1974

A Statistical Study of Cost and Its Implications for the Efficient Provision and Pricing of Electricity in the United States.

Mario M. Salinas
Louisiana State University and Agricultural & Mechanical College

Follow this and additional works at: https://digitalcommons.lsu.edu/gradschool_disstheses

Recommended Citation
https://digitalcommons.lsu.edu/gradschool_disstheses/2632

This Dissertation is brought to you for free and open access by the Graduate School at LSU Digital Commons. It has been accepted for inclusion in LSU Historical Dissertations and Theses by an authorized administrator of LSU Digital Commons. For more information, please contact gradetd@lsu.edu.
INFORMATION TO USERS

This material was produced from a microfilm copy of the original document. While the most advanced technological means to photograph and reproduce this document have been used, the quality is heavily dependent upon the quality of the original submitted.

The following explanation of techniques is provided to help you understand markings or patterns which may appear on this reproduction.

1. The sign or “target” for pages apparently lacking from the document photographed is “Missing Page(s)”. If it was possible to obtain the missing page(s) or section, they are spliced into the film along with adjacent pages. This may have necessitated cutting thru an image and duplicating adjacent pages to insure you complete continuity.

2. When an image on the film is obliterated with a large round black mark, it is an indication that the photographer suspected that the copy may have moved during exposure and thus cause a blurred image. You will find a good image of the page in the adjacent frame.

3. When a map, drawing or chart, etc., was part of the material being photographed the photographer followed a definite method in “sectioning” the material. It is customary to begin photoing at the upper left hand corner of a large sheet and to continue photoing from left to right in equal sections with a small overlap. If necessary, sectioning is continued again — beginning below the first row and continuing on until complete.

4. The majority of users indicate that the textual content is of greatest value, however, a somewhat higher quality reproduction could be made from “photographs” if essential to the understanding of the dissertation. Silver prints of “photographs” may be ordered at additional charge by writing the Order Department, giving the catalog number, title, author and specific pages you wish reproduced.

5. PLEASE NOTE: Some pages may have indistinct print. Filmed as received.

Xerox University Microfilms
300 North Zeeb Road
Ann Arbor, Michigan 48108
A STATISTICAL STUDY OF COST AND ITS IMPLICATIONS FOR
THE EFFICIENT PROVISION AND PRICING OF
ELECTRICITY IN THE UNITED STATES

A DISSERTATION

Submitted to the Graduate Faculty of the
Louisiana State University and
Agricultural and Mechanical College
in partial fulfillment of the
requirements for the degree of
Doctor of Philosophy
in
The Department of Economics

by
Mario M. Salinas
B.S., Louisiana State University, 1966
May, 1974
Candidate: Mario M. Salinas

Major Field: Economics

Title of Thesis: A Statistical Study of Cost and its Implications for the Efficient Provision and Pricing of Electricity in the United States

Approved:

B. Randolph Rice
Major Professor and Chairman

James B. Grayham
Dean of the Graduate School

EXAMINING COMMITTEE:

Allan C. Beigun

James F. Payne

William F. Eggbeer

Roger L. Busfield

Date of Examination:

December 3, 1973
ACKNOWLEDGMENTS

The author became interested in the subject matter of this study while taking a graduate course in the economics of public utilities at Louisiana State University. Dr. James P. Payne, Jr., the instructor of that course and a member of the dissertation committee, provided much needed guidance and encouragement. Professor G. Randolph Rice, the committee chairman, reviewed the several drafts prepared and offered numerous constructive criticisms. The comments made by Professors Allan C. DeSerpa and William F. Campbell on the theory chapters and by Professor Roger L. Burford on the empirical analysis were particularly helpful. Thanks are also due to Dr. Sidney L. Carroll, now at the Economics Department of the University of Tennessee, who contributed many invaluable suggestions during the early stages of the work.

Financial assistance was given by the Louisiana State University Graduate School and the Institute of Public Utilities at Michigan State University through doctoral fellowships which allowed the writer to engage in one full year of necessary research. A leave of absence granted afterward by the Interamerican Development Bank of Washington, D.C., permitted him to take time off from his job so that he could again concentrate his attention on the study. Finally, the author is grateful to many friends, his parents, and a very special woman, Ms. Gayla Salinas. Without their constant moral support, this dissertation would have never been completed.
# TABLE OF CONTENTS

<table>
<thead>
<tr>
<th>Section</th>
<th>Page</th>
</tr>
</thead>
<tbody>
<tr>
<td>ACKNOWLEDGMENTS</td>
<td>iii</td>
</tr>
<tr>
<td>LIST OF TABLES</td>
<td>v</td>
</tr>
<tr>
<td>LIST OF FIGURES</td>
<td>vi</td>
</tr>
<tr>
<td>ABSTRACT</td>
<td>vii</td>
</tr>
<tr>
<td>CHAPTER</td>
<td></td>
</tr>
<tr>
<td>I. INTRODUCTION</td>
<td>1</td>
</tr>
<tr>
<td>The U.S. Electric Power Industry</td>
<td>1</td>
</tr>
<tr>
<td>Purpose of the Study</td>
<td>3</td>
</tr>
<tr>
<td>Method of Investigation</td>
<td>8</td>
</tr>
<tr>
<td>II. ECONOMIC PRINCIPLES OF ELECTRICITY COST AND PRICING</td>
<td>11</td>
</tr>
<tr>
<td>The Natural Monopoly Thesis</td>
<td>12</td>
</tr>
<tr>
<td>Price Discrimination</td>
<td>16</td>
</tr>
<tr>
<td>Price Regulation</td>
<td>26</td>
</tr>
<tr>
<td>Peak Load Pricing</td>
<td>34</td>
</tr>
<tr>
<td>III. ELECTRICITY COST: A SURVEY OF THE EMPIRICAL EVIDENCE</td>
<td>55</td>
</tr>
<tr>
<td>The Nature of Electric Utility Costs</td>
<td>55</td>
</tr>
<tr>
<td>Cost Function Studies</td>
<td>57</td>
</tr>
<tr>
<td>Production Function Studies</td>
<td>70</td>
</tr>
<tr>
<td>The Need for Further Work</td>
<td>81</td>
</tr>
<tr>
<td>IV. A SUGGESTED ELECTRICITY COST FUNCTION</td>
<td>83</td>
</tr>
<tr>
<td>Sample and Data</td>
<td>83</td>
</tr>
<tr>
<td>The Cost Model</td>
<td>85</td>
</tr>
<tr>
<td>Statistical Analysis</td>
<td>94</td>
</tr>
<tr>
<td>Regression Results</td>
<td>97</td>
</tr>
<tr>
<td>V. A PRICE AND COST COMPARISON OF ELECTRICITY</td>
<td>112</td>
</tr>
<tr>
<td>Existing vs. Cost-Reflecting Rate Schedules</td>
<td>113</td>
</tr>
<tr>
<td>Price-Marginal Cost Relationships</td>
<td>116</td>
</tr>
</tbody>
</table>
# TABLE OF CONTENTS (Continued)

<table>
<thead>
<tr>
<th>CHAPTER</th>
<th>PAGE</th>
</tr>
</thead>
<tbody>
<tr>
<td>VI. SUMMARY AND CONCLUSIONS</td>
<td>125</td>
</tr>
<tr>
<td>BIBLIOGRAPHY</td>
<td>134</td>
</tr>
<tr>
<td>APPENDIX A. ELECTRIC UTILITIES INCLUDED IN THE OVERALL SAMPLE AND IN THE VARIOUS SUBSAMPLES</td>
<td>141</td>
</tr>
<tr>
<td>APPENDIX B. PRICE TO MARGINAL COST RATIOS FOR THE CUSTOMER CLASS SUBSAMPLES</td>
<td>144</td>
</tr>
<tr>
<td>VITA</td>
<td>146</td>
</tr>
</tbody>
</table>
## LIST OF TABLES

<table>
<thead>
<tr>
<th>TABLE</th>
<th>PAGE</th>
</tr>
</thead>
<tbody>
<tr>
<td>4-1. Multiple Regression, Whole Sample, Pooled Data, 1959 to 1968</td>
<td>98</td>
</tr>
<tr>
<td>4-2. Multiple Regression, Whole Sample, Cross-Sectional Data, 1959 to 1968</td>
<td>102</td>
</tr>
<tr>
<td>4-3. Multiple Regression with Dummy Variables, Whole Sample, Pooled Data, 1959 to 1968</td>
<td>106</td>
</tr>
<tr>
<td>4-4. Multiple Regression, Geographical Subsamples, Pooled Data, 1959 to 1968</td>
<td>108</td>
</tr>
<tr>
<td>4-5. Multiple Regression, Size Subsamples, Pooled Data, 1959 to 1968</td>
<td>111</td>
</tr>
<tr>
<td>5-1. Multiple Regression, Customer Class Subsamples, Pooled Data, 1959 to 1968</td>
<td>120</td>
</tr>
<tr>
<td>FIGURE</td>
<td>DESCRIPTION</td>
</tr>
<tr>
<td>--------</td>
<td>-------------</td>
</tr>
<tr>
<td>2-1.</td>
<td>Monopoly Costs and Pricing</td>
</tr>
<tr>
<td>2-2.</td>
<td>Third Degree Discrimination and Simple Monopoly Pricing</td>
</tr>
<tr>
<td>2-3.</td>
<td>Second Degree Discrimination</td>
</tr>
<tr>
<td>2-4.</td>
<td>First Degree Discrimination</td>
</tr>
<tr>
<td>2-5.</td>
<td>Marginal and Average Cost Pricing</td>
</tr>
<tr>
<td>2-6.</td>
<td>Short Run and Long Run Total Cost Curves</td>
</tr>
<tr>
<td>2-7.</td>
<td>Pricing for Constant Demand</td>
</tr>
<tr>
<td>2-10.</td>
<td>Periodical Demands of Unequal Length</td>
</tr>
<tr>
<td>2-11.</td>
<td>Shifting Peak Case</td>
</tr>
<tr>
<td>2-12.</td>
<td>Impossible Case</td>
</tr>
<tr>
<td>2-13.</td>
<td>Two-Level Load Curve</td>
</tr>
<tr>
<td>2-14.</td>
<td>Four-Level Load Curve Before and After Peak Load Pricing</td>
</tr>
<tr>
<td>2-15.</td>
<td>Four Periodical Demands: Optimal Solution</td>
</tr>
<tr>
<td>2-16.</td>
<td>Multiplicity of Price Offers</td>
</tr>
</tbody>
</table>
ABSTRACT

This dissertation has a twofold objective: (a) estimating empirically an electricity cost function so as to note its implications regarding the efficient provision and pricing of electric service in the United States; and (b) introducing all relevant economic principles of cost and pricing in the electric power industry, a subject which it is felt has not received adequate treatment in most price theory and public utility economics books.

The structural characteristics of the industry along with the generation, transmission, and distribution aspects of electricity supply are described in Chapter I. Chapter II develops the natural monopoly thesis, followed by discussions on the theory of price discrimination (first, second, and third degree discrimination), price regulation (average cost pricing, marginal cost pricing, and regulated price discrimination), and peak load pricing. Special emphasis is placed on the goal of attaining an optimum allocation of resources from the point of view of society.

The abundance of published data for electric utilities has made this industry a fertile field of research for economists interested in the verification of cost theory. Numerous empirical investigations have examined costs in the electric power industry, reaching various conclusions relating to the shape of the respective curves. The methods and results of these previous studies are reviewed in Chapter III in order to first, illustrate the complexity of the topic and second, show
that for the purposes at hand further work was needed in this area as many of these investigations lacked from conceptual as well as empirical validity.

In Chapter IV a new average cost function for electricity supply is proposed and regression techniques are utilized in its estimation. Attention is given not only to the relationship of cost to output, size or capacity, and number of customers but also to the influence of factors such as technology and resource prices. In contrast to the majority of the previous studies, the firm, not the plant or the generator, is used as the unit of observation; further, not only the costs of generation, but also the costs of transmission and distribution, are considered.

It is demonstrated that economies of scale and economies of utilization occur—meaning, respectively, that long run and short run decreasing average costs are the norm—in the provision of electricity and that the point at which economies of scale are exhausted has not yet been reached. Economies of utilization are more important than economies of scale as a source of cost savings, implying that better employment of existing capacity results in a greater reduction in unit cost than expansion in capacity. Moreover, the application of marginal cost pricing will give rise to economic losses for the individual firms.

It is argued in Chapter V that the different block rates charged by American electric utilities to the several classes of customers, by not being variable according to the time of use (peak and off-peak), do not suitably mirror cost and consequently lead to a poor utilization of the economy's resources. Furthermore, it is shown that these different rates do not reflect properly the variations in the cost of providing electric service to residential, commercial, and industrial customers.
Thus, third degree or class discrimination is inherent in the pricing policies of U.S. utilities. Because last block rates are apparently unequal to marginal cost, it is inferred that this discrimination promotes neither the most efficient employment of existing capacities nor optimal investment decisions.

Finally, Chapter VI summarizes the results, draws additional conclusions concerning cost and pricing in the electric power industry, and indicates various complementary areas worthy of future research.
CHAPTER I

INTRODUCTION

The U. S. Electric Power Industry

Although electricity was first generated in 1831 by a dynamo developed by Michael Faraday, the electric power industry did not begin until the incandescent light bulb was perfected by Thomas A. Edison in 1879. By 1882 the first electric light and power system, the Edison Electric Illuminating Company of New York, had begun operations with an initial capital of one million dollars. Since then the industry has not only experienced phenomenal growth, but by affecting almost every part of our national economic life it has assumed first importance in the vast field of public utility enterprises.¹

Today over 3,600 systems of different legal and economic characteristics comprise the electric power industry. These systems vary greatly in size, type of ownership, and range of power supply functions performed. Four different ownership segments compose the industry: investor-owned, State and local public agencies, cooperatives, and Federal agencies. The largest segment is the investor-owned group. This group

in 1968 accounted for 76.7 percent of the total electricity generated in the United States, owned over 76 percent of the industry's generating capacity, and served 79 percent of its total customers. Although the investor-owned segment consists of over 400 firms, about 90 percent of its output is generated by the 211 companies that constitute classes A and B of electric utilities. These two classes of investor-owned electric utility systems form the most important single group in the electric power industry producing approximately 70 percent of the total electricity generated in the United States in 1968.

In supplying electricity to the final consumer three distinct functions must be fulfilled: generation, transmission, and distribution. Of the two basic methods used to generate electricity, i.e., hydroelectric and steam or thermal generation, the latter is the predominant one. Hydroelectric plants transform the energy of falling water into electricity while steam-electric plants use the energy in fossil fuels (coal, natural gas, oil) or nuclear fuels (mainly uranium). The fuel is burned under a boiler where its energy is changed to heat and pressure in the steam. This pressure in turn spins a steam turbine which is connected to an electric generator. In the generator the turbine energy is finally converted to electrical energy. Transmission is the process of transporting the electrical energy at high voltage from the generating plants.

---

2 Class A utilities are those having annual electric operating revenues of $2.5 million or more. Class B utilities are those with annual electric operating revenues of $1 million or more but less than $2.5 million.

3 Steam generation using fossil fuels accounted for 91.8 percent of the total electricity generation by classes A and B utilities in 1968. Coal alone was responsible for over 50 percent of the total.
to bulk delivery points while distribution is the final process by which electricity is delivered to the ultimate consumer at lower voltage.\textsuperscript{4}

Population growth coupled with an increasing dependence on electrical energy guarantees a continuously rising demand for electricity. The growth and efficiency of the electric power industry, which are prime economic goals today, will become an absolute necessity in the near future if the United States expects to maintain an industrial civilization with a high standard of living for all.

\textbf{Purpose of the Study}

The primary concern of this study is to empirically derive an electricity cost function so as to note its implications with regard to the efficient provision and pricing of electric service in the United States. It is generally assumed that firms in the electric power industry possess certain similar cost characteristics which, in relation to the size of the market, set them apart from the general run of American business.

First, electric utilities are frequently referred to as "natural" monopolies, meaning that the natural result of market forces in the industry is the development of a monopoly organization. The argument is based on the conviction that significant economies of scale exist in the supply of electricity. Given demand, a large firm because of lower average cost could supply the entire market at a lower price than several smaller firms having the same total capacity. Competition in

this industry would be self-destructive; eventually bankruptcy or merger would leave the field to one firm. Thus, economies of scale seem to justify the presence of only one optimum size producer in a market. This reasoning lends support to the widely held belief that appropriate public policy in the electric power industry is to allow a monopolistic supplier to operate, subjected to some degree of regulation to assure that the public obtains the benefits of whatever lower costs are achieved.

Second, production and use must be simultaneous because electricity cannot be stored. Enough capacity is required to meet the coincident demand, or peak load, of all customers even though this maximum demand on the system may come only for a few minutes or a few hours at periodic intervals of time. Except for peak demand periods electric utilities commonly have unused capacity. The maintenance of this capacity means that electric utilities must make relatively greater investments in plant and equipment than other industries, a requirement that results in a cost structure dominated by fixed costs. Decreasing average costs with fixed system size can be expected since better utilization of equipment permits the heavy fixed costs to be spread over a larger output. Just as economies of scale would lead to monopoly in the electric power industry, economies of utilization would also diminish competition. In order to increase off-peak sales, the firms would tend to cut their prices, with discrimination or severe price wars to the detriment of both companies and consumers being the likely result.

These two cost characteristics have important implications with respect to the marginal cost pricing proposal. Many economists have put forth the notion that electricity should be priced at marginal cost in order to achieve a socially efficient allocation of resources. But
if, as it is argued above, economies of scale and economies of utilization exist in electricity supply a policy of pricing at marginal cost would lead to inevitable losses.⁵ Stated differently, if the average cost function is decreasing the marginal cost function must lie below it. This means that the price determined by the intersection of the demand and marginal cost curves would be less than the corresponding average cost and therefore its use would result in an economic loss. This situation would require a subsidy if the electric utility is to continue in operation. Nevertheless, it has been pointed out that an alternative to achieve the same target of a socially efficient allocation of resources, without the need of a subsidy, would be the use of a regulated discriminatory scheme consisting of either two-part pricing, with a per unit charge equal to marginal cost, or block pricing, with a charge in the last block equaling the same cost.

A secondary objective of this study is to introduce, as compactly as possible, the relevant economic principles of cost and pricing in the electric power industry outlined above. It is felt that the subject has not received an adequate treatment in most price theory and public utility economics books. Thus, Chapter II will develop the natural monopoly thesis, followed by discussions on the theory of price discrimination, price regulation, and peak load pricing. Special emphasis will be placed on the goal of attaining an optimum allocation of resources from the point of view of society.

The abundance of published data for electric utilities has made

---

⁵This result holds whether short run or long run marginal cost pricing is used since economies of utilization and economies of scale denote respectively declining short run and long run average costs.
this industry a fertile field of research for economists interested in the verification of cost theory. Numerous statistical and analytical investigations have examined costs in the electric power industry, reaching various conclusions with respect to the shape of the different curves (short run and long run). It is the aim of Chapter III to review the methods and results of these previous studies in order to first, illustrate the complexity of the topic and second, show that for the purposes at hand further work was needed in this area as these investigations suffered in a conceptual as well as in an empirical sense. A fundamental criticism is that the majority of the studies have used the plant or the generator as the unit of observation for cost and not the economically relevant entity, the firm.\(^6\) Firms, not plants or generators, are regulated and it is at the level of the firm that investment and pricing decisions are made.

Chapters IV and V constitute the core of the present work. In Chapter IV a new cost function for electricity supply is proposed and regression techniques are utilized in its estimation. Attention is given not only to the relationship of cost to output and firm size or capacity, but also to the influence of other factors. In particular the effects on cost of number of customers, resource prices, technology, and type of fuel are investigated. The function is used to test the two theoretical cost characteristics mentioned at the beginning of this section, namely that economies of scale and economies of utilization are significant in the provision of electricity or alternatively, that

\(^6\)The electric utility firm in general is comprised of several plants, and each plant in turn is composed of one or more generating units.
in both the long run and the short run decreasing average cost curves are the norm for electricity supply. In addition, the implication of the findings with regard to the proposal of pricing electric energy at marginal cost—i.e., whether or not marginal cost pricing will result in an economic loss—is noted. Essentially then the thrust of Chapter IV is to see to what extent economic theory and practice agree.

It will be argued in Chapter V that the pricing systems currently employed by U.S. electric utilities do not adequately reflect marginal cost and hence lead to a poor utilization of the economy's resources. Customers are divided into three main groups or classes: residential, commercial, and industrial, with a different schedule of rates applicable to each class. Furthermore, each rate schedule usually offers the individual customer within each class a graduated, descending scale of rates for incremental blocks of service taken. An attempt will be made to determine if these different rates charged to the three classes of customers are properly justified by variations in cost; if they are not, it can be inferred that discrimination is inherent in the pricing policies of American utilities. This test is important because discrimination, unless it can be shown to be of the peculiar form discussed earlier—i.e., with either a per unit or a last block charge equal to marginal cost—promotes neither the most efficient use of existing capacities nor optimum investment decisions.

Finally, Chapter VI summarizes the results and draws a number of conclusions concerning cost and pricing in the electric power industry. It only remains to add that this study was motivated by two developments: a) the special emphasis given in the last few years to the marginal cost pricing principles. The ensuing excerpt from the 1966 Report
of the President's Council of Economic Advisers is typical:

For maximum economic efficiency, rates should be related to costs, but not to an arbitrary allocation of costs. . . . "Cost-oriented rates" in the true economic sense are related to the economist's concept of marginal cost. . . . In order to ensure efficiency, marginal, rather than average, cost should be the principal regulatory criterion in applications for rate reductions. . . . Where competition and new technology dictate rate reductions, competitive rates could be lowered to the level of marginal cost;

b) the renewed general public interest expressed recently on the issue of price discrimination. Notice the two following statements:

Utility rate structures vary from state to state, but typically a poor person who does not use much electricity, who does not care whether his line is underground or above ground, who lives in a congested area where cost of service is low, pays three times as much per kilowatt-hour as an industry which is creating both pollution and energy supply problems. And the poor person typically pays twice as much as the air-conditioned suburban homeowner who is demanding underground lines.

The new issues being raised at hearings--issues such as whether business and industry should pay less for electric service than residential users--have led to a demand in the regulatory commissions for economists, accountants and actuaries, and triggered a general growth of the commissions themselves.

It is hoped that the findings of this investigation will shed some light on these important topics which attract the attention not only of economists but of society as a whole.

Method of Investigation

Before proceeding to the main body of the paper a few methodological comments are in order. In general there are two distinct approaches

---

to the study of cost functions, the analytical and the statistical techniques. Even though both are valid, the choice of procedure depends on the objective in mind.

The analytical approach, used mostly by engineers, consists of an ex ante investigation of the way costs should behave. Engineering or technological considerations are used to select the appropriate variables and to determine their effects on cost. Examples of the use of this technique can be found in the planning and design of plants, machinery, and other capital goods. The analytical or engineering approach attempts more to explain the cost function—that is, why are costs incurred and how do they behave given a change in the relevant variables—than to indicate the cost.

The statistical approach, employed mostly by economists, involves an ex post investigation where historical cost data are correlated with output, capacity, resource prices, and other a priori selected variables, with the ultimate objective of deriving a function that reflects the way costs behave. The fundamental tool of this approach is multiple regression, a technique that permits not only the establishment of the relationship between cost and the several chosen factors but also the testing of whether such a relationship is statistically significant.

In spite of the conceptual differences that exist between the analytical and statistical approaches they are complementary in that both are used in the search for cost functions. One technique can be

---

10 Although economists have traditionally preferred the statistical approach, some have used the analytical technique. Cost studies of electricity using each of these approaches will be reviewed in Chapter III.
used to supplement and check upon the other. Specifically, engineering knowledge can be used as a basis for the selection of the appropriate variables for the function while numerical estimates of the parameters can be derived from economic statistics as well as from engineering data. An ideal cost estimation study should, if possible, include equally both methods— the analytical or ex ante to see how costs should behave and the statistical or ex post to see how they actually behave. However, for the most part the statistical approach is utilized in the present work. The reason for emphasizing this technique is that it is the only one valid for hypothesis testing. Even if the engineer claims that costs should behave in a certain way on the basis of technological considerations underlying the production function, only historical or ex post data can be used to test whether costs actually behaved in that fashion.
CHAPTER II

ECONOMIC PRINCIPLES OF ELECTRICITY COST AND PRICING

It has been said that "a person observing the real world of
economic phenomena is confronted with a mass of data that is, at least
superficially, meaningless. In order to discover order in this morass
of facts and to arrange them in a meaningful way, it is necessary to
develop theories ..."¹ It is precisely the objective of this chapter
to consider, as compactly as possible, the theories that have been
developed to explain cost and pricing in the electric power industry.
The subject, in the author's judgment, has not received an adequate
treatment in the majority of price theory and public utility economics
books.

The natural monopoly argument, i.e., the economic justification
for having only one supplier of electricity in a particular market, is
examined first. The principles of price discrimination and price regu-
lation follow, respectively, in the next two sections. The main thesis
of the sections is that in order to attain the goal of a socially
optimum allocation of resources, electricity should be priced at marginal
cost, even though this may lead to losses for the individual firms. The
types of discriminatory schemes that can be practically used by electric
utilities, if uncontrolled, will probably produce an output larger than

¹C. E. Ferguson, Microeconomic Theory (Homewood, Ill.: Richard
under simple monopoly but less than under average cost and thus marginal
cost pricing. However, under regulation, rate discrimination can not
only yield the socially optimum output, but even more important, it
can do so without the deficit that accompanies marginal cost pricing.
Finally, although it is not directly related to the empirical results
of this study, the peak load pricing problem is considered in the last
section. Its implications with respect to a more efficient price
policy—which must await the further discussion on cost in the two sub-
sequent chapters—are presented in Chapter V.

The method of exposition consists of initially stating and
illustrating the various principles utilizing simple cases, i.e., with
linear demand functions, ignoring costs so that maximization of profit
is equivalent to maximization of revenue, etc.. Each is followed by a
summary of the results in the more general or complex situations, to-
gether with a citation of the source where a comprehensive analysis is
carried out and the proofs developed.

The Natural Monopoly Thesis

Since competition among electric utilities is unworkable and
would eventually lead to the development of monopoly, electric utilities
are referred to as "natural" monopolies. Their outstanding economic
characteristic is that they operate at greatest efficiency when being
the sole suppliers in particular markets. Significant arguments have
been advanced to defend this unique result.

First, there are undeniable space limitations which labor against
the maintenance of competition in the electric power industry. Overhead
power lines are unsightly at best, and if a community were served by
several companies the aesthetic offense would be unnecessarily magnified. Underground conduits and cables occupy choice sites in metropolitan areas. It is not hard to imagine the many obstructions that would arise from an unnecessary duplication of utility company facilities--torn streets, traffic jams, and so on. Second, strong economic reasons arising from the cost of establishing an efficient production firm in relation to the size of the market, namely economies of scale and economies of utilization, also support the natural monopoly thesis.

As noted in Chapter I, the economies of large scale production in the electric power industry are so great that, other things equal, the larger the firm the lower are unit costs of production. A firm using a small plant would not be able to compete with a firm using a large plant. Furthermore, assuming that the size is fixed, average costs of production fall as output increases because electric utilities have very high fixed costs and relatively low variable costs. The supply of electricity not only requires expensive specialized capital equipment but also electric utilities must maintain extra capacity or

---

2 Although normally referred to as a physical and aesthetic offense that can be avoided with monopoly--a practice followed here--excess duplication of utility company facilities is an economic problem in the area of externalities. In this respect consult Harold Demsetz, "Why Regulate Utilities?" Journal of Law and Economics (April, 1968), pp. 62-63.


4 "About 77 percent of the total costs of providing electric service are fixed costs; the remaining 23 percent are variable costs." Vennard, The Electric Power Business, pp. 216-217.
equipment in order to satisfy the peak demand on the system. The unused
capacity that results during off-peak periods gives electric utilities
an incentive to lower their prices in order to increase sales. Thus
economies of utilization also tend to make competition unstable in the
electric power industry.

To recapitulate, the pressures for increasing output and thereby diminish costs, both in the short run and in the long run, are so
great that every effort would be made by firms to undersell rivals until
all competition had finally disappeared. Besides the practical and
esthetic reasons, two compelling economic arguments were given for the
support of monopoly in the electric power industry: (a) Because economies
of scale are very significant, the firm's long run average cost curve
declines over a wide range of output. Given market demand, the achieving of low unit costs and therefore low unit prices for consumers depends
upon the existence of only one firm. (b) Because of heavy fixed costs,
the firm's short run average cost curve decreases with output. While
one electricity supplier could take advantage of economies of utilization,
the presence of a number of firms would divide the total market and re-
duce the sales of each competitor. Each electric utility would be
pushed back up its declining average cost curve. Firms would under-
utilize their fixed capacities, with the consequence that unit costs and
therefore electricity rates would necessarily be high.

These findings are illustrated in Figure 2-1. The demand (D)
and marginal revenue (MR) curves faced by a typical electric utility
together with its cost curves are shown. Note the shape of both the
short run (SAC) and long run (LAC) average cost curves, the latter being
compatible with a homogeneous production function of degree greater than
Long run equilibrium requires that marginal revenue be equal to long run marginal cost (LMC) and also to short run marginal cost (SMC). Hence the profit maximizing output and price are \( q \) and \( p \) respectively, and

The appropriate scale or capacity is represented by \( SAC_2 \). Suppose now that another electric utility is established in the community and that the two firms agree to share the market equally. That is, at each possible price, each will take one-half the market demand. Thus, the demand curve facing each of the utilities is given by \( MR = \frac{1}{2}D \), and the associated marginal revenue curve is given by \( MR \). Finally, assume that the two firms have identical cost curves. Each will now be of smaller scale \( SAC_1 \), produce an output \( q_t \), and charge a price \( P_t \). This price is

\[ 5 \text{In reality electric utilities do not follow a policy of uniform pricing but charge different prices for electricity in different markets. This practice, as explained in Chapter I, may give rise to price discrimination, a subject treated in the next section.} \]
higher than the original, and so the consumer is worse off without monopoly than with it.

**Price Discrimination**

From the viewpoint of economics, it can be said that a seller practices price discrimination if the prices he charges for the various units of his product or products are not proportional to the costs of providing the units sold. Stated differently, discrimination occurs when rates are based upon variations in demand, rather than variations in costs. This practice, unless regulated, increases the profits of any monopolist and leads to a misallocation of resources. In general three different degrees of price discrimination can be identified:

A first degree discrimination would involve the charge of a different price against all the different units of commodity, in such wise that the price exacted for each was equal to the demand price for it, and no consumers' surplus was left to the buyers. A second degree would obtain if a monopolist were able to make n separate prices, in such wise that all units with a demand price greater than x were sold at a price x, all with a demand price less than x and greater than y at a price y, and so on. A third degree would obtain if the monopolist were able to distinguish among his customers n different groups, separated from one another more or less by some practical mark, and could charge a separate monopoly price to the members of each group.6

Two conditions are necessary for third degree discrimination.7 First, the monopolist must be able to keep the markets separate. If he cannot, his product will be purchased in the lower price market (assuming a two market situation) and resold in the market with the higher

---


7 The theory of this type of discrimination was developed by Joan Robinson in her *Economics of Imperfect Competition* (London: Macmillan and Co., Ltd., 1933), pp. 179-208. The discussion above is a summary exposition of her results.
price. Eventually the prices in the two markets will become equal.

Second, the elasticity of demand (e) at each price level (P) must differ between the two markets. Ignoring costs for a moment, the monopolist will always be able to increase profits by selling an additional unit in the market with the higher marginal revenue (MR). This implies that he should distribute his output between the two markets in such a way that marginal revenue is equalized, i.e., profit maximization requires that

$$MR_1 = P_1(1 - 1/e_1) = MR_2 = P_2(1 - 1/e_2)$$

where the subscripts 1 and 2 refer to the two distinct markets. If the elasticities of demand are the same in the markets, $$P_1 = P_2$$ and so there is no price discrimination.

Adding costs to the analysis, the total output under third degree discrimination is determined by equating the marginal cost of the whole output (MC) with aggregate marginal revenue (AMR) and therefore with the marginal revenue in each market, i.e., $$MC = AMR = MR_1 = MR_2$$. The AMR curve is obtained by summing horizontally $$MR_1$$ and $$MR_2$$. Figure 2-2 depicts these results and compares them with those of uniform or simple monopoly pricing. $$D_1$$ and $$D_2$$ are the demand curves in the two markets and SAR = AD is the simple monopolist's average revenue or aggregate demand (horizontal summation of $$D_1$$ and $$D_2$$). SMR is the marginal curve to AD or simple monopolist's marginal revenue. It coincides with AMR except for a small triangular part. DAR is the average revenue curve of the discriminating monopolist and given AMR and SMR, it must lie above SAR = AD.

In order to maximize profits the simple monopolist will produce
output $q_a$, at which $MC = SMR$. He will charge a uniform price $P_b$ selling $q_{1a}$ in the first market and $q_{2a}$ in the second. The third degree discriminating monopolist will produce output $q_d$ and charge prices $P_1$ and $P_2$ in markets 1 and 2 respectively. The corresponding quantities sold are $q_{1d}$ and $q_{2d}$. In relation to the simple monopolist, the discriminating one earns a greater profit by charging a higher price and selling a smaller amount in the market whose demand is less elastic at $P_s$ (market 2) and charging a lower price and selling a greater amount in the market whose demand at $P_s$ is more elastic (market 1). A larger profit is obvious since at the equilibrium total output, the difference between

---

8The total outputs under third degree discrimination ($q_a$) and simple monopoly ($q_a$) are the same in this example because of the use of straight line demands and the ability of the monopolist to serve both markets under uniform pricing.
average revenue and the common average cost (AC) is greater for the discriminating monopolist than for the simple monopolist.

A detailed comparison of simple monopoly and third degree discrimination, using the type of analysis illustrated above, leads to the following conclusions:

(a) total output is larger under the latter when neither market can be served under uniform monopoly pricing but both can under third degree discrimination. This situation may arise if the long run average cost curve lies above the aggregate demand curve throughout the range of possible outputs but below the discriminating average revenue curve for some outputs. Under uniform pricing the monopolist would suffer losses but under third degree discrimination he could either break even or make a profit. Hence, output under discrimination would be greater by the full amount of the firm's output; 9

(b) with two markets, total output is always larger under third degree discrimination when only the market with the less elastic demand can be served under uniform monopoly pricing but both markets can be served under third degree discrimination. 10 Furthermore, if marginal cost is either constant or falling the discriminating monopolist will charge respectively the same or a lower price than the simple monopolist in the common market. In this case, and also in (a) above, third degree discrimination is clearly beneficial in that it yields a larger output and the same or lower prices to some or all customers, with higher prices to none; 11

---

9 Robinson, *Economics of Imperfect Competition*, p. 203.
10 Ibid., pp. 189-190.
11 Ibid., pp. 204-205.
(c) if both markets can be served under uniform monopoly and
third degree discriminatory pricing, it can be proved that

... total output under discrimination will be greater or less
than under simple monopoly according as the more elastic of the
demand curves in the separate markets is more or less concave
than the less elastic demand curve; and that the total output will
be the same if the demand curves are straight lines, or indeed in
any other case in which the concavities are equal.12

The straight line demand case is the one pictured in Figure 2-2;

(d) when three or more markets are considered, the fact that a
greater number are served under third degree discrimination than under
uniform monopoly pricing does not necessarily mean that output is larger
under the former. The shapes and positions of the demand curves in the
several markets determine which type of pricing will yield the larger
output.13

The theory of third degree discrimination can be used to ration-
alize partially pricing by electric utilities. The companies are able
to divide customers into three main groups or classes: residential,
commercial, and industrial. Moreover, the elasticity of demand increases
when moving across these groups in that order. Industrial demand is
more elastic than commercial or residential demands reflecting the fact
that industrial customers may find it possible not only to use substi-
tute sources of energy but to generate their own electricity. Thus, it
is argued that this explains why the rates charged by the utilities in
general decrease when moving from residential to commercial to industrial
customers.

12 Ibid., p. 190.
13 Merton H. Miller, "Price Discrimination in the Railway Industry"
140-142.
But electric utilities do not impose a single and different rate to each class but a schedule of rates. The rate schedule applicable to each class usually offers the individual customer in it a graduated, descending scale of prices for incremental blocks of service taken. For example, a typical monthly rate schedule for residential customers is as follows: the first 20 kilowatt-hours, 6¢ per kilowatt-hour; the next 50 kilowatt-hours, 5¢ per kilowatt-hour; the next 130 kilowatt-hours, 3¢ per kilowatt-hour; and over 200 kilowatt-hours, 1.5¢ per kilowatt-hour. This type of pricing constitutes block or second degree discrimination. 14

Figure 2-3 illustrates this sort of discrimination for a monopolist with zero marginal costs and limited to charging three different prices in a market whose demand is represented by the straight line PQ. The monopolist will levy prices \( OP_1 = (3/4)OP \) for output \( OQ_1 \), \( OP_2 = \frac{3}{4}OP \) for output \( Q_1Q_2 \), and \( OP_3 = \frac{3}{4}OP \) for output \( Q_2Q_3 \) (\( Q_1Q_2 \) and \( Q_2Q_3 \) each equals \( \frac{3}{4}QO \)) which maximize total revenue \( TR = OP_1X_1O_1 + Q_1A_1X_2Q_2 + Q_2A_2X_3Q_3 \) subject to the condition that \( OP_1 > OP_2 > OP_3 \), and that each pair of price-output points is on the demand line. Note that the simple monopoly price in this case is \( OP_2 \) and that the corresponding output \( OQ_2 \) is less than \( OQ_3 \), the total output achieved under block discrimination. In terms of the marginal conditions for total revenue maximization, \( OP_3 \) must be set at the output at which marginal revenue \( 3 \) is equal to the marginal cost of total output; \( OP_2 \) at the output at which marginal

---

14 The theory of this kind of discrimination was developed by Ralph Kirby Davidson in his Price Discrimination in Selling Gas and Electricity (Baltimore: Johns Hopkins Press, 1955), pp. 27-37. The discussion above summarizes his findings.
revenue 2 is equal to $OP_3$; and $OP_1$ at the output at which marginal revenue 1 is equal to $OP_2$.

Hence, with a three price schedule and under conditions of zero marginal costs and a straight line demand, "the prices are equidistant from each other and the blocks of output associated with each price are equal to each other and equal to one-fourth of the total amount the consumers would buy if a uniform price equal to marginal cost were set." For $n$ prices under the same conditions, "every block will be of equal size and equal to $1/(n+1)$ times the quantity bought at a uniform price.
equal to marginal cost."\(^{15}\) A similar type of analysis can be used to find the single schedule of rates that maximizes total profit for a monopolist with nonzero marginal costs and facing a curved demand function from either a class of customers or the market as a whole.

Assuming that the market is composed of three different kinds of consumers, it can be shown that output will be largest if the monopolist uses either block pricing with one rate schedule for all customers (second degree discrimination) or block pricing with separate rate schedules for the various classes (second and third degree discrimination combined). If the three kinds of consumers can be served under a single rate schedule, output will be largest under the former pricing policy. Output will be the smallest when either third degree discrimination or simple monopoly pricing is used. The largest profit will be obtained under a combination of second and third degree discrimination, followed by second degree discrimination, third degree discrimination, and single monopoly pricing.\(^{16}\)

A combination of second and third degree discrimination, as presumably practiced by electric utilities, can be advantageous if it yields a larger output and lower prices for some or all customers, with higher prices to none. This kind of situation clearly occurs when the long run average cost curve lies above aggregate demand but below the average revenue curve resulting only from combined second and third

---

\(^{15}\) Ibid., p. 31.

\(^{16}\) For a proof of these results see ibid., pp. 44-59. With no regulation, the output achieved under any of these methods is generally less than that obtained through marginal cost pricing. This type of pricing is explained in the next section of this chapter.
degree discrimination. The monopolist could not cover total costs at any uniform price; the only way he could stay in operation would be with the aid of a subsidy. Losses would be reduced with third degree discrimination, i.e., a different rate to each class of customers, or with second degree discrimination, i.e., a single block rate schedule for all consumers, but the monopolist could not still cover total costs.

The deficit would be eliminated only if the monopolist were to use distinct block rate schedules for the various customer classes, i.e., a combination of second and third degree discrimination. Assuming that a subsidy is not possible, it can be concluded that prices would be lower and output would be larger under this type of pricing, for the firm could not operate at all with any of the other mentioned pricing schemes. Under any different position of the long run average cost, aggregate demand, and discriminatory average revenue curves, it can be demonstrated that a combination of second and third degree discrimination... will not necessarily increase output beyond that achieved when a single block schedule is open to all customers, and reduce rates to all consumers; indeed, even the opposite is possible. The strongest presumption appears to be that the combination of class pricing and block discrimination will result in an increase of total output and in higher rates to old customers.17

Finally, a monopolist could obtain maximum possible profits by charging a different price for each unit of output, namely the highest price anyone in the market would be willing to pay for that unit. This pricing scheme constitutes perfect or first degree discrimination and could be realized only through either of the following two types of arrangements: (a) by auctioning off each unit of output to the highest

17Ibid., p. 180. It should be remembered that these conclusions assume no price regulation. This subject is treated in the next section.
bidder, or (b) if the monopolist knew the individual demand curves, he could use an "all or nothing" contract with each customer, i.e., the monopolist would make the buyer pay all that he (the buyer) would under the threat of being denied the good altogether. The assumption of knowledge of individual demand curves is highly dubious but even if it were valid, neither the latter approach or the auctioning method would be feasible in actual practice, not only due to regulation, but because of the excessive costs they would entail.

Figure 2-4 pictures the first degree discrimination case. Each unit of output, being sold at the highest possible price, adds to total revenue an amount equal to that price. Thus the aggregate demand (AD) or simple monopoly average revenue curve (SAR), assumed to be a horizontal summation of like individuals' demand curves, represents the marginal revenue curve under perfect discrimination (DMR). The curve located to the right of \( AD = SAR = DMR \) is the average revenue under this type of
discrimination (DAR). The simple monopoly marginal revenue (SMR) together with the marginal and average cost curves (MC and AC) are also shown.

The simple monopoly output is that at which \( MC = SMR \), namely \( q_s \); the corresponding price and total profit are \( P_s \) and \( P_s C_s \) times \( q_s \), respectively. The output, average revenue, and total profit under first degree discrimination are larger. They are respectively \( q_d \), determined by the intersection of MC and DMR, \( P_d \), and \( P_d C_d \) times \( q_d \). Note also that \( q_d \) is equal to the output that would be achieved under marginal cost pricing and that in this case, while simple monopoly pricing would not allow this output to be produced without a deficit, perfect discrimination would.

**Price Regulation**

Up to this point the discussion has assumed that electric utilities can set prices at will in order to maximize profits. But in practice the rates they charge are subject to the scrutiny of regulatory commissions who seek to improve the social consequences of natural monopoly, viz., reduce prices, increase output, and prevent abnormal profits. Two different control methods are considered in this section: marginal and average cost pricing.

If the ultimate objective of the regulatory commission is to achieve an optimum or efficient allocation of resources, it should enforce marginal cost pricing. In general, if price is taken to be a measure or index of the value of the product to society and marginal cost a measure of the value of resources used up in producing an additional unit of the product, setting price equal to marginal cost will yield the socially desirable level of output. On the other hand, if the commission
wants to eliminate economic profits and permit only a fair return, average
cost pricing, i.e., a price equal to average cost, should be employed.

In Figure 2-5 the demand (D) and marginal revenue (MR) curves
faced by an electric utility together with its cost curves are shown.
The discriminatory average revenue curve (DAR) can be neglected for the
moment. Since electricity suppliers usually operate under conditions

\[ \text{FIGURE 2-5} \]

MARGINAL AND AVERAGE COST PRICING

of decreasing costs or increasing returns to scale, long run average
cost (LAC) lies above long run marginal cost (LMC). The short run aver-
age and marginal cost curves are labeled SAC and SMC respectively.
Under simple monopoly long run equilibrium conditions the output is \( q_a \),
the price is $P_\text{e}$, the scale or capacity is $\text{SAC}_\text{e}$, and economic profits are made because $P_\text{e}$ is greater than the average cost of $q_\text{e}$. At this output price exceeds marginal cost revealing that society values additional units of electricity more highly than the resources used up in their production.

This situation is corrected through marginal cost pricing. The intersection of demand and marginal cost in the long run yields the socially optimum output $q_\text{m}$. The socially optimum or marginal cost price is $P_\text{m}$ and the scale of the firm is $\text{SAC}_\text{m}$. The problem with this type of pricing is that $P_\text{m}$ is less than average cost meaning that $q_\text{m}$ can be produced only at a loss to the firm. Thus, the enforcement of this price upon the regulated electric utility would cause its bankruptcy, unless the deficit were offset by a government subsidy financed through taxes.

If marginal cost pricing is to result in a welfare optimum in the Pareto sense, these taxes would have to be of the lump-sum variety which fall upon producers' or consumers' surplus and hence do not violate the marginal conditions of production or exchange.\(^\text{18}\) It is unlikely that this type of taxes could provide sufficient revenue. Even if they could, to the extent that they were not collected from the people who receive the benefit of the subsidy, support of the marginal cost pricing principle would require interpersonal comparisons of utility. Moreover,

---

\(^{18}\)Harold Hotelling, "The General Welfare in Relation to Problems of Taxation and of Railway and Utility Rates", *Econometrica* (July, 1938), p. 242. Hotelling specifically suggested the use of income taxes and taxes on inheritances and land values. While the latter are definitely of the lump-sum variety, it has been shown that income taxes are not. Income taxes are said to affect the marginal conditions of production and probably the marginal conditions of exchange. See Robert W. Harbeson, "A Critique of Marginal Cost Pricing," *Land Economics* (February, 1955), p. 59.
the subsidization of output at the optimum allocation point would distort long run investment planning in the electric power industry. Price would not be able to ration resources among alternative uses in an adequate manner because it would not cover average cost. Consequently there would be no profit test to indicate the proper long run allocation of resources toward the production of electricity.\(^\text{19}\)

Due to these difficulties, regulatory commissions have in practice backed away from implementing marginal cost pricing and have concentrated in establishing a fair return price. In fact, the courts have held not only that any price that leads to losses and eventual bankruptcy would deprive electric utility owners of their private property without due process of law but more precisely that regulatory agencies must permit a fair return to owners. Referring again to Figure 2-5, the price determined by the intersection of the demand and long run average cost

curves allows the utility just to cover its total costs, including a normal profit. This price, labeled \( P_a \), is the fair return or average cost price. The corresponding output is \( q_a \) and the scale or size is \( SAC_a \). Note that \( q_a \) is less than the socially optimum output \( q_m \) since \( P_a \) exceeds marginal cost. Therefore, average cost pricing would entail an underallocation of resources to electricity supply.

In conclusion, whether a policy of average or marginal cost pricing is enforced, price regulation would improve upon the results of simple monopoly. This is clear because under either method output would be larger, price would be lower, and the economic profits of the utility would be reduced. The analysis, however, has excluded the use of discriminatory pricing schemes which may permit the accomplishment of the optimum allocation of resources goal just as marginal cost pricing, but without a need for a subsidy.

It was indicated in the previous section of this chapter that price discrimination in general tends to result in a larger output than simple monopoly. Moreover, it has been demonstrated that when two markets can be served under average cost pricing or under third degree discrimination, average cost pricing always gives a greater output. When only one market can be served under average cost pricing whereas both markets can be served under third degree discrimination, if average cost is rising, output is necessarily larger under average cost pricing. If

\[ \text{Notwithstanding, it should be mentioned that some economists not only believe that regulatory commissions are incapable of forcing electric utilities to operate at a specified combination of output, price, and cost but have even introduced empirical evidence to show that their control has been ineffective. For example, see George J. Stigler and Claire Friedland, "What Can Regulators Regulate? The Case of Electricity," Journal of Law and Economics (October, 1962), pp. 1-16.} \]
average cost is falling, output under third degree discrimination can be less, the same, or greater than output under average cost pricing depending upon the shapes (slopes) and positions of the demand curves in the two markets. Only when both markets can be served under third degree discrimination but neither under average cost pricing, output is inevitably larger under the former.21 A similar examination shows that in most cases second degree discrimination alone and second and third degree discrimination combined are likely to result in smaller outputs than average cost pricing.22

Hence, it can be concluded that when all markets must be served and under conditions of decreasing costs or increasing returns to scale --which are peculiar to electric utilities--the different types of price discrimination, with the exception of first degree, will probably produce an output larger than under simple monopoly but less than under average cost and therefore marginal cost pricing. However, these findings assume that discrimination is uncontrolled. Under regulation, it has been argued that second degree or a combination of second and third degree price discrimination can yield not only the average cost but the larger marginal cost pricing output. Even more important, under either system the latter output can be attained without the deficit that accompanies

21 These results on the comparison of average cost pricing and third degree discrimination were derived by Layton H. Miller in his article "Decreasing Average Cost and the Theory of Railroad Rates," Southern Economic Journal (April, 1955), pp. 400-403.

22 Davidson, Price Discrimination, pp. 152-160.
marginal cost pricing and with an optimum allocation of resources.\textsuperscript{23}

As noted in the preceding section of this chapter, although unregulated perfect or first degree discrimination can achieve the same ends, it must be rejected on the basis of its impossibility in actual practice.

A regulated discriminatory scheme designed to reach the same results of marginal cost pricing without a need for a subsidy could consist of either two-part or block pricing. Under the former consumers would pay a flat fee for the right to purchase any electricity plus a per unit charge equal to marginal cost. The flat fee would have to be adjusted so that total costs are covered by total revenue, and by setting the per unit charge equal to marginal cost, consumers could buy electricity at a price which reflected the value of the resources being used. The flat fee should not prevent anyone willing to purchase power at the per unit charge from doing so. Under the latter pricing system customers would buy successive blocks of electricity at lower per unit prices, with price in the last block equaling marginal cost. The blocks would have to be devised so that all customers willing to purchase additional power in the last block could do so. The prices and sizes of the earlier blocks would have to be adjusted so that the electric utility can cover its total costs. In terms of Figure 2-5 either of these pricing systems—two-part or block—would yield the optimum or marginal cost output $q_m$. Discriminatory average revenue (DAR), lying above the demand curve (D),

would equal long run average cost (LAC) for this output. Thus, total revenue would match total cost and no deficit would occur.

Even though this discussion has implied that in theory regulated discriminatory schedules of rates designed to yield revenues covering all costs while producing as good an allocation of resources as marginal cost pricing exist, advocates of the latter policy have said that in practice such schedules are very difficult, if not impossible, to find. The revenue requirement could be satisfied but since individual demand functions are widely different, in nearly all cases any scheme of discriminatory rates would fail to meet the marginal conditions of welfare maximization for some people and therefore would not achieve an optimum allocation of resources. Specifically, the effective price at the margin for the small consumer would be above that for the large consumer and thus above marginal cost. In more detail,

if the block schedule is designed to fit the demand curve of the average consumer, the rate applicable to the last block may well be above the price which some consumers would pay for that quantity of service. These consumers would not be able to purchase the utility's service at marginal cost and would purchase less than they would under a marginal-cost pricing system. Recognizing the differences of tastes and incomes among different consumers, it is apparent that a separate block schedule would be needed for each customer if the most efficient allocation of resources were to be realized. Such a pricing scheme would be extremely costly, if it were feasible.

This argument is powerful if second degree discrimination, i.e., a single block rate schedule for all customers of the electric utility, is sought. But if consumers are separated into classes, such as

---


residential, commercial, and industrial, demand functions within these classes may be approximately the same. The use of an appropriate block rate structure for each class would produce as good an allocation of resources as marginal cost pricing. Moreover, demand curves are not smooth and continuous and single-valued; they contain many discontinuities and may be almost perfectly inelastic within the relevant range. Taking advantage of such discontinuities and inelasticities, construction of block rate schedules for the various groups of customers, which do not violate the marginal conditions for welfare maximization, would be quite possible. The schedules would not interfere with the meeting of these conditions since it would be doubtful for example that households would greatly reduce their consumption of electricity because they could not obtain additional amounts at the industrial rate. Hence, it must be concluded that a combination of second and third degree discrimination, i.e., different block rate structures for the several classes of consumers, leading to an optimum allocation of resources and with total revenue covering total costs would not be difficult to arrive at, despite the views to the contrary of the proponents of marginal cost pricing.

Peak Load Pricing

As noted in Chapter I, because electricity cannot be stored its production and use must be simultaneous. Enough capacity is required to meet the coincident demand, or peak load, of all customers even though

---


this maximum demand on the system may come only for a few minutes or a few hours at periodic intervals of time. Electric utilities

... have been concerned for nearly a century with determining methodologies, techniques, and philosophies for coping with this peaking of demand. The problem of meeting these variations in load with some optimum sized plant capacity and the accompanying investments and costs, all in the framework of a pricing structure, is called the peak-load pricing problem.28

This problem has been solved through the use of marginal cost pricing guidelines.29 To illustrate the problem and its solution two assumptions are made: (a) the electric utility is composed of a single generating plant plus transmission and distribution facilities serving one community; and (b) total variable costs increase approximately in proportion to output up to some capacity limit which cannot be exceeded. In Figure 2-6 this assumption is reflected by the short run total cost curves STC1, STC2, and STC3, corresponding to plants of capacity q1, q2, and q3 respectively.


The long run total cost function, LTC, is an envelope of short run total cost curves. The outputs $q_1$, $q_2$, and $q_3$ at which the STC curves are tangent to LTC constitute not only maximum but also optimum outputs for each of the three plants. They are optimum in the sense that no other plants can produce them at lower total cost. The marginal cost curves depicted in Figure 2-7 are the slopes of the relevant total cost functions in the previous figure. The short run marginal cost curves, $SMC_1$, $SMC_2$, and $SMC_3$, are horizontal to the point of capacity and then vertical (indeterminate). They cut long run marginal cost, LMC, at the optimum and maximum outputs $q_1$, $q_2$, and $q_3$.

Two conclusions emerge from the cost curves in Figure 2-7: (a) given a particular plant, for any output below the capacity output, short run marginal cost equals average variable cost and hence is less than average total cost by an amount equal to average fixed cost; (b)
long run marginal cost is equal to the sum of marginal energy or short run marginal cost and marginal capacity cost. In other words, "the long run cost of producing one more unit of electricity is equal to the addition to total energy costs (mainly fuel costs, in the case of conventional thermal plants) caused by the production of this additional unit, plus the addition to total capacity costs (mainly interest and amortization charges) caused by the installation of the necessary additional capacity." 30

Abstracting temporarily from the peak load problem, i.e., assuming that the demand for electricity does not vary with the hour, day, or season, an efficient allocation of resources requires a pricing rule

consisting of two parts: (a) electricity should be charged for at a price equal to the short run marginal cost of supplying it, and (b) plant capacity should be expanded when this price is higher than long run marginal cost and contracted when it is lower. These adjustments in the capacity of the plant should be made until price or short run marginal cost equals long run marginal cost. These results are illustrated in Figure 2-7, where D is the constant demand function.

Assuming that the plant with the short run marginal cost curve \( SMC_1 \) is actually in use, the first part of the ideal pricing rule would yield a price \( P_1 \) and an output \( q_1 \). But \( P_1 \) exceeds long run marginal cost and thus capacity should be increased. On the other hand, if the plant with short run marginal cost function \( SMC_3 \) were the relevant one, price and output would be \( P_3 \) and \( q_3 \) respectively. Since \( P_3 \) is less than long run marginal cost, the second part of the ideal pricing rule would call for a decrease in capacity. An efficient allocation of resources would finally occur with the use of the plant whose short run marginal cost curve is \( SMC_2 \), a price \( P_2 \), and output \( q_2 \). Under this optimum situation \( P = SMC = LMC \), that is, "provided there is an optimal investment policy, short-term pricing is also long-term pricing, and there is no longer any contradiction between the two."\(^{31}\) Moreover, the price \( P_2 \) is equal to the sum of the short run marginal energy cost \( w \) and the long run marginal capacity cost \( v \).

If the plant actually in use is of incorrect capacity, a problem arises in that pricing at short run marginal cost would require frequent

changes in rates as demand varies. Given that price stability is desirable, a rate equal to what the short run marginal cost would be if the plant were actually of the correct capacity, i.e., a rate equal to long run marginal cost, should be charged. However, it has been argued that this pricing proposition is inefficient. Specifically,

. . . optimality requires that the benefits of pricing according to short-run marginal cost . . . be weighed against the benefits of Boiteux's stable price proposal and an appropriate balance struck. For this purpose, a more broadly conceived social welfare function that makes explicit the gains to be secured through price stability is required. The trade-off between the short-run benefits of price flexibility and the long-run benefits of stability can then, presumably, be optimally arranged.

Up to this point the analysis has been based on a constant demand curve. In reality the demand for electricity varies with the hour, day, or season, and it is this fact that gives rise to the peak load problem. To illustrate, assume that the daily load curve consists of two independent 12-hour parts, a peak or day demand \(D_p\) and an off-peak or night demand \(D_n\). Assume also that long run marginal cost \(LMC\) is constant. This supposition avoids the deficit that would occur if marginal cost pricing were applied under conditions of decreasing long run average cost. Figure 2-8 pictures these different functions along with the short run marginal cost curve \(SMC\) corresponding to the plant in use. All cost curves refer to 12-hour time intervals.

According to the ideal pricing rule stated previously, the rate

\[32\] Ibid., pp. 70-72. In Boiteux's terminology, short run and long run marginal costs appear as differential and development costs respectively.

charged should equal short run marginal cost and plant capacity must be determined through a comparison of price and long run marginal cost. Thus, the first part of the rule clearly indicates that day electricity should be priced at \( P_d \) and night electricity at \( P_n \). The quantities taken would be \( q_d \) and \( q_n \) respectively. The second part of the rule, however, becomes more complex. Given two periodical demands of equal duration and constant long run marginal cost, it has been proven that plant capacity is optimal when the sum of the two prices equals twice the (12-hourly) long run marginal cost, or alternatively, when the arithmetic mean of the prices equals that cost.\(^{34}\) Capacity should be expanded when the sum of the prices (each equal to short run marginal cost) is more than twice the (12-hourly) long run marginal cost, and

![Graph](image)

**Figure 2:8**

PERIODICAL DEMANDS: UNOPTIMAL CAPACITY

---

\(^{34}\) Boiteux, "Peak-Load Pricing," pp. 75-76 and 86-87.
contracted when it is less.

Since LMC = w + v, where w is the marginal energy cost and v the marginal capacity cost, the optimal capacity condition can be stated as $P_d + P_n = 2(w + v)$. It is evident that this condition is not satisfied in Figure 2-8. Because $P_d + P_n < 2(w + v)$, plant capacity should be contracted until an equality is attained. The optimal solution is shown in Figure 2-9, where SMC corresponds to a smaller plant. Note that the night rate $P_n$ covers the marginal energy cost of the night output $q_n$, i.e., $P_n = w$; and that the day rate $P_d$ covers the marginal energy cost of the day output $q_d$ plus the entire (24-hourly) marginal capacity cost, i.e., $P_d = w + 2v$. Hence, $P_d + P_n = 2(w + v)$. Under these conditions, the peak or day demand $D_d$ bears all of the capacity costs.

![Graph showing marginal costs and optimal capacity conditions](image)

**Figure 2-9**

**PERIODICAL DEMANDS: OPTIMAL CAPACITY**

The analysis can now be extended to take into account the case
of periodical demands of unequal length. For example, consider the situation pictured in Figure 2-10 where $D_n^{(1/3)}$ represents an 8-hour off-peak load and $D_d^{(2/3)}$ a 16-hour peak load. The cost nomenclature is the same as before; the cost functions refer to 24-hour time intervals. To arrive at the optimal solution, the "effective demand for capacity curve", $D_e$, is constructed. This curve, which is obtained from $D_n^{(1/3)}$ and $D_d^{(2/3)}$ through a weighting average method, has the property that it intersects LMC at the optimum capacity output $q_d$ for which $P_d = w + v/f_d$ on the corresponding periodic demand load $D_d$; $f_d$ refers to the fraction of the cycle during which this demand prevails. As it is seen below, $P_d$ is the proper price to use for $D_d$.

![Figure 2-10](image)

**Figure 2-10**

**Periodical Demands of Unequal Length**

---

35 This generalization along with a discussion of the welfare motivation behind the peak load pricing problem are the main contributions of Williamson. See his article "Peak-Load Pricing," pp. 810-827.

36 For the exact procedure of derivation see ibid., pp. 817-819.
In terms of Figure 2-10, given LMC, its intersection with \( D_e \) determines the optimal plant represented by SMC and of capacity \( q_d \). The appropriate prices, therefore, are \( P_n = w \) in the off-peak period and \( P_d = w + v/(2/3) \) during the peak. The corresponding outputs are \( q_n \) and \( q_d \). These prices and outputs are correct since they are the only ones under which total revenue equals total cost, a condition that must necessarily hold in long run equilibrium in this system which assumes constant returns to scale. To demonstrate this equality, note that the revenue obtained from the off-peak customers \((1/3)P_n q_n\) matches exactly the off-peak cost of \((1/3)wq_n\). Thus, the revenue derived from the peak customers, i.e., \((2/3)(w + 3v/2)q_d\) or \((2/3)wd + vq_d\), must cover both energy cost during the peak and the entire capacity cost if zero net revenue is to be realized. That this is true is evident since peak energy cost is \((2/3)wd\) and capacity cost per cycle is \(vq_d\).

The problem can also be formulated algebraically and identical results obtained through the following social welfare function:

\[
W = (TR_n + S_n)f_n + (TR_d + S_d)f_d - wq_nf_n - wq_df_d - vq_d
\]

where the subscripts \( n \) and \( d \) refer to the off-peak and peak periods respectively; \( f \) is fraction of the cycle accounted for by each period; \( W \) is net welfare gain; \( TR \) is total revenue; \( S \) is consumers' surplus; \( w \) is marginal energy cost; \( v \) is marginal capacity cost; and \( q \) is output. 37

Partial differentiation with respect to \( q_n \) and \( q_d \) in order to maximize \( W \) yields:

---

37 Note that this social welfare function is of the form \( W = TR + S - TC \) or \( W = S + (TR - TC) \), where the net welfare gain \( W \) is the sum of consumers' surplus \( S \) and producers' net revenue, i.e., total revenue \( TR \) minus total cost \( TC \). For the full development of this function and some applications see ibid., pp. 811-813 and 820-821.
\[
\frac{\partial W}{\partial q_n} = P_n f_n - w f_n = 0
\]
\[
\frac{\partial W}{\partial q_d} = P_d f_d - w f_d - v = 0
\]

Solving for the prices \( P_n \) and \( P_d \) gives:

\[
P_n = w
\]
\[
P_d = w + v/f_d
\]

With \( f_n = 1/3 \) and \( f_d = 2/3 \), \( P_n = w \) and \( P_d = w + v/(2/3) \) which are the same values obtained in Figure 2-10. Moreover, in the case of periodical demands of equal length \( f_n = 1/2 \) and \( f_d = 1/2 \); hence \( P_n = w \) and \( P_d = w + 2v \) or \( P_n + P_d = 2(w + v) \) which are the same results attained in Figure 2-9. In general then, price during the off-peak interval must be set equal to marginal energy cost \((w)\); the peak price must be set at the latter plus marginal capacity cost \((v)\) divided by the fraction of cycle time accounted for by the peak load \((f_d)\).\(^{38}\)

The above mentioned prices are appropriate when the off-peak load fails to use plant to capacity. The peak price \( P_d \) bears the entire burden of the capacity costs. But given a nonoptimal plant, the charging of a price such as \( P_d \) may result in \( D_d \) ceasing to be the peak demand, especially if the assumption of independent loads for the two periods is relaxed. After the proper adjustments both \( D_d \) and \( D_n \) share in the capacity costs. This situation, referred to as the shifting peak case, is depicted in Figure 2-11 where \( D_n \) and \( D_d \) are respectively night and day periodical demands of equal (12-hour) length.

If \( SM'C \) is the short run marginal cost curve of the plant actually in use, the initial night and day prices \( P_n' \) and \( P_d' \) will give

\(^{38}\) Ibid., p. 821.
rise to outputs $q'_n$ and $q'_d$. Since $P'_n + P'_d < 2(w + v)$, capacity should be contracted. The optimal plant is that with the short run marginal cost curve $SMC''$, where $AB = FG$. The price of night electricity is $P''_n$, that of day electricity $P''_d$, and $P''_n + P''_d = 2(w + v)$. Note that night and day outputs are equal, i.e., $q''_n = q''_d$, and that both demands share in the capacity costs.  

Figure 2-12 illustrates the so-called "impossible" case in terms of two periodical demands of equal duration. Both $D_n$ and $D_d$ intersect the horizontal part of the short run marginal cost curve $SMC$. In this instance $P_n = P_d = w$ and none of the capacity costs can be recovered. The condition $P_n + P_d = 2(w + v)$ gives $w + w = 2(w + v)$ or $2v = 0$, which

---

is absurd. Therefore, this case demonstrates that if a long run optimal solution is to be achieved, the peak demand $D_{p}$ must always bear a proportion, if not the whole, of the capacity costs.  

Up to now it has been assumed that the daily load curve consists of two levels, as in Figure 2-13, where the height of each level depends on the rate charged. In reality, of course, demand in a time interval is also a function of prices in other periods and the daily load curve includes more than two levels. The analysis can be easily extended to take into account these facts. In the process and through the use of the load curve, the adjustment brought about by the substitution of peak

---

40 Boiteux, "Peak-Load Pricing," p. 76.
load pricing for a tariff uniform in time will be shown.

Suppose that a single price gives rise to the situation presented in Figure 2-14, where the dotted line load curve is composed of four equal length demand intervals. Because the peak occurs during period 3, peak load pricing would require a rate in this period covering marginal energy cost and all capacity costs. Prices in other periods would be set only at marginal energy cost. If these rates were applied, the peak would likely be depressed as electricity consumption in period 3 is restricted or shifted to other periods. The prices would again have to be changed until eventually a set which spreads and levels the load
curve at a reduced capacity is found. 41

These rates are shown in Figure 2-15 where the curve SMC, which makes AB = FG, corresponds to the optimal plant. Note that the prices $P_2$ and $P_3$ cover marginal energy cost and share marginal capacity cost. The rates $P_1$ and $P_4$ equal only marginal energy cost. The solid line in Figure 2-14 represents the new load curve after these prices have been set.

Having summarized the solution to the peak load pricing problem, the main criticisms that have been advanced against it must now be

---

considered. First of all, it has been argued that the solution is determinate only if the assumption of uniform marginal price over quantity demanded is adopted. But this assumption is highly questionable. Since electric utilities offer quantity discounts, quantity premiums, and block tariffs, no single-valued relationship between quantities demanded and price exists. It becomes necessary to distinguish between marginal price and average price, and for each marginal price there may exist several quantities demanded, as the terms of the whole price offer are changed.

Thus, the geometrical solution to the peak load pricing problem becomes more complex.


43 Ibid., pp. 465-466.
This point is illustrated in Figure 2-16, where $M_n$ and $M_d$ represent the separate marginal price offers in two periods, night and day, respectively. At night, electricity is available at a quantity discount. This means that marginal price falls as larger quantities are purchased and that it lies below average price throughout the range. During the day the opposite holds. Electricity is available only at a quantity premium; marginal price increases and hence exceeds average price. Note that, as constructed, $M_n + M_d = LMC$ at any level of output. Consequently, the combined total revenue will match exactly the total cost of any given capacity as long as this capacity is fully utilized during both periods. It will be assumed that all possible sets of rates are analogous to $M_n$ and $M_d$ in these characteristics.
The problem is to find a set of price offers such that capacity output is achieved at both night and day periods. In Figure 2-16, \( M_n \) and \( M_d \) result in quantities \( q_n \) and \( q_d \) taken off the market. Since \( q_n \neq q_d \), a different pair of price offers must be found. Through a trial and error process, a satisfactory set, such as that represented by \( M'_n \) and \( M'_d \), may be arrived at. Note that now both night and day customers desire to purchase the same output \( q' \), which represents an optimal system capacity. The night marginal price at equilibrium is the same under \( M'_n \) and \( M_n \) to indicate, as said previously, that for each marginal price there may exist several quantities demanded, as the price offers are varied.

Once an efficient set of price offers has been established, the so called marginal evaluation schedules for the consumers of night and day electricity can be constructed. These are shown as \( E'_{n} \) and \( E'_{d} \) in Figure 2-16. Specifically,

these curves are similar to demand curves, but they are different in that their uniqueness depends on the specific price offers in being. And there will be a different set of marginal evaluation curves for each separate set of price offers. It is for this reason that marginal evaluation curves, or "demand curves," independently derived, cannot be employed to "find" equilibrium capacity or optimal marginal prices.\(^{44}\)

In sum, \( q' \) is just one of the many possible capacity outputs at which the consumption of night and day electricity can be equated. Furthermore, any such output \( q' \) can be attained during both periods with different sets of price offers, leading to a multiplicity of distributions of the total cost. Any of these sets, such as \( M'_n \) and \( M'_d \) leading to \( E'_{n} \) and \( E'_{d} \), could represent the peak load pricing solution.

\(^{44}\) Ibid., p. 469.
Hence, the solution is unique only if the assumption of uniformity in marginal price over quantity demanded is granted.45

The second criticism that can be levied against the peak load analysis is that, being an application of marginal cost pricing, it neglects the deficit that will arise under conditions of decreasing long run average cost. The difficulties associated with this deficit have been already discussed.46 The third and final criticism considered here is that in some cases peak load pricing involves price discrimination, unless short run marginal cost is interpreted in an opportunity cost sense.47

Discrimination is not apparent since it has been said that under peak load pricing all rates charged equal short run marginal cost. Optimal plant capacity is determined by a comparison of the sum of these rates and the relevant long run marginal cost. The catch lies in that short run marginal cost is indeterminate at capacity output, i.e., "at system capacity short run marginal cost is defined to equal whatever price is necessary to equate demand with capacity output."48 If only


46 See pp. 28-33 above.

47 Boîteux did not mention price discrimination in his analysis but Steiner specifically admitted it existed in the multiple peak situation. See Steiner, "Peak Loads and Efficient Pricing," p. 590. Hirshleifer, on the other hand, has been the main supporter of the opposite point of view, i.e., that peak load pricing does not involve discrimination if "by cost we ultimately mean the most valuable alternative forgone." Hirshleifer, "Peak Loads and Efficient Pricing: Comment," p. 457.

one demand intersects the vertical portion of the SMC curve, it is clearly the peak demand and it is charged the full marginal cost of capacity. In this situation there is no price discrimination. If, however, full capacity is utilized in two or more periods, "then each period shares the marginal capacity cost and the period with the greater actual demand gets charged the larger share."49 This is a case of discrimination, again provided that the excess of price over marginal energy cost in each peak period, i.e., the vertical portion of the SMC function, is not defined as economic rent imputed to the scarce plant capacity.

The two situations have actually been illustrated graphically. A non-discriminatory example is shown in Figure 2-9. Both prices are determined by the intersection of the demand curves and short run marginal cost. The off-peak or night period is charged a price \( P_n \) equal to marginal energy cost \( w \). Since the peak or day demand is solely responsible for capacity, the peak price \( P_d \) correctly covers marginal energy cost \( w \) plus the entire marginal capacity cost \( 2v \). A case of discrimination occurs in Figure 2-15. The off-peak demands \( D_1 \) and \( D_4 \) are appropriately charged a price equal to marginal energy cost. On the other hand, each of the peak prices \( P_2 \) and \( P_3 \) covers marginal energy cost and shares marginal capacity cost. Although the sum of \( P_2 \) and \( P_3 \) correctly includes the total marginal capacity cost, this cost is allocated "in proportion to the intensities . . . of the two demands above the horizontal \( w \)."50 The higher demand \( D_3 \) is charged the larger share. This is pricing in accordance to demand or "what the traffic

---

will bear" rather than according to cost. Thus, unless one accepts the opportunity cost argument, it is a case of discrimination. "It would therefore be open to anyone who claimed that some other method of allocating overheads was more consistent with the basic theory of marginal cost pricing to say of Boiteux's analysis at this point:
C'est magnifique, mais ce n'est pas la tarification au coût marginal."  

CHAPTER III

ELECTRICITY COST: A SURVEY OF THE EMPIRICAL EVIDENCE

The abundance of published data for electric utility plants and firms has made this industry a fertile field of research for economists interested in the verification of cost theory. Numerous statistical and analytical investigations have examined costs in the electric power industry reaching various conclusions with respect to the shape of the different curves. It is the aim of this chapter to review the methods and results of these previous studies in order to first, illustrate the complexity of the topic and second, show that for the purposes at hand further work is needed in this area as these investigations suffered in a conceptual as well as in an empirical sense.

To facilitate the understanding of the literature, the chapter begins with a discussion of the nature of electric utility costs. Because empirical evidence on cost can be obtained from either cost or production data, studies of both cost and production functions in the electric power industry are then reviewed. Finally, by closing with a recapitulation of the principal shortcomings of these works, the chapter clearly justifies the additional research undertaken here.

The Nature of Electric Utility Costs

In supplying electricity to the final consumer three different functions must be performed: generation, transmission, and distribution.¹

¹These functions are described in Chapter I, pp. 2-3.
Accordingly, annual electric utility costs may be classified as generation, transmission, and distribution costs. On the average, generation costs account for approximately 50 per cent of the total. Transmission comprises about 10 per cent and the remaining 40 per cent are distribution costs. Each of these costs categories can in turn be divided into two components: (a) the annual fixed charges—interest or cost of money, depreciation or amortization, interim replacements, insurance, and taxes—expressed as a percentage of the total investment in land, structures, and equipment; and (b) the annual operation and maintenance expenses covering essentially the costs of materials, supplies, labor, and fuel.²

Although this classification is adequate for engineering and accounting purposes, it does not have much relevance from an economic viewpoint. Consequently, in traditional economic analysis of electric utilities the following division of cost is used: (a) energy or output costs, (b) capacity or demand costs, and (c) customer or consumer costs.

Energy costs vary with the quantity of electricity, that is with the number of kilowatt-hours produced. These costs are largely made up of fuel and labor expenses. Capacity costs are a function of the maximum or peak demand in kilowatts.³ Since increases in the peak demand

---


³A kilowatt-hour (kwh) is a unit of electric energy. It measures the output of electricity generated or consumed and thus, it is analogous to other measures of quantity such as a gallon of water or a cubic foot of gas. A kilowatt (kw) is a unit of electric power. It measures the rate at which electricity is being generated or consumed. For example, a light bulb rated at 0.150 kilowatts (150 watts) consumes 0.150 of a kilowatt-hour during each hour it is used. If operated for ten hours, 1.5 kilowatt-hours of electricity would be consumed (10 X 0.15 = 1.5). The relationship between a kwh and a kw or between energy and power therefore is one of time. Energy equals power multiplied by time; and power equals energy divided by time.
on the system require additional capacity, these costs consist of investment expenses related to generating plants, transmission lines, substations, and part of the distribution system. Lastly, customer costs depend upon the number of consumers served. They include a portion of the general distribution system, local connection facilities, metering equipment, meter reading, billing, collecting, and accounting.

In conclusion, the total cost of an electric utility is a function of output, peak demand or capacity, and number of customers. Depending upon whether capacity remains fixed or varies, the total cost is either short run or long run. But in addition, other factors influence the total cost of electricity supply. The following are perhaps the most significant, although the list is not all-inclusive: resource prices, technology, and type of fuel used. The empirical evidence on all of these variables affecting cost is considered next.

Cost Function Studies

(1) J. A. NORDIN

Nordin was interested in finding the relationship between total fuel cost and output in a coal using electric light and power plant.\(^4\) The data covered 541 eight-hour shifts in six months of 1941. He obtained the following equation:

\[
Y = 16.68 + 0.125X + 0.00439X^2
\]

where \(Y\) is total fuel cost for an eight-hour period and \(X\) is eight-hour total output in per cent of capacity. Variance analysis showed that this was a significant improvement on a linear relation, but that a third-

degree function did not improve the fit. The equation implied that the marginal fuel cost relationship was an upward sloping straight line.

For the purposes of the current study, Nordin's pioneer work on electricity generation is inadequate in that it refers exclusively to fuel costs in only one electric plant.

(2) J. B. LANSING

The purpose of Lansing's study was to investigate the long run average cost curves for steam electric plants, i.e., the relationships between the size of those plants and the cost per kilowatt-hour of generating electricity. A cross-sectional sample consisting of 90 plants owned by classes A and B electric utilities and operating in 1945 was used. Throughout the study Lansing emphasized the word "investigate"; he did not try to reveal the long run average cost curves of theory but attempted to uncover the principal obstacles to the discovery of such curves. His real objective was to remove enough of these barriers to shed some light upon the curves themselves.

Graphical analysis of deflated unit costs, adjusted to operation at an average of 50 per cent of capacity, and size of plant allowed Lansing to conclude that economies of scale are likely to be exhausted at a medium size giving rise to a horizontal long run average cost function. Specifically, he determined that steam electric plants tend to become more elaborate over 75,000 kilowatts, with the result that investment per kilowatt shows little or no tendency to decline. The

---

implication of this finding for marginal cost pricing is clear. For medium or large size plants, long run marginal cost equals long run average cost and therefore this type of pricing would not cause an economic loss.

With respect to the objectives of the present inquiry Lansing's investigation suffers from a number of shortcomings. First, it is limited to generation costs, that is, transmission and distribution costs are not considered. Second, the unit of observation is the plant and not the firm. Finally, although Lansing accounted for the effect of utilization of capacity and resource prices on electricity cost, he did not adequately correct for technological changes. Since the plants in his sample were built over a number of years, his long run average cost curve reflects the influence not only of scale but also of technology.

(3) K. S. LOMAX

Using cross-sectional data Lomax attempted to estimate the long run average cost function for electricity generation in two regions of the United Kingdom. His sample consisted of 37 steam electric plants operating for more than 6,600 hours in 1947-48. Lomax found that functions linear in the logarithms gave the best results:

---

6 It should be remembered that the electric utility firm in general is comprised of several plants, and each plant in turn is composed of one or more generating units. The economically relevant entity for cost analysis must be the firm since it is at the level of the firm that pricing decisions are made.

where $Y$ is operation and maintenance cost per kilowatt-hour generated, $X_1$ is capacity of generators in kilowatts, $X_2$ is the load factor, and the symbol $\propto$ denotes proportionality. The load factor variable, defined as the ratio between the average load over the year and the peak demand, was included in the belief that the character of the load on a plant produces differences in unit costs—"the lower will be the cost the more uniform is the demand."\(^8\)

The equations indicate that for a given load factor unit costs fall as the size of plant increases, and with given size of plant unit costs fall as the load factor increases. However, these results must be interpreted with caution. Lomax limited his study to the operation and maintenance costs of electricity generation, i.e., fuel, materials, and labor. Investment expenses were excluded. Furthermore, as in Lansing's investigation, plants were used in the sample and these differed considerably in the time when they were built. Thus, the decreasing long run average costs that Lomax obtained may be the result not only of economies of scale but also of technological improvements in the generation of electricity.

\(^{(4)}\) J. McNulty

Utilizing 1949 data from 99 electric utilities belonging to classes A and B, McNulty investigated the relationship between

\(^{8}\)Ibid., pp. 194-195.
administrative costs and size or scale of operations. The analysis was repeated for 91 companies in 1953. Defining \( Y \) as total administrative cost and \( X \) as value of plant less depreciation, McNulty obtained the following results:

\[
Y = -0.1 + 0.024X \quad 1949
\]

\[
Y = 0.1 + 0.021X \quad 1953
\]

The constant terms were not significantly different from zero and the application of the \( F \) test did not reject the linearity hypothesis.

For the needs of the present study, McNulty’s treatment is obviously inadequate in that it is confined to administrative costs, i.e., all management and supervision expenses incurred in the generation, transmission, and distribution of electricity. In addition, his measure of scale of operations (value of plant less depreciation), being a dollar quantity, reflects differences in the price of capital paid by the firms.

(5) J. JOHNSTON

Johnston attempted to derive the short run and long run cost curves for electricity generation on the basis of a sample of 40 firms in the United Kingdom. Time series data covering a period extending from 1928 to 1947 was used. Short run cost functions were estimated for each of the 17 firms whose installed capacity did not change during the 20 year period; long run cost curves were estimated for the 23 firms


whose capacity did change. The study was essentially limited to the working or operation and maintenance costs of electricity generation. There was no available data on the investment or capital costs of the firms.\footnote{Johnston used evidence from a cross-sectional sample of over 100 U. S. firms in 1947 to conclude that average capital costs fall rather sharply at first, but then become constant as output varies over a wide range of different scales of plant. Ibid., p. 71.}

The short run cost function was of the form

\[ Y = a + bX + cX^2 + dT \]

where \( Y \) is total deflated working cost; \( X \) is annual output; \( T \) is time; and \( a, b, c, d \) are the parameters to be estimated. The variable \( T \) was included in order to take into consideration all the factors that affect costs over the years—obsolescence of plant, changed management techniques and production methods, and so on.

For only 5 of the 17 short run cost functions the coefficient of \( X^2 \) was significantly different from zero at the 5 per cent level. Furthermore, for 4 of these 5 functions the coefficient had a negative sign, contrary to the theoretical expectation which postulates increasing average variable and marginal cost functions for a quadratic total cost curve. Johnston then concluded that in the short run the total cost function is linear with constant average variable and marginal cost curves. The average total cost curve at first falls and then flattens out tending asymptotically toward the constant marginal cost line. The coefficient of \( T \) was significant in 7 of the 12 total cost equations containing only a single linear term in output. In the majority of these relationships its sign was positive "indicating a predominance of
those factors such as plant obsolescence, etc., making for an increase in costs.\textsuperscript{12}

A similar analysis was carried out in order to estimate the long run cost curves of the 23 firms whose capital equipment changed during the period studied. Assuming that as installed capacity varied over time the firm operated on the long run total cost envelope of the short run total cost curves, Johnston concluded that a regression of total cost on output over time was truly an estimate of the long run total cost function for the firm. Accordingly, his long run treatment used an equation of exactly the same form as that of the short run cost curve.

The results supported the conclusion that in the long run the total cost function is mainly linear in output X, with or without a significant term in time T. Long run average cost, after a steep initial fall, approximates the constant long run marginal cost line over the major part of the range of possible outputs. Hence, Johnston's long run findings are in substantial agreement with those reached by Lansing in his earlier study of electricity generation in the United States. Both authors derive an essentially constant long run average cost curve, which is compatible with a linear homogeneous production function for steam electric generation.

Johnston's short and long run results lend support to the hypothesis that marginal cost pricing could be practiced without a deficit. However his study, besides being limited to the working costs of electricity generation, can be subjected to a number of criticisms arising from the absence of ceteris paribus conditions. The effects

\textsuperscript{12} Ibid., p. 55.
on cost of changes in the degree of capacity utilization were not considered. The treatment of technology was inadequate. No allowance was made for the fact that new generators replacing or adding to existing capacity could differ from the old ones in thermal efficiency and type of fuel used. The average age of equipment was not considered. While specific variables could have been introduced to account for these factors, Johnston chose to make the dubious assumption that their overall influence varies slowly and smoothly over the years. Thus the inclusion of time as an additional explanatory variable in the cost equations. In conclusion, these criticisms of Johnston's study show that many improvements in his estimation of the cost curves for electricity generation are possible, as he did not successfully correct for the complexity of the interactions of factors in the ceteris paribus clause.

(6) W. IULO

The primary purpose of Iulo's work was to determine which of a number of historical, operating, and market factors of privately owned electric utilities were related to their unit costs. Cross-sectional analyses were carried out for each of the years 1952 through 1957 on the basis of a sample of over 160 class A and B firms. The following seven variables, listed in decreasing order of importance, were found to be linearly related to average electric costs: consumption per residential customer, distribution among consumer classifications, hydro-electric fuel costs, capacity utilization, steam-electric fuel

---

costs, consumption per commercial and industrial customer, and typical size of steam-electric generating stations.

Iulo's study was not addressed to the determination of the cost functions of economic theory but to an explanation of why unit costs differed among investor owned electric utility firms. He made no implicit or explicit assumptions about the nature of the production process. Moreover, his sample was not satisfactory for the purposes of this research. Two reasons can be cited. First, it included only firms that sell electricity to each of the three main classes of customers: residential, commercial, and industrial. Cost differences arising from sales to only one or two of these consumer categories could not be accounted for. Secondly, the firms in the sample used either or both main methods of generating electricity: hydroelectric and steam or thermal generation. Hence, technological differences vitiated Iulo's cost results.

(7) S. LING

The objective of Ling's study was "to construct and analyze cost functions for steam-electric power generating systems based on an analytical model which simulates a typical large utility system in the United States, using a set of specific engineering cost estimates, assumptions as to technological relations and development patterns." His treatment therefore was of an ex ante nature and thereby contrasted with the statistical or ex post approach used in the other works reviewed here.

---

The model selected for consideration was a basic generating system with aggregate capacity of 2,500 megawatts, consisting of 10 units of 50, 12 units of 100, and 4 units of 200 megawatts.\textsuperscript{15} Annual investment and operation and maintenance costs for differing degrees of capacity utilization were obtained from technical sources. The system was then allowed to increase from 2,500 to 13,700 megawatts following an optimal expansion pattern developed by electrical engineers. At several system sizes in this range costs were again estimated for utilization or load factors varying between 40 and 100 per cent.

This method of analysis resulted in a set of data relating cost, size, and load factor. From this information the following average cost function was derived:

\[
C = 5534 \times S^{-0.1688N} - 1.8406 + 0.1428 \ln N
\]

where \( C \) = annual average generating cost in mills per kilowatt-hour, \( S \) = system installed capacity in megawatts, and \( N \) = system load factor in per cent.

Ling multiplied this equation through by output to obtain total cost. The partial differentiation of the latter with respect to capacity and output yielded marginal capacity and energy cost functions.

The negative exponent of \( S \) indicated that average generating cost decreased as system size increased. The exponent of \( N \) ranged from -1.1831 to -1.3146 evaluated at \( N = 100 \) and \( N = 40 \) respectively. Thus average generating cost was also a decreasing function of system load factor. Marginal energy cost was found to fall with size and rise with load factor. The latter characteristic reflected the fact that as the

\textsuperscript{15}One megawatt equals one thousand kilowatts.
load was increased toward the peak with capacity kept constant, less efficient generating units were used at the expense of higher incremental fuel costs. The marginal capacity cost function declined with both size and load factor.

Ling's investigation is unique in that he combined engineering information with economic theory in order to derive cost curves in the electric power industry. His results showed that economies of scale and economies of utilization existed in the industry and that marginal cost pricing would result in losses to the individual firms. However, his study first was confined to the generation of electricity, i.e., transmission and distribution were not considered, and second, being of an ex ante type, it simply reflected engineering evidence on costs. Such evidence may indicate that costs should behave in a certain fashion, but only statistical or ex post data can be used to test that claim. Although Ling fitted his cost function to 1938-1958 observations from four U.S. electric utilities, the findings are compounded with technological changes arising from the secular relationship that exists between increases in size and variations in steam conditions. In other words, his statistical cost equations mirrored both movements along and movements of the production function.

(8) C. E. OLSON

In his investigation of the electric power industry Olson attempted to estimate the long run and short run average cost curves for

---

electricity generation. Multiple regression analysis was applied to 1965 data from a sample of 76 plants. These plants, all built between 1956 and 1965 and housing generating units of similar capacities and vintages, were classified according to the type of fuel they burn; there were 52 plants in the coal using group and 24 in the noncoal group. A regression equation of the following form was fitted to each subsample:

$$\log C = \sum_{i=0}^{12} b_i \log X_i \quad , \quad i = 0, 1, 2, \ldots, 12$$

where

- $C$ = average generating cost,
- $X_0$ = a constant,
- $X_1$ = size of generating unit,
- $X_2$ = number of units per plant,
- $X_3$ = the reciprocal of plant utilization, i.e., capacity times 8760 hours per year divided by annual output,
- $X_4$ to $X_{12}$ = dummy variables representing date of installation; $X_4$ equals 2.718 for plants that started operation in 1957 and 1.000 for other years; $X_5$ to $X_{12}$ are defined similarly for 1958-1965 plants, and
- $b_0$ to $b_{12}$ = the parameters to be estimated.

This log linear equation meant that average generating cost was assumed to be a product of the explanatory variables. Thus, the $b$ values represented partial elasticities reflecting the relative effect on cost from percentage changes in these variables.

The size of generating unit and the utilization factor were found to be significant determinants of electricity generating costs. For both types of plants $b_1$ and $b_3$ were negative and positive, respectively, indicating that average generating cost fell as unit size and plant utilization increased. Moreover, the fact that the absolute value of


18 Note that: (a) the transformation of these variables into natural logarithms converts them to 1 and 0 respectively, and (b) there is no dummy variable for 1956 which is used as the base year. Ibid., p. 36.
b_3 exceeded that of b_1 showed that "economies of utilization are far more important than economies of scale as a potential source of cost savings for steam-electric generation."^{19}

On the other hand, the number of units and the date of installation did not have any appreciable influence on the cost per kilowatt-hour, meaning respectively that: (a) economies of scale occurred on a unit basis rather than on a plant basis, and (b) the impact of technology during the period studied was not significant. Both results were as expected since first, "there is no a priori reason to expect economies from multi-unit operation, unless the units are very small" and second, "much of the technological improvement in conventional steam-electric generating equipment came before and at the beginning of the period studied."^{20}

Olson's statistical study was unsatisfactory for the objectives of the present inquiry in that it was restricted to the generation aspect of electricity supply,^{21} with the unit of analysis being the generator.^{22} Furthermore, Olson excluded land and structure costs because they have a tendency to vary with geographical location. But

^{19}Ibid., p. 41. Specifically, the absolute values of b_1 and b_3 were approximately 0.156 and 0.705, respectively. They indicated that while a 10 per cent increase in the capacity of a generating unit produced a 1.56 per cent decrease in unit generating costs, a 10 per cent increase in plant utilization resulted in a decrease of more than 7 per cent in the same costs.

^{20}Ibid.

^{21}Although he did not consider distribution costs, Olson presented ex ante or engineering evidence to demonstrate that economies of scale and utilization existed in electricity transmission. Ibid., pp. 43-54.

^{22}Data per generator was not available; that is the reason why his sample consisted of plants housing generators of similar size and vintage.
having done this, operation and maintenance costs, although corrected for fuel price changes, were not adjusted to take into account the differences in the wage rate among plants in distinct regions. Hence the absence of ceteris paribus conditions, namely variations in the price of labor, biased Olson's empirical evidence on electricity generating costs.

Production Function Studies

(1) R. KOMIYA

The primary goal of Komiya's work was to distinguish between the shifts along and the shifts of the production function in the steam-electric power industry. Specifically, he tried to separate the effects of economies of scale from those of changes in technology on the basis of a sample of 235 plants built between 1930 and 1956. In order to accomplish this objective Komiya used the following procedure:

(a) The sample was divided into four groups according to the time period in which the plants were built (1930-45, 1946-50, 1951-53, and 1954-56). Each of these was in turn classified by fuel type into two subgroups, coal and noncoal using plants. Thus, the resulting eight cells included only plants belonging to the same technological stratum.

(b) A production function represented by a set of three input-output relationships was computed for each time period-fuel type cell:

\[ Y_f = A_f x_f^{b_f} \]
\[ Y_c = A_c x_c^{b_c} x_2^{u_c} \]
\[ Y_e = A_e x_e^{b_e} x_2^{u_e} \]

where

- \( Y_f \) = fuel input per generating unit when operated at capacity level of operation, in terms of BTU's (British thermal units) per hour;
- \( Y_c \) = capital cost of equipment in constant (1947) dollars per generating unit. The costs of construction and land were excluded;
- \( Y_e \) = average number of employees during the year, per generating unit;
- \( x_1 \) = the average size of generating unit in megawatts;
- \( x_2 \) = the number of generating units in the plant; and
- \( A_f, b_f, u_f = \) the parameters to be estimated.

(c) Finally, while meaningful \( b \)'s and \( u \)'s were used to indicate economies or diseconomies of scale for any vintage-fuel type classification (shifts along the production function), significant variations in the parameters of the equations among the different subgroups were used as evidence of technological change (shifts of the production function).

Komiya found that the values of \( b \)'s and \( u \)'s were positive and significantly smaller than unity implying that as the average size and number of generating units in any particular class of plant rose, the input of the particular resource increased proportionally less causing a fall in per unit costs. In other words, economies of scale turned out to be very important in steam power generation. In addition, the significant changes that resulted in the parameters among the cells indicated that the major achievement of technological progress in the industry was a reduction in the fuel, capital, and labor requirements per generating unit over time.

The study by Komiya, nevertheless, was deficient in several
respects. First, he used the steam-electric plant as the unit of observation and limited his investigation to generation costs, excluding land and structure expenses. Second, Komiya's measure of labor input--average number of employees per generating unit during the year--could have been in error due to differences in the total number of hours a laborer worked during the year and/or variations in the labor requirements among geographical regions. Third, Komiya did not correct for the influence of fuel and labor prices in the input relationships for these resources. Lastly, he did not consider the effect on the production function of differences in the degree of capacity utilization. His entire data was adjusted to plants operating at full capacity and therefore his results are relevant only for such plants.

(2) M. NERLOVE

Using data from a cross section of 145 firms in 44 states in the year 1955, Nerlove attempted to measure the degree of returns to scale in the steam-electric power generating industry.\(^{24}\) He assumed that the basic objective of the individual firm in the industry was "that of minimizing the total cost of production of a given output, subject to the production function and the prices it must pay for factors of production."\(^{25}\)

To achieve his goal Nerlove used the long run total cost function as a reduced form equation to estimate the parameters of a production


\(^{25}\)Ibid., p. 168.
function. The production function employed was of the Cobb-Douglas type,

\[ y = a_0 x_1^{a_1} x_2^{a_2} x_3^{a_3} u \]  

(1)

where \( y \) is output in kilowatt-hours; \( x_1, x_2, x_3 \) are respectively labor, capital, and fuel inputs; \( a_0, a_1, a_2, a_3 \) are parameters to be estimated; and \( u \) is a random disturbance or residual term.

Defining \( c \) as total production or generation costs and \( p_1, p_2, p_3 \) as the prices of labor, capital, and fuel respectively, Nerlove derived the traditional long run total cost function

\[ c = ky^{1/r} p_1^{a_1/r} p_2^{a_2/r} p_3^{a_3/r} v \]  

(2)

where

\[ k = r(a_0 a_1 a_2 a_3)^{-1/r}, \]

\[ v = u^{-1/r}, \]

\[ r = a_1 + a_2 + a_3, \]

from the minimization of costs

\[ c = p_1 x_1 + p_2 x_2 + p_3 x_3 \]  

(3)

subject to the production constraint imposed by equation (1). The cost function, which is linear in the logarithms of the variables, was estimated for the firms in the sample. The parameter \( r \) measured the degree of returns to scale. The production function was then calculated from the estimates of the parameters of the cost equation.

---

The results of Nerlove's analysis indicated that the bulk of privately owned electric utilities operated in the region of increasing returns to scale. Thus, these companies would need to receive subsidies in order to cover costs at socially optimal outputs. These conclusions however must be qualified since Nerlove restricted his study to generation costs and did not distinguish between movements along and movements of the cost function. The latter shortcoming was a product of many factors. By not accounting for differences in the age of equipment, Nerlove abstracted from all questions of technological change. Even though cost is a function of both scale and capacity utilization, these variables were not considered; neither were the geographical location of, and the type of fuel used by, the firm. In short, the interpretation of Nerlove's results as giving any significant measure of the degree of returns to scale is limited simply because ceteris paribus did not hold.

(3) Y. BARZEL

Barzel set out to investigate the production process in the steam-electric power generating industry.27 His data consisted of pooled observations from a sample of 220 plants installed between 1941 and 1959. Each plant was observed annually from its first year of full time operation until any major change was undertaken in it or until 1960, the last year for which data were available at the time of the study.

In a manner analogous to that of Komiya, Barzel divided the production function into three input equations, one each for fuel, labor, and capital. Specifically, he assumed that

\[ X_i = f(S, L, D, A, P_1, \ldots, P_n) \]

where \( X_i \) is input of the resource, \( S \) is the plant size, \( L \) is the load factor, \( D \) is the date of installation, \( A \) is the age of plant, and the \( P \)'s represent relative factor prices. Then he estimated this relationship for each resource in log linear form.

The coefficients of the logarithms of size and load factor turned out to be positive and significantly smaller than unity for the three inputs. This result meant that as plant size and load factor rose, the quantities of resources used increased more slowly than output causing average costs to fall. Barzel concluded that substantial economies of scale and utilization existed in the steam-electric power industry. But these economies were not uniform over all factors of production. Economies of scale were most pronounced for labor, less so for capital, and even less for fuel. Capital, labor, and fuel was the corresponding order of importance for economies of utilization.

The date of installation was represented by dummy variables whose coefficients, although not all significant, indicated shifts in the production function due to technological change. These shifts showed that labor, fuel, and capital requirements decreased during the period studied. The increase in efficiency was greatest for labor with fuel and capital coming respectively behind.

Finally, while age of plant was of no importance, the relative resource prices indicated that factor substitution was present in the steam-electric power industry. For example, in the capital input
equation the coefficient of the logarithm of price of labor relative to that of capital was 0.271, meaning that "a one per cent increase in anticipated labor cost leads to a 0.271 per cent increase in the original investment in the plant, presumably in labor-saving devices." 28

Besides the now familiar criticisms of using the plant as the unit of analysis and limiting the study to the generation process, Barzel's investigation suffered from two additional deficiencies. First, the input of labor was measured by the average number of employees in each plant in a given year. Barzel correctly recognized that this average was capable of containing errors "due to differences in the total number of hours a worker worked during the year as between years, between plants at a point of time, and possibly even within plants due to improper weighting of part-time work, and due to differences in the quality of labor both cross-sectionally and over time." 29 Second, differences in the type of fuel used among and within plants were not considered in the study of the fuel input function. However, the utilization of coal, oil, and/or natural gas is known to affect the fuel requirements of steam-electric plants.

(4) P. J. DHRYMES and M. KURZ

The study by Dhrymes and Kurz examined the impact of size and technological changes on steam-electric generation. 30 It combined the sample stratification technique of Komiya and the cost minimization


29Ibid., p. 139.

hypothesis of Nerlove. The sample, consisting of 362 plants constructed between 1937 and 1959, was classified according to size of plant and technological period. Each plant was included in the sample only once, the year of observation being taken as the year following construction of the plant. The parameters of a production function were estimated for each size of plant-technological period group from input equations derived under the assumption that entrepreneurs act so as to minimize cost under an output constraint. Specific conclusions with respect to returns to scale and technological progress were then derived by comparing the parameters so estimated for the various cells.

In detail, the model used by Dhrymes and Kurz can be explained as follows: a production function of the ACMS type was assumed,

\[ Q = K\left(\sum_{i=1}^{n} a_i X_i\right)^{b_1} 1/d \]

where \( Q \) is output; \( X_i \) is the \( i \)th input (\( n \) equals 3 denoting the inputs of fuel, labor, and capital); and \( a_i, b_1, d, K \) are parameters to be estimated. Given a cost function

\[ C = \sum_{i=1}^{n} P_i X_i \]

where \( C \) denotes total generation cost and \( P_i \) the price of the \( i \)th input, the problem was to minimize (2) subject to a fixed output constraint obeying (1). Thus,

This was done because a year was considered sufficient time for a newly constructed plant to attain its normal level of operation— the level at which Dhrymes and Kurz wanted to observe the plants. Ibid., p. 297.

The letters ACMS stand for Arrow, Chenery, Minhas, and Solow, the developers of this kind of production function (known also as the CES or constant elasticity of substitution function). For a discussion of its properties see Walters, "Production and Cost Functions," pp. 6-8.
(3) \[ \min \sum_{i=1}^{n} P_i X_i + L \tilde{Q}_0 - Q(X_1, \ldots, X_n) \]

where \( L \) is the Lagrangian multiplier and \( Q_0 \) the given output. The first order conditions,

(4) \[ P_j - L \left( \frac{\partial F}{\partial X_j} \right) = 0 \]

\[ j = 1, \ldots, n \]

were developed leading to the input equations

(5) \[ \ln X_i = \frac{1}{b_i} \ln \frac{a_i b_i}{a_i b_i} + \frac{1}{b_{i-1}} \ln P_i + \frac{b_{i-1}}{b_{i-1}} \ln X_n \]

\[ i = 1, \ldots, n \]

Substituting (5) in (1) gave rise to an implicit relation between the price ratios \( P_i/P_n \), output \( Q \), and the nth input \( X_n \). This relation was solved for \( X_n \). Hence, a set of inputs optimal for cost minimization was selected, and the problem was solved.\(^{33}\)

The results obtained led Dhrymes and Kurz to conclude that increasing returns to scale was the prevalent phenomenon in steam electric generation. The rate of returns to scale with respect to fuel and capital turned out to be less than that of labor. Technological changes on the other hand were found to have reduced the fuel, capital, and labor requirements of the generation process during the period studied. These conclusions were in substantial agreement with those of Komiya and Barzel; but just as in their case, they were derived from an analysis of steam plants and apply solely to the generation of electricity. Moreover, Dhrymes and Kurz did not consider the degree of capacity utilization of plants and failed to distinguish them with respect to the type of fuel used.

\(^{33}\) Dhrymes and Kurz, "Technology and Scale," p. 293.
(5) M. GALATIN

The main objectives of Galatin's investigation of the steam-electric power generating industry were "to derive measures of, and differentiate between, the effects of changes in scale and technology." The uniqueness of his study rested in the treatment of the machine or generator, rather than the plant or the firm, as the unit of analysis. The sample selected consisted of 158 plants having generators of the same size and vintage, but between these plants the size and vintage of the machines varied.

A plant was included in the sample from its first full year of operation until 1953 or until units of a different size and/or vintage were added to the plant. . . . The years of operation covered in the sample, which included plants of machine vintages from 1920 to 1953, were from 1938 to 1953. The year of installation of a machine was taken to be its vintage, i.e., the index of the degree of technological change embodied in machines.

The plants in the sample were classified according to vintage and fuel type. Thus, in any year of observation in a vintage-fuel type cell there was a cross-section of observations on machines, and for each machine in each cell there was a time series of observations.

A production function represented by three input equations was considered. The fuel relationship for the ith machine in a vintage-fuel type cell was of the form

\[ a_{it} = f\left(\frac{x_{it}}{x_{ik}}, x_{ik}\right) \]

where \( a_i \) is the input of fuel for the machine in BTU's per kilowatt-hour; \( x_{ik} \) is the size or capacity of the machine in megawatts; \( X_i \) is the


35 Ibid., pp. 97-98.
capacity in megawatts at which the machine is actually operated
\(0 \leq X_i \leq X_{ik}\); and the subscript \(t\) refers to the time period. The ratio
\(X_{it}/X_{ik}\) denotes then the degree of capacity utilization of the machine
in the period.

There were two difficulties in relation to the computation of
this equation. First, the relevant time period for Galatin was not the
year but an instant of time with the machine operating "hot and connected
to load," i.e., burning fuel and producing electricity. Second, measures
of fuel input and capacity utilization per machine were not available.
To solve these problems Galatin devised a method that enabled him to
deduce the characteristics of this equation from a similar one estimated
with annual plant data.\(^{36}\)

The effects of scale on fuel input were indicated by shifts of
equation (1) for machines of different sizes but of the same vintage
and fuel type while the influence of technological change was reflected
by shifts of the same equation for machines of the same size and fuel
type but of different vintage. This method of analysis showed that
economies of scale in fuel consumption existed over the full range of
the sample and that technological change had resulted in fuel input sav-
ings over the years studied.

The subsequent functional relationships for capital and labor
inputs were estimated for various vintage-fuel type cells of plants:

\[
\frac{C_T}{N} = g(N, X_k)
\]

\[
L = h(N, X_k, U)
\]

\(^{36}\text{Ibid., pp. 34-45 and 98-107.}\)
where

\[ C_T = \text{total capital cost of a plant, i.e., costs of land, structures and equipment;} \]
\[ N = \text{number of machines in the plant;} \]
\[ X_k = \text{size of each machine;} \]
\[ L = \text{average number of employees in a plant during the year;} \]
\[ U = \text{plant capacity utilization.} \]

Only plants comprised of machines of the same size and vintage were considered.

The analysis of functions (2) and (3) indicated that economies of capital cost and labor input occurred as the size of machines and the number of machines in a plant increased. Technological changes had reduced input requirements. Lastly, the degree of capacity utilization was also a significant variable in explaining labor input, but for small changes in capacity the effect was small.

In the light of the present study, Galatin's work suffered from a number of shortcomings. Galatin did not consider the transmission and distribution aspects of electricity supply. His conclusions, namely the existence of economies of scale and the resource savings stemming from technological change, were derived from empirical evidence using the generator as the unit of observation. His measures of capital and labor input were biased by differences in the price of these resources both cross-sectionally and over time. Thus, Galatin's investigation provided neither the information nor the analytic framework required to satisfy the kind of objectives pursued here.

**The Need for Further Work**

The empirical evidence on costs in the electric power industry, for the most part, seems to show that electric utilities have declining long run and short run average cost curves. Economies of scale and
economies of utilization appear to be the rule in the industry. Hence, marginal cost pricing should not be adopted because it would lead to losses for the individual firms.

The evidence reviewed, even though it supports the theoretical results outlined in Chapter II, is far from conclusive. Several criticisms were made to substantiate this point. In the first place, the majority of the studies examined used either the plant or the generator as the unit of observation. But as Nerlove pointed out, the economically relevant entity is the firm. 37 Firms, not plants or generators, are regulated and it is at the level of the firm that investment and pricing decisions are made. Second, the investigations were limited to generation costs. 38 Although a firm may operate in the region of increasing returns to scale as far as generation is concerned, when transmission and distribution are included the firm may be in the range of decreasing returns. Finally, the works reviewed were beset by difficulties in the statistical isolation or deflation of the ceteris paribus factors. Thus, in spite of the substantial amount of research in this field, the questions of economies of scale, economies of utilization, and marginal cost pricing must still be dealt with. Chapter IV undertakes such a task.

37 Nerlove, "Returns to Scale," p. 167.

38 There were two exceptions: McNulty and Iulo. Nevertheless, McNulty confined his study to the administrative costs incurred in the generation, transmission, and distribution of electricity while Iulo had sample problems. See pp. 60-61 and 64-65 above.
CHAPTER IV

A SUGGESTED ELECTRICITY COST FUNCTION

The existent empirical studies of costs in the electric power industry were reviewed and analyzed for limitations in the previous chapter. The objectives here are to propose and to estimate a new cost function for electricity supply that corrects for the main shortcomings of these investigations. Accordingly: (a) the unit of observation is the firm; (b) the costs of generation, transmission, and distribution are considered; and (c) the ceteris paribus factors are accounted for. The function is used to test the two theoretical cost characteristics outlined in Chapter II, namely that economies of scale and economies of utilization are significant in electricity supply or alternatively, that in both the long run and the short run decreasing average cost curves are the norm for electricity supply. In addition, the implication of the findings with respect to the proposal of pricing electric energy at marginal cost--i.e., whether or not marginal cost pricing will result in an economic loss--is noted.¹ Essentially then an attempt is made in this chapter to determine to what extent economic theory and practice agree.

Sample and Data

A sample consisting of 56 firms satisfying the following criteria

¹Further conclusions regarding public policy for the efficient or low cost provision of electric service are drawn in Chapter VI.
was selected: (1) they were privately owned electric utilities belonging to classes A and B. As stated in Chapter I, these firms constitute the most typical and important segment of the electric power industry; (2) at least 90 per cent of their capacity was in fossil fuel (coal, gas, oil) steam generation equipment. Because of the great qualitative differences between fossil fuel steam and nuclear and hydraulic production of electricity, firms predominantly using the latter methods of generation were excluded. These firms, however, account for less than a third of the United States power production; finally, (3) the electric utilities in the sample not only had to perform the three distinct functions of generation, transmission, and distribution but also they had to generate more than two-thirds of their own energy which they transmitted and distributed. Firms which performed only one or two of these functions and firms which were essentially purchasers of electricity were excluded because they were unrepresentative of industry operations. The electric utilities included in the sample are listed in Appendix A.

The data were a mixture of cross-section and time series observations on the variables. They covered a ten year time period extending from 1959 to 1968, the latest year for which complete information was available at the time this study was undertaken. Thus, there were 560 observations collected for each variable, i.e., 56 firms over 10 years. The use of pooled data implies that the cost equation derived applies to a given firm without change for several years and to a given year without change for several firms. Three sources of information were used: Statistics of Privately Owned Electric Utilities in the United States, an annual report published by the Federal Power Commission; Moody's Public Utility Manual, a yearly publication; and Employment and Earnings.
States and Areas 1929-69, a bulletin published by the Bureau of Labor Statistics of the U.S. Department of Labor. The data for each variable is readily available from these sources.

The Cost Model

The selection of the type of cost function to be estimated, e.g., total cost vs. average cost, depends to a large extent upon the primary objectives of the study. Given that these are to examine the questions of economies of scale and economies of utilization; and to determine whether a firm that adopts a marginal cost pricing system can operate without a subsidy, an average cost function is postulated in this section. Following traditional economic analysis of electric utilities, the cost per kilowatt-hour of electricity supply is related to capacity, output, and number of customers, other things equal.² Strangely enough, previous empirical investigations of the subject, to the author's knowledge, have not attempted to derive a functional relationship of this exact form.³

It has been said that the cost function "is a ceteris paribus proposition that demands an intricate processing of the normally available accounting data, if these are to yield the hidden relationship which the cost function represents."⁴ That is, in building a model of cost the historical data reflect the influences of many causes; hence, the ceteris paribus factors must be accounted for if the true relationship

²See Chapter III, pp. 56-57.

³This perhaps can be attributed to the fact that the main concern of those studies was the analysis of only the generation cost aspects of electric utility plants.

between average cost and capacity, output, and number of customers is to be accurately established.

Three approaches exist for the treatment of the ceteris peribus factors. The first one, which has been the most popular, is to deflate or correct the cost figures with the purpose of eliminating, whenever possible, the effects of such factors. For example, changes in the annual operation and maintenance expenses of an electric utility may be the result of variations in the salaries and wages of its employees and the price of the fuel utilized, both in response to influences other than the firm's purchases. An adjustment is made by deflating the cost figures by an appropriate index of factor prices. This procedure, however, has been shown to lead "to bias in the estimation of the cost curve unless correct weights, which depend on (unknown) parameters of the production function, are used." 5

The second approach is to recalculate the cost figures by applying some selected set of factor prices to the actual factor inputs of each time period. It has been demonstrated, though, that where the proportions in which factors are employed can be altered in reaction to changes in their relative prices, this technique will produce an overstatement of the costs of every period except the one to which the selected factor prices relate. 6

The third and last method of correction is to include the ceteris

5 Nerlove, "Returns to Scale," pp. 172-173.

paribus factors directly in the cost equation as additional explanatory variables. This is the procedure followed here. The cost model is described in detail below.

**DEPENDENT VARIABLE** - The annual average or per unit cost of electricity is the variable to be explained. For a particular electric utility this variable is calculated from the division of the yearly total cost of generation, transmission, and distribution by the corresponding kilowatt-hour output. The total cost figure is obtained by adding the annual operation and maintenance expenses—materials, supplies, labor, and fuel—to the annual fixed charges—cost of money, depreciation, interim replacements, insurance, and taxes. The latter are estimated as 12.5 per cent of the original cost investment in utility plant in service, comprising land, structures, and equipment.\(^7\)

**INDEPENDENT VARIABLES** - Capacity, output, number of customers, and the ceteris paribus factors—namely, resource prices, technology, and type of fuel—are in general the explanatory variables incorporated into the cost function. The size or capacity of the firm, which is the result of investment expenses in generation plants, transmission lines, substations, and part of the distribution system, is included in order

---

\(^7\)The 12.5 per cent figure for the annual fixed charges is based on computations by Federal Power Commission personnel. In this regard consult the following Commission reports: *National Power Survey*, Part I, pp. 282-283; *Hydroelectric Power Evaluation* (Washington, D.C.: U.S. Government Printing Office, 1968), pp. 77-78; and *Hydroelectric Power Evaluation*, Supplement No. 1 (Washington, D.C.: U.S. Government Printing Office, 1969), p. 3. The first publication estimates the annual fixed expenses of utilities using the steam generation method. The other two do the same thing in order to compare these expenses with those of hydroelectric power projects. A similar figure for the annual fixed charges has been used in previous studies. For example, see Ling, *Economies of Scale*, p. 65, and Olson, *Efficient Electricity Supply*, p. 34.
to analyze the long run question of returns to scale. It is commonly asserted that, other things equal, the larger the electric power enterprise, the lower its unit cost, meaning that increasing returns or economies of scale are the long run rule in the industry. If this is so, then an inverse relationship between capacity and average cost should be obtained empirically.

Electric utilities must have enough capacity to meet the coincident demand, or peak load, of all customers even though this maximum demand on the system may come only for a few minutes or a few hours at periodic intervals of time. Except for peak demand periods, there is normally unused capacity. The maintenance of this capacity implies that electric utilities must make relatively greater investments in plant and equipment than other industries, a requirement that gives rise to a cost structure dominated by fixed costs. Thus, it is suggested that economies of utilization arise in the supply of electricity from the distribution of the overhead costs associated with a given size over varying amounts of output, i.e., average cost should be a decreasing function in the short run because of the dispersion of the heavy fixed costs.

To test this result, rather than considering plain output generated as a variable in the cost equation, it is more convenient to express it as a proportion of the output that would be produced if the electric power firm were to operate at full capacity. The ratio of actual to potential output—i.e., annual output generated in kilowatt-hours divided by the product of installed capacity in kilowatts times 8,760, the number of hours in a year—then becomes a measure of the
extent to which the electric company uses its existing capacity.\textsuperscript{8} Coupled with the existence of economies of scale, a finding of economies of utilization, signified by an inverse relationship between the output ratio and unit cost, would have an important implication with respect to the marginal cost pricing proposal; namely, that since the average cost function is declining in both the long run and the short run, setting a price equal to marginal cost, whether long run or short run, will give rise to losses for the individual firms.

The number of customers variable is included in the cost equation in order to account for: (a) part of the cost of the distribution network of the electric utility; (b) the expenses incurred as the customer utilizes the service, such as metering costs, bookkeeping and collection charges, etc.; and (c) the cost of installation and connection experienced before the beginning of service to the new consumer. It is expected that an increase in the number of customers, other things equal, should result in a rise of electricity unit cost.

It is evident that the average cost of electricity supply depends upon the prices paid for the factors of production and that the relationship, with other influences removed, should be a direct one, i.e., as factor prices rise so does average cost. Fuel expenditures are the most important component of annual operation and maintenance costs,

\textsuperscript{8}Alternatively, the complement of this ratio can be said to represent the amount of "excess" capacity existing in the given firm. That is, "excess" in the sense that "if it were not for the demand and other characteristics that resulted in uneven levels of consumption or generation among the hours of the day or the days of the year, the energy requirements of the utility could have been met with a proportionately smaller amount of installed capacity if this capacity were continuously employed." Iulo, \textit{Electric Utilities}, p. 61.
representing about one third of the total and around three-fourths of those expenses associated only with the generating operation. Because utilities are able to burn more than one type of fuel—coal, oil, gas—in order to provide the steam required for electricity generation, the prices of the different fuels have to be put upon a comparable basis if their effect is to be reflected by a single variable. Since the main attribute of a fuel is its ability to give up heat when consumed, the common unit used for this purpose is the British Thermal Unit (BTU). Hence, the price of fuel, expressed in $ per million BTU's, is incorporated into the cost function.

The price of labor, stated in $ per hour, is another resource expense variable contained in the cost equation. Because it is not available for all the firms in the sample, the wage rate employed in the estimation process is that of all manufacturing workers in the main area where the utility does most of its business. A criticism arises in that to the extent that the average hourly earnings mirror the various industrial compositions in the different regions for which the data are reported, the individual figures do not represent accurately the same type and distribution of labor skills. Nonetheless, "this limitation would be present at any level of approximation short of a wage-rate series for the specific types of labor skills utilized by the electric utility industry."9

Increases in the price of capital over time may result in an electricity company which did the bulk of its investing ten or more years ago, having lower unit costs than another one whose major expansions

---

9 Ibid., p. 68.
have occurred more recently. Therefore the price of capital, like other resource prices, should be an explanatory variable added explicitly to the cost relationship. To compute the price of capital one must know among other things the rate at which the firm can borrow, the cost of equity financing, and the actual cost of construction of each item of plant at the time it was actually built. The problem however is that this kind of information is nonexistent. In order to circumvent this obstacle and account for changes in the price of capital, a variable termed the weighted average age of the firm and measured in years has been devised.

But the inclusion of this variable, which represents an addition to previous works in the field, is also designed to rationalize another element that affects unit electric cost, namely technology. In the past thirty years, technological advances have influenced the generation, transmission, and distribution aspects of electric utility operations. Hence, the weighted average age of the firm is important because it reflects not only the price of capital but also the level of technology prevailing at the time of installation. Specifically, the weighted average age variable is computed by first expressing the annual net expansions of the firm capacity since 1946 as a proportion of the total capacity in service and secondly, using these fractions as weights in conjunction with the corresponding age. The selection of 1946 as the base is justified because practically zero capacity was added during

10 Thus, as one author has said, many "conceptual as well as practical difficulties are involved in formulating an appropriate measure of the price of capital. Such problems are, in fact, the raisons d'être for . . . [using a model] which permits us to ignore capital prices altogether." Nerlove, "Returns to Scale," p. 190.
the World War II years and prior data on this variable is not reliable.

The following examples should help clarify the calculation procedure: for a particular firm in the year 1959

$$WAA_{59} = \frac{K_{46}}{K_{59}}(14) + \frac{K_{47}-K_{46}}{K_{59}}(13) + \frac{K_{48}-K_{47}}{K_{59}}(12) + \ldots + \frac{K_{59}-K_{58}}{K_{59}}(1)$$

where WAA is weighted average age in years, K is capacity in kilowatts, the subscript denotes the particular year, and the numbers in parentheses indicate the corresponding age in years in 1959; similarly for a firm in 1960

$$WAA_{60} = \frac{K_{46}}{K_{60}}(15) + \frac{K_{47}-K_{46}}{K_{60}}(14) + \frac{K_{48}-K_{47}}{K_{60}}(13) + \ldots + \frac{K_{60}-K_{59}}{K_{60}}(1).$$

A finding of a direct relationship between the weighted average age of the firm and unit cost can be interpreted as meaning that newer capacity or less age is associated with lower kilowatt-hour cost and consequently that technological improvements have offset the higher capital prices over the years.

The effect of technology is additionally represented in the cost function by a measure of thermal efficiency, namely the heat rate. This variable, which shows the calorific input in BTU's required to generate one kilowatt-hour of electricity, is expected to be directly related to average cost. As the heat rate decreases (increases), average cost should fall (rise). Implicit in the use of this variable as a proxy for technology is the assumption that progress in the transmission and

---

11 The net capacity addition figures, i.e., $K_i-K_{i-1}$ where $i$ denotes the particular year, do not reflect the mere replacements of old by new capacity. Since data on actual additions and retirements is not available, these changes cannot be considered.
distribution of electricity occurs at approximately the same rate as that in steam generation. This assumption is partially supported because in reality although improvements in transmission efficiency have taken place at a faster rate than those in thermal or generation efficiency, the opposite has held true for distribution. 12

Lastly, it is generally accepted that the type of fuel in use may have a substantial effect upon the electric utility unit cost. The three major types of fuel utilized by the firms in the sample are coal, natural gas, and oil. Each of the three has certain inherent advantages and disadvantages, either for technological or economic reasons. For example, the adoption of a given fuel depends upon its inherent burning efficiency, storage facilities and costs, waste-product removal, etc. Many utilities have equipment set up to operate with more than one type in order to produce the steam needed for the generation of electricity. Under appropriate circumstances the employment of a combination of fuels may yield the lowest over-all average cost to the firm. To account for this factor a variable defined as the percentage that output generated using coal as a fuel is of total output generated is included in the cost function. The a priori relation is conceptually indeterminate, i.e., this variable can be either directly or inversely related to cost per kilowatt-hour, indicating that the greater the proportion of coal consumed, the higher or lower, respectively, is unit electric cost.

Statistical Analysis

In the preceding section the following functional relationship for the average cost of an electric utility is proposed:

\[ c = f(x_1, x_2, x_3, x_4, x_5, x_6, x_7, x_8) \]

where:
- \( c \) = average or unit cost in $ per kilowatt-hour;
- \( x_1 \) = firm size or capacity in kilowatts;
- \( x_2 \) = output ratio or utilization factor, i.e., annual output in kilowatt-hours divided by the product of capacity in kilowatts times 8,760 hours per year;
- \( x_3 \) = number of customers;
- \( x_4 \) = price of fuel in $ per million BTU's;
- \( x_5 \) = wage rate in $ per hour;
- \( x_6 \) = weighted average age of the firm in years;
- \( x_7 \) = heat rate in BTU's per kilowatt-hour; and
- \( x_8 \) = per cent that output generated using coal as a fuel is of total output generated.

The objective of the statistical analysis is to derive via ordinary least squares methods a regression equation which describes this relationship. The general procedure followed is outlined below.

Two forms of the cost function were selected for investigation:

(1) \[ c = h + \sum_{i=1}^{8} a_i x_i \]

(2) \[ c = v \prod_{i=1}^{8} x_i^{b_i} \]

where \( h, v, a_i, b_i \) = the parameters to be estimated. The first equation was tried because the sample values of the independent variables appeared to fall within relatively narrow limits and the relationships seemed to be monotonic. Because it was linear, this equation implied that a unit change in an independent factor always resulted in a constant change in the cost per kilowatt-hour. Since it was more reasonable to assume that a unit percentage change in an explanatory variable was always associated with a constant percentage change in average cost, the second equation was considered. This equation then suggested that relative and not
absolute changes in the explanatory variables affected unit electric costs. Specifically, it implied a curvilinear relationship with cost per kilowatt-hour being a function of the product of the independent variables and the b parameters representing partial elasticities.  

In order to determine which of the two equations is the more accurate representation of the average cost function, the ensuing basic criteria were applied: (a) given that the adjusted coefficient of multiple determination shows the proportion of the variation in unit cost that is explained by the influence of the independent variables, the equation with the superior value for this coefficient was deemed more appropriate; and (b) the direction of the relationship between the significant factors and average cost in the equation chosen had to be in conformity with a priori expectations. For example, higher resource prices were supposed to be associated with greater cost per kilowatt-hour; if they were not, the relationship had to be considered illogical and thus rejected.

The cost equation selected was estimated not only for the whole sample, using pooled as well as cross-sectional observations, but also for subsamples taken on the basis of the geographical location and size of the firms. Many factors that vary from one region to another may affect average electric costs. For example, utilities operating in the northern states may have higher unit costs because of severe climatic conditions. Companies situated near good sources of cooling water such as the Great Lakes tend to have lower cost per kilowatt-hour than those located in arid or semiarid regions like the

\[ b_1 = \frac{x_1}{c} \left( \frac{\partial c}{\partial x_1} \right) \]

That is, \( b_1 = \frac{x_1}{c} \left( \frac{\partial c}{\partial x_1} \right) \).
Southwest. ¹⁴ Electric plants in the South are usually of the outdoor type, while in the North they are chiefly of the indoor category. The construction, operation, and maintenance expenses differ for these types of plants. Since firms in each geographical area are more homogeneous with respect to these factors, it was expected that fitting the equation to regional subgroups would improve the explanatory power of the regression.

Because of the specification of the model, the cost-size relationship for the entire sample could only be either continually decreasing or continually increasing. In view of the importance of the economies of scale question, the possibility of changes in this relationship—e.g., decreasing and then increasing—was investigated by estimating the cost equation chosen for size subsamples and then comparing the coefficients of the capacity variable among them.¹⁵ An example can help clarify the rationale of this approach. Assume that the cost-size relationship for the whole sample turns out to be continually declining, as denoted by a negative (and significant) coefficient of the capacity variable ($x_1$). It may be though that economies of scale are actually exhausted or offset by diseconomies at a certain capacity, bringing about a constant or rising long run average cost curve. A test is made by fitting the cost equation selected to size subgroups. If the scale coefficient ($b_1$) approaches zero or becomes positive when moving across the regressions

¹⁴ This cooling water is used for steam condensing purposes.

¹⁵ A similar analysis for economies of utilization was not carried out since the majority of the utilities in the sample recorded utilization factors within the relatively narrow range of 40 to 60 per cent.
from the small to the large size subgroups, this can be used as evidence to conclude that economies of scale decrease in importance or even disappear as electric utilities grow larger.

**Regression Results**

Equations (1) and (2) were estimated on the basis of the entire sample of 56 firms. The data consisted of pooled observations covering the ten year period extending from 1959 to 1968. Hence, the number of observations (n) was 560 for each variable. Applying the two criteria established in the previous section, equation (2) was chosen as the more accurate representation of the average cost function. Specifically, the value of the adjusted coefficient of multiple determination ($R^2$) for equation (2) was higher than that for equation (1); they were respectively 0.831 and 0.639. Furthermore, while the direction of the relationship between the independent variables and unit cost in equation (2) agreed with a priori expectations, the same was not true in equation (1). The coefficients of the prices of fuel ($x_4$) and labor ($x_5$) in equation (1), although significant, had negative signs. Therefore, that equation indicated that higher prices for these resources, other things equal, were associated with lower average cost, an outcome that prima facie was unreasonable and had to be discarded.

Table 4-1 summarizes the findings obtained from the least squares regression corresponding to the equation selected, that is, equation (2). Notice that the relationship becomes linear through a logarithmic transformation, i.e., by taking the logarithms of the variables on both sides of the equation. Thus,

\[ c = v \prod_{1}^{b_1} x_i \]
is equivalent to

\[ \log c = \log v + \sum b_i \log x_i \]

or

\[ C = k + \sum b_i x_i \]

where the constant term \( k \) and the capital letters denote the natural logarithms of \( v \) and the similar lower-case letters, respectively. The log linear form represented by equation (3) is actually the one referred to in the table.

**TABLE 4-1**

**MULTIPLE REGRESSION, WHOLE SAMPLE, POOLED DATA, 1959 TO 1968**

<table>
<thead>
<tr>
<th>Independent Variable</th>
<th>Regression Coefficient ((b_i))</th>
<th>t-Statistic</th>
</tr>
</thead>
<tbody>
<tr>
<td>( x_1 )</td>
<td>-0.431</td>
<td>-15.525</td>
</tr>
<tr>
<td>( x_2 )</td>
<td>-0.545</td>
<td>-13.006</td>
</tr>
<tr>
<td>( x_3 )</td>
<td>0.403</td>
<td>10.812</td>
</tr>
<tr>
<td>( x_4 )</td>
<td>0.308</td>
<td>8.369</td>
</tr>
<tr>
<td>( x_5 )</td>
<td>0.089</td>
<td>3.718</td>
</tr>
<tr>
<td>( x_6 )</td>
<td>0.117</td>
<td>5.941</td>
</tr>
<tr>
<td>( x_7 )</td>
<td>0.356</td>
<td>4.876</td>
</tr>
<tr>
<td>( x_8 )</td>
<td>-0.007</td>
<td>-3.957</td>
</tr>
</tbody>
</table>

\( k = -6.650, \text{ t-statistic } = -5.996 \)

\( n = 560 \)

\( R^2 = 0.831 \)

It can be seen that the regression results are encouraging. Here, the signs of all the coefficients conform to a priori considerations, the t-statistics indicate that these coefficients are all significant at the 1 per cent level, and the value of the corrected coefficient of multiple determination shows that 83.1 percent of the total variation
in the cost per kilowatt-hour is accounted for by the eight independent variables analyzed.

The coefficients of the size ($X_1$) and utilization ($X_2$) variables are negative revealing the predicted inverse relationship between these factors and unit electric cost. Thus, it can be concluded that the average cost of electricity supply is a declining function in both the long run and short run because of the existence, respectively, of economies of scale and economies of utilization. The implication with respect to a policy of either long run or short run marginal cost pricing is clear; since in both cases the marginal cost curve must lie below the average cost curve, setting a price determined by the intersection of the demand and marginal cost functions will lead inevitably to economic losses for the particular firms.

Note also that the values of the coefficients of size ($X_1$) and utilization ($X_2$), being partial elasticities, show respectively that while a 10 per cent increase in capacity results in a 4.31 per cent decrease in the cost per kilowatt-hour, a 10 per cent increase in utilization yields a 5.45 per cent decrease in the same cost. Hence, economies of utilization appear to be a more important source of cost savings than economies of scale. From a policy standpoint, this means that greater attention should be paid to improving the utilization ratios of the individual electric utilities than to expanding their capacity.

As expected, the coefficient of the number of customers factor ($X_3$) is positive indicating that the need for more connection facilities, metering equipment, meter reading, billing, collecting, and accounting arising as more consumers are added to the system, other things equal, acts so as to increase unit electric cost. In the same manner, higher
resource prices are seen to be associated with higher values of cost per kilowatt-hour as demonstrated by the positive coefficients of the price of fuel \(X_4\) and wage rate \(X_5\) variables. Recall that, in fact, an opposite finding in this regard was one of the causes that led to the rejection of equation (1) as the better representation of the average cost function.

The relationship between the weighted average age of the firm \(X_6\) and unit electric cost is also a direct one. As explained earlier, the implication here is that increases in the price of capital over time have been offset by technological progress and thus the younger the firm, the lower the cost—an assertion that is supported by some of the previous studies in the field concerned with the technological development aspect of electricity supply. The effect of technology is confirmed by the heat rate variable \(X_7\). Its positive coefficient indicates that decreases in the heat rate—i.e., a technological improvement denoting that less BTU's of heat are needed to generate one kilowatt-hour of electricity—correspond to lower average cost.

It is known that the cost of building coal-fired plants as well as the annual operation and maintenance expenses are larger than the similar cost and expenses of plants designed to burn only oil or gas. On the other hand, coal-fired plants have a heat rate advantage over oil- or gas-burning plants. "Inherently coal is the most efficient of the three fuels and a good grade of coal properly fired will produce

\[16\] For example, consult the works of Komiya, Barzel, Dhrymes and Kurz, and Galatin reviewed in Chapter III, pp. 70-72 and 74-81. For some of the recent technological advancements in the provision of electricity see Chapter VI, p. 130.
more useful heat energy than an equivalent BTU amount of gas or oil fuel." \(^{17}\)

The negative coefficient of the percentage that coal generated output is of total output generated \((X_g)\) shows that the higher this percentage, the lower is unit electric cost. Hence, given that the firm has plants designed to burn the three kinds of fuel, efficiency considerations seem to outweigh the added expenses as more coal is used.

The log linear regression equation was next fitted to the 56 firm sample in each of the years 1959 through 1968. The objective here was to determine whether the cross-sectional findings were compatible with those derived from the preceding pooled analysis. The year to year examination, for example, could be used to ascertain whether there were other important factors that affected the unit cost of electricity supply, factors whose influences in the global investigation had averaged out via the larger number of observations over the ten year span. The results, presented in Table 4-2, are reassuring. Just as before, the regression coefficients are all significant at the 1 per cent level and the direction of the relationship reflected by each coefficient sign agrees with what logically is expected. A look at the values of the coefficients reveals that the net effect of the eight individual variables considered upon kilowatt-hour cost seems to remain fairly constant. Moreover, the adjusted coefficient of multiple determination for each year fluctuates between the relatively narrow range of 0.817 to 0.857, as compared to 0.831 for the pooled data in Table 4-1. Thus, the combination of variables studied explains approximately the same proportion of the total variation in average electric cost annually and for the

### Table 4-2

Multiple Regression, Whole Sample, Cross-Sectional Data, 1959 to 1968

<table>
<thead>
<tr>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>$b_1$</td>
<td>-0.400</td>
<td>-0.405</td>
<td>-0.430</td>
<td>-0.408</td>
<td>-0.416</td>
</tr>
<tr>
<td></td>
<td>(-7.767)</td>
<td>(-7.779)</td>
<td>(-7.442)</td>
<td>(-7.101)</td>
<td>(-6.899)</td>
</tr>
<tr>
<td>$b_2$</td>
<td>-0.471</td>
<td>-0.531</td>
<td>-0.541</td>
<td>-0.498</td>
<td>-0.481</td>
</tr>
<tr>
<td></td>
<td>(-8.169)</td>
<td>(-6.232)</td>
<td>(-5.978)</td>
<td>(-7.320)</td>
<td>(-6.614)</td>
</tr>
<tr>
<td>$b_3$</td>
<td>0.433</td>
<td>0.387</td>
<td>0.421</td>
<td>0.401</td>
<td>0.392</td>
</tr>
<tr>
<td></td>
<td>(7.014)</td>
<td>(6.996)</td>
<td>(7.163)</td>
<td>(6.422)</td>
<td>(5.988)</td>
</tr>
<tr>
<td>$b_4$</td>
<td>0.308</td>
<td>0.299</td>
<td>0.311</td>
<td>0.314</td>
<td>0.295</td>
</tr>
<tr>
<td></td>
<td>(4.224)</td>
<td>(3.971)</td>
<td>(3.718)</td>
<td>(4.004)</td>
<td>(4.552)</td>
</tr>
<tr>
<td>$b_5$</td>
<td>0.100</td>
<td>0.059</td>
<td>0.063</td>
<td>0.071</td>
<td>0.083</td>
</tr>
<tr>
<td></td>
<td>(3.118)</td>
<td>(2.744)</td>
<td>(2.910)</td>
<td>(3.006)</td>
<td>(2.814)</td>
</tr>
<tr>
<td>$b_6$</td>
<td>0.109</td>
<td>0.114</td>
<td>0.122</td>
<td>0.113</td>
<td>0.128</td>
</tr>
<tr>
<td></td>
<td>(3.215)</td>
<td>(2.999)</td>
<td>(3.221)</td>
<td>(3.344)</td>
<td>(2.876)</td>
</tr>
<tr>
<td>$b_7$</td>
<td>0.354</td>
<td>0.361</td>
<td>0.348</td>
<td>0.344</td>
<td>0.363</td>
</tr>
<tr>
<td></td>
<td>(3.822)</td>
<td>(3.112)</td>
<td>(4.004)</td>
<td>(3.522)</td>
<td>(3.217)</td>
</tr>
<tr>
<td>$b_8$</td>
<td>-0.008</td>
<td>-0.005</td>
<td>-0.004</td>
<td>-0.008</td>
<td>-0.011</td>
</tr>
<tr>
<td></td>
<td>(-2.901)</td>
<td>(-3.101)</td>
<td>(-2.774)</td>
<td>(-2.883)</td>
<td>(-3.005)</td>
</tr>
<tr>
<td>$k$</td>
<td>-6.658</td>
<td>-7.103</td>
<td>-7.061</td>
<td>-7.224</td>
<td>-6.823</td>
</tr>
<tr>
<td></td>
<td>(-3.501)</td>
<td>(-2.977)</td>
<td>(-3.252)</td>
<td>(-3.321)</td>
<td>(-3.632)</td>
</tr>
<tr>
<td>$n$</td>
<td>56</td>
<td>56</td>
<td>56</td>
<td>56</td>
<td>56</td>
</tr>
<tr>
<td>$R^2$</td>
<td>0.849</td>
<td>0.823</td>
<td>0.829</td>
<td>0.817</td>
<td>0.857</td>
</tr>
<tr>
<td>------</td>
<td>------</td>
<td>------</td>
<td>------</td>
<td>------</td>
<td>------</td>
</tr>
<tr>
<td>$b_1$</td>
<td>-0.399</td>
<td>-0.413</td>
<td>-0.422</td>
<td>-0.436</td>
<td>-0.411</td>
</tr>
<tr>
<td></td>
<td>(-6.914)</td>
<td>(-7.306)</td>
<td>(-7.448)</td>
<td>(-6.851)</td>
<td>(-7.398)</td>
</tr>
<tr>
<td>$b_2$</td>
<td>-0.462</td>
<td>-0.572</td>
<td>-0.534</td>
<td>-0.527</td>
<td>-0.478</td>
</tr>
<tr>
<td></td>
<td>(-5.936)</td>
<td>(-5.820)</td>
<td>(-6.001)</td>
<td>(-5.787)</td>
<td>(-6.142)</td>
</tr>
<tr>
<td>$b_3$</td>
<td>0.428</td>
<td>0.436</td>
<td>0.390</td>
<td>0.410</td>
<td>0.402</td>
</tr>
<tr>
<td></td>
<td>(5.877)</td>
<td>(6.003)</td>
<td>(5.554)</td>
<td>(5.871)</td>
<td>(5.900)</td>
</tr>
<tr>
<td>$b_4$</td>
<td>0.322</td>
<td>0.304</td>
<td>0.308</td>
<td>0.316</td>
<td>0.300</td>
</tr>
<tr>
<td>$b_5$</td>
<td>0.086</td>
<td>0.068</td>
<td>0.072</td>
<td>0.077</td>
<td>0.085</td>
</tr>
<tr>
<td></td>
<td>(2.752)</td>
<td>(3.222)</td>
<td>(2.936)</td>
<td>(2.805)</td>
<td>(2.813)</td>
</tr>
<tr>
<td>$b_6$</td>
<td>0.101</td>
<td>0.124</td>
<td>0.115</td>
<td>0.103</td>
<td>0.112</td>
</tr>
<tr>
<td></td>
<td>(2.914)</td>
<td>(3.015)</td>
<td>(2.857)</td>
<td>(2.912)</td>
<td>(3.003)</td>
</tr>
<tr>
<td>$b_7$</td>
<td>0.355</td>
<td>0.368</td>
<td>0.349</td>
<td>0.345</td>
<td>0.350</td>
</tr>
<tr>
<td></td>
<td>(3.846)</td>
<td>(3.976)</td>
<td>(4.013)</td>
<td>(3.231)</td>
<td>(3.574)</td>
</tr>
<tr>
<td>$b_8$</td>
<td>-0.007</td>
<td>-0.005</td>
<td>-0.004</td>
<td>-0.007</td>
<td>-0.010</td>
</tr>
<tr>
<td></td>
<td>(-2.762)</td>
<td>(-3.024)</td>
<td>(-2.903)</td>
<td>(-2.855)</td>
<td>(-2.946)</td>
</tr>
<tr>
<td>$k$</td>
<td>-6.993</td>
<td>-7.043</td>
<td>-7.102</td>
<td>-6.674</td>
<td>-6.660</td>
</tr>
<tr>
<td></td>
<td>(-3.524)</td>
<td>(-3.648)</td>
<td>(-3.410)</td>
<td>(-3.109)</td>
<td>(-3.386)</td>
</tr>
<tr>
<td>$n$</td>
<td>56</td>
<td>56</td>
<td>56</td>
<td>56</td>
<td>56</td>
</tr>
<tr>
<td>$R^2$</td>
<td>0.821</td>
<td>0.830</td>
<td>0.840</td>
<td>0.847</td>
<td>0.836</td>
</tr>
</tbody>
</table>

The figures enclosed in parentheses are the t-values corresponding to the regression coefficients.
Summarizing the relationships in each of the years analyzed in Table 4-2, the coefficients of the size \( X_1 \) and utilization \( X_2 \) variables are negative, with the absolute value of the latter always exceeding that of the former. Once more, economies of utilization appear to be of greater importance than economies of scale in reducing the cost per kilowatt-hour. Marginal cost pricing, long run or short run, will give rise to losses for the single firms. The positive coefficients of the variables number of customers \( X_3 \) and the prices of fuel \( X_4 \) and labor \( X_5 \) imply that increases in these factors are associated with higher values of unit electric cost. The relationship between the weighted average age of the firm \( X_6 \) and the heat rate \( X_7 \) on the one hand and the average cost of electricity supply on the other is also a direct one indicating that technological progress is a cost diminishing force. Finally, the fact that the coefficient of the variable representing the percentage that coal generated output is of total output generated \( X_9 \) is negative attests to the efficiency advantages of this fuel. Hence, the greater the proportion of it in use, the lower is the kilowatt-hour cost.

To investigate further the possibility of differential shifts in the cost function between years, dummy variables were added to equation (3). Thus, the following log linear regression relationship was estimated on the basis of the combined observations over the ten year period:

\[
C = k + \sum_{i=1}^{17} b_i X_i \quad i = 1, 2, \ldots, 17
\]

where \( X_9 \) to \( X_{17} \) comprise a set of dummy variables; \( C, X_1 \) to \( X_8 \) are the
same as before; and $k$, $b_1$ are the unknown parameters. $X_9$ has a value of 1 for 1960 observations and 0 for those in other years. $X_{10}$ to $X_{17}$ are defined similarly for 1961 to 1968 observations, respectively.  

There is no dummy variable for 1959 since it is taken as the base year. Notice that the coefficients of the dummy variables are supposed to depict the influence, if any, of year to year fluctuations.

Table 4-3 summarizes the regression. The coefficients of the dummy factors, all significant at the 5 per cent level, show that the constant term rises when moving from 1959 to 1968. An upward trend in unit electric cost is exposed, a trend that apparently contradicts the findings in Table 4-2. Witness however that while the coefficient of the price of labor ($X_5$) is significant in that table, it is now non-significant. An examination of the data reveals that during the sample period wages climbed every year, from an average rate of $2.24$ per hour in 1959 to $3.07$ per hour in 1968 or by 37.1 per cent. It is probable that in Table 4-3 the dummy variables are simply reflecting the cost increasing effect on electricity supply of these higher wages or alternatively, that there the significance of $X_9$ to $X_{17}$ is accounting for the nonsignificance of $X_5$. Further, given that the signs and values of the coefficients of the remaining significant variables plus the value of the corrected coefficient of multiple determination compare to the

---

18 Recall that the constant $k$ and the capital letters refer to the logarithms of $v$ and the corresponding lower-case letters. That is, $k = \log v$, $C = \log c_i$, and $X_i = \log x_i$ for all $i$ so that equation (4) is equivalent to $c = v \prod_{i=1}^{17} x_i^{b_i}$, $i = 1, 2, ..., 17$. With respect to the dummy variables, this implies that $x_9$ has a value of 2.71828 for 1960 observations and 1.00000 for those in other years, $x_{10}$ to $x_{17}$ being analogously defined for 1961 to 1968 observations, respectively.
TABLE 4-3
MULTIPLE REGRESSION WITH DUMMY VARIABLES,
WHOLE SAMPLE, POOLED DATA, 1959 TO 1968

<table>
<thead>
<tr>
<th>Independent Variable</th>
<th>Regression Coefficient ($b_i$)</th>
<th>t-Statistic</th>
</tr>
</thead>
<tbody>
<tr>
<td>$X_1$</td>
<td>-0.421</td>
<td>-14.861</td>
</tr>
<tr>
<td>$X_2$</td>
<td>-0.532</td>
<td>-13.107</td>
</tr>
<tr>
<td>$X_3$</td>
<td>0.427</td>
<td>11.863</td>
</tr>
<tr>
<td>$X_4$</td>
<td>0.306</td>
<td>9.469</td>
</tr>
<tr>
<td>$X_5$</td>
<td>-0.005**</td>
<td>-0.200</td>
</tr>
<tr>
<td>$X_6$</td>
<td>0.129</td>
<td>4.128</td>
</tr>
<tr>
<td>$X_7$</td>
<td>0.382</td>
<td>5.003</td>
</tr>
<tr>
<td>$X_8$</td>
<td>-0.005</td>
<td>-3.257</td>
</tr>
<tr>
<td>$X_9$</td>
<td>0.021</td>
<td>1.972</td>
</tr>
<tr>
<td>$X_{10}$</td>
<td>0.033</td>
<td>1.991</td>
</tr>
<tr>
<td>$X_{11}$</td>
<td>0.047</td>
<td>2.544</td>
</tr>
<tr>
<td>$X_{12}$</td>
<td>0.059</td>
<td>2.678</td>
</tr>
<tr>
<td>$X_{13}$</td>
<td>0.080</td>
<td>2.771</td>
</tr>
<tr>
<td>$X_{14}$</td>
<td>0.086</td>
<td>2.903</td>
</tr>
<tr>
<td>$X_{15}$</td>
<td>0.094</td>
<td>3.112</td>
</tr>
<tr>
<td>$X_{16}$</td>
<td>0.100</td>
<td>3.242</td>
</tr>
<tr>
<td>$X_{17}$</td>
<td>0.111</td>
<td>3.255</td>
</tr>
</tbody>
</table>

$k = -7.003$, $t$-statistic $= -5.872$

$n = 560$

$R^2 = 0.828$

The symbol ** implies not significantly different from zero at the 5 per cent level.
corresponding ones in Table 4-2, it is concluded that the cost function has remained stable over the ten year span, i.e., the upward tendency disclosure by the dummy variables is not accepted.

Regression equation (3) was then fitted to two distinct subsamples taken according to the geographical location of the individual electric utilities. They were:


II. - West South Central (Oklahoma, Arkansas, Louisiana, and Texas): 14 firms.

On the basis of the overall sample size of 56 firms, I and II were the only two relatively large regional subsamples that could be identified. Furthermore, in each the utilities were homogeneous with regard to the type of fuel employed. Those in subgroup I were almost exclusively coal users, i.e., \( x_g = 95 \) per cent, while those in subgroup II were solely gas users, i.e., \( x_g = 0 \) per cent. Because these figures experienced very little change during the 1959-1968 interval, the variable \( x_g \)--or, to be exact, its log counterpart \( X_g \)-- was dropped from the regression for these subgroups.

The results are given in Table 4-4. Note first that the coefficients of all the factors in both subsamples agree with those derived from the entire sample in Table 4-1, with one exception: that of the price of fuel \( (X_q) \) in subsample I. This coefficient, although positive, is now insignificant reflecting the possibility that no substantial variations occurred in the price of coal. A review of the data in effect

\[19\] The companies included in each subsample are listed in Appendix A.
### TABLE 4-4
MULTIPLE REGRESSION, GEOGRAPHICAL SUBSAMPLES, POOLED DATA, 1959 TO 1968

<table>
<thead>
<tr>
<th></th>
<th>I. East North Central</th>
<th>II. West South Central</th>
</tr>
</thead>
<tbody>
<tr>
<td>(b_1)</td>
<td>-0.398</td>
<td>-0.413</td>
</tr>
<tr>
<td></td>
<td>(-13.440)</td>
<td>(-14.001)</td>
</tr>
<tr>
<td>(b_2)</td>
<td>-0.527</td>
<td>-0.496</td>
</tr>
<tr>
<td></td>
<td>(-12.282)</td>
<td>(-12.823)</td>
</tr>
<tr>
<td>(b_3)</td>
<td>0.422</td>
<td>0.395</td>
</tr>
<tr>
<td></td>
<td>(11.977)</td>
<td>(10.326)</td>
</tr>
<tr>
<td>(b_4)</td>
<td>0.100**</td>
<td>0.316</td>
</tr>
<tr>
<td></td>
<td>(0.307)</td>
<td>(7.009)</td>
</tr>
<tr>
<td>(b_5)</td>
<td>0.099</td>
<td>0.070</td>
</tr>
<tr>
<td></td>
<td>(3.124)</td>
<td>(3.225)</td>
</tr>
<tr>
<td>(b_6)</td>
<td>0.134</td>
<td>0.108</td>
</tr>
<tr>
<td></td>
<td>(3.285)</td>
<td>(3.006)</td>
</tr>
<tr>
<td>(b_7)</td>
<td>0.341</td>
<td>0.322</td>
</tr>
<tr>
<td></td>
<td>(3.026)</td>
<td>(2.944)</td>
</tr>
<tr>
<td>(\xi)</td>
<td>-6.673</td>
<td>-7.023</td>
</tr>
<tr>
<td></td>
<td>(-4.999)</td>
<td>(-4.712)</td>
</tr>
<tr>
<td>(n)</td>
<td>150</td>
<td>140</td>
</tr>
<tr>
<td>(R^2)</td>
<td>0.910</td>
<td>0.896</td>
</tr>
</tbody>
</table>

The figures enclosed in parentheses are the t-values corresponding to the regression coefficients.

The symbol ** implies not significantly different from zero at the 5 per cent level.
demonstrates that the coal price remained at about 25 cents per million BTU's for each of the firms in subsample I over the 1959-1968 term. On the other hand, the significance and positive sign of the \( x_4 \) coefficient for firms in subgroup II seems consistent with the fact that the price of gas rose approximately from 15 to 20 cents per million BTU's over the period. Second, for each subgroup the value of the adjusted coefficient of multiple determination is higher than the corresponding one for the whole sample. Hence, the expectation discussed in the previous section, i.e., that the more uniform the firms with respect to geographical factors, the greater is the explanatory power of the regression, is confirmed.

Finally, the log linear relationship represented by equation (3) was estimated for three well-defined subsamples taken on the basis of the capacity of the particular electric utilities during the 1959-1968 span. 20 These were:

I. - Small (capacity less than 750,000 kilowatts): 15 firms.
II. - Medium (capacity between 750,000 and 1,500,000 kilowatts): 8 firms.
III. - Large (capacity over 1,500,000 kilowatts): 7 firms.

In all of the regressions preceding this analysis the coefficient of the capacity variable \( (X_1) \) was significant and negative, which owing to the nature of the model denoted a continuously declining long run average cost curve. The purpose here, as explained in detail earlier, was to determine whether this average cost curve turned up—i.e., whether economies of scale disappeared—as size expanded via a comparison of the

---

20 See Appendix A for the group of companies contained in each subsample.
scale coefficients \( (b_1) \) among the three subgroups.

Table 4-5 presents the findings. For each subsample, again the signs and values of the significant coefficients of the various factors and the figure for the corrected coefficient of multiple determination concur with those of prior tables. Concentrating on the negative coefficient of the capacity variable, i.e., on \( b_1 \), it is seen to diminish in absolute value when moving from the small to the large size subgroup. The implication is that the same percentage increase in capacity contributes to smaller percentage reductions in average electric cost as the firms grow in size. Specifically, while a 10 per cent rise in capacity leads to a 4.83 per cent drop in cost per kilowatt-hour for the small utilities, the same percentage increase in capacity produces 4.39 and 4.01 per cent decreases in cost per kilowatt-hour, respectively, for the medium and large firms. Even though these results show that economies of scale tend to become less important as size expands, it can be inferred from the negative sign and significantly different from zero value of the coefficient of the capacity variable for the large utilities that the point at which these economies are exhausted has not yet been reached.
<table>
<thead>
<tr>
<th></th>
<th>I. Small (less than 750,000 kws)</th>
<th>II. Medium (between 750,000 and 1,500,000 kws)</th>
<th>III. Large (over 1,500,000 kws)</th>
</tr>
</thead>
<tbody>
<tr>
<td>( b_1 )</td>
<td>-0.483 (-14.212)</td>
<td>-0.439 (-15.296)</td>
<td>-0.401 (-14.836)</td>
</tr>
<tr>
<td>( b_2 )</td>
<td>-0.556 (-13.972)</td>
<td>-0.538 (-14.003)</td>
<td>-0.517 (-13.014)</td>
</tr>
<tr>
<td>( b_3 )</td>
<td>0.408 (11.400)</td>
<td>0.397 (12.887)</td>
<td>0.388 (12.777)</td>
</tr>
<tr>
<td>( b_4 )</td>
<td>0.311 (8.108)</td>
<td>0.319 (9.935)</td>
<td>0.327 (9.103)</td>
</tr>
<tr>
<td>( b_5 )</td>
<td>0.098 (3.115)</td>
<td>0.071 (3.276)</td>
<td>0.070 (3.832)</td>
</tr>
<tr>
<td>( b_6 )</td>
<td>0.135 (3.982)</td>
<td>0.114 (4.001)</td>
<td>0.108 (4.054)</td>
</tr>
<tr>
<td>( b_7 )</td>
<td>0.372 (4.821)</td>
<td>0.351 (3.942)</td>
<td>0.344 (4.078)</td>
</tr>
<tr>
<td>( b_8 )</td>
<td>-0.004 (-3.001)</td>
<td>-0.006 (-2.902)</td>
<td>-0.010 (-3.126)</td>
</tr>
<tr>
<td>( k )</td>
<td>-6.871 (-5.492)</td>
<td>-7.003 (-4.521)</td>
<td>-7.014 (-5.254)</td>
</tr>
<tr>
<td>( n )</td>
<td>150</td>
<td>80</td>
<td>70</td>
</tr>
<tr>
<td>( R^2 )</td>
<td>0.844</td>
<td>0.827</td>
<td>0.850</td>
</tr>
</tbody>
</table>

The figures enclosed in parentheses are the t-values corresponding to the regression coefficients.
CHAPTER V

A PRICE AND COST COMPARISON OF ELECTRICITY

Pricing systems for electricity that are more conducive to a socially efficient allocation of resources are not only desirable but also feasible. The first objective of this chapter is to argue that, in spite of this fact, pricing systems currently employed by American utilities do not adequately reflect marginal cost and hence lead to a poor utilization of the economy's resources. A brief examination of the existing types of rates in relation to a cost-depending rate schedule suggested by the theoretical discussions in previous chapters provides sufficient support for this assertion. In addition, an attempt is made here to determine if the different rates charged to the several classes of customers are properly justified by variations in cost; if they are not, it can be concluded that discrimination of the third degree is inherent in the pricing policies of U.S. electric utilities.¹ The test needed for this purpose involves a comparison requiring company price data, obtained from Federal Power Commission sources, and cost estimates arising from the functional model derived in Chapter IV. This test is important because third degree discrimination, unless it is shown to be combined with a peculiar form of second degree or block pricing—i.e.,

¹This kind of discrimination, as evidenced in the hearings of regulatory commissions, is the one that has received the most attention from the general public.
where the charge in the last block is equal to marginal cost and where the remaining blocks are such that anybody willing to purchase additional power in that last block can do so—promotes neither the most efficient use of existing capacity nor optimum investment decisions.

**Existing vs. Cost-Reflecting Rate Schedules**

Privately owned electric utilities in the United States currently employ different types of rate schedules. The block meter type is the most commonly used for residential and small size commercial customers. Under this rate schedule the consumer is offered declining prices per kilowatt-hour for successive blocks of energy taken. This is designed to depict the fact that the unit cost of electricity falls as output increases. On the other hand, the two-part Hopkinson demand rate schedule is normally applied to medium and large commercial and industrial customers. Under this type of rate the consumer is offered decreasing prices per kilowatt and per kilowatt-hour for successive blocks of demand and energy taken, respectively. The Hopkinson rate is intended to benefit the customer not only for a greater use but also for a higher load factor, i.e., "as the customer increases his use without any increase in maximum demand, or with a less than proportionate increase in maximum demand, his load factor will increase and his average rate will decrease."² Besides the different kinds of rate schedules, it should be noted that the specific block sizes and block rates

---

established by the electric utilities vary for each class of customers.

In contrast, the treatment of the theory of cost and pricing in Chapter II and the first section of Chapter III indicates that an electricity rate schedule reflecting marginal cost should consist of a monthly fixed charge differentiated by consumer and a charge per kilowatt-hour variable according to the time of use.\(^3\) The monthly amount should cover the cost of adding the specific customer to the utility system, i.e., connection facilities, metering equipment, meter reading, billing, collecting and accounting. Because technically this would require up to as many rates as there are customers, in practice the monthly charge could vary by customer class (residential, commercial, and industrial) since the cost differences among customers within the same class are likely to be minor. The kilowatt-hour charge during

off-peak periods should be set equal to the marginal energy cost (mainly fuel and labor expenses) while during peak periods it should include this cost plus the marginal capacity cost (mainly investment expenses related to extra generating equipment, transmission lines, and substations). 4

A comparison between this suggested rate schedule and the rate schedules currently employed by U.S. electric utilities clearly shows that the latter do not suitably mirror costs and that their application leads to a probably serious misallocation of resources. In general, the rates charged by these companies to the several classes of customers do not vary with the time of use and hence do not reflect differences in resource costs between peak and off-peak periods. Peak period consumers, who are entirely responsible for capacity costs, pay exactly the same price as off-peak period consumers. By encouraging high peak consumption, this uniform price—based on an implicit averaging of total costs—contributes to investment in capacities which are not efficiently utilized in other periods and thus to an overallocation of resources to electricity supply. Charging higher peak prices, in accordance with cost, would act so as to flatten and widen the peak. Capacity requirements would be reduced and therefore resources would be freed for other activities whose users were prepared to pay the real cost of supply. Lower off-peak rates, also reflecting cost, would stimulate off-peak consumption thereby permitting a more effective utilization of existing

4 The same result could be achieved through the application of block rate schedules, with price in the last block variable according to the time of use (peak and off-peak).
In brief, even a partial adoption of peak load pricing rules would produce an improvement in the allocation of resources towards the electric power industry and consequently would benefit the economy as a whole.

Likewise, it is alleged that the different rates applied by the electric utilities to the several classes of customers do not represent properly the discrepancies in the cost of their service. Although variations in cost are taken into account in setting the rates, demand or value of service considerations are said to play also an important role. It is the next objective of this chapter to investigate this so-called third degree discriminatory aspect of electric utility pricing, that is, the extent, if any, to which the distinct rates charged to the various classes of customers are based on differences in demand and not on differences in cost.

Price-Marginal Cost Relationships

Utilities point out that the apportionment of electricity among customer classes affects the cost of service. Significant cost differentials exist in the supply of electricity to residential, commercial, and industrial customers, justifying the charging of different rates to each of these groups. Specifically, the cost of service rises when moving

---

5 Of course, these conclusions assume that demand for electricity is price elastic. For some evidence in this respect consult Franklin M. Fisher, A Study in Econometrics: The Demand for Electricity in the United States (Amsterdam: North-Holland Publishing Company, 1962).

6 For example, see Charles F. Phillips, Jr., The Economics of Regulation (Homewood, Illinois: Richard D. Irwin, Inc., 1965), pp. 358-359.
from industrial to commercial to residential consumers, thereby supporting the use of lower industrial rates, followed by increasingly higher commercial and residential rates.

As stated in Chapter II, price discrimination takes place when the prices the seller charges for the various units of his product or products are not proportional to the costs of providing the units sold.  

This discrimination is of the third degree when the disproportions between prices and costs arise in several markets which the seller is able to distinguish, markets that not only must be kept separate but also must differ in elasticity of demand. Noting that from an economic efficiency viewpoint the relevant cost concept is marginal cost and that with regard to electricity supply there are three main markets, i.e., residential, commercial, and industrial, a more explicit definition of this type of discrimination for the electric power industry results: price discrimination of the third degree occurs when electricity is sold

---

7 This is the definition advanced by Davidson in his pioneer work on the subject and accepted, among others, by Steiner and Phillips. Consult Davidson, Price Discrimination, p. 23; Steiner, "Peak Loads and Efficient Pricing," p. 586; and Phillips, The Economics of Regulation, p. 307. An alternative definition of discrimination, used for instance by Hirshleifer, refers to the differences between prices and costs—as opposed to the proportions of prices to costs. See Hirshleifer, "Peak Loads and Efficient Pricing: Comment," p. 458. Because it is more common in industry practice to talk about relative changes or percentages—notice with respect to electric utilities the emphasis on rate of return calculations in the hearings of regulatory commissions—and since it is more meaningful to say that the price is for example equal to 2 or 3 times the cost rather than the difference between the two is 2 cents or 3 dollars, the first definition is the one adopted in this study.

8 This is the kind of cost employed by all of the authors in the two definitions of discrimination mentioned in the preceding footnote.
to residential, commercial, and industrial customers at prices such that

\[
\frac{P_r}{MC_r} \neq \frac{P_c}{MC_c} \neq \frac{P_i}{MC_i}
\]

where \( P \) denotes price, \( MC \) denotes marginal cost, and the subscripts \( r, c, i \) refer to residential, commercial, and industrial customers, respectively.

Given this definition, the test sought in this section for third degree discrimination in the sale of electricity required the estimation of price and marginal cost for the three different categories of consumers so as to verify whether the inequalities held. The same sample of the previous chapter, i.e., 56 privately owned electric utilities analyzed over the ten year period extending from 1959 to 1968, was utilized as the source of data for this purpose. Although price information on a customer class basis could be easily gathered, the same was not the case for marginal cost.

The distribution of costs among the three consumer classifications constitutes a formidable task. For example, it is exceedingly difficult to determine what portion of such things as overhead and underground lines, and general maintenance, supervision, and engineering expenses is attributable to residential, commercial, and industrial customers, respectively. In the absence of detailed studies on how costs vary with the kind of consumer, it has been said that all of these allocations are judgmental. Under the complexity of this problem, to avoid making an arbitrary assignment that would lead to the values of the three needed marginal costs—i.e., residential \((MC_r)\), commercial

---

(MC_c), and industrial (MC_i)—the ensuing statistical method was employed. Three subsamples of 40 observations each were selected from the overall pooled sample of 560 observations. The distinguishing characteristic was the destination of output sales. Observations in subsamples I, II, and III belonged to firms selling the greatest proportion of their output to residential, commercial, and industrial customers, respectively. On the average the proportions were 45 per cent for residential in subsample I, 41 per cent for commercial in subsample II, and 56 per cent for industrial in subsample III. Whereas ideally higher proportions would have been more suitable, e.g., 80 or 90 per cent, they could not be found. Notwithstanding, it was assumed that if a marginal cost MC was obtained from subsample I, this cost would be nearer the residential marginal cost than anything else, i.e., MC_I = MC_r. Similar reasoning led to the presumptions that marginal costs for subsamples II and III more closely approximated commercial and industrial marginal costs, respectively, i.e., MC_{II} = MC_c and MC_{III} = MC_i.

The three types of marginal cost were then derived from these subsamples via a four step procedure. First, the unit cost function of Chapter IV, \( c = \sum_{i=1}^{8} x_i^{b_i} \) or, alternatively, \( C = k + \sum_{i=1}^{8} b_i X_i \) where \( C = \log c, k = \log v, \) and \( X_i = \log x_i \), was fitted to each subsample. The results, compatible with the ones in that chapter, are displayed in Table 5-1. Second, both sides of the average cost (c) equation for each subsample were multiplied by output (q)—recall that the utilization factor (x_2) was defined as output (q) divided by the product of a

---

10 Appendix A includes the firm and year corresponding to each of the observations in these subsamples.
TABLE 5-1
MULTIPLE REGRESSION, CUSTOMER CLASS SUBSAMPLES, POOLED DATA, 1959 TO 1968

<table>
<thead>
<tr>
<th></th>
<th>I. Residential</th>
<th>II. Commercial</th>
<th>III. Industrial</th>
</tr>
</thead>
<tbody>
<tr>
<td>$b_1$</td>
<td>-0.398</td>
<td>-0.416</td>
<td>-0.440</td>
</tr>
<tr>
<td></td>
<td>(-10.842)</td>
<td>(-10.217)</td>
<td>(-11.983)</td>
</tr>
<tr>
<td>$b_2$</td>
<td>-0.566</td>
<td>-0.502</td>
<td>-0.478</td>
</tr>
<tr>
<td></td>
<td>(-9.774)</td>
<td>(-8.367)</td>
<td>(-11.997)</td>
</tr>
<tr>
<td>$b_3$</td>
<td>0.438</td>
<td>0.406</td>
<td>0.388</td>
</tr>
<tr>
<td></td>
<td>(9.507)</td>
<td>(7.920)</td>
<td>(8.944)</td>
</tr>
<tr>
<td>$b_4$</td>
<td>0.293</td>
<td>0.303</td>
<td>0.327</td>
</tr>
<tr>
<td></td>
<td>(8.121)</td>
<td>(7.259)</td>
<td>(8.924)</td>
</tr>
<tr>
<td>$b_5$</td>
<td>0.100</td>
<td>0.086</td>
<td>0.071</td>
</tr>
<tr>
<td></td>
<td>(4.008)</td>
<td>(4.999)</td>
<td>(5.840)</td>
</tr>
<tr>
<td>$b_6$</td>
<td>0.126</td>
<td>0.112</td>
<td>0.101</td>
</tr>
<tr>
<td></td>
<td>(4.480)</td>
<td>(3.631)</td>
<td>(5.056)</td>
</tr>
<tr>
<td>$b_7$</td>
<td>0.369</td>
<td>0.349</td>
<td>0.337</td>
</tr>
<tr>
<td></td>
<td>(4.425)</td>
<td>(4.566)</td>
<td>(5.727)</td>
</tr>
<tr>
<td>$b_8$</td>
<td>-0.004</td>
<td>-0.009</td>
<td>-0.013</td>
</tr>
<tr>
<td></td>
<td>(-3.142)</td>
<td>(-3.458)</td>
<td>(-3.621)</td>
</tr>
<tr>
<td>$k$</td>
<td>-6.661</td>
<td>-6.900</td>
<td>-7.107</td>
</tr>
<tr>
<td></td>
<td>(-4.102)</td>
<td>(-3.948)</td>
<td>(-5.003)</td>
</tr>
<tr>
<td>$n$</td>
<td>40</td>
<td>40</td>
<td>40</td>
</tr>
<tr>
<td>$R^2$</td>
<td>0.862</td>
<td>0.853</td>
<td>0.859</td>
</tr>
</tbody>
</table>

The figures enclosed in parentheses are the t-values corresponding to the regression coefficients.
constant $(8760)$ times capacity $(x_1)^{11}$ i.e., $x_2 = q/(8760x_1)$; hence, $q = 8760x_1x_2$—in order to arrive at total cost $(t)$. Third, taking the partial derivative of total cost with respect to output, while keeping all variables except the utilization factor as constants, produced the marginal cost (MC) function for each subsample. Specifically, in each case

$$t = qc = (8760x_1x_2)(\sum_{i=1}^{8} x_i^{b_i})$$

thus,

$$MC = \frac{\partial t}{\partial q} = \left(\frac{\partial t}{\partial x_2}\right)\left(\frac{\partial x_2}{\partial q}\right)$$

which can be readily shown to yield

$$MC = (1 + b_2)c$$

Finally, by assigning values to the variables in these MC equations, individual estimates in the three subsamples (I or residential, II or commercial, and III or industrial) of the marginal or extra cost of a kilowatt-hour of electricity, in mills, were obtained.

Having secured the marginal costs necessary to check for third degree discrimination, attention was turned to the required prices. For the subsample firms, rate data showing the average charge per kilowatt-hour for different quantities of electricity consumed was available from a report entitled *Typical Electric Bills*, published annually by the Federal Power Commission. Given the electricity outputs in each subsample, the appropriate prices, in mills per kilowatt-hour, were selected. Following the reasoning above, the prices in subsamples I, II, and III $(P_I, P_{II},$ and $P_{III})$ were the residential, commercial, and industrial prices $(P_r, P_c,$ and $P_I),$ respectively.

---

11 See Chapter IV, pp. 88-89.
The various proportions of price to marginal cost in the three subsamples were computed. The resulting mean figures were:

\[
\frac{P_r}{MC_r} = 2.77 \quad \frac{P_c}{MC_c} = 2.55 \quad \frac{P_i}{MC_i} = 2.13
\]

Tests performed at the 5 per cent level revealed that these ratios were significantly different from each other thus lending support, in conformity with the definition advanced earlier in this section, to the thesis that the pricing policies of electric utilities involve third degree discrimination. The figures indicated, for example, that apparently while in the residential market the price is 177 per cent higher than the marginal cost, in the commercial and industrial markets the prices are only 155 per cent and 113 per cent greater, respectively, than the corresponding marginal costs.

In the preceding analysis the kind of price employed was a weighted average based upon a representative block rate schedule. Given a descending scale of rates for incremental blocks of service taken, this weighted average exceeds the actual charge paid in the last block. Because it has been stated that the goal of an optimum allocation of resources could be achieved through block pricing, provided that the price in the last block equals marginal cost, and since it is likely that the price in the last block reflects marginal cost more accurately, it was decided to check for third degree discrimination using that particular price.

---

12. These proportions are presented in Appendix B.

13. The t-values obtained in the test comparisons of \( \frac{P_r}{MC_r} \) vs. \( \frac{P_c}{MC_c} \) vs. \( \frac{P_i}{MC_i} \), and \( \frac{P_c}{MC_c} \) vs. \( \frac{P_i}{MC_i} \) were 3.982, 12.738, and 10.072, respectively.
For each subsample observation, the price $P^1$ belonging to the last energy block of a typical rate schedule applied by the firm was obtained from the National Electric Rate Book, a yearly publication by state issued by the Federal Power Commission. The proportions of these prices to the previously derived marginal costs for the three subsamples were then calculated.\(^{14}\) The mean values,

$$\frac{P^1}{MC_r} = 1.66 \quad \frac{P^1}{MC_c} = 1.44 \quad \frac{P^1}{MC_1} = 1.05$$

being significantly different from each other at the 5 per cent level,\(^{15}\) again showed that third degree discrimination occurs in the electric power industry. The ratio was once more highest for the residential market and lowest for the industrial market, with the figure for the commercial market somewhere in between.

Summarizing, the results of this section appear to demonstrate that the distinct rates charged by the electric utilities to the several classes of customers do not represent proportionally the variations in the cost of the service to those customers. The values of the price to marginal cost ratios—either type, $P/MC$ or $P^1/MC$—for the three consumer classifications seem to imply that the least amount of discrimination, discrimination in the sense of proportional discrepancy of price to cost, takes place in the industrial sector, followed in increasing order by the commercial and residential sectors. A logical explanation is that industrial demand is more elastic than commercial and residential

\(^{14}\)Appendix B exhibits these proportions.

\(^{15}\)The t-statistics corresponding to the test comparisons of $P^1/MC_r$ vs. $P^1/MC_c$, $P^1/MC_r$ vs. $P^1/MC_1$, and $P^1/MC_c$ vs. $P^1/MC_1$ were 7.743, 23.346, and 15.547, respectively.
demands, as evidenced by the fact that industrial customers may find it possible not only to utilize substitute sources of energy but to generate their own electricity. It can be finally concluded that third degree or class discrimination, as currently practiced by U.S. utilities, may be a factor contributing to the less efficient employment of resources in the electricity segment of the economy.
CHAPTER VI

SUMMARY AND CONCLUSIONS

It will be recalled from Chapter I that this work had the two-fold objective of: (a) estimating empirically a cost function for electricity supply so as to note its implications in the areas of economies of scale, economies of utilization, marginal cost pricing, and price discrimination; and (b) introducing the relevant economic principles of cost and pricing in the electric power industry. This chapter summarizes the results and lists the conclusions of the investigation.

The structural characteristics of the electric power industry along with the generation, transmission, and distribution aspects of electricity provision were described in Chapter I. Justification for the use of the statistical rather than the analytical method to the study of cost functions was also given there. The relevant economic theory was explained in Chapter II. Besides the practical and aesthetic reasons, two compelling economic arguments against the maintenance of competition in the electric power industry were mentioned: declining long run and short run average costs for the individual utilities. Economies of scale were said to cause the former while heavy fixed costs were responsible for the latter.

Chapter II continued by pointing out that price discrimination, in comparison to uniform or simple monopoly pricing, can be clearly beneficial if it yields a larger output and the same or lower prices to
some or all customers, with higher prices to none. After dismissing first degree discrimination because of its impossibility in actual practice, it was noted that the presumably common combination of second degree (block) and third degree (class) discrimination, if uncontrolled, is likely to result in an increase in output but also in higher prices and profits. The section on regulation indicated that if the ultimate objective of the commission is to permit only a fair or normal return with a larger output, average cost pricing should be enforced. But if the objective is to achieve the largest output consistent with an optimum allocation of resources, marginal cost pricing should be tried.

It was then suggested that since the use of marginal cost pricing would give rise to losses for the firms, the same goal with total revenue now matching total cost could be achieved through the employment of a regulated discriminatory scheme consisting of either two-part pricing, with a per unit charge equal to marginal cost, or block pricing, with a charge in the last block equaling the same cost. Finally, the use of marginal cost pricing guidelines to solve the so-called "peak-load pricing problem"—the problem of meeting the peaking of electricity demand with some optimum capacity and the accompanying investments and costs, all in the framework of a pricing structure—was explained.

Existing empirical evidence on electricity cost surveyed in Chapter III, even though it agreed with the theoretical results, was far from conclusive. Three criticisms were made in support of this point: (a) the majority of the studies examined used either the plant or the generator as the unit of observation; (b) only generation costs were considered; and (c) data adjustments to remove the influence of the ceteris paribus factors—i.e., factors such as resource prices and
technology which tend to obscure the true relationship between cost and capacity, output, and number of customers—were not satisfactory.

To correct for these shortcomings a new average cost function for electricity supply was proposed in Chapter IV. Accordingly, the firm—being the economically relevant entity—was the unit of investigation, transmission and distribution costs were added to those of generation, and the ceteris paribus factors were included directly in the function as additional explanatory variables so as to account properly for their effect. Multiple regression analysis, applied to pooled observations from a sample of 56 privately owned electric utilities over the 1959-1968 period, produced an average cost equation of the form:

\[ c = v \prod_i x_i \]

or

\[ C = k + \sum_i b_i x_i \]

where the constant term \( k \) and the capital letters denote the natural logarithms of \( v \) and the corresponding lower-case letters, respectively. The equation—which followed the traditional economic division of electric utility cost into capacity, output, and customer components, other things equal—was also estimated (a) on the basis of cross-sectional observations, (b) with dummy variables for the sample years, and (c) for geographical location and size subsamples.

The regression results were encouraging. The signs of the coefficients were easily rationalized, the \( t \)-statistics indicated that the coefficients were all significant at the 1 per cent level, and the adjusted coefficient of multiple determination (\( R^2 \)) showed that in all cases
more than 81 per cent of the total variation in the cost per kilowatt-hour was accounted for by the eight independent variables considered.

It was demonstrated that economies of scale and economies of utilization occurred—meaning, respectively, that long run and short run decreasing average costs were the norm—in the supply of electricity and that the point at which economies of scale are exhausted had not yet been attained. Moreover, economies of utilization were in all cases more important than economies of scale as a source of cost savings, i.e., better use of existing capacity led to a greater reduction in unit cost than expansion in capacity.

Three major implications for public policy emerge from the findings of both economies of scale and economies of utilization in the electric power industry. In the first place, the theoretical postulate that marginal cost pricing would lead to losses for the individual firms is sustained. As James R. Nelson has said:

... neither M. Boiteux nor any other economist ... would claim that their studies have achieved the impossible task of eliminating the deficit problem from marginal cost pricing. What they have done is to demonstrate the exceptional importance and value of marginal cost analysis in a decreasing cost industry, due to the exceptional importance of avoiding prices which are below marginal cost. This is true, a fortiori, when decreasing costs are accompanied by multiple cost dimensions and by a tradition of price differentiation—as is true for electricity.1

Secondly, the use of promotional rates—not less than marginal cost—designed to encourage off-peak consumption would increase the utilization factor thereby resulting in lower average cost.

Finally, the findings support the main conclusion of the Federal Power Commission National Power Survey: that cost savings in the

1 Nelson, Marginal Cost Pricing in Practice, pp. xvi-xvii.
generation, transmission, and distribution of electricity could be achieved by moving from "isolated or segmented operations, and from existing pools of limited scope, to participation in fully coordinated power networks covering broad areas of the country." The reasons are twofold: (a) intersystem coordination, by permitting the service of wider regions, would justify larger additions to capacity. Thus, economies of scale could be taken advantage of; (b) better load diversity and reduced reserve capacity arising from interconnections and pooling of firms would lead to economies of utilization and hence lower cost per kilowatt-hour.

The second reason needs further explanation. The simultaneous peak load of a group of systems is always less than the sum of their separate noncoincident peaks, owing to differences in time zones, types of customers, living habits, and diversity from seasonal variations in demand. Strong interconnections to allow the sharing of facilities to meet the individual peaks would result in a reduced total capacity requirement thereby raising the utilization factor and lowering average cost. Similar improvements in utilization and cost could be obtained through a reduction in combined reserve capacity arising from these interconnections. This type of capacity is needed to cover scheduled maintenance and also to provide a margin of protection against two significant contingencies: unexpected load growth and emergency equipment outages. The reduction would be possible since, neglecting maintenance which could be appropriately arranged, it would be unlikely that unanticipated load increases and outages of units on all firms in the group would occur.

As quoted in Phillips, The Economics of Regulation, p. 597.
at precisely the same time.

The function estimated in Chapter IV also indicated that: (a) increases in the number of customers and resource prices were associated with higher average cost; (b) the younger the firm and the greater the thermal efficiency, the lower the cost per kilowatt-hour; and (c) there were cost advantages in using coal vis-à-vis other types of fuel. Three important conclusions can be derived from these results.

First, since the total costs of connecting the consumer and reading his meter, operating and maintaining the local distribution system, and performing the business operations are independent of output, a doubling or tripling of customer usage would lower average cost. On the other hand, a greater number of consumers would lead to higher per kilowatt-hour cost. Thus, if promotional campaigns are to be successful the ensuing increases in per capita consumption should more than offset the cost raising effect of attracting new customers.

Secondly, technological improvements leading to reductions in unit cost more than compensated for the increases due to higher resource prices during the 1959-1968 period. Among these improvements the most significant were: decreases in the heat rate, development of synthetic insulation, fully automated generating stations, new designs and materials for towers, underground cable for residential service, and extra-high-voltage (EHV) transmission. Consequently the average unit price of electricity fell during the period. However since 1968 this trend has been reversed. While the rate of technological progress has slowed,

---

increases in factor prices have not and therefore cost per kilowatt-hour and average price have risen.

Lastly, if electric utilities in a broad area were to be interconnected through a large transmission system, the most economical generating sites could be selected. This would involve choosing low labor cost areas and most important situating plants near the appropriate fuel sources. Hence, an integrated transmission network would reduce unit cost by permitting individual firms to take advantage of locational benefits.

It was argued in Chapter V that the different rates charged by American electric utilities to the several classes of customers, by not being variable according to the time of use (peak and off-peak), do not suitably mirror cost and consequently lead to a poor utilization of the economy's resources. Furthermore, it was shown that these rates do not reflect properly the variations in the cost of providing electric service to residential, commercial, and industrial customers. Thus, third degree or class discrimination was said to be inherent in the pricing policies of U.S. utilities. Because last block rates were apparently unequal to marginal cost, it was concluded that this discrimination, as currently practiced, promotes neither the most efficient employment of existing capacities nor optimal investment decisions.

Changes in demand patterns and technological advancement will undoubtedly affect the cost function of electricity supply in the near future. Public concern about the availability of fossil fuels (coal, natural gas, oil) as sources of energy, increases in their prices, and environmental considerations will tend to dampen the growth of electricity demand; furthermore, they will contribute to accelerating the
technological development and the use of alternative methods, e.g., nuclear power generation, which previously were thwarted by expense and/or safety factors. These areas, which have received very little attention in this study, can be the subject of fruitful additional research. Also of particular note is that the cost equation derived here is based on the only data that can be easily collected, namely data on private costs. Ideally, what should have been included are the total economic costs of electricity provision, total economic costs being the sum of private costs and social costs, where social costs comprise external costs such as those connected with pollution, and regulatory costs. However, the problem of empirically investigating the breadth of costs can be illustrated as follows:

... the costs associated with externalities and regulation are not easy to quantify. The inconvenience caused by a blackout typifies this problem—how is it possible to determine the costs of a power failure? The same difficulty exists concerning the cost of regulation. The costs associated with maintaining a regulatory commission are easy enough to assess, but this cost represents only a part of the total cost of regulation. Also included are the extra costs that must be incurred by the companies being regulated and, in addition, any inefficiency brought about through regulatory restraints must also be included.  

Hence, the problems involved in the measurement of the social costs of electricity supply constitute a worthy topic but one that will require a new and innovative methodology.

In sum, this study was motivated by a desire to analyze theoretically and empirically the areas of economies of scale, economies of utilization, marginal cost pricing, and price discrimination in the U.S. electric power industry. It was felt that previous works by public

---

4 Olson, Efficient Electricity Supply, p. 2.
utility economists did not satisfactorily treat or provide evidence on these subjects and that a more rigorous approach was needed. It is up to the reader's judgment to determine how far this inquiry succeeded in accomplishing these endeavors.
BIBLIOGRAPHY

Articles


134


**Books**


Robinson, Joan. **The Economics of Imperfect Competition.** London: Macmillan and Co., Ltd., 1933.


**Public Documents and Other Materials**


APPENDIX A

ELECTRIC UTILITIES INCLUDED IN THE OVERALL SAMPLE AND IN THE VARIOUS SUBSAMPLES

I. Overall Sample

<table>
<thead>
<tr>
<th>Firm Name</th>
<th>Identification Number</th>
</tr>
</thead>
<tbody>
<tr>
<td>Tucson Gas and Electric Company</td>
<td>01</td>
</tr>
<tr>
<td>Hartford Electric Light Company</td>
<td>02</td>
</tr>
<tr>
<td>United Illuminating Company</td>
<td>03</td>
</tr>
<tr>
<td>Florida Power Corporation</td>
<td>04</td>
</tr>
<tr>
<td>Florida Power and Light Company</td>
<td>05</td>
</tr>
<tr>
<td>Gulf Power Company</td>
<td>06</td>
</tr>
<tr>
<td>Tampa Electric Company</td>
<td>07</td>
</tr>
<tr>
<td>Savannah Electric and Power Company</td>
<td>08</td>
</tr>
<tr>
<td>Central Illinois Light Company</td>
<td>09</td>
</tr>
<tr>
<td>Central Illinois Public Service Company</td>
<td>10</td>
</tr>
<tr>
<td>Illinois Power Company</td>
<td>11</td>
</tr>
<tr>
<td>Mt. Carmel Public Utility Company</td>
<td>12</td>
</tr>
<tr>
<td>Indianapolis Power and Light Company</td>
<td>13</td>
</tr>
<tr>
<td>Public Service Company of Indiana, Inc.</td>
<td>14</td>
</tr>
<tr>
<td>Interstate Power Company</td>
<td>15</td>
</tr>
<tr>
<td>Kansas Gas and Electric Company</td>
<td>16</td>
</tr>
<tr>
<td>Kansas Power and Light Company</td>
<td>17</td>
</tr>
<tr>
<td>Central Louisiana Electric Company, Inc.</td>
<td>18</td>
</tr>
<tr>
<td>Gulf States Utilities Company</td>
<td>19</td>
</tr>
<tr>
<td>New Orleans Public Service, Inc.</td>
<td>20</td>
</tr>
<tr>
<td>Baltimore Gas and Electric Company</td>
<td>21</td>
</tr>
<tr>
<td>Boston Edison Company</td>
<td>22</td>
</tr>
<tr>
<td>Detroit Edison Company</td>
<td>23</td>
</tr>
<tr>
<td>Kansas City Power and Light Company</td>
<td>24</td>
</tr>
<tr>
<td>St. Joseph Light and Power Company</td>
<td>25</td>
</tr>
<tr>
<td>Atlantic City Electric Company</td>
<td>26</td>
</tr>
<tr>
<td>Public Service Company of New Mexico</td>
<td>27</td>
</tr>
<tr>
<td>Long Island Lighting Company</td>
<td>28</td>
</tr>
<tr>
<td>Cincinnati Gas and Electric Company</td>
<td>29</td>
</tr>
<tr>
<td>Cleveland Electric Illuminating Company</td>
<td>30</td>
</tr>
<tr>
<td>Columbus and Southern Ohio Electric Company</td>
<td>31</td>
</tr>
<tr>
<td>Dayton Power and Light Company</td>
<td>32</td>
</tr>
<tr>
<td>Ohio Edison Company</td>
<td>33</td>
</tr>
<tr>
<td>Ohio Power Company</td>
<td>34</td>
</tr>
<tr>
<td>Toledo Edison Company</td>
<td>35</td>
</tr>
</tbody>
</table>
### APPENDIX A (Continued)

<table>
<thead>
<tr>
<th>Firm Name</th>
<th>Identification Number</th>
</tr>
</thead>
<tbody>
<tr>
<td>Oklahoma Gas and Electric Company</td>
<td>36</td>
</tr>
<tr>
<td>Public Service Company of Oklahoma</td>
<td>37</td>
</tr>
<tr>
<td>Duquesne Light Company</td>
<td>38</td>
</tr>
<tr>
<td>Metropolitan Edison Company</td>
<td>39</td>
</tr>
<tr>
<td>Pennsylvania Electric Company</td>
<td>40</td>
</tr>
<tr>
<td>Pennsylvania Power Company</td>
<td>41</td>
</tr>
<tr>
<td>UGI Corporation (United Gas Improvement Company)</td>
<td>42</td>
</tr>
<tr>
<td>West Penn Power Company</td>
<td>43</td>
</tr>
<tr>
<td>Central Power and Light Company</td>
<td>44</td>
</tr>
<tr>
<td>Dallas Power and Light Company</td>
<td>45</td>
</tr>
<tr>
<td>El Paso Electric Company</td>
<td>46</td>
</tr>
<tr>
<td>Houston Lighting and Power Company</td>
<td>47</td>
</tr>
<tr>
<td>Southwestern Electric Power Company</td>
<td>48</td>
</tr>
<tr>
<td>Southwestern Public Service Company</td>
<td>49</td>
</tr>
<tr>
<td>Texas Electric Service Company</td>
<td>50</td>
</tr>
<tr>
<td>Texas Power and Light Company</td>
<td>51</td>
</tr>
<tr>
<td>West Texas Utilities Company</td>
<td>52</td>
</tr>
<tr>
<td>Monongahela Power Company</td>
<td>53</td>
</tr>
<tr>
<td>Wisconsin Electric Power Company</td>
<td>54</td>
</tr>
<tr>
<td>Hawaiian Electric Company, Inc.</td>
<td>55</td>
</tr>
<tr>
<td>Maui Electric Company, Ltd.</td>
<td>56</td>
</tr>
</tbody>
</table>

### II. Geographical Subsamples

<table>
<thead>
<tr>
<th>Subsample Name</th>
<th>Firm Identification Number</th>
</tr>
</thead>
<tbody>
<tr>
<td>East North Central (Wisconsin, Michigan, Illinois, Indiana, and Ohio)</td>
<td>09, 10, 11, 12, 13, 14, 23, 29, 30, 31, 32, 33, 34, 35, 54</td>
</tr>
<tr>
<td>West South Central (Oklahoma, Arkansas, Louisiana, and Texas)</td>
<td>18, 19, 20, 36, 37, 44, 45, 46, 47, 48, 49, 50, 51, 52</td>
</tr>
</tbody>
</table>

### III. Size Subsamples

<table>
<thead>
<tr>
<th>Subsample Name</th>
<th>Identification Number</th>
</tr>
</thead>
<tbody>
<tr>
<td>Small (capacity less than 750,000 kilowatts)</td>
<td>01, 06, 08, 12, 15, 18, 25, 26, 27, 41, 42, 46, 52, 55, 56</td>
</tr>
<tr>
<td>Medium (capacity between 750,000 and 1,500,000 kilowatts)</td>
<td>11, 24, 31, 32, 36, 37, 40, 44</td>
</tr>
<tr>
<td>Large (capacity over 1,500,000 kilowatts)</td>
<td>05, 23, 30, 33, 34, 47, 54</td>
</tr>
</tbody>
</table>
### IV. Customer Class Subsamples

<table>
<thead>
<tr>
<th>Subsample Name</th>
<th>Firm Identification Number</th>
</tr>
</thead>
<tbody>
<tr>
<td>Residential</td>
<td>04, 05, 18, 25, 26, 28, 42</td>
</tr>
<tr>
<td>Commercial</td>
<td>15, 17, 22, 24, 27, 45</td>
</tr>
<tr>
<td>Industrial</td>
<td>07, 19, 30, 33, 39, 43</td>
</tr>
</tbody>
</table>

The years of observation for the firms in I, II, and III above were 1959 to 1968. In the case of IV the years of observation were:

### APPENDIX B

**PRICE TO MARGINAL COST RATIOS FOR THE CUSTOMER CLASS SUBSAMPLES**

<table>
<thead>
<tr>
<th></th>
<th>Residential</th>
<th>Commercial</th>
<th>Industrial</th>
</tr>
</thead>
<tbody>
<tr>
<td>P/MC</td>
<td>P^1/MC</td>
<td>P/MC</td>
<td>P^1/MC</td>
</tr>
<tr>
<td>2.730</td>
<td>1.853</td>
<td>2.478</td>
<td>1.438</td>
</tr>
<tr>
<td>2.919</td>
<td>1.657</td>
<td>3.018</td>
<td>1.880</td>
</tr>
<tr>
<td>2.970</td>
<td>1.440</td>
<td>2.028</td>
<td>1.106</td>
</tr>
<tr>
<td>2.806</td>
<td>1.829</td>
<td>2.112</td>
<td>1.558</td>
</tr>
<tr>
<td>2.783</td>
<td>1.719</td>
<td>2.369</td>
<td>1.444</td>
</tr>
<tr>
<td>2.975</td>
<td>1.477</td>
<td>2.622</td>
<td>1.432</td>
</tr>
<tr>
<td>2.343</td>
<td>1.889</td>
<td>2.940</td>
<td>1.396</td>
</tr>
<tr>
<td>2.675</td>
<td>1.695</td>
<td>2.333</td>
<td>1.489</td>
</tr>
<tr>
<td>2.850</td>
<td>1.728</td>
<td>2.267</td>
<td>1.521</td>
</tr>
<tr>
<td>2.938</td>
<td>1.542</td>
<td>2.325</td>
<td>1.119</td>
</tr>
<tr>
<td>2.544</td>
<td>1.421</td>
<td>2.653</td>
<td>1.428</td>
</tr>
<tr>
<td>2.730</td>
<td>1.846</td>
<td>2.942</td>
<td>1.496</td>
</tr>
<tr>
<td>2.816</td>
<td>1.491</td>
<td>2.510</td>
<td>1.501</td>
</tr>
<tr>
<td>2.567</td>
<td>1.656</td>
<td>2.392</td>
<td>1.399</td>
</tr>
<tr>
<td>2.440</td>
<td>1.520</td>
<td>2.317</td>
<td>1.382</td>
</tr>
<tr>
<td>2.968</td>
<td>1.492</td>
<td>2.448</td>
<td>1.440</td>
</tr>
<tr>
<td>3.369</td>
<td>1.800</td>
<td>2.659</td>
<td>1.432</td>
</tr>
<tr>
<td>2.062</td>
<td>1.693</td>
<td>2.514</td>
<td>1.523</td>
</tr>
<tr>
<td>2.700</td>
<td>1.751</td>
<td>2.386</td>
<td>1.372</td>
</tr>
<tr>
<td>2.809</td>
<td>1.810</td>
<td>2.546</td>
<td>1.365</td>
</tr>
<tr>
<td>2.724</td>
<td>1.852</td>
<td>2.594</td>
<td>1.622</td>
</tr>
<tr>
<td>2.629</td>
<td>1.724</td>
<td>2.602</td>
<td>1.287</td>
</tr>
<tr>
<td>3.032</td>
<td>1.692</td>
<td>2.406</td>
<td>1.429</td>
</tr>
<tr>
<td>2.986</td>
<td>1.600</td>
<td>2.588</td>
<td>1.443</td>
</tr>
<tr>
<td>2.661</td>
<td>1.599</td>
<td>2.552</td>
<td>1.417</td>
</tr>
<tr>
<td>2.892</td>
<td>1.652</td>
<td>2.687</td>
<td>1.398</td>
</tr>
<tr>
<td>2.532</td>
<td>1.481</td>
<td>2.695</td>
<td>1.516</td>
</tr>
<tr>
<td>2.724</td>
<td>1.527</td>
<td>2.478</td>
<td>1.430</td>
</tr>
<tr>
<td>3.164</td>
<td>1.729</td>
<td>2.560</td>
<td>1.446</td>
</tr>
<tr>
<td>3.071</td>
<td>1.862</td>
<td>2.765</td>
<td>1.382</td>
</tr>
<tr>
<td>2.274</td>
<td>1.498</td>
<td>2.775</td>
<td>1.342</td>
</tr>
<tr>
<td>2.938</td>
<td>1.472</td>
<td>2.737</td>
<td>1.542</td>
</tr>
<tr>
<td>2.608</td>
<td>1.801</td>
<td>2.233</td>
<td>1.382</td>
</tr>
<tr>
<td>2.691</td>
<td>1.703</td>
<td>2.592</td>
<td>1.540</td>
</tr>
</tbody>
</table>
Note: \( P \) denotes the weighted average price, \( P^1 \) is the price belonging to the last energy block, and \( MC \) refers to marginal cost.

<table>
<thead>
<tr>
<th>P/MC</th>
<th>P(^1)/MC</th>
<th>P/MC</th>
<th>P(^1)/MC</th>
<th>P/MC</th>
<th>P(^1)/MC</th>
</tr>
</thead>
<tbody>
<tr>
<td>3.224</td>
<td>1.627</td>
<td>2.707</td>
<td>1.489</td>
<td>2.021</td>
<td>1.056</td>
</tr>
<tr>
<td>3.316</td>
<td>1.561</td>
<td>2.510</td>
<td>1.378</td>
<td>2.080</td>
<td>1.004</td>
</tr>
<tr>
<td>2.265</td>
<td>1.608</td>
<td>2.769</td>
<td>1.412</td>
<td>2.182</td>
<td>0.968</td>
</tr>
<tr>
<td>2.829</td>
<td>1.672</td>
<td>2.729</td>
<td>1.321</td>
<td>2.088</td>
<td>1.031</td>
</tr>
<tr>
<td>2.578</td>
<td>1.733</td>
<td>2.699</td>
<td>1.499</td>
<td>1.678</td>
<td>1.022</td>
</tr>
<tr>
<td>2.829</td>
<td>1.756</td>
<td>2.616</td>
<td>1.526</td>
<td>2.033</td>
<td>1.115</td>
</tr>
</tbody>
</table>
VITA

Mario M. Salinas, a permanent resident of the United States and a citizen of Venezuela, was born November 21, 1943. He attended the public schools in the city of Caracas in his own country and upon graduation received a four year scholarship from Mobil Oil Company to continue his education. The scholarship allowed him to come to Baton Rouge, Louisiana where he entered Louisiana State University in 1962. There he majored in chemical engineering and minored in business administration. During his years as an undergraduate student he joined various honorary fraternities and professional societies, among them Pi Mu Epsilon (mathematics), Phi Lambda Upsilon (chemistry), Tau Beta Pi (engineering), Phi Eta Sigma (freshman honorary), Phi Kappa Phi (general scholastic honorary), the American Institute of Chemical Engineers, and the American Chemical Society. In May, 1966, he received a B.S. degree, cum laude, and after a summer assignment for Mobil Chemical Company in New York and Caracas, he returned to Louisiana State University to pursue a doctorate in economics.

As a graduate student from 1966 to 1969, Mr. Salinas was the recipient of research assistantships from the Louisiana Water Resources Research Institute and Gulf South Research Institute, a fellowship from the Institute of International Education in New York, and a teaching assistantship from the University Economics Department. He became a member of several honorary fraternities and professional organizations, including Omicron Delta Epsilon (economics; he was president of the
University chapter for a year), the American Economic Association, and the Southern Economic Association. During the fall semester of 1969, the candidate took his general examinations for the Ph.D. degree, passing them with distinction. Subsequent doctoral fellowships, granted by the Louisiana State University Graduate School and the Institute of Public Utilities at Michigan State University, permitted him to complete the necessary research for his dissertation. In August, 1971, Mr. Salinas joined the Economics and Social Development Department of the Interamerican Development Bank in Washington, D.C., where he is presently employed.