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A Consumer's Guide to the Economics of Electric-Utility Ratemaking

MASTER

Prepared for:

U.S. Department of Energy
Administrator, Economic Regulatory Administration
Division of Utility Regulatory Assistance
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GUIDE TO SYMBOLS*

Acronyms

IOU = Investor Owned Utility
TVA = Tennessee Valley Authority
REC = Rural Electric Cooperative
REA = Rural Electrification Authority
FDC = Fully Distributed Cost
PDR = Peak Demand Responsibility
NPD = Noncoincident Peak Demand
AED = Average Excess Demand
MC = Marginal Cost
SRMC = Short Run Marginal Cost
LRMC = Long Run Marginal Cost
LRIC = Long Run Incremental Cost
FAC = Fuel Adjustment Clause
CWIP = Construction Work in Progress
AFUDC = Allowance for Funds Used During Construction
PLTD = Peak-Load/Time Differential

*The Acronyms are listed in the order in which they appear in the Guide. The equation symbols are listed in the order in which they appear in the Guide.

Equation Symbols

TC = Total Cost

TR = Total Revenue

TOE = Total Operating Expenses

TE = Total Earnings

OE = Operation Expenses

AD = Annual Depreciation

TX = Taxes

ROR = Rate of Return

RB = Rate Base

PREFACE

A Consumer's Guide to the Economics of Electric Utility

Ratemaking was prepared under the direction of the Illinois Office of Consumer Services which is funded by DOE Grant No. DE-FG-01-79-RG 09154. The Guide has been revised for general use for all consumers of electricity in the United States at the request of officials of the U.S. Department of Energy, Economic Regulatory Administration, Office of Utility Systems, Division of Regulatory Assistance.

This Guide was prepared by Dr. James I. Sturgeon, Research Director, Mid-America Economics Institute, Dr. John R. Munkirs, Sangamon State University, Dr. Alvin K. Grandys, Director, Illinois Office of Consumer Services, and Dr. Michael O. Ayers, Sangamon State University. The authors are grateful to Mr. M. Larry Kaseman, Mr. Paul E. Johnson and other anonymous reviewers of the U.S. Department of Energy for their comments on the Guide. All errors that may occur remain the sole responsibility of the authors. The views and opinions of authors expressed herein do not necessarily state or reflect those of the State of Illinois or any agency thereof.

INTRODUCTION

This book is for consumers of electricity. It is designed to aid in the understanding of electric utility ratemaking. The book deals primarily with the economics of electric public utilities, although certain legal and organizational aspects of utilities are discussed.

Each of the seven chapters addresses a particular facet of public utility ratemaking. Chapter One contains a discussion of the evolution of the public utility concept, as well as the legal and economic justification for public utilities. The second chapter sets forth an analytical economic model which provides the basis for the next four chapters. These chapters contain a detailed examination of total operating costs, the rate base, the rate of return and the rate structure. The final chapter discusses a number of current issues regarding electric public utilities. These include concerns related to fuel adjustment costs, advertising, taxes, construction work in progress, and lifeline rates.

Some of the examples used in the Guide are from particular states, such as Illinois and California. These examples are used to illustrate specific points. Consumers in other states can generalize them to their states and not change the meaning or significance of the points.

Each chapter is organized as a learning tool for consumers who want to understand public utility concepts. The first section of each chapter is an overall discussion of the topic for that chapter. After each discussion is a flow chart. This chart

provides a graphic view of the concepts discussed in the chapter. It can be referred to while reading the discussion, and referred to later as a convenient synopsis of the subject. At the end of the Guide is a set of definitions. The definitions are designed to give specific meaning to the key words and concepts in each chapter. They are designed to aid in understanding the topic of each chapter. By referring to the definitions citizens can become less intimidated by the sometimes unfamiliar and unique language involved in electric utility regulation.

Each sub-part of each chapter is designed to reinforce the others so that by the time citizens have read the chapter they will be equipped to discuss the topic in the chapter. The Guide concludes with a bibliography. This bibliography provides citizens with additional sources of information. Those wishing further detail on a particular point should consult sources listed in the bibliography.

CHAPTER :
ONE : THE PUBLIC UTILITY CONCEPT
:

INTRODUCTION

This chapter examines the evolution of the concept of public utilities. First comes a brief history of the relationship between business and government, designed to show that public utility regulation is not a new concept. Throughout a period of several hundred years government has been involved, in varying degrees, with the regulation of business. Public utility regulation is one form of government regulation which emerged during those centuries.

Some may find it unusual that a book designed to aid consumers in understanding present day electric utilities would contain such a history. It is unusual to some extent. But in order to understand how public utilities function today, one should have at least a nodding acquaintance with the past. Furthermore, without a clear understanding of the philosophy of public utility regulation and the purposes it is supposed to serve, it is very difficult to argue the case for regulation. One must come to understand that public utility regulation is one of the forms of regulation which establishes the relationship between business and government; a relationship with a long heritage. Many people criticize the study of the past as irrelevant but such ignorance of the past is often the cause of mistakes in the present. Therefore, in order to understand the philosophy of public utility regulation one must take the

time to understand its past and its evolution. Public utility regulation did not burst into existence in its present form; it emerged from social, political, and economic conditions, and it is still emerging. This emergence is a function of its evolution.

Following the historical development is a discussion of the rationale, or justification, both legal and economic, for public utility regulation. Next is an examination of the methods and goals of regulation. This discussion emphasizes the impact of regulation on the consumer, the investor, and the general welfare. After these discussions is a flow chart, providing a graphic view of the public utility concept. It can be referred to during the reading of the first part as a convenient synopsis. At the end of the Guide is a set of definitions, designed to give specific meaning to the key words and phrases in this chapter.

THE HISTORICAL RELATIONSHIP BETWEEN GOVERNMENT AND BUSINESS

The idea of publicly regulated utilities is relatively young, but the control, or regulation, of business by government is not. A brief look at history reveals that the public control of business dates at least to the ancient Greeks. However, about one thousand years of history can be skipped in order to begin with what might be called the modern governmental regulation of business. This dates from the rise of towns and cities in the 11th century.

With the rise of towns and cities came the development of guilds, both merchant and craft. By about 1300 almost all towns

in England and Western Europe had guilds. The guild was the primary form of organizing production in towns. While these organizations were started by businessmen and craftsmen, for the expressed purpose of discouraging competition and imposing general rules for production and marketing, guilds soon began to be supported and regulated by the towns. Towns began protecting guilds by allowing them to enforce their rules. By 1400 towns and cities began using variations of the guild to further their own purposes: they issued licenses and franchises to traders. Licenses and franchises, like the guilds, granted exclusive rights to conduct a particular business; that is, the businesses were monopolies.

Gradually political forms changed from that of cities and towns to what we know today as nations. These are sometimes called nation-states. With these changes came changes in economic organization. As nation-states evolved they began to take over the powers of the towns and cities. It was a short step from guilds and licensed traders protected by towns to the economic system known as mercantilism. Mercantilism was characterized by an effort to closely regulate all commerce and production, while at the same time supporting and encouraging it. The Crown (Monarch) issued Royal charters to persons and joint-stock companies which granted them the exclusive right to engage in a particular business. These charters included everything from shipbuilding to playing cards. Once the charter was issued the business was protected from competition by the Crown. In return the Crown received the allegiance of the people

to whom it granted charters. The Crown also received revenue from increased commerce via increased tax revenues. These revenues were used to support a standing army with which to maintain the position of the nation.

As the legislatures began to increase their power at the expense of Monarchs, businessmen (especially those who were not granted charters) began to demand that the shackles of government be removed from commerce. The courts were called upon to judge a number of cases involving the legality of exclusive charters. In 1603 in the case of *Darcey v. Allen* the English Court handed down a famous decision which began the unshackling process. In this case Darcey held a Royal charter to produce all of the playing cards in London. Allen brought suit, demanding that he, too, be allowed to produce playing cards. The Court ruled in Allen's favor; citing the evils of monopoly as its justification for the decision.

With this decision began a process of lessening the restrictions on business. As the restrictions on business were lessened more and more disputes arose concerning who had the right to engage in particular businesses. An offsetting weight was placed against the free and open right of anyone to engage in any business by the view of Lord Justice Hale in 1650. His view was later relied upon in other cases and is worth quoting:

"A man, for his own private advantage, may in a port or town, set up a wharf or crane, and may take what rates he and his customers can agree for crantage, wharfage, housellage, pesage; for he doth no more than is lawful for any man to do, viz., makes the most of his own If the king or subject have a public wharf, unto which all persons that come to that port must come and unlade or lade their goods as for the purpose, because they are the wharfs only

licensed by the queen, . . . or because there is no other wharf in that port, as it may fall out where a port is newly erected; in that case there cannot be taken arbitrary and excessive duties for crantage, wharfage, pesage, and so forth, neither can they be enhanced to an immoderate rate, but the duties must be reasonable and moderate, though settled by the king's license or charter. For now the wharf and crane and other conveniences are affected with a public interest and they cease to be juris privati only. As if a man set out a street in new building on his land, it is no longer bare private interest, but it is affected with a public interest.¹

The direction of regulation was clearly established by the year 1800. It was moving toward less and less restriction and regulation. At the same time society witnessed a lessening of restrictions on business it saw the introduction of controls, on a limited basis, on abuses of individual business freedom.

Out of the give and take of lessening and tightening controls the public utility concept begins to emerge and the modern relationship between business and government begins to take shape.

Let us shift our attention to the emergence of this concept as it occurred in the United States. To do this we must first examine the basis for the relationship between business and government. This basis is of course the United States Constitution. Next we will see how the courts have interpreted the Constitution in landmark decisions. This will lead to an understanding of how the courts judge regulation of public utilities.

¹Quoted in Eli Winston Clemens, Economics and Public Utilities, (New York: Appleton-Century-Crofts, Inc., 1950), p. 15.

In the United States the regulation of business by government is provided for in the Federal Constitution. The Constitution in Article 1, Section 8, gives the government the right "to regulate commerce with foreign nations, and among the several States, and with Indian Tribes." It is called the commerce clause. Article 1, Section 8, contains another clause that grants the government the implied right to regulate business. The so-called "necessary and proper clause" contains the provision for the implied powers of government and gives it the right:

To make all laws which shall be necessary and proper for carrying into execution the foregoing powers, and all other powers vested by this Constitution in the government of the United States or in any department or officer thereof.

The Constitution also clears the way for state regulation in the Tenth Amendment. It provides that "the powers not delegated to the United States by the Constitution, nor prohibited by it to the states, are reserved to the states, respectively, or to the people." This clause has also been interpreted as giving the Federal and state governments the power to police and safeguard the health, morals, safety and general welfare of the public. As such, it grants the right to pass laws to control persons and businesses and restrain them from endangering the public's general welfare, etc.

In the Fifth and Fourteenth Amendments the Constitution provides a brake for such regulation by granting persons the right that they shall not "be deprived of life, liberty, or property without due process of law; nor shall private property be taken for public use, without just compensation."

These two amendments are the basis for protecting the rights of business to be conducted privately and without undue interference from the government.

Thus the Constitution sets the broad limits for the distinction between the public and the private sectors of the economy. The language of the Constitution is clear in the sense that it provides for the regulation of business and for the protection of property from seizure without due process. Thus the relationship between government and business is a constitutional one.

The Constitution is not clear regarding how business is to be regulated nor which businesses can or should be regulated. This problem was left to the Judicial and Legislative branches of government.

The Judicial branch has been called upon to give specific meaning to the intentions of the Constitution and of laws subsequently enacted by the legislature. The Legislative branch has been called upon to write laws spelling how and under what conditions regulation should take place. The laws are reviewed by the courts and the Court decided in 1803 in *Marbury v. Madison* that "an act of the legislature repugnant to the constitution, is void" ²

The courts began articulating the relationship between business and government as early as 1827, but it was not until 1877 that the public utility concept properly emerges. In 1877

²Quoted in Clair Wilcox, Public Policies Toward Business, (Homewood, Illinois: Richard D. Irwin, Inc., 1971), p. 29.

the Supreme Court handed down its landmark decision in the case of *Munn v. Illinois*. Illinois had enacted a law requiring licenses for warehouses and elevators and prescribing maximum rates they could charge. Munn and Scott, proprietors of a Chicago storage elevator, refused to take out a license and charged rates above the prescribed limit. Suit was brought by the State of Illinois. The Supreme Court ruled in the State's favor. Interestingly, the decision was based on the view of Lord Chief Justice Hale in that the state could invade private property rights when the property was "affected with a public interest." *Munn v. Illinois* became the basis upon which the public utility concept was built. In the years immediately following the decision a number of industries were found to be affected with a public interest. Some of these industries were railroads, water, grist mills, stockyards, gas, telephone, and electricity.³

In response to the developing understanding of the government's role in regulating business, the Federal government created the Interstate Commerce Commission in 1887. The Commission was established to regulate business operation and rate setting in the railroad industry.

Public utility regulation via state commissions developed more slowly and it was not until twenty years later that the first state commissions were set up. In 1907 Wisconsin and New York took the lead, each creating a regulatory commission. By

³Ibid., p. 39.

1920 nearly two-thirds of the states had set up commission forms of regulation over public utilities, although most had only limited powers and jurisdiction.

The courts in deciding cases after 1877 used *Munn v. Illinois* as a basis to declare other industries public utilities. The trend seemed to have no practical limits. However, in 1923 the U.S. Supreme Court upheld a lower court in deciding the case of *Wolff Packing Co. v. Kansas*. In this case the Supreme Court found no monopoly, no emergency, and no obligation to the public. The decision was important for two reasons. First, the Court said that a business becomes affected with a public interest by the nature of its relationship to the public, not by declaration of a legislature. Secondly, Chief Justice Taft attempted to classify and define the criteria for a business said to be clothed with a public interest. He set forth three categories of such business: 1) those which operated under a public grant implying a duty of rendering service such as railroads, common carriers, and public utilities; 2) those which had been regulated since the earliest times such as innkeepers, cabs, and grist mills; and 3) those which were not public at their inception but had risen to be such through the passage of time.⁴

The *Wolff* case began to define what could be considered a public utility and in *Nebbia v. New York* the Supreme Court further defined the concept of public utilities. The concept affected with a public interest was interpreted to mean "no more

⁴Clemens, *Op. Cit.*, p. 318.

than that an industry, for adequate reason, is subject to control for the public good."⁵ In essence *Nebbia* settled the issue of the right of the states to regulate industries. Justice Roberts said ". . . so far as the requirement of due process is concerned . . . a state is free to adopt whatever economic policy may reasonably be deemed to promote public welfare If the laws passed are seen to have a reasonable relation to a proper legislative purpose, and are neither arbitrary nor discriminatory, the requirements of due process are satisfied"⁶

The Supreme Court also ruled that the states "upon proper occasion and by appropriate measures the state may regulate a business in any of its aspects, including the prices to be charged for the products or commodities it sells."⁷ This ruling touched off a controversy regarding what were to be appropriate measures. Through a number of cases dating from 1886 the opinion of the Court had been that the rates set by the states or commissions were subject to judicial review. In this review the Court had taken as a major concern whether the rates were confiscatory of the property by being set too low, thus violating due process.

However, in cases following *Nebbia* and culminating in *Federal Power Commission v. Hope Natural Gas* the Court moved toward the view that rates were the business of commissions and

⁵*Nebbia v. New York*, 291 U.S. 502 (1934).

⁶*Ibid.*

⁷*Ibid.*

were not per se subject to judicial review. In the Hope case the Court specifically held that the typical rate case does not contain issues that fall within the purview of the Court. The Court did not abandon its concern for the end result of a rate case, thus establishing the presumption that the commissions were within their rights to set rates, and that the Court would not favorably view overturning the various commissions.

Over the years the public utility concept has become deeply rooted in the law and social traditions of the United States. The concept has been thrashed out in a long history of cases and is not yet definitely settled.

Government has not always viewed electricity as a public utility. Before World War I most cities thought regulation was not needed. Competition, it was thought, would keep prices down. Many cities granted multiple franchises to electric companies. Chicago, for example, granted twenty-nine franchises between 1882 and 1905. In most all cases the result was not healthy competition working to keep prices down but many inefficient companies soon taken over by a strong one.⁸ In time cities began to face this situation and view electricity as a natural monopoly; so, many cities moved to regulation by public commissions. Both private utilities and the reform minded and emerging middle class were amenable to such regulation. The utilities viewed regulation as better than the other apparent alternative, public ownership. The new middle class reformers disliked the activities of the lower class party machines.

⁸Clemens, Op. Cit., p. 38.

Mayors and aldermen, they thought, could be replaced by commissioners who could concentrate on the technical aspects of regulation without spending time on political aspects. Commissions, it was argued, could regulate utilities, thus freeing them from fickle city councils which issued franchises in return for bribes.

Commissions could be established at the city or state level, but both utilities and reformers favored state commissions. State commissions seemed likely to be more honest and would represent a different political coalition than did cities.

State regulation began in New York and Wisconsin in 1907 and spread to 45 other states and the District of Columbia by 1922. It turned out to be less than an unqualified success. Some states had strong commissions which controlled the utilities but others had commissions controlled by the utilities. At best commission regulation was conservative and unwilling to act innovatively to bring about efficient operation and fair rates.⁹

An alternative to commission regulation was municipal ownership. With municipal ownership the public was thought to benefit in two ways. Those served by the city system enjoyed lower prices while those not served had a yardstick to measure their own prices against. If a city plant could produce power at 5 cents per kilowatt hour, so could a private company. In Cleveland, Columbus, Los Angeles and other cities both private and public systems existed. The competition between public and

⁹James C. Bonbright, Principles of Public Utility Regulation, (New York: Appleton-Century-Crofts, Inc., 1950), pp. 42-43.

private was sometimes direct and as a result these cities had among the cheapest rates in the nation.¹⁰

Government ownership was not restricted to cities. The Federal government embarked on major electric utility projects. The more famous of these are the Tennessee Valley Authority (TVA), the Bonneville Power Authority (BPA), and the Boulder Canyon Power Authority (BCPA). Each of these have had a tremendous impact on the electric utility industry as well as the nation as a whole. For example, when TVA began generating at Muscle Shoals, the city of Cincinnati, 200 miles away, applied to buy electricity. Cincinnati's privately owned utility company sharply reduced its rates in order to forestall this move.¹¹

Another form of non-private ownership is the cooperative. Most of the electric cooperatives emerged in the 1930's and were patterned after the Alcorn Associates, a group of farmers in Alcorn County, Mississippi, who formed a cooperative to string 100 miles of wire from TVA's Wilson Dam. The Alcorn Associates borrowed money from TVA and in one year made enough profit to repay one-half of the loan, charging prices no higher than those in nearby cities and towns.¹²

The Rural Electrification Cooperatives (R.E.C.'s) built upon the Alcorn model and in 1935 the Rural Electrification Authority (REA) was created. The REA was used to extend long term loans

¹⁰David H. Davis, Energy Politics, (New York: St. Martin's Press, Inc., 1978), p. 145.

¹¹Ibid., p. 148.

¹²Ibid., p. 153.

to the cooperatives. These REC's became the vehicle for electrifying rural areas. The REC's were based on the principle of providing service for an area, not just for the most profitable ones. The response of the privately owned utilities was four pronged. First, they engaged in "creaming," taking the most profitable customers and leaving the higher cost ones to the cooperatives. Second, they built "spite lines" to compete with REC lines. Third, they made it difficult for REC's to buy electricity from them, leaving them dependent upon Federal generating facilities. Fourth, they attacked them as socialistic and communistic or, at the least, as unfair government competition.¹³ (Of course the coops were privately owned but they were government financed.)

The privately owned utilities were under heavy attack. Not only did the TVA and the REC's threaten their physical stature, Congress began threatening their financial structure. The passage of the Public Utility Holding Company Act of 1935 marked the beginning of the end of weak government control over utilities. The Act brought control over their financial structure via the Securities and Exchange Commission (SEC). The SEC had to approve stock issues and it regulated the capital structure by determining the percentage of common stocks, bonds, and preferred stocks. The Act also amended the Federal Power Commission Act, giving it more latitude in dealing with rates.

The combination of federally generated power for REC's for rural distribution, financial control by the SEC, and rate

¹³Ibid., p. 154.

regulation by state commissions and the Federal Power Commission set the course for the development of the electric utility industry from 1935 until 1955.

For the time being we will put aside the history of the relations between government and business, and the emergence of the growth of the public utility concept.

This does not mean that the years following 1955 were not important, but different problems began to emerge. These problems range from environmental concerns to lack of proper rate regulation and include such things as proper rates of return, efficiency, and political manipulation of the regulatory structure. These problems will be discussed later in this book.

As this historical sketch showed, the public utility concept has been substantially defined and legitimized by the courts and Congress and is presently a bona fide method of regulating business. Yet it is not sufficient to justify regulation by drawing upon legal and social history. The justification of regulation is a larger problem and we will turn now to an examination of the causes and characteristics which justify public utility regulation.

RATIONALE AND CHARACTERISTICS

The previous section has established that throughout much of history, governments have been involved in regulating business, and society has differentiated what should be wholly private from what should be regulated in some manner. Next we must examine why certain industries are regulated while others are not. That is, what is the rationale for regulated industries in a country

that purports to encourage competition? Basically, the answer is that in some instances, competition is infeasible.

A brief digression on the nature of competition will be helpful in explaining the rationale for regulation. Traditional economic theory studies cause and effect relationships between market structure and economic performance. If a market is competitive, individual firms are forced to 1) charge a price equal to the average cost of production, 2) operate in a technically efficient manner, and 3) be guided by consumer demand in determining how much and what products need producing. If a firm falls short in meeting these criteria, competition from other producers forces it out of business.

A competitive market structure, by definition, means "many" individual producers. No precise number can be attached to the label "many," but it is understood that the number must be large enough to make collusion between firms a practical impossibility. Given this condition each firm will be forced to sell its product at a price equal to the value of the product, or, in economic terms, where price equals both the marginal and average cost of production. If a particular firm charges a price above the average cost of production, consumers are free to trade with its competitors.

If a particular firm is technically inefficient, its production cost will be greater than that of its rivals. Thus it will be forced to sell its product at a higher price or exit the market. Other things being equal, it will lose its customers to more efficient firms with lower production costs. Competition

forces each firm to strive to achieve and maintain maximum technical efficiency.

Lastly, no individual firm will be large enough to manipulate consumer demand. Economists call this condition consumer sovereignty. Consumer sovereignty means that the driving force of all economic activity comes from the individual. Only firms which produce what the consumer wants will have customers. In essence, each firm must correctly anticipate consumer demand and compete with other firms for the consumer dollar.

Traditional economic analysis also teaches that entrepreneurs should maximize profits and act in their own self interest. Adam Smith, an 18th century English economist sometimes called the father of free enterprise economics, states the case most succinctly in one of the most frequently quoted passages in economics, in saying that the entrepreneur "... neither intends to promote the public interest, nor knows how much he is promoting it ... He intends only his own security; and by directing that industry in such a manner as its produce may be of the greatest value ... he intends only his own gain ..."¹⁴ Society has nothing to fear from behavior motivated by self interest, since competitive market structures act as a regulatory mechanism. In essence, the argument is that as long as competitive market structures exist, individuals acting in their own self interest and profit maximizing will be

¹⁴Adam Smith, An Inquiry Into the Nature and Cause of The Wealth of Nations, (New York: The Modern Library, 1937), p. 423.

led as if by an "invisible hand" to promote the public interest. In turn, the public's interest in the production of goods and services is best served when firms are technically efficient, prices are equal to the average cost of production and consumer sovereignty prevails.

Under competition the efficiency of the firm and the equity of its prices are assured. But what happens when competition does not prevail? In the United States the government has sought to come to grips with this problem in two ways. One way has been antitrust laws. These laws were passed in an attempt to insure that markets would be competitive. When business tried to avoid or damage competition and create a monopoly the government, through the Justice Department and the Federal Trade Commission, was empowered to restore competition.

The second way, and the one which is of interest here, is through the regulation of certain businesses. This method is chosen when competition is deemed to be an inefficient mechanism for securing efficiency and equity.

Now we turn to the question of why competition is not efficient in some industries. This, in large part, is the justification for public utility regulation. As in many areas of human endeavor, there is not a common language to explain the phenomenon of public utilities. Lawyers use one set of words while economists use another set.

Essential Causes of Public Utilities

Lawyers use the idea of monopoly based upon a long legal tradition going back to *Darcey v. Allan* and the Lord Justice Hale's discussion of the wharf case. When they use the term

monopoly they mean one supplier or producer of a product. Sometimes a monopoly exists in a specific region of the country or in a town or city. This is usually the case with public utilities such as water, gas, and electricity.

When there is only one producer of a product that producer, if unchecked, can charge whatever the "traffic will bear." That is, it can extract a monopoly price for its product. Sometimes monopolies are created by enterprising businessmen who are able to drive out all the other competitors. Other times there is only room in a market for one producer. When this latter case occurs, we have what economists call a natural monopoly.

Economists use the term natural monopoly instead of the term monopoly when referring to public utilities. Natural monopoly differs from monopoly in that there is something in the technical relations of production which causes an inefficient use of resources if more than one producer is in the market. These technical relations are called economies of scale and therefore natural monopolies are a result of economies of scale. If economies of scale exist, the average cost of production decreases as production increases. FIGURE 1 below shows this graphically.

FIGURE 1

If the cost per unit of output falls over the entire range of output, then market demand can be most efficiently (at lowest cost per unit) supplied by only one plant. To illustrate this vital point, suppose that market demand for electricity is 40 kilowatt hours (KWH). If we use FIGURE 1 we see that one plant could produce this output at a cost per unit of 2 cents. On the other hand, if two plants, each producing 20 units of output, were built to meet the consumer demand of 40 units the cost per unit would be 4 cents. This is illustrated in FIGURE 2.

It is generally thought that electric utility companies are subject to considerable economies of scale.

FIGURE 2

Within a given geographic area an electric company usually performs all three of the main stages of production: generation, transmission, and distribution. Economists call this vertical integration, while lawyers say that there is an intimate connection of production with transportation and distribution. In some industries there appear to be significant economies of vertical integration, but in electricity these appear to be relatively moderate.

This does not mean that there are not significant economies of scale in each of the three stages. Rather it means when the three are put together in one firm there do not appear to be significant reductions in the average cost per kilowatt. The explanation of vertical integration in electric utilities is more historical accident than economic. For whatever reasons, electric utilities have been vertically integrated almost from their inception.

While there are not significant economies for the combined stages, each stage appears to have very significant scale economies. In the generation stage some are suggesting that technology has reached its limit and that the scale economies have been exhausted. They are arguing that due to increasing costs of construction, especially in newer plants, and the increasing cost of fuel to operate generating plants that electricity generation has become an increasing cost industry.* This may or may not be true but it is still the case that up to relatively large capacities there are economies of scale in generation. If the economies have been exhausted and if larger plants are built the average cost per unit will rise. It is still true however that a turbine with a capacity of 100,000 KWH has a lower average cost per unit than one with a capacity of 10,000 KWH.

The transmission of electricity involves moving bulk electricity from the generating plant to sub-stations located near markets. The lines which transmit the electricity are supported by steel, concrete, or wood towers.

Transmission appears to have very significant economies of scale. The Federal Power Commission has estimated that the

*This is a complicated argument and there is no general agreement as to whether it is an increasing or decreasing cost industry. Some would say the average cost curve has shifted upward due to increased absolute cost while others would say that market demand is so large that the economies of scale have been exhausted and the industry is operating in the increasing portion of the long run average cost curve. For an analytical discussion of this problem see the appendix following this chapter.

FIGURE 3

Source: Federal Power Commission, National Power Survey, (Washington, D.C.: Federal Power Commission, 1970), p. I-13-9.

average cost per KWH declines as the voltage of the transmission line increases from 230 volts (KV) to 765 KV and these economies are not totally exhausted even at 4 thousand megawatts. FIGURE 3 shows this relationship.

It is possible that the scale economies can be exhausted in transmission because there may be a limit to how much electricity can be carried over a line. At any rate the economies of scale in transmission are very large and do not appear close to exhaustion at the present time.

Even as large as the generation and transmission economies appear to be it is distribution at the local level where the case for natural monopoly most clearly exists. No serious student of

public utilities denies this existence and the absolute necessity for monopoly at this level.

To illustrate the point of why there are economies of scale in distribution let us examine two different cases. Suppose there are three companies distributing electricity in your town. Now suppose you buy your electricity from one company, your next door neighbor from another, and your neighbor across the street from yet another. Each company would have to install a cable to each home. Each would have to have a maintenance crew, a service department, a collections department and so on. All of these would be included in their average cost per kilowatt hour. If the example is extended to an entire city it does not require much imagination to see that the cables of different companies would be crisscrossing one another as would crews working on maintenance and repairs; all consumers would pay higher utility bills.

If a single company existed only one cable would be required and hook up wires to each house would be shorter. Also, the firm would have to have fewer crews, both maintenance and repair, because there would be less work because there are fewer cables, etc. A simplified example of both cases is pictured in FIGURE 4. Part A of FIGURE 4 illustrated the case of multiple companies and Part B illustrates the case for one company.

FIGURE 4

It is relatively easy to see why economies of scale are at work in the electric utility industry, especially in the transmission and distribution. These economies result in a strong argument for a natural monopoly in electric utilities. Yet the courts have held that the existence of natural monopoly is not sufficient for an industry to be declared a public utility. This leads us to the second essential cause of public utilities.

Again lawyers and economists use different words to explain this cause. Lawyers, going back to Hale and other legal precedents, use the term "affected with a public interest." This means that the product must take a "toll from all who pass" and if they do not pass the general welfare of the community will be harmed. For example, if there was only one manufacturer of hoola hoops many people might be affected but they could cease buying the product and little harm would come to the general welfare. The hoola hoop industry might be a candidate for the antitrust agencies, but not the public utility regulators. On the other

hand if the price of electricity is too high, the general welfare is greatly affected.

The products which lawyers say are affected with a public interest are those which economists say have inelastic demand. By this economists mean that the amount of the product demanded does not decline significantly as the price increases. One of the main reasons for this sort of relationship between price and demand is that a product is essential to the public welfare. That is to say the public would be significantly worse off without the product.

There are a number of reasons why the demand for a product tends to be relatively inelastic. The two which are most important for electricity are substitutes and income. When a product competes with other products and it is relatively easy for the consumer to interchange them, it is said to have close substitutes. If the product is to compete in price with these substitutes, the producer cannot raise its price above the level at which consumers will switch. In the case of hoola hoops a number of products might be substitutes, skate boards for example. But homeowners or apartment dwellers have few, if any products, which can be substituted for electricity in most of its homes uses.* Most consumers would be willing to pay monopoly prices for electricity rather than substitute candles, gas lamps,

*The exception is home heating. In this use natural gas can be substituted. However, the decision is most likely made at the time of construction or extensive remodeling. Changing from electricity to natural gas is a relatively expensive proposition once the furnace has been bought and installed.

or fireplaces for cooking. Indeed the public would be greatly harmed if it were forced to use antiquated techniques simply because they could not afford electricity. Thus on the score of substitutes we find that electricity has no close substitutes: this tends to make its demand inelastic.

If expenditures on a product represent a small percentage of income demand tends to be more inelastic. Economists call this income elasticity of demand. This means that as the price of the product rises or falls changes in the quantity demanded are insignificant because the total amount spent on the product has but a slight effect on the consumer's total expenditures. Until recent years the percentage of total income that consumers spent for electricity was quite small. This percentage has increased somewhat in the last three or four years. It is not known whether these increases have been sufficient to change the income elasticity of demand for electricity.

In summary, there are two essential causes for electricity being classified a public utility. Lawyers cite these as monopoly and affectation with a public interest. Economists call them natural monopoly and inelastic demand.

There are two other causes which classify an industry as a public utility. First, both economists and lawyers talk about physical limits. Many areas of commerce have physical limits. For example, the air will only hold so many radio waves before the signals jam together, resulting in garbled reception. The public is protected from this by limiting the number of radio signal producers. This concept is somewhat related to economies

of scale and we can cite an earlier example. If we examine the example of the distribution of electricity, not only would it be economically inefficient, but wasteful, to have more than one set of electric cables and wires. Imagine the maze of wires if a city had several electric power companies distributing electricity. If several companies were allowed to install electric cables, not to mention phone lines, water pipes, gas pipes, and television cables, it would not be long before the earth and sky would be a tangled maze of crisscrossing wires, many going to nearly the same place.

The second lesser cause which makes electricity a public utility is that set-up costs, or initial investment, are very high. Since there are significant economies of scale in each of the three stages of production, in order to begin producing and distributing electricity a firm must build a large generation plant and install transmission and distribution systems. One cannot start with a small plant and build it up over the years with revenues earned from the business. It must be built to handle all demand at the time it comes on stream. This means that a firm must invest a large sum of money up front before revenues can be earned. As a result of these high set-up costs many firms are unable to enter. If entry is precluded by high set-up costs market power may be exerted by existing producers.

From the causes of public utilities, we now turn to an examination of their characteristics. There is a fine line between causes and characteristics. The difference has to do with the direction of causation: we shall argue that

characteristics are derived from causes by the companies, the commissions, and the consumer. We shall examine five characteristics of public utilities all of which are involved in electricity.

Essential Characteristics of Public Utilities

First, as has been mentioned earlier, a public utility is confined to a limited geographic region. This means that each company confines its sales within a geographic limit: a city, a region in a state, an entire state, or a region of the nation. The supply of electricity in the United States is decentralized into a patchwork of geographically separate operations. There is no overall coordination of the system although neighboring firms sometimes pool capacity in order to meet peak load demand. Some of the regions and the companies which service them are listed in TABLE 1.

A second characteristic is that within the geographic region the company is regulated usually by a commission. A company must receive the consent of the commission to enter a new market, to supply new or to abandon established service, and the commission determines the rates. Absent regulation, the consumers would be at the mercy of the company and as a monopolist, the company could charge exorbitant prices. However, regulation does not guarantee that the consumer will not be overcharged or the company held to lower than a fair return.

A public utility company must receive from a commission a certificate of public convenience and necessity. This certificate is granted under the terms that the company agrees to

TABLE 1

THE TWENTY LEADING INVESTOR OWNED
ELECTRIC/GAS UTILITY FIRMS, ORDERED BY SIZE,
BASED ON DOLLAR SALES, 1976

Company	
1. Consolidated Edison	New York City
2. Pacific Gas & Electric	North and Central California
3. Southern Company	Ala., Georgia, Miss., Florida
4. Commonwealth Edison	Northern Illinois
5. Public Service Electric and Gas	New Jersey
6. American Electric Power	Ohio, W. Virginia, Indiana, Etc.
7. Southern California Edison	California
8. Consumers Power	Michigan
9. Detroit Edison	Southeast Michigan
10. Philadelphia Electric	Philadelphia
11. Florida Power & Light	Florida
12. Pacific Lighting	California
13. Middle South Utilities	Ark., Miss., & Louisiana
14. Duke Power	Western N. & S. Carolina
15. Virginia Electric and Power	Eastern Virginia
16. Texas Utilities	Central Texas
17. Niagara Mohawk Power	Upper New York State
18. General Public Utilities	New Jersey, Pennsylvania
19. Houston Lighting & Power	Texas
20. Northern States Power	Minnesota, N. & S. Dakota

Source: Fortune Magazine, July 1977, p. 172.

submit to the regulations of the commission. In return the company is given the sole right to generate, transmit and distribute (or any combination agreeable to both parties) electricity in that region.

It is important to understand that an industry which meets the criteria for regulation is not necessarily regulated. That is an industry may evolve into a natural monopoly and its product may be price inelastic and remain unregulated. Some are suggesting that automobiles fill this category. The reason that one industry is regulated and the other is not is probably historical. It may also be that the political and economic conditions are such that no one wants to take on the battle of trying to bring a large and powerful industry, such as automobiles, under direct regulation. The point is that public utilities are regulated and this is one of their characteristics.

A third characteristic of industries that meets the criteria for a public utility is that the buyer is at a disadvantage in the bargaining process. Clearly if a product has an inelastic demand, i.e. is essential to the consumer, and it can only be bought from one company, the result would be harmful to the buyer. If somehow the buyer could force arms-length pricing by some means it could bring about a fair price. But unless he/she has something to bargain with, i.e. some countervailing power, he/she cannot force arms-length bargaining. Thus the consumer must turn to a commission with control over rates to try to obtain

a fair price. As we shall see, some consumers of electricity may be able to negotiate a price, but these are usually large industrial users, not residential users.

The idea of different classes of consumers, i.e. industrial, commercial, and residential, leads to a fourth characteristic of public utilities, especially electric public utilities. In the case of electricity the product cannot be stored. This technological reality leads to the phenomenon of price discrimination. Price discrimination means that different classes of consumers are charged different prices. As will be explained in more detail in Chapter Six, the demand for electricity is typified by peaks and valleys during the year as well as during a day. Generating plants must have sufficient capacity to meet the peaks, because the product cannot be stored to meet peak demand. See FIGURE 5, page 35.

The utility attempts to smooth out the demand for electricity and thus use its capacity more efficiently. In order to do this it must charge different (lower) rates for consumers who use electricity during non-peak times in order to entice them to use the product. Traditionally it has been thought that these consumers are industrial or business concerns.* These companies, it is said, will have more stable but less inelastic demand for electricity. If the utility did not charge them a lower rate than household consumers they would use a substitute power source such as coal or natural gas. By offering a lower

* See Chapters Six and Seven for a detailed examination of peak load pricing.

TYPICAL DAILY LOAD PATTERNS

rate to this class of consumers the utility increases its revenue.

These economic and legal causes and characteristics of public utilities amount to justification for establishing a monopoly. But when this is done the consumer must be protected from monopoly prices and the inefficiency in the allocation of resources which usually accompanies monopoly.

The problem of how to regulate these monopolies has taken many forms and it is to an examination of these which we now turn.

METHODS AND GOALS OF REGULATION

The first method of control is statutes and ordinances. A statute is enacted by a legislature, either Federal or state, while an ordinance is passed by a city council. In both cases provision is usually made for enforcement by means other than private litigation. This usually means that businesses must register and file reports with a public agency. Additionally the law may provide for compliance by authorizing public prosecutors to bring civil suits to enjoin illegal behavior. Violation of statutes and ordinances may bring fines and imprisonment. Statutes and ordinances may be written in general terms and their enforcement left to a public agency, or they may be written in great detail. Usually the statute method has proven successful in laying down general principles, but detailed statutes have proven incapable of adapting to changing conditions.

Other methods of control are franchises, certificates, and licenses. All of these are used as a means of controlling entry into an industry or service.

A franchise is a contractual agreement which grants a

private firm the right to engage in a particular business. Franchises have been used to control municipal utilities. The length of the contract varies from perpetuity to a short term. They usually involve the exclusive right to construct and operate facilities along a city's streets. Since they are contractual in nature, franchises have sometimes been difficult to break when conditions have demanded. This weakness has relegated the modern use of franchises to governance of the use of city streets, although in the past they were used to grant sweeping monopoly power.

Certificates, usually called certificates of public convenience and necessity, are used to exclude competitors from regulated industries. Certificates are not contracts and hence bestow not rights, but privileges.

A license has a variety of uses. It can be used as a source of revenue for the state or city, for policing purposes, or as a mechanism to protect the public from unqualified practitioners of a profession. Licenses may be granted without cost to all who apply or they may be used to exclude competitors from a field. Like a certificate, a license is granted as a privilege and is usually temporary, renewable, and revocable.

Another series of controls by government is taxes, subsidies, and expenditures. These three may be used by government to direct business into and out of certain activities. They may also be used in an attempt to change consumer behavior. For example, taxes have been imposed on the so-called "vice goods" such as tobacco and liquor, as well as on

various luxury goods, in order to discourage consumption. Tax exemption has also been employed to induce conduct desired by government. For example, by taxing those who do not cooperate and exempting those who do the government has induced coal producers to fix prices and restrict output.

Subsidies are also used to induce desired behavior. Subsidies may be concealed or visible. A concealed subsidy may take the form of loans at less than market interest rates or of charging less than market price for the performance of some task. A visible subsidy may be a direct payment or gift. For example, in the 19th century public lands were given to railroads in order to insure settlement of open country. Presently cash payments are made to builders of merchant ships in order to keep the shipyards busy. Acceptance of subsidies is voluntary on the part of the business and compliance is bought by the government rather than commanded.

The government has regulated business by insisting upon specific provisions in agreements between it and private firms. If a firm wishes to perform a project under government contract it may be required to agree to certain terms which are not part of ordinary contracts. For example, the government may insist that a certain wage rate be paid to labor or that the firm not discriminate on the basis of race, color, sex, etc. This type of regulation has the advantage of being flexible and it is voluntary (the firm does not have to accept the contract awarded by the government). However, it can only be used when the government has something to buy or sell and hence is limited in scope.

Industry self-government is another form of control. This method employs rules voluntarily adopted by the members of an industry or trade. These rules are submitted to a public agency for review and approval and then enforced by both the industry members and the government. This method was used extensively during the depression under the auspices of the National Industrial Recovery Act and is used today in securities markets, export trade associations, some agricultural commodities and transport bureaus. Industry self-government is very similar to some of the trade guilds of the 13th and 14th centuries and its main disadvantage is the same as the guilds: the adopted rules need not take into account the interests of consumers or the general welfare. The main advantage of industry self-government is that it eases enforcement because of the voluntary cooperation of industry.

Related to industry self-government are wage-price guidelines. This device has been used repeatedly by Presidents of the United States to attempt to persuade labor and business leaders to hold down wages and prices. During the depression President Roosevelt appealed to businessmen to raise wages but not prices in order to increase demand. During the prosperity of the fifties President Eisenhower asked that wages and prices both be held down in order to curb inflation. Both attempts were largely unsuccessful. President Kennedy's attempt to hold down prices in the steel industry was somewhat more successful. But by 1965 the rate of inflation was increasing and guidelines on wages and prices ceased to have even moderate success.

Public opinion, when aroused, can sometimes bring results and government has disseminated information to the public in order to curb business and labor. For example, the Federal Power Commission has published rate comparisons between public and private companies in different cities. This may have done more to modify rate structures of privately owned utilities than some commissions, but publicity has its limitations. It is deeply resented by those it is used against, and they often launch counter campaigns based on different information. This often results in confusion rather than clarification and the public is often ill prepared to tell what is true and what is not.

Two methods used by the government involve direct government intervention. One is emergency controls. This method is used during times of emergency such as war or crippling work stoppages. Authoritarian controls then supersede the market. They have been used eighteen times, beginning in the Civil War. Very often the government takes control of production facilities. The purpose is to insure continued operation of essential products. At the end of the emergency period, control is returned to the owners and markets.

The other method is government ownership and operation. This method gives the government direct control of industry policies. It has been largely confined to cities and states in such areas as water systems, electricity, and liquor stores. However, the Federal government has a significant amount of ownership. These include the post office, atomic energy, and, as previously mentioned, the TVA in electricity generation. The

principal objection to government ownership involves questions of service and comparative efficiency. Others object on ideological grounds.

The final method of control examined here is administrative or commission regulation. This method is used when the policies of an industry are to be supervised in some detail. Usually a commission is composed of three or more members. Commissions are usually set up by a statute enacted by a state or Federal legislature. This form of control is widespread in both state and Federal governments. The first state commission was established by Massachusetts in 1838 to regulate banking, while the first Federal commission, the Interstate Commerce Commission, was established in 1887 to regulate railroads.

The principal advantages of commission regulation lie in the possible combination of expertise, continuous supervision, and prompt (and sometimes informal) action. Its main disadvantages stem from its involvement in politics and bureaucratic administration: sometimes commissions are influenced by political or vested interests rather than remaining independent. Also, a commission usually has its own staff and this staff can become bogged down in administrative detail, embroiling commissions in matters of procedure rather than in regulating the industry.

Another problem with commission regulation is that historically it has been subject to what is called "industry-mindedness." This means that many times commissioners either start out with or gradually acquire the attitudes of the

industries they regulate. There are a number of reasons for this occurring. For example, few people know as much about the electric utility industry as the people who work for it. Thus when commissioners want information on a technical or non-technical aspect of the industry they customarily call upon members of the industry. There is nothing particularly unethical in this practice, but one cannot expect industry representatives to endorse a view which they think will be harmful to their industry or company. If commissioners receive information only from industry representatives over time they usually acquire "industry-mindedness."¹⁵

¹⁵Louis M. Kohlmeier, Jr., The Regulators, (New York: Harper & Row, Publishers, Inc., 1969), pp. 69-72.

CHART 1

THE PUBLIC UTILITY CONCEPT

APPENDIX

The long run average cost curve is a composite of the cost of operating various sizes of plants. If the cost per unit decreases over the entire curve it looks like the one in FIGURE 1-A below, and is said to reflect economies of scale* and hence decreasing cost, over its entire length.

If the curve decreases and then increases it looks like the one in FIGURE 2-A and is said to reflect economies of scale (decreasing cost) up to point A and diseconomies of scale (increasing cost) to the right of point A. Point A represents the most efficient long run output for a plant.

*One thing that is important to note at the outset is that economies of scale are a phenomenon that are unique to a firm, not an industry. But in the case of most electric utilities one company has a monopoly in an area. Therefore in these areas the firm is the industry and it is possible to discuss economies of scale within an industry context.

FIGURE 2-A

Those who argue that the electric utility industry is a decreasing cost industry mean that it experiences economies of scale over the entire range of its long run average cost curve. They would say that the cost curve for the industry is similar to the one in FIGURE 1-A. Those who argue that the industry is an increasing cost industry mean that as output expands the average cost per unit increases. This includes the situation in which cost per unit decreases for a time and then begins to increase. To those who hold this position, the cost curve for the electric utility industry looks like the one in FIGURE 2-A.

Clearly, both arguments cannot be correct. There are two possible explanations for an increase in the cost per kilowatt hour.

First, the industry may have experienced growth to a point which has exhausted all of the economies of scale. In this case one could argue that the industry had been on the decreasing portion of the long run average cost curve, but now has had to build larger plants to keep up with demand and consequently has moved to the increasing portion of the cost curve. This is

illustrated in FIGURE 3-A. In this case the firm has moved from plant size 1, then to plant size 2. In both cases cost decreased. But when demand continued to increase a larger plant, plant size 3, had to be built and cost per unit increased. If this argument is correct, it means that greater efficiency would occur if the industry had more firms operating with plant size 2. That is, this argument leads to a breakdown in the idea that a natural monopoly exists in electricity generation.

FIGURE 3-A

The second possibility is that the industry remains a decreasing cost industry, but has experienced an increase in absolute cost. This means that the price of its inputs have increased and caused the cost curve to shift upward. This is illustrated in FIGURE 4-A. In this case the industry is still experiencing decreasing cost as larger plants are built to meet increased demand. This means that cost curve $Lac1$ and $Lac2$ in FIGURE 4-A have the same shape, both still having economies of scale. All that has happened is that the absolute level of cost has increased and the cost curve shifted from position 1 to

position 2. It is true that plant size 2A has greater costs than plant size 1, but this is due to increased absolute cost, not to exhaustion of economies of scale.

FIGURE 4-A

This argument is important because the implications for policy are considerably different. If the industry has become one of increasing cost the policy called for would be one which increased the number of firms, i.e. which provided competition instead of regulation in electricity generation. If it is still a decreasing cost industry the policy would be one of continued regulation with closer supervision of costs.

CHAPTER : THE ANALYTICAL FRAMEWORK:
TWO : AN OVERVIEW
:

INTRODUCTION

As noted in the preceding chapter, regulatory commissions are confronted with the general task of bringing about the same economic results in the electric utility industry - where privately owned electric utilities (IOU's) have a complete monopoly licensed by government that would naturally occur under competitive market structure conditions where there are "many" producers of a given product.¹ Specifically this means that a regulatory commission must strike a balance among the interests of the consumer, the investor, and the utility company, as well as those of the general public. Society at large may be interested not only in efficient and non-wasteful allocation of resources, but may also be deeply concerned about inflation, economic growth, and environmental problems. The consumer is concerned directly with being forced to pay overcharges, while utility stockholders are concerned directly with obtaining a fair return on their financial investments. Salaries, pensions, working conditions, etc. for a utility company's employees can directly affect, adversely or positively, the operation of a utility: this in turn, can adversely or positively affect prices paid by consumers and dividends received by stockholders. In

¹Obviously industries that are characterized by competitive market structures ("many" producers) are almost extinct in the industrial sector of the American economy.

actual practice, creating a balance between these often conflicting economic forces is primarily accomplished through political considerations.

As Professor Kahn, a noted utility economist, eloquently and aptly states:

Governmental price-fixing is an act of political economy, and, it bears repeating, this means that it necessarily and quite properly involves the striking of a balance between conflicting economic interest, influenced by political considerations in both the crassest and the broadest possible senses, and informed by community standards of fairness.²

It cannot be stated too often that public utility regulation is a political process. Justifiably or not, it is often widely believed that powerful vested interest groups (for the most part large industrial concerns and the public utilities themselves) have an inordinate amount of influence over the regulatory process. Students of the electric utility industry say that "in time" many, if not most, commissioners become "industry minded." Notwithstanding the political nature of the regulatory situation, most decisions made by commissioners concerning how much total revenue a utility should be allowed to collect for its services are justified through economic jargon - economic jargon that few except a small select group of lawyers and economists understand. Thus in order to make the regulatory commissions responsible and accountable to all its constituents, a clearer understanding of the economics of the utility industry is indispensable to consumers and consumer advocates. In short, a

²Alfred E. Kahn, The Economics of Regulation: Principles and Institutions, (New York: John Wiley & Sons, Inc., VOL. 1, 1970), p. 42.

political process with only minority participation cannot be expected to be responsible to the majority. In turn, responsible participation requires knowledge. A consumer organization will especially require knowledge of the economics of utilities, and familiarity with much of the jargon associated with it. This chapter displays the basic economic framework of the electric utility industry. Subsequent chapters discuss in more detail each major component.

THE ECONOMIC FRAMEWORK

Electric utility economics encompasses two basic processes. First one must consider the total cost (TC) a utility incurs when providing the public with a service.

Second, one must determine the rate structure or prices that a utility must charge its customers in order to bring in sufficient funds, total revenues (TR), to cover total cost. In essence, the regulatory commission attempts to equate total cost to total revenue. In equation form this would appear as:

$$1) \quad TC = TR$$

Total Cost

Total cost can be subdivided into two basic categories: total operating expenses (TOE) and total earnings (TE). Giving the basic equation:

$$2) \quad TC = TOE + TE$$

In turn, TOE consist of operation expenses (OE), annual depreciation (AD), and taxes (TX), such that:

$$3) \quad TOE = OE + AD + TX$$

Historically TOE has run around 75 to 80 percent of total cost. Operation expenses may well account for 55-60 percent of total cost; taxes for 5-10 percent, and annual depreciation for 10-15 percent. Contrary to conventional wisdom, it may not always be in the electric utility's interest to hold cost down. As Clair Wilcox, a noted regulatory economist, says of operation expenses:

Expenditures made on behalf of investors may be charged to consumers. Management may profit by voting themselves high salaries and substantial bonuses. Holding companies may gain by forcing their subsidiaries to purchase goods and services at excessive prices. In some cases, the groups controlling regulated companies may be incompetent. In others they may be dishonest. To guard against such possibilities, expenses of operations must be supervised.³

Operation expenses usually include such things as fuel, salaries, advertising, litigation, public relations, income taxes, and net investment tax credit adjustments, as well as various expenses such as financial and engineering consultants. Obviously consumers are quite interested in how much of the price they pay for electricity, if any, is due to such items as inflated salaries, wasteful advertising, and public relations. On the one hand, it is easily recognizable that for regulation to be effective a utility must not be allowed to incur extravagant costs and then pass them on to its customers through increased prices. On the other hand, a commission must allow a utility operation expenses large enough so as not to adversely affect the "service, safety and efficiency" of the utility's operation.

³Clair Wilcox, Public Policies Toward Business, (Homewood, Illinois: Richard D. Irwin, Inc., 1966), p. 305.

Students of electric utility economics have rarely found enforcement mechanisms for controlling total operation expenses to be overly vigorous.

Total earnings (TE) in electric utility economics mean virtually the same thing as profit to a non-regulated enterprise. In essence, profit and TE are synonymous. TE, then, refers to the amount of dollars a utility is allowed to collect in order to compensate investors. The commission determines the amount of TE a utility will need by multiplying the value of the utility's property by a fair rate of return (ROR). This can be represented by this equation:

$$4) \quad TE = ROR(RB)$$

The rate base (RB) is often defined as "the dollar value established by a regulatory commission of a company's plant, equipment and intangible capital used and useful in serving the public (minus accrued depreciation) on which the utility is entitled to a reasonable rate of return." In essence the rate base is the estimated cost of a utility's productive properties minus any accrued depreciation. Establishing this "estimated cost" is referred to as "valuation."

The valuation process includes several major considerations, which can be briefly characterized as:

- A) Determining which properties are tangible and reproducible
- B) Determining which properties that a utility owns are used and useful in serving the public
- C) Determining which costing methods should be employed in assigning values - original cost, reproduction cost, market value, etc.

- D) Determining whether to take cost data directly from a company's books, or by making an item by item appraisal
- E) Determining the proper amount of depreciation and subtracting this amount from the cost of the property
- F) Determining the value to be assigned to property that is tangible but not reproducible, such as land
- G) Determining the value to be assigned to property that is intangible, such as goodwill or franchise value

The value of an unregulated business is determined by the market. In other words, in the private sector the value of a business is whatever someone is willing to pay for ownership rights. But in the public utility sector the commission creates a utility's value primarily through determining costs. Thus the "value problem" forms part of the core of public utility regulation. The commission should strike a balance between the utility managers and investors, who quite naturally would profit from an inflated rate base, and consumers, who should not be forced to pay electric rates derived from an inflated rate base due to improper valuation procedures.

Equally important in determining total earnings (TE) is the rate of return (ROR). The ROR can be defined as "the ratio of total earnings to a specified rate base, expressed as a percentage of that base." In establishing an allowable ROR, commissions often use what is called the "cost of capital" method. Suppose a utility presented a commission with capitalization statistics as follows:

<u>Capital Structure</u>	<u>Amount Outstanding</u>	<u>Interest Rate</u>	<u>\$ Cost</u>
Bonds	\$ 5,000,000	8%	\$ 400,000
Preferred Stock	2,000,000	10%	200,000
Common Stock	<u>3,000,000</u>	15%	<u>450,000</u>
Total	\$10,000,000		\$1,050,000

Here the utility is telling the commission that its cost of capital is \$1,050,000. Assuming a rate base of \$10 million, the commission by granting the utility a 10.5 percent ROR would allow the utility to collect enough total earnings to pay the cost of invested capital. Establishing the proper ROR is a crucial factor in public utility regulation. As Professors Mosher and Crawford have so succinctly stated:

If the return is too high, it will spell high rates to customers which may easily lead to market curtailment of use. Again, high return will facilitate the sale of securities that may result in the expansion of the industry over and beyond the normal requirements. Because of the consequent fixed charges, such overexpansion may then impose an intolerable burden on ratepayers

On the other hand, if the return is too low, there would be a dearth of capital requisite for the maintenance of proper service standards, deterioration of the property, and a lack of extensions called for by the normal expansion of the population.

In the face of such possibilities, the determination of fair returns easily becomes a, if not the, major function of regulating bodies.⁴

Here again the role of the commission should be to strike a balance between the vested interest of investors, or public utility managers, and of utility customers.

⁴William Mosher and Finla G. Crawford, Public Utility Regulation, (New York: Harper Brothers Publishers, 1933), p. 225.

Combining equations 2, 3, and 4 we have:

$$5) \quad TC = ROR(RB) + OE + AD + TX$$

The first task of the regulatory commission in a rate proceeding is to determine the value and/or magnitude of the variables in equation five. Equation five is often called the "total revenue requirement" since enough revenues must be collected to cover total cost: $TC = TR$. It follows then that if the TR collected is to be large enough to cover TC, the TR requirement equation can be stated as follows:

$$6) \quad TR = ROR(RB) + OE + TX + AD$$

Total Revenue

Unlike many businesses, electric utilities do not sell their product at a single price. An electric utility divides its customers into classifications and charges each class a different rate/price per kilowatt hour (KWH) of electricity. The three basic classifications are 1) residential, 2) commercial, and 3) industrial. Commercial customers are also referred to as "Small Light and Power" customers while industrials are referred to as "Large Light and Power" customers. To illustrate this point, the average price per KWH of electricity charged these three customer classifications in 1976 was as follows:⁵

Residential	3.45¢ per KWH
Commercial	3.46¢ per KWH
Industrial	2.07¢ per KWH

⁵Statistical Committee of the Edison Electric Institute, Statistical Yearbook, (New York: Edison Electric Institute, 1977), p. 2.

In addition to price discrimination between customer groupings, electric utilities also provide "quantity discounts" within a single customer group. For example, in a "declining block" rate structure, quantity discounts are given for increased usage. A typical declining block rate structure for residential customers may look as follows:

0-100 KWH per month	5¢ per KWH
101-300 KWH per month	4¢ per KWH
301-500 KWH per month	3¢ per KWH
501- ? KWH per month	1.5¢ per KWH

As shown in Table 1, page 58, due to price discrimination between customer classes there is considerable difference between total usage and total revenues generated in each class. For example, considering only these three basic customer classifications, residential customers used 34.5 percent of the electricity generated but provided 41.1 percent of the total revenue; while industrial customers used 40.7 percent of the electricity generated but provided only 29.3 of the total revenue. Utility companies usually try to defend price differences on the basis of differences in cost. Of course, prices should always reflect differences in cost. But utilities, having monopoly market power, may attempt to charge higher prices where demand is strong and alternatives not readily available, and may charge lower prices where demand is relatively weak and alternatives readily available. Such price discrimination may be economically justifiable if it can be shown that it lowers cost and prices for all customers as a whole. Nonetheless, if electric utilities possess monopoly market power, price

discrimination may be an area of concern to commissions and consumers.

The commission, then has two problems concerning the total revenue requirement. First, it must determine the absolute dollar amount of total revenues needed. In electric utility economics total revenue is often referred to as the rate level. As noted above, the commission establishes the rate level or total revenue requirement by ascertaining the utility's total cost of doing business. Second, the commission must determine the amount of discrimination in prices that is economically justifiable. The actual KWH difference in prices between and within customer classifications is known as the rate structure.

CHART 1 on page 59 shows, in flow chart form, the relationship between TR and TC as well as the major components of each. A glossary of terms structured to parallel the flow chart is provided following Chapter Seven. Used in conjunction with each other the flow chart and glossary may provide a helpful educational tool for better understanding the basic framework of electric utility economics. Summarizing in equation form:

$$2) \quad TC = TOE + TE$$

$$\text{Where } 3) \quad TOE = OE + AD + TX$$

$$\text{And } 4) \quad TE = ROR(RB)$$

$$\text{If } 1) \quad TC = TR$$

$$\text{Then } 6) \quad TR = ROR(RB) + OE + AD + TX$$

In subsequent chapters we will undertake a more detailed yet still quite brief discussion of total operating cost, the rate base, the rate of return and the rate structure.

TABLE 1

USAGE AND TOTAL REVENUE DATA BY
CUSTOMER CLASSIFICATION IN
THE ELECTRIC LIGHT AND
POWER INDUSTRY, 1976

Customer Class	Usage		Revenues	
	Bil.KWH	Percent	\$Billions	Percent
Residential	613	34.5	21.1	41.1
Commercial	441	24.8	15.2	29.6
Industrial	725	40.7	15.0	29.3
Total	1,779	100.0	51.3	100.0

Source: U.S. Department of Commerce, The Statistical Abstract of the United States, (Washington, D.C.: U.S. Department of Commerce, 1978), p. 603.

CHART 1

THE ANALYTICAL MODEL

CHAPTER :
THREE : TOTAL OPERATING EXPENSES
:

INTRODUCTION

As we saw in the preceding chapter, a utility commission must establish a total revenue requirement which insures that total revenue equals total cost. For the purposes of utility bookkeeping, total cost (TC) is subdivided into two parts, total operating expenses (TOE) and total earnings (TE), as shown in this equation:

$$1) \quad TC = TOE + TE$$

In this chapter we will examine the TOE component of this equation.

Examining total operating expenses is important because the higher the operating expenses of a utility, the higher the total revenue requirement, and, therefore, the rate level. Historically, total operating expenses have amounted to 75 to 80 percent of a given utility's total cost and make up the largest sum to be controlled through rate setting. Thus, consumers' interests are best served by having total operating expenses at the lowest level which will provide satisfactory services. In other words, consumers want to be sure that the costs they must pay go for things that benefit them. Consumers generally do not want to pay expenses which simply provide a return for investors, nor do they want to cover the costs incurred for extravagant and unnecessary expenditures by management. Both consumers and

investors alike are interested in efficient operation of utility facilities. If an operation is to be efficient, costs cannot be distorted for any reason or in any manner.

PRIMARY ECONOMIC ELEMENTS

Operation Expenses

There are three major cost categories that make up total operating expenses -- operation expenses (OE)*, annual depreciation (AD), and taxes (TX). Thus,

$$2) \text{ TOE} = \text{OE} + \text{AD} + \text{TX}$$

The operation expenses component of the TOE generally consists of expenses for salaries, advertising, legal fees, fuel, public relations, and various services such as financial and engineering consultants -- those expenses incurred in running the operation.

In other words, OE are the expenses a utility company incurs while supplying customers with electricity. The functions upon which these costs are based are generally classified into six categories: production, transmission, distribution, customer accounting and collection, sales promotion, and administrative and general. A summary of the operation expenses for all investor owned utilities in the U.S. is presented, by category, in TABLE 1. Typically, operation expenses constitute between 55 and 60 percent of total operating expenses.

As can be seen, production or generating expenses account

*While reading this book, the reader should remain aware that in official public utility accounting (as well as in this manual) there is a distinction made between operating expenses and operation expenses. That distinction is the subject under discussion here.

for about 80 percent of operation expenses and 60 percent of total operating expenses. These percentages will vary, however, by utility company, depending on the type of generating facilities used. For example, a hydroelectric plant generally costs less to operate than does a steam or nuclear generating plant.

Once electricity is generated, it must be transmitted through power lines to some location from which it will be distributed to the various groups of customers. Expenses associated with this phase of an operation are called transmission expenses. Transmission expenses typically amount to approximately 2 percent of OE and 1 percent of TOE. Some companies have almost no transmission expenses, because they buy electricity from other companies which transmit the electricity to the purchasing company's distribution facility. Those companies that transmit their own electricity incur costs which vary with the distance between generation and distribution facilities. As this distance increases, transmission expenses rise.

Expenses associated with the distribution of electricity to the various utility's customers generally comprise 8 percent of OE, but only 5 percent of TOE. Like generation and transmission expenses, distribution expenses vary among utility companies. This variation is usually due to differences in the number and density of customers. In general, as the number and density of customers increase, the percentage cost for distribution decreases.

The remaining OE categories -- customer accounting and collection, sales promotion, and administrative and general --

TABLE 1

TOTAL OPERATING EXPENSES FOR
INVESTOR OWNED ELECTRIC
UTILITIES IN THE U.S.
1976

(\$000,000)

Expense Category	All U.S. IOU's
Operation Expenses	\$ 26,785
Production	23,470
Transmission	572
Distribution	1,906
Customer Accounts	1,055
Sales Expenses	49
Admin. and General	2,520
Depreciation	4,198
Taxes Other Than Income	4,174
Income Taxes	
Federal	520
Other	172
Total Operating Expenses	\$ 41,126

Source: U.S. Department of Energy, Statistics of Privately Owned Electric Utilities in the United States, 1976, (Washington, D.C.: U.S.G.P.O., April, 1978), pp. 34-41.

account for about 16 percent of operation expenses for all investor owned utilities in the United States and about 9 percent of TOE. These areas are a relatively small percentage of total operation expenses, but they are important aspects of costs. Further discussion of some of these costs is presented in Chapter Seven, Current Issues. The remainder of this section is devoted to a discussion of the remaining components of TOE.

Annual Depreciation

One cost incurred by any company involved in producing goods is the cost of wear and tear on production equipment. The wear and tear on the equipment and machinery causes a depreciation in the total value of the equipment and machinery used or found to be useful during any year. Thus the term developed to describe this type of cost is annual depreciation.

While annual depreciation of physical property of the utility is fundamentally an accounting concept, all plant and equipment producing electricity suffers "real" wear and tear. In discussing depreciation engineers talk about the life cycle of all of a utility's physical property used and useful in generating electricity and of the value of equipment actually used up in production. Accountants estimate deterioration in the use value of the physical property as a cost of doing business.

Once estimated, depreciation charges are made against current income to the firm, like all other forms of TOE. Such depreciation allowances are made against individual items of physical property, rather than against types or groups of physical property. This allows companies to make individual

assessments of the part of the usable engineering life which has expired and an individual assessment of annual cost to the firm for each piece of equipment.

Taxes

The final element in the current discussion is taxes. Historically, taxes have amounted to about 5 to 10 percent of TOE. This includes all revenues which a utility must pay to a governmental unit, including sales, property, social security, unemployment compensation, franchise, state and Federal excise, and income taxes. Since the utility must pay these taxes in the process of doing business, they are a cost, and recoverable from consumers through electric rates. Though a relatively small percentage of TOE, they are handled by the utility company in ways that are considered controversial. This controversy is discussed later in this chapter and in Chapter Seven as well.

METHODS OF EVALUATION

Many of the expenses a utility incurs are allowed if they are judged to be reasonable and necessary rather than extravagant or excessive. However, it is difficult to determine when a cost is extravagant and should be disallowed.

An alternative to disallowing costs, once incurred, is to scrutinize and control expenditures before they occur by requiring annual budgets of proposed expenditures. By 1975, nineteen commissions had the power to require that budgets be submitted in advance. But even these commissions lack budgetary control. Furthermore, no commission has either issued rules or established standards to govern expenditures. Without these

standards, and some budgetary control, commissions are left to a subjective examination of costs after the costs have been incurred.

One might think that management generally has an incentive to keep costs as low as possible, but since utilities are allowed to collect enough revenue to cover the TOE and a predetermined amount of total earnings, there is little monetary or regulatory incentive to hold costs down; indeed sometimes the opposite is true. This means that a regulatory commission has a responsibility to scrutinize costs. Implicit in their examination is the difficult problem of evaluating costs. It is usually presumed that costs are reasonable unless the case is shown to be otherwise. It is the responsibility of a company to show that a reported expense has actually been or will be incurred in the near future. It must also show that the expense was necessary for the conduct of business. We will now examine some of the problems involved in the evaluation of each element of total operating costs.

Operation Expenses

There are several problems typically encountered in evaluating the necessity and reasonableness of operation expenses. One such problem relates to management salaries. A commission has the problem of attempting to evaluate whether or not salaries are reasonable. Since they can be charged as a cost, there is an incentive for management to vote itself high salaries. This has happened in some companies -- but by no means all -- for both officers' and directors' salaries.

Another type of problem occurs when utilities buy equipment or services from holding companies or unregulated affiliates. For example, if a utility buys coal from a coal company with which it is affiliated and the coal company is unregulated, ordinary business price negotiation may be absent. In this case the coal may be sold to the utility at rates higher than market prices. The coal company shows the profit, while the utility incurs the costs, and the utility consumer pays an inflated rate. Commissions can examine the books and compare "transfer prices" (prices paid the coal company by the affiliate utility) to market prices to see if this practice is occurring in any of the utilities under its jurisdiction.

Costs which are accounted as charitable contributions also create problems. These contributions are justified by the utility company on the grounds that it is part of the community and is expected to be socially responsible. On the other hand, if consumers pay for these donations they are making involuntary contributions to organizations to which they might not choose to contribute voluntarily.

Somewhat related to such costs are public relations expenditures which attempt to promote goodwill for the company, or to seek public approval of proposed rates. Both of these expenses are incurred by the company, but the consumer's obligation to pay such expenses is difficult to assess, since some of them work against the goals of consumers. Recently these types of costs have been disallowed by public service commissions in some states.

Commissions have traditionally allowed companies to put the cost of litigating rate cases into operation expenses. However, they have sought to hold these costs to reasonable levels and have had the companies amortize them over a period of years, rather than charge them off in one year. Indeed, commissions have usually required that all non-recurring expenses be spread out over a number of years.

Utility companies incur expenses when they promote the sale of electricity to new customers. At one time it was thought that increasing consumption would lower costs, helping both consumers and investors. Recently some have argued that increased consumption leads to higher costs; the question is, should consumers be asked to pay, via advertising and promotional practices, the cost of increasing the return to investors at the expense of raising utility bills? Commissions have usually allowed these costs if they were not extravagant or excessive. However, some of these expenses are being challenged by consumer groups and public service commissions in some states are disallowing them. A more detailed examination of advertising expenses is to be found in Chapter Seven.

Depreciation

Whether the depreciation allowance is based upon accounting principles or engineering principles, it becomes a matter of judgment as to the number of years over which the actual cost must be written off. Thus a basic understanding of basic depreciation methods will assist an individual to apply these concepts to the practices being carried on by their commission.

It will also point up some of the difficulties involved in the concept of annual depreciation.

There are two primary methods by which a utility may choose to estimate depreciation costs -- the straight-line method and the liberalized method. It should be noted that each of the primary methods have variations which are adopted by companies on occasion. Both methods and some of their variants are discussed below.

Under the straight-line method the cost of the physical property, less the estimated salvage or scrap value of the item, is allocated in equal amounts over the asset's estimated useful life. This is based upon an engineering estimate which can be changed or adjusted at any time should circumstances prove the initial estimate to be in error. The straight-line method affords simplicity of computation once the useful life has been established.

A variation of the straight-line method is the sinking fund method. Under the sinking fund method lower depreciation allowances are made in earlier years and progressively higher allowances are made in later years. Proponents of the sinking fund method argue that such depreciation allowances more closely match the physical deterioration or use-value of the item in question. These "common sense" estimates, however, are seldom substantiated by reliable data, and are equally bound by human judgment.

Variations from the straight-line method which seek increasingly greater write-offs in earlier years of the useful

life of physical property are termed "liberalized depreciation." Liberalized depreciation accounting conforms to certain approved methods of computing depreciation allowances for Federal and/or state income tax purposes, and is applicable to property with a useful life of three or more years. Two of the liberalized methods in practice for tax purposes are the sum-of-the-years-digits method and the declining balance method.

Under the sum-of-the-years digits method, the annual deduction for depreciation is derived by multiplying the actual cost of the property, less an estimated salvage value, by the estimated number of years of useful life remaining, then dividing the resulting product by the sum of all the digits corresponding to total years of estimated service. For a property with an assumed life of 25 years, the sum of the digits would be $(25 + 24 + 23 \dots + 3 + 2 + 1) = 325$. (A simple way to calculate this figure is to multiply the number of years by the number of years plus one and divide by two, i.e., $(25 \times 26) \div 2 = 325$. In year number one the annual depreciation is 25/325ths of the cost less salvage value, while in year 25 the annual depreciation would be 1/325ths of that value.)

Another method of liberalized depreciation accounting is the declining balance method, in which the depreciation rate is stated as a fixed percentage (up to twice the applicable straight-line rate) per year, and the annual charge is derived by applying the rate to the net balance, determined by subtracting the accumulated depreciation deduction of previous periods from the cost of the property. When the property of any year is

almost fully depreciated, it is necessary to add to the reserve the small amount required to bring the reserve up to 100% of the retirement value (actual cost less salvage), or depreciation charges would continue in decreasingly smaller amounts to infinity.

The amount of annual depreciation can vary considerably, (depending upon which method the company chooses). The consumer is affected by this depreciation charge in a number of ways. First, depreciation is a cost which the consumer pays in order to help insure that funds will be available to replace worn out equipment. Second, depreciation charges are removed from the rate base, lowering the total revenue requirements. Third, depreciation is sometimes treated differently for tax purposes than for rate base purposes. These matters are discussed in more detail in Chapter Four and Chapter Seven.

TAXES

As noted earlier, a public utility is subject to several categories of taxes. Some of these taxes are allowed to be accounted for as a cost of doing business by commissions, while others are not. Typically, taxes such as sales, excise, property, social security and franchise are allowed as "ordinary expenses of doing business." One problem may arise here. Most of these taxes are levied by state and local government, primarily by the state. If a given unit of government becomes dependent upon the tax revenues received from taxing public utilities, that unit of government, knowing that these taxes are passed directly to a captive group of electricity consumers,

might push the taxes to a level not otherwise considered equitable. In other words, just as extravagant costs by management might possibly be included in TOE, so might "extravagant" taxes. Such taxes can cause an undue burden to be placed on electricity consumers.

To the extent that income taxes are considered by commissions as ordinary business expenses and hence included in TOE, regulated industry investors receive preferential treatment. In unregulated industries, income taxes are taken from the total earnings of a company, after ordinary costs of doing business are accounted for.

When income taxes are treated as costs, an automatically increasing spiral is built into utility rates. Higher rates due to taxes bring higher earnings, which bring higher taxes, which raise costs again.

Further discussion of taxes is to be found in Chapter Seven. The remainder of this chapter is devoted to an examination of court cases which have justified and defined the methods of allocating total operating costs.

COURT CASES

As noted at the beginning of this chapter, total operating expenses are an important ingredient in the ratemaking process. It has also been noted that traditionally they have been solely within the purview of management, and commissions have not supervised the costs of utility companies. However, since 1892, the Supreme Court has recognized the right of commissions to supervise costs. In that year, in the case of Chicago and Grand

Trunk Railway Co. v. Wellman, the court ruled that some provision must be made to disallow the practice of transferring earnings into operating expenses. The Court stated:

. . . It is agreed that the defendant's operating expenses were \$2,404,516.54. Of what do these operating expenses consist? Are they made up partially of extravagant salaries: Fifty to one hundred thousand dollars to the president, and in like proportion to subordinate officers? Surely, before the courts are called upon to adjudge an act of the legislature fixing the maximum passenger rates for railroad companies to be unconstitutional . . ., they should be fully advised as to what is done with the receipts and earnings of the company; for if so advised, it might clearly appear that a prudent and honest management would, within the rates prescribed, secure to the bondholders their interest, and to the stockholders reasonable dividends. While the protection of vested rights of property is a supreme duty of the courts, it has not come to this, that the legislative power rests subservient to the discretion of any railroad corporation which may, by exorbitant and unreasonable salaries, or in some other improper way, transfer its earnings into what it is pleased to call 'operating expenses.'

The Supreme Court has not consistently held this view. During the booming 1920's the Court ordered that operating expenses could not be questioned by commissions except in extreme circumstances. In the case of Southwestern Bell Telephone Co. v. Public Service Commission of Missouri, the Court held:

The Commission is not the financial manager of the corporation and it is not empowered to substitute its judgment for that of the directors of the corporation; nor can it ignore items charged by the utility as operating expenses unless there is an abuse of discretion in that regard by the corporate officers.

This view made it practically impossible to control expenses resulting from transactions between a parent company and its subsidiaries. It also allowed nearly any "legal" expense to be charged off to consumers.

In 1930 the Supreme Court, mindful of a flood of criticism, began taking steps to reverse this view. In the case of *Smith v. Illinois Bell Co.* (1930), the Court ruled that the Illinois Commission was empowered to reject costs incurred via intrasystem purchases of goods and services. The process of intrasystem purchases involves a subsidiary buying from its parent company or from another of the parents' subsidiaries. Since these are intrafirm transactions any price could be charged. The price then becomes a cost to the subsidiary, and it is allowed to recover that cost in its rates. The parent company may be under more or less strict regulation than some of its subsidiaries, and depending upon the circumstances, may wish to show expenditures in one firm and revenues in another. The problem is that intrafirm transaction prices are not subject to competitive market forces, and if exempted from commission scrutiny, they are not regulated at all. This process if allowed to function provides the mechanism for a utility to escape practically all regulation of its rates.

The Supreme Court expanded its revision to the *Southwestern Bell* case in the case of *Acker v. the United States* (1936). In this case it ruled that the regulatory authority could reject expenditures on the grounds that they were unwise. This gave much broader scope to control of costs by the commissions, and contradicted the view that costs were solely a matter of managerial judgment. As Justice Roberts said:

The contention is that the amount to be expended for these purposes is purely a question of managerial judgment. But this overlooks the consideration that the charge is for a public service, and regulation.

cannot be frustrated by a requirement that the rate be made to compensate extravagant or unnecessary costs for these or any purposes.

The courts have also been involved in delineating the scope of total operating expenses. In the case of Knoxville v. Knoxville Water Co. (1909) the Supreme Court ruled that annual depreciation falls into the category of operating expenses. It stated that the company is entitled to earn a sufficient amount to provide for the replacement of depreciable equipment when it comes to the end of its useful life. Further, the Court ruled that current repairs on facilities were to be included in operating costs.

In the Galveston Electric Co. v. Galveston case (1922) the Supreme Court held that taxes should be charged off as costs and that a utility was entitled to collect sufficient revenue from customers to cover these taxes. It also stated in a general way the elements of total operating costs and why they were important. In the Court's words:

In calculating whether the five-cent fare will yield a proper return, it is necessary to deduct from gross revenue the expenses and charges; and all taxes which would be payable if a fair return were earned are appropriate deductions. There is no difference in this respect between state and federal taxes or between income taxes and others.

In other words, the Court ruled that the determination of a proper return to the investor must allow the investor to recover all the expenses incurred, including taxes. This ruling is the basis for allowing income taxes to be treated as an operation expense, with all of the attendant difficulties.

This brief review of court cases indicates that the Supreme Court has established two things concerning total operating expenses: 1) the right of commissions to judge the wisdom and necessity of the expenditures of public utilities, and 2) the general categories into which they are divided. The commissions have been somewhat lax in the first case, but have generally followed the dictates of the courts in the categories of costs.

CHART 1

TOTAL OPERATION EXPENSES

CHAPTER : THE RATE BASE AS A
FOUR : COMPONENT OF TOTAL EARNINGS
:

INTRODUCTION

In electric utility economics the total earnings (TE) requirement is viewed as a cost of doing business. In turn the two basic components in establishing the TE requirement are the rate base (RB) and the rate of return (ROR). As Professors Koontz and Gable state:

The formula most commonly used for arriving at reasonable earnings is to multiply a fair valuation of the property used and useful for public service by a fair rate of return. Therefore, once a rate base has been determined, a regulatory commission must decide upon a rate of return that is 'fair.'¹

This chapter contains a brief examination of the TE concept and the rate base as a component of the TE requirement. The ROR as a component of the TE requirement is examined in Chapter Five.

TOTAL EARNINGS

As noted in Chapter Two, the total cost (TC) equation is stated as follows:

$$\begin{aligned} &1) \quad TC = TOE + TE \\ \text{WHERE} \quad &2) \quad TOE = OE + TX + AD \\ \text{AND} \quad &3) \quad TE = ROR(RB) \end{aligned}$$

Thus once total operating expenses (TOE) have been determined the problem becomes one of determining the TE requirement.

¹Harold Koontz and Richard W. Gable, Public Control of Economic Enterprise, (New York: McGraw Hill Company, Inc., 1956), p. 255.

It is important not to confuse TE with total revenue, income or earned surplus. In order to help make the basic distinctions between these terms more concise, consider the following definitions:²

TOTAL REVENUE (TR) - The actual dollar amounts a utility is authorized to collect from its customers. After subtracting total operating expenses from total revenue ($TR - TOE$), we get

TOTAL EARNINGS (TE) - The actual dollar amount a utility is authorized to collect in order to pay the cost of invested capital (interest, stock dividends and incidental capital expenses). After paying all invested capital expenses except dividends on common stock, we get

NET EARNINGS (NE) - The amount of actual dollars available for return to common stockholders as dividends or to be retained as earned surplus.

DIVIDENDS - A portion of the amount of actual dollars available for return to stockholders and actually distributed to them in form of cash disbursements.

EARNED SURPLUS (ES) - A portion of the amount of actual dollars available for return to common stockholders not actually distributed to them in the form of dividends but retained in the firm.

This brings us to a somewhat confusing but crucially important aspect of electric utility economics. Actual total earnings is the residual left over after subtracting the cost of doing business from total revenue (TR). Viewed in this manner it is easy to begin thinking that the size of a utility's TE is determined by the size of its TR. But precisely the opposite is the case, that is, the amount of TR a utility is authorized to

²Francis X. Welch, Public Utility Regulation, (Washington, D.C.: Public Utilities Reports, Inc., 1961), p. 483. The definitions used as well as the format have been altered but the basic idea for this kind of representation was taken from Welch.

collect is itself determined by the commission. In equation form this can be shown as follows:

IF 4) $TR = TC$

AND 5) $TC = TOE + TE$

THEN 6) $TR = TOE + TE$

Thus the amount of TR a utility is authorized to collect is arrived at by first determining the TE requirement and the TOE requirement.

Nonetheless it follows algebraically from equation six that actual TE is computed as follows:

7) $TE = TR - TOE$

It is true 1) that algebraically TE equals TR minus TOE, and 2) that from an accounting standpoint a utility's actual TE are computed by subtracting TOE from TR; but this must not be misunderstood as the method used by the regulatory commission in determining the actual dollar amount of TE a utility is authorized to collect. As stated, TE is viewed by the regulatory commission as a necessary cost of doing business. Once this cost is determined the utility is then authorized to collect enough TR to cover expenses incurred.

On the one hand, if a utility's actual TE after subtracting TOE from TR are less than the TE authorized by the commission, the utility may seek to increase its TR by petitioning for a rate increase. On the other hand, if a utility's actual TE are greater than the TE authorized by the commission, the commission may attempt to have the utility lower its rates, which will cause a drop in TR, which in turn will cause a decrease in actual TE.

As already noted in Chapter Two, in order to set the appropriate TE requirement for a utility, regulators must 1) establish the net investment in the utility, that is, the utility's rate base (RB) and 2) determine what constitutes a fair and reasonable rate of return (ROR) on the rate base. A utility's TE requirement can be shown in equation form as follows:

$$8) \text{ TE} = \text{ROR}(\text{RB})$$

In establishing a fair and reasonable RB, a fair and reasonable ROR and an appropriate TE level, the commission may attempt to strike a balance between the interest of the utility's investors, customers, and employees as well as the interest of the general public. For example, consumers are concerned that a utility's RB not be inflated and that they be required to pay only for the actual cost of plant and equipment used and useful in providing them with service. Investors are concerned that a utility's RB be an accurate reflection of their capital contribution and that the RB not be deflated or undervalued. Also, the ROR should be high enough to fairly compensate existing investors and allow for the attraction of new capital investment, but at the same time should be low enough to prevent the extraction of monopoly profits from consumers. After establishing a reasonable TE requirement by multiplying the dollar value of the RB by the fair and reasonable ROR, a commission could allow for the collection of higher TE in order to retard economic growth, or, conversely, restrict TE in order to lessen the adverse effects of a recession. In essence, a commission may authorize the collection of TE lower or higher than the TE

requirement arrived at from applying equation eight above in order to promote or retard the use of electricity.

PRIMARY ECONOMIC ELEMENTS

In rate base determinations, commissions seek to set a price for each of the individual items which collectively make up the rate base. These items are functionally divided into physical plant (tangible and reproducible), intangibles, and land (tangible and non-reproducible). Physical plant, in the context of ratemaking, includes machinery and equipment such as generators, transformers, and utility poles. Allowances called incidental costs, such as operating materials, supplies, prepayments, and working capital, are also generally included in this primary economic element of the rate base.³ Another major determinant of the rate base's physical plant may be an allowance for construction work in progress (CWIP). CWIP is an account on the company's books which represents the total amount of the funds expended for a utility plant under construction, but not yet in service. This item may or may not be included in the rate base, but ultimately, when placed in service, it will become part of the physical plant. With most commissions today, the extent of CWIP's inclusion in the rate base has become a major issue in the determination of earnings. This issue is discussed in Chapter Seven.

³For example, the Illinois Commerce Commission allows the inclusion in the rate base on a case by case basis of a 60-70 day working supply of coal for use in the generation of electricity. Commonwealth Edison Co. has been allowed a 90-100 allowance.

Beyond physical plant, a utility system may have on its books items which are not tangible but which have a monetary value to the firm. Such items as franchises and consents, patent rights, licenses, privileges and other intangible property may be included in the rate base because an acquisition cost has been associated to it. Such items as goodwill and franchise values, while once included, are no longer included, since no actual cash outlay is directly associated, i.e., it has no cost of production to the firm.

Land, which may include land rights and leaseholds, is another item included in the rate base. Unlike physical plant it has no cost of production and generally increases steadily in value. The latter factor alone makes the timing of its acquisition one of many issues concerning its accounting treatment and inclusion in the rate base. It is, moreover, a selectively small portion of the rate base, though not an inconsequential amount in total dollars expended.

ECONOMIC PRINCIPLES

ACTUAL COST OF SERVICE

Most commissions today use the actual money spent for primary economic elements in determining the total cost of properties devoted to the public service. The result is that these figures are largely removed from controversy, except for questions of retroactive fairness. Some commissions, however, do value these properties at other than the actual money outlay. In any case, regulators must necessarily make some arbitrary distinctions on matters of inclusions in the rate base and on

arriving at a new rate base. In other words, the relevant net rate base (RB) for revenue requirement purposes is the estimated gross value (GV) of the utility's property used and useful minus accrued depreciation (D), that is $RB = (GV - D)$. Gross value may be found by adding up the values the commission finds for the primary economic elements included in the rate base. Accrued depreciation then, is the sum total of depreciation attributable to these elements at the time of the rate base determination.⁴

USED AND USEFUL

In determining which items should be included in the rate base, commissions necessarily include only that portion of the primary economic elements which are devoted to the current operations of the company. Thus, the rate base might exclude such items as physical plant and equipment which has been or will be purchased or sold, in the process of reclassification, leased to others, held for future use, or under construction. The inclusion of property in the rate base should occur when the commission has made a critical review of the relevance of the costs before including them in the rate base. A determination by a commission in one proceeding that an item has been found "used and useful" does not mean that it will always remain so, or preclude the issue from arising in following proceedings.

⁴The reasonableness of a depreciation allowance for both operating expenses and net value of the rate base is still one of the most complex and controversial problems of determining the rate base.

VALUATION METHODS

In addition to determining which items are to be included in the rate base, commissions set the value of those items as well. Historically, commissions have adopted methods which value the primary economic elements so as to account for legal interpretations, as well as to strike a balance between the interests of the producers and consumers. In establishing the value of the items included in the rate base, commissions find themselves dealing with plant and equipment of various vintages: that is, plant and equipment of various ages and various technologies, purchased with dollars of unequal buying power. Thus, a working knowledge of valuation methodologies is essential to a basic understanding of the rate base process.

ORIGINAL COST

The "original cost" valuation method seeks to determine the actual cash outlay associated with the primary economic elements. Thus "original cost", sometimes referred to as the actual cost rule, sets value at the firm's actual or out-of-pocket cost. In practice, in applying the "original cost" method commissions may vary the actual cost rule and therefore establish a compromised rate base. Variations or modifications to actual cost valuation include historical cost--a cost of an asset committed to serving the public, having been incurred, is recorded as a "matter of history". (It is possibly the acquisition cost to the transferee company.) The term "prudent investment" cost refers to either an actual cost or a historical

cost with the distinction that it be prudent (neither obviously wasteful or dishonest).

Basically, in applying the "original cost" method most commissions record plant and equipment costs at actual cost. Acquisition (historic) costs are also recorded. Any difference between acquisition cost and original cost are credited to a special account which is subject to depreciation. If the excess of acquisition cost were included in the rate base, for ratemaking purposes, there is still a question regarding amortization rates. Thus, even with an actual cost rule and arms-length bargaining, establishing the rate base is far from being a standardized process.

Use of original costs, historical costs, or prudent investment costs allow regulators to simplify the verification of accounting records. These records are easily understood, minimize maintenance expenses, improve accuracy, speed the disposition of rate cases, make decision making more analytical, and provide uniform accounts for comparability. These factors in turn insulate the utility from fluctuations in its records that result from general economic instability, reduce the risk to investors, and promote investments in the utility based upon a return on costs. Unfortunately, this method alone does not account for changes in the value of money over time or for inflationary pressures which result in a declining rate of return in terms of the value of money.

REPRODUCTION, FAIR VALUE, AND REPLACEMENT
COST METHODOLOGIES

When establishing the value of the rate base, regulators have adopted a variety of valuation methods which seem to account for inflationary pressures and the purchasing power of money over the years. While possibly accounting for these factors, the vast majority of regulatory commissions have adopted original cost methods because of their simplicity. Regulators generally feel the value of other methods are outweighed by their resulting expense and rate case delay: consumers pay the expense, and the delay may adversely affect the financial health of the utility.

Regulators have relied upon the rate of return to account for such factors as inflationary pressures and the purchasing power of money. Thus a general understanding of some of the basic terms will suffice, unless one finds oneself in a state that applies something other than an original cost method. In that case, one must be prepared to unravel what is probably a unique method, and one that is difficult to quantify.

Reproduction cost is the cost of duplicating the existing plant and equipment at current prices. It has at least six main variations. Fair value is considered a composite measure which considers accrued depreciation on actual cost, reproduction cost when new less depreciation, and other factors, each weighted according to their effect on value. Replacement cost prices old plant at the price of a modern technology version. Historically, both the literature and the commissions have done little to distinguish the differences in these methods. The term fair value has often been incorrectly used when referring to any

methodology other than "original cost". Moreover, commissions are still referred to as "fair value" jurisdictions though some derivation of reproduction, replacement or fair value cost methodologies are actually used.

DEPRECIATION

Determining depreciation as an element of the rate base process is a central issue in determining total revenues the utility may earn. Since the allowance for depreciation impacts on both the absolute size of the rate base and on total operating expenses, it is an extremely important issue. The proper allowance for depreciation for the rate base's primary elements is among the most difficult problems of rate base determination. In practice, allowances for depreciation are both an accounting and an engineering matter. Therefore, accounting treatment identifies this allowance as a cost, while engineering treatment holds depreciation as a deduction to the remaining useful life of the primary economic element, which lessens its value to the firm.

From a blend of accounting convenience and engineering estimates, utility commissions make annual deductions to the rate base and record these allowances into an accrued depreciation reserve account. This accrued depreciation accounting for rate base purposes allows the utility to recoup capital investments in fixed assets in the form of a cash flow to the utility, i.e., an annual cost to the rate payer. Annual depreciation to the rate base must therefore be considered a cost of doing business or an operating expense. As a deduction to the rate base, the resulting net investment (gross valuation - accrued depreciation

reserve) is the valuation figure upon which the investor is entitled to a "fair and reasonable" rate of return. Net investment also represents costs to be recouped in the future from the customer over the remaining useful lives of the primary economic elements left in the rate base.

As discussed in Chapter Three, the choice of alternative accounting methods with proper depreciation allowance varies with human judgment. These judgments ultimately seek to account for the allowance's effect upon the earnings of the utility. As illustrated in FIGURE 1 below, provisions for depreciation of the rate base fall into basically two categories--uniform annual rates (straight-line) or variable annual rates (liberalized).

FIGURE 1

The simplest and most usual procedure is called the straight-line method. Use of the straight-line method results in a constant and uniform depreciation allowance rate applied to the rate base. It is often claimed that variations from the straight-line method more closely match the physical properties of depreciation. The physical property's use-value is then assumed to decline faster in earlier years than in later years. Among those methods which produce the highest depreciation allowance in earlier years and lowest changes in the last years

are the sum-of-the-years digits method and the declining balance methods (which depreciates physical property the fastest). It should, however, be noted that reasonable data to justify such high allowances is generally not available, and is uncertain at best. Commissions generally have held to the use of straight-line because of its simplicity, in spite of its lack of theoretical preciseness.

LEGAL EVOLUTION OF RATE BASE VALUATION

The measurement of the rate base has historically been the most significant legal issue confronting public utility regulators. As early as 1877, the Supreme Court was active in the legal evolution of the rate base concepts. In *Munn v. Illinois*, 1877, the courts refused to establish standards by which to judge the reasonableness of commissions' valuation decisions. In *Smyth v. Ames*, 1898, however, the Supreme Court reversed this decision and defined reasonableness for the rate base as the "fair value" valuation of that rate base. "Fair value" or the "worth" of the rate base at the time of the rate case was a concept which lasted for about 50 years. As such, the courts held that if the value of property had increased, then the utility should be allowed to benefit from its inclusion in the valuation of the rate base. By 1926, the "fair value" rule had reached its high water mark in the decision in the case of *McCardle v. Indianapolis Water Co.* The Court allowed the utility an annual yield of more than 300% on the original investment.

During the thirties and forties, the Supreme Court and regulatory commissions alike began the abandonment of "fair

value" rate base and began to value the rate base on the basis of original cost. The concurring opinions of Justices Black, Douglas, and Murphy in the 1942 Natural Gas Pipeline Case stated that "... the commission is now freed from the compulsion of admitting evidence on reproduction cost or of giving any weight to the element of fair value. The commission may adopt ... prudent investment as a rate base"⁵ In the Federal Power Commission v. Hope Natural Gas Co. Case, 1944, the Supreme Court more clearly delineated today's guiding principle. Justice Douglas said, "Under the statutory standard of 'just and reasonable,' it is the results reached and not the method employed which is controlling It is not the theory but the impact of the rate order which counts. If the total effect of the rate order cannot be said to be unjust and unreasonable, judicial inquiry...is at an end."⁶ In bringing the rule of "fair value" to an end, the Court said: "Rates which enable the company to operate successfully, to maintain its financial integrity, to attract capital, and compensate its investors for risks assumed cannot be condemned as invalid, even though they might produce only a meager return on the so-called 'fair value' rate base."⁷ Throughout this legal history, the courts consistently left the development of standards to the regulatory commission. Though no longer legally mandatory in the U.S., a

⁵Natural Gas Pipeline Co. v. Federal Power Commission, 315 U.S. 606.

⁶Federal Power Commission v. Hope Natural Gas Co., 320 U.S. 602.

⁷Ibid.

considerable minority of states still today maintain valuation of the rate base on the basis of the "fair value" doctrine.

CHART 1

TOTAL EARNINGS: THE RATE BASE DETERMINATION

CHAPTER :
FIVE : THE RATE OF RETURN AS A
: COMPONENT OF TOTAL EARNINGS
:

INTRODUCTION

As noted in Chapter Four, a utility's total earnings requirement is primarily determined by multiplying the valuation of the property used and useful for public service by a fair rate of return (ROR). In equation form this is stated as:

$$1) TE = ROR(RB)$$

Historically the courts and regulatory commissions have devoted most of their attention and time to rate base (RB) considerations but it is readily apparent that the rate of return is equally important, if not more so, in determining a utility's authorized total earnings (TE). For example, a utility with a \$5 billion RB and an allowable ROR of five percent would generate authorized TE of \$250 million. A one percent increase in the ROR, from five percent to six percent, would increase authorized TE by \$50 million or from \$250 million to \$300 million. However, to increase authorized TE by \$50 million through inflating the RB would necessitate increasing the estimated value of the RB by 20 percent or from \$5 billion to \$6 billion. In essence a slight variation in the ROR means much more in absolute dollar terms than does a substantial variation in the RB. Since many utilities have rate bases valued in the billions of dollars, small variations in the ROR allowance do in fact often increase TE by millions of dollars.

In establishing the allowable ROR the commission must again

attempt, to achieve equilibrium between the interest of both investors and consumers. In order to expand and modernize its facilities to meet the needs of an expanding economy the utility must be able to attract capital by selling stocks and bonds. TE must be high enough to attract needed capital, i.e., new investors, if the utility is to continue to serve its consumers. In addition there is an equity question regarding the monetary rewards allowed past investors. If a utility's ROR is inordinately low, the market value of its equity stocks and its dividend payments will no doubt decline. Past investors may have no recourse in such conditions but to sell their stock at a loss. Not only would this be unfair to past investors but it may negatively affect the attitude of future investors. The commission then must be careful to insure that a utility's TE are high enough to reward past investors fairly for their capital contributions and to attract additional investments. Nonetheless, if TE are excessively high it may unduly encourage expansion beyond economically reasonable limits. Moreover, as noted in Chapter Two, TE in electric utility economics is synonymous with net profits in non-regulated enterprises. Consumers confronted with few alternative sources of supply available in the market must be protected against paying electric rates which generate unreasonable profit levels. In theory the commission bears a heavy responsibility in maintaining a just and equitable equilibrium between its various constituents when ascertaining what in fact constitutes a fair and reasonable ROR.

This chapter contains a brief examination concerning 1) the basic economic elements to be considered in analyzing the ROR,

2) the primary methods available for evaluating the reasonableness of a given ROR, and 3) selected court cases pertinent to the evolution of our thinking regarding the ROR.

PRIMARY ECONOMIC ELEMENTS

TE is defined as the absolute dollar amount a utility is authorized to collect in order to pay the cost of invested capital (interest on debt, dividends on stock and incidental capital expenses). TE for a public utility is identical to after tax profits for a non-regulated business enterprise. The actual amount of TE a utility collects is expressed in equation form as:

$$2) \quad TE = TR - TOE$$

But the absolute dollar amount of TE authorized by the commission is more appropriately expressed as:

$$3) \quad TE = ROR (RB)$$

On the one hand, Equation 2 expresses actual TE as a residual arrived at by subtracting actual or realized TOE incurred from the actual or realized TR collected. On the other hand, Equation 3 expresses TE as a "cost of doing business" which the commission must establish so that the amount of TR the utility is authorized to collect can be determined.

The ROR is the ratio of TE (net profits) to a specified RB (net invested capital) expressed as a percentage. In equation form this is simply:

$$4) \quad ROR = \frac{TR - TOE}{RB}$$

Here again, Equation 4 represents the actual rate of return earned by the utility, not the ROR authorized by the commission.

On the other hand, Equation 5 below expresses the ROR as a "cost of doing business"; that is:

$$5) \text{ ROR} = \frac{\text{TE}}{\text{RB}} \text{ or rate of profit} = \frac{\text{net profit}}{\text{net invested capital}}$$

The ever recurring struggle in commission after commission is over that portion of TR collected which becomes profit.¹ Since the ROR and/or the rate of profit is simply TE expressed as a percentage of the RB, once the appropriate value of the RB is determined, increasing the authorized ROR increases TE and conversely, decreasing the authorized ROR decreases TE. The crucial question, then, becomes how to determine a fair ROR. When TE is seen as a necessary cost of doing business, i.e., as the money collected to reward or compensate investors, one is seemingly compelled to ask what the actual costs incurred by the utility are in securing capital.

The commissions and courts have overwhelmingly accepted the cost of service principle for determining the gross valuation of a utility's RB. Likewise, the predominant methodology accepted for determining a utility's relevant ROR is also based on the "actual cost of service" principle. In other words, investors must be compensated for supplying the utility with money. The actual cost of service principle in electric utility economics is widely accepted for purposes of establishing both the appropriate rate base and a fair ROR. As Bonbright says:

... The basic principle of rate making implicit in an actual-cost measure of the rate base goes a considerable

¹Clair Wilcox and William G. Shepherd, Public Policies Toward Business, (Homewood, Illinois: Richard J. Irwin, Inc., 5th ed., 1975), p. 361.

distance toward establishing the relevant tests of a fair rate of return. This principle is that of service at cost The actual-cost rule That is to say, this allowance is itself designed to cover a part of the total cost of service, namely, those costs incurred by the company in securing the necessary capital. Thus the twofold rule that a public utility may charge rates designed to cover its operating cost plus a fair return is converted into the apparently simpler rule that the rates of charge shall cover the company's total cost including its cost of capital.²

Corporations have two primary external sources for attracting funds: capital from the issuance of debt, and capital from the issuance of preferred and common stocks. A utility's total capitalization is called the sum of its long-term debt (primarily bonds), preferred stock and common stock. Bonds and preferred stock are often called senior capital while common stock is referred to as junior or equity capital.

There are three fundamental differences between junior and senior capital instruments. First, bonds and preferred stockholders usually have a contractual agreement specifying the rate of interest or dividends to be paid by the utility. Common stockholders are entitled to that portion of TE left only after the bond and preferred stockholders have been paid. Second, in the event of liquidation, bond and preferred stockholders again receive payment before common stockholders. Third, junior, or

²James C. Bonbright, Principles of Public Utility Rates, (New York: Columbia University Press, 1961), pp. 240-41.

equity capital, stockholders are the actual owners of the corporation and as such have voting rights in proportion to their stockholdings.³

The composite capital structure of all privately owned electric utilities in the United States is shown in TABLE 1, page 100.⁴ It appears from examining TABLE 1 that the capitalization ratios for electric utilities have remained relatively stable over the last decade with long term debt staying about 53 percent, preferred stocks about 11 percent, common stocks about 24 percent and retained earnings about 12 percent.

The following definitional schematic, first presented in Chapter Four, may again be helpful in envisioning how a utility incurs its capital service cost and also how it disposes of that portion of its TR it was authorized to collect to pay its capital service cost.

TOTAL REVENUE (TR) - The actual dollar amounts a utility is authorized to collect from its customers. After subtracting total operating expenses (TOE) from TR we get TE: $(TR - TOE = TE)$.

³Preferred stockholders are usually granted preemptive voting rights for electing a certain percentage of the Board of Directors if their dividend payments are not received when due. Moreover in recent years more and more preferred stock issues carry full voting privileges.

⁴During this time period (1967-1976) there were approximately 210 to 217 Class A & B investor owned utilities in the U.S. Class A utilities are defined as utilities that have operating revenues of \$2.5 million or more. Class B utilities are defined as utilities with \$1 million or more but less than \$2.5 million.

TABLE 1

THE COMPOSITE CAPITAL STRUCTURE
OF INVESTOR OWNED ELECTRIC
UTILITIES, 1967-1976

Capital Structure	<u>Year's Ending as of December 31</u>									
	1976	1975	1974	1973	1972	1971	1970	1969	1968	1967
Long Term Debt (primarily bonds)	51.4	52.3	53.0	52.3	53.1	54.2	54.8	54.6	53.8	53.0
Preferred Stock	12.4	12.4	12.2	12.1	11.8	10.7	9.8	9.4	9.6	9.6
Common Stock	24.8	24.0	23.5	23.8	23.5	23.3	23.2	23.4	24.1	25.2
Retained Earnings	11.4	11.3	11.3	11.8	11.6	11.8	12.2	12.6	12.5	12.2

SOURCE: Federal Power Commission, Statistics of Privately Owned Electric Utilities in the United States, 1967-1976 eds.

TOTAL EARNINGS (TE) - The actual dollar amount a utility is authorized to collect in order pay the cost of invested capital expenses.

NET EARNINGS (NE) - The amount of actual dollars available for return to common stockholders or to be retained as earned surplus. After paying dividends to common stockholders, we get

EARNED SURPLUS (ES) - A portion of the amount of actual dollars available for return to common stockholders but not actually distributed to them in the form of dividends. For ratemaking purposes earned surplus is treated as a component of common stock.

Traditionally, the accepted accounting practice in corporate finance is to treat earned surplus (ES) as belonging to the common stock account. In electric utility economics ES is also treated as a component of equity capital or junior stock. Needless to say, as always, even when there is agreement that the cost of service principle provides the most objective and equitable approach to establishing a fair ROR, the crucial problem remains of determining exactly what the actual cost of service for providing capital is or should be. It is to this question that we now turn our attention.

ROR METHODS AND EVALUATION TECHNIQUES

In most utility rate cases the criteria used to establish the relevant cost of service or fair ROR generally includes:⁵

- 1) COST OF CAPITAL - Here an attempt is made to measure the utility's actual average payments to their past and present security holders as well as an attempt to measure the average cost of new capital.

⁵Other criteria often included in ROR rate hearing discussions include the efficiency of management, national and regional economic conditions, the utility's obligation to pay fixed charges already incurred or perhaps the value of a utility's service to its customers.

- 2) COMPARABLE RETURNS - Here an attempt is made to compare the utility's ROR with the ROR in other enterprises (regulated and unregulated) with comparable risk.
- 3) ATTRACTION OF CAPITAL - Here an attempt is made to estimate how high the ROR should be in order to motivate capital suppliers to be forthcoming with the necessary amounts of capital investments the utility must have in order to continue providing a service to the public.

We will discuss each of the three major criteria, cost of capital, comparable earnings, and capital attraction. All three are extremely important in ROR rate hearings and the relative importance given any particular criteria is generally a matter of local circumstances and personal value judgments. As Professors Wilcox and Shepherd aptly state:

The rate actually allowed by the commissions and the courts has been conventional or arbitrary to a degree. It has usually been based on expert testimony and rules of thumb, with little pretense of economic analysis. There has been no real study of the conditions governing investment decisions, the character of alternative investment opportunities, or the expectations that must be satisfied if new investments are to be made. Bankers and brokers appearing for the companies give their opinion that future risks are likely to be great and that earnings consequently must be high if securities are to be sold. Witnesses for the public point out that risks in the past have been small. The commissions and the courts have exercised judgment as best they can, coming up with a figure that they rarely attempt to explain. Usually, this figure has fallen somewhere between 6 and 10 percent.⁶

Cost of Capital

The cost of capital is simply the ROR demanded by investors from the utility for providing the utility with money. After determining a utility's actual capital structure one can begin to

⁶Clair Wilcox and William G. Shepherd, Public Policies Toward Business, (Homewood, Illinois: Richard D. Irwin, Inc., 1975), p. 371.

attempt to compute its actual cost of capital. As Professor Bonbright says:

This threefold division of the corporate capital by reference to its major sources permits the analysts to compute separately the cost of the debt capital, the cost of preferred stock capital, and a cost or cost equivalent of the common-equity capital. The separation is very helpful, since the cost of the two classes of senior capital can usually be computed with a close approach to accuracy, leaving only the so-called cost of the equity component subject to major differences of opinion.⁷

Assume that Moody's and Standard and Poor's, two benchmark financial reporting firms, have rated a particular utility's bonds AAA and that the going market price of AAA securities is 6.0 percent. Also, suppose that the cost of preferred and common stocks for this utility is judged to be 7 and 11 percent, respectively. Given a capital structure consisting of 50 percent long term debt, 12 percent preferred stock and 38 percent common stock, the cost of capital can be computed as follows:⁸

<u>Capitalization</u>	<u>Capitalization Ratios</u>	<u>Interest Rate</u>	<u>ROR on Total Capital</u>
Debt	50%	Times 6.0% Equals	3.0%
Preferred	12%	Times 7.0 Equals	0.84
Common	38	Times 11.0 Equals	<u>4.18</u>
Percentage Cost of Total Capital			8.02%

In this example the firm's fair ROR is computed at 8.02 percent. Assuming this utility has a \$2 billion rate base, its

⁷James C. Bonbright, Principles of Public Utility Rates, (New York: Columbia University Press, 1961), pp. 242-43.

⁸When employing the cost of capital methodology an additional cost for financial expenses incurred in handling stock and bond transactions is usually included.

authorized TE is \$160,400,000. If the utility's actual TE is less than this a rate increase may be needed, just as a rate decrease may be in order if the utility's actual TE is higher. The composite cost of long term debt, preferred and common stock as well as the actual ROR on the RB for all Class A and B privately owned electric utilities in the United States is presented in TABLE 2, page 105. The data is for the years 1967 through 1976 inclusive. This information can be computed for any individual investor owned utility from the data in the Federal Power Commission's report entitled Statistics of Privately Owned Electric Utilities in the United States.⁹

While the computational procedures for establishing the cost of capital are relatively straightforward, there are several fundamental problems in this approach that merit discussion.

First, in deciding the overall ROR on the RB one must consider the nature of the utility's capitalization ratios. Two utilities, both with an allowable ROR on the RB of 8 percent, may generate startlingly different yields to their respective equity stockholders even if they have similar RB evaluations. Consider the following example:

UTILITY A			
<u>Capital Structure</u>	<u>Amount Outstanding</u>	<u>Interest Rate</u>	<u>\$ Cost</u>
Debt	\$ 2,000,000	4%	\$ 80,000
Preferred	2,000,000	5	100,000
Common	6,000,000	?	?
Total	\$10,000,000	8%	\$800,000

⁹This report is published yearly by the Commission and can be purchased by writing the Superintendent of Documents, U.S. Government Printing Office, Washington, D.C. 20402.

TABLE 2

THE COMPOSITE COST OF LONG TERM DEBT, PREFERRED
AND COMMON STOCKS AND THE RATE OF RETURN
ON THE RATE BASE FOR INVESTOR
OWNED ELECTRIC UTILITIES
1967-1976

Capital Structure and Rate Base	<u>Year's Ending as of December 31</u>									
	1976	1975	1974	1973	1972	1971	1970	1969	1968	1967
Long Term Debt	7.0	6.8	6.3	5.9	5.7	5.5	5.1	4.6	4.3	4.0
Preferred Stock	7.6	7.2	6.8	6.4	6.1	5.9	5.2	5.0	4.9	4.6
Common Stock	11.5	11.2	10.7	11.5	11.8	11.7	11.8	12.2	12.3	12.8
Return on Rate Base	8.6	8.2	7.6	7.6	7.6	7.4	7.3	7.4	7.3	7.4

SOURCE: Federal Power Commission, Statistics of Privately Owned Electric Utilities in the United States, 1967-1976 eds.

In this example Utility A has contracted to pay bondholders and preferred stockholders 4 percent and 5 percent, respectively. Given the capital structure indicated, if the commission establishes a fair ROR of 8 percent on the RB the utility would be authorized to collect \$800,000 in TE.¹⁰ After subtracting \$180,000 from its TE to pay its contracted capital expenses (debt and preferred stock), Utility A has \$620,000 left to pay common stockholders. This translates into a ROR for equity stockholders of approximately 10.33 percent. Now consider this example:

UTILITY B

<u>Capital Structure</u>	<u>\$Amount Outstanding</u>	<u>Interest Rate</u>	<u>\$ Cost</u>
Debt	\$ 4,000,000	4%	\$160,000
Preferred	4,000,000	5	200,000
Common	2,000,000	?	?
Total	<u>\$10,000,000</u>	<u>8%</u>	<u>\$800,000</u>

Here also Utility B has contracted to pay bondholders and preferred stockholders 4 percent and 5 percent, respectively. And if the commission establishes a fair ROR of 8 percent on the RB for Utility B also, Utility B would likewise be authorized to collect \$800,000 in TE. But after subtracting \$360,000 from their TE to pay contracted capital expenses, Utility B has a residual of \$440,000 to pay common stockholders. This translates into a ROR for equity stockholders of 22 percent. Of course the

¹⁰In this example it is being assumed that the actual RB is identical to the company's capitalization, i.e., that the RB equals \$10,000,000. While there should be a reasonably close relationship between a utility's capitalization and its RB evaluation, typically there are differences often amounting to hundreds of thousands of dollars. In the above example if Utility A's actual RB were \$10,500,000, applying the 8 percent ROR to the actual RB would generate TE of \$840,000.

difference between Utility A and B is their respective ratio of capitalization. Utility B has a heavy contracted debt, so much as to be seriously vulnerable during recessionary periods in the economy. Utility B's fixed capital expenses are twice that of Utility A's and these expenses must be paid even if demand slackens and TE deteriorate. In addition, Utility B's customers are paying the utility's equity stockholders a much higher profit than may be justified. In the cost of capital approach the commission should always take into account the company's actual capitalization ratios. If it does not, the utility may simply substitute cheaper senior debt and preferred securities for the more expensive junior equity type.¹¹ The debt to equity ratio is often referred to as leverage, and by shifting from equity financing to contractual debt financing a utility is said to be increasing its financial leverage. Many times, when a company's debt equity ratio or financial leverage becomes high enough to be considered "risky" by the financial community, the company finds that its bond ratings deteriorate, which causes the company to pay a higher cost for debt and for preferred securities than would otherwise be the case. In setting the TE requirement the commission must not only take into account a utility's actual capitalization ratio, but must also have some sense of what sound financial integrity and economic efficiency principles call for regarding capitalization ratios, as well as some common sense

¹¹It should also be mentioned that interest on debt is a deductible business expense while dividends on stock are not deductible. Raising capital by bonds as opposed to equity financing may have appeal as a tax saving device.

appraisal of the changes that a utility can be realistically expected to accomplish in the way of changing its capitalization ratios, if that is deemed desirable. Although determining the proper capitalization ratio or the direction in which the utility should be moving in this regard is a very complex issue, it nonetheless must be confronted if regulation is to succeed.

The second major problem that merits some consideration in the cost of capital approach is how to establish the cost of equity capital.

As Francis X. Welch, former Editor of Public Utilities Fortnightly notes:

It is comparatively simple to determine what bond money will cost and what preferred stock capital will cost. Bonds of different sizes and types of companies both utilities and non-utilities, are analyzed and noted so that it is possible to forecast what a utility company will have to pay for 'bond money' Preferred stocks, which also pay contractual dividend rates, after bond interest is taken care of, can likewise be fairly closely predicted as to price for a particular type of utility company.

It is in the realm of equity or junior financing, meaning common stocks, that difficulties arise.¹²

Needless to say, the return to equity capital must be set at a high enough level so that the utility can sell its securities. One way of doing this is to determine how investors go about making their investment decisions. A common methodology used by some investors is the earnings-price ratio.¹³ The

¹²Francis X. Welch, Public Utility Regulation, (Washington, D.C.: Public Utilities Reports, Inc., 1961), p. 564.

¹³Similar measurement techniques consist of determining regular stock dividends, dividend price ratios and the earnings-net-proceeds ratio. For an excellent discussion of these methodologies see Bonbright's, Principles of Public Utility Rates.

earnings-price ratio shows the relationship between a utility's net earnings per share and the quoted prices of its common stock on the stock market.

For example, if the commission finds that common stock in the past has sold quite well at an earnings-price ratio of 1:10 it may set the utility's authorized ROR for equity capital at 10 percent. But remember, in addition to being equitable to past investors, the commission's task is also to establish a rate of return that will insure that the utility will be able to attract capital in the future. And the necessary return for this purpose will depend upon factors that are simply not quantifiable: factors such as the future expectations of investors, inflation, deflation, unemployment or in general terms the overall state of the economy.

Lastly, the companies used by the commission for the test in determining the expected cost of equity capital may themselves have been enjoying monopoly profits or may have been in a high risk industry whose investors naturally demand higher returns. Commissions must be very careful in choosing the companies to be used as benchmarks for determining the cost of equity capital. In essence, the cost of capital methodology is by no means a precise and objective tool for implementing the cost of service principle in establishing a fair ROR. While the cost of capital methodology may be a useful and reasonable tool for the commission to consider in its deliberations it must certainly not be thought of as being scientific, even in the broadest sense of the word.

Comparable Returns

In attempting to establish a ROR that will generate TE consistent with the cost of service principle, commissions often use the yardstick or comparable returns approach. This is done by comparing the ROR of a particular utility with the ROR of some other company (regulated or non-regulated) that is regarded as comparable. Of course the problem here is to determine what criteria must be established in order to determine whether two companies are in fact comparable. For example, first, the degree of risk in most public utilities is simply not as great or at least is considered to be relatively minute, when compared with other types of enterprise, and the ROR demanded by investors is often greatly influenced by the degree of risk involved. Second, one must be aware that many industries possess substantial monopoly market power and that their return will usually be substantially higher than those in competitive market structure conditions. Thus the commission has the problem of determining the degree of monopoly or competitiveness that exists in a given industry. Third, one must take into consideration overall economic conditions not only within and between industries, but region by region as well as nationally. Because of these reasons there simply is not any consensus nor is there likely to be as to what constitutes comparable industries to serve as a benchmark for public utilities.

In addition, suppose such a benchmark were forthcoming, i.e., the commission found what it considered to be a comparable industry on the basis of risk and of general economic conditions. If that industry had a highly efficient management

but the utility did not, why should the utility be rewarded with the same earnings level? TE should in part always be related to economic efficiency.

Lastly, the commission, as noted in the previous section, must always be mindful not only of the overall return to capital but must pay particular attention to a utility's capitalization ratios, i.e., it must be mindful of the ROR for each type of security the utility has issued. In other words, a comparable return says nothing about what type of capital structure is relevant or desirable or in fact what type of capital structure actually does exist in either of the two firms or industries being compared.

Many students of electric utility economics view the comparable returns approach somewhat skeptically. For instance, Professors Wilcox and Shepherd content that:

In short, a comparable earnings criterion for regulation of fair return is a will-o-wisp, with little substance.... There should be no illusion that the standard has much scientific or practical substance.¹⁴

Perhaps it would be more to the point to say that establishing the ROR for any given utility is still much more of an art than a science.

¹⁴Clair Wilcox and William G. Shepherd, Public Policies Toward Business, (Homewood, Illinois: Richard D. Irwin, 1975), p. 363.

Attraction of Capital

Whether or not a company can stay in business is often determined by whether or not it can sell its securities to financial investors. If a utility does not earn a high enough ROR to compete successfully for investors' funds, it probably will not survive as a business enterprise. Investors quite naturally will invest their dollars where they can obtain the highest return on their risk. None of this is to be denied; companies must be able to sell their stocks and bonds if they are to remain in business. But this simple statement of fact can in no way help guide the commission in determining what the actual ROR should be. Every problem confronted in attempting to establish a fair ROR by the cost of capital approach and/or the comparable return approach confronts the commission once again when it attempts to actually set a specific ROR figure based on the attraction of capital criteria.

In other words, most will agree that if a utility's earnings are not sufficient to attract capital that its earnings are probably too low. But the task of the commission is to allow a ROR just high enough to attract an economically efficient flow of capital to the utility and no more. Just because a utility can successfully attract capital at a given point in time does not mean that it is being run efficiently, that it has a financially sound capitalization ratio, or that it is properly planning for the future. A high ROR may simply mean that consumers are

contributing monopoly profits to investors who have assumed little if any risk. The ROR should obviously be high enough to allow a utility to pay its "cost of capital" and to "attract capital" just as it should obviously be as high as the ROR earned by "comparable enterprises" - but, how high is that? It is from the courts that we get such terms as cost of capital, comparable earnings and attraction of capital and it is to a few relevant court decisions that we will now turn our attention.

ROR AND THE COURTS

The first major pronouncement by the courts attempting to define a fair rate of return was in the case of Wilcox v. Consolidated Gas Co. in 1909. The Supreme Court stated that:

There is no particular rate of compensation which must in all cases and in all parts of the country be regarded as sufficient for capital invested in business enterprise. Such compensation must depend greatly upon circumstances and localities; among other things, the amount of risk in the business is a most important factor, as well as the locality where the business is conducted and the rate expected and usually realized there upon investments of a somewhat similar nature with regard to the risk attending them. There may be other matters which in some cases might also be properly taken into account in determining the rate which an investor might properly expect or hope to receive and which he would be entitled to without legislative interference. The less risk, the less right to any unusual returns upon the investments. One who invests his money in a business of a somewhat hazardous character is very properly held to have the right to a larger return without legislative interference, than can be obtained from an investment in Government bonds or other perfectly safe security.....¹⁵

¹⁵Wilcox v. Consolidated Gas Co., 212 U.S. 19 (1909).

The major emphasis in this decision seemed to be that the ROR depended greatly upon circumstances and locality, and upon the ROR usually realized upon investments of a somewhat similar nature with regard to risk. In this decision we see the first glimmer of the comparable return criteria.

In the case of Bluefield Waterworks and Improvement Co. in 1929 the Supreme Court listed a number of factors that should be given attention in ROR considerations and specifically noted that commissions should exercise "fair and enlightened judgment." Justice Butler argued that:

What annual rate will constitute just compensation depends upon many circumstances and must be determined by the exercise of a fair and enlightened judgment, having regard to all relevant facts. A public utility is entitled to such rates as will permit it to earn a return on the value of the property which it employs for the convenience of the public equal to that generally being made at the same time and in the same general part of the country on investments in other business undertakings which are attended by corresponding risks and uncertainties; but it has no constitutional right to profits such as are realized or anticipated in highly profitable enterprises or speculative ventures. The return should be reasonably sufficient to assure confidence in the financial soundness of the utility and should be adequate, under efficient and economical management, to maintain and support its credit and enable it to raise the money necessary for the proper discharge of its public duties. A rate of return may be reasonable at one time, and become too high or too low by changes affecting opportunities for investment, the money market and business conditions generally.¹⁶

In this decision the Court placed heavy emphasis both on the

¹⁶Bluefield Waterworks and Improvement Co. v. West Virginia Public Service Commission, 262 U.S. 679 at 692-693 (1923).

comparable return and on the attraction of capital criteria, but gave little assistance in determining how these criteria can actually be applied except to say that the commissions should exercise "enlightened judgment."

The Bluefield case is widely believed to be the major judicial statement on ROR matters and merits careful consideration. In 1944 the Supreme Court in the Hope Natural Gas case reaffirmed the Court's previous Bluefield decision and further stated that commissions should carefully balance the interests of consumers and investors. Justice Douglas stating his argument said:

The rate-making process under the Act, i.e., the fixing of "just and reasonable" rates, involves a balancing of the investor and the consumer interests From the investor or company point of view it is important that there be enough revenue not only for operating expenses but also for the capital costs of the business. These include service on the debt and dividends on the stock..... By that standard the return to the equity owner should be commensurate with returns on investments in other enterprises having corresponding risks. That return, moreover, should be sufficient to assure confidence in the financial integrity of the enterprise, so as to maintain its credit and to attract capital.....¹⁷

Since the Hope Natural Gas case, the cost of capital methodology for determining the actual cost of service ROR seems to have received much more attention. In these three landmark cases the courts listed a number of factors for consideration in establishing the ROR, including 1) the company's financial history, 2) the competence of management, 3) the financial policy and capital structure of the firm, 4) the cost of capital,

¹⁷Federal Power Commission v. Hope Natural Gas Co., 320 U.S. 591 (1944).

5) risk, 6) economic and financial conditions, 7) the attraction of capital, and 8) comparable returns. The courts have acted rather like the general who always told his troops what to do but never had any ideas about how to do it. Once again the flow chart and definitions at the end of this chapter, may be useful for reviewing the key concepts and developing an overall attitude towards the ROR.

CHART 1

TOTAL EARNINGS: THE RATE OF RETURN

APPENDIX

BOND RATINGS Rating Systems which provide the investor with a simple series of graduation by which the relative investment qualities of bonds are indicated. Moody's Investor Service and Standard & Poor's Corporation are the principal bond rating agencies.

<u>Moody's</u>			<u>Standard & Poor's</u>	
<u>Rank</u>	<u>Rating</u>	<u>Quality Description</u>	<u>Rating</u>	<u>Quality Description</u>
1st	AAA	Best Quality	AAA	Highest Grade
2nd	AA	High Quality	AA	High Grade
3rd	A	Higher Medium Quality	A	Upper Medium Grade
4th	BAA	Lower Medium Quality	BBB	Medium Grade
5th	BA	Speculative Elements	BB	Lower Medium Grade
6th	B	Generally Lack Characteristics of the Desirable Investment	B	Speculative
7th	CAA	Poor Standing	CCC	Outright Speculations
8th	CA	Speculative Obligations, Often in Default	CC	Outright Speculations
9th	C	Lowest Rated Class of Bonds Poor Prospects	C	Income Bonds Not Paying Interest
10th	--	-----	D	Outright Defaults

CHAPTER :
SIX : THE RATE STRUCTURE
:

INTRODUCTION

Summarizing Chapters Three through Five in equation form we can state that:

	1) $TC = TOE + TE$
Where	2) $TOE = OE + TX + AD$
And	3) $TE = ROR(RB)$
If	4) $TR = TC$
Then	5) $TR = ROR(RB) + OE + TX + AD$

Equation 5 is the utility's Total Revenue (TR) requirement. The TR requirement is the amount of money the utility must collect from its customers in order to remain a viable enterprise. Once the TR requirement has been established, the commission must turn its attention to establishing precisely how the utility should go about setting the prices it charges its customers. This task is called Rate Structure (RS) design. In establishing the appropriate TE requirement and TOE requirement the commission is primarily concerned with maintaining equity between consumers and investors or balancing their interests fairly. In RS design the commission is primarily concerned with 1) establishing rates adequate to meet the utility's TR requirement, and 2) maintaining equity between different customer classifications. As Francis X. Welch, formerly editor of Public Utilities Fortnightly says:

The commission has the duty and responsibility of seeing not only that the utility does not collect overall revenues which are unreasonable at the

general level, but also of seeing that no one class of service is discriminated against, or receives preferred treatment.¹

In essence electric utilities do not charge a uniform price for each kilowatt hour (KWH) of electricity they sell. Instead, electric utilities charge different prices to different customer classifications and also offer reduced prices for buying in large quantities. In TABLE 1, page 122 there is a list of the average price per KWH charged by electric utilities to various customer classifications. Electric utilities divide their customers into two basic categories: 1) sales to ultimate customers, and 2) sales for resale. Ultimate Customer (UC) refers to those customers "purchasing electricity for their own use and not for resale." The UC category is further subdivided into seven classifications including Residential, Commercial, Industrial, Railroad and Railways, and Interdepartmental Sales. Sales for Resale (SFR) refers to those customers of public authorities who buy electricity for the purpose of selling it to someone else. The SFR category is further subdivided into four classifications, including Investor Owned Electric Utilities, Cooperatives, Municipally Owned Utilities and Federal and State Electric Agencies.² As shown in TABLE 1, page 122, investor owned utilities charged Residential customers an average of 3.77 cents per KWH of electricity in 1976 while charging Industrials and

¹Francis X. Welch, Public Utility Regulation, (Washington, D.C.: Public Utilities Reports, Inc., 1961), p. 493.

²For a precise explanation for each of these eleven classifications see definitions.

Railroads and Railways an average of 2.25 cents and 3.29 cents, respectively. Since electric utilities differentiate between customers in their pricing policies the commission must pay close attention to RS design. As Clair Wilcox notes:

One pattern of differentiation may be neutral in its effect upon competition among concerns that buy a common service, such as electric power...; another may give one competitor an unfair advantage and place a second under an unfair handicap. One pattern may require all customers to contribute, on an equitable basis, to the costs incurred in servicing them; another may grant one group a subsidy and subject a second to a tax....³

Historically, regulatory commissions have not been as active in RS design as they have been in RB and ROR considerations. But the decade of the 70's may in retrospect be viewed as the renaissance of electric utility RS design. As Richard D. Cudahy, former Chairman and Commissioner-Public Service Commission of Wisconsin, and J. Robert Molko, former Chief Economist-Public Service Commission of Wisconsin, so aptly state:

The design of electric rates has recently emerged from the closet of regulatory neglect to a new prominence. Traditionally, state public service commissions have concerned themselves primarily with aggregate utility revenue requirements (needed to attract and retain capital) and have left rate design or structure - the formulation of rate relationships as they affect classes of customers, magnitude of usage of demand and other factors - primarily to the utilities.⁴

³Clair Wilcox, Public Policies Toward Business, (Homewood, Illinois, Richard D. Irwin, Inc., 3rd ed., 1966), p. 334.

⁴Richard D. Cudahy and J. Robert Molko, "Electric Peak-Load Pricing: Madison Gas and Beyond," Wisconsin Law Review, 1976.

TABLE 1
AVERAGE PRICE PER KWH CHARGED BY
INVESTOR OWNED UTILITIES TO
VARIOUS CUSTOMER
CLASSIFICATIONS, 1976

Customer classification	Average Price Per KWH
A. Sales to ultimate customer	
Residential	3.77 cents
Commercial	3.73
Industrial	2.25
Public street & highway lighting	5.61
Other public authorities	2.83
Railroads and Railways	3.29
Inter-departmental sales	1.40
B. Sales for resale	1.83

Source: U.S. Department of Energy, Statistics of Privately Owned Electric Utilities in the United States, 1976, (Washington, D.C.: U.S.G.P.O., April, 1978).

In this chapter we will examine the primary economic elements involved in RS design, and several methods for actually computing the cost of service to different customer classifications.

PRIMARY ECONOMIC ELEMENTS

The regulatory commission, the courts, as well as the utilities themselves, seem to agree that in general the prices customers pay for electricity should be an accurate reflection of the actual cost of providing the service. But the actual cost of generating electricity may differ from hour to hour within any given day, from day to day within any given week, from week to week within any given month, and from month to month within any given year. Price differentiation on the basis of cost variations is not only justifiable but desirable, both for equity and for efficiency. Nonetheless, many students of electric utility economics believe that price variations between customer classifications are not derived primarily from cost variations but rather from variations in customer demand. On the one hand a utility, being a licensed monopoly, may set prices higher than actual cost in situations where the need for electricity is almost a necessity for normal existence and the buyer has the ability to pay. On the other hand, a utility may set prices below actual cost for a customer who could and perhaps would provide the service for themselves if the price were too high. In this section we will examine 1) the functional and causal aspects of cost and price variations, 2) basic rate principles, 3) rate structure design and criteria, 4) economic pricing principles, and 5) several computational methodologies employed

in allocating cost.

Functional and Causal Aspects of Cost

Costs are categorized so that one can more accurately compute specific cost and then set prices based on the actual cost of service. This cost categorization process involves looking at a utility's cost from both a functional and causal point of view. Functionally, costs reflect the dollars that must be spent to perform a certain function. Looked at causally, cost reflects the respective cost responsibilities of the different customers who require these functions so they may be provided with electricity. The four functional cost categories include generation cost, transmission cost, distribution cost, and customer cost. The following definitions may be helpful in visualizing these functional cost categories:

GENERATION COST - Those capital and operating expenses incurred in building a generating station that will transform other forms of energy into electric energy.

TRANSMISSION COST - Those capital and operating expenses incurred in the process of transporting electric energy in bulk from a source or sources of supply to other principal parts of the system, or to other utility systems.

DISTRIBUTION COST - Those capital and operating expenses incurred in the process of distributing electric energy from convenient points on the transmission or bulk power system to the customer.

CUSTOMER COST - Those capital and operating expenses incurred by the utility in taking on another customer. Usually includes such cost as services and metering, as well as accounting and sales promotion expenses.

The three causal cost categories include demand related cost, energy related cost, and customer related cost. The following definitions may help visualize these cost categories:

DEMAND/CAPACITY COST - The capital and operating expenses incurred by the utility on behalf of an individual customer in providing sufficient capacity (a large enough generation,

transmission and distribution system) to meet the maximum demand of that customer when needed. Demand cost is often used interchangeably with capacity cost. Demand costs vary with the kilowatts (KW)⁵ of power demanded. These costs are usually charged to customers as \$ per KW.

ENERGY COST - The operating expenses incurred by a utility on behalf of an individual customer in providing that customer with a kilowatt hour (KWH) of electric energy. Energy cost is used interchangeably with KWH cost. Energy costs vary directly with KWH usage and are primarily fuel costs. These costs are usually charged to customers as ¢ per KWH.⁵

CUSTOMER COST - The capital and operating expenses incurred by the utility on behalf of an individual customer relating primarily to the number and size (usage) of customers. Customer cost does not vary significantly with the amount of energy used.

The next step is to show how functional cost and causal cost may be interrelated. In TABLE 2, page 126, there is a flow diagram illustrating these interrelationships which the reader may find helpful.

Generation cost consists of 1) the capital cost of electric generating stations, 2) operating expenses, and 3) fuel cost. Cost due primarily to the capital cost of generating facilities classified as demand/capacity cost, while operating expenses may be divided between demand/capacity related cost and energy related cost. Fuel costs are almost always allocated entirely to

⁵Kilowatt hour (KWH) is a unit of energy and kilowatts (KW) refers to the rate at which electricity is distributed. Kilowatts refers to kilowatt hours per hour. Thus a generator that has a 9000 kilowatt capacity can distribute 9000 kilowatt hours per hour. In a 24-hour day the generator can produce (9000 X 24 = 216,000) KWH of electricity.

TABLE 2
THE INTERRELATIONSHIP BETWEEN
FUNCTIONAL RELATED COST AND
CAUSAL RELATED COST

Functional Cost	Causal Cost
1. Generation	
→ Building cost	→ Demand/capacity/\$ per KW
→ Operation and maintenance	→ Demand/capacity\$ per KW
	→ Energy/¢ per KWH
→ Fuel	→ Energy/¢ per KWH
2. Transmission	→ Demand/capacity/\$ per KW
3. Distribution	→ Demand/capacity/\$ per KW
	→ Customer/\$, flat charge
4. Customer	→ Customer/\$, flat charge

the energy cost category. The capital and operating expenses associated with transmission costs are usually considered demand/capacity related cost. The capital and operating expenses associated with distribution cost are divided between demand/capacity related cost and customer cost. In many cases the secondary distribution system (the distribution system that primarily serves retail customers) may amount to almost 40 percent of the utility plant. Typically, various parts of the secondary distribution system are allocated as customer related cost.⁶ The functional category of customer cost corresponds directly to the causal category of customer cost. These customer related capital and operating expenses vary proportionately with the number of customers served and have little if any relationship to the KWH of energy used or to KW energy demands.

Viewing cost causally, Total Cost variations per KWH in producing electricity cannot be accounted for on the basis of differences in Energy Cost, since energy costs are approximately the same for each KWH of electricity produced. Although some variations per KWH are attributable to difference in customer cost, customer cost variations are not substantial and it is basically due to differences in demand/capacity cost where

⁶ Allocating the operating expenses and capital cost of a utility's secondary distribution system to the customer cost category is not sound from an economic point of view, and many utility economists consider it to be an undesirable outcome of using the historical or embedded cost methodology in allocating DEMAND and CUSTOMER COST. Cost allocation methodologies for computing demand, energy and customer cost are discussed in the next to last section of this chapter.

the fundamental difference in the cost per KWH in the generation, transmission, and distribution of electricity exists.

Traditionally, when attempting to explain and derive estimations of actual cost variations per KWH in producing electricity based on demand/capacity cost, utility accountants have developed what are known as System, Customer, and Diversity load factor formulas. These formulas are based on a utility's load curve. A utility's load curve is simply the kilowatts the utility actually generates plotted against the hours of the day.⁷ In FIGURE 1, page 129, there is a hypothetical example of an electric utility's daily load curve. In this example plant capacity is 9,000 kilowatts, maximum KW peak demand is 7,000 kilowatts, and total production during the day is equal to 117,000 kilowatt-hours.

The System Load Factor is the ratio of average load to peak demand: peak demand is the maximum demand placed on the system at any given time. The System Load Factor in our example, then, would be expressed as:

$$\frac{4875 \text{ KW}}{7000 \text{ KW}} = 70 \text{ percent}$$

The Customer Load Factor is the ratio of the customer's average consumption to his/her maximum consumption. Using the hypothetical example illustrated in FIGURE 1 customer A's load factor would be:

$$\frac{1250 \text{ KW}}{2000 \text{ KW}} = 62.5 \text{ percent}$$

⁷Utilities develop daily, monthly and yearly load curves for production and cost estimation purposes.

FIGURE 1

HYPOTHETICAL DAILY LOAD CURVE FOR AN ELECTRIC UTILITY

The System's Diversity Factor is the ratio of the maximum non-coincident demands of all customers to the system's peak demand. In our example assuming Customer A, B, and C's maximum non-coincident demands are 2,000, 2,500, and 3,000 kilowatts respectively, while system peak demand is 7,000 kilowatts, the diversity factor in this example would be expressed as:

$$\frac{7500}{7000} = 1.07$$

Now, if the utility managers can raise the system load factor they can lower the average production cost per kilowatt hour. Assume the utility gets a request for a maximum of 1,000 kilowatts of electricity from 12 midnight to 8 a.m. What would it cost the utility to deliver this much electricity during this off-peak time period? The only cost the utility would incur would be energy and customer costs. Demand/capacity cost for a 9,000 kilowatt operation is already being paid for the existing customers.

In other words, whatever the system load at any given time, the demand/capacity cost charged to existing customers must be high enough so that the utility can earn a fair ROR for its debt holders and stockholders on all of their invested capital, since the utility is entitled to earn a fair ROR on its RB.

The utility may argue that adhering strictly to the cost of service principle justifies charging lower rates to this off-peak customer. Further, if the utility allocates any demand/capacity cost to this customer at all, theoretically, existing customers could benefit by receiving lower rates themselves. This is so

because by spreading total demand/capacity cost out over more kilowatts of electricity the total average cost per KWH will decrease, since energy and customer cost remain constant per KWH. If the new customer actually used its maximum 1,000 kilowatts throughout the time period (12 midnight-8 a.m.) the utility's system load factor would increase from 70 percent to 74 percent. In essence, by gaining this off-peak customer the utility increased its diversity factor from 1.07 to 1.21, which in turn increased the system load factor. It is important to note that large industrial or commercial customers, not residential ones, are the only ones likely to use significant KWH's in off-peak times.

This utility could also argue that giving quantity discounts to large customers who have historically demonstrated off-peak usage patterns could also increase the system load factor. If the customer in our above example had a maximum kilowatt demand of 2,000 kilowatts instead of 1,000 kilowatts the system load would have increased to 79 percent. How could the utility entice this off-peak customer to use 2,000 kilowatts as opposed to 1,000 kilowatts? Suppose the utility granted this customer a rate structure as follows:

0-1000 KWH	6¢ per KWH
over 1000 KWH	3¢ per KWH

The customer could lower its average KWH fuel cost from 6¢ per KWH to 4.5¢ per KWH if it used 2,000 kilowatts continuously throughout the time period. But the only way the customer can achieve this quantity discount is by using more electricity. Traditionally, utility rate analysts have argued that offering

quantity discounts through a declining block rate structure is an effective device for increasing a utility's system load factor. As long as the 4.5¢ per KWH rate brings in enough revenue to cover the customer's energy and customer cost and contributes something to demand/capacity cost, the utility's average production cost per KWH will be reduced.⁸ Finally, the utility may attempt to increase its system load factor by improving its existing customer load factor. This can be done by encouraging customers to increase their consumption of electricity at off-peak periods. What all this comes down to is that a KWH of electricity produced at peak has a greater demand/capacity cost associated with it than a KWH of electricity produced off-peak. System load factors for electric utilities in the United States are about 40 to 60 percent.

⁸One must not conclude from this argument that declining block rates are economically justifiable in the electric utility industry. Declining block rates are justifiable only under very specific actual cost circumstances. Moreover, utility analysts have traditionally used examples like that used above to justify declining block rates or quantity discounts for off-peak users as well. In other words, promotional rates have encouraged increased consumption during off-peak winter periods and summer peaking periods, promoting space heating in the winter months and air conditioning in the summer. This of course causes greater need for increased capacity (building new power plants) which in turn creates greater excess capacity during off-peak periods, which in turn could be used to justify ever more promotional (declining block rates) pricing gimmicks. In essence, regulatory commissions must consider the long run effects of short run promotional rates.

As Professors Shepherd and Wilcox point out:

There is in the nature of electricity cost a basis for differentiating rates, setting them at different levels for different classes of customers and reducing them as a customer buys in larger quantities.⁹

To the extent that prices or utility rates actually reflect the actual cost of service principle electric utilities will, because of the nature of their production process, have numerous customer classifications each with their own distinct rate schedules. We will now turn our attention to an examination of the two generic types of electric rate classifications utilized by the electric utility industry in the United States.

Generic Rate Classifications

There are two rate classifications used in the United States - Meter Rates and Demand Rates.¹⁰ Meter Rates refer to any method of pricing that is based solely on quantity. In essence, Meter Rates make absolutely no price variations to customers, regardless of differences in demand cost variation and customer cost variation in the actual generation, transmission, and

⁹Clair Wilcox and William G. Shepherd, Public Policies Toward Business, (Homewood, Illinois: Richard D. Irwin, Inc., 5th ed., 1970), p. 411.

¹⁰In recent years many people have suggested that social consideration external to the actual cost of service incurred by the utility should receive consideration when designing rates. This could well lead to a third rate classification perhaps entitled Social Rates. In addition, many economists are seriously concerned that social cost, usually called externalities, be taken into consideration when designing rates. Such cost would include, for example, air and water pollution cost. These types of external cost have traditionally been ignored when utility rate analysts compute cost and design rate schedules. See Chapter Seven for a brief discussion concerning one form of social ratemaking known as lifeline rates.

distribution of electricity. There are four basic types of meter rates - Block, Step, Straight Line, and Flat. The earliest rates developed by the electric utility industry were meter rates. Under a STRAIGHT LINE METER RATE customers are charged a constant price per KWH of electricity despite differences in customer cost and demand cost. Given a FLAT METER RATE customers are charged a fixed amount per day or per month despite differences in consumption. Under BLOCK METER RATES a specific price per KWH is charged for all or any part of a block and reduced or increased prices per KWH are charged for succeeding blocks. Here again the charge is computed without any consideration of differences in customer cost or in demand cost variation. Given STEP METER RATES customers are first placed at a given rate depending upon the step their total consumption places them in. The various steps are determined without any consideration to individual customer classification based on different demand/capacity cost or on customer cost. Once the steps are established customers are billed a specific price per KWH for their entire consumption.

In the early 1900's an English engineer, Dr. John Hopkinson, developed what are now classified as Demand Rates. Demand rates refer to any method of pricing that results in price variation among customer classifications, based upon differences in energy cost variation, or demand cost variation and on customer cost variation in the actual generation, transmission, and distribution of electricity. There are four basic types of demand rates - Flat, Hopkinson, Three Part, and Wright. In a FLAT DEMAND RATE SCHEDULE a customer is charged a specific amount

based upon the number of energy consuming devices he/she uses. The fee usually takes the form of so much per watt, so much per kilowatt, or so much per installed horsepower, and the customer is billed on a monthly or in some cases a yearly basis.

The HOPKINSON DEMAND RATE is sometimes called a two part rate schedule, since the customer is billed on the basis of two separate charges. One rate is a demand charge based on the customer's estimated demand/capacity cost. The second rate is an energy charge based upon estimated energy cost. For instance, the bill may be \$2 per KW and 2¢ per KWH.

THREE PART DEMAND RATES are identical in principle to the Hopkinson Demand Rate Schedule except that in addition to both a demand/capacity charge and an energy charge the bill also shows a separate charge based upon the estimated customer cost.

WRIGHT DEMAND RATES are essentially a two block rate schedule. The first block consists of a high initial rate per KWH; the size of the block is based on the customer's maximum demand on system capacity. All kilowatt hours in excess of the initial block will be charged a considerably lower rate per KWH. Wright Demand Rates were the first designs in the United States that took into consideration a customer's demand/capacity cost to the system. Today some form of Demand Rates (Flat, Hopkinson, Three Part, and Wright) are used by nearly every electric utility in the United States. However, another form of rate classification known as Social Rates seems to be gaining in popularity. We will now turn our attention to Rate Structure Design.

Rate Structure Design

There are four basic types of rate structure designs: 1) declining block rates, 2) inverted block rates, 3) flat rates, and 4) peak-load rates. Here is a simplified illustration of a declining block rate structure:

1st 500 KWH per month	5¢ per KWH
501 - 1000 KWH per month	3¢ per KWH
over 1000 KWH per month	1¢ per KWH

On the other hand an inverted block rate might look like this:

1st 500 KWH per month	1¢ per KWH
501 - 1000 KWH per month	3¢ per KWH
over 1000 KWH per month	5¢ per KWH

A flat rate structure can be portrayed like this:

\$5.00 per month - fixed charge
\$0.05 per KWH - per month

A simplified peak-load rate structure can be pictured thusly:

\$5.00 per month - fixed charge
\$0.05 per KWH per month (7 a.m. to 8 p.m.)
\$0.03 per KWH per month (8 p.m. to 7 a.m.)

A more complicated Hopkinson two-part Demand Rate/Declining Block Rate Structure might appear in this form:

<u>Demand/Capacity Charge</u>		<u>Energy Charge</u>	
1st 5 KW	\$2.00 per KW	1st 500 KWH	5¢ per KWH
2nd 5 KW	\$1.00 per KW	501 - 1000 KWH	3¢ per KWH
over 10 KW	\$0.50 per KW	over 1000 KWH	1¢ per KWH

Under this particular demand rate/declining block rate structure a customer who had a demand of 6 kilowatts and who used 6000 KWH would be billed as follows:

<u>Demand/Capacity Charge</u>		<u>Energy Charge</u>	
5 KW (\$2.00)	= \$10.00	500 KWH (5¢)	= \$25.00
1 KW (\$1.00)	= 1.00	500 KWH (3¢)	= 15.00
	<u>\$11.00</u>	5000 KWH (1¢)	= 50.00
			<u>\$90.00</u>

Total \$101.00 plus tax

Now let us consider a Hopkinson two-part Demand Rate/Inverted Block Rate Structure that looks like this:

<u>Demand/Capacity Charge</u>		<u>Energy Charge</u>	
1st 5 KW	\$0.50 per KW	1st 500 KWH	1¢ per KWH
2nd 5 KW	\$1.00 per KW	2nd 500 KWH	3¢ per KWH
over 10 KW	\$2.00 per KW	over 1000 KWH	5¢ per KWH

<u>Demand/Capacity Charge</u>		<u>Energy Charge</u>	
5 KW (\$0.50)	= \$2.50	500 KWH (1¢)	= \$ 5.00
1 KW (\$1.00)	= 1.00	500 KWH (3¢)	= 15.00
	<u>\$3.50</u>	5000 KWH (5¢)	= 250.00
			<u>\$270.00</u>

Total \$273.50 plus tax

The last two examples made a very important point: demand rates (Hopkinson two-part, Three Part, or the Wright rate) may take several rate structure forms. In addition, any one of the demand rates above may have two or three different rate structures within any rate schedule. Consider the following illustration:

<u>Demand/Capacity Charge</u>		<u>Energy Charge</u>
1st 5 KW	\$2.00 per KW	8¢ per KWH
2nd 5 KW	\$1.00 per KW	
over 10 KW	\$0.50 per KW	

In the above example the demand/capacity charge is of the declining block rate structure variety while the energy charge is a flat rate structure. A Block Meter Rate or a Step Meter Rate can take the form of either a declining block or inverted block rate structure. If the rates at which customers are billed accurately reflect actual cost conditions, the form of the rate structure (flat, declining, inverted, peak-load) will depend upon the cost conditions inherent in the production process.

We will now briefly consider the underlying economic criteria upon which rate structure design are grounded.

The Economic Criteria Underlying Rate Structure Design

In his benchmark book, Principles of Public Utility Rates, Dr. James C. Bonbright set forth what he termed the canons of sound rate structure. Bonbright's criteria have gained widespread acceptance and are frequently quoted. His criteria consist of:

1. The related 'practical' attributes of simplicity, understandability, public acceptability, and feasibility of application.
2. Freedom from controversies as to proper interpretation.
3. Effectiveness in yielding total revenue requirements under the fair-return standard.
4. Revenue stability from year to year.
5. Stability of the rates themselves, with a minimum of unexpected changes adverse to existing customers. (Cf. 'The best tax is an old tax.')
6. Fairness of the specific rates in the apportionment of total costs of service among the different consumers.
7. Avoidance of 'undue discrimination' in rate relationships.
8. Efficiency of rate classes and rate blocks in discouraging wasteful use of service, while promoting all justified types and amount of use
 - (A) In the control of the total amounts of service supplied by the company, and
 - (B) In the control of the relative uses of alternative types of service (on-peak versus off-peak electricity, Pullman travel versus coach travel, single-party telephone service versus service from a multiparty line, etc.)¹¹

¹¹James C. Bonbright, Principles of Public Utility Rates, (New York: Columbia University Press, 1961), p. 291.

Bonbright concludes that criteria 3, 6, and 8 are of primary importance. In other words, a rate structure that gives both efficiency and equity due consideration must allow the firm to 1) collect enough TR to cover its legitimate TOE and TE requirements, 2) set rates based on the cost of service principle so as to not discriminate between customer classifications, and 3) set rates so as to promote efficient use of existing plant capacity while at the same time not setting rates which continually promote wasteful and inefficient use of electricity, and contribute to the need for continual expansion of system capacity.

These concepts in themselves seem rather straightforward and, in order to accomplish all three tasks one has only to determine the actual cost of service. In fact, the central theme in establishing fair, efficient, and reasonable 1) operation expenses, 2) rate bases, 3) rates of return, and 4) rate structures simply stated is the cost of service. But as previously noted in Chapters Three through Five, the hairsplitting occurs in trying to establish the method of evaluation one should use in determining actual cost. On this point there is anything but universal or even mild agreement upon techniques.

The two generic types of cost allocating methods for establishing the actual cost of producing electricity will be discussed in the next section of this chapter. Here we must still establish what implicit types of cost structures underlie the four different generic rate structures. In other words, if one is to establish a rate structure based on the cost of service

philosophy, then the type of rate structure (declining, increasing, flat or peak-load) will depend upon the type of cost structure the firm incurs when producing electricity for individual customers. If a utility customer is presented with a bill that exhibits a declining block demand/capacity charge and a declining block energy charge (and prices do in fact reflect cost), the utility is saying that the greater the amount of KW demand and the greater the amount of KWH usage, the cheaper it will be to service this particular customer. If a utility has a declining block rate structure (for all its customers, for demand/capacity cost, energy cost and customer cost), peak as well as off-peak, the assumption is that the utility is experiencing decreasing cost. In other words, with each new plant brought into existence the demand/capacity cost, energy cost and customer cost decrease per KW and per KWH of electricity generated.

Likewise, an inverted rate structure for a particular customer classification or for all customer classifications, respectively, would indicate that with greater amounts of KW demand as well as greater amounts of KWH usage the utility's production costs are increasing. A flat rate structure would indicate that as more electricity is produced costs per KW and per KWH are not increasing or decreasing but are remaining constant.

If a customer is presented with a bill that reflects charges substantially higher for electric energy used on-peak than for off-peak (a peak-load rate structure), the electric utility is signaling the customer that cost per KW and per KWH for

generating electricity varies substantially between peak and off-peak periods.

Another important fact needs to be made explicit. For a particular customer classification, demand/capacity cost may be increasing per KW of electricity, while at the same time energy cost per KWH and customer cost are decreasing. In this case if the customer's bill did not specify a separate demand/capacity charge, energy charge, and customer charge but lumped all three together, the bill could be of the declining block variety and probably is for a residential customer. This would indicate that the customer's cost per KW demand, while increasing, was more than offset by his/her decreasing customer and energy cost. What this all means is that increasing production cost in one phase of electric energy production may be more than offset by decreasing cost in another area. For example, fuel cost may be increasing, the cost of generating plants may be constant, and the cost of transmission and distribution systems may be decreasing, resulting in a constant cost industry. In any event, if one follows the cost of service principle, the rate structure cannot be predetermined. The relevant rate structure will be a consequence of accurately established cost. The question then becomes, as always, what techniques to use in attempting to track cost. To this we will now turn our attention.

COST ALLOCATION EVALUATION TECHNIQUES

There are two basic cost allocation techniques used by electric utilities in the United States. They are: the Fully Distributed Cost method and the Marginal Cost or Incremental Cost

method.

Fully Distributed Cost

In the Fully Distributed Cost (FDC) method the utility rate analyst attempts to apportion the total cost of service accurately among the various customer classifications and also to apportion the demand/capacity cost, energy cost, and customer cost within each customer classification. Energy cost can be apportioned among customers on the basis of actual consumption as registered by meters. Customer cost can likewise be accurately ascertained. Many customer costs, such as billing and metering, can be divided equally among all customers, because these kinds of customer cost do not change substantially with changes in consumption per KWH or per KW. But the rate analyst using the FDC approach does run into severe difficulty when he attempts to apportion demand/capacity cost. And in rate proceedings it is usually the allocation of demand/capacity cost around which major controversies take place.¹²

The difficulty in demand/capacity cost allocation is known as the Joint Cost problem. In essence Joint Costs are a common cost, which means they cannot be causally related to a particular customer class. Joint Cost does not change proportionately to changes in output per KWH or per KW, but decrease as output

¹²One must not conclude from these remarks that the demand/capacity cost allocation problem is the only important problem in cost allocation. For example, there is considerable controversy over what should be included in the customer cost category as well as in the demand/capacity cost category. In addition, fuel costs do not always vary proportionately with output, since peak generators are less efficient and use more fuel per KWH than non-peak generators.

increases. Common examples of joint costs include items such as capital cost (interest, dividends) and operating expenses (salaries, taxes). Whatever method is used to allocate these common costs, the conclusion remains simply a value judgment and of course value questions are arguable. In the last half century some 30 or so methods for allocating demand/capacity cost have been developed. In our discussion we will examine the three more prominent methods, the Peak Demand Responsibility Method (PDR), the Noncoincident Peak Demand Methods (NPD), and the Average and Excess Demand Methods (AED).

In the PDR approach a utility's demand/capacity cost are proportioned among customer classifications in proportion to each classification's percentage of the system peak. As illustrated using the data from FIGURE 1, page 129 demand/capacity cost would be allocated between Customers A, B and C in the following manner:

Peak Demand Responsibility Method

<u>Customers</u>	<u>Peak Maximum KW Demand</u>	<u>Percent of KW Demand by Class</u>	<u>Allocation of KW Plant Capacity</u>
A	1750	25.0%	2250
B	2250	32.1	2889
C	3000	42.9	3861
TOTAL	7000	100.0%	9000

First, compute the average maximum peak KW demand for each customer during the peak demand period. Second, determine each customer's percentage of the system peak and then multiply that percentage by the systems total capacity. Clearly, the major flaw in this approach is that any customer who does not consume electricity during a system's peaking period will not be allocated any capacity/demand cost, no matter how much electricity the customer uses during off-peak periods.

In the NPD approach a utility's demand/capacity cost are proportioned among customer classifications in proportion to each classification's maximum KW demand. For example, using the data from Figure 1, page 129, demand/capacity cost would be allocated between Customers A, B, and C as follows:

<u>Noncoincident Peak Demand Method</u>			
<u>Customers</u>	<u>Peak Maximum KW Demand</u>	<u>Percent of KW Demand by Class</u>	<u>Allocation of KW Plant Capacity</u>
A	2000	26.7%	2403
B	2500	33.3	2997
C	3000	40.0	3600
TOTAL	7500	100.0%	9000

First, ascertain the maximum KW demand for each customer whenever that maximum demand occurs peak or off-peak. Second, determine each customer's percentage of the combined maximum KW demand, and then multiply that percentage by the system's total capacity. The major flaw in this approach is that it does not in any way account for the actual time that individual customer classifications use the plant's facilities. One customer may have a maximum demand of 500 KW for only 1 hour, while another will have a maximum demand of 500 KW for 24 hours. In the NPD approach each would be apportioned the same demand/capacity cost. The PDR approach is subject to the same criticism.

By using the AED procedure the utility rate analyst is trying to avoid the flaws inherent in both the PDR and NPD methods. With the AED approach the utility rate analyst allocates a portion of the utility's demand/capacity cost to each customer on the basis of each customer's average KW load and allocates the remainder of the demand/capacity cost (the difference between

maximum KW load and average KW loads) by the noncoincident peak methodology. The AED method applied to our hypothetical utility in FIGURE 1, page 129, would yield these results:

<u>Average and Excess Demand Method</u>						
(1)	(2)	(3)	(4)	(5)	(6)	(7)
Customer	Customer Load Factor	Maximum KW Demand	Avg. Load Allocation	Excess Load	Excess Load Allocation	Total Allocation
A	62.5%	2000	1250	750	1178.4	2428.4
B	58.3	2500	1458	1042	1637.2	3095.2
C	72.2	3000	2166	834	1310.4	3476.4
Total		7500	4874	2626	4126	9000

First, determine the average KW load per customer classification. If the customer load factor is known this can be computed by multiplying each customer's maximum KW demand by his/her load factor (column 2 x 3). This will yield the actual Average KW load demand capacity/cost allocation to each customer, (column 4). Second, subtract each customer's average KW load from his/her maximum KW load (column 3 - 4). This yields each customer's excess peak load (column 5). Then multiply the ratio of the system's total excess load (4126, system capacity minus column 4) to its total excess peak load (2626, column 5) by each individual customer's excess peak load (column 5). This will yield the actual Excess load demand/capacity cost allocation, (column 6). For example, customer A's excess load allocation is $4126/2626 \times 750 = 1178.4$. Then add the average KW load and the excess load demand/capacity cost allocation, columns 4 and 6, to obtain each customer's total demand/cost allocation (column 7).

Of the three methods (PDR, NPD, and AED) most professional economists would consider the AED approach the most sound. This approach comes closer to tracing the actual demand/capacity cost

customer responsibilities since it takes off-peak usage into consideration. However all three methods are subject to criticism. First, stated simply, the whole argument is a tautology. The end in view of the rate analyst is to establish rates/prices based on actual cost. But the rate analyst uses cost data for computing prices/rates, cost data that was itself determined by previous prices. In other words, the rate specialist is allocating demand/capacity cost among customers in order to establish prices, but the individual customer's actual KW demand on system capacity is itself determined by the prices that the rate analyst previously set. In essence, costs are being presented to justify prices/rates and the costs were determined themselves by previous prices. At first blush this may seem reasonable but on closer examination it is erroneous as a rational economic justification for variations in prices among utility customers.¹³

The second major criticism of the FDC technique is that the utility's actual total capacity cost is based upon the historical average of all its capital expenses. In other words, the cost of building plants 20 or 40 years ago is averaged in with the cost of new plant capacity. Thus the actual cost of building new power plants is grossly underestimated. Then consumers are hit with large rate increases after new plants come on stream and actually begin producing electricity. Most professional economists for years have supported some form of Marginal Cost

¹³Clair Wilcox, Public Policies Toward Business, (Homewood, Illinois: Richard D. Irwin, Inc., 3rd ed., 1966), p. 346.

Pricing as the only valid economic principle for establishing actual cost. We will now turn our attention to this cost allocation technique.

Marginal Cost Pricing

The implicit assumption underlying the arguments in favor of some form of Marginal Cost (MC) pricing is that the competitive price system is the most efficient allocator of a society's resources. Of course the first academic champion of competitive capitalism was Adam Smith. Smith, the founding father of Classical Economics, provided the philosophical and economic arguments favoring competitive capitalism as a means of organizing economic activity in the book An Inquiry Into the Nature and Causes of the Wealth of Nations in 1776. A century later, Alfred Marshall and other neoclassical economists, notably W. Stanley Jevons and Leon Walras developed the analytical models that portrayed how cost and prices would tend to behave, given the existence of purely competitive market structures. Due to competition, firms are forced to operate at the minimum point on their average total cost curves, at the point where average total cost equals marginal cost. In addition, they would also set prices at this same point, due to competition, and thus price would also equal the firm's marginal cost. Since a firm's cost curves reflect the technical production conditions under which the industry operates, when operating at the minimum point on its average total cost curve the firm is also operating in the most technically efficient manner, which means that resources are being used efficiently.

In essence, firms operating under competitive market structure conditions would be led by Adam Smith's "invisible hand" to 1) marginal cost price, and 2) operate in a technically efficient manner. Professor Harold Hotelling was the first American economist to fully develop and advocate the use of the marginal cost pricing principle as the primary pricing criteria that regulatory commissions should adopt.¹⁴ The argument was straightforward: 1) if firms operating under competitive market structure conditions set prices at marginal cost, and 2) if regulatory agencies were interested in bringing about those conditions that naturally occur under competitive market structure conditions, then 3) regulatory commissions should require utilities to set rates/prices equal to marginal cost. In this brief discussion we will confine ourselves to examining the basic principles involved in marginal cost pricing including 1) definitional and cost/price relationships, 2) the case for and against Short Run Marginal cost price/ratemaking, and 3) the case for and against Long Run Marginal Cost price/ratemaking.

Marginal Cost Definitions and Cost/Price Relationships

Marginal cost refers to the increase in a firm's total production cost due to increased output. When a firm increases its output in the short run by increasing its utilization of existing facilities, we call the change in the firm's total production cost its Short Run Marginal Cost (SRMC). On the other

¹⁴Harold Hotelling, "The General Welfare in Relation to Problems of Taxation and of Railway and Utility Rates," Econometrics, 1938, pp. 242-269.

hand, when a firm increases its output by increasing plant capacity, either by addition to existing facilities or building entirely new facilities, changes in total production cost are called Long Run Marginal Cost (LRMC). Consider the following model:

FIGURE 2

Assume that the utility in this model was producing Q_1 kilowatts of electricity and charging the price P_1 per KWH. Now assume that as people get up in the morning they consume more electricity and demand Q_2 kilowatts of electricity. According to the marginal cost pricing rule the price for electricity consumed at 8 A.M. should be raised from P_1 to P_2 since the SRMC of producing electricity on-peak is greater than the SRMC or producing electricity off-peak. What cost does the utility incur in increasing output from Q_1 to Q_2 ? Since the utility did not build new facilities but merely expanded the rate of output of existing facilities, demand/capacity cost must have remained constant.

Basically, then, the difference in the MC per KWH of electricity in this example is due primarily to what economists call variable cost. Variable costs are those costs that change

substantially in direct relationship to changes in the rate of output. In electric utility economics, variable costs consist basically of customer and energy cost. Constant or fixed costs are those costs that do not change substantially with changes in output and in electric utility economics constant costs are analogous to demand/capacity cost. Why, then, does SRMC fluctuate so greatly in the electric utility industry?

First, electric utilities use their most efficient generators under normal operating conditions and hold their least efficient and obsolete generators in standby reserve. The average and marginal cost curves will turn up when the utility is forced to use these less efficient generators at on-peak periods. In essence, fuel cost per KWH greatly increases when using the older obsolete generators, causing MC to be substantially above average cost.

Second, a hallmark of the electric utility industry is excess plant capacity. In the above diagram the utility would be using its resources in the most efficient (optimum) manner by producing at Q_0 . Most of the time, however, utilities will produce to the left of Q_0 . The system load factor for electric utilities in the U.S. is generally in the neighborhood of 40 to 60 percent of actual plant capacity.

Implicit in the above analysis are several very important ideas that must be kept in the forefront when considering MC pricing or ratemaking.

First, MC pricing may lead to more efficient use of existing plant capacity. On the one hand, by setting prices very low

during traditional off-peak periods, one may stimulate a shift in consumption patterns. Lower prices per KWH for output to the left of Q_0 may stimulate consumption thereby creating movement toward a more optimum use of existing facilities. On the other hand, much higher prices per KWH for on-peak users does not cause a reduction in consumption, they will at least a) give users price signals to provide the information necessary for rational decision making and b) cause on-peak users to pay rates that actually reflect the cost of services.

Second, SRMC pricing will not necessarily lead to revenue collections which fall short of a utility's TR requirement. As shown in our example above, SRMC may be above, below or equal to a utility's average total cost. In essence, MC pricing is perfectly consistent with the total revenue requirement and cost of service objectives which most regulatory commissions state as primary considerations in rate structure design.

Finally, MC pricing will not necessarily lead to either a declining, increasing, or constant block rate structure. If rates accurately trace cost it is the actual cost conditions that will determine the form of the rate structure. If the electric utility industry is in fact a decreasing cost industry, i.e., if the cost per KW and per KWH decreases in both the short run with changes in the rate of output and in the long run as capacity expands (more plants are built), then MC pricing will lead to a declining block rate structure. But if the electric industry is in fact an increasing cost industry, i.e., if the cost per KW and per KWH increases in both the short run and the long run, then MC

pricing leads to an inverted rate structure. The shape of an industry's long run cost curve is the deciding cost factor underlying the form a rate structure will take that, in fact, accurately tracts cost. Thus in MC pricing it becomes very important to define "long run." For most practical purposes in rate design one can consider the long run to mean 5 to 10 years. It is common to speak of Long Run Incremental Cost (LRIC) ratemaking in order to differentiate the precise economic term of LRMC from what practitioners usually consider when computing cost changes incurred in changing plant capacity, or in building entirely new facilities.

In that sense LRIC cost is a future oriented pricing mechanism because it allocates the cost for additional plant capacity to those on-peak customers who will require additional capacity. In actual practice it is not difficult to forecast the incremental capital and operating expenses that can be expected to arise from building new production units. The crucial point is that in LRIC cost pricing those costs that were considered constant costs in the short run are, for LRIC ratemaking purposes, variable costs. We will now very briefly examine the arguments for and against SRMC pricing.

SRMC Pricing - Pro and Con

The primary arguments for SRMC pricing are 1) that it tends to lead to a more efficient use of existing plant capacity, and 2) that it accurately tracts cost. The primary arguments against SRMC pricing are 1) that prices which correspond to changes in MC would tend to fluctuate so severely as to make rational ratemaking

impossible and 2) that SRMC pricing would lead to chronic shortages in TR. As noted above, the latter argument concerning shortages in TR is not economically sound. Nonetheless, the hard core SRMC proponents would argue that in the name of economic efficiency, utilities should be mandated to MC pricing and if TR shortfalls result, utilities could be subsidized through special taxes. Likewise, they argue if TR collection exceeds TE and TOE requirements the excess TR can be taxed away. There are not many proponents of the SRMC ratemaking point of view in the United States, and proponents of the LRIC point of view are growing in number and influence, and have the weight of sound economic analysis solidly on their side. It is probable quite accurate to say that the overwhelming preponderance of economic opinion maintains that LRIC pricing is far superior for rate design than the fully distributed cost method.

LRIC Pricing - Pro and Con

The primary arguments advanced for LRIC pricing are usually 1) that it tends to lead to a more efficient allocation of resources and 2) that it more accurately reflects long run cost. The primary arguments advanced against LRIC are that it will not allow for sufficient TR collection and 2) implicitly, at least, that it is a drastic break from tradition and well understood practices.

The proponents of LRIC pricing argue that the most relevant costs are those costs that one can expect to prevail in the coming 4 or 5 years time span. As Professor Bonbright notes:

It is these long run, anticipated rates, when compared with anticipated prices for substitute products or services, on which individuals must rely in making rational decisions whether to install oil-heating or gas-heating furnaces; whether to buy gas ranges or electric ranges for the kitchen; whether to locate an aluminum-reduction plant near the source of hydroelectric power on the St. Lawrence River or to locate it instead near the source of low-cost steam-electric power in the Ohio Valley.¹⁵

In essence, then the proponents of SRMC pricing are more interested in the efficient use of existing plant capacity, while the proponents of LRIC pricing are more concerned with the future allocation of resources. For example, should families allocate money to insulate their homes or should they build on a new room? Insulation will cut down on the need for building more electric generating plants while the new room may cause increased demand for electricity. In order for the consumer to make a rational decision he/she must have proper price signals, so he/she can estimate cost accurately. Regarding the TR deficiency argument, in a recent study concerning the Madison Gas and Electric Company it was noted that:

Just as important as the recognition in Madison Gas of the wisdom of using LRIC as a basis for rate design was the finding that, 'on the facts of that case' if rates for each class of customer were set at LRIC, the revenue generated would be approximately equal to the revenue requirement of the company, which the commission found to be just and reasonable for the current test year using average or embedded accounting cost.¹⁶

¹⁵James C. Bonbright, Principles of Public Utility Rates, (New York: Columbia University Press, 1961), p. 333.

¹⁶Richard D. Cudahy and J. Robert Molko "Electric Peak-Load Pricing: Madison Gas and Beyond," Wisconsin Law Review, 1976, pp. 47-48.

Once again, then, pricing will not 1) necessarily lead to excesses in or deficiencies of TR or 2) necessarily lead to inverted, constant or declining block rates. Finally, as with the other chapters, a flow diagram is provided as a review and a learning aid.

CHART I

RATE STRUCTURE DESIGN

CHART I CONT'D.

:
CHAPTER:
SEVEN : CURRENT ISSUES
:

INTRODUCTION

The purpose of this chapter is to introduce readers to several issues which are currently receiving considerable attention by all parties involved in matters related to public utility regulation. The chapter is divided into six separate sections. Each section deals with a specific issue: Automatic Fuel Adjustment Clauses, Advertising, Taxes, Construction Work in Progress, Lifeline Rates, and Peak-Load Pricing. Discussion of each issue begins with introductory comments defining the issue and noting its importance to the consumers. The arguments generally offered both for and against each issue are then presented. For the most part, these discussions are descriptive in nature. The choice to either support or oppose a particular issue is left to the reader.

AUTOMATIC FUEL ADJUSTMENT CLAUSE

Introduction

Much of the discussion in the earlier chapters focused on the considerations of a regulatory commission in determining the appropriate structure and level of rates for a utility. Further, the discussions implied that any change in the structure or level of rates normally comes after a review of the possible change by the appropriate regulatory body. There are, however, some adjustments that can be made in rates without such a review;

adjustments that occur automatically. The authority of a utility to make such adjustments is generally included as a clause in the appropriate utility law(s). Such authority is called an Automatic Revenue Adjustment Clause.

The general purpose of such a clause is to "protect" the revenues of a utility during periods of rapid inflation. In the event that only one element of a utility's operation costs is increasing rapidly at a given time, an automatic adjustment clause can be adopted to allow the utility a rapid reimbursement for that particular cost. For example, as taxes rose rapidly during the early 1930's depression years in an attempt to keep the various levels and units of government solvent, automatic tax adjustment clauses were adopted to relieve some pressure from the utilities. The most prominent form of automatic revenue adjustment clause currently used by utilities is the fuel adjustment clause (FAC).

It should be noted that, while FAC's are currently receiving a great deal of public attention, such clauses have been in existence for many years. FAC's were first used during World War I. During that period, fuel costs increased rapidly and it was claimed that regulatory action to raise rates to match the rising costs were too slow.¹ In response to this situation FAC's were introduced.

According to the Paul Rodger's study on current issues in rate setting, "... by 1958, a majority of electric utilities had

¹Paul Rodgers, et al, Current Issues in Electric Utility Rate Setting, (Washington, D.C.: National Association of Regulatory Utility Commissioners, 1976) , p. 8.

adopted fuel clauses" It is further noted, however, that "... most clauses, ..., were limited to commercial and industrial customer classifications." This reminds us that something new has been added to the use of FAC's in the recent past -- residential customer rate classes. A study of FAC's conducted for the Environmental Action Foundation notes:

FPC data shows that in 1970, only 35% of the large investor-owned utilities have fuel adjustments in their residential rate schedules, but by 1974 this proportion had increased to 65%.²

In the wake of the fuel crisis facing the nation since the early 1970's, the fuel adjustment clause has caused considerable changes in the revenue responsibilities of electric utility customers and hence in the revenues of the utilities. Sandra Jerabek notes, "fuel adjustment charges made up only 6.1% of the total revenues collected by electric utilities in 1973." In 1974 the figure was over 8%. This represents a substantial increase in revenues, yet this increase was not necessarily subject to the scrutiny normally afforded an increase in revenues based on a request for rate increases. Is there a sound justification for such a policy?

The discussion which follows presents arguments both for and against FAC's and some considerations for alternative FAC schemes. The discussion is structured in this fashion to allow the reader to make informed choices about fuel adjustment clauses.

²Sandra Jerabek, A Citizen's Guide to the Fuel Adjustment Clause, (Washington, D.C.: Environmental Action Foundation, 1975), p. 3.

Before beginning a discussion of the pros and cons of FAC's, a caution is offered. While the presentation that follows speaks generally of FAC's, it should be remembered that there are many different techniques for calculating fuel costs for FAC purposes, and FAC's are handled by the various states' regulatory commissions in a variety of ways. Because of these differences, the consequences of the use of FAC's to consumers of electricity will vary. Some of the differences among states can be found for illustrative purposes in a 1974 Federal government study on FAC's:

A few commissions say they allow no FAC's in the tariffs of regulated utilities -- Minnesota, Oregon, Washington, Montana, Idaho. Still others don't regulate at all -- Nebraska and South Dakota. A number of states -- California, Florida, New Jersey, Wyoming -- say they do have fuel adjustment clauses but they are not automatic and hearings must be held.

Even in those states where FAC's are automatic, differences in their operation are to be found. Many have monthly commission reviews, some reviewing electric utilities only and some electric and gas utilities ... some give only REA electrics an automatic purchased power cost adjustment. One state (Connecticut) requires that hearings be held when the charges under FAC's reach 20% of the total monthly charges billed.³

Arguments for the Use of FAC's

Proponents of the Fuel Adjustment Clause concept cite several reasons why FAC's are a necessary regulatory tool. It is argued that FAC's are essential to assure that utilities remain financially healthy and stable. As noted earlier, fuel costs -- both oil and coal -- have risen considerably throughout the

³Douglas Jones and Susan Dovell, Electric and Gas Utility Rate and Fuel Adjustment Clause Increases, 1974, prepared for the Subcommittee on Intergovernmental Relations and the Subcommittee on Reports, Accounting and Management of the Senate Committee on Government Operations, (Washington, D.C.: U.S.G.P.O., 1975), p. 4.

1970's. Generally, the utility companies do not own significant shares (if they own any at all) of the oil and/or coal companies from which they purchase their fuels. The utilities have little control over the prices of these fossil fuels. If fuel costs begin to rise rapidly, as they have in the recent past, the utilities have to make adjustments in their operating revenue. Through the use of FAC's, a utility may adjust effective rates to recover the lost revenue stemming from the rising fuel costs. Such a revenue recovery allows a utility to achieve its targeted total earnings and hence its rate of return.

Were the companies not allowed to recoup such increased operation costs, total earnings would drop. Should total earnings decline, the rate of return to invested capital would decline. This situation could have an adverse effect on otherwise favorable bond ratings. It might become increasingly difficult to attract capital at reasonable rates to finance capacity expansion. (It is argued that capacity expansion might become necessary because, without the FAC and in the absence of an otherwise authorized rate increase, consumers would be receiving false pricing signals for the use of electricity, i.e., the prices would not reflect the high cost of fuel. Consumers buying electricity at artificially low rates might be led to increase consumption thus the need for expanded capacity.) In short, the utility's financial position could become unstable, affecting its ability to attract capital and to achieve a reasonable rate of return.

By law, utilities must supply the needs of their customers on demand. Firms not subject to government regulation have the

option to curtail output, if costs of production increase. Because utilities are mandated to meet the needs of their customers, this latter option is not available. The only way a utility can meet rising costs is by raising prices. Should a utility be required to apply for a rate increase and hearings be held, it might be 10 to 12 months before the increase is approved. This long delay, as noted in the preceding paragraph, could affect the financial health of the firm. The argument, then, is that since utilities do not have the option to cut back output in times of rapidly rising costs, they should be allowed to adjust prices accordingly.

It is thought that FAC's can also avoid the need to conduct a large number of otherwise unnecessary and expensive hearings. If fuel costs rise rapidly over a period of time it might become necessary, if hearings are required to review each rate adjustment, to conduct frequent hearings. The larger the number of regulated firms operating in a state, the greater the possible number of hearings necessary. The same principle holds in times of declining fuel costs. Rates will, under FAC's, be adjusted downward without the need for a hearing. Examples of the downward adjustment in rates are cited in the Paul Rodgers, et al, study for NARUC:

. . . . Certain residential customers received credits to their monthly bills through the FAC's. Appalachian's (Appalachian Power Company) customers had credits in 32 months and Wheeling Electric Company had credits in 41 months during the 1960's. VEPCO's (Virginia Electric Power Co.) efforts from 1960 through 1968 were successful in reducing fuel costs, indicated by the reduction in fossil fuel costs from 30.36¢ to 26.73¢ per

million BTU, which reductions were reflected in lower rates to VEPCO's customers.⁴

The question remains, for every such cost justified adjustment to rates, need a hearing be required?

Some proponents argue that FAC's are as defensible as current rate proposals, such as peak-load pricing, or time of day rates. They argue that under each of these rate schemes, electricity rates rise and fall as daily projected costs of production rise and fall. FAC's are to perform the same function -- keep rates at a level which reflects their cost of production.

Arguments Against the Use of FAC's

In opposition to the use of FAC's, opponents believe that all changes in rates should be subjected to review by an appropriate regulatory body in order to insure that electric rates are "just and reasonable." Without such a review, the opponents argue, there is little incentive for a utility to operate efficiently or to minimize fuel costs. Paul Rodgers quotes Senator Lee Metcalf as stating:

Thanks to the Fuel Adjustment Clause - better termed the 'Fool Adjustment Clause' -- the utilities do not in the manner of prudent businessmen engage in hard bargaining with the coal companies.⁵

Examples of abuses attributable to the lack of commission review are presented in the 1974 Federal government study of FAC's as follows:

. . . Coal from Appalachian Power's captive mine has

⁴Paul Rodgers, et al, Current Issues in Electric Utility Rate Setting, (Washington, D.C.: National Association of Regulatory Utility Commissioners, 1976), p. 10.

⁵Paul Rodgers, et al, Current Issues in Electric Utility Rate Setting, (Washington, D.C.: NARUC, 1976), p. 14.

been marked up in price for FAC purposes. The West Virginia Public Service Commission found that the utility, a subsidiary of American Electric Power, obtained more than \$2 million by this method during the first nine months of last year. In Connecticut an obsolescent efficiency factor in the fuel clause used by United Illuminating cost customers an estimated \$7 million annually.

Ohio Edison chose to buy high-priced spot market coal rather than enforce its contract with a supplier who had agreed to provide coal at a lesser cost. Transportation expenses, were found included in Virginia Electric and Power's fuel adjustment clause. The Peoples Council of the Maryland Public-Service Commission has charged that Potomac Electric and Power Company included 17 extraneous items, including executive salaries, in its fuel adjustment clause.⁶

It is thought that abuses such as these could have been detected and prohibited earlier than they were, had a regulatory body reviewed the rate-fuel cost situations of the various utilities.

Another complaint generally lodged against the use of FAC's deals with expansion. With increased public awareness for the need to research and develop alternatives to fossil fuels, opponents to the FAC argue that automatic rate adjustments due to rising fuel costs give utility management little incentive to explore the possible use of alternative energy sources, when planning new plant generating capacities. It seems only good business to make no changes in operating behavior, if the cost of doing business can be automatically passed on to users. Thus, if there are no costs to a utility for using a certain resource, the utility will likely continue to use that resource.

⁶Douglas Jones and Susan Dovell, Electric and Gas Utility Rate and Fuel Adjustment Clause Increases, 1974, prepared for the Subcommittee on Intergovernmental Relations and the Subcommittee on Reports, Accounting, and Management of the Committee on Government Operations of the U.S. Senate, (Washington, D.C. : U.S.G.P.O., 1975), p. VII.

Opponents say that FAC's work in favor of and are desired by the utilities during periods of inflation but work against the consumers in periods of deflation. During periods of deflation, FAC's should work to automatically decrease rates as fuel costs decline. Opponents contend that utilities challenge the use of FAC's during these latter periods. Sandra Jerabek writes:

...Some power companies have been successful in manipulating the fuel adjustment to serve their own purposes. According to Consumer Reports, when fuel prices declined during the mid- and late- '60's, some utilities were actually able to obtain permission from federal and state regulators to drop fuel clauses, only to reinstate them when prices began to soar in the early '70's. For example, the New England Power Company asked the Federal Power Commission for permission to drop its fuel adjustment in 1968, just before a switch from coal to oil which decreased fuel costs. The FPC gave its approval, while allowing a general rate reduction, in the face of opposition from affected municipal utilities who maintained that retaining the fuel adjustment would have reduced rates further by \$1.4 million. When fuel costs were increasing a few years later, the FPC allowed the company to reinstate a fuel clause.⁷

Such a use of FAC's violates the notion that rates should be just and equitable.

Some opponents argue that of the many different FAC designs, too many contain loopholes "...which allow utilities to collect more than actual increases in the cost of fuel."⁸ Some of the loopholes cited by Sandra Jerabek are related to cost accounting considerations, while others relate more to management estimates of the efficiency of generating facilities. These matters are best highlighted by presenting an example of an actual FAC

⁷ Sandra Jerabek, p. 5.

⁸ Sandra Jerabek, p. 5.

policy. The Public Utilities Commission of Ohio is chosen, because data regarding their FAC policy is readily available in the Paul Rodgers', et al, report on current issues in rate setting.⁹ (Inclusion of the Ohio PUC policies in a discussion of FAC loopholes does not mean necessarily that Ohio had adopted faulty FAC policies. Ohio's policies will be used simply to frame a general discussion about how FAC's are calculated.)

According to the Rodgers' study, the Ohio Commission's schematic for the "operating mechanics" of FAC's included the following six points:

"OPERATING MECHANICS" OF FAC POLICIES
OF THE PUBLIC UTILITIES COMMISSION OF OHIO

1. Basic Fuel Costs -- This component of the FAC calculation entails the establishment of the cost of fuel to the utility. The figure allowed in Ohio is that established in a utility's most recent rate proceeding.
2. Fuel Cost Adjustment Factor (FCAF) -- This factor is used to convert fuel cost figures into electricity production cost figures. Since electricity is billed on a per KWH used basis, changes in fuel cost must somehow be converted into changes in the cost per KWH of electricity produced to facilitate billing. The FCAF is designed to determine the change in KWH price which is attributable to changes in the cost of fuel.

To facilitate this conversion the cost increments of fuel upon which cost adjustments will be made must be established. Cost increments generally take the form of "cents per millions BTU's," to convert the cost/million BTU's to KWH terms, the utility's heat rate is used. (The heat rate defined is the number of BTU's of fuel required to produce one KWH of electricity. The heat rate, then, is affected by the quality of the fuel and the productive efficiency of a utility's generating facilities,) borrowing the numerical example from Rodgers, an FCAF is calculated from the following equation:

⁹Paul Rodgers, et al, Current Issues in Electric Utility Rate Setting, (Washington, D.C.: NARUC, 1976), pp. 21-27.

$$\text{FCAF} = \frac{\text{Fuel Cost}}{1,000,000 \text{ BTU's}} \times \text{Net Heat Rate}$$

ASSUME: The fuel cost increment is 0.1¢/1,000,000 BTU's
 AND: The net heat rate (NHR) is 10,000 BTU's/KWH

$$\text{THEN FCAF} = .001¢/\text{KWH} = \frac{(0.1)(10,000)}{1,000,000 \text{ (or one million)}}$$

Interpreted this means that for every .1¢ per million BTU change in the fuel cost, the price per KWH of electricity will change .001 cent.

3. Stipulations as to which electric power is subject to adjustment -- Typically all KWH of electricity sold are subject to the cost adjustment. In some instances utilities are allowed to impute a FCAF for purchased power.
4. Stipulation as to which fuel is to be used in calculating the adjustment -- The heat rate is measured based on the fuel actually consumed during a given period. The fuel used to measure the cost/ton includes both that actually consumed during the period and that in inventory.
5. Stipulation as to how the cost of fuel is to be determined -- In determining total cost for FAC purposes it is necessary to decide which factors are to be allowed. In Ohio the costs of fuel are limited to fuel costs FOB at the mine plus transportation costs. It is also possible to include the cost associated with the handling, unloading, and disposal of the fuel. It is also possible to use a weighted average of the fuel costs over the period in question.
6. Stipulation as to when charges incorporating the coal adjustments may be billed -- In Ohio, the fuel adjusted costs cannot be included in a consumer's bill until after the month in which the costs were calculated ends. Also, notification of new cost adjustments must be given the Commission for review before they can be included in the bills.

The effects of such an FAC can vary considerably, depending on the methods of determination of such things as fuel costs, heat rate, electricity sales included and excluded, fuel associated costs to be included and excluded, and the time at

which consumers' bills should reflect the increased fuel costs. Those persons wishing to read more detailed presentations of the issues should read both Sandra Jerabek's and Paul Rodgers' studies listed in the bibliography.

Possibilities for the Application of FAC's

After review of the pro's and con's of FAC's, there seem to be several options as regards positions one could advocate.

1. One possible position to advocate is the abolition of the use of fuel adjustment clauses. While this seems an extreme position to take, on February 20, 1975, the Public Service Commission of West Virginia issued the following order:

...The effectiveness of FAC's should be terminated as of midnight, March 31, 1975, and that FAC's be redesigned...and then held in abeyance for future emergency use, if at all.¹⁰

2. Another possibility is to have completely automatic fuel cost adjustments. Such automatic adjustments could be purely for delivered fuel costs or for fuel and associated costs.
3. A third option is to advocate FAC's which provide for automatic pass through of fuel costs with a scheduled commission review once those costs reached some predetermined and fixed percent of the utility's total monthly bill charges. For example, as noted earlier, Connecticut required hearings only when charges under the FAC's reached 20% of total bill charges.
4. A fourth option is to promote the use of FAC's but make any cost adjustments made thereunder subject to the review of the appropriate commission.

¹⁰Paul Rodgers, et al, Current Issues in Electric Utility Rate Setting, (Washington, D.C.: NARUC, 1976), p. 28.

ADVERTISING

INTRODUCTION

Two issues stand out in the controversy over advertising: 1) who should pay for it, and 2) whether it should be allowed in times of energy shortages. The second issue has been receiving considerable attention since the onset of the "Energy Crisis". Electric utility advertising practices are being questioned by consumer groups, members of the U.S. Congress, state legislators, regulatory commissions, and environmental groups. While this second issue is important, it will not be treated here. The first question, who should pay the cost, is the subject of this section.

Economic theory argues that advertising a product tends to shift the demand for that product upward, and make it more inelastic --- less sensitive to price changes. These two factors imply that consumption will increase at increased prices if the advertising is successful. Electric utilities engage in various types of advertising, and spend large amounts of money in the process. Furthermore, these advertising expenditures have been growing. From 1960 to 1970 Sales Expenses* by investor owned electric public utilities increased from \$171 million to \$306 million. These amounts do not include an additional expenditure of 5 to 7 percent (about \$22 million in 1970) for institutional advertising. (Institutional advertising is discussed in more

*Sales Expenses include sales promotion such as financial assistance to contractors, service and merchandising subsidies, guarantees of maximum utility bills, free repair service, and cash bonuses; plus advertising.

detail later in the current chapter.) Presumably these expenditures increase the demand for electricity.

TYPES OF ELECTRIC UTILITY ADVERTISING

There are two specific types of advertising practiced by electric utilities: promotional and institutional. They can be distinguished by the content of the message in the advertisement.

Promotional Advertising

This type of advertising is designed to retain or promote the use of electricity by consumers. It may be broken down into four categories: 1) ads which promote the use of electricity in space heating, 2) ads urging customers to use additional electrical appliances, 3) ads which describe the need for more power plants to provide for increasing demand, and 4) ads asking customers to conserve electricity during peak demand periods.

Space Heating

The Edison Electric Institute, a trade association of investor owned electric utilities, spends between \$2.5 and \$3 million annually on its space heating advertising program. A survey by "Electrical World" magazine indicates that this advertising has been relatively successful. The campaign has been responsible for nearly one-fourth of residential conversions from gas heating to electric heating. Another study shows that the number of homes heated electrically rose from 0.6 million in 1960 to 3.8 million in 1970. An estimated 11 million homes will be heated electrically by 1980. Of course, not all of this

increase is attributable to advertising. For example, in some states installation of gas heat in new homes is restricted by state regulation.

Electrical Appliances

While electric utilities are not directly interested in the products themselves, many advertisements promote the use of such electric appliances as dishwashers, stoves, refrigerators, freezers, and hot water heaters. When such appliances are purchased, electricity usage increases. This type of promotional advertising is often designed to encourage increased usage of already owned appliances as well. Some of these practices are 1) providing free, or at less than cost, wiring and appliances or equipment to building contractors, 2) financing the sale of appliances or equipment on more favorable terms than those generally applicable to sales by non-utility dealers, and 3) granting trade-in allowances on the purchase of appliances or equipment in excess of reasonable value.

Need For More Power

Both of the above types of advertising, which in many areas are being phased out, are designed to promote the use of electricity and hence increase demand. The third type aims at a different target. Here the goal is to persuade the general public of the urgent need to expand generating facilities. This expanded capacity is needed, so say the ads, in order to 1) prevent rationing which would deny consumers the power they want, 2) provide for a growing population, 3) help utilize new

technologies, 4) help clean up the environment, and 5) help implement recycling of resources. This "need for more power" advertising is directly and indirectly promotional. It directly promotes the use of more electricity and it indirectly promotes the substitution of "clean power" for polluting power.

Conservation

The final type of promotional advertising, conservation advertising, is aimed in the opposite direction. It promotes the use of less electricity. This type of advertising is aimed at two targets. First, it attempts to inform consumers of the reasons for and methods of conserving energy. For example, some ads provide instruction in the proper use of equipment and appliances which result in less electricity consumption. Others attempt to persuade consumers to turn off lights and other equipment when not in use and to turn down (or up) thermostats in order to use less energy in heating and cooling. Still others provide information on the benefits of home insulation.

Second, many electric utilities have begun advertising campaigns to educate consumers on peak load periods. These ads usually try to persuade people to use electricity during off-peak periods instead of peak periods. This, they stress, will allow more efficient operation of generating plants which will lower costs to consumers.

Institutional Advertising

Institutional advertising is designed to achieve interests that enhance the utility's ability to obtain a particular goal.

In general there are three types of institutional advertising: goodwill, political, and rate justification.

Goodwill Advertising

Goodwill advertising is designed to create or enhance the image of the utility company in the eyes of its customers and the general public. This type of advertising includes ads describing the company's role in public service: environmental cleanup and protection, and public work projects which improve economic conditions. The purpose of such advertising is to create an image of the company as an important and helpful citizen of the city, state, or nation.

Political Advertising

Political advertising is used by utility companies to influence public opinion regarding the election of public officials who are thought to be "friendly" to utilities' problems and goals. It is also used to influence the appointment of public officials, such as commissioners, who determine public policies affecting utilities. These expenditures are not campaign contributions, but rather general advertisements which support a specific issue or general policy. Sometimes political advertising takes the shape of attempting to influence public opinion concerning the adoption or repeal of legislation or propositions which affect public policy.

Rate Justification Advertising

This type of advertising is very specific. It is designed to promote the public's acceptance of rates proposed by the utility in rate cases. This advertising provides the utility's side of the case as to why the rates it has proposed are reasonable and fair. Generally, the rates are based upon the costs which the utility company incurs as well as trying to show why it should be allowed a specific rate of return on its rate base.

Issues

As mentioned at the beginning of this section, two issues are involved in advertising: 1) who should pay the cost, and 2) whether it should be allowed in times of shortage. The first issue is the one which will be dealt with in this section, although the second is indirectly involved. The issues will be discussed as they relate to each of the major types of advertising.

Promotional Advertising

On one side of the issue of who should pay for promotional advertising are the electric utility industry's investors and managers. Their argument is that promotional advertising is a legitimate expense incurred on behalf of consumers and therefore consumers should pay. The reasoning behind the argument is that advertising increases consumption, which in turn lowers costs, because additional production can be added at less than the average historical cost, thus lowering the per unit cost for all consumers. This argument may no longer be true. (See the Appendix to Chapter One.) They also argue that advertising which

provides consumers with information on peak loads, safety, and proper efficient use of appliances and equipment should be paid by consumers. This information is not without cost, and consumers directly benefit because they use less electricity and therefore pay lower utility bills.

On the other side of the issue are consumers and groups which represent the interest of consumers. Their argument is that promotional advertising designed to increase consumption leads to the need for more plants and equipment. These, they argue, cost more than existing equipment and thus raise prices to consumers. They insist that the true beneficiaries are investors and management, and since they are the beneficiaries, they should pay the cost.

It seems clear that the issue of payment for advertising concerns who should pay for the increased consumption which follows from advertising. If advertising lowers unit costs, it probably does so by allowing more efficient use of existing plant, rather than by creating greater demand which necessitates growth and hence more costly plant construction.

Consumers generally do not dispute that certain types of promotional advertising are to their benefit. These types are those which provide information on load factors, how to conserve energy, and how to utilize electricity to protect their health and safety. With respect to this type of advertising there does not appear to be an issue regarding who should pay the costs. Consumers should pay the reasonable cost involved in acquiring this information. However, there may be a question raised as to the most efficient way to acquire this type of information. It

may be that advertising is not well suited to conveying certain types of information on the reduction of consumption. Further, it may be that the utility company has a vested interest in conveying information which does not completely set forth the costs of reducing consumption.

Institutional Advertising

In the past utilities have been allowed to include institutional advertising in their operation expenses. This grew out of the practice of attempting to create conditions in regulated industries similar to those in unregulated industries. Of course communication via advertising was (and is) used in the unregulated industries and there did not then appear to be a strong reason for barring regulated industries from engaging in this practice.

However, today there is considerable interest in the use of institutional advertising by electric utilities and most consumer groups argue that it should not be allowed as a consumer expense. They argue that institutional advertising is used to promote the image of the company and to manipulate rather than serve the public interest. This manipulation may not be in the interest of consumers, and they may not wish to be involuntary contributors to a process that is not of their own choosing.

Consumers also say that most institutional advertising is designed to influence and control the electricity market, and that such market control benefits investors and management, not

consumers or the general welfare. Since they do not benefit from institutional advertising, consumers argue that they should not be held responsible for paying the cost.

TAXES

INTRODUCTION

Of, course, taxes are levied against all forms of business enterprise which operate to make a profit. As noted in Chapter Three, there are many types of taxes. In various ways taxes are levied against a company's sales, property, and income. These taxes are levied by all levels of government--Federal, state and local. In the area of public utility regulation, there is controversy regarding 1) The types of taxes that should be allowed to be accounted for as an operating expense and hence added to a utility's rates, 2) the amount of taxes, once accounted for in the rates, actually paid, and 3) the tax liability of stockholders for dividend income received from a utility company. Since most of these three areas of controversy are concerned with taxes on a utility company's income, the current discussion will be limited to income taxes only.

WHO PAYS INCOME TAXES

Income taxes are treated as a cost imbedded in electric rates and thus are directly borne by consumers. This is unlike non-regulated industries, whose income taxes are deducted from a company's net income before dividends are paid to stockholders. This feature provides utilities with a built in justification for rate increases -- as income tax liabilities increase, rates should be increased. Thus some argue that income taxes should not be directly borne by consumers, but by investors, as is the case in non-regulated industries. Investors and the courts argue that income taxes are a cost of providing service and as such should be borne by consumers. If taxes were borne by investors,

they say, it would decrease their rate of return and tend to discourage investment. This in turn would reduce the quality and quantity of service.

HOW MUCH INCOME TAX IS ACTUALLY PAID

The next part of the controversy involves the actual payment of these income taxes. A number of studies, mostly by the late Senator Lee Metcalf, have indicated that investor owned utilities actually pay less money in income tax than the revenues they are allowed to collect from consumers for this purpose. Senator Metcalf, in fact, on three separate occasions introduced a bill to the Senate designed to exempt investor owned utilities from income tax liabilities and impose an excise tax instead. The argument behind the bills was that investor owned utilities collect taxes at a tax rate of approximately 48 percent from consumers, and the utilities actually pay a substantially lower rate, the actual rate of income taxation on investor owned utilities has been declining since 1955, in that year income taxes amounted to about 15 percent of earnings. By 1975 this rate had declined to less than 2 percent. Senator Metcalf is quoted in the Congressional Record as saying:

Under the present system, the investor owned utilities, IOU's, have become taxkeepers, rather than taxpayers, the amount of money intended for Federal income taxes which is being kept by the IOU's is substantial, and is growing larger each year. At the end of 1974, the electric utilities were holding \$5.4 billion in unpaid Federal taxes which had been collected from customers. That was an increase of 23 percent over the \$4.4 billion which they had at the end of 1973.¹¹

¹¹Statement of Senator Lee Metcalf, U.S. Congressional Record, August 5, 1977, p. 1

An additional point to be made here is that tax avoidance, while legal, is costly. The "armies of accountants" necessary for a utility to find and exploit tax loopholes do not come cheap. And the cost of employing these accountants is of course paid by consumers.

The ability to avoid Federal income taxes is derived from two general sources: from a 1954 law allowing accelerated depreciation of new equipment, and from investment tax credits.

Accelerated depreciation has been discussed previously but it should be added that Federal tax codes provide that tax savings need not be passed along to consumers. By using normalized accounting the company can place these monies in an accumulated tax deferral account, which is used to finance new investment. Investors argue that this allows them to finance new investment without borrowing at high interest rates. Thus the customer is better off since they would have to pay the interest on the loans via rate increases.

Consumers argue that the tax deferral account amounts to an interest free loan which the company uses to invest in new plant and equipment. This equipment is then included in the rate base and consumers end up paying the return on their own money.

The use of investment tax credits began in 1962 and increased in 1971. Such tax credits allow public utilities (as well as other companies) to reduce their tax liabilities by investing in new plant and equipment. The purpose of these tax credits is to stimulate investment and increase employment. They may well have done this, but they have also had other effects. One of the

effects has been the creation of what Howard Morgan, former Federal Power Commissioner, called "phantom taxes".

The investment tax credit and accelerated depreciation combined help create these phantom taxes. Senator Metcalf's bill was aimed at these taxes. Some states, in light of this concern have now set up special prohibitions regarding these "tax collections" by utilities from consumers. The issue of phantom taxes is very important and consumers should be aware of the problems and pitfalls in this area. An excellent discussions of these types of taxes can be found in the December 1976 issues of "The Power Line," a publication of the Environmental Action Foundation.

STOCKHOLDER TAX LIABILITY

One other matter should be mentioned. It is usual for owners of all types of stock in U.S. corporations to pay taxes on dividends they receive. The current tax law, however, exempts from taxes the first 100 dollars of dividend income. If, however, a utility pays out more than its yearly profits as dividends (dividends can be paid from a company's retained earnings) then, for tax purposes, part of the dividend is treated as a return of capital to stockholders instead of as a dividend.

That part treated as a return of capital is exempt from the stockholder's tax. This means that not only is the utility collecting phantom taxes from consumers, it is then paying out part of that collection as tax-free income to investors.

CONSTRUCTION WORK IN PROGRESS

INTRODUCTION

A significant current regulatory issue is the appropriateness of an allowance for Construction Work in Progress (CWIP) in the rate base, versus an Allowance for Funds Used During Construction (AFUDC). CWIP is an allowance added to a utility's current rate base for the dollar amount of plant and equipment under construction but not yet placed in service. AFUDC is an allowance for the dollar amount of plant and equipment under construction when placed into service which is added to some future rate base. AFUDC also accounts for accumulated financing costs to the utility for carrying on such investments. Each of these affects the utility's rate base differently. CWIP increases the size of the rate base in current years, while AFUDC increases the rate base size in future years. Thus, consumers pay for construction now or pay for it later. In either case, the magnitude of the money involved necessitates that regulators account for and balance the interests of consumers and investors.

Utilities construct new facilities because, as population and living standards rise, they are required to expand capacity. Factors such as inflation, the use of more expensive technologies, and longer construction periods which generally entail cost over-runs, have caused both an absolute and relative increase in construction costs. The effect of these changes has been that both CWIP and AFUDC accounting allowances increased substantially during the seventies. The Federal Power Commission reports:

Until recent years, the construction period for new plant was fairly short, construction costs were low, and financial conditions were such that the accounting and rate-making question was more of academic interest than a matter of serious financial concern to utilities. In addition, until quite recently the amounts of money tied up in construction work in progress, and the proportion of income represented by AFUDC, were quite small. Considered as a proportion of net income available for common stock of electric utilities, AFUDC has risen from 3.9% in 1965 to 19.4% in 1970, to 28.2% in 1972 and 35% in 1974, before dipping slightly to 32% in 1975. As a proportion of net electric utility plant in service, CWIP rose from 6.3% in 1965-66 to 19.4% in 1973-74...¹²

Currently there are three problems related to a utility's responsibility to provide customers with sufficient plant and equipment to meet overall demands. First, there is a cash flow problem for utility companies. This is sometimes referred to as illiquidity, or shortage of cash. This problem can be highlighted by looking at the way in which financing of expansion has changed. For example, in the early sixties electric utilities financed about 40 percent of their funding for plant expansion through outside lending markets. Currently about two-thirds of plant expansion funding comes from such external sources.

The second problem stems from the fact that electric utilities have experienced difficulty in attracting outside capital. Because of rising interest rates throughout capital markets, utilities have been able to attract capital only at relatively high interest rates.

Lastly, electric utilities have experienced an erosion of

¹²Federal Power Commission, 10 FPA, 5-1136-37, p. 4

their earnings because of rapid inflation. This erosion has resulted in an inability to maintain the rates of return prescribed by their state commission. Such an inability to maintain rates of return may in itself become a justification for requesting further rate increases.

By altering the allowances for CWIP or AFUDC, whichever is used, commissions have aided utilities in their cash flow dilemmas. Herein lies the problem with which the remainder of this section is concerned- 1) should utilities be allowed to account for the cost of CWIP even though the plant and equipment are not yet in service? and 2) what is the appropriate amount of construction expense to be allowed at any given time? We will explore the arguments for and against the inclusion of CWIP in a utility's rate base.

ARGUMENTS FOR THE INCLUSION OF CWIP IN THE RATE BASE

The inclusion of CWIP in the rate base can and has been justified when it is clearly demonstrated that severe financial difficulties -- such as illegality, inability to finance capital needs, and inability to maintain authorized rates of return -- exist for the utility in question. As noted before, these problems are generally faced by the entire electric utility industry, since increased demands for power, inflationary pressures, and other factors may vary even within state jurisdictions; however, commissions treat each utility's financial cash flow problems individually. Accordingly, as a commission allows the amount of allowable CWIP to increase, the size of the rate base upon which an immediate return is earned is

increased, while cash flow and other financial difficulties are also relieved. Hence it is argued that some allowance for CWIP is valid, as a regulatory measure for enhancing the utility's cash flow. Both investors and management see CWIP as desirable.

Proponents argue that the allowance for CWIP in the rate base is consistent with the principle that only property which is "used and useful" should be included in the rate base. In addition, commissions have historically made allowances in rate base accounting for plant held for future use, fuel reserves, and other materials and supplies. While these allowances do not provide immediate service to the utility's customers, they do assure consumers that a utility's services will continue uninterrupted in the near future. Similarly, CWIP is seen to provide equivalent benefits of continued service.

Proponents of CWIP argue that the alternative, the Allowance for Funds Used During Construction Method, does nothing to increase the actual cash flow to the utility. Rather, AFUDC is considered inflexible and unable to account for the special needs of a particular utility, thus deterring investors. Opponents of AFUDC state further that there is substantial evidence indicating that the investors do not treat the accounting earnings attributable to AFUDC as the equivalent of actual cash income. It is said that this occurs because AFUDC, in a utility's accounting procedures, is treated as a credit to the income account, which results in total earnings being overstated. In areas where earnings are overstated, investors typically adjust the figures downward by the amount of "overstatement." When AFUDC is used, potential investors adjust the projected and past

earnings downward. These lower earnings figures are then used to justify demands on behalf of investors for higher interest rates. If these higher interest rate demands are not met, investors may shift resources away from the electric utility industry.

Proponents add that exclusion of CWIP from the rate base, coupled with investor discounts of AFUDC reported earnings, is creating a bias against investment in more capital intensive technologies such as nuclear power. Because these technologies are said to offer savings in operating and efficiency costs, it is claimed that consumers are forced to pay higher overall rates than might otherwise be the case.

Industry representatives note that the earlier cash flow pattern resulting from the inclusion of CWIP in the rate base lowers the need to seek external financing for new plant. In turn, it reduces the amount of capital costs. Thus, the stated results of the inclusion of CWIP are significant cost savings and therefore lower rates.

The Federal Energy Administration, now the U.S. Department of Energy, in supporting CWIP over AFUDC noted:

Assuming the same cost of capital under either regulatory procedure and a simple discount rate for utilities and consumers, the cost of new plant to the consumer in terms of present value is the same whether AFUDC is used or CWIP is included in the rate base. Since it appears that inclusion of CWIP would reduce the cost of capital to a utility, the cost to the consumer

would be lower where CWIP is included, both in absolute or present value analysis.¹³

ARGUMENTS AGAINST THE INCLUSION OF CWIP IN THE RATE BASE

All opponents to the inclusion of CWIP in the rate base point to the added burden CWIP places on all consumers. In recent years the Federal Power Commission, state commissions, consumers, and industry representatives have sought to quantify the impact of CWIP on consumers. Many of these studies were quite technical and are not specifically discussed here. Those wishing to review them in detail should obtain a copy of Paul Rodgers' Current Issues in Electric Utility Rate Setting, cited in the bibliography. Suffice it to say, a study performed by the Michigan regulatory commission indicated that, even in cases where the inclusion of CWIP in the rate base improved investor confidence so that utilities could finance capital expansion at much lower interest rates than would have otherwise been possible, consumers were generally better off without the inclusion of CWIP. In the words of the Michigan Commission, "The customer is 'better off' not paying plant costs during the construction phase of a plant's life."

The Federal Energy Regulatory Commission, (formerly the FPC), while aware of utility cash flow problems, still ruled that without clear demonstration of severe financial difficulty which

¹³Written Statement of the Federal Energy Administration, Docket No. RM-75-13, Roger Feldman, Deputy Assistant Administrator for Finance and Environment, Energy Resource Development, Federal Energy Administration, Washington, D.C., p. 10, as cited in Paul Rodgers, Current Issues in Electric Utility Rate Setting, Washington, D.C.: NARUC, 1976, p.73

cannot be alleviated without substantially increasing the cost of electricity to consumers, CWIP cannot be allowed in the rate base.

Opponents also state that the inclusion of CWIP is unfair to consumers under the principle of "used and useful." Including expenses for a plant not yet in service inevitably means that some customers will have to pay for plant and equipment but never use it. Those who are ill or elderly may die, and others may leave the service territory before the plant is placed in service. AFUDC, on the contrary, requires those who directly benefit through services actually rendered to pay for those services. Thus CWIP is seen as imposing an inappropriate burden upon many who might not otherwise receive any or all of the services paid for. Moreover, all other consumers are said to have lost the discretion to purchase other goods and services in lieu of future services from the utility. Thus, consumers directly or indirectly are said to be disenfranchised from their purchasing decisions in an otherwise free market.

Inclusion of CWIP is also said to distort the results of the regulatory process. Senator Metcalf noted, "Utility managements will no longer have any efficiency incentive to complete plant construction expeditiously. Investors will earn a return whether capital is invested productively or not."¹⁴ Any incentive to build plant and equipment also brings an incentive to increase sales, i.e., promote consumption in order to more fully utilize

¹⁴Statement of Senator Metcalf (D. Mont.) re FPC Docket NO. RM75-13, December 20, 1974, as cited in Paul Rodgers', et al, Current Issues In Electric Utility Rate Setting, Washington, D.C. NARUC, 1976, p. 83.

facilities. As facilities are built to meet this added consumption, capacity must again be increased. Thus, an allowance for CWIP is seen as reducing the scrutiny of utility construction policies by the regulatory commission. Wasteful consumption and building, as well as misallocation of financial resources into the industry and away from consumers, could result from this lack of commission review.

After a careful review of alternatives to the inclusion of CWIP, consumers tend increasingly to support those which address institutional factors.[†] Those alternatives are: the use of present capacity more⁶ efficiently; the adoption of conservation practices and programs by the utility and its customers; and the improvement of regulatory reporting and monitoring procedures in order to reduce regulatory lag. Thus, consumers are asking utilities, regulators, and themselves as well, to take the lead to hold down the costs imposed upon each other.

KEEPING THE RECORD STRAIGHT

Although some state commissions have permitted the general inclusion of CWIP where AFUDC is not capitalized, many other states hold that under the principle of "used and useful", a plant under construction does not provide present services to customers. In these cases the costs of work in progress may never be allowed. Most commissions, however, make some allowance based upon a demonstration of special need. In recent years many more states have adopted this case-by-case approach. Allowances made on this basis mitigate the blanket inclusion of CWIP into the rate base. Still, the FERC, which plays a dominant role in

influencing ratemaking practices at the state level, adheres to the traditional practice that CWIP be totally excluded from the rate base except where the utility is in severe financial distress.

Proponents' and opponents' arguments, and the mixed stance of regulatory commissions, suggest that the CWIP controversy will intensify in the years to come. Even in state jurisdictions where CWIP is prohibited, it may remain an issue: Federal regulators may eventually adopt the incremental approach to CWIP, placing renewed pressures on state jurisdictions to follow suit. Thus, consumers and commissions opposing an allowance for CWIP must be prepared to present both technical evidence supporting their arguments, and supporting financial evidence as to whether severe financial distress has been proven by those advocating an allowance for CWIP.

LIFELINE RATES

INTRODUCTION

One of the more talked about utility rate reform proposals is called Lifeline. Lifeline, simply defined, is an inverted rate structure thought to be designed to give relief to low and/or fixed income consumers in times of rapidly rising electricity costs. Because Lifeline rates, in the final analysis, are justified by proponents more on the basis of the social purpose they serve in providing relief to low income citizens than on the basis of economic cost, discussions about Lifeline tend to be shrouded in confusion and controversy. This presentation is designed to eliminate some of the confusion but not necessarily end the controversy. The decision to support or not support such a rate structure is left to the reader.

LIFELINE RATES DEFINED

As discussed in Chapter Six, the electricity rate structure or scheme most commonly used by utilities is called the declining block rate structure. An example of declining block structure is shown in FIGURE 1.

FIGURE 1

The typical rate structure advocated in Lifeline rate proposals is inverted. In other words, rates, rather than decreasing as KWH consumption increases, increase as KWH consumption increases. An example of a lifeline rate structure is presented in FIGURE 2.

FIGURE 2

In this example the KWH of electricity consumption allowed at the low lifeline rate of 4¢/KWH is 375. Electricity consumption in amounts over 375 KWH is billed at a rate of 6.0¢/KWH.

In the past few years many different Lifeline proposals have been offered throughout the country. The KWH block allowable at low Lifeline rates has ranged from a low of 200 KWH in some

proposals to a high of 700 KWH in others: the most typical allowable block is 300 KWH. Proposed rates have also varied, the lowest being 2¢/KWH, while other proposals leave the establishment of the rate to the discretion of the regulatory commission within the state wherein the proposal is being made.

Typical of the explanations of Lifeline is the testimony given by Dr. Eugene P. Coyle before the California House Commerce Committee's Energy and Power Subcommittee in April, 1976.

Dr. Coyle stated:

The idea of Lifeline is that the residential consumer should be able to purchase the basic necessities of modern life at a price that puts these within reach of all. Although a primary purpose of the Lifeline rate is to provide a service within the budget of the low-income people such as aged persons living on fixed incomes, the Lifeline rate should apply to all residential customers regardless of income.¹⁵

Mr. Robert H. Frank, testifying for the Chemung County Neighborhood Legal Services, Inc., of Elmira, New York, before the Public Service Commission of New York in May, 1976, stated:

All Lifeline proposals share the income redistributive objective of making available at low cost a volume of monthly electric service sufficient to meet some minimal consumption standard.¹⁶

THE LIFELINE CONTROVERSY

The controversy surrounding Lifeline rates has many facets but generally focuses on two major areas of concern:

¹⁵Eugene P. Coyle, Testimony before the Subcommittee on Energy and Power of the House Commerce Committee of California, April, 1976, p. 13.

¹⁶Robert H. Frank, Testimony before the Public Service Commission of New York, Case No. 26806, May, 1976, p. 3.

1. Lifeline provides for the sale of a fixed, low volume of electricity at a low rate with the idea in mind of subsidizing electricity consumption of low and/or fixed income citizens. The question often arises: are low income persons also low volume users of electricity? Some argue yes while others say no.
2. Traditionally rate structures have been established, at least for the most part, on economic cost bases, in this regard certain questions are raised about Lifeline: Are low Lifeline rates justified by low costs of service? If not, is the social purpose of income redistribution the only purpose served by such rates?

These two major areas of concern are discussed in more detail below.

Are The Low Income Citizens Also Low Volume Users?

As noted earlier, the general purpose of Lifeline rates is to grant relief to persons with low or fixed incomes in obtaining one of the necessities of life -- electricity. The target group for Lifeline is, of course, the low income citizen. The focus of the Lifeline program, however, is the low volume user. (The low Lifeline rate is assigned to the first block of KWH of electricity used.) A problem arises if low income citizens are not in fact low volume users of electricity. If they are not low volume users, they will receive little relief, since under Lifeline programs, artificially high rates are charged the higher volume users of electricity, to recoup the revenues lost from charging artificially low rates for the first block of KWH of electricity used. High volume users, then, would typically pay higher bills than they would without Lifeline rate structures.

This can be demonstrated by presenting an example of a Lifeline and a non-Lifeline rate situation from Dr. Coyle's testimony before a California House Subcommittee. In his testimony Dr. Coyle proposed the implementation of a two-part

rate for the residential customers of Pacific Gas & Electric (PG&E) -- a large California utility. His proposed Lifeline rate structure was comprised of a \$1.00 customer charge and energy charges of 2.0¢/KWH for the first 400 KWH and 2.9¢/KWH for all over 400 KWH.¹⁷ Customer bills based on Coyle's rates and the existing rates of PG&E are presented in the table below.

TABLE 1

COMPARISON OF PACIFIC GAS & ELECTRIC CO.
BILLS (1974) WITH A LIFELINE BILL
PROPOSAL OF DR. E. P. COYLE

Proposed	Usage	Present	E. P. Coyle's
	KWH	Bills	Lifeline Bills
	100	\$ 4.50	\$ 3.00
	200	6.80	5.00
	250	7.86	6.00
	300	8.91	7.00
	400	10.91	9.00
	500	12.91	11.90
	800	18.91	20.60
	1000	22.92	26.40
	1500	31.93	40.90
	3000	58.96	84.40

Source: Dr. Eugene Coyle, Testimony before the Energy and Power Subcommittee of the House Commerce Committee, April, 1976, p. 95.

As can be seen, once a user's KWH of electricity consumption exceeds 400 KWH, electric bills calculated from the Lifeline rate structure begin to rise rapidly. A low income user of 800 KWH would actually be penalized by this Lifeline rate structure. This situation highlights the concern for the relationship between volume used and income in Lifeline rate proposals.

¹⁷Eugene P. Coyle, Testimony before the California House Commerce Committee, April, 1976, p. 95.

There have been many studies made across the country related to the volume of electricity used by customers in various income classes. One might think that if studies are being made, their conclusions should end the controversy, by demonstrating that low income citizens either are or not low volume electricity users. This, however, has not happened. Moreover, various studies have led to varying conclusions. For example, Steve Mintz, when reporting on Lifeline rates for the FEA Office of Consumer Affairs, noted that a study done by Carolina Gas and Electric Company (CG&E) resulted in the conclusion that CG&E's lowest volume users were in fact the more affluent ones.¹⁸ Further, an executive of the Edison Electric Institute, reporting the sentiments of the Federal Energy Administration's (FEA) Electric Utilities Advisory Committee to the FEA stated "...there is a growing body of evidence which suggests that low income customers are frequently not minimal users of electric energy." Supporting this statement he cited the findings of a study of the customers of PG&E as follows:

1. Low income does not necessarily indicate low usage of electricity. The low income customer of electricity was found to be often a higher-than-average user.
2. There is no significant correlation between consumer income and usage of electricity.
3. Inverting the rate structure or flattening the rates would penalize rather than aid, low income customers who are dependent on electric heat.

¹⁸Steven Mintz, "The Lifeline Rate Concept," A report prepared for the Office of Consumer Affairs of the Federal Energy Administration, Washington, D.C., p. 12.

The committee's conclusion, drawn from their assessment of the PG&E customer study, was that "...the low income/low use hypothesis, frequently advanced in arguments for so-called 'lifeline rates' or conservation rates, is not supported by factual analysis."¹⁹

Study results such as those above highlight one point of controversy which leads to some of the confusion. For Lifeline programs to be successful in their purpose, do all low income consumers of a given utility's services have to benefit from the program. If not all, then how many? 60%? 80%? 90%? Some apparently believe, as is implied in the FEA Electric Utilities Advisory Committee's communication, that most low income consumers should benefit if the program is to be justified. (That is, if it can be justified at all.) An exact answer to the "how many" question is obviously judgmental. It is possible that some regulatory commissions would approve a Lifeline proposal wherein only 60% of the low volume users also had low income, while other regulatory commissions might decide that 90% of the identified low volume users should have low income. Resolution of this issue highlights part of the political aspect of the ratemaking process. What does seem to be absolutely necessary in determining the feasibility of instituting a Lifeline program in a particular area or city, however, is the performance of studies which determine such things as income and electricity consumption patterns. This is suggested because some studies performed

¹⁹A letter from W. Donham Crawford, Chairman, Electric Utilities Advisory Committee to the Federal Energy Administration to Mr. Frank Zarb, Administrator of the FEA, February 6, 1975.

over the past few years have indeed found a relationship between low income and low volume of use.

Steve Mintz, after noting the CG&E study results, discussed studies done by the Rand Corporation and Consolidated Edison Electric Company of New York. In these latter studies, Mintz indicated that low income households were found to be also low volume users.²⁰ Similar findings were presented in a study of residential customer usage patterns performed for the Pennsylvania Electric Company. The conclusions from this study are presented below:

The first conclusion drawn from the study is that the senior citizens and low income residential sub-groups of residential customers for the Penelec system are less than average users of electricity when compared with the over-all system. This would be true for both residential classes of service, those with and those without electric water heaters. The second conclusion relative to the special sub-groups of welfare recipients is that in the service classification without electric water heater, they too are less than an average user of electricity, whereas in the service classification with electric water heater their average use is approximately equivalent to Penelec's average use customer.²¹

Dr. Joe Pace, Vice President of the National Economic Research Associates, Inc. (NERA), made income and use volume studies in every state. His intention was to identify those states wherein Lifeline rates might work the best, i.e., where the greatest percent of low volume users were also low income. Dr. Pace concluded that if a

²⁰Steven Mintz, "The Lifeline Rate Concept", a report prepared for the Office of Consumer Affairs of the FEA, pp. 17-18.

²¹Paul Rodgers, et al, Current Issues in Electric Utility Rate Setting, a report prepared for the National Association of Regulatory Utility Commissioners, Washington, D.C., April, 1976, p. 148.

large portion of the low income users fit in one or more of the following categories, any proposed program should be seriously reviewed as to its possible success in relieving low income citizens.

- A. Low income persons or families whose electric bills are allocated to their rent payments from a landlord's master meter. Since Lifeline rates generally set their low rate with the first 300 KWH of electricity used, any multi-family dwelling which has one meter for all those living in the dwelling which totals all electricity used each month by all those families living in the dwelling will cause a problem since electricity consumption read from the meter will generally be quite a bit in excess of the Lifeline block.
- B. Low income persons or families who pay their own utility bill but have an electric water heater in their homes. A hot water heater alone consumes approximately 390 KWH per month. General home lighting consumes about 90 KWH per month. Just lighting and the hot water alone then can bring a person's consumption close to 500 KWH per month. To the extent that the person has additional appliances -- electric stove, refrigerator, etc. -- the usage will be potentially larger.
- C. Low income persons or families who pay their own utility bills but have and use electric space heaters. This situation is, particularly during the winter, similar to that discussed in "B" above.
- D. Low income persons or families who are farmers. It is thought that farmers generally are not low volume users of electricity.²²

Overall, what is suggested regarding the determination of the potential success of a Lifeline program is that each utility or utility consumer group will have to perform a study of the characteristics of the users of its utility's services. The relationship between income and electricity usage patterns depend

²²Joe D. Pace, "Lifeline Rates and Energy Stamps," a presentation to the National Economic Research Associates, Inc., New York, June, 1975.

on many things such as the number, type, age of appliances used typically within a given community, the typical size of families, general living patterns and habits, and climate. Each utility system has its own unique characteristics and trait.

Are Low Lifeline Rates Cost Justified?

If, after the performance of a study, it were found that the low volume users of a given system were predominantly low income citizens, would it then be appropriate to initiate a Lifeline program? Not necessarily. It might be necessary to determine whether or not some cost justification for having a low Lifeline rate and an inverted rate structure were present. Proponents of Lifeline have consistently argued that Lifeline is cost-justified. To a rate economist or engineer the notion of cost justification is tied to the concept of cost-of-service.

As was discussed in Chapter Six, utility rates are generally determined on the basis of cost-of-service. The cost-of-service considerations are associated with both the functional and causal elements of the cost structure of providing the services required by electricity consumers. To the Lifeline proponents the cost justification seems to stem from the excess revenue problem facing a utility which uses incremental costing methods to determine costs for ratemaking purposes. The Lifeline proponents generally first assume that a utility uses a marginal cost technique for the purpose of rate determination, and next, that rates based on such a technique will yield excess revenues to the utility.

Robert Frank, while testifying on Lifeline before the New York Public Service Commission stated:

...After a careful investigation of the issues involved in the design and implementation of a cost-based rate structure for the electric utility industry, I have concluded that a properly designed Lifeline proposal is not only in harmony with an incremental cost-based rate structure but is also virtually required by the internal consistency requirements of such a pricing mechanism.²³

Dr. Eugene Coyle in his testimony cited earlier stated:

Lifeline electric utility rates are a necessary part of a cost-justified, economically sound response to the energy/inflation crisis that has struck the nation's electric utilities.

.....
The discussion about Lifeline...ought to focus on the economics of the industry and the costs involved in serving customers. When viewed in this framework it turns out that Lifeline under today's conditions is justified on a cost basis...²⁴

Both Coyle and Frank go on to argue, however, that a Lifeline program (each proposed a slightly different type of Lifeline program in their testimony) will aid the regulatory commissions in coping with the problem of excess revenue. They claim that this problem stems from the fact that for ratemaking purposes, revenue requirements for a utility are generally determined on an embedded cost basis. In turn if the rates established to recoup the required revenue are determined on a marginal cost basis, an excess revenue will be generated. Hence the problem of redistribution. The redistribution of the excess can, according to Coyle, be handled by providing a low rate for residential customers in the initial energy rate block. This will yield what Frank calls a common Lifeline proposal. (Dr. Coyle's proposal

²³Robert Frank, Testimony before the Public Service Commission of New York, Case No. 26806, May, 1976, p. 7.

²⁴Eugene Coyle, Testimony before the Subcommittee on Energy and Power of the California House Commerce Committee, April, 1976, p.1.

was shown earlier in TABLE 1). Frank poses what he calls an alternative Lifeline proposal which provides for the distribution of the excess revenues in a lump sum of money. The lump sum will be given to all customers regardless of the amount of electricity consumed.

Now we can see that the Frank and Coyle notion of cost-justification, differs from that of most electric utility economists and engineers. It might be possible to justify Lifeline as one of many possible techniques for solving an excess revenue problem for utilities, should such exist. It confuses matters a bit, however, to say, simply because Lifeline might solve this latter problem, that Lifeline is therefore cost justified. One might more correctly say the Lifeline is possibly "excess revenue" justified.

There are other arguments both for and against Lifeline. For example, Coyle, Frank, Mintz and others argue that Lifeline rates, while they assist the poor, function as conservation rates as well. Since the rates under a Lifeline program are generally inverted, higher volumes of electricity consumption are discouraged by the higher tailend rates. A question remains, however, are conservation rates cost-justified?

As you can see, the controversy will go on for a long while. The most attempted here is to clarify a few points of confusion so the controversy can continue in a healthy fashion.

PEAK-LOAD TIME DIFFERENTIAL PRICING

Introduction

In rate structure design the average cost of producing a KW of electricity is usually computed by utilizing what is called the "Historical Embedded Cost" methodology. In this procedure the demand/ capacity cost for providing generation, transmission, and distribution facilities 20 or 30 years ago is averaged with current capacity cost. In turn demand/capacity costs are defined as those capital and operation expenses incurred by the utility on behalf of its customers, in order to provide sufficient capacity to meet their demands. The rate analyst then apportions these demand/capacity costs among the utility's nine or so customer classifications.

In essence, the historical embedded cost procedure leads to rate structures based on past customer decisions. What is clearly needed are price signals that accurately reflect future cost over the next several years. Rational consumers have no potential to use their rational faculties in allocating resources wisely unless they receive proper cost data. Economists advocate using the Long Run Incremental Cost (LRIC) method for computing demand/capacity cost, since LRIC more accurately tracts future capacity cost than the historically embedded cost approach. The following definitions should be kept clearly in mind when LRIC, or marginal cost (MC) pricing are being discussed:

Short Run - a time period sufficient to allow increases or decreases in output using existing capacity only, but not sufficient time to increase plant capacity, i.e., add on to a plant or build a new one.

Long Run - a time period sufficient to allow increases in existing plant capacity or to build a new plant.

Short Run Marginal Cost (SRMC) - A change in the total cost of production increased by a relatively small increase in output using existing plant capacity.

Long Run Marginal Cost (LRMC) - A change in the total cost of production incurred due to production increases from a change in plant capacity or from building a new plant.

Long Run Incremental Cost (LRIC) - A change in the total cost of production incurred by additions to existing plant capacity reasonably expected to be added over the next several years or from building new facilities reasonably expected to be built over the next several years.

In applying the LRIC procedure, "several years" is usually defined as 5 to 10 years. Rates derived from capacity cost based on the LRIC procedure represent a reasonable and practical approach to ascertaining actual demand/capacity cost customer responsibility. But once capacity costs are ascertained, one must still allocate these costs among the utility's customers. In other words, we have not yet considered the Rate Structure problem. In essence, the LRIC approach does provide better price signals to all of the utility's customers collectively but one must still determine the degree to which various customer classifications bear responsibility for the additions to capacity. Clearly the logic inherent in the LRIC approach is that the need for additional capacity is caused by on-peak users. Therefore, most LRIC proponents also advocate that only on-peak users should pay the additional demand/capacity cost incurred by the utility. Nonetheless after determining the relevant demand/capacity cost via the LRIC procedure, the rate analyst could proceed to use a method for assigning capacity cost to the various customer classifications that allocate demand/

capacity cost to both peak and off-peak users. In any event LRIC pricing is the practitioner's practical application of the theoretical LRMC procedure for determining the relevant demand/capacity cost which the rate analyst assigns to customers. As noted above, these capacity costs are usually allocated between nine or so different customer groups. For example, the residential classification may be allocated 40 percent while the commercial and industrial group would be allocated 30 percent and 20 percent of the additional demand/capacity cost. In other words, there is no differentiation between various customers within any given group. By combining Peak-Load/Time Differential (PLTD) pricing with the LRIC procedure one can actually measure each customer's maximum KW demand on a utility system's capacity.

Note, once again, that after determining each customer's actual maximum KW demand one must still decide how to actually assign capacity cost to each individual customer. In other words, are off-peak customers to be entirely free of any demand/capacity cost? Are capacity costs to be assigned only to peak users? Of course, most people who advocate PLTD pricing also advocate assigning demand/capacity cost only to on-peak users but there is nothing inherent in metering that precludes using cost allocation methods assigning capacity cost to both peak and off-peak users. A small but growing and influential number of economists, rate analysts and regulatory commissions are advocating PLTD pricing. We will now examine the principles underlying the PLTD procedure.

PRINCIPLES OF PLTD PRICING

There are seven basic principles underlying PLTD pricing:

- 1) Electric utilities should be run in an efficient and equitable manner.
- 2) The actual cost of service is the appropriate pricing criterion for achieving both equity and efficiency.
- 3) The actual cost of producing a KWH of electricity depends upon the time (of day, week, month and season) when it is produced.
- 4) The cost of producing a KWH of electricity varies substantially between peak and off-peak periods.
- 5) Demand/capacity costs are determined primarily by peak users.
- 6) Rates for peak users should reflect their responsibility for additional plant capacity, i.e., peak load users should have higher rates than off-peak users.
- 7) Electric rates should be a reflection of each individual's KW demands on the system, i.e., individuals should not be lumped into large groups.

The fundamental notion behind PLTD pricing is that by giving each individual consumer the proper price signal, consumers, especially on-peak users, may shift their consumption patterns which may 1) substantially reduce strains on system capacity, 2) cause present facilities to be used more efficiently, and 3) reduce the need for additional plant capacity without reducing the amount of KWH usage. In fact, in FIGURE 3, there is an example showing how a utility can increase its KWH production substantially yet not produce a strain on system capacity.

The utility in our example starts out with a system capacity of 8,000 KW, a 44 percent load factor, a maximum peak demand of 5,000 KW, a 75 percent utilization factor, and 64,000 KWH of electricity generated. Following Growth Pattern I, the utility

increases its load factor to 47 percent, and generates 92,000 KWH of electricity. But at this point maximum KW demand has grown to 8,000 KW, leaving the utility with no excess reserve capacity. The system, of course, would break down under such conditions and would be forced to reduce power to its customers while attempting to increase capacity as quickly as possible. In Growth Pattern I, system peak grew by 3,000 KW. Proponents of PLTD pricing advocate assigning all additional demand/capacity cost for additional production capacity to these on-peak customers. In addition they contend that if PLTD pricing had been in effect, that consumers might have shifted their consumption patterns, resulting in 1) more efficient use of existing facilities and 2) no new needs for additional capacity. For example, the utility could have followed a growth pattern in KWH production as shown in Growth Pattern II. In Growth Pattern II the utility also increased its KWH generation from 64,000 KWH to 92,000 KWH, but on-peak KW demand only increased from 5,000 KW to 6,000 KW, leaving the utility with a 25 percent excess capacity reserve at the time of maximum peak demand. The difference between Growth Pattern I and Growth Pattern II is that consumers shifted consumption or added it during off-peak time periods. Thus

FIGURE 3

IN THIS FIGURE THERE IS A HYPOTHETICAL UTILITY WITH 2 DISTINCT ALTERNATIVE GROWTH PATTERNS

LOAD FACTOR = 44%
 UTILIZATION FACTOR = 75%
 GENERATION = 64,000 KWH
 RESERVE = 27%

Utility A - Growth Pattern I

LOAD FACTOR = 47%
 UTILIZATION FACTOR = 100 %
 GENERATION = 92,000 KWH
 RESERVE = 0

Utility A - Growth Pattern II

LOAD FACTOR = 64%
 UTILIZATION FACTOR = 75%
 GENERATION = 92,000 KWH
 RESERVE = 25%

the system's load factor rose from 44 percent to 64 percent, indicating more efficient use of existing plant capacity. Would PLTD pricing actually cause a change in consumption patterns?

A recent British experiment did show significant improvement in average daily load factors for the time-differential rates. There was also some seasonal shift of usage. These indications are encouraging since they tend to demonstrate the feasibility of shifting demand between one time of day and another (and, to a far slighter extent, between one season and another). In response to price signals reflecting demand and energy cost.²⁵

Nonetheless, even if consumers had not shifted their consumption patterns, at least under PLTD pricing the on-peak users would bear the major demand/capacity cost responsibilities. A typical PLTD rate schedule may look as follows:

Hypothetical PLTD Rate Schedule

\$4 fixed charge per month

Summer:

5¢ per KWH	10 a.m. to 2 p.m.
2¢ per KWH	2 p.m. to 10 a.m.

Winter:

4¢ per KWH	9 a.m. to 1 a.m.
2¢ per KWH	5 p.m. to 7 p.m.
	1 p.m. to 5 p.m.
	7 p.m. to 9 a.m.

In the above rate schedule there are two time differentials. First, there is a seasonal time differentiation between winter and summer and second, there is a daily time differential between peak and off-peak time periods. Finally, PLTD is in no way to be

²⁵Richard D. Cudahy and J. Robert Molko, "Electric Peak-Load Pricing: "Madison Gas and Beyond," Wisconsin Law Review, 1976.

considered a social rate designed to subsidize a particular customer class, PLTD is the practitioner's attempt to SRMC price and is based fundamentally on the principle that prices which reflect the actual cost of services lead to both efficiency and equity in the production, distribution, and pricing of electricity.

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CHAPTER ONE

THE PUBLIC UTILITY CONCEPT: DEFINITIONS

Guilds - The Primary form of organizing production in medieval towns and cities. These organizations discouraged competition or profit-seeking and sought to impose general rules on the methods of production, rates of pay, practices of marketing, and so on.

Mercantilism - An economic system which regulated commerce and production in great detail, while, at the same time, supporting it. This economic system was prominent during the 17th, 18th, and 19th centuries in Europe.

Public Utility - A business or service which is engaged in regularly supplying the public with some commodity or service which it needs.

Joint-Stock Company - An early name for the business form from which evolved what is now called a corporation. Sometimes the "stock" of such a company was held jointly by the Crown and private individuals.

Police Power - The right of the States to force business to safeguard the health, safety, morals, and general welfare of its citizens.

Commerce Clause - A constitutional passage that gives Congress the right to regulate the processes through which trade is carried on.

Due Process - A course of legal proceedings according to those rules and principles which have been established in the United States system of jurisprudence for the enforcement and protection of private rights.

Common Law - A body of decisions handed down by the English Courts prior to 1650 in private litigations. These decisions embodied the customs and concepts that grew out of an agricultural and handicraft economy and formed the first judicial basis for the regulation of business in the United States.

Monopoly - A privilege or peculiar advantage vested in one or more persons or companies, consisting in the exclusive right (or power) to carry on a particular business or trade, manufacture a particular article, or control the sale of the whole supply of a particular commodity.

Affected With a Public Interest - The use of property in a manner to make it of public consequence, affecting the community at large. Such property is subject to control for the public good.

Variable Costs - Those expenditures which change or can be changed as output is increased or decreased.

Fixed Costs - Those expenditures that stay the same, cannot be changed, as output is increased or decreased in the short run.

Natural Monopoly - An industry in which maximum economic efficiency is obtained when one company produces, distributes, transmits, etc., all of the commodity or service in that industry.

Economies of Scale - Technological or pecuniary circumstances which cause long run average cost to decline as output from a single plant expands.

Verticle Integration - The existence of more than one stage of production under one business, corporate ownership, or management..

Demand Elasticity - a) price elasticity - an indicator of the effect of a change in price on the quantity demanded, b) income elasticity - an indicator of the effect of a change in consumer income on expenditures for a good or service at a given price. If consumers change their expenditures for a good or service more than proportionately to a change in income, demand is said to be elastic, if less than proportionately, demand is said to be inelastic.

Substitutability - The ability to change from one product to another without losing benefits.

Public Utility Demand - The rate at which electric energy is delivered to or by a system, part of a system, or a piece of equipment expressed in kilowatts, or other suitable unit at a given instant or averaged over any designated period of time.

Economic Demand - A schedule of the various amounts of a product that will be purchased at various prices.

Regulation - The means employed by government to control business. Compliance may be brought about by mere persuasion, by offering inducements, by threatening unfavorable publicity, and by ordering that the law be obeyed.

Certificate of Public Convenience and Necessity - A special permit, commonly issued by a state commission, which authorizes a utility to engage in business, construct facilities, or perform some other service. Such certificates are used to deliberately exclude competition from an area where better service is to be offered by monopolies. Certificates do not confer rights; they are issued as a privilege.

Ordinance - A provision passed by a city council which declares, commands or prohibits certain acts or practices within the city limits. A city law.

Statute - A provision enacted by a state or Federal legislature which declares, commands, or prohibits certain acts or practices within the jurisdiction of the legislative body. A state or Federal law.

Franchise - A special privilege conferred by government on an individual or corporation which grants the right to construct and operate facilities along a city's streets.

CHAPTER TWO
ANALYTICAL MODEL: DEFINITIONS

Customer Classes - Electric utility customers, usually classified as 1) residential, 2) commercial and light industry, 3) industrial, and 4) wholesale.

Rate Level (RL) - The actual dollar amount a utility is authorized to collect. The term may refer either to the aggregate dollars collected from all classes (total revenue requirement), or to the actual dollars collected from a particular customer class.

Total Revenue (TR) - The actual dollar amount a utility is authorized to collect.

Rate Structure (RS) - The actual distribution of the "total revenue requirement" among different customer classes, and the design of billing charges within each customer class.

Total Cost (TC) - The actual dollar amount a utility spends in order to maintain service to the public. The two basic components of total cost are total earnings and total operating cost.

Total Earnings (TE) - The actual dollar amount a utility is authorized to collect in order to pay the cost of invested capital, (interest on debt, stock dividends, and incidental capital expenses); $TE = ROR(RB)$

Rate Base (RB) - The dollar value established by a regulatory commission of a company's plant, equipment and intangible capital used and useful in serving the public, i.e., invested capital minus accrued depreciation. The rate base is often referred to as net capital investment or net utility plant; $RB = (GV - D)$

Rate of Return (ROR) - The ratio of total earnings to a specified rate base, expressed as a percentage; otherwise defined as the percent of the rate base the utility is allowed to collect, in dollars revenue, to pay the cost of invested capital.

Total Operating Expenses (TOE) - The cost of doing business (not including total earnings) primarily consisting of operating expenses, taxes and depreciation; $(TOE = OE + TX + AD)$

Operation Expenses (OE) - A group of expenses applicable to utility operations, composed primarily of salaries, advertising, litigation, public relations, income taxes, and net investment tax credit adjustments, as well as various services such as financial and engineering consultants.

Taxes (TX) - Payments made to governmental bodies consisting primarily of ad valorem, property, payroll, franchise, and gross revenue or gross receipt taxes.

Annual Depreciation (AD) - A yearly allowance that a utility is allowed to charge as an operating expense in order to build up a reserve cash balance so that property that becomes functionally obsolete, wears out or is consumed in public service can be replaced and service will not be impaired.

CHAPTER THREE
TOTAL OPERATING COST: DEFINITIONS

Operation Expenses (OE) - A group of costs incurred by a public utility composed of: production, transmission, distribution, customer accounting and collections, sales expenses, and administrative and general. These costs may be variously composed of: salaries, interest, rent, charitable contributions, and advertising.

Production Expenses - A group of expenses incurred in the generation of electricity. These include the cost of fuel for generators, salaries, repair and maintenance of generating equipment.

Transmission Expenses - A group of expenses incurred in the process of moving electricity from generating plants to distribution substations. These costs include repair and maintenance of lines, rent or right-of-way payments, and salaries.

Distribution Expenses - A group of costs incurred in the process of moving electricity from substations to consumers. These costs include salaries, customer accounting and collections, and repair and maintenance of distribution equipment.

Customer Accounting and Collection Expenses - These are the costs that are incurred due to billing customers and keeping track of all of the customers' records.

Sales Promotion Expenses - These are a group of expenses incurred due to: advertising, promotional practices, creating goodwill, and influencing the market.

Administration and General - A group of expenses incurred in the process of managing the utility's short and long run plans and day-to-day business.

Depreciation - (as defined by the National Association of Railroad and Utilities Commissioners) - "the expiration or consumption, in whole or in part, of the service life, capacity, or utility of property resulting from the action of one or more of the forces operating to bring about the retirement of such property from service". Physical depreciation is caused, through the passage of time, by forces such as wear and tear, rust, rot and decay. Functional depreciation may occur sooner: when facilities are rendered obsolete by innovation in technology, made inadequate by growth in demand, or condemned by changes in legal requirements. Depreciation may also result from contingencies. The specific accounting methods for estimating depreciation are found in Chapter Four.

Depreciation (Provision For) - Charges made against income to provide for distributing the cost of depreciable plant less estimated net salvage over the estimated useful life of the asset

(using mortality turnover or other appropriate methods) in such a way as to allocate it as equitably obtained from the use of facilities.

Annual Depreciation (AD) - A yearly allowance that a utility is allowed to charge as an operating expense in order to build up a reserve cash balance so that property that becomes functionally obsolete, wears out or is consumed in public service can be replaced and service is not impaired.

Income Taxes - Revenues paid to state and Federal government based upon the net profit (before income taxes) of a utility.

Federal Excise Tax - A tax levied upon certain commodities or services by the Federal government. These taxes are collected by the utility or business as specified amounts whenever a product or service is sold.

Taxes (TX) - Payments made to governmental bodies consisting primarily of ad valorem, property, payroll, franchise, and gross revenue or gross receipt taxes.

General Property Taxes - Revenues paid to state and local government based upon the assessed value of the tangible property of an economic unit.

Franchise Licenses - A permit granted as a privilege to an individual or corporation which grants the right to construct and operate facilities along a city's streets.

Holding Company - This usually means a corporation (parent company) that directly or indirectly owns a majority or all of the voting securities of one or more electric utility companies which are located in the same or contiguous states. The Securities and Exchange Commission defines a holding company as - "any company which . . . owns, controls . . . 10% or more of the outstanding voting securities of a public utility company."

Arms-Length Bargaining - A process of arriving at a price in which all the parties involved have their own best interest at stake.

Amortization - The gradual extinguishment of an amount in an account by pro-rating such amount over a predetermined period, such as the life of an asset or liability to which it applies, or the period during which it is anticipated the benefit will be realized.

Non-Recurring Expenses - Costs which a utility incurs on a one time basis or at widely spaced and irregular intervals. Such expenses are usually spread over a period of time by a commission rather than being expensed in just one year.

Salvage Value - The amount that fully depreciated plant and equipment can be sold for on the market.

Obsolescence - The outdating of equipment due to technological improvements.

Test Period (Test Year) - Any period (12 months) used by the regulatory commission as a basis for evaluating the rate base, depreciation, taxes, and operating expenses of the utility. It may be the most recent period, the most recent calendar year or some combination of past and future months.

CHAPTER FOUR
RATE BASE: DEFINITIONS

Rate Base (RB) - The dollar value as established by a regulatory commission of a company's plant, equipment, and intangible capital used and useful in serving the public, i.e., invested capital investment of net utility plant; $RB = (GV - D)$.

Test Year - Any 12-month period used by the regulatory commission as a basis for evaluating the rate base, depreciation, taxes and operating expenses of the utility. It may be the most recent period, the most recent calendar year or some combination of past and future months.

Physical Plant (Tangible and Reproducible) - All machinery, equipment and related costs necessary or valuable in the conduct of the utility's operation.

Incidental Construction Costs - Certain costs known as "overhead" incurred by a company. Included are cost of incorporation, legal, engineering, and administrative services, and interest, insurance, and taxes during construction.

Construction Work in Progress - An account in the books of the company which represents the total of funds expended for utility plants being constructed but not yet placed in service.

Intangibles - Organization, franchises and consents, patent rights, licenses, privileges, and other intangible property necessary or valuable in the conduct of the utility's operation and not specifically chargeable to any other account.

Land (Tangible and Non-reproducible) - The cost of land and land rights used in conjunction with the conduct of the utility's operation.

Used and Useful - That portion of the rate base in service which is necessary or valuable in the conduct of the utility's operation.

Book Value - Costs recorded on the company's books. The amount listed in the company's accounting records without deductions of related accumulated provisions for depreciation, amortization or other purposes.

Original Cost - The cost of such property to the person first devoting it to the public service.

Historical Costs - Construction and acquisition costs of an asset serving the public, including additions and betterments, less depreciation, which has become a "matter of history".

Prudent Investment - Historical cost less any amounts found to be dishonest or obviously wasteful.

Reproduction Cost - The cost of duplicating the existing plant and equipment at recent prices.

Fair Value Cost - A composite measure of determining cost which considers accrued depreciation on actual cost, reproduction cost new less depreciation, and other factors, each weighted according to their effect on value.

Replacement Cost - The cost of duplicating the old plant with the modern technology version.

Depreciation (as defined by the National Association of Railroad and Utilities Commissioners) - "The expiration or consumption, in whole or in part, of the service life, capacity, or utility of property resulting from the action of one or more of the forces operating to bring about the retirement of such property from service." Physical depreciation is caused by forces such as wear and tear, rust, rot, and decay. Functional depreciation may come sooner, when facilities are rendered obsolete by innovations in technology, made inadequate by growth in demand, or condemned by changes in legal requirements. Depreciation may also result from contingencies.

Depreciation (Provision For) - Charges made against income to distribute the cost of depreciable plant less estimated net salvage over the estimated useful life of the asset (using mortality turnover or other appropriate methods) in such a way as to allocate it as equitably obtained from the use of facilities.

Straight-Line Method - Under this method of computing provisions for depreciation, the cost of the asset less estimated salvage is allocated in equal amounts over the asset's estimated useful life.

Liberalized Methods - This refers to certain approved methods of computing depreciation allowance for Federal and/or state income tax purposes, applicable to plant additions with a useful life of three years or more. These methods permit relatively larger depreciation charges during the earlier years of the life of the property and relatively smaller charges during the later years, in contrast with the straight-line method, under which annual charges are the same for each year.

Sum-of-the-Years' Digits Method - One of the liberalized methods of computing depreciation deductions. Under this method the annual deduction is derived by multiplying the cost of the property less estimated net salvage, by the estimated number of years of service life remaining, and dividing the resultant product by the sum of all the digits corresponding to the total years of estimated service life. For a property with an assumed 25 year life the sum of the digits would be

25+24+23+22+ etc. --- +5+4+3+2+1 or 325. A simple way to compute this figure is to multiply the number of years by the number of years plus one and divide by 2, i.e. $(25 \times 26) \div 2 = 325$. The first year's full depreciation deduction would be 25/325ths; the second year's would be 24/325ths, etc., of the cost of the property.

Declining Balance Method - Another of the liberalized methods of computing depreciation deductions. Under this method, the depreciation rate is stated as a fixed percentage (up to twice the applicable straight-line rate) per year and the annual charge is derived by applying the rate to the net plant balance which is determined by subtracting the accumulated depreciation deduction of previous periods from the cost of the property. When the property of any vintage year is almost fully depreciated it is necessary to add to the reserve the small remaining amount required to bring the reserve up to 100% of the retirement value (Cost less salvage), otherwise depreciation charges would continue on in decreasingly smaller amounts to infinity.

CHAPTER FIVE
RATE OF RETURN: DEFINITIONS

Rate Base (RB) - The dollar value established by a regulatory commission of a company's plant, equipment and intangible capital used and useful in serving the public, i.e., invested capital minus accrued depreciation. The rate base is often referred to as net capital investment or net utility plant;
 $RB = (GV - D).$

Rate of Return (ROR) - The ratio of total earnings to a specified rate base, expressed as a percentage; otherwise defined as the percent of the rate base the utility is authorized to collect, in dollars, to pay the cost of net invested capital.

Total Earnings (TE) - The absolute dollar amount a utility is authorized to collect in order to pay the cost of invested capital (interest on debt, stock dividends and incidental capital expenses); $TE = ROR(RB).$

Net Earnings (NE) - The amount of absolute dollars available for return to common stockholders or to be retained as earned surplus. After paying dividends to common stockholders we get earned surplus.

Earned Surplus (ES) - A portion of the amount of absolute dollars available for return to common stockholders, but not actually distributed to them in the form of dividends. For rate-making purposes earned surplus is treated as a component of common stock.

Bonds (Mortgage) - Certificates of indebtedness representing long-term borrowing of capital funds, the terms of which contain an indenture pledging the property as security for the loan and providing for the appointment of a trustee to represent the bondholders. If the lien of the mortgage is limited to specific property owned at the time the mortgage was created and to replacements thereof, the mortgage is described as "closed." If the lien extends to additional bonds under the terms and provisions of the indenture, the mortgage is referred to as an "open-end" mortgage.

Long-Term Debt - Includes outstanding mortgage bonds, debentures, advances from associated companies, and notes which are due one year or more from date of issuance. The portion of such securities (inclusive of sinking fund requirements) that is due within one year from the date of the balance sheet is usually included in Current and Accrued Liabilities, but Long-Term Debt to be refinanced within one year should continue to be reported under Long-Term Debt.

Preferred Stock or Preferred Capital Stock - Capital Stock to which preferences or special rights attach particularly as to dividends and/or proceeds in liquidation.

Senior Capital - Bonds and Preferred Stocks. Senior Capital holders usually have a contractual agreement specifying the rate of interest or dividends to be paid and in the event of liquidation receive payment before common stockholders.

Common Stock - Represents the ownership in a corporation if there is no other special class of stock. Common stock and capital stock are synonymous terms. Common equity includes common stock, capital surplus, and accumulated retained earnings or earned surplus.

Junior Capital - Refers to common stocks or equity stockholders.

Capitalization - The total of Long-Term Debt, Preferred Stock and Common Stock Equity. For balance sheet presentation, several modifications are sometimes made: current maturities of Long-Term Debt are not included in the Capitalization section, but Short-Term Debt (with an original maturity of less than one year), which will be refinanced by Long-Term Debt is sometimes included. Capitalization does not mean nor is it equivalent to a utility's RB.

Capitalization Ratios - The percentages of Long-Term Debt, Preferred Stock, and Common Stock Equity (or their components) -- to Total Capitalization.

Financial Leverage - The ability of the firm to change the percentage of earnings available to common stockholders through a change in the capitalization structure. The "leverage ratio" is the ratio of total invested funds to common stocks. As this ratio increases so does the ROR to common stockholders.

Cost (Net) of Capital - The return asked, or being asked, by investors for the use of their money committed to investment in utility companies, expressed as percentages of the capital funds (debt, preferred stock, common equity).

CURRENT COST METHODOLOGIES

For Long-Term Debt - The contractual interest rate expressed as a percentage of the net proceeds, less estimated financing expenses, currently received from the sale of new issues of bonds of companies.

For Short-Term Debt - The contractual interest rate asked by financial institutions for short-term loans and by sellers of commercial paper on loans maturing in less than one year. The effective rate on short-term bank loans may be greater because of the requirement to maintain compensating balances.

For Preferred Stock - The contractual dividend rate expressed as a percentage of the new proceeds, less

estimated financing expenses, currently being received from the sale of new issues of preferred stock.

The current cost of capital for Long-Term Debt or Preferred Stock may also be computed by determining the current yield at market price plus an allowance for the cost of financing, including any discount necessary to distribute a large block of new securities.

For Common Stock - A mathematical computation, which varies as to its formula, of expected future earnings to the net proceeds received from the sale of common stock after deducting underwriters' commission, and other costs of issuance including pressure and allowance for underpricing in a rights offering -- or ratio of expected future earnings to current market price. Since many factors enter into estimating future earnings (e.g., territory served, regulatory climate, interest costs, growth prospects, management, etc.) the calculation cannot be measured precisely and can only be estimated on the basis of informed judgment.

Historical Cost Methodology - Capital cost rates at the time the securities were actually sold by the company, applicable for long-term debt and preferred stock. For common stock the historical cost is sometimes measured by the cost of the most recent issues.

Total Capital Cost Methodology - The overall, or total, cost of capital is measured by the sum of the cost of the individual components of capital (bonds, preferred and common stocks) weighted, by issues within a class and then by classes, according to their relative proportions of total capital.

Earnings/Price Ratio (E/P) - The annual earnings per share of common stock divided by the market price per share of common stock.

Price/Earnings Ratio (P/E) - The market price per share of common stock divided by the annual earnings per share of common stock.

CHAPTER SIX
RATE STRUCTURE DESIGN: DEFINITIONS

I. Customer (Electric) - A customer is an individual, firm, organization, or other electric utility which purchases electric service at one location under one rate classification, contract, or schedule. If service is supplied to a customer at more than one location, each location shall be counted as a separate customer unless the consumptions are combined before the bill is calculated.

A. Ultimate Customers - Those customers purchasing electricity for their own use and not for resale.

1) Residential - A customer, sales, and revenue classification covering electric energy supplied for residential (household) purposes. The classification of an individual customer's account when the use is both residential and commercial is based on principal use.

2) Commercial (Small Light and Power) - A customer, sales, and revenue classification covering energy supplied for commercial purposes, except energy supplied under special contracts or agreements or service classifications applicable only to municipalities, or division or agencies of Federal or state governments, or to railroads and railways.

3) Industrial (Large Light and Power) - A customer, sales, and revenue classification covering energy supplied for industrial purposes, except energy supplied under special contracts or agreements or service classifications applicable only to municipalities, or division or agencies of Federal or state governments, or to railroads and railways.

NOTE: Most companies classify customers as Commercial or Industrial using the standard industrial classification or predominant KWH use as yardsticks; others will classify as industrial all customers whose demands or annual use exceeds some specified limit. These limits are generally based on a utility's rate schedules.

4) Public Street and Highway Lighting - A customer, sales, and revenue classification covering electric energy supplied and services rendered for the purposes of lighting streets, highways, parks, and other public places, or for traffic or other signal service, for municipalities or other divisions or agencies of Federal or state governments.

5) Other Public Authorities - A customer, sales, and revenue classification covering electric energy

supplied to municipalities or divisions or agencies of Federal or state governments (as ultimate customers) under special contracts or agreements or service classifications applicable only to public authorities, except such items as are includable in the classifications public street and highway lighting, sales to railroads and railways, and sales for resale. Excludes Atomic Energy Commission sales, which are classified as industrial.

- 6) Interdepartmental Sales - Kilowatt hour sales of electric energy to other departments (gas, steam, water, etc.) and dollar value of such sales at tariff or other specified rates.
 - 7) Railroads and Railways - A customer, sales, and revenue classification covering electric energy supplied to railroads and interurban and street railways for general railway use, including the propulsion of cars or locomotives, where such energy is supplied under separate and distinct rate schedules.
- B. Sales for Resale - A customer, sales, and revenue classification covering electric energy supplied (except under interchange agreements) to other electric utilities or to public authorities for resale or distribution.
- 8) Investor Owned Electric Utilities - Those electric utilities organized as tax-paying businesses usually financed by the sale of securities in the free market, and whose properties are managed by representatives regularly elected by their shareholders. Investor owned electric utilities, which may be owned by an individual proprietor or a group of people, are usually corporations owned by the general public.
 - 9) Cooperatives (Cooperatively Owned Electric Utilities) - A group of persons who have organized a joint venture for the purpose of supplying electric energy to a specified area. Such ventures are generally exempt from the Federal Income Tax Laws. Most cooperatives have been financed by the Rural Electrification Administration.
 - (10) Municipally Owned Electric System - An electric utility system owned and/or operated by a municipality engaged in serving residential, commercial, and/or industrial customers, usually - but not always - within the boundaries of the municipality.

(11) Federal and State Electric Agencies

Generation Cost - Those capital and operating expenses incurred in the building a generating station that will transform other forms of energy into electric energy.

Transmission Cost - Those capital and operating expenses incurred in the process of transporting electric energy in bulk from a source or sources of supply to other principal parts of the system or to other utility systems.

Distribution Cost - Those capital and operating expenses incurred in the process of distributing electric energy from convenient points on the transmission or bulk power system to the customer.

Customer Cost - Those capital and operating expenses incurred by the utility in taking on another customer. Usually includes such cost as services and metering as well as accounting and sales promotion expenses.

Demand/Capacity Cost - The capital and operating expenses incurred by the utility on behalf of an individual customer in providing sufficient capacity (a large enough generation, transmission and distribution system) to meet the maximum demand of that customer on an as needed basis. Demand/Capacity cost is often used interchangeably with capacity cost. Demand/Capacity costs vary with the kilowatts (KW) of power demanded. These costs are usually charged to customers as \$ per KW.

Energy Cost - The operating expenses incurred by a utility on behalf of an individual customer in providing that customer with a kilowatt hour (KWH) of electric energy. Energy cost is used interchangeably with KWH cost. Energy costs vary directly with KWH usage and are primarily a fuel cost. These costs are usually charged to customers as ¢ per KWH.

Customer Cost - The capital and operating expenses incurred by the utility on behalf of an individual customer that relate primarily to the number and size (usage) of customers and do not vary significantly with the amount of energy used.

Load - The amount of electric power delivered at a given point.

Load Curve - The amount of electric power demanded plotted against a set period of time. Utilities compute daily, weekly, monthly and yearly load curves.

Peak Load - The maximum load in a stated period.

Load Factor - The ratio of the average load over a designated period to peak load occurring in that period.

Customer Load Factor - The ratio of a customer's average load to his/her maximum peak load.

Coincident Demand - Any demand for electricity that occurs simultaneously with any other demand for electricity.

Noncoincident Demand - The sum of all individual maximum demands for electricity regardless of the time of occurrence.

Diversity Factor - The ratio of the maximum demand of a system, or part of a system, to the installed capacity of the system, or part of the system under consideration.

Utilization Factor - The ratio of the maximum demand of a system, or part of a system, to the installed capacity of the system, or part of the system under consideration.

Meter Rates - Any method of pricing that is based solely on quantity. Meter rates make absolutely no price variations to customers based upon difference in demand/capacity cost variation and customer cost variations inherent in the actual generation, transmission and distribution of electricity. There are four basic types of meter rates - block, step, straight line and flat.

Block Meter Rates - A certain specified price per unit is charged for all or any part of a block of such units, and increased or reduced prices per unit are charged for all or any part of succeeding blocks or such units, with each such increased or reduced price per unit applying only to a particular block or portion thereof.

Step Meter Sales - A certain specified price per unit is charged for the entire consumption, the rate or price depending on the particular step within which the total consumption falls.

Straight-Line Meter Sales - The price charged per unit is constant, i.e., does not vary on account of an increase or decrease in the number of units.

Flat Meter Rates - The customer is charged a fixed amount per day or per month.

Demand Rates - Any method of pricing that results in price variations to and among customer based upon differences in usage, cost variations, demand/capacity cost variations, and customer cost variations inherent in the actual generation, transmission and distribution of electricity. There are four basic types of demand rates - Flat, Hopkinson, Three Part and Wright.

Flat Demand Rates - A charge for electric service based upon the customer's installation or energy-consuming devices. This is usually so much per watt, per kilowatt, or per horsepower, per month or per year. Sometimes this type of rate is

nominally so much per customer per year, or per month, for each of various classes of customers, but estimated demand and quantity of energy likely to be used play an important part in the determination of the class. Such a rate may be modified by the "Block" or "Step" methods.

Hopkinson Demand Rates - The method of charge which consists of a demand charge based upon demand (either estimated or measured) or connected load, plus an energy charge, based upon the quantity of energy used. Either the demand charge or the energy charge, or both, in a Hopkinson Demand Rate, may be of the block form.

Three Part or Three Charge Demand Rates - Any of the foregoing types of rates may be modified by the addition of a customer charge. When such a charge is introduced in the Hopkinson Demand Rate, it becomes a "Three Part Rate," or "Three Charge Rate," which consists of a charge per customer or per meter plus demand and energy charges. This rate may be expressed also in either the block or the step form.

Wright Demand Rates - That method of charge which was the first to recognize load factor conditions by inclusion of demand costs in an initial high rate per kilowatt hour, applicable to a certain number of hours use of a customer's load, all excess kilowatt hours being at a lower rate.

Rate Structures - The actual distribution of the total revenue requirement among different customer classes as well as the design of billing charges within each customer class. There are four basic rate structure designs: declining block rates, inverted block rates, peak-load rates and flat rates.

Declining Block Rate Structure - The pattern of unit charges within a customer class that assesses a lower unit charge as usage increases.

Inverted Block Rate Structure - The pattern of unit charges within a customer class that assesses a higher unit charge as usage increases.

Flattened Rate Structure - The pattern of unit charges that reduces or eliminates differential charges per unit of consumption based on quantity of usage.

Peak-Load Rate Structure - The pattern of unit charges that assesses higher prices of usage occurring at those peak periods when the utility is required to meet its maximum demands and lower prices to usage occurring at those off-peak periods when excess or idle capacity exist. Sometimes known as a "time of day" rate structure.

Marginal Cost - Marginal cost at any output level is the extra cost of producing one more unit of output. It is computed by subtracting total dollar cost of adjacent outputs.

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