT	65	110308	25370	82252	10407	229477	962
% OF TOTAL	0.028	45.294	11.108	36.012	4.556	100.000	
AMOUNT	226	209064	139767	129233	24824	533114	1062
% OF TOTAL	0.042	39.215	25.217	24.468	4.656	100.000	
AMOUNT	52	66224	34754	124242	13146	258568	1162
% OF TOTAL	0.020	33.375	13.447	48.071	5.088	100.000	
AMOUNT	31	20750	26204	36314	1144	118444	1262
% OF TOTAL	0.026	42.447	22.124	32.348	2.654	100.000	
AMOUNT	34	61261	29705	77015	4419	174474	1362
% OF TOTAL	0.019	32.120	17.029	44.151	3.680	100.000	
AMOUNT	0	100244	36627	76593	6628	221993	1462
% OF TOTAL	0.000	45.134	16.589	34.367	3.087	100.000	
AMOUNT	54	74472	50243	107597	17572	251174	1562
% OF TOTAL	0.022	31.726	20.007	42.941	7.404	100.000	
AMOUNT	165	124596	47662	107070	14139	295652	1662
% OF TOTAL	0.063	44.143	16.121	36.215	5.459	100.000	
AMOUNT	5	328004	147248	197949	24435	662545	1762
% OF TOTAL	0.001	49.643	22.225	29.440	4.292	100.000	
AMOUNT	107	233625	39709	222357	43814	539447	1862
% OF TOTAL	0.020	43.277	7.361	41.220	8.122	100.000	
AMOUNT	273	154124	34402	167286	22465	378547	1962
% OF TOTAL	0.072	40.714	9.088	44.192	5.934	100.000	
AMOUNT	0	124914	27225	93335	8547	254021	2062
% OF TOTAL	0.000	49.175	10.718	36.743	3.365	100.000	
AMOUNT	0	235003	71231	201168	14041	521849	2162
% OF TOTAL	0.000	43.111	13.650	38.549	2.691	100.000	
AMOUNT	12	60133	36351	97861	4739	201096	2262
% OF TOTAL	0.006	29.903	18.076	48.464	2.351	100.000	
AMOUNT	112	123940	62123	130973	7350	354504	2362
% OF TOTAL	0.032	44.424	17.524	36.945	2.075	100.000	
SUMMARY	INTAN	PRUD	TRANS	JUST	GEN	TOTAL	
% OF TOTAL	0.025	41.354	15.612	39.007	3.998	100.000	

	INTAN	PRUD	TRAINS	DIST	GEN	TOTAL	CO-YR
AMOUNT	355	44181	10712	82551	5559	173338	161
\$ OF TOTAL	0.193	24.328	6.180	39.088	3.207	100.000	
AMOUNT	75	102975	49775	223187	13974	469966	261
\$ OF TOTAL	0.016	30.932	10.591	47.488	2.973	100.000	
AMOUNT	11	128724	52850	116678	15355	325153	361
\$ OF TOTAL	0.003	39.325	20.190	35.774	4.708	100.000	
AMOUNT	371	210094	96347	271386	19183	617313	461
\$ OF TOTAL	0.060	34.028	13.607	47.199	3.107	100.000	
AMOUNT	8	48644	23376	39740	4416	112544	561
\$ OF TOTAL	0.007	43.207	20.783	31.745	4.278	100.000	
AMOUNT	90	60347	26315	65320	9109	167141	661
\$ OF TOTAL	0.048	40.134	14.059	34.897	4.868	100.000	
AMOUNT	45	30525	1628	24452	2473	67523	761
\$ OF TOTAL	0.027	27.025	2.411	36.405	1.662	100.000	
AMOUNT	145	747345	286913	856496	61081	1981943	861
\$ OF TOTAL	0.007	40.230	14.476	42.205	3.082	100.000	
AMOUNT	65	114047	23115	77552	4035	222794	961
\$ OF TOTAL	0.029	21.104	10.375	34.409	1.606	100.000	
AMOUNT	226	208936	130980	102956	23585	522443	1061
\$ OF TOTAL	0.043	40.030	26.086	24.320	4.521	100.000	
AMOUNT	52	96153	33543	113582	12006	245364	1161
\$ OF TOTAL	0.021	37.125	13.070	40.291	4.893	100.000	
AMOUNT	31	34702	22860	35692	2536	100083	1261
\$ OF TOTAL	0.031	30.730	22.841	32.862	2.536	100.000	
AMOUNT	34	91251	28208	73488	5495	168876	1361
\$ OF TOTAL	0.020	30.270	16.703	43.516	1.491	100.000	
AMOUNT	0	77412	30899	70978	8782	147971	1461
\$ OF TOTAL	0.000	41.394	16.434	37.760	4.406	100.000	
AMOUNT	54	14001	40173	99097	11674	230074	1561
\$ OF TOTAL	0.023	34.372	17.463	43.087	5.074	100.000	
AMOUNT	185	107547	64041	98731	14538	266042	1661
\$ OF TOTAL	0.070	40.825	18.354	37.111	5.840	100.000	
AMOUNT	5	328244	142111	151303	24484	648547	1761
\$ OF TOTAL	0.001	50.612	21.912	23.330	4.145	100.000	
AMOUNT	107	233234	39401	212432	40816	526495	1861
\$ OF TOTAL	0.024	44.100	7.484	40.443	7.752	100.000	
AMOUNT	273	123637	33160	154363	22712	348645	1961
\$ OF TOTAL	0.074	41.676	8.495	43.229	6.025	100.000	
AMOUNT	0	124074	24394	89380	4124	245977	2061
\$ OF TOTAL	0.000	50.441	7.917	36.337	1.305	100.000	
AMOUNT	0	235311	67362	140492	13686	506853	2161
\$ OF TOTAL	0.000	40.424	13.290	37.593	2.701	100.000	
AMOUNT	12	80231	33375	42352	6534	194509	2261
\$ OF TOTAL	0.006	30.486	14.187	47.480	3.382	100.000	
AMOUNT	112	123871	52558	123383	5913	335837	2361
\$ OF TOTAL	0.034	40.817	15.650	36.739	1.781	100.000	
SUMMARY	INTAN	PRUD	TRAINS	DIST	GEN	TOTAL	
\$ OF TOTAL	0.026	41.904	15.095	39.028	1.943	100.000	

	IVIAN	PRUD	TRANS	DIST	GEN	TOTAL	CH-YR
AMOUNT	320	86104	7132	53518	4628	133708	160
% OF TOTAL	0.234	60.939	5.334	40.027	3.461	100.000	
AMOUNT	76	101400	87080	207258	13167	449300	260
% OF TOTAL	0.017	40.457	10.476	46.120	2.930	100.000	
AMOUNT	11	113501	58995	106324	13707	292893	360
% OF TOTAL	0.004	30.871	20.147	36.303	4.680	100.000	
AMOUNT	371	100034	9708	268383	14385	564946	460
% OF TOTAL	0.066	33.283	15.843	47.504	3.254	100.000	
AMOUNT	8	37601	20041	32982	5023	96315	560
% OF TOTAL	0.008	34.107	21.431	34.244	5.215	100.000	
AMOUNT	70	85344	24108	34374	4262	177275	660
% OF TOTAL	0.039	40.171	13.533	33.895	4.661	100.000	
AMOUNT	45	29134	861	23145	2384	55194	780
% OF TOTAL	0.042	24.742	0.871	41.934	4.314	100.000	
AMOUNT	145	70044	27329	80248	8050	189921	860
% OF TOTAL	0.008	34.724	14.574	42.491	3.703	100.000	
AMOUNT	65	49712	22379	73326	7456	203388	980
% OF TOTAL	0.032	44.038	11.006	36.061	3.864	100.000	
AMOUNT	226	14644	126403	147384	22287	440543	1060
% OF TOTAL	0.046	34.453	25.444	30.044	4.543	100.000	
AMOUNT	52	37324	30168	105436	10264	205699	1160
% OF TOTAL	0.025	28.825	14.076	51.452	4.992	100.000	
AMOUNT	31	36722	21967	33242	2513	96475	1260
% OF TOTAL	0.032	40.137	22.070	34.457	2.605	100.000	
AMOUNT	34	81234	26403	84150	5395	162780	1360
% OF TOTAL	0.021	37.620	16.364	42.481	3.314	100.000	
AMOUNT	0	7644	24227	87240	4153	118110	1460
% OF TOTAL	0.000	42.074	15.458	36.984	4.484	100.000	
AMOUNT	54	70080	33473	41385	10491	213693	1560
% OF TOTAL	0.025	30.605	15.050	42.727	5.042	100.000	
AMOUNT	185	107384	44015	43609	14494	260092	1660
% OF TOTAL	0.071	41.289	16.423	33.941	5.726	100.000	
AMOUNT	5	324520	130223	140489	25534	629246	1760
% OF TOTAL	0.001	51.574	21.465	22.401	4.058	100.000	
AMOUNT	107	241870	39344	205293	19134	515940	1860
% OF TOTAL	0.021	44.040	7.865	34.789	3.585	100.000	
AMOUNT	273	153147	31847	151447	20134	356894	1960
% OF TOTAL	0.076	42.011	8.937	42.434	5.641	100.000	
AMOUNT	0	109586	21666	77872	4828	217910	2060
% OF TOTAL	0.000	50.276	9.942	35.733	4.050	100.000	
AMOUNT	0	211403	65205	174901	13117	470107	2160
% OF TOTAL	0.000	45.054	13.667	36.288	2.790	100.000	
AMOUNT	12	80174	33531	87023	6403	187143	2260
% OF TOTAL	0.006	32.134	17.917	46.501	3.421	100.000	
AMOUNT	112	154474	47864	110064	5486	324011	2360
% OF TOTAL	0.035	47.677	14.772	33.823	1.494	100.000	
SUMMARY	IVIAN	PRUD	TRANS	DIST	GEN	TOTAL	
% OF TOTAL	0.027	41.771	15.134	34.064	4.000	100.000	

	INTAN	PRUD	TRANS	DISI	GEN	TOTAL	CO-YR
AMOUNT	320	67861	3765	30894	4456	129246	159
% OF TOTAL	0.248	52.889	2.959	23.358	3.447	100.000	
AMOUNT	76	159230	44201	190317	11775	405599	259
% OF TOTAL	0.019	39.228	10.898	46.922	2.903	100.000	
AMOUNT	12	113907	55083	95457	12088	276544	359
% OF TOTAL	0.004	41.206	19.918	34.515	4.356	100.000	
AMOUNT	371	182257	80257	243413	14782	503040	459
% OF TOTAL	0.074	46.223	15.953	48.385	3.338	100.000	
AMOUNT	8	37137	19219	30430	4896	91600	559
% OF TOTAL	0.009	40.503	20.961	33.188	5.340	100.000	
AMOUNT	70	86296	21885	33728	7726	146945	659
% OF TOTAL	0.047	44.494	14.542	23.727	5.180	100.000	
AMOUNT	45	29142	480	21839	2338	53842	759
% OF TOTAL	0.084	24.125	0.891	40.561	4.339	100.000	
AMOUNT	145	71840	262518	784513	39461	1803035	859
% OF TOTAL	0.008	39.733	14.960	42.401	2.298	100.000	
AMOUNT	65	99339	22261	60780	7768	198210	959
% OF TOTAL	0.033	20.138	11.231	34.701	3.918	100.000	
AMOUNT	228	106276	121175	140418	19299	447944	1059
% OF TOTAL	0.050	37.132	27.060	31.447	4.310	100.000	
AMOUNT	52	39390	27970	98888	9443	193643	1159
% OF TOTAL	0.027	30.435	14.428	49.423	5.088	100.000	
AMOUNT	30	29315	20824	30548	2049	82804	1259
% OF TOTAL	0.036	35.493	25.144	36.890	2.523	100.000	
AMOUNT	34	61240	26107	64478	4145	159024	1359
% OF TOTAL	0.021	30.510	16.417	41.804	3.248	100.000	
AMOUNT	0	75576	22240	61414	6710	148940	1459
% OF TOTAL	0.000	44.731	14.935	39.185	3.983	100.000	
AMOUNT	54	77482	31324	82143	10440	202040	1559
% OF TOTAL	0.027	30.544	15.516	40.649	5.265	100.000	
AMOUNT	185	107914	43401	88886	14593	254179	1659
% OF TOTAL	0.073	42.054	17.075	34.655	7.741	100.000	
AMOUNT	5	281122	133844	133342	23443	551554	1759
% OF TOTAL	0.001	47.343	24.230	24.178	4.250	100.000	
AMOUNT	107	206621	38058	193554	34259	473599	1859
% OF TOTAL	0.023	43.428	8.056	40.469	7.445	100.000	
AMOUNT	273	134034	31316	144157	14231	348015	1959
% OF TOTAL	0.078	44.202	8.993	41.423	5.239	100.000	
AMOUNT	0	108922	19442	72484	4373	209251	2059
% OF TOTAL	0.000	52.088	9.291	34.640	2.001	100.000	
AMOUNT	0	178814	58015	185418	12658	415305	2159
% OF TOTAL	0.000	43.727	13.969	44.878	3.096	100.000	
AMOUNT	11	20493	30182	80975	5117	166978	2259
% OF TOTAL	0.007	30.339	18.075	48.494	3.064	100.000	
AMOUNT	112	126271	43139	107359	4986	283827	2359
% OF TOTAL	0.039	42.193	15.199	37.826	1.763	100.000	
SUMMARY	INTAN	PRUD	TRANS	DISI	GEN	TOTAL	
% OF TOTAL	0.029	41.199	15.346	39.411	4.015	100.000	

	INTAN	PRUN	TRANS	DISF	GEN	TOTAL	CO-YR
AMOUNT	172	67545	4965	47362	4284	124428	156
% OF TOTAL	0.138	54.305	3.990	38.068	3.443	100.000	
AMOUNT	75	142787	32793	173076	10428	340057	256
% OF TOTAL	0.022	36.103	8.643	51.161	3.066	100.000	
AMOUNT	12	143006	51472	82282	10316	247308	358
% OF TOTAL	0.005	41.651	20.421	33.271	4.252	100.000	
AMOUNT	371	143016	73155	218101	14754	449397	458
% OF TOTAL	0.083	31.524	16.273	48.532	3.283	100.000	
AMOUNT	8	23704	16105	27383	4750	73910	556
% OF TOTAL	0.011	32.071	24.456	36.993	6.427	100.000	
AMOUNT	70	85861	19719	44588	7314	137548	658
% OF TOTAL	0.051	47.582	14.336	32.416	5.315	100.000	
AMOUNT	45	30966	430	14191	2285	52217	756
% OF TOTAL	0.086	37.982	0.823	36.752	4.376	100.000	
AMOUNT	498	826034	247490	728286	59917	1680226	858
% OF TOTAL	0.030	37.708	14.907	43.746	3.604	100.000	
AMOUNT	65	44124	21806	63827	7474	192300	958
% OF TOTAL	0.034	31.544	11.340	33.191	3.967	100.000	
AMOUNT	228	151540	114241	132957	14917	417681	1056
% OF TOTAL	0.054	36.516	27.354	31.438	4.535	100.000	
AMOUNT	52	57423	20245	84118	9284	142527	1158
% OF TOTAL	0.028	31.679	14.379	48.425	6.084	100.000	
AMOUNT	31	24544	14326	28111	1997	76713	1258
% OF TOTAL	0.034	37.124	24.552	37.713	2.537	100.000	
AMOUNT	34	41514	23069	83554	4073	132444	1356
% OF TOTAL	0.026	31.125	17.417	47.407	3.030	100.000	
AMOUNT	0	73404	24302	36495	6450	140655	1456
% OF TOTAL	0.000	45.780	15.108	35.122	4.010	100.000	
AMOUNT	54	7627	28066	73884	9230	109741	1556
% OF TOTAL	0.028	40.903	15.273	38.931	4.484	100.000	
AMOUNT	145	42980	42164	82929	16541	232803	1656
% OF TOTAL	0.074	34.934	18.113	35.622	6.246	100.000	
AMOUNT	5	253732	128865	128876	24310	513793	1756
% OF TOTAL	0.001	45.491	24.692	25.088	4.731	100.000	
AMOUNT	107	205813	37055	181804	34321	459205	1856
% OF TOTAL	0.023	44.841	8.069	39.592	7.474	100.000	
AMOUNT	273	133485	28933	146547	17318	316744	1956
% OF TOTAL	0.086	42.704	9.134	43.108	5.467	100.000	
AMOUNT	0	42476	17789	84770	4275	147310	2056
% OF TOTAL	0.000	44.371	9.447	36.715	4.418	100.000	
AMOUNT	0	154481	44077	153393	12622	374753	2156
% OF TOTAL	0.000	42.604	13.045	40.932	3.368	100.000	
AMOUNT	12	41784	28541	75316	4991	150676	2256
% OF TOTAL	0.008	27.719	18.975	49.946	3.312	100.000	
AMOUNT	112	144017	40443	47567	4565	252212	2356
% OF TOTAL	0.044	43.220	16.245	38.677	1.610	100.000	
SUMMARY	INTAN	PRUN	TRANS	DISF	GEN	TOTAL	
% OF TOTAL	0.035	40.155	15.557	40.015	4.234	100.000	

	INTAN	PRUD	TRANS	DIST	GEN	TOTAL	CO*YR
AMOUNT	172	65442	3555	40267	3914	118750	157
% OF TOTAL	0.145	56.284	2.974	37.277	3.296	100.000	
AMOUNT	75	142718	28761	159765	9724	321043	257
% OF TOTAL	0.023	38.225	8.959	49.764	3.024	100.000	
AMOUNT	12	60442	41346	72102	9215	203147	357
% OF TOTAL	0.006	34.574	20.375	35.494	4.536	100.000	
AMOUNT	371	119314	51759	140497	13272	375214	457
% OF TOTAL	0.094	31.744	13.795	50.770	3.537	100.000	
AMOUNT	8	22735	15102	24769	4342	67077	557
% OF TOTAL	0.012	33.031	22.538	36.965	6.555	100.000	
AMOUNT	70	33372	15777	37749	4084	93097	657
% OF TOTAL	0.075	35.862	16.954	40.555	4.343	100.000	
AMOUNT	85	19319	495	16940	864	37643	757
% OF TOTAL	0.114	21.244	1.314	44.976	2.294	100.000	
AMOUNT	444	200826	217551	640497	39685	1528753	857
% OF TOTAL	0.032	36.685	14.231	45.148	3.904	100.000	
AMOUNT	66	84240	21114	39871	7288	172699	957
% OF TOTAL	0.038	48.427	12.231	34.682	4.222	100.000	
AMOUNT	226	123674	106285	125316	18492	378097	1057
% OF TOTAL	0.060	33.051	28.425	33.516	4.946	100.000	
AMOUNT	52	38015	24069	81878	4014	152986	1157
% OF TOTAL	0.034	25.843	15.744	53.533	2.240	100.000	
AMOUNT	31	29087	16775	26060	1922	73875	1257
% OF TOTAL	0.042	34.173	22.707	35.276	2.602	100.000	
AMOUNT	34	41214	20936	38864	4742	125770	1357
% OF TOTAL	0.027	32.764	16.643	46.797	3.770	100.000	
AMOUNT	0	39743	22674	51311	6086	139864	1457
% OF TOTAL	0.000	42.751	16.211	36.686	4.351	100.000	
AMOUNT	54	38005	25314	65486	7274	155114	1557
% OF TOTAL	0.035	38.757	14.314	42.217	4.693	100.000	
AMOUNT	185	40424	38618	75651	7430	212770	1657
% OF TOTAL	0.087	42.714	19.150	35.555	3.492	100.000	
AMOUNT	5	203000	115451	121870	23483	465609	1757
% OF TOTAL	0.001	43.772	24.403	26.174	5.124	100.000	
AMOUNT	107	100434	35348	169806	32446	418545	1857
% OF TOTAL	0.026	43.134	8.445	40.576	7.800	100.000	
AMOUNT	273	108004	26610	128599	15631	280157	1957
% OF TOTAL	0.097	38.874	9.205	45.902	5.601	100.000	
AMOUNT	0	63169	16247	63064	7840	170310	2057
% OF TOTAL	0.000	46.825	9.538	37.023	4.614	100.000	
AMOUNT	0	112543	36640	139873	12193	301249	2157
% OF TOTAL	0.000	37.359	12.163	46.431	4.047	100.000	
AMOUNT	11	41753	25882	69574	9852	148077	2257
% OF TOTAL	0.008	24.182	15.090	46.630	6.680	100.000	
AMOUNT	112	47515	37480	87077	4107	226291	2357
% OF TOTAL	0.049	43.043	16.563	38.880	1.815	100.000	
SUMMARY	INTAN	PRUD	TRANS	DIST	GEN	TOTAL	
% OF TOTAL	0.034	38.637	15.359	41.590	4.396	100.000	

	INTAN	PRJD	TRANS	DIS	GEN	TOTAL	CO-YR
AMOUNT	0	47054	2263	41009	3763	94991	156
% OF TOTAL	0.000	50.855	2.382	43.171	3.961	100.000	
AMOUNT	76	107094	18508	140342	9240	280070	256
% OF TOTAL	0.027	36.528	6.608	51.538	3.299	100.000	
AMOUNT	12	80210	39028	81943	7904	189097	356
% OF TOTAL	0.005	42.817	20.639	32.757	4.180	100.000	
AMOUNT	367	105446	42949	185150	12102	325913	456
% OF TOTAL	0.113	36.324	13.147	50.673	3.713	100.000	
AMOUNT	8	22742	13672	22139	2153	40705	556
% OF TOTAL	0.013	37.447	22.522	30.470	3.547	100.000	
AMOUNT	70	33370	14438	32409	3693	83340	656
% OF TOTAL	0.084	40.922	16.117	39.349	4.429	100.000	
AMOUNT	45	19307	494	15324	813	35943	756
% OF TOTAL	0.125	53.456	1.373	42.587	2.259	100.000	
AMOUNT	494	525406	201395	628995	40158	1416746	856
% OF TOTAL	0.035	37.092	14.229	44.397	4.246	100.000	
AMOUNT	65	83734	21088	26471	4754	166516	956
% OF TOTAL	0.039	50.264	12.604	32.952	4.056	100.000	
AMOUNT	226	122344	98862	114499	14193	354126	1056
% OF TOTAL	0.064	34.549	27.917	32.333	5.117	100.000	
AMOUNT	52	36807	18972	71422	4408	136061	1156
% OF TOTAL	0.038	28.522	13.944	52.787	4.710	100.000	
AMOUNT	31	17345	14889	23492	1855	57812	1256
% OF TOTAL	0.054	30.002	25.754	40.981	3.209	100.000	
AMOUNT	34	41204	19530	55038	4152	119963	1356
% OF TOTAL	0.028	34.351	15.280	45.479	3.461	100.000	
AMOUNT	0	24454	20427	44908	5170	127344	1456
% OF TOTAL	0.077	43.373	16.353	35.830	4.059	100.000	
AMOUNT	52	26929	22198	26165	7013	142357	1556
% OF TOTAL	0.037	39.990	15.293	39.454	4.928	100.000	
AMOUNT	185	71273	33086	70433	7900	182877	1656
% OF TOTAL	0.101	36.073	18.092	38.514	4.320	100.000	
AMOUNT	5	158114	104257	113908	24038	401376	1756
% OF TOTAL	0.001	39.399	25.729	28.363	6.488	100.000	
AMOUNT	107	177484	27989	145951	30379	382110	1856
% OF TOTAL	0.028	40.501	7.325	38.196	7.950	100.000	
AMOUNT	267	108874	23358	119458	14026	246003	1956
% OF TOTAL	0.100	40.938	8.781	44.908	5.273	100.000	
AMOUNT	0	74010	11443	25898	7051	148402	2056
% OF TOTAL	0.000	49.871	7.711	37.667	4.751	100.000	
AMOUNT	0	151889	31360	124914	10387	278146	2156
% OF TOTAL	0.000	40.081	11.275	44.910	3.734	100.000	
AMOUNT	12	32822	24228	83026	5220	125318	2256
% OF TOTAL	0.010	26.211	19.330	50.285	4.165	100.000	
AMOUNT	112	95412	35594	77093	3689	211910	2356
% OF TOTAL	0.053	43.072	16.773	36.361	1.741	100.000	
SUMMARY	INTAN	PRJD	TRANS	DIS	GEN	TOTAL	
% OF TOTAL	0.049	39.122	15.000	41.261	4.547	100.000	

	INTAN	PRUD	TRANS	UIST	GEN	TOTAL	CO-YR
AMOUNT	0	47779	2101	38235	3610	91811	155
% OF TOTAL	0.000	24.041	2.376	41.645	3.934	100.000	
AMOUNT	76	45596	17497	132616	8848	294633	255
% OF TOTAL	0.030	31.543	8.871	52.081	3.475	100.000	
AMOUNT	12	72440	33646	52089	6598	165247	355
% OF TOTAL	0.007	41.844	20.342	31.765	3.992	100.000	
AMOUNT	367	46753	34862	142101	11178	290241	455
% OF TOTAL	0.126	32.333	13.733	48.956	3.851	100.000	
AMOUNT	8	22703	12645	14446	2139	57191	555
% OF TOTAL	0.014	39.697	22.198	34.352	3.740	100.000	
AMOUNT	69	33347	12712	28691	3662	78441	655
% OF TOTAL	0.088	42.841	16.148	36.558	4.686	100.000	
AMOUNT	45	13756	494	13052	784	29131	755
% OF TOTAL	0.160	40.900	1.756	40.397	2.787	100.000	
AMOUNT	145	22206	17089	50498	6508	135146	855
% OF TOTAL	0.011	30.639	14.435	42.101	4.815	100.000	
AMOUNT	65	71249	19716	42714	6151	146835	955
% OF TOTAL	0.044	40.500	13.423	33.448	4.188	100.000	
AMOUNT	220	106915	35158	105148	14708	324146	1055
% OF TOTAL	0.070	32.083	29.358	32.437	2.154	100.000	
AMOUNT	52	38203	17491	53713	4621	124040	1155
% OF TOTAL	0.042	30.453	14.318	51.357	3.725	100.000	
AMOUNT	31	17337	14434	21465	1668	55335	1255
% OF TOTAL	0.056	31.131	26.085	39.514	3.314	100.000	
AMOUNT	34	41263	18440	50483	3452	114342	1355
% OF TOTAL	0.030	30.091	15.123	44.557	3.194	100.000	
AMOUNT	0	24532	19244	42498	6956	123130	1455
% OF TOTAL	0.000	44.985	12.402	35.327	6.085	100.000	
AMOUNT	51	26634	17855	44417	4172	130243	1555
% OF TOTAL	0.034	43.881	13.730	38.013	4.738	100.000	
AMOUNT	185	34747	27277	34311	7327	153847	1655
% OF TOTAL	0.120	38.435	17.710	38.552	4.763	100.000	
AMOUNT	5	15794	44212	105138	24032	377324	1755
% OF TOTAL	0.001	41.434	23.643	27.863	6.634	100.000	
AMOUNT	107	153474	20571	145264	28474	334699	1855
% OF TOTAL	0.031	45.244	6.054	34.814	8.190	100.000	
AMOUNT	267	148982	22654	112770	15134	259771	1955
% OF TOTAL	0.104	43.044	8.722	43.611	3.826	100.000	
AMOUNT	0	82511	10065	50230	7009	129815	2055
% OF TOTAL	0.000	46.182	7.732	39.688	2.398	100.000	
AMOUNT	0	48169	27824	110435	9750	246378	2155
% OF TOTAL	0.000	34.445	11.243	44.905	3.957	100.000	
AMOUNT	11	26061	21804	56868	3846	109495	2255
% OF TOTAL	0.010	24.623	19.915	51.937	3.512	100.000	
AMOUNT	112	82043	30311	89561	3604	186741	2355
% OF TOTAL	0.060	44.014	16.340	37.252	1.930	100.000	
SUMMARY	INTAN	PRUD	TRANS	UIST	GEN	TOTAL	
% OF TOTAL	0.030	34.732	14.921	40.473	4.816	100.000	

	INTAN	PRUD	THANS	DIST	GEN	TOTAL	CO-YR
AMOUNT	0	47506	1974	35055	3516	88051	154
% OF TOTAL	0.000	53.953	2.242	39.812	3.993	100.000	
AMOUNT	76	55560	18892	121935	4502	242765	254
% OF TOTAL	0.031	62.361	6.876	50.226	4.502	100.000	
AMOUNT	12	63601	30142	45074	5823	144512	354
% OF TOTAL	0.008	71.922	20.855	31.186	4.029	100.000	
AMOUNT	369	63920	34946	123770	10043	253047	454
% OF TOTAL	0.145	71.104	13.810	48.912	9.969	100.000	
AMOUNT	8	22400	11704	17653	2077	53903	554
% OF TOTAL	0.015	25.657	21.715	32.750	3.453	100.000	
AMOUNT	70	25833	10700	25165	2089	63847	654
% OF TOTAL	0.110	29.454	16.756	39.408	3.271	100.000	
AMOUNT	45	8946	472	11838	766	22067	754
% OF TOTAL	0.204	10.140	0.519	53.646	3.471	100.000	
AMOUNT	145	442434	150241	514477	62408	1199905	854
% OF TOTAL	0.012	50.872	15.021	42.876	5.218	100.000	
AMOUNT	65	70545	19238	44792	4177	138817	954
% OF TOTAL	0.047	80.519	13.857	32.267	3.009	100.000	
AMOUNT	226	106717	88369	97042	14095	308449	1054
% OF TOTAL	0.073	121.596	28.649	31.461	5.218	100.000	
AMOUNT	52	25909	15715	56458	3710	101844	1154
% OF TOTAL	0.051	29.840	15.430	55.436	3.643	100.000	
AMOUNT	31	17301	14015	20307	1629	53253	1254
% OF TOTAL	0.058	19.870	26.303	38.112	3.057	100.000	
AMOUNT	34	41224	18851	46413	3134	107661	1354
% OF TOTAL	0.032	46.295	15.652	43.110	2.911	100.000	
AMOUNT	0	52337	14955	37511	4650	109453	1454
% OF TOTAL	0.000	59.817	13.663	34.271	4.248	100.000	
AMOUNT	51	42265	17050	42767	4992	107255	1554
% OF TOTAL	0.048	48.217	15.901	39.885	4.749	100.000	
AMOUNT	185	59443	24776	48480	17709	150593	1654
% OF TOTAL	0.123	67.873	16.452	32.193	11.760	100.000	
AMOUNT	5	150524	76756	93046	23938	344269	1754
% OF TOTAL	0.001	171.723	22.295	27.027	6.953	100.000	
AMOUNT	107	135909	18783	123922	28762	307563	1854
% OF TOTAL	0.035	154.109	6.107	40.292	9.352	100.000	
AMOUNT	267	108709	22029	106334	14350	251689	1954
% OF TOTAL	0.106	124.192	8.752	42.248	5.701	100.000	
AMOUNT	0	52605	8861	45499	4627	113593	2054
% OF TOTAL	0.000	59.311	7.801	40.054	5.834	100.000	
AMOUNT	0	54414	23747	46967	9173	218355	2154
% OF TOTAL	0.000	62.382	11.102	43.237	4.279	100.000	
AMOUNT	11	26947	19806	50528	3642	100934	2254
% OF TOTAL	0.011	30.699	19.623	50.060	3.608	100.000	
AMOUNT	112	42327	26192	83305	3518	175454	2354
% OF TOTAL	0.064	48.942	14.928	38.081	2.005	100.000	
SUMMARY	INTAN	PRUD	THANS	DIST	GEN	TOTAL	
% OF TOTAL	0.040	46.699	14.916	40.151	5.193	100.000	

	INTAN	PRUD	TRANS	DISI	GEN	TOTAL	COYR
AMOUNT	0	47259	3466	31638	3460	83861	153
% OF TOTAL	0.000	50.307	1.770	37.736	4.127	100.000	
AMOUNT	76	76549	13736	112895	8294	213566	253
% OF TOTAL	0.036	30.783	6.432	52.567	3.882	100.000	
AMOUNT	12	22445	26689	37615	5070	122381	353
% OF TOTAL	0.010	43.303	21.808	30.736	4.143	100.000	
AMOUNT	336	75764	22225	108634	9100	219041	453
% OF TOTAL	0.154	34.506	11.515	49.591	4.154	100.000	
AMOUNT	6	22241	11006	15681	1768	50724	553
% OF TOTAL	0.016	43.447	21.648	30.914	3.525	100.000	
AMOUNT	70	25769	4463	22354	1472	59525	653
% OF TOTAL	0.118	43.271	15.542	37.554	3.145	100.000	
AMOUNT	45	2024	448	10532	748	20849	753
% OF TOTAL	0.216	43.242	2.347	50.516	3.588	100.000	
AMOUNT	145	437433	148968	480637	49465	1116668	853
% OF TOTAL	0.013	34.173	13.347	43.042	4.430	100.000	
AMOUNT	65	70126	17066	40536	4132	134047	953
% OF TOTAL	0.048	52.314	14.238	30.310	3.193	100.000	
AMOUNT	226	83949	75366	84400	13772	262913	1053
% OF TOTAL	0.086	31.430	29.666	34.080	5.236	100.000	
AMOUNT	52	25825	14474	44989	3101	93875	1153
% OF TOTAL	0.056	27.601	15.425	53.519	3.320	100.000	
AMOUNT	30	17253	12211	18725	1567	49746	1253
% OF TOTAL	0.060	34.625	24.537	37.626	3.149	100.000	
AMOUNT	35	40514	12652	41921	7714	100740	1353
% OF TOTAL	0.035	40.220	15.736	41.315	2.694	100.000	
AMOUNT	0	40504	12810	33475	3192	90393	1453
% OF TOTAL	0.000	44.416	14.173	37.474	3.532	100.000	
AMOUNT	51	34233	12769	37187	7346	91744	1553
% OF TOTAL	0.050	37.514	13.412	40.515	8.003	100.000	
AMOUNT	185	30141	20716	42414	6610	120591	1653
% OF TOTAL	0.153	41.621	17.237	35.508	5.481	100.000	
AMOUNT	5	133344	57048	86437	14463	302191	1753
% OF TOTAL	0.002	44.133	22.237	28.740	4.914	100.000	
AMOUNT	107	135004	16365	114705	24098	294294	1853
% OF TOTAL	0.036	43.477	5.561	38.976	4.548	100.000	
AMOUNT	267	89471	20116	44096	12942	221892	1953
% OF TOTAL	0.120	40.322	9.066	44.660	5.833	100.000	
AMOUNT	0	43433	7756	39199	4806	96594	2053
% OF TOTAL	0.000	42.379	9.029	40.581	6.011	100.000	
AMOUNT	0	66504	24881	87157	4472	183615	2153
% OF TOTAL	0.000	36.260	11.385	47.519	4.537	100.000	
AMOUNT	12	21254	18742	44348	3486	88516	2253
% OF TOTAL	0.014	24.644	21.230	50.124	3.938	100.000	
AMOUNT	112	61271	21467	36421	3100	142791	2353
% OF TOTAL	0.078	42.630	15.048	34.793	2.171	100.000	
SUMMARY	INTAN	PRUD	TRANS	DISI	GEN	TOTAL	
% OF TOTAL	0.044	34.981	14.232	40.930	4.793	100.000	

	INTAN	PRUD	TRADS	DIST	GEN	TOTAL	CO-TR
AMOUNT	0	39258	1430	29363	3277	73530	152
% OF TOTAL	0.000	53.390	1.945	40.208	4.457	100.000	
AMOUNT	76	78993	11400	103011	8166	203692	252
% OF TOTAL	0.037	30.766	5.620	51.556	4.019	100.000	
AMOUNT	12	39803	19320	32196	4396	95747	352
% OF TOTAL	0.013	41.616	20.170	33.612	4.589	100.000	
AMOUNT	323	58024	21095	93480	7437	190362	452
% OF TOTAL	0.170	32.734	11.083	49.106	3.907	100.000	
AMOUNT	8	8026	8592	13320	1369	31349	352
% OF TOTAL	0.026	27.698	21.028	40.882	4.367	100.000	
AMOUNT	70	19129	7939	19920	1692	48770	652
% OF TOTAL	0.144	39.223	16.319	40.845	3.469	100.000	
AMOUNT	43	8984	498	9133	628	19246	752
% OF TOTAL	0.233	40.574	2.582	47.351	3.256	100.000	
AMOUNT	145	293496	62007	273222	41122	670342	852
% OF TOTAL	0.022	43.435	9.250	40.759	6.134	100.000	
AMOUNT	65	22597	15877	37306	1745	102267	952
% OF TOTAL	0.059	40.132	14.531	33.870	3.428	100.000	
AMOUNT	220	51386	31192	80597	13435	208036	1052
% OF TOTAL	0.109	24.679	24.730	38.967	6.495	100.000	
AMOUNT	52	17170	12574	42898	2837	75531	1152
% OF TOTAL	0.069	22.732	16.647	56.795	3.756	100.000	
AMOUNT	31	12391	10490	16904	1484	41270	1252
% OF TOTAL	0.075	27.952	25.418	40.960	3.596	100.000	
AMOUNT	36	11114	12554	38017	2201	73934	1352
% OF TOTAL	0.049	20.558	16.994	51.420	2.980	100.000	
AMOUNT	0	31110	12191	31219	2920	77439	1452
% OF TOTAL	0.000	40.174	15.783	40.314	3.771	100.000	
AMOUNT	51	23070	12106	33403	4533	73163	1552
% OF TOTAL	0.070	31.432	16.547	45.855	6.196	100.000	
AMOUNT	185	49503	18130	34951	6262	114031	1452
% OF TOTAL	0.162	43.412	15.899	30.935	5.491	100.000	
AMOUNT	3	105074	45177	80546	14194	255992	1752
% OF TOTAL	0.002	41.044	21.945	31.464	5.543	100.000	
AMOUNT	107	98690	13441	106551	27137	249926	1852
% OF TOTAL	0.044	40.130	5.465	43.326	11.035	100.000	
AMOUNT	267	88631	19244	91297	11709	211148	1952
% OF TOTAL	0.126	41.976	7.114	43.238	5.545	100.000	
AMOUNT	0	33834	8024	34824	5397	80079	2052
% OF TOTAL	0.000	42.221	7.523	43.487	6.740	100.000	
AMOUNT	0	20982	19567	78291	4374	157234	2152
% OF TOTAL	0.000	32.424	12.457	49.793	5.326	100.000	
AMOUNT	12	22200	18789	37467	3138	79606	2252
% OF TOTAL	0.015	27.487	21.090	47.066	3.942	100.000	
AMOUNT	112	60057	15671	49258	2703	128701	2352
% OF TOTAL	0.087	47.363	12.176	38.273	2.100	100.000	
SUMMARY	INTAN	PRUD	TRADS	DIST	GEN	TOTAL	
% OF TOTAL	0.056	39.371	12.944	42.169	5.460	100.000	

	INTAN	PRUJ	TMANS	DIST	GEN	TOTAL	CO=FR
AMOUNT	0	39214	1430	27187	3701	71012	151
\$ OF TOTAL	0.000	22.213	2.013	38.268	4.506	100.000	
AMOUNT	76	88187	9845	97073	7492	182813	251
\$ OF TOTAL	0.042	37.273	5.385	53.203	4.098	100.000	
AMOUNT	12	32774	16701	25126	4785	81703	351
\$ OF TOTAL	0.015	40.120	20.441	34.025	3.000	100.000	
AMOUNT	254	63491	19145	89083	4754	169412	451
\$ OF TOTAL	0.153	30.810	11.325	49.022	3.490	100.000	
AMOUNT	8	4321	4744	13617	1226	23916	551
\$ OF TOTAL	0.033	10.067	12.036	36.037	2.126	100.000	
AMOUNT	465	18920	7714	14076	1514	46697	651
\$ OF TOTAL	0.998	40.525	14.224	19.709	3.242	100.000	
AMOUNT	45	8980	345	4388	540	18429	751
\$ OF TOTAL	0.248	48.724	2.702	43.396	2.930	100.000	
AMOUNT	145	290870	56746	257328	40727	645864	851
\$ OF TOTAL	0.022	40.034	5.744	39.842	6.306	100.000	
AMOUNT	65	22865	13928	33559	3422	103949	951
\$ OF TOTAL	0.063	20.254	13.400	32.287	3.292	100.000	
AMOUNT	228	82702	44688	72236	10790	190622	1051
\$ OF TOTAL	0.119	34.843	23.833	37.845	5.460	100.000	
AMOUNT	52	17126	10753	37438	7638	88507	1151
\$ OF TOTAL	0.076	24.099	15.696	55.378	1.851	100.000	
AMOUNT	31	12324	4003	16141	1348	38845	1251
\$ OF TOTAL	0.080	31.724	73.177	41.552	3.485	100.000	
AMOUNT	38	21321	11944	33942	2825	69320	1351
\$ OF TOTAL	0.059	30.757	17.230	49.036	2.921	100.000	
AMOUNT	0	31885	11165	24059	2748	73047	1451
\$ OF TOTAL	0.000	42.544	15.263	38.407	3.761	100.000	
AMOUNT	51	22970	11521	33571	4275	69448	1551
\$ OF TOTAL	0.073	23.075	15.675	44.020	6.156	100.000	
AMOUNT	185	41180	15148	37958	4257	99728	1651
\$ OF TOTAL	0.186	41.242	15.169	38.062	2.271	100.000	
AMOUNT	5	84741	50154	75681	13435	278904	1751
\$ OF TOTAL	0.002	39.189	21.402	33.040	5.467	100.000	
AMOUNT	107	48534	13623	49587	29248	241119	1851
\$ OF TOTAL	0.044	40.874	5.650	41.302	12.130	100.000	
AMOUNT	267	81784	18389	85481	10398	198719	1951
\$ OF TOTAL	0.136	41.474	9.348	43.555	5.387	100.000	
AMOUNT	0	26588	4971	30403	4190	67354	2051
\$ OF TOTAL	0.000	39.475	7.380	45.439	7.708	100.000	
AMOUNT	0	34881	15502	89674	7183	132340	2151
\$ OF TOTAL	0.000	30.211	11.714	52.448	5.426	100.000	
AMOUNT	12	19085	15887	33168	2787	70919	2251
\$ OF TOTAL	0.017	20.911	22.373	48.769	3.930	100.000	
AMOUNT	112	48921	12182	41195	2335	102745	2351
\$ OF TOTAL	0.109	42.467	11.857	40.094	2.273	100.000	
SUMMARY	INTAN	PRUJ	TMANS	DIST	GEN	TOTAL	
\$ OF TOTAL	0.072	34.643	12.524	42.059	3.623	100.000	
	INTAN	PRUJ	TMANS	DIST	GEN	TOTAL	CO=FR
OVERALL							
SUMMARY	INTAN	PRUJ	TMANS	DIST	GEN	TOTAL	
\$ OF TOTAL	0.038	40.530	15.048	39.981	4.358	100.000	

## APPENDIX D

## DYNAMO MODEL

Dynamo is a computer program for translating mathematical models into a program which enables the model to be simulated on a digital computer. Dynamo consists of a number of algebraic relationships that relate the variable one to another. The dynamo model is the list of all of these relationships or equations. The format for each equation is specific, therefore limited. The Dynamo User's Manual (23) provides the exact punching format for the 58 equation formats which may be used.

Since this is a simulation model, it is necessary to provide a method for moving the model through time. The formulation of the model is such that each equation in the model must be solved at each point in time during the simulation. This provides a new value for each variable at each time point. The time notation used in the model structure is shown in Figure 35.

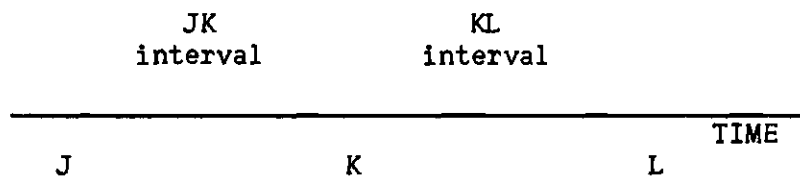


Figure 35. Time Notation.

The present time is denoted as time K, the previous point in time is time J and the next point in time will be time L. The respective intervals between these points are referred to as intervals JK and KL. The values found at time J for all variable will be used at time K to solve again all of the equations. In this model the time interval was selected as one hour. Thus for a one year simulation period, each equation is solved 8,760 times.

The model of the electric utility company developed in this study has been translated into the dynamo language. It is presented on the following pages.

ALTERNATIVE A  
125MW, 130MW, 180MW

C CP1I=125  
C AP1I=18347357  
C TP1I=1  
C CP2I=130  
C AP2I=14443492  
C TP2I=7656  
C CP3I=180  
C AP3I=19489280  
C TP3I=24444  
C BGUIP1=81  
45A BGUIP2.K=STEP(26,7656)  
C MNG=40  
58A I1A.K=TABHL(GN1,MW1A.K,40,125,5)  
58A I1B.K=TABHL(GN1,MW1B.K,40,125,5)  
58A I1C.K=TABHL(GN1,MW1C.K,40,125,5)  
C GN1\*=10.96/10.87/10.78/10.69/10.60/10.51/10.42/10.33/10.24/10.15/1  
X1 0.07/10.02/9.97/9.94/9.92/9.91/9.90/9.91  
58A I2A.K=TABHL(GN2,MW2A.K,40,130,5)  
58A I2B.K=TABHL(GN2,MW2B.K,40,130,5)  
58A I2C.K=TABHL(GN2,MW2C.K,40,130,5)  
C GN2\*=10.50/10.43/10.36/10.30/10.23/10.16/10.09/10.02/9.96/9.89/9.8  
X1 3/9.79/9.76/9.73/9.72/9.72/9.73/9.75/9.78  
58A I3A.K=TABHL(GN3,MW3A.K,55,180,5)  
58A I3B.K=TABHL(GN3,MW3B.K,55,180,5)  
58A I3C.K=TABHL(GN3,MW3C.K,55,180,5)  
C GN3\*=10.11/10.07/10.03/9.99/9.95/9.92/9.88/9.83/9.80/9.76/9.72/9.6  
X1 8/9.64/9.60/9.57/9.54/9.51/9.49/9.47/9.46/9.45/9.45/9.445/9.45/9.4  
X2 5/9.455

UNIT DOWN TIMES

FOR VALIDATION STUDY ONLY

45A O10.K=STEP(-P1,707)  
45A O1U.K=STEP(P1,830)  
45A O2D.K=STEP(-P1,892)  
45A O2U.K=STEP(P1,902)  
45A O3D.K=STEP(-P1,2027)  
45A O3U.K=STEP(P1,2081)  
45A O4D.K=STEP(-P1,3215)  
45A O4U.K=STEP(P1,3493)  
45A O5D.K=STEP(-P1,3935)  
45A O5U.K=STEP(P1,3973)  
45A O6D.K=STEP(-P1,4953)  
45A O6U.K=STEP(P1,4991)  
45A O7D.K=STEP(-P1,5111)  
45A O7U.K=STEP(P1,5384)  
45A O8D.K=STEP(-P1,5388)  
45A O8U.K=STEP(P1,5425)  
45A O9D.K=STEP(-P1,6503)  
45A O9U.K=STEP(P1,6533)  
45A O10D.K=STEP(-P1,6997)  
45A O10U.K=STEP(P1,7024)  
45A O11D.K=STEP(-P1,7796)  
45A O11U.K=STEP(P1,8118)  
45A O12D.K=STEP(-P1,8303)

45A 012U.K=STEP(P1,8315)  
45A 013D.K=STEP(-P1,8806)  
45A 013U.K=STEP(P1,8862)  
45A 014D.K=STEP(-P1,9143)  
45A 014U.K=STEP(P1,9198)  
45A 015D.K=STEP(-P1,9559)  
45A 015U.K=STEP(P1,9597)  
45A 016D.K=STEP(-P1,10006)  
45A 016U.K=STEP(P1,10038)  
45A 017D.K=STEP(-P1,10677)  
45A 017U.K=STEP(P1,10753)  
45A 018D.K=STEP(-P1,11681)  
45A 018U.K=STEP(P1,11698)  
45A 019D.K=STEP(-P1,11892)  
45A 019U.K=STEP(P1,12739)  
45A 020D.K=STEP(-P1,13323)  
45A 020U.K=STEP(P1,13591)  
45A 021D.K=STEP(-P1,16031)  
45A 021U.K=STEP(P1,16087)  
45A 022D.K=STEP(-P1,17327)  
45A 022U.K=STEP(P1,17336)  
45A 023D.K=STEP(-P1,17711)  
45A 023U.K=STEP(P1,17729)  
45A 024D.K=STEP(-P1,18743)  
45A 024U.K=STEP(P1,18774)  
45A 025D.K=STEP(-P1,19390)  
45A 025U.K=STEP(P1,19443)  
45A 026D.K=STEP(-P1,19871)  
45A 026U.K=STEP(P1,19919)  
45A 027D.K=STEP(-P1,20400)  
45A 027U.K=STEP(P1,20403)  
45A 028D.K=STEP(-P1,20699)  
45A 028U.K=STEP(P1,20748)  
45A 029D.K=STEP(-P1,21383)  
45A 029U.K=STEP(P1,21438)  
45A 030D.K=STEP(-P1,21864)  
45A 030U.K=STEP(P1,22003)  
45A 031D.K=STEP(-P1,22485)  
45A 031U.K=STEP(P1,22510)  
45A 032D.K=STEP(-P1,23063)  
45A 032U.K=STEP(P1,23144)  
45A 033D.K=STEP(-P1,24238)  
45A 033U.K=STEP(P1,24732)  
45A 034D.K=STEP(-P1,25682)  
45A 034U.K=STEP(P1,25732)  
45A 051D.K=STEP(-P2.K,7772)  
45A 051U.K=STEP(P2.K,7781)  
45A 052D.K=STEP(-P2.K,8433)  
45A 052U.K=STEP(P2.K,8494)  
45A 053D.K=STEP(-P2.K,8590)  
45A 053U.K=STEP(P2.K,8743)  
45A 054D.K=STEP(-P2.K,9566)  
45A 054U.K=STEP(P2.K,9567)  
45A 055D.K=STEP(-P2.K,9570)  
45A 055U.K=STEP(P2.K,9571)  
45A 056D.K=STEP(-P2.K,9646)  
45A 056U.K=STEP(P2.K,9701)  
45A 057D.K=STEP(-P2.K,9900)  
45A 057U.K=STEP(P2.K,9907)  
45A 058D.K=STEP(-P2.K,9912)

45A 058U.K=STEP(P2.K,9916)  
 45A 059D.K=STEP(-P2.K,9990)  
 45A 059U.K=STEP(P2.K,10003)  
 45A 060D.K=STEP(-P2.K,10319)  
 45A 060U.K=STEP(P2.K,10375)  
 45A 061D.K=STEP(-P2.K,10487)  
 45A 061U.K=STEP(P2.K,10542)  
 45A 062D.K=STEP(-P2.K,11302)  
 45A 062U.K=STEP(P2.K,11308)  
 45A 063D.K=STEP(-P2.K,11495)  
 45A 063U.K=STEP(P2.K,11551)  
 45A 064D.K=STEP(-P2.K,12191)  
 45A 064U.K=STEP(P2.K,12209)  
 45A 065D.K=STEP(-P2.K,12845)  
 45A 065U.K=STEP(P2.K,14060)  
 45A 066D.K=STEP(-P2.K,14067)  
 45A 066U.K=STEP(P2.K,14186)  
 45A 067D.K=STEP(-P2.K,15026)  
 45A 067U.K=STEP(P2.K,16031)  
 45A 068D.K=STEP(-P2.K,17207)  
 45A 068U.K=STEP(P2.K,17262)  
 45A 069D.K=STEP(-P2.K,17735)  
 45A 069U.K=STEP(P2.K,17765)  
 45A 070D.K=STEP(-P2.K,18071)  
 45A 070U.K=STEP(P2.K,18086)  
 45A 071D.K=STEP(-P2.K,18239)  
 45A 071U.K=STEP(P2.K,18260)  
 45A 072D.K=STEP(-P2.K,20207)  
 45A 072U.K=STEP(P2.K,20252)  
 45A 073D.K=STEP(-P2.K,20375)  
 45A 073U.K=STEP(P2.K,20386)  
 45A 074D.K=STEP(-P2.K,20401)  
 45A 074U.K=STEP(P2.K,20577)  
 45A 075D.K=STEP(-P2.K,21359)  
 45A 075U.K=STEP(P2.K,21366)  
 45A 076D.K=STEP(-P2.K,21556)  
 45A 076U.K=STEP(P2.K,21607)  
 45A 077D.K=STEP(-P2.K,21659)  
 45A 077U.K=STEP(P2.K,21683)  
 45A 078D.K=STEP(-P2.K,23235)  
 45A 078U.K=STEP(P2.K,23945)  
 45A 079D.K=STEP(-P2.K,25317)  
 45A 079U.K=STEP(P2.K,25983)  
 45A 080D.K=STEP(-P2.K,26149)  
 45A 080U.K=STEP(P2.K,26157)  
 7A P1D1.K=01D.K+01U.K  
 7A P1D2.K=02D.K+02U.K  
 7A P1D3.K=03D.K+03U.K  
 7A P1D4.K=04D.K+04U.K  
 7A P1D5.K=05D.K+05U.K  
 7A P1D6.K=06D.K+06U.K  
 7A P1D7.K=07D.K+07U.K  
 7A P1D8.K=08D.K+08U.K  
 7A P1D9.K=09D.K+09U.K  
 7A P1D10.K=C10D.K+010U.K  
 7A P1D11.K=C11D.K+011U.K  
 7A P1D12.K=C12D.K+012U.K  
 7A P1D13.K=C13D.K+013U.K  
 7A P1D14.K=C14D.K+014U.K  
 7A P1D15.K=C15D.K+015U.K

7A P1D16.K=C16D.K+O16U.K  
 7A P1D17.K=C17D.K+O17U.K  
 7A P1D18.K=C18D.K+O18U.K  
 7A P1D19.K=C19D.K+O19U.K  
 7A P1D20.K=C20D.K+O20U.K  
 7A P1D21.K=C21D.K+O21U.K  
 7A P1D22.K=C22D.K+O22U.K  
 7A P1D23.K=C23D.K+O23U.K  
 7A P1D24.K=C24D.K+O24U.K  
 7A P1D25.K=C25D.K+O25U.K  
 7A P1D26.K=C26D.K+O26U.K  
 7A P1D27.K=C27D.K+O27U.K  
 7A P1D28.K=C28D.K+O28U.K  
 7A P1D29.K=C29D.K+O29U.K  
 7A P1D30.K=C30D.K+O30U.K  
 7A P1D31.K=C31D.K+O31U.K  
 7A P1D32.K=C32D.K+O32U.K  
 7A P1D33.K=C33D.K+O33U.K  
 7A P1D34.K=C34D.K+O34U.K  
 11A P1DC1.K=P1D1.K+P1D2.K+P1D3.K+P1D4.K+P1D5.K+P1D6.K+P1D7.K+P1D8.K  
 10A P1DC2.K=P1D9.K+P1D10.K+P1D11.K+P1D12.K+P1D13.K+P1D14.K  
 10A P1DC3.K=P1D15.K+P1D16.K+P1D17.K+P1D18.K+P1D19.K+P1D20.K  
 10A P1DC4.K=P1D21.K+P1D22.K+P1D23.K+P1D24.K+P1D25.K+P1D26.K  
 10A P1DC5.K=P1D27.K+P1D28.K+P1D29.K+P1D30.K+P1D31.K+P1D32.K  
 7A P1DC6.K=P1D33.K+P1D34.K  
 10A P1DC.K=P1DC1.K+P1DC2.K+P1DC3.K+P1DC4.K+P1DC5.K+P1DC6.K  
 7A P2D1.K=O51D.K+O51U.K  
 7A P2D2.K=O52D.K+O52U.K  
 7A P2D3.K=O53D.K+O53U.K  
 7A P2D4.K=O54D.K+O54U.K  
 7A P2D5.K=O55D.K+O55U.K  
 7A P2D6.K=O56D.K+O56U.K  
 7A P2D7.K=O57D.K+O57U.K  
 7A P2D8.K=O58D.K+O58U.K  
 7A P2D9.K=O59D.K+O59U.K  
 7A P2D10.K=C60D.K+O60U.K  
 7A P2D11.K=C61D.K+O61U.K  
 7A P2D12.K=C62D.K+O62U.K  
 7A P2D13.K=C63D.K+O63U.K  
 7A P2D14.K=C64D.K+O64U.K  
 7A P2D15.K=C65D.K+O65U.K  
 7A P2D16.K=C66D.K+O66U.K  
 7A P2D17.K=C67D.K+O67U.K  
 7A P2D18.K=C68D.K+O68U.K  
 7A P2D19.K=C69D.K+O69U.K  
 7A P2D20.K=C70D.K+O70U.K  
 7A P2D21.K=C71D.K+O71U.K  
 7A P2D22.K=C72D.K+O72U.K  
 7A P2D23.K=C73D.K+O73U.K  
 7A P2D24.K=C74D.K+O74U.K  
 7A P2D25.K=C75D.K+O75U.K  
 7A P2D26.K=C76D.K+O76U.K  
 7A P2D27.K=C77D.K+O77U.K  
 7A P2D28.K=C78D.K+O78U.K  
 7A P2D29.K=C79D.K+O79U.K  
 7A P2D30.K=C80D.K+O80U.K  
 10A P2DC1.K=P2D1.K+P2D2.K+P2D3.K+P2D4.K+P2D5.K+P2D6.K  
 10A P2DC2.K=P2D7.K+P2D8.K+P2D9.K+P2D10.K+P2D11.K+P2D12.K  
 10A P2DC3.K=P2D13.K+P2D14.K+P2D15.K+P2D16.K+P2D17.K+P2D18.K  
 10A P2DC4.K=P2D19.K+P2D20.K+P2D21.K+P2D22.K+P2D23.K+P2D24.K

```

10A P2DC5.K=P2D25.K+P2D26.K+P2D27.K+P2D28.K+P2D29.K+P2D30.K
10A P2DC.K=P2DC1.K+P2DC2.K+P2DC3.K+P2DC4.K+P2DC5.K+0
C P1=125

58A MWMX.K=TABHL(RNDY,NMC.K,1,72,1) MONTHLY MAX MW PEAK
C RNDY*=401/403/350/342/326/327/335/333/348/351/352/406/395/374/391/
X1 365/368/370/354/374/383/400/433/452/449/425/421/408/426/412/409/40
X2 8/430/420/435/529/521/499/464/455/468/460/452/462/467/467/462/537/
X3 572/520/552/517/531/500/495/527/551/565/558/652/577/587/522/520/53
X4 7/540/544/562/567/547/597/637
58A MWMN.K=TABHL(ANDY,NMC.K,1,72,1) MONTHLY MIN MW PEAK
C ANDY*=231/229/209/213/203/197/211/201/229/209/196/222/242/240/230/
X1 242/247/231/226/227/248/238/251/248/255/270/285/275/275/278/273/29
X2 1/265/280/290/295/305/329/324/285/300/299/295/297/277/307/312/337/
X3 362/377/325/317/370/340/340/367/377/347/377/352/377/407/367/347/36
X4 7/387/392/387/402/392/402/452
1L MWDL.K=MWDL.J+(DT)(MWD.J+0) TOTAL SYSTEM MWH
6N MWDL=0
44A MWD.K=(MWDD.K)(DLPC.K)/100
7A MWDD.K=MWMN.K+I.K
52L I.K=I.J+(DT)(I1.J-I2.J-I3.J+0)
6N I=0
41A I1.K=PULSE(DDD.K,24,24)
6N I1=0
41A I2.K=PULSE(I.K,744,NHM.K)
6N I2=0
41A I3.K=PULSE(I1.K,744,NHM.K)
6N I3=0
12A DLPC.K=(DLP.K)(CFM.K)
7A CFM.K=CF.K-CFA CORRECTION FACTOR MODIFIED
C CFA=.050
7A CF.K=C1.K+C2.K
10A C1.K=CF58U.K+CF58D.K+CF59U.K+CF59D.K+CF60U.K+CF60D.K
10A C2.K=CF61U.K+CF61D.K+CF62U.K+CF62D.K+CF63U.K+0
45A CF58U.K=STEP(CF58.K,1)
45A CF58D.K=STEP(-CF58.K,8761)
45A CF59U.K=STEP(CF59.K,8761)
45A CF59D.K=STEP(-CF59.K,17521)
45A CF60U.K=STEP(CF60.K,17521)
45A CF60D.K=STEP(-CF60.K,26281)
45A CF61U.K=STEP(CF61.K,26281)
45A CF61D.K=STEP(-CF61.K,35041)
45A CF62U.K=STEP(CF62.K,35041)
45A CF62D.K=STEP(-CF62.K,43801)
45A CF63U.K=STEP(CF63.K,43801)
58A CFS8.K=TABHL(YR58,U.K,1,31,1) 1958 CORRECTION FACTOR
C YR58*=1.00/1.01/1.01/1.00/1.02/1.06/1.10/1.09/1.09/1.14/1.13/1.16/
X1 1.15/1.14/1.13/1.11/1.10/1.09/1.07/1.06/1.05/1.04/1.03/1.02/1.01/1
X2 .00/.99/.99/.99/.99/1.00
58A CF59.K=TABHL(YR59,U.K,1,31,1) 1959 CORRECTION FACTOR
C YR59*=1.00/.99/1.00/1.01/1.05/1.08/1.10/1.11/1.17/1.18/1.18/1.17/1
X1 .16/1.14/1.13/1.12/1.11/1.10/1.08/1.08/1.06/1.05/1.04/1.03/1.02/1.
X2 01/1.01/1.00/.99/1.00/1.00
58A CF60.K=TABHL(YR60,U.K,1,31,1) 1960 CORRECTION FACTOR
C YR60*=1.00/.99/1.02/1.03/1.05/1.08/1.10/1.11/1.11/1.12/1.14/1.14/1
X1 .13/1.12/1.11/1.10/1.09/1.08/1.07/1.06/1.05/1.04/1.03/1.02/1.01/1.
X2 00/1.00/1.00/1.00/1.00/1.00
58A CF61.K=TABHL(YR61,U.K,1,31,1) 1961 CORRECTION FACTOR
C YR61*=1.00/1.02/1.05/1.05/1.08/1.09/1.09/1.12/1.14/1.14/1.16/1.16/
X1 1.15/1.14/1.14/1.12/1.11/1.11/1.09/1.08/1.07/1.06/1.05/1.04/1.03/1

```

```

X2      .02/1.01/1.01/1.00/1.00/1.00
58A     CF62.K=TABHL(YR62,U.K,1,31,1)          1962 CORRECTION FACTOR
C       YR62*=1.00/1.01/1.01/1.00/1.02/1.03/1.05/1.06/1.08/1.09/1.10/1.10/
X1      1.09/1.08/1.08/1.07/1.07/1.06/1.05/1.04/1.03/1.02/1.01/1.01/1.00/
X2      99/.98/.99/.99/.99/1.00
58A     CF63.K=TABHL(YR63,U.K,1,31,1)          1963 CORRECTION FACTOR
C       YR63*=1.00/1.01/1.02/1.02/1.03/1.06/1.08/1.08/1.10/1.09/1.10/1.10/
X1      1.10/1.09/1.08/1.08/1.07/1.07/1.06/1.05/1.05/1.04/1.03/1.02/1.01/1
X2      .01/1.01/1.00/1.00/1.00/1.00
1L      U.K=U.J+(DT)(X2.J-Q.J)
41A     X2.K=PULSE(1,24,24)
6N      X2=0
41A     Q.K=PULSE(NDM.K,744,NHM.K)
6N      Q=0
6N      U=1
21A     DDD.K=(1/NDML1.K)(MWMX.K-MWMN.K)
7A      NDML1.K=NDM.K-1
        DAILY LOAD PROFILE
11A     DLP.K=LPA.K+LPB.K+LPC.K+LPD.K+LPE.K+LPF.K+LPG.K+0
11A     LPA.K=LP1U.K+LP1D.K+LP2U.K+LP2D.K+LP3U.K+LP3D.K+LP4U.K+LP4D.K
11A     LPB.K=LP5U.K+LP5D.K+LP6U.K+LP6D.K+LP7U.K+LP7D.K+LP8U.K+LP8D.K
11A     LPC.K=LP9U.K+LP9D.K+LP10U.K+LP10D.K+LP11U.K+LP11D.K+LP12U.K+LP12D.
X1      K
11A     LPD.K=LP13U.K+LP13D.K+LP14U.K+LP14D.K+LP15U.K+LP15D.K+LP16U.K+0
11A     LPE.K=LP16D.K+LP17U.K+LP17D.K+LP18U.K+LP18D.K+LP19U.K+LP19D.K+0
11A     LPF.K=LP20U.K+LP20D.K+LP21U.K+LP21D.K+LP22U.K+LP22D.K+LP23U.K+0
7A      LPG.K=LP23D.K+LP24U.K
45A     LP1U.K=STEP(LP1.K,1)
45A     LP1D.K=STEP(-LP1.K,2161)
45A     LP2U.K=STEP(LP2.K,2161)
45A     LP2D.K=STEP(-LP2.K,4345)
45A     LP3U.K=STEP(LP3.K,4345)
45A     LP3D.K=STEP(-LP3.K,6553)
45A     LP4U.K=STEP(LP4.K,6553)
45A     LP4D.K=STEP(-LP4.K,8761)
45A     LP5U.K=STEP(LP1.K,8761)
45A     LP5D.K=STEP(-LP1.K,10921)
45A     LP6U.K=STEP(LP2.K,10921)
45A     LP6D.K=STEP(-LP2.K,13105)
45A     LP7U.K=STEP(LP3.K,13105)
45A     LP7D.K=STEP(-LP3.K,15313)
45A     LP8U.K=STEP(LP4.K,15313)
45A     LP8D.K=STEP(-LP4.K,17521)
45A     LP9U.K=STEP(LP1.K,17521)
45A     LP9D.K=STEP(-LP1.K,19681)
45A     LP10U.K=STEP(LP2.K,19681)
45A     LP10D.K=STEP(-LP2.K,21865)
45A     LP11U.K=STEP(LP3.K,21865)
45A     LP11D.K=STEP(-LP3.K,24073)
45A     LP12U.K=STEP(LP4.K,24073)
45A     LP12D.K=STEP(-LP4.K,26281)
45A     LP13U.K=STEP(LP1.K,26281)
45A     LP13D.K=STEP(-LP1.K,28441)
45A     LP14U.K=STEP(LP2.K,28441)
45A     LP14D.K=STEP(-LP2.K,30625)
45A     LP15U.K=STEP(LP3.K,30625)
45A     LP15D.K=STEP(-LP3.K,32833)
45A     LP16U.K=STEP(LP4.K,32833)
45A     LP16D.K=STEP(-LP4.K,35041)
45A     LP17U.K=STEP(LP1.K,35041)

```

```

45A LP17D.K=STEP(-LP1.K,37201)
45A LP18U.K=STEP(LP2.K,37201)
45A LP18D.K=STEP(-LP2.K,39385)
45A LP19U.K=STEP(LP3.K,39385)
45A LP19D.K=STEP(-LP3.K,41593)
45A LP20U.K=STEP(LP4.K,41593)
45A LP20D.K=STEP(-LP4.K,43801)
45A LP21U.K=STEP(LP1.K,43801)
45A LP21D.K=STEP(-LP1.K,45961)
45A LP22U.K=STEP(LP2.K,45961)
45A LP22D.K=STEP(-LP2.K,48145)
45A LP23U.K=STEP(LP3.K,48145)
45A LP23D.K=STEP(-LP3.K,50353)
45A LP24U.K=STEP(LP4.K,50353)
58A LP1.K=TABHL(WIN,X.K,1,24,1)
C WIN*=61/58/56/55/55/64/77/86/92/94/93/93/89/85/82/83/87/97/99/94/9
X1 0/82/73/63
58A LP2.K=TABHL(SPG,X.K,1,24,1)
C SPG*=61/59/58/58/58/67/76/85/91/92/93/94/92/89/86/88/90/94/98/99/9
X1 5/86/74/66
58A LP3.K=TABHL(SUM,X.K,1,24,1)
C SUM*=61/59/58/57/56/60/66/78/88/93/94/96/94/93/91/95/96/96/96/99/9
X1 5/85/74/65
58A LP4.K=TABHL(FAL,X.K,1,24,1)
C FAL*=56/54/52/51/55/60/69/76/84/86/88/86/85/83/83/84/88/99/98/93/8
X1 6/79/68/59
1L X.K=X.J+(DT)*(1-X1.J)
41A X1.K=PULSE(24,24,24)
6N X=0
6N X1=0
51A MW.K=CLIP(MWG.K,0,MWG.K,MNG)
7A MWG.K=MWD.K-BGOP.K MW TO BE GEN AT GANNON
7A BGOP.K=BGOP1-BGOP2.K
54A MW1A.K=MIN(P1C.K,MW.K) LOAD PLANT 1A
18A FC1A.K=(C1BTU.K)(I1A.K-BTUA.K)
54A MW2A.K=MIN(P2C.K,MW.K) LOAD PLANT 2A
18A FC2A.K=(C2BTU.K)(I2A.K-BTUA.K)
54A MW3A.K=MIN(P3C.K,MW.K) LOAD PLANT 3A
18A FC3A.K=(C3BTU.K)(I3A.K-BTUA.K)
54A FCAA.K=MIN(FC1A.K,FC2A.K)
54A AFCA.K=MIN(FC3A.K,FCAA.K)
49A FCA.K=SWITCH(0,AFCA.K,MW.K) FUEL COST/MW-A
49A MWG1A.K=SWITCH(MW1A.K,0,FC1AD.K)
7A FC1AD.K=FCA.K-FC1A.K
12A TFC1A.K=(FC1A.K)(MWG1A.K) FUEL COST-DOLLAR/HR-1A
49A MWG2A.K=SWITCH(MW2A.K,0,FC2AD.K)
7A FC2AD.K=FCA.K-FC2A.K
12A TFC2A.K=(FC2A.K)(MWG2A.K) FUEL COST-DOLLAR/HR/2A
49A MWG3A.K=SWITCH(MW3A.K,0,FC3AD.K)
7A FC3AD.K=FCA.K-FC3A.K
12A TFC3A.K=(FC3A.K)(MWG3A.K) FUEL COST-DOLLAR/HR-3A
8A TFCA.K=TFC1A.K+TFC2A.K+TFC3A.K FUEL COST-DOLLAR/HR-A
8A MWGA.K=MWG1A.K+MWG2A.K+MWG3A.K MW GENERATED-A
7A MWAA.K=MWG.K-MWGA.K
51A MWBA.K=CLIP(MWAA.K,0,MWAA.K,MNG)
7A PICB.K=P1C.K-MWGA.K PLANT 1B CAPABILITY
54A MW1B.K=MIN(P1CB.K,MWBA.K) PLANT 1B LOAD
18A FC1B.K=(C1BTU.K)(I1B.K-BTUA.K)
7A P2CB.K=P2C.K-MWGA.K PLANT 2B CAPABILITY
54A MW2B.K=MIN(P2CB.K,MWBA.K) PLANT 2B LOAD

```

18A	FC2B.K=(C2BTU.K)(I2B.K-BTUA.K)	
7A	P3CB.K=P3C.K-MWG3A.K	PLANT 3B CAPABILITY
54A	MW3B.K=MIN(P3CB.K,MWBA.K)	PLANT 3B LOAD
18A	FC3B.K=(C3BTU.K)(I3B.K-BTUA.K)	
54A	FCBB.K=MIN(FC1B.K,FC2B.K)	
54A	AFCB.K=MIN(FC3B.K,FCBB.K)	
49A	FCB.K=SWITCH(O,AFCB.K,MWBA.K)	FUEL COST/MW-B
7A	FC1BD.K=FCB.K-FC1B.K	
49A	MWG1B.K=SWITCH(MW1B.K,O,FC1BD.K)	
12A	TFC1B.K=(FC1B.K)(MWG1B.K)	FUEL COST-DOLLAR/HR-1B
7A	FC2BD.K=FCB.K-FC2B.K	
49A	MWG2B.K=SWITCH(MW2B.K,O,FC2BD.K)	
12A	TFC2B.K=(FC2B.K)(MWG2B.K)	FUEL COST-DOLLAR/HR-2B
7A	FC3BD.K=FCB.K-FC3B.K	
49A	MWG3B.K=SWITCH(MW3B.K,O,FC3BD.K)	
12A	TFC3B.K=(FC3B.K)(MWG3B.K)	FUEL COST-DOLLAR/HR-3B
8A	TFCB.K=TFC1B.K+TFC2B.K+TFC3B.K	FUEL COST-DOLLAR/HR-C
8A	MWGB.K=MWG1B.K+MWG2B.K+MWG3B.K	MW GENERATED-B
7A	MWAB.K=MWAA.K-MWGB.K	
51A	MWDB.K=CLIP(MWAB.K,O,MWAB.K,MNG)	
7A	P1CC.K=P1CB.K-MWG1B.K	PLANT 1C CAPABILITY
54A	MW1C.K=MIN(P1CC.K,MWBB.K)	PLANT 1C LOAD
18A	FC1C.K=(C1BTU.K)(I1C.K-BTUA.K)	
7A	P2CC.K=P2CB.K-MWG2C.K	PLANT 2C CAPABILITY
54A	MW2C.K=MIN(P2CC.K,MWBB.K)	PLANT 2C LOAD
18A	FC2C.K=(C2BTU.K)(I2C.K-BTUA.K)	
7A	P3CC.K=P3CB.K-MWG3B.K	PLANT 3C CAPABILITY
54A	MW3C.K=MIN(P3CC.K,MWBB.K)	PLANT 3C LOAD
18A	FC3C.K=(C3BTU.K)(I3C.K-BTUA.K)	
54A	FCCC.K=MIN(FC1C.K,FC2C.K)	
54A	AFCC.K=MIN(FC3C.K,FCCC.K)	
49A	FCC.K=SWITCH(O,AFCC.K,MWBB.K)	FUEL COST/MW-C
7A	FC1CD.K=FCC.K-FC1C.K	
49A	MWG1C.K=SWITCH(MW1C.K,O,FC1CD.K)	
12A	TFC1C.K=(FC1C.K)(MWG1C.K)	FUEL COST-DOLLAR/HR-1C
7A	FC2CD.K=FCC.K-FC2C.K	
49A	MWG2C.K=SWITCH(MW2C.K,O,FC2CD.K)	
12A	TFC2C.K=(FC2C.K)(MWG2C.K)	FUEL COST-DOLLAR/HR-2C
7A	FC3CD.K=FCC.K-FC3C.K	
49A	MWG3C.K=SWITCH(MW3C.K,O,FC3CD.K)	
12A	TFC3C.K=(FC3C.K)(MWG3C.K)	FUEL COST-DOLLAR/HR-3C
8A	TFCC.K=TFC1C.K+TFC2C.K+TFC3C.K	FUEL COST-DOLLAR/HR-C
8A	MWGC.K=MWG1C.K+MWG2C.K+MWG3C.K	MW GENERATED-C
7A	MWAC.K=MWAB.K-MWGC.K	
8A	TFC.K=TFC1C.K+TFC2C.K+TFC3C.K	TOTAL FUEL COST/HR
8R	MWG1.KL=MWG1A.K+MWG1B.K+MWG1C.K	MW/HR-PLANT1
1L	MWH1.K=MWH1.J+(DT)(MWG1.JK+O)	MWH-PLANT1
8R	MWG2.KL=MWG2A.K+MWG2B.K+MWG2C.K	MW/HR-PLANT 2
1L	MWH2.K=MWH2.J+(DT)(MWG2.JK+O)	MWH-PLANT 2
8R	MWG3.KL=MWG3A.K+MWG3B.K+MWG3C.K	MW/HR-PLANT 3
1L	MWH3.K=MWH3.J+(DT)(MWG3.JK+O)	MWH-PLANT 3
8A	TMWH.K=MWH1.K+MWH2.K+MWH3.K	TOTAL MWH
8R	FC1.KL=TFC1A.K+TFC1B.K+TFC1C.K	FUEL COST/HR-PLANT 1
1L	TFC1.K=TFC1.J+(DT)(FC1.JK+O)	TOTAL FUEL COST-1
8R	FC2.KL=TFC2A.K+TFC2B.K+TFC2C.K	FUEL COST/HR-PLANT 2
1L	TFC2.K=TFC2.J+(DT)(FC2.JK+O)	TOTAL FUEL COST-2
8R	FC3.KL=TFC3A.K+TFC3B.K+TFC3C.K	FUEL COST/HR-PLANT 3
1L	TFC3.K=TFC3.J+(DT)(FC3.JK+O)	TOTAL FUEL COST-3
8A	FC.K=TFC1.K+TFC2.K+TFC3.K	TOTAL FUEL COST
8A	MWGT.K=MWGA.K+MWGB.K+MWGC.K	

```

6N MWH1=0
6N MWH2=0
6N MWH3=0
6N TFC1=0
6N TFC2=0
6N TFC3=0
58A C1BTU.K=TABHL(CMBTU,NMC.K,1,72,1)
C CMBTU*=.3958/.3870/.3714/.3688/.3602/.3677/.3671/.3452/.3379/.3335
X1 /.3484/.3535/.3558/.3365/.3543/.3489/.3387/.3606/.3477/.3440/.3463
X2 /.3375/.3352/.3216/.3194/.3214/.3256/.3169/.3184/.3168/.3247/.3326
X3 /.3266/.3253/.3171/.3194/.3254/.3262/.3280/.3233/.3260/.3263/.3201
X4 /.3227/.3214/.3155/.2974/.3063/.3072/.3025/.3060/.3032/.3115/.3060
X5 /.3008/.3044/.3057/.3030/.3080/.3003/.3005/.3026/.3054/.2972/.3015
X6 /.3028/.3096/.3063/.3025/.2972/.3030/.3014
6A C2BTU.K=C1BTU.K
6A C3BTU.K=C1BTU.K
1L BTUA.K=8TUA.J+(DT)(BTUA1.J+BTUA2.J)
6N BTUA=0
41A BTUA1.K=PULSE(-HRC,2160,8760)
41A BTUA2.K=PULSE(HRC,7296,8760)
C HRC=.5
6N BTUA1=0
6N BTUA2=0
7A P1C.K=CP1I+P1DC.K PLANT 1 CAPABILITY
7A P2C.K=P2.K+P2DC.K PLANT 2 CAPABILITY
45A P3C.K=STEP(CP3I,TP3I) PLANT 3 CAPABILITY
45A P2.K=STEP(CP2I,TP2I)
6N P2C=0
6N P3C=0

58A NDM.K=TABHL(JANE,NUM.K,1,12,1) NO. DAYS IN CURRENT MONTH
C JANE* =31/28/31/30/31/30/31/31/30/31/30/31
1L NUM.K=NUM.J+(DT)(NUM1.J-NUM2.J)
41A NUM1.K=PULSE(1,744,NHM.K)
12A NHM.K=(NDM.K)(24) NO. HRS IN CURRENT MONTH
6N NUM=1
6N NUM1=0
6N NUM2=0
41A NUM2.K=PULSE(12,8760,8760)
1L NMC.K=NMC.J+(DT)(NUM1.J+0) NO. MONTHS CUMULATIVE
6N NMC=1
1L NYC.K=NYC.J+(DT)(NUM3.J+0) NO. YEARS CUMULATIVE
41A NUM3.K=PULSE(1,8760,8760)
6N NYC=1
6N NUM3=0

```

## SINGLE PAYMENT PRESENT WORTH FACTOR CALCULATIONS

```

10A IRA.K=IRA1.K+IRA2.K+IRA3.K+IRA4.K+IRA5.K+0
6N IRA=0
45A IRA1.K=STEP(AIRA1,TIRA1)
45A IRA2.K=STEP(AIRC1,TIRC1)
45A IRA3.K=STEP(AIRC2,TIRC2)
45A IRA4.K=STEP(AIRC3,TIRC3)
45A IRA5.K=STEP(AIRC4,TIRC4)
C AIRA1=.027
C TIRA1=1
C AIRC1=-.006
C TIRC1=8761
C AIRC2=-.003

```

C TIRC2=17521  
 C AIRC3=.003  
 C TIRC3=35041  
 C AIRC4=-.002  
 C TIRC4=43801  
 20A IRM.K=IRA.K/12  
 12A IMNTH.K=(IRM.K)(NMC.K)  
 28A PWF.K=(1)EXP(-IMNTH.K)  
 41A MPWF.K=PULSE(PWF.K,744,NHM.K) MONTHLY PRESENT WORTH FACTOR  
 6N MPWF=0  
 41A APWF.K=PULSE(PWF.K,8760,8760) ANNUAL PRESENT WORTH FACTOR  
 6N APWF=0  
  
 PRESENT WORTH-FUEL COSTS  
  
 12A PWFC.K=(MFC.K)(MPWF.K) PRESENT WORTH FUEL COSTS/MO  
 1L MFC.K=MFC.J+(DT)(FCH.J-I6.J) MONTHLY FUEL COST LEVEL  
 6N MFC=0  
 8A FCH.K=FC1.K+FC2.K+FC3.K FUEL COST/HR  
 41A I6.K=PULSE(MFC.K,744,NHM.K)  
 6N I6=0  
 1L PWFCL.K=PWFCL.J+(DT)(PWFC.J+0) PRESENT WORTH TOTAL FUEL  
 COST LEVEL  
 6N PWFCL=0  
  
 PRESENT WORTH-PLANT INVESTMENT  
  
 1L WPIL.K=WPIL.J+(DT)(PWPI.J+0) PRESENT WORTH PLANT  
 INVESTMENT LEVEL  
 6N WPIL=0  
 12A PWPI.K=(PWF.K)(PI.K)  
 1L PIL.K=PIL.J+(DT)(PI.J+0)  
 6N PIL=0  
 8A PI.K=P1I.K+P2I.K+P3I.K  
 41A P1I.K=PULSE(AP1I,TP1I,NEVER)  
 41A P2I.K=PULSE(AP2I,TP2I,NEVER)  
 41A P3I.K=PULSE(AP3I,TP3I,NEVER)  
 6N PI=0  
 C NEVER=60000  
  
 DEPRECIATION CHARGES AND BOOK VALUE  
  
 7A BV.K=APIL.K-ADCL.K BOOK VALUE OF PLANT  
 INVESTMENT  
 41A APIL.K=PULSE(PIL.K,8760,8760) ANNUAL PLANT INVESTMENT  
 LEVEL  
 1L ADCL.K=ADCL.J+(DT)(ADC.J+0) ANNUAL DEPRECIATION CHARGES  
 LEVEL  
 41A ADC.K=PULSE(DC.K,8760,8760) ANNUAL DEPRECIATION CHARGE  
 6N ADCL=0  
 6N ADC=0  
 12A DC.K=(DDBR)(BV.K) DEPRECIATION CHARGE  
 C DDBR=.06667  
 6N APIL=0  
  
 PRESENT WORTH-INCOME TAX CREDIT DUE TO DEPRECIATION  
  
 C ITR=.5 INCOME TAX RATE  
 12A ATCD.K=(ADC.K)(ITR) ANNUAL INCOME TAX CREDIT  
 12A PTCD.K=(APWF.K)(ATCD.K) PRESENT WORTH ANNUAL

```

1L   PTCDL.K=PTCDL.J+(DT)(PTCD.J+0)      INCOME TAX CREDIT
                                           PRESENT WORTH ANNUAL
6N   PTCDL=0                               INCOME TAX CREDIT LEVEL

                                           PRESENT WORTH-INSURANCE

12A  AINS.K=(APIL.K)(INSR)                ANNUAL INSURANCE
12A  PAINS.K=(APWF.K)(AINS.K)            PRESENT WORTH ANNUAL
                                           INSURANCE
1L   PAIL.K=PAIL.J+(DT)(PAINS.J+0)       PRESENT WORTH ANNUAL
                                           INSURANCE LEVEL
6N   PAIL=0
C    INSR=.0008185                        ANNUAL INSURANCE RATE

                                           PRESENT WORTH-PROPERTY TAXES

12A  APTX.K=(APIL.K)(PTR)                ANNUAL PROPERTY TAX
C    PTR=.00481906                       ANNUAL PROPERTY TAX RATE
12A  PAPT.X.K=(APWF.K)(APTX.K)           PRESENT WORTH ANNUAL
                                           PROPERTY TAX
1L   PAPTL.K=PAPTL.J+(DT)(PAPT.X.J+0)    PRESENT WORTH ANNUAL
                                           PROPERTY TAX LEVEL
6N   PAPTL=0

                                           OTHER GENERATION COSTS

7A   GOG.K=MWD.K-MWGT.K                  OTHER GENERATION-MWF
1L   GOGML.K=GOGML.J+(DT)(GOG.J-I7.J)
6N   GOGML=0
41A  I7.K=PULSE(GOGML.K,744,NFM.K)
13A  CGOGM.K=(GOGML.K)(MPWF.K)(CGOG)
C    CGOG=5.0
1L   PGOG.K=PGOG.J+(DT)(CGOGM.J+0)       PRESENT WORTH GENERATION
                                           OTHER THAN AT GANCON
6N   PGOG=0

                                           NET PRESENT WORTH OF ALL COSTS AND CREDITS

10A  PWTC.K=FWFCL.K+PAPIL.K+PAIL.K+PAPTL.K-PTCDL.K+PGOG.K

PRINT 1)FC/2)FWFCL/3)PGOG/4)FIL/5)PWPIL/6)PTCDL/7)PAIL/8)PAPTL/9)PWTC/10
KI    )FMWF/11)MWDL
SPEC  DT=1.0/LENGTH=52566/PRTPER=8761/PLTPER=0

```

VARIABLES AND CONSTANTS TO BE CHANGED FOR EACH ALTERNATIVE  
 ALTERNATIVE A  
 125MW, 130MW, 180MW

C CP1I=125  
 C AP1I=18347357  
 C TP1I=1  
 C CP2I=130  
 C AP2I=14443492  
 C TP2I=7656  
 C CP3I=130  
 C AP3I=17489280  
 C TP3I=24444  
 C MNG=40  
 SBA I1A.K=TABHL(GN1,MW1A.K,40,125,S)  
 SBA I1B.K=TABHL(GN1,MW1B.K,40,125,S)  
 SBA I1C.K=TABHL(GN1,MW1C.K,40,125,S)  
 C GN1\*=10.96/10.87/10.78/10.69/10.60/10.51/10.42/10.33/10.24/10.15/1  
 X1 0.07/10.02/9.97/9.94/9.92/9.91/9.90/9.91  
 SBA I2A.K=TABHL(GN2,MW2A.K,40,130,S)  
 SBA I2B.K=TABHL(GN2,MW2B.K,40,130,S)  
 SBA I2C.K=TABHL(GN2,MW2C.K,40,130,S)  
 C GN2\*=10.50/10.43/10.36/10.30/10.23/10.16/10.09/10.02/9.96/9.89/9.8  
 X1 3/9.79/9.76/9.73/9.72/9.72/9.73/9.75/9.78  
 SBA I3A.K=TABHL(GN3,MW3A.K,55,180,S)  
 SBA I3B.K=TABHL(GN3,MW3B.K,55,180,S)  
 SBA I3C.K=TABHL(GN3,MW3C.K,55,180,S)  
 C GN3\*=10.11/10.07/10.03/9.99/9.95/9.92/9.88/9.83/9.80/9.76/9.72/9.6  
 X1 8/9.64/9.60/9.57/9.54/9.51/9.49/9.47/9.46/9.45/9.45/9.45/9.45/9.4  
 X2 5/9.455  
 C HGCP1=0  
 C RGOP2=0  
 C P1DC=0  
 C P2DC=0

VARIABLES AND CONSTANTS TO BE CHANGED FOR EACH ALTERNATIVE  
 ALTERNATIVE B  
 350MW

C MNG=105  
 C CP11=350  
 C AP11=44346365  
 C TP11=1  
 C CP21=0  
 C AP21=0  
 C TP21=60000  
 C CP31=0  
 C AP31=0  
 C TP31=60000  
 DBA I1A.K=TABHL(GN1,MW1A.K,105,355,10)  
 DBA I1B.K=TABHL(GN1,MW1B.K,105,355,10)  
 DBA I1C.K=TABHL(GN1,MW1C.K,105,355,10)  
 C GN1\*=10.00/9.86/9.725/9.6/9.485/9.4/9.35/9.312/9.275/9.24/9.212/9.  
 X1 185/9.16/9.14/9.126/9.115/9.11/9.103/9.1/9.1/9.11/9.125/9.145/9.16  
 X2 8/9.19/9.225  
 C I2A=12.0  
 C I2B=12.0  
 C I2C=12.0  
 C I3A=12.0  
 C I3B=12.0  
 C I3C=12.0  
 C HGCF1=0  
 C HGCF2=0  
 C P1DC=0  
 C P2DC=0

ALTERNATIVE C  
150MW, 200MW

C MNG=45  
 C CP1I=150  
 C AP1I=21236365  
 C TP1I=1  
 C CP2I=200  
 C AP2I=23110000  
 C TP2I=25536  
 C CP3I=0  
 C AP3I=0  
 C TP3I=60000  
 S8A I1A.K=TABHL(CN1,MW1A.K,45,150,5)  
 S8A I1B.K=TABHL(CN1,MW1B.K,45,150,5)  
 S8A I1C.K=TABHL(CN1,MW1C.K,45,150,5)  
 C GN1#=10.23/10.19/10.15/10.10/10.06/10.03/9.98/9.93/9.88/9.84/9.80/  
 X1 9.76/9.72/9.68/9.65/9.62/9.61/9.61/9.61/9.62/9.63/9.65  
 S8A I2A.K=TABHL(CN2,MW2A.K,60,200,5)  
 S8A I2B.K=TABHL(CN2,MW2B.K,60,200,5)  
 S8A I2C.K=TABHL(CN2,MW2C.K,60,200,5)  
 C GN2#=10.10/10.06/10.03/9.98/9.93/9.88/9.84/9.80/9.76/9.72/9.68/9.6  
 X1 3/9.59/9.56/9.53/9.51/9.48/9.46/9.44/9.425/9.418/9.41/9.403/9.403/  
 X2 9.41/9.415/9.42/9.428/9.435  
 C I3A=12.0  
 C I3B=12.0  
 C I3C=12.0  
 C BSCP1=0  
 C BSCP2=0  
 C P1DC=0  
 C P2DC=0

ALTERNATIVE D  
150MW, 130MW, 75MW

C MNG=20  
 C CP11=150  
 C AP11=21236365  
 C TP11=1  
 C CP21=130  
 C AP21=14443492  
 C TP21=25536  
 C CP31=70  
 C AP31=8038500  
 C TP31=43056  
 SBA I1A.K=TABHL(GN1,MW1A.K,45,150,5)  
 SBA I1B.K=TABHL(GN1,MW1B.K,45,150,5)  
 SBA I1C.K=TABHL(GN1,MW1C.K,45,150,5)  
 C GN1\*=10.23/10.19/10.15/10.10/10.06/10.03/9.98/9.93/9.88/9.84/9.80/  
 X1 9.76/9.72/9.68/9.65/9.62/9.61/9.61/9.61/9.62/9.63/9.65  
 SBA I2A.K=TABHL(GN2,MW2A.K,40,130,5)  
 SBA I2B.K=TABHL(GN2,MW2B.K,40,130,5)  
 SBA I2C.K=TABHL(GN2,MW2C.K,40,130,5)  
 C GN2\*=10.50/10.43/10.36/10.30/10.23/10.16/10.09/10.02/9.96/9.89/9.8  
 X1 3/9.79/9.76/9.73/9.72/9.72/9.73/9.75/9.78  
 SBA I3A.K=TABHL(GN3,MW3A.K,20,70,5)  
 SBA I3B.K=TABHL(GN3,MW3B.K,20,70,5)  
 SBA I3C.K=TABHL(GN3,MW3C.K,20,70,5)  
 C GN3\*=12.30/11.35/10.80/10.50/10.27/10.12/10.05/10.05/10.15/10.33/1  
 X1 0.60  
 C B5CP1=0  
 C B5CP2=0  
 C P1DC=0  
 C P2DC=0

## BIBLIOGRAPHY

1. Barzel, Yoram, "Productivity in the Electric Power Industry, 1929-1955," The Review of Economics and Statistics, 45, November, 1963, p. 395.
2. Blake, K. and G. Gordon, "Systems Simulation with Digital Computers," IBM Systems Journal, Vol. 3, No. 1, 1964, p. 14.
3. Brown, Alvin, "Judging the Effectiveness of Organization," Advanced Management, Vol. 20, No. 1, January, 1955, p. 13.
4. Cook, Donald C., "Special Problems of Electric Regulation," Public Utilities Fortnightly, Vol. 74, No. 10, November 5, 1964, p. 35.
5. Clark, Charles L., "A General Multiple Regression and Correlation Analysis Program for the Burroughs 5500 Computer," Operations Research Series ORS-025/R, Detroit, October 15, 1962 (Revised December 20, 1964).
6. Dean, Joel, Capital Budgeting, New York, Columbia University Press, 1951.
7. Dickie, H. F., and E. C. Thronsdon, "Manufacturing Systems Simulation," Factory, 118, October, 1960, p. 114.
8. Drucker, Peter F., The Practice of Management, New York, Harper and Brothers, 1954.
9. Drury, Horace B., Scientific Management, New York, Columbia University Press, 1915.
10. Dyson, J.; P. L. Goldsmith; and J. S. M. Robertson, "A General Simulation Programme for Material Flow in Batch Chemical Plants," Technometrics, Vol. 3, No. 4, November, 1961, p. 497.
11. Edwards, Nathan D., "Performance Analysis," Advanced Management, Vol. 23, No. 1, January, 1958, p. 24.
12. Evans, King, "How Do You Rate Management's Effectiveness?" Pulp and Paper, Vol. 39, July 12, 1965, p. 40.
13. Forrester, Jay W., Industrial Dynamics, New York, The Massachusetts Institute of Technology Press and John Wiley and Sons, Inc., 1961.

## BIBLIOGRAPHY (Continued)

14. Grant, Eugene L.; and W. Grant Ireson, Principles of Engineering Economy, New York, The Ronald Press Company, 1964.
15. Iulo, William, Electric Utilities-Costs and Performances, Pullman, Washington, Washington State University Press, 1961.
16. Justin, Joel D. and Mervine, William G. Power Supply Economics, New York, J. Wiley and Sons, Inc., 1934.
17. Kendrick, John W.; and Daniel Creamer, "Measuring Company Productivity," National Industrial Conference Board, 74, 1961.
18. Legrande, Earl, "The Development of a Factory Simulation System Using Actual Operating Data," Management Technology, Vol. 3, No. 1, May, 1963, p. 1.
19. Lindsay, Robert and Arnold W. Sametz, Financial Management, Homewood, Illinois, Richard D. Irwin, Inc., 1963.
20. Martindell, Jackson, The Appraisal of Management, New York, Harper and Brothers, 1962.
21. McGregor, Douglas, "An Uneasy Look at Performance Appraisal," Harvard Business Review, Vol. 35, No. 3, May-June, 1957, p. 89.
22. Modigliani, F. and M. H. Miller, "The Cost of Capital, Corporation Finance and the Theory of Investment," American Economic Review, June, 1958, p. 271.
23. Pugh, A. L., Dynamo Users Manual, Cambridge Massachusetts, Massachusetts Institute of Technology Press, 1963.
24. Roberts, Edward B., "Industrial Dynamics and Design of Management Control Systems," Management Technology, Vol. 3, No. 2, December, 1963, p. 100.
25. Rowe, A. J., "Computer Simulation Applied to Job Shop Scheduling," Report of Simulation Symposium, Feb., 1958.
26. Schleh, Edward C., "The Fallacy in Measuring Management," Dun's Review and Modern Industry, Vol. 82, No. 5, November, 1963, p. 49.
27. Scott, John Angus, The Measurement of Industrial Efficiency, London, Sir Isaac Pitman and Sons, 1950.

28. Shapton, W. Robert, "Functional Measurement for Management by Objective," National Association of Accountants, Vol. 41, December, 1959, p. 61.
29. Shycon, Harvey N.; and Richard B. Maffei, "Simulation -- Tool for Better Distribution," Harvard Business Review, Vol. 38, No. 6, November-December, 1960, p. 65.
30. Simon, Herbert A., Administrative Behavior, New York, The Macmillan Company, 1957.
31. Skroteki, Bernhardt G. and Vopta, William A. Applied Energy Conversion, New York, McGraw-Hill Book Company, Inc., 1945.
32. Springer, Clifford H.; Robert E. Herlihy and Robert I. Beggs, Advanced Methods and Models, Homewood, Illinois, Richard D. Irwin, Inc., 1965.
33. Vennard, Edwin, The Electric Power Business, New York, McGraw-Hill Book Company, Inc., 1962.
34. Weinwurm, Ernest H., "Measuring Executive Performance," Proceedings Sixth International Meeting, Institute of Management Sciences, Paris, September 7-11, 1959 (Published 1961).
35. Weston, J. Fred, Managerial Finance, New York, Holt, Rinehart and Winston, Inc., 1962.
36. "Comparisons are Modish," The Economist, Vol. 200, September 9, 1961, p. 1004.
37. Federal Power Commission, Steam Electric Plant Construction Costs and Annual Production Expenses, 1962/1963, US FPC, Washington.
38. How Does Your Firm Compare with Others in Your Line, Dun and Bradstreet, Inc., New York, 1962.
39. "How Does Your Firm Compare," The Economist, Vol. 191, June 6, 1959, p. 965.
40. Proceedings of the 3rd Annual Conference on Public Utility Validation and the Rate Making Process, Iowa State University, May, 1964.
41. "Setting Standards for Executive Performance," American Management Research Study 42, New York, 1960.
42. Steam-Electric Plant Factors Various Years, Washington D. C., National Coal Association, 1962-1963.

43. The Economic Almanac 1964, National Industrial Conference Board, Inc., New York, 1964.
44. Uniform System of Accounts for Class A and B Electric Utilities, National Association of Railroad and Public Utilities Commissioners, Washington, D. C., 1960.
45. "Westinghouse Announces Powercasting Program," Electrical World, Vol. 152, No. 18, November 2, 1959, p. 92.

## VITA

Lester J. Turvaville was born in Tampa, Florida, on November 21, 1930, the son of Roy G. and Katie (nee Jackson) Turvaville. He attended public schools in Tampa and Tallahassee and was graduated from Hillsborough High School in Tampa in June, 1948. While in high school the author was a member of the Key Club, National Honor Society and the H Club.

In July, 1948, he entered the University of Florida to pursue an engineering education. In January, 1951, the author resigned from the university and in February, 1951, enlisted in the U. S. Navy. He was married on December 21, 1953, to Jane Elise Merlin. After serving 40 months he was honorably discharged and returned to the University of Florida and enrolled in the industrial engineering curriculum. On October 4, 1955, a daughter, Teresa Kay, was born. After graduating with high honors the author remained for eight months in graduate school and then was employed by the Martin Company of Orlando. On May 13, 1957, a son, Randall Jackson was born. The author returned to graduate school at the University of Florida and completed requirements for the Master of Science degree in August, 1958.

He was employed by the Tampa Electric Company as an Industrial Sales Engineer in the Tampa division.

On November 24, 1962, another son, Roy Merlin, was born. The author was promoted to Administrative Assistant to the Assistant to the President. During this period of time the author was a charter member of the Florida

West Coast chapter of the American Institute of Industrial Engineers and subsequently held every office in the chapter including President.

On September, 1963, the author entered the Ph.D. program in the School of Industrial Engineering at Georgia Institute of Technology. He was a graduate teaching assistant and was the recipient of a Ford Foundation Fellowship and Loan. On November 2, 1965, another son, Andrew Thomas was born. On January 16, 1966, Andrew was deceased.

The author accepted a position as Assistant Professor in the Industrial and Systems Engineering Department at the University of Florida in September, 1966.